carbon capture journal

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Oxyfuel for CCS - dispelling the myths

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CEFCO’s pilot plant

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Global CCS Institute carbon capture technology series

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Carbon Capture Journal
2nd Floor, 8 Baltic Street East, London EC1Y 0UP
www.carboncapturejournal.com
Tel +44 (0)207 017 3405
Fax +44 (0)207 251 9179

Editor
Keith Forward
editor@carboncapturejournal.com

Publisher
Karl Jeffery
jeffery@thedigitalship.com

Subscriptions
subs@carboncapturejournal.com

Advertising and Sponsorship
John Finder
Tel +44 (0)207 017 3413
jfinder@onlymedia.co.uk

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Front cover: Dioxy goes through a furnace where one carbon atom (the face) is combined with two small oxygen atoms (the ear muffs) to become carbon dioxide. From Kairòs Studio's animation 'The Arctic Adventures of Dioxy' for Longyearbyen CO2 Lab in Norway

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Clarifying oxyfuel combustion for CCS

Thomas Stringer, Director of R&D Execution at Alstom, dispels some of the myths surrounding oxy-fuel combustion carbon capture as applied to power generation in an interview with Martin Oettinger, Senior Adviser, Carbon Capture and Transportation (Power Generation), for the Global CCS Institute.

From a regulatory perspective, what might be the advantages and disadvantages of oxy-fuel compared to pre-combustion and post-combustion capture technologies?

Oxy-combustion does not present difficult side emissions in the vent gas. Moreover, despite a higher concentration (since vent gas does not contain the huge flow of N2 as in air-fired mode), the quantities released in terms of NOx and SOx are lower.

From a public awareness perspective, what is the level of understanding regarding oxy-fuel technology and its advantages and disadvantages compared to pre-combustion and post-combustion capture technologies?

Sometimes, oxy-combustion is seen as a complex technology versus post-combustion since it is believed that the boiler will be deeply modified with high oxygen (also seen as an 'explosive' media). This is a wrong perception which is extremely important to correct.

Oxy-combustion operation is very similar to conventional air-fired operation and it is developed from already known systems and processes. Air is replaced by a mixture of pure oxygen and re-circulated flue gas (not 100 per cent oxygen!) with properties similar to air.

The operation, similar to existing air-firing operation, was confirmed through pilot-scale continuous operation, some for more than three years. The start-up of all pilots was very smooth and all estimated performance was reached during the tests.

The large air separation units are already commercial for other applications and the gas processing unit is developed from existing concepts also used in other industries (ie : except the specific purification unit, similar systems will also be implemented for post-combustion).

Compared to post-combustion, oxy-combustion does not involve huge amounts of chemicals. The emission profile remains unchanged (even improved, in particular regarding NOx production).

What are the implications on achievable power plant ramp rate (for oxy-fuel power plants relative to conventional SCPF power plants)?

The new components of oxy-combustion process will not bring additional limitations to the load changes of the power plant compared to an air-firing mode.

Assessment of oxy-combustion cost of electricity versus other CCS options; how does it compare on costs?

Alstom has recently conducted a comprehensive cost study to compare oxy-combustion and post-combustion in different locations, based on an evaluation of the levelized cost of electricity under typical conditions. Main assumptions of this detailed CCS cost study are summarized below:

- The reference plant is based on a supercritical cycle, including further cycle improvement in the 2020 to 30 period.
- Size is 800 MWe net range for all cases evaluated, bituminous coal for Europe.
- CO2 transport and storage and storage considered on-shore in a saline aquifer.
- 90 per cent of the CO2 emitted is captured.

Current reference design work and cost analysis gave calibrated input for 2015, then learning corrections were applied through the 2015-30 period:

- performance improvement for the reference plants and the CCS capture systems; and
- cost reduction upon the market ramp-up.

The levelized cost of electricity is the theoretical constant electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial expenses, and the payment of a return to investors. No inflation/escalation was accounted.

The resulting costs of electricity for hard coal CCS (oxy and post-combustion) is presented in figure 1 below and is compared with a reference steam power plant without CCS (more detail about the assumptions are available within the article Cost assessment

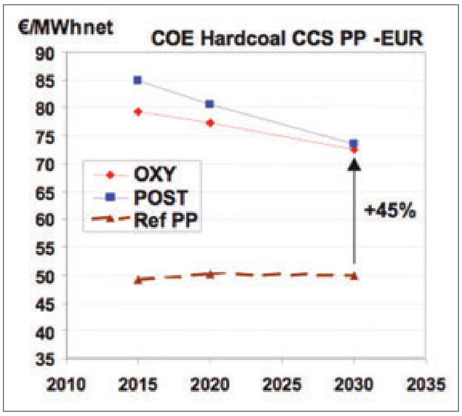


Figure 1 - Cost of electricity evolution without CO2 price - Europe - hardcoal - CCS oxy- and post-combustion

of fossil power plants equipped with CCS under typical scenarios presented at Power-gen Europe 2011). In that figure, no CO2 price is accounted.

The increase in costs of electricity for steam power plants equipped with CCS could be cut to about 45 per cent in Europe in 2030. Under the set of hypothesis taken for this study, oxy and post-combustion lead to close results, and obviously, considering the other key features of this technology development further detailed in this article, oxy should play a significant role in the deployment of CCS.

Then, specific site conditions will also have to be taken into account and may further create differences between the technologies with specific project and site conditions (cooling temperature, type of coal, etc).

In figure 1, we did not show any effect of the CO2 price in order to directly evaluate the 'incremental' effect of CCS as compared to today's case without CCS. Figure 2 includes the CO2 price effect for oxy-combustion. Also assumed is an evolution over time from approximately 20 EUR/t in 2015/2020 up to 70 EUR/t in 2030. The effect of this CO2 price on the resulting costs of electricity of the reference power plant (releasing 100 per cent of its CO2) can be seen to grow far higher than the oxy power plant costs of electricity (capturing 90 per cent of the CO2 emitted). For the case considered, a CO2 price of 40 €/t would offset the differential costs of electricity between the reference and oxy power plants.

Our sensitivity analysis also shows that the costs of electricity range of CCS power plants, inclusive of transport and storage and CO2 price variation, remains competitive as compared to other free carbon technologies (such as nuclear, hydro, wind on and off-shore and solar).

Is oxy-combustion eligible to retrofit?

Oxy-combustion is eligible to retrofit and to CCS-ready concepts.

Oxy-combustion is an adaptation of existing components or subsystems to a new application: most of the subsystems already exist. The test results from large pilot projects have further confirmed the robustness of the technology. Past experience indicates that it should be technically possible to convert a non-capture-ready plant to oxy-combustion; pending necessary land-space is available.

In such a case, the performance will not be as good as that of a new high efficiency plant with an optimized oxy-CCS solution, but that is a normal situation for retrofit scenarios and will be the case in a post-combustion solution as well. An example of this is the Total Lacq project, where an existing 50 year old boiler was retrofitted to oxy-combustion. All these are also key reasons to consider oxy-combustion for capture-ready power plants.

Is oxy-combustion a candidate to CCS-ready concepts?

As explained above, oxy-combustion is eligible to retrofit, and retrofitting an oxy-ready plant to oxy-combustion capability and CO2 capture is technically straightforward when considered during the initial design of the power plant. Moderate modifications to the power plant will be required for the future conversion to oxy-combustion if considered during the initial design phase.

Future boiler island modifications could include for example a new flue gas recirculation system, oxygen supply piping, oxygen heater, new CO2 product ductwork to the GPU and associated controls and instrumentation for the new systems.

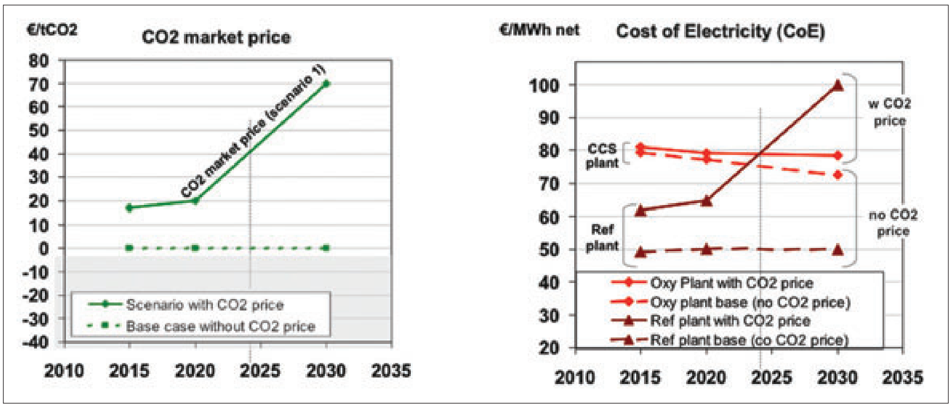


Figure 2 - Cost of electricity evolution with CO2 price - Europe - hardcoal - Oxy-combustion

Specific parameters of the oxy-boilers could be verified to ensure its future conversion and optimisation, however, pressure part replacement may not be required if considered initially. At initial design, necessary allowances may be also proposed to incorporate the future modifications, including those of the balance of plant to allow future heat integration or electrical systems additions, etc.

As per the legislation adopted by the European Parliament on 17 Dec. 2008, operators of new fossil-fuel power plants with capacity greater than 300 MWe shall assess the CCS-readiness of their new power plants. Adopted in April 2009 the directive is under implementation in the national laws by the Member States.

To design a capture ready solution, it is essential to have in-depth technical and economical knowledge of the capture system and of the power plant, and incorporate lessons learnt from pilots and demonstration projects. The new capture system must be highly integrated with the rest of the power plant. As explained earlier, for capture-effective power plants, this integration is one of the most critical parameters to optimize the cost and performance. The incremental pre-investments of the capture ready coal-fired power plants compared to a conventional plant should have a minor impact on plant cost and performance prior to the CCS conversion.

In summary, Alstom believe that CCS deployment with oxy-combustion technology will play a significant role in parallel to post-combustion technologies:

- it is a sound technology derived from existing processes; its robustness has been confirmed through several years of smooth operation of the oxy field pilots;
- it has great potential in terms of performance optimisation through integration;
- it is eligible to capture ready and it can address existing fleet;
- no significant modifications to the turbine island are required; and
- type and quantity of contaminant emission profile will be unchanged.

More information

This piece originally appeared as a blog on the Global CCS Institute website titled, "Clarifying oxy-fuel combustion: an interview with Thomas Stringer of Alstom."
www.globalccsinstitute.com

CO2-EOR as a 'soft start' for UK CCS

CO2-EOR has the potential to kick start a carbon storage industry in the UK, providing the incentive to invest in offshore oil fields and develop the infrastructure for transporting CO2, but there needs to be a push from government to get it going, said speakers at Finding Petroleum's London event.

CO2-EOR coupled with carbon storage in the UK North Sea is technically feasible but economically uncertain.

This was the view of the panel at a Finding Petroleum event in London, "Extending the life of the North Sea - building a CO2 utilisation and storage industry," where speakers discussed how CO2-EOR could be an enabler for CCS in the UK.

CO2 Enhanced Oil Recovery (EOR) involves injecting carbon dioxide into an oil field which would otherwise be nearing the end of it's useful life in order to push more oil out. It could be coupled with carbon storage so that the CO2 is left trapped in the reservoir when EOR operations have finished.

Although several tudies have been done in the UK, until now no projects have been started mainly due to the economic risks involved.

A Statoil study in 2007 looking at EOR in the Draugen field using CO2 from a proposed natural gas fired power plant also found that it was not economically viable in that case; the extra oil revenues did not make up for the downtime and cost associated with refitting the platform for CO2 injection.

Jim Lorsong

Jim Lorsong, Exploration and Production Director at 2Co Energy, looked at a scenario for economic CO2-EOR in the North Sea. He concluded that there were commercial opportunities, but some difficulties remain, particularly regulations relating to project hand-over at the end of production and the need for economic incentives to reduce risk for developers starting out on a project.

Extra oil revenues could offset the costs of storing CO2 and monitoring and verifying its containment, and there is the added benefit of possible re-use of infrastructure and delaying the costs of decommissioning for oil companies and the government.

One of the major problems is the large upfront investment needed for an offshore project. "A big issue is that it is much harder to do phased developments offshore," said Mr Lorsong. "Since 1979 people have been seriously considering doing CO2-EOR in the North Sea but no-one has ever done a pilot. It probably costs around half as much to do a pilot as a full development so you just have to pay your money and take your chances. So the first 'pilot' will be a full scale development."

"I firmly believe that as soon as somebody does this once it would open a floodgate."

Comparing to the U.S., about half of all the EOR projects in North America are not in shallow low permeability reservoirs but actually look quite similar to North Sea reservoirs. The reservoirs in the North Sea are typically of much better quality, so potentially would perfom better leading to a higher recovery factor than in the U.S.

They also typically have less wells offshore, because it would simply not have been economical to develop them otherwise, and this should help with containment at the storage stage.

"I firmly believe that as soon as somebody does this once it would open a floodgate."" - Jim Lorsong, Exploration and Production Director, 2Co Energy

He pointed out that it was a cheap source of CO2 that underpinned the onshore EOR industry in the U.S. and that the potential availability of large volumes of cheap CO2 would be a game changer for the UK market. "Up until now operators have had better choices," he continued, "you could drill for satellites, field extensions, or simply go to other basins, go and drill in Angola where profit margins are higher, so it hasn't been a very attractive proposition."

What is needed to make these project economically viable is some form of incentive through taxation, he said. Either through reduced petroleum revenue tax, or field allowances that would help to offset the capital cost early in the life of the project. "In my opinion, the revenue that you would accrue from a modest reduction in tax would greatly exceed any revenue lost in the short term."

Jon Gluyas

Jon Gluyas, Professor in CCS at Durham University, talked about two major components of the issue, capacity, injectivity and integrity in the North Sea and the opportunity for CO2-EOR to be a "soft start" for a CO2 storage industry in the UK.

He talked about the fantastic knowledge base available in the North Sea, with near complete 3D coverage of license areas

and 2D coverage elsewhere which would be of critical importance in understanding what happens to CO2 in the subsurface.

"Integrity of these sites is pre-eminent if we're going to be able to convince the general public, convince government to be able to put CO2 in the ground."

