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Bhawna Singh

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Faculty of Engineering Science and Technology
Department of Energy and Process Engineering
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Dedicated to my parents

ABSTRACT

Carbon capture and storage (CCS) is the most viable option to reduce CO_2 emissions from power plants while continuing the use of fossil fuels required to satisfy the increasing energy demand. However, CCS is an energy intensive process, and demands additional energy, chemicals and infrastructure. The capture processes may also have certain direct emissions to air (NH_3, aldehydes, solvent vapor etc.) and generate solid wastes from degradation byproducts. A trade-off in environmental impacts is expected, and with the large-scale application of CCS needed to make any significant reduction in CO_2 emissions, these potential trade-offs can become enormous in magnitude. Therefore a systematic process of evaluation of complete life cycle for all available CCS options and large-scale CCS deployment scenarios is needed. Life Cycle Assessment (LCA) methodology is well-established and best suited for such analysis.

Methodology of hybrid life cycle assessment is used in this work and methodological developments are made to build-up simple approaches for evaluation of future CCS systems and scenarios. The thesis also extends the result presentation to more comprehensible damage indicators and evaluates control potentials for human health, ecosystem damage and resource depletion for the technology.

The results of the study shows that the CCS systems achieve significant reduction in global warming impact but have multiple environmental trade-offs depending on the technology. These trade-offs are mainly due to energy penalty from capture process, infrastructure development and waste treatment processes. Damage assessment shows that the CCS systems greatly reduce human health damage and ecosystem damage by mitigating the climate change impact while increasing the resource consumption. Scenario assessment results show the clear advantage of global CCS integration scenarios over the Baseline scenario having significantly lower impact potential scores for all impact and damage categories from fossil-based electricity production.

This thesis thus illustrates the assessment of a novel technology, its overall benefits and damages, development potentials and the implications of its large scale application.

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Bhawna Singh

Trondheim, March 2011

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Paper 2 Veltman, K., Singh, B., Hertwich, E., 2010. Human and environmental impact assessment of post-combustion CO_2 capture focusing on emissions from amine-based scrubbing solvents. *Environmental Science and Technology* 44: 1496-1502.

Paper 3 Singh, B., Strømman, A. H., Hertwich, E., 2010. Comparative impact assessment of CCS portfolio: Life cycle perspective. Presented at *International Conference on Greenhouse Gas Technologies 2010* (GHGT-10) 19-23 September 2010, Netherlands. *Accepted in Energy procedia.*

Paper 4 Singh, B., Strømman, A. H., Hertwich, E. G., 2010. Environmental damage assessment of carbon capture and storage : Application of end-point indicators. *Submitted to Journal of Industrial Ecology*.

Paper 5 Singh, B., Strømman, A. H., Hertwich, E. G., 2010. Environmental assessment of fossil-based electricity scenarios: Implications of carbon capture and storage. *Submitted to Energy and Environmental Science*.

AUTHOR'S CONTRIBUTION

The papers are co-authored. The author of the thesis has performed the following work for the papers:

Paper 1 Data collection, modeling, analysis and writing.

Paper 2 Contributed to the power plant emission modeling.

Paper 3 Data collection, modeling, analysis and writing.

Paper 4 Data collection, modeling, analysis and writing.

Paper 5 Data collection, modeling, analysis and writing.

1. INTRODUCTION

1.1 Background

Human activities since the industrial revolution have greatly increased the concentration of greenhouse gases (GHGs) in atmosphere, resulting in global warming (IPCC 2001). The effect of global warming is said to cause adverse climate changes world-wide. CO_2, a greenhouse gas released by burning fossil fuels and biomass makes the largest contribution to anthropogenic climate change. Currently the world economies emit approximately 26Gtons of CO_2 annually to the atmosphere and in the absence of explicit efforts to address climate change and increasing demand of energy could result in 9000Gt cumulative CO_2 emitted to atmosphere over this coming century (GTSP 2006). However, to prevent dangerous anthropogenic interference with the climate system UNFCCC the cumulative amount of CO2 released to atmosphere over this century would need to be limited to 2600-4600 GtCO2 (GTSP 2006).

Technology will play a key role to limit CO_2 emissions in atmosphere and various technological options so proposed include (IPCC 2005):
(i) reducing energy consumption, e.g. by increasing energy efficiency.
(ii) switching to less carbon intensive fuels, e.g. natural gas instead of coal.
(iii) increasing the use of renewable energy sources or nuclear energy.
(iv) sequestering CO_2 by enhancing biological absorption, e.g. forestation.
(v) capturing and storing CO_2 chemically or physically.

Carbon dioxide capture and storage (CCS) technology involves capturing CO_2 from industrial and energy related fossil burning sources using some solvent or other process, transport of captured CO_2 to a storage location and storing it away from the atmosphere for long-term. Fossil-fuel fired power plants are the single largest point sources of CO2 emissions and form the most likely application of carbon capture and storage. CCS also draws additional attention as it allows continuing the use of fossil fuels required to satisfy the increasing energy demand. The *Energy Technology perspectives* scenarios (IEA 2008) demonstrate that CCS will need to contribute nearly one-fifth of the necessary emissions reductions to reduce global GHG emissions by 50% by 2050 at a reasonable cost. CCS is therefore essential to achieve deep GHGs emission cuts. World major economies have started CCS technology development programmes to achieve its commercial deployment. Several power plant projects using carbon capture and storage are planned (ZEP 2009). The European Commission has also proposed a directive providing legal framework for environmentally safe capture and geological storage of carbon dioxide in the European Union (Commission 2008).

Various factors to be considered for deciding the role of CCS in climate change mitigation include cost and capacity of emission reduction, demand for primary energy, and range of applicability and associated technical risk. Other important factors are the social and environmental consequences, the safety of the technology, the security of storage and ease of monitoring and verification and the extent of opportunities to transfer the technology to developing countries. This research work evaluates and discusses the environmental aspects of carbon capture and storage.

Why life cycle assessment of CCS?

CO_2 capture technology captures 85-95% of the CO_2 produced at the power plant. However, the capture process in itself has high energy requirements and causes efficiency penalty on power cycles. This results in consumption of more primary fuel to produce same amount of electricity, increasing the emission of non-CO_2 pollutants from combustion and other fuel production related emissions. Solvent related emissions (NH_3, aldehydes, solvent vapor) and wastes generated from the CO_2 capture process may have adverse environmental impacts. Capture facility and extensive infrastructure for CO_2 transportation and storage is also required. Thus, the CCS system induces demand on fuel, chemicals and infrastructure; increase the indirect emissions in the value chain and direct emissions from power plant and capture facility. Application of CCS technology on large-scale will result in huge magnitude of such emissions. A trade-off in environmental impacts is expected, and therefore a systematic process of evaluation for all stages of CCS and impacts related to large-scale CCS deployment is needed.

Life Cycle Assessment (LCA) is a well-established method of analyzing environmental impacts in a systematic manner. In addition to the calculation of overall impacts, LCA can also be used to identify the site for potential developments in the chain so as to minimize the adverse impacts.

1.2 Literature review

Much work has been published on the technical and economic evaluation of CCS, strengthening the idea of CCS being a major potential option for mitigating global warming. Few environmental LCAs have also been conducted mostly focusing on coal systems and particular CCS technology. An early review of these studies was presented in Hertwich et al. (2008) and an updated overview of the scope of existing LCA studies is presented in table 1.1.

These studies differ in terms of the technologies assessed, detail in processes modeled, completeness of the life cycle inventory and emissions included in the assessment. Doctor et al. (1993), Summerfield et al. (1995), Waku et al. (1995) and Audus and Freund (1997) made some early assessments of different CCS configurations based on mass and energy balance. Waku et al. reported the emission control potential for liquefied natural gas combined cycle power plant and integrated coal gasifier combined cycle power plant (IGCC) in the range of 61%-69% and 65%-76%, respectively. Summerfield et al. concluded that the majority of the atmospheric emissions come from fuel processing and transport rather than from the power generation process themselves. Rao et al. (2002) used an Integrated Environmental Control Model (IECM) simulation framework to model a complete coal fired power plant with multi-pollutant environmental controls including CCS and concluded that the CO_2 control system generates several new waste products, principally ammonia gas and hazardous reclaimer

Table 1.1. Literature review - scope of environmental assessments of power generation with CCS system

	Fuel		Capture			Transport		Storage				LCA method				Emissions		
Study	C	NG	PoC	PrC	Oxy	P	S	G	ER	O	Ot	MEB	FG	F	H	CO_2	GHG	Ot
Doctor et al. (1993)	X			X		X		X				X				X		
Summerfield et al. (1995)	X	X	X	X		X		X		X	X	X				X		X
Waku et al. (1995)	X	X	X	X		X	X	X		X		X				X		
Audus & Freund (1997)	X	X	X	X				X		X	X	X				X		
Rao & Rubin (2002)	X		X									X	X			X		X
Lombardi (2003)	X	X	X	X	X									X		X	X	
Benetto et al. (2004)	X		X											X		X	X	X
Khoo & Tan (2006)	X		X			X	X	X	X	X				X		X	X	X
Viebahn et al. (2007)	X	X	X	X	X	X		X						X		X	X	X
Koornneef et al. (2008)	X		X			X		X						X		X	X	X
Hertwich et al. (2008)		X	X			X			X						X	X	X	X
Odeh & Cockerill (2008)	X	X	X	X		X		X							X	X	X	X
Pehnt & Henkel (2009)	X		X	X	X	X		X						X		X	X	X
Korre et al. (2010)	X		X											X		X	X	X
Veltman et al. (2010)	X	X	X										X					X
Singh et al. (2010)		X	X			X		X							X	X	X	X
Nie et al. (2010)	X		X		X	X		X						X		X	X	X
Singh et al. (2010)	X	X	X	X	X	X		X							X	X	X	X

Fuel: C, coal; NG, natural gas. Capture: PoC, post-combustion; PrC, pre-combustion; Oxy, oxyfuel. Transport: P, pipeline; S, ship.

Storage: G, geological; ER, enhanced oil recovery; O, ocean; Ot, others. LCA method: MEB, mass and energy balance; FG, foreground LCA; F, full LCA; H, Hybrid LCA.

bottoms, while on the other hand reducing emissions of particulate matter and acid gases such as SO_2, HCl and NO_2. Lombardi (2003) provided a comparative assessment of capture processes for different power plant configurations, focusing on CO_2 emission and concluded that IGCC plant gave highest score for greenhouse effect with majority of emissions coming from the maintenance/operation phases. Khoo and Tan (2006) analyzed different capture technologies combined with various sequestration systems for coal fired power plants. Viebahn et al. (2007) used an integrated assessment approach for screening-level LCA for CCS and other renewable energies, taking into consideration all relevant technologies and pollutants. For a pulverized hard coal power plant with CCS, the study showed that all environmental impact parameters increase by about 40%. Koornneef et al. (2008) made life cycle assessments of three pulverized coal fired electricity supply chains with and without CCS and concluded that the most notable environmental trade-offs from CCS were human toxicity, ozone layer depletion and fresh water ecotoxicity . Odeh and Cockerill (2008) examined life cycle GHG emissions for fossil fuel power plant with CCS. Hertwich et al. (2008) employed hybrid life cycle assessment method to assess the global warming and acidification impacts over the life cycle of a NGCC combined with CO_2 capture for enhanced oil recovery (EOR). Pehnt and Henkel (2009) presented LCAs for several lignite power plant technologies. Korre et al. (2010) compared life cycle performance of coal power generation system with and without post-combustion CO_2 capture, and also evaluated alternative solvents. Veltman et al. (2010) calculated impacts of post-combustion capture focusing on emissions from amine based solvent on human and environment. Singh et al. (2010a) used hybrid life cycle model to calculate various impacts for electricity generation from natural gas plant with post-combustion CO2 capture, transport and storage.

The state-of-art LCA's for CCS available at the start of this research work was limited to particular capture process, coal fired plants and/or few selective impacts, mainly global warming. Latter studies introduced the LCA focus to broad range of impact categories. This research work contributed the first full scale LCA for natural gas CCS system (Singh et al. 2010a). Latest work in this field has been presented at the International Conference on Greenhouse Gas Technologies 2010 (GHGT-10), where Nie et al. (2010) presented work on comparative assessment of the environmental impacts of oxyfuel and postcombustion CCS systems for coal, and Singh et al. (2010b) presented the results for comparative life cycle assessment of CCS portfolio with different CCS options for coal and natural gas, considering post-combustion, pre-combustion and oxyfuel capture; pipeline transport and geological storage of the captured CO_2.

1.3 Research objectives

This research work has two objectives.

First, to evaluate the life cycle impacts and consequent damages from various carbon capture and storage (CCS) technologies for electricity generation from coal and natural gas. Overall impacts from different CCS options are compared with the respective electricity generation system without CCS to give net benefits and trade-offs for each system. And, Second, to assess the environmental implications of large scale CCS deployment scenarios. The scenarios with large scale CCS application will have high magnitude of impacts. Research and development in technology and learning-by-doing may reduce the related life cycle impacts for CCS in future. These potential future techno-economic improvements and extent of CCS deployment will influence the environmental scenarios with CCS.

1.4 Structure of the work

Chapter 2 provides an overview of carbon capture and storage technology, discussing various options for the technical components and their economic cost. This chapter also provides economic potential and implementation scenarios for CCS.

General framework for life cycle assessment and the approaches used in the research work for the comparative assessment, evaluation of future environmental performance and CCS scenario assessment are introduced and discussed in chapter 3.

Chapter 4 provides the goal and scope, inventory analysis and results for the life cycle environmental assessments. Inventories for different electricity generation technologies and important inputs are attached separately as appendix. Detailed discussion for comparative impact assessment for various CCS configurations and a synopsis of the scenario assessment are presented. Futuristic LCA and results for CCS scenarios are discussed elaborately in the attached paper. Chapter 5 provides summary of the articles based on the research work. Full papers are attached to the thesis. Conclusions for the study and recommendations for future work are made in chapter 6.

2. CARBON CAPTURE AND STORAGE

2.1. Technical overview

Carbon capture and storage technology comprises of three components: separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term sequestration away from atmosphere. There is wide range of technology options (Figure 2.1) for these 3 components which are in various stages of development, availability and economic feasibility.

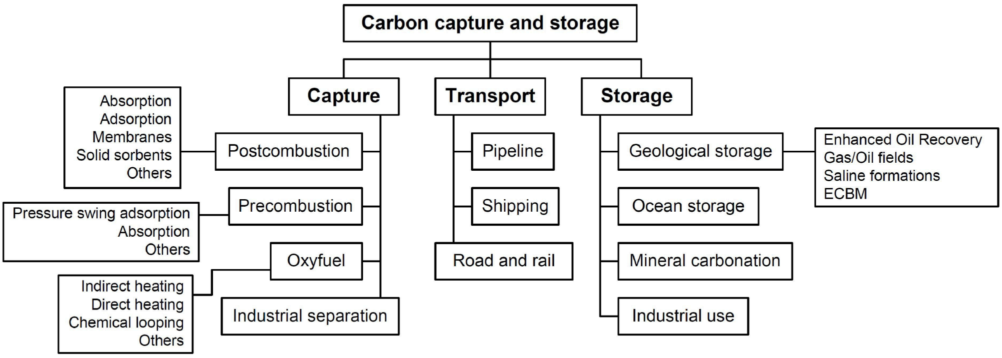


Figure 2.1. Various technology options for carbon capture and storage

2.1.1. Capture

Post-combustion capture

Post-combustion capture system separates CO_2 from the flue gases generated from large-scale fossil fuel combustion such as in power plants, cement kilns and industrial furnaces. Absorption process based on chemical solvents (usually an amine eg. MEA, MDEA, Sulfinol) is currently the preferred technique for post-combustion CO_2 capture. Figure 2.2 show a general schematic of a coal fired power plant with amine based post-combustion capture system.

In a typical absorption based post-combustion CO_2 capture process the hot flue gas stream at 100^{o}C is cooled down to the absorber temperatures between 40-60^{o}C and is brought into contact with the solvent in the absorber. The CO_2 gets bound with the chemical solvent in the

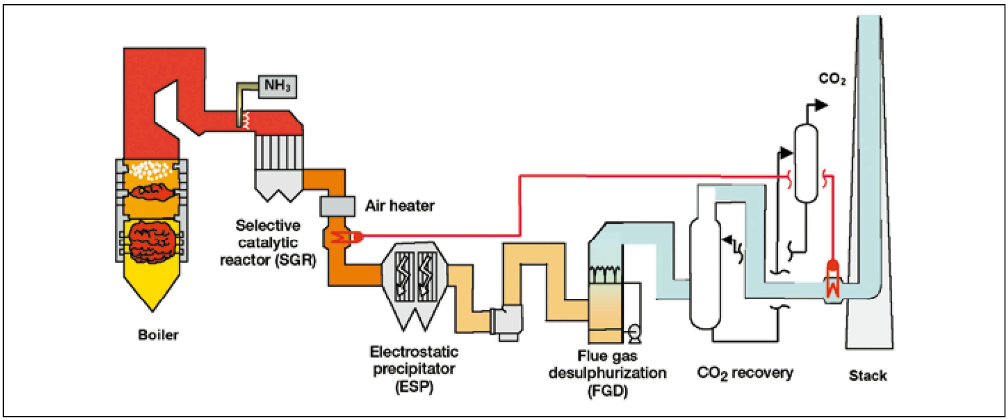


Figure 2.2. Schematic of a pulverized coal-fired power plant with amine based CO_2 capture system and other emission controls (Source: IPCC 2005)

absorber and this 'rich' solvent is pumped to the top of the stripper, where the regeneration of the chemical solvent is carried out at the elevated temperatures (100-140^{o}C). The CO_2 product gas stream leaves the stripper and the 'lean' solvent, containing far less CO_2 is cooled and pumped back to the absorber. The thermal energy needed to regenerate the solvent and the electrical energy required to operate pumps, blower and to compress the CO_2 recovered results in efficiency penalty on power cycles.

CO_2 content of the flue gases vary from 3-15% depending on the fuel type and the flue gas is usually at atmospheric pressure. Typical CO_2 recovery with this process is 80-95%. NO_x and SO_x are pre-removed to very low values before CO_2 capture to prevent their reaction with the solvent which otherwise leads to the formation of heat stable salts causing a loss in absorption capacity of the solvent, extra consumption of chemicals to regenerate the solvent and risks the formation of solids waste.

Various novel solvents with reduced energy consumption for solvent regeneration are being developed. Besides solvents, novel process designs with improved packing types, higher concentration of MEA solution, catalytic removal of oxygen in flue gases etc. are studied. Pressure swing adsorption process, membrane separation, use of solid sorbents eg. CaO are other emerging technologies for post-combustion CO_2 capture.

Pre-combustion capture

Pre-combustion capture system principally involves producing a mixture of hydrogen and carbon monoxide (syngas) from a primary fuel and then separating the CO_2 stream. The H_2 stream so produced is then used as fuel. Figure 2.3 presents a schematic for gasification process producing electricity with CO_2 capture, hydrogen or other chemical products.

Fuel is converted into synthesis gas ($CO+H_2$) via two main routes, 'steam reforming' and 'partial oxidation'. In steam reforming, high temperature steam reacts with fuel and in partial oxidation the fuel is reacted with oxygen. Sulphur (H_2S) and particles are to be removed to

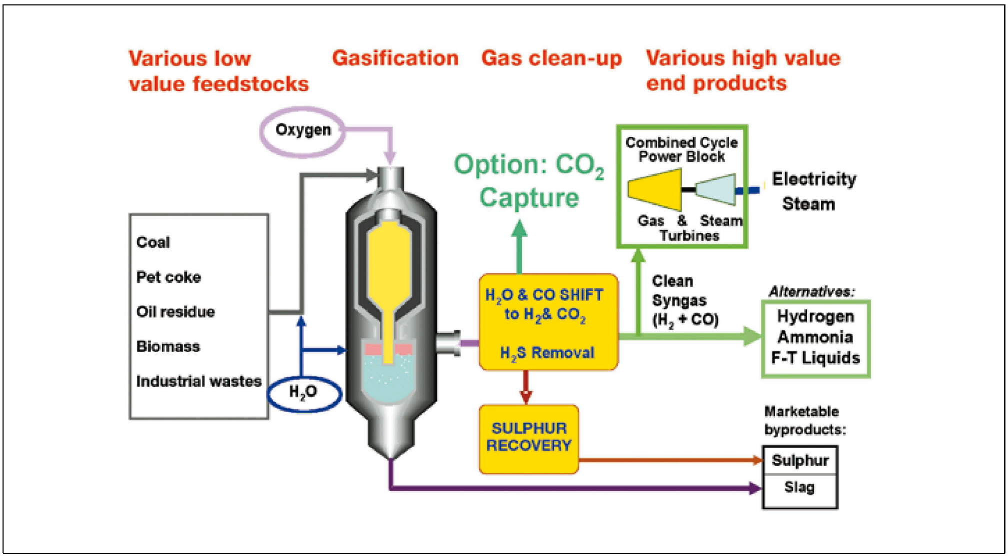


Figure 2.3. Schematic of a gasification process showing options with CO_2 capture and electricity, hydrogen or chemical production (Source: IPCC 2005)

maintain the operability of the catalyst and avoid any damage to gas turbine or damage in the subsequent processing steps.

Steam reforming : $C_xH_y + xH_2O \leftrightarrow xCO + (x+y/2)H_2$

Partial oxidation : $C_xH_y + x/2O_2 \leftrightarrow xCO + (y/2)H_2$

This is followed by 'water gas shift reaction' where carbon monoxide is reacted with steam at high temperature in presence of catalyst (e.g. Fe-Cr catalyst, copper-based catalyst) and converted to CO_2.

Water gas shift reaction : $CO + H_2O \leftrightarrow CO_2 + H_2$

This CO_2/H_2 mixture with 15-60% concentration of CO_2 and total pressure of 2-7 MPa is sent to the separation stage. Physical solvent based absorption processes are mostly applicable to remove CO_2 from such mixed stream from the shift reaction. Common physical solvents for pre-combustion CO_2 capture are selexol, rectisol, purisol etc. the regeneration of solvent is carried out by release of pressure at which CO_2 evolves from the solvent. The process has low energy consumption, as only the energy for pressurizing the solvent is required.

Chemical solvents similar to those used in post-combustion capture can also be used to remove CO_2 from syngas at partial pressures below 1.5 MPa. Pressure swing adsorption, sorption enhanced reactions, membrane reactors, use of calcium oxide can be other options for CO_2 separation from syngas.

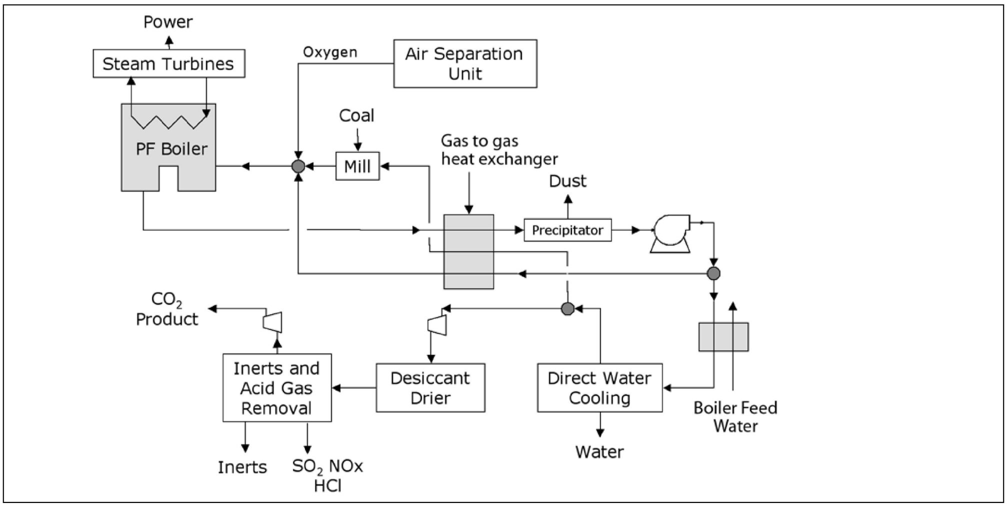


Figure 2.4. Schematic of an oxyfuel, coal fired power plant (Source: IPCC 2005)

Oxy-fuel combustion capture

Oxyfuel combustion capture system involves burning fossil fuel in nearly pure oxygen and producing a nitrogen free flue gas with water vapor and carbon dioxide as its main components. Condensation of the flue gas then creates an almost pure CO_2 stream. Figure 2.4 shows a schematic of oxyfuel combustion in coal fired power plant.

The Oxyfuel combustion process eliminates nitrogen from the flue gas by combusting the fuel in a mixture of oxygen and recycled flue gases. Combustion of fuel with pure oxygen has a combustion temperature of about 3500°C, far too high for typical power plant materials. This combustion temperature is controlled by the proportion of flue gas and gaseous or liquid-water recycled back to the combustion chamber. The net flue gas, after condensation contains about 80-98% CO_2 depending on the fuel and oxyfuel combustion process. A sequence of steps also removes ash and other particles, sulfur, inert gases etc.

The CO_2 capture efficiency is very close to 100% in oxyfuel combustion capture system. A challenge to this technology is the air separation technology needed to produce oxygen. Air separation is highly energy demanding, thus reducing overall plant efficiency. Current methods of oxygen production by air separation comprise cryogenic distillation, adsorption using multi-bed pressure swing units and polymeric membranes.

2.1.2. Transport

Pipeline

Pipelines are the most established and common method for transporting CO_2. Gaseous CO_2 is dried and compressed typically to a pressure above 8MPa in order to avoid two-phase flow and increase the density of the CO_2, making it easier and less costly to transport. Pipelines can be designed for onshore and offshore CO_2 transport. Onshore and underwater CO_2 pipelines are similar to construction of hydrocarbon pipelines which have an established base of engineering experience. Onshore pipelines are usually buried to depth of 1m and the offshore lines are almost always buried in shallow water. Deeper water pipelines, narrower than 400mm are trenched and sometimes buried to protect them from the damage by fishing gear. Other equipments for operation and maintenance include valves, compressors, pumps, tanks, monitoring points and block valves. Pipelines are periodically cleaned and inspected by 'pigs', piston -like devices driven along the line by gas pressure. Pipelines are also monitored externally. Land pipelines are inspected from the air and the underwater pipelines are monitored by remotely operated, video recording capable submersibles, detecting leaks acoustically or by measuring chemical releases.

