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Life Cycle Assessment of Power Generation Technologies with CO₂ Capture

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Master of Energy and Environmental Engineering

Submission date: July 2012

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Norwegian University
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Department of Energy
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EPT-M-2012-130

MASTER THESIS

for

Dan Jakob Wangen

Spring 2012

Life cycle assessment of power generation technologies with CO₂ capture

Livsløpsanalyse av kraftproduksjon med CO₂ fangst

Background

Carbon capture and storage (CCS) technology is based on the concept of capturing CO₂ (from large point sources e.g. fossil fuel or biomass energy facilities) and sequestering it away from atmosphere (e.g. aquifers, abandoned oil and gas wells) for long periods of time. The objective of the technology is to allow the use of carbon-rich fuels, albeit with significantly reduced global warming (GWP) impact. Capturing of CO₂ needs use of chemicals (e.g. solvents) and putting up of infrastructure for capture, transport and storage. More perceptibly, capture process puts an energy penalty on the energy system, thus reducing the net-energy produced. Several studies have evaluated the environmental consequences of CCS technology options and concluded that on the life cycle perspective there are considerable increases in non-GWP impacts e.g. acidification, eutrophication, eco-toxicity.

Aim

This project aims to assess the life cycle impacts of electricity generation from coal and natural gas feedstock with carbon capture and storage. Absorption based post-combustion CO₂ capture process, which is the most studied and currently being used in sour gas purification is considered for evaluation, and different solvent options (both state-of-art and novel e.g. MEA, DMEA, Sulfinol, potassium carbonate) are assessed. The assessment also extensively details the upstream process of fuel production and discusses the impacts from CO₂ storage. The secondary goal is to compare the life cycle impact results with the existing results in literature.

The analysis should include the following elements:

1. Compilation of performance data for electricity production and CO₂ capture processes.
2. Development of life cycle inventory for individual energy system.
3. Life Cycle Assessment of the considered state-of-art and novel CCS configurations.
4. Comparative analysis of LCA results to the existing literature.

Within 14 days of receiving the written text on the master thesis, the candidate shall submit a research plan for his project to the department.

When the thesis is evaluated, emphasis is put on processing of the results, and that they are presented in tabular and/or graphical form in a clear manner, and that they are analyzed carefully.

The thesis should be formulated as a research report with summary both in English and Norwegian, conclusion, literature references, table of contents etc. During the preparation of the text, the candidate should make an effort to produce a well-structured and easily readable report. In order to ease the evaluation of the thesis, it is important that the cross-references are correct. In the making of the report, strong emphasis should be placed on both a thorough discussion of the results and an orderly presentation.

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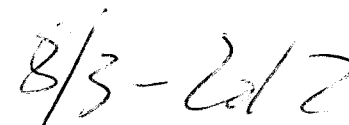
Pursuant to "Regulations concerning the supplementary provisions to the technology study program/Master of Science" at NTNU §20, the Department reserves the permission to utilize all the results and data for teaching and research purposes as well as in future publications.

The final report is to be submitted digitally in DAIM. An executive summary of the thesis including title, student's name, supervisor's name, year, department name, and NTNU's logo and name, shall be submitted to the department as a separate pdf file. Based on an agreement with the supervisor, the final report and other material and documents may be given to the supervisor in digital format.


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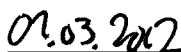
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Abstract

Carbon Capture and Storage has large a potential to mitigating the CO₂ emissions caused by fossil fuel powered power plants. CCS reduces the energy efficiency of the plant and increases the demand on chemicals and infrastructure. It is though not only the direct emissions from the power plants that have an impact on the environment. The entire supply chain of the power plant has an impact, and it is therefore necessary to evaluate the entire life cycle of the plant.

This thesis consists of a full process LCA of post-combustion absorption based carbon capture and storage (CCS) technologies for both coal power plants and natural gas power plants. The assessed CCS technologies are based on the solvents MEA, MDEA and chilled ammonia. MEA is the most commonly used solvent in post-combustion capture, while MDEA and chilled ammonia represents novel CCS technologies that are still under development.

It was shown that a 90% capture rate was possible for all of the assessed capture technologies. It was further shown that the total global warming potential (GWP) could be decreased with above 60%. 90% reduction is not possible because of indirect emissions in the supply chain. The reduction in GWP comes at a cost of decreasing energy efficiency, which further leads to an increase in consumption of materials and infrastructure. This causes the non-GHG related impacts to increase, compared to a base scenario without CCS.

CCS technology based on MDEA was calculated to be the technology with the lowest impact, mainly because it has the lowest energy requirement. Chilled ammonia was assessed as the technology with the largest impacts. The reason for this is that the chilling process is very energy intensive and therefore decreases the efficiency more, compared to the other technologies assessed. Also the large emissions of ammonia have a large impact on the acidification potential and the marine eutrophication potential.

Acknowledgements

This thesis has been written at the Department of Energy and Process Engineering (EPT) at the Norwegian University of Science and Technology (NTNU) in Trondheim Norway.

I would like to thank Professor Anders Hammer Strømman and Bhawna Singh for their supervision and help with this master thesis. I am very grateful for their continuous support, motivation and encouragement throughout this semester.

I also would like to thank the Industrial Ecology program and the Energy and Environmental Engineering program and all their students and employees for their constant encouragement and support. I would like to especially thank Anne Marit Melbye and Kaja Sofie Falsen Berg, whom I have shared offices with, while this thesis was written.

Lastly I would like to thank my family for their continuous support throughout my studies.

Dan Jakob Wangen

July 2012, Asker Norway

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1 Introduction

1.1 Background

The Intergovernmental Panel on Climate Change (IPCC) has shown that human activities have increased the concentration of greenhouse gases (GHGs) in the atmosphere (IPCC, 2001). The increased concentration of GHGs leads to global warming and climate change which has a wide range of effects on humans and ecosystems. Carbon dioxide (CO₂) is the biggest contributor of climate change of the GHGs, which is released by the combustion of fossil fuels and biomass. Especially CO₂ released from combustion of fossil fuels have an adverse effect on the concentration of GHGs in the atmosphere because it is not part of the short term carbon cycle.

The International Energy Agency (IEA) estimates that the world's energy demand will increase with 35% during the next 30 years (IEA, 2010). Coal and natural gas will be a large contributor in the production of energy to meet these demands. Carbon Capture and Storage (CCS) is an option that offers the possibility of limiting CO₂ emissions to the atmosphere from fossil fuel consumption (Røttereng, 2011). Capturing CO₂ from coal and natural gas power plants and storing it outside the carbon cycle, is an option to mitigate the GHG emissions to the atmosphere. According to the IPCC it is necessary that the global GHG emissions peak by 2020 and a subsequent reduction of emission by 25% by 2050, to limit a global average temperature increase of 2°C. CCS has been identified as one of the options to mitigate the GHG emissions, and according to the IEA; CCS has the potential to mitigate 10Gt of CO₂ released to the atmosphere by 2050 (IEA, 2008b).

The four main processes within a CCS system are capture of CO₂, transportation, injection and storage. With the exception of the last process these are all industrial processes which have a long track record. CO₂ capture has been used for several decades in gas processing plants where CO₂ is separated from natural gas. The transportation and injection of CO₂ into reservoirs has also a relatively long track record through enhanced oil recovery (EOR) projects. There are some uncertainties connected to the storage of CO₂ in reservoirs, this is mainly caused by a lack of experience in long term storage and that every storage location is unique. However the experience from the oil and gas sector has given us useful experience in mapping and handling reservoirs, and today there are three large-scale integrated CCS plants in operation which store the captured CO₂ in deep saline formations (Global CCS Institute, 2011).

There are two main forms of CCS technologies available today; pre combustion- and post combustion capture. Pre combustion capture is based on converting carbon based fuel into synthesis gas, which is a mixture of primarily carbon monoxide (CO) and water (H₂O). The next step is to make the CO react with steam, which will produce CO₂ and hydrogen (H₂). The CO₂ can then be captured before the combustion of the H₂. Post combustion capture is based on capturing the CO₂ from the flue gas from a power generating technology. Post

combustion capture can have a larger potential to mitigate the increasing level of GHG concentration in the atmosphere because it can theoretically be retrofitted to any existing power plant or industry with high CO₂ emissions.

1.2 Research Objectives

The research objective is to complete a full process life cycle assessment (LCA) of post combustion capture technologies from NGCC and PC power generating technologies. The capture technologies that will be considered are based on the solvents MEA, MDEA and chilled ammonia. These post combustion capture technologies will be compared with two different base scenarios which are NGCC and PC power plants with a world average efficiency and with a Best Available Technology (BAT) assumption.

Post combustion capture is the most common capture technology, where MEA is also the most commonly used absorbent, therefore this assessment will cover a large portion of available CCS technologies.

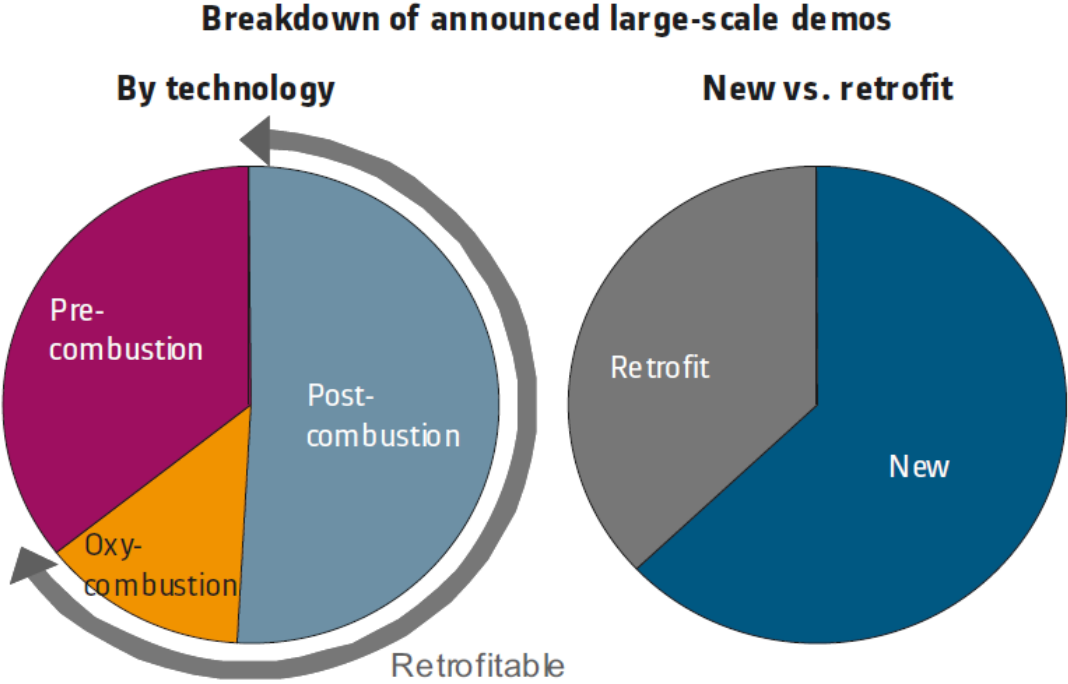


Figure 1 – Breakdown of announced large scale demos (Telikapalli et al., 2011)

The full process LCA will have a specific focus on the tradeoffs that occurs with the altered flue gas caused by the capture process. There is a large benefit of capturing the CO₂ to mitigate the global warming potential of a power plant. However the solvents and chemicals used in the capture process can escape with the cleaned flue gas and have impacts on ecosystems and human health, among others.

