

Parametrised Life Cycle Assessment of Electricity Generation in Hard-Coal-Fuelled Power Plants with Carbon Capture and Storage

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List of Abbreviations

ALLEGC	Average lifetime levelised electricity generation costs
AP	Acidification potential
ASU	Air separation unit
BALANCE	Software for Life Cycle Assessment
BMBF	German Federal Ministry of Education and Research
BMU	German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety
BMWA	German Federal Ministry of Economics and Labour
BREF	Reference document on best available techniques
BWPlus	Baden Württemberg Environmental Ministry's program 'living basis environment and its protection'
CASTOR	CO ₂ from Capture to Storage (European project)
CCS	Carbon capture and storage
CED	Cumulated energy demand
COORETEC	Project initiative ' CO₂ reduction technologies '
CO ₂ Sink	European project on the geological storage of CO ₂
ECBM	Enhanced coal bed methane
EcoSpold	Data format for the exchange of LCA data
EGR	Enhanced Gas Recovery
EGT	Electricity generation technology
EIO-LCA	Life Cycle Assessment based on economic input / output tables
EOR	Enhanced oil recovery
EP	Eutrophication potential
ESP	Electrostatic precipitator
EUSUSTEL	European Sustainable Electricity (European project)
FGD	Flue gas desulphurisation
FNR	Agency for Renewable Resources
GHG	Greenhouse gas
GWP	Global warming potential
HP	High pressure
HRSG	Heat recovery steam generator
HTP	Human toxicity potential
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IER	Institute of Energy Economics and the Rational Use of Energy
I/O-tables	Economic Input / Output tables
IP	Intermediate pressure
IPPC	Integrated Pollution and Prevention Control
ISO	International Organisation for Standardisation

LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LP	Low pressure
LPG	Liquefied petrol gas
MEA	Monoethanolamine
NEEDS	New Energy Externalities Development for Sustainability (European project)
NGCC	Natural gas combined cycle
NMVOC	Non methane volatile organic compounds
OMS	Oliver Mayer-Spohn (abbreviation for results of this study)
OTM	Oxygen transport membrane
PCC	Pulverized coal combustion
PEF	Project European Research Centre
P-LCA	Parametrised Life Cycle Assessment
PM	Particulate matter (PM ₁₀ – Particulate matter with a diameter smaller than 10 µm)
POCP	Photochemical ozone depletion potential
ppm	parts per million
PWR	Pressurized water reactor
PSA	Pressure swing adsorption
R&D	Research and development
SCADA	Supervisory control and data acquisition
SCR	Selective catalytic (NO _x) reduction
SETAC	Society of Environmental Toxicologists and Chemists
SODP	Stratospheric ozone depletion potential
RECCS	Structural-economic Comparison of R egenerative Energy Technologies with C CS (German project)
TEG	Tri-ethylene glycol
UGR	Environmental economic accounting (in German: Umweltökonomische Gesamtrechnung)
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
VDI	The Association of German Engineers (German: Verein deutscher Ingenieure)
VSA	Vacuum swing adsorption
WCI	World Coal Institute
YOLL	Years of life lost

Summary

The capture of CO₂ from the flue gases of large point sources and the following CO₂ storage in geological formations is referred to as carbon capture and storage (CCS). CCS technologies are intended to heavily reduce the CO₂ emissions of fossil-fuelled power generation.

This study investigates the economic and environmental performance of hard-coal-fuelled electricity generation with CCS over the entire life cycle and thereby reveals both positive and negative aspects. Major improvements are (as intended) a considerable reduction in the specific CO₂ emissions and thus a substantial mitigation of the global warming potential of hard-coal-fuelled electricity generation. Furthermore, CCS technologies come along with a reduction in specific SO₂ and NO_x emissions. Since the operation of CO₂ capture units requires lower flue gas concentrations of SO₂ and NO_x than in currently operated power plants, CO₂ capture technologies constitute a driver for the development and deployment of more advanced flue gas cleaning systems. The anticipated decrease in CO₂, SO₂ as well as NO_x emissions into air at the same time entails a reduction in external costs, especially due to mitigated damages from climate change and mitigated impacts on human health.

On the other hand, CCS technologies cause a deterioration of the environmental and economic performance of hard-coal-fuelled electricity generation. This is since the demand for energy and material resources is increased by the operation of facilities for the capture, transportation and injection of CO₂. There is an efficiency penalty due to CO₂ capture, since from the same amount of steam coal less electricity is generated over the life time of the power plant. Furthermore, additional material and energy resources are necessary for installation of new facilities for CO₂ capture as well as for construction of the infrastructure for transportation and storage of the captured CO₂. These aspects entail additional costs for investment and energy supply, so that the average lifetime levelised electricity generation costs (ALLEGC) of hard-coal-fuelled power plants are increased by 17 % to 43 %, when CCS technologies are applied. In addition, the increased supply and processing of material and energy resources for CCS technologies are involved with higher specific emissions into air, soil and water and thus constitute an additional environmental burden.

The major part of this deterioration of the environmental and also economic performance originates from the efficiency penalty due to CO₂ capture. Transportation and storage of the captured CO₂ on the other hand has been revealed to contribute only at the subordinate level.

For investigated future time horizons an additional deterioration of the environmental performance arises from changes at the steam coal supply. Due to the phase-out of German domestic steam coal mining by 2018, German steam coal is replaced by imported steam coal from other partly far distant countries. This replacement requires additional transportation services, causes a reduction of the efficiency over the steam coal supply chain and thus results in a higher release of emissions as well as in a higher demand for both energy and material resources.