Shipping

The use of ships for transporting CO_2 across the sea is in a developing stage. CO_2 can be transported as liquid in ship tankers that carry CO_2 in insulated tanks at a temperature well below ambient and high pressure. Construction of carbon dioxide tankers is same as construction of existing gas carriers. Liquid CO_2 is charged from the temporary storage tank to the pressure-type and semi-refrigerated CO_2 cargo tank. High pressure and refrigeration prevent contamination of CO_2 by humid air, formation of dry ice and capture and liquefy boil-off and exhaust CO_2 during transportation. At the onshore delivery point, the CO_2 is unloaded from ships into temporary storage tanks and at the offshore delivery points, ships might unload to a platform, to floating storage facility or directly to a storage site.

Road and rail

Road and rail tankers are also technically feasible options. These systems transport CO2 at a temperature of $-20^{o}C$ and at 2MPa pressure. However, they are uneconomical compared to pipelines and ships, except on a very small scale, and are unlikely to be relevant to large-scale CCS.

2.1.3. Storage

Geological storage

Geological storage of CO_2 can be made to oil and gas reservoirs, deep saline formations, unminable coal beds etc. and uses the same technologies as developed by oil and gas industry. Prior to storage, CO_2 is compressed to a dense 'supercritical' fluid state and then injected into the rock formation at depth below 800m. Fraction of CO_2 retained in formation depends on a combination of physical and geochemical trapping mechanisms. Presence of impermeable layer of shale and clay rock above the storage formation is known as 'cap rock' and makes physical trapping for CO_2. The mechanism known as geochemical trapping occurs as the CO_2 reacts with the in situ fluids and host rock. Chemical reactions between the dissolved CO_2 and rock minerals form ionic species, converting fraction of the injected CO_2 to solid carbonate minerals over millions of years. Well-drilling technology, injection technology, computer simulation of storage reservoir performance and monitoring from existing applications are being developed further for utilization in the design and operation of geological storage.

Ocean storage

Ocean storage could be done by injecting CO_2 into the water column (below 1000m) via a fixed pipeline or a moving ship, or by depositing CO_2 via a fixed pipeline or offshore platform onto the sea floor at depths below 3000m where CO_2 is denser than water and can form a 'lake' delaying dissolution of CO_2 into the surrounding environment. The dissolved and dispersed CO_2 would eventually become part of the global carbon cycle and eventually equilibrate with the CO_2 in the atmosphere. Ocean storage and its ecological impacts are still in the research phase.

Mineral carbonation

Mineral carbonation involves converting CO_2 to solid inorganic carbonates using alkaline and alkaline-earth oxides, such as magnesiun oxide (MgO) and calcium oxide (CaO), which are present in naturally occuring silicate rocks. Chemical reactions between these materials and CO_2, produces silica and carbonates that are stable over long time scales and can therefore be disposed in areas such as silicate mines or re-used for construction purposes. Naturally occurring mineral carbonation process is very slow and needed to be considerably accelerated to be viable for CO_2 storage. A commercial process would require mining, crushing and milling of the mineral-bearing ores and their transport to a processing plant receiving a concentrated CO_2 stream from the capture plant. The carbonation process energy required would be 30 to 50% of the capture plant output. The technology is currently in the research stage.

Industrial uses of CO_2

Industrial uses of CO_2 include chemical and biological processes where CO_2 is a reactant, such as in urea and methanol production, as well as in various technological applications e.g. in horticulture industry, food packaging, welding, beverages and fire extinguishers. The typical lifetime of CO_2 storage by industrial processes is only few days to months and do not contribute meaningfully to climate change mitigation. Also, the total industrial use is much smaller compared to the anthropogenic CO_2 emissions.

2.2. Cost of carbon capture and storage

2.2.1. Component costs

Cost of CO_2 capture

The cost of capturing CO_2 is the largest component of overall CCS costs and includes the additional capital requirements, added operating and maintenance costs incurred for any particular application. A large number of technical and economic factors related to the design and operation of both the CO_2 capture system and the power plant influence the overall cost of capture. Table 2.1 provides a summary of CO_2 capture cost based on current technology.

Cost of CO_2 transport

CO_2 transportation costs depend on the volumes needed to be transported and the distances

Table 2.1. CO_2 capture cost based on current technology

Cost measures		NGCC plant	PC plant	IGCC plant
Plant efficiency with capture, LHV basis	%	48	33	35
CO_2 reduction per kWh	%	86	85	86
Total capital requirement with capture	US$/kW	998	2096	1825
COE with capture	US$/MWh	54	73	62
Increase in capital cost with capture	%	76	63	37
Increase in COE with capture	%	17	27	16
Cost of CO_2 captured	US$/t$CO_2$	44	29	20
Cost of CO_2 avoided	US$/t$CO_2$	53	41	23
COE = Cost of Electricity, year 2002 basis				

(Source: based on IPCC 2005, Rubin et al. 2007)

involved. Pipeline is the most common and usually most economical method to transport CO_2. The three major cost elements for pipelines are construction costs, operation and maintenance costs and other costs. Offshore pipelines are about 40% to 70% more costly than onshore pipes of the same size. A cost competitive transport option for longer distances at sea might be the use of large tankers. Transport cost of 6 MtCO_2 per year by ship tankers would cost about 10US$/t$CO_2$/500km or 5US$/tCO_2/250km. Transporting same amount over a distance of 1250km would cost about 15US$/t$CO_2$ and is close to the cost of pipeline transport.

Table 2.2. Estimates of CO_2 storage cost

Options	Representative cost range (US$/t$CO_2$ stored)
Geological - storage	0.5-8.0
Geological - monitoring	0.1-0.3
Ocean	
Pipeline	6-31
Ship	12-16
Mineral carbonation	50-100

(Source: based on IPCC 2005)

Cost of CO_2 storage

Geological storage uses similar technology and equipments as in oil and gas industry; however, there is significant variability of cost due to site-specific factors e.g. onshore/offshore, reservoir depth and geological characteristics of the storage formation. The cost of ocean storage is a function of the offshore distance and injection depth. Storage cost for mineral carbonation includes conventional mining and chemical processing. Table 2.2 provides an estimate on different CO_2 storage costs.

2.2.2. Cost of CO_2 captured and CO_2 avoided

'Cost of CO_2 captured' is based on the mass of CO_2 captured or removed from power plant emissions. 'Cost of CO_2 avoided' reflects the average cost of reducing unit mass of atmospheric CO_2 emissions while providing the same amount of useful product as a 'reference plant' without CCS. The cost of CO_2 captured is lower than the cost of CO_2 avoided because the energy required to operate the CO_2 capture systems increases the amount of CO_2 emitted per unit of product.

Cost of CO_2 captured (US\$/tCO_2) = $[(COE)_{capture} - (COE)_{ref}] / (CO_2\ kWh^{-1})_{captured}$

Cost of CO_2 avoided (US\$/tCO_2) = $[(COE)_{capture} - (COE)_{ref}] / [(CO_2\ kWh^{-1})_{ref} - (CO_2\ kWh^{-1})_{captured}$

Where, COE = levelized cost of electricity (US\$/kWh), $CO_2\ kWh^{-1}$ = CO_2 mass emission rate (in tonnes) per kWh generated. The subscripts 'capture' and 'ref' refer to the plant with and without CO_2 capture, respectively.

Mitigation cost estimations for power plant with capture and geological storage as 30-71US\$/tCO_2 avoided for pulverized coal power plant, 38-91US\$/tCO2 avoided for natural gas combined cycle (NGCC) power plant and 14-53US\$/tCO2 for integrated coal gasification combined cycle (IGCC) power plant.

2.3. Economic potential of CCS

Assessments of the economic potential of CCS are based on energy and economic models that study future CCS deployment and costs in the context of scenarios that achieve economically efficient, least-cost paths to the stabilization of atmospheric CO2 concentrations. Models indicate that an explicit policy substantially limiting the emission of greenhouse gases to the atmosphere is needed to deploy CCS on large scale.

2.3.1. Energy scenarios with CCS

IEA Energy Technology perspectives 2008 provide energy scenarios based on projections of economic growth, fuel prices and other macroeconomic drivers. The *Baseline scenario* reflects expected developments on the basis of energy and climate policies already implemented and planned. The *ACT scenarios* envisage bringing global energy-related CO_2 emissions in 2050 back to 2005 levels. The *BLUE scenarios* foresee to reduce CO_2 emissions in 2050 by 50% as compared to 2005 levels. Both ACT and BLUE scenarios also aim for reduced dependence on oil and gas. Figure 2.5 presents technology contribution to the reduction in CO_2 emissions from the baseline scenario in the ACT map and BLUE map scenarios at 2050.

Baseline scenario

In the Baseline scenario, CO_2 emissions are projected to triple from 20.6Gt in 1990 to an unsustainable 62Gt in 2050. It also projects increase of 179% in global electricity production between 2005 and 2050. Electricity production is currently responsible for 32% of total global fossil-fuel use and 41% of the energy-related CO_2 emissions. In 2050, coal based generation is forecast to be 252% higher than 2005, accounting for 52% of all power generation. With an assumption of a negligible price for CO_2, CCS is mainly limited to enhanced oil recovery (EOR) and fuel-transformation applications.

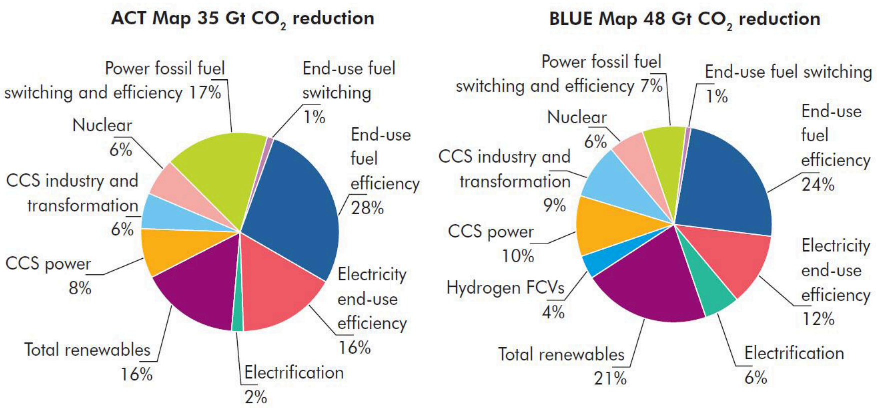


Figure 2.5. Reduction in CO_2 emissions by technology area in ACT map and BLUE map scenarios, 2050 (Source: IEA 2008)

ACT map scenario

In the ACT map scenario, with 50US$/t$CO_2$ emission reduction incentive, global emissions stabilize at around 27Gt CO_2 by 2050. CO_2 capture and storage would increase to 5.1 Gt per year in 2050, and CCS would represent 14% of the total CO_2 abated. 18% of the total electricity generation in 2050 would be from plants equipped with CCS. Retrofitting of power plants with CO_2 capture would play an important role in the power sector. The CO_2 emission reduction incentives and other measures introduced in the ACT map scenario significantly change the electricity mix, resulting in increases in nuclear and renewable power and reductions in fossil-fuelled power.

BLUE map scenario

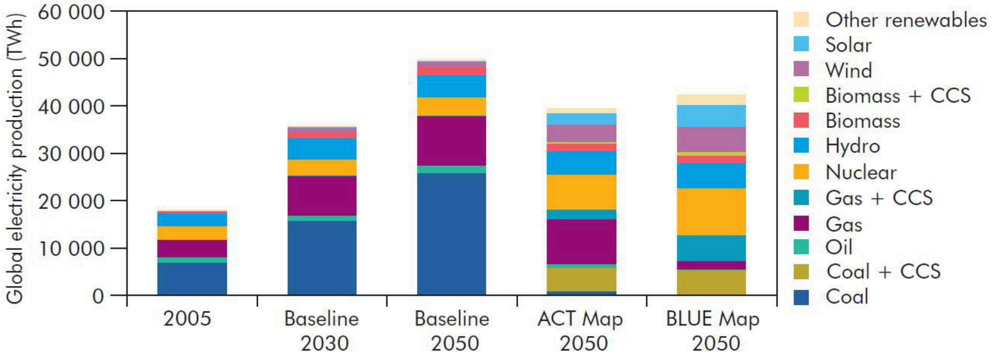


Figure 2.6. Global electricity production by fuel in the Baseline, ACT map and BLUE map scenarios (Source: IEA 2008)

In the BLUE map scenario, with an incentive of 200US$/t$CO_2$, CCS would increase to 10.4Gt in 2050, saving 19% of the total CO_2 abated. 27% of the total electricity generation in 2050 would be from plants equipped with CCS. Retrofitting would play a smaller part and CCS be mainly incorporated into new generation capacity. In the BLUE map scenario all coal-fired production and 40% of all gas-fired production is from plants equipped with CCS, virtually decarbonizing the electricity sector by 2050. Figure 2.6 presents global electricity production by fuels for different scenarios.

3. METHODOLOGY

3.1. Life Cycle Assessment

Life Cycle assessment (LCA) is a technique to evaluate the environmental impacts associated with the life cycle of products, processes or services. The term 'life cycle' indicates that all stages in a product's life viz. resource extraction, manufacture, distribution, use and end disposal, are taken into account. The idea of LCA is to account for all environmental impacts to avoid any 'problem shifting' from one life-cycle stage to other, from one location to other or from one environmental problem to other. LCA can be used to compare the environmental performance of products in order to be able to choose the least burdensome. It can also be used to optimize the environmental performance of a single product or of a company. There is a series of international standards for LCA, ISO 14040 -14044. ISO 14044 is designed for the preparation, conduct and critical review of life cycle inventory analysis. It also provides guidance on quality of data collected, impact assessment and interpretation of LCA results (ISO 2006).

3.1.1. General LCA framework

The standard framework for LCA has four consecutive stages: Goal and scope definition, inventory analysis, impact assessment and interpretation. Figure 3.1 presents an illustration for a life cycle model and the LCA procedure (Baumann and Tillman 2004).

Goal and scope definition

In the ‘goal and scope definition’ stage, the purpose or intended application of the study is decided, usually in terms of ‘functional unit’. Functional unit is a quantitative measure of the function fulfilled by the studied product or service. System boundaries describing which processes to include, level of detail and thus the requirements on data are then established. Finally the method to be applied for assessing potential environmental impacts and the impact categories are defined.

Inventory analysis

Inventory analysis includes construction of flow model according to the system boundaries as decided in goal and scope definition, data collection for all inputs (materials, energy) and

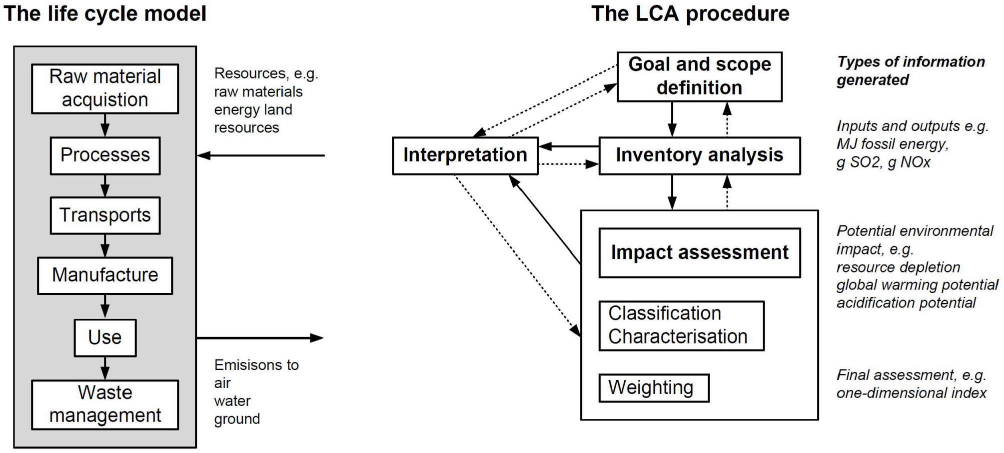


Figure 3.1. Life cycle model and the LCA procedure (Source: Baumann and Tillman 2004)

outputs (solid waste, air/water emissions) for the product system and calculation of the amount of resource use and pollutant emission of the system in relation to the functional unit.

Life cycle impact assessment

Life Cycle Impact Assessment (LCIA) stage aims to translate the information on emissions and resource use from inventory analysis stage to more environmentally relevant information on impacts e.g. global warming, acidification etc. In the first step ‘classification’, the inventory parameters are sorted according to the type of environmental impacts they contribute to. In the next step ‘characterization’, the relative contributions of the emissions and resource consumptions to each type of environmental impact are calculated. The next steps are ‘normalization’ and ‘weighting’. In the normalization step, the characterization results are calculated relative to the actual magnitude of each impact in the region where the product is produced and used. Weighting step gives a single score by assigning a weighting factor to each impact category depending on their relative importance. Classification and characterization are compulsory in LCA according to the standard, whereas normalization and weighting are optional steps.

Interpretation

In the interpretation stage, the findings of inventory analysis and/or impact assessment are combined consistent with the defined goal and scope in order to reach conclusions and recommendations. Sensitivity analysis and uncertainty analysis are important aspects in this stage.

3.1.2. LCA approach for the study

Several independent studies have found that LCA can suffer from incomplete system boundaries and advocate the combined use economic input–output (IO) and process-based life cycle inventories (LCI), often referred as ‘hybrid life cycle assessment’ to avoid underestimation (Strømman et al., 2006, 2009; Suh et al., 2004; Treloar, 1997). Hybrid LCA offers the advantage of both, the data specificity of process LCA and the system completeness of input–output analysis. The research work in this thesis uses the hybrid LCA approach, incorporating detailed unit process level information into the input-output model of the background economy.

The basic block for all LCA calculations is the normalized requirements matrix 'A', containing a combination of physical and monetary units.

$$A = \begin{bmatrix} A_{ff} & 0 & 0 \\ A_{pf} & A_{pp} & 0 \\ A_{nf} & 0 & A_{nn} \end{bmatrix} \qquad \text{..... (1)}$$

In equation (1) A_{ff} represents the requirements of physical units and describes the interdependency of the foreground processes. A_{pf} represents the normalized physical inputs from the background processes and A_{nf} represents the normalized monetary inputs to the foreground processes. A_{pp} describes the inter-process flow of physical entities, and A_{nn} describes the inter-sectorial economic requirements of the background economy. Flows from foreground to background processes and economy are set to zero (not for scenario assessment), as the product flows associated with the functional unit are negligible compared to the national level flows. Process model data is used to generate inter-process foreground matrix, ecoinvent v2 database (Ecoinvent 2007) is used for background processes and the input-output model of the US 1998 economy is used for background economy (Suh 2005). The characterization factors from ReCiPe 2008 method (ReCiPe, 2009) are used to estimate the potential environmental impacts of the emissions incurred. The factor of 0.24 kg 1,4-DCB-equiv./kg (Veltman et al., 2010) for human toxicity potential of monoethanolamine (MEA) is used.

3.2. Life cycle impact assessment: Mid-point v/s End-point

3.2.1. Mid-point v/s End-point

Life Cycle Impact Assessment (LCIA) may employ a number of methods based on environmental mechanisms converting the emissions of hazardous substances and extractions of natural resources into midpoint level impact category indicators such as acidification, climate change and ecotoxicity; or methods extending the cause and effect chain to assess damage to human health and ecosystem impacts as a result of climate change, ecotoxicity, as well as other categories addressed using midpoint indicators. In midpoint approach, the environmental relevance of impacts is generally presented by qualitative comparison, while in the endpoint approach the environmental relevance is already considered in the indicators. Endpoint indicators are more understable to the decision makers. Midpoint modeling is a comprehensive approach with a relatively good level of certainty. Endpoint modeling, on the other hand, has more structured and informed weighting across categories in terms of common understandable indicators, making it useful to wide audiences (Bare et al. 2002, Hertwich et al. 2002). A dual-approach for environmental assessments presenting mid-point results to understand environmental impact potentials and end-point results to present comprehensible information will facilitate the decision making together with scientific, in-depth understanding of related impacts.

3.2.2. ReCiPe 2008

ReCiPe 2008 (Goedkoop et al. 2009) is a life cycle impact assessment method providing results at both mid-point and end-point levels. This method uses environmental mechanisms as the basis for modeling and is harmonized in terms of modeling principles and choices. An environmental mechanism is a series of effects that together can create certain damage for humans, ecosystem etc. Figure 3.2 shows a simplified representation of the midpoint and endpoint approach to climate change. The impact category indicator at the midpoint level is infrared radiative forcing (CO_2 equivalents), while the impact category indicator at the endpoint level is damage to human health (DALY) and damage to ecosystem diversity (species.yr). It shows that a number of substances increase radiative forcing, making earth's temperature to rise and result in damage to living organism possibly due to changes in their habitats. The uncertainties clearly get higher with the length of environmental mechanism chain.

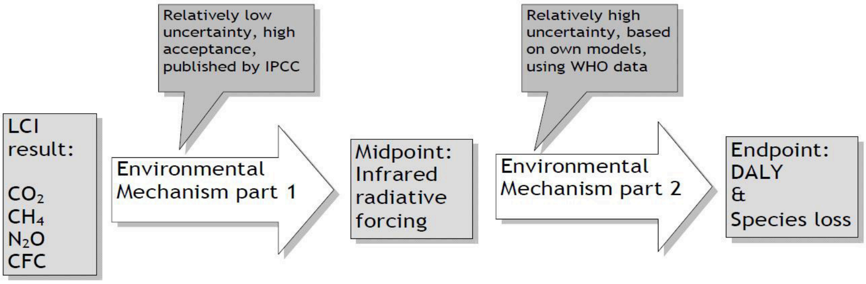


Figure 3.2. Harmonised mid-point endpoint model for climate change, linking to human health and ecosystem damage (Source: Goedkoop et al. 2009)

ReCiPe 2008 provides eighteen impact categories at midpoint level viz. climate change, ozone depletion, terrestrial acidification, freshwater eutrophication, marine eutrophication, human toxicity, photochemical oxidant formation, particulate matter formation, terrestrial ecotoxicity, freshwater ecotoxicity, marine ecotoxicity, ionizing radiation, agricultural land occupation, urban land occupation, natural land transformation, water depletion, mineral resources depletion and fossil depletion. These midpoint impact categories are further converted and aggregated into three endpoint damage indicators for human health damage (DALY), ecosystem damage (species.yr), and resource depletion ($). Figure 3.3 shows relationship pathways between various LCI parameters, midpoint indicators and endpoint indicators.

Disability adjusted life year (DALY) is a measure of overall disease burden from health problem and is calculated as the sum of the Years of Life Lost (YLL) due to premature mortality in the population and the Years Lost due to Disability (YLD) for incident cases of the health condition. Ecosystem damage given as *species.yr* is a measure of loss of species during a year and is based on Potentially Disappeared Fraction (PDF) of species from a region. Resource depletion is given in *monetary units ($)* and is the measure of the increased resource cost. The cost for metal depletion is based on the marginal cost increase of the resource caused by the gradual decrease of ore grade, and for fossil fuel, the cost is based on the need to switch from conventional energy resources to energy intensive and costly unconventional resources due to fossil fuel scarcity.

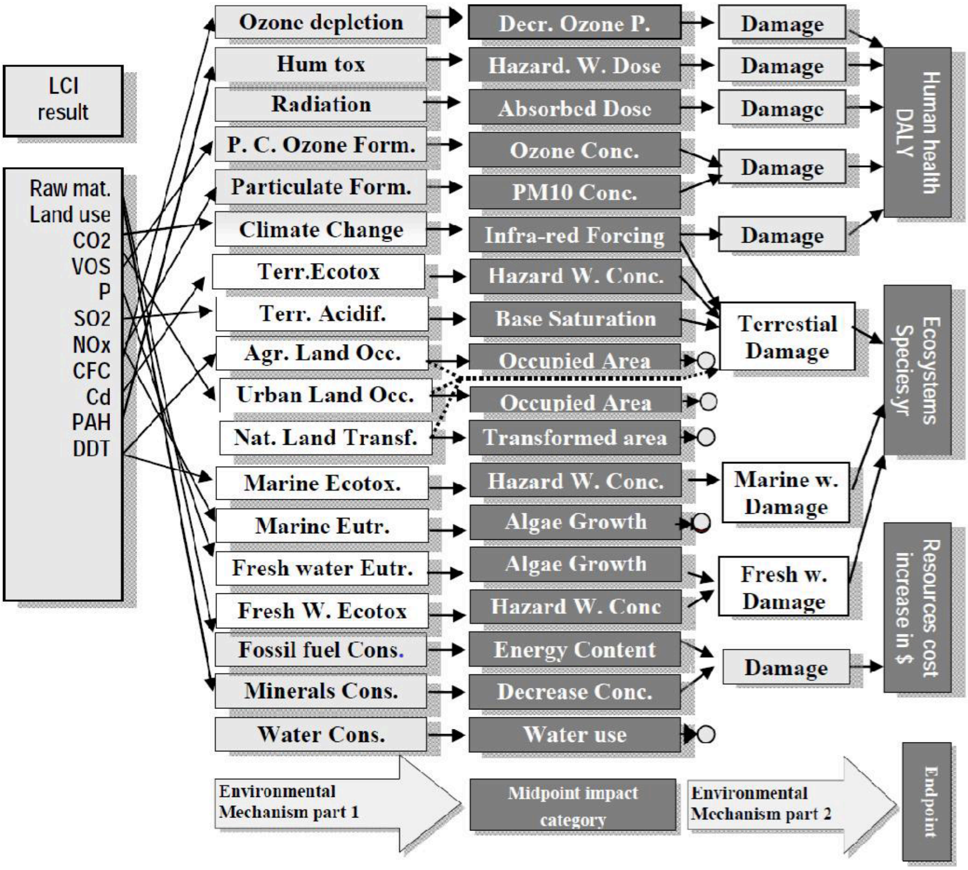


Figure 3.3. Relationship between LCI parameters, midpoint indicators and endpoint indicators in ReCiPe 2008 (Source: Goedkoop et al. 2009)

3.3. Framework for futuristic LCA and scenario assessment

LCA has efficiently been used to assess a static snapshot of material flows and environmental impacts associated with a product value chain. The evolution of technology, products and background processes with time can significantly affect these life cycle results, and remains a challenge to estimate. Consideration of the temporal evolution of the impacts is necessary to understand future environmental performance of a technology, effects from large scale and long-time application, and assist in making better informed policy decisions.

Few LCA studies have considered the time domain with technical advancements, by using scenarios for specific years and calculating material stocks (Kandelaars and van den Bergh 1997; Bergsdal et al. 2007; Babbitt et al. 2009) or their economic and/or environmental implications (Mendivil et al. 2006; Pehnt 2006; van Beukering and Janssen 2010). Mendivil et al. (2006), presented the LCA method of technology evolution and its application to ammonia production over the last fifty years, and reported the evolution of related emissions and global warming impact. Pehnt (2006) investigated the evolution of renewable energy technologies and presented effect of specific parameters, for a technology at year 2030. Van Beukering and Janseen (2010) used a system dynamic approach with a combination of other life cycle tools to make a dynamic integrated analysis of truck tires in western Europe and calculated both environmental and economic consequences.