Another topic that is of high relevance to CCS technology, is the energy consumption caused by the capture and storage process. The capture process has a parasitic energy consumption

which reduces the total efficiency of the power plant and leads to an energy penalty. This leads to an increased cost of production because of the increased fuel consumption.

Pre combustion capture will not be assessed in this thesis.

1.3 Literature Review

The earliest studies on the environmental impacts of CCS was based on mass and energy balances (e.g. (Doctor et al., 1993), (Summerfield et al., 1995), (Waku et al., 1995)). In later years a large amount of articles have been published where LCA has been used as a methodology to assess CCS as a technology (e.g. Hertwich et al. (2008), Koornneef et al. (2008), Odeh and Cockerill (2008), Korre et al. (2010), Singh (2011)). In 2012 the journal Energy published a framework for environmental assessment of CCS systems (Sathre et al., 2012), where some of the key issues in current LCA literature was discussed. These being the energy penalty, non-climate environmental impacts, uncertainty and scale up problems among others.

Several detailed literature reviews of CCS and LCA have recently been published (Hertwich et al. (2008), Marx et al. (2011), Singh (2011), Koornneef et al. (2012)). Through these reviews it becomes evident that the majority of LCA on post combustion capture is based on the MEA process. Through this literature study it has not been identified any published LCA on pure MDEA systems. However several studies focus on the life cycle impacts of CCS systems where MDEA is a part of a mixture of amines (e.g. Lombardi (2003), Carpentieri et al. (2005) and Aroonwilas and Veawab (2007)). The chilled ammonia capture method is relatively new, and the patent for the technology was first registered in 2006 (Gal and Jayaweera, 2010). Because the technology is still under development; limited amount of information is available. However one crude environmental study on the chilled ammonia process have been published (Horsssen et al., 2009).

Since CCS is a technology still under development it is important to identify some of the most recent and through reports describing the technologies. This is to identify the life cycle inventories (LCI) that the LCA are based upon. For example Peeters et al. (2007) describes the development potential of CSS technologies, especially related to the energy performance of the systems. The energy penalty of the capture technologies is one of the main obstacles in developing the technology and several studies focus on this (e.g Page et al. (2009) and Le Moullec (2012))

1.4 Structure of the work

Chapter 2 provides an explanation of the methodology used in the assessment. The general framework for LCA is explained, as well as the life cycle impact assessment methodology used. The software used in the calculations is also presented.

A technical overview of CCS technologies is given in chapter 3. The goal of this chapter is to identify the life cycle inventories used in the calculations. As a result of the technologies

discussed in chapter 3 a presentation of the scenarios used in the assessment is described in chapter 3.9.

In chapter 4 a detailed energy assessment of the capture systems is shown. Both the thermodynamic energy requirements and the electrical requirements of the different capture technologies are derived.

In chapter 5 the results of the full process LCA is presented, while chapter 6 contains the discussion and conclusion.

2 Methodology

2.1 Life Cycle Assessment

According to the ISO 14040 standard; Life Cycle Assessment (LCA) is defined as the “compilation and evaluation of the inputs, outputs and potential environmental impacts of the environmental burden of products at all stages in their life cycle“(ISO 14040:2006 (E)).

There are four phases in an LCA study (Figure 2). These four phases are an iterative process where the preceding steps are revisited before continuing to the next.

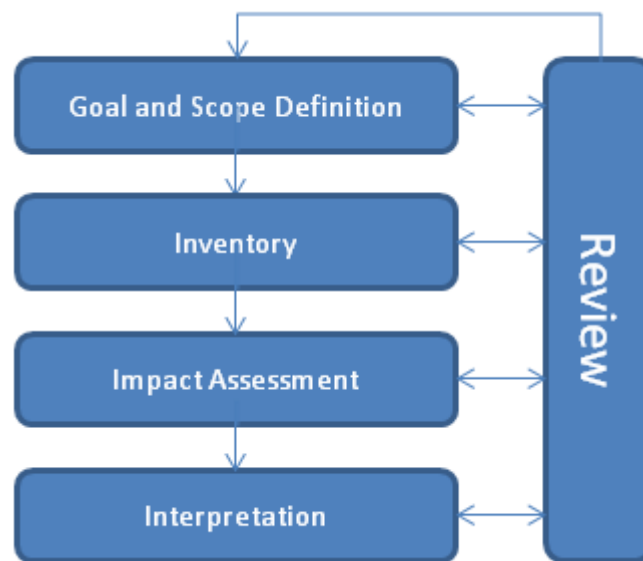


Figure 2 – The Four Phases an LCA

The scope, including the system boundary and level of detail, of an LCA depends on the subject and the intended use of the study (ISO 14040:2006 (E)). The first step establishing a goal and scope definition is to identify the “*functional unit*”. In the case of this thesis the functional unit is set to 1 kWh of produced electricity. The second step is to establish the system boundaries describing which processes to include, the level of detail and thus the data requirements. The characterization methodology used in phase 3 is also decided.

Phase 2, the inventory, is the phase that describes the data collection. In the LCA terminology the data the assessment is based upon is called the life cycle inventory (LCI).

Phase three is the impact assessment. This is the part where the LCI data, which includes information on emissions and resource use, is converted into impact categories (e.g. global warming potential, acidification potential and eutrophication potential). It exist many different frameworks for characterizing the impact of a Life Cycle Inventory (LCI), and it is not defined any standard Life Cycle Impact Assessment (LCIA) in the ISO standard (ISO 14040:2006 (E)).

The last phase is the interpretation phase, where the findings of the previous phases are discussed with the goal of reaching a conclusion based on the assessments.

2.2 Arda and ReCiPe

The results have been calculated with the NTNU in-house software Arda, which is developed by the Industrial Ecology program at the Norwegian University of Science and Technology. The software is based on the Ecoinvent database (Ecoinvent, 2007) where the ReCiPe framework is used to calculate the life cycle impact assessment results.

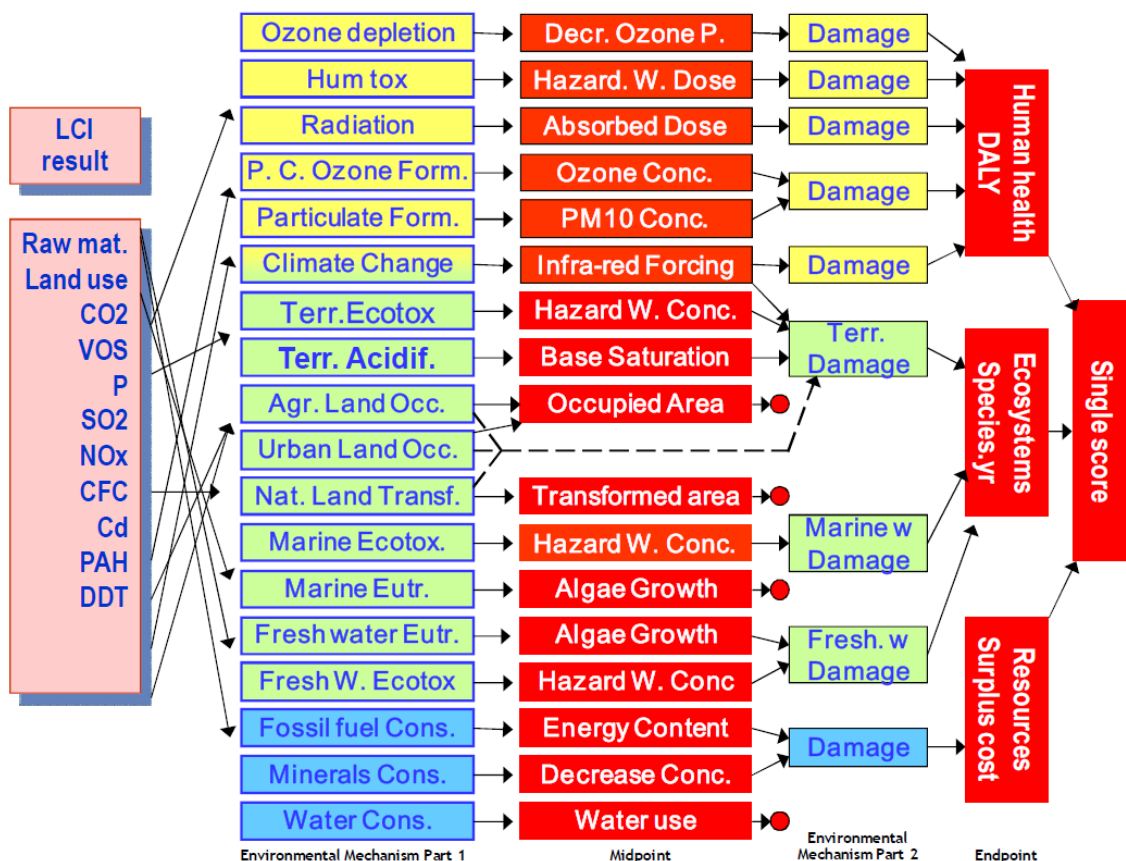


Figure 3 – ReCiPe framework (Goedkoop et al., 2009)

ReCiPe (Goedkoop et al., 2009) is a LCIA framework which has the goal of transforming a long list of LCI results into a limited number of impact categories. The ReCiPe methodology is based on the CML 2000 (Guinee et al., 2002) and the EcoIndicator 99 (Goedkoop and Spriensma, 2000) methodology. The difference in these two methodologies is that the CML 2000 has a focus on midpoint indicators, whereas the EcoIndicator 99 has a focus on endpoint indicators. The ReCiPe was therefore created with the thought of uniting these two approaches.

The ReCiPe framework consists of 18 midpoint indicators and three end point indicators (Figure 3). The midpoint indicators have relatively low uncertainty and high acceptance within the LCA community. The endpoint indicators has in comparison relatively high uncertainty (Goedkoop et al., 2009).

3 Carbon Capture and Storage

3.1 Coal Power Plant

The coal power plant that is set as the base scenario for this assessment is a super critical pulverized coal (PC) power plant. However, of the installed global coal-fired generation capacity of 1142GW, only 155GW are supercritical (IPCC, 2005). The basis of this assessment is therefore on the best available technology (BAT), and not necessarily on the industry standard.

The coal power plant is based on theecoinvent process (Ecoinvent, 2007) *“hard coal burned in power-plant/MJ/DE”*. This has been modified to illustrate a 400MW pulverized coal power plant. Two different scenarios have been developed based on a world average efficiency (35,1%) and a BAT efficiency assumption (43,4%) according to data from the IEA (IEA, 2008a). The scenarios modeled with CCS are based on the BAT efficiency while the world average efficiency scenario is only used as a scenario for comparison.

Since sulfur dioxide (SO₂) is an acid gas it will react with the capture systems. Normally the flue gas passes a desulfurization scrubber which removes approximately 90% of the sulfur dioxide before the flue gas is emitted to the atmosphere. This must be increased, depending on the capture technology, and it is assumed that the infrastructure within the coal power plant can handle this without changing the plant. The fuel is modeled as hard coal, and the emission profile can be found in Table 11 in the appendix.

