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Carbon Capture and Storage

Chris Hendriks

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Introduction

The goal of CO_2 capture is to isolate carbon from the energy carrier in a form suitable for transport and storage. It is generally believed that a relatively (nearly) pure stream of carbon dioxide must be produced. This improves the economics for compression, transport and storage. Also sink capacity is better utilised by injecting pure CO_2.

A CCS operation typically involves four activities: capturing; compression, transporting, and storing. All these activities have impact on the costs and emission profile of the CCS operation.

Capture of CO_2

Sources that appear to lend themselves best to capture include large-point sources of CO_2 such as conventional pulverised steam power plants, coal or natural gas-fired combined cycles, and fuel cells. In addition to power plants, industrial sources are being considered for application of capture technologies, like cement plants, oil refineries, iron and steel plants, ammonia and hydrogen production plants, and natural gas processing sites. Capture from disperse sources of CO_2 emissions like residential buildings and transport vehicles need a different approach. Possible opportunity is the introduction of fuel cells for vehicular propulsion combined with central production of hydrogen including CO_2 capture.

There are numerous ways to capture carbon dioxide from energy conversion processes. These CO_2 capture processes can conveniently be divided into four main categories: pre-combustion; post-combustion, oxyfuel combustion and 'pure' sources of CO_2. These main routes are depicted in Figure 1.

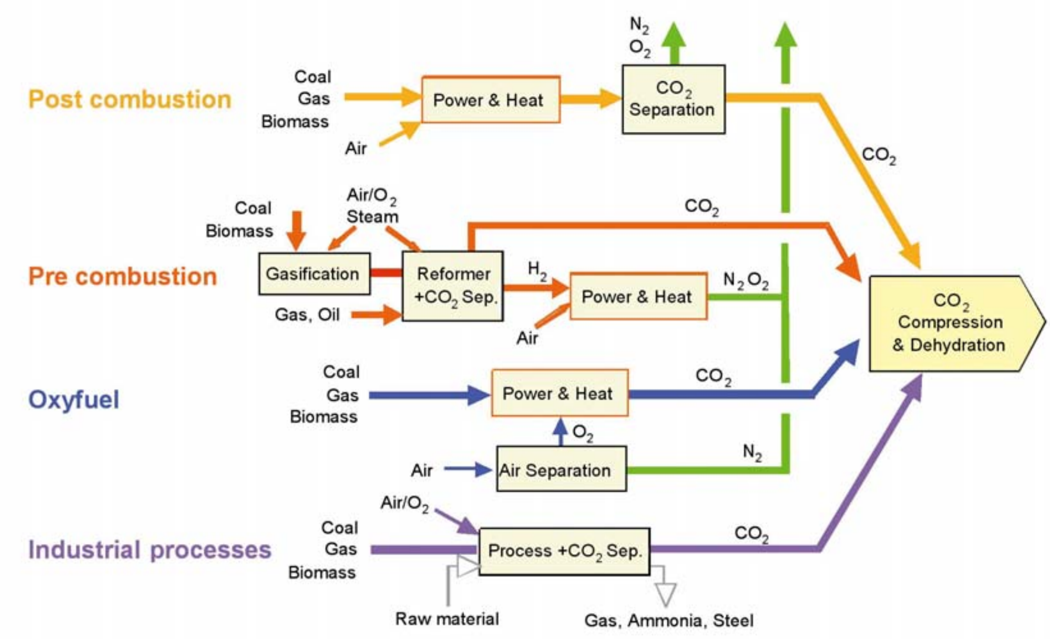

Figure 1. Overview of CO2 capture processes and systems (IPCC, 2005)

In the pre-combustion process (also decarbonisation of fuel called), the carbon containing fuel is converted to a mixture of carbon monoxide and hydrogen. In a second step the carbon monoxide is shifted further with water to carbon dioxide and an extra amount of hydrogen. In a CO_2 separation unit, the carbon dioxide is separated from the hydrogen. In principal hydrogen can be produced out of any fuel, either of fossil origin or from biomass. Purity of the captured CO_2 is generally high. The systems typically capture 85 to 100% of the produced CO_2.
In a post-combustion process, the CO_2 is separated from the flue gases of an installation. The best-known and developed technology is separation of CO_2 from flue gases by an amine-based solvent. Other ways to capture CO_2 is by using membranes (polymer- based, ceramic or metal-base) or in combination of membranes and solvent. Recovery systems based on amines are proven on commercially scale, but only for small units. These systems can recover 85 to 95% of the CO_2 in the flue gas and produces CO_2 with a purity of over 99.9%.
Oxyfuel combustion process eliminates nitrogen from the flue gas by combusting a fuel in either pure oxygen or a mixture of pure oxygen and (recycled) carbon dioxide. The combustion products consist mainly of carbon dioxide and water vapour. It will also contain relatively large volumes of other contaminants like SO2 and NOx. The recovery degree is typically high in these kinds of processes.
Some industrial processes, like ammonia, ethylene oxide production or gas processing, already produce CO_2 with a high level of purity.

It should be mentioned that together with carbon dioxide capture, often other emissions of pollutants to the atmosphere like SOx, NOx and particulates also will be reduced. This is either a pre-requisite for the capture process (e.g. otherwise the pollutants hinders the capture process in post-combustion processes) or it is a direct consequence of the capture process (e.g. in oxyfuel processes in which all flue gases are captured).