He mentioned ongoing research at Durham University into whether injection of CO2 would lead to fault systems moving or being lubricated, leading to flow of CO2 and potentially leakage.

Experience with EOR in Texas has led to an estimated one billion barrels of extra oil production over the last thirty years, he said. Applying this to the UK, if you take the low end of their observations, 5% additional recovery, this equates to around three billion barrels.

If you take industrial CO2 production from Scotland and the North of England, over a twenty year period you have around a billion tonnes of CO2 which is about the right volume to sustain EOR activity.

"We need to do it now. Our infrastructure is declining and will continue to decline. As more fields come offline the chances of doing this diminish, so let's get on with it."

The panel discussion, from left to right, Ian Phillips (Petrofac), Jim Lorsong (2Co Energy), Peter Fagiano (Altona), Jon Gluyas (University of Durham) and Gardiner Hill (moderator)

Getting projects going

Ian Phillips, Director, CO2 Infrastructure, Petrofac, said that when people talk about the need to demonstrate CO2-EOR it's a combined commercial and economic issue rather than a question of technical feasibility. Several organisations have to make large investments to get the value chain up and running, each of which are more or less dependent on the others for their revenue. If the power station operator has a problem with their capture plant then the storage operator has suddenly lost part of its revenue. "There's a big issue of the commercial relationship between the parties down the value chain."

""We need to do it now. Our infrastructure is declining and will continue to decline. As more fields come offline the chances of doing this diminish, so let's get on with it." - Jon Gluyas, Professor in CCS at Durham University

"Fundamentally there is still no reason why a power operator has to capture CO2. The EU tried to impose a tax with its CO2 allowance trading system, but at the moment it's a joke. The price is around €8 per tonne which is just an irritation and a bit of extra accounting for a power company, which is going to pass the cost onto the customer anyway."

"There is a lot of talk of incentives to get this going, but I think just as with something like acid rain, we have to say, 'You've got ten years to do this so get on with it.' There's an emissions performance standard in the legislation and if governments collectively impose emissions limits, initially for coal and then later gas, then nobody has any choice. As I heard from a power company executive, 'In that case we're all equally stuffed,' so it's a level playing field. But asking everyone to be nice and invest a billion and a half on a demonstration project just isn't going to happen."

"Well Ian has described a push, I would like a pull, although obviously we would both like both things," added Mr Lorsong. "I would like to see a tax incentive, so early adopters could see commercial returns on EOR projects. I believe that once a pipeline is established in the North Sea there will be an avalanche of projects only limited by the supply of CO2."

"It will not only be an attractive business but will create a demand for CO2 and move us towards a situation where CCS is driven by market forces rather that government feeling."

Government support

At a recent Westminster Energy Environment and Transport Forum, Adam Dawson, Chief Executive, Office of Carbon Capture & Storage, Department of Energy and Climate Change, gave an indication of the UK Government's position on CO2-EOR.

"When I look at CCS projects around the world almost all projects that are currently under construction or have taken FID are linked in some way or another with EOR," he said.

"In the UK there is the potential for EOR and there are people in this audience who will tell you all about it better than I can. I'm not judging whether it's feasible or not, but if it were, currently you can imagine you might pay £20 a tonne, say, to dispose of CO2. In the States they pay $20 a tonne to use CO2 for EOR. So if you can turn that round from a £20 cost to a £20 benefit, if you are emitting ¾ of a tonne for every megawatt hour you produce, you can do the maths and that works out about £30 a megawatt hour, you could take off the levelised cost, if EOR were to work. If we can show that EOR works or is a prospect for our programme, then that's something that could drive a direct cost reduction."

More information

Talks are from a Finding Petroleum event at the Geological Society in London, on January 18th, "Extending the life of the North Sea - building a CO2 utilisation and storage industry."

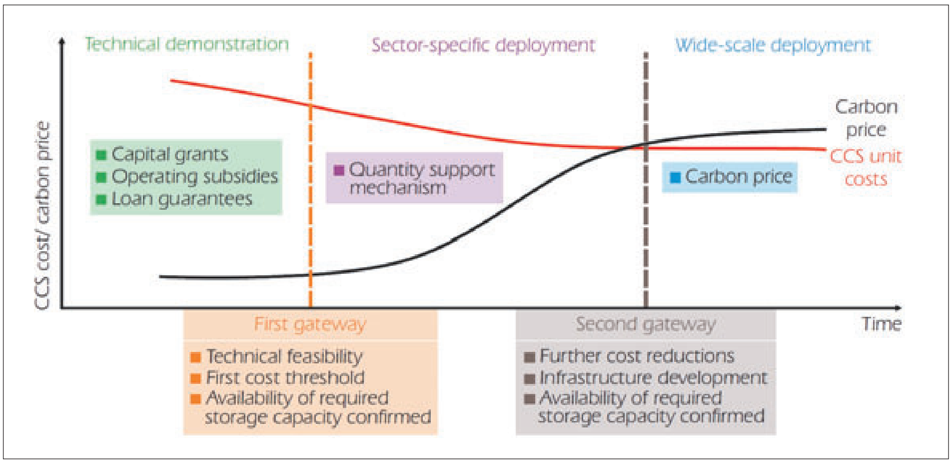
www.findingpetroleum.com

IEA releases CCS policy strategy

The free guide aims to assist those involved in designing national and international policy related to carbon capture and storage, setting out a series of gateways for developing policy.

Because of the uncertainty of CCS costs and performance and opportunities offered by other technologies, policy makers value flexibility in incentive policy. However, investors respond strongly to perceived levels of policy commitment. They are particularly sensitive to policy risk when assets (such as CCS) are long-lived and heavily dependent on policy support (Hamilton, 2009).

A potential solution is to set policy within a stable framework, so that the broad architecture and rules of policy evolution are certain. This may lead to lower costs of finance, greater research and development expenditure and more effective infrastructure planning and coordination.



Possible gateways within a CCS policy framework

Benefits to firms and government

Within a stable framework, breakpoints or "policy gateways" can provide the flexibility required. They comprise three components:

- the criteria defining when or if policy moves to the next stage;
- the policies within each stage; and
- an outline of how government will react if gateways are missed

Gateways can be used to link commitment of government and private resources to achieving certain targets (such as performance thresholds). This allows government to commit funds without the risk of overstretching its resources or imposing poor value-for-money obligations on others. In a scenario in which learning benefits turn out to be small, for instance, policy gateways would allow for cost control without reneging on earlier assurances. For firms, this greater policy commitment may reduce policy risk and ease financing costs by reducing the risk of asset stranding.

How gateways work

Many different types of gateways could be put in place within a CCS policy framework (Figure 4). In a first policy phase, for example, public capital grants and operating subsidies deliver a sufficient number of projects to test efficacy of the technology.

Structures are set up to ensure collaboration and knowledge sharing between the parties to maximise learning benefits. After an initial operating period of some years, policy might switch to the next phase, provided that certain criteria have been met, probably relating to technological efficacy or the development of commercially competitive uses for CO2 in the local market.

A second phase could be a period of larger scale deployment where wider deployment is tried in at least one sector, even if CCS costs cannot be covered by a carbon price alone. Widespread deployment, even in one sector, is unlikely to be feasible through public grants, so the emphasis would switch to private financing with implicit subsidies.

These subsidies could take the form of some kind of quantity commitment, either made by government (such as CO2 contracts) or imposed on the private sector (such as portfolio standards). Such quantity commitment could help fuel the development of commercial uses by guaranteeing a low-cost supply of CO2.

Without international co-ordination, such subsidy-based policy would be difficult in sectors that are significantly trade exposed, but it would reduce risk for investors and provide the supply chain with confidence about magnitude and timing of investments – overcoming some of the key risks faced by these players. Policy would evolve beyond this phase only if CCS costs fall below a predefined threshold.

During the second phase, the policy might extend to infrastructure, setting out arrangements for network development and storage. It might establish codes of practice, liability regimes, rights of access and franchises, as well as commercial arrangements and protections against the failure of Page | 13 the network or storage operator.

If CCS technology becomes fully proven at commercial scale, and the supply chain matures, then a third phase could follow in which CCS is stimulated by a price instrument wherever it is a cost-effective solution. This might be achieved through a stable economy-wide carbon price, but narrower, sectoral approaches might also be used. In this phase, long-term planning of infrastructure development might be appropriate, to build greater interconnection and resilience.

What happens if the criteria are not satisfied? If the first gateway is missed, then government may wish to reallocate public support to other technologies that show more promise. If the scaleup proves unsuccessful and the second gateway is missed, the government could continue with a moderate carbon price, accepting that it may not lead to CCS deployment, if alternative technologies are coming forward. In the event that other technology options are not available, there will need to be a continued focus on CCS development even in the face of higher-than-expected costs. This might be pursued by continuing CCS-specific support measures.

More information

Download the full report at:
www.iea.org

Global CCS Institute technology series

The Global CCS Institute is publishing a series of reports that provide a greater level of detail on CCS technology options, with a focus mainly on the power industry. The reports have been developed by the Electric Power Research Institute (EPRI) for the Institute.

The reports are divided by technology (post-combustion, pre-combustion, and oxy-combustion) with an overview report that provides a very useful comparison of technologies, summarised below.

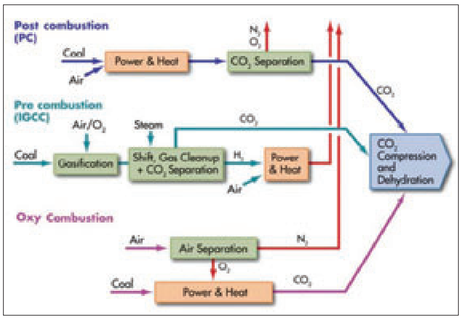
Advantages and disadvantages of major CO2 capture technologies

Post combustion capture advantages

- Can be retrofitted to existing plants allowing the continued operation of valuable resources
- In either new build or retrofit application it enables the continued deployment of the well established Pulverized Coal (PC) technology familiar to power industries worldwide
- The continued development of improved materials for Ultra Supercritical (USC) plants will increase the efficiency and reduce the CO2 emissions of future PC plants
- The widespread R&D on improved sorbents and capture equipment should reduce the energy penalty of PCC capture
- Sub-scale demonstration of PCC is proceeding. The 110 MW Boundary Dam project of Saskatchewan Power with PCC using the Cansolv process is under construction with planned operation in 2014.

Post combustion capture challenges

- Amine processes are commercially available at relatively small scale and considerable re-engineering and scale-up is needed
- The addition of capture with current amine technologies results in a loss of net power output of about 30% and a reduction of about 11 percentage points in efficiency. In the case of retrofit this would imply the need for replacement power to make up for the loss.
- Most sorbents need very pure flue gas to minimize sorbent usage and cost. Typically < 10 ppmv or as low as 1 ppmv of SO2 plus NO2 is required depending on the particular sorbent
- Steam extraction for solvent regeneration reduces flow to low-pressure turbine with significant operational impact on its efficiency and turn down capability.
- Water use is increased significantly with the addition of PCC particularly for water cooled plants where the water consumption with capture is nearly doubled per net MWh. For air cooling the water consumption is also increased with capture by about 35% per net MWh.
- Plot space requirements are significant. The back-end at existing plants is often already crowded by other emission control equipment. Extra costs may be required to accommodate PCC at some more remote location.



Technical Options for CO2 Capture from Coal Power Plants

Pre combustion capture advantages

- Pre combustion capture using the water-gas shift reaction and removal of the CO2 with AGR processes is commercially practiced worldwide.
- Pre combustion capture of the CO2 under pressure incurs less of an energy penalty (~20%) than current PCC technology (~30%) at 90% CO2 capture.
- Ongoing R&D on improved CO shift catalysts, higher temperature gas clean up and membrane separation technology for hydrogen and CO2 has the potential to produce a step-change reduction in the energy penalty of capture
- Water use, while still substantial, is lower than with PCC
- The ongoing continued development of larger more efficient gas turbines can markedly improve the efficiency of future IGCC plants
- The Kemper County plant in Mississippi, an IGCC plant with pre combustion capture, is under construction with planned operation in 2014.

Pre combustion capture challenges

- While the energy loss with addition of pre-combustion capture is lower than with the addition of PCC the energy loss is still significant
- The commercial demonstration of large F or G gas turbines firing hydrogen has yet to be demonstrated in an IGCC plant with capture
- In the event of a need to vent the CO2 additional purification may be needed
- IGCC is not yet very widely used in the power industry
- The capital costs of IGCC without capture are much higher than SCPC without capture. The IGCC costs need to be reduced to compete more effectively.

Oxy combustion advantages

- Oxy-combustion power plants should be able to deploy conventional, well-developed, high efficiency steam cycles without the need to remove significant quantities of steam from the cycle for CO2 capture.
- The added process equipment consists largely of rotating equipment and heat exchangers; equipment familiar to power plant owners and operators. (No chemical operations or significant on-site chemical inventory).
- Ultra-low emissions of conventional pollutants can be achieved largely as a fortuitous result of the CO2 purification processes selected, and at little or no additional cost.
- On a cost per tonne CO2 captured basis, it should be possible to achieve 98+% CO2 capture at an incrementally lower cost than achieving a baseline 90% CO2 capture.
- Development of chemical looping combustion with advanced ultra-supercritical steam cycles could result in an oxy-combustion power plant (with CO2 capture) that is higher efficiency than air-fired power plants being built today (without CO2 capture).
- The best information available today (with the technology available today) is that oxy-combustion with CO2 capture should be at least competitive with pre- and post-combustion CO2 capture and may have a slight cost advantage.

Oxy combustion challenges

- It is not possible to develop sub-scale oxy-combustion technology at existing power plants. An oxy-combustion power plant is an integrated plant and oxy-combustion technology development will require commitment of the whole power plant to the technology. Thus, the technology development path for oxy-combustion may be more costly than that for either pre-combustion or post-combustion capture which can be developed on slip streams of existing plants.
- The auxiliary power associated with air compression in a cryogenic air separation unit and CO2 compression in the CO2 purification unit will reduce net plant output by up to 25% compared to an air fired power plant with the same gross capacity (without CO2 capture).
- There is no geological or regulatory consensus on what purity levels will be required for CO2 compression, transportation and storage. For this reason, most oxy-combustion plant designs include a partial condensation CO2 purification system to produce CO2 with purity comparable to that achieved by amine post combustion capture. Oxy-combustion costs may be reduced if the purity requirements could be relaxed.
- Air-fired combustion is commonly anticipated for start-up of oxy-combustion power plants. The very low emissions achieved by oxy-combustion with CO2 purification cannot be achieved during air-fired start-up operations without specific flue gas quality controls for air-fired operations that are redundant during steady state oxy-fired operations. If a significant number of annual restarts are specified, either these added flue gas quality controls will be required (at additional capital cost) or provisions must be made to start up and shut down the unit only with oxy-firing and without venting significant amounts of flue gas.
- Plot space requirements are significant for the air separation unit and CO2 purification units.