3.2 Natural Gas Power Plant

The natural gas power plant is modeled as a 400 MW combined cycle (NGCC) power plant based on the ecoinvent process *“natural gas, burned in power plant/MJ/UCTE”*. Two scenarios have been developed based on the world average efficiency (42,0%) and a BAT efficiency (58,1%) (IEA, 2008a), as similarly done with the coal power plant. The same assumption that was made for the coal power plant regarding sulfur dioxide concentrations in the flue gas is made for the NGCC plant also. However the amount of sulfur dioxide is lower in the flue gas of combusted natural gas and therefore the assumption has less impact on the NGCC power plant. The emission profile for the combusted natural gas can be found in Table 12 in the appendix.

3.3 Capture Technologies

There are several different technologies developed to capture CO₂ after combustion. Absorption or scrubbing is the most commonly used technology, and is based on absorbing acid gasses (CO₂) from the flue gas by contact with a liquid absorbent or solvent. The process takes place in tall towers where turbulent flow promotes rapid CO₂ transfer from gas to liquid. The emerging gas and liquid is easy to separate because of differences in density. To recover the captured CO₂ the rich solvent is pumped to a stripper in which it is exposed to hotter CO₂ free gas, typically steam. The heating of the solvent causes desorption of the CO₂ and the and the stripped liquid is pumped back to the scrubber while the steam - CO₂

mixture is cooled to condense the steam, leaving high purity CO₂ suitable for compression and, after transportation to an appropriate site, sequestration (Herzog et al., 2009). The most commonly used liquid adsorbents used are amines and ammonia.

Another way to capture CO₂ after combustion is using physical sorbents through adsorption. A number of nonreactive sorbents can be used to recover the CO₂ from the flue gas, including carbonaceous materials and crystalline materials known as zeolites. The physical sorbents has a lower reactivity with CO₂ than liquid solvents which are used in absorption, and thus not an economical viable solution for power generation with CCS. It can though be used for CCS in industrial processes where the required CO₂ purity is at most 90% (Radosz et al., 2008).

Chemical sorbents can also be used to capture CO₂. Calcium carbonate (CaCO₃, limestone) releases CO₂ when heated to 850°C and transforms into calcium oxide (CaO). The calcium oxide reacts with CO₂ at 650°C and thus capturing the CO₂ and creating again calcium carbonate. This reaction cycle is commonly used in many industrial processes and the high CO₂ capture capacity and its long track record therefore makes the CaO/CaCO₃ system an attractive option. However, since the calcium carbonate both reacts with CO₂ and SO₂, it loses its capture capacity quickly and requires frequent replacement (Rodriguez et al., 2008).

Membrane-based separation is also a technology under development which could potentially be used for CO₂ capture. The membranes are often made of thin polymeric films, which can separate chemicals by the relative rate which they permeate. Membrane based filtration is a mature technology with experience through desalination, but also through gas filtration, i.e. recovery of oxygen from air or removal of carbon dioxide from natural gas. The downside with membrane-based separation is that it is generally pressure driven, and thus has a large energy penalty especially considering the relative low partial pressure of CO₂ in the flue gas (Herzog et al., 2009). In Figure 4 an overview of the post combustion capture technologies discussed in this chapter is shown.

In this thesis, only MEA, MDEA and chilled ammonia, which are all absorbents, are assessed.

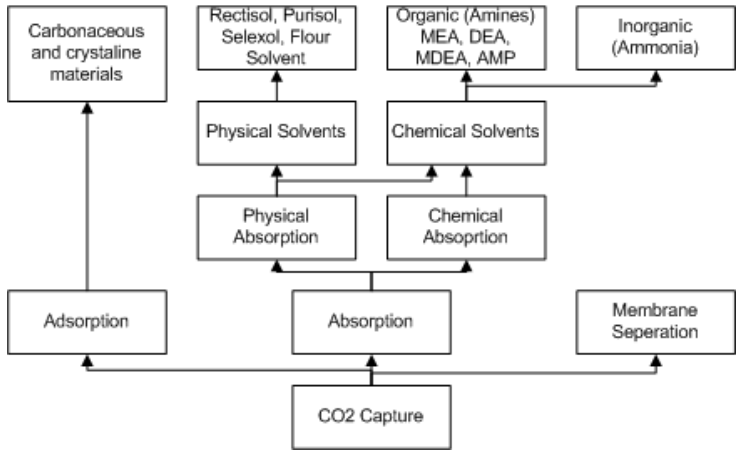


Figure 4 – Overview of capture methods and solvents (adapted from (Padurean et al., 2011))

3.4 MEA Capture

Amines are water soluble organic chemicals that contain reactive nitrogen atoms. They are ideal for CO₂ capture because they have a high reaction rate which is reversible with acid gasses. They are also relatively inexpensive but they are corrosive and therefore the construction cost and maintenance cost can be high. Amines are relatively nonvolatile but in the presence of oxygen and/or sulfur dioxide they gradually volatilize. This necessitates inject of fresh solution and also means that volatilized amines can be emitted through the cleaned flue gas. MEA is the most commonly used solvent in post combustion capture technologies.

MEA stands for *monoethanolamine* and has both an alcohol group and an amine group. The general molecular formula is C₂H₇NO, however this formula can be misleading since the functional groups are not specifically shown (see Figure 5).

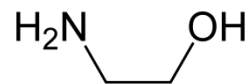


Figure 5 – Molecular formula MEA

In Figure 6 a generic simplified flow sheet of the capture process is shown. The absorber in the MEA system operates at a temperature of approximately 40°C and therefore the flue gas entering the absorber must be cooled down to approximately 40°C -50°C. For a NGCC power plant it can be assumed that the temperature of the flue gas is approximately 110°C - 120°C and these gasses must be cooled down before the absorber. Since the absorber temperature is above normal outdoor temperature, it is assumed that the cooling process is energy neutral, excluding the pumps needed. For coal power plants the temperature of the flue gas is assumed to be approximately 40°C-50°C because it has been through a wet flue gas desulfurization scrubber (Kothandaraman, 2010).

In the absorber the flue gas enters the bottom of the absorption tower under a small pressure and rises to the top of the tower. There are different types of technologies that depend on various concentrations of MEA. In this report a concentration of 30 wt% MEA was used with a lean loading of 0,15 moles of CO₂/mole of MEA and a rich loading of 0,45 moles of CO₂/mole of MEA. This gives a working capacity of 0,3 (Table 2). The lean amine solvent enters the top of the absorption tower and reacts with the CO₂ present. The rich amine leaves from the bottom of the absorber where it's sent to the cross-heat exchanger.

Before entering the stripper the CO₂ rich amine is normally pressurized to approximately 1,5 bars. The CO₂ rich MEA mixture enters the top of the stripper and flows down the column, counter to the direction of the vapors from the reboiler. The CO₂ will break its chemical bonds with MEA because of the increase in temperature. The gas leaving the top of the stripper is a mixture of CO₂ and water vapor. This mixture is cooled down to condensate the water so that the CO₂ can be separated from the water. The pure CO₂ gas is then pressurized to a supercritical state before being pumped to the storage site.

At the bottom of the stripper the CO₂ lean MEA solvent leaves before entering the heat exchanger, and if needed a chiller, to achieve the desired temperature in the absorber. Especially in the case of coal fired power plants it is necessary to use an MEA reclaimer to treat some of the heat stable salts that forms when MEA react with SO_x and NO_x. The buildup of salts in the amine stream is undesirable as this lowers the circulation speed of the amine and reduces the solvents capacity for CO₂ absorption. It is therefore typical to use a strong alkali like NaOH with some heat to dissociate the salts, resulting in the recovery of most of the MEA. Because of this degradation some MEA must be added continuously (Kothandaraman, 2010).

In the MEA system, the CO₂ reacts with water and forms a carbamate, carbonate or bicarbonate. The following reversible equations describe the reactions occurring in the MEA system.

- (1) $2H_2O \leftrightarrow H_3O^+ + OH^-$
- (2) $CO_2 + 2H_2O \leftrightarrow HCO_3^- + H_3O^+$
- (3) $MEA + HCO_3^- \leftrightarrow MEACOO^- + H_2O$
- (4) $MEA + H_3O^+ \leftrightarrow MEA^+ + H_2O$
- (5) $HCO_3^- + H_2O \leftrightarrow CO_3^{2-} + H_3O^+$

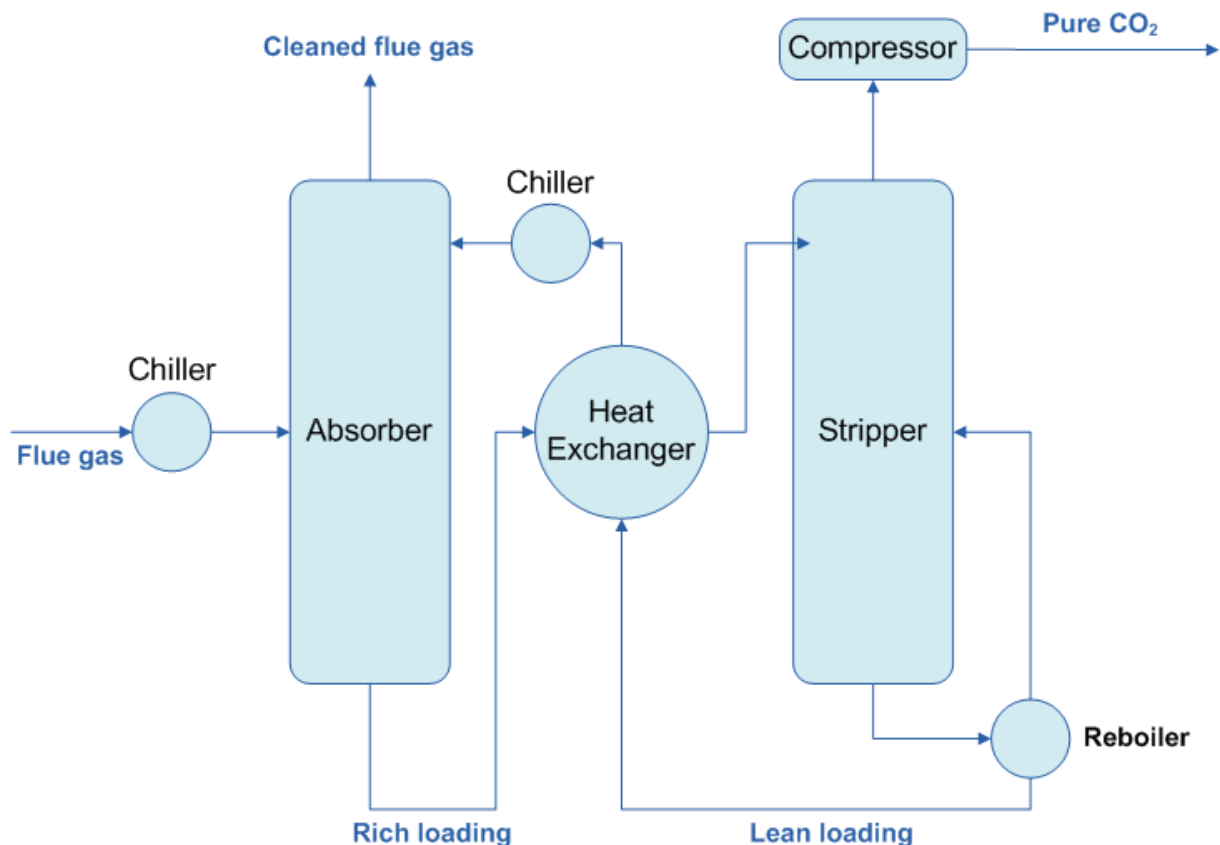


Figure 6 – Simplified Capture Unit

3.5 MDEA Capture

MDEA is a chemical similar to MEA. MDEA is an abbreviation for *methyl diethanolamine*, with the general molecular formula of $C_5H_{13}NO_2$ (see Figure 7). An MDEA capture system is basically the same as an MEA capture system, except MDEA have a few advantageous characteristics. It has a higher working capacity; this meaning that the amount of CO_2 captured per unit of solvent is higher for MDEA than for MEA. MDEA has also a higher solubility with water than MEA, therefore leading to a lower circulation rate and a higher capture rate. Lastly MDEA has a lower chemical binding energy; this means that regenerating the MDEA requires less energy compared to MEA.