Compression and transport of CO_2

To transport CO_2 efficiently and safely by pipeline the pressure needs to be at least 80 to 100 bars. At this pressure the density versus the compression ratio is in many cases optimal. Higher pressures require more energy and investment costs while there is little gain in density (i.e. smaller pipelines). Depending on the pressure drop over the pipeline sometimes higher entrance pressures are required. Compression of large amounts of CO_2 is typically done by a multistage-step centrifugal compressor. Water is removed during compression and when needed by a drying installation after the CO_2 has been compressed.

Transport of large amounts of carbon dioxide is usually most conveniently done by pipelines. In cases of large distances over sea, sometimes tanker transport might be more attractive. Ships may also be attractive when high flexibility of transport routes are required. In that case CO_2 has to be liquefied and transported at about 7 bars and minus 55 ºC.

Storage of CO_2

Carbon dioxide can be stored in underground layers. Generally the following types of storage reservoirs are distinguished:

- Empty natural gas fields
- Empty oil fields
- Remaining oil fields to explore with enhanced oil recovery (EOR)
- Unminable coal layers to which enhanced coal bed methane recovery can be applied (ECBM)
- Aquifers (water containing underground layers).

Clearly oil, gas, and coal fields have proven their capability of holding oil and gas over geological time periods. Nevertheless, CO_2 has other properties than natural gas and the exploitation of the field by drilling wells make a reservoir more vulnerable for leakages. Gas storage in aquifers is a human-induced phenomenon and therefore relatively new, although several natural analogues are known and currently under investigation.

Costs of CCS

There is no simple answer on the question how much CCS costs. The costs depend on many factors like fuel prices, cost of capital and operational and maintenance costs. Costs are further determined by regulatory requirements like monitoring and safety issues. Furthermore, CCS involves a chain of operations on which geography and geology may have major impacts on the costs. Countries with little storage capacity or with distribution between capture and storage locations will face higher costs than other countries.

CCS is a relatively new technology, and large-scale implementation has not yet been done. In one form or another, the components are commercially available, but there is relatively little commercial experience with configuring all of these components into fully integrated CCS systems at the kind of scales required. Cost estimates can therefore not rely on massive historical data and need to rely on experiences of comparable activities. As for all new technologies, CCS will likely undergo major cost reductions (compared to the estimates for current implementation). Therefore, cost estimate for the period after 2020/2025 will have substantial uncertainty margins.

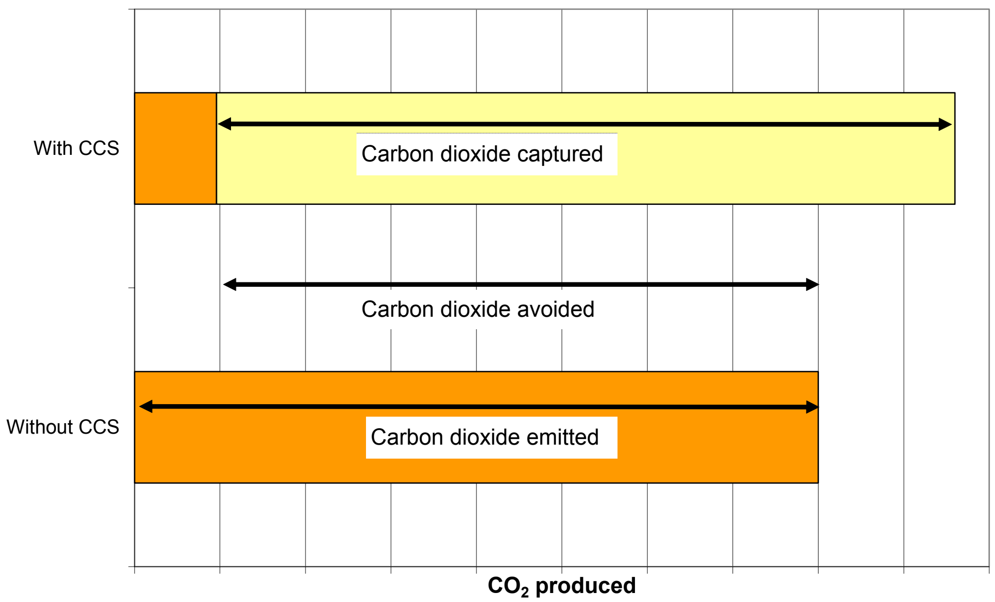

Figure 2. Relation between CO2 produced CO2 captured and CO2 avoided.

The economics of CCS are typically calculated as the costs increase of the production (e.g. €/kWh) or per tonne of CO_2 avoided. ***Figure 2*** explains the principle of 'avoidance'. The net reduction of CO_2 emissions to the atmosphere by applying CCS depends on several factors, with the fraction of CO_2 captured and increased CO_2 emissions resulting from energy use for the CCS process being the most important. The costs (expressed as €/tCO_2 avoided) can only be defined against a pre-defined reference situation.

$$CostPerTonAvoided = \frac{(Annual\cos ts_{cap} - Annual\cos ts_{no\_cap})}{(Annual_{Avoided-CO_2})} \quad [€/ton]$$

We can distinguish three cost elements, namely capture (including compression), transport and storage. Typically, the capture bears the largest costs with about 70-80% of the total costs. Cost for geological storage and transport have a significant range because the costs are depending on significant site specific factors; terrain conditions, depth of storage, remoteness of location, onshore and offshore. On top of that, when storage is combined with EOR, EGR or ECBM also revenues can be obtained.