More information

www.globalccsinstitute.com

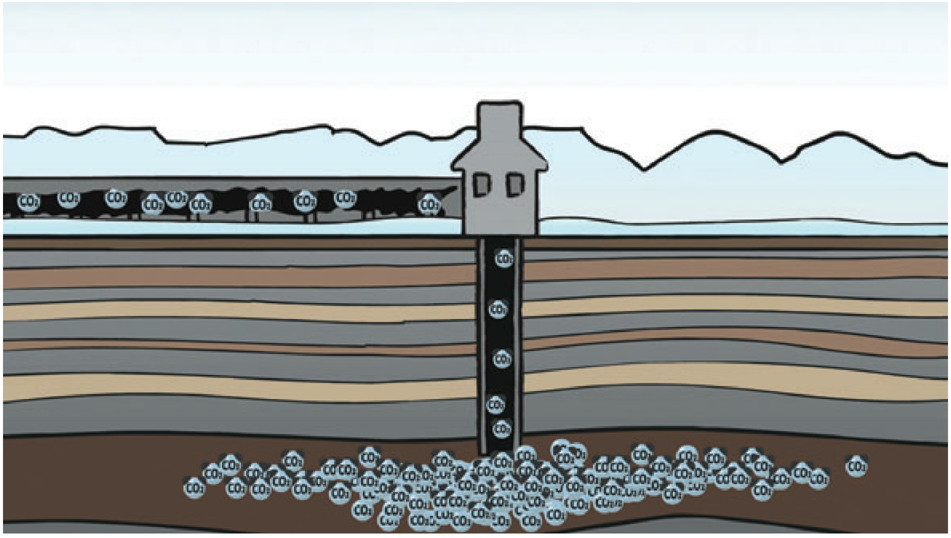
Explaining CCS - The Arctic Adventures of Dioxy

Longyearbyen CO2 Lab in Norway commissioned Kairòs Studio to create an animation to explain to school children (and some adults) the principles of carbon capture and storage. The result is a series of videos available for free on youtube.

Daniele Di Domenico and Simone Cau at Kairòs Studio created the animation in collaboration with scientists at the reasearch institute in Svalbard, Norway.

Longyearbyen CO2 Lab is a collaboration of universities, government and industrial partners to demonstrate the full CCS value chain.

"When Kei Ogata and Kim Senger contacted us to create a flash animation featuring the Longyearbyen CO2 Lab's carbon capture project we jumped at the idea, but we were also conscious of the difficulties and hard work involved; to explain a complex scientific/technical project to groups of school children would be challenging," said Daniele Di Domenico and Simone Cau at Kairòs Studio.



"Our first thought was: We need a story, to represent 60.000 tons of CO2 molecules in an underground environment. A starting point that our young audience would relate to like a party or a TV show! So we invented the underground theatre with it's lead character Dioxy, the protagonist of the story, the last molecule to arrive in the reservoir."

Working closely with Kei (postdoc-UNIS) and Kim (PHD-Bergen University/UNIS), they used flash animations to represent the fantastic world of Dioxy and video footage to show Longyearbyen, and the scientific work carried out by the CO2 team. "Music plays a crucial roll with two catchy theme songs, which open and close the story."

The result is a video/animation of 23 minutes, composed of 8 episodes, that can be used for different media channels from television to web diffusion

Dioxy's story starts at Mine 7, and takes you on a journey from the mining, and transporting of the coal to the power plant, through the forming and separating of the CO2 gas, to the final stages of injection beneath Adventdalen.

Through a creative and dynamic media, Dioxy and her friends explain to school children (and many enthusiastic adults) the concept of carbon capture and storage (CCS) through the work carried out by the Longyearbyen CO2 lab.

The Kairòs Studio views this as a first experience for a new way of "geo-science popularization."

More information

www.youtube.com/user/TheKairo studio

co2-ccs.unis.no/Dioxy.html

www.kairostudio.it

Air pollution from CCS

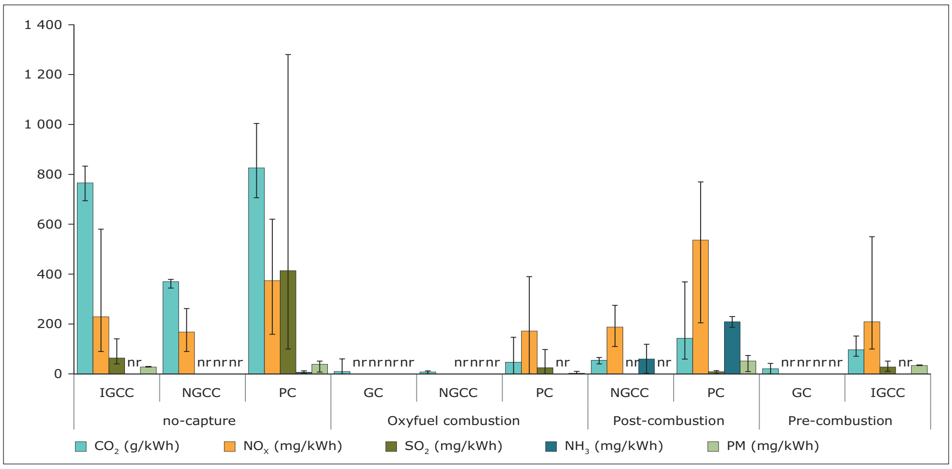
The report, from the European Environment Agency (EEA), looks at the effect of CCS on the emissions of common air pollutants, concluding that CCS has some positive and some negative effects, varying greatly according to the pollutant.

Pollutants considered in the report were the main GHGs CO2, methane (CH4) and nitrous oxide (N2O) and the main air pollutants with potential to harm human health and/or the environment, nitrogen oxides (NOX), sulphur dioxide (SO2), ammonia (NH3), non-methane volatile organic compounds (NMVOCs) and particulate matter (PM10).

In terms of emissions of pollutants, it is well known that efforts to control emissions of GHGs or air pollutants in isolation can have either synergistic or antagonistic effects on emissions of the other pollutant group, in turn leading to additional benefits or disadvantages occurring, says the report.

In the case of CCS, the use of CO2 capture technology in power plants leads to a general energy penalty varying in the order of 15–25 % depending on the type of capture technology applied. This energy penalty, which offsets the positive effects of CO2 sequestration, requires the additional consumption of fuel, and consequently can result in additional 'direct' emissions (GHG and air pollutant emissions associated with power generation, CO2 capture and compression, transport and storage) and 'indirect' emissions, including for example the additional fuel production and transportation required.

Offsetting the negative consequences of the energy penalty is the positive direct effect of CCS technology, which is the (substantial) potential reduction of CO2 emissions. It is thus important that the potential interactions between CCS technology implementation and air quality are well understood as plans for a widespread implementation of this technology mature.



Emission rates of various pollutants for different conversion technologies with and without CO2 capture

Notes: The indicated values are based on various fuel specifications and are dependent on the configuration and performance of the power plant and CO2 capture process.
'nr' = not reported; IGCC = Integrated Gasification Combined Cycle; NGCC = Natural Gas Combined Cycle; PC = Pulverised Coal; GC = Gas Cycle.
Source: Horssen et al., 2009; Koornneef et al., 2010, 2011.

Impacts of CCS

The amount of direct air pollutant emissions per unit electricity produced at future industrial facilities equipped with CCS will depend to a large extent on the specific type of capture technology employed. Three potential CO2 capture technologies were evaluated for which demonstration scale plants are expected to be in operation by 2020, post-combustion, pre-combustion and oxyfuel combustion.

Overall, and depending upon the type of CO2 capture technology implemented, synergies and trade-offs are expected to occur with respect to the emissions of the main air pollutants NOX, NH3, SO2 and PM. For the three capture technologies evaluated, emissions of NOX, SO2 and PM will reduce or remain equal per unit of primary energy input, compared to emissions at facilities without CO2 capture.

However, the energy penalty which occurs with CCS operation, and the subsequent additional input of fuel required, may mean that for some technologies and pollutants a net increase of emissions per kilowatt-hour (kWh) output will result. The largest increase is found for the emissions of NOX and NH3; the largest decrease is expected for SO2 emissions. There is at present little available quantitative information on the effect of CCS capture technologies on NMVOC emissions.

In addition to the direct emissions at CCS-equipped facilities, a conclusion of the review is that the life-cycle emissions from the CCS chain, particularly the additional indirect emissions from fuel production and transportation, may also be significant in some instances. The magnitude of the indirect emissions, for all pollutants, can exceed that of the direct emissions in certain cases.

Emissions from other stages of the CCS life-cycle, such as solvent production (for CO2 capture) and its disposal are considered of less significance, as well as the third order emissions from the manufacturing of infrastructure.

In considering both direct and indirect emissions together, some of the key findings of the review are:

• increases of direct emissions of NOX and PM are foreseen to be in the order of the fuel penalty for CCS operation, i.e. the emissions are broadly proportional to the amount of additional fuel combusted;

• direct SO2 emissions tend to decrease since its removal is a technical requirement for CO2 capture to take place to avoid potential reaction with amine-based solvents;

• direct NH3 emissions can increase significantly due to the assumed degradation of the amine-based solvent used in post-combustion capture technologies;

• indirect emissions can be significant in magnitude, and exceed the direct emissions in most cases for all pollutants;

• the extraction and transport of additional coal contributes significantly to the indirect emissions for coal-based CO2 capture technologies, with other indirect sources of emissions including the transport and storage of CO2 contributing around 10–12 % to the total;

More information
www.eea.europa.eu

Policy, company and regulation news

CarbonNet awarded AU$100 million

www.dpi.vic.gov.au

The Australian and Victorian Governments will collectively provide AU$100 million towards the development of CarbonNet.

CarbonNet is the second project selected for funding under the Australian Government's Carbon Capture and Storage Flagships program.

The CarbonNet Project aims to capture carbon emissions from power plants, industrial processes and new coal-based industries in the Latrobe Valley and store it in geological basins.

The combined funding of $100 million ($70 million from the Commonwealth and $30 million from the Victorian Government) will support feasibility work as part of the $1 billion plus CarbonNet project to demonstrate low emission brown coal electricity generation in the region.

The Victorian Department of Primary Industries manages the CarbonNet Project. The feasibility work will include modelling and testing of potential CO2 storage sites.

In addition to announcing funding for CarbonNet, Commonwealth Minister for Resources and Energy, Martin Ferguson, also announced that the Victorian Government has been awarded an offshore tenement for CO2 storage site exploration in the Gippsland Basin.

Further, both governments awarded the HRL Dual Gas project a final six-month extension on the previous date of 31 December 2011 to meet the conditions of the respective funding deeds.

Global CCS Institute grants over AU$2million to CCS research and projects

The Global CCS Institute has announced funding for leading Australian carbon capture and storage demonstration projects and research initiatives.

The Institute is providing:

$1.84 million in support to CSIRO for a body of research quantifying the potential impact of CO2 capture technology on air quality;

$240,000 in support to CarbonNet towards a measuring, monitoring and verification study that will ensure emissions are stored and accounted for; and

$226,000 in support to Worley Parsons towards a study looking at the impacts of post-combustion capture deployment on an existing sub-critical pulverised fuel power plant. This study will be carried out at the Loy Yang A power station in Victoria.

"These are very important projects," said Holger Bietz, General Manager for Projects, Financial and Commercial at the Global CCS Institute. "The work with CSIRO in particular will draw international attention, given that it will develop a methodology to allow regulators to safely approve capture projects in Australia and any jurisdiction around the world."

Previously, the Institute has extended support to the Collie-South West Hub and Victoria's CarbonNet as well as CCS demonstration projects around the world.

(From left to right): Leigh Hackett (Alstom), Peter Emery (Drax) and Mike Huggon (BOC Group) sign the agreement, welcoming BOC Group as a co-developer of the 426 MW oxy-fired carbon capture and storage (CCS) project at the Drax site in North Yorkshire.

CPS Energy agrees PPA with Texas Clean Energy Project

www.texascleanenergyproject.com

The Texas Clean Energy Project (TCEP) will supply electricity to CPS Energy under a recently signed Power Purchase Agreement (PPA).

Under the agreement CPS Energy will purchase approximately 200 megawatts (MW) of power from the TCEP, located just west of Midland-Odessa. This will be the first U.S. purchase by a utility of low carbon power from a commercial scale, coal based power plant with carbon capture.

The 400-MW TCEP plant is an Integrated Gasification Combined Cycle (IGCC) poly-generation facility capable of capturing 90 percent of the carbon dioxide it produces, as well as 99 percent of sulfur dioxide, 90 percent of nitrogen oxide, and 99 percent of mercury.

TCEP was a third round selection under DOE's Clean Coal Power Initiative, a cost-shared collaboration between the Federal government and private industry aimed at stimulating investment in low emission coal based power generation technologies through successful commercial demonstrations.

The $2.4 billion plant will receive $450 million in funding from the Clean Coal Power Initiative; of this, $211 million comes from the American Recovery and Reinvestment Act of 2009. The facility is expected to be fully operational in 2015.

BOC joins Drax, Alstom project

www.draxgroup.plc.uk

Industrial gases provider BOC will join as a co-developer on the 426 MW oxy-fired carbon capture and storage project under development at the Drax site in North Yorkshire, UK.

BOC brings air separation technology to the project as well as plant engineering and integration capabilities from its parent The Linde Group.

The project will link into the Humber Cluster CO2 transport and off-shore storage network currently under development by the UK National Grid.

The project is a candidate for EU NER-300 funding, the developers further intend to apply for support under the upcoming UK DECC CCS Demonstration Programme. The completed project will demonstrate the technical and commercial viability of CCS as a competitive low-carbon technology and an important part of the post 2020 energy mix in the UK.

