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# The impacts of $CO_2$ capture technologies on transboundary air pollution in the Netherlands

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# Preface

This study has been performed for the Netherlands Environmental Assessment Agency / Milieu- en Natuurplanbureau (contact: Pieter Hammingh) within the framework of Beleidsgericht Onderzoeksprogramma Lucht en Klimaat (BOLK) 2008-2009 for the Dutch Ministry of Housing, Spatial Planning and Environment (VROM, contact Jan Wijmenga). The report concerns the results of a first inventory phase of one of four projects conducted in this framework on the impact on transboundary air pollution emissions from the climate options biomass and $CO_2$ capture.

# Executive summary

*Introduction*

The objective of the inventory phase 1 of the project is two-fold:

- To assess the impacts of different $CO_2$ capture technologies on emissions of transboundary air pollutants in the Netherlands in 2020. Other possible environmental impacts such as toxic emissions and safety are considered qualitatively.
- To provide recommendations for further research in the in-depth phase 2 in order to address the current knowledge gaps found in this area.

*Methodology*

The research is conducted in three steps:

1. Inventory: In-depth literature survey and consultation round of (inter)national experts;
2. Evaluation: Characterisation for a broad set of aspects (technical description, application area, development stage, economic, energy and environmental performance, uncertainty and knowledge gaps), comparison and assessment of carbon capture technologies, including a general life cycle analysis of transboundary air pollution;
3. Impact analysis: For a selection of carbon capture technologies, a number of what-if scenarios has been analysed.

*Evaluation of $CO_2$ capture technologies*

Three types of $CO_2$ capture technologies have been investigated, viz. post combustion, pre combustion and oxyfuel. All three $CO_2$ capture technologies are likely ready to be demonstrated before 2020.

The $CO_2$ capture technologies can be shortly characterised as follows:

| Main characteristic | Capture technology and application |
|---|---|
| Short-term & relatively cheap | Post combustion Amine PC (Pulvurized Coal) |
| Short-term & relatively clean | Post combustion Amine NGCC (Natural Gas Combined Cycle) |
| Mid-term & relatively clean coal | Pre combustion IGCC (Integrated Gasification Combined Cycle) |
| Long-term & clean | Oxyfuel Gas Cycle |
| Long-term & cheapest | Chilled ammonia PC |

**Retrofitting existing** power plants with $CO_2$ capture seems to favour the post-combustion $CO_2$ capture technology which requires no modification of the combustion process. Retrofitting existing coal fired power plants with oxyfuel combustion is according to some sources also possible but requires combustion modifications. Retrofitting Integrated Gasification Combined Cycle with pre combustion $CO_2$ capture brings forwards numerous issues but is possible.

Two **cost-effective scenarios for $CO_2$ mitigation** from van den Broek (UU) indicate that $CO_2$ emission reduction potentials for **power generation** are in the order of 50 Mt $CO_2$ in 2020 at $CO_2$ avoidance costs of 30 to 50 € / tonne $CO_2$ avoided. Technologies

which are cost-effective relative to a coal based baseline scenario are post combustion capture using amines on existing pulverized coal plants (retrofit) and pre combustion on new coal fired Integrated Gasification Combined Cycle.
$SO_2$ and $NO_x$ emissions from power generation are relevant for the national emission ceiling having a contribution of about 20% to 25% of the national total in 2020. Other emissions of transboundary air pollution from the power sector have a relatively small contribution.

In **industry**, the costs per tonne $CO_2$ captured are relatively low (up to 25 € per tonne $CO_2$) for the processes which concern a relatively high $CO_2$ concentration and require no additional heat. It concerns the ammonia, hydrogen and ethylene oxide production, gas processing and iron and steel. The capture potential of these sources attractive for $CO_2$ capture amounts presently to 6 Mt $CO_2$ per year.
The costs of applying a technology in an industrial process highly depends on the situation, e.g. can it be fitted in taking into account the availability and security of the plant and its production, the standards and legislation required etc.
Large industrial sources suited for $CO_2$ carbon capture can potentially influence national $SO_2$ emission (currently in the order of 30%) and PM emissions (20%). Of the other transboundary air pollutants, less than 10% of the Dutch national totals is caused by large industrial processes. Hence, no major impacts are expected for these other pollutants.

*Impacts of $CO_2$ capture on national air pollution emissions*
NEC (National Emission Ceilings directive) emissions ($SO_2$, $NO_X$, $NH_3$, NMVOC, $PM_{10}$ and $PM_{2.5}$) have been estimated by applying simple $CO_2$ capture correction factors on the IIASA's NEC emission factors. These correction factors were calculated by the emission ratio of plants without and with $CO_2$ capture from the literature inventory. These factors do not take into account country specific situations with respect to plants and fuel quality.

For the power sector, **$SO_2$** emissions are very low for scenarios that include large scale Carbon Capture and Storage (CCS) implementation in 2020, viz. in the order of 1 ktonne $SO_2$ instead of 12 ktonne according to the NEC5 scenario (which includes also small scale power and heat generation). This scenario is used in the process of negotiating the National Emission Ceilings for the Netherlands with the European Commission.

In all capture scenarios, **$NO_x$** emissions are a factor 2 to 4 lower than in the NEC5 scenario due to lower contributions of small scale power and heat production. Large scale implementation of the post combustion technology on existing coal fired plants in 2020 may result in (slightly) higher $NO_x$ emissions compared to the implementation of the other $CO_2$ capture technologies or no capture.

Large scale implementation of the post combustion technology in 2020 may result in more than 5 times higher **$NH_3$** emissions compared to scenarios without CCS and with other $CO_2$ capture options, if the issue of $NH_3$ emission control is not addressed. In that case, $NH_3$ from power generation is a significant source of a few percent to the national total.

**Particulate Matter** emissions are equal or higher than in the NEC5 scenario. In the latter case, retrofitting pulverized coal plants with post combustion capture results in higher PM emissions than from pre combustion on IGCC. The scenario with large scale implementation of the oxyfuel technology shows the lowest emissions of particulate matter.

**NMVOC** emissions from capture technologies are less well known than emissions from other pollutants. From the NEC scenario appears that more than half of the emissions from the power sector stem from biomass use. So, the combination of carbon capture and biomass has to be researched also for NMVOC emissions (though emission contribution to the national total is in the order of 5%).

*Other impacts*
The effect of **biomass (co-)firing** in power plants with pre or post combustion $CO_2$ capture is not well researched, although it seems likely that both $SO_2$ and $NO_x$ emissions will be lower, since the sulphur content and the flame temperature will be lower for biomass than for coal. For other emissions is it not possible to make an educated guess.

The **indirect emissions** exceed the direct emissions in most cases for all NEC substances. The major part of these indirect emissions is caused by mining, preparation and transport of coal. In general $CO_2$ capture is likely to increase emissions of transboundary air pollutants over the lifecycle due to increased fuel consumption in the order of 15% to 25% depending on the capture technology type. The geographical **location of emissions** due to fuel preparation is outside the Netherlands and therefore do not influence the Dutch national emission ceilings and standards.

**Other impacts** of $CO_2$ capture are the safety of $CO_2$ transport and storage and toxic wastes of chemical solvents that will be produced in large quantities. These are not studied in detail in this project.

*Recommendations for further research*
Four research activities are recommended to address the knowledge gaps which were revealed in the present analysis:

1) **Improve inventory** on transboundary air pollutants from $CO_2$ capture technologies:
    a) standardise and harmonise the data on energy, economic and environmental performances
    b) measurements of emission factors of transboundary air pollutants, particularly $SO_2$, $NO_x$, PM, $NH_3$, NMVOC and (other) degradation products of amines, preferably on existing coal and gas fired power plants
2) **Improve application** for Dutch situation:
    a) gather detailed information on the implementation of $CO_2$ capture taking into account the specific situation of the Dutch power generation park
    b) detailed analysis of CCS implementation in industrial processes and impact on costs and potentials
    c) role of European and Dutch legislation (emission standards and air quality regulation) and impact on costs
3) **Extend scope** and add aspects:
    a) analyse a variety of solvents
    b) lifecycle analysis: improve the energy supply chain
    c) other environmental aspects such as waste and emissions to water
    d) biomass: assess the impacts on NEC emissions
    e) extend the time horizon to 2030 and 2050

4) **Improve scenarios** for the Netherlands:
   a) refine correction factors used to calculate the impact of CCS in NEC emissions
   b) policy analysis of both greenhouse gases and transboundary air pollution for 2020 (ECN / MNP)
   c) cost-effectiveness analysis of both greenhouse gases and transboundary air pollution for the long term using the energy model MARKAL (UU)

# Contents

# 1 Introduction

## 1.1 Background

Recently, the 13th United Nations climate change conference adopted the Bali roadmap, an agenda to start global negotiations for increasingly stringent post-Kyoto mitigation measures. This means that the energy supply and demand of countries have to change significantly in order to meet the greenhouse gas emissions goals for the year 2020 that will be set in 2009.

One of the mid- and long-term mitigation options to combat climate change is carbon capture and storage (CCS). It comprehends capturing of $CO_2$ from flue gases and storing it instead of releasing it into the atmosphere. Storage of the $CO_2$ is envisaged either in deep geological formations, in the deep ocean, or in the form of mineral carbonates.

Technology for large scale capture of $CO_2$ is to some extent already commercially available (e.g. for some industrial processes) and fairly well developed. However, up to now no large scale power plant operates with a full carbon capture and storage system. Moreover, although $CO_2$ has been injected into geological formations for various purposes (e.g. enhanced oil recovery), the long term storage of $CO_2$ remains a relatively untried concept. Therefore, the environmental impacts of CCS are not too well known yet and could be significant.

This is particularly important in the framework of the National Emissions Ceilings Directive (NEC; 2001/81/EC) and the Gothenburg Protocol of the United Nations Economic Commission for Europe which set national ceilings for the emissions of $SO_2$, $NO_x$, VOCs and $NH_3$. Both the NEC-Directive and the Gothenburg Protocol are currently under revision, setting national emission targets for the year 2020. These targets are being negotiated on the basis of scenarios in which the energy supply and demand is a starting point for the discussion on the abatement options and emission reduction targets of a country.

In this context, the inclusion in a scenario of greenhouse gas mitigation plans in general and of CCS in particular could have large impacts on transboundary air pollution by a change in (fossil) fuel supply and demand but also by the emissions from CCS itself. Therefore, the Dutch Ministry of Housing, Spatial Planning and the Environment (VROM) requires more information on the synergy and/or contradictory effects of CCS for greenhouse gas and transboundary air pollution policies.

## 1.2 Objective

The objective of the inventory phase 1 of the project is two-fold:
- To assess the impacts of different $CO_2$ capture technologies on transboundary air pollution in the Netherlands in 2020. Other possible environmental impacts such as toxic emissions and safety are considered qualitatively.
- To provide recommendations for further research in the in-depth phase 2 in order to address the current knowledge gaps found in this area.

The inventory summarises all (public) available information that is relevant for transboundary air pollution and presents it in understandable terms for environmental experts and policymakers who are not CCS experts.

The project surveys the present scientific literature and interviews key players in the carbon capture community in the Netherlands to present the current insights and state of capture technology, particularly with respect to transboundary air pollution. This has been done taking into account the angles of both research and policy needs. The information gathered is combined with scenario information for the year 2020 on carbon capture technology and transboundary air pollution in order to sketch ranges of possible impacts of carbon capture technologies in the Netherlands in this year.

## 1.3 Reading instruction

The structure of this report is as follows.
Chapter 2 Approach explains the methodology and the research process taken in the project.
Chapter 3 Capture technology description introduces the different capture technologies in the form a structured description.
Chapter 4 Results describes the results of the assessment of capture technologies in terms of a comparative analysis and a what-if emission scenario analysis for the Netherlands.
Chapter 5 Conclusions and recommendations closes the report with conclusions and recommendations for further research.

# 2 Approach

## 2.1 Overall methodology

The present inventory aims to summarise and evaluate all available information on capture technologies that is relevant for transboundary air pollution. In addition to this, the impacts of the application of $CO_2$ capture on the national emission ceilings of transboundary air pollution are assessed for the Netherlands in 2020. Figure 2.1 plots the main steps followed in this project.

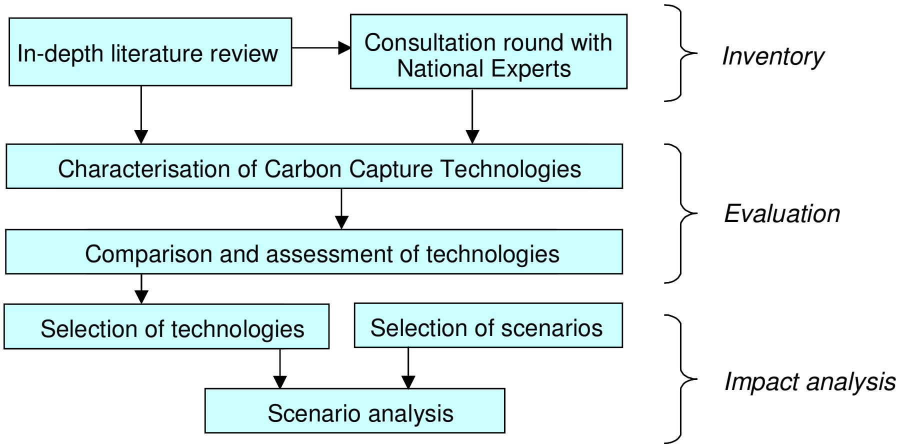

Figure 2.1 Method followed in this project

Although the project looks at the CCS chain (i.e. the capture of $CO_2$ from flue gases, its transport and storage) the focus remains on $CO_2$ capture technologies. A detailed explanation of the reasoning behind this choice is presented in Chapter 3.4. Finally, this research focuses mainly on transboundary air pollution and national emission ceilings, hence, other environmental issues including indirect emissions (from the up- or downstream parts of the life cycle) are not included in the scenario analysis. These issues are, however, discussed in a separate section.

## 2.2 Literature review and interviews

In the last decade, large international and national research efforts have been made on the development of carbon capture and storage (CCS) technologies. Typical examples of research programs are Coal21(Australia), CO2CRC (Australia), the Clean Power Coalition (Canada), the Energy Carbon sequestration program (US-DoE), FutureGen (US), COORETEC (Germany), CLIMIT (Norway), the Cleaner Fossil Fuels Programme (UK), he Clean Power Coalition (Canada) and. the Energy Carbon Sequestration Program (US-DoE). In the Netherlands, large research programmes on CCS have been launched, viz. Cato and Captech[1].

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[1] For information on this programmes see: http://www.co2-cato.nl and http://www.co2-captech.nl

The first step in the project is to gather existing information on $CO_2$ capture technologies and NEC emission factors. This is done by reviewing international literature and interviewing national CCS experts. Because of the large quantity of information available, a structured approach using explicitly defined criteria is applied to collect, aggregate and present the information. This helps also to (partially) deal[2] with the problem of differences in the methodologies used, scales considered, assumptions made on technical performance and economic factors present in the studied literature studied. This is explained in more detail in the next section.

The national experts who were interviewed have an understanding of the Dutch context and application of CCS in the Netherlands and are active players of the international CCS community. The expert panel consisted of:
- Kay Damen (NUON, expert on pre combustion and system analysis)
- Paul Feron (CSIRO Energy Technology, lead expert on CCS)
- Peter Geerdink (TNO, expert on oxyfuel combustion, chemical looping combustion)
- Frank Geuzebroek (SHELL, expert on pre and post combustion)
- Jan Hopman (TNO, expert on post combustion)
- Daan Jansen (ECN, expert on pre combustion)
- Geert Versteeg (Procedé, expert on post combustion)

The interviewees provided comments on critical parts of the results (particularly the summary table). Furthermore, their input has been used to give certain issues a deeper perspective and to check information gathered from the literature.

## 2.3 Characterisation and evaluation of technologies

### *2.3.1 Identification of subjects*

The current CCS inventory phase of the project has the final objective of informing environmental experts and policymakers who are not CCS experts. Because of the large quantity of information available, a structured approach has been used to collect, aggregate and present the information. In other words, in this report each capture technology is characterised according to a fixed format. This approach enables drawing conclusions and presenting results in an understandable and transparent way. The latter is an important aspect since the results of the study are conceived as the starting point for discussion and further research rather than a final presentation of the environmental impacts of CCS.

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[2] It is not within the scope of this study to standardise the assumptions and data used in the different studies. The differences in assumptions, however, have been taken into account when assessing the technologies and analysing the results.

$CO_2$ capture technologies are characterised by the following aspects:

- Technical description: describes main aspects of the technology and its theoretical potential;
- Application area: identifies whether the technology will be applied for coal or gas fired plants in electricity generation, industry or others;
- Development stage: technological development and time horizon for implementation;
- Economic performance: energy efficiency and cost-effectiveness of the technology;
- Environmental performance: inventory of the main aspects in terms of emissions of greenhouse gases and transboundary air pollution;
- Uncertainties (including knowledge gaps).

The characterisation of capture technologies covers a broad range of subjects (e.g. efficiency, fuel use, energy penalty, costs in terms of kWh and $CO_2$ avoided). For the purpose of this project, it is not necessary to have an in-depth understanding of all aspects. Nevertheless, it is important to have a broad overview of all aspects in order to recognise the combination of advantages and disadvantages of each technology. Hence, presenting only environmental information would give a very incomplete and hardly useful result.

For each subject, a series of explicit and mostly quantitative criteria have been chosen to evaluate and compare different types of capture technologies. These criteria have been assessed carefully since data in the literature are often inconsistent. The data is inconsistent with respect, for instance, to year of analysis (insights and cost data), time horizon (foreseen development) and reference technology (technology and fuel characteristics without CCS). Using explicit criteria enlightens this inconsistency and to some extent enables correction. Inflation correction to the year 2007 has been applied to all cost data. Furthermore, all energy data in the review refer to lower heating values, unless stated otherwise.

Table 2.1 presents the assessment criteria for each identified aspect. The first aspect technology application refers to the type of combustion plant a $CO_2$ capture facility is applied on. The development phase is indicated by different research and development stages related to scale and time to market (see also Appendix A).

Under the heading Application three criteria indicate technology related issues which are relevant to implementation in practice. First, can the technology be applied on an existing installation (and used to retrofit the plant)? Is the total technology (conversion and $CO_2$ capture) regarded as a robust technology which will have sufficient availability (operation hours)? Finally, can the technology be applied in the process industry? It is assumed that by default $CO_2$ capture technologies can be applied on power plants.

The economic performance is indicated by energy performance in the form of the overall electrical efficiency of power generation and the efficiency penalty in percentage points by the capture installation itself. The economic performance is indicated for the overall process by the electricity generation costs and for the capture process by the $CO_2$ avoidance costs.

The environmental performance is assessed by $CO_2$ and transboundary air pollution emissions per kWh net generated electricity. In addition, other environmental aspects such as safety and waste can be indicated in the last category, ‘Other impacts’.

Table 2.1 Criteria used to assess each identified aspect of each $CO_2$ capture technology

| Aspect | Criterion |
|---|---|
| Technology application | Pulverised Coal (PC) / Integrated Gasification Combined Cycle (IGCC) / Natural Gas Combined Cycle (NGCC) / Gas Cycle (GC) |
| Development phase | laboratory scale / pilot / demonstration / pre-commercial / commercial |
| Application | retrofit (y/n?)<br>robust (y/n?)<br>process industry (y/n?) |
| Economic performance | electrical efficiency (in %)<br>cost of electricity (Euro cts/kWh)<br>$CO_2$ avoidance costs (Euro per tonne avoided)<br>efficiency penalty (% pts) |
| Environmental performance | $CO_2$ emissions (g/kWh)<br>$NO_x$ emissions (g/kWh)<br>$SO_2$ emissions (g/kWh)<br>$PM_{10}$ emissions (g/kWh)<br>$NH_3$ emissions (g/kWh)<br>Other impacts |

### 2.3.2 *Evaluation and selection*

The evaluation criteria for each subject are summarised for each capture technology in a table (see chapter 4.1). This table provides an overview of the major weaknesses and strengths that are relevant for the future development and application of different types of $CO_2$ capture technologies.

The data in this table are surrounded with large uncertainty due to inconsistencies, knowledge gaps and a lack of representativeness. Some scores are based upon a limited number of sources, for instance the developer of a new technology, when this is the only source available. It is also possible that the reference technologies in one category stem from different countries, having different techno-economic properties and using different fuel qualities.

In the table, three colours are used to indicate the value of a score. The colours are yellow (average of scores for a certain aspect), green (better than average) and red (worse than average). These colours are introduced to send the main message: is a certain aspect a weakness (indicated by red), strength (green) or a neutral aspect (yellow). The colour patterns give information on the relative differences between the technologies.

Still, the reader has to be careful with the interpretation of this table. In order to identify the potential impact of $CO_2$ capture technologies, it is necessary to take into account the kind of technology they would be replacing (e.g. a pulverized coal plant could be retrofitted with post combustion capture or be replaced by an Integrated Gasification Coal Plant). Data of a capture technology from the table alone would not provide a complete picture of the (possible) impacts and therefore, to determine the net impact the development of ‘what-if’ scenario analysis is needed.

In this project, ‘what-if’ scenarios have been developed using a selected number of capture technologies. This selection has been based on the different environmental profiles (particularly emissions of transboundary air pollution) that can be reached at different time horizons and different costs.

## 2.4 Scenario analysis and assessment of impacts

### *2.4.1 Power generation*

The objective of the what-if scenario analysis is to illustrate the range of potential impacts on transboundary air pollution of several $CO_2$ capture technologies. The differences between the types of technologies as well as the uncertainties (both for the capture and the reference technologies) are large. Also, the uncertainties about the reference situation in the year 2020 are large since greenhouse gas mitigation options and targets are still under discussion.

In order to illustrate the impact of different types of $CO_2$ capture options, a baseline scenario without climate policy measures and two $CO_2$ mitigation scenarios stemming from (van den Broek et al., 2008) are used. The two mitigation scenarios aim to meet national greenhouse gas emission targets for a series of years among which 2020. In the power generation sector, several $CO_2$ capture technologies contribute to the cost-effective mitigation solution. In that sense, these scenarios present thorough and in-depth research material on application potentials in the Netherlands in 2020. Two variants are added to illustrate the impacts of several other $CO_2$ capture technologies which are not present in the technology mix of the scenarios of van den Broek.

For the scenarios, transboundary air pollution of technologies without capture is calculated using emission factors from the Dutch part of the GAINS model run by IIASA for the update of the NEC directive (June 2007). These data have been reviewed by Dutch experts (ECN, MNP) and are accepted by the Dutch government in the process of negotiating the National Emission Ceiling for the Netherlands.

The emission factors for air pollution from power plants with $CO_2$ capture are calculated by multiplying the technologies without $CO_2$ capture with a relative factor derived from the technology assessment. This factor is the ratio of emissions in a plant with and a plant without $CO_2$ capture as calculated in a literature source. This ratio includes both the emissions due to the new capture technology and the change in emissions from the power plant due to increasing fuel consumption caused by the capture technology.

This method is explained in more detail in the next paragraphs.

#### *2.4.1.1 Scenarios*

The emission levels are roughly estimated by using three scenarios[3] developed by (van den Broek et al., 2008) of which two incorporate CCS implementation before 2020. The UU-MARKAL model used by van den Broek et al. (2008) calculates the most optimal technological configuration of the energy supply system for a certain time interval given certain constraints (e.g. policy or technical determined constraints). The most

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[3] These scenarios are all variants of the Strong Europe scenario developed by the CPB. In this scenario it is assumed that electricity growth is 1.5% per year until the year 2020.

optimal configuration is in this respect the configuration with the lowest net present value. Under the various constraints (e.g. the $CO_2$ reduction target) defined in the three scenarios the UU-MARKAL model is used to calculate the most optimal configuration. This leads to different configurations of the energy supply system for the three scenarios.

The three scenarios[4] are all the extended vintage structure (i.e. long life time for fossil fuelled power plants) variants as defined by van den Broek:

- In the **Business as usual (BAU)** scenario no climate policy is in place. This means that no $CO_2$ reduction target is defined for the power and heat sector.
- In the **Postponed Action** scenario a 15% $CO_2$ reduction in 2020 in the power and heat sector compared to the $CO_2$ emission level in 1990 is assumed. This scenario incorporates $CO_2$ reduction targets from 2020 onwards.
- In the **Direct Action** scenario a 15% $CO_2$ reduction in 2020 in the power and heat sector compared to the $CO_2$ emission level in 1990 is assumed. This scenario incorporates $CO_2$ reduction targets from 2010 onwards.

In the power production sector several power generation technologies are distinguished. The model developed by van den Broek et al.(2008) incorporates also post combustion capture at coal and gas fired power plants, and pre combustion capture at IGCC power plants. This can be new plants with CCS directly installed or existing power plants that are retrofitted with CCS technologies.

The two scenarios with $CO_2$ reduction targets results in the implementation of CCS technologies. The CCS technologies installed are however limited to pre combustion $CO_2$ capture at IGCC power plants and post combustion capture at pulverized coal fired power plants. In other words, the scenarios do not include oxyfuel combustion and post combustion capture at gas fired power plants.

Therefore, two additional variants of the Direct Action scenario are developed. The choice for the Direct Action scenario is arbitrary with the sole purpose of restricting the number of variants.

- In the **Direct Action- post combustion gas** variant all gas fired power plants in the power and heat sector are equipped with post combustion $CO_2$ capture. The coal fired power plants are unaltered in this scenario. This means that all gas fired power plants are directly equipped or retrofitted with $CO_2$ capture in the year 2020.
- In the **Direct Action – oxyfuel** variant all new built gas and coal fired power plants from 2010 onwards are assumed to be equipped with the oxyfuel combustion concept. The existing coal power plants are retrofitted with oxyfuel technology.

#### *2.4.1.2 Emission factors and emissions*

For the 5 scenarios derived from the UU-MARKAL model, emission levels of NEC substances and $CO_2$ are estimated by multiplying the fuel consumption with emission factors. The emission factors used for this estimation are derived from the NEC_NAT_CLE_OPTV4 scenario which is included in the GAINS model developed

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[4] Van den Broek et al. (2008) also developed variants of the three scenarios: the normal vintage structure and an extended vintage structure variant. In the normal vintage variant the life time for gas and coal fired power plants is 30 years. In the extended vintage variant the life time is respectively 40 and 50 years for gas and coal fired power plants.

by the IIASA. This scenario defines emission factors for the power production technologies installed in the year 2020 in the Netherlands. However, no emission factors are defined for technologies that are equipped with $CO_2$ capture technologies. Therefore, a simple approach is used in this study to estimate the emission factors for technologies equipped with $CO_2$ capture in the year 2020. From the gathered literature an average factor is derived for each substance that indicates the relative increase or decrease in emission per MJ due to the application of a type of $CO_2$ capture technology, see Equation 2.1. When possible, this factor is calculated for each individual case in the gathered literature.

Equation 2.1

$$RF_{x,y,z} = \frac{EF_{CCS}}{EF_{noCCS}}$$

Where:

$RF_{x,y,z}$ = Relative Factor for substance x, given $CO_2$ capture technology y and power production technology z

$EF_{CCS}$ = Emission Factor reported/estimated in a case in the literature for substance x and $CO_2$ capture technology y and power production technology z

$EF_{noCCS}$ = Emission Factor for substance x reported/estimated for reference case without $CO_2$ capture

The emission factors from the NEC_NAT_CLE_OPTV4 scenario are multiplied with the Relative Factor to acquire an emission factor (per PJ fuel input) that is differentiated for power production technology, new or existing power plant, and $CO_2$ capture technology.

The estimated fuel requirements in each scenario are then multiplied with the emission factors to estimate the emission levels for NEC substance in 2020 from large scale electricity production.

In this basic approach, a correction is made for the fact that a lot of data represent foreign power plants for different time horizons, having different energy efficiencies and using different fuel qualities. Disadvantage of this method is that certain characteristics specific for the Netherlands are not taken fully into account (e.g. all Dutch coal fired power plants are already equipped with flue gas desulphurisation with removal efficiencies up to 99%).

#### *2.4.1.3 Context*

The resulting scenarios present a consistent illustration of the impact of the implementation of $CO_2$ capture on the emissions of $SO_2$, $NO_x$, VOC, $NH_3$, $PM_{10}$ and $PM_{2.5}$. However, note that the baseline is a ‘no policy’ scenario. Furthermore, the two mitigation scenarios only represent measures taken to mitigate climate change. Transboundary air pollution is not an issue in this scenario. Therefore, the NEC scenario for the Dutch power generation sector is presented in order to be able to compare the results with the latest view from the angle of transboundary air pollution policies.

Finally, information on costs, emissions and a lesser extent potentials gathered in this project will be used in the national energy modelling framework of ECN to evaluate $CO_2$ capture in a cost-effectiveness analysis of greenhouse gases and transboundary air pollution for the Netherlands in the year 2020.

### *2.4.2 Industrial processes*

A number of the technological options for $CO_2$ capture can be applied both in power generation and in industry. Therefore, the technological description of application of $CO_2$ capture in industry is described in the technological assessment.

The level of information with respect to application of industrial $CO_2$ capture in the Netherlands is limited. Therefore, this subject is analysed in two basic steps.

First, the $CO_2$ emission potentials and requirements for capital and energy for $CO_2$ capture opportunities at large industrial sources in the Netherlands are taken from Damen 2007. Based upon these data, costs in euro per tonne avoided $CO_2$ are calculated and presented. This provides an indication of the theoretical $CO_2$ mitigation potential and costs at large industrial sources in the Netherlands.

Next, the emission contribution of different sectors to the national total of transboundary air pollutants in the Netherlands in 2020 is presented according to the NEC5 current legislation scenario of IIASA. This graph sketches the national significance of emissions of NEC pollutants from sectors with large industrial sources which theoretically are suited for $CO_2$ capture. The power generation sector is also explicitly included in this graph.

Although information is lacking to estimate the practical implementation potential and the specific consequences in terms of NEC emissions in industry, the significance of the sectors emission contribution in the national total gives a first impression of the possible importance of impacts on national NEC emissions from these industrial sources.

## 2.5 Other aspects

### *2.5.1 Transport and storage*

Transport and storage of $CO_2$ is an issue with typical localised dimensions. Storage potentials in coal seams, gas and oil fields, saline aquifers are discussed to see whether limitations can be expected from this aspect in the Netherlands.

In a small country as the Netherlands, transport and storage of $CO_2$ is only capture technology specific in the way that energy is needed to compress $CO_2$ to transport and inject $CO_2$ in reservoirs. The energy needed is generated by the specific power plant with a certain efficiency and emission profile. Therefore, it seems logical to see transport and storage as an additional factor as a result of additional efficiency decreases.

### 2.5.2 *Life cycle impacts*

Current information on emissions in different stages of the life cycle of CCS is limited. Generally, data on air pollution is focussed on the capture process in combination with the combustion process. The upstream and downstream processes are rarely included in the analysis.

A limited number of life cycle studies on the environmental impacts of $CO_2$ capture are available. These studies (see section 3.6) are used to draw conclusions for several types of capture technologies on the importance of the rest of the life cycle with respect to transboundary air pollution. This is done by distinguishing different parts of the life cycle and analysing the causes for emissions in each of these parts. Depending on these causes, generalisations can be made for other types of capture technologies (or not).

A distinction is made between the fuel cycle consisting of fuel preparation in addition to power generation, the solvent cycle (capturing $CO_2$) consisting of solvent production, $CO_2$ capture and waste treatment and the $CO_2$ cycle comprising of $CO_2$ compression, transport and storage.

The direct emissions as assessed in the technology assessment root in parts of these three cycles, viz. power generation, $CO_2$ capture and compression. In this study, the life cycle analysis aims to provide a first estimation of the importance of the other emissions not directly stemming from power generation and capture technology.

Furthermore, the location of the emission in the life cycle is relevant for the National Emission Ceiling of transboundary air pollution. When the source of the emissions is known, the parts of emissions abroad and from national sources can be estimated.

## 2.6 Relation to other BOLK projects

Clear relations exist between the subjects of the present project on CCS and the project on biomass in large scale combustion plants (ECN), and the lifecycle analysis of biomass (Ecofys). Biomass combustion in coal fired power plants is already current practice. Hence, it can be expected that this will be the case in coal fired power plants equipped with (certain types of) carbon capture. This issue is addressed in the current study for as far as information is available. It should however be noted that little information is available on the impact of biomass combustion in power stations with CCS with regard to transboundary air pollution.

Finally, the information on capture technologies and their applications with respect to costs, emissions and a lesser extent potentials will be translated into model specifications of energy options to mitigate greenhouse gases and/or transboundary air pollution to be used in the national energy modelling framework of ECN. Together with information from the other BOLK projects, an integrated cost-effectiveness analysis will be made for the Dutch energy sector in the year 2020.

# 3 Capture technology description

## 3.1 General introduction to capture technologies

Large carbon dioxide ($CO_2$) point sources will be the main application for carbon capture. They include fossil fuel power plants, fuel processing plants and other industrial plants, such as iron, steel, cement and bulk chemical plants. Capturing from small and mobile sources is expected to be more difficult and expensive. There are four basic systems for capturing $CO_2$ from use of fossil fuels and/or biomass, schematically drawn in Figure 3.1.

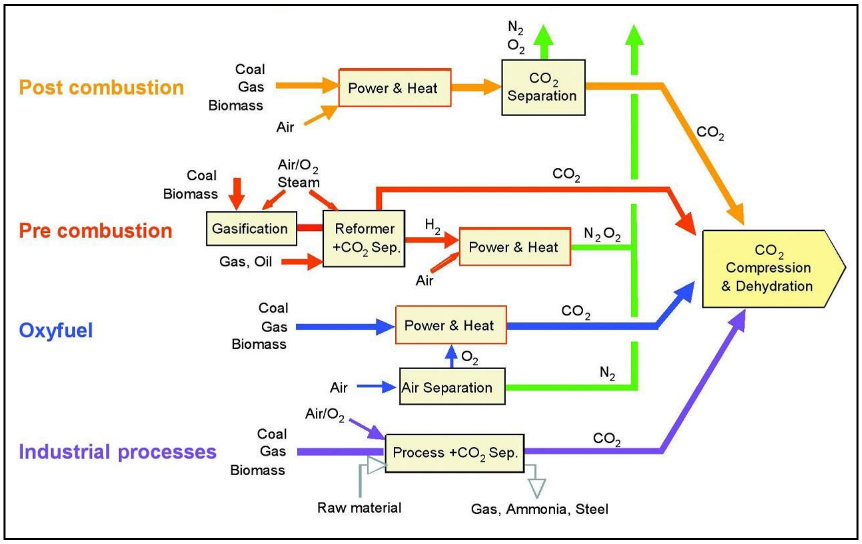

Figure 3.1 Carbon Capture Technologies (IPCC, 2005)

*Post combustion capture*

Capturing the $CO_2$ from the flue gas, produced by a combustion process is called post combustion capture. The flue gas is passed through separation equipment, which separates the $CO_2$. The $CO_2$ is stored; the remaining gas is discharged to the atmosphere. (Described in more detail in Chapter 3.2)

*Pre combustion capture*

Syngas, containing carbon monoxide (CO) and hydrogen ($H_2$), is produced by the reaction of a fuel and oxygen or air and/or steam. The CO is shifted to $CO_2$ with steam in a catalytic reactor. The $CO_2$ is separated from the $H_2$ rich gas which can be used in other applications. (Described in more detail in Chapter 3.3)

*Oxyfuel combustion capture*

In the oxyfuel combustion process, nearly pure oxygen is used for the combustion in stead of air. The resulting flue gas contains mainly $CO_2$ and $H_2O$. (Described in more detail in Chapter 3.4)

*Capture from industrial processes*

$CO_2$ has been captured from industrial process streams for decades. Examples are the purification of natural gas, and the production of hydrogen containing synthesis gas for the manufacturing of ammonia, alcohols and synthetic liquid fuels. Other $CO_2$ emitting industries are cement, iron and steel production (IPCC, 2005).

Since these industrial processes concern high concentrations of $CO_2$, these processes provide potentially cost-effective opportunities for $CO_2$ capture. This is illustrated in Figure 3.2.

Since the capture technology is in principle not different from the types of technology applied in other sectors such as the power generation, the industrial applications are discussed for each type of technology (post and pre combustion and oxyfuel) in the next sections in the paragraphs on the aspect Application.

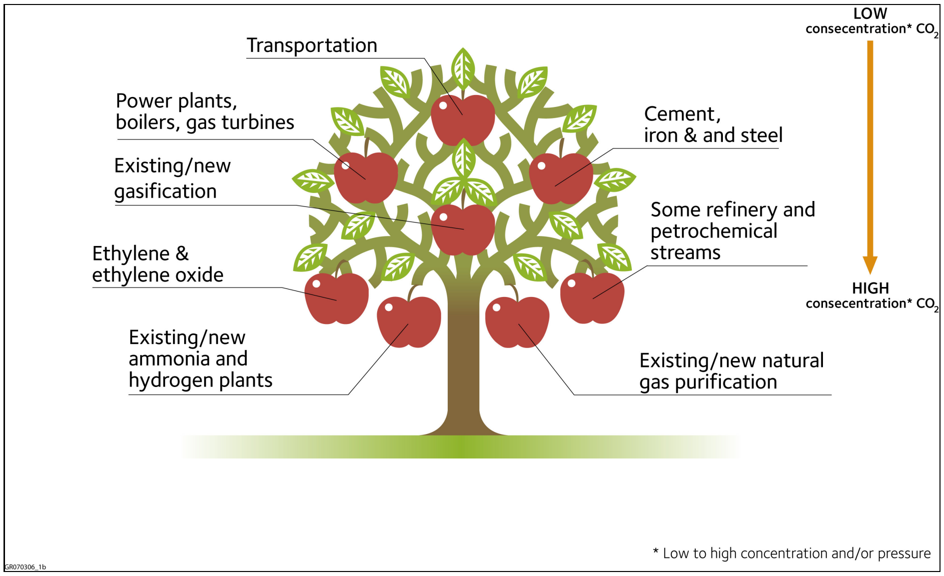

Figure 3.2 The early opportunities or “low hanging fruits” tree for $CO_2$-capture (Olistat/Kårstad, 2007)

## 3.2 Post Combustion $CO_2$ Capture

The first basic system for the carbon capture is post combustion capture. As suggested by the name, carbon dioxide ($CO_2$) is captured after the combustion process. The flue gas stream, emitted by a power station contains only a small amount of $CO_2$ (Table 3.1). Other gases include nitrogen, oxygen and water vapour. Storing all gases underground would require larges volume of storage space and high energy costs for compression. Therefore $CO_2$ has to be separated from the other components. A number of techniques are available and will be described in the next paragraphs (IEA GHG, 2001).

Table 3.1 $CO_2$ concentration in power station flue gas

| | **$CO_2$ concentration in flue gas after combustion (Vol %, approx.)** |
|---|---|
| Pulverized coal (PC) | 14 |
| Coal fired Integrated Gasification combined cycle (IGCC)*) | 9 |
| Natural gas combined cycle (NGCC) | 4 |

*) For an IGCC pre combustion capture is the preferred technology

### *3.2.1 Technical description*

In Figure 3.3 a flow sheet for the post combustion carbon capture technology is given. The solvent scrubbing part can be replaced by another post combustion technology like, membranes or direct chilling. In the following paragraphs a summarized technical description of four post combustion techniques (amines, chilled ammonia, direct chilling and membranes) will be given.

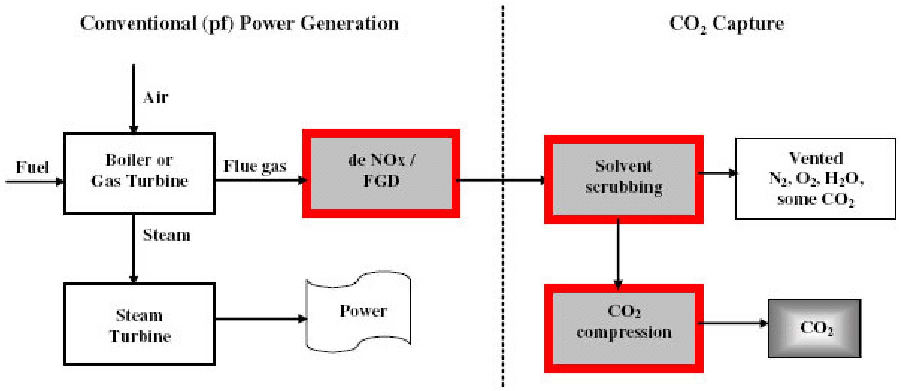

Figure 3.3 Flowsheet for PCC (post combustion capture) process, the solvent scrubbing can be replaced by another technology CC technology like membranes or direct chilling (Wall, 2007)

#### *3.2.1.1 Amines*

Absorption processes in post combustion capture make use of the reversible nature of the chemical reaction of an aqueous alkaline solvent, usually an amine, with an acid or sour gas. One of the most well known amines is MEA (Mono Ethanol Amine). The process flow diagram of a commercial absorption system is presented in Figure 3.4. After cooling the flue gas, it is brought into contact with the solvent in the absorber. A blower is required to overcome the pressure drop over the absorber. At absorber temperatures typically between 40 and 60°C, $CO_2$ is bound by the chemical solvent in the absorber. The flue gas then undergoes a water wash section to balance water in the system and to remove any solvent droplets or solvent vapour carried over, and then it leaves the absorber. It is possible to reduce $CO_2$ concentration in the exit gas down to very low values, as a result of the chemical reaction in the solvent, but lower exit concentrations tend to increase the height of the absorption vessel. The 'rich' solvent, which contains the chemically bound $CO_2$ is then pumped to the top of a stripper (or regeneration vessel), via a heat exchanger. The regeneration of the chemical solvent is carried out in the stripper at elevated temperatures (100°C–140°C) and pressures not very much higher than atmospheric pressure. Heat is supplied to the reboiler to maintain the regeneration conditions. This leads to a thermal energy penalty as a result of heating up the solvent, providing the required desorption heat for removing the chemically bound $CO_2$ and for steam production which acts as a stripping gas. Steam is recovered in the condenser and fed back to the stripper, whereas the $CO_2$ product gas leaves the stripper. The ‘lean’ solvent, containing far less $CO_2$ is then pumped back to the absorber via the lean-rich heat exchanger and a cooler to bring it down to the absorber temperature level (Gijlswijk et al., 2006).

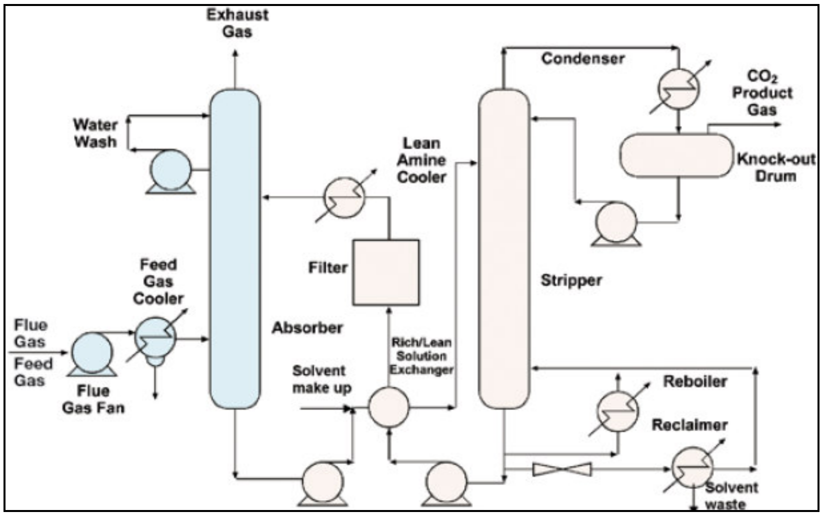

Figure 3.4 Process flow diagram for $CO_2$ recovery from flue gas by chemical absorption (IPCC, 2005)

The advantages of the amine technology are:
- Most mature $CO_2$ capture technology for power plants
- High $CO_2$ reduction is possible
- Retrofit possible

The disadvantages of the amine technology are:
- High costs for energy and equipment
- Large volumes of gas have to be handled
- Degradation of amines
- Harmful and corrosive solvents
- Emissions of organic component (VOC)
- Emissions of ammonia
- Plot space requirements
- Water and cooling requirements

### *3.2.1.2 Chilled ammonia*

A second solvent based carbon capture technology is the chilled ammonia process (CAP). Ammonia based scrubbing processes are similar in operation to the amine system. Ammonia and its derivatives react with $CO_2$ via various mechanisms, one of which is the reaction of ammonium carbonate (AC), $CO_2$, and water to form ammonium bicarbonate (ABC).