Capture costs

The costs of CO_2 capture include the additional capital requirements, plus added operating and maintenance costs. For current technologies a substantial portion of the overall costs is due to energy requirements for the process.

Based on extensive research and literature reviews, an indication is made for capture costs for power plants. However, a large number of technical and economic factors related to the design and operation of the CO_2 capture system influence the costs. For this reason, reported costs of CO_2 capture vary widely, even for similar applications.

Research to capture from industrial sources has, despite the huge potential, not been performed that extensively. Costs indications are therefore hardly available.

Table 1 presents a summary of investment costs, operation and maintenance costs and efficiencies for the main types of power plant: natural gas fired combined cycles, (ultra)supercritical pulverized coal plants and integrated coal combined cycles. The estimates are presented for three view years: 2010, 2020 and 2030, taking into account technological learning and cost reductions which might be expected by massive implementation of the technologies. Table 2 depicts typical costs for capture from industrial sources.

Reductions in costs of technologies resulting from learning-by-doing and other factors have been systematically observed over many decades. Because historical cost trends are not available for capture systems, these trends can be taken from similar types of technologies, i.e. flue gas desulphurization (FGD) systems, selective catalytic reduction (SCR) systems, pulverized coal (PC) boilers, gas turbine combined cycles (GTCC), liquefied natural gas (LNG) production systems, oxygen production systems and steam methane reforming (SMR) technology for hydrogen production. The learning rates represent the reduction in costs (both capital and O&M costs), with each doubling of cumulative capacity of the technology. Rubin et al. (2005) analysed a cost reduction of about 10 to 18 percent for CCS on fossil fuel power plants for each doubling of capacity, with CCS integrated into IGCC plants having the largest cost reduction potential.

Table 1. synthesized costs for capture from power plants

Conversion technology	Fuel	year	new/retrofit	CO2 capture technology class	Net electric efficiency	Net electric efficiency	Efficiency penalty	CO2 capture efficiency	Base plant Total capital requirement	Base plant O&M	CCS plant Total capital requirement	CCS plant O&M	Total plant Total capital requirement	Total plant O&M
					w/o CCS	with CCS	%-points	%	€/kW(2003)	€/kW(2003)	€/kW(2003)	€/kW(2003)	€/kW(2003)	€/kW(2003)
NGCC	natural gas	2010	retrofit	Post-combustion	na	na	10%	85%	na	na	460	22	na	na
NGCC	natural gas	2020	retrofit	Post-combustion	na	na	8%	90%	na	na	330	17	na	na
NGCC	natural gas	2030	retrofit	Post-combustion	na	na	ne	ne	ne	ne	ne	ne	ne	ne
NGCC	natural gas	2010	new	Post-combustion	56%	48%	8%	85%	560	23	360	22	920	45
NGCC	natural gas	2020	new	Post-combustion	60%	54%	6%	90%	470	20	288	17	758	37
NGCC	natural gas	2030	new	Post-combustion	62%	58%	4%	90%	440	18	160	14	600	32
NGCC	natural gas	2010	retrofit	Pre-combustion	na	na	ne	90%	na	na	na	na	na	na
NGCC	natural gas	2020	retrofit	Pre-combustion	na	na	ne	90%	na	na	na	na	na	na
NGCC	natural gas	2030	retrofit	Pre-combustion	na	na	ne	ne	na	na	na	na	na	na
NGCC	natural gas	2010	new	Pre-combustion	na	na	ne	ne	na	na	na	na	na	na
NGCC	natural gas	2020	new	Pre-combustion	60%	53%	7%	100%	470	20	470	13	940	33
NGCC	natural gas	2030	new	Pre-combustion	62%	57%	5%	100%	440	18	330	12	770	30
NGCC	natural gas	2010	retrofit	Oxyfuel	na	na	ne	ne	ne	ne	ne	ne	ne	ne
NGCC	natural gas	2020	retrofit	Oxyfuel	na	na	ne	ne	ne	ne	ne	ne	ne	ne
NGCC	natural gas	2030	retrofit	Oxyfuel	na	na	ne	ne	ne	ne	ne	ne	ne	ne
NGCC	natural gas	2010	new	Oxyfuel	56%	ne	ne	ne	na	na	ne	ne	ne	ne
NGCC	natural gas	2020	new	Oxyfuel	60%	50%	10%	100%	470	20	430	13	900	33
NGCC	natural gas	2030	new	Oxyfuel	62%	57%	5%	100%	440	18	260	12	700	30
SOFC	natural gas	2030	new	Oxyfuel	??	59%	??	80%	??	??	??	??	1530	45
PC	coal	2010	retrofit	Post-combustion	na	na	12%	88%	na	na	900	41	na	na
PC	coal	2020	retrofit	Post-combustion	na	na	11%	90%	na	na	700	33	na	na
PC	coal	2030	retrofit	Post-combustion	na	na	ne	ne	ne	ne	ne	ne	ne	ne
PC	coal	2010	new	Post-combustion	47%	37%	10%	88%	1100	46	700	41	1800	87
PC	coal	2020	new	Post-combustion	50%	43%	7%	90%	1070	41	500	33	1570	74
PC	coal	2030	new	Post-combustion	53%	48%	5%	90%	1020	38	400	25	1420	63
PC	coal	2010	retrofit	Pre-combustion	na	na	na	na	na	na	na	na	na	na
PC	coal	2020	retrofit	Pre-combustion	na	na	na	na	na	na	na	na	na	na
PC	coal	2030	retrofit	Pre-combustion	na	na	ne	ne	ne	ne	ne	ne	ne	ne
PC	coal	2010	new	Pre-combustion	47%	ne	ne	ne	1100	46	ne	ne	ne	ne
PC	coal	2020	new	Pre-combustion	50%	ne	ne	ne	1070	41	ne	ne	ne	ne
PC	coal	2030	new	Pre-combustion	53%	ne	ne	ne	1020	38	ne	ne	ne	ne
PC	coal	2010	retrofit	Oxyfuel	na	na	na	na	na	na	na	na	na	na
PC	coal	2020	retrofit	Oxyfuel	na	na	na	na	na	na	na	na	na	na
PC	coal	2030	retrofit	Oxyfuel	na	na	ne	ne	ne	ne	ne	ne	ne	ne
PC	coal	2010	new	Oxyfuel	47%	ne	ne	ne	1100	46	ne	ne	ne	ne
PC	coal	2020	new	Oxyfuel	50%	42%	8%	100%	1070	41	500	33	1570	74
PC	coal	2030	new	Oxyfuel	53%	46%	7%	100%	1020	38	400	25	1420	63
IGCC	coal	2010	retrofit	Pre-combustion	na	na	na	na	na	na	na	na	na	na
IGCC	coal	2020	retrofit	Pre-combustion	na	na	na	na	na	na	na	na	na	na
IGCC	coal	2030	retrofit	Pre-combustion	na	na	ne	ne	ne	ne	ne	ne	ne	ne
IGCC	coal	2010	new	Pre-combustion	45%	37%	8%	90%	1600	61	600	34	2200	95
IGCC	coal	2020	new	Pre-combustion	49%	43%	6%	90%	1500	51	600	32	2100	83
IGCC	coal	2030	new	Pre-combustion	52%	47%	5%	95%	1400	42	500	27	1900	69