3.3.1. Approach for futuristic LCA

Futuristic life cycle assessment of a technology represents its potential environmental evolution. It is based on the results from technical and economic development of the performance of a certain process over time. In this research work, future life cycle impacts of electricity generation from coal and natural gas with and without CCS are evaluated. The technical evolution of these power systems is developed using the projections in controlling parameters, e.g. efficiency, energy penalty, capital cost, amine-related emissions etc.

In the first step of this exercise, various parameters influencing the environmental performance of the system are identified. The future developments in these parameters as given in the literature are used to obtain respective continuous trends, by the method of curve fitting, for the time period 2000 to 2050. The inputs required by the system change with the parameters and are reflected by the variable elements in the normalized process requirement matrix (A). Each technical advance during this time horizon results in a new process layout, for which the updated inventory is obtained by simulation. The normalized requirements matrix 'A(t)', containing a combination of physical and monetary units is defined using the time dependent foreground matrix and background input matrices to the foreground. LCA calculations give the total output 'X(t)' needed per functional unit (1kWh electricity) at the particular time 't'.

$$A(t)\Big|_{t=t_0}^{t_n} = \begin{bmatrix} A_{ff}(t) & 0 & 0 \\ A_{pf}(t) & A_{pp} & 0 \\ A_{nf}(t) & 0 & A_{nn} \end{bmatrix}\Bigg|_{t=t_0}^{t_n} \qquad \ldots\ldots (2)$$

$$X(t)\Big|_{t=t_0}^{t_n} = \begin{bmatrix} I - A(t) \end{bmatrix}\Bigg|_{t=t_0}^{t_n} \times Y \qquad \ldots\ldots (3)$$

$A_{ff}(t)$ in equation (2) represents the foreground system, $A_{pf}(t)$ and $A_{nf}(t)$ represents requirements of background physical processes and monetary requirements from the background economy. The background system is assumed to be constant. Though the production of electricity with CCS will influence the background system by partially decarbonising the processes, however, the associated background changes with the functional unit will be quiet negligible.

This influence could be considerable for large volumes of final demand and is included in the scenario assessment.

3.3.2. Approach for scenario assessment

Environmental analysis of energy scenarios considers the dynamic development in energy generation technologies, production processes, development across the background system and changes in demand. A schematic representation of a dynamic energy system is presented in figure 3.4, and it shows that the influence from techno-economic initiatives, government policies, environmental regulations, market demands etc will affect the diffusion of technology, resulting in change in production processes and the background systems.

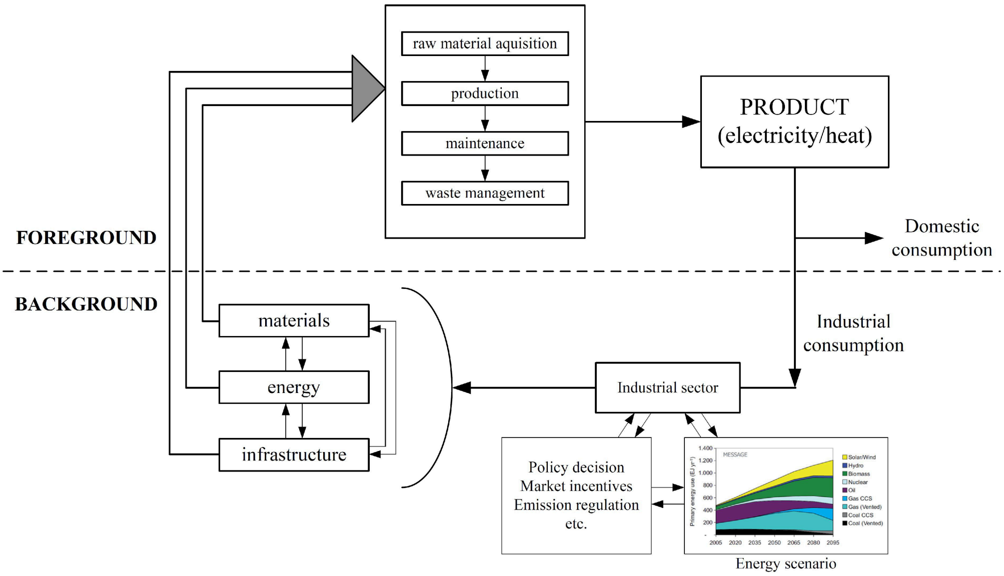


Figure 3.4. Schematic representation of a dynamic energy system (primary energy projections are adapted from IPCC, only for illustration purpose)

As in case with futuristic LCA study, the time-dependent parameters are modified for the time period till 2050. A simplified approach assuming linear variation with time is used to define the parameters given in different IEA scenarios (energy efficiency, electricity demand and electricity mix.). Parameters not defined by IEA are assumed to have time-trends as defined for futuristic LCA study.

The final demand changes over time and is different for various scenarios (IEA scenarios given for 2005-2050) and a time dependent trend is obtained for the demand 'Y', similarly by curve fitting.

The influence on the background processes, from large scale deployment of CCS and improvements in power plant technology is included in the scenario assessment by considering the changes in electricity mix given for each scenario. $A_{fp}(t)$ in equation (4) represents the coal and natural gas based electricity flows to the background processes and the influence of changes in electricity mix on the background processes is incorporated in $A_{pp}(t)$. The total output 'X(t)' needed for electricity demand at a particular time 't' is given by equation (5).

$$A(t)\Big|_{t=t_0}^{t_n} = \left.\begin{bmatrix} A_{ff}(t) & A_{fp}(t) & 0 \\ A_{pf}(t) & A_{pp}(t) & 0 \\ A_{nf}(t) & 0 & A_{nn} \end{bmatrix}\right|_{t=t_0}^{t_n} \quad \text{..... (4)}$$

$$X(t)\Big|_{t=t_0}^{t_n} = \left.\begin{bmatrix} I - A(t) \end{bmatrix}\right|_{t=t_0}^{t_n} \quad x \quad Y(t)\Big|_{t=t_0}^{t_n} \quad \text{..... (5)}$$

Considerations for the improvements in individual background processes and future economic model of the region is out of the scope of this study , therefore no future progress is accounted in any material production (e.g. process of fuel production, solvent production, etc.) and the inter-industry economic flows.

4. ENVIRONMENTAL ASSESSMENT OF CARBON CAPTURE AND STORAGE

4.1. Goal and scope

The study has two-point goals. Firstly, to evaluate the life cycle impacts and consequent damages from various carbon capture and storage (CCS) technologies for electricity generation from coal and natural gas and compare these systems with respective electricity generation system without CCS. Secondly, to assess the environmental implications of large scale CCS deployment scenarios, considering the potential future techno-economic improvements. The scope of assessment is limited to hypothetical generic systems and does not present any region specific case.

4.1.1. Functional unit

***Comparative assessment*:** The functional unit for comparative assessment is chosen as 1kWh of net electricity produced at the power plant facility.

***Scenario assessment*:** Scenarios assessment is made for coal and natural gas based electricity demand in that particular scenario.

4.1.2. System description

The foreground system for electricity generation using CCS includes electricity production The study assesses CCS systems for coal and natural gas electricity production using three capture techniques viz. post-combustion capture, pre-combustion capture and oxyfuel capture; CO_2 transport over 500km pipeline and storage at a secure geological site 1000m below the sea floor. Foreground system for various configurations includes electricity production at power plant, CO_2 capture, transport and storage.

General framework for all power plants and CCS systems

All reference power plants are assumed to have 400MW net electricity output. World average technology for electricity production is also evaluated and the net electrical efficiencies of the average and best-available technologies are taken from IEA (IEA 2008). Specific performance parameters and emission factors are discussed separately for each CCS system. Figure 4.1-4.3 shows the foreground system boundaries and Table 4.1 presents the performance parameters of the assessed systems. CO_2 captured using a specific capture technique is dried, compressed and supplied to the transport chain at 110bar and transported via 500km pipeline to the geological storage site. The optimum economic pipe diameter (Peters et al. 2003, Zhang et al. 2006) for CO_2 transport is estimated for each case. Some additional energy is also required for recompression of CO_2, due to the pressure drop during transport. A pressure drop of 10 bar per 100 km (Spath and Mann 2004, Wildbolz 2007) demands a recompression station after 300 km to maintain the pressure well above the critical pressure (74 bar). The energy required for recompression for a pressure drop of 30 bar using a gas turbine efficiency of 85% is calculated for each case. CO_2 is then supplied into the injection well about 1000m deep and sequestered in proven geological site. Additional energy is required to inject CO_2 into storage formation at a pressure higher than reservoir fluid pressure, so-as-to maintain it above the supercritical pressure. The injection pressure is a function of the injection depth and the pressure profile found in the underground. The energy required for injection is calculated for each case, assuming reservoir at hydrostatic pressure of 78.4 bar (Wildbolz 2007) and overpressure of 20 bar (Wildbolz 2007, Zweigel and Heill 2003). In the Sleipner project an injection pressure of 66 bar (Wildbolz 2007) is enough to inject the CO_2. The exact modeling of the injection process is complex and a first assumption based on literature value is made in this study. Monitoring of the storage site and leakage of CO_2 is not considered in this study.

Post-combustion capture, transport and storage system

In a typical post-combustion capture process, the treated flue gas is passed through a chemical absorption column where the solvent takes up the CO_2. The CO_2-rich solvent is regenerated by heating in the stripper unit. The CO_2 is then compressed and supplied to the pipeline (Figure 4.1).

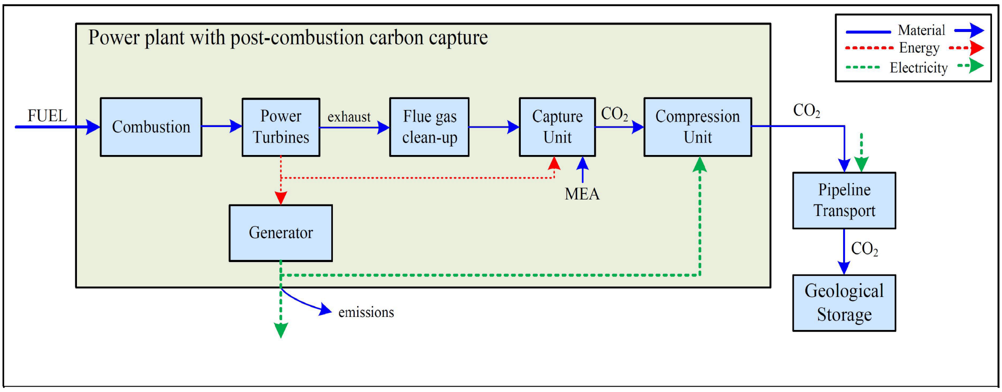


Figure 4.1. Foreground system boundary for post-combustion CCS system

The supercritical coal power plant consists of a combustion chamber, a steam-cycle unit and a state-of-art flue gas treatment facility. A net efficiency of 43.4% (IEA 2008) is assumed for the plant and the emissions are derived from ecoinvent v2 database. For the system with CO_2 capture, 90% CO_2 is assumed to be captured using monoethanolamine (MEA). Some fresh MEA is added to make up for the losses (degradation losses and vapor losses) during the

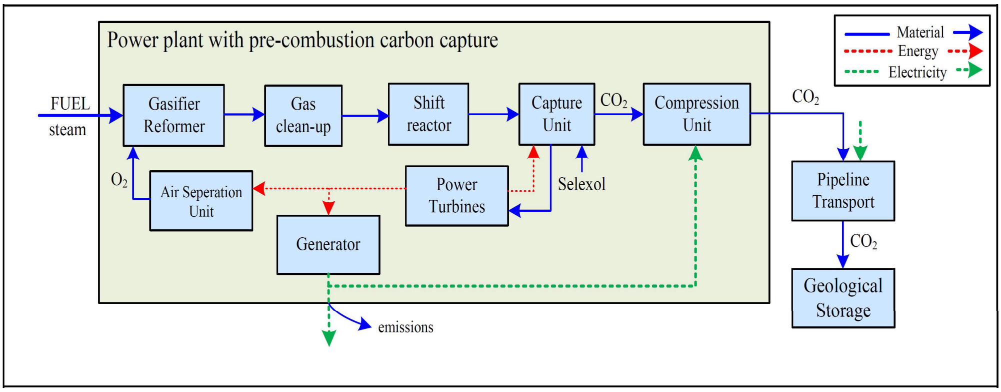


Figure 4.2. Foreground system boundary for pre-combustion CCS system

process. The energy requirements for the capture process are for regeneration of solvent, solvent pumps, flue gas blower, cooling water pumps and CO_2 compression, resulting in an energy penalty of 10.2% (estimated from IPCC 2005). The capture process also removes SO_2, NO_2 and particulates (Rao and Rubin 2002). A solvent make-up of 1.6 kg MEA/tCO_2 (IPCC 2005) is needed due to its loss via vapors and formation of degradation products. Besides the chemical solvent, the capture process also requires caustic soda to reclaim the amine from the heat stable salt and activated carbon to remove degradation products. Air emissions and degradation waste from capture process are quantified based on literature (IEA GHG 2006, Koornneef et al. 2008, Rao and Rubin 2002, Veltman et al. 2010). The optimum economic pipe diameter of 300mm is estimated for CO_2 pipeline transport. An energy demand of 574kW is calculated due to the pressure drop in the pipeline, and additional 161kW is required for the storage.

For a natural gas fired power plant, electricity is produced using a state-of-art natural gas combined cycle, with net efficiency of 58.1% (IEA 2008). The emissions from the power plant are derived from ecoinvent v2 database. For the system with CO_2 capture, 90% CO_2 is assumed to be captured using MEA as solvent. The energy requirements for the capture process results in an energy penalty of 8% (estimated from IPCC 2005). The MEA based emissions are quantified based on Veltman et al. 2010 and NVE 2007. Degradation reclaimer waste contains corrosion inhibitors (Thitakamol et al. 2007, Veltman et al. 2010) making it hazardous to landfill and the waste is assumed to be incinerated. Captured CO_2 is compressed to 110 bar at the power plant and supplied to the pipeline. The optimum economic pipe diameter of 200mm is calculated and the energy demand is 261kW for recompression, and 73kW for injection.

Pre-combustion capture, transport and storage system

In a typical pre-combustion capture process, steam and oxygen is added to the primary fuel producing a mixture of hydrogen and carbon monoxide (syngas). This is followed by the 'shift' reaction to convert CO to CO_2 by the addition of steam. The CO_2 is removed from the CO_2/H_2 gas mixture, and the gas mixture is then supplied to combined cycle generating electricity (Figure 4.2).

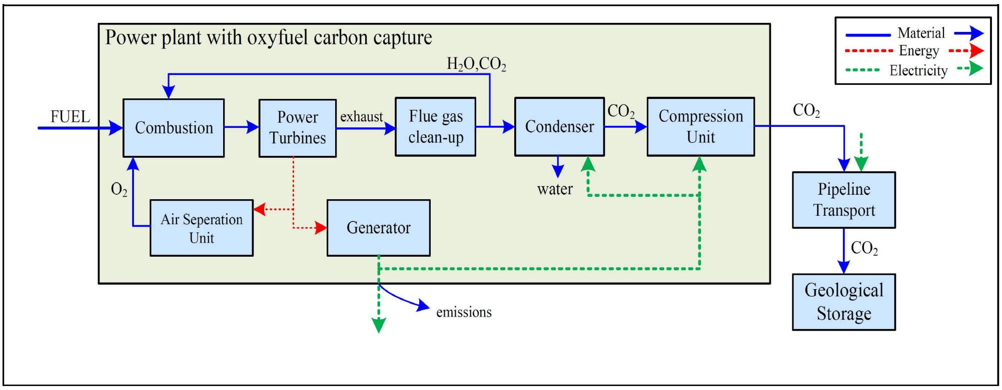


Figure 4.3. Foreground system boundary for oxyfuel CCS system

The IGCC power plant consists of a gasification unit, a gas cleaning unit and a gas-fired combined-cycle unit. A net efficiency of 44.1% (IEA 2008) is assumed for the plant and the emissions are derived from Ratafia-Brown et al. 2002. For the IGCC system with CO_2 capture, 90% CO_2 is assumed to be captured using selexol. The efficiency loss due to 'water-gas-shift' reaction and solvent circulation is assumed to be 6.5% (derived from IPCC 2005). Consumption of 0.005 kg selexol/MWh from IGCC is projected (Rubin 2005), however no literature is found considering solvent loss to atmosphere or emission of solvent degradation products (Selexol is the trade name for a mixture of dimethyl ethers of polyethylene glycol, widely used as an acid gas removal solvent). An additional reduction of particulates by 50% from syngas is assumed (Odeh and Cockerill 2008) by the selexol capture process. Selexol is non-toxic and has a low vapor pressure (Chen 2005), therefore it is assumed that all spent solvent ends up as solid waste and is incinerated. The optimum economic pipe diameter is estimated to be about 300mm and the energy demand is 544kW for recompression, and 152kW for storage.

For natural gas feedstock, primary fuel (natural gas), steam and oxygen is fed to the reformer. In the auto-thermal reformer, partial combustion of methane provides the heat for the endothermic reforming reaction, hence avoiding CO_2 emissions from external firing (Solli et. al. 2009). A net efficiency of 56% is assumed for the plant as the literature suggests a range of 54.5% to 56.2% (Nord et al. 2009, IEA GHG 2000 in IPCC 2005). In the pre-combustion CO_2 capture unit, 85% CO_2 is assumed to be captured using selexol. The efficiency loss of 7.9% is assumed (IEA GHG 2000 in IPCC 2005). The optimum economic pipe diameter is estimated to be about 200mm and the energy requirement is 255kW for recompression, and 71kW for injection.

Oxyfuel capture, transport and storage system

In a typical oxyfuel combustion process, fuel is combusted in either pure oxygen or O_2/CO_2 mixtures, thus eliminating nitrogen from the flue gas. The flue gas consist mainly of CO_2 and water vapor together with excess oxygen, which after cooling to condense water vapor, contains about 80-98% CO_2 (IPCC 2005). (Figure 4.3). Application of oxyfuel combustion in a power plant implies reduction in net efficiency due to energy requirement of the air separation unit (ASU).

For the coal power plant, a baseline efficiency of 43.4% (same as supercritical power plant), with an overall efficiency loss of 8.8% points is assumed (Dillon et al. 2005), and the emission factors are based on literature (Croiset et al. 2000, Dillon et al. 2005, IPCC 2005; Yan et al. Vattenfall AB). 90% CO_2 is assumed to be captured by condensation separation, which is then compressed, dried and further purified before delivery to pipeline. The optimum economic pipe diameter is calculated to be about 300mm. The pressure drop in the pipeline results in an energy demand of 574kW for recompression, and additional 161kW is required for the storage.

In the natural gas oxyfuel combustion system, the baseline efficiency is 58.1% (same as NGCC power plant), with an assumption of 11.3% efficiency loss (Dillon et al. 2005) due to energy allowance for ASU, and the emission factors are derived from the literature review (Dillon et al. 2005, IPCC 2005, Tan et al. 2002). 96% CO_2 is assumed to be captured. The optimum economic pipe diameter is estimated to be about 200mm and the energy demand is 278kW for recompression, and 78kW for injection.

4.1.3. Techno-economic improvements in CCS and scenarios' specifications

CCS scenarios assessment is based on IEA projections on contribution of electricity from coal and natural gas, with or without CCS to the total global electricity demand. Pulverized coal combustion and natural gas CCS system for the power plants and CCS system consisting of post-combustion capture with monoethanolamine as solvent, pipeline transport over 300km and geological storage at 1000m beneath sea floor are assumed to be used. The assessment considers the techno-economic evolution of post-combustion CO_2 capture process and power generation, changes in demand from coal and natural gas based electricity and future electricity mix until year 2050. However, to make any assumptions for individual background processes (e.g., fuel production, transport, solvent production etc.) is out of the scope of this research work, and therefore are considered invariable.

Evolution in power plant system and CO_2 capture process

Future power generation is expected to evolve around efficiency increase, carbon capture, lower capital investment intensity and economic performance of renewable electricity. This study uses plant efficiency, capital cost and potential improvements in amine-based CO_2 capture process as the basis for evaluating the future environmental impacts from these electricity generation systems.

The principal technical developments of pulverized coal (PC) technology include increase in plant thermal efficiency, better load change capacity and advanced flue gas cleaning units to meet emissions limits; while the technical development of natural gas combined cycle technology will be determined by the development of gas turbines (Bauer et al. 2008). Therefore the potential for efficiency improvements and reduction in capital investment

Table 4.1. Performance parameters for different power generation systems

		Coal[a]					
Parameters		**world average**	**supercritical BAT**	**IGCC**	**supercritical with post-combustion capture**	**IGCC with pre-combustion capture**	**oxyfuel capture**
CO_2 capture		–	–	–	90 %	90 %	90 %
Net efficiency		35 %	43.4%	44.1%	33.2%	37.6%	34.6%
Energy penalty		–	–	–	10.2%	6.5%	8.8%
Co-capture		–	–	–	SO_2, NO_2, particulates	particulates	–
Solvent consumption	kg/tCO_2	–	–	–	1.6 (MEA)	0.007 (selexol)	–
Power plant capital cost[b]	\$/kW	1286	1286	1326	2096	1825	1857
CO_2 sequestered	Mt/y	–	–	–	2.2	2.1	2.2
Energy for transport and storage	kW	–	–	–	735	696	735
Emissions							
CO_2	g/kWh	946.6	763.4	722.8	100.1	85.7	95.5
SO_2	mg/kWh	673.5	543.2	287.5	26.8	341.0	679.4
NO_x	mg/kWh	637.6	514.2	328.6	641.1	389.8	322.1
NH_3	mg/kWh	–	–	1.6	31.4	1.9	–
Particulates	mg/kWh	108.5	87.5	86.1	57.3	51.1	109.4
solvent	mg/kWh	–	–	–	56.5	–	–
solid degradation product	kg/tCO_2	–	–	–	3.2	0.007	–
		Natural gas[a]					
Parameters		**world average**	**NGCC**	**partial oxidation**	**NGCC with post-combustion capture**	**partial oxidation with pre-combustion capture**	**oxyfuel capture**
CO_2 capture		–	–	–	90 %	85 %	96 %
Net efficiency		42 %	58.1%	56 %	50.1%	48.1%	46.8%
Energy penalty		–	–	–	8 %	7.9%	11.3%
Co-capture		–	–	–	SO_2, NO_2, particulates	particulates	–
Solvent consumption	kg/tCO_2	–	–	–	1.6 (MEA)	0.007 (selexol)	–
Power plant capital cost[b]	\$/kW	568	568	447	998	978	1034
CO_2 sequestered	Mt/y	–	–	–	1	1	1.1
Energy for transport and storage	kW	–	–	–	334	327	356
Emissions							
CO_2	g/kWh	479.6	346.7	359.7	40.5	62.8	17.4
SO_2	mg/kWh	4.3	3.1	3.2	0.0005	3.7	3.9
NO_x	mg/kWh	428.2	309.6	321.2	343.9	374.0	194.1
NH_3	mg/kWh	–	–	–	12.7	–	–
Particulates	mg/kWh	4.3	3.1	3.2	1.8	1.9	3.9
solvent	mg/kWh	–	–	–	22.8	–	–
solid degradation product	kg/tCO_2	–	–	–	3.2	0.007	–

[a] 8000 full load hours per year with plant life-time of 25 years

[b] IPCC (2005), Rubin et al. (2007)

intensity is assumed to be substantial for these plants. Current and projected values for plant efficiency and capital investment in the period 2000-2050 from the literature (David and Herzog, Herzog 1998, Rao and Rubin 2002, NETL 2002, Spath and Mann 2004, Rubin et al. 2005, IPCC 2005 (for IEA GHG 2004, Parsons 2002), Wong and Whittingham 2006, Rubin et al. 2007, Martinsen et al. 2007, Abu-Zahra et al. 2007, Peeters et al. 2007, Broek et al. 2008, Bauer et al. 2008, IEA 2008, Odeh and Cockerill 2008, Koornneef et al. 2008. Pehnt and Henkel 2009) is used to identify their future trends. The values are considered in the year of their publications if not stated otherwise. Figure 4.4 shows the future trend for efficiency and capital cost for coal and natural gas power generation systems with and without CO_2 capture. Plant efficiencies are projected to increase by 10 and 7 efficiency points by 2050 for coal and natural gas plant respectively, from the current value. Capital costs for power plants

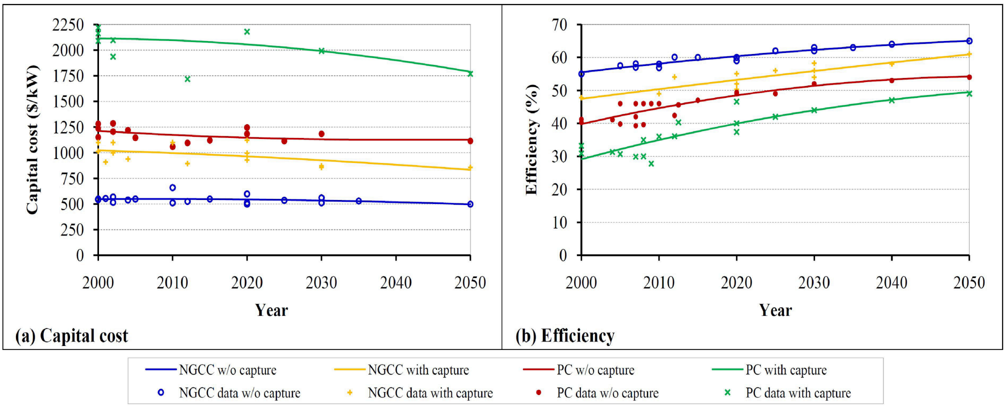


Figure 4.4. Evolution of capital cost and efficiency of power plants with and without CO_2 capture

without CO_2 capture unit are stable, while the investment for power plant with capture have a downward trend, projecting about 15% decrease in capital cost per kW for both coal and natural gas power plant by year 2050.

The key parameters identified by Rao et al. (2006) for the development potential of amine-based CO_2 capture process are sorbent concentration (wt%), sorbent regeneration heat requirement (kJ/kg CO_2 captured), sorbent loss (kg/tonne CO_2 captured) and sorbent cost (US$/tonne sorbent). In this study the energy penalty of a capture process is translated as decrease in net efficiency of the power plant, and the development trends (Figure 4.4) show a potential of 15% and 10% increase in efficiency points by 2050 for coal and natural gas power plants with CO_2 capture respectively, as compared to the current efficiency. Literature shows current usage of 1.5 - 2.4 kg MEA/ tonne CO_2 captured (Rao and Rubin 2002, IEA GHG 2006, Knudsen et al. 2007, Peeters et al. 2007, Pehnt and Henkel 2009, Veltman et al. 2010). A continuous trend in sorbent loss is obtained by assuming a 49% reduction in sorbent loss by year 2015 (Rao et al. 2006, by 2020 in Peeters et al. 2007) and 76% reduction by 2030 (Peeters et al. 2007) are assumed. As no literature is available suggesting a further decrease in future sorbent loss, therefore keeping a conservative approach no development in this parameter is assumed after 2030.