The following advantages of the ammonia based process are expected:
- Energy and cost savings because of a lower heat of reaction
- Potential for high $CO_2$ capacity

- Lack of degradation during absorption/regeneration
- Tolerance to oxygen in the flue gas
- Low cost
- Potential for high regeneration at high pressure which results in lower energy requirement for compression

The main disadvantage is that it is not commercial process. The chilled ammonia process operates at near freezing temperatures (0-10°C), and the flue gas is cooled prior to absorption using chilled water and a series of direct contact coolers. The main technical problems are related to the cooling of the flue gas and the absorber to operate below 10°C. This is necessary to achieve high $CO_2$ capacity and removal efficiencies, and to prevent the emissions of ammonia during absorption/regeneration, and to prevent the equipment of fouling with deposition of ammonium bicarbonate (Figueroa et al., 2008).

#### *3.2.1.3 Direct chilling*

$CO_2$ can be separated from other gases by cooling and condensation. This technology is widely used for gas streams with a high $CO_2$ concentration (>90%). These are available in oxy-combustion processes where higher concentrated gas streams are present.
An advantage of the technology is the production of liquid $CO_2$, ready for transport (for instance by shipping). A disadvantage is the amount of energy for especially the low concentrated gas streams and the components that have to be removed before cooling, e.g. water, to prevent blockages.

#### *3.2.1.4 Membranes*

Membranes can be used for separating $CO_2$ from flue gasses. For low concentrated gas streams and a high purity multiple stages are necessary. This will result in high costs. There are a numerous types of gas separating membranes, like porous inorganic membranes, palladium membranes, polymeric membranes and zeolites. The basic principle behind membrane separation is a kind of molecular sieve. $CO_2$ molecules can pass the membrane, others are blocked. Some scientist consider the membrane process as energy saving, space saving, easy to scale up and as the future technology for $CO_2$ separation. As a disadvantage the current state of development can be seen, which is far from commercial (Yang et al., 2008).

In another concept, membrane contactors (a combination of membranes and amine solutions) can be used. The $CO_2$ containing flue gas passes through the membrane tube, while the amine solution flows along the shell side. The $CO_2$ permeates through the membrane and is absorbed in the amine solution, while the impurities are blocked and will not degrade the amine solution by reaction to a salt. The advantages of absorption (high selectivity) and membranes (modularity, small size) are combined (Feron, 2002).

#### *3.2.1.5 Retrofit*

Post combustion technologies are in principle suited to apply to an existing power plant. The feasibility and cost of all these options is highly dependent on site-specific factors, including the size, age and efficiency of the plant, and the availability of additional space. Some reports indicate that retrofitting an amine scrubber to an existing plant results in greater efficiency loss and higher costs. Other also indicates that a more cost-effective option is to combine a capture system retrofit with rebuilding the boiler and turbine to increase plant efficiency and output (IPCC, 2005).

While no major technical hurdles exist for retrofitting most PC plants with post combustion capture, the expected de-rating, capital requirements and increase in operation and maintenance costs pose significant challenges to owners and policymakers if and when actions are taken to reduce $CO_2$ emissions from these facilities (Bohm, M.C. et al., 2007).

### *3.2.2 Application area*

All mentioned technologies can be used to separate $CO_2$ from the flue gas in coal fired and natural gas combined cycled systems. In Table 3.2 an overview is given of planned post combustion carbon capture plants.

Direct chilling will normally be applied in high $CO_2$ concentrated gas streams, as present in oxy-fuel processes. An exception is the project of Enecogen. They are planning to build a 840 MW NGCC power plant at "De Maasvlakte" next to the planned LNG terminal of Liongas. The waste cold from the re-gasification of the LNG can be used for the cryogenic $CO_2$ capture. In this case "free" cold can be used for separating the low $CO_2$ concentrated flue gases. The direct chilling technology will not be discussed in the remaining of the report.

Table 3.2 Planned post combustion plants (after MIT, 2008)

| Project Name | Location | Feedstock | Size MW | $CO_2$ fate | Start-up |
|---|---|---|---|---|---|
| E.ON CATO pilot | Maasvlakte, Netherlands | Coal | | Vented | 2008 |
| Electrabel pilot | Nijmegen | Coal | | Vented | 2008/2009 |
| ENECOGEN (LNG Liongas) | Rotterdam | Gas | 840 | ? | 2013 |
| AEP Alstom Mountaineer | USA | Coal | 30 | Seq | 2008 |
| Williston | Canada | Coal | 450 | EOR | 2009-15 |
| AEP Alstom Northeastern | USA | Coal | 200 | EOR | 2011 |
| Sargas Husnes | Norway | Coal | 400 | EOR | 2011 |
| Scottish & Southern Energy Ferrybridge | UK | Coal | 500 | Seq | 2011-2012 |
| Naturkraft Kårstø | Norway | Gas | 420 | Undecided | 2011-2012 |
| WA Parish | USA | Coal | 125 | EOR | 2012 |
| RWE npower Tilbury | UK | Coal | 1600 | Seq | 2013 |
| UK CCS project | UK | Coal | 300-400 | Seq | 2014 |
| Statoil Mongstad | Norway | Gas | 630 CHP | Seq | 2014 |
| UAE Project | UAE | Oil | TBD | EOR | Undecided |
| | Sweden | Oil | 5 | Undecided | Undecided |

### *3.2.3 Development phase*

In Figure 3.5 an overview is given of the maturity of post combustion $CO_2$ capture technologies. In the diagram it is indicated that almost all major components are commercially available, but at another scale and not integrated and optimized for this purpose. The process also demands a very clean flue gas, which is not common in ordinary power plants. The post combustion technologies, described in the former paragraphs will be described in more detail below.

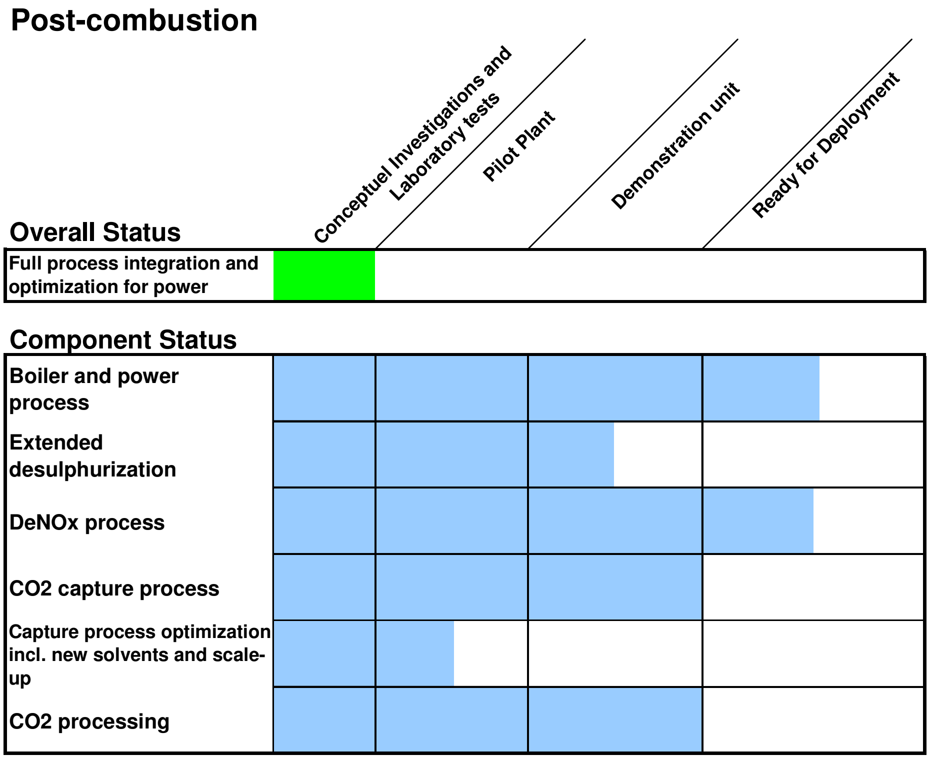

Figure 3.5 Illustration of the maturity of the post combustion technology Adapted from (ZEP, 2006) after expert consultation.

Post-combustion capture is proven at a considerable scale on coal (800 tonne/day; ABB, Trona) and for Natural Gas (300 tonne/day; Fluor, Bellingham). This is about 30-40 MW scale (5-10% of full scale). Note that these technologies are not the most advanced. Newer solvents still need to be proven at the intermediate scale (especially for coal operational issues are identified in the CASTOR project related to combination of coal flue gas with amine solvents). Upscaling is considered a big step, but experts think it can be handled. A big issue is $SO_2$ in the flue gas that will contaminate the solvent. A provider like MHI is very careful and demands 1 ppm, others like CANSOLV are more forgiven. Shell does have some developments in this area that will be disclosed soon. (Geuzebroek, 2008)

#### *3.2.3.1 Amines*

Chemical absorption with the use of amine solutions has been used in the natural gas industry over 60 years. It is the main technology for the separation of $CO_2$ from flue gasses in today's world. Practice is based on a reducing atmosphere. The oxidizing environment could introduce degradation problems. The stability of the amines and the energy consumption of the stripping process have large room of further improvement.

Commercially available processes are
- The Kerr-McGee / ABB Lumus Crest Process
- Fluor Daniel Econamine process
- The Kansai Electronic Power Co., Mitsubishi Heavy Industries, Ltd. Process. (Gijlswijk et al., 2006)

#### *3.2.3.2 Chilled ammonia*

The chilled ammonia process (CAP) is under development by Alstom. Alstom designed, constructed and operates a 1.7 MW system that captures $CO_2$ from a portion of coal-fired boiler flue gas at We Energies' Pleasant Prairie Power Plant (March 2008). It is also scheduled for a test in mid-2008 on AEP's 1300-MW Mountaineer Plant in New Haven, as a 30-MW (thermal) product validation with up to 100,000 tonnes of $CO_2$ being captured per year (Figueroa et al., 2008).

#### *3.2.3.3 Membranes*

Membranes for post combustion carbon capture are at a lab scale level of development. Nano structured membranes are under development within the Nanoglowa project, which brings together universities, power plant operators, industry and SMEs. 26 organisations from 14 countries throughout Europe join the NANOGLOWA-consortium in order to develop optimal nanostructured membranes and installations for $CO_2$ capture from powerplants.

In April 2008 TNO-CATO post combustion pilot plant at the site of the E.ON coal-fired power plant on the Maasvlakte was opened. This pilot can test membrane contactors, next to solvents, in real industrial settings, as it is using a side stream of the coal-fired power plant.

Table 3.3 Development phase of post combustion CC technologies

| Technology | Development Phase |
|---|---|
| Amines | Pre commercial |
| Chilled Ammonia | Pilot |
| Membranes | Lab scale |

### *3.2.4 Economic and Energy Performance*

Post combustion capture of $CO_2$ contributes 75 percent to the overall CCS cost and CCS increases the electricity production cost by 50 percent. Although these numbers may vary with different CCS schemes, reducing the capture cost is the most important issue for the CCS processes to be acceptable to the energy industry (Yang et al., 2008).

In Table 3.4 the economic and energy performances are indicated. Due to the strongly increased fuel prices and prices of industrial installations, costs will in general be higher than stated in the table, based on literature. A detailed table on economic and energy performances is given in Appendix C.

Table 3.4 Economic and energy performance of Post Combustion technologies (IPCC, 2005; Rubin et al., 2007); (Tzimas et al., 2007); (Davison, 2007); (Nexant Inc., 2006); (DoE/NETL, 2007a); (Peeters et al., 2007))

| Capture | Application | Electrical efficiency (%) | CoE (Euro cents 2007/kWh) | Euro 2007 / tonne avoided | Efficiency penalty (% pts) |
|---|---|---|---|---|---|
| No Capture | PC | 40*) | 4.1 | - | - |
| | NGCC | 56 | 4.4 | - | - |
| Amine | PC | 30 | 7.9 | 53 | 11 |
| | NGCC | 49 | 6.4 | 55 | 8 |
| Chilled Ammonia | PC | 39**) | n.a. | 16**) | n.a. |
| Membranes | | n.a. | n.a. | n.a. | n.a. |

*) New PC plants (will) have an increased electrical efficiency of 46 (Feron, 2008) or even up to 50 (Geuzenbroek, 2008)

**) Data based on one source (technology supplier)

#### *3.2.4.1 Amines*

Using amine solutions for capturing $CO_2$ from flue gasses will increase the use of energy and costs of electricity. The size and cost will be comparable with a conventional $SO_2$ scrubber; the scrubber will consume one-quarter to one-third of the total steam produced by the plant. The National Energy Technology Laboratory (NETL) estimated in 2000 that this scheme would increase the cost of electricity production by 70% (Yang et al., 2008).

#### *3.2.4.2 Chilled ammonia*

The biggest saving by far, using the chilled ammonia in stead of the MEA system is the steam extraction for absorbent regeneration. The steam consumption in the reboiler of the ammonia-based system is less than 15% of the consumption of the MEA system mainly due to the lower heat of reaction and the lower steam fraction in the regenerated $CO_2$ stream. The main auxiliary power saving relative to a MEA system is the much smaller $CO_2$ compressor and ID fan. Additional power is required for cooling. In laboratory testing it has been demonstrated the potential to capture more than 90 percent of $CO_2$ at a cost that is far less than other carbon capture technologies (ALSTOM, 2006).

The performances for the chilled ammonia look promising. However this data are only based on one source (technology developer) and expected to be to optimistic by experts in the field of carbon capture (Geuzenbroek, 2008), (Hopman., 2008), (Versteeg, 2008).

#### *3.2.4.3 Membranes*

A recent paper (Bounaceur et al., 2006) indicates that membranes can provide significant improvements over today's available technology, amine absorption. The energetic costs of amine absorption (4-6 GJ/tonne $CO_2$ recovered)[5] are much higher than for membrane processes (0.5–1 GJ/tonne $CO_2$ recovered). The data are based on simulations and not validated by experimental results. Future work will need to include the effects of more realistic conditions.

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[5] Peeters (2007) indicates in his paper that regeneration energy for the amine process are expected to decrease from 4.4 MJ/kg $CO_2$ (2010) down to 2.6 MJ/kg $CO_2$ (2020) and 1.6 MJ/kg $CO_2$ (2030).

### 3.2.5 *Environmental performance*

Table 3.5 summarises the environmental performances of the post combustion technologies. A more detailed table is given in Appendix C.

Table 3.5 Environmental performance of Post Combustion technologies (IPCC, 2005; Rubin et al., 2007); (Tzimas et al., 2007); (Davison, 2007); (Nexant Inc., 2006); (DoE/NETL, 2007a); (Peeters et al., 2007))

| **Capture** | **Application** | **$CO_2$ (g/kWh)** | **$NO_x$ (g/kWh)** | **$SO_x$ (g/kWh)** | **$PM_{10}$ (g/kWh)** | **$NH_3$ (g/kWh)** | **NMVOC (g/kWh)** |
|---|---|---|---|---|---|---|---|
| No Capture | PC | 830 | 0.39 | 0.44 | 0.05 | 0.01 | 0.001 |
| | NGCC | 370 | 0.17 | - | - | - | n.a. |
| Amine | PC | 145 | 0.57 | 0.001 | 0.06 | 0.23 | n.a. |
| | NGCC | 55 | 0.19 | - | - | 0.002 | n.a. |
| Chilled Ammonia | PC | | Expected to be comparable with amines | | | | |
| Membranes | | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. |

#### 3.2.5.1 *Amines*

$NO_2$ and $SO_2$ from the flue gas can react with amines into non regenerable salts. They have to be removed from the flue gas by $NO_x$ burners with selective catalytic reduction (SCR) and flue gas desulphurization (FGD) technologies. However, $NO_x$ consists for about 10% of $NO_2$. Hence, no large reductions are expected here. The environmental impact for post combustion capture processes are influenced primarily by the increased fuel use. The environmental impact themes on human toxicity and terrestrial ecotoxicity show an increase because of the use of solvents, in particular the production of MEA (Gijlswijk et al., 2006).

The flue gas reacts with the amines and is believed to cause high $NH_3$ emissions (more than 20 times higher than a plant without capture). However, this value is uncertain. Currently, TNO is developing and pilot testing the development of a new class of biodegradable amines named Coral which will show no VOC emissions and produce less $NH_3$ (Hopman., 2008).

From the expert interviews it became clear that the solid waste of ammonium salt will be a serious item. A 1000 MW power plant is expected to produce 10 - 20 ktonne of solid waste (mainly amine salts) per year (Geuzenbroek, 2008); (Versteeg, 2008).

Tzimas investigates in his paper the impact of capture of carbon dioxide ($CO_2$) from fossil fuel power plants on the emissions of nitrogen oxides ($NO_x$) and sulphur oxides ($SO_x$), which are acid gas pollutants. The capture is not likely to increase the emissions from one individual plant, on the contrary, some $NO_x$ and $SO_x$ will be removed during capturing.[6] The large-scale implementation of carbon capture is however likely to increase the emission levels of $NO_x$ from the power sector due to the reduced efficiency of power plants equipped with capture technologies. Furthermore, $SO_x$ emissions from coal plants should be decreased to avoid significant losses of the chemicals that are used to capture $CO_2$ (Tzimas et al., 2007).

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[6] Amines react with $NO_2$ from the flue gas, which generally contains 90% NO, 10% $NO_2$ and few $N_2O$. The emitted $NO_x$ includes NO and some non captured $NO_2$. So $NO_x$ emissions increase less as expected from the increased fuel consumption (Tzimas, 2007).

No quantitative data on NMVOC emissions are available for the amine capturing process. They are expected to increase when using the conventional volatile amine solvents.

The capture of $CO_2$ with the use of post combustion concepts is assumed to have an effect on the emission of particulate matter. In the case of post combustion capture the emission of PM per MJ is assumed to be lower. Together with the efficiency penalty, PM emissions are expected to increase per kWh. In the literature the assumptions on this matter vary considerable, on the one hand some scholars assume a deep reduction of PM due to the application of post combustion $CO_2$ capture; on the other hand, other scientists assume that it will not have an effect on PM emissions per MJ.

#### *3.2.5.2 Chilled ammonia*

No information on the environmental performance of the chilled ammonia process is available. The volatile $NH_3$ can evaporate, but due to its solubility in water it can be easily captured to a high degree. It is expected that the environmental performance will be comparable to the amine process.

#### *3.2.5.3 Membranes*

No information on the environmental performance of the membrane process is available.

### *3.2.6 Uncertainties*

The reliability of the emissions with carbon capture is uncertain. In general data on new technologies are debatable; these are mostly based upon assumptions and not real measurements. There is an urgent need for emission measurements at pilot plants.

It is presumed that for the environmental emissions the mining and (trans)shipment of coal will be a factor of increasing importance. It is important to have a look at the whole production chain (Feron, 2008).

### 3.2.7 *Conclusions on post combustion $CO_2$ capture*

The post combustion process can be applied to new and most of the existing power plants, and has the greatest near by potential for $CO_2$ capture. Solvent based processes, especially the use of amines, are the most mature technologies; large experience is available for other applications. They will most likely be applied in the first generation carbon capture plants.

Chilled ammonia and membranes are both promising techniques which are less energy consuming than the amine system. However the latter is by far the most mature technology. A large amount of research is needed for chilled ammonia and especially membranes before they can technically and commercially be applied. Recently pilot tests with chilled ammonia and membrane contactors have been started.

Flue gas streams only contain small amount of $CO_2$. Direct chilling, suited for high concentrations, is in principle not an option for the post combustion carbon capture process, unless “waste cold” is available.

Adequate economic and energy data are only available for no capture plants and those using the amine process. For chilled ammonia and membranes only few, rather optimistic data are available from the technology developers. Capturing $CO_2$, using amines, will increase the cost of electricity 50% (NGCC) to 100% (PC), based on available data from the past. The recent increase in fuel prices and in equipment costs will drastically affect the costs.

In general data on the emissions of captured plants are scarce. And when available, they are based on estimations, using numerous assumptions on the plant configuration and performance.

The large-scale implementation of post combustion carbon capture with amines is likely to increase the emission levels of $NO_x$ per kWh from the power sector due to the reduced efficiency of power plants with capture technology. $NH_3$ emissions are expected to increase due to the use of amines or ammonia; however it is unclear to what level.

Furthermore for coal based plants, $SO_x$ emissions will most likely decrease, since significant losses of the chemicals that are used to capture $CO_2$ would be avoided. No significant changes for $PM_{10}$ are expected, no data on NMVOC are available.

In all cases the emissions are dependent on fuel quality and on the plant configuration, with respect to e.g. the SCR, FGD and other scrubbing sections in the plant and the legislation with respect to emissions.

In general the emissions of natural gas based plants are less than for coal based plants. $NO_x$ emissions are significantly lower, whereas no $SO_x$ and $PM_{10}$ are emitted.

## 3.3 Pre combustion $CO_2$ capture

The term pre combustion refers to the process of capturing the carbon dioxide from a carbon based fuel (biomass, coal, natural gas, etc.) before the combustion step. This requires a hydrocarbon to be broken down into hydrogen ($H_2$) and carbon monoxide (CO), i.e. synthetic gas or syngas. This process is referred to as reforming or partial oxidation for gaseous fuels and gasification for solid fuels. It basically involves these three reactions:

Steam reforming: $C_xH_y + xH_2O \leftrightarrow xCO + (x+y/2)H_2$ endothermic
Partial oxidation/gasification: $C_xH_y + {}^{x}/_{2}\, O_2 \leftrightarrow xCO + (y/2)H_2$ exothermic

Shift reaction: $CO + H_2O \leftrightarrow CO_2 + H_2$ exothermic

To make $CO_2$ capture with high efficiencies possible the syngas that is formed after steam reforming or partial oxidation/gasification has to be shifted. The shift reaction, or water gas shift reaction, yields energy and a gas stream with high $CO_2$ and $H_2$ concentrations. The carbon in the gas is now predominantly in the form of $CO_2$. This $CO_2$ can be removed with chemical and physical solvents, adsorbents and membranes. The hydrogen can be used to generate electricity (IPCC, 2005). In this section various pre combustion capture options are discussed.

### *3.3.1 Pre combustion – Solid and liquid fuels*

#### *3.3.1.1 Technical description*

For solid and liquid fuels pre combustion $CO_2$ capture can be applied in an IGCC (Integrated Gasification Combined Cycle) power plant (see Figure 3.6). In an IGCC a solid or liquid (slurry) fuel is fed into the gasifier where gasification of the fuel yields syngas. The oxidant can be air or oxygen. In the latter case nearly pure oxygen is supplied by an (cryogenic) Air Separation Unit (ASU), which can be (partially) integrated in the combined cycle.

The syngas produced in the gasifier contains primarily carbon monoxide (CO) and hydrogen ($H_2$). The product gas would then be cooled and cleaned. Impurities in the syngas can be, dependent on the gasification process: hydrogen sulphide ($H_2S$), carbonyl sulphide (COS), ammonia ($NH_3$), hydrogen cyanide (HCN), hydrogen chloride (HCl), mercury (Hg), particulates, tars, alkali and trace metals (Salo and Mojtahedi, 1998); (Tzimas et al., 2007). These impurities are to a large extent removed from the syngas with the use of filters, cyclones and wet scrubbers prior to the acid gas removal (AGR) step. The acid gas removal involves a hydrolysis step (carbonyl sulphide (COS[7]) and water react into $H_2S$ and $CO_2$). $H_2S$ is then removed from the gas stream with a chemical or physical solvent and fed into a gas treating unit where it is converted into elementary sulphur. Another option is to convert the sulphur compounds into sulphuric acid.

The 'clean' syngas is then fed into the gas turbine combined cycle (GTCC) plant where the syngas is combusted with air. Injection of steam and $N_2$ from the ASU, and syngas saturation can be used to control (i.e. lower) the temperature in the gas turbine combustor in order to reduce $NO_x$ formation.

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[7] In general, approximately 5% of the sulfur in the coal is released as COS.

In an IGCC with pre combustion $CO_2$ capture the process configuration will change. In Figure 3.6 the additional processes are highlighted. In the shift conversion step the CO in the syngas reacts with steam to form $H_2$ and $CO_2$. The carbon in the syngas is now predominantly in the form of $CO_2$ and can be removed from the gas stream using a physical or chemical solvent. Many chemical and physical solvents (or mixtures of both) are currently offered by various manufactures. (e.g. Selexol, Rectisol, MDEA and others, for more information we refer to (DOE/NETL, 2007b)).

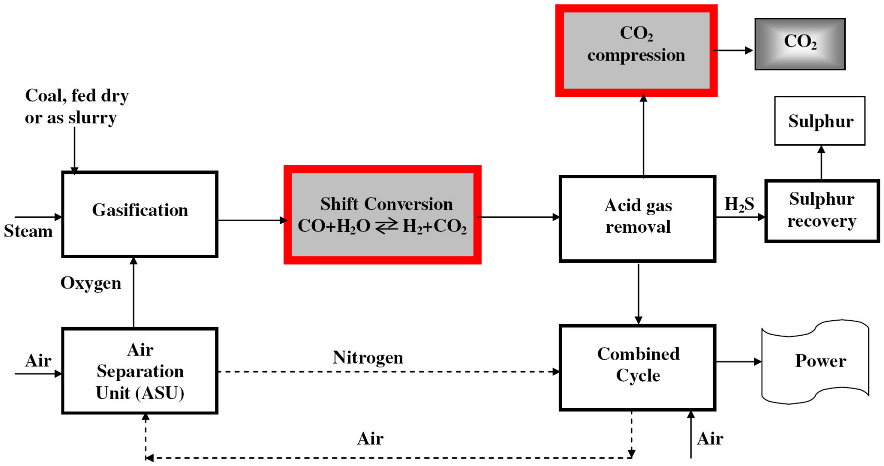

Figure 3.6 Flow sheet for pre combustion process in an IGCC configuration, with additional processes required for $CO_2$ capture highlighted (from (Wall, 2007)). Note that this flow sheet depicts the sour shift configuration. The sweet shift configuration would have an additional COS hydrolysis and acid gas removal step (for $H_2S$) prior to the shift conversion.

#### *3.3.1.2 Application area*

The pre combustion capture process is in essence a $CO_2$ separation process for gas streams that are formed after partial oxidation or gasification of solid and liquid (such as heavy hydrocarbons) fuels. Sectors where these gas streams are produced and used are for instance the (petro-)chemical industry, steel and iron industry and in the power sector. According to Minchener (2005), in 2005 160 modern gasification plants are in operation. These are used or can be used for the production of electricity, ammonia, oxy-chemicals, syngas, methanol, hydrogen and syntethic fuels. (e.g. coal-to-liquids and biomass-to-liquids). One of the main benefits of the gasification process is thus that the syngas can be used to for multiple purposes or products. Early opportunities for gasification with pre combustion $CO_2$ capture and storage may be industrial process such as the coal-to-liquids process that already require the separation of $CO_2$. In Pernis the pre combustion capture technology is already used and $CO_2$ from that process is partly used in the horticulture sector. Also, a part of the captured $CO_2$ is planned to be injected in a nearly empty gas field near Barendrecht starting in 2010.

##### *3.3.1.2.1 Power sector*

Only a few coal fired IGCC plants designed solely for the production of electricity are operating today. Gasifiers are thus mainly operated in the (petro)-chemical industry and are considered a proven technology. The limited availability[8] of demonstration IGCC power plants is often considered a problem for the application of gasification in the power sector. Availability of IGCC is however coming close to that of PC. (Damen, 2008)

Currently, several suppliers offer gasifier technology in three variants: the fixed bed, fluidized bed and the entrained flow gasifier. The entrained flow gasifier is seen as the most flexible technology variant, is preferred in recent IGCC applications (Beer, 2007; Minchener, 2005) and shows the overall most benign environmental performance. (Zheng and Furinsky, 2005) For the entrained flow gasifier also two basic variants exist, the dry-fed gasifiers (such as the Shell gasifier) and slurry-fed gasifiers. In general, the dry-fed gasifiers show a better energetic performance and higher flexibility. However, for IGCC applications with $CO_2$ capture the slurry-fed gasifiers seem to be more economical and have a lower efficiency penalty when using hard coal. (Maurstad, 2005)

The IGCC at Buggenum currently operated by NUON uses the Shell dry-fed, entrained flow gasifier and is able to co-gasify biomass with coal as the primary fuel. A new IGCC is planned to be built and operated by NUON in the Netherlands. This power plant is being designed to be flexible regarding its fuel input. The gasifier is being designed to be fed with mixes of for instance biomass, coal and pet coke. The gas turbine is being designed to be able to fire gas with varying compositions, including (mixtures of) natural gas and syngas.

One of the main drivers for IGCC power plants is their high thermodynamic efficiency. A second driver is the ability to (co-)gasify low cost fuels and wastes with low emission levels. The latter is due to its efficient gas cleaning section and the formation of unleachable slag, a solid by-product of gasification. However, the co-gasification of wastes and biomass may have a negative effect on the efficiency and availability of the plant. For example, biomass co-gasification may result in fouling of cooling surfaces. (ZEP, 2006)

When applying pre combustion $CO_2$ capture on IGCC facilities, or gasifiers in general, the main processes involved in $CO_2$ capture are considered to be the same independently of the fuel input (oil, coal, biomass and waste) (ZEP, 2006). Valero and Uson (2006) note however that operating strategies of an IGCC should vary with the fuel mix, due to different constituents of coal and biomass. Sulphur and ash content are generally lower for biomass compared to coal. Chlorine, oxygen and hydrogen content are generally higher (Brown et al.; Valero and Uson, 2006). The composition of the fuel feed has an impact on the composition of the syngas exiting the gasifier. This may in turn affect for instance the shift process and $CO_2$ capture energy requirement. Such operating issues when firing biomass (or waste fuels) should be taken into consideration for IGCC applications with pre combustion $CO_2$ capture (Damen, 2008).

According to Bohm et al. (2007) retrofitting of IGCCs with pre combustion $CO_2$ capture brings forwards numerous issues, they may include: the availability of space, the modification or replacement of turbines, replacing the syngas cooling technology, the addition of the $CO_2$ removal section (sweet shift) and the replacement of an AGR section (sour shift), and the derating of the gas turbine. Designing a plant capture ready will have benefits when $CO_2$ capture is planned to be installed at a later date. The IGCC

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[8] Availability here is defined as the number of hours that a power plant is available for power production per year.

planned by NUON is possibly retrofitted with pre combustion $CO_2$ capture and is designing the IGCC capture ready. An approach of interest for IGCC with pre-combustion capture is to install a natural gas fired CCGT first without gasification and without $CO_2$ capture. If policy and market conditions are favourable the gasification plant with $CO_2$ capture can be installed. This approach is followed to some extent by NUON as well as they are building their CCGT power plant first, then, if economically feasible, the gasification plant. This approach is also studied by E.ON in the UK.

###### *3.3.1.2.2 Iron and steel production*

Gielen (2003) investigated the capture of $CO_2$ from several steel production processes such as Direct-reduced iron (DRI)[9], cyclone converter furnace (CCF), COREX process and from integrated steel mills. The integrated steel mills (the BF and BOF processes), COREX and CCF variants can be considered as oxygen fired gasification processes where part of the syngas is used to reduce the iron ore. Basically, the $CO_2$ capture technology suitable for IGCC is also interesting for these iron and steel making processes.

In a blast furnace (BF) iron ore is reduced with pulverized coal and cokes. The blast furnace process yields pig iron and blast furnace gas. The pig iron can then be converted to steel in a basic oxygen furnace (BOF). The basic oxygen furnace yields steel and BOF gas. $CO_2$ may be captured from both the BF and BOF gas.

The BF gas contains CO (20-28%), $H_2$ (1–5%), $N_2$ (50-55%), $CO_2$ (17-25%), $NH_3$, hydrocarbons, PAH, sulphur and cyanide compounds. It also contains significant amount of particulates matter, which includes unburned carbon and heavy metals (IPPC, 2001). Gases from the BF, BOF and gas from cokes production from the Corus facility in Ijmuiden are currently being used in CHP plants IJmond01 and Velsen Noord (NUON) to produce electricity and heat.

In the Netherlands the capture of $CO_2$ from the BF gas produced at the Corus facility may be an interesting option. The capture of $CO_2$ would involve additional equipment to compress and shift the BF gas. This yields a flow with increased concentration and partial pressure of $CO_2$ and hydrogen. The compression[10] of the BF gas and the capture of $CO_2$ require electricity, 0.48 GJ/t $CO_{2\ \text{captured}}$ / and 0.34 GJ/t $CO_{2\ \text{captured}}$ (0.09 MWh) respectively, totalling 0.82 GJ/ t $CO_{2\ \text{captured}}$ (0.23 MWh). The remaining BF gas, consisting primarily of $N_2$ and $H_{2,}$ has a higher calorifc value and can be fed into a gas turbine to generate electricity. Another option is to treat further the remaining BF gas including $H_2$ separation using membranes (Gielen, (2003). The $H_2$ flow is expanded in a turbine and yields about 0.20 GJ/t $CO_{2\ \text{captured}}$ (0.06 MWh). In total the process would require 0.62 GJ/t $CO_{2\ \text{captured}}$ (0.17 MWh).

Pre combustion technology may also be suited for $CO_2$ capture from the BOF gas. This gas has a higher CO concentration (55-80%) and lower $CO_2$ concentration (10-18%) compared to the BF gas. (IPPC, 2001) After shifting and compressing the BOF gas the $CO_2$ can be removed from the gas stream.

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[9] Direct reduced iron refers to production process of iron by directly reacting the iron ore with a reducing gas constituting mainly $H_2$ and CO. This gas may be derived from coal or natural gas. The latter is currently the most used feedstock (Gielen, 2003).

[10] $CO_2$ is compressed to 100 bar for transport.

The $CO_2$ capture from the BF gas may have environmental benefits according to Lampert and Ziebik (2007). They argue that the purified gas (after $CO_2$ capture) may be used in the BF process as reducing agent. This is because Lampert and Ziebik (2007) assumed no shift reaction in their $CO_2$ capture configuration. The purified gas has therefore high reducing gas concentrations in the form of CO and $H_2$. When this gas is used in the BF process it may decrease coke consumption and with it avoid emission associated with coke production.

At the iron and steel production facility owned by Corus in Ijmuiden the capture of $CO_2$ with the pre combustion capture process would have an impact on the power and heat integration at the Corus site. First, there would be a lower electricity production and probably has to be substituted (e.g. by natural gas firing). Second, the compression of the gasses would require additional electricity. Next to power and heat integration also other technical issues arise. For instance, the gas turbines of the IJmond01 and Velsen Noord CHPs are not designed to fire hydrogen rich fuels. Therefore, re-design or replacement of the gas turbines is probably necessary. For these reasons, pre combustion $CO_2$ capture at the CORUS site is not expected to be ready for implementation on the short term. Implementation on the medium to longer term, i.e. around 2020, may be an option.

#### *3.3.1.3 Development phase*

The technology to capture $CO_2$ from the syngas generated in a gasifier can be considered proven technology and is commercially available in other gasification applications than for electricity production, e.g. hydrogen, chemical (ammonia) and synthetic fuel production. (Nexant Inc., 2006) An example is the Great Plains synfuels plant in North Dakota where synthetic fuels and chemicals are produced from coal gasification and where about 2.5 Mt of $CO_2$ was captured in 2007 using pre-combustion capture technology (i.e. based on Rectisol). The captured $CO_2$ is transported to Canada, where it is used in an EOR (enhanced Oil Recovery) project (DGC, 2008; Eliason and Perry, 2004).

The pre combustion concept is however not proven in an IGCC configuration for power generation. In Figure 3.7 the relative maturity of the different components of a power plant are assessed. The most critical components in the development and deployment are the gasifier and the turbine. The IGCC power plant has to prove to be reliable. Availability of the power plant is namely a critical factor in the economics of the power generation process. The gas turbine has to be designed and optimized for hydrogen rich fuels. This means that the efficiency and environmental performance ($NO_x$ formation) has to be in the same range of the performance of natural gas fired turbines. Regarding the syngas processing both shifts (sour and sweet) processes are currently being applied in industry and are thus available. The acid gas removal processes including the $CO_2$ capture process are also already applied. Note that although already applied in industry, the $CO_2$ capture process has not been demonstrated at IGCC plants. The real challenge lies in the integration and optimization of these components in a reliable power plant. Currently, several pilot and demonstration projects are being planned (see Table 3.6).

Before large scale implementation in IGCC configuration the technology should be proven on the pilot and demonstration plant scale. Some emerging technologies may be of interest for ‘second generation’ pre combustion capture applications. One is, for instance, membrane development for: the separation of oxygen required for the gasification instead of cryogenic air separation (the current applied technology); the separation of $CO_2$ and $H_2$, and, finally, water gas shift membrane reactors which would incorporate both the shift reaction and $CO_2$ capture into one step.

Another process that would incorporate both the Water Gas Shift and $CO_2$ capture step is the Sorption Enhanced Water Gas Shift (SEWGS). This technology is being developed and tested by ECN for the operation with natural gas but is also studied for application in an IGCC[11] by ECN and KEMA. The syngas is fed into the SEWGS where the CO and $H_2O$ are converted to $H_2$ and $CO_2$ by reaction over a catalyst. The $CO_2$ formed is adsorbed with the use of a solid sorbent. This technology would yield a high purity $CO_2$ (and $H_2$) stream which can be compressed, transported and stored. The technology does not require cooling of the syngas prior to the shift reaction and requires less steam, which means a lower energy penalty is allocated to $CO_2$ capture and thus a higher overall cycle efficiency. This technology is however considered to ready for implementation only on the longer term (Jansen, 2008).

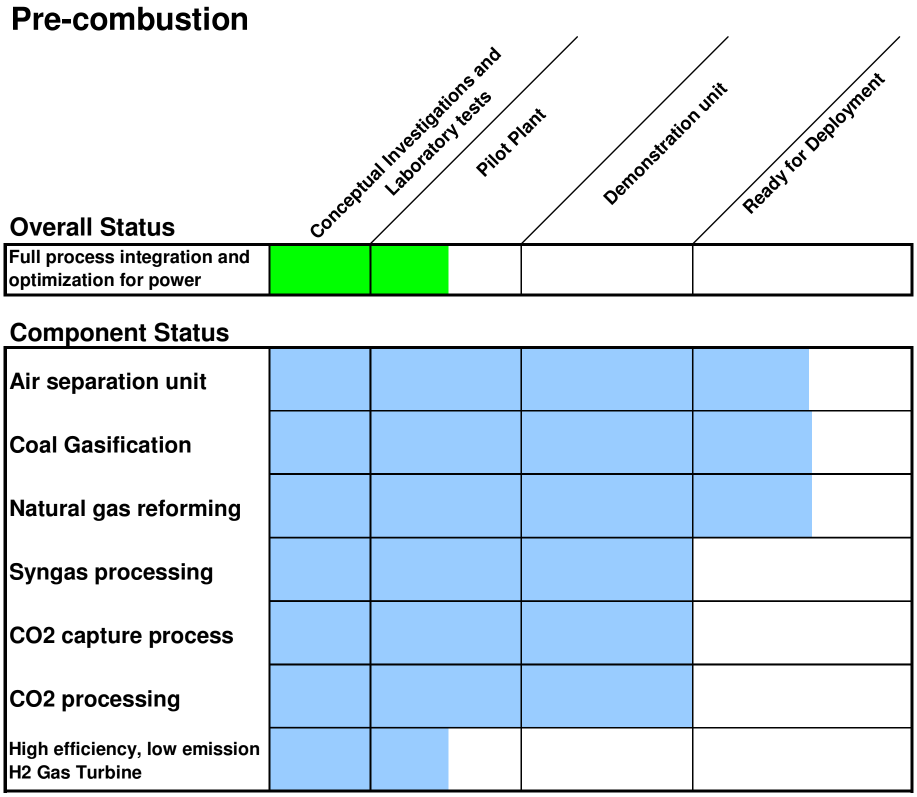

Figure 3.7 Maturity of pre combustion $CO_2$ capture components. Adapted from (ZEP, 2006) after expert consultation.

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[11] The SE-WGS is also being tested with a mixture containing $H_2S$ to test the effect of a sour shift on the catalyst and sorbent. Results indicate that the sorbent adsorbs $H_2S$ and is not destroyed by $H_2S$ loading. The $CO_2$ capacity is however suppressed as part of the sorbent is occupied by $H_2S$. The main fraction of $H_2S$ then ends up in the $CO_2$ stream.

Other means to increase efficiency on the longer term are hot gas cleaning in the gas cleaning processes. In the energy conversion step fuel cells (e.g. SOFC[12]) may be used to generate electricity by converting hydrogen. (US DOE, 2007) For the short and medium term improvement and development of new solvents is envisaged to lower the energy penalty associated with the capture of $CO_2$. (US DOE, 2007) (Nexant Inc., 2006; ZEP, 2006)

Table 3.6 Overview of pre combustion pilot and demonstration projects (after (MIT, 2008))

| **Project Name** | **Location** | **Feedstock** | **Size MW** | **Start-up/ Status** |
|---|---|---|---|---|
| NUON IGCC pilot | Buggenum | Coal/biomass | pilot | 2008/9 |
| NUON IGCC Magnum/ Eemshaven | Eemshaven | Coal/biomass/ petcoke/others | Demonstration ~80% capture of one out of three gasifiers | 2013 |
| GreenGen | China | Coal | 250/800* | 2009 |
| ZeroGen | Australia | Coal | 100 | 2010 |
| E.ON Killingholme | UK | Coal | 450 | 2011 |
| BP Carson | USA | Petcoke | 500 | 2012 |
| Progressive/ Centrica | Eston Grange, UK | Coal/Petcoke | 800 | 2012 |
| Appalachian Power | USA | Coal | 629 | 2012 |
| Wallula Energy Resource Center | USA | Coal | 600-700 | 2013 |
| BP Rio Tinto Kwinana (DF3) | Australia | Coal | 500 | 2014 |
| RWE Zero CO2 | Germany | Coal | 450 | 2015 |
| Monash Energy | Australia | Coal | Coal to liquids | 2016 |
| Powerfuel Hatfield | UK | Coal | 900 | Undecided |
| Polygen Project | Canada | Coal/Petcoke | 300 | Undecided |
| FutureGen | USA | Coal | 275 | 2012, Cancelled |

* 250 MW demonstration plant followed by an 800 MW commercial plant

### *3.3.1.4 Economic and energy performance*

#### *3.3.1.4.1 Power sector*

In an IGCC it is possible to use physical absorbents instead of chemical absorbents generally proposed in the post combustion capture process. The main advantage of using physical sorbents is the lower energy requirement in the $CO_2$ capture process, which is the most important factor in the efficiency penalty of post combustion processes. The use of physical sorbents does not (or only to a limited extent) require

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[12] This is not very likely according to Jansen (2008) as the SOFC can better be used to generate electricity from the syngas yielding $CO_2$ and water. Overall it is not likely that fuel cells would be used in IGCC applications due to difficulties in scaling up the SOFC stacks and the fuel feed gas requirements of fuel cells. It is questionable whether these requirements can be met by the gasification and gas cleaning processes.

heat to strip the $CO_2$ from the sorbent. The most important factor in the pre combustion process is the removal of chemical energy from the syngas. Further, energy is needed to compress and circulate the solvent. In the pre combustion concept $CO_2$ compression requires less energy compared to post combustion capture as the $CO_2$ is available at higher pressures after separation.