In the direct comparison of technologies for CO₂ transportation, the CO₂ transportation via pipeline has clearly turned out more advantageous for German conditions in terms of economic and environmental performance than CO₂ barge transportation. This is mainly due to an additional and energy intensive step of CO₂ compression, which is necessary after barge transportation in order to reach the pressure for injection of CO₂ into a storage site. The transportation of CO₂ in steel tanks, which are shipped on barges, is performed at a considerably lower pressure level than CO₂ pipeline transportation. Thus, the latter does not require the additional compression before CO₂ injection.

The economic performance of hard-coal-fuelled electricity generation with CCS will be improved by the internalisation of external costs, as it is the case with CO₂ allowances within the scope of the European emission trading scheme. Against the background of the price development of CO₂ allowances within the second emission trading period from 2008 – 2012 between 15 and 28 €/per ton of CO₂, at the latter price level an economic operation of IGCC (integrated gasification combined cycle) power plants with CCS and oxyfuel power plants is anticipated for the next decade based on the considered assumptions in cost calculation. For the competitiveness of CCS it is furthermore relevant, that already for the first large-scale hard-coal-fuelled power plants with CCS lower ALLEGC have been calculated than for current regenerative electricity generation technologies based on wind or solar power. However, apart from the economic performance of CCS technologies, a crucial aspect for their market penetration will be the societal acceptance of these technologies and thereby particularly the long-term safety of geological CO₂ storage sites.

The most favourable environmental and also economic performance has been found for IGCC power plants with CO₂ pre-combustion capture, closely followed by oxyfuel technology. In the direct comparison to these technologies the performance of CO₂ post-combustion capture in pulverized coal combustion (PCC) power plants turned out to be involved with a higher demand for energy and material resources and thus also higher costs. Furthermore, PCC power plants with CCS revealed higher specific emissions than the first cited CCS technologies.

All investigated CCS technologies are anticipated to be ready for large-scale commissioning within the next decade. For hard-coal-fuelled electricity generation, this means that future power plant capacities with CCS are able to strongly contribute to a mitigation of the release of anthropogenic CO₂ emissions, especially when they are commissioned in order to replace outdated power plant units without CO₂ capture.

Zusammenfassung

Die Abscheidung von CO₂ aus dem Rauchgas großer Punktquellen und die anschließende CO₂-Speicherung beispielsweise in geologischen Gesteinsformationen wird als ‚Carbon Capture and Storage‘ (CCS) bezeichnet. Durch den Einsatz von CCS-Technologien sollen die CO₂-Emissionen der ‚Energieerzeugung‘ aus fossilen Energieträgern erheblich reduziert werden.

Diese Arbeit untersucht die Wirtschaftlichkeit und Umweltverträglichkeit der Steinkohleverstromung mit CCS entlang des gesamten Lebenszyklus und zeigt dabei sowohl positive als auch negative Aspekte auf. Deutliche Verbesserungen stellen (wie beabsichtigt) die bedeutende Reduktion der spezifischen CO₂-Emissionen und somit eine Verringerung des Treibhauspotentials der Steinkohleverstromung dar. Darüber hinaus geht die Anwendung von CCS-Technologien mit einer Verringerung der spezifischen SO₂- und NO_x-Emissionen einher. Da der Betrieb von CO₂-Abscheideanlagen geringere Rauchgaskonzentrationen an SO₂ und NO_x erfordert, als es in derzeit betriebenen Steinkohlekraftwerken der Fall ist, machen CO₂-Abscheideanlagen die Entwicklung und den Einsatz von verbesserten Rauchgasreinigungsanlagen erforderlich. Diese Verringerung der luftgetragenen Emissionen an CO₂, SO₂ und NO_x führt gleichzeitig zu einer Reduktion der externen Kosten der Steinkohleverstromung mit CCS, insbesondere durch verringerte Schäden infolge des geringeren Beitrags zum Klimawandel sowie geringerer Auswirkungen auf die menschliche Gesundheit.

Andererseits gehen CCS-Technologien mit einer Verschlechterung der Wirtschaftlichkeit und der Umweltauswirkungen der Kohleverstromung einher. Der Bedarf an Material- und Energieressourcen pro erzeugte Kilowattstunde Strom steigt durch den Betrieb von Anlagen zur Abscheidung, zum Transport sowie der Speicherung von CO₂ deutlich an. Aufgrund der Verschlechterung des Kraftwerkswirkungsgrades durch die CO₂-Abscheidung wird in CCS-Kraftwerken aus derselben Menge an Kesselkohle weniger Strom während der Lebensdauer des Kraftwerks erzeugt. Zudem werden zusätzliche Material- und Energieressourcen für die Installation von neuen Anlagen zur CO₂-Abscheidung sowie für die Errichtung der Infrastruktur für CO₂-Transport und CO₂-Speicherung benötigt. Diese Aspekte verursachen zusätzliche Investitions- und Energiekosten, so dass für Kraftwerke mit CCS ein Anstieg der Stromgestehungskosten um 17 % bis 43 % gegenüber Kraftwerken ohne CCS ermittelt wurde. Gleichzeitig führt die Bereitstellung sowie der Einsatz von zusätzlichen Material- und Energieressourcen für die CCS-Technologien zu höheren spezifischen Emissionen in Boden, Wasser und Luft und somit zu einer zusätzlichen Umweltbelastung.

Der größte Teil dieser zusätzlichen Umweltbelastung und der ansteigenden Stromgestehungskosten wird durch die Verschlechterung des Kraftwerkswirkungsgrades durch die CO₂-Abscheidung verursacht. Der zusätzliche Transport und die Speicherung des abgeschiedenen CO₂ hingegen tragen im Vergleich dazu deutlich weniger zur Verschlechterung der Wirtschaftlichkeit und der Umweltauswirkungen bei.