Scenarios specifications

Three scenarios for electricity generation are defined as given in Energy Technology Perspectives (IEA) – Baseline, ACT map, and BLUE map scenario. The electricity demand from coal and natural gas is identified and assessed in this study. In the Baseline scenario energy related CO_2 emissions in 2050 are 130% above the level of 2005, making the scenario unsustainable. In ACT map scenario CO_2 emissions are brought back to today's level by 2050 and in the extremely challenging BLUE map scenario worldwide CO_2 emissions are halved by 2050. Most electricity generated by coal-fired power plants in the ACT map and BLUE map scenarios, and half of the gas-fired power generation in the BLUE map scenario, comes from plants equipped with CCS. This accounts for 8% of the CO_2 emissions reductions in the ACT map scenario and 10% in the BLUE map scenario, leading to the capture of 2.8Gt to

Table 4.2. Global electricity production from coal and natural gas

Production (TWh/yr)	2005	Baseline 2050	ACT map 2050	BLUE map 2050
Coal	7334	25825	949	0
Coal + CCS	0	3	4872	5468
Natural gas	3585	10557	9480	1751
Natural gas + CCS	0	83	1962	5458

(Source: based on IEA 2008)

Table 4.3. Global electricity mix projections for 2050

Share (%)	2005	Baseline 2050	ACT map 2050	BLUE map 2050
Nuclear	15	8	19	23
Oil	7	3	2	0
Coal	40	52	2	0
Coal + CCS	0	0	12	13
Gas	20	21	24	4
Gas + CCS	0	0	5	13
Hydro	16	9	13	12
Bio/Waste	1	3	4	4
Bio + CCS	0	0	1	2
Geothermal	0	1	2	3
Wind	1	2	9	12
Tidal	0	0	0	1
Solar	0	0	6	11
Hydrogen	0	0	0	1

(Source: based on IEA 2008)

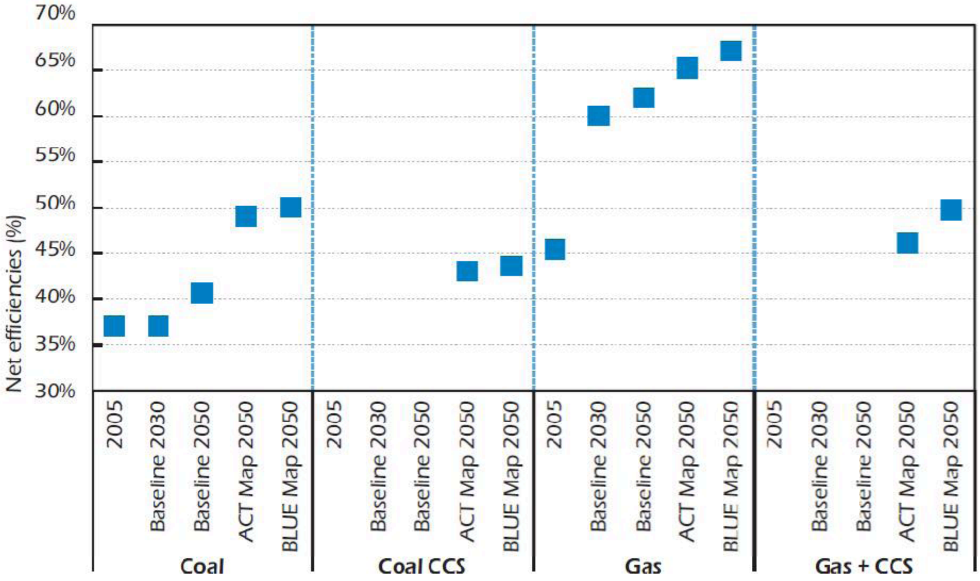


Figure 4.5. Net efficiencies of fossil-fuel fired power plants (Source: IEA 2008)

4.8Gt of CO_2. Price of USD 50-200/tCO_2 in the mitigation scenarios also leads to the development of renewable electricity leading to higher contribution in global electricity production in BLUE map scenario. Table 4.2 gives the global electricity production from coal and natural gas for the different scenarios and Table 4.3 presents projections of electricity mix composition for year 2050. Figure 4.5 presents the projections for net energy efficiencies of fossil-fuelled power plants in the three scenarios. CCS includes post-combustion chemical absorption and some oxyfuel capture. The share of oxyfuel capture rises over time for gas and for coal fired power plants, however this study assumes all CCS with post-combustion capture only.

4.2. Inventory analysis

The detailed inventory of the foreground system is based on the process parameters of specific power plant type and the capture process, pipeline and injection well specifications and energy requirement for transport and storage. Complete inventory tables for the foreground processes are provided in appendix.

Power generation and CO_2 capture

The LCI data for fuel supply and combustion (for state-of-art technologies) is derived from the Ecoinvent v2 database (Ecoinvent, 2007). Emission factors for futuristic technologies are based on literature, and the inventory of the capture operation is based on process modeling data. Power plant emissions per kWh electricity depend on the plant efficiency and are accounted for by assuming the same emission parameters per unit of fuel input as for the current reference technologies. LCI data for air emissions due to amine degradation is calculated to be proportional to the solvent lost and other air emissions and degradation waste from capture process are quantified based on literature (IEA GHG 2006, Rao and Rubin 2002, Veltman et al. 2010). Infrastructure for power plant and capture unit is accounted as capital investment (IPCC, 2005) attributed to various sectors in US I/O 1998 database (Suh, 2005). Other emissions arising from upstream, e.g., the production of fuel (coal/natural gas), absorbent etc. and the emissions from downstream, e.g., waste treatment and disposal are also included in the assessment.

Table A3 and A4 in appendix present various inputs and direct emissions from the coal and natural gas combustion respectively, for all the 3 viz. post-, pre- and oxyfuel combustion technologies. Details on inputs and emissions for each capture technology is presented in table A5.

Transport

LCI data for pipeline is derived from ecoinvent v2 (offshore natural gas pipeline in North Sea with a diameter of 1000mm and 25mm thickness). This conservative approach will likely overestimate material requirements. In practice, bigger diameter pipelines with higher mass flow rates are expected to be used, reducing the material use and cost per ton CO_2 transported. Capacity of pipeline needed for coal and natural gas is different (about 2MtCO_2/yr for coal and 1MtCO_2/yr for natural gas. Table A9 presents inputs and emissions for 500 km long pipeline for both fuel types.

Storage

LCI data for the well is taken as offshore drilling well from ecoinvent v2. Each injection well is assumed to be 1000m deep and is presented in Table A10. Monitoring of the storage site and leakage is not considered in the study.

4.3. Impact assessment

The main objective of CCS systems is to control CO_2 emissions, having some co-benefits for SO_2, NO_x and particulates removal with certain technologies. However, there are various other direct and indirect emissions throughout the value chain, from raw material extraction for fuel and infrastructure, to the waste treatment and disposal. A detailed discussion of comparative impact assessment is presented below and is also briefly provided in Singh et al. 2010b. Scenario assessment for fossil-based electricity, considering the techno-economic developments in power plant and capture technology, changes in electricity demand and electricity mix is then presented. An elaborate discussion of scenario assessment is made in Singh et al. 20xxb and a short discussion of main findings from scenario assessment is made in this section.

4.3.1. Comparative impact assessment

Global Warming Potential (GWP)

Electricity generation from a power plant without CO_2 capture implies emission of CO_2 and other greenhouse gases (CH_4, N_2O etc.) as the direct emission from fuel combustion and also as the indirect emissions from fuel production, infrastructure development, auxiliary transport etc. The capture process at power plant facility captures 85-96% of CO_2 from the flue gas, however other GHGs are not captured via this process and instead there are additional such emissions due to more fuel combustion because of energy penalty from capture process as well as additional indirect GHG emissions. A relevant term to understand the net CO_2 reduction potential of CCS is the 'amount of CO_2 avoided' and is calculated in Singh et al. (2010a). Further, the global warming mitigation potential of CCS is the net efficiency of avoiding greenhouse gas emissions over the complete life cycle.

Figure 4.6 shows global warming impact (GWP) from different electricity generation systems, with a breakdown into direct impact from combustion at power plant and indirect impact from the value chain. Results show considerable reduction in GHG (CO_2 equivalents) by application of CO_2 capture; however the life cycle reduction rates are significantly lower than the CO_2 capture rates at the power plants. The net reduction in CO_2eq from the coal CCS systems is 74-78%, while for the natural gas systems it is reduced to 64-73%. The lower efficiency of GHG reduction in the case with natural gas feedstock is due to relatively lower contribution of CO_2 emissions from the fuel combustion process than from coal in the electricity generation systems.

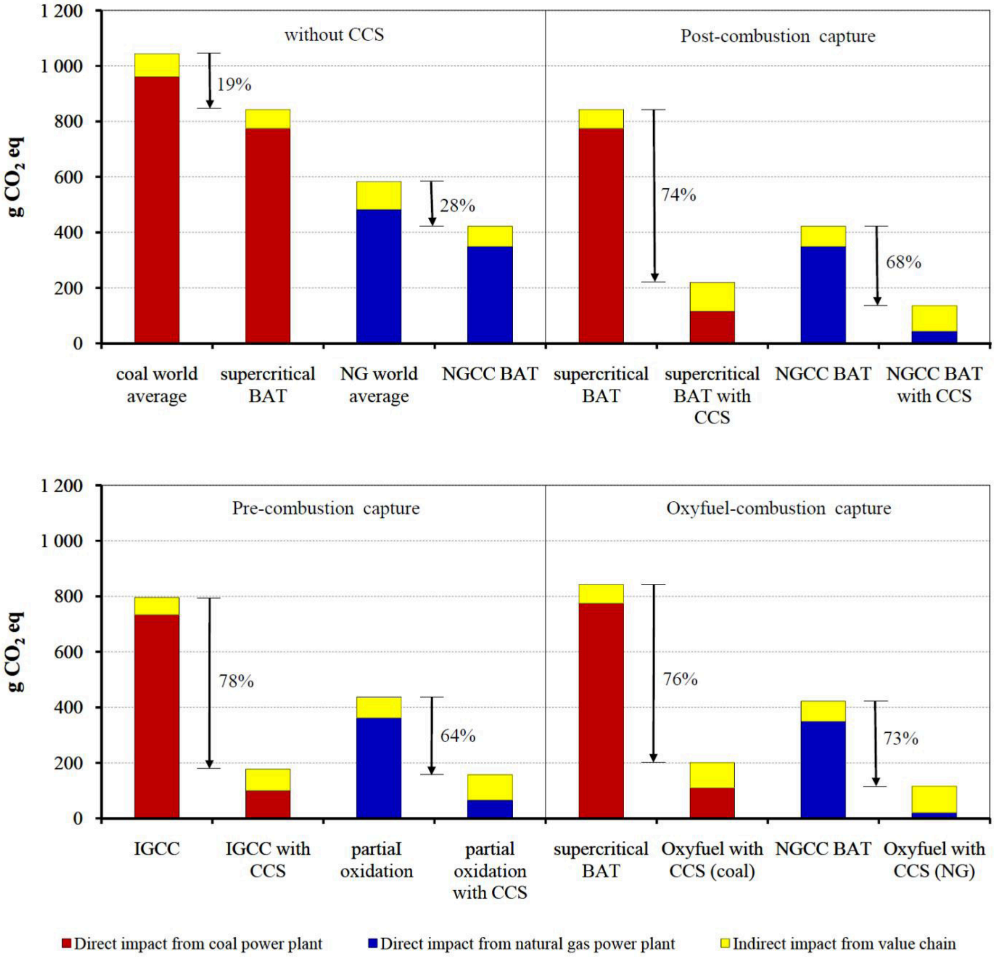


Figure 4.6. Global Warming Potential (GWP) from different electricity generation systems

Direct emission of CO_2 at the power plant without capture contributes to more than 90% of life cycle GHG emissions in the case of coal and more than 82% in the case of natural gas. For the power plants with CCS system, the direct CO_2 emission at the coal plant is responsible for over 46% of life cycle GHG emissions and over 30% at the natural gas plant (except for oxyfuel combustion with CCS at the natural gas power plant, where direct CO_2 emission makes only about 15% of life cycle GHGs due to high capture efficiency). The remaining CO_2eq in the CCS chain are mainly emitted in the fuel supply chain, dominated by coal mining for coal systems and gas production and transportation for natural gas systems. Contribution from MEA production and reclaimer waste disposal is also of relative significance for post-combustion CCS systems. Primary infrastructural requirements (power plant, fuel production and transport and storage infrastructure) contributes about 7 - 9% to the life cycle GWP impact for different CCS systems and is dominated by infrastructural requirements for the fuel supply chain. The contribution from the transport and storage chain is relatively small at only about 2% of the total GWP impact.

Table 4.4. Absolute impact scores for 1 kWh of electricity generation from different technologies

Coal power generation systems										
Impact	**GWP**	**TAP**	**FEP**	**MEP**	**POFP**	**PMFP**	**HTP**	**TETP**	**FETP**	**METP**
Unit (kg eq)	**CO_2**	**SO_2**	**P**	**N**	**NMVOC**	**PM_{10}**	**1,4-DB**	**1,4-DB**	**1,4-DB**	**1,4-DB**
world average coal	$1.0*10^{0}$	$1.6*10^{-3}$	$4.0*10^{-6}$	$2.1*10^{-4}$	$1.5*10^{-3}$	$5.6*10^{-4}$	$1.2*10^{-2}$	$2.2*10^{-5}$	$2.0*10^{-4}$	$2.6*10^{-4}$
supercritical BAT	$8.4*10^{-1}$	$1.3*10^{-3}$	$3.3*10^{-6}$	$1.7*10^{-4}$	$1.2*10^{-3}$	$4.5*10^{-4}$	$9.6*10^{-3}$	$2.0*10^{-5}$	$1.7*10^{-4}$	$2.1*10^{-4}$
supercritical BAT with CCS	$2.2*10^{-1}$	$1.1*10^{-3}$	$7.7*10^{-6}$	$2.4*10^{-4}$	$1.5*10^{-3}$	$4.2*10^{-4}$	$1.5*10^{-2}$	$4.2*10^{-5}$	$5.1*10^{-4}$	$3.9*10^{-4}$
IGCC	$8.0*10^{-1}$	$9.3*10^{-4}$	$1.0*10^{-6}$	$1.1*10^{-4}$	$9.5*10^{-4}$	$3.5*10^{-4}$	$5.2*10^{-3}$	$1.8*10^{-5}$	$8.0*10^{-5}$	$1.0*10^{-4}$
IGCC with CCS	$1.8*10^{-1}$	$1.1*10^{-3}$	$2.3*10^{-6}$	$1.4*10^{-4}$	$1.1*10^{-3}$	$3.8*10^{-4}$	$7.3*10^{-3}$	$2.8*10^{-5}$	$1.3*10^{-4}$	$1.9*10^{-4}$
oxyfuel with CCS	$2.0*10^{-1}$	$1.5*10^{-3}$	$5.2*10^{-6}$	$1.7*10^{-4}$	$1.2*10^{-3}$	$5.1*10^{-4}$	$1.3*10^{-2}$	$3.3*10^{-5}$	$2.4*10^{-4}$	$3.3*10^{-4}$
Natural gas power generation systems										
Impact	**GWP**	**TAP**	**FEP**	**MEP**	**POFP**	**PMFP**	**HTP**	**TETP**	**FETP**	**METP**
Unit (kg eq)	**CO_2**	**SO_2**	**P**	**N**	**NMVOC**	**PM_{10}**	**1,4-DB**	**1,4-DB**	**1,4-DB**	**1,4-DB**
world average NG	$5.8*10^{0}$	$5.5*10^{-4}$	$1.2*10^{-6}$	$8.1*10^{-5}$	$8.4*10^{-4}$	$1.9*10^{-4}$	$2.5*10^{-3}$	$1.6*10^{-5}$	$4.2*10^{-5}$	$1.8*10^{-4}$
NGCC BAT	$4.2*10^{-1}$	$4.0*10^{-4}$	$8.8*10^{-7}$	$5.8*10^{-5}$	$6.1*10^{-4}$	$1.4*10^{-4}$	$1.8*10^{-3}$	$1.3*10^{-5}$	$3.1*10^{-5}$	$1.3*10^{-4}$
NGCC BAT with CCS	$1.4*10^{-1}$	$5.1*10^{-4}$	$2.6*10^{-6}$	$7.5*10^{-5}$	$7.1*10^{-4}$	$1.7*10^{-4}$	$3.2*10^{-3}$	$2.3*10^{-5}$	$1.6*10^{-4}$	$2.1*10^{-4}$
partial oxidation	$4.4*10^{-1}$	$4.2*10^{-4}$	$9.0*10^{-7}$	$6.0*10^{-5}$	$6.1*10^{-4}$	$1.5*10^{-4}$	$1.8*10^{-3}$	$1.2*10^{-5}$	$3.1*10^{-5}$	$1.3*10^{-4}$
partial oxidation with CCS	$1.6*10^{-1}$	$5.0*10^{-4}$	$1.8*10^{-6}$	$7.1*10^{-5}$	$7.3*10^{-4}$	$1.8*10^{-4}$	$3.0*10^{-3}$	$2.1*10^{-5}$	$6.0*10^{-5}$	$2.0*10^{-4}$
oxyfuel with CCS	$1.2*10^{-1}$	$4.1*10^{-4}$	$1.8*10^{-6}$	$4.9*10^{-5}$	$5.6*10^{-4}$	$1.4*10^{-4}$	$3.2*10^{-3}$	$2.3*10^{-5}$	$6.3*10^{-5}$	$2.1*10^{-4}$

Mid-point impact potentials

Impact potential scores are calculated for 10 environmental mid-point indicators: global warming potential (GWP), terrestrial acidification potential (TAP), fresh water eutrophication potential (FEP), marine eutrophication potential (MEP), photochemical oxidant formation potential (POFP), particulate matter formation potential (PMFP), human toxicity potential (HTP), terrestrial ecotoxicity potential (TETP), fresh water ecotoxicity potential (FETP), and marine ecotoxicity potential (METP). A brief discussion of selected impacts is also presented in Singh et al. (2010b). Table 4.4 presents impact characterization result for six power plant systems each for coal and natural gas. As expected, the impact scores for all categories are higher for world average technology than the best-available technology (supercritical plant for coal and NGCC for natural gas), showing the potential for possible improvements. However, comparison with CCS systems shows that the world average technology implies lower impacts for certain categories, raising concerns for toxicity and eutrophication impacts with use of CCS. Table 4.5 gives the percentage change in impact for the systems with different CO_2 capture technologies. The impacts are unevenly distributed over various processes, e.g., fuel extraction, transport, combustion at the power plant, CO_2 capture, infrastructure, solvent production , as well as locations, e.g., mining sites, offshore natural gas production facility, chemical manufacturing sites, power plant facility, dispersed transportation, iron & steel industry, etc. Figure 4.7 presents the relative contribution of processes towards the total impact for all the three CCS approaches with coal and natural gas feedstock.

Post-combustion capture, transport and storage system

The designed 90% CO_2 capture efficiency for post-combustion coal and natural gas CCS systems resulted in a net reduction of 74% and 68% GWP, respectively. The coal CCS system shows an overall reduction of 13% in acidification potential (TAP) and 7% in particulate matter formation (POFP) due to co-capture of SO_2, NO_x, and particulate matter. However, due

Table 4.5. Change in impact for different CCS configurations with respect to system without CCS

Impacts		Coal			Natural gas		
		Post-combustion[a]	Pre-combustion[b]	Oxyfuel[a]	Post-combustion[a]	Pre-combustion[b]	Oxyfuel[a]
Global warming	%	-74	-78	-76	-68	-64	-73
Terrestrial acidification	%	-13	20	13	26	20	2
freshwater eutrophication	%	136	120	59	200	94	111
marine eutrophication	%	43	20	1	30	18	-15
Photochemical oxidation	%	27	20	-1	17	18	-8
particulate matter formation	%	-7	8	12	23	21	2
human toxicity	%	52	41	38	74	62	73
terrestrial ecotoxicity	%	114	58	67	76	76	77
Fresh water ecotox.	%	205	60	46	413	90	103
Marine ecotoxicity	%	88	80	57	66	50	63

[a] reference plant is supercritical BAT for coal and NGCC BAT for natural gas

[b] reference plant has IGCC for coal and partial oxidation for natural gas

to lower pollutant content in the natural gas combustion exhaust stream, the co-capture is insufficient to mitigate any additional impact from the natural gas chain, resulting in an overall increase of 26% in acidification impact and 23% in particulate matter formation.

The post-combustion CCS systems show significant increase in freshwater eutrophication, marine eutrophication and various toxicity potentials. Results show an increase of 136% for the coal CCS system and 200% for the natural gas CCS system in FEP scores. FEP is caused by emission of phosphorus and phosphate to water. Power plant waste treatment, development of infrastructure for the fuel production chain and transport, and storage are the main contributing processes to this impact. Analysis of these processes reveals that disposal of furnace waste from steel manufacturing (for infrastructure), coal ash disposal (for cases of coal feed stock only), and reclaimer waste disposal are the dominating contributors to FEP. Marine eutrophication (MEP) is mainly caused by emission of the nitrogenous compounds (NO_x, NH_3, organic bound nitrogen etc.). Co-capture of NO_x in the post-combustion system is offset by the emission from additional fuel combustion and NH_3 emission from solvent degradation, leading to an increase of 43% with the coal and 30% increase with the natural gas system in MEP. Direct emission from power plant is the major contributor to this impact, making 36% and 60% of the overall MEP for coal and natural gas, respectively. MEA production contributes about 7-8% to MEP impact, coming from production of ethylene and ammonia. Waste treatment makes an important contribution of 17% to the impact from coal post-combustion CCS system, with major contributions from nitrate and ammonia emission in flue gas desulphurization (FGD) and selective catalytic reduction (SCR) processes, respectively, while the disposal of reclaimer bottom contributes less than 1% to the impact.

Various toxicity impacts show increases of 51% to 205% for the coal CCS system and 66% to 413% in the natural gas system. The main contribution to toxicity is generally associated with the infrastructure requirements and heavy metal emissions associated with the material production. Results show that the infrastructure demand for natural gas CCS systems contributes over 85% to human toxicity (HTP), terrestrial ecotoxicity (TETP), and marine ecotoxicity (METP) and 34% to freshwater ecotoxicity impact (FETP), while for the coal CCS systems, infrastructure development makes about 27% of HTP, 70% of TETP, 19% of FETP and 36% of METP. Direct emissions from the coal systems significantly influence

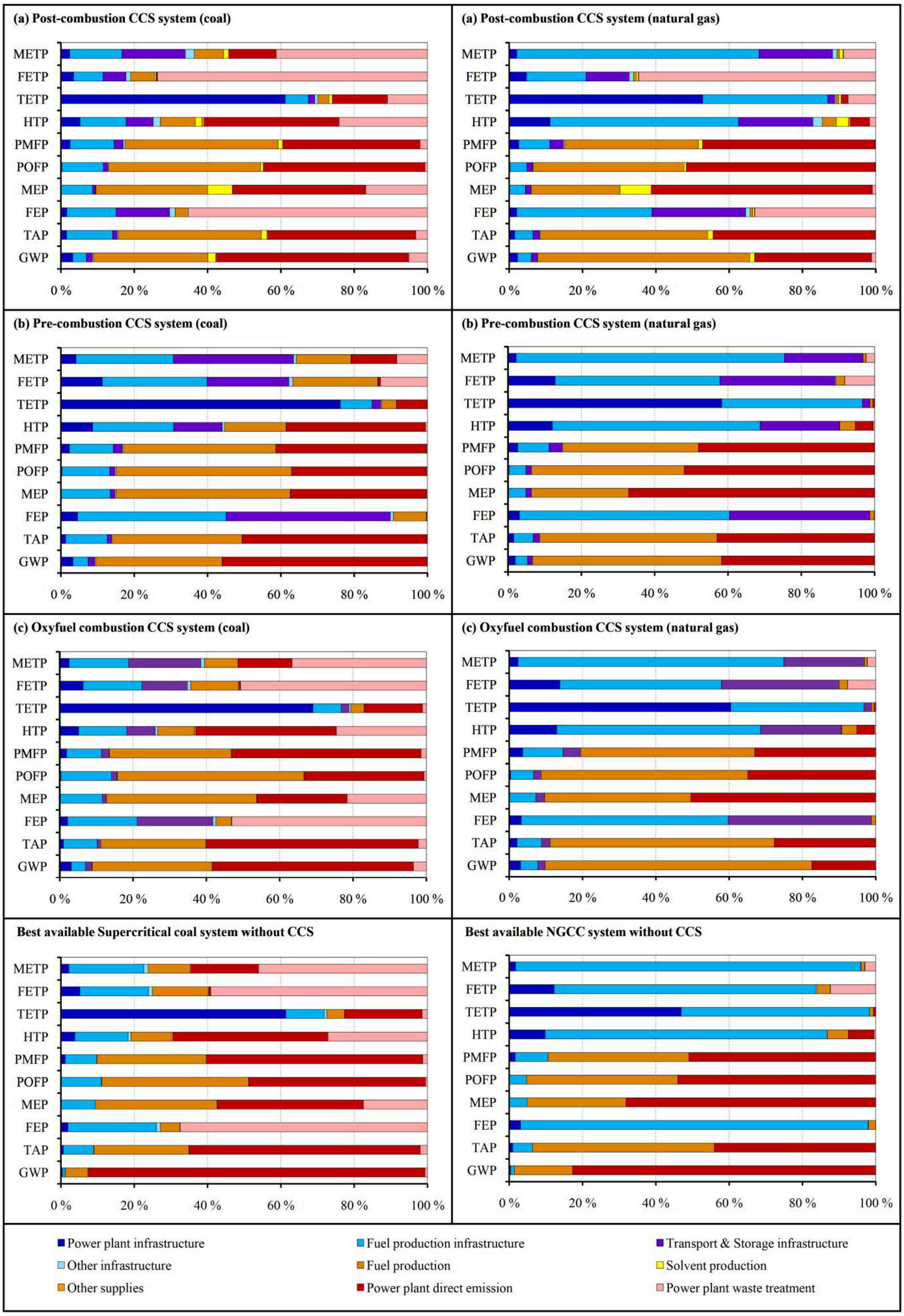


Figure 4.7. Contribution analysis for various environmental impacts from different electricity generation systems

HTP, TETP and METP scores, making a dominant contribution of about 37% to the human toxicity impact due to the energy penalty and emission of MEA, formaldehyde, and acetaldehyde from the capture system. The post-combustion CCS has the highest FETP impact (compared to all studied systems), with a 2-fold increase for coal and a 4-fold increase for the natural gas system. In these systems the highest contribution (74% for the coal system and 65% for the natural gas system) is from the power plant, where the disposal of reclaimer solid wastes alone is responsible for 48% of the FETP score in the coal system and 62% of the FETP score in the natural gas system which is caused by leaching from the landfill of incinerator ash from the reclaimer waste to surface- and groundwater. The majority of the marine ecotoxicity impact in the coal CCS system emanates from waste treatment (19% from coal ash disposal and 9% from reclaimer waste disposal of the total score).