In Table 3.7 a summary of values of the energetic performance derived from literature is presented for the IGCC technology with and without $CO_2$ capture. It should be stressed that the efficiency of the IGCC with and without capture depends on several factors, for instance: the chosen gasification technology (e.g. Shell, GE Energy, CoP), shift configuration, assumptions on future development of IGCC technology, level of heat integration, fuel quality (e.g. coal rank), $CO_2$ emissions factor (g $CO_2$ / MJfuel), $CO_2$ product pressure and $CO_2$ removal efficiency.

Table 3.7 Energetic performance of IGCC power plants with and without $CO_2$ capture

| | **Without capture** | **With capture** |
|---|---|---|
| Electrical efficiency (%) | 38-47 | 32 -41 |
| Efficiency penalty (in % pts) | - | 5-9 |
| Primary Energy increase per kWh (%) | - | 16-28 |
| Capture efficiency (%) | - | 85-91 |
| $CO_2$ product pressure (MPa) | - | 8.4-15.3 |

The economical performance of a power plant is mainly determined by the capital cost, fuel cost and operation and maintenance (O&M) cost. In general an IGCC power plant involves a higher investment compared to a pulverized coal power plant. The application of $CO_2$ capture increases the costs. This is mainly due to significant additional investments for the $CO_2$ capture and compression equipment; the cost of fuel per net generated output is increased due to the efficiency penalty and the O&M also increases. In Table 3.8 a summary of values for the economic performance derived from literature is presented for the IGCC technology with and without $CO_2$ capture.

Table 3.8 Economic performance of IGCC power plants with and without $CO_2$ capture

| | **No-capture** | **With capture** |
|---|---|---|
| Euro per tonne avoided (constant 2007 euros) | - | 19-38 |
| Cost of electricity (in euro cts/kWh) | 4.7-6.6 | 5.8-9.0 |
| $CO_2$ emissions (in g/kWh) | 694-833 | 71-152 |

Note that the factors that determine the energetic performance also influence the economic performance. Additionally, for the economic performance, assumptions on capitals cost, interest rate, power plant lifetime and fuel cost have a large influence on the estimation of cost of electricity and cost per tonne $CO_2$ avoided. In literature the values assumed for these factors vary significantly. This explains the large variance in cost of electricity and cost of avoidance shown in Table 3.8. Furthermore, over the past years investment cost of industrial facilities in general and thus IGCC facilities has risen significantly as has the cost of coal. This implicates that the figures mentioned above are expected to be underestimated by at least 30%.

#### *3.3.1.4.2 Iron and steel production*

Both (Gielen 2003) and (Lampert and Ziebik 2007) studied the energetic and economic performance of pre combustion $CO_2$ in the iron and steel industry, i.e. capture from the COREX and BF process. In Table 3.9 the main results of these studies are summarized. The lower specific power consumption calculated by (Lampert and Ziebik 2007) is partly due to an assumed lower $CO_2$ product pressure. Also, (Lampert and Ziebik 2007) did not include a shift conversion step, which means that not all carbon is removed from the off gases as a part of it remains in the form of CO. Hence, $CO_2$ capture is therefore limited as the purified gas still contains a high concentration of CO. An advantage of this approach may be that the CHP (i.e. the gas turbine) does not have to be adapted or replaced in order to be able to fire hydrogen rich fuels.

Table 3.9 Energetic and economic performance of pre combustion $CO_2$ capture in the iron and steel industry

| Parameter | Unit | COREX process | Blast furnace process | Source |
|---|---|---|---|---|
| Specific power consumption | GJe/t $CO_2$ | 0.56 | 0.34-0.62 | (Gielen, 2003) |
| | GJe/t $CO_2$ | 0.335 | 0.505 | (Lampert and Ziebik, 2007) |
| Cost per tonne $CO_2$ captured | Euro (2007)/tonne | 17.8* | 16.3-18.3* | (Gielen, 2003) |

* Original cost results were given in US$/tonne and assumed to be constant 2003 $.

#### *3.3.1.5 Environmental performance*

As mentioned earlier the overall environmental performance of IGCC facilities is rather good due to its efficient gas cleaning section. How this environmental performance is affected by the addition of $CO_2$ capture is discussed in this section. Although the focus here is on NEC emissions, other environmental impacts of concern are also briefly discussed.

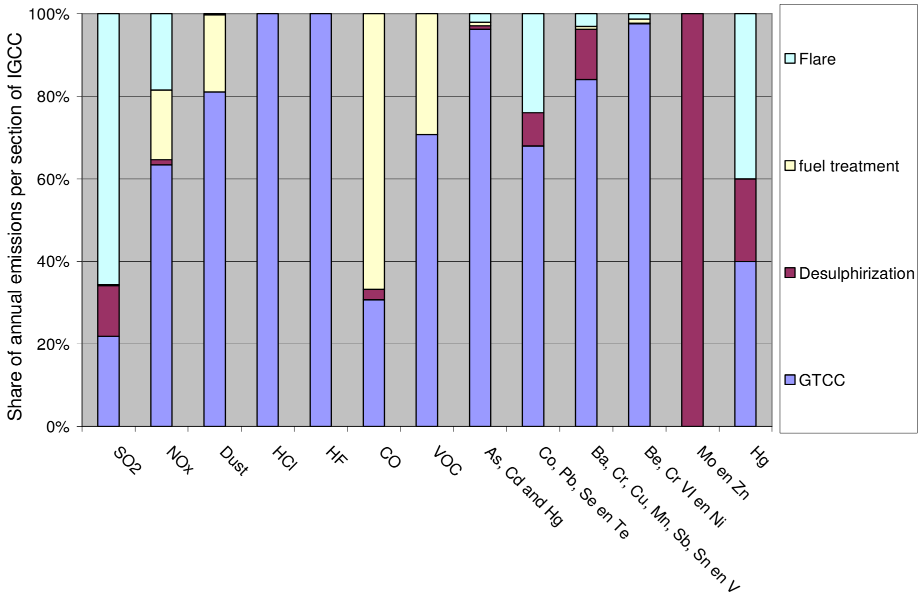

Figure 3.8 Annual emissions of the major power plant sections of the NUON IGCC at Buggenum in the year 2004. (Derived from (NUON, 2005))

### *3.3.1.5.1 $SO_x$*

IGCC technology without $CO_2$ capture already has very low $SO_x$ emissions due to the high level of recovery of sulphur compounds ($H_2S$ and COS) from the syngas in the acid gas removal step and subsequent gas treating units. This configuration enables over 99% removal of sulphur compounds from the syngas (see Table 3.10).

Table 3.10 Performance op sulphur removal technologies for high sulphur bituminous coal (Illinois #6) (Nexant Inc., 2006)

| **Sulphur Removal Technology** | **MDEA** | **Selexol** | **Rectisol** | **Sulfinol-M** |
|---|---|---|---|---|
| Type of solvent | Chemical | Physical | Physical | Mixture of Physical and Chemical** |
| Uncontrolled emission reduction % | 99.37 | 99.83 | 99.91 | >99.8* |

* source (KEMA, 2006)

** source (DOE/NETL, 2007b)

The product of this process train is elemental sulphur or sulphuric acid, which can be sold. Remaining sulphur compounds in the syngas are emitted mainly as sulphur oxides after combustion. Also, some ammonium sulphate may be formed which is a known constituent of atmospheric aerosols, i.e. fine particulate matter.

In Figure 3.8 the environmental profile of the NUON IGCC facility at Buggenum is shown. The figure depicts the fraction of emissions per sub-unit of the facility. For $SO_2$ it is clear that the flare and to a lesser extent the desulphurization section are responsible for the largest part of the $SO_2$ emissions. This means that a fraction of the removed sulphur is emitted in the desulphurization section of the IGCC. The largest fraction is however emitted by the flaring of gasses. Over 2004 and 2005 the share of the flare and the desulphurization section varied between 64-66% and 12-23%, respectively. Flaring is part of start up and shot down procedures and is performed during outages of the desulphurization section.

When implementing $CO_2$ capture, $SO_2$ emissions from the GTCC are expected to be affected by the capture process[13]. In both the sweet and the sour shift approaches some $H_2S$ may be present in the $CO_2$ stream, i.e. <20 ppm. Also, some $CO_2$ will be removed in the first stage together with the $H_2S$ and will subsequently be emitted into the atmosphere.

The NETL (2007b) reports lower values for $SO_2$ emission per primary energy input for the cases with $CO_2$ capture, see Table 3.11. This is partly due to their assumption that the sorbent used for AGR (without $CO_2$ capture) is replaced by Selexol with higher $H_2S$ removal efficiencies. However, this is only applicable on the CoP and Shell technologies. The GE gasifier shows lower emissions for the case with $CO_2$ capture (using equal removal efficiencies; both with Selexol). Thus for all cases the literature shows that sulphur removal per primary energy input is higher due to the addition of a $CO_2$ capture[14] step. This will result, however, in the presence of a trace amount of $H_2S$ in the $CO_2$ stream.

Table 3.11 Effect of pre combustion $CO_2$ capture on $SO_2$ emission (DOE/NETL, 2007b)

| **Technology description** | **$SO_2$ emissions (in mg/MJ)** | **Effect of $CO_2$ capture** | **$SO_2$ emissions (in mg/kWh)** | **Effect of $CO_2$ capture** | **Sulphur removal efficiency** | **Removal technology** |
|---|---|---|---|---|---|---|
| GE Energy | 5.66 | | 51.4 | | 99.6% | Selexol |
| GE Energy with CCS | 4.27 | -24% | 45.7 | -11% | 99.6% | Selexol 1st Stage |
| CoP E-Gas™ | 5.56 | | 49.1 | | 99.5% | Refrigerated MDEA |
| CoP E-Gas™ with CCS | 3.80 | -32% | 41.7 | -15% | 99.7% | Selexol 1st Stage |
| Shell IGCC plant | 5.55 | | 46.9 | | 99.5% | Sulfinol-M |
| Shell IGCC plant with CCS | 4.69 | -15% | 50.9 | +9% | 99.7% | Selexol 1st Stage |

Original data is in lb/$MWh_{gross}$, converted to g/$kWh_{net}$ and g/MJ LHV by using a conversion factor LHV/HHV =0.965.
Sulphur content 2.51% wt (as received) Illinois No. 6 bituminous coal
CoP = ConocoPhillips
All $CO_2$ capture cases are based on the sour water gas shift configuration

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[13] In the case of a sour shift, the pre combustion capture installation makes the process of COS hydrolysis redundant as this occurs in the water gas shift reactor. After the WGS the $H_2S$ is removed (in the case of sour shift) in the first absorber and $CO_2$ in the second. In the case of the sweet shift first the $H_2S$ is removed from the syngas, after COS hydrolysis. Then, the WGS reactors shift the composition of the syngas towards higher $CO_2$ and $H_2$ concentrations. A second acid gas removal process removes the $CO_2$ from the syngas. The latter configuration is currently envisaged in the by NUON planned IGCC if it is equipped with $CO_2$ capture.

[14] The $CO_2$ capture process of the to be built NUON IGCC facility is likely a sweet shift configuration with two separate AGR processes, one for $H_2S$ and one for $CO_2$. Also in this configuration $SO_2$ emissions are highly likely to be lower (per primary energy input), due to the co-capture of $H_2S$ in the $CO_2$ removal process. (Damen, 2008)

Although the increased removal of $H_2S$ is expected to result in a lower $SO_2$ emission factor per primary energy input, the emission factor per net generated electricity can in some cases be higher. See for example the Shell IGCC-CCS case in Table 3.11. This increase is due to efficiency penalty caused by the $CO_2$ capture process.

With the IGCC technology it is also possible to capture $H_2S$ and $CO_2$ together and inject the $CO_2$-$H_2S$ mixture in the underground. (Ordorica-Garcia et al., 2006) (US DOE, 2007) This will, however, complicate transport and storage requirements, as the $H_2S$ in the mixture might pose corrosion problems for pipeline transport and may cause unwanted interactions in the underground storage reservoir.

(Valero and Uson, 2006) note that if biomass is co-gasified, the sulphur content of the fuel mix is in general lowered. This will result in lower levels of $H_2S$ in the syngas. Whether this will influence the emission of $SO_x$ depends on the operating strategy for the acid gas removal section.

#### *3.3.1.5.2 $NO_x$*

During normal operation, $NO_x$ emissions in the IGCC with $CO_2$ capture are mainly generated during the combustion of the hydrogen rich syngas with air in the gas turbine. The hydrogen rich syngas must be diluted in order to reduce the flame temperature in the gas turbine. According to (Chiesa et al., 2005), the flame temperature it strongly related to $NO_x$ formation. The flame temperature is dependent on the syngas composition and heating value. Both of these will change when applying $CO_2$ capture. If dilution with steam or nitrogen is not applied, the flame temperature during firing of hydrogen rich fuel will increase resulting in an increase in $NO_x$ formation.

The main problem during $H_2$ rich fuel combustion in gas turbines is that conventional dry low $NO_x$ burner technology can not be applied. Such a technique is not safe when dealing with $H_2$ rich fuel gas as the $H_2$ would react promptly during mixing of air and fuel, due to lower ignition temperature of hydrogen. Remaining $NO_x$ reduction techniques that are then available are dilution with steam and/or with nitrogen from the ASU, and post combustion reduction (e.g. Selective Catalytic Reduction - SCR). (Chiesa et al., 2005)

Taking the changing fuel composition, flow and combustion characteristics into account the (IEA GHG, 2006b) reports that $NO_x$ emissions could be higher for an IGCC with CCS compared to a reference IGCC without $CO_2$ capture. According to (Tzimas et al., 2007) $NO_x$ emissions will be comparable to those of a NGCC without capture, i.e. 0.10 g/kWh. (Davison, 2007) reports 0.40-0.55 g/kWh for an IGCC with capture and 0.39-0.58 g/kWh for one without capture. In one (Shell gasifier, Selexol solvent) of the two cases analyzed by Davison $NO_x$ emissions decrease per kWh and in the other (GE gasifier, Selexol solvent) the $NO_x$ emissions increase. An explanation for this is however not presented.

(DOE/NETL, 2007b) reports lower values for $NO_x$ emission per primary energy input for the cases with $CO_2$ capture, see Table 3.12 This effect can mainly be attributed to the assumption that due to capture a smaller volume of (hydrogen rich) syngas is combusted.. This, together with the assumption that the $NO_x$ emissions from the gas turbine are equal (i.e. 15 ppmv @ 15% $O_2$) for both with and without capture, results in a total lower emission of $NO_x$ per primary energy input. This results, however, requires turbine manufacturers to solve problems around $NO_x$ formation in hydrogen rich gas turbines. Considerable research efforts are already allocated to this topic by turbine manufacturers.

Table 3.12 Effect of pre combustion $CO_2$ capture on $NO_x$ emission (DOE/NETL, 2007b)

| **Technology description** | **$NO_x$ emissions (in g/MJ)** | **Effect of $CO_2$ capture** | **$NO_x$ emissions (in g/kWh)** | **Effect of $CO_2$ capture** |
|---|---|---|---|---|
| GE Energy (GEE) | 0.0244 | | 0.222 | |
| GE Energy (GEE) with CCS | 0.0208 | -15% | 0.223 | ~0% |
| ConocoPhillips (CoP) E-Gas™ | 0.0265 | | 0.234 | |
| ConocoPhillips (CoP) E-Gas™ with CCS | 0.0222 | -16% | 0.243 | +4% |
| Shell IGCC plant. | 0.0261 | | 0.220 | |
| Shell IGCC plant with CCS. | 0.0218 | -17% | 0.236 | +7% |

Original data in HHV, used conversion factor LHV/HHV =0.965

Emission estimates are based on an advanced F-class turbine with $NO_x$ emissions of 15 ppmv @ 15% $O_2$

Although (DOE/NETL, 2007b) reports that $NO_x$ emissions per primary energy input are expected to decrease, the emissions per net generated electricity can in some cases be higher. For the Shell and CoP cases (Table 3.12) the value of $NO_x$ emissions per kWh increases due to the efficiency penalty associated to $CO_2$ capture. For the GE case with capture the net increase is smaller than 1%.

If regulations should be become stricter, deeper $NO_x$ reduction is possible by adding a Selective Catalytic Reduction (SCR) process. This will reduce $NO_x$ emissions by circa 80% (Nexant Inc., 2006). The application of SCR in IGCC plants poses, however, additional costs and some operational difficulties[15]. The co-benefit of $CO_2$ capture is that a deeper reduction of sulphur compounds may be expected in the syngas, resulting in more benign conditions for the application of SCR in IGCC plants.

The cost of additional $NO_x$ removal is estimated by Chiesa et al. (2005) to be between 2000 and 8000 $ per ton $NO_x$. (Nexant Inc., 2006) estimates between 7,290 -13,120 $/t $NO_x$. These figures include the cost of deep sulphur reduction required for SCR application in an IGCC without $CO_2$ capture. For an IGCC with $CO_2$ capture the additional cost of SCR implementation are expected to be lower.

Another possible side effect of SCR application is the emission of unreacted ammonia, or ammonia slip. This is especially the case when the SCR is applied on exhaust gasses with low $NO_x$ concentrations. An optimal between $NO_x$ reduction and ammonia slip should therefore be found. (Rao, 2006)

In Figure 3.8 it is shown that a significant fraction of $NO_x$ emissions can be emitted during flaring. During normal operation, i.e. no frequent start-up and shut-down procedures, the main fraction of emissions is expected to be emitted by the GTCC

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[15] First there is an additional energy penalty associated with the operation of the SCR due to pumping and vaporization of the ammonia, and due to reduced output of the gas turbine caused by the pressure drop over the SCR. (Ratafia-Brown et al., 2002) Furthermore there are environmental issues due to the possible reaction of unreacted ammonia with $SO_3$ which may form ammonium salts, such as ammonium sulphate. This may cause fouling and corrosion of the equipment. Furthermore, salts that are not deposit are emitted as particulate matter.

section. Nevertheless, when determining emission factors for IGCC power plants (with and without $CO_2$ capture), ideally, emissions during non-normal operation should be included (a figure with emissions in a non-normal operation is shown in Appendix B).

###### *3.3.1.5.3 $NH_3$*

$NH_3$ is formed during gasification from the reaction of fuel bound nitrogen with hydrogen. It is however removed from the syngas in the gas cleaning section using wet scrubbing. The same water wash section that removes $NH_3$ for $NO_x$ control, will also remove chlorides to an acceptable level (Phillips, 2006). To achieve high nitrogen removal, HCN in the syngas is converted to $NH_3$ by passing the syngas over a catalyst.

Overall $NH_3$ from an IGCC with capture emissions are considered negligible. As a result, (Rubin et al., 2007) report zero $NH_3$ emissions when comparing PC and NGCC with IGCC. In contrast, NUON (2006) reports over 3 tonne of $NH_3$ emitted over the year 2005 in their IGCC. This equals 0.3-0.4 mg/MJ (~3 g/MWh). The source of this emission was however not specified. Furthermore, in their environmental reports for the period 2000-2004 NUON did not report any or very small $NH_3$ emissions (e.g. in 2002 a total amount of 53 kg was reported due to flaring).

(Ratafia-Brown et al., 2002) report 0.2 mg/MJ based on measured performance of an IGCC without $CO_2$ capture and without a SCR installed.

As already mentioned, it is possible to equip an IGCC with a SCR to reduce $NO_x$ emissions. There is however a trade-off between SCR efficiency and ammonia slip, and hence between $NO_x$ and $NH_3$ emissions. Ammonia slip from SCR, if applicable, is very small < 5 ppmv and is assumed comparable to normal air combustion in a pulverized coal power plant and a NGCC power plant.

###### *3.3.1.5.4 $PM_{10}$ and $PM_{2.5}$*

The emission of particulate matter is inherently low in an IGCC facility as only a small fraction of the ash released by the fuel is released as fly ash. Particulate matter that is entrained in the syngas is almost totally removed by, for instance, cyclone's (candle)filters and wet scrubbing systems. Additional removal also occurs in the acid gas removal step (Ratafia-Brown et al., 2002). A high level of particulate removal is necessary prior to syngas combustion as it may have detrimental effect on the turbine. (Nexant Inc., 2006)

Table 3.13 Overview of particulate matter emissions from IGCC power plants with and without $CO_2$ capture

| Case | Fuel | $PM_{10}$ In mg/MJ | $PM_{10}$ In mg/kWh | Source |
|---|---|---|---|---|
| IGCC no capture | Bituminous coal | 3.2* | 26.7-28.9* | (DOE/NETL, 2007b) |
| IGCC with capture | Bituminous coal | 3.2* | 34.1-34.7* | (DOE/NETL, 2007b) |
| IGCC with capture | Bituminous coal | 2.8-3.1 | - | (US DOE, 2007) |
| | Sub-bituminous coal | 2.7-3.4 | - | (US DOE, 2007) |

* Particulate matter is not explicitly specified as $PM_{10}$ and thus may include all particulate matter.

Particulates that are not removed in the gas cleaning section are emitted with the gas turbine exhaust gas. Additionally in the gas turbine ammonium salts may form, as described earlier, which is also particulate matter. According to (Ratafia-Brown et al.,

2002) sulphates formed during combustion contribute to $PM_{2.5}$ levels. In the literature no further distinction is made between $PM_{10}$ and $PM_{2.5}$. According to Damen (2008) the formation of ammonium sulphate is reduced due to enhanced capture of sulphur compounds. Preliminary estimates anticipate significant lower particulate emissions when applying $CO_2$ capture in an IGCC power plant.

The emission of particulate matter from an IGCC may change if biomass is co-gasified as in general the ash content of biomass is lower than that of coal. (Valero and Uson, 2006)

#### *3.3.1.5.5 NMVOC*

Two main sources of NMVOC in IGCC plants are the stack of the GTCC section and the fuel treatment section (see Figure 3.8). The first source of VOC may be limited by stable and efficient gasification and combustion in the gas turbine. (Nexant Inc., 2006) Ratafia-Brown et al. (2002; p 2-56, 2-36) reports that in general the emissions of organic pollutants, which includes aldehydes and ketones, VOCs, SVOCs, and PAHs, and chlorinated dioxins and furans, of coal fired power plants (including IGCC) are very low. Furthermore they state, although based on limited data, that IGCC plants seem to outperform NGCC plants on the amount of VOC, PAH and aldehyde emissions.

Table 3.14 Overview of VOC emissions from IGCC power plants

| **Case** | **Fuel (% of heat input)** | **VOC in mg/MJ** | **VOC in mg/kWh** | **Source** |
|---|---|---|---|---|
| NUON Buggenum IGCC* | Coal (88%)/ natural gas (10%) / biomass (2%) | 0.76 | 6.5 | (NUON, 2006) |
| NUON Magnum IGCC** | Coal (74%) / pet coke (26%) | Max 0.26 | Max 2.1 | (KEMA, 2006) |
| Wabash River IGCC*** | Bituminous coal | 0.855 | 7.42 | (Ratafia-Brown et al., 2002) |
| FutureGen IGCC with $CO_2$ capture**** | Bituminous coal | 0.63-0.72 | - | (US DOE, 2007) |
|  | Sub-bituminous coal | 0.54-0.68 | - | (US DOE, 2007) |

* Emissions in 2005

** Estimates in environmental impact assessment

*** Emissions in 1997 and 1998

**** Range for three gasifier variants (Shell, GE, CoP), all equipped with $CO_2$ capture

Note that data sources do not specify whether VOC include or exclude methane.

For an IGCC equipped with $CO_2$ capture the VOC emissions from the GTCC section are expected to decrease per primary energy input. The main argument for this is the higher hydrogen and significantly lower carbon content in the fuel gas entering the gas turbine due to $CO_2$ capture. The formation of hydrocarbons is therefore hindered. A quantitative estimate is however unknown. (Damen, 2008)

The second source of NMVOC can be the pre-treatment of biomass prior to gasification. In particular the drying of biomass may result in the formation and emission of terpenes, a VOC. (McKendry, 2002) (NUON, 2006)

A third source is the desulphurization section (see Figure 3.8). According to data provided by CITACT (2007) also VOCs are emitted during shut down and start up procedures, representing about 50% of total annual emissions.

Whether VOC emissions will change per kWh when applying $CO_2$ capture will depend on the relative decrease in emissions from the GTCC due to $CO_2$ capture per MJ and the increase primary energy requirement due to the efficiency penalty.

###### *3.3.1.5.6 Other environmental impacts of concern*

Another important emission from coal fire power plants is mercury. Mercury emission will vary with the mercury content in the fuel and the removal of it in the gas cleaning section. The use of beds containing activated carbon in this section may ensure deep removal of Hg (90-95%). Halogen compounds are formed during gasification, being HCl and HF. They are mainly captured in the wet scrubber section. However, about 40% of chloride may be emitted by the stack. The main other emission media for chloride is the waste water effluent. (US DOE, 2007) (Ratafia-Brown et al., 2002) (Nexant Inc., 2006)

Carbon monoxide emissions from an IGCC with capture are reduced as the WGS process is introduced, converting CO and $H_2O$ into $H_2$ and $CO_2$. A second source of CO emissions is the pre-preparation of the fuel, i.e. storage and grinding. The latter emissions will not be directly affected by the $CO_2$ capture process, although per kWh those emissions will probably increase as more fuel has to be stored and handled per kWh.

Due to the increase in the use of primary energy per kWh any unaffected emission or solid formation by the $CO_2$ capture process will increase accordingly (per kWh). This includes solid by-product and waste formation, and emissions to water. Examples are slag production, ash formation and elemental sulphur production. The emission of the solvent used for capture is not considered to be environmental issue in the case of pre combustion capture, as any trace quantities of the solvent in the syngas will be combusted in the gas turbine section. (Jansen, 2008)

###### *3.3.1.5.7 Uncertainties and knowledge gaps*

One of the uncertainties regarding pre combustion $CO_2$ capture from solid fuels is the emission of $NO_x$. Current gas turbines are not designed, optimized and available for the combustion of hydrogen rich fuels. The efficient combustion of hydrogen rich fuels with low emission levels is therefore one of the R&D priorities. Besides the environmental performance of the gas turbine, the chosen gasifier technology also influences the $NO_x$ emission estimate per kWh, as the increase in primary energy requirement due to $CO_2$ capture varies per gasifier technology. Finally, the application of SCR, although not applied in any case studied here, also influences the estimation of $NO_x$ emissions.

Estimates for the emissions of $SO_2$ given for IGCCs with $CO_2$ capture depend heavily on several assumptions: the sulphur content in the fuel, the removal efficiency of the AGR section and the concentration of sulphur compounds in the $CO_2$ stream. Especially the first parameter is important as the sulphur content in the Dutch coal mix is probably lower compared to the coal mix assumed in the reviewed studies. Reported emission factors are thus probably not representative for IGCCs operated in the Netherlands.

Nevertheless, $SO_2$ emissions are in general considered to be very low for IGCC with $CO_2$ capture.

For the estimates of particulate emissions the data provided in the literature does not differentiate between $PM_{10}$ and $PM_{2.5}$. For instance, (DOE/NETL, 2007b) reports only filterable PM which indicates particulate emissions from the gasification process. This does not include particulate emissions from the GTCC section or particulate emissions from the fuel treatment section. This means that data is not consistent and comparison between different literature sources is difficult.

There are also several uncertainties to be pointed out for NMVOC emissions. First, there is only limited data available on the emissions of NMVOC from IGCC power plants (with or without $CO_2$ capture). Secondly, the emission data that is reported is reported as VOC and thus it is not clear whether this in- or excludes methane. Thirdly, it is unclear whether the reported emission factors include the NMVOC emissions from fuel treatment. As this forms a considerable share of the total NMVOC emissions the emissions factors presented here may be an underestimation. Finally, although it is expected that the implementation of $CO_2$ capture reduces the NMVOC emission (from the GTCC section only) per MJ, to what extent and whether this reduction is also present per kWh is currently unknown.

The emission profile of an IGCC with capture in general depends on numerous variables. For example, a plant may be equipped with an SCR which reduces $NO_x$, but probably will increase $NH_3$ emissions. The chosen gasification technology has an impact on the composition of the syngas, the capture penalty, the net electrical efficiency and the emission profile. The configuration of the gas cleaning section (including the chosen $CO_2$ capture technology) may vary from plant to plant. Finally, also the fuel mix may have an impact on the emission profile. In the consulted literature no data was found on the effect of co-gasification of biomass, or waste materials, on $CO_2$ capture. However, it may be expected that the fuel mix has an impact on the performance of an IGCC with $CO_2$ capture. All these variables together result in the fact that it is currently rather difficult to accurately estimate the emission profile -and with it the emissions of NEC substances- for an IGCC with pre combustion $CO_2$ capture.

There are also uncertainties in the cost estimates of pre combustion capture applications. The assumptions in the studies on the energetic performance and important cost parameters (capital cost, project lifetime, interest rate, O&M cost and fuel cost) vary considerably. Furthermore, both capital cost and fuel cost have been increasing for power plants over the last years. This means that the estimates presented in this study may very well be an underestimation of actual cost of electricity and $CO_2$ avoidance.

For the iron and steel industry it is difficult to estimate the impact of the implementation of $CO_2$ capture on the emission of NEC substances. First, the research for pre combustion $CO_2$ capture development has targeted the power sector. Little information was found on its application in other industries. Secondly, the application of $CO_2$ capture in the iron and steel production industry will require energy. To estimate the change in NEC emissions it is necessary to know how this energy is supplied and what fuel is used. The $CO_2$ capture process may reduce the electricity generated with off-gases from the production processes. This electricity production may be replaced by gas fired or coal fired power plants (or other supply options) which will have different consequences on the NEC emissions estimates. Another option is that the $CO_2$ capture process makes it possible to reduce the demand for coke in the production process. This would lead to an avoidance of emissions by the coke oven, but also will lead in a reduction of electricity production which has to be substituted. These aspects should be researched further.

Next to the uncertainties in emissions and cost also some technological uncertainties should be resolved. The main R&D needs described in literature for the IGCC configuration with $CO_2$ capture are (after Minchener (2005) and (ZEP, 2006)):

- The development of improved material for the gasifier and HRSGs;
- Development of high pressure gasification;
- Development of improved fuel feeding and handling systems;
- Development of new technologies for oxygen production with low cost and low energy requirements;
- Development and demonstration of gas turbines for hydrogen rich fuels;
- Complementary design and optimisation studies, including full integration of $CO_2$ capture and compression.
- Improvement of the operational flexibility of the IGCC

One of the most important factors in further development of the IGCC with pre combustion capture is the realization of demonstration projects to enhance technological learning.

### *3.3.2 Pre combustion - Gaseous fuels*

#### *3.3.2.1 Technical description*

As discussed earlier, the pre combustion capture of $CO_2$ from gaseous fuels involves reforming or partial oxidation of the gas yielding syngas. In this section three pre combustion $CO_2$ capture concepts are separately discussed. They are the ATR, ATR SE-WGS and the MSR-H2.

##### *3.3.2.1.1 ATR*

ATR stands for auto thermal reformer and relates to the reforming of the gas ($C_xH_y$) yielding a stream consisting primarily of CO, $H_2$, $CO_2$ and $N_2$. The ATR process uses compressed air and natural gas mixed with steam to generate syngas. This syngas is shifted, as in the IGCC WGS, in the two shift reactors to mainly $CO_2$ and $H_2$. The stream is then cooled and the steam condenses and water can be separated. The fuel gas ($CO_2 + H_2$) is fed into an absorber to remove the $CO_2$ and yield a stream with a high concentration of $H_2$ and $N_2$. Minor constituents are CO, $CO_2$ and trace amounts of hydrocarbons. This fuel gas is compressed and fed into a gas turbine combustor. The flue gas is then expanded in the gas turbine and fed into the HRSG to generate steam for the steam turbines. Compressed air is the oxidizing medium in this concept and the fuel is a hydrogen rich fuel diluted with nitrogen. This requires a similar gas turbine and combustor as in the IGCC case with $CO_2$ capture. This also means that $NO_x$ is formed during combustion. According to (Kvamsdal and Mejdell, 2005) $NO_x$ formation is comparable to that of a NG fired turbines. For deeper reduction of $NO_x$ emissions a SCR can be installed. (Ertesvag et al., 2005; Kvamsdal et al., 2007; Kvamsdal and Mejdell, 2005)

#### *3.3.2.1.2 ATR SE-WGS*

The main difference with previous explained ATR concept is that the water gas shift reaction and adsorption (by a solid sorbent) of $CO_2$ are performed simultaneously in the Sorption Enhanced WGS reactor. Any sulphur compounds have to be removed from the natural gas prior to reforming as the catalyst may not be resistant to sulphur(compounds), resulting in virtual zero $SO_x$ emissions. In the SE-WGS a WGS catalyst and a $CO_2$ adsorbent shifts the syngas to $H_2$ and $CO_2$ and separates the $H_2$ from the $H_2O$ and $CO_2$. The mixture of $CO_2$ and $H_2O$ is fed into a condenser and the $CO_2$ can be compressed and dried for transport. The main benefit of adding the SE-WGS over conventional WGS reactors is that the syngas from the ATR does not have to be cooled as significantly. This means a reduction in sensible heat loss in the gas turbine feed gas and hence a higher cycle efficiency. (Jansen, 2008)

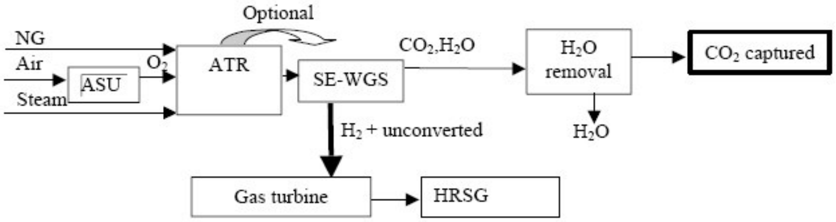

Figure 3.9 ATR SE-WGS pre combustion concept (after (IEA GHG, 2006b))

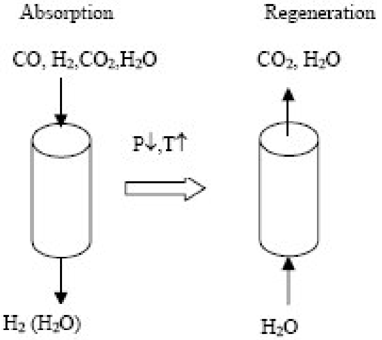

Figure 3.10 SE reformer in sorption mode (left) and regeneration mode (right) (after (IEA GHG, 2006b))

#### *3.3.2.1.3 MSR-$H_2$*

MSR-$H_2$ stands for methane steam reformer with $H_2$ separation. It is in the essence a NGCC where the natural gas combustor is replaced by a MSR-$H_2$ reactor with $H_2$ combustion and an additional $CO_2$/steam turbine. The received natural gas is compressed, heated and partially reformed before entering the MSR-$H_2$ reactor. The hydrogen is separated with the use of a membrane that selectively permeates hydrogen. As the hydrogen is removed from the reactor through sweeping with steam, the water gas shift reaction occurring inside the reactor is enhanced, i.e. to the product side yielding $CO_2$ and $H_2$. The mixture of steam (the sweep gas) and $H_2$ is combusted and expanded in a gas turbine. Afterwards the exhaust gases are heated with supplemental firing (see above) and fed into the MSR-$H_2$ reactor to supply heat. After exiting the reactor the gases are used to generate steam in the HRSG and are emitted to atmosphere. The rest products $CO_2$ and steam from the MSR- $H_2$ reactor are expanded in a $CO_2$ /steam turbine and condensed to separate the $CO_2$ from the $H_2O$. To reach near 100% $CO_2$ capture the unburned hydrocarbons and unconverted CO can be combusted in an afterburner. This would require the installation of an (cryogenic) ASU. (Kvamsdal and Mejdell, 2005)

#### *3.3.2.2 Application area*

Reforming and partial oxidation of (natural) gas is already applied widely for the production of hydrogen in for instance the ammonia production process. In the ammonia production process the pre combustion $CO_2$ capture technology is being used since several decades. The technology generally makes use of physical and chemical (or hybrid) absorption processes. (IPCC, 2005; Mendivil et al., 2006) Part of the $CO_2$ that is removed during ammonia production in Netherlands is currently being used for urea production and in for instance the food and beverage industry. The amount of $CO_2$ available for storage in the Netherlands is estimated to be around 1.3 Mt per year. (Damen, 2007) The energy requirement for $CO_2$ capture is generally allocated to the ammonia production process and therefore only energy is required to compress the $CO_2$ for transport. This can be done for instance with electric and gas fired compressors.

Another application is in the gas-to-liquids process where gas is reformed or partially oxidised to form syngas, which is in turn converted to liquid hydrocarbons, e.g. via the Fischer Tropsch process.

The gas fired pre combustion capture concepts discussed here are all power and heat production concepts and thus find its main application in the power and heat sector.

#### *3.3.2.3 Development phase*

Figure 3.7 shows that no major bottlenecks are expected for the gas reforming section of the ATR and ATR SEWGS power cycles. (ZEP, 2006) According to Kvamsdal et al. (2006, 2007) and Kvamsdal and Mejdell (2005) the ATR reactor can be considered mature as it as already widely used in the chemical industry. They indicate that the main bottleneck lies with the combustion turbine. As with the IGCC with pre combustion capture the gas turbine has to cope with hydrogen rich fuels (e.g. 55% $H_2$). Further, the optimization and integration of these individual components is still area of research. Nevertheless, Kvamsdal and Mejdell (2005) expect that the ATR concept can be implemented in the near future. This technology is near to the demonstration phase.

The ATR SE-WGS concept has compared to the ATR concept the SE-WGS as main new component. This SE-WGS process is currently tested at ECN. The most critical parameters in the SE-WGS reactor are the stability of the adsorbent and the use of steam for cleaning the sorbent. Another important parameter is the operating pressure of the reactor which influences the compression energy requirement. Jansen (2008) estimates that this concept may be ready for implementation in 2015. This would however require promising results from the tests and the employment of pilot projects so that the concept can be tested, optimized and scaled up further. This technology is currently thus in the pilot phase.

The MSR-$H_2$ concept is considered a future term concept. The main reason for this is the hydrogen membrane reactor which is an immature component in this kind of application. (Kvamsdal and Mejdell, 2005) (Kvamsdal et al., 2007) Furthermore, the $CO_2$/steam turbine required envisaged in this concept has to be demonstrated in these kinds of applications. As with the ATR and ATR SE-WGS the combustion of hydrogen rich fuels in a gas turbine has limited operating experience. (Kvamsdal et al., 2006) Overall, the technology has not yet been demonstrated and is still in the laboratory/pilot phase.

#### *3.3.2.4 Economic and energy performance*

As already mentioned the capture of $CO_2$ is already performed in ammonia production process. The concept of capture is similar to the power and heat production concepts that are discussed in more detail here. The main difference is that energy required for capture and with the cost is in general allocated to ammonia production. Damen (2007) estimates that 410 $MJ_e$/tonne $CO_2$ is required to compress the $CO_2$ for transport.

Table 3.15 summarizes the energetic performance of the power and heat production concepts discussed in detail in this report. It shows that the capture penalty compared to NGCC without capture is higher for the near term concepts, i.e. the ATR concepts. The ATR SE-WGS is expected to have a lower efficiency penalty compared to the ATR with conventional water gas shift reactors and absorption process due to the higher operating temperature of the SE-WGS process and with that less sensible heat loss. The MSR-H2 concept is expected to outperform both ATR concepts as shown in Table 3.15.

Table 3.15 Energetic performance of pre combustion $CO_2$ capture concepts

| **Concept** | **Electrical efficiency %** | **Capture penalty %** | **Capture Efficiency %** | **Source** |
|---|---|---|---|---|
| ATR SE-WGS | 47–48 | 9–10 | 90 | (Damen et al., 2006) |
| ATR- absorption | 46.9 | 9.9* | 90 | (Kvamsdal et al., 2007) |
| MSR-H2 | 51–53** | 5–6** | ~100 | (Damen et al., 2006) |
| | 49.6% | 7.1* | 100*** | (Kvamsdal et al., 2007) |

* Compared to NGCC (56.7% net efficiency). Jansen (2008) comments that NGCC efficiency in 2020 may be 60%.

** According to Jansen (2008) 50-51% is more realistic this also means that the capture penalty should be estimated to be somewhat higher, i.e. 6-8% pts.

*** In the case where an ASU is installed and afterburner combusts CO and unconverted fuel. (Kvamsdal and Mejdell, 2005)

In this study only data on the economic performance is gathered for the MSR-$H_2$ concept. Damen et al. (2006) have calculated that the cost of electricity for this concept is about 5 euro cents/kWh with a $CO_2$ avoidance cost of 24 euro per tonne.

#### *3.3.2.5 Environmental performance*

The $CO_2$ that is captured during ammonia production requires compression for transport. The environmental impacts including NEC emissions are then depending on the energy carrier that is used to power the compression train. This can natural gas, electricity or steam. For more information on possible emissions due to compression see sections 3.5 and 3.6.

The environmental performance of the power and heat concepts is discussed below in more detail.

##### *3.3.2.5.1 $SO_x$*

Sulphur content of natural gas is already very low. However, as sulphur compounds often have a detrimental effect on the life time and performance of the reforming catalysts (in the ATR, SE-WGS and MSR-$H_2$ concepts) and membranes (in the MSR-

$H_2$ concept) these will have to be removed prior to fuel conversion. (IEA GHG, 2006b) (Kvamsdal and Mejdell, 2005) The gas fired pre combustion concepts are expected to have negligible $SO_2$ emissions.

###### *3.3.2.5.2 $NO_x$*

$NO_x$ emissions for pre combustion concepts are expected to be typically higher than for conventional state-of the art NGCC cycles due to higher $NO_x$ formation during the combustion of hydrogen rich fuels, i.e. > 25 ppm with the equivalent of about >50 g/GJ. The hydrogen rich fuel gas must be diluted with steam or nitrogen to reduce the flame temperature. According to Chiesa et al. (2005), in the air blown ATR, $N_2$ is a “natural” by-product of the ATR process and is therefore suited to control the $NO_x$ formation during the combustion of hydrogen rich fuel. In the shown concept of the ATR SE-WGS the $N_2$ is available from the ASU. In the MSR-$H_2$ the $N_2$ may be available if an ASU is installed. The MSR-$H_2$ without an ASU would require steam dilution to keep $NO_x$ emissions acceptable. (Kvamsdal and Mejdell, 2005)

For all concepts it is possible to reduce $NO_x$ emissions by installing a SCR. A possible trade-off is then the emission of unreacted $NH_3$ and a decrease in the electrical efficiency.

###### *3.3.2.5.3 $NH_3$*

Theoretically, it is possible to equip the discussed concepts with a SCR. This will have an impact, however, on the investment cost and thermal efficiency of the cycle. A potential negative side-effect may be the emission of unreacted $NH_3$, which is also a pollutant that contributes to acidification and eutrophication.

###### *3.3.2.5.4 $PM_{10}$ and $PM_{2.5}$*

The emission of particulate matter from gas cycles in general can be considered negligible.

###### *3.3.2.5.5 NMVOC*

As for the IGCC concept with pre combustion capture, the carbon content in the gas that enters the GTCC section is very low. Further, unconverted fuel and CO emissions are expected to be lower compared to current NGCC technology. The replacement of natural gas with hydrogen (due to the capture process) is expected to lower the emission of any hydrocarbons.