Table 2. overview capture costs for industrial sources

type plant	typical CO2 purity	CO2 capture technology class	typical size	heat requirement	power requirement	TCR	O&M
			Mt/y	kJ/kgCO2	kJe/kgCO2	M€/kgCO2/s	%
Ammonia	100%	post-combustion	0.2-0.5	0	420	1.3	4%
Ammonia	100%	post-combustion	0.5-2	0	420	1	4%
Ammonia	8%	post-combustion	0.2-0.5	3200	420	3.5	6%
Ammonia	8%	post-combustion	0.5-2	3200	420	2.8	6%
Hydrogen	100%	post-combustion	0.1-0.3	0	420	3	4%
Hydrogen	100%	post-combustion	0.3-1.0	0	420	1.3	4%
Iron&steel	20%	post-combustion	0.5-2	0	620	3	6%
Iron&steel	20%	post-combustion	2-4	0	620	2.2	6%
Refineries	7-13%	pre-combustion	0.5-2	3200	420	3.5	6%
Refineries	7-13%	pre-combustion	2-4	3200	420	2.8	6%
Cement	15-15%	post-combustion	0.5-2	3200	420	3.5	6%
Cement	15-15%	post-combustion	2-4	3200	420	2.8	6%

Transport costs

Costs of pipelines are formed by construction costs (material and installation), operation and maintenance costs (monitoring, operation and energy) and other costs (right of way, design, permitting).
Costs are sensitive to scale of volume and almost proportional to distance. Costs may differ very substantial depending on local circumstances. Figure 3 shows typical costs (€/t) for transport over 100 km. As example, the onshore transport costs in the Netherlands are depicted. These costs are considerably higher due to difficult geology and the high density of population. The availability of storage reservoirs and the geography of the country/region (e.g. distance from sources to storage reservoirs), will have substantial influence on costs for transport. For larger distances over seas, ships may prove to be competitive. Ships also add to the flexibility of the transport system.

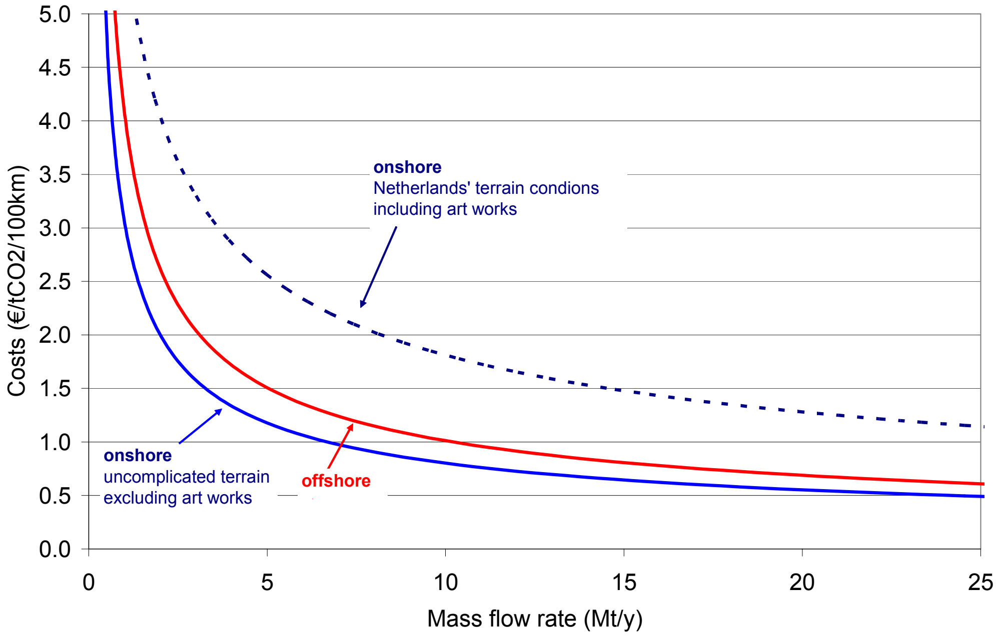

Figure 3. Indication of transport costs for onshore and offshore pipelines per 100 km. Capital charge rate of 10% is assumed