Bei den untersuchten zukünftigen Zeithorizonten ist eine zusätzliche Verschlechterung der Umweltverträglichkeit durch Veränderungen bei der Bereitstellung der Kesselkohle zu verzeichnen. Aufgrund des beschlossenen Ausstiegs aus dem deutschen Steinkohlebergbau bis 2018 wird der Anteil deutscher Kesselkohle in Zukunft durch Kesselkohleimporte aus teilweise weit entfernten Ländern ersetzt. Dieser Ersatz deutscher Kesselkohle ist mit zusätzlichen Transportaufwendungen und einer Verringerung der Effizienz bei der Kesselkohlebereitung verbunden. Dadurch sind höhere Emissionen und auch ein höherer Bedarf an Material- und Energieressourcen zu erwarten.

Im direkten Vergleich von CO₂-Transportmöglichkeiten weist der CO₂-Pipelinetransport für deutsche Verhältnisse deutliche Vorteile hinsichtlich Wirtschaftlichkeit und Umweltauswirkungen gegenüber dem CO₂-Transport per Binnenschiff auf. Dies liegt in erster Linie daran, dass im Anschluss an den CO₂-Binnenschifftransport eine zusätzliche, energieintensive Kompression des abgeschiedenen CO₂ notwendig ist, um das Druckniveau für die anschließende CO₂-Verpressung zu erreichen.

Die Wirtschaftlichkeit der Kohleverstromung mit CCS wird sich durch eine Internalisierung von externen Kosten verbessern, wie es bei CO₂-Emissionszertifikaten im Rahmen des europäischen Emissionshandelssystems der Fall ist. Vor dem Hintergrund der Preisentwicklung von CO₂-Emissionszertifikaten innerhalb der zweiten Handelsperiode von 2008 – 2012 zwischen 15 und 28 €/pro Tonne CO₂ werden für letzteres Preisniveau basierend auf den verwendeten Annahmen bei der Kostenrechnung wirtschaftliche Betriebskosten von IGCC-Kraftwerken mit CCS sowie von Oxyfuel-Kraftwerken innerhalb der nächsten Dekade erwartet. Für die Wettbewerbsfähigkeit von CCS-Technologien ist es darüber hinaus von Bedeutung, dass bereits für die ersten Kraftwerke zur Steinkohleverstromung mit CCS im hohen Leistungsbereich geringere Stromgestehungskosten errechnet wurden, als die derzeitige regenerative Stromerzeugung aus Wind- und Sonnenenergie aufweist. Abgesehen von der Wirtschaftlichkeit von CCS stellt jedoch die gesellschaftliche Akzeptanz dieser Technologien einen entscheidenden Faktor für deren Markteinführung und Verbreitung dar. Dabei steht in erster Linie die Frage der langfristigen Sicherheit der geologischen CO₂-Speicherstätten im Mittelpunkt.

Die beste Wirtschaftlichkeit sowie die geringste Umweltbeeinträchtigung wurde für IGCC-Kraftwerke mit CO₂-Abscheidung vor der Verbrennung, dicht gefolgt von Oxyfuel-Kraftwerken ermittelt. Im direkten Vergleich zu diesen Technologien wiesen Kohlestaubfeuerungs-Kraftwerke mit CCS einen höheren spezifischen Bedarf hinsichtlich Material- und Energieressourcen sowie dadurch auch höhere Kosten auf. Darüber hinaus wurden für Kohlestaubfeuerungs-Kraftwerke mit nachgeschalteter chemischer Wäsche höhere spezifische Emissionen als für die erstgenannten CCS-Technologien ermittelt.

Für alle untersuchten CCS-Technologien wird die Einsatzreife für große Kraftwerkskapazitäten innerhalb der nächsten Dekade erwartet. Für die Steinkohleverstromung bedeutet dies, dass zukünftige Kraftwerke mit CCS in der Lage sein werden, einen bedeutenden Beitrag zur Reduktion anthropogener CO₂-Emissionen zu leisten. Und dies umso mehr, wenn sie an Stelle alter Kraftwerksanlagen ohne CO₂-Abscheidung zum Einsatz kommen.

1 Introduction

Greenhouse gases (GHGs), which are gaseous substances able to trap radiant heat within the Earth's atmosphere, have become a concern due to their potential link to climate change. The GHG of most interest is carbon dioxide (CO₂), since it makes up around 80 % of anthropogenic GHG emissions. Over the last century, the concentration of CO₂ in the atmosphere has risen from about 280 parts per million (ppm) at a pre-industrial level to approximately 385 ppm in 2005 /177/. This increase is in large part driven by the use of fossil fuels for power generation, which involves the release of large quantities of CO₂.

Since fossil fuels are expected to remain the most important fuel for power generation for both developed and developing countries for the next decades /112/, considerable efforts and new solutions are required to achieve major reduction in the release of CO₂ emissions.

Possible ways to mitigate the release of CO₂ emissions are efficiency improvements of energy production processes or switching to less carbon-intensive fossil fuels such as the replacement of hard coal by natural gas. However, the effectiveness of these measures is limited. Much more significant reductions of CO₂ emissions can be achieved by capturing the CO₂ from fossil fuelled power generation and permanently retaining it from being released into the atmosphere. This is referred to as carbon capture and storage (CCS) and is investigated in this study at the example of electricity generation from hard coal.

CCS constitutes a process chain consisting of three major steps:

- CO₂ capture: The CO₂ emissions emerging from the electricity generation process are separated and retained.
- CO₂ transportation: The retained CO₂ emissions are compressed to liquid state and transported to a CO₂ storage site.
- CO₂ storage: The transported liquid CO₂ is injected into a storage formation, which guarantees long-term isolation from the atmosphere.

1.1 Aim and Scope

The capture of CO₂ from large point sources and the following CO₂ storage in geological formations is intended to heavily reduce the greenhouse effect caused by fossil fuelled power generation. This CCS technology, however, on the other hand comes with an additional demand for material and energy resources as well as with additional release of emissions, which is caused by the facilities for capture, compression, transportation and storage of the CO₂.