###### *3.3.2.5.6 Other environmental impacts of concern*

Environmental impacts other than the NEC emissions discussed include environmental impacts in the life cycle of the concepts. For the ATR SE-WGS the production and disposal of the sorbent may have additional environmental impacts, this has however not been studied in detail (Jansen, 2008). The production and disposal of the membranes and catalysts used in the concepts may also have adverse effects on the environment. Catalysts may for instance contain nickel, platinum, rhodium and palladium.

##### *3.3.2.6 Uncertainties and knowledge gaps*

A main source of uncertainties is the development stage of the discussed concepts (laboratory and pilot scale). This means that no emission measurements and accurate estimates of emission factors are available for these concepts. Emission factors are generally discussed qualitatively for these concepts.

Regarding $NO_x$ emissions the same discussion that is put forward for combustion of hydrogen rich fuel in gas turbines after gasification is valid for the gas fired pre combustion concepts (see section 3.3.2.5). $NO_x$ emissions are thus uncertain and can be higher than conventional NGCC power plants. However, the application of a SCR is possible in these concepts.

In this study little information is gathered on the economical performance of the gas fired pre combustion concepts. This should be gathered or assessed in further research.

Technical uncertainties are different for the various concepts. The main technical uncertainty for the ATR concept at the component level is the performance of the gas turbine for hydrogen rich fuels. This component is critical for all concepts. For the ATR SE-WGS the SE-WGS reactor is an additional critical component which has to prove to be reliable for continuous operation before it can be implemented in the power and heat sector. The MSR-$H_2$ has the largest technical uncertainties of the concepts. This is because the MSR-$H_2$ concept incorporates the application of a membrane reactor that can be considered immature. For all concepts system integration and optimization can be another critical step in the development.

### *3.3.3 Conclusions pre combustion $CO_2$ capture*

Pre combustion $CO_2$ capture can be considered a mature technology in industrial applications. The application in IGCC power plants for the gasification of solid and liquid fuels is near to be demonstrated. The application of pre combustion $CO_2$ capture in gas fired power cycles is currently tested in pilot plants and may also find its demonstration in the near future.

$NO_x$ emissions depend mainly on the performance of the gas turbine which has to be able to be fed with hydrogen rich fuel gas. Considerable research efforts are already allocated to this topic by turbine manufacturers. The pre combustion capture increases the hydrogen content of the fuel gas which may lead to higher $NO_x$ emissions from the gas turbine. Overall, lower, equal or higher $NO_x$ emissions may be expected per kWh also due the capture penalty. If required, the pre combustion concepts may be equipped with add-on $DeNo_x$ facilities.

$SO_2$ emissions from gas fired concepts are considered to be negligible. $SO_2$ emissions from an IGCC depend on the sulphur content of the fuel, the removal efficiency of the acid gas removal section and the level of sulphur compounds in the captured $CO_2$ stream. The application of $CO_2$ capture may result in a decrease of the emission of $SO_2$ per MJ but depending on the efficiency penalty may result in an increase per kWh. Both increase as decrease per kWh have been reported in literature. In general, $SO_2$ emissions are expected to be very low for IGCC with $CO_2$ capture.

$NH_3$ formed during gasification in an IGCC is removed or converted to a high degree. The result is that $NH_3$ emissions from an IGCC are reported in literature to be very low. It is not known whether $NH_3$ emissions are influenced by applying $CO_2$ capture. No $NH_3$ emissions from gas fired pre combustion concepts are reported in the consulted literature. It is possible to equip pre combustion cycles with a SCR to reduce $NO_x$ emissions. Ammonia slip from a SCR is very small <5 ppmv and is assumed comparable to normal air combustion in a pulverized coal power plant and a NGCC power plant.

PM emissions from an IGCC power plant are already low due to high removal efficiencies in the gas cleaning section of the IGCC. The application of pre combustion $CO_2$ capture may lower PM emissions per MJ due to enhanced capture of sulphur compounds hindering the formation of ammonium sulphate. The emission of particulate matter from gas cycles in general can be considered negligible.

In an IGCC power plants there are two main origins of NMVOC emissions: the GTCC section and the fuel treatment section. The formation of NMVOC in the first is expected to be reduced due to $CO_2$ capture. Quantitative estimates for the reduction of NMVOC in the GTCC section are not reported. The emissions from the fuel treatment are expected to remain equal per MJ. The net effect of both may be an increase or decrease per kWh. For gas fired cycles the replacement of natural gas with hydrogen (a consequence of the $CO_2$ capture process) is expected to lower the emission NMVOC. Quantitative estimates are however absent.

Overall it is found that accurately estimating the emission profile - and with it the emissions of NEC substances - for power plants equipped with pre combustion $CO_2$ capture is currently rather difficult. Reported emissions are mostly based on numerous assumptions on the technological configuration and performance which may vary considerably in the literature. For more accurate estimates measurements on demonstration projects using the pre combustion capture technology are required.

The effect of biomass co-gasification in IGCC power plants with $CO_2$ capture on the performance (energetic and operational) and on the emission profile is currently unknown.

## 3.4 Oxyfuel combustion

The term oxyfuel combustion refers to the combustion of carbonaceous fuels in an oxygen rich medium, i.e. a denitrified combustion medium. The main reason for this is to increase $CO_2$ concentration of the flue gas which result a lower energy requirement for $CO_2$ capture. The oxygen stream is often diluted with recycled flue gas (RFG) to lower the combustion temperature. Oxyfuel combustion can be applied to coal (and biomass) and natural gas fired concepts. The implications of the application of the oxyfuel concepts depend on the power cycle where it is implemented. Power cycles for gaseous and solid fuels vary significantly. Therefore, in this section oxyfuel concepts for solid and liquid fuels (coal/biomass/oil), and gaseous fuels are discussed separately.

### *3.4.1 Oxyfuel combustion – Solid and liquid fuels*

### *3.4.1.1 Technical description*

In Figure 3.11 an example is given for a coal fired power plant using the oxyfuel combustion concept. The main difference in this configuration of the power plants processes is the addition of an air separation unit (ASU). The ASU separates the oxygen from the air resulting in a nearly pure stream of oxygen, i.e. >95%. The oxygen is then diluted by recycled flue gas (RFG) so that the combustion medium is a mixture of $O_2$ and $CO_2$ with some impurities due to air leakage into the boiler. Combustion with pure oxygen is however the ultimate goal of oxyfuel combustion, as this will reduce mass flow in the boiler and flue gas cleaning sections significantly. This in turn will reduce the specific investment cost of the power plant. The high temperatures and concerns about coal combustion chemistry encountered with pure oxygen combustion are averted by recycling the flue gas. The recycling of the flue gas is thus currently necessary to control the temperature in the boiler. The combustion temperature is limited by currently used materials. In the future, development in high temperature resisting materials may allow higher combustion temperatures in the boiler.

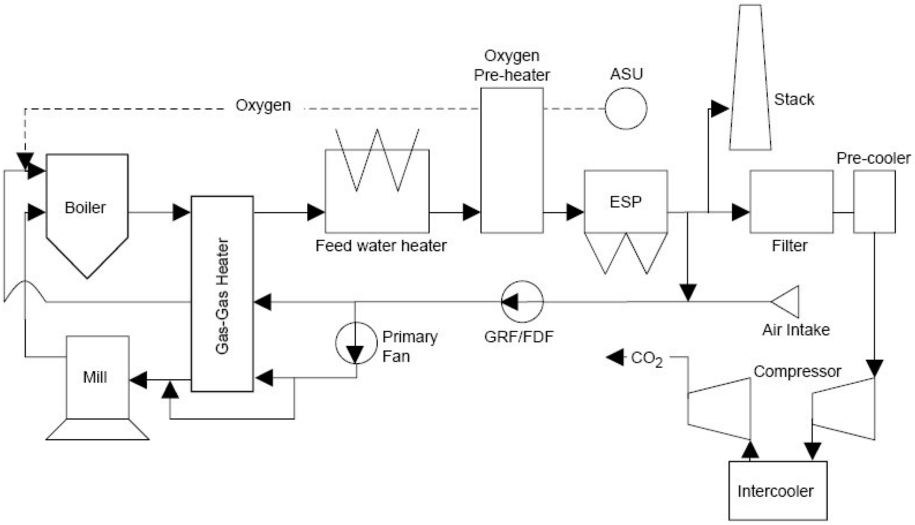

Figure 3.11 Flow sheet for a coal fired power plant using the oxyfuel concept (after (Buhre et al., 2005))

The oxyfuel combustion concept has the main advantage that the concentration of $CO_2$ in the flue gas is increased beyond 90%. This means that separation of $CO_2$ is not required anymore; instead, if impurities ($N_2$, $NO_x$, $SO_x$, $O_2$ and argon) are removed from the flue gas the product will be nearly pure $CO_2$. Impurities in the flue gas are similar to those found in air combustion of coal, with the exception of $NO_x$ formation. $NO_x$ formation is limited as virtually only fuel bound nitrogen is able to form $NO_x$. Thermal $NO_x$ formation, the reaction of nitrogen in the combustion air with oxygen, is hindered as most of the nitrogen is separated from the combustion air in the ASU (see also section 3.4.1.5).

#### *3.4.1.2 Application area*

The combustion with oxygen is currently applied in the glass and metallurgical industry (Buhre et al., 2005) (M. Anheden et al., 2005) (IPCC, 2005; p.124). As of yet the concept has not been applied of large utility scale boilers for steam generation and power production.

The oxyfuel concept is according to several authors suitable for the retrofit of existing coal fired boilers, and boilers and heaters on refinery complexes. The latter can be fired with fuel oil and refinery gas (Buhre et al., 2005; Tan et al., 2006) (IPCC, 2005; p.124).

The main components that have to be modified or added in the case of a retrofit of pulverized coal fired boilers and fluidized bed boilers are the installation of an ASU, adjustment of the (configuration of) burners, flue gas recycle system and $CO_2$ treatment and compression installation. The specific characteristics of fluidized bed boilers make these boilers more suitable for oxyfuel retrofit or design compared to pulverized coal boilers as less flue gas recycle is needed. The heat transfer capacity of the fluidized particles in the boiler makes temperature control easier. This enables size and, consequently, cost reduction of the boiler (Jordal et al., 2004) (Wang et al., 2008).

The fuels that can be used in this concept are generally the same as for existing boiler systems. Fluidized bed combustion is in general known for its ability to co-fire a wide range of (lower quality) fuels. This ability to co-fire is more limited for pulverized coal combustion. One of the areas currently under research[16] for the oxyfuel concept is the co-firing of biomass.

Research performed at ECN includes testing of biomass combustion in oxygen rich conditions. One of the aims is to gain insights in combustion characteristics and ash behaviour. One of the issues may be the slagging and fouling encountered in oxyfuel firing of biomass as well as the ash quality. These ashes should to a large extent be re-used in for instance the concrete production and in the road construction sector. The quality of the ashes (bottom ash and fly ash) should meet certain requirements in order to be acceptable for use (Jansen, 2008). This is both from an environmental as economical point of view an important aspect that should be researched for the oxyfuel concept.

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[16] The Department of Chemical Engineering–DTU in cooperation with Department of Manufacturing Engineering and Management-DTU, Dong Energy Generation and Vattenfall are set to finalise their research on oxyfuel combustion of coal and biomass in 2010 (see: http://www.miljovenligelproduktion2007.dk/composite-227.htm). Among the research targets are: understanding of general combustion characteristics, ash characteristics, corrosion of heat transfer surfaces of boilers and flue gas treatment for $SO_2$ and $NO_x$.

Further, some general R&D topics for co-firing of biomass are applicable for the oxyfuel combustion as well. These include further research on: "the possibilities of further $NO_x$ reduction by fuel staging, problems concerning the deactivation of SCR catalysts, characterization and possible utilisation of ashes from co-combustion plants, as well as corrosion and ash deposition problems" (Baxter and Koppejan, 2004).

#### *3.4.1.3 Development phase*

Up to now the combustion process for utility boilers is only proven in test and pilot facilities. And although no significant differences are present compared to air firing, the combustion process and optimal configuration of the burners is considered to be the most important hurdle to overcome, see Figure 3.12. Another important issue which should be addressed is the air infiltration into the boiler, which results in a dilution of the flue gases (and thus an increase of total volume of flue gasses) and an increase of available nitrogen that may form $NO_x$ during combustion.

The concept is and has being studied in desk-top studies and several test facilities mainly to assess the viability of the concept to produce $CO_2$ for enhanced oil recovery, later for $CO_2$ storage, and with a specific focus on $NO_x$ emission performance (Buhre et al., 2005; IPCC, 2005; M. Anheden et al., 2005).

For Oxyfuel firing of coal (hard coal and lignite) it is a benefit that the conventional steam cycle can be used. The concept however requires alteration of the boiler and burners, and changes in flue gas cleaning equipment. The components used in the concept are commercially available although not optimized for Oxyfuel combustion. For instance, flue gas cleaning equipment such as the ESP, bag house filter and FGD system are not optimized and sized for Oxyfuel firing. These components have to be optimized for a decrease in mass flow with higher concentrations of impurities. Hence, the performance of these flue gas cleaning systems is not yet fully known, although potential capital savings and increase in performance may be expected (ZEP, 2006).

In Table 3.16 an overview of proposed projects is presented. Several boiler manufacturers are developing the technology for implementation in 2010-2012. Two projects are planned to start operation in 2008. The project commenced by Total encompasses the conversion of an oil fired steam boiler, $CO_2$ treatment and compression, transport and injection in a nearly depleted natural gas field.

A coal fired Oxyfuel pilot plant is being built for Vattenfall with a 30 MWth capacity and is expected to be operational in 2008. Vattenfall plans to systematically scale up the Oxyfuel concept with a 300 MW demo plant in 2015 and a commercial 1000 MW power plant in 2020.

Also very recently a 40 MW oxyfuel combustion demonstration project was announced firing pulverized coal with recycled flue gas. This test facility is planned to start operation in 2009 and will focus on testing materials and gain knowledge on corrosion, fouling and slagging mechanisms within the concept (Carbon Capture Journal, Feb-21-2008).

Table 3.16 Overview of proposed projects incorporation oxyfuel combustion with non-gaseous fuels (after (MIT, 2008))

| Project Name | Location | Feedstock | Size MW | $CO_2$ Fate | Start-up |
|---|---|---|---|---|---|
| Total Lacq | France | Oil | 35 | Sequestration | 2008 |
| Vattenfall oxyfuel | Germany | Coal | 30/300/1000* | Undecided | 2008 |
| Callide-A Oxy Fuel | Australia | Coal | 30 | Sequestration | 2009 |
| Doosan Babcock Energy | United Kingdom | Coal | 40 | Vented | 2009 |
| SaskPower Clean Coal | Canada | Coal | 450 | Undecided | Cancelled |

* Pilot scale 30 MW, demonstration scale 300 MW and full commercial scale 1000 MW

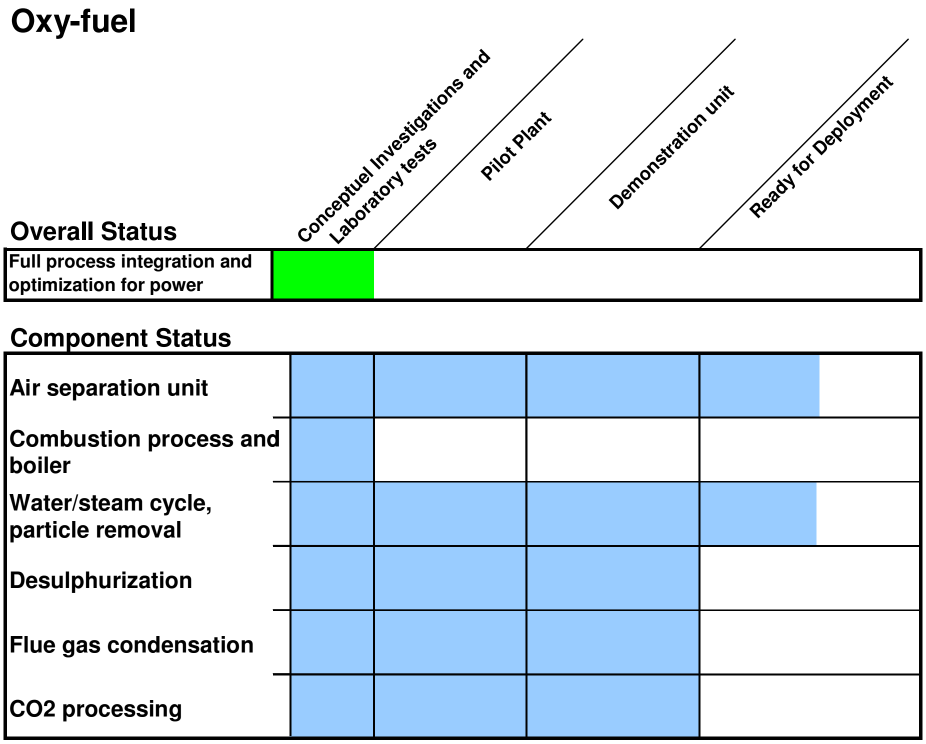

Figure 3.12 Stage of development of the oxyfuel concept components Adapted from (ZEP, 2006) after expert consultation.

The main points of interest for development are process (heat) integration and verification of concept on a large scale. Future developments are aimed at increasing the $O_2$ concentration up to pure oxygen firing enabling smaller boilers, lower capital cost and an increase in cycle efficiency. This requires however the development of materials that can withstand high temperatures. Another future development lies in the type of air separation technology. Currently, cryogenic ASUs are used which require significant amount of energy with high associated cost. Improvement in this technology is possible but is also considered to be limited (M. Anheden et al., 2005). Oxygen separation can also be performed with the use of membranes that are selective for $O_2$, e.g. the Ion Transport Membranes (ITM)[17] (Andersson and Johnsson, 2006; ZEP, 2006). The goal of the development of the ITM ASU is to reduce the cost by 30% compared to a conventional cryogenic ASU (DOE and NETL, 2007). Other concepts are oxygen separation with the use of (bio mimetic)solvents and solid sorbents. (ZEP, 2006) Future options for oxygen separation are also currently under research at ECN (Jansen, 2008).

#### *3.4.1.4 Economic and energy performance*

The economic performance is mainly dominated by the higher investment cost for the ASU and the $CO_2$ compression/liquefaction and cleaning chain. Also, an increase in operation cost is inevitable due to the higher endogenous energy demand, i.e. the capture penalty. On the other hand some flue gas cleaning equipment (SCR and FGD) may be omitted if co-sequestration of sulphur components with the $CO_2$ is to be allowed (Andersson and Johnsson, 2006). Andersson and Johnsson (2006) also estimated that the investment cost of a FGD installation can be significantly lower in the oxyfuel concept, i.e. about 40%.

Further, cost of $CO_2$ avoidance and COE depend heavily on the assumed fuel cost. In Table 3.17 the lower end of the cost range are derived from (Andersson and Johnsson, 2006) who have calculated the cost for an oxyfuel concept fired with lignite (low quality, low cost fuel) and co-sequestration of $SO_2$.

Table 3.17 Economic performance of coal fired power plants with and without oxyfuel $CO_2$ capture

| | **Without capture** | **oxyfuel** |
|---|---|---|
| Euro per tonne avoided (constant 2007) | - | 18-62 |
| cost of electricity (in euro cts/kWh) | 2.2-6.2 | 5.0- 9.2 |
| $CO_2$ emissions (in g/kWh) | 705.8- 1004 | 0.0-146.5 |

The Oxyfuel boiler shows higher gross power output compared to air firing through increased boiler efficiency. This increase is offset by oxygen separation and $CO_2$ compression, which are the largest energy consumers in this concept. Compared to the post and pre combustion capture concepts no energy is required for the separation of $CO_2$ from the flue gas. Impurities in the flue gas, however, must be removed depending on the required composition for transport and storage. This may require additional energy in the liquefaction and compression steps of the $CO_2$ or requires the inclusion of a FGD and SCR installation which leads to an increase in endogenous energy demand. In Table 3.18 it is shown that the net efficiency penalty ranges between 8.4 and 12.3 percent points. One of the most important factors that may explain these differences is the chosen technology configuration. If oxyfuel is applied on an advanced ultra supercritical boiler with high thermodynamic efficiency, than the capture penalty will be lower. If the technology is applied on already installed (i.e. retrofit) with lower thermodynamic efficiencies, then the capture penalty will be higher. Other factors are the assumed $CO_2$ product pressure, capture efficiency, assumptions on $CO_2$ cleaning train (i.e. the omission of SCR and FGD facilities) and on energy requirements for oxygen separation.

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[17] According to working group 1 of the ZEP (2006) several international R&D programmes are ongoing for this technology, although it seems better suited for natural gas cycles and within an IGCC configuration than for coal steam cycles as the ITM technology requires a high level of heat integration which is more difficult to achieve in PC power plants. The heat integration is inherent to the process conditions of the ITM which requires pressurized (~20 bar) and heated (800°C) air.

Table 3.18 Energetic performance of coal fired power plants with and without oxyfuel $CO_2$ capture

| | **Without capture** | **oxyfuel** |
|---|---|---|
| Electrical efficiency (%) | 33-46 | 29-37.5 |
| Efficiency penalty (in % pts.) | | 8.4-12.3 |
| Primary Energy increase per kWh (%) | 100 | 124.3-140.6 |
| Capture efficiency | | 86-100 |
| $CO_2$ product pressure (in MPa) | | 10-15.27 |

### *3.4.1.5 Environmental performance NEC+PM*

The performance of the oxyfuel concept regarding the environment and emissions of NEC substances is different compared to that of an air fired power plant. This is the consequence of changes in the combustion conditions in the boiler and changes in the flue gas treatment section. In literature, predominantly the formation of $SO_x$ and $NO_x$ are discussed, which are affected due to changes in the combustion process when oxyfuel combustion is applied.

#### *3.4.1.5.1 $SO_x$*

According to Buhre et al. (2005) the $SO_x$ emissions per tonne of coal combusted are essentially unchanged. This means that the uncontrolled emissions of $SO_x$ are about the same as for an air fired configuration. However, the composition and concentration of $SO_x$, constituting $SO_2$ and $SO_3$, does change. Croiset and Thambimuthu (2001) found that due to FGR, recycled $SO_2$ is further oxidized to $SO_3$, yielding higher concentrations of $SO_3$. Croiset and Thambimuthu (2001) also found that when the flue gas was recycled, after removing the water content, part of the sulphur was found to be trapped in the condensed water. The removal was however not significant. Tan et al. (2006) found lower mass emission rates of sulphur compounds in the $O_2$ combustion tests with FGR and explained this by the retention of sulphur compounds on ash deposits and on cooling surface of the flue gas cooler. They also reported that high alkaline concentrations in the coal increase retention of sulphur compounds in the fly and bottom ash. Yamada (2007) found a 30% reduction of $SO_x$ emissions due to the retention of $SO_x$ on ashes (both bottom and fly ash) during oxyfuel combustion tests.

In Table 3.19 the results of $SO_2$ formation during oxyfuel combustion tests with lignite are shown. They indicate a reduction of $SO_2$ formation of up to 65% compared to air fired operation.

A negative side effect of higher $SO_x$ concentrations in the flue gas is that it might pose equipment corrosion problems. A possible positive side effect is however that higher $SO_3$ concentration in the flue gas may enhance the capture efficiency of the ESP. Another expected positive side effect is that higher $SO_x$ concentrations may increase the capture efficiency of flue gas desulphurization technologies. As already mentioned, co-sequestration of sulphur compounds is possible, which makes the FGD section redundant. Also, sulphur compounds may be recovered from the $CO_2$ stream in the form of sulphuric acid. If these options are not feasible or not allowed, then a FGD installation can be installed. Redundancy of the FGD is questionable as this may lead to high $SO_x$ concentrations which may pose corrosion issues. Tests in a research facility indicate that $SO_x$ removal was improved in the case of oxygen rich combustion, which can partly be explained by longer gas residence time in the FGD. The reduced flue gas stream also allows for smaller equipment (Marin and Carty, 2002) (Chen et al., 2007) (WRI, 2007) (Chatel-Pelage et al., 2003).

In circulating fluidized bed boilers often limestone is injected into the furnace to control $SO_x$ emissions. In the case of oxygen firing the in furnace desulphurization efficiency with limestone was found to be between 4 and 6 times higher compared to air firing (Buhre et al., 2005; ZEP, 2006).

Table 3.19 $SO_2$ formation and reduction when firing in oxygen rich medium (after (Andersson, 2007))

| Test case description* | g/GJ | $SO_2$ formation compared to air base case in % |
|---|---|---|
| Air | 510 | - |
| $O_2$ 25% (Recycle Rate 0.79) | 181 | 35% |
| $O_2$ 27% (Recycle Rate 0.77) | 187 | 37% |
| $O_2$ 29% (Recycle Rate 0.75) | 199 | 39% |

* In all cases lignite was used

In Table 3.20 ranges for $SO_2$ emissions from oxyfuel combustion power plants are presented. These ranges indicate that in general $SO_2$ emissions will decrease compared to coal fired power plants without oxyfuel. In the oxyfuel cases with co-sequestration no $SO_2$ emissions are reported to occur. It should be stressed that the values presented here show a large variance. This is due to the assumptions that may vary case by case. These are assumptions on: the sulphur content in the coal, uncontrolled $SO_x$ formation (including ash retention), the removal efficiency of the FGD section and removal rate in $CO_2$ treatment section.

Table 3.20 Ranges for $SO_2$ emissions found in literature (Andersson and Johnsson, 2006; Davison, 2007; DOE and NETL, 2007; IEA GHG, 2005)

| | Without $CO_2$ capture | oxyfuel | oxyfuel with co-sequestration |
|---|---|---|---|
| $SO_2$ emissions (in g/kWh) | 0.25-1.28 | 0.001-0.098 | 0 |
| $SO_2$ emissions (in g/MJ) | 0.027-0.152 | 0.000135-0.0091 | 0 |

### *3.4.1.5.2 $NO_x$*

Originally the oxyfuel concept was researched in 1980’s as it was considered a promising option to produce $CO_2$ for enhance oil recovery. Later it was reconsidered to be a promising option for $CO_2$ storage and $NO_x$ reduction. (Buhre et al., 2005) $NO_x$ reduction and underlying mechanisms was thus one of the topics specially addressed when researching the oxyfuel concept. As a consequence, the formation of $NO_x$ is fairly well understood.

As already mentioned, $NO_x$ formation during oxyfuel combustion is found to be lower as the thermal $NO_x$ formation is suppressed. (WRI, 2007) (Croiset and Thambimuthu, 2001) (Tan et al., 2006) (Buhre et al., 2005) This is primarily due to the low concentration of $N_2$ in the combustion medium. (Tan et al., 2006) Next to suppression of thermal $NO_x$ also another form of $NO_x$ formation is reduced, fuel $NO_x$. As fuel $NO_x$ is a product of the reaction between fuel bound nitrogen and oxygen in the combustion medium it cannot be prevented. However, it was found that the recycling of flue gas and thus $NO_x$ most likely results in the chemical reduction of $NO_x$ into $N_2$. (Croiset and Thambimuthu, 2001) This mechanism is expected to take place in the volatile matter release section. Tan et al. (2006) suggests that recycled $NO_x$ is destroyed in the flame through the reaction of $NO_x$ with hydrocarbon radicals. Buhre et al. (2005) also mentions that the interactions between fuel bound nitrogen, $NO_x$ and hydrocarbons may be a potential mechanism, denoted reburning.

Buhre et al. (2005) denotes the recycling of flue gas $NO_x$ as the primary mechanism for $NO_x$ reduction. This is supported with results from Andersson (2007) showing that the reduction of $NO_x$ formation is limited without flue gas recycling.

A factor that affects $NO_x$ formation when recycling flue gas depends on, amongst others, the recycle ratio of the flue gas, the oxygen concentration, boiler temperature and burner system design and configuration. (Croiset and Thambimuthu, 2001) (Tan et al., 2006)

Some test results of oxyfuel combustion test are presented in Table 3.21, 22 and 23. The results show that overall the $NO_x$ formation is reduced when combustion occurs in an oxygen rich medium. The exception is the bituminous coal firing case of Tan et al. (2006), which shows an increase in $NO_x$ formation. An optimal design of the burners is according to them therefore a necessity to control $NO_x$ formation in the case of oxyfuel combustion.

Table 3.21 $NO_x$ reduction for $O_2$/FGR tests for three coal ranks (after (Tan et al., 2006) (Croiset and Thambimuthu, 2001))

| **Coal rank; combustion medium** | **$NO_x$ formation (g/GJ)** | **$NO_x$ formation compared to air fired case** | **Source** |
|---|---|---|---|
| Bituminous | 233 | 110% | (Tan et al., 2006) |
| Sub-bituminous | 148 | 63% | |
| Lignite (with improved burner design) | 68 | 25% | |
| Bituminous; 28% $O_2$/ $CO_2$ | 200-231 | 60%-62% | (Croiset and Thambimuthu, 2001) |
| Bituminous; 35% $O_2$/ $CO_2$ | 285-303 | 85%-82% | |
| Bituminous; 28% $O_2$, dry FGR | 92-105 | 27%-28% | |
| Bituminous; 35% $O_2$, dry FGR | 162-162 | 48%-44% | |
| Bituminous; 42% $O_2$, dry FGR | 200-220 | 60%-59% | |

* Lignite test was performed with an improved burner design.

No qualification of the used heating value is given (LHV or HHV)

Table 3.22 $NO_x$ formation and reduction when firing in oxygen rich medium (after (Chatel-Pelage et al., 2003))

| **Test case description*** | **g/GJ** | **$NO_x$ formation compared to air base case in %** |
|---|---|---|
| staged combustion NO / FGR -NO –base case | 191 | - |
| staged combustion NO / FGR rate -low | 90 | 47% |
| staged combustion NO / FGR rate- high | 59 | 31% |
| staged combustion Yes / FGR rate-NO | 121 | 63% |
| staged combustion Yes / FGR rate -low | 56 | 29% |
| staged combustion Yes / FGR rate -high | 46 | 24% |

LHV/HHV conversions factor of 0.96 is used to convert emission factors to g/GJ (LHV).

* In all cases bituminous coal was used.

Table 3.23 $NO_x$ formation and reduction when firing in oxygen rich medium (after (Andersson, 2007))

| **Test case description*** | **g/GJ** | **$NO_x$ formation compared to air base case in %** |
|---|---|---|
| Air | 233 | - |
| $O_2$ 25% (Recycle Rate 0.79) | 56 | 24% |
| $O_2$ 27% (Recycle Rate 0.77) | 62 | 27% |
| $O_2$ 29% (Recycle Rate 0.75) | 65 | 28% |

* In all cases lignite was used

Overall, the reduction potential of oxyfuel combustion for $NO_x$ can according to Buhre et al. (2005) be than about 60-70%. Chatel-Pelage et al. (2003) found that $NO_x$ formation was reduced to 24% with fuel staging and high FG recirculation rate compared to a similar air fired case, see Table 3.27. Farzan et al. (2005) reported nearly 65% reduction in their oxyfuel combustion case. Yamada (2007) found a reduction in $NO_x$ formation of 60-70%. Similar values are given by Andersson (2007) who performed combustion tests with lignite and found that $NO_x$ emissions were reduced by 72-76%.

The above mentioned results from combustion experiments do give insight in the formation of $NO_x$. However, the final emission of $NO_x$ depends also on the flue gas treatment section. The flue gas stream has a high $CO_2$ concentration and also still contains levels of $NO_x$ (it also contains Ar, $N_2$, $O_2$ and $SO_2$) when it enters the $CO_2$ treatment train in the power plant. According to DOE and NETL (2007) there are several options for the treatment of the raw $CO_2$ stream, neither of them require an additional $DeNO_x$ facility. The option to be chosen depends on the quality requirements of the $CO_2$ stream for transport and storage. The first option is to co-sequester the pollutants together with the $CO_2$. This requires only compression and drying of the flue gas stream. The second option is that the $CO_2$ is also purified with multiple auto-refrigeration flash steps. The gaseous pollutants are, in that case, to a high degree separated from the $CO_2$ stream and vented into the atmosphere. This implies that a fraction of the $NO_x$ is co-sequestered and a large part is emitted into the atmosphere. A $DeNO_x$ installation may be installed for additional reduction and would be equipped to clean this vent stream. (IEA GHG, 2006a)

In Table 3.24 possible ranges for $NO_x$ emissions from oxyfuel concepts compared to normal air operation are presented. In general the values show that the net $NO_x$ emissions will decrease compared to conventional coal fired power plants. In the co-sequestration cases some emission of $NO_x$ are estimated. These are $NO_x$ emissions from the combustion of the natural gas that is assumed by DoE and NETL (2007) for the production of oxygen in some of the researched oxyfuel configurations.

Table 3.24 Ranges for $NO_x$ emissions found in literature (Andersson and Johnsson, 2006; Davison, 2007; DOE and NETL, 2007; IEA GHG, 2005)

| | **without $CO_2$ capture** | **oxyfuel** | **oxyfuel with co-sequestration** |
|---|---|---|---|
| $NO_x$ emissions (in g/kWh) | 0.22-0.62 | 0-0.39 | 0 -0.010 |
| $NO_x$ emissions (in g/MJ) | 0.025-0.227 | 0 -0.0322 | 0-0.000477 |

IEA GHG (2005b) mentions the option that rather pure streams of $NO_x$ (and $SO_2$) can be separated from the $CO_2$ stream. These streams can be used to produce nitric (and sulphuric) acids and as such may be used as feedstock in for instance, fertilizer production. These streams have to be distilled from the $CO_2$ stream and thus require a simple additional distillation step.

Sarofim (2007) mentions a purification configuration proposed by Air Products where residual $SO_x$ and $NO_x$ are removed to a very high degree, 100% and 90-99% respectively, together with condensed water in the form of sulphuric and nitric acid ($H_2SO_4$ and $HNO_3$). Another claimed benefit is the removal of Hg in this configuration.

In section 3.4.1.2 it was already mentioned that research is performed on co-firing of biomass in the oxyfuel concept. In the consulted literature no experimental results or desktop studies on the co-firing of biomass were found. The co-firing of biomass may have additional benefits regarding the formation of $NO_x$, although increase in the formation of $NO_x$ may also occur. Baxter and Koppejan (2004) stress that $NO_x$ formation when co-firing may increase or decrease or remain the same. The net formation of $NO_x$ is rather complex and depends on several parameters: the fuel, firing conditions and operating conditions. Veijonen et al. (2003) underline this complexity with reporting that there is some contradiction in the results of research on the effect of biomass co-firing on $NO_x$ formation. Part of the results namely shows an increase in $NO_x$ formation, others show a decrease. An important aspect mentioned by Veijonen et al. (2003) may however provide a hypothesis for $NO_x$ formation when co-firing biomass in an oxyfuel concept. They mention that biomass is superior to bituminous coal as a reducing fuel and that this reduction is based on reactions between hydrocarbon radicals and NO. This mechanism is also described earlier in this section as one of the main mechanisms explaining the reduction of $NO_x$ formation in oxyfuel combustion. When biomass has more favourable characteristics regarding this mechanism, then $NO_x$ formation may decrease further when co-firing biomass in the oxyfuel concept.

#### *3.4.1.5.3 $NH_3$*

Ammonia slip from a SCR, if applicable, is very small < 5 ppmv and cannot be easy compared to normal air combustion in pulverized coal power plant and NGCC power plant. The slip of ammonia will result in a trace amount of ammonia in the flue gas. This flue gas stream is then further treated in the $CO_2$ compression and cleaning section.

Information on whether an increase of $NH_3$ formation during combustion or reactions with or venting of ammonia will occur is not found in the consulted literature.

#### *3.4.1.5.4 NMVOC*

As far as can be ascertained no information is presented in present pertaining literature on the effect of oxyfuel combustion on the formation, reduction and final emission of VOC. VOC formation is a result of incomplete combustion and is decreases with increasing combustion temperature. The formation of VOC may change due to combustion in oxygen rich environment as it has an impact on the combustion temperature and total carbon burnout. Zheng and Furimsky (2003) and Tan et al. (2006) mention that higher CO levels in the flue gas can be expected in oxyfuel combustion, although Tan et al. (2006) also mention a carbon burn out over 99%. Results presented by Andersson (2007) also show somewhat higher CO concentrations in the oxyfuel combustion cases. The higher CO concentration is thought to be the consequence of lower diffusion rate of volatiles. This may imply that also VOC are not oxidized and remain in the flue gas. However, the chemical reduction of $NO_x$ to $N_2$ by the reaction of $NO_x$ with fuel bound nitrogen and hydrocarbons is earlier mentioned as on of the potential mechanisms. This may imply that more hydrocarbons (i.e. VOC) are oxidized. The fate of the formed VOC is unknown but it can be assumed that part of the VOCs are either co-sequestered or vented from the $CO_2$ treatment section.

#### *3.4.1.5.5 PM10 and $PM_{2.5}$*

As already mentioned before, the increased concentration of $SO_3$ in the flue gas may have a positive effect on the capture efficiency of the ESP (Tan et al., 2006) which may consequently result in higher capture rates of particulate matter.

Buhre et al. (2005) conclude in their review on oxyfuel combustion that the effect of oxyfuel combustion on fly ash size distribution have not yet been experimentally determined. An extra note on this matter is however that due to changing combustion chemistry the formation of submicron ash particles[18] may be influenced.

Zheng and Furimsky (2003) have performed a model study to assess, among others, the formation of trace elements and ashes during oxyfuel combustion of coal. They found that oxyfuel combustion had little influence[19] on the composition of the ash and trace elements formation in the vapour phase. Buhre et al. (2005) comment on these findings by mentioning that it is not clear whether Zheng and Furimsky (2003) include flue gas recycle in their model predictions. As elevated concentrations of trace elements in the flue gas due to the combustion in a nitrogen deprived medium should also be included in the feed gas composition (the gas that enters the boiler). This may alter the model outcomes.

Andersson and Johnsson (2006) have estimated in a desktop study that the dust emissions are seven times lower per kWh in the oxyfuel combustion case compared to air fired case firing lignite.

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[18] Sub micron ash particles may be formed from reactions in a burning char particle. The $CO/CO_2$ ratio in the particle is changed due to oxyfuel combustion and this influence the vaporization of so-called refractory oxides. These refractory oxides may then form a fume by oxidation.

[19] Zheng and Furimsky (2003) stress that their findings should not be generalized as for other coal compositions fly ash compositions may be affected by oxyfuel combustion.

IEA GHG (2005b) indicates that the role of the installed ESP changes when recirculation flue gases, as is envisaged in the first generation oxyfuel concepts. In an air fired power plant the ESP removes particulate matter in order to avoid emissions to the atmosphere. In the oxyfuel power plant the ESP is installed to prevent equipment failure, in particular fans (for flue gas recycle) and compressors. A suggested area of further R&D is the higher deposition rate of fly ash in the flue gas passes in the case of oxyfuel firing.

DoE and NETL (2007) estimates that PM are reduced further with ~90% compared to an air fired case. This relates to their assumption that part of the non-captured PM in an ESP is co-sequestered with the $CO_2$. The PM that is emitted is emitted in the vent stream of the $CO_2$ purification train. This vent streams is also assumed to contain $SO_2$, $NO_x$, Hg and $CO_2$.

Overall, the particulate matter emissions are reported to decrease with oxyfuel combustion compared to air firing, see Table 3.25. Both per MJ as per kWh particulate emissions are estimated to be lower.

Table 3.25 Ranges for PM10 emissions found in literature (Andersson and Johnsson, 2006; Davison, 2007; DOE and NETL, 2007; IEA GHG, 2005)

| | **Without $CO_2$ capture** | **oxyfuel** | **oxyfuel with co-sequestration** |
|---|---|---|---|
| $PM_{10}$ emissions (in g/kWh) | 0.007-0.051 | 0.001 | 0 |
| $PM_{10}$ emissions (in g/MJ) | 0.00083-0.006 | 0.000093-0.00077 | 0 |

#### 3.4.1.6 *Other environmental impacts of concern*

In literature it is suggested that due to higher oxygen concentrations a larger part of elemental mercury (Hg) is converted to ionized Hg species, which will possibly result in higher capture efficiencies of Hg in flue gas cleaning sections ($DeSO_x$ and DeHg). (Chatel-Pelage et al., 2003; Marin and Carty, 2002) (WRI, 2007) this may be an additional benefit of $CO_2$ capture with oxyfuel combustion.

#### 3.4.1.7 *Uncertainties and knowledge gaps*

The main uncertainties regarding the estimation of emissions from oxyfuel combustion relate to its immaturity. Demonstration of the technology is necessary to clarify combustion characteristics and the performance of the flue gas and subsequent $CO_2$ cleaning sections. The performance of the FGD section under higher $SO_x$ concentrations has to be determined. The same holds for the SCR unit (when applied). In general the level of $NO_x$ and $SO_2$ removal from $CO_2$ disposal stream has to be determined and novel removal systems for these substances have to be demonstrated.

Although Hg removal is expected to be easier in the oxyfuel concept, methods to remove the Hg from the $CO_2$ stream have to be demonstrated. Further, the mechanisms behind Hg behaviour and fate of Hg in oxyfuel combustion have to be understood more thoroughly.

There is no information found on biomass co-firing in the oxyfuel concept in pertaining literature. Consequently emissions from co-firing biomass have to be determined.

Further R&D issues that are mentioned in literature are:

- The heat transfer performance of new and retrofitted plant and the impact of oxygen feed concentration and $CO_2$ recycle ratio;
- Assessment of retrofits for electricity cost and cost of $CO_2$ avoided;
- Further understanding of the combustion of coal in an $O_2/CO_2$ atmosphere, including ignition, burn-out, and emission profile;
- Research on efficiency improvements by the development of materials that can withstand higher steam conditions and combustion temperatures;
- Low cost $NO_x$ and $SO_2$ removal technologies for oxyfuel combustion;
- Research on corrosion and deposition studies with various fuels;
- Research and development in new oxygen separation technologies.

### *3.4.2 Oxyfuel combustion – Gaseous fuels*

In literature also several gas fired Oxyfuel cycles have been proposed. The concepts discussed in this study comprise the Oxyfuel combined cycle, water cycle, Graz cycle, advanced zero emission power plant concept (AZEP), Solid oxide fuel cell integrated with a gas turbine and chemical looping. The technical descriptions of these concepts are given below.

#### *3.4.2.1 Technical description*

##### *3.4.2.1.1 Oxyfuel combined cycle*

The first concept, the Oxyfuel combined cycle which is shown in Figure 3.13 is comparable to a normal natural gas fired combined cycle (NGCC) power plant. The alteration of the power plant comprises mainly the addition of an ASU, which supplies nearly pure and pressurized oxygen to the gas turbine. Near stoichiometric combustion results in a flue gas which constituents are predominantly $CO_2$, $H_2O$ and $O_2$. The hot flue gas is send to heat recovery steam generator (HRSG) where steam is generated and expanded in the steam turbines. The $H_2O$ remaining in the flue gas can be removed by cooling and knockout.