Pre-combustion capture, transport and storage system

Pre-combustion CCS reduces 78% GWP from the coal and 64% from the natural gas system. However, these systems result in substantially higher freshwater eutrophication impact and all toxicity impacts as compared to the systems without CCS. The IGCC technology in itself is a clean coal technology and has lower environmental impacts than all other coal technologies (with or without CCS) except for global warming impact, which, as expected, is higher than the coal systems with CCS. The IGCC coal system significantly reduces the SO_2 and NO_x content in the flue gas from syngas combustion; however, there is no such advantage with partial oxidation for the natural gas system.

Fresh water eutrophication results show significant increases of 120% for the coal and 94% for the natural gas CCS systems. Development of infrastructure for the fuel production chain and transport and storage systems are the main contributing processes (causing 91% for the coal and 99% for the natural gas systems) to FEP, mainly due to disposal of solid waste from steel manufacturing process. Infrastructure development chain also makes a major contribution to all toxicity potentials, causing 43% of HTP, 87% of TETP, 63% of FETP, and 64% of the METP score from the coal CCS system. For the natural gas CCS system, infrastructure development contributes over 95% to all four toxicity impacts, mainly from infrastructure for natural gas production, except for terrestrial ecotoxicity impact where power plant infrastructure causes 58% of the overall TETP. Analysis shows that emissions and disposal of solid wastes from steel manufacturing, well drilling, and copper production are the important processes contributing to various toxicity potentials. For the coal CCS system, power plant waste treatment contributes about 8% to METP and 13% to FETP score, mainly due to the disposal of residue from the cooling tower. Coal production and direct emission from the power plant are two other important processes contributing to the toxicity impacts from the coal CCS systems.

Oxyfuel capture, transport and storage system

The oxyfuel coal CCS system reduces global warming impact by 76%, and the high capture efficiency of 96% with the natural gas oxyfuel CCS system results in a 73% reduction of GWP. The reduced NO_x content in the flue gas results in comparable MEP impact as supercritical BAT technology for coal and natural gas, with a net reduction of 15% (compared

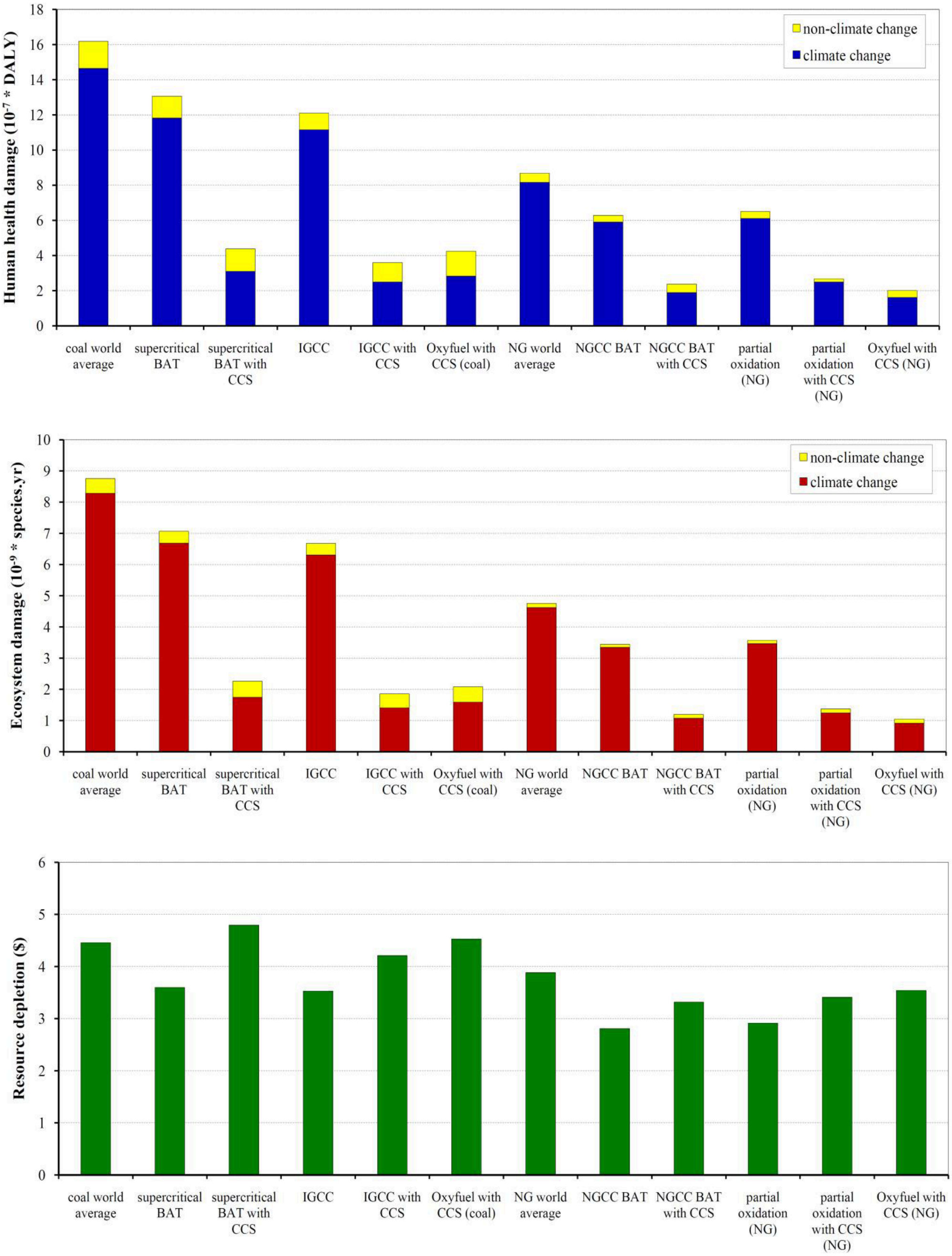


Figure 4.8. Damage assessment per kWh given as human health damage, ecosystem damage and resource depletion for different electricity generation technologies

to NGCC). The NO_x reduction also results in a decrease of photochemical oxidation potential (POFP). However, the energy requirement of the air separation unit (ASU) and CO_2 compression unit in the oxyfuel CCS system requires increased fuel combustion per kWh which increases the overall impacts through the chain.

Similar to post-combustion and pre-combustion CCS systems, the oxyfuel CCS also shows a considerable increase in freshwater eutrophication and toxicity potentials. FEP scores show increases of about 60% for the coal system and 110% for the natural gas system. The power plant waste treatment process (mainly the process of coal ash disposal) is the major contributor to the FEP score for the coal feedstock, causing about 52% of the total impact. Fuel production and transport and storage infrastructure development, cause 99% and 43% of FEP for the natural gas and coal systems, respectively. Further, the toxicity potentials show increases of 38% to 67% for the coal system and of 63% to 103% for the natural gas system. While the infrastructure development is largely responsible for all toxicity impacts from the natural gas oxyfuel system, for the coal systems, these processes comprise 26% of HTP, 79% of TETP, 36% of FETP, and 39% of METP impact. Direct emissions from the coal plant contributes mainly to the HTP score, and the power plant waste treatment processes (FGD, coal ash disposal, etc.) contributes significantly to the METP and FETP scores.

Damage assessment

Overall damage assessment over 3 end-point indicators - human health damage (DALY), ecosystem damage (species.yr), and resource depletion ($) are calculated and presented in figure 4.8. Human health damage and ecosystem damage results are presented with a breakdown into climate change and non climate change related damages. These results are generalized and are only to be used comparatively, as the absolute values will considerably depend on location, regional climate, population, size, etc. Detailed discussion on damage assessment from 3 most viable CCS configurations - pulverized coal and NGCC with post-combustion capture and IGCC with pre-combustion capture is presented in Singh et al. (20xxa)

Results show a significant potential of improvement in the world average technology. The CCS systems greatly reduce human health damage and ecosystem damage by mitigating the climate change impact. The post-combustion capture process has co-advantage of reducing damage to human health from photochemical smog and particulates but increases the health damage due to toxicity. There is an increase in damage from processes in the value chain; however, the reduction in climate change-related human health is of substantially higher magnitude, proving CCS to be an efficient damage control measure. IGCC technology with CCS for coal and oxyfuel combustion with CCS for natural gas is found to have the least human health damage among all the systems. Ecosystem damage shows a similar damage reduction trend with CCS. CCS technology implies higher resource depletion due to additional fuel and material demand, with a dominating contribution from fossil fuel usage. World average technology shows high resource consumption mainly attributed to their low efficiency. Among the various CCS technologies for coal, pre-combustion CCS is least resource intensive and causes least human and ecosystem damage.

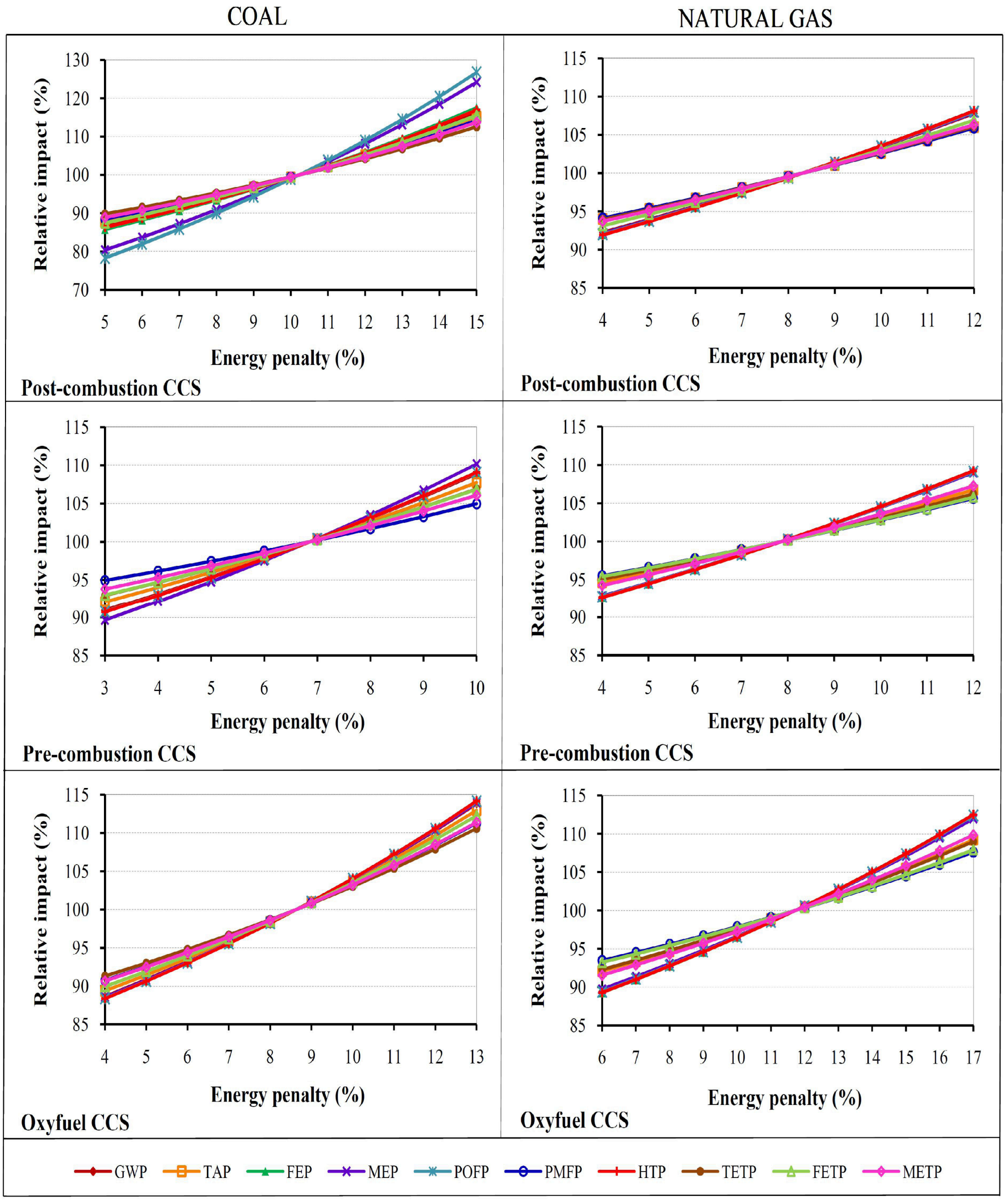


Figure 4.9. Effect of energy penalty on life cycle impacts from various technologies given as impact relative to the studied systems

From the natural gas CCS technologies, all three (post-combustion, pre-combustion, and oxyfuel) are comparable in term of resource depletion.

Sensitivity analysis

A sensitivity analysis is performed to understand the influence of CO_2 transport distance, the influence of energy penalty due to capture process on life cycle impacts of the CCS systems and the effect of MEA characterization factor for human toxicity on the life cycle human toxicity impact.

Figure 4.9 presents the effect of energy penalty from the capture unit on various environmental impacts for the studied CCS systems. Impacts for different electricity generation CCS systems at +/- 50% range of energy penalty, relative to the respective systems are presented. Energy penalty not only influences the global warming potential by emission of GHGs from fuel combustion, it also influences fuel consumption and hence the impacts from upstream production processes. The spread-out graphs on different impacts depicts the different contribution of energy penalty to the impacts. The analysis shows that the energy penalty has comparatively higher influence on the coal CCS systems, with the post-combustion coal CCS system showing significant dependence of eutrophication and photochemical oxidation formation impacts. These impacts are from upstream fuel combustion and waste treatment from power plant and production processes. Influence of the energy penalty on human toxicity from natural gas CCS systems is much more significant than for coal CCS systems, because in natural gas systems the fuel production infrastructure development is the major contributor to the impact. The global warming potential (GWP) varies about 20-30% for coal CCS systems and 15-25% for natural gas CCS systems, in the studied range of energy penalty.

Existing long-distance CO_2 pipelines range from about 100km (90km - Bati Raman, Turkey) to 800km (808km - Cortez, USA) (IPCC, 2005). In this study, analysis is made for 200km, 500km, and 1000km pipeline transport systems for sequestering 1Mt/y and 2Mt/y each (1Mt/y and 2Mt/y are the approximate CO_2 mass transport rates from a 400MW natural gas and coal power plant, respectively) . The infrastructure requirement for pipeline and recompressor stations, and the energy demand for compression, will vary for the cases causing changes in impacts with distance. Any recompression needed before injecting CO_2 to the storage site is included in the transport chain so as to have fewer recompression stations in the CCS chain. It is assumed that CO_2 is always maintained well above the critical pressure (minimum at 80bar), which therefore requires recompression every 300km. Table 4.6 presents the absolute impact scores from transport for different sensitivity cases. Analysis shows that transport over 200 km requires no recompression during transport, transport over 500km needs recompression once, and transport over 1000 km needs CO_2 recompression at three stations.

Further, prior to injecting CO_2 at the storage site, recompression is needed for the 200km and 500km pipeline transport cases, while the energy supplied at the last station for the 1000km case is sufficient to inject CO_2 without compression. The results show increases in all impacts as expected, and it also shows that the environmental cost for long distance transfer is non-linear. The majority of the impacts come from

Table 4.6. Environmental impact scores from transport and storage chain for different CO_2 transport distance and amount sequestered per year

		200 km		500 km		1000 km	
Impact	**Unit (kg eq)**	**1Mt/y**	**2Mt/y**	**1Mt/y**	**2Mt/y**	**1Mt/y**	**2Mt/y**
GWP	CO_2	$2.6*10^6$	$4.0*10^6$	$7.1*10^6$	$1.1*10^7$	$1.5*10^7$	$2.3*10^7$
TAP	SO_2	$1.0*10^4$	$1.6*10^4$	$2.9*10^4$	$4.5*10^4$	$5.8*10^4$	$9.4*10^4$
FEP	P	$7.4*10^2$	$1.1*10^3$	$1.9*10^3$	$2.8*10^3$	$3.7*10^3$	$5.6*10^3$
MEP	N	$1.2*10^3$	$1.8*10^3$	$3.2*10^3$	$4.9*10^3$	$6.4*10^3$	$1.0*10^4$
POFP	NMVOC	$1.2*10^4$	$1.8*10^4$	$3.1*10^4$	$4.8*10^4$	$6.3*10^4$	$9.8*10^4$
PMFP	PM_{10}	$7.2*10^3$	$1.1*10^4$	$1.9*10^4$	$2.9*10^4$	$3.8*10^4$	$5.8*10^4$
HTP	1,4-DB	$7.2*10^5$	$1.1*10^6$	$1.8*10^6$	$2.8*10^6$	$3.7*10^6$	$5.6*10^6$
TETP	1,4-DB	$5.0*10^2$	$7.6*10^2$	$1.3*10^3$	$2.0*10^3$	$2.6*10^3$	$4.1*10^3$
FETP	1,4-DB	$2.1*10^4$	$3.1*10^4$	$5.3*10^4$	$8.0*10^4$	$1.1*10^5$	$1.6*10^5$
METP	1,4-DB	$3.9*10^4$	$5.8*10^4$	$9.8*10^4$	$1.5*10^5$	$2.0*10^5$	$2.9*10^5$

transport infrastructure development (pipeline) with a considerable amount coming from the energy demand as well. The contribution from the energy requirement to all impacts increases with transport rate and distance.

Characterization factor (CF) refers to the extent of impact caused by unit emission of a certain compound and is defined by modeling the cause-effect chain. MEA solvent used in post-combustion capture may have certain potential to be toxic for humans, but is not yet developed in the ReCiPe method used in this study. Here, the value of characterization factor for MEA is taken as 0.24 kg 1,4 DB to urban air/ kg MEA calculated by Veltman et al. 2010 for a generic location. A sensitivity analysis is performed to understand the dependence of

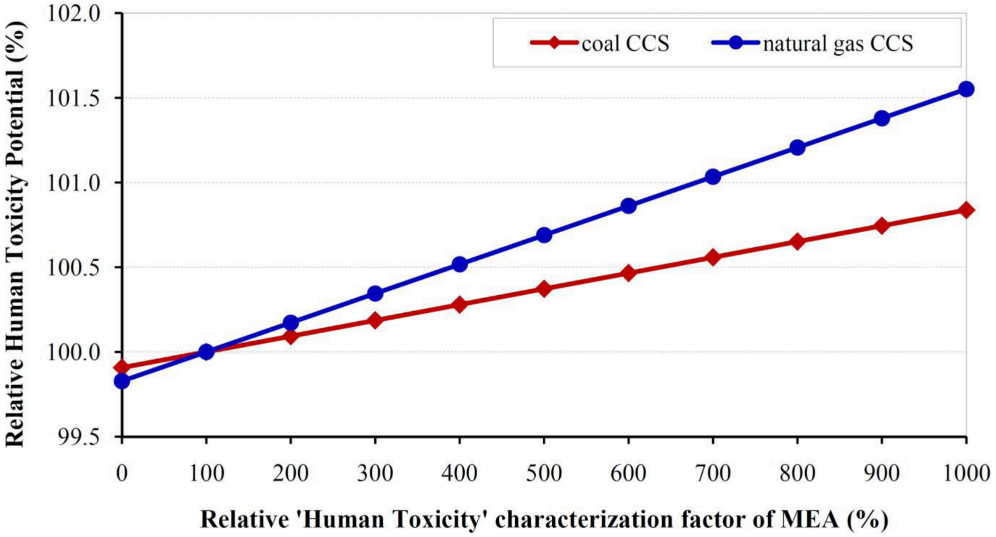


Figure 4.10. Sensitivity of human toxicity potential for coal and natural gas post-combustion CCS systems with respect to the MEA characterization factor

human toxicity potential on the assumed characterization factor. Relative human toxicity impact is calculated for 0 to 1000% value of the CF and is presented in figure 4.10. Results show an increase of only about 1% and 2% respectively for coal and natural gas post-combustion CCS systems, for the given range of characterization factor values, confirming a low contribution of MEA emission to the overall life cycle human toxicity impact and a relatively robust result with the CF value assumption. MEA is mainly emitted to air from the capture process and may have pronounced direct impact (3% of direct human toxicity impact for natural gas Singh et al. 2010, and lower for coal CCS) at the plant site, resulting in relatively higher dependence of direct human toxicity impact on the CF values.

4.3.2. Evolution of environmental performance

Projected future technical improvements in power generation in general and fuel efficiency and capture process in particular will reduce the environmental impacts associated with CCS and electricity generation from fossil fuels. Figure 4.11 shows the evolution of various environmental impacts and human health damage from coal and natural gas electricity generation systems with and without carbon capture and storage. An elaborate discussion of the future environmental performance is presented in Singh et al. (20xxb). The analysis of the futuristic performance of CCS shows that the technical evolution of the power generation and capture process significantly influences the major contributing processes and/or the fuel and material demand per unit of output, resulting in a decrease of adverse impacts over time. Impact potential scores in Figure 4.11 show an expected reducing trend in all environmental impacts, both for systems with CCS and without CCS. Evolution of energy efficiency will significantly reduce the per unit demand of fuel leading to reductions in various environmental impacts. A gradual reduction of 4% efficiency points in energy penalty from capture process by 2050 for both coal and natural gas CCS systems coupled with fuel combustion efficiency improvements of 10% for coal and 7% for NGCC results in improvements of 30% and 18% in the GWP for the coal and natural gas CCS systems respectively by 2050. Beyond GWP, the evolution of CCS system leads to a significant decrease in other environmental impacts. Results show that the environmental performance of the CCS systems will improve over various impacts by about 30% for coal and 20% for natural gas feed stock, by 2050. The decrease in impacts is mainly due to development in the capture process, resulting in controlled emissions from amine degradation (MEA, formaldehyde and acetaldehyde) and reduced energy penalty. Freshwater eutrophication potential (FEP), mainly attributed to disposal of wastes from power plant and steel furnace remains to be significantly high even by 2050, projecting 85-145% (higher value for natural gas system) higher FEP impact as compared to the electricity system without CCS.

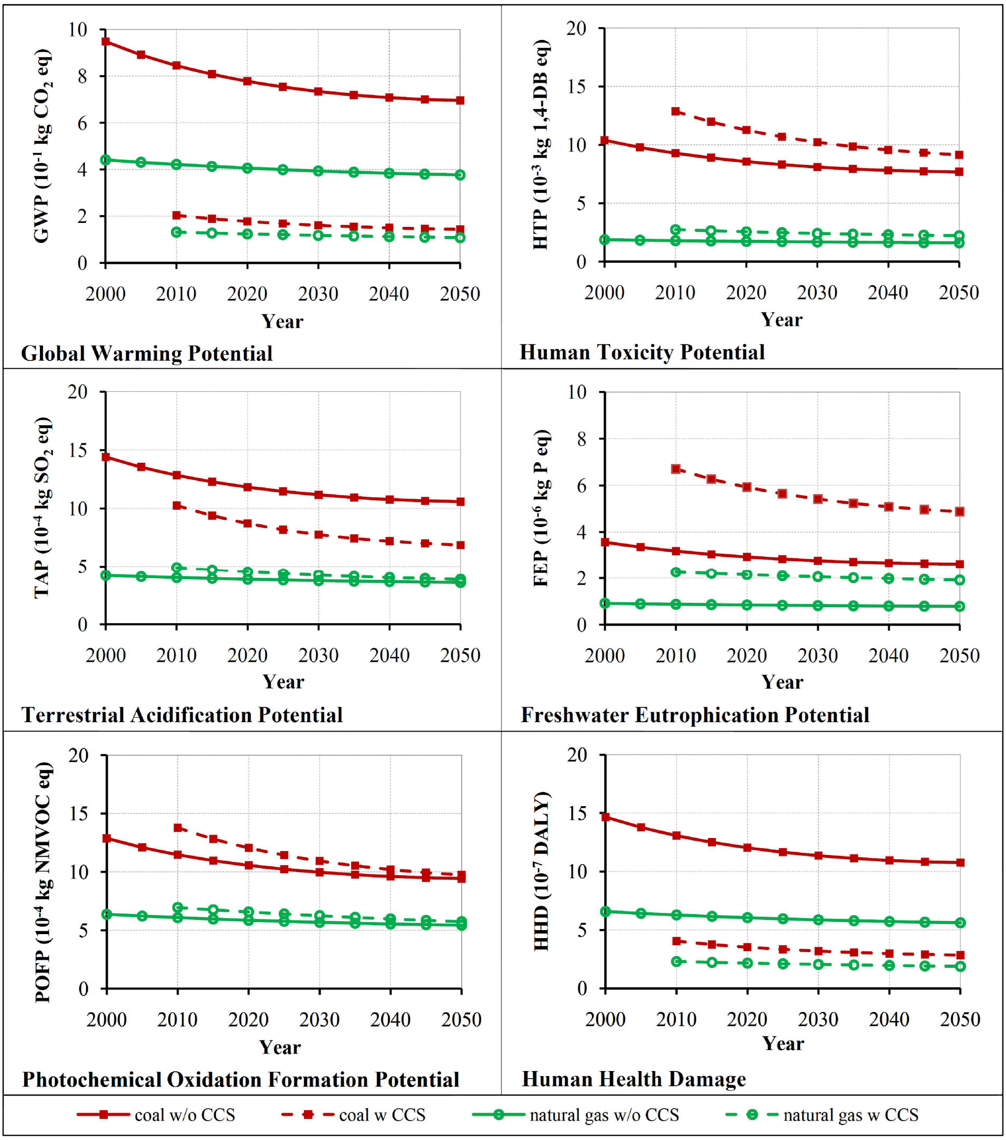
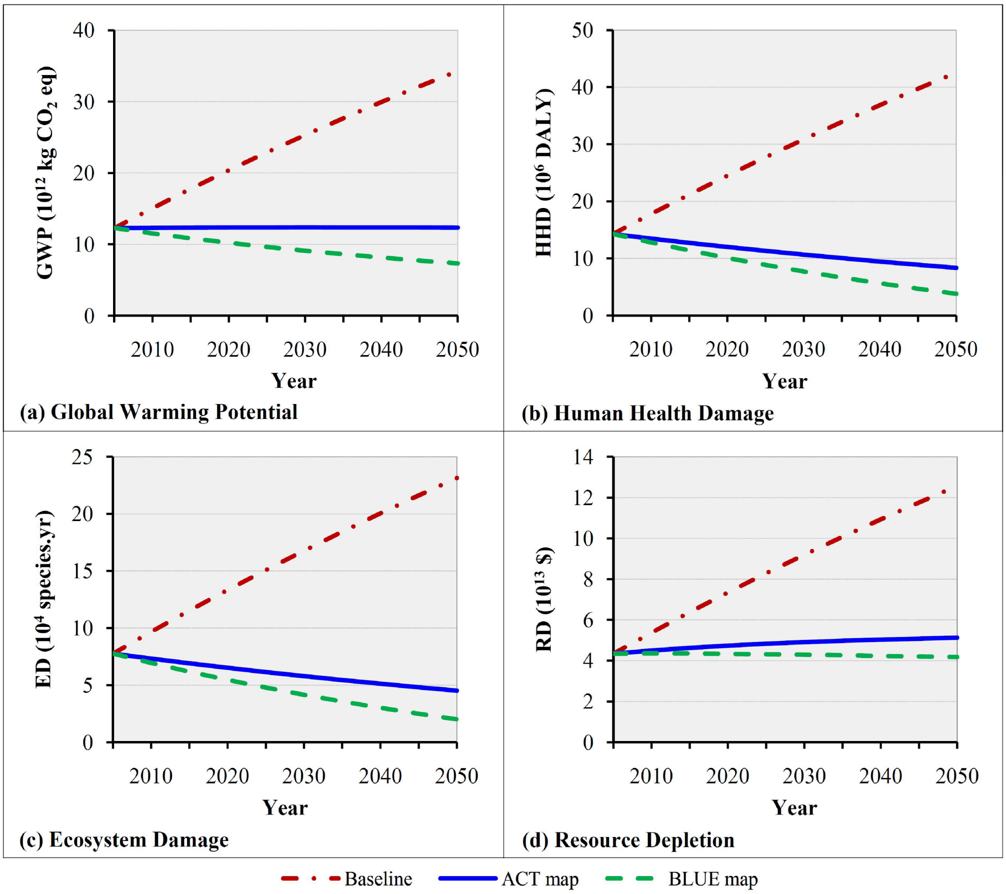


Figure 4.11. Calculated absolute impact potential scores for 1kWh of electricity generation from fossil fuel system with and without post-combustion CCS



(a) Global Warming Potential

(b) Human Health Damage

(c) Ecosystem Damage

(d) Resource Depletion

Figure 4.12. Global warming potential (GWP) and damage assessment for different scenarios

4.3.3. Scenario assessment

Electricity generation from coal and natural gas feedstock incorporates carbon capture and storage technology at different diffusion rates for the considered scenarios. Projected changes in electricity demand, techno-economic improvements in power generation, technology-shift in energy production towards CCS and renewable energy will influence the associated environmental impacts and damages for different scenarios. Figure 4.12 shows the global warming potential (GWP) and damage assessment as human health damage (DALY – Disability Adjusted Life Year), ecosystem damage (species.yr) and resource depletion (\$) of the three IEA scenarios for coal and natural gas based electricity generation. A detailed discussion of the impact assessment of various coal and natural gas based electricity scenarios is presented in Singh et al. (20xxb).