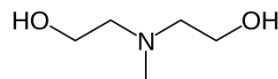
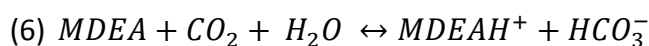


Figure 7 – Molecular formula MDEA

MDEA is often used as a part of a blend of different amines, e.g. MEA-MDEA blends (Aroonwilas and Veawab, 2007) or MDEA-piperazine blends ((Peeters et al., 2007)). However in this assessment the MDEA scenarios will be based on a pure MDEA solvent.

MEA is known as a primary alkanolamine, where one hydrogen atom of the ammonia molecule is replaced by an ethanol group. MDEA is known as a tertiary alkanolamine, where all hydrogen atoms have been replaced by either alkyl or alkanol groups. This difference affects the way the solvents react with CO_2 . Since MDEA lack the ability to eliminate a hydrogen atom it cannot form a carbamate. Therefore the reaction with CO_2 is considered to be a hydrolysis catalyzed reaction. This meaning that the CO_2 is not directly chemically bound to the MDEA (Derks, 2006) (see Eq. (6))



3.6 Chilled Ammonia

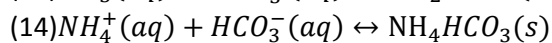
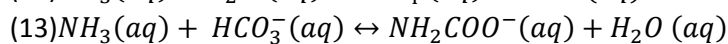
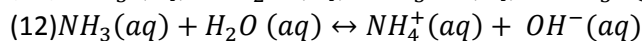
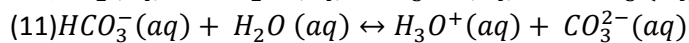
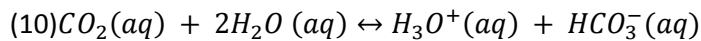
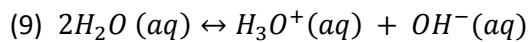
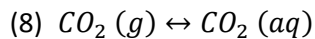
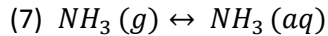
Ammonia-based solvents offers possibilities for developing absorption processes which are less corrosive and more stable than amines. The CO_2 uptake per unit of ammonia is also estimated to be 3 times higher comparing with MEA. The theoretical maximum removal efficiency of CO_2 for ammonia solvents can reach 99% comparing with MEA solvents which have a theoretical maximum removal efficiency of 94% (Yeh and Bai, 1999). However ammonia-based solvents have a downside since ammonia is a toxic gas. It is therefore important to avoid emissions through the cleaned flue gas.

The chilled ammonia process was first patented in 2006 (Gal, 2006), and has been successfully implemented as a pilot study (5 MW, We Energies, US). It has also been validated in an operational plant (54 MW, AEP Mountaineer, US) with successful results. The technology will further be tested at the Technology Center Mongstad (TCM) for an extended

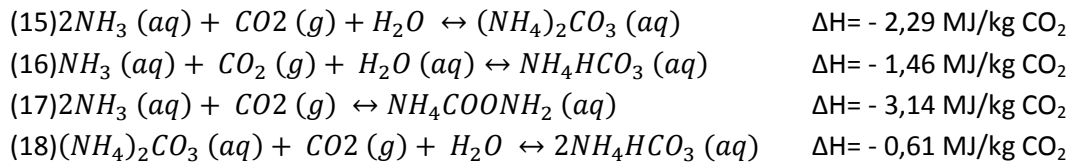
period of time starting summer 2012 (Alstom, 2012). This means that the technology is still under development, and limited amount of information is available for the public.

The chilled ammonia process starts with chilling the flue gas to approximately 0-10°C (see Figure 6). The chilled flue gas reacts with the chilled ammonia mixture in the absorber, and the CO₂ is bound to the ammonia. The CO₂ rich ammonia mixture leaves the bottom of the absorber and is pressurized to approximately 30 bars before passing through a heat exchange. The solution might be further heated after passing through the heat exchanger to fully dissolve all solids present in the CO₂ rich ammonia mixture. The temperature in the reboiler of the stripper ranges between 140-150°C. Thus meaning there is a temperature swing of about 140°C between the absorber and stripper. This is to some degree mitigated by the cross-heat exchanger, but there is still a large energy requirement. The pure CO₂ gas leaves the top of the stripper before being compressed into a supercritical fluid, ready for transportation to a storage site. The lean CO₂ mixture leaves the bottom of the stripper before going through the cross-heat exchanger and the chiller before entering the absorber starting the process over again.

The capture process happens in the absorber in low temperature as earlier stated. This is because the absorption rate of ammonia increases with decreasing temperature. The chemistry of the system is based on the reaction of CO₂ with an ammonium carbonate solution.



In Eq. (7) – Eq. (14) the chemistry of the chilled ammonia system is shown. It is very complex because CO₂ reacts in many different ways with the ammonia. It is therefore difficult to calculate the thermodynamic energy requirements of the chilled ammonia system. As seen in Eq. (14) the chilled ammonia process also involves the precipitation of ammonium bicarbonate due to the low temperature in the absorber. This means that the CO₂ rich solution leaving the absorber is a slurry and not completely fluid. The ammonia solution can react with CO₂ in four different ways, which is summarized in Eq. (15) – Eq.(18). It is difficult to define the reaction pattern of CO₂ and ammonia without simulation of the entire system or collection of data from operational plants. In Kothandaraman (2010) the reaction pattern where simulated and the chemical regeneration requirements of ammonia was estimated to be 1,28 MJ/kg CO₂, suggesting that Eq. (18) is a reaction more common than the others. Further calculations were not done to investigate the chemistry of reactions since this is outside the scope of this thesis.



3.7 Transportation and storage

The CO₂ can either be liquefied or compressed into a supercritical fluid when transported in pipelines to the storage site. Since liquefaction of CO₂ is most suitable for tanker transport and has a higher energy requirement than compression into a supercritical state (Page et al., 2009), liquefaction has not been considered in this assessment.

The transportation system has been modeled in this report as a 250 km offshore pipeline. Theecoinvent process “*pipeline, natural gas, long distance, high capacity, offshore/ GLO/ km*” has been used as a proxy with a lifetime of 25 years. The length of 250 km was chosen to avoid issues concerning pressure drops and the need for boosters along the pipeline. The pipeline has a maximum capacity of 2876 tons CO₂/hour which is more than enough to handle the captured CO₂ from both the coal (275tons CO₂/hour) and natural gas power plant (125tons CO₂/hour). The same transportation system was therefore chosen for both the coal and natural gas power plant

The storage site has been modeled with theecoinvent process “*well for exploration and production, offshore/ OCE/ m*”. The depth of the well was assumed to be 1000 meters, and the same type of well was used for both the natural gas and coal power plant. Leakage from the well has not been considered in this assessment.

3.8 Changes in emission profile

The capture process changes the emission profile of the power plant. The largest difference is of course caused by the removal of the CO₂ from the flue gas, but also other changes occur. Because the absorbents react with all chemicals in the flue gas; complex substances may be released. This is especially true for the processes using amine capture. The amine capture pilot plant at Technology Centre Mongstad is expected to have emissions of 26 different substances caused by the capture process itself (Berglen et al., 2008). Because many of these chemicals are not accounted for in theecoinvent database, a simplified emission profile based on Singh (2011) have been used. Because of limited information available on the MDEA capture system the changed emission profile is based on the MEA system. There is also an issue of information availability for the chilled ammonia system. The most essential substance that is emitted with the flue gas is naturally ammonia. The value used is based on tests conducted by Kozak et al. (2009), which correspond with the design values used by Alstom at TCM (Berglen et al., 2008). The changes in the emission profile are attached in the appendix.

3.9 Scenarios

10 scenarios were developed to analyze the discussed CCS technologies

- Scenario 1A: Pulverized coal power plant with world average efficiency
- Scenario 1B: Natural gas combined cycle power plant with world average efficiency

- Scenario 2A: Super critical pulverized coal power plant
- Scenario 2B: Super critical natural gas combined cycle power plant

- Scenario 3A: Super critical pulverized coal power plant with MEA capture
- Scenario 3B: Super critical natural gas combined cycle power plant with MEA capture

- Scenario 4A: Super critical pulverized coal power plant with MDEA capture
- Scenario 4B: Super critical natural gas combined cycle power plant with MDEA capture

- Scenario 5A: Super critical pulverized coal power plant with chilled ammonia capture
- Scenario 5B: Super critical natural gas combined cycle power plant with chilled ammonia capture

Scenario 1A and 1B is only used for comparison reasons, while scenario 2 is the base scenarios which the latter scenarios are based upon.

4 Energy consumption assessment

The thermodynamic energy consumption of a CCS plant can be separated into several categories:

- Regeneration energy
 - Energy required to reverse the chemical binding of CO₂ to the solvent
 - Energy required to heat the solution
 - Energy required for water evaporation
- Parasitic power loss
 - Energy required to power pumps and blowers
- Compression energy
 - Energy required for pressurizing the CO₂ before pipeline transport

4.1 Chemical Regeneration Energy

The chemical regeneration energy (ΔH_{rx}), also known as the CO₂ chemical binding energy, is the energy required to reverse the reaction between the CO₂ and the capturing solvent. The energy required depends solely on the solvents formulation. Rao et al. (2004) and Peeters et al. (2007) cites that the energy requirement for separating CO₂ and MEA is 1,9 MJ/kg CO₂. In Peeters et al. (2007) it is argued that the high regeneration energy requirement for MEA is

one of the main arguments for identifying new solvents. MDEA is one example where the regeneration energy requirement is much lower 1,14MJ/kg CO₂ (Le Moullec, 2012). For ammonia the regeneration energy requirement is different because the solvent can react in four different ways with CO₂ (see Eq. (15) - (18)). The chemical regeneration energy requirement for ammonia varies between 0,61 – 3,14 MJ/kg CO₂ (Eq. (15) (12)- (18)) depending on the chemical reaction. As earlier mentioned Kothandaraman (2010) set up an ASPEN simulation of the chilled ammonia system and calculated that the average is 1,28 MJ/kg CO₂. This number will be used in further calculations.