As shown in Figure 3.13, part of the flue gas is circulated back into the gas turbine. This is needed to reduce the temperature in the gas turbine as the turbine materials are currently not able to withstand the high temperatures during pure oxygen combustion. This means that also the turbine compressor and combustor have to modified, i.e. a new engine has to be developed. Further, the system components have to be integrated and optimized. (IEA GHG, 2006b) (ZEP, 2006) (Kvamsdal et al., 2007)

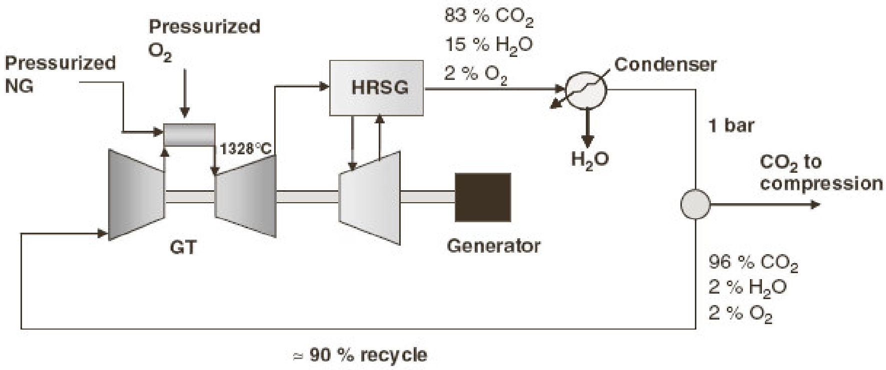

Figure 3.13 Gas fired oxyfuel combined cycle concept (after (Kvamsdal et al., 2007))

### 3.4.2.1.2 Water cycle

A 50 MWe demonstration project of the water cycle concept is proposed to be built by SEQ/Eneco near Drachten (northern part of Netherlands). (Buyze et al., 2004) The concept is based on (natural) gas combustion in pure oxygen, all in the presence of pure water. The compressed water is injected in the gas generator, or high pressure combustor. The pressurized pure oxygen required for the combustion is supplied by a cryogenic ASU. The combustion products are mainly high pressure steam and $CO_2$ which are expanded in a steam turbine. In Figure 3.14 a single reheat stage is presented, however, multiple reheat stages are possible. Also, in this figure High Pressure (HP) and Low Pressure (LP) steam turbines are shown, whereas another water cycle concept shows a single reheat configuration with a HP, Intermediate Pressure (IP) and LP steam turbine (CO2-Norway AS, 2004).

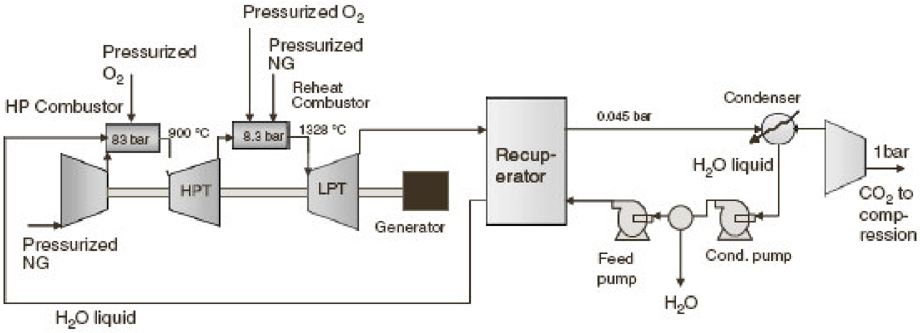

Figure 3.14 Water cycle oxyfuel concept (after (Kvamsdal et al., 2007))

The $H_2O$ / $CO_2$ mixture exiting the LP stream turbine exchange heat with recycled $H_2O$. In the condenser $CO_2$ and $H_2O$ are separated after which the water is recycled into the power cycle and the $CO_2$ is compressed and dried for transport. The expected composition of the exported $CO_2$ is presented in Table 3.26. This concept is inherently without atmospheric emissions of $NO_x$ and $SO_x$. According to Clean Energy Systems, emissions of CO, VOC and particulate matter can virtually be eliminated by combustion control (i.e. temperature, pressure, residence time, fuel/oxygen mixing etc). The exported $CO_2$ will however contain trace amounts of $SO_2$, $NO_x$, CO and VOC due to unburned carbon and oxidation of nitrogen and sulphur which may be present in the natural gas, see Table 3.26. (CO2-Norway AS, 2004)

Table 3.26 Composition of exported $CO_2$ (from ($CO_2$-Norway AS, 2004))

| **$CO_2$ stream Composition** | **Concentration** |
|---|---|
| $SO_2$ | < 10 ppm |
| $NO_x$ | < 1 ppm |
| CO | < 100 ppm |
| $C_nH_{(2n+2)}$ | < 10 ppm |

When these levels of impurities are deemed unacceptable, the alternative is to remove the impurities from the natural gas prior to combustion (sulphur) or from the $CO_2$ stream during in the $CO_2$ treatment section (CO, VOC, $NO_x$ $SO_x$). (IEA GHG, 2006b) Subsequently, these impurities are then vented or require further treatment and disposal.

#### *3.4.2.1.3 Graz cycle*

In the GRAZ cycle a mixture of compressed steam, natural gas, oxygen and $CO_2$ is combusted to generate a hot gas mixture of steam and $CO_2$, see Figure 3.15. This mixture is expanded in a HP gas turbine after which the gas is fed into a HRSG to generate steam. This steam is expanded in the HP steam turbine to 40 bar, after which is it fed into the combustor. The gas exiting the HRSG is expanded in a LP turbine and fed into the condenser, where water and $CO_2$ are separated. The $CO_2$ is then compressed and dried and ready for transport. A part of the $CO_2$ /steam mixture that exits the HRSG is recycled, after compression and cooling steps, back into the combustor.

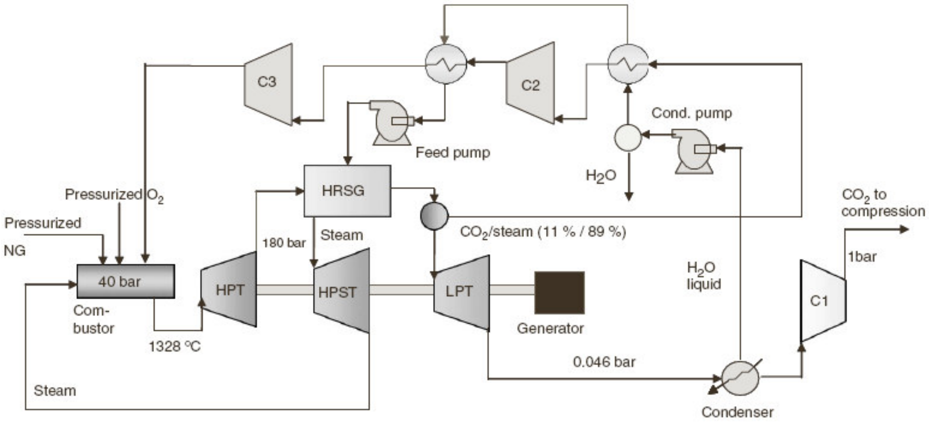

Figure 3.15 GRAZ cycle Oxyfuel concept (after (Kvamsdal et al., 2007))

The main limitations for the implementation of this concept are that the LP and HP turbines (that expand the $CO_2$ steam mixture) are not available and have to be developed. Another component that is not available is the combustion chamber. Next to the immaturity of several components, difficulties in the integration and optimisation of the components into a reliable power cycle are expected.

#### *3.4.2.1.4 AZEP*

The Advanced Zero Emission Power plant (AZEP) is virtually a NGCC power plant where the natural gas combustor is replaced by a Mixed Conducting Membrane (MCM) reactor. In this concept the pressurized air and natural gas are fed into the MCM reactor where three reactions occur. The compressed air and fuel are physically separated by an oxygen and heat conducting membrane. The oxygen from the air is transported through the membrane to react with the fuel into $CO_2$ and $H_2O$ (steam). The heat from the oxidation of the fuel is transferred with the use of a high temperature heat exchanger to the oxygen depleted air. This heated air is expanded in a turbine after which the heat is used in the HRSG to generate electricity in a Rankine bottoming steam cycle. The $CO_2$/ $H_2O$ mixture exiting the MCM reactor can be expanded in a $CO_2$/steam turbine to enhance the thermodynamic efficiency of the cycle. Then, the mixture is cooled as it is fed into the condenser and $CO_2$ and $H_2O$ can be separated.

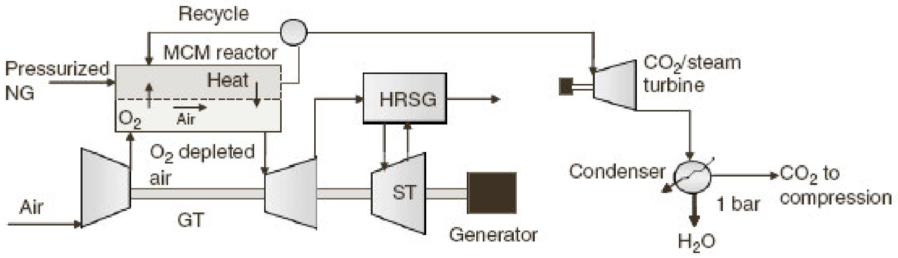

Figure 3.16 AZEP oxyfuel concept (after (Kvamsdal et al., 2007))

The concept shown in Figure 3.16 is the so called AZEP 100% configuration and refers to ~100% capture. Also AZEP configurations with lower (i.e. ~85%) $CO_2$ capture efficiencies are proposed. These configurations utilize an afterburner which is installed after the MCM reactor. This afterburner will fire natural gas to increase the temperature of the gas entering the turbine and with it will increase the thermodynamic efficiency of the cycle. The main drawback is that $CO_2$ from the fuel that is burned in the afterburner is not captured, hence the lower capture efficiency. Furthermore, firing of natural gas with air may have result in the formation of $NO_x$.

Critical components in this concept that are expected to hinder near term deployment are the MCM reactor and the $CO_2$ /steam turbine. The MCM reactor integrates three units for the three reactions in series. This requires a high degree of integration and interaction between the three units which enhances the complexity of this component. The AZEP concept in general thus requires some ‘technological breakthroughs’ in order to be ready for implementation. (Kvamsdal et al., 2007)

#### *3.4.2.1.5 SOFC + Gas Turbine*

The solid oxide fuel cell (SOFC) virtually replaces the gas combustor of the air fired NGCC. In Figure 3.17 the working concept of the SOFC is shown. The fuel is partially reformed into $CO_2$, CO and $H_2$, and enters the anode side of the fuel cell. Compressed and pre-heated air enters the SOFC at the cathode side. The oxygen in the air is reduced to $O_2^{2-}$ ions by gaining electrons. The oxygen ions are transported through the electrolyte and react with the fuel on the anode side, the electrochemical reaction. The fuel reacts into $H_2O$ and yields again electrons. The SOFC thus directly generates electricity. Next to the electrochemical reaction two other processes occur in the SOFC, namely: internal reforming of hydrocarbons and the water gas shift reaction.

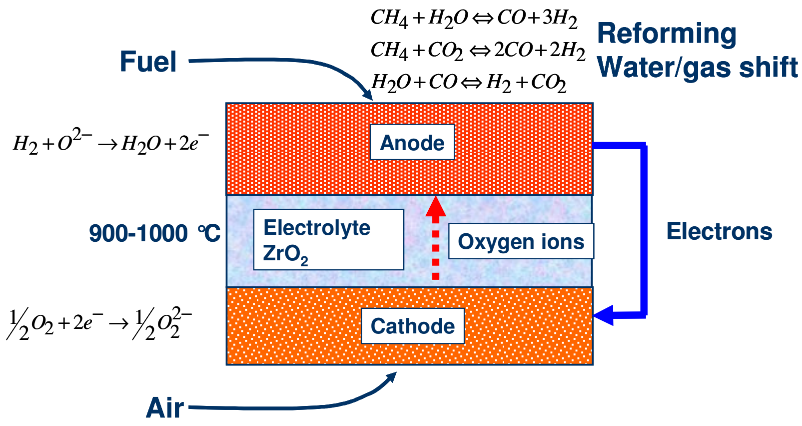

Figure 3.17 SOFC concept (after (Maurstad, 2004))

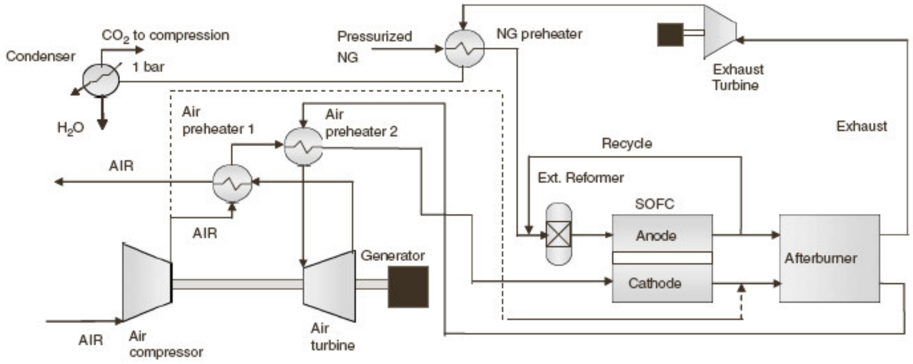

Figure 3.18 SOFC with gas turbine oxy fuel concept (after (Kvamsdal et al., 2007))

The SOFC integrated in a power cycle is shown in Figure 3.18. In this figure it is depicted that the off gases from the SOFC are combusted in an afterburner. This is necessary as the SOFC does not convert all the fuel. (Jansen, 2008) The afterburner can, however, also be replaced by a second SOFC to convert the remaining fuel in the gas stream. The hot oxygen depleted gas of the afterburner (or 2nd SOFC) is expanded in an air turbine to generate electricity. The exhaust gas (mainly $H_2O$ and $CO_2$) is expanded in the exhaust turbine. Then the gas stream is used to pre-heat the natural gas and is finally fed into the condenser to separate the $CO_2$ and $H_2O$.

#### *3.4.2.1.6 Chemical looping combustion*

The chemical looping combustion (CLC) concept is considered an Oxyfuel technology as the technology includes the separation of oxygen with the use of oxygen carriers from the air before reaction with the fuel. In Figure 3.19 the concept is schematically depicted. The figure shows that compressed air is fed into the oxidizing reactor (OX) were a metal oxide (oxygen carrying metals that are considered are: Cu, Co, Ni, Fe and Mn) is formed through the exothermic reaction of a metal with oxygen. This is the oxygen carrier that transports the oxygen to the reduction reactor (RED).

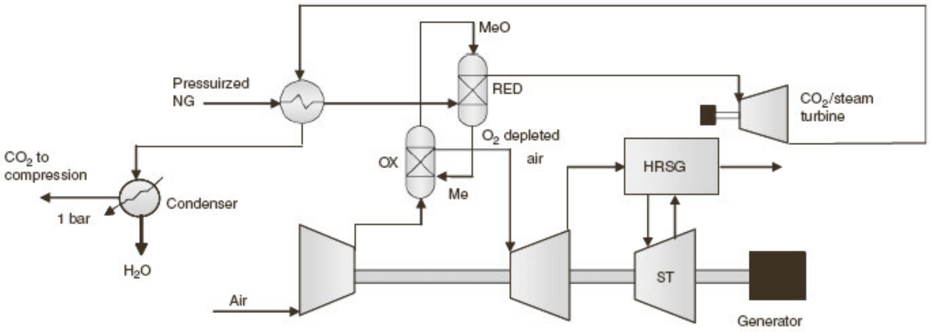

Figure 3.19 Chemical looping oxyfuel concept (after (Kvamsdal et al., 2007))

In the reduction reactor the fuel reacts (oxidizes) with the oxygen from the metal oxide (MeO). The exhaust gases ($CO_2$ and steam) are then expanded in $CO_2$/steam turbine. The gas stream is then fed to the condenser after passing the heat exchanger to pre-heat the natural gas. In the condenser the $H_2O/CO_2$ mixture is cooled and the $CO_2$ is separated, ready for compression and drying. The hot oxygen depleted air that exits the oxidation reactor is expanded in a gas turbine to generate electricity. The hot gases are then fed into the HRSG to generate electricity in a bottoming Rankine steam cycle.

The technology shown here is based on a fluidized bed reactor which is a mature technology. The application the technology in CLC has however some uncertainties. The main bottlenecks are the gas solid separation performance of the fluidized bed concept and the wear and loss of oxygen carriers (Kvamsdal and Mejdell, 2005).

Future concepts of chemical looping combustion were explored by ten Asbroek et al. (2006). These concepts involve membrane assisted fixed bed reactors opposed to the interconnected fluidized bed reactors in the ‘conventional’ CLC concept. In the conventional concept the oxygen carriers are cycled through the reduction and oxidation reactors. In the fixed bed concepts the oxygen carriers remain in a fixed bed and the reactor operates either in oxidation or reduction mode by switching between air and natural gas feed. The cycle can operate semi-continuously by installing multiple reactors. The major benefits of these fixed bed concepts are expected to overcome the problems encountered in the interconnected concepts. These problems are separation of the solids and the gas stream, as particles (oxygen carriers) in the gas stream may damage the gas turbine and may be emitted into the atmosphere. In the fixed bed concept the gases and solids are separated by a membrane. A second problem is the wear of oxygen carriers, which is expected to be reduced in the fixed bed concept. The third problem is efficient use of the oxygen carrier. This is expected to be enhanced by using membranes (Geerdink, 2008; ten Asbroek and Feron, 2006; ten Asbroek et al., 2006).

A variant of the fixed bed concept has been developed and is being tested by TNO in the Netherlands. Important research areas for this concept are the screening and selection of suitable membranes and oxygen carriers. Also the reactor design and integration into power cycles remains an area of further research (Geerdink, 2008).

#### *3.4.2.2 Application area*

The concepts discussed here are in particular of interest for utility sized power plants and combined heat and power (CHP) plants. Kvamsdal et al. (Kvamsdal et al., 2007) assessed multiple gas fired concepts including the oxyfuel concepts discussed here. They assumed in their benchmark that all concepts would have a capacity of 400 MWe, i.e. utility scale. They however stressed that these capacities are not likely for the SOFC concept. This is due to the difficulties in scaling up SOFC stacks. (Jansen, 2008) The SOFC concept is therefore considered to find its application mainly in the CHP sector with capacities of several MW. For other emerging concepts (AZEP, CLC and MSR-H2) it is also questionable whether they mature and reach utility scale. (Kvamsdal et al., 2007)

A possible application area for the fixed bed CLC concept is the horticulture sector. (Geerdink, 2008) A variant of the CLC reactor proposed for power generation is planned to being installed at several greenhouse gas horticulturists. The main rationale for this application is that currently growers use natural gas to produce heat (and some electricity) and $CO_2$ to enhance crop yields. The main problem however is that $CO_2$ and heat demands are not synchronic. The growers need $CO_2$ during the day time and heat during the night. The main benefit of the CLC reactor is that it is a cyclic reactor, i.e. it produces heat (and no $CO_2$) during the oxidation phase and produces $CO_2$ (and less heat) during the reduction phase. This makes it possible to let the oxidation reaction occur during the night and the reduction reaction during the day. Although this is not a technology incorporating $CO_2$ storage, it is a mean for $CO_2$ abatement. Furthermore, the application of the technology in this sector may increase technical learning and will help development of the CLC technology for larger scale applications.

In general, all discussed concepts are not suitable for the retrofit of existing natural gas fired cycles. (Kvamsdal and Mejdell, 2005) (ZEP, 2006) Kvamsdal and Mejdell (Kvamsdal and Mejdell, 2005) (ten Asbroek and Feron, 2006) do however estimate that the CLC and AZEP concept are more suitable for retrofitting compared to the other concepts.

In the pertaining literature it is not found if it is possible to (co)-fire oil products, blast furnace gases and biomass in oxyfuel concepts.

#### *3.4.2.3 Development phase*

The oxyfuel cycles for natural gas are considered promising technologies regarding their energetic performance compared to other gas fired options with CCS, and feasibility in both technical and economical terms. (ZEP, 2006) However, significant efforts in RD&D are required for all concepts to be ready for implementation on the near or medium term. Kvamsdal et al. (Kvamsdal et al., 2007; Kvamsdal and Mejdell, 2005) have recently benchmarked several gas fired cycles with $CO_2$ capture. The candidate concepts and their expected term of realization are presented in Table 3.27.

Table 3.27 Indication for development phase of oxyfuel concepts and critical components (based on (Geerdink, 2008; Jansen, 2008; Kvamsdal et al., 2007; Kvamsdal and Mejdell, 2005)

| Oxy fuel concepts | Development phase | Critical components |
|---|---|---|
| Oxyfuel combined cycle | Laboratory/ Pilot | Combustor, turbine ($CO_2$ as working fluid) |
| Water cycle | Pilot/demonstration | Combustor, turbine |
| Graz cycle | Laboratory/ Pilot | Combustor, turbine |
| Advanced zero emissions power plant | Laboratory | MCM reactor |
| Solid oxide fuel cell integrated with a gas turbine | Laboratory/ Pilot | Fuel cell (SOFC), afterburner (including oxygen conducting membrane) |
| Chemical looping combustion | Laboratory/ Pilot | CLC reactor |

The expected implementation term is primarily the consequence of the development of critical components that is needed. Examples are the turbines and combustors for the near and medium term options and additionally the fuel reactors for the future term concepts. Furthermore, after solving the R&D requirements for the individual components, the integration of these components into a reliable and efficient cycle requires further efforts.

The implementation term for as presented in the table may be an overestimation. Kvamsdal and Mejdell (Kvamsdal and Mejdell, 2005) estimate that implementation of the SOFC concept can be achieved between 2015 and 2030. It can be considered more realistic that this concept is ready for commercial introduction on a multi MW scale near 2015 than near 2030 (Jansen, 2008). Also, the SOFC concept is already being tested by, for instance, Siemens on a 220 kW scale (without $CO_2$ capture) (ten Asbroek and Feron, 2006). Up scaling can considered to be an area of further development (Jansen, 2008).

The CLC concept still requires significant development time and is expected to find its most earliest commercial application in 2020 according to (Kvamsdal et al., 2007; Kvamsdal and Mejdell, 2005). (Geerdink, 2008) however estimates that if considerable efforts are allocated to this concept that commercial application may be realized before 2020. Smaller scale applications are already planned for the horticulture sector in 2008/2009.

Combustion tests to prove the concept of the water cycle have been performed on the pilot scale. Further, a demonstration plant of the water cycle concept is currently being planned to be built in the Netherlands. The implementation term for this concept can thus be considered near term. A full commercial scale power plant using this concept may be available in the medium term. Larger scale demonstrations of this concept are also planned[20]. It is however undecided when and if these projects are implemented (MIT, 2008).

#### 3.4.2.4 *Economic and energy performance*

The thermodynamic performance of the oxyfuel concepts discussed in this study is presented in Table 3.28. The lower efficiency of the oxyfuel combined cycle, water

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[20] A 70 MW plant in Worsham-Steed, Texas, USA and 50-70 MW near Stavanger, Norway.

cycle and Graz cycle is mainly due to the energy requirement of the cryogenic ASU. Further improvement in cryogenic air separation is possible but is also considered to be limited. (M. Anheden et al., 2005) A higher degree of integration with the power cycle may be one of the options to enhance cycle efficiency of the concepts using air separation (ZEP, 2006) (Kvamsdal et al., 2007).

The concepts that do not use an ASU show higher thermodynamic efficiencies. A positive outlier in this respect is the SOFC concept which shows an efficiency that is higher than a conventional NGCC and thus results in a negative value for the efficiency penalty, see Table 3.28.

Another important part of the efficiency reduction for all concepts compared to a conventional NGCC can be attributed to the compression of $CO_2$.

Table 3.28 Energetic and economic performance of gas fired power plants with and without $CO_2$ capture by means of oxyfuel combustion (Davison, 2007; IEA GHG, 2005b; Kvamsdal et al., 2007)

| | **no-capture** | **oxyfuel concepts** | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | **AZEP 100%** | **AZEP 85%** | **CLC** | **Graz cycle** | **SOFC + GT** | **Water cycle** | **Oxyfuel CC** |
| Oxygen separation principle | - | MCM | | Oxygen carrier | ASU | SOFC membrane | ASU | ASU |
| Electrical efficiency (in %) | 53-58[1] | 50 | 53 | 51 | 49 | 67 | 45[2] | 45-47 |
| Efficiency penalty (in % pts.)[3] | . | 7 | 4 | 5 | 8 | .-11 | 12 | 10-11 |
| Primary Energy increase (in %) | - | 13.4 | 8 | 10.5 | 16.7 | -15.8 | 27.1 | 20.6-24.4 |
| Capture efficiency (in %) | - | 100 | 84 | 100 | 100 | 100 | 100 | 97-100 |
| $CO_2$ emissions (in g/kWh) | 344-379 | 0 | 60 | 0 | 0 | 0 | 0 | 0-11 |
| $CO_2$ emissions (in g/MJ | 55-59 | 0 | 9 | 0 | 0 | 0 | 0 | 0-1 |
| Euro per tonne avoided (constant 2007) | | | | | | | | 69-85 |
| cost of electricity (in euro cts/kWh) | 3.0-6.2 | | | | | | | 5.5-8.3 |

[1] 60% efficiency is highly likely to be reached before 2020. (Jansen, 2008)

[2] Medium-term plant efficiency will be at least 51%. (CO2-Norway AS, 2004)

[3] This efficiency penalty is determined by using a NGCC with an efficiency of 57% as reference technology for all concepts except the oxyfuel CC concept.

Data on the economic performance of these concepts are only gathered for the oxyfuel combined cycle. However, ten Asbroek and Feron (ten Asbroek and Feron, 2006) reviewed various oxyfuel concepts and concluded that oxyfuel technologies can only become more economical attractive then post combustion capture if significant technological progress is achieved and simultaneously the technological progress in post combustion capture levels out.

### *3.4.2.5 Environmental performance NEC and PM*

#### *3.4.2.5.1 $SO_x$*

Typically sulphur content of natural gas is very low and thus $SO_2$ emissions are negligible for natural gas fired power plants. When applying oxyfuel concepts the sulphur oxides remain in the $CO_2$ stream and are co-sequestrated with the $CO_2$. An option is however to remove the sulphur before combustion. This is necessary in the MSR-H2, CLC and SOFC concept as the fuel cell, membranes and oxygen carriers require deep desulphurization for stable operation and performance. (Energy Nexus

Group, 2002) (Geerdink, 2008; Jansen, 2008) Another option is to remove the $SO_x$ from the $CO_2$ stream. This can then be vented or be removed in the form of sulphuric acid (as discussed for the solid oxyfuel concept).

Seebregts and Volkers (Seebregts and Volkers, 2005) mention that some gas fired installations in the Netherlands co-fire oil products or blast furnace gasses (from steel production) and, as a consequence, emit $SO_2$. They estimate that emission factors will not be above 4 g/GJ without $CO_2$ capture. For gas fired installations co-firing liquid biomass (e.g. oil) an emission factor of 2.6-4.4 g $SO_2$ /GJ is estimated by Seebregts and Volkers (2005).

Although in literature no information was found on the co-firing of biomass, oil and blast furnace gas in oxyfuel concepts, it may be expected that $SO_2$ emissions are lower compared to conventional gas fired power plants. This is expected because $SO_2$ may be co-sequestered with the $CO_2$ or be removed efficiently in the $CO_2$ treatment section.

#### *3.4.2.5.2 NOx*

$NO_x$ formation when firing natural gas is dominated by the flame temperature. High flame temperatures result in the formation of thermal $NO_x$, which is a reaction of nitrogen in the air with oxygen. In the oxyfuel concepts the nitrogen is removed from the air before combustion or the air and fuel are separated by a membrane. The formation of $NO_x$ is thus significantly hindered. Nitrogen in the gas may be a source for $NO_x$ formation but this can considered to be negligible. Furthermore, any $NO_x$ that is formed will remain in the $CO_2$ stream and be co-sequestered with the $CO_2$.

As for $SO_2$, it is possible to remove $NO_x$ from the $CO_2$ stream, if required. The removed $NO_x$ can then be vented or treated further. (IEA GHG, 2006b)

For the AZEP concept the $NO_x$ formation is considered to be low as the MCM reactor operates under lower temperatures than normally encountered in a gas turbine. In the case that supplemental firing is used in this concept to enhance the cycle efficiency, $NO_x$ formation will be higher. Nevertheless, $NO_x$ emissions are expected to be lower than conventional gas cycles. Sundkvist et al. (2004) performed a LCA for the AZEP concept with 100% $CO_2$ capture (i.e. without supplemental firing) and estimated $NO_x$ emissions over the life cycle to be 0.006 g/kWh

According to several authors, CLC is capable of thoroughly eradicating thermal $NO_x$ formation (Kvamsdal and Mejdell, 2005) (Naqvi et al., 2004). I this concept $NO_x$ may only be formed trough thermal $NO_x$ formation as fuel bound $NO_x$ will be found in the captured $CO_2$ stream. Naqvi et al. (2004) explains that thermal $NO_x$ is significantly lower than in conventional processes as oxidation of the metal occurs at lower temperatures than in a conventional natural gas fired turbine. As thermal $NO_x$ increases with combustion temperature (oxidation of metal in the case of CLC) lower temperatures ensure lower thermal $NO_x$ formation.

Ishida and Jin (1996) performed a combustor test with the use of Nickel oxides and found no thermal $NO_x$ formation during their tests. This led them to conclude that CLC is without $NO_x$ formation. A recent review concluded that $NO_x$ formed during the fuel conversion step in the reduction reactor is captured together with the $CO_2$ and that some thermal $NO_x$ may be emitted to the atmosphere. Albeit that it is expected that $NO_x$ emissions are lower due to lower temperatures during oxidation.(IEA GHG, 2006b)

Thermal $NO_x$ formation in the fixed bed concept may occur in the gas turbine where hot ($O_2$ depleted) gas from the reactor in oxidizing mode is expanded and where unreacted natural gas is combusted. $NO_x$ formation is however not specifically addressed by ten Asbroek et al. (2006).

A variant of the CLC technology is developed and tested by TNO. This variant is based on the membrane assisted fixed bed reactor. During tests it was found that no thermal $NO_x$ formation was formed in the reactor at reactor temperatures of up to 1200°C, the maximum temperature during the tests. (Geerdink, 2008)

$NO_x$ formation in the SOFC concept is very low as the fuel is not combusted but chemically ‘converted’. This means that lower temperatures are found in the fuel cell compared to thermal oxidation in a conventional cycle. This lower temperature ensures very low $NO_x$ formation and emissions. (Jansen, 2008; Lundberg et al., 2000)
(Energy Nexus Group, 2002)

###### *3.4.2.5.3 $NH_3$*

Theoretically, it is possible to equip a CLC with a SCR. This will have impact, however, on the investment cost and thermal efficiency of the cycle. A potential negative side-effect may be the emission of unreacted $NH_3$, which is also a pollutant that contributes to acidification and eutrophication.

###### *3.4.2.5.4 NMVOC*

Geerdink (2008) noted that it is likely that in the CLC concept unreacted hydrocarbons (VOC) may exit the reactor during the reduction phase. It is however expected that these emissions can be controlled to acceptable limits by optimized process control during the chemical reduction phase. With better understanding of CLC process control these emissions are expected to be minimized as well.

In general the unreacted fuel (and also CO) is in all concepts captured together with the $CO_2$ during the liquefaction if the $CO_2$ in the $CO_2$ treatment section the largest part of these gases are expected to be removed (i.e. flashed off) from the $CO_2$. It is possible to convert the main part of these gases in a catalytic converter or afterburner. (IEA GHG, 2006b) The latter can be for instance applied on the SOFC concept.

###### *3.4.2.5.5 $PM_{10}$ and $PM_{2.5}$*

Particulate emissions are considered negligible in natural gas fired concepts. If particulates may form during combustion it is highly likely that they will remain in the $CO_2$ stream or are vented. See for more information section 3.4.1.5.5.

###### *3.4.2.5.6 Other environmental impacts of concern*

One environmental impact of concern may be the cryogenic production of oxygen. The oxygen production and storage may put forward safety risks as their may be explosion risks. Oxygen production at power plants is however currently regulated and already implemented at the IGCC at Buggenum. It can be considered a manageable risk.

Other environmental impacts of concern for the oxyfuel concepts are life cycle emissions. Due to the capture penalty life cycle emissions in the natural gas production chain are increased per kWh for some concepts compared to a conventional NGCC. Sundkvist et al. (Sundkvist et al., 2004) estimates for instance that the emissions of CO, CH4 and the use of water in the life cycle will increase for the AZEP concept compared to a conventional NGCC.

For the CLC concept another concern may be the loss of metal oxides. These metal oxides may contribute to the environmental impacts of energy supply with this concept as it might bring forward direct environmental impacts, i.e. some metals are considered toxic. Also, these oxygen carriers may bring forward environmental impacts in their life cycle, e.g. during mining, treatment and disposal.

#### *3.4.2.6 Uncertainties and knowledge gaps*

For the gas fired oxyfuel concepts no detailed estimates for emission factors of NEC substances are found in the pertaining literature. Most of the information on emissions that affect air quality is presented qualitative. According to the qualitative information most of the NEC substances, of which $NO_x$ is the most important for gas fired power plants, will be lower for the oxyfuel concepts compared to conventional NGCC power plants.

In the oxyfuel concepts the NEC substances that are formed during combustion of chemical conversion may partly be co-sequestered with the $CO_2$. Whether, and to what extent, this is acceptable for the $CO_2$ transport and storage, and if this is allowed under current legislation remains uncertain.

For this study insufficient information was gathered on the economical performance of advanced oxyfuel concepts. For the benchmark of the various oxyfuel concepts it is necessary to gather more information on the economics of these concepts.

### *3.4.3 Conclusions oxyfuel $CO_2$ capture*

The oxyfuel concept with $CO_2$ capture firing coal is near to be demonstrated. Most oxyfuel concepts firing natural gas are mainly in the laboratory or pilot scale, although one concept is to be demonstrated in the near future in the Netherlands, i.e. the water cycle.

$SO_2$ emissions are expected to decrease per MJ and per kWh when applying the oxyfuel concept in coal fired power plants. This is expected because of:

- The lower levels of uncontrolled $SO_2$ emissions from combustion in an oxygen rich medium due to increased retention in ashes;
- Reduced flue gas volume leads to higher $SO_x$ concentrations which are likely to increase the removal efficiency of $SO_2$ in FGDs;
- Other technologies for $SO_2$ removal implemented in the purification train of the $CO_2$ stream may be very efficient in removing $SO_2$ and yielding sulphuric acid;
- $SO_2$ may be (partly) co-sequestered with the $CO_2$.

The sulphur content of natural gas is very low and thus $SO_2$ emissions are expected to be negligible for natural gas fired power plants. When applying oxyfuel concepts the sulphur oxides remain in the $CO_2$ stream and are co-sequestrated with the $CO_2$. An option is however to remove the sulphur before combustion or from the $CO_2$ stream.

$NO_x$ formation during oxyfuel combustion of coal is found to be lower as the thermal $NO_x$ formation is suppressed. The results from literature show that in general the $NO_x$

formation is reduced when combustion occurs in a denitrified medium. The actual emission of $NO_x$ depends on the technological configuration of the flue gas treatment section. $NO_x$ emission may be co-sequestered, vented, treated in a $DeNO_x$ facility or removed in the form of nitric acid. Overall, $NO_x$ emissions per MJ are expected to decrease. The efficiency penalty may however result in a net increase of $NO_x$ per kWh in some literature cases.

$NO_x$ emissions from gas fired oxyfuel concepts are in general also expected to be very low as the nitrogen is separated from the combustion medium hindering $NO_x$ formation. Any $NO_x$ formed may be co-sequestered with the $CO_2$ or removed from the $CO_2$ stream after combustion.

In literature no information is found on the effect of oxyfuel combustion on the formation and emission of $NH_3$. When an oxyfuel concept is equipped with a SCR, $NH_3$ slip may lead to a very small emission. The application of a SCR in oxyfuel concepts is however not often envisaged in literature.

In general the unreacted hydrocarbons (VOC) are in all oxyfuel concepts captured together with the $CO_2$. These may be co-sequestered with the $CO_2$ or are removed from the $CO_2$ stream and can then be vented or burned. Quantitative estimates for these emissions were not found in the pertaining literature.

For coal fired oxyfuel concepts the particulates emissions are estimated in literature to be lower, both per MJ as per kWh, compared to conventional pulverized coal fired power plants,. A high degree of PM removal is expected as this is required for the reliable operation of compressors and fans. PM may also be partly co-sequestered with the $CO_2$. The removal efficiency of the ESP may be improved as a consequence of increased concentrations of $SO_3$ in the flue gas, thereby enhancing PM removal. Particulate matter emissions are considered negligible for natural gas fired oxyfuel concepts.

Uncertainties in estimates gathered in this study are the consequence of variations in assumptions in the literature. The level of flue gas cleaning and the technologies that are to be implemented for that are currently the main uncertainties when estimating the level of NEC emissions. There is a considerable lack of data on emissions (estimations) for gas fired oxyfuel concepts. The emission factors for oxyfuel applications in coal power plants are based on pilot tests and desktop studies. Demonstration of the technology with emission monitoring is required for more accurate estimation of emission factors.

The effect of biomass co-firing in oxyfuel concepts on the performance and emission profile is currently unknown although research has started aiming to close that research gap.

## 3.5 Transport and storage description

### *3.5.1 $CO_2$ transport*

Carbon dioxide can be transported in a gaseous (via pipelines or ships), or a liquid mode (via pipelines, ships or tanks). Solid transport is not currently applicable from an economical and energy usage stand-point. $CO_2$ can be liquefied and transported by marine tankers. Due to its intrinsic PVT properties, $CO_2$ can be transported either with a semi-refrigerated tank structure (approx. -50°C and 7 bars), or a compressed gas carrier ($CO_2$ does not exist in a liquid state at atmospheric pressures). Current engineering is focusing on ship carriers with a 10-50 ktonnes capacity. Ship transport of $CO_2$ can provide flexibility, as it allows the combination and collection of several small-medium sources, a reduction in the infrastructure CAPEX costs, and adapting to storage requirements. It is estimated however that shipping only becomes economically viable with distances over 1000 km (IPCC, 2005). Cost of ship transport, including intermediate storage facilities, and harbor fees, varies from $ 15 US/t $CO_2$ for 1000 km to 30 $ for 5000 km (IEA GHG, 2005a). Liquefied $CO_2$ can also be transported by rail of with road tankers; however, since the amounts that can be transported by batch are rather small, and thus transporting large amounts of $CO_2$ will result in large costs, this is not considered as an attractive option for large scale CCS projects.

For large volumes (>1 Mtpa $CO_2$) and short distances (<500 km), pipelines are considered the most cost effective. Shipping $CO_2$ via pipelines is an established technology for small volumes, in the range of a few Mtpa (IPCC, 2005). There are over 2500 km of existing long-distance $CO_2$ pipelines handling over 50 Mtpa, with diameters ranging up to 30 in (0.762 m) (Gale and Davison, 2002). The transport of $CO_2$ through pipelines can take place in the liquid, dense liquid, gaseous and supercritical phase. In order to optimize flow rate it is recommended that transport should take place in the dense phase or in the supercritical one (in this way two-phase flow is avoided). However, keeping a supercritical state implies that the pipeline should be constantly heated (temperatures higher than 31.1ºC and pressures above 73.8 bar are required), which makes it economically unattractive. Consequently, it is considered that $CO_2$ should be transported in the dense state (with pressures above 80 bars). This has several advantages: in this phase $CO_2$ acts like a liquid, but can be compressed to a density of 800-900 kg/m$^3$; it occupies a smaller volume, which results in a smaller pipeline diameter and thus in lower costs and finally, since $CO_2$ will be transported with the goal of storing it in geological reservoirs, having high pressures in the transport network is desired since delivery pressures of at least 80-100 bars for injection are required (Hendriks et al., 2007).

A $CO_2$ infrastructure would be similar to any other gaseous or liquid delivery systems. As an example, Figure 3.20 shows three possible trunckline routes for $CO_2$ transportation in the Netherlands. There are a few differences in handling for $CO_2$ that are not found in other commodities (e.g. natural gas). Operationally, except for the need for extra compression or pumping in the dense phase, all other forms of transport are very similar for products that need to be liquefied to be readily transported.

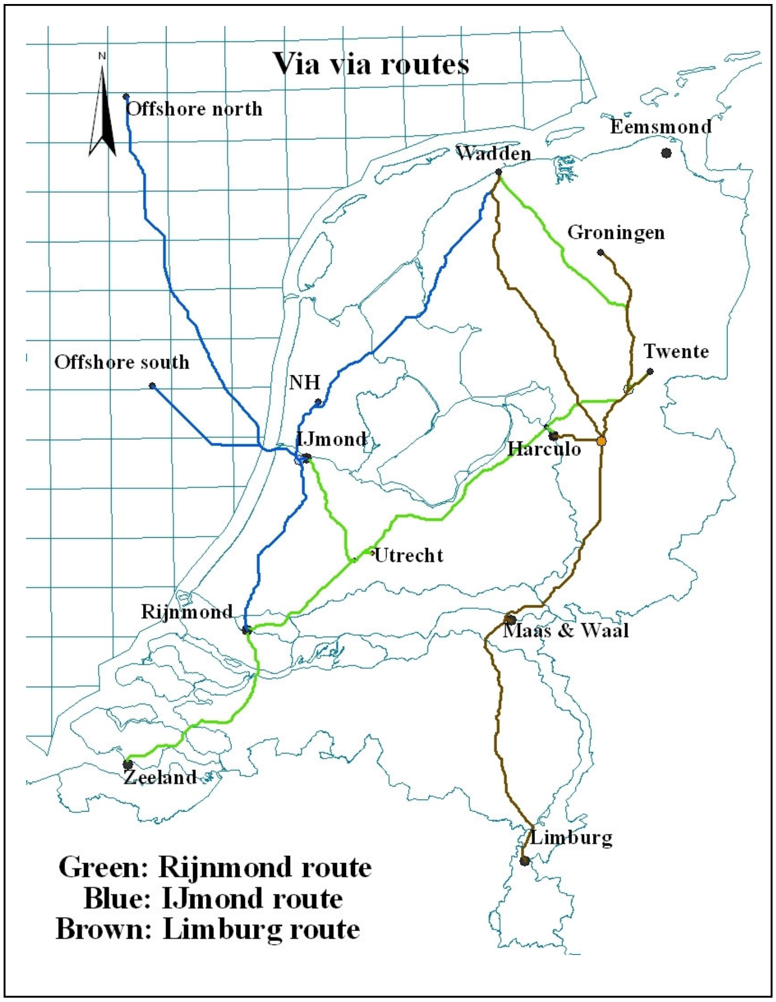

Figure 3.20 Possible trunkline routes for $CO_2$ transportation in the Netherlands. The IJmond route: $CO_2$ collection near Spaarndam and transportation to sinks in Offshore north, Offshore south, NH or Wadden. The Limburg route: from Limburg via Maas & Waal and Harculo to sinks in Wadden, Groningen and Twente. Rijmond route: from Zeeland via Rijnmond, IJmond, Utrecht and Harculo to the sinks in Wadden, Groningen and Twente (Brederode E. et al., 2008)

### *3.5.2 Impacts on NEC emissions*

A literature review of environmental impact assessments of pipeline constructions (including $CO_2$ pipelines for Enhanced Oil Recovery) reveals that main impacts on air quality from this type of project under normal operation[21], will be during construction from (i) movement of heavy equipment for trenching and transport of pipes, (ii) trenching activities including storage of excavated materials, (iii) movement of personnel, and (iv) construction of the pump house and take-off stations. The mechanical equipment, trucks, and electric generator sets for the welding machines will

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[21] The impacts of sudden releases of $CO_2$, $H_2S$ and other substances that could be emitted during a failure from either the pipeline transmission line or directly from the well head during underground injection (known as catastrophic failure) have not been taken into account in this inventory. The assessment of the magnitude and importance of this kind of impacts requires specific simulations in air dispersion models that take into account pipeline characteristics and meteorological conditions. This is considered outside the scope of this project.

produce pollutants such as dust ($PM_{10}$); carbon monoxide (CO); nitrogen dioxide ($NO_x$); and sulfur dioxide ($SO_2$) from fuel combustion ((AMEC Earth & Environment, 2005; Mayacan, 1996; Ministry of Heatlh, 2004; NETL, 2007; RSK, 2007; Zapert J. and Connell S., 2004). The review also showed that in all cases the significance of effects on air quality due to overburden disturbance is considered to be minor, as they will be localized, of small magnitude and short duration. Furthermore, there appear to be standard responses to these impacts which affect most development projects of this type (e.g. application of dust suppressants such as water, calcium chloride, or tree lignin) and for which standard procedures and best practice can be applied. It is therefore decided in this study not to examine this aspect in more detail.