This study aims at investigating the economic and environmental performance of hard-coal-fuelled electricity generation with CCS. Starting from an introduction of different power plant concepts for hard-coal-fuelled electricity generation with and without CCS, the energy and material flows, the release of emissions and the associated costs over the life cycle of these power plant concepts are identified and quantified. Taking into account the technical

development over different time horizons, the benefits and drawbacks of CCS are evaluated in respect to their impact on resources, climate and environment, whereas environment in this context refers to both ecosystems and humankind.

For all investigated power plant concepts with and without CCS, average life time levelised electricity generation costs (ALLEGC) are calculated and compared to the external costs that arise from the released emissions. As a further outcome, the environmental and economic performance of hard-coal-fuelled electricity generation in currently installed power plants is compared to future power plant concepts with and without CCS. Here, the technical specification and cost data for these future concepts are taken from the technology roadmaps of current R&D.

For the investigation of the environmental performance the approach of life cycle assessment (LCA) according to the standard ISO 14040ff is applied. In the course of this study, this LCA methodology is supplemented by the integration of parameters in order to improve its application for a thorough analysis of current and future electricity generation technologies. This parametrised LCA, still being in accordance to the ISO standards, allows the modification of technical settings and assumptions within an LCA study, so that an investigation of the development of CCS technologies for future time horizons is facilitated. By means of parameter modification sensitivity analyses on different technical specifications are performed, which for instance comprise variations of the power plant capacity, the power plant efficiency as well as other parameters within CCS chain. Thereby, the influence of different aspects of CCS technology on material and energy demand as well as on the release of emissions and finally on possible environmental impacts is highlighted.

As a final outcome, the economic and environmental performance of the investigated technologies with and without CCS are compared and evaluated. Thereby a comparison to other electricity generation technologies is also drawn.

1.2 Outline of the Study

Chapter 1 opens with an introduction of the topic and then presents the scope of this study. Starting with the technical background, chapter 2 provides an overview on electricity generation from hard coal and its anticipated role in the mid- to long-term future. Facing the release of high quantities of the greenhouse gas CO₂, different technological concepts for carbon capture are outlined. Also, within this context currently planned large-scale power plant projects using CCS are mentioned.

Chapter 3 presents the methodology applied in this study, which is LCA, and discusses the properties of this approach for a thorough analysis of both current and future electricity generation technologies. Starting from limitations of this approach at such an analysis, a methodological expansion of LCA is introduced.

How this expanded LCA methodology is applied for the analyses of different technical development stages of power plant concepts with CCS is shown in chapter 4 illustrated by the

software tool BALANCE. In a few paragraphs, the update of this LCA software and the integration of the methodological expansions relevant for the conduction of this study are presented.

Chapter 5 comprises the environmental, economic and technical analysis of current and future hard-coal-fuelled power plants for electricity generation with and without CCS. By means of a detailed goal and scope definition, the investigated stages of technical development and their specifications are illustrated.

Results are presented, discussed and analysed in chapter 6. Investigated scenarios are compared and evaluated, whereas central issues are further analysed by means of sensitivity analyses. As a final step of the analysis, a comparison with the environmental and economic performance of other electricity generation technologies is drawn.

All findings are collected and conclusions are drawn in chapter 7. The conclusions are discussed with reference to the calculations and outcome of other LCA studies on CCS technologies.

Lastly, chapter 8 provides a summary and relates the findings to the scope of this study.

2 Background

This chapter provides an overview of electricity generation from hard coal and its anticipated role in the mid- to long-term future. Following this, different technological concepts for carbon capture are introduced and some planned applications at large-scale power plant level are outlined.

2.1 Electricity Generation from Hard Coal and Release of CO₂

According to the world energy outlook 2006, fossil fuels are expected to globally remain the dominant source of energy till 2030 and most probably also the following two decades /167/.

Most abundant and affordable resources among fossil fuels are existent for coal, which is available in many regions of the world. Thus, coal is expected to play a significant role in meeting the future energy demand. The economic development of many countries, including, amongst others, also the fast growing countries of India and China is predominantly based on coal resources. Starting from these basic conditions, the global hard coal demand is projected to grow at an average annual rate of 1.8 % /167/, whereby power generation will account for 81 % of this increase. Also, in Europe an increase of hard coal demand especially for power generation is anticipated. This entails that hard coal based electricity generation in Europe is expected to stay at current or even slightly elevated capacity level by 2030 and the following decades /167/.

Major concerns from the use of coal for electricity generation arise from its environmental impact. One aspect is the emission of pollutants such as sulphur oxides, nitrogen oxides, particulates and harmful trace elements. Within the last decades, highly efficient technologies have been developed to successfully minimise the release of these emissions. A major challenge arises from the high amount of CO₂ emissions, which are generated by coal-fuelled electricity generation and have become a global concern due to their linkage to climate change. As shown in Table 2-1, coal-fuelled power generation features a considerable contribution to the overall CO₂ emissions in Germany, Europe and especially worldwide.

Table 2-1: Contribution of coal to overall CO₂ emissions of Germany, Europe, World in 2006
(source: derived from /175/ /176/)

[million tons of CO ₂]	Germany	Europe	World
Total CO₂ emissions	895	7,528	30,047
CO₂ emissions from coal	319	1,366	12,064

In a power plant featuring an electric capacity of 500 MW_e and an efficiency of 46 % yearly approximately 3,500 tons of CO₂ are emitted for assumed base load conditions of 7,500 full load hours per year. This correlation refers to German steam coal /107/ /109/ and can be followed by equation 2-1.

$$annual\ m(CO_2)_{hard-coal-fuelled\ electricity\ generation} = \frac{capacity \cdot full\ load\ hours \cdot 334 \frac{g\ CO_2}{kWh}}{efficiency} \quad (2-1)$$

Presently different means for a reduction of these CO₂ emissions are explored. The most promising technology able to achieve a heavy reduction in CO₂ emissions is the capture of this greenhouse gas directly at the point of its origin, the power plant.