4.2 Heating of solution

According to Peeters et al. (2007) the energy required for the heating of the solution can be calculated with the general equation shown in Eq. (19):

$$(19) \quad Q = c m_s \Delta T$$

where Q is the heat added, c is the specific heat of the solution, m_s is the mass of the solution, and ΔT is the change in temperature. The equation has to be adjusted since in this context we are interested in the energy requirements per unit of CO₂ captured.

$$(20) \quad Q = c \frac{m_s}{m_{CO_2}} \Delta T$$

The specific heat of the solution has to be calculated based on the specific heat of both the solvent and the water in its mixture. Thus the sorbent concentration has an impact on the energy requirement. The specific heat of 28 wt% ammonium hydroxide (NH₄OH), the form of which ammonia is when diluted in water has not been found in the literature study for this thesis. The literature that discusses the energy requirement of heating ammonia solutions assume the same heating capacity as for water (Resnik et al., 2004). This assumption can be justified by comparing the heating capacity of liquid ammonia (4,74 J/g K) and water (4,19 J/g K). In SGTE (2004) the specific heat of 6,1 wt% ammonium hydroxide is given as 4,17 J/g K which further justifies the assumption. The specific heat of ammonia cannot directly be used to calculate the specific heat of the solution because the value is different for the substance in liquid and gas form, since it reacts with the water in the solution. The specific heat of the solvents analyzed is shown in Table 1.

Solvent	Specific Heat Capacity [J/g K]
100 wt% MEA	2,74
100 wt% MDEA	1,72
100 wt% NH ₃ (l)	2,06
100 wt% NH ₃ (g)	4,74
6,1 wt% NH ₄ OH	4,17
100wt% Water	4,19

Table 1 – Specific heat of solvents

In Table 2 the characteristics used to calculate the sorbent concentration and the capture rate is shown. Rich loading is the amount of CO₂ chemically bound to one unit of a solvent after entering the stripper, while the lean loading is the same but measured in the flow exiting the stripper. The working capacity is then the difference between the lean and rich loading and expresses the solvents capture efficiency.

Amine	Maximum sorbent concentration (wt%)	Moles of CO ₂ per mole of solvent			Source
		Lean loading	Rich loading	Working capacity	
MEA	30	~0,15	~0,45	~0,3	(Peeters et al., 2007)
MDEA	50	~0,05	~0,5	~0,45	(Peeters et al., 2007)
NH ₃	28	~0,33	~0,67	~0,33	(Darde et al., 2010)

Table 2 – Characteristics of solvents studied

When including the energy obtained through heat exchangers, the change in temperature between the absorber and the stripper in a state of the art MEA capture system is 15°C (ΔT) (Peeters et al., 2007). The same change in temperature is assumed for the MDEA system. In the patent (Gal and Jayaweera, 2010) filed by ALSTOM Technologies Ltd. for the chilled ammonia system the temperature in the absorber is recommended to be between 0-20 °C while the temperature in the stripper should be between 100-150°C to achieve optimal absorption and desorption. In Darde et al. (2010) the temperature was calculated to be 10°C in the absorber while the temperature in the stripper was calculated to be 110°C to achieve optimal absorption and desorption while taking into account the energy consumption. The temperature difference between the absorber and the stripper, excluding the heat exchanger, in an MEA capture system is approximately 65°C. Assuming a linear relationship between the effective change in temperature with and without heat exchangers the ΔT in the NH₃ system will be approximately 23 degrees.

Solvent	Energy Requirement relative to temperature [KJ/kg CO ₂ K]	ΔT [K]	Q - Sensible heat requirement [KJ/ kg CO ₂]
MEA	57,90	15	868,57
MDEA	35,56	15	533,39
NH ₃	17,55	23	404,95

Table 3 – Energy required to heat the solution

In Table 3 the energy requirement for heating the solutions are shown. Ammonia has the lowest energy requirement, even though it has a larger difference in temperature and a higher heat capacity. This can be explained by the high capture rate per gram of solution.

4.3 The heat of vaporization

In the stripper water is evaporated to carry the CO₂ overhead and sufficiently regenerate the solvent (Niswander et al., 1993). The amount of water evaporated per unit of captured CO₂ is affected by the temperature in the stripper and the CO₂ loading capacity. Water evaporation in the stripper is responsible for a relatively large share of the energy requirements, though little information is available in the literature (Peeters et al., 2007). According to Feron and Jansen (1995) 1-2 moles of water has to be evaporated in the

stripper per kg of CO₂ captured in an MEA system. IEA GHG (2000) operates with a different number stating that 0,72-0,76 moles of water has to be evaporated per kg of CO₂ captured. The energy required to evaporate the water can be found by calculating the change in enthalpy. The formula used to calculate the energy requirement is shown in equation (21)

$$(21) \quad Q_{evap} = (H_{100^{\circ}\text{C}} - H_{T1} + H_{vap}) \times m_{H2O}$$

where $H_{100^{\circ}\text{C}}$ is the enthalpy of water at 100°C, H_{T1} is the enthalpy of water at the temperature in the stripper (T1), H_{vap} is the enthalpy for vaporizing and m_{CO_2} is the amount of water evaporated. According to Bandyopadhyay (2011) the CO₂ rich solvent enters the stripper at approximately 40-65°C. Assuming a temperature of 50°C (T1) and the amount of water that evaporates to 0,74 moles; the total energy used in water evaporation equals 747 kJ/kg CO₂. This is comparable to the 700kJ/kg CO₂ Peeters et al. (2007) calculated. In Table 1 the enthalpy factors used in the calculations are shown, as well as the total energy requirement of heating one mole of H₂O from 50°C to vaporized water.

Temperature	Enthalpy Water (H) [kJ/mol]
50°C	3,8
100°C	7,5
vaporization	40,7
50°C H ₂ O (l) - 100°C H ₂ O(g)	44,4

Table 4 - Enthalpy of water

For comparison purposes the vaporization energy requirement for the different amounts of water vaporized, which is cited in the literature, is shown in Table 5 **Error! Reference source not found.**. The same energy requirement is assumed for MDEA based capture systems as there is little information available in the literature.

Moles of water vaporized (mH ₂ O)	Q _{vap} [kJ/kg CO ₂]
2	2019,010584
1	1009,505292
0,76	767,2240218
0,74	747,033916
0,72	726,8438102

Table 5- Heat of vaporization

For the chilled ammonia system, little information on the energy requirements of vaporizing water in the stripper can be found. Small scale testing has though shown that the high pressure at which the CO₂ rich solvent enters the stripper makes the water spontaneously vaporize and no additional energy needs to be added (Resnik et al., 2004). The thermal regeneration energy requirement is summarized in Table 6.

	Chemical Binding Energy [kJ/kg CO ₂]	Heating of Solution [kJ/kg CO ₂]	Heat of Vaporization [kJ/kg CO ₂]	Total Regeneration Energy [kJ/kg CO ₂]
MEA	1910	869	747	3526
MDEA	1140	533	747	2680
NH ₃	1280	405	0	1015

Table 6 - Total Regeneration Energy

The thermal energy requirement should not be confused with the electricity requirements of the capture process or the net energy penalty. This is because a large amount of the total regeneration energy requirement is fueled by waste heat and steam, which otherwise would not be utilized. It is though valuable for comparison of the energy requirement of the different capture techniques

4.4 Energy for Pumps and Blowers

According to Peeters et al. (2007) about 15% of the total energy requirement is caused by the parasitic power loss of pumps and blowers in the capture system. The energy required by pumps is based on the CO₂ loading, in other words the amount of CO₂ captured per unit of solvent. The energy required by blowers is dependent on the absorption rate, this meaning the residence time of the flue gas in the absorber. There is little generic information available on this in the literature because it depends on the plant design, e.g. length of pipes etc. However Page et al. (2009) has through industry contacts estimated that for standard MEA capture systems the parasitic power loss equals to 470kJ/kg CO₂. This value corresponds with other literature stating that the parasitic power loss of a generic MEA capture system is in the range of 510-370kJ/kg CO₂ (Rochelle, 2009).

4.5 Compression Energy

The CO₂ has to be pressurized to a super critical state before transportation to the storage site. The critical point is at 301,1K and 73,8 bar (Figure 8). The compression work with 100% isentropic efficiency to pressurize the CO₂ to the critical point equals 271 kJ/kg CO₂ (Le Moullec, 2012). Though 73,8 bars is sufficient to reach supercritical state, it is common to pressurize the CO₂ to 110 bars because of pressure drop in the pipeline during transportation. The energy requirement to pressurize the CO₂ depends on how many stages there are in the compression train. The literature (e.g. (Page et al., 2009), (Le Moullec, 2012) (Peeters et al., 2007)) uses different values depending on the efficiency of the compressor and number of stages. The integration of the compression train can also lead to a reduction of steam requirements in the reboiler, by utilizing the heat from the compression system, thus indirectly increasing the efficiency of the compression train. With this in mind the literature refers to values in the range of 327kJ/kg CO₂ (Le Moullec, 2012) to 464kJ/ kg CO₂ (Page et al., 2009). In this thesis the value 381 kJ/kg CO₂ (Peeters et al., 2007) is used, where it is assumed that 35% of the heat is reused in the reboiler.

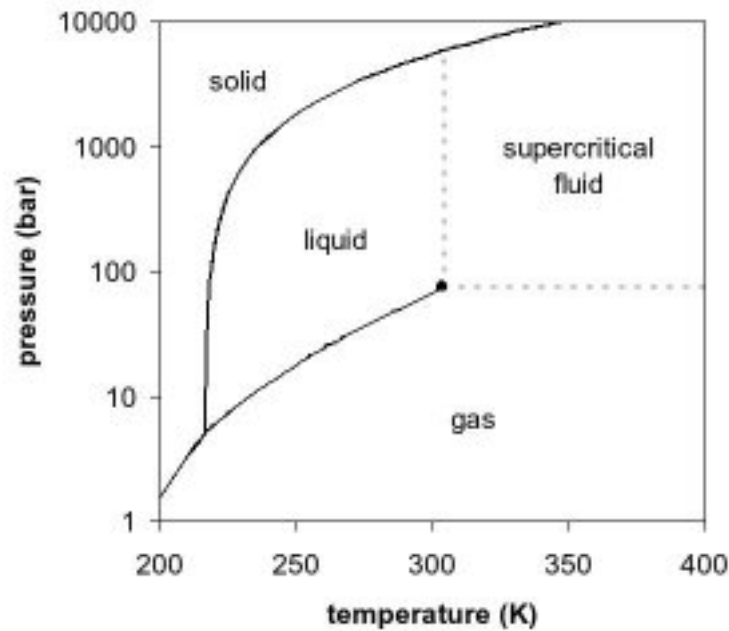


Figure 8 – Phase diagram CO₂ (New World Encyclopedia, 2012)

As earlier explained the energy required for compression of the captured CO₂ is less for the chilled ammonia capture system compared to the MEA and MDEA capture system. This is because the pressure in the stripper is higher in the chilled ammonia system. Since the CO₂ has to be pressurized from approximately 1 bar (the pressure of the flue gas) to 110 bar in total throughout the capture system the same value for compression energy has been used for all of the capture systems.

4.6 Reservoir injection energy

The energy needed to inject the energy is rarely discussed in literature; this is because it is normally outside the scope of papers discussing the energy requirements of carbon capture technologies. It is though important in this thesis as the entire life cycle of the carbon capture and storage is assessed. In Singh (2011) it was estimated that a 160kW compressor was needed to inject 2,2 Mt of CO₂ in super critical state into a 1000 meter deep reservoir. Assuming that it is operational 8000 h/year this equals to approximately 2,1 kJ/kg CO₂.

4.7 Total thermodynamic energy requirement.

The total thermodynamic energy requirements of the systems assessed are presented in Table 7. No detailed information on the total energy requirement for MDEA or NH₃ can be found in the literature. However comparing the energy requirement for MEA we can see that the value calculated in this thesis is consistent with other studies (Table 8). It is important to mention that the energy consumption caused by chilling processes are not included in this thermodynamic energy assessment.