### *3.5.3 $CO_2$ underground storage*

Options for deep underground $CO_2$ storage involves storing $CO_2$ in large natural reservoirs, or reservoirs that currently contain salt water (i.e. deep saline aquifers), gas, oil or coal (i.e. hydrocarbon fields, coal seems) or salt (salt caverns). The two first are considered the most promising due to estimated large capacities. A brief description of each reservoir type can be found in Table 3.30.

Table 3.30 Type of reservoirs, based on (Bachu et al., 2007).

| Reservoir type | Description |
|---|---|
| Aquifers | An aquifer is layer, formation or groups of formations of permeable rocks, saturated with water and with a degree of permeability that allows water withdrawal through the wells and hence will also allow injection of fluids. Aquifers being considered for $CO_2$ storage are deep aquifers saturated with (saline) formation water. |
| Hydrocarbon | Porous and permeable rocks that contain fluids other than water, such as hydrocarbons (oil and or gas), $CO_2$ and $H_2S$. These reservoirs are structural and stratigraphic traps at the top of aquifers that have been charged with oil and or gas during the process of hydrocarbon generation, migration and accumulation. |
| Coal seams | Sedimentary rocks of organic nature. It has a brittle structure and a system of micropores, which allows gas diffusion and cleats (fractures) that allow the flow of Gas ($CH_4$, $CO_2$) and/or water. Coal has higher affinity for gaseous $CO_2$ than for methane, thus $CO_2$ storage in coal beds is based on the concept that the injected $CO_2$ will replace the methane in coal and stay adsorbed onto the coal surface as long as the coal is undisturbed. |

#### *3.5.3.1 Geological storage capacity in the Netherlands*

There have been several studies looking at the Dutch geological storage capacity. Table 3.31 shows a comparison of the values reported. It is important to note that:

1) The most uncertain values are those reported for deep saline aquifers and unmineable coal seams.
2) To keep the $CO_2$ in supercritical state: Pressure>74 bar and T>304K. Considering a normal geothermal and hydrostatic gradient, this is translated into a minimal depth for the top of the storage reservoir of 800 m.

3) In the case of hydrocarbon fields it is assumed that the entire in-situ volume of ultimate recoverable hydrocarbons can be replaced by the same volume of $CO_2$. Only fields that are capable of storing more than 4MT $CO_2$ are considered (in gas fields this corresponds to an UR of about 2Gm$^3$).
4) In the case of aquifers: they should have at least a thickness of at least 10 m.
5) For coal seams: only those up to a depth of 1500 m.

Figure 3.21 shows a distribution of 169 possible storage reservoirs (corresponding to the capacities estimated in (TNO, 2007) and the parameters 1 to 4 named above).

Table 3.31 Estimated $CO_2$ storage capacity in the Netherlands according to different studies

| | **Joule II report** | **(Hamelinck et al., 2001)** | **(Wildenborg et al., 2003)**<br>**(Schuppers et al., 2003)** | **(TNO, 2007) (Energiened)** |
|---|---|---|---|---|
| Oil reservoirs | 0.03 Gt (100% onshore) | ---- | 0.05 Gt | 0.04 Gt |
| Gas reservoirs | 9.28 Gt (91% onshore) | ----- | 10.1 Gt (7.35 Gt Groningen field) | 10.1 Gt (2.03 Gt if Groningen and small fields (<15 Mt) are excluded) |
| Deep saline aquifers | ---- | ------ | 1100 Mt (9.8 Gt if open traps are considered). | 602 Mt onshore (405 Mt if only fields with capacities over 5Mt are considered); 300 Mt offshore; >10Gt if open traps are considered |
| Coal seams | ----- | 1-8 Gt | 173 Mt (range 39-594) | 298-496 Mt |

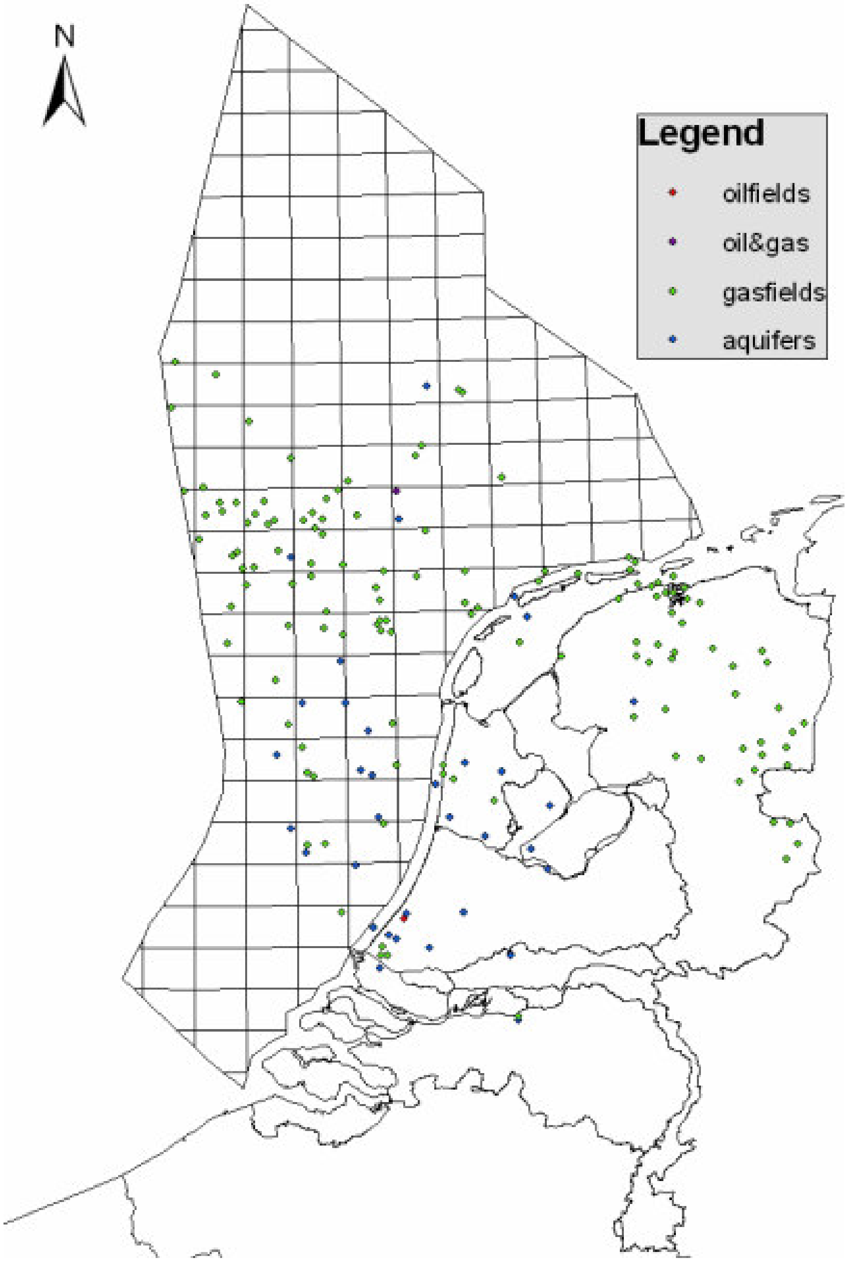

Figure 3.21 Potential $CO_2$ storage locations in the Netherlands

### *3.5.4 Impact on NEC emission levels*

Drilling wells for $CO_2$ storage would emit the criteria pollutants $NO_x$, CO, VOC, $PM_{10}$, and $PM_{2.5}$. Sources of criteria pollutant emissions at well sites during the production phase would include combustion emissions from generators powering well-site pumps ($NO_x$, CO, VOC, and formaldehyde) and fugitive particulate emissions from unpaved road travel and from wind erosion of disturbed areas such as the unreclaimed portions of well pads ($PM_{10}$ and $PM_{2.5}$). It should be noted that wells being used for gas and oil extraction could be also used for injecting $CO_2$. In such a case the only emission will be during the production phase.

Conversion of the existing depleted oil and gas field to $CO_2$ storage would require a compressor station in case the $CO_2$ is not at the well is at a pressure below 80 bar or during operation if higher pressures are required. Compressor stations will create noise and air pollution, and involve handling small quantities of hazardous materials. However, most modern compressor stations are low emission units and will be equipped with oxidation catalyst control for CO, VOC, and formaldehyde emissions. As an example, Table 3.32 shows potential operational emission rates of a compressor station designed for underground gas storage[22]. Although it is not possible at the moment to make realistic calculations on the amount of pollutants emitted during well construction and operation, from analogous situations, it is expected that $CO_2$ storage would have a minor and localized impact on air pollution and will not affect NEC thresholds at the national level.

Table 3.32 Emission summary of a gas fired compressor station (EP Colorado Interstate gas, 2007)

| **Equipment** | **Natural gas compressor (hp)** | **Potential critical pollutant emissions (tonnes per year)** | | | | |
|---|---|---|---|---|---|---|
| | | **$NO_x$** | **CO** | **VOC** | **$SO_2$** | **$PM_{10}$** |
| Compressor Caterpillar | 4735 | 28.6 | 5.1 | 4.98 | 0.07 | 0.01 |
| Emergency generator | 1.400 | 1.1 | 1.4 | 2.48 | 0.01 | 0.00 |
| Glycol reboiler | NA | 0.88 | 0.74 | 0.05 | 0.01 | 0.07 |
| Utility boiler | NA | 1.31 | 1.10 | 0.07 | 0.01 | 0.10 |
| Flare pilot | NA | 0.04 | 0.04 | 0.00 | 0.00 | 0.00 |
| Dehydrator | NA | --- | ---- | 0.33 | ---- | ---- |
| Fugitive emissions | NA | --- | ---- | 0.56 | ---- | ---- |

## 3.6 Life cycle impacts

### *3.6.1 Overview of life cycle*

In this chapter the effects of CCS on air pollution are looked at with a broader perspective. The implementation of CCS leads to expansion of among others the fuel production industry, solvent manufacturing industry, (gas treatment) equipment manufacturing industry and waste treatment. This brings about increased air emissions, which implies that $CO_2$ capture and storage influences air quality in an indirect way as well. This chapter examines the extent and order of magnitude of these additional effects. 3.22 is an overview of the chain of processes associated with carbon capture and storage.

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[22] Data for compression units for underground $CO_2$ storage was not found, but operating conditions (and hence emission) can be preliminary assessed by looking at equipment used at similar facilities, e.g. for underground gas storage. Emission estimates may be revised as more detailed information becomes available.

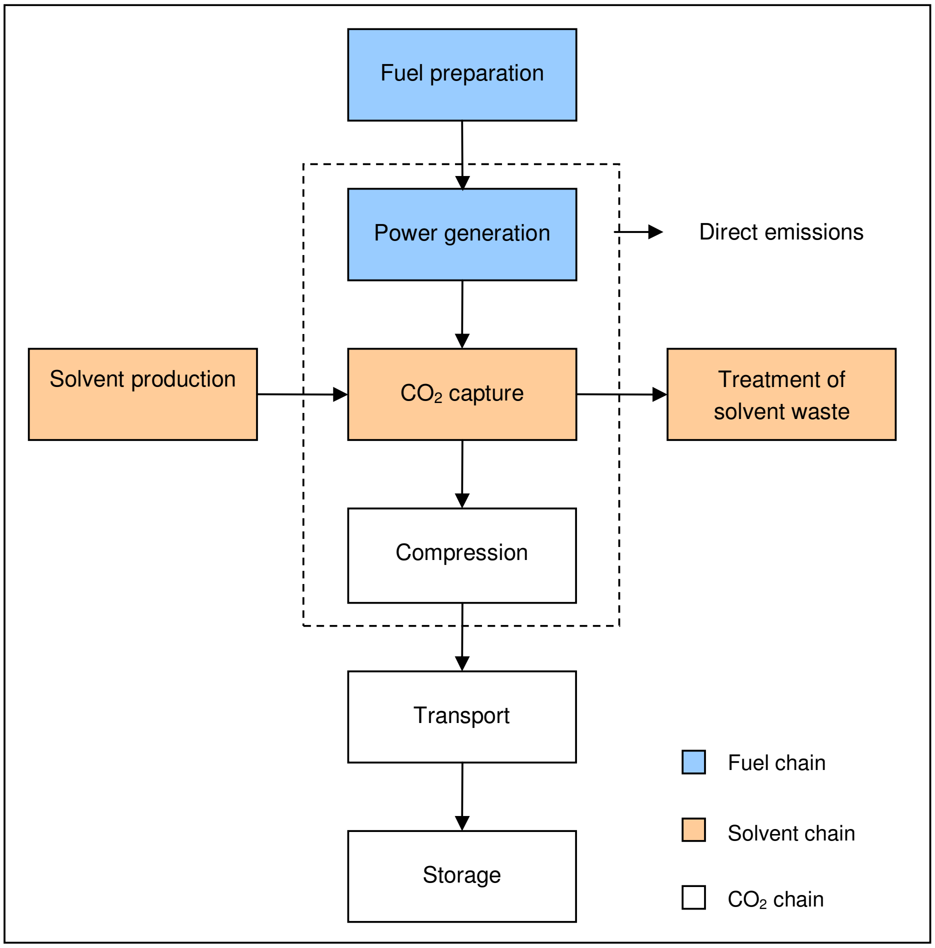

Figure 3.22 Life cycle of power generation with CCS

Power generation has been discussed in paragraphs 3.2 and 3.3. The next sub-paragraphs cover the activities in the other boxes in the diagram. Furthermore, sub-paragraph 3.6.8 evaluates the manufacture of real estate and equipment, which we will call $3^{rd}$ order processes. The findings in all sub-paragraphs are expressed per unit of process. In 3.6.9 the findings are summarized and expressed per MWh of electricity generated, and we subsequently evaluate whether the life cycle impact is significant or not, and which processes contribute most or are worthwhile investigating in more detail.

### *3.6.2 Fuel preparation*

Regardless of the technology, the energy penalty of $CO_2$ capture gives rise to additional fuel consumption per MWh of electricity, compared to power generation without $CO_2$ capture. The emissions associated with fuel mining and preparation are very different for coal and natural gas. Table 3.32 shows an indication of the emissions related to the production of pulverized coal and natural gas. Figures are based on (Ecoinvent Centre, 2007).

Included in these figures are:

- For coal: coal mining and preparation, coal processing, coal storage and transportation.

- For gas: gas field exploration, natural gas production, gas purification, long distance transportation, and regional distribution.

The figures reflect the mix of supplier countries and fuel specifications of the Netherlands in 2000.

Table 3.32 Emissions from fuel preparation (Ecoinvent Centre, 2007)

| | Emissions per MJ primary | | |
|---|---|---|---|
| **Substance** | **Pulverized coal** | **Natural gas** | **Unit** |
| $NO_x$ | 140 | 9.0 | mg |
| $SO_2$ | 98 | 1.4 | mg |
| $PM_{10}$ | 9.2 | 0.71 | mg |
| NMVOC | 15 | 1.1 | mg |
| $NH_3$ | 7.2 | 0.018 | mg |

As can be expected, the relatively energy intensive process of coal mining, preparation and transport has much higher air emissions than similar activities for natural gas. On the other hand, the larger part of these emissions occurs in remote areas.

### *3.6.3 Compression of $CO_2$*

The energy needed for compression is usually derived from within the power plant, and is expressed in the energy penalty dealt with in paragraphs 3.2 and 3.3.

### *3.6.4 Transport of $CO_2$*

The energy requirement of transport of $CO_2$ is relatively low. For offshore long-distance high pressure transport of natural gas a value of 0.8 MJ per tonne-km is given in (Ecoinvent Centre, 2007). The values in Table 3.33 exclude the production and civil work for the pipeline itself. Those are included in paragraph 3.6.8.

Table 3.33 Estimation of emissions from pipeline transport of $CO_2$ (Ecoinvent Centre, 2007).

| | 1 tkm* pipeline transport | Unit |
|---|---|---|
| $NO_x$ | 160 | mg |
| $SO_2$ | 1.5 | mg |
| $PM_{10}$ | 0.60 | mg |
| NMVOC | 3.7 | mg |
| $NH_3$ | 0.013 | mg |

*) tkm = tonne.kilometer - transport of one tonne of $CO_2$, over 1 kilometre

Pipeline transport of highly pressurized $CO_2$ over distances shorter than 100 km, which will probably be the case in the Netherlands, likely do not require additional energy input, other than energy for the initial compression. The figures in the table hereafter are therefore indicative for transport beyond 100 km only.

### *3.6.5 Storage of $CO_2$*

Paragraph 3.5.3.2 describes the effects of storage on NEC emissions. (EP Colorado Interstate gas, 2007) describes a natural gas buffer. Its energy consumption is used here as a proxy for $CO_2$ storage. The installation consists mainly of two Caterpillar 3516TALE natural gas-fired reciprocating engine compressors (4735 horsepower each) and a propane refrigeration unit for humidity control (Caterpillar 3606LE with

1775 hp). Under full load the combination is capable of pressurizing and pumping 236,000 $m^3$ of natural gas per hour into a mine, with a fuel consumption of 79 GJ/h. This results in a fuel consumption of 0.29 $MJ/m^3$ under ideal circumstances. Here we assume the same figure for $CO_2$. Starting from 100 bar of injection pressure (approximately 800 $kg/m^3$), this equals 0.36 MJ of fuel (natural gas) per tonne of $CO_2$. Table 3.5.3 shows an indication of the on-site emissions and the indirect emissions related to geological storage of $CO_2$.

The indirect emissions are a result of preparation of the fuel consumed by the pressurization/pumping station. The emission levels mentioned in the table are relatively high, because mining and transport infrastructure is included also. Please consider that the indirect emissions occur outside the Netherlands at least partially.

Table 3.34 Estimation of emissions from geological storage of $CO_2$ (EP Colorado Interstate gas, 2007) (Ecoinvent Centre, 2007)

| | **Emissions per tonne of stored $CO_2$** | | |
|---|---|---|---|
| **Substance** | **On-site emissions** | **Indirect emissions** | **Unit** |
| $NO_x$ | 41 | 3.2 | mg |
| $SO_2$ | 0.1 | 0.5 | mg |
| $PM_{10}$ | 0.0 | 0.3 | mg |
| VOC* | 7 | 0.4+8.4** | mg |
| $NH_3$ | n.a. | 0.01 | mg |

*) Including methane;

**) Methane

### 3.6.6 *Manufacture of solvents*

#### 3.6.6.1 *Solvents for post combustion capture*

Amine based solvents are usually produced from basic chemicals like ammonia, methanol and ethylene oxide. MEA is distilled from a mixture of MEA, DEA and TEA (mono-, di- and tri-ethanolamine), produced in batch mode from ethylene oxide and ammonia. The solvent consists of MEA and a number of additives that function as oxygen scavengers and corrosion inhibitors.

Chilled ammonia is basically just ammonia, manufactured usually by natural gas reforming.

#### 3.6.6.2 *Solvents for pre combustion capture*

Methyl diethanolamine (MDEA) is manufactured in a way comparable to MEA: from ethylene oxide and mono-methylamine (MMA), which in turn is distilled from the reaction between ammonia and methanol, resulting in MMA, DMA and TMA (mono-, di- and tri-methylamine).

Selexol is a dimethylether of polyethyleneglycol.

Table 3.35 contains an indication of the emissions during the production of 1 kg of solvent.

For MEA, 75-85% of the emissions originate from the raw material manufacturing, except for $NH_3$. For MDEA, raw material manufacturing contributes over 90%.

Table 3.35 Indication of air emissions due to solvent manufacturing

| | Emission from manufacturing 1 kg of solvent (mg) | | | | | |
|---|---|---|---|---|---|---|
| | $NO_x$ | $SO_2$ | $PM_{10}$ | NMVOC | $NH_3$ | Data source |
| Post combustion | | | | | | |
| MEA | 6300 | 6600 | 840 | 1700 | 1600 | (Gijlswijk et al., 2006) |
| Ammonia | 2400 | 4400 | 720 | 740 | 14 | (Ecoinvent Centre, 2007) |
| Precombustion | | | | | | |
| MDEA | 5800 | 5700 | 620 | 1700 | 180 | (Gijlswijk et al., 2006) |
| Selexol | | | No data available | | | |

data based on version 1.2 of (Ecoinvent Centre, 2007). Raw material ratio adapted. Added distillation step has been modelled in Aspen.

### 3.6.7 *Treatment of solvent waste*

MEA-based post combustion capture and MDEA-based pre combustion capture result in 3.2 and 0.024 kg of reclaimer sludge per tonne of $CO_2$ captured (Gijlswijk et al., 2006). Solvent sludge has to be treated as hazardous waste, for which the incineration is bound to strict regulations. No detailed model is available for a hazardous waste incinerator at the moment, so a model of a municipal solid waste incinerator is used instead (Eggels and van der Ven, 2000). A calculation has been made of the emissions resulting from the incineration of solvent sludge, see Table 3.36. The figures are likely to be an overestimation, for hazardous waste incinerators should emit less due to stricter regulations.

Table 3.36 Indication of air emissions due to solvent residue incineration

| | 1 kg of reclaimer sludge | Unit |
|---|---|---|
| $NO_x$ | 8300 | mg |
| $SO_2$ | 370 | mg |
| $PM_{10}$ | 38 | mg |
| NMVOC | 270 | mg |
| $NH_3$ | 520 | mg |

### 3.6.8 *Manufacture of infrastructure*

Third order processes in the ‘power generation with $CO_2$ capture’-life cycle include manufacturing and building the power plant, manufacturing and building the additional equipment for $CO_2$ capture, production of trucks and pipelines and preparation of the storage location.

We assume the capture equipment requires as much material as half the power plant. At this point we have no knowledge about the actual needs.

Table 3.37 shows an indication of the emissions for equipment per MWh of electricity or per tonne of $CO_2$. Please note that the uncertainty of these data is very large.

(IPCC, 2005) provides total equipment costs for NGCC, PC and IGCC power plants with and without capture. Under the assumption that the environmental impact of manufacture of equipment correlates reasonably with total costs, the costs ratio has been used to extrapolate the environmental impact for capture.

Table 3.37 Indication of air emissions resulting from material manufacturing of infrastructure

| | **Natural gas fired power plant (NGCC), 1 MWh** | | **Coal fired power plant (PC), 1 MWh** | | **Manufacturing and civil works pipeline (per tkm $CO_2$ transport)** | **Unit** |
|---|---|---|---|---|---|---|
| **Substance** | **Power plant** | **+ Capture** | **Power plant** | **+ Capture** | | |
| $NO_x$ | 530 | 400 | 13000 | 8200 | 9.6 | mg |
| $SO_2$ | 520 | 400 | 8600 | 5400 | 5.1 | mg |
| $PM_{10}$ | 170 | 130 | 5700 | 3600 | 4.6 | mg |
| VOC* | 100 | 80 | 2300 | 1500 | 1.7 | mg |
| $NH_3$ | 12 | 9.1 | 190 | 120 | 0.10 | mg |
| Data source | (Ecoinvent Centre, 2007) | (Ecoinvent Centre, 2007)<br>(IPCC, 2005) | (Ecoinvent Centre, 2007) | (Ecoinvent Centre, 2007)<br>(IPCC, 2005) | (Ecoinvent Centre, 2007) | |

### *3.6.9 Evaluation*

To assess the total chain effect on NEC emissions, all parts of the chain as described in the former sub-paragraphs have been expressed per MWh of electricity. A few assumptions have been made:

- For coal gasification (IGCC) with MDEA, the power plant efficiency of IGCC with selexol has been taken;
- Solvent consumption for MEA and MDEA is 1.6 and 0.012 kg per tonne of $CO_2$ (Gijlswijk et al., 2006);
- Solvent waste production for MEA and MDEA is 3.2 and 0.024 kg per tonne of $CO_2$ (Gijlswijk et al., 2006);
- Amounts of captured $CO_2$ have been derived from remaining $CO_2$ emissions and capture efficiency, see chapter 4.

Figure 3.23 up to 3.27 inclusive summarize the direct and indirect emissions of the five NEC substances for five scenarios:

- Natural gas fired power station without $CO_2$ capture
- Natural gas fired power station with amine (MEA) based $CO_2$ capture
- Pulverized coal fired power station without $CO_2$ capture
- Pulverized coal fired power station with amine (MEA) based $CO_2$ capture
- Integrated coal gasification power station with MDEA based pre combustion $CO_2$ capture.

Please bear in mind that the results are indicative only.

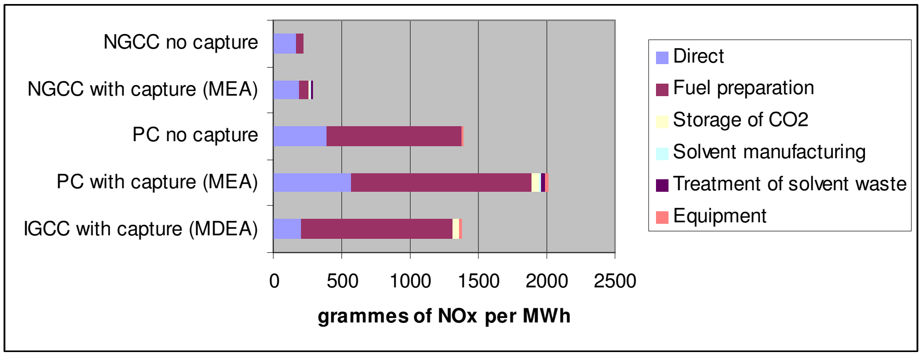

Figure 3.23 Direct and indirect $NO_x$ emissions

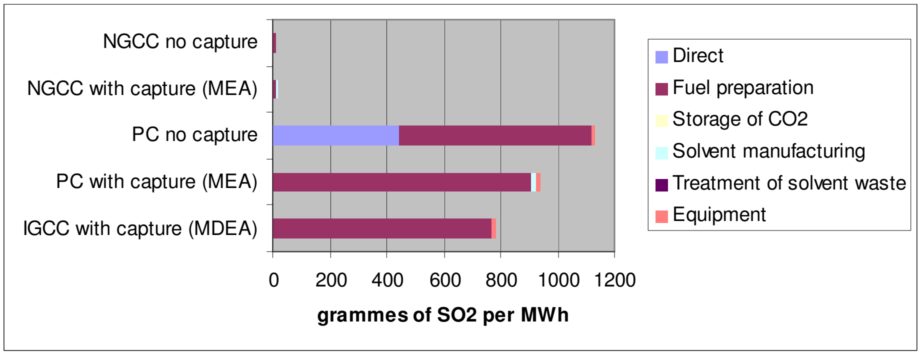

Figure 3.24 Direct and indirect $SO_2$ emissions

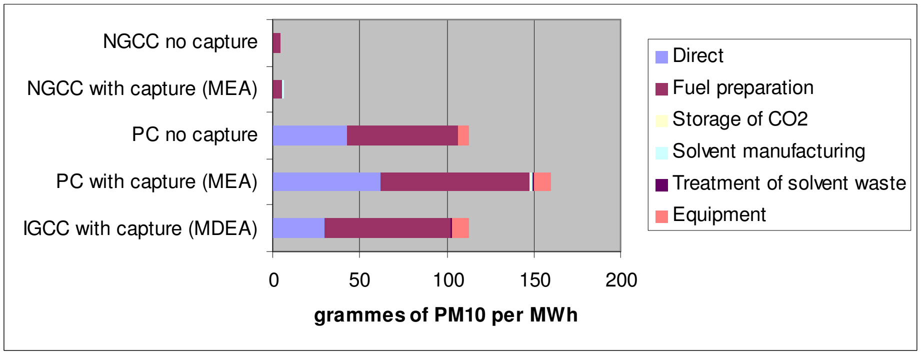

Figure 3.25 Direct and indirect $PM_{10}$ emissions

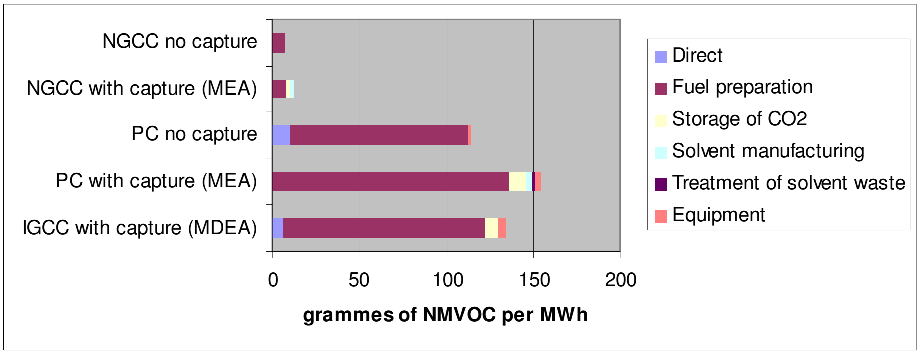

Figure 3.26 Direct and indirect NMVOC emissions

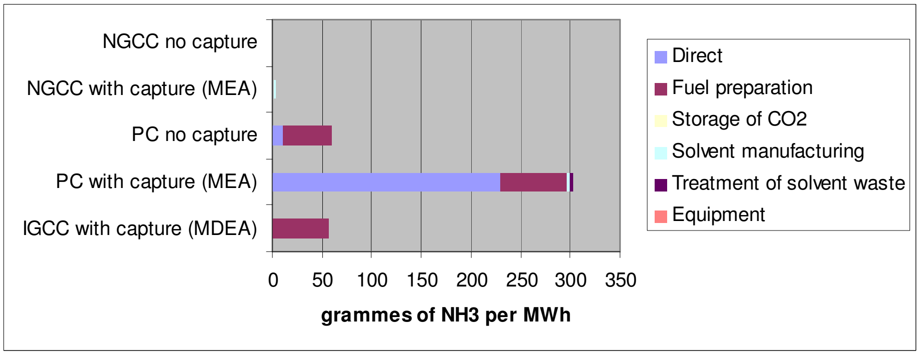

Figure 3.27 Direct and indirect $NH_3$ emissions

A number of conclusions can be drawn from the five charts:

- Power generation using natural gas has low emissions compared to coal based power generation, directly as well as indirectly;
- The indirect emissions are not negligible, and exceed the direct emissions in most cases for all NEC substances;
- The preparation of coal has a large part in the indirect emissions; other indirect emissions contribute 0-12% for coal cases.

For gas based cases, fuel preparation determines 100% of the emissions for $SO_2$, $PM_{10}$ and NMVOC, because no direct emissions have been assumed. For $NO_x$, fuel preparation (and transport) contributes 25-35%, other indirect emissions 11% for NGCC with capture. Ammonia emissions are low in the NGCC cases, and for 50% related to solvent production and slurry disposal.

Table 3.38 shows an overview of the contribution of sources for pulverized coal based power generation with capture.

Table 3.38 Contribution of direct and indirect emissions for 1 MWh of electricity related to a pulverized coal-fired power plant with MEA based $CO_2$ capture

| Substance | Direct | Fuel preparation | Storage of $CO_2$ | Solvent manufacturing | Treatment of solvent waste | Equipment |
|---|---|---|---|---|---|---|
| $NO_x$ | 28% | 65% | 3% | 1% | 2% | 1% |
| $SO_2$ | 0% | 97% | 0% | 1% | 0% | 2% |
| $PM_{10}$ | 39% | 53% | 0% | 1% | 0% | 6% |
| NMVOC | 0% | 88% | 6% | 2% | 1% | 3% |
| $NH_3$ | 76% | 22% | 0% | 1% | 1% | 0% |

### *3.6.10 Discussion*

This study focuses on Dutch NEC emissions. A part of the indirect emissions do not take place in the Netherlands, and thus do not contribute to NEC emission levels. Future studies that go more into detail should consider the location of the actual indirect emissions.

Slightly outdated data have been used for the calculation of the indirect emissions. Possibly lower values can be obtained from more recent literature. A glance at Ecoinvent 2.0 (which has not been used due to accessibility issues) shows that the NEC emissions of e.g. coal preparation have decreased up to 10%, compared to Ecoinvent 1.3. The main data sources have not been updated and date back to 1999. Inventory of data directly from involved companies is recommended.

One important aspect has not been taken into account in this screening: the treatment of coal ash. Future studies should consider the specific Dutch situation.

# 4 Results

## 4.1 Comparative evaluation

The previous chapter introduced main aspects of $CO_2$ capture technologies. Table 4.1 shows a summary of the characterisation of these technologies and their reference cases. Table 4.1 only shows the average values found in the literature, a list including the ranges is presented in Appendix C.

This table provides an overview of major weaknesses and strengths that are relevant for the future development and application of different types of capture technologies. This is done by using three colours. Red (an aspect is considered a weakness, i.e. worse than average), green (an aspect is considered strength, i.e. better than average) and yellow (an aspect is considered neutral, i.e. average). The colour scheme emphasises the large uncertainties surrounding the data. Note that the colour green does not mean ‘good’, like ‘good for the environment’. The main message from the table is that there is not a clear winning technology which is better in most aspects than others.

Looking at the environmental performance of capture technologies, the major difference is found between capture technology on coal fired plants and gas fired plants. Coal fired plants show ranges that can be characterized as worse to average while gas fired plants show ranges from average to better. The performance on transboundary air pollution of coal fired power plants (including Integrated Gasification Combined Cycle) with $CO_2$ capture is lower than that of gas fired power plants. Note that since emission performances are expressed in gram pollutant per kWh produced electricity and the efficiency losses are generally larger for coal fired plants than for gas fired plants, differences in air pollution performance between coal and gas fired plants are strengthened by the indicator.

The table also shows that in terms of Euro per tonne of $CO_2$ avoided, coal fired plants with capture are in general the most advantageous. Estimations of this cost strongly depend on the reference case to which a plant with $CO_2$ capture is compared to. The assumptions in the studies on the energetic performance and important cost parameters (capital cost, project lifetime, interest rate, O&M cost and fuel cost) vary considerably. Furthermore, both capital cost and fuel cost have been increasing for power plants over the last years. This means that the estimates presented in this study may very well be an underestimation of actual cost of electricity and $CO_2$ avoidance.

In the table, coal with capture (PC or IGCC) is compared to coal without capture as is the case with gas (NGCC or GC). However, in case of low generation costs for coal fired plants, also gas fired power plants without and with capture have to be compared with coal fired power plants to assess the avoidance costs per tonne $CO_2$. This type of analysis will be executed in the integrated cost-effectiveness analysis by ECN in a follow-up of this project.

Table 4.1 Overview of aspects and criteria to characterise several $CO_2$ capture technologies and their reference technologies (green is better than average, yellow is average and red is worse than average). This table only shows average values. Ranges are shown in Appendix C.

| Technology | | | Development phase | Application | Economic performance | | | | Environmental performance | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capture Technology | | Application | | retrofit/ robust/ process industry | electrical efficiency (%) | CoE (€-cts/kWh) constant 2007 | € per tonne avoided (constant 2007) | efficiency penalty (% pts) | $CO_2$ emissions (g/kWh) | $NO_x$ emissions (g/kWh) | $SO_2$ emissions (g/kWh) | $PM_{10}$ emissions (g/kWh) | $NH_3$ emissions (g/kWh) | Other impacts |
| **No capture** | | PC | commercial | | 40% * | 4.1 | - | 0 | 830 | 0.39 | 0.44 | 0.05 | 0.01 | |
| | | NGCC | commercial | | 56% | 4.4 | - | 0 | 370 | 0.17 | - | - | - | |
| | | IGCC | commercial | | 42% | 5.7 | - | 0 | 766 | 0.23 | 0.05 | 0.014 | - | |
| **Post** | Amine | PC | pre-commercial | Yyy | 30% | 7.9 | 53 | 11 | 145 | 0.57 | 0.001 | 0.06 | 0.23 | Toxic waste |
| | Amine | NGCC | pre-commercial | Yyy | 49% | 6.4 | 55 | 8 | 55 | 0.19 | - | - | 0.002 | Toxic waste |
| | Chilled ammonia | PC | pilot | Yyy | 39% | n.a. | 16 | n.a. | n.a. (estimated in order of Amine PC) | | | | | |
| | Membranes | | lab scale | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | n.a. | |
| **Pre** | | GC | demonstration | Nyy | 49% | n.a. | n.a. | 9 | 21 | n.a. (estimated in order of Amine NGCC) | | | | |
| | | IGCC | demonstration | Yyy | 36% | 7.6 | 30 | 7 | 98 | 0.21 | 0.016 | 0.003 | 0.0007 | |
| **Oxyfuel** | | PC | pilot | y?ny | 32% | 7.7 | 42 | 11 | 47 | 0.17 | 0.025 | 0.0003 | - | |
| | | GC | pilot | y?ny | 53% | n.a. | n.a. | 4 | 10 | - | - | - | - | |
| | | NGCC | pilot | y?ny | 46% | 6.9 | 77 | 11 | 8 | 0.00 | 0.00 | - | - | |

n.a. = not available

PC = Pulverised Coal;

NGCC = Natural Gas Combined Cycle;

IGCC = Integrated Gasification Combined Cycle;

GC = Gas Cycle

* New coal fired plants have a higher efficiency

Other major differences are shown between types of capture technologies. Post combustion technologies are relatively well developed in industry although they need to be scaled up considerably to be applied on a full scale in power plants. They are expected to have a lower risk in their application since these technologies leave the present power plant intact (add-on technology). These technologies are ready to be applied on the mid-term but have a relatively low environmental performance (without additional add-on measures) with the exception of $SO_2$.

Pre combustion technology shows a relatively better environmental performance and is applied in large scale in present day industry. However, its application in the power sector (in for instance an IGCC configuration) has to be proven. The real challenge lies in the integration and optimization of the $CO_2$ capture process in the already complex IGCC power plant to design a reliable power plant. Theoretically, oxyfuel capture technology is the cleanest (with the gas variant being referred to as an almost zero emission plant) but also the least developed and robust at the moment. Demonstration of both the coal and gas fired concept before 2015 is however very likely.
Chilled ammonia and membranes are capture technologies at such an early development stage that robust conclusions can hardly be made about them.

Table 4.2 Summarised results from Table 4.1

| Main characteristic | Capture technology and application |
|---|---|
| Short-term & relatively cheap | Post combustion Amine PC |
| Short-term & relatively clean | Post combustion Amine NGCC |
| Mid-term & relatively clean coal | Pre combustion IGCC |
| Long-term & clean | Oxyfuel Gas Cycle |
| Long-term & cheapest | Chilled ammonia PC |

With the exception of chilled ammonia (due to a lack of data on the environmental performance), this set of capture technologies is selected for the ‘what-if’ scenario analysis to illustrate the impact of these technologies on transboundary air pollution in the Netherlands in the year 2020. This is described in more detail in the next paragraph.

## 4.2 Air pollution impact scenarios for 2020

### *4.2.1 Power sector*

The main goal of this section is to asses the effect of implementing $CO_2$ capture technologies in the Dutch power sector on the emission levels of NEC substances in 2020. The emission levels are roughly estimated by using three scenarios[23] developed by (van den Broek et al., 2008). Two of these scenarios incorporate CCS implementation before 2020.

Van den Broek uses the UU-MARKAL model to run the scenarios. This model calculates the most optimal technological configuration of the energy supply system for a certain time interval given certain constraints (e.g. policy or technical determined constraints). The most optimal configuration is in this respect the configuration with the lowest net present value.

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[23] These scenarios are all variants of the Strong Europe scenario developed by the CPB. In this scenario it is assumed that electricity growth is 1.5% per year until the year 2020.

The three scenarios used in this project have an extended vintage structure[24] as defined by van den Broek et al. (2008):

- In the **Business as usual (BAU)** scenario no climate policy is in place. This means that no $CO_2$ reduction targets are defined for the power and heat sector.

- In the **Postponed Action** scenario it is assumed a 15% $CO_2$ reduction in 2020 in the power and heat sector compared to 1990 $CO_2$ emission levels. This scenario incorporates $CO_2$ reduction targets from 2020 onwards.

- In the **Direct Action** scenario it is also assumed a 15% $CO_2$ reduction in 2020 in the power and heat sector compared to 1990 $CO_2$ emission levels. The difference with the Postpone action scenario is that the Direct Action scenario incorporates $CO_2$ reduction targets from 2010 onwards.

The possible configurations of the energy supply sector in the year 2020 are presented in Table 4.3. Note that in this table only the electricity production is presented (heat production is not included). In this project only the electricity production in the large scale power production sector is further used and analysed, as it is considered the most likely sector for CCS implementation ($CO_2$ capture at small scale power and heat production is considered unrealistic before 2020).

Table 4.3 Electricity production (in PJ) in the three scenarios for various types of production in the year 2020

| | BAU | Postponed Action | Direct Action |
|---|---|---|---|
| Large scale power plants | 337 | 300 | 294 |
| CHP | 145 | 175 | 175 |
| Nuclear | 13 | 13 | 13 |
| Wind | - | 10 | 15 |
| Other* | 17 | 17 | 17 |
| **Total** | **512** | **515** | **514** |

* This includes for instance facilities for waste incineration.

The Postponed and Direct Action scenarios result in the implementation of CCS technologies. However, the CCS technologies installed are limited to pre combustion $CO_2$ capture at IGCC power plants and post combustion capture at pulverized coal fired power plants. In other words, the scenarios do not include oxyfuel combustion and post combustion capture at gas fired power plants. Therefore, two additional variants of the Direct Action scenario are developed in this study:

- In the **Direct Action- post combustion gas** variant all gas fired power plants in the power sector are directly equipped or retrofitted with $CO_2$ capture in the year 2020. The coal fired power plants remain unaltered in this scenario.

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[24] Van den Broek et al. also developed two variants for the three scenarios: one with a normal vintage structure (life time for gas and coal fired power plants is 30 years) and one with an extended vintage structure variant (life time is respectively 40 and 50 years for gas and coal fired power plants).

– In the **Direct Action – oxyfuel** variant all *new* built gas and coal fired power plants from 2010 onwards will be equipped with the oxyfuel combustion concept. Existing coal power plants are retrofitted with oxyfuel technology.

The choice for the Direct Action scenario is arbitrary with the sole purpose of restricting the number of variants. The developed variants of the Direct Action scenario are set to meet the same electricity production as the original Direct Action scenario. Furthermore, the mix of gas and coal fired capacity is assumed the same for all Direct Action variants, i.e. 35% of the produced electricity is from gas fired power plants and 65% is from coal fired power plants. This is also about equal to the mix of coal and gas found in the Postponed Action scenario, i.e. 67% is coal fired and 33% is gas fired.

The configuration of the energy supply system in the developed Direct Action variants does not meet the constraints set for the original scenario and does not represent the most optimal configuration of the energy supply sector. These variants are merely developed to estimate the possible impacts of the implementation of the other $CO_2$ capture options in the Dutch power production sector on the emission levels of NEC substances.

In Table 4.4 an overview is presented for the five scenarios used in this study. The table presents the power production technologies that are installed in the sector under study and also shows the installed $CO_2$ capture technologies for each scenario.