2.2 Concepts for Carbon Capture and Current Application in Power Plants

In current technology research and development there are mainly three pathways for the capture of CO₂, which are explained in the following. Additionally, a simplified process diagram of these CO₂ capture approaches is shown in Figure 2-1:

1. CO₂ post-combustion capture: This capture approach constitutes an end-of-pipe technology and involves the separation of CO₂ emissions by scrubbing the flue gas, which is released at the process of electricity generation.
2. CO₂ pre-combustion capture: The basic idea of this capture approach is to achieve a decarbonisation of the fuel already before the process of electricity generation takes place. Therefore, fuel is gasified with pure oxygen and processed to a gas stream, which finally consists of mainly carbon dioxide and hydrogen. After scrubbing of the carbon dioxide from this gas stream a carbon-free electricity generation based on hydrogen is possible. Thereby, electricity is generated firstly in a gas turbine and secondly in a steam cycle.
3. Oxyfuel combustion: This pathway owes its name to the combustion of fuel taking place in pure oxygen instead of air. Without the dilution by nitrogen and other constituents of the air, this combustion constitutes an almost pure oxidation of hydrocarbons resulting in carbon dioxide and water as main reaction products. After removal of the water, a highly concentrated stream of carbon dioxide remains, featuring only a small share of combustion products from fuel impurities.

CO₂ capture technologies are most cost effective and most efficient when applied to large, stationary sources of CO₂, such as fossil-fuelled power plants for electricity generation. Thereby around 85 – 98 % of the CO₂ emissions can be captured [124]. The exact capture rate depends on the capture technology applied and on the specifications of the considered power plant.

Generally, the capture of CO₂ constitutes an energy-intensive process. The energy for the CO₂ capture is usually taken from the process of electricity generation and thus reduces the overall efficiency of the respective power plant.

There are several coal-fired power plant projects underway for large-scale and commercial application of the above described CO₂ capture approaches. Table 2-2 provides an overview of these projects, which are planned to be commissioned between 2010 and 2020. This project list highlights the topicality of CCS and the importance to evaluate the economic, environmental and technical performance of different power plant concepts with CO₂ capture.

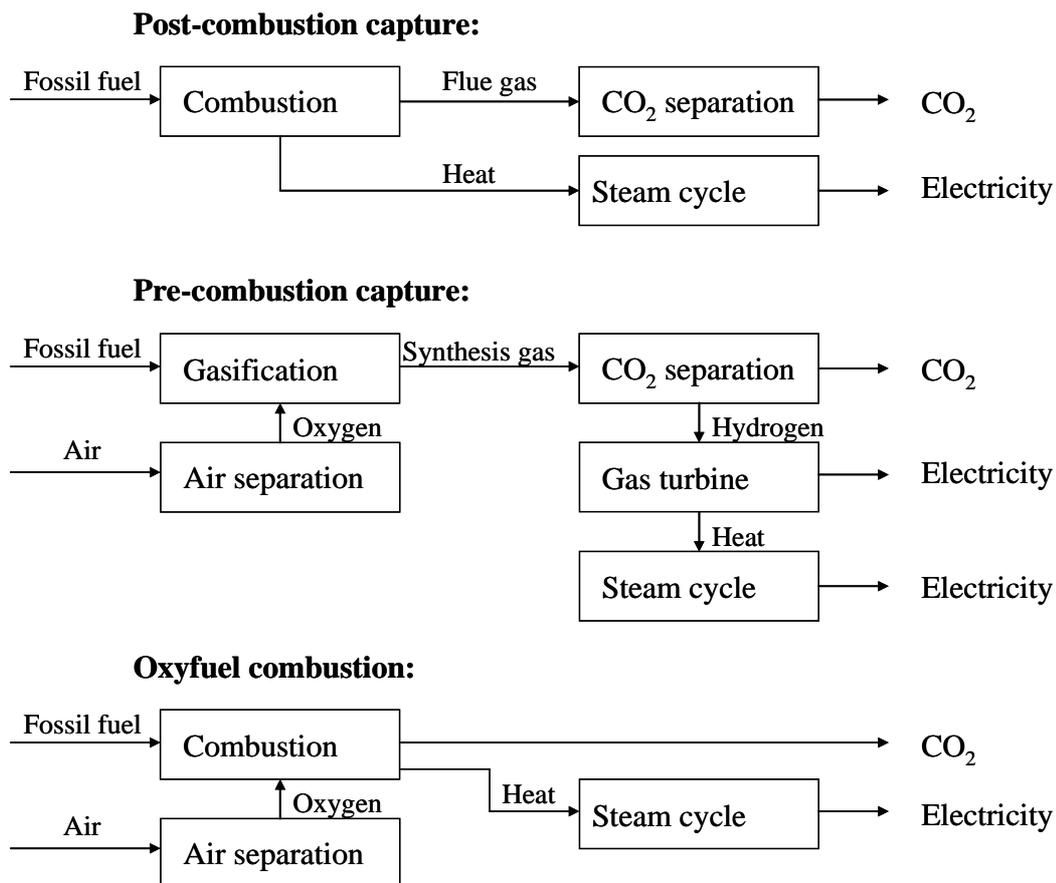


Figure 2-1: Simplified process diagram of the main CO₂ capture approaches

Table 2-2: Medium to large-scale coal-fuelled power plant projects with CO₂ capture (source: derived from /112/)