Solvent	MEA	MDEA	NH ₃
	[kJ/kg CO ₂]	[kJ/kg CO ₂]	[kJ/kg CO ₂]
Chemical Binding Energy	1910	1140	1280
Heating of Solution	869	533	405
Heat of Vaporization	747	747	0
Parasitic Power Loss	470	470	470
Compression Energy	382	382	382
Total Energy Requirement	4377	3272	2537

Table 7 – Total thermodynamic energy requirement

Source	Solvent	Status	Regeneration energy (MJ/kg CO ₂)
(Gibbins et al., 2004)	MEA	State-of-the-art	4,00–4,25
(Feron and Asbroek, 2004)	MEA	State-of-the-art	4,2
(Rao et al., 2004)	MEA	Present value	4.3 (range: 3.2–5.9)
(Peeters et al., 2007)	MEA	Present value	4,4
This study	MEA	State-of-the-art	4,4

Table 8 – Energy requirement for MEA in literature (inspired by (Peeters et al., 2007))

As these values are calculated on the basis of one unit of CO₂, these values can therefore be used for both NG PP and PC PP. The total thermodynamic energy requirement does not directly correlate with the energy efficiency of the power plant because many of the processes are fueled by waste heat through. Also many of the processes are fueled by steam, which does not directly correspond to electricity because of efficiency loss in the steam generator.

4.8 Electric Penalty

To calculate the loss of potential electricity which could be sold to the grid (electric penalty) caused by the capture system, it is necessary to simulate the entire system or perform field tests. This is because of the large amount of variables in power production system which is too complex to calculate manually. Therefore the electric penalty is not based on the thermodynamic energy requirement calculated in the previous sub chapter. The electric penalty is based upon available literature and is directly used in the LCA of the scenarios earlier presented. The values are from (Kothandaraman, 2010).

Power sink	MEA ^A	MDEA ^B	NH ₃ ^A
	[kwh/kg CO ₂]	[kwh/kg CO ₂]	[kwh/kg CO ₂]
Reboiler steam	2,13E-01	1,27E-01	1,50E-01
Water wash desorber duty	0,00E+00	0,00E+00	1,58E-02
Refrigeration	0,00E+00	0,00E+00	2,11E-01
CO ₂ Compression	1,00E-01	1,00E-01	2,79E-02
Blower and auxiliaries	4,45E-02	4,45E-02	6,98E-02
Total	3,57E-01	2,72E-01	4,74E-01

A* - (Kothandaraman, 2010)

B* - Calculated based on regression of chemical binding energy

Table 9 – Electric Penalty

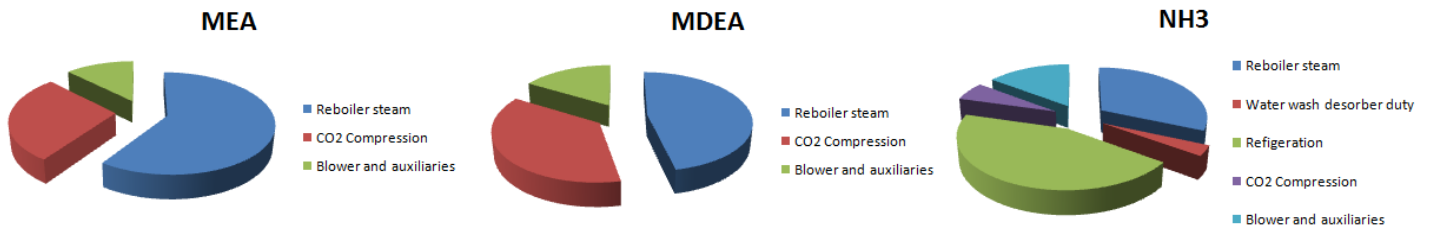


Figure 9 – Electric Penalty Pie Chart

As can be seen in Figure 9 and Table 9 the electric penalty of the chilled ammonia system is higher than the amine based systems. This is because of the large energy requirements caused by the cooling of the CO₂ lean ammonia mixture, which was not calculated in the previous sub-chapter. The electric penalty was calculated based upon a coal fired power plant; however it can be assumed that the energy requirements of a NGCC might be higher because of the lower concentration of CO₂ in the flue gas.

5 Results

5.1 LCIA

The impact potential scores were calculated for all of the 18 midpoint impact categories used in the RECIPE framework. The life cycle impact assessment results of the 10 most relevant impact categories are shown in Table 10. As expected the world average scenario has higher impact scores compared to the BAT scenario. This shows the environmental mitigation potential of an increase in energy efficiency.

Coal Power										
Impact	GWP	TAP	FEP	MEP	POFP	PMFP	HTP	TETP	FETP	METP
Unit (kg eq)	CO2	SO2	P	N	NMVOC	PM10	1,4-DB	1,4-DB	1,4-DB	1,4-DB
1A average	1,04E+00	9,58E-04	5,59E-04	7,24E-04	1,40E-03	4,07E-04	3,75E-01	9,06E-06	8,08E-03	7,82E-03
2A BAT	8,41E-01	7,74E-04	4,51E-04	5,84E-04	1,13E-03	3,29E-04	3,03E-01	7,36E-06	6,52E-03	6,31E-03
3A MEA	3,72E-01	1,04E-03	5,66E-04	7,43E-04	1,41E-03	3,99E-04	3,81E-01	1,44E-05	8,39E-03	8,02E-03
4A MDEA	3,23E-01	9,95E-04	5,39E-04	7,10E-04	1,35E-03	3,81E-04	3,63E-01	1,34E-05	8,01E-03	7,65E-03
5A NH3	4,39E-01	2,47E-03	6,01E-04	8,42E-04	1,50E-03	6,03E-04	4,04E-01	1,44E-05	8,91E-03	8,51E-03

Natural gas										
Impact	GWP	TAP	FEP	MEP	POFP	PMFP	HTP	TETP	FETP	METP
Unit (kg eq)	CO2	SO2	P	N	NMVOC	PM10	1,4-DB	1,4-DB	1,4-DB	1,4-DB
1B average	5,81E-01	5,44E-04	5,59E-04	8,28E-05	8,19E-04	1,91E-04	3,70E-03	9,51E-06	7,53E-05	2,11E-04
2B BAT	4,20E-01	3,94E-04	4,51E-04	5,99E-05	5,92E-04	1,39E-04	2,81E-03	6,89E-06	5,59E-05	1,55E-04
3B MEA	1,63E-01	4,78E-04	5,66E-04	7,52E-05	6,67E-04	1,66E-04	5,58E-03	1,05E-05	2,13E-04	2,91E-04
4B MDEA	1,52E-01	4,69E-04	5,39E-04	7,41E-05	6,52E-04	1,63E-04	5,60E-03	1,00E-05	2,13E-04	2,88E-04
5B NH3	1,77E-01	1,11E-03	6,01E-04	1,01E-04	6,86E-04	2,52E-04	5,44E-03	1,05E-05	2,11E-04	2,92E-04

Table 10 – LCIA results

In Figure 10 the global warming potential of the different scenarios are shown. The MDEA capture system has the lowest global warming potential, and this can be explained with the fact that it has the lowest energy usage. The chilled ammonia capture process has the highest global warming potential when comparing the three capture technologies. It is also the technology that has the highest indirect emissions. In fact over 50% of the global warming potential is indirect in the natural gas power plant with chilled ammonia capture.

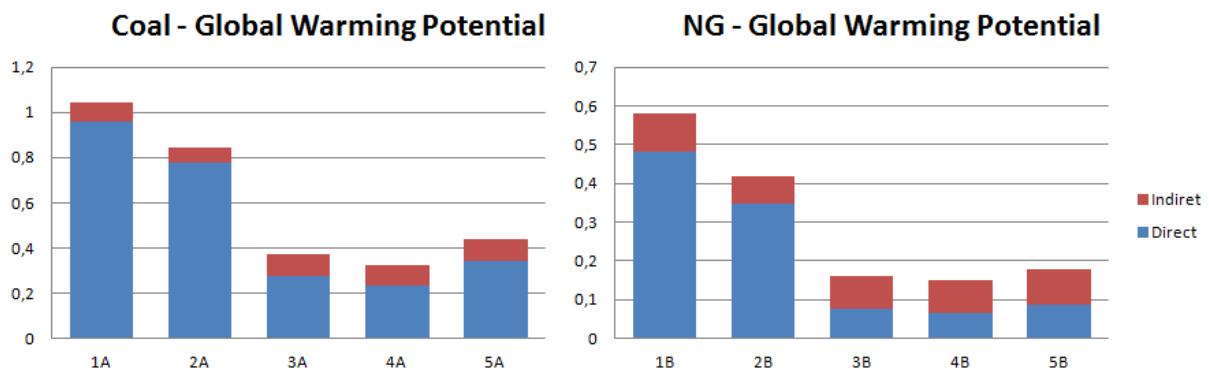


Figure 10 – Global warming potential

By breaking down the direct GHG emissions (Figure 11), it becomes clear that the direct emissions along with the emissions connected to the production of the fuel are the main sources of emissions. The infrastructure of the capture unit including pipelines and wells has a very little impact and accounts only for 1% increase in GHG emissions. Comparing the absolute value of the global warming potential between the coal power plant and the natural gas power plant it is worth noticing that the total GHG emissions of scenarios 3A-5A is approximately equal to the NG BAT (2B) scenario.

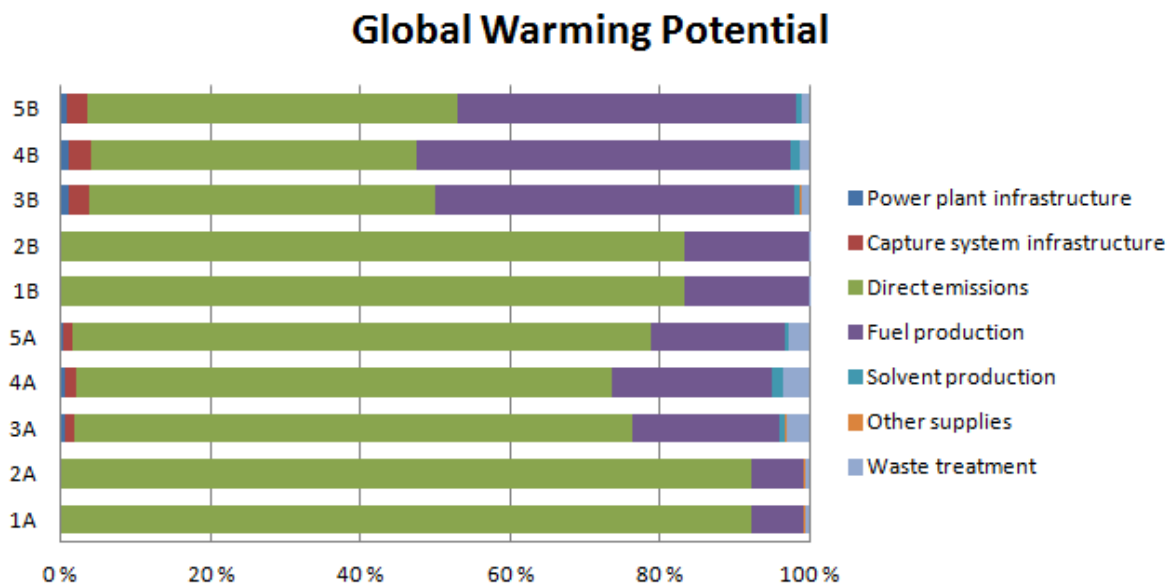


Figure 11 - GWP Breakdown

In Figure 12 the acidification potential of the technologies assessed is shown. The co-capture of NO_x and SO₂ has little effect on the total acidification potential, and the total acidification potential is higher for all CCS scenarios compared to the BAT scenario.