Drax Power Limited is the owner and operator of Drax Power Station, the largest coal fired power station in the UK. The output capacity from the station's six generators is 4,000MW.

At current output levels Drax supplies 7% of the UK's electricity needs, and through substituting sustainable biomass for some of its coal, the power station also produces around 7% of the UK's renewable power.

U.S. Budget seeks more funds for CCS

fossil.energy.gov

$275.9 million for CCS research has been requested in President Obama's FY 2013 budget announcement.

While the U.S. demonstration programme continues to be funded through the Recovery Act, more funds are needed for research and development.

The program announced supports research to significantly reduce coal power plant emissions, including CO2, and substantially improve efficiency to reduce carbon emissions, leading to a viable near-zero atmospheric emissions coal energy system, and supporting carbon capture, use and storage. It also includes $35 million for NETL staff to conduct in-house coal R&D.

- Carbon Capture. The President's budget requests $60.4 million for carbon capture R&D. This sub-program is focused on the development of post-combustion and pre-combustion CO2 capture technology for new and existing power plants as well as industrial sources.

- Carbon Storage. The FY 2013 budget requests $95.5 million for carbon storage and utilization R&D. The activities conducted under this sub-program will be used to benefit the existing and future fleet of fossil fuel power generating facilities by reducing the cost-of-electricity impacts and providing protocols for carbon capture, storage and utilization demonstrations whose principal objective is to capture, transport, store, and monitor the CO2 injected in geologic formations.

- Advanced Energy Systems. The President's budget requests $55.2 million for advanced energy systems R&D. This sub-program focuses on reducing the cost of gasification and enabling affordable CO2 capture, while increasing plant availability and efficiency, and maintaining the highest environmental standards.

- Cross-cutting Research. The FY 2013 budget requests $29.8 million for cross-cutting research, fostering the development and deployment of innovative systems for improving efficiency and environmental performance.

Foster Wheeler to lead Don Valley CCS project

www.2Coenergy.com

2Co Power has appointed Foster Wheeler Energy Limited (FWEL) to lead its CCS power plant development at the Don Valley Power Project in the UK.

The planned 650MW (net) Don Valley Power Project near Hatfield Colliery in Yorkshire will provide low carbon electricity to the equivalent of around a million UK homes, capturing at least 90 per cent of its entire CO2 output (up to five million tonnes a year). Planning permission for the power plant has already been granted and main construction activities are planned to start in 2013.

The intent is that Foster Wheeler's appointment as Project Management Consultant of the £3 billion power plant will run until the plant comes into operation in 2016. Its initial role will be to assist 2Co Power in the preparation of an Engineering, Procurement and Construction (EPC) contract for the project build over the next six months.

When built, The Don Valley Power Project will combine a coal gasification plant, with CO2 capture on all of the plant, with a conventional style gas-fired power station but one that is fired by a hydrogen-rich fuel.

It is one of Europe's most advanced and economically viable CCS projects, says 2Co Power, and has already attracted an initial €180 million in EU funding. Its business model also involves CO2 storage and additional oil recovery potential under the North Sea.

2Co Energy Limited has also recently hired two leading carbon capture and storage experts - Jonathan Briggs and Graeme Miller - to lead commercial development and deployment.

Jonathan Briggs joins as Managing Director of 2Co Power. Jonathan led the Hydrogen Energy joint venture between BP and Rio Tinto in California, and was responsible for managing the $2.5 billion carbon capture and storage project that is now under development by SCS Energy.

Graeme Miller joins as Commercial Director. He was most recently Commercial Director for Hydrogen Energy's CCS power project in California and previously worked on BP's original Peterhead CCS project.

Duke Energy & China Huaneng sign CCS research agreement

www.duke-energy.com

Duke Energy and China Huaneng Group have signed a three-year agreement expanding their research cooperation in the areas of advanced coal and carbon capture and sequestration technologies.

The two parties initially signed a Memorandum of Understanding in 2009 to pursue high-level discussions and information sharing on a number of renewable and clean-energy fronts. In 2009, Huaneng Group developed a facility that economically captured 120,000 tons of the carbon dioxide per year emitted from the 1,320-megawatt coal-fired Shidongkou power station in China.

The expanded agreement calls for an engineering study to determine the potential feasibility of applying Huaneng Group's low-cost carbon capture process at unit 3 of Duke Energy's Gibson Station in Indiana. There are no plans to make any modifications to the power plant at this stage of the study. There are five units at Gibson with a combined capacity of 3,145 megawatts.

Funding for the project will be provided by the U.S.-China Clean Energy Research Center (CERC), which was established by the two countries in 2009 for such collaborative endeavors.

Duke and Huaneng will create a Joint Working Group that will begin meeting in the near future to coordinate the project.

APEC RFP: deployment of CCS in developing economies

www.apec.org

The Asia-Pacific Economic Cooperation (APEC) has released a Request for Proposals (RFP), titled, "Feasibility of accelerating the deployment of carbon capture, utilization, and storage (CCUS) in developing APEC economies."

The deadline for submission of proposals to the APEC Secretariat is March 23, 2012.

The project will focus on CO2 reuse prospects in developing APEC economies, practical possibilities for CO2 reuse and stimulating interest in exploring the near-term opportunities for CCUS in these economies.

The project will cooperate with the Carbon Sequestration Leadership Forum (CSLF), whose focus has recently been broadened to include CCUS.

The objectives of the project are:

(1) to produce a feasibility assessment for CCUS-EOR in developing APEC economies, including: data and information needs for evaluating CCUS-EOR opportunities; barriers to exploitation of these opportunities; policies and programs to facilitate the development of large-scale CCUS-EOR demonstration projects; elements of CCUS-EOR permitting frameworks that are likely to require particular attention by the relevant authorities in developing APEC economies; and recommendations for cost-effective capacity-building activities in the area of CCUS-EOR in these economies;

(2) to share experiences in and disseminate the most up-to-date information from APEC, the CSLF, and other international fora concerning the identification of potential opportunities for reuse of CO2 from fossil fuel power generation in developing APEC economies, in particular for enhanced oil or gas recovery.

Lower energy penalty CO2 capture system

In the second part of the article, the authors discuss recent results from CEFCO's process pilot plant and the generation of value added products such as fertilizers.

By Robert E. Tang, President, CEFCO Global Clean Energy and Dr. Anupam Sanyal, President, International Environmental & Energy Consultants

A ground-level photo of the pilot facilities with two of the five co-inventors: Donald Degling and Robert Tang

Part 1 of the article (CCJ Jan/Feb 2012) introduced an innovative low cost CO2 Removal technology; case histories of its U.S. EPA, DOE and DOD approved application in Hazardous Waste Combustion ("HWC") Maximum Achievable Control Technology ("MACT"); its recently patented process for application to coal/oil fired boilers, cement and petro-chemical industries; and the description of its demonstration in a 1-3 MW thermal unit and energy penalty comparison with that of a traditional amine process.

This part aims to describe the recent results of the CEFCO Process pilot plant, compliance with the U.S. EPA Power MACT, NESHAPs, and CSAPR ("Cross-State Transport Rule"), and generation of value added end-products making the CEFCO Process a profit center in contrast with the high energy penalty traditional processes.

Current status of the CEFCO testing at Pilot Plant

The supersonic shockwave technology (often described in EPA literature as "tandem nozzle", "free-jet scrubbing" or "free-jet collision" technology) previously invented by the CEFCO co-founder Thomas Ewan and incorporated into the present CEFCO patented technology, produces the superior 99+% Particulate Capture.

It has already been recognized by the EPA as a HWC[1] MACT technology from 1997 onward and has been published as HWC MACT compliant on May 22, 2002 under EPA's "Guide to Phase I MACT Compliance" for HWC Maximum Achievable Control Technology. Ewan's Technology was codified in Federal Statute under 40 CFR §63.109 et al.

CEFCO has deemed that Particulate Capture and all Acidic Gases Capture have been proven and put into commercial and governmental usage; therefore, additional work need not be spent on testing on this pollutant capture aspect of the CEFCO Process. All future testing will focus on the co-production of valuable and sellable products of the CEFCO Process. The capture capability will be offered to the licensed users of the CEFCO Process in the market place for compliance with the upcoming MACT, CSAPR and NESHAPs rules of the EPA.

Furthermore, both CEFCO and Peerless Mfg. Co. ("PMFG", the licensed manufacturer of the CEFCO Process Equipment in the territory of the USA) announced on November 9, 2011the successful completion of large scale prototype tests associated with the first two pollution control modules of the CEFCO Process equipment.

They further announced that PMFG and CEFCO are seeking a sponsor to conduct a pilot program at a potential customer facility, inviting all end-user operators in the following industries to contact the respective company to initiate a pilot-demonstration program: Cement Producers, Oil & Gas Processors and Refiners, and Power Generators."

Status of the SO2 capture and co-incidental CO2 capture and product-conversion testing at Pilot Plant

While developing and demonstrating the CEFCO Process to the U.S. Power Industry in mid-2011, it was requested by certain U.S. power producers to minimize the CO2 Capture ability of the CEFCO Modules in the earlier reactors in order to reduce the operating, transportation and handling costs of

1 The Ewan's free-jet collision HWC MACT technology is used for radioactive waste and particulate capture by the Nuclear Regulatory Commission of the DOE and for hazardous chemical weapons incineration by DOD and for EPA's Superfund remediation programs.

CO_2 Capture (and the Bicarbonate-Carbonate Regeneration Cycle[2]) — i.e., in the Sulfur Reactor System ("SRS") and the Nitrogen Reactor System ("NRS") Modules, thereby leaving CO_2 Capture to be primarily performed in the Carbon Reactor System ("CRS") Module, the last module, if and when it is required.

CEFCO Global Clean Energy responded affirmatively and successfully for the SRS Module represented by Eq. 7(see later), by forcing the product-forming capture reaction into the supersonic shockwave and exiting through a subsonic nozzle into the sub-atmospheric adiabatic zone. Thus, the CEFCO Process circumvented the need for the steps in Eqs. 2 through 4, and Eq. 6, and obtained the desired result of capturing virtually all of the SO_2 to produce the valuable Potassium Sulfite-Sulfate Fertilizer product i.e., in an alternative reaction condition without using a combination of KOH and K_2CO_3 to lessen the CO_2 Capture capability, as it was specifically requested by the client.

The following equations[3] show the chemistry involved in traditional and well-known removal of SO_2 and CO_2, except for the last equation, whose appearance here clearly illustrates the application of the CEFCO Process for a superior result. In honoring the request by potential users, CEFCO Global Clean Energy has suppressed the CO_2 Capture and Product-Conversion by eliminating the use of K_2CO_3 as a reagent in the SRS Module. This action specifically negated Eqs. 3 and 4 (as shown below). K_2CO_3 is known to be a more powerful reagent (reacting faster) for capturing CO_2 than KOH.

However, the supersonic shockwave employed by the CEFCO Process is also a very powerful source of energy and acts as the catalyst to allow the traditionally slower KOH to also capture a fair amount of CO_2 very simply and swiftly (as shown in Eqs. 5 and 6, below). Consequently, CEFCO Global Clean Energy has altered the pH level and other parameters to reduce the amount of CO_2 Capture so that the bulk of CO_2 Capture is deferred and will take place in the CRS Module.

The typical chemical reactions of the CEFCO Process inside the SRS Module are provided below:

Eq. 1: $SO + H_2O_2$ (or ½ O_2 only from any oxidation source) → $SO_2 + H_2O$
Eq. 2: $SO_2 + H_2O_2 \rightarrow H_2SO_4$
Eq. 3: $H_2SO_4 + K_2CO_3 + KOH \rightarrow K_2SO_4 + KHCO_3 + H_2O$ (net result – Exothermic)
Eq. 4: $CO_2 + K_2CO_3 + H_2O \rightarrow 2KHCO_3$ (more effective Carbon Capture)
Eq. 5: $CO_2 + KOH \rightarrow KHCO_3$ (effective Carbon Capture)
Eq. 6: $4KHCO_3$ + Heat (200 deg F) → $2K_2CO_3 + 2CO_2 + 2H_2O$

CO_2 in Carbon Capture will be liberated as a purified gas and sent to compression or storage, or to make biofuels, etc. and the same Reagent K_2CO_3 is once again re-generated in a cyclic re-circulated operation continually. The CEFCO Process can make its own reagent K_2CO_3 to be used subsequently in the CRS Module.

The CEFCO Process is also a net-generator of new water, by liberating prehistoric water previously trapped in fossil-fuels, in a "water-constrained" environment:

Eq. 7: $SO_2 + 2KOH \rightarrow K_2SO_3 + H_2O$ (net result — Exothermic)
Eq. 8: K_2SO_3 + ½ $O_2 \rightarrow K_2SO_4$ (solid crystals)

This equation proves SO_2 Capture and the conversion of the capture into Potassium Fertilizer as a valuable product.

This result is produced by the recognition and application of Hess's Law:

SO_2 + 2 KOH (reagent) → $K_2SO_3 + H_2O$ (Reaction Product – Liquid Potassium Sulfite Fertilizer)
$SO_2 + H_2O \rightarrow H_2SO_3$ (Intermediate-Transient Product)
H_2SO_3 + 2 KOH (reagent) → K_2SO_3 + 2 H_2O (Liquid Reaction Product)

Conventional Oxidation Reactions Forming Final Stable Solid Product:

2 K_2SO_3 + O_2 (or + $2H_2O_2$) → 2 K_2SO_4 (or + $2H_2O$) (Reaction Product – Solid Potassium Sulfate Fertilizer Crystals)

Therefore, the production of valuable Potassium Sulfate fertilizer is achieved from the exceeding 99% capture of the targeted sulfur content in coal and other fossil-fired flue gases.

Furthermore, by not using the more powerful and more expensive K_2CO_3 and only using the cheaper KOH reagent, the CEFCO Process succeeded in capturing much less CO_2 within the SRS Module than originally planned in accordance with the performance instruction from the power producers.

As described above, the capture of virtually all SOx is achieved in the SRS together with a smaller quantity of CO_2 than originally designed (in the form of Bicarbonate-Carbonate). The resulting Bicarbonate-Carbonate end-product (as shown in Eq. 5) can be sold to various industrial users as an incremental cost-reduction or a cost recovery step for the power producers.