Project name / project leader	Location	Capacity [MW]	Expected start-up	CO ₂ capture technology
ZeroGen	Australia	50	2010	Pre-combustion capture
Hydrogen Energy (BP & Rio Tinto)	Australia	500	2014	Pre-combustion capture
GreenGen	China	250	2018	Pre-combustion capture
Dynamis - Hypogen	Europe	250	2012	Pre-combustion capture
RWE	Germany	400-450	2014	Pre-combustion capture
Vattenfall	Germany	250	2020	Oxyfuel
Progressive Energy	UK	800	2011	Pre-combustion capture
Powerfuel	UK	900	Post-2012	Pre-combustion capture
E.On	UK	450	Post-2012	Pre-combustion capture
E.On	UK	2x800	2015	Post-combustion capture
RWE nPower	UK	1,000	2016	Post-combustion capture
Carson Project	USA	500	2011	Pre-combustion capture
FutureGen	USA	275	2012	Pre-combustion capture

3 Methodology

Starting from the standardised methodology for LCA, this chapter introduces and discusses the application of this approach for a thorough analysis of both current and future electricity generation technologies. Starting from limitations of the LCA methodology and current LCA studies when facing such an objective, a methodological expansion of the LCA approach is outlined.

3.1 Life Cycle Assessment (LCA)

LCA is a conceptual framework and methodology for the investigation and assessment of the environmental impacts of a product on a cradle-to-grave basis. This approach investigates the entire product life cycle comprising the phases of production, use and disposal. Within these life cycle phases all energy and material flows are surveyed and followed from the extraction of natural resources up to the end of life treatment. The aim of this life cycle investigation is the identification and quantification of all input flows extracted from the environment (energy and material resources) and output flows to the environment (emissions and waste materials). Based on this investigation, potential environmental impacts concerning resource use, climate change, ecosystems as well as human beings are derived and assessed. This holistic approach ensures that not only the direct environmental impacts of the production processes, but also indirect impacts originating from the infrastructure, transportation processes as well as the supply of energy carriers and materials (construction materials, operating supplies etc.) are taken into account.

Table 3-1: Overview of ISO-norms relevant for LCA
(Source: /96/)

ISO Norm	Description	Year of adoption
ISO 14014	Principles and framework	1997 / 2006 (Revision)
ISO 14041	Goal and scope definition and inventory analysis	1998
ISO 14042	Life Cycle Impact Assessment	2000
ISO 14043	Life Cycle Interpretation	2000
ISO 14044	Requirements and guidelines	2006
ISO/TR 14047	Examples of application of ISO 14042	2003
ISO/TR 14048	Data documentation format	2002
ISO/TR 14049	Examples of application of ISO 14041 to goal and scope definition and inventory analysis	2000
ISO/TR 14050	Environmental management vocabulary	2002

ISO – International Organisation for Standardisation

TR – Technical Report

The methodology for the conduction of LCA studies was predominantly developed and formalized by the U.S. Environmental Protection Agency (EPA) and the Society of Environmental Toxicologists and Chemists (SETAC) in the 1990s /1/. Promoted by several SETAC workshops on different aspects in LCA between 1990 and 1993 both in Europe and North America, the LCA methodology was summarised and codified in the SETAC publication ‘Guidelines for Life Cycle Assessment – A Code of Practice’ /2/. This structuring together with

the authority and credibility of SETAC, which in its management board is equally composed of researchers from academia, industry and governmental organisations, paved the way for international standardisation. From 1997 to 1999 delegates from 24 countries and observers from further 16 countries prepared four standards, ISO 14040 to ISO 14044, for the methodology of LCA /3/. In the following years up to now, this ISO series of four norms on LCA was complemented by further standards and technical reports as shown in Table 3-1.

3.2 Life Cycle Assessment Methodology According to ISO 14040 Series

The norm series ISO 14040 to ISO 14044 of the International Organisation for Standardisation (ISO) provides a standard framework on how to perform LCA studies. In ISO 14040, LCA is defined as the compilation and evaluation of the inputs, outputs and potential environmental impacts of a product system throughout its life cycle /4/. In this context the term 'product' is used in a comprehensive understanding representing any goods or service. The modelling of the product life cycle by a network of unit processes (with elementary and product flows) is referred to as product system. Figure 3-1 gives an example of such a product system according to ISO 14041.