Damage assessment results in figure 4.12 shows significant continuous decrease in human health damage and ecosystem damage with the global large scale diffusion of CCS and shift to non-fossil based electricity technologies. BLUE map scenario with higher diffusion of CCS as compared to ACT map scenario, gives a reduction of 75% in human health damage and ecosystem damage with an associated modest decline of about 5% in resource depletion by 2050, as compared to year 2005. The decrease in resource depletion with the rise in global application of CCS, which in itself is an energy intensive process; is attributed to the lower electricity share of coal and gas. Impact potentials over different environmental categories vary for various scenarios depending on electricity technology mix. ACT map and BLUE map scenarios has reduced share of coal and natural gas based electricity, significant efficiency improvements and high diffusion of CCS technology resulting in lower impacts as compared to Baseline scenario (figure 4.12). Global warming impact (GWP) in ACT map scenario remains unchanged and in BLUE map scenario reduces by 40% as compared to 2005. Above scenario attributes also give certain co-benefits by reducing total acidification and human toxicity impacts, but shows significant increase (40-100%) in eutrophication and other toxicity potentials stressing the trade-offs in impacts from CCS Singh et al. (20xxb).

4.4. Uncertainties

For all CCS options in this study, the leakage of CO_2 is assumed negligible. Leakage rate between 1% and 0.00001% per year are discussed in literature, and the lower leakage values are justified by the existence of natural underground CO_2 deposits of substantial age (Holloway, 2005). Monitoring of the transport network and storage site is also not included in the system.

For the comparison of different capture options, there is uncertainty about non-CO_2 emissions for the future plant technologies. For the oxyfuel power plant, NO_x is assumed to be reduced by 50% due to the absence of thermal NO_x and reduction of NO to molecular nitrogen. Literature suggests an even higher reduction of 80% in the case of a hard coal plant (US DOE, 2007 in Pehnt and Henkel, 2009); however, there are also studies that suggest no NO_x reduction (Johnsson et al., 2006; Varagani et al., 2006 in Pehnt and Henkel, 2009). Values for NO_x emission effect photochemical oxidation, particulate matter formation, acidification, and marine eutrophication impacts. The physical solvent (selexol) used in pre-combustion carbon capture is assumed to have no losses to the atmosphere or emission of solvent degradation wastes; however, there is no literature found analyzing the possible reaction/degradation mechanism for the compound. Concerning the power plant technology with CCS, the most important uncertainty is the overall efficiency which is significantly influenced by the energy penalty resulting from solvent regeneration and air separation unit (for oxyfuel). This study estimates the energy penalty based on available literature. Because this is an important economic parameter, it is the major focus of further research (by modification in solvents, power cycles, process optimization, etc.). Any decrease in energy penalty will significantly reduce the impacts from the fuel chain.

Future environmental performance of the technologies is based on techno-economic improvements in power plant and capture systems. This study identifies the trend in efficiency development based on available future projections. There is much information on current and near-term values, but long term projections are lacking. Since efficiency is also an important economic parameter, it will be a major focus of further research. The study uses the assumption of monoethanolamine based post-combustion CO_2 capture to be the only viable CCS till 2050. This assumption is predominately made due to lack of data and future projections for other capture techniques. Further the study uses a conservative approach to calculate capture related impacts by considering no improvement after 2030 in solvent waste generation. With the R&D progress for more efficient solvents, novel capture technology, water-wash technique, reduced reclaimer wastes etc., further reduction in impacts is possible.

Other important uncertainty is related to the modeling of the background system for scenario assessment. This study considers the changes in electricity mix over time as given for different IEA scenarios. In addition to the changes in electricity mix, there may be improvements in individual background processes towards higher efficiency, better technology etc.. Defining the complete future background system is out of the scope of this study, therefore no future progress is accounted in any material production (e.g. process of fuel production, solvent production, etc.) and the inter-industry economic flows. Though, the most influencing background process ‘fuel production’ being a developed technology, any further reduction in GHG emissions from upstream fuel combustion and fugitive emissions (mainly CH_4 emissions during capping, processing, transmission etc. in natural gas production and during venting of residual gas in coal mining) will reduce the related GWP scores.

5. SUMMARY OF PAPERS

PAPER I: Life cycle assessment of natural gas combined cycle power plant with post-combustion carbon capture, transport and storage

Hybrid life cycle assessment has been used to assess the environmental impacts of natural gas combined cycle (NGCC) electricity generation with carbon dioxide capture and storage (CCS). The CCS chain modeled in this study consists of carbon dioxide (CO_2) capture from flue gas using monoethanolamine (MEA), pipeline transport and storage in a saline aquifer. Results show that the sequestration of 90% CO_2 from the flue gas results in avoiding 70% of CO_2 emissions to the atmosphere per kWh and reduces global warming potential (GWP) by 64%. Calculation of other environmental impacts shows the trade-offs: an increase of 43% in acidification, 35% in eutrophication, and 120–170% in various toxicity impacts. Given the assumptions employed in this analysis, emissions of MEA and formaldehyde during capture process and generation of reclaimer wastes contributes to various toxicity potentials and cause many-fold increase in the on-site direct freshwater ecotoxicity and terrestrial ecotoxicity impacts. NO_x from fuel combustion is still the dominant contributor to most direct impacts, other than toxicity potentials and GWP. It is found that the direct emission of MEA contribute little to human toxicity (HT < 1%), however it makes 16% of terrestrial ecotoxicity impact. Hazardous reclaimer waste causes significant freshwater and marine ecotoxicity impacts. Most increases in impact are due to increased fuel requirements or increased investments and operating inputs. The reductions in GWP range from 58% to 68% for the worst-case to best-case CCS system. Acidification, eutrophication and toxicity potentials show an even larger range of variation in the sensitivity analysis. Decreases in energy use and solvent degradation will significantly reduce the impact in all categories.

PAPER II: Human and environmental impact assessment of post-combustion CO_2 capture focusing on emissions from amine-based scrubbing solvents to air

Carbon Capture and Storage (CCS) has become a key technology in climate change mitigation programs worldwide. CCS is well-studied in terms of greenhouse gas emission reduction potential and cost of implementation. Impacts on human health and the environment have, however, received considerably less attention. In this work, we present a first assessment of human health and environmental impacts of a post-combustion CO_2 capture facility, focusing on emissions from amine-based scrubbing solvents and their degradation products to air. We develop characterization factors for human toxicity for monoethanolamine (MEA) as these were not yet available. On the basis of the limited information available, our assessment indicates that amine-based scrubbing results in a 10-fold increase in toxic impact on freshwater ecosystems and a minor increase in toxic impacts on terrestrial ecosystems. These increases are attributed to emissions of monoethanolamine. For all other impact categories, i.e., human toxicity, marine ecotoxicity, particulate matter formation, photochemical oxidant formation, and terrestrial acidification, the CO_2 capture facility performs equally well to a conventional NGCC power plant, albeit substantial changes in flue gas composition. The oxidative degradation products of MEA, i.e., formaldehyde, acetaldehyde, and ammonia, do not contribute significantly to total environmental impacts.

PAPER III: Comparative impact assessment of CCS portfolio: Life cycle perspective

This study presents life cycle assessments of different capturing technologies with natural gas and hard coal feedstock for fossil fuel power plant. Post-combustion capture with amine-based absorption, pre-combustion capture with selexol absorption and oxyfuel-combustion capture by condensation of flue gas from oxygen fired fuel combustion are considered. The captured CO_2 is transported over 500km pipeline and sequestered in secure geological storage. Results show a substantial decrease in greenhouse gas emissions for all CO_2 capture approaches in comparison with power plants without CCS, reducing the net global warming potential (GWP) by 64-78% depending on the technology used. The emissions at the plant and in the chain lead to considerable increases in toxicity and eutrophication impacts. Human toxicity impact increases by 40-75%, terrestrial ecotoxicity by 60-120%, and freshwater eutrophication by 60-200% for different technology. The detailed assessment of the impacts quantifies impact contribution from various processes in the chain and identifies the energy penalty and infrastructure as the major contributing processes to the increase in most of the impacts.

PAPER IV: Environmental damage assessment of carbon capture and storage : Application of end-point indicators

An end-point life cycle impact assessment is used to evaluate the damages of electricity generation from fossil-fuel based power plants with carbon dioxide capture and storage (CCS) technology. Pulverized coal (PC), integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) power plants are assessed for CO_2 capture, pipeline transport and storage in geological formation. Results show that the CCS systems reduce the climate change related damages but increase the damages from toxicity, acidification, eutrophication, resource consumption etc. Because climate change related damages are dominant, the CCS technology significantly reduces overall environmental damage, with a net reduction of 60-70% in human health and 65-75% in ecosystem damage. Most of the damage is due to fuel production and combustion processes. The energy and infrastructure demand placed by CCS causes increases in depletion of natural resources by 33% for PC, 19% for IGCC and 18% for NGCC power plant, mostly due to increased fossil fuel consumption.

PAPER V: Environmental assessment of fossil-based electricity scenarios: Implications of carbon capture and storage

This study evaluates the environmental implications of large scale deployment of carbon capture and storage. Coal and natural gas based electricity demand for different IEA scenarios with the projected futuristic techno-economic improvements in CCS are considered. The modeled CCS chain consists of post-combustion CO_2 capture from flue gas using monoethanolamine (MEA), pipeline transport and storage in a saline aquifer. Future developments in the controlling parameters are used to obtain a continuous trend with time for the period till 2050. Hybrid life cycle assessment approach is then used to assess the environmental impacts. Results show that the projected progress in influencing parameters considerably reduces the adverse environmental impacts associated with CCS. With the decrease in energy penalty from CO_2 capture, the overall reduction in greenhouse gas emissions achieved through CCS will increase to 79% for coal and 72% for natural gas plants, by 2050. Impact potentials of different impact categories for electricity generation with CCS will decrease with about 30% for coal and about 20% for natural gas by 2050. Results for coal and natural gas based electricity scenarios show a 2-fold increase in all impact categories for the Baseline scenario at 2050 as compared to 2005. Global warming potential for the ACT map is found to be approximately unchanged, while a 40% decrease in GWP is projected in BLUE map scenario at 2050. Impact intensity of coal and natural gas based electricity mix shows a decrease of 10-15% in all impact categories in Baseline scenario at 2050, as the consequence of projected efficiency improvements. ACT map and BLUE map show steeper decline of 30-60% in global warming, acidification and human toxicity impacts per kWh, but the BLUE map scenario, with higher CCS diffusion, projects 20-90% increase in eutrophication, terrestrial and freshwater ecotoxicity at 2050.

6. CONCLUSIONS

6.1. Overall evaluation
6.2 Scientific contributions
6.3 Recommendations for future research

6.1. Overall evaluation

The goal of this thesis was to *compare different carbon capture and storage technologies* and to *study the environmental implications of applying CCS at large-scale*. To be able to achieve this, inventories were developed for different CCS configurations for both coal and natural gas feedstock viz. capture via post-combustion, pre-combustion and oxyfuel; transport of CO_2 via pipeline and sequestration in proven geological storage. Impact assessments were then made for the technologies and CCS scenarios.

Main findings

The results of the study reveal that the CCS systems achieve a significant reduction of greenhouse gas emissions but have multiple environmental trade-offs depending on the technology. The implementation of CCS reduces the greenhouse gas emissions by 74%, 78%, and 76% from coal systems with post-combustion, pre-combustion, and oxyfuel capture, respectively. For natural gas CCS systems, the reduction in GHGs is 68%, 64%, and 73% for post-combustion, pre-combustion, and oxyfuel capture, respectively. For cases with CCS, a major portion of GWP (52-73%) for natural gas emanates from the fuel production chain, and 17-42% from the power plant. The CO_2 transport and storage chain contributes only about 2% to the total GWP impact. For coal CCS systems, fuel combustion is still the major source of GWP (52-56%). There is a net increase in all other environmental impact categories (except some reduction (7-15%) in acidification (TAP) and particulate formation (PMFP) for post-combustion coal CCS system due to co-capture of SO_2 and particulates from the flue gas. The Oxyfuel CCS system for natural gas compared to best available technology also shows some reduction in marine eutrophication (MEP) and particulates formation (POFP). Human toxicity impact increases by 40-75%, terrestrial ecotoxicity by 60-120%, and freshwater eutrophication by 60-200% for the different technologies. Much of this increase is due to the emission of phosphates to the ground water from the landfill disposal of wastes from power plants and residual furnace wastes from metal manufacturing. IGCC systems for coal with and without CCS have the least environmental impacts compared to other respective coal systems. For natural gas feedstock CCS systems with partial oxidation or oxyfuel proves better, with low energy penalty (partial oxidation capture), high CO_2 capture efficiency (oxyfuel capture) and no toxic chemical emissions. However, these systems are yet only in the research phase, and are much less developed and studied. Damage assessment finally confirms that CCS systems greatly reduce human health damage and ecosystem damage by mitigating the climate change impact while increasing the resource consumption.

The results for environmental evolution of CCS systems show that the future techno-economic developments will enable a significant reduction of impacts improving the overall environmental performance of the CCS system with time. At 2050, the CCS systems will have a life cycle GWP mitigation efficiency of 79% and 71% for coal and natural gas respectively. Environmental performance of the CCS systems for all other impact categories will improve by about 30% for coal and 20% for natural gas fuel. The information so obtained, coupled with the electricity scenarios brings an understanding of the environmental implications of large scale deployment of carbon capture and storage technology. Scenario assessment results show the clear advantage of ACT map and BLUE map scenarios (mitigation scenarios with global CCS integration) over the Baseline scenario having significantly lower impact potential scores for all impact and damage categories. Future impact potentials of global warming, terrestrial acidification and human toxicity in ACT map and BLUE map scenarios show a decreasing and/or leveling trend suggesting co-advantages of CCS, however, these scenarios also show future increase for eutrophication, terrestrial ecotoxicity and freshwater ecotoxicity impacts, attributed to the additional material and energy demand and capture related emissions. Damages to human health, ecosystem and resource depletion are significantly lower with the CCS scenarios, however, it is important to consider that these scenarios (ACT map and BLUE map) have a lower share of coal and gas based electricity and much of the electricity is to be supplied from renewable or nuclear sources.

Interpretation

Comparison of different CCS options shows the monoethanolamine based post-combustion capture system to have the highest environmental impacts. MEA is the most widely studied solvent but given its high energy requirement for regeneration and considerable environmental effects, it is likely to use other less energy intensive and novel solvents e.g. potassium carbonate, chilled ammonia etc. Best estimates based on literature values have been made to define the performance parameters for each plant and capture type. Presentation of mid-point impact potentials as percentage increases may give an alarming view on the environmental impacts of CCS. This study presents and justifies the rationale of a dual approach, considering the practical relevance of each impact category. The mitigation scenarios though assessed with an simplified approach using specific fuel type and amine based capture, present an overview of the environmental implications of fossil based electricity. Differences in fuel grade and their global distribution, together with more energy efficient solvents and capture will influence the absolute results for the scenarios.

Much of the chemicals discussed and being developed to be used as solvents for CO_2 capture lack information on their toxic effects. This study uses the recent-most characterization method (ReCiPe 2008), having values for ecotoxicity potential of MEA and the human toxicity potential is used from the in-house calculations for generic urban air emission (Veltman et al. 2010). There is a need to evaluate the characterization values for every new solvent under development, to be able to understand its behavior and potential effect on the environment and humans.

Carbon dioxide is classified as a non-toxic, non-hazardous and non-irritant substance. However, long-term human exposure to airborne 0.5 to 1% carbon dioxide concentration results in metabolic acidosis and increased calcium deposits in soft tissues. The substance is toxic to the cardiovascular system and upper respiratory tract at concentration over 3%. At concentrations above about 2%, CO_2 has a strong effect on respiratory physiology and concentrations above 7-10% can cause unconsciousness and death. Any accidental release of CO_2 if it displaces oxygen such that the oxygen concentration is reduced to 15-16% causes asphyxiation (IPCC 2005). CO_2 migration from a storage reservoir to the surface will change the groundwater chemistry, potentially affecting shallow groundwater used for drinking, industry and agriculture. Dissolved CO_2 forms carbonic acid, altering the pH of the brine, potentially causing mobilization of toxic metals, sulphates or chlorides. This gives water an odd odour, colour or taste and at high levels may even render the groundwater unfit for drinking or irrigation (IPCC 2005). Therefore a risk assessment of CO_2 is necessary to determine the risks and establish necessary risk management procedures.

CO_2 may also escape from the geological storage formations through the porous rock structure, fracture and faults in the cap rock or through poorly completed and abandoned pre-existing wells. Storage sites will presumably be designed to securely confine all injected CO_2 for geological time scales and any subsequent release will question the effectiveness of storage site, reduce the efficiency of capture mitigation system and may also have some local health, safety and environmental hazards. The fraction of CO_2 retained in geological storage depends on geological characteristics of the storage site, storage system design, injection system, related reservoir engineering and well-sealing technologies. In principle it is possible to estimate the expected performance of a storage location and an adherence to design guidelines gives efficient sequestration. For large-scale CO_2 storage projects, for a well selected, designed, operated and monitored site, 99% of the stored CO_2 is very likely to be retained over the first 100 years and 99% is likely to be retained over the first 1000 years (IPCC 2005).

6.2. Scientific contributions

Use of chemicals and energy for CO_2 capture had raised some apprehensions for carbon capture technologies. There are prior studies discussing the possible trade-offs in impact with CO_2 capture technology. Few studies have also presented the absolute results for specific technology, plant type and fuel (mainly postcombustion capture with coal). But these studies differ in their basic assumptions about the system and may therefore not be directly comparable. This study makes an assessment of the novel 'carbon capture and storage' technology for both coal and natural gas feedstock and the three capture options (post-combustion, pre-combustion and oxyfuel) along the same basic assumptions, presenting consistent and directly comparable results. This study also assesses the environmental implications of climate change mitigation scenarios with CCS using LCA approach and certain straightforward basic assumptions.

This study evaluates and compares different CCS options for coal and natural gas, discussing various trade-offs and net-benefits. This information brings a holistic environmental understanding of CCS as necessary to avoid any problem shifting (as with bio-fuels shifting problem to food-crop land-use). This study also identifies the key areas to reduce trade-offs, and it is also found that technical developments to reduce energy penalty, degradation products, and solid waste management from disposal processes are required to reduce the negative environmental impacts. This allows the future research to focus on these areas and reduce the impacts of CCS. This study also discusses the environmental relevance of CCS in more understandable terms of damages to human health, ecosystem and resource depletion. This facilitates the decision makers to derive policies for sustainable development. The study also evaluates the environmental implications of large scale CCS deployment scenarios. This required understanding potential future developments in CCS and the assessment presents impacts and damages from fossil-based electricity in these scenarios.

This study also contributes to assessment methodology via presenting end-point and scenario assessments. The study represents an early application of end-point indicators from the ReCiPe method, giving simple and comprehensible results, and justifies a dual-approach for environmental assessments, presenting mid-point results to understand environmental potentials and identification of key areas to reduce the adverse impacts and end-point results to present comprehensible information to decision makers. This study also presents a methodological approach for futuristic assessment and scenario assessments incorporating the learning in processes, influence on background processes, variable demand etc. This approach is useful in understanding beforehand, the possible outcomes of implementing a technology on large scale and advocates the role and importance of life cycle assessment in decision making for sustainable developments.

6.3. Recommendations for future research

The assessment of the future-oriented technology has few inherited limitations and should be considered in further study of carbon capture and storage technologies.

- The study assesses the most commonly discussed options for CO_2 capture. With much research and developments ongoing in this field, more efficient chemical solvents, and novel capture concepts are developed and need to be holistically assessed.
- The issue of CO_2 leakage and associated impacts at storage sites needs elaborate understanding of chemical/mechanical changes in the soil structure brought by injection of huge amounts of CO_2.
- Characterization factors for less studied novel solvents are needed to be developed to evaluate their impacts.
- The CCS scenarios studied have also increased shares of renewable and nuclear electricity. This implies that there will be some additional impacts/damages related to non-fossil electricity generation. It is expected that various renewable electricity generation technologies will have lower global warming impact than fossils, reducing the overall climate change, however there may be other increased environmental implications for scarce metals, land use, biodiversity etc. A full scale futuristic life cycle assessment of different renewable technology options is needed to completely understand the environmental implications of different energy scenarios.

- Future changes in various background processes will influence the scenario assessment. Improvements in certain significant industrial sectors could be studied and included in such assessments.

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Paper III

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Paper IV

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Environmental damage assessment of carbon capture and storage: Application of end-point indicators

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Summary

An end-point life cycle impact assessment is used to evaluate the damages of electricity generation from fossil-fuel based power plants with carbon dioxide capture and storage (CCS) technology. Pulverized coal (PC), integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) power plants are assessed for CO_2 capture, pipeline transport and storage in geological formation. Results show that the CCS systems reduce the climate change related damages but increase the damages from toxicity, acidification, eutrophication, resource consumption etc. Because climate change related damages are dominant, the CCS technology significantly reduces overall environmental damage, with a net reduction of 60-70% in human health and 65-75% in ecosystem damage. Most of the damage is due to fuel production and combustion processes. The energy and infrastructure demand placed by CCS causes increases in depletion of natural resources by 33% for PC, 19% for IGCC and 18% for NGCC power plant, mostly due to increased fossil fuel consumption.

keywords: life cycle assessment, CO_2 capture, endpoint indicators, ReCiPe, Disability-Adjusted Life Years

INTRODUCTION

Carbon dioxide capture and storage (CCS) is widely recognized as the most viable option to reduce CO_2 emissions from large-scale fossil fuel usage. Besides allowing electricity generation from fossil-based power plants, necessary to satisfy increasing energy demand, it also has an important role to smooth the transition from 'unsustainable' conventional power production to 'sustainable' renewable energy systems. CO_2 is captured at large point sources, compressed and transported for storage in geological formations, in the oceans, in mineral carbonates or for use in industrial processes (IPCC 2005). Various techno-economic feasibility studies have been performed for available technological options and have strengthened the idea of CCS being a major potential option for mitigating global warming.

With the growing discussions and prospect of large-scale implementation, concerns for adverse environmental impacts from CCS have also arisen. CCS is an energy intensive process; it demands additional chemicals and infrastructure. This material and energy demand will increase the emissions in parts of the value chain. The capture processes may also have certain direct emissions and generate solid wastes from degradation byproducts. A trade-off in environmental impacts and related damages is expected, which may offset some of the damage control due to CO_2 capture. A systematic process of evaluation of the complete life cycle is needed to understand this trade-off. Life Cycle Assessment (LCA) is a well-established method and best suited for such analysis. Early environmental assessments of CCS have primarily focused on capture process, CO_2 emissions and global warming (Audus and Freund 1997; Doctor et al. 1993; Lombardi 2003; Waku et al. 1995). Few studies have also presented results for various other environmental impacts (Benetto et al. 2004; Hertwich et al. 2008; Khoo and Tan 2006; Koorneef et al. 2008; Korre et al. 2010; Odeh and Cockerill 2008; Pehnt and Henkel 2009; Rao and Rubin 2002; Singh et al. 2010; Summerfield et al. 1995; Viebahn et al. 2007), and showed increases in various impacts, primarily eutrophication, acidification and toxicity. These increased environmental impacts eventually cause some damage to living systems, and may partially negate the damage control made by reducing global warming.