The following are equations showing CO_2 Capture under the CEFCO Process:

CO_2 + KOH (reagent) → $KHCO_3$ (Carbon Capture)
CO_2 + K_2CO_3 (reagent) + H_2O → 2 $KHCO_3$ (Carbon Capture)

Transient Reactions (Effect of Hess's Law):

$CO_2 + H_2O \rightarrow H_2CO_3$
KOH (reagent) + $H_2CO_3 \rightarrow KHCO_3 + H_2O$ (Carbon Capture)

Conventional Decarbonation = Liberation of CO_2 Dioxide Reaction:

Heat (205 deg F) + 2 $KHCO_3 \rightarrow K_2CO_3$ (regenerated) + CO_2 ↑(liberated gas) + H_2O

Note: K_2CO_3 re-generation process, supra, liberates CO_2 as gas and produces a supply of recovered water for many subsequent uses. This liberated "new water" may be returned to the Plant to repay the "borrowed water" as previously described. The regenerated K_2CO_3 may be returned to the system to capture additional CO_2, or may be sold for high value to industrial users, such as to the petro-refinery industry, as a reagent for their processes.

Current status of the CO2 capture and product-conversion testing at Wichita Falls Pilot Plant

As to current technical progress at Peerless' Wichita Falls Facilities in Texas, CEFCO Global Clean Energy operates the SRS Module consuming only the "net use of KOH" on a stoichiometric molar basis to achieve superior capture and conversion into Potassium Sulfite fertilizer showing the most cost-efficient result in a cyclic recirculating-regenerating mode.

Thus, the CEFCO Technology minimized premature CO_2 Capture by deliber-

2. The use of Bicarbonate-Carbonate in the CEFCO Process must be distinguished from the Honeywell UOP Benfield™ Process (a 1954 conventional thermodynamic process), which uses repeatedly heated and cooled Sodium Bicarbonate-Carbonate cycles and is extremely energy and time consuming, and cannot offer the same energy and cost efficiency. The 2010 CEFCO™ Process is dramatically different from the 1954 Benfield™ Process.
3. These Carbon Capture Eqs. 3 thru 6 have been well-known and proven by chemists to work with NaOH + Na_2CO_3, as well as with KOH + K_2CO_3. Under conventional thermo-chemistry, they involve the use of adding expensive heat, pressure and catalyst at a cost commonly referred to in the Power Industry as the "energy penalty". CEFCO uses shockwaves (generated by "spent steam" or "post-production steam" in the Steam Return-Loop) and aerodynamic reactors as a low cost substitute, and thereby to minimize any "energy penalty".

Heavy viscous liquid exiting the bottom of the Aero-Coalescer of the SRS Module is showing the captured and converted sulfur compounds and the CO_2 (as $KHCO_3$) flowing continuously into the product settling tank. Samples are taken and tested periodically

ately not using any K_2CO_3 as capturing reagent in its SRS reaction process. The CEFCO Process' reactor is powerful enough that there is "No Need" to go through any K_2CO_3 step and will save substantial OPEX for its users. The end-product is sellable and valuable liquid K_2SO_3 (and eventually oxidising into K_2SO_4 solid crystal) fertilizer for the American agricultural cooperative market.

The CEFCO System has operated at a temperature range and atmospheric condition that avoided premature CO_2 Capture and, thus, minimized the extraneous consideration of the "Bicarbonate and Carbonate Cycle" at a significant saving in energy and reagent costs. (Compare: earlier Footnotes).

The CEFCO Technology's parametric testing of the modules continues at Wichita Falls, and CEFCO Global Clean Energy will work on other capture aspects to achieve overall cost-efficiency. The next task as requested by the Power Industry will be to operate and achieve the same desirable result of NOX Capture in the NRS Module by obtaining the valuable KNO_3 fertilizer as the end-product, while reducing significantly the expected CO_2 Capture. This progress will be reported in the future.

Thus, CEFCO Global Clean Energy is working to achieve the U.S. Power Industry's aim of deferring the vast majority of CO_2 Capture into the last Module alone, the CRS, as the specifically-dedicated CO_2 Capture and Conversion Module. Overall OPEX would have been minimized as a result. The economics are being tested and results will be reported in the future.

Furthermore, CEFCO Global Clean Energy is proactively working on full and comprehensive compliance with the current MACT, NESHAPs and CASPR Transport Rule . . . and the eventual GHG or Carbon Rules in the future.

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1. "Supersonic Emissions Control": Power Engineering Jan 2009

2. "Patent Rights Will Soon Be Available for Novel Emission Process": Power Engineering Aug. 2009

3. "Sending Shockwaves Through the Multi-pollutant Control Business": Modern Power Systems Oct. 2010

4. "Ewan & Cooper Processes Unite in Paradigm Shifting Patent": Power Engineering International Nov 2010

5. Electric Power May 2011

6. Coal-Gen 2011 August 2011

7. "Newly Patented Technology for Carbon Capture and Comprehensive Maximum Achievable Control Technology": Power-Gen Europe June 2011

8. "How Shockwaves Can Cut the Energy Penalty": Modern Power Systems Oct. 2011

9. "Good As Gold": Manufacturing Today March 2011

10. "Dallas Firm Tests Emerging Technology": The Dallas Morning News, March 29, 2011

11. Joint Press Release (November 9, 2011): "PMFG, Inc. (parent of Peerless Mfg. Co.) and CEFCO Global Clean Energy, LLC Announce Successful Prototype Testing of Selective Pollution Control Modules."

Shown in a translucent amber coloured bottle: The bottle shows the captured pollutants settled down and turned into 3-layers of sellable end-products: white Potassium Bicarbonate crystals at the bottom layer, the grayish off-white Potassium Sulfate Fertilizer crystals in the layer above it, and the dull viscose opaque liquid layer of Potassium Sulfite Fertilizer above them

More information

Robert E. Tang, President, CEFCO Global Clean Energy
robert.tang@cefcoglobal.com

Robert Tang is the Chief Executive Officer of CEFCO Global Clean Energy, LLC, and is a co-inventor of the CEFCO Process. He also serves on the Board of Directors of several major specialty engineering and construction companies, one of which has great emphasis and experience in the utility power industry and air pollution control (AQCS) industry, and the other is in the petro-chemical and refining industry. Tang received his B.A. from Columbia University in 1971 and two additional graduate degrees from Oxford University in England in 1973 and 1979. Tang led all the five co-inventors to invent and apply for the newly patented technology. US Patent and Trademark Office issued Patent #7,842,264 on Nov. 30, 2010.

Anupam Sanyal Ph.D., President, International Environmental & Energy Consultants, Inc.
Lakeland, Florida
1 863 816 2705
IEEC@AOL.COM

Anupam Sanyal has over 50 years international experience in Power & Chemical Industries. Dr Sanyal is a Consultant to the World Bank.

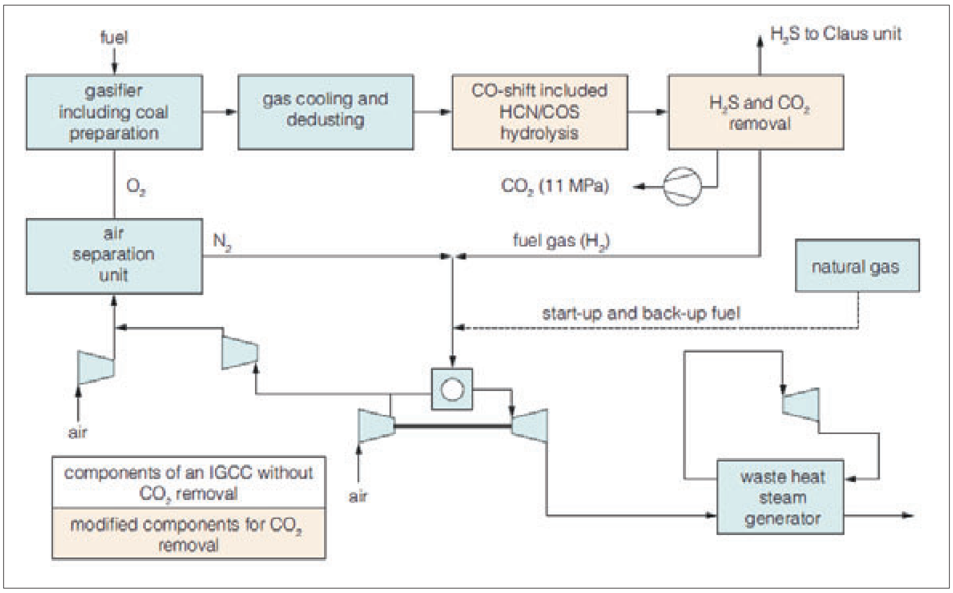
www.cefcoglobal.com
www.steamcoal.co.uk

IEA Clean Coal Centre study on pre-combustion capture of CO2 in IGCC

Pre-combustion capture of CO2 in IGCC by Robert Davidson, published by the IEA Clean Coal Centre, covers the technical aspects of an IGCC plant, mothods for CO2 capture and a survey of pilot plants planned and operational.

Pre-combustion capture involves reacting a fuel with oxygen or air and/or steam to give mainly a 'synthesis gas (syngas)' or 'fuel gas' composed of carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO2 and more hydrogen. CO2 is then separated, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as boilers, furnaces, gas turbines, engines and fuel cells.

Pre-combustion capture is suitable for use in integrated gasification combined cycle (IGCC) plants especially since the CO2 partial pressures in the fuel gas are higher than in the flue gas. The figure (right) shows the components of an IGCC that are modified for CO2 removal. It is these components, the water-gas shift (WGS) reaction and the removal of CO2, that form the subject of the report on pre-combustion capture of CO2 in IGCC plants.



IGCC with CO2 removal (Meyer and others 2005)

At the heart of the pre-combustion capture process is the WGS reaction that converts carbon monoxide and steam to carbon dioxide and hydrogen. The reaction

$$CO + H2O \rightarrow CO2 + H2$$

consists of a slightly exothermic conversion process, and is consequently promoted at low temperatures. However, low temperatures limit the rate of reaction and therefore it is necessary to use appropriate catalysts. Other parameters affecting reaction rate are pressure (up to 30 MPa, above which its effect becomes practically negligible) and steam carbon monoxide molar ratio.

The WGS unit influences the efficiency of a power plant. For a standard WGS design, the efficiency loss for an IGCC with CO2 separation due to WGS (without having encountered any measures for separation or CO2 compression) is in the order of 3–4%.

The loss of efficiency caused by the WGS is to a major extent governed by the steam demands necessary for sufficiently high CO conversion ratios. Also, the insertion of a shift converter into an existing IGCC plant with no shift would mean a near total rebuild of the gasification waste heat recovery, gas treatment system, and the heat recovery steam generator, with only the gasifier and gas turbine retaining most of their original features.

The report goes on to cover means of CO2 capture by physical and chemical solvents, solid sorbents, and membranes.

The most recent techno-economic analyses comparing pre-combustion capture with other capture technologies are remarkably similar: the investment costs, cost of electricity (COE), and net efficiencies of the different CO2 capture technologies have been found to be comparable. In economic terms no clear winner has yet emerged.

There are some IGCC pilot and demonstration plants already in existence or under construction. A few of these are already in, or close to, operation of carbon capture units. Among these is the 335 MW plant at Puertollano in Spain operated by Elcogas S.A. A 14 MWth pilot plant for CO2 capture and H2 production is operating.

The pilot plant consists of a WGS unit to convert CO into CO2, a CO2 separation unit based on absorption processes with amines (active methyldiethanolamine – aMDEA), and a H2 purification unit (PSA) – all commercial processes. Achieving design specifications of the main streams has been very easy (CO2 >99.6 % and pure H2 >99.995 %) and the rate of CO2 captured is 91.7%. The first estimation of the cost of avoided CO2 is approximately 25–30 €/t.

More information

The IEA Clean Coal Centre is a provider of information on the clean and efficient use of coal worldwide, particularly clean coal technologies, in a balanced and objective way, without political or commercial bias.

The report is available to purchase for £255.

www.iea-coal.org

CO2 storage - do impurities matter?

Tom Mikunda from ECN, a leading Dutch energy institute, looks at the impurities that can be present in captured CO2 and how research efforts are identifying how this affects its behaviour in a geophysical storage site

Is the presence of impurities in the CO2 stream destined to be stored underground a problem? The possible impacts of impurities are reservoir-specific and depend on the mineralogical composition of the rocks and of course the type of impurity and its concentration. Impacts can vary from slight dissolution creating micro-voids, to mineralisation which fills-up the pore-space.

Although the potential mechanisms through which certain impurities could affect storage capacity or integrity are well understood, simulating the exact conditions of a storage complex and the gradual accumulation of impurities in the laboratory pose significant problems.

Introduction

CO2-rock interactions are investigated with models and laboratory experiments using pure CO2. However, as a consequence of the capture process, the CO2 stream is likely to contain impurities, which may alter the behaviour of the stream through the compression, transport and storage elements of the CCS chain. Research on the effects of these impurities on the integrity of geological storage formations is limited.

The ‘other components’ or ‘impurities’ in CO2 streams[1] can include nitrogen (N2), oxygen (O2) and water (H2O), but also air pollutants such as sulphur and nitrogen oxides (SOx and NOx), particulates, hydrochloric acid (HCl), hydrogen fluoride (HF), mercury, other metals and trace organic and inorganic contaminants. In addition small amounts of chemical solvents used in post-combustion capture may be present in the CO2 stream. The removal of certain contaminants may be required for health, safety and environmental protection reasons, but also to ensure the effective transport and storage of the CO2 stream.

However, without overlooking the importance of health, safety and the protection of the environment, the extent to which impurities must be removed from the CO2 stream is also an economic issue. Reaching higher levels of CO2 purity will involve a number of incremental gas treatment processes each incurring capital and operation costs, potentially increasing the energy penalty and reducing CO2 avoidance. It is important that if deemed necessary, legal provisions regulating the maximum levels of impurities permitted in a captured CO2 stream strikes a balance between the economics of the entire CCS chain and protecting people and the environment. In order to do this, policymakers need access to reliable scientific research, review existing regulation and consult a range of stakeholders.

Impurities from capture installations

The nature and quantity of impurities present in a stream of captured CO2 is dependent on the fuels used, the capture process (the type of solvent used) and any gas treatment steps either prior or subsequent to CO2 capture (Visser et al., 2008). The composition of the resultant CO2 stream is contingent on the associated capture processes, and distinct differences in CO2 stream composition exist between the three main categories of post-combustion, pre-combustion or oxyfuel capture (Anheden et al., 2004).