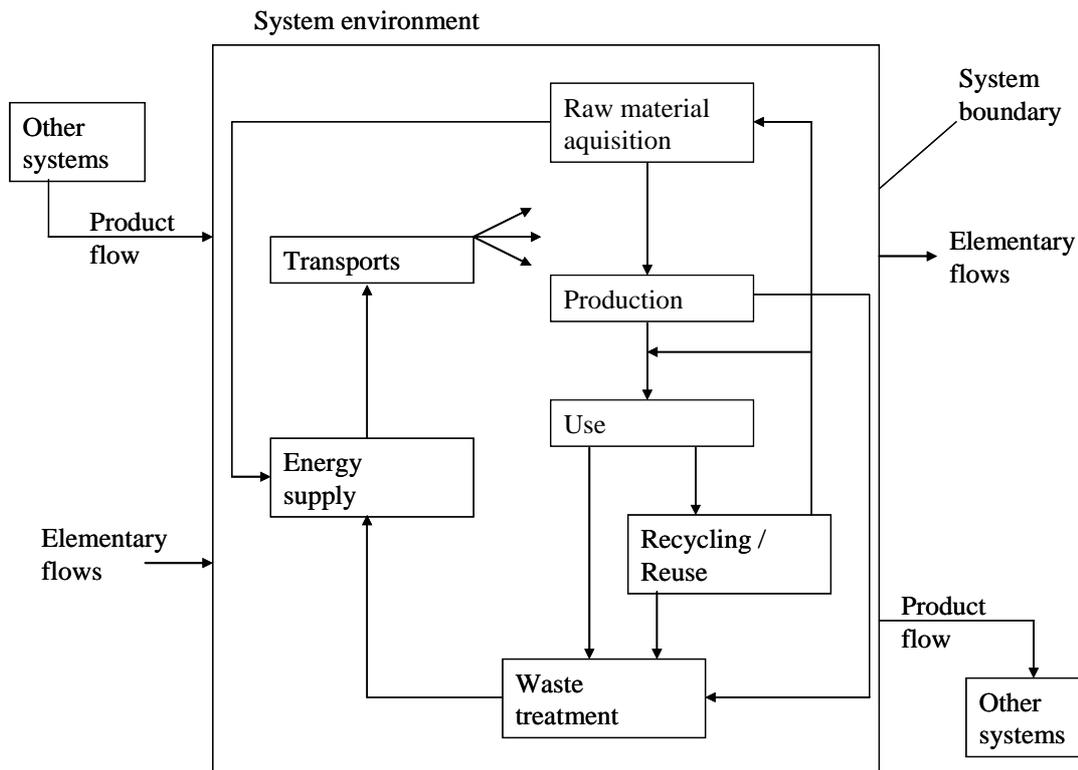


Figure 3-1: Product system according to ISO 14041
(source: /5/)

In an LCA study, all data and results are expressed in reference to a functional unit, which gives a description and quantification of the function of the investigated product system. In case of electricity generation this functional unit is typically defined as one unit of busbar electricity,

which is one kilowatt-hour of electricity generated and delivered to the grid (kWh_e). Consequently, data on material and energy demand, on release of emissions and on potential environmental impacts are aggregated over the entire product life cycle and finally allocated in reference to this functional unit (e.g. CO₂ emissions / kWh_e).

According to ISO 14040 an LCA study comprises four steps, as illustrated in Figure 3-2 /4/. Starting from a goal and scope definition, input and output flows of the investigated product system are identified and quantified in the step of Life Cycle Inventory (LCI). Based on these flows, the potential impact of the product system on the environment is evaluated (Life Cycle Impact Assessment – LCIA). Finally the results of the hitherto existing analysis are interpreted in relation to the objectives of the study (Life Cycle Interpretation).

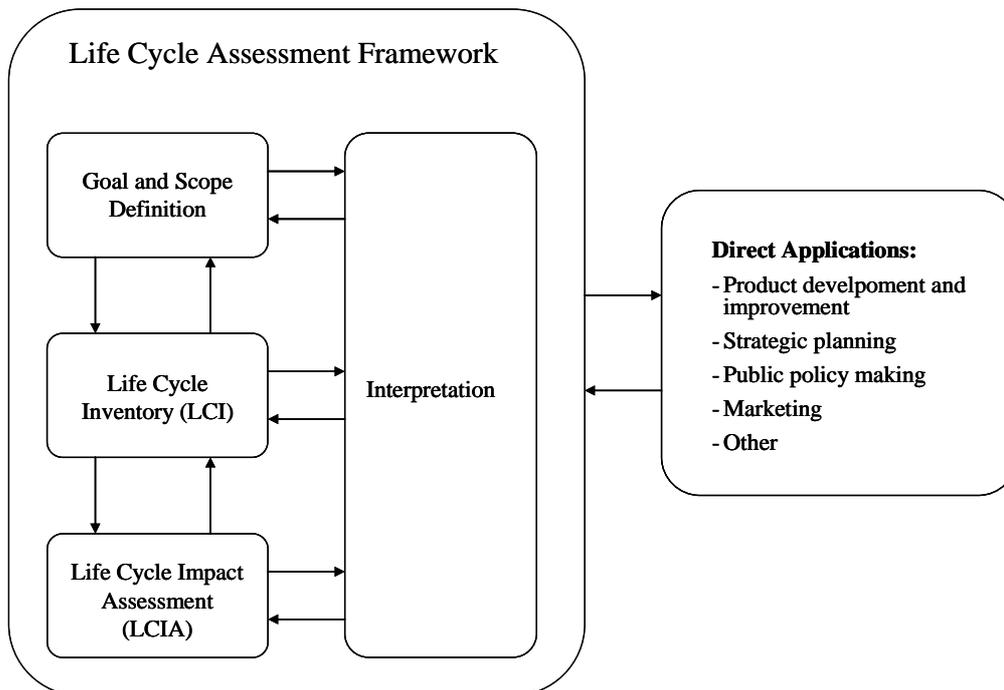


Figure 3-2: Steps of an LCA study according to ISO 14040
(source: /4/)

The arrows in Figure 3-2 illustrate that the individual steps are interrelated to each other. This means that the workflow of an LCA study, which is done in the above mentioned order of life cycles phases, constitutes an iterative process. Comparable to a learning process, results in later steps of an LCA study can have an influence on previous steps. Information revealed during the course of the study, may impose a revision of earlier steps.

3.2.1 Goal and Scope Definition

In this first step of an LCA, which is specified in ISO 14041, the aim of the LCA study as well as all assumptions concerning the following investigation of the product system are outlined /5/.

On the part of LCA practitioners there is growing consensus that there are basically two types of LCA studies with different aims /9/ /10/ /11/ /12/ /13/ /14/ /15/ /16/. These studies are referred to as 'attributional LCA' and 'consequential LCA', which as terminology was coined in 2001 at a

workshop on LCI electricity data in Cincinnati /128/. Sometimes, however, also the terms ‘accounting, descriptive or retrospective LCA’ and ‘change-oriented or prospective LCA’ appear.

According to /15/ an attributional LCA aims at investigating the current state of a product system by describing the environmentally relevant physical flows to and from the product life cycle and its subsystems. In contrast, consequential LCA investigates the effect of changes within the product system on the LCA results. An LCA study on hard-coal-fired electricity generation would be an attributional LCA, whereas the investigation of the changes made to this system by the integration of carbon capture technology would represent a consequential LCA.