This study assesses the trade-off between the benefits and damages of carbon capture and storage technology. The assessment is based on a hybrid LCA model using elaborate physical data for all processes and economic data for infrastructure of the power plant and the CO_2 capture facility. End-point damage indicators are used to assess the damages caused by different environmental mechanisms on humans, ecosystems and resources. The study represents an early application of end-point indicators from the ReCiPe method (Goedkoop et al. 2009), and takes the results of our earlier work on CCS mid-point impact assessment to one step further towards decision making. End-point indicators give simple and comprehensible results, unlike mid-point methods that give abstract results for impact categories and require knowledge of environmental mechanisms and impacts. Conventional mid-point impacts of the technologies presented here have been analyzed by Singh et al. (20xx) and a summary is provided in the online supplementary material. Section 2 describes the methodology for the life cycle inventory and the end-point method for impact assessment. Section 3 gives a description of the technologies and inventories of the systems. Section 4 presents results and discussion for the damages, and section 5 presents the conclusion and outlook for future work.

METHODS

Life Cycle Impact Assessment (LCIA) may employ a number of methods based on environmental mechanisms converting the emissions of hazardous substances and extractions of natural resources into midpoint level impact category indicators such as acidification, climate change and ecotoxicity; or methods extending the cause and effect chain to assess damage to human health, ecosystem impacts as a result of climate change, ecotoxicity, as well as other categories addressed using midpoint indicators. Midpoint modeling is a comprehensive approach with a relatively good level of certainty. Endpoint modeling, on the other hand, has more structured and informed weighting across categories in terms of common understandable indicators, making it useful to wide audiences (Bare et al. 2002; Hertwich et al. 2002). ReCiPe 2008 LCIA method is harmonized in terms of modeling principles and offers results at both the midpoint and endpoint level. Figure 1 shows a simplified representation of the relationship between inventory parameters, midpoint impacts and endpoint impact for human health damage. Here, various impact categories at the midpoint level (radiative forcing, ozone concentration, hazard index etc.) are assessed further with damage models (Goedkoop et al. 2009) in terms of a common endpoint, human health damage measured in DALY (Disability Adjusted Life Years). Similarly, other midpoint indicators are aggregated to give ecosystem damage and resource depletion. For more detail, see Goedkoop et al. (2009).

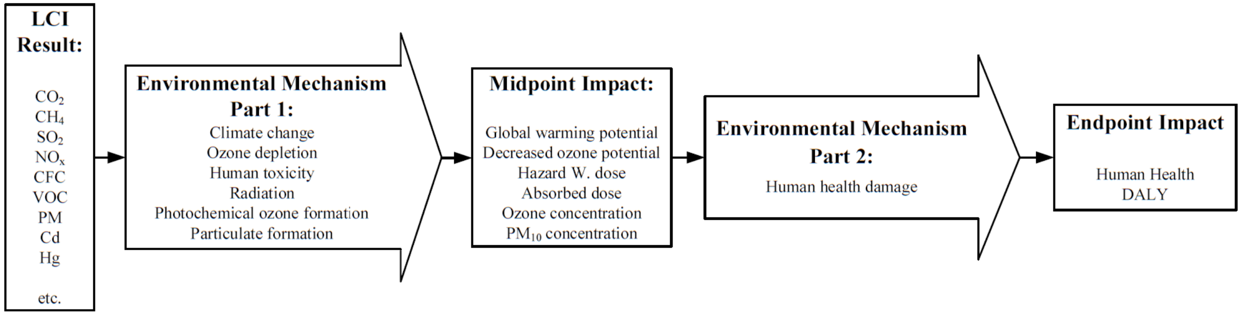


Figure 1. Simplified representation of relationship between LCI parameters, midpoint impacts and endpoint impact for human health damage (Adapted from ReCiPe 2008)

This study uses the hybrid LCA approach with the endpoint characterization factors from ReCiPe 2008 method v1.02 (ReCiPe 2009) to estimate the potential damage to human health, ecosystem and resource depletion. The detailed unit process level information obtained from process data, Ecoinvent v2 database and the input-output model of the background US economy are used to model the systems. The results from a traditional mid-point approach are supplied in the supporting information. A factor of 0.24 1,4-DCB kg eq/kg (Veltman et al. 2010) for human toxicity potential of monoethanolamine (MEA) is used.

There are 16 damage pathways: climate change human health, ozone depletion, human toxicity, photochemical oxidation, particulate matter formation, ionizing radiation, climate change ecosystem, terrestrial acidification, freshwater eutrophication, terrestrial ecotoxicity, freshwater ecotoxicity, agricultural land occupation, urban land occupation, natural land transformation, metal depletion and fossil depletion. These pathways are aggregated to three damage indicators for human health damage (DALY), ecosystem damage (species.yr), and resource depletion ($). *Disability adjusted life year (DALY)* is a measure of overall burden of disease and is calculated as the sum of the Years of Life Lost (YLL) due to premature mortality in the population and the Years Lost due to Disability (YLD) for incident cases of poor health. Ecosystem damage given as *species.yr* is a measure of loss of species during a year and is based on Potentially Disappeared Fraction (PDF) of species from a region. Resource depletion is given in *monetary units ($)* and is the measure of the increased resource cost. The cost for metal depletion is based on the marginal cost increase of the resource caused by the gradual decrease of ore grade, and for fossil fuel, the cost is based on the need to switch from conventional energy resources to energy intensive and costly unconventional resources due to fossil fuel scarcity.

System Description

All power plants are assumed to have 400MW net electricity output and the 'functional unit' for the study is chosen as 1 kWh of net electricity produced. Specific performance parameters and emission factors are discussed separately for each power plant and are presented in Table 1. The foreground system consists of fuel combustion in a power plant, a capture process, and transport and storage of CO_2. Process information on

Table 1. Performance parameters for different power generation systems

Parameters		Coal[a]				Natural gas[a]	
		supercritical PC	supercritical PC with CCS	IGCC	IGCC with with CCS	NGCC	NGCC with CCS
CO_2 capture		–	90 %	–	90 %	–	90 %
Net efficiency		43.4%	33.2%	44.1%	37.6%	58.1%	50.1%
Energy penalty		–	10.2%	–	6.5%	–	8 %
Co-capture		–	SO_2, NO_2, particulates	–	particulates	–	SO_2, NO_2, particulates
Solvent consumption	kg/tCO_2	–	1.6 (MEA)	–	0.007 (selexol)	–	1.6 (MEA)
Power plant capital cost[b]	$/kW	1286	2096	1326	1825	568	998
CO_2 sequestered	Mt/y	–	2.2	–	2.1	–	1
Energy for transport and storage	kW	–	352	–	160	–	334
CO_2 emission	g/kWh	763.4	100.1	722.8	85.7	346.7	40.5
Solvent vapor emission	mg/kWh	–	56.5	–	–	–	22.8
Solid degradation product	kg/tCO_2	–	3.2	–	0.007	–	3.2

[a] 8000 full load hours per year for 400MW plant with life-time of 25 years

[b] IPCC (2005), Rubin et al. (2007)

technical parameters is gathered from the literature and used to define process model data for the study. The detailed inventory of the foreground system is then modeled, based on the research work on power plant and capture process performance coupled with available datasets (Singh et al. 20xx). The LCI data for fuel supply and combustion is derived from literature and Ecoinvent v2 database (Ecoinvent 2007). The inventory of the capture operation is based on process modeling data. Infrastructure for power plant and capture unit is accounted as capital investment (IPCC 2005) attributed to various sectors in US I/O 1998 database (Suh 2005). Other upstream emissions, e.g., from the production of fuel (coal/natural gas), absorbent etc. and downstream emissions, e.g., from waste treatment and disposal are also included in the assessment.

The captured CO_2 is supplied to the transport chain at 110 bar and transported over 300 km to a geological storage site. The optimum economic pipe diameter is estimated for each case (Peters et al. 2003; Zhang et al. 2006) and the LCI data for pipeline is derived from Ecoinvent v2 (offshore natural gas pipeline in North Sea with a diameter of 1000mm and 25mm thickness). This conservative approach will likely overestimate material requirements. In practice, bigger diameter pipelines with higher mass flow rates are expected to be used, reducing the material use and cost per ton CO_2 transported. A pressure drop of 10 bar per 100 km (NREL 2004; Wildbolz 2007) is assumed for the transport. The transported CO_2 is then injected into the storage well. Storage mainly requires well drilling, CO_2 injection, and monitoring. CO_2 is to be stored above supercritical pressure; therefore some additional energy is required to inject CO_2 into a storage formation at a pressure higher than reservoir fluid pressure. A single CO_2 injection well is assumed at the geological storage site about 1000m below the sea floor. LCI data for the well is taken as offshore drilling well from Ecoinvent v2. The energy required for injection is calculated for each case, assuming reservoir at hydrostatic pressure of 78.4 bar (Wildbolz 2007) and overpressure of 20 bar (SINTEF 2003; Wildbolz 2007). Monitoring of the storage site is not included in this study, and leakage of the injected CO_2 is assumed to be negligible.

Supercritical Pulverized Coal (PC)

The supercritical coal power plant consists of a combustion chamber, steam-cycle unit and state-of-art flue gas treatment facility. A net efficiency of 43.4% (IEA 2008) is assumed for the plant and the emissions are derived from Ecoinvent v2 database. For the system with CO_2 capture, 90% CO_2 is assumed to be captured using monoethanolamine (MEA). Some fresh MEA is added to make up for the losses (degradation losses and vapor losses) during the process. The energy requirements for the capture process are for regeneration of solvent, solvent pumps, flue gas blower, cooling water pumps and CO_2 compression, resulting in an energy penalty of 10.2% (estimated from IPCC 2005). The capture process also removes SO_2, NO_2 and particulates (Rao and Rubin 2002). A solvent make-up of 1.6 kg MEA/tCO_2 (IPCC 2005) is needed due to its loss via vapors and formation of degradation products. Besides chemical solvent, the capture process also requires caustic soda to reclaim amines from heat stable salt, as well as activated carbon to remove degradation products. Air emissions and degradation waste from capture process are quantified based on literature (Koorneef et al. 2008; IEA GHG 2006; Rao and Rubin 2002; Veltman et al. 2010).

Natural gas combined cycle (NGCC)

Calculations for a state-of-art natural gas combined cycle plant are based on a net efficiency of 58.1% (IEA 2008). The emissions from the power plant are derived from Ecoinvent v2. For the system with CO_2 capture, 90% CO_2 is assumed to be captured using MEA as solvent. The energy requirements for the capture process results in an energy penalty of 8% (estimated from IPCC 2005). A solvent make-up of 1.6 kg MEA/tCO_2 due to its loss via vapors and formation of degradation products, caustic soda to reclaim the amine from the heat stable salt and activated carbon to remove degradation products are also needed in the capture process (IPCC 2005). The MEA based emissions are quantified based on Veltman et al. (2010), and NVE (2007). Degradation reclaimer waste contains corrosion inhibitors (Thitakamol et al. 2007; Veltman et al. 2010) making it hazardous to landfill and the waste is assumed to be incinerated.

Integrated gasification combined cycle (IGCC)

The IGCC power plant consists of a gasification unit, a gas cleaning unit and a gas-fired combined-cycle unit. A net efficiency of 44.1% (IEA 2008) is assumed for the plant and

Table 2. End-point impact assessment for different CCS configurations with respect to system without CCS

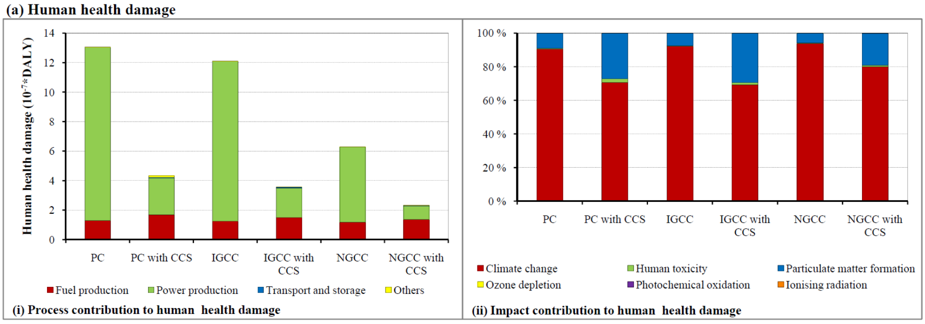
Impact	(Unit)	PC	PC with CCS (% change)	IGCC	IGCC with CCS (% change)	NGCC	NGCC with CCS (% change)
Climate change human health	(DALY)	$1.2*10^{-6}$	-74	$1.1*10^{-6}$	-78	$5.9*10^{-7}$	-68
Ozone depletion	(DALY)	$2.4*10^{-11}$	87	$2.3*10^{-11}$	56	$1.7*10^{-10}$	21
Human toxicity	(DALY)	$6.7*10^{-9}$	47	$3.6*10^{-9}$	33	$1.3*10^{-9}$	60
Photochemical oxidation	(DALY)	$4.6*10^{-11}$	26	$3.7*10^{-11}$	20	$2.4*10^{-11}$	16
Particulate matter formation	(DALY)	$1.2*10^{-7}$	-1	$9.1*10^{-8}$	14	$3.7*10^{-8}$	21
Ionising radiation	(DALY)	$1.2*10^{-10}$	242	$1.1*10^{-10}$	23	$2.0*10^{-11}$	514
Climate change ecosystems	(species.yr)	$6.7*10^{-9}$	-74	$6.3*10^{-9}$	-78	$3.3*10^{-9}$	-68
Terrestrial acidification	(species.yr)	$7.7*10^{-12}$	-13	$5.4*10^{-12}$	20	$2.3*10^{-12}$	26
Freshwater eutrophication	(species.yr)	$1.5*10^{-13}$	121	$4.5*10^{-14}$	84	$3.9*10^{-14}$	169
Terrestrial ecotoxicity	(species.yr)	$2.5*10^{-12}$	112	$2.2*10^{-12}$	57	$1.7*10^{-12}$	75
Fresh water ecotoxicity	(species.yr)	$4.4*10^{-14}$	189	$2.0*10^{-14}$	45	$8.0*10^{-15}$	400
Agricultural land occupation	(species.yr)	$1.4*10^{-10}$	35	$1.3*10^{-10}$	20	$2.3*10^{-12}$	134
Urban land occupation	(species.yr)	$1.6*10^{-10}$	32	$1.6*10^{-10}$	19	$3.8*10^{-12}$	41
Natural land transformation	(species.yr)	$7.6*10^{-11}$	42	$7.0*10^{-11}$	27	$8.6*10^{-11}$	22
Metal depletion	($)	$2.5*10^{-4}$	67	$2.4*10^{-4}$	43	$9.3*10^{-5}$	70
Fossil depletion	($)	$3.6*10^{-0}$	33	$3.5*10^{-0}$	19	$2.8*10^{-0}$	18

the emissions are derived from Ratafia-Brown et al. (2002). For the IGCC system with CO_2 capture, 90% CO_2 is assumed to be captured using selexol. The efficiency loss due to 'water-gas-shift' reaction and solvent circulation is assumed to be 6.5% (derived from IPCC (2005)). Consumption of 0.005 kg selexol/MWh from IGCC is projected (Rubin et al. 2005), however no literature is found considering solvent loss to atmosphere or emission of solvent degradation products. An additional reduction of particulates by 50% from syngas is assumed (Odeh and Cockerill 2008) by the selexol capture process. Selexol is non-toxic and has a low vapor pressure (Chen 2005), therefore it is assumed that all spent solvent ends up as solid waste and is incinerated.

RESULTS AND DISCUSSION

A CCS system controls CO_2 emissions and in turn reduces the damage caused by climate change. It also has some co-benefits for SO_2, NO_x and particulates removal with certain technologies. However, there are various other direct and indirect emissions throughout the value chain, from raw material extraction for fuel and infrastructure, to the waste treatment and disposal; causing environmental impacts and damage to life and resources. Table 2 presents endpoint impact characterization results for the studied power plant systems. The impact scores from the three CCS systems show a decrease in climate change related damage, but increases over other damage categories, as compared to respective power plants without CCS, with the exception of human health damage due to particulate formation and ecosystem damage due to terrestrial acidification, from post-combustion CCS system with coal power plant. Figure 2 shows damage assessment of human health damage, ecosystem damage and resource depletion from different electricity generation systems, with a breakdown into various processes, and contribution from different endpoint impacts. Figure 3 presents a comparative structural path analysis for human health damage, giving details of the impact from individual processes in the value chain. Here, the foreground processes are presented as nodes, and the total DALY score is distributed along various paths.

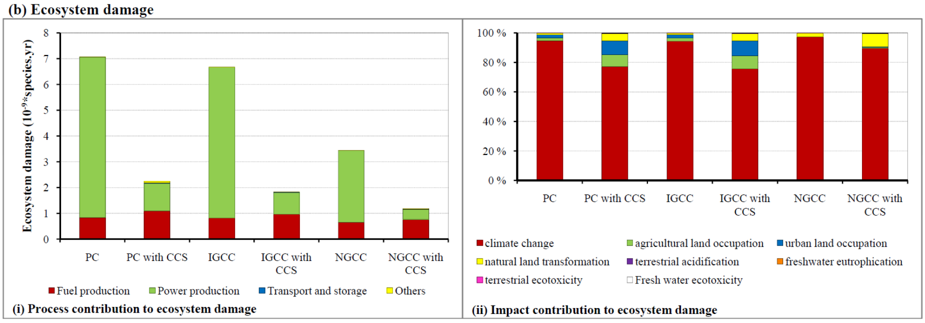
(a) Human health damage



(i) Process contribution to human health damage

(ii) Impact contribution to human health damage

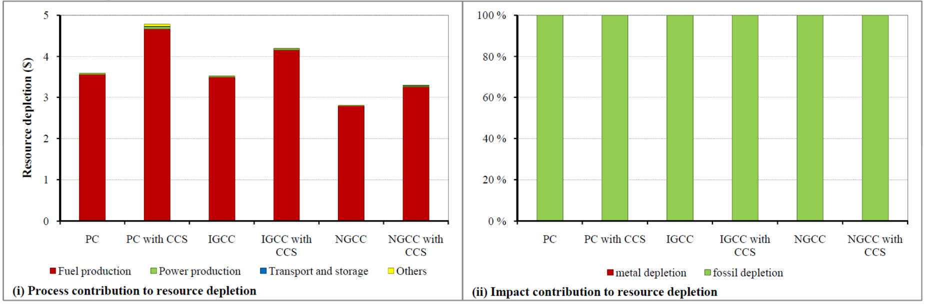
(b) Ecosystem damage



(i) Process contribution to ecosystem damage

(ii) Impact contribution to ecosystem damage

(c) Resource depletion



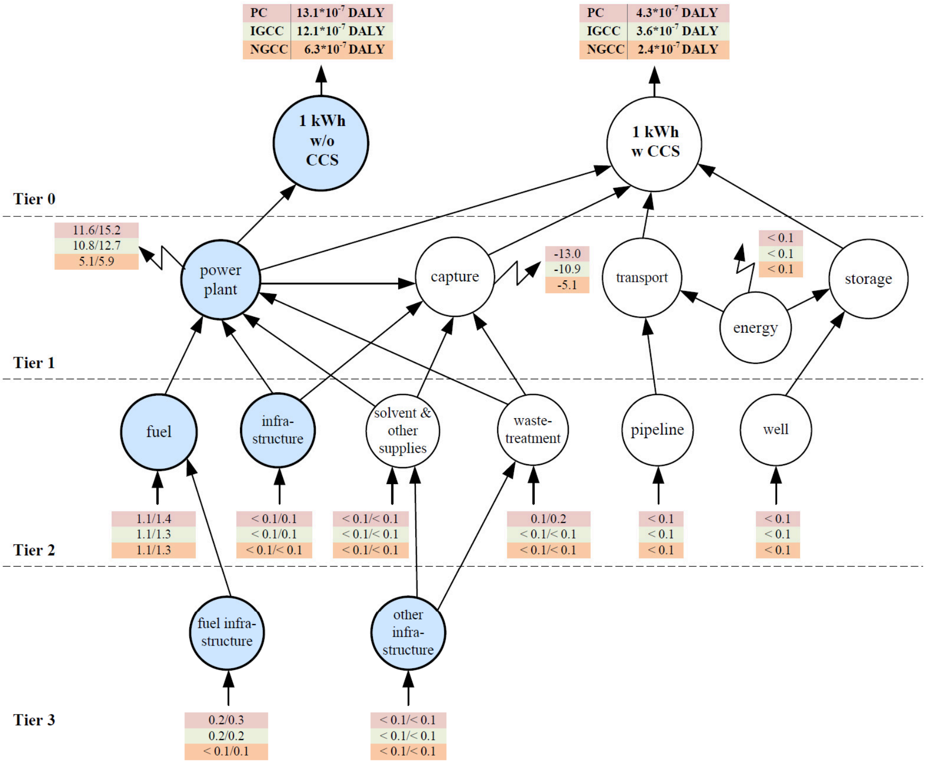
(i) Process contribution to resource depletion

(ii) Impact contribution to resource depletion

Figure 2. Damage assessment for different electricity generation technologies: (a) human health damage, (b) ecosystem damage and (c) resource depletion

Human health damage

Assessment results show a significant reduction in climate change related damage to human health with CCS: 74% for PC, 78% for IGCC and 68% for NGCC electricity generation system. However, the increased emissions emanating from various processes in the value chain, e.g., fuel extraction, transportation, infrastructure development, fuel combustion, CO_2 capture, solvent production, waste treatment etc, due to additional material and energy demand for CCS causes increase in human health damage due to



Unit : 10^{-7}*DALY w/oCCS / wCCS

Figure 3. Structural path analysis of human health damage (DALY) for 1kWh electricity generation from (🟥) Pulverized coal system PC, (🟩) Integrated gasification coal system IGCC, and (🟧) Natural gas system NGCC

ozone depletion, human toxicity, photochemical oxidation, particulate formation and ionizing radiation (Table 2). The net benefit of CCS technology for power production, in control of human health damage is thus 67% for PC plant, 71% for IGCC plant and 63% for NGCC plant. The NGCC plant has a lower value of damage control from CCS due to relatively higher GHG emission during natural gas production, and these emissions could potentially be reduced. Process contribution to human health damage presented in Figure 2a(i) shows that the fuel production chain and emission from the power plant are the two most contributing processes towards human health damage. For the system without CCS, power production contributes >80% (90% for PC, 89% for IGCC and 81% for NGCC) of the total damage, while the use of CCS reduces this contribution to 58% for PC, 56% for IGCC and 38% for NGCC system. Transport and storage of CO_2 contributes only about 1% of the overall DALY score. Solvent (monoethanolamine) production for post-combustion CCS system in PC and NGCC power plants contributes 2% of the damage. The contribution from selexol production for pre-combustion CCS system in IGCC is <<1%. Capture related emissions and waste treatment processes contribute <2% for PC and NGCC systems and <<1% for IGCC system to the total human health damage. Further, the *structural path analysis* given in Figure 3 elaborates the net human health damage from various chains for three cases each with and without CCS. The damage from each path cumulates to give the net damage from the system considered. DALY due to direct emission from electricity generation (fuel combustion and capture) is given in tier 1, and the scores for important background processes are given in tier 2 and tier 3. The illustration clearly shows that combustion and fuel production cause almost all of the damage in electricity production. Other value chain processes presented as nodes contribute negligible to the total damage. The SPA analysis also gives the comparative damage from each process for different power plant technologies, with and without CCS. Impact contribution to DALY presented in Figure 2a(ii) shows that climate change is the dominating cause for human health damage. For the systems without CCS, it is responsible for over 90% of the DALY score, and for systems with CCS it still causes 70% of the overall damage. Particulate matter formation is the second most damaging impact, contributing about 10% to damage for power plant without CCS and 20% to 30% damage from system with CCS (lower value being for NGCC system). The CO_2 capture process has co-benefits of reducing SO_2, NO_x, and particulate emission (SO_2 and NO_x only in post-combustion capture), reducing the health damage from photochemical oxidation and particulate formation. However the energy penalty from the capture process generally overcomes this gain. Only in the case of post-combustion capture from PC plant, it gives co-benefit of reducing about 30% on-site damage from particulate matter formation, nearly balancing the overall life cycle score for this damage both for with and without CCS case.

Ecosystem damage

Assessment results in Table 2 show a significant reduction of about 70% in climate change related ecosystem damage. Like with human health damage, however, the increased direct and indirect emission throughout the value chain, due to additional demand placed by CCS increase acidification (except for PC plant), eutrophication, ecotoxicity and land occupation. The net benefit of CCS technology for electricity production, in controlling ecosystem damage is thus reduced to 68% for PC, 73% for IGCC and 66% for NGCC. Figure 2b(i) gives the process contribution to ecosystem damage and shows that fuel production chain and power production process are the two dominant contributors to the damage. Power production process makes over 80% for the system without CCS, and the use of CCS system reduces this contribution to 48% for PC, 46% for IGCC and 33% for NGCC power plant. Transport and storage chain contributes only about 1% of the overall damage score. Impact contribution in Figure 2b(ii) shows that climate change is the most important cause for ecosystem damage. It makes over 95% of the damage in power systems without CCS, over 75% for coal power systems with CCS and 90% for NGCC with CCS. Other major portion is from land occupation and transformation, required to produce the fuels and develop the infrastructure of the value chain. Agricultural land occupation, urban land occupation and natural land transformation, together cause 22% of the ecosystem damage for PC power plant, 24% for IGCC and 10% for NGCC plant with CCS system. Land use in coal CCS systems is mainly due to coal mining process, while in natural gas CCS systems, the power plant infrastructure and fuel production are significant. SO_2 and NO_x co-capture in case of PC plant, reduces the damage caused by terrestrial acidification. This reduction amounts to 44% compared to the damage from direct emission during electricity generation, and accounts for 13% reduction in life cycle damage from acidification. Emissions from the treatment of CCS waste contribute about 1% to the total ecosystem damage.

Resource depletion

Resource depletion result in Table 2 shows significant increase of 40-70% in metal depletion and 20-35% in fossil depletion score with CCS technology. The increase in fossil depletion is mainly due to the energy penalty from capture process, whereas the infrastructure demand for CO_2 transport is mainly responsible for the increase in metal depletion. The net increase in the resource damage due to CCS is 33% for PC plant, 19% for IGCC plant and 18% for NGCC power plant. Process contribution to the resource damage given in Figure 2c(i) shows that fuel production makes almost 100% of the depletion for all the cases. This is also supported by the contribution of fossil depletion to the total resource depletion category, as shown in Figure 2c(ii). The increase in primary energy demand of 31% for PC, 18% for IGCC and 17% for NGCC with capture due to energy penalty confirms its significant contribution to resource depletion. The contribution from the metal demand for infrastructure development is negligible. This type of result can be explained by the characterization factors calculated based on the availability and production cost of the resources.

Overall, it is found that the CCS system significantly reduces the climate change related damages but cause increase in damages due to toxicity, acidification, eutrophication, resource consumption etc. However, as the climate change related damages are sizeable, the CCS technology proves to control the total damage to human and ecosystems, while consuming more natural resources. Further, this study identifies that the energy demand is the dominating parameter for the resource depletion and maximum damage is due to fuel and power production, therefore technical developments to control the GHG emissions during fuel production and to reduce the energy penalty from the capture process are required to further reduce the damages.