Table 4.4 Installed technologies in the power sector in the 5 scenarios studied for the year 2020. The NEC 5 IIASA scenario is also shown as reference

| **Technology** | **BAU** | **Postponed Action** | **Direct Action** | | | **NEC5 IIASA** |
|---|---|---|---|---|---|---|
| | | | **Original** | **Post combustion gas** | **Oxyfuel** | |
| IGCC | yes | yes | yes | x | x | yes |
| IGCC-CCS* | x | Pre | Pre | Pre | x | x |
| PC** | yes | x | yes | yes | x | yes |
| PC new*** | x | yes | x | x | x | yes |
| PC new capture | x | x | x | x | Oxy | x |
| PC capture retrofit | x | Post | Post | Post | Oxy | x |
| Existing gas-fired** | yes | yes | yes | x | yes | yes |
| NGCC new*** | yes | yes | yes | x | x | yes |
| NGCC new capture | x | x | x | Post | Oxy | x |
| NGCC capture retrofit | x | x | x | Post | x | x |
| Biomass | x | x | x | x | x | yes |

* Installed from 2020 onwards

** Installed before 2010.

*** Installed from 2010 onwards.

Pre = pre combustion $CO_2$ capture installed; Post = post combustion $CO_2$ capture installed; Oxy = oxyfuel technology installed with $CO_2$ capture

The resulting emission scenarios present a consistent illustration of the impact of $CO_2$ capture on emissions. However, note that the baseline is a ‘no policy’ scenario. Furthermore, the two mitigation scenarios only represent measures taken to mitigate climate change. Transboundary air pollution is not an issue in this scenario. Therefore, the NEC scenario (IIASA 2007) for the Dutch power generation sector is presented as a reference in order to be able to compare the results with the latest view from the angle of transboundary air pollution policies. For the NEC5 scenario the configuration of the whole power and heat sector is presented.

Hence, two CCS what-if scenarios and two what-if variants are constructed. The scenarios present a cost-effective climate policy response according different time preferences based upon the study of van den Broek. The CCS technologies playing a role in these scenarios are pre and post combustion CCS technologies on coal fired plants.
The two additional variants on the Direct Action scenario illustrate the additional impact of post combustion CCS on gas fired plants and the impact of oxyfuel CCS on both coal and gas fired power plants. At least the latter scenario is regarded as highly unrealistic for 2020, but included for illustrative purposes to demonstrate the impacts of different CCS technologies.

For the 5 scenarios (3 original plus 2 variants) derived from the UU-MARKAL model the fuel consumption and emission levels of NEC substances and $CO_2$ are estimated for the year 2020. The UU MARKAL scenarios provide the technological configuration and electricity production in the power sector. From that it is possible to derive the primary energy requirement with the electrical efficiencies (including capture penalties) for the various power generating technologies. To calculate the NEC emissions in 2020, emission factors for the various technologies are required. The GAINS model from IIASA defines emission factors for the power production technologies installed in the year 2020 in the Netherlands. However, no emission factors are defined for technologies that are equipped with $CO_2$ capture technologies. Therefore, a simple approach is used in this study to estimate the emission factors for technologies equipped with $CO_2$ capture in the year 2020 using the relative difference in emission factors reported in literature for equal power plants with and without $CO_2$ capture (e.g. a pulverized coal power plant with and without post combustion $CO_2$ capture) from a unique source. For more information, see chapter 2.4.

Then the emission factors from the GAINS model are multiplied with the Relative Factor (see Figure 4.4, 4.7, 4.9, 4.11 and 4.15) to acquire a new emission factor (per PJ fuel input) per power production technology (new or existing power plant) and per $CO_2$ capture technology. The estimated fuel requirements in each scenario are then multiplied with the emission factors to estimate the emission levels for NEC substances in 2020 from large scale electricity production.

#### *4.2.1.1 Electricity production*

Figure 4.2 depicts the electricity production in the year 2020 in large scale power plants. The figure shows a higher electricity production with large scale power plants in the BAU scenario compared to scenarios with a $CO_2$ reduction target. The total electricity demand is assumed to be the same in 2020 for the three original MARKAL UU scenarios (see Figure 4.1). In the reduction scenarios relatively more electricity is generated with alternative energy sources (i.e. wind energy) and CHP plants (see Table 4.3 for more details). This explains the lower electricity production values for the reduction scenarios. The Postponed Action and Direct Action scenarios (and its two variants) show similar total electricity production with large scale power plants.

The figure also shows the technologies that are installed for electricity production (see Table 4.4). In the BAU the largest share is generated by new (built from 2010 onwards) and existing (built before 2010) coal fired power plants; only some new gas fired power plants are installed. In the reduction scenarios more gas fired power plants are installed and a large share of the electricity is generated by coal fired power plants equipped with $CO_2$ capture. Especially the IGCC with pre combustion $CO_2$ capture has a significant share in both the Direct and Postponed Action scenarios.

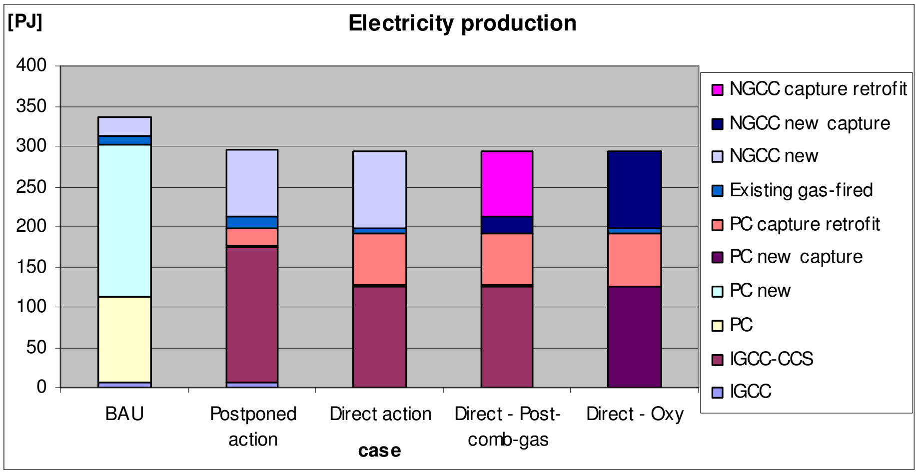

Figure 4.2 Electricity production from large scale power plants in the Netherlands in the year 2020 and in the five scenarios (cases).

### *4.2.1.2 Primary energy use*

Figure 4.3 shows the total primary energy consumption for each scenario. The figure depicts that the primary energy input, i.e. fuel consumption, varies per technology and thus per scenario, see also Figure 4.4. This is mainly due to the variance in energetic performance of the various CCS technologies that are installed. For instance, in the Postponed Action CCS is implemented at a later date. This means that only newly built (and more efficient) coal fired power plants are retrofitted with post combustion capture. Further, a large share of the electricity supply is generated with IGCCs equipped with $CO_2$ capture which have overall higher efficiencies than pulverized coal fired power plants equipped with CC. This is clearly shown in the Direct Action scenario in which a considerable amount of coal fired power plants is retrofitted with $CO_2$ capture, hence the higher fuel consumption. The Direct Action scenario with the post combustion retrofit of all new gas fired power plants shows somewhat higher fuel consumption due to the efficiency penalty.

Primary energy requirement in the oxyfuel variant is high as nearly all power plants (excluding existing natural gas fired power plants) are equipped with $CO_2$ capture. Also note the significant higher fuel consumption for the IIASA NEC5 scenario compared to the other five scenarios. The difference between the MARKAL UU scenarios and the NEC5 scenario is that for the NEC5 scenario fuel consumption for the whole power and heat sector is presented. The NEC5 scenario shows significantly higher consumption of natural gas and biomass compared to the other five scenarios. Biomass is not included in the scenarios derived from the MARKAL UU model.

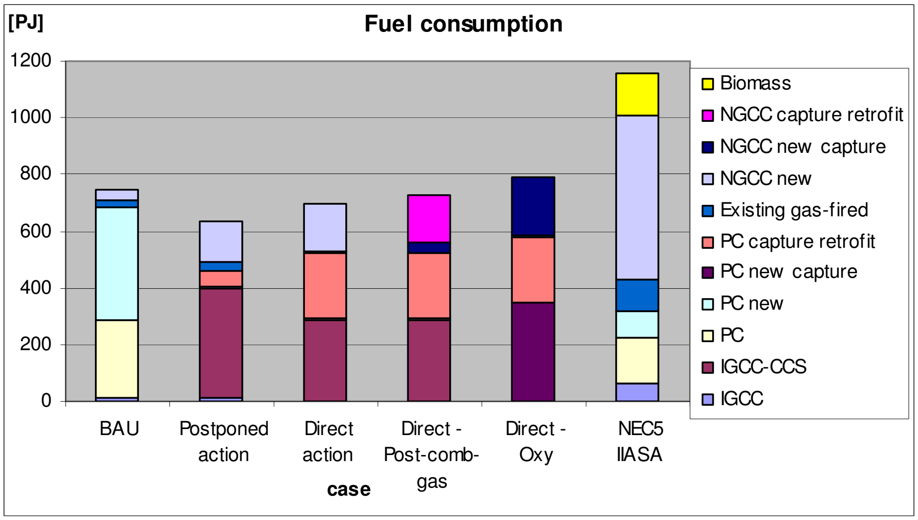

Figure 4.3 Fuel consumption of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

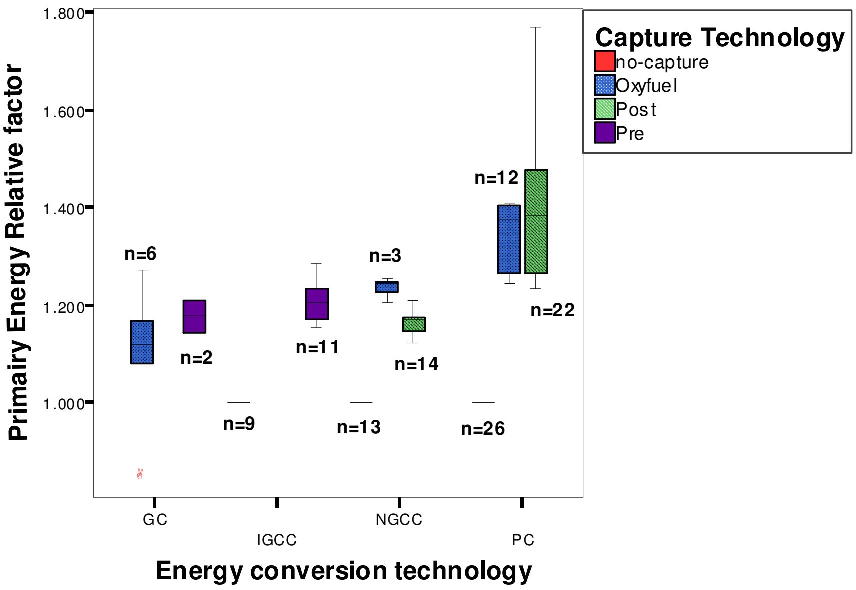

Figure 4.4 Relative Factor for primary energy requirement per $CO_2$ capture and energy conversion technology. Each box shows the median, quartiles and extreme values. n refers to the number of literature cases on which the values are based.

#### *4.2.1.3 $CO_2$ emissions*

Figure 4.5 shows the $CO_2$ emissions in the various scenarios. The $CO_2$ emissions in the BAU scenario are about 68 Mtonne in 2020. Both reduction scenarios (Postponed and Direct Action) show the same levels of $CO_2$ emission, i.e. 16 Mt.

$CO_2$ emissions in the Direct Action variants are lower as there is also more installed capacity equipped with $CO_2$ capture. This holds especially for the oxyfuel variant where nearly all power electricity is generated by power plants equipped with $CO_2$ capture.

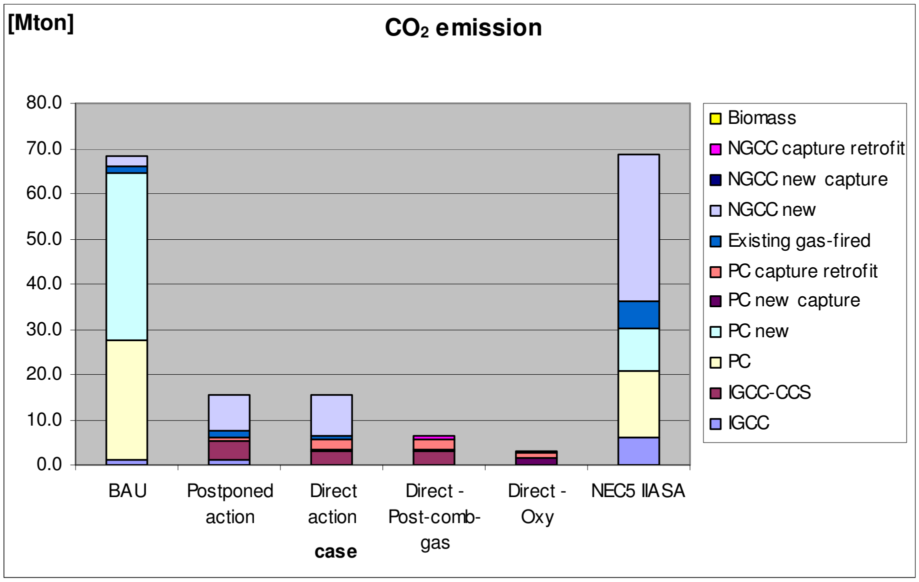

Figure 4.5 $CO_2$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

#### *4.2.1.4 $SO_2$*

Figure 4.6 depicts the results of the estimates for the emission of $SO_2$ for the various scenarios. $SO_2$ emissions in the BAU scenario are high due to the large share of coal fired electricity generation. This is significantly higher when compared to the estimates obtained from the NEC5 scenario. The latter scenario includes the whole power and heat sector where the BAU scenario only includes large scale power plants. The NEC5 results in lower $SO_2$ emissions as it estimates large installed capacity of gas fired power plants, which are here assumed to emit no $SO_2$.

The total emission of $SO_2$ in the $CO_2$ reduction scenarios with CCS are estimated to drop significantly. This is mainly due to the implementation of IGCC power plants which have low $SO_2$ emissions, either with or without CCS. Furthermore, the application of pre combustion $CO_2$ in an IGCC is estimated here to reduce $SO_2$ emissions per MJ and per kWh. Secondly, in the scenarios with post combustion capture at coal power plants, $SO_2$ emissions also decreases due to enhanced removal of $SO_2$ that is required for $CO_2$ capture. In the scenario where oxyfuel is installed the $SO_2$ emissions are also estimated to be very low as it is expected that $SO_2$ can be removed with high efficiencies in these concepts.

The estimated $SO_2$ emission load is about 1 ktonne for all $CO_2$ reduction scenarios.

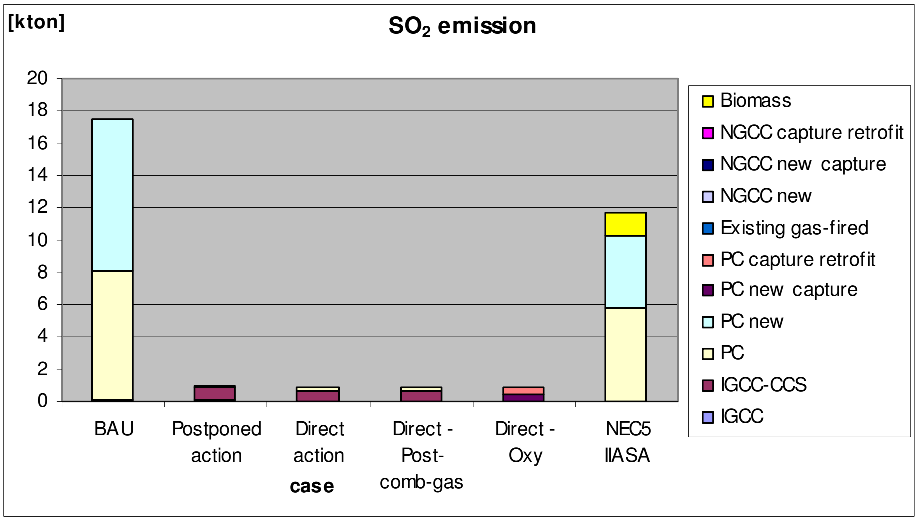

Figure 4.6 $SO_2$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

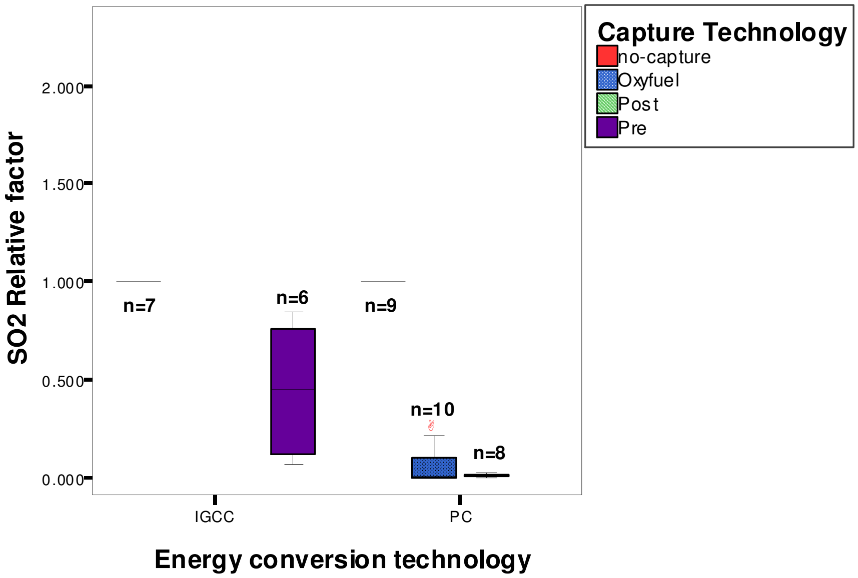

Figure 4.7 Relative Factor for $SO_2$ emissions per MJ presented per $CO_2$ capture and energy conversion technology. Each box shows the median, quartiles and extreme values. n refers to the number of literature cases on which the values are based.

### *4.2.1.5 $NO_x$*

Figure 4.8 shows that $NO_x$ is mainly emitted by coal fired power plants in the BAU scenario. $NO_x$ emissions in the NEC5 scenario are dominated by gas fired installations. In the scenarios with CCS, $NO_x$ emissions are lower compared to the BAU and are estimated to be the lowest for the Postponed Action and oxyfuel variant of the Direct Action scenario. For the Postponed Action scenario this can be mainly ascribed to the large scale implementation of IGCC power plants with CCS. The application of $CO_2$ capture in an IGCC will, according to the data gathered in this study, decrease the $NO_x$ emissions per MJ. However, it should be noted that the $NO_x$ emissions factors for IGCC power plants derived from the GAINS database are considered to be very low, i.e. about 9 g/GJ. In the gathered literature an average emission factor of 26 g/GJ for IGCC without CCS is found. Hence, the values shown here for IGCC power plants with IGCC are possibly an underestimation.

$NO_x$ emission levels in the oxyfuel variant of the Direct Action scenario are also considered to be significantly lower than those in the BAU scenario. This is due to two main assumptions: that coal fired oxyfuel power plants will show lower levels of $NO_x$ formation in the combustion process and that further removal of $NO_x$ in the $CO_2$ treatment train is possible. The oxyfuel variant shows no $NO_x$ emission from gas fired power plants equipped with CCS as the emission factor is assumed to be zero. This can indeed be considered a progressive estimate.

The Direct Action variants (original scenario and post combustion gas variant) with relative large scale implementation of post combustion $CO_2$ capture technologies show a significantly higher $NO_x$ emission level compared to the other scenarios with CCS. This is due to the relative high emission factors for $NO_x$ for existing power plants, both for gas and coal fired. When these power plants are retrofitted, the capture penalty leads to an increase in primary energy requirement for the production of electricity. And as the $NO_x$ emissions per MJ are largely unaffected[25] by the implementation of a $CO_2$ capture unit, the result is a net increase in $NO_x$ emissions per kWh.

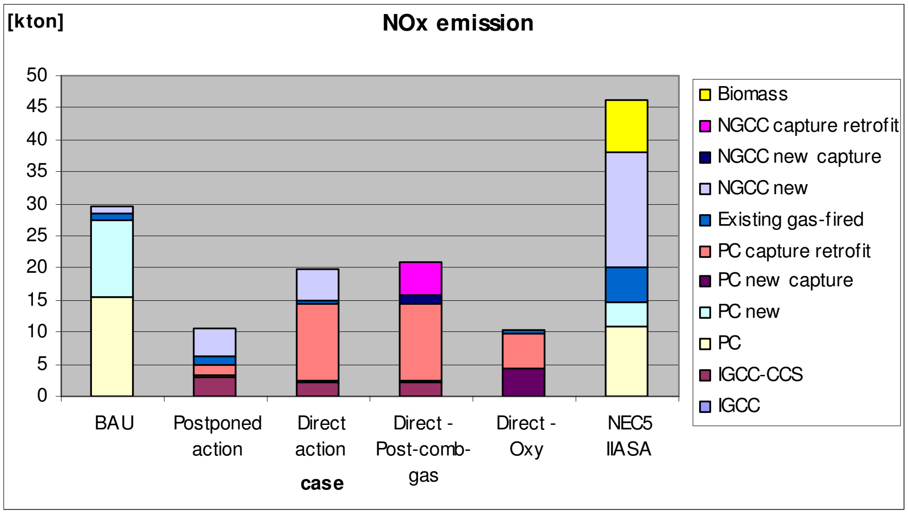

Figure 4.8 $NO_x$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

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[25] In the case an amine based solvent is used, a fraction of the $NO_2$ may react with the amine resulting in a reduction of $NO_x$ emission per MJ. $NO_2$ is however not a dominant component within the total $NO_x$; the main fraction is NO which is expected to be unaffected by the $CO_2$ capture process.

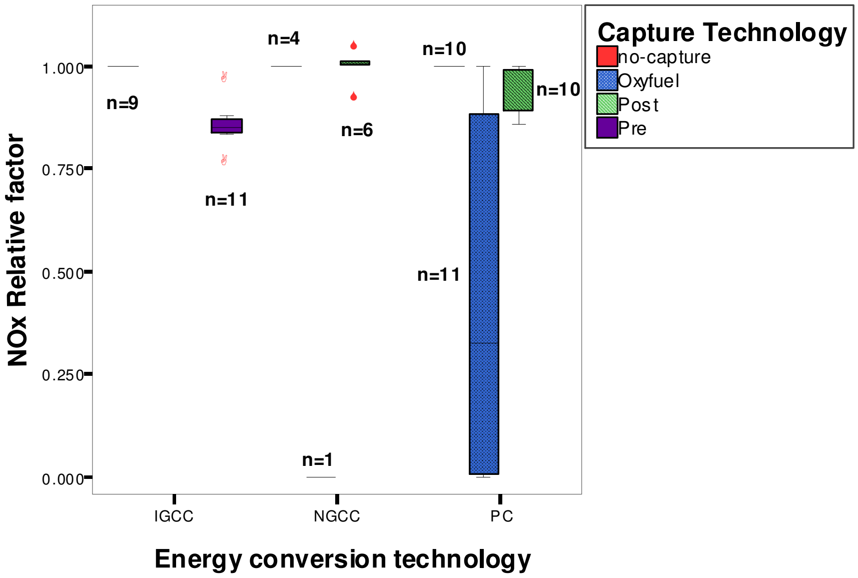

Figure 4.9 Relative Factor for $NO_x$ emissions per MJ presented per $CO_2$ capture and energy conversion technology. Each box shows the median, quartiles and extreme values. n refers to the number of literature cases on which the values are based.

### *4.2.1.6 $NH_3$*

Figure 4.10 shows the estimates for $NH_3$ emissions. The $NH_3$ emissions for the BAU scenario are estimated in the order of 0.8 ktonne. The figure clearly shows the significant increase in $NH_3$ emissions reaching about 5 ktonne in the Direct Action scenarios with relative large scale implementation of post combustion $CO_2$ capture technologies. This is due to the high ‘Relative Factor’ that is applied for post combustion $CO_2$ capture at coal fired power plants. These $NH_3$ emissions are assumed to be caused by solvent degradation (i.e. an amine based solvent) that is assumed to be used in the post combustion capture concept. It should however be noted that this outcome is based on only one reference from literature (Rubin et al., 2007) and, consequently, the uncertainty regarding this estimate is considered to be high.

The oxyfuel variant shows about the same level of $NH_3$ emissions as the BAU scenario. This is because it is assumed that the $NH_3$ emissions (per MJ) are unaffected by the $CO_2$ capture process. This may however be an over estimation for the oxyfuel variant, since it is not certain whether an oxyfuel power plant will be equipped with a SCR or SNCR (the main source of $NH_3$ emissions from power plants). Also, the possibility exists that if an oxyfuel power plant is equipped with a SCR that the ammonia slip is partially co-sequestered with the $CO_2$.

For the NEC5 scenario $NH_3$ emissions from biomass combustion represent a considerable share of the total $NH_3$ emissions estimated for the power and heat sector. This can be explained by the high emission factor that is assumed in the GAINS database for biomass combustion (3 mg/MJ) compared to, for instance, coal combustion (1 mg/MJ).

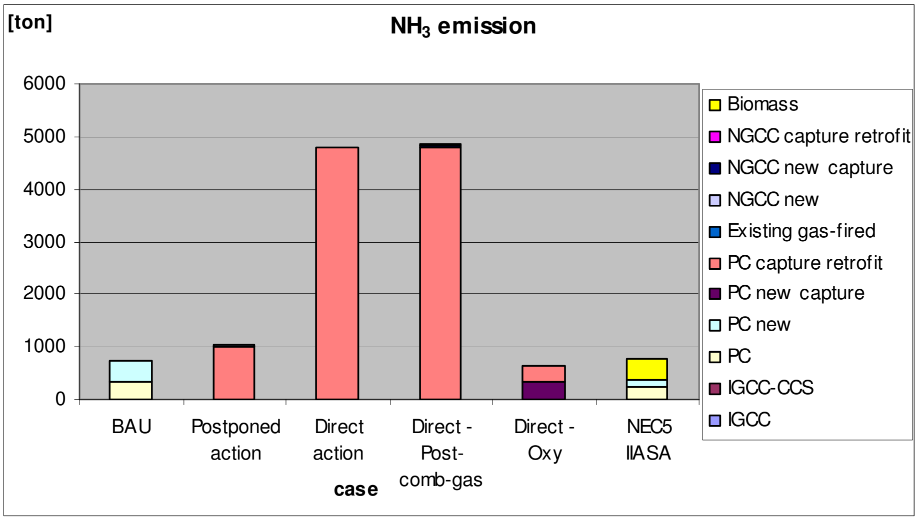

Figure 4.10 $NH_3$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

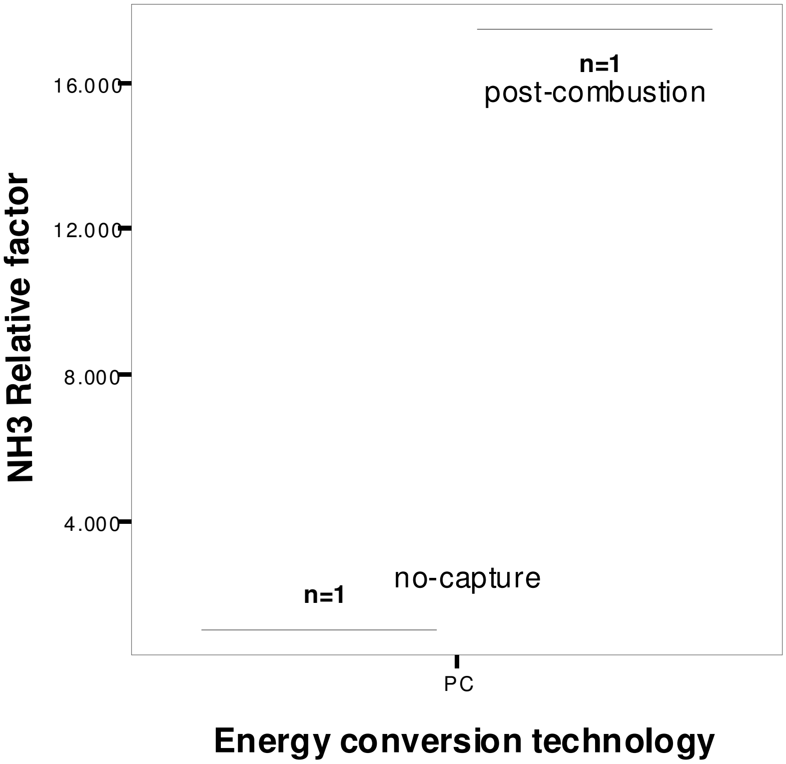

Figure 4.11 Relative Factor for $NH_3$ emissions per MJ presented for post combustion $CO_2$ capture at pulverized coal fired power plants. n refers to the number of literature cases on which the values are based.

### *4.2.1.7 NMVOC*

In this study Relative Factors for NMVOC emissions from power plants equipped with $CO_2$ capture could not be derived from the gathered literature. Therefore, estimates for NMVOC emissions for the BAU and $CO_2$ reduction scenarios are merely based on the emission factors derived from the GAINS database. The NMVOC emissions are assumed to be unaffected by $CO_2$ capture and to increase with the increase in primary energy demand by CCS. Note however that the Postponed Action scenario shows a lower emission level. This is due to the lower emission factor for IGCC power plants (1 mg/MJ) compared to other power generation technologies (2 mg/MJ).

Although no Relative Factors could be derived from the literature, it is discussed earlier that NMVOC emission may decrease per MJ when implementing pre combustion and oxyfuel $CO_2$ capture.

Further, no information was found on the influence of post combustion $CO_2$ capture on the emission of NMVOC. For the purpose of the calculations, it is assumed that post combustion $CO_2$ capture have no effect and NMVOC emissions only increase with primary energy demand.

NMVOC emissions are significantly higher in the NEC5 scenario compared to the other scenarios. This can be mainly ascribed to the combustion of biomass. Co-combustion of biomass is not included in the MARKAL UU scenarios for 2020. NMVOC emissions may as a consequence be underestimated in the MARKAL UU scenarios.

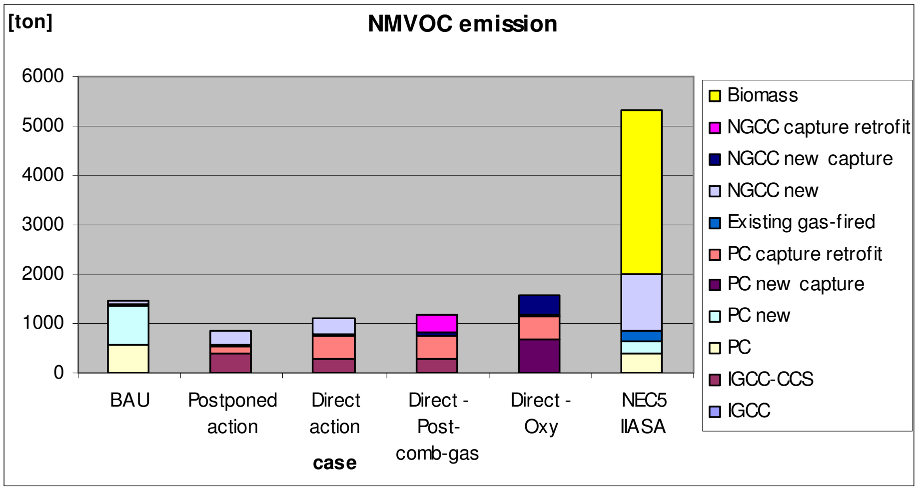

Figure 4.12 NMVOC emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

### *4.2.1.8 $PM_{10}$ and $PM_{2.5}$*

Figure 4.13 and 4.14 shows similar emission profiles for $PM_{10}$ and $PM_{2.5}$. This is due to the assumption that $PM_{10}$ and $PM_{2.5}$ represent a constant fraction of total particulate matter smaller than 10 µm, i.e., 43% of particulate matter is estimated to be $PM_{2.5}$ and 57% is $PM_{10}$.

For the BAU scenario the total $PM_{10}$ and $PM_{2.5}$ emissions are estimated to be 1.6 and 1.3 kt, respectively. These emissions are mainly emitted by new and existing coal fired power plants. In the scenarios with CCS, the emission of $PM_{10}$ and $PM_{2.5}$ are considerably lower. This is partly due to the implementation of IGCC power plants which are assumed to have lower emission factors compared to pulverized coal fired power plants. It should however be noted that for the IGCC power plants the average emission factors from the gathered literature has been used instead of the emission factor for IGCC included in the GAINS database. The reason for this is that the PM emission factors reported in the GAINS database where higher for IGCC power plants than for pulverized coal fired power plants. This is not considered to be in line with the knowledge present in the literature.

For the CCS scenarios it was assumed that pre combustion $CO_2$ capture has no influence on the emission of PM (per MJ) from an IGCC. According to data gathered in this study it may be possible that PM emissions and in specific $PM_{2.5}$ emission will be lower due to the enhanced capture of sulphur compounds from the syngas, which is expected to reduce the formation of sulphates, which are characterized as $PM_{2.5}$.

The capture of $CO_2$ with the use of post combustion and oxyfuel concepts is assumed to have an effect on the emission of particulate matter. In the case of post combustion capture the emission of PM per MJ is assumed to be lower. Together with the efficiency penalty, PM emissions are expected to increase per kWh. In the literature the assumptions on this matter vary considerable, on the one hand some scholars assume a deep reduction of PM due to the application of post combustion $CO_2$ capture; on the other hand, other scientists assume that it will not have an effect on PM emissions per MJ.

Oxyfuel coal fired power plants with $CO_2$ capture are expected to have significantly lower PM emissions. This is partly due to the enhanced removal efficiency of the ESP that is possible during oxyfuel combustion. Deep removal of PM from the flue gas is necessary to prevent wear and failure of equipment in the flue gas ($CO_2$ stream) treatment section (e.g. fans and compressors). Further, PM may be partially co-sequestered with the $CO_2$ stream. Another possibility is that it will be vented from the $CO_2$ treatment section which results in the emission of PM into the atmosphere.

Overall, this results in the estimation that PM (both $PM_{10}$ and $PM_{2.5}$) emissions are the lowest in the oxyfuel variant of the Direct Action scenario, about 85 tonne $PM_{2.5}$ and 104 tonne $PM_{10}$. The post combustion gas variant of the Direct Action scenario shows the highest PM emissions (808 tonne $PM_{2.5}$ and 1038 tonne $PM_{10}$).

The NEC5 scenario for the whole power and heat sector shows relatively low emission levels for $PM_{10}$ and $PM_{2.5}$ as this scenario envisages that a large share of the power and heat is supplied by gas fired installations.

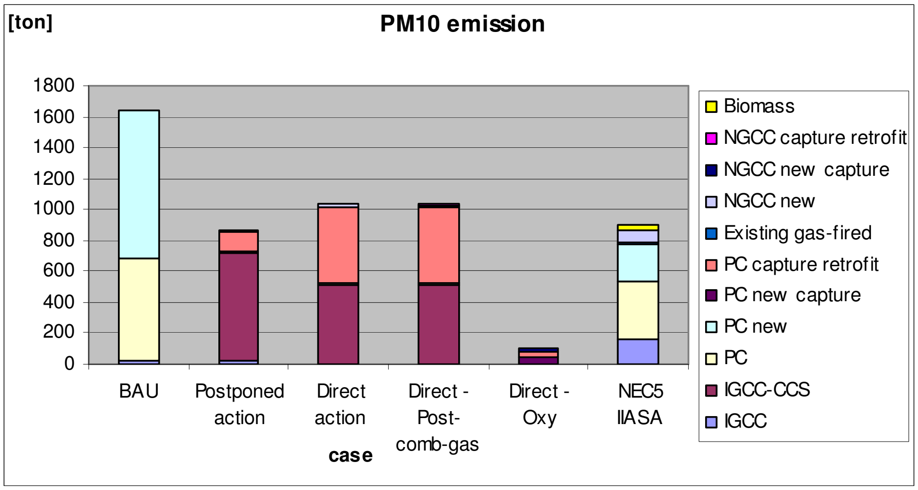

Figure 4.13 $PM_{10}$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

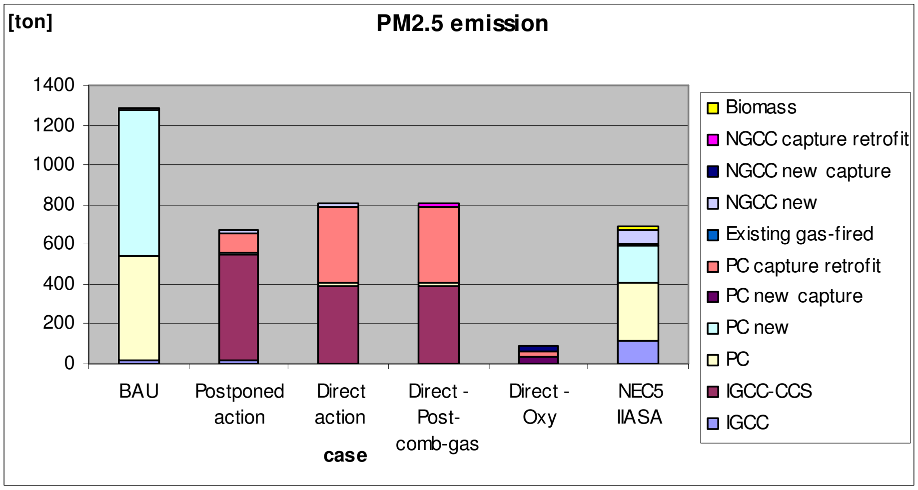

Figure 4.14 $PM_{2.5}$ emissions of large scale power plants in the Netherlands in the year 2020 in the five scenarios and in the NEC5 scenario.

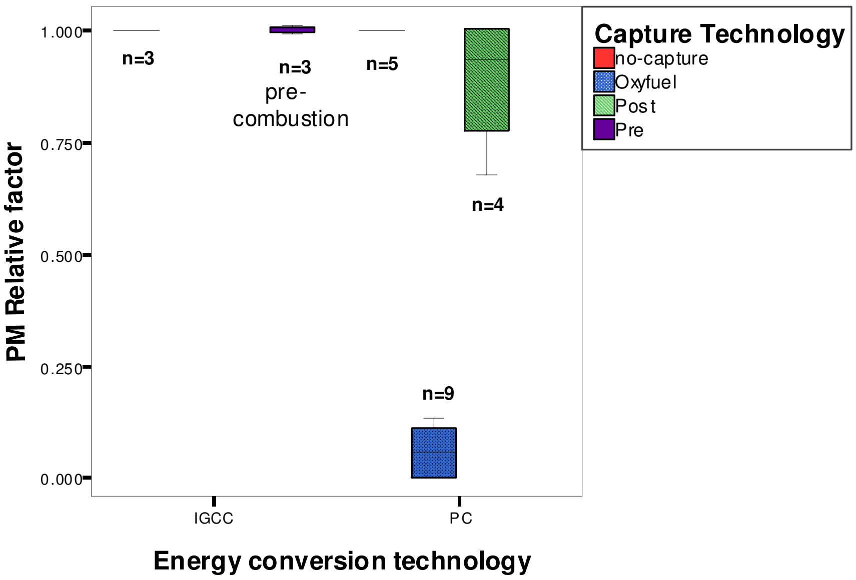

Figure 4.15 Relative Factor for Particulate Matter emissions per MJ presented per $CO_2$ capture and energy conversion technology. Each box shows the median, quartiles and extreme values. n refers to the number of literature cases on which the values are based.

### *4.2.1.9 Uncertainties and Limitations*

It should be stressed that the presented emission levels of NEC substances for various scenarios should be regarded as highly uncertain. This is due to various limitations of the used methodology and the uncertainties in the underlying data (see the technology characterization chapters).

Emission factors presented in the literature for energy conversion technologies with $CO_2$ capture are most often based on assumptions and not on measurements. Furthermore, in the pertaining literature often attention is not paid to emissions other than $CO_2$ which leads to a remarkable lack of detailed studies on for instance NEC substances. The estimated emission factors and the derived Relative Factor used in this study should therefore be regarded as estimations made by experts rather than exact emission measurements. Despite this constrain, the Relative Factor provides insights into whether and to what extent $CO_2$ capture has an influence on the emission of NEC substances.

Applying these Relative factors on the emission factors used by the IIASA in their GAINS model to estimate the emission factor for power plants equipped with CCS brings forth uncertainties as well. By applying the Relative factor we implicitly assume that the reference technologies (i.e. IGCC, NGCC and PC without CCS) in the consulted literature have on average the same technological configurations (e.g. emission reduction techniques and their removal efficiencies) as the technologies defined in the GAINS model (i.e. IGCC NGCC and PC without CCS). As this is not the case, the estimation of emission factors with this method may lead to considerable uncertainties in the estimation of levels for NEC emissions in 2020.
The level of implementation of CCS and the $CO_2$ capture technology that is installed in the year 2020 also remains uncertain and is subject to technical, political and economical developments in the coming decade. This can, according to the reviewed

literature combined with the calculations performed in this study have a significant impact on the NEC emission levels in 2020.

Finally, some methodological inconsistencies should be discussed for the developed variants of the Direct Action scenario (the post combustion gas variant and oxyfuel variant). For these variants the electricity production was kept equal to that of the original Direct Action scenario. This implicates that in order to compensate for the efficiency penalty in plants equipped with $CO_2$ capture, additional generating capacity has to be installed. When $CO_2$ is captured at newly built power plants then this has no inconsistencies as a consequence. It implicates merely that more capacity (in $GW_{th}$) have to be installed to generate the same amount of electricity. In the case of retrofit this is however more problematic. The installed capacity of existing power plants in $GW_{th}$ remains the same and only installed capacity in $GW_e$ decreases. Thus additional capacity should be installed to overcome this decrease in installed electricity generating capacity. This means that the efficiency penalty strictly cannot be used to increase fuel consumption and with that the emissions of existing power plants, which is the approach we used in this study. The efficiency penalty results thus in increased fuel consumption of new power plants or import. The methodology used in this study is in this respect thus not fully consistent.

### *4.2.2 Industrial processes*

The technology descriptions of $CO_2$ capture technologies indicated that a number of opportunities exist for capture of $CO_2$ emissions from the industry. To give an impression of the available opportunities in the Dutch industry, Table 4.5 based upon Damen 2007 presents an indication of industrial $CO_2$ sources in the Netherlands that can apply $CO_2$ capture.

The total $CO_2$ emissions from the large industrial sources interesting for $CO_2$ capture are estimated in the table at 20 Mt per year, which is in the order of 10% of the national $CO_2$ emissions.

Table 4.5 also indicates the requirements for energy and capital and the total costs of $CO_2$ capture per tonne $CO_2$. The latter has been calculated on the basis of Total Capital requirement and costs of electricity and heat requirements from Damen 2007. The costs per tonne avoided $CO_2$ are relatively low (up to 25 € per tonne $CO_2$) for the processes which concern a relatively high $CO_2$ concentration and require no additional heat. It concerns the ammonia, hydrogen and ethylene oxide production, gas processing and iron and steel. The capture potential of these sources attractive for CCS amounts to 6 Mt $CO_2$.