Storage costs

Storage costs are mainly driven by well drilling costs. Offshore storage tends to be considerably more expensive if expensive platforms have to be operated. Revenues may come from enhanced oil recovery (EOR), enhanced gas recovery (EGR) or enhanced coal bed methane recovery (ECBM) activities. EGR and ECBM are still in a demonstration phase. Especially for the EOR the application of CO_2 injection may be restricted to a certain operation time table, i.e. before the field is abandoned, when still use can be made from existing infrastructure. Reinstallation of infrastructure may turn out to be expensive. There can not general revenue figures be given for EOR operations, as this depends heavily on local conditions. In general it can be stated that offshore operation will bear higher costs than onshore and subsequently will reduce the revenues from EOR. Assuming additional 2 barrel of oil per tonne of CO_2, revenues may amount to 60 €/tCO_2 – assuming an oil price of 30 €/bbl. However, substantial additional costs for EOR operation should be subtracted from this amount. Table 3 shows an estimated cost range for storage options.

Table 3. Storage cost ranges for various types of reservoirs

Type of storage reservoir	Storage costs range US reservoirs ($\$/tCO_2$) [building cost curve for US, IEA, 2005]	[Hendriks, 2002 global storage] €/tCO_2	IPCC SR €/tCO_2
Deep saline aquifers	12 – 15 (12.5)	2 - 11	0.2 – 4.5: onshore 0.5 – 30.2: offshore
Deep gas fields	11 – 13 (12.5)	1 - 8	0.5 – 12.2 (onshore)
oil fields	-13 – 37 (16.6)	minus 10 - 20	1.2 – 8.1
CO_2-ECBM	-7 – 30 (9.5)	0 - 30	
Overall	-13 – 37 (12.3)	minus 10 - 30	0.5 - 8.0

Figure 4 shows typical costs for the total CCS chain for new power plants. It should be noted that the accuracy of the presented costs are moderate and is also depending on location, fuel costs and other external factors. The figure presents power production costs without and with CCS attached to the same plant and CO_2 avoidance costs.

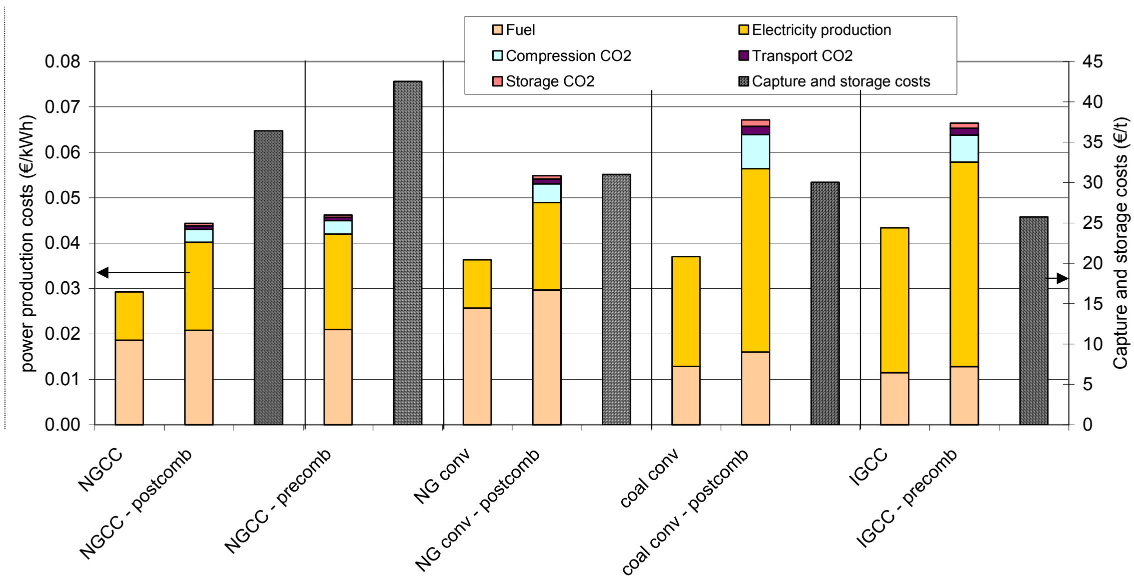

Figure 4. Typical capture and storage costs for new power plants. Assumed transport distance of 100 km. Capital charge rate of 11% (10% discount rate; 25 years economical lifetime)

Cost development and R&D requirements

Considerable alternatives for capture technologies are in consideration and under research at the moment. With respect to pre-combustion, post-combustion of oxyfuel capture processes no 'winner' can be identified yet. This can also be illustrated by the fact that demonstration projects has been announced covering this variation of technologies, e.g. an oxyfuel demonstration plant of Vattenfall in eastern of Germany, an IGCC plant partly equipped with CCS by Nuon in northern of the Netherlands, and a small post-combustion demonstration plant based on chilled ammonia to be build by Alstom and E.ON in southern of Sweden. Developments are expected for all technologies: improved membranes systems, enhanced performance of solvents, and chemical looping processes. However, substantial R&D is required to reach or surpass the anticipated cost reductions in capture technologies. Although substantial less potential for cost reduction is expected for transport and storage, R&D is required to safety aspects and capacity understanding. For storage, improved storage site selection and characterization methodologies, risk analysis methodologies and monitoring technologies are required. R&D is also required to understand better CO_2 enhanced oil recovery, ECBM and EGR and its technical and economical implications.