CO2 capture from industrial process, such as blast furnaces or cement kilns present another level of complexity in the stream composition, as the potential suitability of different types of capture technologies, either based on chemical adsorption or physisorption is much less understood.

The composition of the captured CO2 stream resulting from the post-combustion capture process is understood to contain fewer impurities as existing regulations, specifically the Industrial Emissions Directive[2], which requires sets Emission Limit values (ELVs) on sulphur dioxide (SO2), nitrogen oxides (NOx) and dust particles. The removal of these pollutants will precede the removal of CO2 from the remaining flue gas passing.

The CO2 stream after the CO2 capture process will contain small (up to 0.3% by volume each) amounts of nitrogen, oxygen, argon, water and, in some cases, very small amounts of ash, trace metals, SO2 and NOx (< 0.01% by volume each; ICF International, 2010). Furthermore, elevated levels of NOx (50ppm) has been proven to cause significant degradation of the monoethalineamine (MEA)[3], the byproducts of which (such as alkalonamines, anionic heat stable salts and ammonia) will consequently reduce the efficiency of CO2 removal (Pederson et al., 2010).

During pre-combustion capture, coal or biomass is gasified, resulting in a syngas composed of H2 and CO, the latter which is converted to CO2 through a water-gas shift process with the remaining hydrogen rich fuel used in a number of applications such as boilers, furnaces and gas turbines (Visser et al., 2007). The water gas shift process does result in a concentrated stream of CO2 (>98%), however small amounts of hydrogen (H2; 1.5%) and hydrogen sulphide (H2S; ≈ 0.2%) may be present (ICF International, 2010). However, because gasification takes place in a reducing environment, no SO2 or NOx will be present in the captured CO2 stream (Visser et al., 2007).

Dependent on feed composition and feed pressure, the purity of a CO2 stream from an oxyfuel pulverized coal or natural gas installation can vary. The flue gas from an oxyfueled pulverized coal power plant contains approximately 63% CO2, and thus needs to be purified (Pipitone & Bolland, 2009). The type and amounts of impurities present in the final CO2 stream depends on the method of CO2 purification. Incidental substances such as SOx, NOx, and Mercury (Hg), and significant amounts of nitrogen, argon and oxygen may be present in the captured CO2 stream (ICF International, 2010). Oxyfuel combustion processes will also be regulated by the EU Large Combustion Plants Directive, which replaces restrictions on SO2, NOx and dust particles.

In addition to CO2 streams stemming from power generation processes, CO2 capture processes may also be applied to industrial processes such as blast furnaces, cement kilns and certain parts of oil refineries. Capture techniques for these applications are currently in development, such as the oxyfuel cement kiln and the oxygen blast furnace with CO2 capture. Even though at present it is still unclear which capture options are most suitable for various industrial processes, it is understood that high purity captured CO2 streams can be achieved, albeit with additional energy and cost.

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1. The term impurities will be used in this report
2. Directive 2010/75/EU)
3. A common chemical solvent used in post-combustion capture systems

Regulation of captured CO2 stream composition

A solitary piece of European regulation currently comments on the requirements for the composition of a captured stream of CO2. The European Union Directive on the geological storage of CO2[4], defines the CO2 stream as 'a flow of substances that results from CO2 capture processes.' The Directive also loosely defines the required stream composition that can be legally transported. Article 12(1) states in part:

'A CO2 stream shall consist overwhelmingly of carbon dioxide. To this end, no waste or other matter may be added for the purpose of disposing of that waste or other matter.'

Although clearly prohibiting the co-disposal of waste gases in a CO2 stream, the Directive does not set absolute quantitative restrictions on the substances that compose the CO2 stream, but uses qualitative criteria. The Directive does recognize that the CO2 stream may contain incidental associated substances from the capture process, or substances used for monitoring and verification purposes, however all incidental or added substances must be below levels that would:

a) 'adversely affect the integrity of the storage site or the relevant transport infrastructure;

b) pose a significant risk to the environment or human health; or

c) breach the requirements of applicable Community legislation.'

To meet the above criteria, operators are required to carry out a risk assessment in respect of the stream composition and maintain a register of the quantity, properties and composition of streams injected. However with reference to point 'a)' above, questions can be raised regarding how various compositions of CO2 streams may affect the integrity of the storage site. It is currently unclear whether sufficient information exists to allow a well-informed decision about the level of impurities that can be injected into a storage site.

In legal terms, the use of qualitative criteria for a gaseous stream composition (which can be quite easily quantified) seems inappropriate, as the term 'overwhelmingly' used in Article 12(1) could be interpreted differently between operators. The term 'overwhelmingly' was initially utilized in the London Protocol, the first international marine-environment protection instrument that permits the offshore geological storage of CO2 (Holwerda, 2011). In the Directive, the formula that CO2 streams "consist overwhelmingly of carbon dioxide" was chosen as it allows for a case-by-case assessment of the levels of impurities, recognizing the natural variation in storage site characteristics and different transport constructions[5].

Brockett (2009) informs that during the drafting of the Directive, the European Parliament's Environment Committee had proposed an amendment to the Directive, calling for a CO2 concentration of ≥95% and above, and the elimination of H2S and SO2. This amendment was not adopted, on the basis that certain applications of CCS, particularly for the cement and steel industry[6], may have considerable problems reaching such levels of CO2 purity. Furthermore the complete removal of H2S and SO2 is potentially impossible.

The Commission has produced guidance on the practical applications of the qualitative criteria outlined in Article 12 of the Directive. It is also expected that documents specifying the Best Available Techniques (BAT) will be developed for capture installations, and these documents would include CO2 compositions (Brockett, 2009).

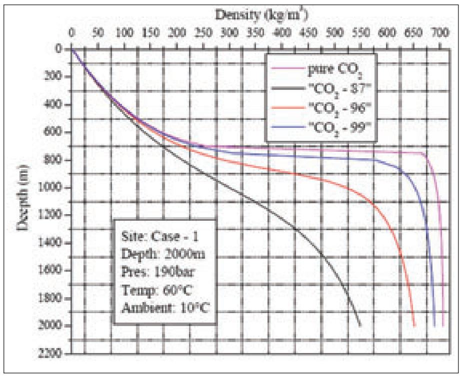


Fig. 1 - The density of CO2 streams with different purities of CO2 at different depths, pressures and temperatures (Yan et al., 2009)

The Directive, including the provisions of Article 12, will also be reviewed and modified if required in 2015.

The impact of impurities on geological formations

Storage capacity

Impurities in a CO2 stream, such as non-condensable gases, reduce the density of the gas stream. The lower density leads to a consequential drop in the total storage capacity of a storage reservoir. A less pure CO2 stream would mean that storage locations would be expended at a faster rate, meaning that higher costs would be incurred both due to the physical pore space occupied, but also through the costs of more frequent re-mobilising of injection equipment, re-installation of sub-surface templates and conducting additional well characterizations. Overall, it is of course desirable to utilize geological storage space as efficiently as possible.

Yan et al., (2009) conducted a techno-economic assessment developing three CO2 purification scenarios (87%, 96% and 99% CO2), stemming from an oxyfuel combustion installation. As well as compression and transport costs, the effects of non-condensable gases (N2, Ar and O2) on storage capacity was also investigated. Figure 1 depicts the results of a simulation, highlighting the density changes of the three CO2 streams as they are injected to various depths. The graph on the left is a simulation of injecting a stream of CO2 to a depth of 2000m, whereas on the rate the depth is 1000m, with cor-

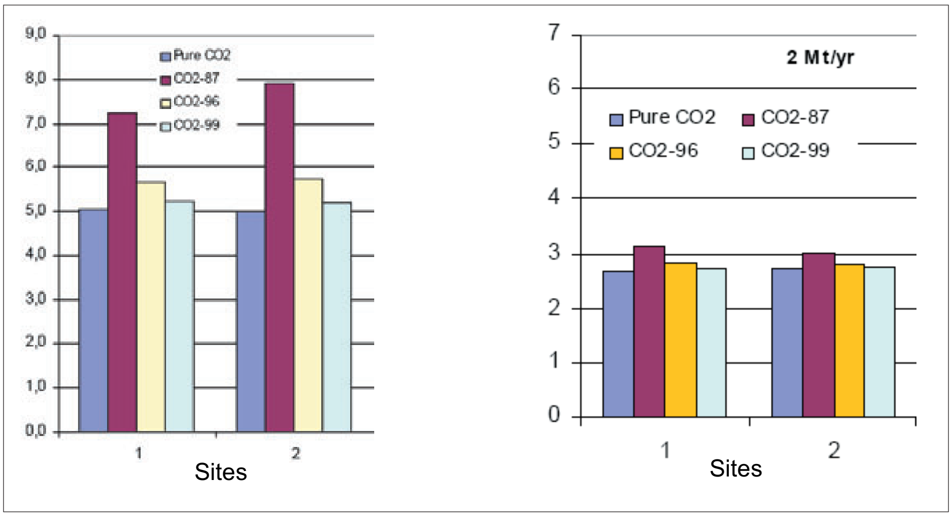


Fig. 2 - The required storage capacity (left) and associated costs (right) of CO2 streams with different purities (Yan et al., 2009)

4. Directive 2009/13/EC – henceforth referred to as 'the Directive'
5. International Marine Regulation, supra note 22, at 4506
6. CCS applications in many industrial sectors, particularly the steel and cement sectors, are currently in the early stages of development. There is not sufficient information on the CO2 reduction potential of such industrial process with CCS, and the costs associated with such applications are uncertain

responding values of the y-axis.

In the assessment, three storage scenarios with altered depths and geothermal conditions were presented, of which two are presented in Figure 1. It is clear that according to Yan et al., (2009), the density of the CO2 stream at both depths of 2000m and 1000m is directly affected by the increased presence of non-condensable gases.

Given that additional amounts of a low purity CO2 stream must be injected to achieve a specified level of CO2 storage, the costs of storage are approximately €0.3/tonne of pure CO2 equivalent higher than in the 99% CO2 stream purity (Figure 2). The costs include the CAPEX, OPEX and annual amortisation, although it is unclear if the injection takes place on or offshore.

Induced porosity and permeability changes

Geochemical reaction between the CO2 gas stream, in-situ brine and minerals in the storage formation can lead to problems during the operational phase, such as reduced permeability and increased pore pressures (Anheden et al., 2004). The blocking of fractures and pore spaces by mineral precipitation is a common feature in many geological settings (Emmanuel & Berkowitz, 2007). It is the growth in secondary minerals in the brine resulting from the precipitation process that are able to alter the geometry of the hydraulic capillaries.

Impurities in the injected gas stream can have direct impacts on the intensity and/or nature of the gas-rock interactions, rapidly reducing the pH of the brine and potentially increasing dissolution of the host rock and precipitation of secondary minerals over time scales ranging from months to thousands of years (Anheden et al., 2004). However, it must also be raised that, depending on numerous in-situ conditions, modifications in permeability brought about by mineral reactions may actually aid the migration of CO2 through the injection zone (ICF International, 2010).

If pure CO2 is injected into a storage formation, once in contact with water a relatively weak carbonic acid (H2CO3) will be formed. However, if other compounds are co-injected with the supercritical CO2, much stronger acids may develop. A number of the most potentially important acids and their relative acidity compared to carbonic acid have been calculated by ICF International (2010), and are presented in Table X. The equilibrium constants used to develop the relative acidities have been calculated at 25ºC and at atmospheric pressure, and thus may vary given geological conditions.

There are a limited number of studies that attempt to quantify the effects that stronger acids may have on the precipitation of minerals in geological formations. Knauss et al., (2005), coupled a chemical model with a simplified flow in a one dimensional (1D) simulation using the reactive transport code CRUNCH (Steefel, 2001; Steefel and MacQuarrie, 1996), in order to simulate the injection of CO2 into a heterogeneous rock formation, calculating the mineralogical changes over the flow path of 1km.

In addition to modelling the impact of the CO2, the simulation, based on an injection period of 5 years, was run with the addition of small amounts of H2S and SO2. The amount of SO2 added was sufficient to reduce the pH to 1, given the experimental reservoir conditions. The results suggest that the co-injection of H2S should not adversely impact injection rates compared to pure CO2.

However if sulphur is able to oxidise to sulphate, which is highly probable given the abundance of oxidants such as water, a sulphuric acid will be formed. This strong acid reduced the pH in the testing domain, and consequently led to significant precipitation of calcite, dawsonite and anhydrite.

Of the main literature sources reviewed, there are a number of consistent findings. Dependent on reservoir geology, the co-injection of SO2 with the CO2 reduces the pH of the formation water to approximately 1, due to the formation of sulphuric acid. H2S is seen to have a lesser impact on the creation of acidic conditions. With the co-injection of SO2, a highly acidified zone forms within a radial distance of 200m from the injection point.

In this acidic zone, rapid mineral dissolution of carbonate and silicate minerals may actually increase the porosity. At the edge of the injection zone (between 150-200m), the increased pH results in the precipitation of various secondary minerals, for example dawsonite, alunite, siderite and ankerite (dependent on the lithology of the formation). After approximately 100 years the level of precipitation is understood to reduce the porosity and potentially the permeability of the formation. A reduction in permeability could modify fluid flow, however this would not impact injectivity as the operational phase of the storage process would be complete.

Implications for EU CO2 storage legislation

In 2015, the European Commission shall review the Directive on the geological storage of CO2, including an assessment of the provision on CO2 stream acceptance and procedure referred to in Article 12 of the Directive. So what should policymakers do?

In terms of setting limits on impurities for storage purposes, some literature points towards a maximum permissible amount of non-condensable gases in the CO2 stream of 4 per cent by volume. This figure is understood to reflect an optimum balance between gas conditioning costs and the costs of compression; however any such limits would need to consider the source of CO2, reservoir mineralogy and overall site characteristics.

Concerning the potential for impurities to induce changes in the porosity and injectivity of a storage site, there are no indications that the amounts expected in captured CO2 streams will reduce the efficiency or integrity of storage.

It is recommended that research on the behaviour of impurities in geological formations continues in order to provide further scientific findings to assist in the review process.