Table 4.5. Overview of industrial $CO_2$ sources, including capture costs and energy use (from and based upon (Damen, 2007)

| **Source** | **$CO_2$ emission [a]** (Mt / yr) | **$CO_2$ purity** | **Heat require-ments** (kJ / kg $CO_2$) | **Electricity require-ments [b]** (kJe / kg $CO_2$) | **Total Capital require-ment [b]** (M€) | **Total costs** (€ / ton $CO_2$) |
|---|---|---|---|---|---|---|
| Ammonia plant 1 | 0.5 | ~100% | | 410 | 26 | 14 |
| Ammonia plant 2 | 0.8 | ~100% | | 410 | 32 | 13 |
| Hydrogen plant 1 | 0.6 | ~100% | | 410 | 29 | 14 |
| Hydrogen plant 2 | 0.1 | ~100% | | 410 | 12 | 21 |
| Ethylene oxide plant 1 | 0.13 | ~100% | | 410 | 13 | 19 |
| Ethylene oxide plant 2 | 0.06 | ~100% | | 410 | 10 | 25 |
| Gas processing plant 1 | 0.4 | ~100% | | 410 | 22 | 15 |
| Steel plant 1 | 3.7 [c] | ~20% | | 620 [e] | 103 | 17 |
| Ethylene plant 1 | 1.4 | ~12% | 3000 | 470 | 277 | 64 |
| Ethylene plant 2 | 2.7 | ~12% | 3000 | 470 | 332 | 56 |
| Ethylene plant 3 | 1.7 | ~12% | 3000 | 470 | 283 | 60 |
| Refineries 1-4 | 6.6 [d] | ~7-13% | 3200 | 480 | 942-2250 | 60-80 |
| Refinery 5 | 1 | ~7-13% | 3200 | 480 | 266 | 73 |

[a] Estimated $CO_2$ emission available for capture and storage.

[b] Includes capture and compression to 110 bar.

[c] Only $CO_2$ produced in blast furnaces, i.e. the carbon input minus carbon incorporated in pig iron (~4%) is considered for capture. Based on the emission statistics for 2003, we estimate approximately 9.2 Mtonne $CO_2$ was produced in blast furnaces and nearly 1 Mt in the basic oxygen furnace. A large share of BF gas is sold to the power sector where it causes a $CO_2$ emission of 5.5 Mt. Note that BOF gas consisting of approximately 55-80% CO and 18% $CO_2$ may also be suited for $CO_2$ capture after shifting.

[d] Estimated emissions from boilers and heaters derived from the national energy balances. $CO_2$ emissions are allocated to individual refineries on the basis of crude oil throughput.

[e] Derived from (Gielen, 2003).

However, the costs of applying a technology in an industrial process highly depends on the situation, e.g. can it be fitted in taking into account the availability and security of the plant and its production, the standards and legislation required etc. A useful scenario needs to take these site and process specific factors into account.

At the moment, not enough data are available to make such estimations on $CO_2$ capture potentials in the Dutch industry. To illustrate, however, the importance of the industrial processes in terms of emissions of $CO_2$ and transboundary air pollutants, Figure 4.16 is presented. National emission shares of transboundary air pollutants are presented for a number of sectors among which the large industries which are relevant for $CO_2$ capture. This is based upon data from the NEC5 current legislation scenario for the year 2020 of ASA.

Looking at $SO_2$ from different sectors, it is clear that $SO_2$ from industrial sources is as important as that from power generation or other sectors (households, commercial sector, agriculture and transport). The largest part of industrial $SO_2$ comes from combustion. The largest part of this source stems from refineries which can be equipped with $CO_2$ capture and is potentially influenced. Other relevant sources are iron & steel, and the chemical industry.
The importance of industry is much less for $NO_x$ (in the order of 10% of national emissions) and $NH_3$ (5% of national total). Only if $NH_3$ emissions increase factors or

more as a result of uncontrolled $NH_3$ emissions of solvent use in the case of chilled ammonia, carbon capture can have an impact on $NH_3$ emissions.

Large industrial sources account for only 5% of national VOC emissions, where the chemical sector is a major source. PM emissions from large industry contribute almost 20% of national emissions, where iron and steel and refineries are large contributors that are relevant for $CO_2$ capture.

It is also important to note that the relevance of $NH_3$, VOC and PM emissions from power generation is also limited up to less than 10% of national emissions.

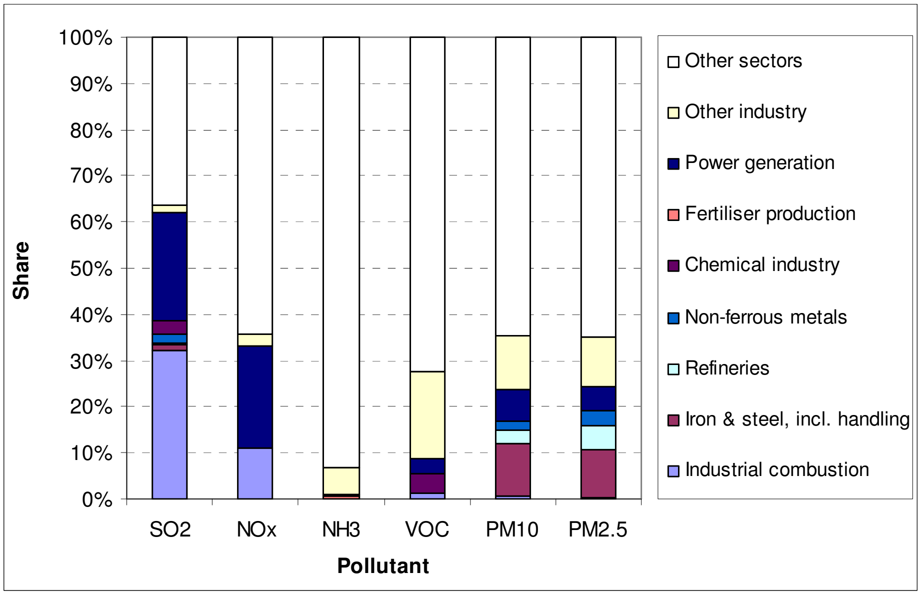

Figure 4.16 Emissions of $CO_2$ and transboundary air pollutants by sector in the Netherlands in 2020 according to the NEC5 Current Legislation scenario (NEC_NAT_CLE_OPTV4) of IIASA.

It is concluded that in the order of 30% of the national $SO_2$ emission and 20% of national PM emissions is potentially influenced by $CO_2$ carbon capture in large industries.
Of the other transboundary air pollutants, less than 10% to the Dutch national totals is coming from large industrial processes. Hence, no major impacts are expected for these other pollutants.

In power generation, $SO_2$ and $NO_x$ emissions are relevant for the national emission ceiling, while other emissions of transboundary air pollution have a relatively small contribution.

Although contributions to national $NH_3$ emissions are very limited, $NH_3$ emissions from post combustion carbon capture could significantly influence national emissions if $NH_3$ emissions are not controlled.

## 4.3 Other impacts

Other known impacts of $CO_2$ capture are the safety of $CO_2$ transport and storage and toxic wastes of chemical solvents. The fact that these issues have not been studied in the present analysis does not indicate that these issues are not important or that their impacts may not be significant.

# 5 Conclusions and recommendations

## 5.1 Conclusions

This phase 1 inventory assesses the impacts of different $CO_2$ capture technologies on transboundary air pollution relevant for the National Emission Ceiling (NEC) for the Netherlands in 2020 and provides recommendations for further research in order to address the current knowledge gaps found.

### *5.1.1 Techno-economic characterisation of capture technologies*

Application of $CO_2$ capture is techno-economically feasible in large scale combustion processes such as in power generation and energy intensive industry. Industrial processes suited for $CO_2$ capture are purification of natural gas, the production of hydrogen, ammonia, ethylene and ethylene oxide, iron and steel and cement. These processes contain already fully concentrated $CO_2$ flows and hence provide potentially cost-effective opportunities for $CO_2$ capture.

Three types of $CO_2$ capture technologies have been investigated, viz. post combustion, pre combustion and oxyfuel. All three $CO_2$ capture technologies are likely ready to be demonstrated before 2020.

**Post combustion** technologies captures $CO_2$ from the flue gas using membranes or solvents such as amines and chilled ammonia. Post combustion requires additional energy (in the order of 15% for gas and 25% for coal firing plants) but does not interfere with the combustion process itself, making it a robust technology suited for retrofitting existing power plants. Post combustion using amines is the most mature technology and is likely to be ready for full scale implementation by 2020. Direct chilling, suited for flue gases with high $CO_2$ concentrations and to be applied in Rotterdam, is in principle not an option for post-combustion $CO_2$ capture, unless “waste cold” is available.

**Pre combustion** technologies convert fuel by gasifying it into syngas from which the $CO_2$ is captured with solvents. The $H_2$ rich syngas can be used in an adapted combustion plant to produce power. Today, only a few Integrated Gasification Combined Cycle (IGCC) power plants are operating. This technology has a lower efficiency penalty and better environmental performance than post combustion technologies using amines.

**Oxyfuel** combustion processes use nearly pure oxygen for the combustion instead of air. The resulting flue gas contains mainly $CO_2$ and $H_2O$. This technology is not operational yet, hence data are surrounded with large uncertainties. The oxyfuel technology promises to have the highest $CO_2$ removal efficiencies and best environmental performance.

**$CO_2$ avoidance cost** for post combustion $CO_2$ capture are in the order of 50 €/tonne $CO_2$ avoided. Avoidance costs are suggested to be the lowest for coal fired pre combustion capture in IGCC and post combustion capture with chilled ammonia (15 to 30 €/tonne $CO_2$ avoided). This conclusion is however based on rather inconsistent economic data with high uncertainty. Moreover, total generation costs are very important and highly dependent on world market energy prices.

**Retrofitting existing** power plants with $CO_2$ capture seems to favour the post-combustion $CO_2$ capture technology which requires no modification of the combustion process. Retrofitting existing coal fired power plants with oxyfuel combustion is according to some sources also possible but requires combustion modifications. Retrofitting IGCCs with pre combustion $CO_2$ capture brings forwards numerous issues but is possible.

### *5.1.2 Emission profiles of capture technologies*

Emission factors presented in the literature for energy conversion technologies with $CO_2$ capture are most often based on assumptions and not on measurements. For the technologies that are currently in the laboratory or pilot phase far less information is available and environmental performance is often discussed qualitatively in literature, if at all.

Moreover, data collected for the inventory are not consistent with respect to year of costs, time horizon, interest rates, life time, reference technology, fuel quality and fuel prices. In the current framework, only the first aspect could be corrected.

The following conclusions can be drawn on the NEC emissions of power generation technologies with different types of $CO_2$ capture technology:

**$SO_2$**

In general, $SO_2$ emissions are expected to be very low for power plants with $CO_2$ capture.
The sulphur content of natural gas is very low and thus $SO_2$ emissions are expected to be negligible for natural gas fired power plants with and without $CO_2$ capture.
For all coal firing conversion technologies, the application of $CO_2$ capture results in a decrease of the emission of $SO_2$ per kWh. Sulphur has to be removed to avoid degradation of the solvent in post combustion processes. In pre combustion and oxyfuel the efficient treatment of, respectively, the syngas and fluegas is expected to result in low $SO_2$ emissions.

**$NO_x$**

In the post combustion concepts $NO_x$ emissions are believed to be largely unaffected by the (amine based) capture process, although consensus seems to be absent. The $NO_2$ part of $NO_x$, being 10%, is assumed to be removed since it causes degradation of the amines. Hence, the $NO_x$ emissions per kWh seem to increase almost proportionally with the increase in primary energy demand due to the addition of $CO_2$ capture.
In literature lower, equal and higher $NO_x$ emissions are reported per kWh when applying pre combustion $CO_2$ capture.
$NO_x$ emissions from oxyfuel concepts are in general expected to be very low, particularly for gas. However, the literature is ambiguous about this subject for coal fired plants.

**$NH_3$**

Only for post-combustion capture concepts $NH_3$ emissions are estimated to significantly increase (with more than a factor 20). This is assumed to be caused by solvent degradation (i.e. an amine based solvent) that is used in the post-combustion capture concept. However, the uncertainty regarding this estimate is considered to be high. Amine improvements in this respect are currently being researched, developed and tested.

**PM**
The emission of particulate matter from natural gas fired cycles in general can be considered negligible.
PM is necessary to be removed for a stable capture process and subsequently expected to be removed by the post-combustion capture process. PM emissions are expected to increase per kWh as a result of the efficiency penalty. In the literature assumptions on this matter vary considerably, however.
It was found that the application of pre-combustion $CO_2$ capture may lower $PM_{2.5}$ emissions from an IGCC.
Also, for coal fired oxyfuel concepts PM emissions are estimated in literature to be lower per kWh, compared to conventional pulverized coal fired power plants.

**NMVOC**
Pre-combustion $CO_2$ capture can increase or decrease the emission of NMVOC. Quantitative estimates of this reduction are absent in the literature.
It is largely unknown whether and to what extent NMVOC emissions are affected by the $CO_2$ capture process in the oxyfuel and post-combustion concepts. Quantitative estimates for NMVOC emissions were not found in the pertaining literature.

The effect of **biomass (co-)firing** in power plants with pre or post combustion $CO_2$ capture is not well researched, although it seems likely that both $SO_2$ and $NO_x$ emissions will be lower, since the sulphur content and the flame temperature will be lower for biomass than for coal. For other emissions is it not possible to make an educated guess. Effects of biomass (co)-firing in oxyfuel concepts on the performance and emission profile are currently also unknown.

**Other impacts** of $CO_2$ capture are the safety of $CO_2$ transport and storage and toxic wastes of chemical solvents that will be produced in large quantities. Also the impact of emissions of amines and degradation products to air can be significant. These are not studied in detail in this project.

### *5.1.3 Life cycle results*

Power generation using natural gas has low emissions of transboundary air pollutants compared to coal based power generation, directly as well as indirectly. It is also found that **switching from coal to gas** fired power generation has larger impacts on direct and indirect emissions than the application of $CO_2$ capture.

The **indirect emissions** exceed the direct emissions in most cases for all NEC substances. The major part of these indirect emissions is caused by mining, preparation and transport of coal.

In general, **$CO_2$ capture** is likely to increase emissions of transboundary air pollutants over the lifecycle due to increased fuel consumption in the order of 15% to 25% depending on the capture technology type. Emissions increase as well due to equipment and solvent manufacturing and treatment, and to a smaller extent due to $CO_2$ storage. For the coal cases these activities contribute in the order of 0-15% to the total emissions over the life cycle.

The geographical **location of emissions** due to fuel preparation is outside the Netherlands and therefore do not influence the Dutch national emission ceilings and standards.

### *5.1.4 Technology assessment*

The $CO_2$ capture technologies can be shortly characterised as follows:

| Main characteristic | Capture technology and application |
|---|---|
| Short-term & relatively cheap | Post combustion Amine PC |
| Short-term & relatively clean | Post combustion Amine NGCC |
| Mid-term & relatively clean coal | Pre combustion IGCC |
| Long-term & clean | Oxyfuel Gas Cycle |
| Long-term & cheapest | Chilled ammonia PC |

### *5.1.5 Emission scenarios for 2020*

#### $CO_2$ mitigation scenarios

Two cost-effective scenarios for $CO_2$ mitigation from van den Broek (UU) indicate that $CO_2$ emission reduction potentials for power generation are in the order of 50 Mt $CO_2$ in 2020 at $CO_2$ avoidance costs of 30 to 50 € / tonne $CO_2$ avoided. Technologies which are cost-effective relative to a coal based baseline scenario are post combustion capture using amines on existing coal plants (retrofit) and pre combustion on new coal fired Integrated Gasification Combined Cycle.

In industry, the costs per tonne $CO_2$ captured are relatively low (up to 25 € per tonne $CO_2$) for the processes which concern a relatively high $CO_2$ concentration and require no additional heat. It concerns the ammonia, hydrogen and ethylene oxide production, gas processing and iron and steel. The capture potential of these sources attractive for $CO_2$ capture amounts presently to 6 Mt $CO_2$ per year.

The costs of applying a technology in an industrial process highly depends on the situation, e.g. can it be fitted in taking into account the availability and security of the plant and its production, the standards and legislation required etc.

#### Transboundary air pollution scenario

The emissions of transboundary air pollution, connected to the processes in power generation and industry which are suited for $CO_2$ capture, are significant in the IIASA NEC5 current legislation scenario. However, this scenario includes only policy measures for transboundary air pollution and no climate policy.

$SO_2$ and $NO_x$ emissions from power generation are relevant for the national emission ceiling having a contribution of about 20% to 25% of the national total in 2020. Other emissions of transboundary air pollution from the power sector have a relatively small contribution.

Large industrial sources suited for $CO_2$ carbon capture can potentially influence national $SO_2$ emission (in the order of 30%) and PM emissions (20%). Of the other transboundary air pollutants, less than 10% of the Dutch national totals is caused by large industrial processes. Hence, no major impacts are expected for these other pollutants.

Although contributions from large sources to national $NH_3$ emissions are very limited, $NH_3$ emissions from post combustion carbon capture could significantly influence national emissions if $NH_3$ emissions are not controlled.

**Transboundary air pollution from $CO_2$ capture scenarios**

NEC emissions have been estimated by applying simple $CO_2$ capture correction factors on the IIASA's NEC emission factors. These correction factors were calculated by the emission ratio of plants without and with $CO_2$ capture from the literature inventory. These factors do not take into account country specific situations with respect to plants and fuel quality.

For the power sector, **$SO_2$** emissions are very low for scenarios that include large scale CCS implementation in 2020, viz. in the order of 1 ktonne $SO_2$ instead of 12 ktonne according to the NEC5 scenario (which includes also small scale power and heat generation).

In all capture scenarios, **$NO_x$** emissions are a factor 2 to 4 lower than in the NEC5 scenario. Large scale implementation of the post combustion technology on existing coal fired plants in 2020 may result in (slightly) higher $NO_x$ emissions compared to the implementation of the other $CO_2$ capture technologies or no capture.

Large scale implementation of the post combustion technology in 2020 may result in more than 5 times higher **$NH_3$** emissions compared to scenarios without CCS and with other $CO_2$ capture options, if the issue of $NH_3$ emission control is not addressed. In that case, $NH_3$ from power generation will be a significant source of a few percent to the national total.

**Particulate Matter** emissions are equal or higher than in the NEC5 scenario. In the latter case, retrofitting coal plants with post combustion capture results in higher PM emissions than from pre combustion on IGCC. The scenario with large scale implementation of the oxyfuel technology shows the lowest emissions of particulate matter.

**NMVOC** emissions from capture technologies are less well known than emissions from other pollutants. From the NEC scenario appears that more than half of the emissions from the power sector stem from biomass use. So, the combination of carbon capture and biomass has to be researched also for NMVOC emissions (though emission contribution to the national total is in the order of 5%).

## 5.2 Recommendations for further research

Four research activities are recommended to address the knowledge gaps which were revealed in the present analysis:

1) **Improve inventory** on transboundary air pollutants from $CO_2$ capture technologies:
    a) standardise and harmonise the data on energy, economic and environmental performances
    b) measurements of emission factors of transboundary air pollutants, particularly $SO_2$, $NO_x$, PM, $NH_3$, NMVOC and (other) degradation products of amines, preferably on existing coal and gas fired power plants
2) **Improve application** for Dutch situation:
    a) gather detailed information on the implementation of $CO_2$ capture taking into account the specific situation of the Dutch power generation park
    b) detailed analysis of CCS implementation in industrial processes and impact on costs and potentials
    c) role of European and Dutch legislation (emission standards and air quality regulation) and impact on costs
3) **Extend scope** and add aspects:
    a) analyse a variety of solvents
    b) lifecycle analysis: improve the energy supply chain
    c) other environmental aspects such as waste and emissions to water
    d) biomass: assess the impacts on NEC emissions
    e) extend the time horizon to 2030 and 2050
4) **Improve scenarios** for the Netherlands:
    a) refine correction factors used to calculate the impact of CCS in NEC emissions
    b) policy analysis of both greenhouse gases and transboundary air pollution for 2020 (ECN / MNP)
    c) cost-effectiveness analysis of both greenhouse gases and transboundary air pollution for the long term using the energy model MARKAL (UU)

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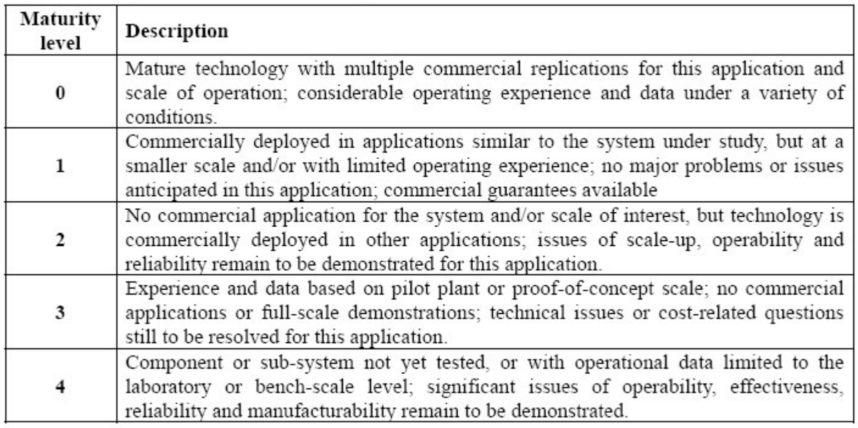
# Appendix A Technology maturity levels

Description of defined maturity levels based upon IPCC



| **Maturity level** | **Description** |
|---|---|
| **0** | Mature technology with multiple commercial replications for this application and scale of operation; considerable operating experience and data under a variety of conditions. |
| **1** | Commercially deployed in applications similar to the system under study, but at a smaller scale and/or with limited operating experience; no major problems or issues anticipated in this application; commercial guarantees available |
| **2** | No commercial application for the system and/or scale of interest, but technology is commercially deployed in other applications; issues of scale-up, operability and reliability remain to be demonstrated for this application. |
| **3** | Experience and data based on pilot plant or proof-of-concept scale; no commercial applications or full-scale demonstrations; technical issues or cost-related questions still to be resolved for this application. |
| **4** | Component or sub-system not yet tested, or with operational data limited to the laboratory or bench-scale level; significant issues of operability, effectiveness, reliability and manufacturability remain to be demonstrated. |

Source: (Kvamsdal et al., 2006)

# Appendix B Detailed technology information

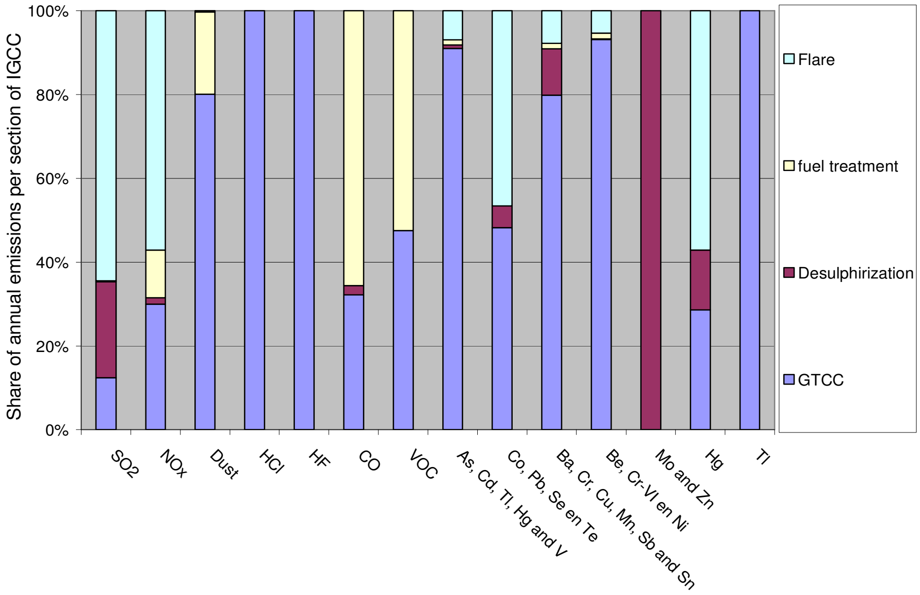


Figure B.1 Annual emissions of the major power plant sections of the NUON IGCC at Buggenum in the year 2005 (NUON, 2006) (Note that due to testing of the facility syngas was flared which explains the large fraction of $NO_x$ emissions due to flaring. During normal operations the main emission source is the GTCC)

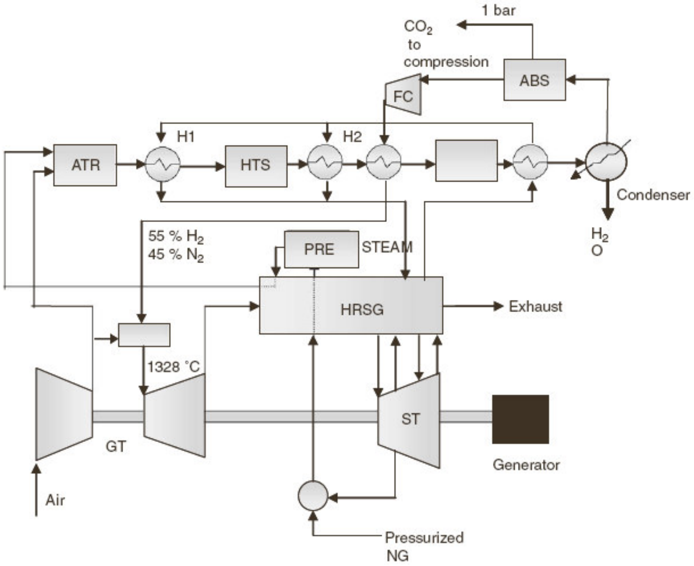


Figure B.2 Pre combustion ATR natural gas fired concept (after (Kvamsdal et al., 2007))

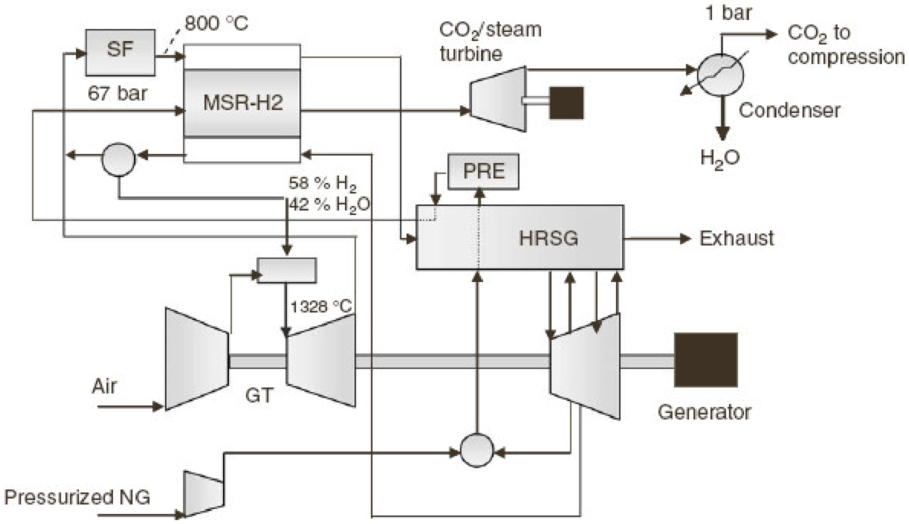


Figure B.3 MSR H2 pre combustion concept (after (Kvamsdal et al., 2007))

# Appendix C Detailed technology characterisation

Table C.1 Number of cases per Capture Technology

| **Capture Technology** | **Energy conversion technology** | **number of cases** |
|---|---|---|
| no-capture | IGCC | 9 |
| | NGCC | 13 |
| | PC | 28 |
| Oxyfuel | GC | 6 |
| | NGCC | 3 |
| | PC | 13 |
| Post | NGCC | 15 |
| | PC | 28 |
| Pre | GC | 2 |
| | IGCC | 20 |

Table C.2 Overview of values for Capacity, Electrical efficiency, efficiency penalty and capture efficiency reported in the literature

| | | Capacity $MW_{e\ net}$ | | | | Electrical efficiency (in %) | | | | Efficiency penalty (in % pts) | | | | $CO_2$ capture efficiency (in %) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **Valid N** | **Min** | **Mean** | **Max** | **Valid N** | **Min** | **Mean** | **Max** | **Valid N** | **Min** | **Mean** | **Max** | **Valid N** |
| no-capture | IGCC | 425 | 608 | 826 | 9 | 38% | 42% | 47% | 9 | . | . | . | 0 | 0.0% | 0.0% | 0.0% | 5 |
| | NGCC | 379 | 558 | 776 | 12 | 53% | 56% | 58% | 13 | . | . | . | 0 | 0.0% | 0.0% | 0.0% | 1 |
| | PC | 248 | 524 | 865 | 26 | 33% | 40% | 46% | 26 | . | . | . | 0 | . | . | . | 0 |
| Oxyfuel | GC | 400 | 400 | 400 | 6 | 45% | 53% | 67% | 6 | 4.2% | 7.3% | 12.1% | 5 | 84.0% | 97.3% | 100.0% | 6 |
| | NGCC | 400 | 427 | 440 | 3 | 45% | 46% | 47% | 3 | 9.7% | 10.6% | 11.3% | 3 | 97.0% | 98.0% | 100.0% | 3 |
| | PC | 532 | 610 | 865 | 13 | 29% | 32% | 38% | 13 | 8.4% | 10.8% | 12.3% | 12 | 86.0% | 95.2% | 100.0% | 13 |
| Post | NGCC | 323 | 524 | 692 | 13 | 45% | 49% | 55% | 15 | 6.0% | 7.7% | 9.9% | 14 | 85.0% | 87.4% | 90.0% | 13 |
| | PC | 140 | 446 | 676 | 24 | 19% | 31% | 40% | 25 | 8.3% | 11.4% | 15.2% | 22 | 85.0% | 89.8% | 96.0% | 21 |
| Pre | GC | 400 | 400 | 400 | 2 | 47% | 49% | 50% | 2 | 7.1% | 8.5% | 9.8% | 2 | 90.0% | 95.0% | 100.0% | 2 |
| | IGCC | 275 | 395 | 730 | 20 | 32% | 36% | 41% | 11 | 5.2% | 7.2% | 9.4% | 11 | 85.0% | 89.5% | 91.0% | 20 |

Table C.3 Overview of values for Cost of electricity and $CO_2$ avoidance reported in the literature

| | | **Cost of electricity (in euro cts/kWh) (constant 2007)** | | | | **Euro per tonne $CO_2$ avoided (constant 2007)** | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **Valid N** | **Min** | **Mean** | **Max** | **Valid N** |
| no-capture | IGCC | 4.7 | 5.7 | 6.6 | 8 | . | . | . | 0 |
| | NGCC | 3.0 | 4.4 | 6.2 | 10 | . | . | . | 0 |
| | PC | 2.2 | 4.1 | 6.2 | 19 | . | . | . | 0 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | 5.5 | 6.9 | 8.3 | 2 | 69 | 77 | 85 | 2 |
| | PC | 5.0 | 7.7 | 9.2 | 13 | 18 | 42 | 62 | 12 |
| Post | NGCC | 4.9 | 6.4 | 8.6 | 11 | 33 | 55 | 89 | 12 |
| | PC | 6.1 | 7.9 | 10.3 | 19 | 16 | 51 | 88 | 22 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 5.8 | 7.6 | 9.0 | 8 | 19 | 30 | 38 | 8 |

Table C.4 Overview of values for $CO_2$ and $NO_x$ emissions reported in the literature

| **Capture technology** | **Energy conversion technology** | **$CO_2$ emissions (in g/kWh)** | | | | **$CO_2$ emissions (in g/MJ)** | | | | **$NO_x$ emissions (in g/kWh)** | | | | **$NO_x$ emissions (in g/MJ)** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | 694 | 766 | 833 | 9 | 84 | 89 | 91 | 9 | 9.0E-02 | 2.3E-01 | 5.8E-01 | 9 | 9.7E-03 | 2.6E-02 | 6.9E-02 | 9 |
| | NGCC | 344 | 370 | 379 | 13 | 55 | 57 | 59 | 12 | 9.0E-02 | 1.7E-01 | 2.6E-01 | 4 | 1.3E-02 | 2.6E-02 | 4.0E-02 | 4 |
| | PC | 706 | 830 | 1004 | 24 | 86 | 92 | 101 | 22 | 2.2E-01 | 3.9E-01 | 6.2E-01 | 12 | 2.5E-02 | 6.0E-02 | 2.3E-01 | 13 |
| Oxyfuel | GC | 0 | 10 | 60 | 6 | 0 | 1 | 9 | 6 | . | . | . | 0 | . | . | . | 0 |
| | NGCC | 0 | 8 | 12 | 3 | 0 | 1 | 1 | 3 | | 0.0E+00 | | 1 | | 0.0E+00 | | 1 |
| | PC | 0 | 47 | 147 | 12 | 0 | 4 | 12 | 12 | 0.0E+00 | 1.7E-01 | 3.9E-01 | 11 | 0.0E+00 | 1.6E-02 | 3.2E-02 | 12 |
| Post | NGCC | 40 | 55 | 66 | 14 | 5 | 7 | 9 | 14 | 1.1E-01 | 1.9E-01 | 2.8E-01 | 6 | 1.4E-02 | 2.5E-02 | 3.7E-02 | 6 |
| | PC | 59 | 145 | 369 | 24 | 3 | 9 | 14 | 21 | 3.3E-01 | 5.7E-01 | 7.7E-01 | 10 | 2.5E-02 | 5.2E-02 | 7.1E-02 | 10 |
| Pre | GC | 0 | 21 | 42 | 2 | 0 | 3 | 5 | 2 | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 71 | 97 | 152 | 11 | 8 | 9 | 14 | 11 | 1.0E-01 | 2.1E-01 | 5.5E-01 | 11 | 9.4E-03 | 2.0E-02 | 5.3E-02 | 20 |

Table C.5 Overview of values for $SO_2$ emissions reported in the literature

| | | $SO_2$ emissions (in g/kWh) | | | | $SO_2$ emissions (in g/MJ) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | 4.0E-02 | 6.4E-02 | 1.4E-01 | 7 | 4.8E-03 | 7.1E-03 | 1.5E-02 | 7 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 2.5E-01 | 4.4E-01 | 1.3E+00 | 12 | 2.7E-02 | 5.1E-02 | 1.5E-01 | 12 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | | 0.0E+00 | | 1 | | 0.0E+00 | | 1 |
| | PC | 0.0E+00 | 2.5E-02 | 9.8E-02 | 11 | 0.0E+00 | 4.6E-02 | 5.3E-01 | 12 |
| Post | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 1.0E-03 | 8.1E-03 | 1.0E-02 | 6 | 8.7E-05 | 7.8E-04 | 9.8E-04 | 6 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 1.0E-02 | 2.8E-02 | 5.1E-02 | 6 | 4.5E-05 | 1.2E-03 | 4.7E-03 | 15 |

Table C.6 Overview of values for $PM_{10}$ and $NH_3$ emissions reported in the literature

| | | $PM_{10}$ emissions (in g/kWh) | | | | $PM_{10}$ emissions (in g/MJ) | | | | $NH_3$ emissions (in g/kWh) | | $NH_3$ emissions (in g/MJ) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** | **Value** | **N** | **Value** | **N** |
| no-capture | IGCC | 2.7E-02 | 2.8E-02 | 2.9E-02 | 3 | | 3.2E-03 | | 3 | . | 0 | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 | . | 0 | . | 0 |
| | PC | 7.0E-03 | 4.3E-02 | 5.1E-02 | 8 | 8.3E-04 | 4.9E-03 | 6.0E-03 | 8 | 1.0E-02 | 1 | 1.1E-03 | 1 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 | . | 0 | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 | . | 0 | . | 0 |
| | PC | 0.0E+00 | 3.3E-03 | 9.5E-03 | 9 | 0.0E+00 | 2.8E-04 | 7.7E-04 | 9 | . | 0 | . | 0 |
| Post | NGCC | . | . | . | 0 | . | . | . | 0 | 2.0E-03 | 1 | 2.5E-04 | 1 |
| | PC | 5.2E-02 | 6.2E-02 | 7.4E-02 | 4 | 0.0E+00 | 3.4E-03 | 5.8E-03 | 6 | 2.3E-01 | 1 | 2.0E-02 | 1 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 | . | 0 | . | 0 |
| | IGCC | 3.4E-02 | 3.4E-02 | 3.5E-02 | 3 | 2.7E-03 | 3.0E-03 | 3.4E-03 | 12 | . | 0 | . | 0 |

Table C.7 Overview of values for NMVOC emissions reported in the literature

| | | NMVOC emissions (in g/kWh) | | | | NMVOC emissions (in g/MJ) | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 9.1E-03 | 1.0E-02 | 1.1E-02 | 3 | 1.0E-03 | 1.1E-03 | 1.1E-03 | 3 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | . | . | . | 0 | . | . | . | 0 |
| Post | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | . | . | . | 0 | . | . | . | 0 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | . | . | . | 0 | 5.4E-04 | 6.5E-04 | 7.2E-04 | 9 |

Table C.8 Overview of values for the Relative factor derived from literature for $NO_x$ emissions

| | | $NO_x$ Relative factor kWh | | | | $NO_x$ Relative factor MJ | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | 1.00 | 1.00 | 1.00 | 9 | 1.00 | 1.00 | 1.00 | 9 |
| | NGCC | 1.00 | 1.00 | 1.00 | 4 | 1.00 | 1.00 | 1.00 | 4 |
| | PC | 1.00 | 1.00 | 1.00 | 9 | 1.00 | 1.00 | 1.00 | 10 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | 0.00 | | | 1 | 0.00 | | | 1 |
| | PC | 0.00 | 0.61 | 1.40 | 10 | 0.00 | 0.42 | 1.00 | 11 |
| Post | NGCC | 1.05 | 1.15 | 1.22 | 6 | 0.92 | 1.00 | 1.04 | 6 |
| | PC | 1.11 | 1.24 | 1.45 | 10 | 0.86 | 0.92 | 1.00 | 10 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 0.95 | 1.03 | 1.11 | 11 | 0.76 | 0.85 | 0.96 | 11 |

Table C.9 Overview of values for the Relative factor derived from literature for $SO_2$ emissions

| | | $SO_2$ Relative factor kWh | | | | $SO_2$ Relative factor MJ | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | 1.00 | 1.00 | 1.00 | 7 | 1.00 | 1.00 | 1.00 | 7 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 1.00 | 1.00 | 1.00 | 9 | 1.00 | 1.00 | 1.00 | 9 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 0.00 | 0.08 | 0.33 | 10 | 0.00 | 0.06 | 0.24 | 10 |
| Post | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 0.00 | 0.02 | 0.03 | 6 | 0.00 | 0.01 | 0.02 | 8 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 0.08 | 0.55 | 1.09 | 6 | 0.07 | 0.45 | 0.85 | 6 |

Table C.10 Overview of values for the Relative factor derived from literature for $PM_{10}$ emissions

| | | $PM_{10}$ Relative factor kWh | | | | $PM_{10}$ Relative factor MJ | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Min** | **Mean** | **Max** | **N** | **Min** | **Mean** | **Max** | **N** |
| no-capture | IGCC | 1.00 | 1.00 | 1.00 | 3 | 1.00 | 1.00 | 1.00 | 3 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 1.00 | 1.00 | 1.00 | 5 | 1.00 | 1.00 | 1.00 | 5 |
| Oxyfuel | GC | . | . | . | 0 | . | . | . | 0 |
| | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 0.00 | 0.08 | 0.19 | 9 | 0.00 | 0.06 | 0.13 | 9 |
| Post | NGCC | . | . | . | 0 | . | . | . | 0 |
| | PC | 1.00 | 1.28 | 1.46 | 4 | 0.68 | 0.89 | 1.00 | 4 |
| Pre | GC | . | . | . | 0 | . | . | . | 0 |
| | IGCC | 1.18 | 1.24 | 1.30 | 3 | 0.99 | 1.00 | 1.01 | 3 |

Table C.11 Overview of values for the Relative factor derived from literature for $NH_3$ emissions

| | | $NH_3$ Relative factor kWh | | $NH_3$ Relative factor MJ | |
|---|---|---|---|---|---|
| **Capture Technology** | **Energy conversion technology** | **Value** | **N** | **Value** | **N** |
| no-capture | IGCC | . | 0 | . | 0 |
| | NGCC | . | 0 | . | 0 |
| | PC | 1.00 | 1 | 1.00 | 1 |
| Oxyfuel | GC | . | 0 | . | 0 |
| | NGCC | . | 0 | . | 0 |
| | PC | . | 0 | . | 0 |
| Post | NGCC | . | 0 | . | 0 |
| | PC | 23.00 | 1 | 17.50 | 1 |
| Pre | GC | . | 0 | . | 0 |
| | IGCC | . | 0 | . | 0 |

# Appendix D Economical normalisation

Cost data that are derived from the gathered literature have been normalized to constant 2007 Euros in this study in order to account for the currency and year of publication. The cost in dollars was first converted to Euros by using the average exchange rate. Then cost in Euros is converted to constant 2007 Euros to account for inflation by using the consumer price index for Europe.

Table D.1 Average exchange rates for US dollar to Euro (source: www.oanda.com) and normalized consumer prices for Europe (source (OECD, 2008))

| Year | US Dollar/Euro | Consumer price index for Europe |
|---|---|---|
| 1999 | 1.07 | 0.77 |
| 2000 | 0.92 | 0.81 |
| 2001 | 0.94 | 0.85 |
| 2002 | 0.94 | 0.88 |
| 2003 | 1.13 | 0.91 |
| 2004 | 1.24 | 0.93 |
| 2005 | 1.24 | 0.95 |
| 2006 | 1.25 | 0.98 |
| 2007 | 1.37 | 1.00 |

In this study all values are based on the lower heating values (LHV) of the fuels, unless otherwise indicated. This means that if original data is presented for the higher heating value (HHV) this is converted to the lower heating value by using the factors below:

Table D.2 Conversion LHV/HHV

| Fuel | LHV/HHV |
|---|---|
| Coal | 0.96 |
| Natural gas | 0.90 |

# Abbreviations

| | |
|---|---|
| ABC | Ammonium BiCarbonate |
| AC | Ammonium Carbonate |
| AGR | Acid Gas Re-Injection |
| ASU | Air Separation Unit |
| ATR | Auto Thermal Reforming |
| AZEP | Advanced Zero Emmission Power plant |
| BAU | Business As Usual |
| BF | Blast Furnace |
| BOF | Basic Oxygen Furnace |
| CAP | Chilled Ammonia Process |
| CAPEX | Capital Expenditures |
| CCF | Cyclone Converter Furnace |
| CCS | Carbon Capture & Storage |
| CHP | Combined Heat and Power |
| CLC | Chimical Loopong Combustion |
| CoE | Cost of Electricity |
| DoE | US Department of Energy |
| DRI | Direct-Reduced Iron |
| ESP | ElectroStatic Precipitation |
| FGD | Flue Gas Desulphurization |
| FGR | Flue Gas Recirculation |
| GC | Gas Cycle |
| GHG | Green House Gas |
| GJ | Giga Joule |
| GTCC | Gas Turbine Combined Cycle |
| HHV | High Heating Value |
| HRSG | Heat Recovery Steam Generator |
| IEA | International Energy Agency |
| IGCC | Integrated Gasification Combined Cycle |
| IPCC | Intergovernmental Panel on Climate Change |
| ITM | Ion Transport Membrane |
| Kt | kilo tonne |
| kWh | kilo Watt hour |
| LCA | Life Cycle Analysis |
| LHV | Low Heating Value |
| LNG | Liquid Natural Gas |
| MCM | Mixed Conducting Membrane |
| MDEA | Methyl Diethanol Amine |
| MEA | Mono Ethanol Amine |
| MPa | Mega Pascal |
| MSR | Methane Steam Reformer |
| Mt | Mega tonne |
| MW | Mega Watt |
| NEC | National Emission Ceiling |
| NETL | National Energy Technology Laboratory (US) |
| NGCC | Natural Gas Combined Cycle |
| NMVOC | Non Methane Volatile Organic Compounds |
| O&M | Operating & Maintenance |

| | |
|---|---|
| PC | Pulverized Coal |
| PM | Particulate Matter |
| RFG | Recycled Flue Gas |
| SCR | Selective Catalytic Reduction |
| SEWGS | Sorption Enhanced Water Gas Shift |
| SNCR | Selective Non Catalytic Reduction |
| SOFC | Solid Oxide Fuel Cel |
| WGS | Water Gas Shift |