Storage capacity consideration

Worldwide, only a few quantitative estimates on storage potentials have been made. These estimates should be treated with care as methodologies for capacity estimates are still in development and there is a substantial lack of reliable geological data, especially for aquifers and coal seams. Capacity is furthermore affected by the safety conditions which will be opposed to storage. As these conditions are still under discussions, storage capacity estimates can not be made with sufficient confident to analyse the role of CCS in detail in future energy system, especially on regional or country level.

Table 4. compilation of storage capacity data [Christensen, 2003, Hendriks, 2004]

	Oil and gas			Unmineable coal seams			Aquifers		
GtCO2	low	best	high	low	best	high	low	best	high
Canada	8	17	27	0	8	51	10	43	156
Canada		*10*			*1*				
U.S.A. *	14	29	86	0	32	190	16	78	354
Big Sky		*1*		*0*		*0*	*271*		*1085*
MGXC		*0*		*2*		*3*	*29*		*115*
MRCSP		*3*		*1*		*1*	*47*		*189*
PCOR		*20*		*8*		*8*	*97*		*97*
SECARB		*32*		*57*		*63*	*360*		*1440*
SOUTHWEST		*21*		*1*		*1*	*18*		*64*
WESTCARB		*5*		*87*		*96*	*97*		*388*
Central Am.	11	24	81	0	0	0	12	31	114
South Am.	18	65	250	0	2	12	21	90	365
Northern Afr.	18	46	109	0	0	0	20	60	170
Western Afr.	10	32	138	0	0	1	11	47	208
Eastern Afr.	0	2	6	0	0	0	1	7	31
Southern Afr.	1	3	17	0	7	45	3	24	125
Western Eur.	32	66	212	0	1	6	33	74	249
Denmark		*1*						*0*	
Germany		*2*						*16*	
Greece		*0*						*2*	
Netherlands		*11*						*2*	
Norway		*13*						*16*	
UK		*10*						*15*	
Eastern Eur.	3	8	16	0	1	4	4	12	36
Croatia		*0.1*			*0.0*			*0.4*	
Poland		*0.6*			*0.5*			*3.8*	
Slovenia		*0.0*			*0.0*			*0.1*	
Slovakia		*0.1*			*0.0*			*1.3*	
Hungary		*0.4*			*0.2*			*0.0*	
Czech Republic		*0.0*			*0.3*			*2.9*	
Bulgaria		*0.0*			*0.0*			*0.8*	
Romania		*2.5*			*0.0*			*3.0*	
Former S.U.	106	308	921	0	25	150	110	366	1219
Middle East	180	440	1159	0	0	0	182	449	1203
Southern Asia	7	21	55	0	2	12	9	44	163
Eastern Asia	6	18	63	0	158	841	8	190	964
China		*10*							
South Korea		*0.0*							
Taipei		*0.2*							
South East. Asia	24	52	115	0	19	114	25	77	258
Indonesia		*10*							
Malaysia		*11*							
Philipines		*0.3*							
Thailand		*2*							
Oceania	8	20	49	0	11	54	0	2	9
Japan	0	0	0	0	0	0	11	59	230
Greenland	0	2	12	0	0	0	1	5	27

Implementation of CCS towards 2030

Based on the assumption that 0.5 Gt industrial and 2 Gt power related CO_2 is avoided by CCS in 2030, this means that in 2030 about 3.5 Gt have to be captured and stored. Under the assumption of a linear built up of CCS implementation, this implies that starting at 2025 about 10 GtCO_2 in total have to be stored. Starting substantial implementation from 2020 this implies that about 20 GtCO_2 has to be stored in 2030. This potential can only be realised if sufficient capacity is available for the whole lifetime of the capture units. Assuming 30 years of operation (and no further growth in capacity), over 100 GtCO_2 storage capacity should be available.

The question is whether this amount of CCS is realistic and whether a realistic time frame can be attached to the implementation; not only seen on global level, but also on regional level.

To address this issue, it should be understand what may determine maximum levels and maximum penetration rates of CCS. We distinguish the following crucial elements:

- pace of implementation and time-scale of large-scale introduction of CCS;
- availability of sufficient storage capacity;
- availability of technology;
- non-technical barriers;
- financial incentives.

Is the pace of technology development sufficient?

Before large-scale implementation of CCS can be done, technology development is still required, mainly in the capture part of the CCS chain. It is envisage that at least two generations of pilot and demonstration plants are required. As demonstration plants need often considerable time this will affect the timing of full-scale commercial implementation. On the other hand, no real technical showstoppers have yet been identified. Based on current development, and the need for demonstration of the technology, large-scale implementation could probably be realised at 2020.