OUTLOOK

The end-point indicator method is used to discuss the damages from the CCS systems, while the mid-point environmental potentials are also provided in the supplementary online material. The end-point method provides easy understanding of the assessment results for the decision makers and facilitates a more structured and informed weighting process, but has much higher uncertainty related to the environmental mechanism. Midpoint modeling is a traditional approach with lower uncertainty at the level of characterized indicator results and present results as different environmental impact potentials (Table S1). These potentials are scientifically well understood, but it is difficult to compare their environmental relevance. Therefore a dual-approach is justified for environmental assessments, which presents mid-point results to understand environmental potentials and identification of key areas to reduce the adverse impacts; and end-point results to present comprehensible information to decision makers.

For CCS, the large potential contribution of climate change to human health and ecosystem damage (see also UNEP 2010) ensures that CCS is evaluated as an environmentally beneficial technology. Divergent outcomes of studies of the future impacts of climate change indicate a wide range of possible impacts. Some potential ecological impacts are not at all included in these assessments. The overall importance of climate change, however, is confirmed by international assessments as discussed in UNEP (2010).

ISO14044 standard requires that the characterization factors to be based on environmental mechanisms linking man-made interventions to a set of areas of protection. A number of such environmental interventions have global scope, while others have regional scope. Environmental mechanisms such as acidification, eutrophication, photochemical ozone formation, toxicity, land use and water use depend on regional conditions and regionally different parameters. ReCiPe method has attempted to generalize the models as much as possible to be relevant for all developed countries in temperate zone, limiting its validity for other regions type. Regional conditions that can affect the validity of ReCiPe are hygienic conditions and food patterns, weather conditions in tropical areas, background concentrations and population density, which may have very significant effects (Goedkoop et al. 2009). It is understood that all these attributes cannot be modeled together for all dimensions; therefore, the absolute damage values will considerably depend on location, regional climate, population size, vegetation type etc.

ACKNOWLEDGEMENT

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Supplementary Material

The table provides mid-point impact assessment results for the studied CCS systems.

Table S1. Mid-point impact assessment for different CCS configurations with respect to system without CCS

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Table S1. Mid-point impact assessment for different CCS configurations with respect to system without CCS

Impact	PC (kg eq)	PC with CCS (% change)	IGCC (kg eq)	IGCC with CCS (% change)	NGCC (kg eq)	NGCC with CCS (% change)
Global warming (CO_2 eq)	$8.4*10^{-1}$	-74	$8.0*10^{-1}$	-78	$4.2*10^{-1}$	-68
Terrestrial acidification (SO_2 eq)	$1.3*10^{-3}$	-14	$9.3*10^{-4}$	20	$4.0*10^{-4}$	26
Freshwater eutrophication (P eq)	$3.3*10^{-6}$	122	$1.0*10^{-6}$	81	$8.8*10^{-7}$	169
Marine eutrophication (N eq)	$1.7*10^{-4}$	42	$1.1*10^{-4}$	19	$5.8*10^{-5}$	29
Photochemical oxidation (NMVOC eq)	$1.2*10^{-3}$	26	$9.5*10^{-4}$	20	$6.1*10^{-4}$	16
Particulate matter formation (PM_{10} eq)	$4.5*10^{-4}$	-8	$3.5*10^{-4}$	6	$1.4*10^{-4}$	21
Human toxicity (1,4-DB eq)	$9.6*10^{-3}$	47	$5.2*10^{-3}$	33	$1.8*10^{-3}$	60
Terrestrial ecotoxicity (1,4-DB eq)	$2.0*10^{-5}$	112	$1.8*10^{-5}$	57	$1.3*10^{-5}$	75
Fresh water ecotoxicity (1,4-DB eq)	$1.7*10^{-4}$	197	$8.0*10^{-5}$	46	$3.1*10^{-5}$	388
Marine ecotoxicity (1,4-DB eq)	$2.1*10^{-4}$	77	$1.0*10^{-4}$	59	$1.3*10^{-4}$	55

Paper V

Singh, B., Strømman, A. H., Hertwich, E. G.. Environmental assessment of fossil-based electricity scenarios: Implications of carbon capture and storage. *Submitted to Energy and Environmental Science*.

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Appendix - Inventory

LIST OF APPENDICES

Table A1. 1 kWh electricity from hard coal[a]

	Unit	Supercritical BAT	IGCC	Supercritical with postcombustion capture	IGCC with precombustion capture	Oxyfuel capture
Materials/fuel						
Compressor	p			8,18E-11	7,40E-11	7,80E-11
Electricity	kWh			2,40E-03	2,06E-03	2,29E-03
Injection well	p			1,64E-11	1,48E-11	1,56E-11
Pipeline	p			1,64E-11	1,48E-11	1,56E-11
Processes						
CO_2 capture	kg			9,01E-01	7,72E-01	8,59E-01
Hard coal combustion	MJ	8,30E+00	8,16E+00	1,09E+01	9,67E+00	1,04E+01

[a] based on performance parameters

Table A2. 1 kWh electricity from natural gas[a]

	Unit	NGCC	Partial oxidation	NGCC with postcombustion capture	Partial oxidation with precombustion capture	Oxyfuel capture
Materials/fuel						
Compressor	p			7,30E-11	7,27E-11	7,83E-11
Electricity	kWh			9,73E-04	9,51E-04	1,11E-03
Injection well	p			1,46E-11	1,45E-11	1,57E-11
Pipeline	p			1,46E-11	1,45E-11	1,57E-11
Processes						
CO_2 capture	kg			3,64E-01	3,56E-01	4,17E-01
Natural gas combustion	MJ	6,20E+00	6,43E+00	7,23E+00	7,48E+00	7,76E+00

[a] based on performance parameters

Table A3. 1 MJ coal combustion

	Unit	Postcombustion[a]	Precombustion[b]	Oxyfuel[c]
Materials/fuel				
Chlorine, liquid	kg	1,00E-05		1,00E-05
Decarbonised water	kg	1,50E-01	3,75E+02	1,50E-01
Hard coal	kg	4,17E-02	4,17E-02	4,17E-02
Light fuel oil	kg	1,70E-05		1,70E-05
Power plant[d]	p	1,51E-12	1,53E-12	1,51E-12
Softened water	kg	6,00E-03	1,50E+01	6,00E-03
Processes				
Coal ash disposal	kg	2,63E-04		2,63E-04
Cooling tower residue disposal	kg	5,00E-06	2,63E-06	5,00E-06
NO_x removal	kg	2,34E-04		2,34E-04
Slag disposal	kg		8,50E-03	
SO_x removal	kg	6,16E-04		6,16E-04
Sulfur byproduct	kg		3,23E-04	
Transport	tkm	4,82E-04	4,82E-04	4,82E-04
Waste heat				
To air	MJ	5,47E-01	5,47E-01	5,47E-01
To water	MJ	1,44E-01	1,44E-01	1,44E-01
Emissions to air				
Ammonia	kg		2,02E-07	
Antimony	kg	8,65E-11	8,65E-11	8,65E-11
Arsenic	kg	1,29E-09	1,29E-09	1,29E-09
Barium	kg	5,71E-09	5,71E-09	5,71E-09
Benzene	kg	2,17E-07	2,17E-07	
Benzo(a)pyrene	kg	2,00E-13	2,00E-13	2,00E-13
Boron	kg	1,23E-07	1,23E-07	1,23E-07
Bromine	kg	6,36E-08	6,36E-08	6,36E-08
Butane	kg	1,90E-08		
Cadmium	kg	5,76E-11	5,76E-11	5,76E-11
Carbon dioxide	kg	9,22E-02	8,9E-02	9,22E-02
Carbon monoxide	kg	8,00E-06	3,8E-06	
Chromium	kg	6,56E-10	6,56E-10	6,56E-10
Chromium VI	kg	8,11E-11	8,11E-11	8,11E-11
Cobalt	kg	3,26E-10	3,26E-10	3,26E-10
Copper	kg	1,65E-09	1,65E-09	1,65E-09
Dinitrogen monoxide	kg	3,97E-06	3,97E-06	3,97E-06
Dioxins	kg	7,00E-15	7,00E-15	7,00E-15
Ethane	kg	4,10E-08		
Formaldehyde	kg	5,80E-08	5,80E-08	5,80E-08
Alkanes	kg	2,19E-07		
Aliphatic unsaturated hydrocarbons	kg	2,16E-07		
Hydrogen chloride	kg	2,08E-06	3,53E-07	2,08E-06
Hydrogen fluoride	kg	1,30E-06	2,02E-08	1,30E-06
Iodine	kg	2,37E-08	2,37E-08	2,37E-08
Lead	kg	5,53E-09	5,53E-09	5,53E-09
Lead-210	kg	1,61E-06	1,61E-06	1,61E-06
Manganese	kg	1,22E-09	1,22E-09	1,22E-09

Mercury	kg	4,10E-09	7,37E-10	4,10E-09
Methane	kg	1,00E-06		
Molybdenum	kg	3,62E-10	3,62E-10	3,62E-10
Nickel	kg	2,49E-09	2,49E-09	2,49E-09
Nitogen oxides	kg	6,21E-05	4,03E-05	3,11E-05
PAH	kg	1,00E-09	1,00E-09	1,00E-09
Particulates < 2.5um	kg	4,73E-06	4,73E-06	4,73E-06
Particulates > 10um	kg	5,28E-06	5,28E-06	5,28E-06
Particulates >2.5um and <10um	kg	5,56E-07	5,56E-07	5,56E-07
Pentane	kg	1,47E-07		
Polonium-210	kg	2,95E-06	2,95E-06	2,95E-06
Potassium-40	kg	2,12E-06	2,12E-06	2,12E-06
Propane	kg	3,50E-08		
propene	kg	1,60E-08		
Radium-226	kBq	4,16E-07	4,16E-07	4,16E-07
Radium-228	kBq	4,16E-07	4,16E-07	4,16E-07
Radon-220	kBq	4,16E-07	4,16E-07	4,16E-07
Radon-222	kBq	4,85E-04	4,85E-04	4,85E-04
Selenium	kg	5,45E-09	5,45E-09	5,45E-09
Strontium	kg	7,14E-10	7,14E-10	7,14E-10
Sulfur dioxide	kg	6,56E-05	3,53E-05	6,56E-05
Thorium-228	kBq	1,14E-07	1,14E-07	1,14E-07
Thorium-232	kBq	1,79E-07	1,79E-07	1,79E-07
Toluene	kg	1,09E-07	1,09E-07	
Uranium-238	kBq	3,47E-07	3,47E-07	3,47E-07
Vanadium	kg	6,53E-10	6,53E-10	6,53E-10
Xylene	kg	9,22E-07	9,22E-07	
Zinc	kg	4,11E-09	4,11E-09	4,11E-09

[a] based on process 'hard coal burned in power plant/MJ/DE'

[b] based on Ratafia-Brown et al. (2002) and postcombustion inventory

[c] based on complete combustion of fuel, postcombustion inventory with 50% reduction in NO_x

[d] based on 8000 full load hours per year for 400MW power plant with life-time of 25 years

Table A4. 1 MJ natural gas combustion

	Unit	Postcombustion[a]	Precombustion[b]	Oxyfuel[c]
Materials/fuel				
Decarbonised water	kg	2,00E-01	2,00E-01	2,00E-01
Natural gas	MJ	1,00E+00	1,00E+00	1,00E+00
Power plant[d]	p	2,02E-12	1,94E-12	2,02E-12
Softened water	kg	6,00E-03	6,00E-03	6,00E-03
Processes				
Cooling tower residue disposal	kg	1,00E-06	1,00E-06	1,00E-06
Waste heat				
To air	MJ	7,20E-01	7,20E-01	7,20E-01
Emissions to air				
Acetaldehyde	kg	8,00E-10	8,00E-10	8,00E-10
Acetic acid	kg	1,21E-07	1,21E-07	1,21E-07
Acenaphthene	kg	7,93E-13	7,93E-13	7,93E-13
Benzene	kg	9,26E-10	9,26E-10	
Benzo(a)pyrene	kg	5,29E-13	5,29E-13	5,29E-13
Butane	kg	9,26E-07		
Carbon dioxide	kg	5,60E-02	5,60E-02	5,60E-02
Carbon monoxide	kg	1,00E-05	5,00E-06	
Dinitrogen monoxide	kg	1,00E-06	1,00E-06	1,00E-06
Dioxins	kg	2,90E-17	2,90E-17	2,90E-17
Ethane	kg	1,37E-06		
Formaldehyde	kg	3,31E-08	3,31E-08	3,31E-08
Hexane	kg	7,93E-07		
Methane	kg	1,00E-06		
Mercury	kg	3,00E-11	3,00E-11	3,00E-11
Nitogen oxides	kg	5,00E-05	5,00E-05	2,50E-05
PAH	kg	8,00E-09	8,00E-09	8,00E-09
Particulates < 2.5 um	kg	5,00E-07	5,00E-07	5,00E-07
Pentane	kg	1,15E-06		
Propane	kg	7,05E-07		
Propionic acid	kg	1,60E-08	1,60E-08	1,60E-08
Sulfur dioxide	kg	5,00E-07	5,00E-07	5,00E-07
Toluene	kg	1,50E-09	1,50E-09	

[a] based on process 'natural gas, burned in power plant/MJ/UCTE'

[b] based on conversion of alkanes and postcombustion inventory with 50% reduction in CO

[c] based on complete combustion of fuel, postcombustion inventory with 50% reduction in NO_x

[d] based on 8000 full load hours per year for 400MW powerplant with life-time of 25 years

Table A5. 1 kg CO_2 capture[a]				
	Unit	Post-combustion	Pre-combustion	Oxyfuel
Materials/fuel				
Activated carbon	kg	6,00E-05		
Decarbonised water	kg	8,00E-01		
Electricity[b,c]	kWh	3,43E-01/4,58E-01	2,39E-01/4,59E-01	2,89E-01/6,06E-01
Monoethanolamine	kg	1,60E-03		
Selexol	kg		6,94E-06	
Sodium hydroxide	kg	1,30E-04		
Processes				
Capture-related solid waste disposal	MJ	3,20E-03	6,94E-06	
Spent carbon disposal	kg	6,00E-05		
Emissions to air				
Ammonia	kg	3,49E-05		
Acetaldehyde	kg	1,67E-10		
Carbon dioxide	kg	-1,00E+00	-1,00E+00	-1,00E+00
Formaldehyde	kg	2,62E-10		
Monoethanolamine	kg	6,27E-08		
Nitogen oxides	kg	- (3,66E-05/4,85E-05)		
Particulates < 2.5um	kg	- (2,85E-05/4,96E-06)	- (2,96E-05/5,25E-06)	
Particulates > 10um	kg	- (3,18E-05/0)	- (3,31E-05/0)	
Particulates >2.5um and <10um	kg	- (3,35E-05/0)	- (3,48E-06/0)	
Sulfur dioxide	kg	- (7,61E-04/9,92E-06)		

[a] based on process parameters in literature

[b] based on energy penalty due to capture and compression at plant, [c] coal/natural gas

Table A6. 1 kg capture-related solid waste disposal

	Unit	Waste[a]			
Materials/fuel					
Ammonia liquid	kg	3,78E-04			
Calcium chloride	kg	3,47E-03			
Cement	kg	3,03E-02			
Chromium	kg	3,03E-07			
Hazardous waste incineration plant	p	1,25E-09			
Hydrochloric acid	kg	1,67E-04			
Hydrogen peroxide	kg	2,89E-05			
Inorganic chemicals	kg	2,79E-04			
Iron chloride	kg	3,21E-05			
Light fuel oil	MJ	1,30E+00			
Natural gas	kg	2,05E-01			
Quicklime	kg	6,22E-03			
Sodium hydroxide	kg	4,61E-02			
Residual material landfill	p	1,58E-10			
Titanium dioxide	kg	1,48E-05			
Processes					
Hazardous waste incineration	kg	1,00E+00			
Residual material landfill	kg	1,51E-01			
Transport	tkm	1,15E-01			
Waste heat					
To air	MJ	1,71E+01			
To water	MJ	3,29E+00			
Emissions to air			***Emissions to water***		
Ammonia	kg	1,02E-05	BOD5	kg	7,77E-03
Bromine	kg	5,0E-07	COD	kg	7,77E-03
Carbon dioxide	kg	1,1E+00	TOC	kg	3,40E-03
Carbon monoxide	kg	1,2E-05	DOC	kg	3,40E-03
Cobalt	kg	2,87E-09	Bromine	kg	2,50E-03
Copper	kg	3,60E-09	Chloride	kg	2,44E-02
Cyanide	kg	9,22E-06	Cobalt	kg	4,10E-06
Dinitrogen monoxide	kg	3,69E-05	Copper ion	kg	4,10E-07
Hydrogen chloride	kg	7,54E-06	Fluoride	kg	4,49E-05
Hydrogen fluoride	kg	1,13E-08	Iodide	kg	1,00E-04
Iodine	kg	2,00E-08	Iron ion	kg	6,81E-05
Iron	kg	5,93E-08	Nickel ion	kg	2,09E-06
Nickel	kg	2,98E-09	Nitrate	kg	5,05E-04
Nitogen oxides	kg	2,66E-04	Phosphate	kg	7,22E-04
Phosphorus	kg	7,00E-07	Silicon	kg	3,13E-02
Silicon	kg	7,29E-05	Sulfate	kg	1,92E-02
Sulfur dioxide	kg	7,70E-06	Zinc ion	kg	1,07E-06
Zinc	kg	2,93E-08			

[a] based on process 'disposal, solvents mixture, 16.5% water, to hazardous waste incineration/kg/CH'

Table A7. 1 kg Solvent production

	Unit	Monoethanolamine[a]	Selexol[b]
Materials/fuel			
Ammonia, liquid	kg	7,88E-01	
Chemical plant	p	4,00E-10	4,00E-10
Electricity	kWh	3,33E-01	3,33E-01
Ethylene oxide	kg	7,34E-01	
Heat	MJ	2,00E+00	2,00E+00
Methanol	kg		1,46E+00
Processes			
Transport	tkm	1,12E+00	1,02E+00
Waste heat			
To air	MJ	1,20E+00	1,20E+00
Emissions to air			
Ammonia	kg	1,58E-03	
Carbon dioxide	kg	2,65E-02	8,69E-03
Ethylene oxide	kg	1,63E-03	
Methanol	kg		2,93E-03
Emissions to water			
BOD5	kg	2,13E-02	1,01E-02
COD	kg	2,13E-02	1,01E-02
DOC	kg	8,02E-03	2,64E-03
TOC	kg	8,02E-03	2,64E-03
Ammonium ion	kg	3,04E-03	
Ethylene oxide	kg	1,47E-03	
Methanol	kg		7,00E-04
Nitrate	kg	6,97E-03	

[a] based on process 'monoethanolamine, at plant/kg/RER'

[b] based on process 'dimethyl ether, at plant/kg/RER'

Table A8. 1 MJ fuel production			
	Unit	Hard coal[a]	Natural gas[b]
Materials/fuel			
Diesel	kg		1,39E-04
Electricity	kWh	1,28E-03	2,88E-03
Ethylene glycol	kg		5,25E-06
Heat	MJ	1,83E-03	
Heavy fuel oil	kg		7,41E-05
Inorganic chemicals	kg		3,34E-05
Light fuel oil	kg		
Natural gas	MJ		4,81E-01
Methanol	kg		8,47E-06
Open cast mine	p	7,66E-13	
Organic chemicals	kg		2,55E-05
Pipeline	km		9,00E-10
Natural gas production platform	p		4,59E-10
Natural gas production well	m		2,81E-06
Underground coal mine	p	5,56E-13	
Processes			
Antifreezer liquid disposal	kg		7,84E-08
Blasting	kg	4,48E-05	
Diesel burned	MJ	1,34E-03	2,41E-02
Emulsion paint remains disposal	kg		3,46E-07
Gas burned	m3		1,00E-02
Gas sweetening	m3		6,87E-02
Hazardous waste disposal	kg		3,47E-05
Low active radioactive waste treatment	m3		4,32E-09
Mineral oil disposal	kg		2,88E-05
Mining waste tailings disposal	kg	1,65E-02	
Municipal solid waste disposal	kg		2,57E-05
Natural gas drying	m3		6,01E-01
Pipeline transport	tkm		2,18E+00
Produced water discharge	kg		6,13E-04
Transport	tkm	4,65E-02	6,99E-02
Wood untreated disposal	kg		5,58E-06
Waste heat			
To air	MJ	4,62E-03	6,23E-02
Emissions to air			
Alkanes	kg		1,08E-05
Aromatic hydrocarbons	kg		5,61E-06
Benzene	kg		2,93E-13
Benzo(a)pyrene	kg		1,47E-15
Butane	kg		2,28E-06
Carbon dioxide	kg		2,41E-03
Carbon monoxide	kg		8,74E-06
CFC-12	kg		1,92E-10
Dinitrogen monoxide	kg		5,14E-10
Ethane	kg		1,08E-04
HCFC-22	kg		1,92E-08
Helium	kg		5,00E-09
Hydrogen sulphide	kg		2,33E-05

Methane	kg	1,19E-04	1,42E-03
Methane bromotrifluoro	kg		1,58E-11
Mercury	kg		3,26E-10
Nitogen oxides	kg		1,87E-06
NMVOC	kg		6,35E-05
Particulates > 10um	kg	1,98E-04	
Particulates >2.5um and <10um	kg		5,21E-09
Propane	kg		3,32E-05
Radon-222	kBq	4,76E-04	5,76E-04
Sulfur dioxide	kg		3,97E-07
Emissions to water			
BOD5	kg	3,97E-09	6,75E-05
COD	kg	3,97E-09	6,75E-05
DOC	kg		1,86E-05
TOC	kg		1,86E-05
AOX	kg		2,19E-10
Aluminium	kg	3,97E-08	
Aluminium ion	kg	3,97E-08	
Arsenic ion	kg	1,59E-12	1,61E-11
Benzene	kg		3,15E-09
Cadmium	kg		3,35E-12
Cadmium ion	kg	3,97E-13	
Carboxylic acids	kg		2,51E-07
Chloride	kg	2,78E-04	2,16E-06
Chromium ion	kg	7,94E-12	4,61E-12
Copper ion	kg	3,97E-11	3,89E-12
Fluoride	kg	1,19E-07	
Inorganic solids	kg	2,70E-06	
Iron ion	kg	7,94E-08	
Lead	kg	7,94E-12	1,47E-10
Manganese	kg	4,76E-08	
Mercury	kg		5,70E-13
Methanol	kg		7,06E-07
Nickel ion	kg	3,98E-09	2,27E-11
Nitrogen	kg		1,63E-08
Oils	kg		2,12E-05
PAH	kg		3,99E-10
Phenol	kg		5,72E-09
Selenium	kg	7,94E-12	
Solved solids	kg	4,56E-06	
Strontium	kg	1,98E-07	
Sulfate	kg	2,14E-05	
Sulfur	kg		5,67E-08
Tin ion	kg	7,94E-12	
Toluene	kg		3,01E-09
Triethylene glycol	kg		5,30E-07
Xylene	kg		3,01E-09
Zinc ion	kg	3,97E-09	6,14E-10

[a] based on process 'hard coal supply mix, at regional storage/kg/US'

[b] based on process 'natural gas, high pressure, at consumer/MJ/RER'

Table A9. Transport pipeline (500 km)

	Unit	for Coal CCS[a,b]	for Natural gas CCS[a,c]
Materials/fuel			
Aluminium	kg	4,98E+05	3,32E+05
Cast iron	kg	6,30E+02	4,20E+02
Concrete	m3	5,42E+04	3,61E+04
Copper	kg	3,15E+01	2,10E+01
Diesel	MJ	3,80E+08	2,53E+08
MG-silicon	kg	7,88E+02	5,25E+02
Reinforcing steel	kg	9,08E+07	6,05E+07
Zinc	kg	2,63E+04	1,75E+04
Processes		0,00E+00	0,00E+00
Drawing of pipes	kg	9,08E+07	6,05E+07
Hazardous waste disposal	kg	1,70E+05	1,13E+05
Municipal solid waste disposal	kg	1,89E+05	1,26E+05
Pipileine disposal	kg	4,55E+07	3,03E+07
Transport	tkm	5,70E+07	3,80E+07
Emissions to water		0,00E+00	0,00E+00
Aluminium	kg	4,23E+05	2,82E+05
Copper ion	kg	2,67E+01	1,78E+01
Iron ion	kg	5,36E+02	3,57E+02
Silicon	kg	6,69E+02	4,46E+02
Titanium ion	kg	1,12E+02	7,44E+01
Zinc ion	kg	2,24E+04	1,49E+04

[a] based on process 'pipeline, natural gas, long distance, high capacity, offshore/km/GLO/I'

[b] based on 30% inventory for 300mm diameter, [c] based on 20% inventory for 200mm diameter

Table A10. 1 injection well (1000m)

	Unit	Well[a]
Materials/fuel		
Barite	kg	2,70E+05
Bentonite	kg	2,00E+04
Chemical, organic	kg	9,05E+03
Chemical, inorganic	kg	4,22E+04
Crude oil	kg	3,16E+04
Diesel	MJ	1,80E+07
Lignite	kg	2,00E+02
Lubricating oil	kg	6,00E+04
Natural gas	MJ	9,55E+05
Portland cement	kg	2,00E+05
Reinforcing steel	kg	2,10E+05
Processes		
Drilling waste disposal	kg	3,00E+04
Hazardous waste disposal	kg	4,00E+03
Transport	tkm	5,68E+05
Emissions to air		
Particulates > 10um	kg	1,48E+01
Emissions to water		
AOX	kg	4,78E-04
BOD5	kg	1,39E+04
COD	kg	1,39E+04
DOC	kg	3,80E+03
TOC	kg	3,80E+03
Aromatic hydrocarbon	kg	2,31E+02
Arsenic	kg	3,78E+00
Barite	kg	1,62E+05
Cadmium ion	kg	3,02E-01
Carboxylic acids	kg	1,70E+03
Chloride	kg	1,30E+03
Chromium ion	kg	1,72E+00
Copper ion	kg	9,15E+00
Glutaraldehyde	kg	2,00E+01
Hydrocarbon	kg	3,00E+03
Lead	kg	1,32E+01
Mercury	kg	2,79E-01
Nitrogen	kg	3,40E+00
Nickel ion	kg	3,44E-01
Oil	kg	4,39E+03
Phenol	kg	4,02E-04
Potassium ion	kg	1,60E+02
Silicon	kg	3,06E-02
Sulfate	kg	6,00E+02
Suspended solids	kg	5,70E+05
Zinc	kg	7,60E+03

[a] based on process 'well for exploration and production, offshore/m/OCE/I'