Acid	Formula	Relative Acidity
Hydrochloric acid	HCL	$2.3 \times (10)^{14}$
Sulphurous acid	H2SO3	$3.5 \times (10)^{4}$
Sulphuric acid	H2SO4	$2.8 \times (10)^{4}$
Carbonic acid	H2CO3	$1.0 \times (10)^{0}$
Nitrous acid	HNO2	$1.0 \times (10)^{3}$

A range of acids and their relatively acidity compared to carbonic acid (adapted from ICF International, 2010)

More information

Thomas Mikunda

Tom Mikunda is a researcher at the Energy research Centre of the Netherlands (ECN). Since joining ECN in 2009, Tom has participated in a wide range of projects related to CCS, including CO2 transportation, CO2 storage, public perception and regulatory issues.

www.ecn.nl

mikunda@ecn.nl

Results of the CASSEM project

The CO2 Aquifer Storage Site Evaluation and Monitoring project (CASSEM) is a UK based study looking at integration and full-chain connectivity from capture and transport to injection, storage and monitoring. Its research is aimed at development of workflows that describe a CCS entry path for a target audience of power utilities, engineering companies and government.

The scope of the project included five key elements:

- Surface facilities: focuses on handling and transport.
- The CO2 store: which provides an outline methodology for solving CO2 storage via a series of process-orientated workflows covering geological modelling, reservoir simulation, monitoring and the assessment of uncertainty and risk.
- Risk and uncertainty: a basic understanding of uncertainty analysis and risk
- The economics of CO2: a transparent and accessible whole-chain analysis tool
- Public perception: comprising an early test and review of the public understanding of CCS in the regions of the exemplar sites.

The methodological approach adopted by industry and the regulators to CCS storage is strongly influenced by the level of knowledge of the subsurface, says the report. Whereas existing oil and gas operators and hydrocarbon service companies have extensive knowledge of the subsurface, new entrants to CCS, such as power companies and transport operators, do not. One of the defining differences is the acceptance of uncertainty.

A power company which operates surface assets will have well-established project development processes that feed into investment decisions based on their acceptance of uncertainty. For example, they will have very high levels of confidence that a new-build power plant will deliver the power output required.

This view of uncertainty is fundamentally different from existing subsurface operators where their project development cycle accommodates for high levels of uncertainty. Hydrocarbon operators will typically accept that boreholes are drilled, with costs in excess of tens of millions (£, $ or €), which will not result in producing hydrocarbons. Given that a power company will operate at one end of the CCS chain and a subsurface operator at the other, this highlights the need for entry paths and understanding along the whole CCS chain.

The CASSEM project was therefore funded to develop a pathway to inform and de-risk investment decisions for new entrants to CCS in the subsurface and in the identification of suitable formations to store CO2.

The value of interaction within a workflow and, ultimately, the uncertainty of subsurface operations is well illustrated, for example, by the work that was carried out on the Firth of Forth. The initial geological interpretation indicated that there was a small but usable storage structure and the CO2flow modelling that had been carried out in Phases 1 and 2 of the flow simulations supported this view. However, doubt remained with regard to faulting from the seismic interpretation. The original seismic data was reprocessed using current processing tools and then reinterpreted. The improved seismic data changed the interpretation of what had been assumed to be faults to be more confidently identified as tightly folded layering.

This reinterpretation increased confidence in the site and follow-up testing of the relative permeability of the aquifer rocks was carried out. This testing, however, revealed very low relative permeability values, impacting on the injectivity and making it an unrealistic storage proposition. This information would have been invaluable to a new-entrant store developer in halting further investment in an unsuitable formation

The CASSEM project combines a 'conventional' geosciences approach to CCS, sets this in context and recognises external influences (e.g. costs, transport, etc.) on CCS deployment. The approach can be summarised in the following three questions:

- Will there be sufficient public support for the CCS deployment?
- How can the risk and uncertainty be framed?
- How should this deployment be costed?

To address the issue of public support, the CASSEM project included work on public perception; unsurprisingly, this work identified that the public understanding of CCS, and of climate change, was very low. Significantly, it demonstrated that by providing the public with unbiased information on climate change and how it could be mitigated, and providing access to credible experts that they could discuss the issues with, people could understand where CCS fitted and through that understanding were supportive of the potential of having a CCS scheme relatively close to where they lived.

"Many projects contain an element of risk management; the CASSEM project went beyond that, using a risk and uncertainty work package to manage our own project risk. Within the project there was a budget allocated to obtain data for the other work streams, and it would have been simple and uncontentious to allocate those funds to each of the work packages on a pro rata basis to carry out the additional experimental work. Instead, the risk and uncertainty FEPs approach was used within the project, for each of the exemplar sites, and, using this approach, the areas of greatest uncertainty were identified and a data acquisition activity undertaken to reduce that uncertainty."

"There are several cost models produced for a CCS deployment. The CASSEM project has produced a financial framework to allow that costing of a CCS deployment. The CASSEM financial model is not just intended to produce a cost per tonne of CO2 emitted, but rather proposes a transparent method for calculating that cost. This model has been published with the expectation that it will be challenged, and through that, develop into a web resource available to the wider CCS community. We hope that this will allow CCS to be judged on an equal footing with other climate change mitigation strategies."

The CASSEM project partners now plan to apply and develop the derived methodologies to test the viability of a multi-user store offshore of the UK. This will be the intended CASSEM 2 project and will aim to take a CCS storage prospect up to the stage where high-cost offshore activity can be undertaken with an understanding of the associated risk. This offshore activity will then form the final stage, CASSEM 3, proving a CCS store by drilling.

More information

The CASSEM report can be downloaded at Scottish Carbon Capture and Storage
www.sccs.org.uk

Accounting for stored CO2 - a framework

The report by the Center for Climate and Energy Solutions (C2ES) provides the first comprehensive framework for calculating CO2 emission reductions from CCS.

The Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects – CCS Accounting Framework – provides methods to calculate emissions reductions associated with capturing, transporting, and safely and permanently storing anthropogenic CO2 in geologic formations.

It includes detailed methodologies to calculate emission reductions at each stage of the CCS process: CO2 capture, transport, and injection and storage. The methods were developed with input from CCS experts in industry, academia, and the environmental community.

For CO2 capture, the report outlines methods for multiple CO2 sources, including electric power plants with pre-combustion, post-combustion, or oxy-fired technologies, and industrial facilities involved in natural gas production, fertilizer manufacturing, and ethanol production.

For CO2 transport, the framework focuses on pipelines, which are the most viable transportation option for large-scale CCS. With respect to the geological storage of CO2, the framework applies to saline aquifers, depleted oil and gas fields, and enhanced oil and gas recovery sites.

It aims for consistency with the principles and procedures from ISO 14064-2:2006. Greenhouse gases – Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements, which represents best practice guidance for the quantification of project-based GHG emission reductions.

Ultimately, the objective of the CCS Accounting Framework is to inform and facilitate the development of a common platform to account for CO2 emissions reductions due to capturing and geologically storing CO2. It also contributes to the public discussion about the viability of CCS to serve as a feasible CO2 mitigation solution.

The emissions accounting procedures in the CCS Accounting Framework apply to multiple CO2 source types, including electric power plants – equipped with pre-combustion, post-combustion, or oxy-fired technologies – and industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production). For CO2 transport, the calculation methodology in this document applies only to pipelines because while other methods of transport, (e.g., truck transport) are possible, they are typically not considered viable options for large-scale CCS endeavors. With respect to the geological storage of CO2, the CCS Accounting Framework applies to saline aquifers, depleted oil and gas fields, and enhanced oil and gas recovery sites.

The CCS Accounting Framework provides a comprehensive set of GHG accounting procedures within a single methodology. The quantification approach includes equations to calculate emissions reductions by comparing baseline emissions to project emissions – the difference between the two represents the GHG reductions due to capturing and sequestering CO2, which would have otherwise entered the atmosphere.

GHG reductions from CCS project = Baseline emissions - Project emissions

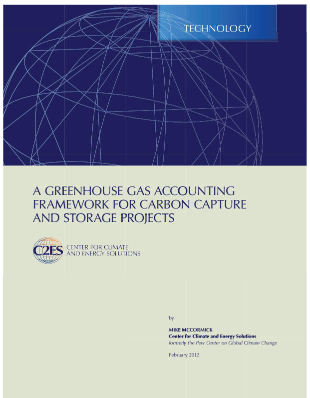
- Baseline emissions represent the GHG emissions that would have entered the atmosphere if not for the CCS project.
- Project emissions are actual GHG emissions from CO2 capture sites, transport pipelines, and storage sites.

The quantification approach to determine baseline emissions presents two baseline options: 1) "Projection-based" and 2) "Standards-based." In both cases, the calculation method uses data from the actual CCS project to derive baseline emissions.

Determining project emissions involves measuring CO2 captured and stored by the project and deducting CO2 emitted during capture, compression, transport, injection, and storage (and recycling of CO2 if applicable).

The procedure to determine project emissions also accounts for GHG emissions from energy inputs required to operate CO2 capture, compression, transport, injection and storage equipment. Energy inputs include "direct emissions" from fossil fuel use (Scope 1 emissions) and, in case required by a program authority, "indirect emissions" from purchased and consumed electricity, steam, and heat (Scope 2 emissions).

CCS project monitoring covers large above ground industrial complexes and expansive subterranean geologic formations. In terms of emissions accounting, monitoring CO2 capture and transport involves well known technologies and practices, established over many years for compliance with federal and state permitting programs. Therefore, the monitoring program would follow generally accepted methods and should correspond with GHG monitoring requirements associated with the relevant subparts of EPA's Greenhouse Gas Reporting Program (GHGRP) and other state-level programs.



On the other hand, monitoring geologic storage sites for the purpose of verifying the safe and permanent sequestration CO2 from the atmosphere is a relatively recent activity that may involve new techniques and technologies.

While there exists no standard method or generally accepted approach to monitor CO2 storage in deep rock formations, project developers will benefit from monitoring practices deployed over the past 35 years in CO2 enhanced oil and gas recovery operations. Thus, the CCS Accounting Framework does not prescribe an approach to monitor CO2 sequestration, as geologic storage sites will vary from site to site and demand unique, fit-for-purpose monitoring plans.

This approach is consistent with the monitoring, reporting and verification (MRV) procedures for geologic sequestration from subpart RR to EPA's Greenhouse Gas Reporting Program, which overlays the monitoring requirements associated with the Underground Injection Control Program.

More information

C2ES is the successor to the Pew Center on Global Climate Change and is an independent non-profit, non-partisan organization promoting strong policy and action to address energy and climate change challenges.

www.c2es.org

Status of CCS project database

The status of 78 large-scale integrated projects data courtesy of the Global CCS Institute

For the full list, with the latest data as it becomes available, please see the pdf version online at www.carboncapturejournal.com or download a spreadsheet at www.globalccsinstitute.com/resources/data

Asset Lifecycle Stage	Project Name	Description	Country
Operate	**Century Plant (formerly Occidental Gas Processing Plant)**	Occidental Petroleum, in partnership with Sandridge Energy, is operating a gas processing plant in West Texas that at present can capture 5 Mtpa of carbon dioxide for use in enhanced oil recovery. Capture capacity will be increased to 8.5 Mtpa in 2012.	UNITED STATES
Operate	**Enid Fertilizer**	Since 1982, the Enid Fertilizer plant has sent around 680,000 tonnes per annum of carbon dioxide to be used in enhanced oil recovery operations in Oklahoma.	UNITED STATES
Operate	**Great Plains Synfuel Plant and Weyburn-Midale Project**	About 3 million tonnes per annum of carbon dioxide is captured from the Great Plains Synfuel plant in North Dakota. Since 2000 the carbon dioxide has been transported by pipeline into Canada for enhanced oil recovery in the Weyburn and Midale Oil Fields.	CANADA
Operate	**In Salah CO2 Storage**	In Salah is a fully operational onshore gas field in Algeria. Since 2004, 1 million tonnes per annum of carbon dioxide are separated from produced gas and reinjected into the producing hydrocarbon reservoir zones for storage in a deep saline formation.	ALGERIA
Operate	**Shute Creek Gas Processing Facility**	Around 7 million tonnes per annum of carbon dioxide are recovered from ExxonMobil's Shute Creek gas processing plant in Wyoming, and transported by pipeline to various oil fields for enhanced oil recovery. This project has been operational since 1986.	UNITED STATES
Operate	**Sleipner CO2 Injection**	Sleipner is the second largest gas development in the North Sea. Carbon dioxide is separated from produced gas at Sleipner T and reinjected into a deep saline formation above the hydrocarbon reservoir zone. This project has been in operation since 1996.	NORWAY
Operate	**Snøhvit CO2 Injection**	The Snøhvit offshore gas field and related CCS activities have been in operation since 2007. Carbon dioxide separated from the gas produced at an onshore liquid natural gas plant is reinjected into a deep saline formation below the reservoir zones.	NORWAY
Operate	**Val Verde Natural Gas Plants (formerly Sharon Ridge)**	This operating enhanced oil recovery project uses carbon dioxide sourced from the Mitchell, Gray Ranch, Puckett, Pikes Peak and Terrell gas processing plants and transported via the Val Verde and CRC pipelines.	UNITED STATES
Execute	**ADM Illinois Industrial Carbon Capture and Sequestration Project**	The project will capture around 1 million tonnes per annum of carbon dioxide from ethanol production. Carbon dioxide will be stored approximately 2.1 km underground in the Mount Simon Sandstone, a deep saline formation.	UNITED STATES
Execute	**Agrium CO2 Capture with ACTL**	Agrium's fertiliser plant in Alberta is currently being retrofitted with a carbon dioxide capture unit. Around 585,000 tonnes per annum of carbon dioxide will be captured and transported via the Alberta Carbon Trunk Line (ACTL) for enhanced oil recovery.	CANADA
Execute	**Air Products Steam Methane Reformer EOR Project**	This project in construction will capture more than 1 million tonnes per year of carbon dioxide from two steam methane reformers to be transported via Denbury's Midwest pipeline to the Hastings and Oyster Bayou oil fields for enhanced oil recovery.	UNITED STATES
Execute	**Boundary Dam Integrated Carbon Capture and Sequestration Demonstration**	SaskPower is currently retrofitting a coal-based power generator with carbon capture technology near Estevan, Saskatchewan. When fully operational in 2014, this project will capture around 1 million tonnes per annum of carbon dioxide.	CANADA
Execute	**Gorgon Carbon Dioxide Injection Project**	This component of a larger gas production and LNG processing project will inject 3.4 to 4 million tonnes of carbon dioxide per annum into a deep saline formation. Construction is under way after a final investment decision was made in September 2009.	AUSTRALIA
Execute	**Kemper County IGCC Project (formerly Plant Ratcliffe)**	Mississippi Power (Southern Company) is constructing an air-blown 582 MW IGCC plant using a coal-based transport gasifier. Up to 3.5 million tonnes per annum of carbon dioxide will be captured at the plant and used for enhanced oil recovery.	UNITED STATES
Execute	**Lost Cabin Gas Plant**	This project will retrofit the Lost Cabin natural gas processing plant in Wyoming with CCS facilities, capturing around 1 million tonnes per annum of carbon dioxide to be used for enhanced oil recovery.	UNITED STATES
Define	**Bełchatów CCS**	PGE EBSA plans to integrate a carbon capture plant into a new built 858 MW unit at the Bełchatów Power Plant. Around 1.8 million tonnes per annum of carbon dioxide will be captured (advanced amine process) and stored in deep saline formations.	POLAND
Define	**Coffeyville Gasification Plant**	CVR Energy is developing a new compression facility at its fertiliser plant in Kansas. The plant currently produces approximately 850,000 tonnes of carbon dioxide which will be transported to the mid-continental region for use in enhanced oil recovery.	UNITED STATES
Define	**Don Valley Power Project (formerly Hatfield)**	Early in 2011, 2Co Energy acquired the Don Valley Power Project, a 650 MW IGCC facility in South Yorkshire. The project intends to capture around 4.8 million tonnes of carbon dioxide per annum for enhanced oil recovery or geological storage.	UNITED KINGDOM
Define	**Eemshaven CCS**	Essent (RWE Group) aims to capture and store around 1.2 million tonnes per annum of carbon dioxide from an existing 1600 MW coal- and biomass-based power plant.	NETHERLANDS