Due to the forecasted increasing demand of power and the relatively high age of the stock, considerable amounts of power capacity will be constructed over the next decades. To be able to apply CCS after 2020 on more plants than built during the period 2020/2030, it is possible to apply the 'capture-ready' approach, i.e. plant built in the period of say 2015/2020 should be built in such a way that retrofitting is relatively easy. This may boost the percentage of plants equipped with CCS in 2030. To our knowledge, currently these lines of thoughts are under development in the European Union. In principle, also retrofitting of existing stock is possible, but often (far) more expensive then newly built plants.

Is there enough storage capacity?

In a first analysis based on the current knowledge of storage potential worldwide (composed from current knowledge), 100 $GtCO_2$ is small compared to the storage capacity available worldwide. If we depart from a conservative assumption that only oil and gas fields are available and/or allowed to store CO_2, still in almost all countries and regions sufficient storage capacity is available, even if conservative low estimates are considered (see Table 4 for break down of storage capacity).

As can been seen, not sufficient information is available for important countries like China and India. The first estimates for storage capacity of oil and gas fields for China are 10 $GtCO_2$, which is considerably less than the required capacity of 70 $GtCO_2$. On the other hand, storage potential of ECBM is potentially very large in China (representing the majority of the storage capacity of East Asia). The ECBM technology for storing CCS is however still in demonstration phase and it is not sure whether it can be applied on sufficient large scale. Also for India with an anticipated required storage estimate of 12 $GtCO_2$ not sufficient information is available. In Japan no substantial oil and gas reserves or aquifers reservoirs have been located up to date. It should be noted that the figures on oil and gas reserves do not show whether the storage capacity is available at the right time. But seen for the time frame (up to 2030) and the relatively small demand, in most cases this will be not an issue.

If we zoom in to smaller country level, there may be more discrepancies. But based on the current info, this is difficult to assess. See Table 4 for more detailed info on storage for some countries.

Is the technology available?

The CCS technology can be applied worldwide and transfer of the capture technology might probably not a show stopper. We expect that the technology for large-scale units can be available for implementation from 2015. However, as there is still the need for demonstration plants and cost reduction, commercial implementation will only take off after 2020. This is especially the case for capture from power plants. In the industry, there are also some 'low hanging fruits' which might be applied in an earlier stage. Examples are relatively pure sources of CO_2 from gas processing, LNG production, ethylene oxide production, hydrogen and ammonia production.

Are there non-technical barriers?

Legal implications and public attitude may be important with respect to carbon capture and storage. Based on the current developments in legal and regulatory issues it is not yet sure the pace is quick enough. Especially this might be the case where it concerns the implementation of larger-scale demonstration facilities. Open issues are e.g. the classification of CO_2, long-term liability, and cross boundary movement of CO_2.

Recently some substantial steps have been made to remove legal barriers. The London Protocol and the OSPAR Convention have been adapted to make possible to inject CO_2 from CCS operation into the subsea bed. In 2008, the EU wants to publish a framework directive on CCS to regulate CCS in Europe, and steps are being made to include the technology in the European Emission Trading Scheme. The European Commission also announced that they consider CCS mandatory after 2020 for new (coal-fired) power plants. Such a step has already been taken by District of British Columbia, where since February 2007 all new coal-fired plants need to be equipped with CCS.

An important aspect is the development of adequate and advanced set of monitoring reporting and verification protocols. The main goal for monitoring is to gain increasing evidence that the CO_2 storage is not leaking and if it is leaking, to take timely remedial action (if required). Monitoring should also be performed to meet regulatory obligations and certifying CO_2 storage for possible emission trading schemes, to inform the public and enhance confidence in the technology and to improve and update risk assessment models.

Despite the increased attention to the subject in the media in the last year, the majority of the public is still quite unaware of this option.

Financial incentives

The financial incentives for the implementation of CCS is almost completely political induced. Exceptions might be application of CO_2 in niche markets as the enhancement of hydrocarbon production or in long during chemical compounds. Strong, long-term and reliable policies are therefore a prerequisite, as CCS requires large upfront investment which should be recovered over a longer period. Investment will only be made, when substantial confidence is present in the market.
Emission trading schemes and the Kyoto instruments Joint Implementation and Clean Development Mechanism[1] are currently seen as the most important instruments to finance CCS activities, especially in the commercial phase of the implementation. Alternatively, CCS could be made mandatory, taking away all uncertainties out of the market.

Scenario for implementation of CCS

Table 5 shows an implementation scheme of CCS for the various regions in the world. It should be noted that the ambitious level to capture 3.5 $GtCO_2$ in 2030 will only be feasible when a adequate and dedicated CO_2 infrastructure will be feasible. This will be a major achievement and can only be realised in 2030 when in an early planning stage, CCS is envisaged. This may be feasible in some regions (e.g. the European Union announcement of mandatory after 2020 and already in Norway and British Columbia (CA)), but in countries like China and India this seems optimistic.