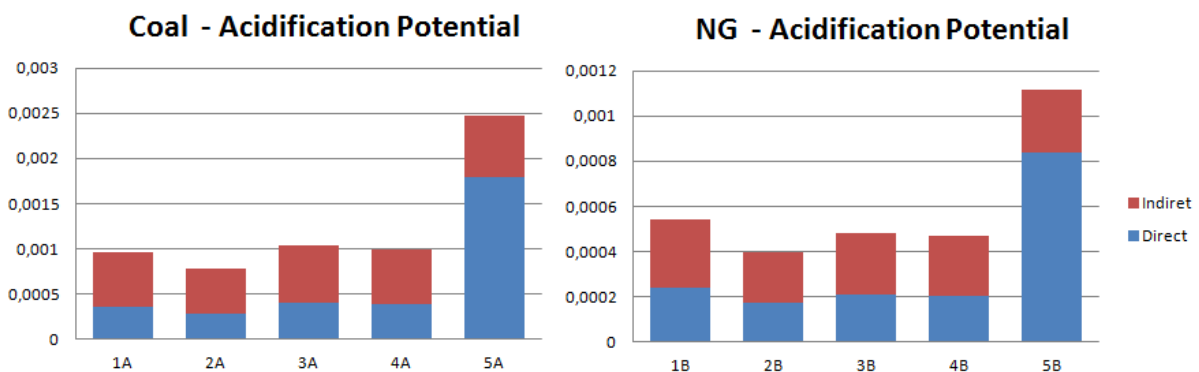


Figure 12 - Acidification Potential

The impact results for human toxicity potential are shown in Figure 13. For both natural gas and coal the indirect emissions has the biggest impact. There are small differences in the impacts caused by the release of the solvent with the flue gas, though these are negligible in the big picture. The main difference in the human toxicity potential can be explained by the decreased efficiency of the power plant and therefore the production of fuel.

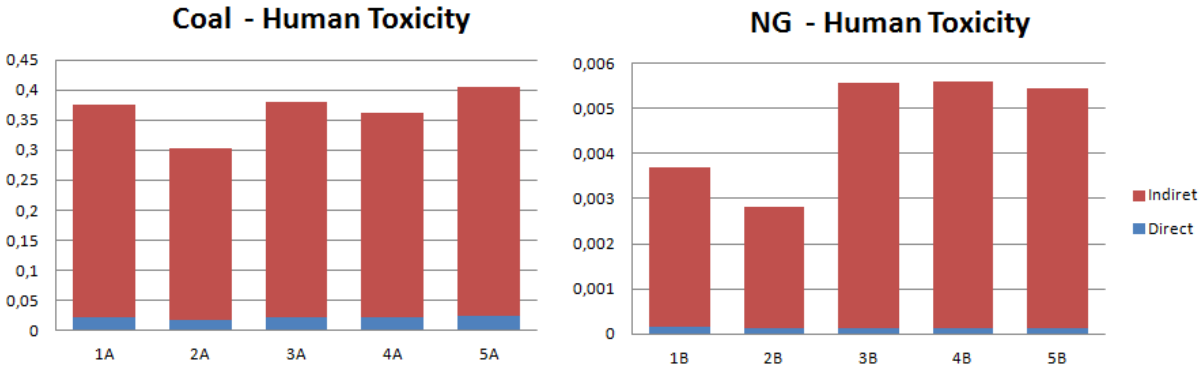


Figure 13 - Human Toxicity

In Figure 14 the ecotoxicity of the scenarios are shown. In general the scenarios with CCS systems installed have a higher impact, and excluding the terrestrial ecotoxicity of coal, they are all dominated by the indirect impacts. As observed in Figure 13, the increased fuel consumption along with the production of solvents used in the capture affects the results. In the terrestrial ecotoxicity of coal the direct emissions have a higher impact. This is because of the formaldehyde and mercury emissions from the coal power plant (see Table 11 in the appendix), which also increase with a decreasing efficiency.

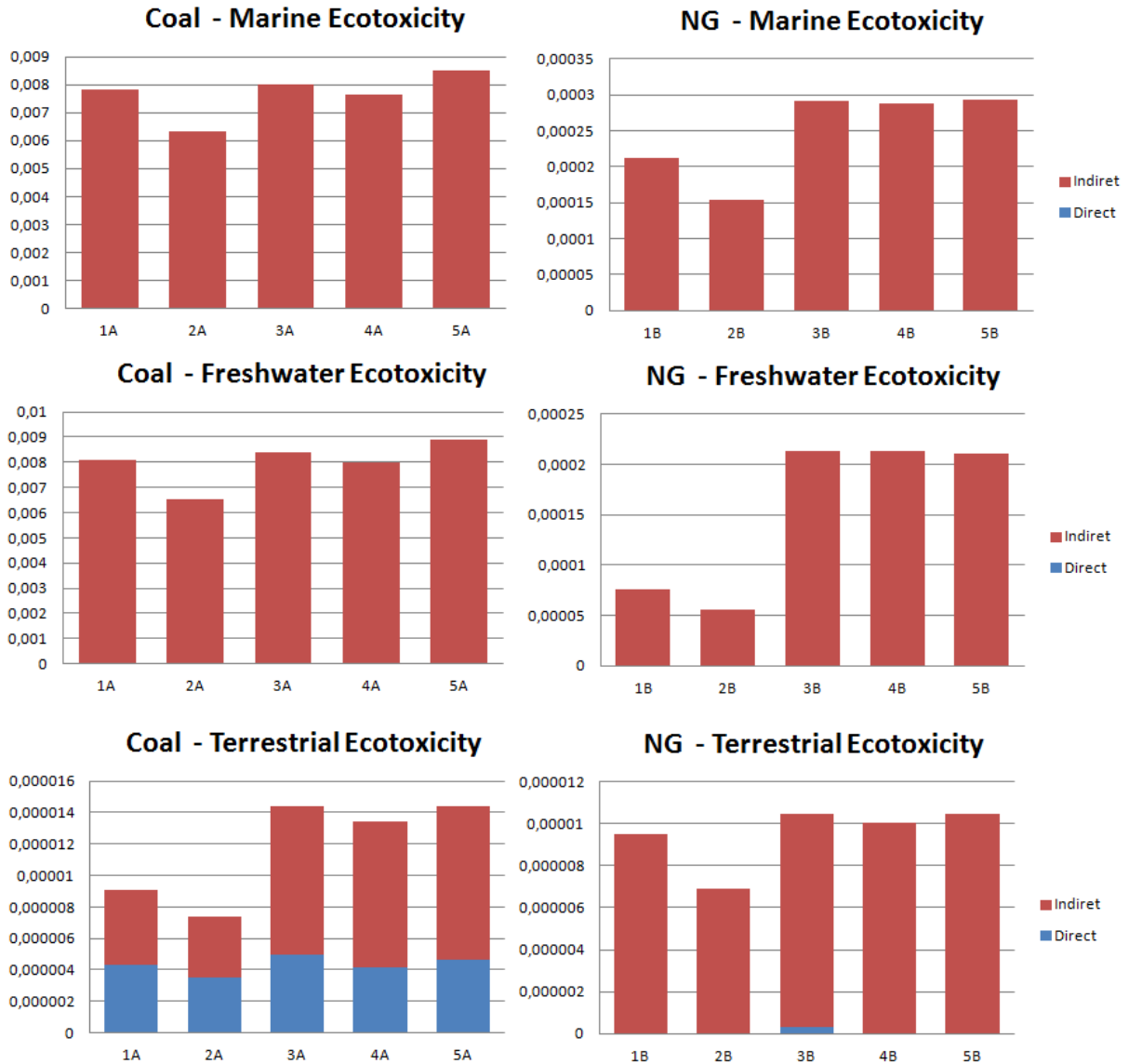


Figure 14 – Ecotoxicity

The eutrophication potential of the scenarios is heavily controlled by the indirect impacts (Figure 15). And the same pattern that was seen in the ecotoxicity potential is recognized in the graphs; the efficiency of the plant is the main reason for the differences between the scenarios. Though for the marine eutrophication it is possible to see the effects of the release of ammonia especially caused by the chilled ammonia process.

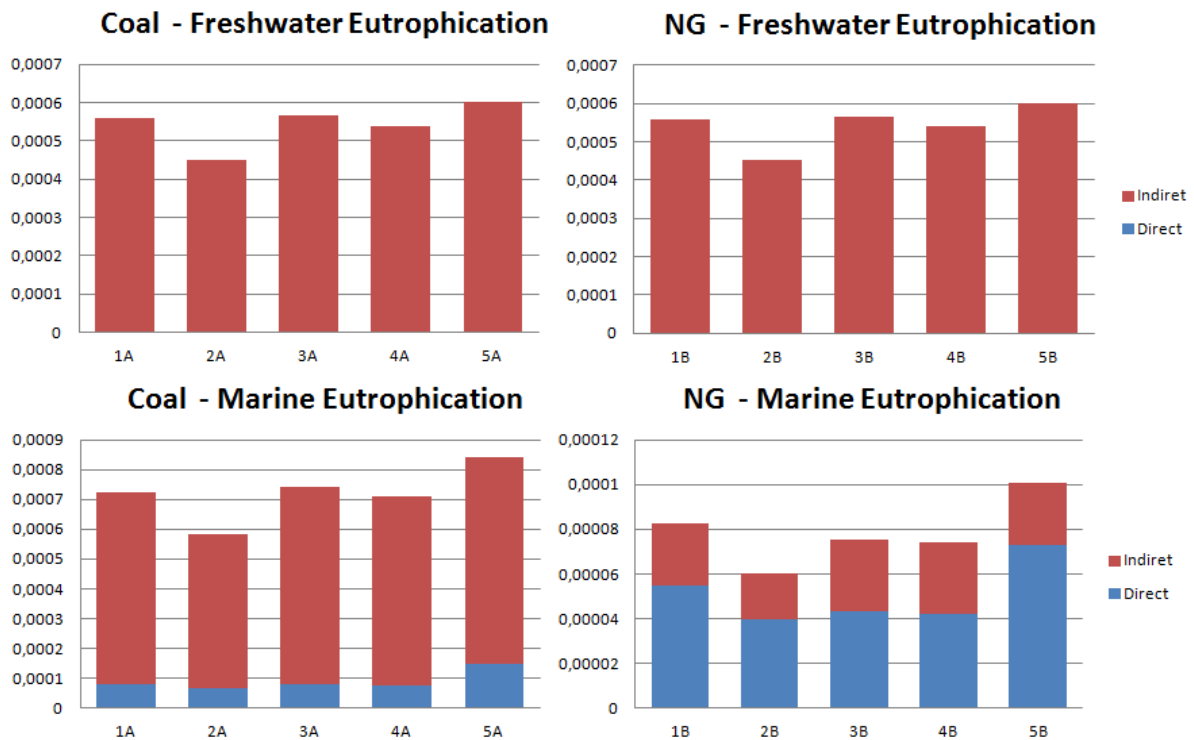


Figure 15 – Eutrophication

One of the issues with LCA is that it can be difficult to interpret the values because the units are difficult to comprehend. It is however possible to normalize the results, and create an absolute value on which the impact categories can be evaluated. In Figure 16 the results are normalized to the average European citizens' impact. It is important to remember that normalization is only a tool to assess the comparative value between the different impact categories. The coal power plants have, as expected, higher values than the natural gas power plants, and especially the eutrophication and ecotoxicity potential are dominating the coal power plant. The ionizing radiation potential is the biggest contributor to the normalized impacts of natural gas. The ionizing radiation is naturally present in fuel deposition and released during extraction. Comparing the absolute values of the normalized scenarios, it is evident that the chilled ammonia capture system has the highest impact.