State / District	Volume CO_2	Operation Date	Facility Details	Capture Type	Transport Length	Transport Type	Storage Type	Project URL
Texas	8.5 Mtpa	2010	Natural Gas Processing	Pre-Combustion	256 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.oxy.com/
Oklahoma	0.68 Mtpa	1982	Fertiliser Production	Pre-Combustion	192 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.kochfertilizer.com/
Saskatchewan	3 Mtpa	2000	Synthetic Natural Gas	Pre-Combustion	315 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.cenovus.com/
Wilaya de Ouargla	1 Mtpa	2004	Natural Gas Processing	Pre-Combustion	14 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.insalahco2.com/
Wyoming	7 Mtpa	1986	Natural Gas Processing	Pre-Combustion	190 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.exxonmobil.com
North Sea	1 Mtpa + 0.1-0.2 Mtpa in	1996	Natural Gas Processing	Pre-Combustion	0 km	Offshore to offshore pipeline	Offshore Saline Formations	http://www.statoil.com/en/
Barents Sea	0.7 Mtpa	2008	Natural Gas Processing	Pre-Combustion	150 km	Onshore to offshore pipeline	Offshore Saline Formations	http://www.statoil.com/en/
Texas	0.4 - 1.3 Mtpa	1972	Natural Gas Processing	Pre-Combustion	132 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.exxonmobil.com/
Illinois	Up to 1 Mtpa	2013	Chemical Production	Industrial Separation	1.6 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.adm.com/
Alberta	0.585 Mtpa	2014	Fertiliser Production	Pre-Combustion	234 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.agrium.com/
Texas	1 Mtpa	2012	Hydrogen Production	Pre-Combustion	Not Specified	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.airproducts.com/
Saskatchewan	1 Mtpa	2014	Power Generation	Post-Combustion	100 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.saskpower.com/
Western Australia	3.4 - 4 Mtpa	2015	Natural Gas Processing	Pre-Combustion	10 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.chevronaustralia.com/
Mississippi	3.5 Mtpa	2014	Power Generation	Pre-Combustion	75 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.mississippipower.com/
Wyoming	1 Mtpa	2012	Natural Gas Processing	Pre-Combustion	370 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.conocophillips.com/
Łódź	1.8 Mtpa	2015	Power Generation	Post-Combustion	51 – 100 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.bot.pl/
Kansas	0.85 Mtpa	2013	Fertiliser Production	Pre-Combustion	112 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.cvrenergy.com/
South Yorkshire	4.75 Mtpa	2015	Power Generation	Pre-Combustion	>400	Onshore to offshore pipeline	Enhanced Oil Recovery	http://www.2coenergy.com/
Groningen	1.2 Mtpa	2017	Power Generation	Post-Combustion	Not Specified	Ship/Tanker	Enhanced Oil Recovery	http://www.rwe.com/

Status of CCS project database

Define	**Emirates Steel Industries**	This project proposes to capture around 800,000 tonnes per annum of carbon dioxide from a steel plant in the Industrial City of Abu Dhabi by 2015. The project is being developed as part of the Abu Dhabi CCS Network (Masdar).	UNITED ARAB EMIRATES
Define	**Green Hydrogen (formerly Air Liquide)**	Air Liquide is building a new hydrogen plant in Rotterdam. The installation of a cryogenic purification unit at the plant, capturing up to 550,000 tonnes per annum of carbon dioxide, is under evaluation.	NETHERLANDS
Define	**Hydrogen Energy California Project (HECA)**	SCS Energy has taken over the HECA project from Hydrogen Energy. The new design will be a 400 MW polygeneration plant capturing 2.3 million tonnes per annum of carbon dioxide for enhanced oil recovery.	UNITED STATES
Define	**Hydrogen Power Abu Dhabi (HPAD)**	This project will convert natural gas into hydrogen and carbon dioxide. The 380 MW hydrogen power plant will generate over 5 per cent of all Abu Dhabi's current power generation capacity. Captured carbon dioxide will be used for enhanced oil recovery.	UNITED ARAB EMIRATES
Define	**Lake Charles Gasification**	Leucadia and Lake Charles Cogeneration plan to build a gasification plant to produce synthetic natural gas from petcoke. Around 4 million tonnes per annum of carbon dioxide will be captured at the plant and used for enhanced oil recovery.	UNITED STATES
Define	**Medicine Bow Coal-to-Liquids Facility**	Medicine Bow Fuel and Power propose to build a greenfield, coal-to-transport fuels plant that will produce up to 21,000 barrels of gasoline per day, and capture up to 3.6 million tonnes of carbon dioxide per annum for enhanced oil recovery.	UNITED STATES
Define	**Northwest Upgrader Refinery with ACTL**	Up to 1.2 million tonnes per annum of carbon dioxide will be captured at this new heavy oil upgrader in Alberta. In partnership with Enhance Energy, the carbon dioxide will be transported via the Alberta Carbon Trunk Line (ACTL) for enhanced oil recovery.	CANADA
Define	**NRG Energy Parish CCS Project**	NRG Energy proposes to capture 1.5 million tonnes per annum of carbon dioxide from its Parish coal-fired power plant in Fort Bend County, Texas, for use in enhanced oil recovery.	UNITED STATES
Define	**OXYCFB 300 Compostilla Project**	This project uses oxyfuel and circulating fluidised bed (CFB) technology on a 30 MW pilot power generation plant which will scale up to 300 MWe. It has received funding from the European Energy Programme for Recovery (EEPR).	SPAIN
Define	**Porto Tolle**	This project will capture around 1 million tonnes per annum of carbon dioxide from a new build coal-based power station using post-combustion capture. The carbon dioxide will be injected into a deep saline formation in the northern Adriatic Sea.	ITALY
Define	**Project Pioneer**	This project will capture 1 million tonnes per annum of carbon dioxide from TransAlta's Keephills 3 coal-based power plant. The carbon dioxide will be used for enhanced oil recovery or sequestered locally.	CANADA
Define	**PurGen One**	SCS Energy is proposing to build a 500 MW IGCC power plant in New Jersey. Around 2.6 million tonnes per annum of carbon dioxide would be transported by pipeline to deep saline formations about 160 km offshore.	UNITED STATES
Define	**Quest**	Quest will capture up to 1.2 million tonnes of carbon dioxide per annum from the Scotford upgrader, and transport it by pipeline for injection into a deep saline formation.	CANADA
Define	**Rotterdam Opslag en Afvang Demostratieproject (ROAD)**	E.ON proposes to capture around 1.1 million tonnes per annum of carbon dioxide from the flue gases of a new coal-based power plant that is currently being constructed within the industrial port of Rotterdam.	NETHERLANDS
Define	**Spectra Fort Nelson CCS Project**	Carbon dioxide sourced at the Fort Nelson natural gas-processing plant will be injected into a nearby saline formation at a depth of approximately 2,200 metres. Injection rates will ramp up to 1.2 to 2 million tonnes per annum of carbon dioxide.	CANADA
Define	**Taylorville Energy Center**	The Taylorville Energy Center is a proposed 602 MW IGCC power plant located in Illinois. Around 3 million tonnes per annum of carbon dioxide will be captured at the plant and stored in onshore deep saline formations or used in enhanced oil recovery.	UNITED STATES
Define	**Tenaska Trailblazer Energy Center**	Tenaska is developing a site near Sweetwater, Texas, to construct a supercritical pulverised coal-based power plant designed to capture up to 85-90 per cent of the carbon dioxide that would otherwise enter the atmosphere.	UNITED STATES
Define	**Texas Clean Energy Project**	Summit Power Group is developing a 400 MW IGCC polygeneration plant capturing 2.7 million of tonnes per annum of carbon dioxide to be used for enhanced oil recovery in the Permian Basin in West Texas.	UNITED STATES
Define	**ULCOS - Blast Furnace**	The Ultra-Low-CO2-Steel (ULCOS) consortium proposes to build a prototype blast furnace that will efficiently capture up to 700,000 tonnes per annum of carbon dioxide from a steel plant. The carbon dioxide would be stored in a deep saline formation.	FRANCE
Evaluate	**Bow City Power Project**	The Bow City Power Project is a proposed super critical 1,000 MW coal-based power plant in Alberta, incorporating post-combustion carbon capture and storage. Around 1 million tonnes per annum of carbon dioxide will be captured for enhanced oil recovery.	CANADA
Evaluate	**Browse Reservoir CO2 Geosequestration**	Up to 3 million tonnes per annum of carbon dioxide would be captured at this proposed liquid natural gas development located on the Dampier peninsula in Western Australia.	AUSTRALIA
Evaluate	**C.GEN North Killingholme Power Project**	C.GEN is proposing a new IGCC plant in north Lincolnshire that would capture around 2.5 million tonnes per annum of carbon dioxide feeding into the National Grid transport and storage network. The project is part of the Yorkshire Forward initiative.	UNITED KINGDOM

Abu Dhabi	0.8 Mtpa	2015	Iron and Steel Production	Industrial Separation	50 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.esi-steel.com/
Zuid-Holland	0.55 Mtpa	2016	Hydrogen Production	Industrial Separation	600 km	Ship/Tanker	Enhanced Oil Recovery	http://www.airliquide.com/
California	2 Mtpa	Not specified	Power Generation	Pre-Combustion	6.4 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.hydrogenenergycalifornia.com/
Western Region	1.7 Mtpa	2017	Power Generation	Pre-Combustion	201 – 250 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.hydrogenenergy.com/
Louisiana	4.5 Mtpa	2014	Synthetic Natural Gas	Pre-Combustion	Not Specified	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.leucadia.com/
Wyoming	3.6 Mtpa	2015	Coal-to-liquids (CTL)	Pre-Combustion	Not Specified	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.dkrwadvancedfuels.com/
Alberta	1.2 Mtpa	2014	Oil Refining	Pre-Combustion	234 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.northwestupgrading.com/
Texas	1.5 Mtpa	2015	Power Generation	Post-Combustion	Not Specified	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.nrgenergy.com/
Leon	1.1 Mtpa	2015	Power Generation	Oxyfuel Combustion	120 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.compostillaproject.es/
Veneto	1 Mtpa	2015	Power Generation	Post-Combustion	101 – 150	Onshore to offshore pipeline	Offshore Saline Formations	http://www.zeportotolle.com/
Alberta	1 Mtpa	2015	Power Generation	Post-Combustion	90 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.projectpioneer.ca/
New Jersey	2.6 Mtpa	2017	Power Generation	Pre-Combustion	160 km	Onshore to offshore pipeline	Offshore Saline Formations	http://www.purgenone.com/
Alberta	1.2 Mtpa	2015	Hydrogen Production	Pre-Combustion	84 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.shell.ca/
Zuid-Holland	1.1 Mtpa	2015	Power Generation	Post-Combustion	≤50 km	Onshore to offshore pipeline	Offshore Depleted Oil and Gas	http://www.road2020.nl/en
British Columbia	2.2 Mtpa	2015	Natural Gas Processing	Pre-Combustion	20 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.spectraenergy.com/
Illinois	3 Mtpa	2016	Power Generation	Pre-Combustion	≤50 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.cleancoalillinois.com/
Texas	5.75 Mtpa	Not specified	Power Generation	Post-Combustion	201 – 250 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://www.tenaskatrailblazer.com/
Texas	2.5 Mtpa	2014	Power Generation	Pre-Combustion	≤50 km	Onshore to onshore pipeline	Enhanced Oil Recovery	http://texascleanenergyproject.com/
Lorraine	0.7 Mtpa	2016	Iron and Steel Production	Industrial Separation	51 – 100 km	Onshore to onshore pipeline	Onshore Saline Formations	http://www.ulcos.org/en/
Alberta	1 Mtpa	2017	Power Generation	Post-Combustion	≤50 km	Onshore to onshore pipeline	Enhanced Oil Recovery	www.bowcitypower.ca
Western Australia	3 Mtpa	2017	Natural Gas Processing	Pre-Combustion	Not Specified	Unspecified pipeline	Saline Formations or Depleted Gas	http://www.woodside.com.au/
North Lincolnshire	2.5 Mtpa	2015	Power Generation	Pre-Combustion	Not Specified	Onshore to offshore pipeline	Offshore Saline Formations	http://www.cgenpower.com/

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www.rossoffshore.no

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Ross Offshore AS, Leif Weldings vei 14, 3208 Sandefjord, Norway
Tel: +47 33 48 46 90 | Fax: +47 33 48 46 91