[1] The Clean Development Mechanism might be a vehicle to speed up the transfer of technology to developing countries. It should be noted that CCS for CDM is currently not yet approved by the UNFCCC. Nevertheless, it is expected that this will be the case far before 2020, assuming that the CDM instrument is still in place

Table 5. Implementation scenario for CCS in new coal and natural gas-fired power plants

	2015		2020		2025		2030	
% of new capacity	coal	NG	coal	NG	coal	NG	coal	NG
USA and Canada	4%	0%	13%	12%	56%	23%	100%	44%
Other OECD	30%	0%	56%	12%	92%	23%	100%	44%
Latin America	0%	0%	5%	8%	21%	18%	42%	26%
Russia	0%	0%	12%	12%	56%	34%	83%	39%
China	0%	0%	6%	6%	24%	12%	56%	17%
India	0%	0%	6%	6%	24%	12%	56%	17%
Other	0%	0%	7%	9%	33%	16%	59%	30%
total	**2%**	**0%**	**10%**	**10%**	**37%**	**20%**	**70%**	**35%**
GW cap. with CCS								
USA and Canada	4	0	16	23	89	65	195	176
Other OECD	6	0	17	14	35	39	45	102
Latin America	0	0	0	7	1	20	2	35
Russia	0	0	1	8	9	26	19	32
China	1	0	20	4	85	12	227	24
India	0	0	2	2	11	5	30	10
Other	0	0	3	22	14	50	28	115
total	**11**	**0**	**60**	**79**	**244**	**218**	**546**	**494**

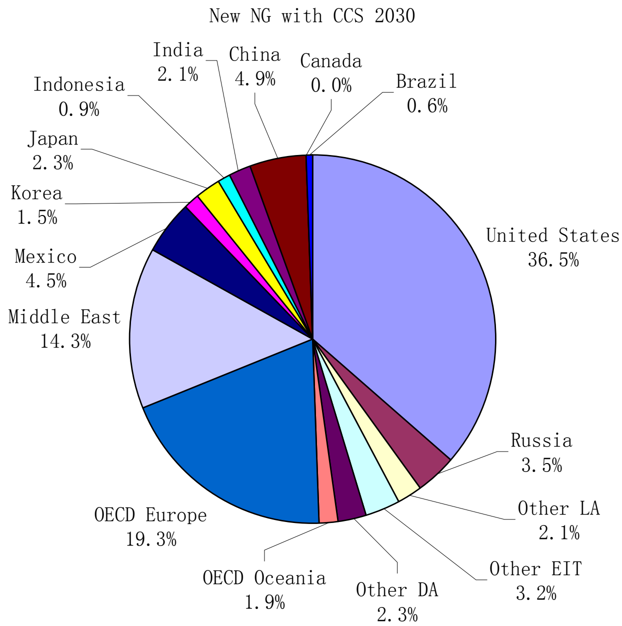

Figure 5. percentage of new NG-fired power plants in 2030 equipped with CCS by country or region

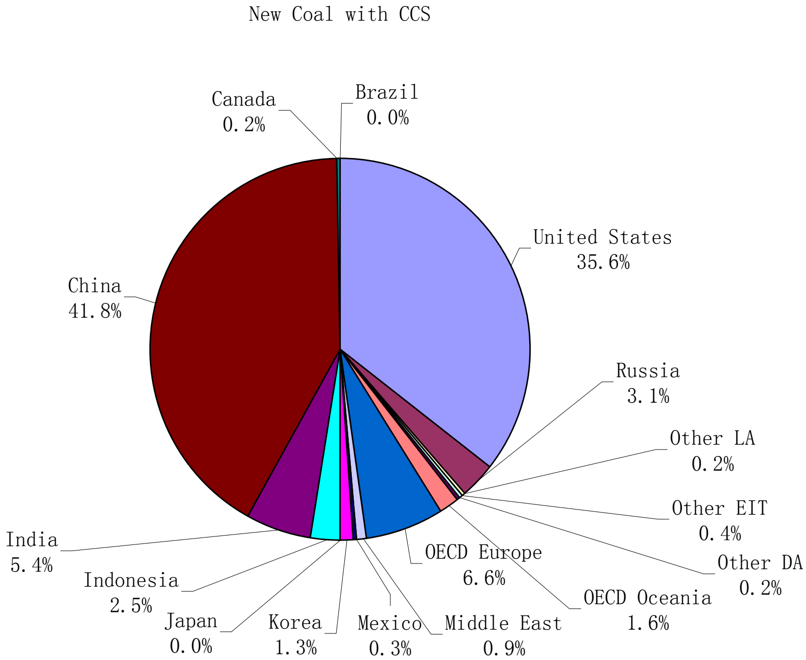

Figure 6. percentage of new coal-fired power plants in 2030 equipped with CCS by country or region

Table 5 shows an implementation scenario for coal and natural gas fired power plants. It starts from the basic assumption that only newly built power stations will be equipped with CCS. For OECD countries, specifically Europe, it is expected that in the period towards 2020 CCS will be implemented for a limited set of plants, or will be made capture-ready to some extent. The expectation is that in the starting phase CCS will mainly be applied in OECD countries, especially those countries with good access to (depleted) hydrocarbon reservoirs or possibly suitable aquifers. After 2020, the rest of the world will gradually implement CCS, mainly applied at coal-fired stations. CCS may also be applied to biomass-fired plants, resulting in a net sink of CO_2. Implementation of CCS and its magnitude will be steered mainly by political willingness to reduce greenhouse gas emissions substantially and the availability of alternative solutions that can contribute significantly in the timeframe up to 2030.

Figure 5 and Figure 6 show the percentage of new power plants (natural gas and coal-fired) with CCS by region for the period 2015 to 2030. In 2030 about 70% of the new coal-fired power plants will be equipped with CCS and about 35% of the natural-gas fired power plants.

Besides power plants also industry may implement CCS. Around 2015 to 2020 and upwards industry may have good opportunities to capture and store CO_2 from pure sources, e.g from production processes for ammonia, hydrogen, ethylene oxide, LNG and gas processing.. In a next stage also the large and heavy industries will introduce CCS, specifically the iron and steel, refineries and cement industry.

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