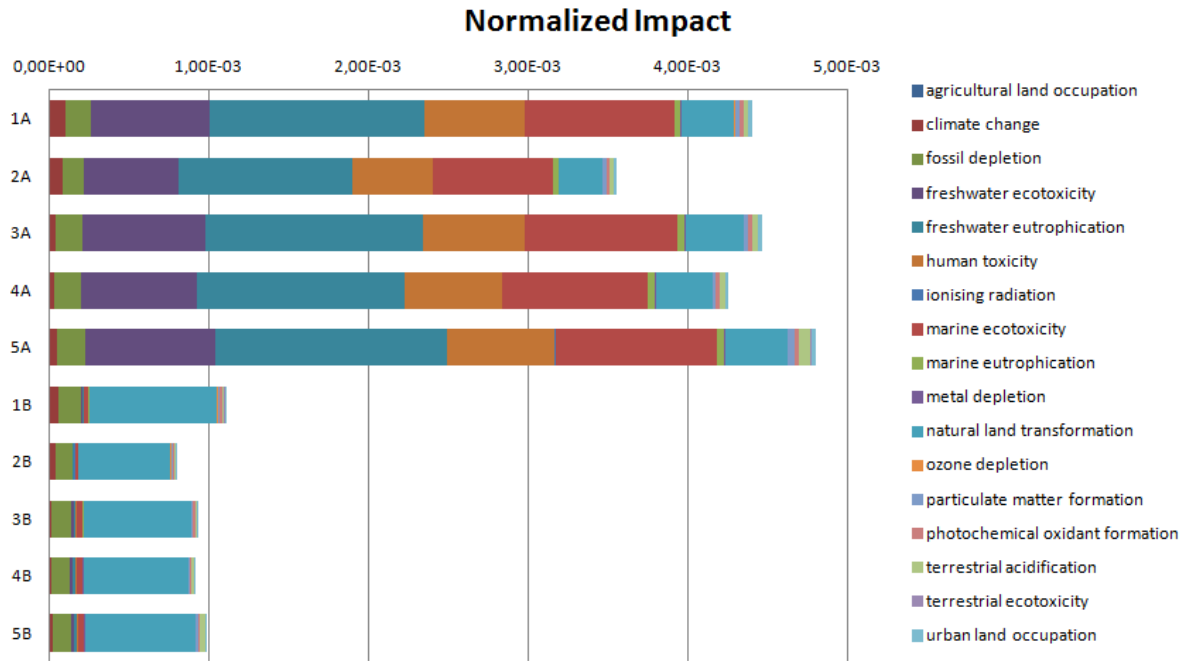


Figure 16 - Normalized Impacts

6 Discussion & Conclusion

6.1 Goal Completion

In this report a literature study has been completed to identify the technical data that is needed to establish the LCI. The technologies are still under development and there are issues with data availability. This is especially true for the more novel capture technologies, MDEA and chilled ammonia.

A full process LCA was completed for a total of 10 scenarios, assessing 3 different post-combustion absorption based capture methods for both supercritical natural gas and coal power plants.

Because of the few sources of data available, a sensitivity analysis has not been completed. Since a large part of the LCI depend only one specific source and not a range of data, it would not be possible to develop high quality sensitivity analysis.

A detailed analysis of the energy requirements was calculated, but further detailed simulations where necessary if the analysis where to be used directly in the LCA.

6.2 Quality assessment

It is important to assess the quality of the assessments done in this report to be able to define the validity of the results. Internal validity and external validity has therefore been assessed.

6.2.1 Internal Validity

The largest area of uncertainty within this report is the data availability. The assessment is only as good as its data. The technologies assessed was to some degree simplified, e.g. the use of ecoinvent processes to

One of the factors that have a large uncertainty is the energy consumption data. The MEA and chilled ammonia systems total energy consumption was based on a single simulation, while the MDEA energy requirement was based on a linear regression. This is definitely the largest uncertainty within the assessment, because it directly affects the efficiency of the power plant.

There are also scaling issues with the data used. Many of the values used in the calculations are either based on simulations or small scale tests. It is not necessarily a linear relationship when scaling up and therefore there is some uncertainty connected to this.

There are also uncertainties connected to the use of the ecoinvent database. This is however a smaller issue since all LCAs conducted on the basis of this database will have the same systematic errors, and therefore only the absolute numbers within this assessment might be wrong while the percentage in difference will remain constant.

There is also an issue with data availability within ecoinvent. For example MDEA does not exist within ecoinvent and a proxy had to be used. The MDEA scenarios have also generally a bigger uncertainty than the other scenarios, because of large data unavailability and therefore had to be based on the MEA scenario with modification mainly based on assumptions.

6.2.2 External Validity

The scenarios used in this assessment were made as generic as possible, and therefore the assessment could be used as a representation of the environmental impacts caused by the technologies assessed. However, since no other LCA of MDEA and chilled ammonia was identified through the literature study it is not possible to compare the life cycle impact results with existing results in literature. It is therefore difficult to assess the external validity of the results.

6.3 Implications

The results showed that there are possible advantages in changing solvents from MEA to solvents with lower regeneration requirement, such as MDEA. Chilled ammonia had consistently the highest impacts of the capture technologies, and this is mainly caused by the large energy requirement of the refrigeration of the flue gas which leads to a lower efficiency. The importance of reducing the energy penalty of the capture technologies was shown, and also the importance of end of pipe removal of solvents was highlighted.

6.4 Future research

LCA was shown to be a useful method when analyzing the impacts caused by power generating technologies with CO₂ capture. As earlier mentioned there was an issue with data availability especially with the novel capture methods, MDEA and chilled ammonia. To decrease the uncertainty and increase the internal validity within the assessment it would be interesting to perform an LCA in collaboration with industry partners with access to data from pilot studies.

To increase the external validity of the assessment it is necessary to develop several new LCA studies on novel post-combustion solvents. This could then be used as a reference to the assessment conducted in this thesis.

There are also many other post-combustion and pre-combustion CCS technologies that have not been evaluated with LCA.

6.5 Conclusion

The results showed the positive effects that CCS has on mitigation of global warming. The ecotoxicity, human toxicity, eutrophication and acidification potential all increased in the scenarios with CCS. This is partly because of the efficiency decrease caused by the energy consumption of the CCS technologies, but also because of the altered emission profile. Especially the chilled ammonia system had large effects on the non GHG related impact

categories. The release of ammonia (nitrogen) had a large impact on the acidification and marine eutrophication potential.

Chilled ammonia was found to be the technology with generally the highest impacts. This is mainly because it is the technology with the highest energy requirement, caused by the chilling process. It has also large impacts caused by slip of ammonia from the absorber into the clean flue gas stream. This has a large effect on the acidification potential and the marine eutrophication potential.

MEA was shown to be the second best technology. The technology is the industry standard but has a high chemical binding energy, making the process of separating the CO₂ and the MEA in the stripper very energy intensive. This is again reflected in the LCIA where the decreased energy efficiency leads to an increase in fuel consumption and therefore higher impacts.

MDEA was shown to be the technology with the lowest environmental impacts. This is because of its low energy requirement compared to the other two technologies assessed. However there is a large uncertainty connected with the numbers used to setup the LCI. This is because of a lack of data in the literature, and large amount of the data used for the MDEA system was based on MEA data.

To conclude, this thesis shows that CCS has a large potential to mitigate the global warming potential of fossil fueled power plants. However there are tradeoffs caused by an increase in generally every non-GHG related impact category caused by an increase in fuel consumption.

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Appendix

Emission Profile

Pollutant	Emissions	Unit
CO2	9,22E+01	g/MJ
CH4	1,00E+00	mg/MJ
N2O	3,97E+00	mg/MJ
SO2	6,56E+01	mg/MJ
NOx	6,21E+01	mg/MJ
CO	8,00E+00	mg/MJ
PM< 2,5	4,73E+00	mg/MJ
PM> 10	5,28E+00	mg/MJ
PM2,5-10	5,56E-01	mg/MJ
Formaldehyde	5,80E-05	g/MJ
Mercury(Hg)	4,10E+00	ug/MJ

Table 11 - Coal emissions per MJ combusted

Pollutant	Emissions	Unit
CO2	5,60E+01	g/MJ
CH4	1,00E+00	mg/MJ
N2O	1,00E+00	mg/MJ
SO2	5,00E-01	mg/MJ
NOx	5,00E+01	mg/MJ
CO	1,00E+01	mg/MJ
PM< 2,5	5,00E-01	mg/MJ
Formaldehyde	3,31E-05	mg/MJ
Acetaldehyde	8,00E-07	g/MJ
Mercury(Hg)	3,00E-02	ug/MJ

Table 12 - NG emissions per MJ combusted

Changes in emission profile

Substance	Unit	3A	3B	4A	4B	5A	5B
		Coal + MEA	NG + MEA	Coal + MDEA	NG + MDEA	Coal + CAP	NG +CAP
CO ₂	g / kg CO2	-1,00E+00	-1,00E+00	-1,00E+00	-1,00E+00	-1,00E+00	-1,00E+00
NH ₃	g / kg CO2	3,49E-02	3,49E-02	3,49E-02	3,49E-02	8,50E-01	8,50E-01
MDEA	g/ kg CO2	0,00E+00	0,00E+00	6,27E-02	6,27E-02	0,00E+00	0,00E+00
MEA	g / kg CO2	6,27E-02	6,27E-02	0,00E+00	0,00E+00	0,00E+00	0,00E+00
Formaldehyde	g / kg CO2	2,62E-04	2,62E-04	2,62E-04	2,62E-04	0,00E+00	0,00E+00
Acetaldehyde	g / kg CO2	1,67E-04	1,67E-04	1,67E-04	1,67E-04	0,00E+00	0,00E+00
SO ₂	mg / kwh	-6,85E+02	-3,61E+00	-6,85E+02	-3,61E+00	-6,85E+02	-3,61E+00
NO _x	mg / kwh	-3,29E+01	-1,77E+01	-3,29E+01	-1,77E+01	-3,29E+01	-1,77E+01
PM < 2,5	mg / kwh	-2,57E+01	-1,81E+00	-2,57E+01	-1,81E+00	-2,57E+01	-1,81E+00
PM > 10	mg / kwh	-2,87E+01	0,00E+00	-2,87E+01	0,00E+00	-2,87E+01	0,00E+00
PM 2,5-10	mg / kwh	-3,02E+00	0,00E+00	-3,02E+00	0,00E+00	-3,02E+00	0,00E+00

Table 13 – Changes in emission profile