After the specification of the type of the LCA study, a clear and unambiguous formulation of the research question is identified including a specification of the investigated product system. Geographic and temporal boundaries of the product system as well as its functional unit are defined. Furthermore it is settled, which processes over the life cycle are included or excluded from the study. Depending on the goal, the LCA practitioner may decide to for instance exclude the end-of-life phase of the product system (as it is done in several studies). Processes, which are expected to make negligible contribution to the overall results, can be excluded from the system boundaries. ISO 14041 recommends defining cut-off criteria for processes, which contribute to less than a defined percentage to the investigated inventories /5/. These cut-off criteria have to be separately defined and applied for the individual energy and material resources as well as for the individual emissions released.

After characterisation of the product system, the inventories (input and output flows) as well as the environmental impact categories are determined that are to be analysed in the course of the LCA study. Since LCA is intended to investigate all attributes and aspects of environment, human health and resource use /4/, ISO 14041 and ISO 14042 recommend the selection of inventories and environmental impact categories to be done in orientation to the aim of the study /5/ /6/.

3.2.2 Life Cycle Inventory (LCI)

The LCI identifies and quantifies all input and output flows of the investigated product system. In this step the extraction of material and energy resources, all energy and material flows as well as the release of emissions into air, water and soil are systematically collected, aggregated over the entire life cycle of the product and finally allocated in reference to the functional unit.

For this data survey ISO 14041 recommends the generation of a process flow diagram /6/, which is commonly done by the methodology referred to as ‘process chain analysis’ /11/ /13/ /17/ /18/. Thereby the life cycle of the investigated product is subdivided into a chain of sub-processes, which characterise the product system and illustrate contributions from all life cycle phases. The system boundaries defined in the goal and scope definition determine which processes are to be included in the investigation.

The process network of such a process chain analysis is commonly pictured in form of a process flow diagram, which has the shape of a tree with several branches. Figure 3-3 shows such a process flow diagram exemplified for the generation of electricity in a fossil fuelled power plant. The tree top represents the final output of the investigated process, which in Figure 3-3 is the generated kilowatt hour of electricity (kWh_e).

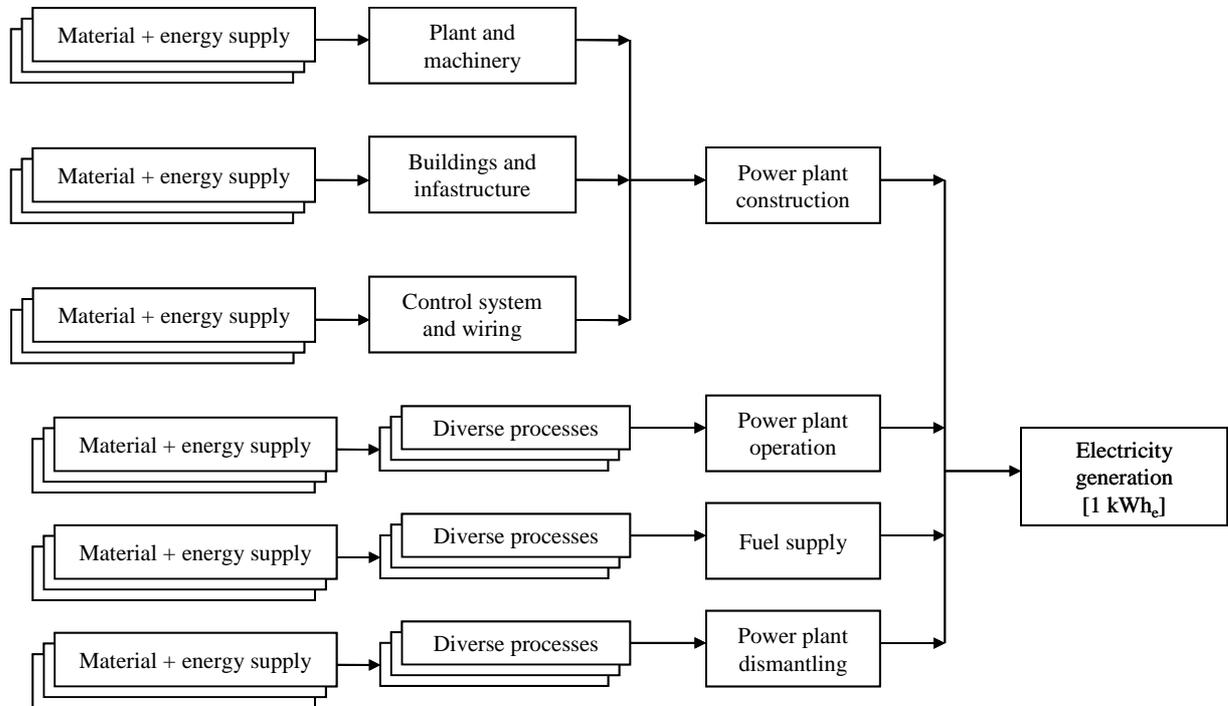


Figure 3-3: Simplified process flow diagram at example of electricity generation in a fossil fuelled power plant

In a process chain analysis, all processes within the investigated product system are subdivided into sub-processes as long as all branches of the tree end up with elementary flows. This means, the only input flows entering the system boundaries in a fully elaborated process chain analysis are material and energy resources, the output flows solely are emissions.

The individual processes in such a fully developed process chain can be generically characterised as shown in Figure 3-4. The shown process inputs are materials and energy resources, which are referred to as elementary flows, and secondly intermediate products. Intermediate products constitute the interconnections between the individual processes and are pictured as arrows in the process tree. This means all intermediate products at the same time constitute both process inputs and process-outputs of other processes. When moving along a process tree, it can be followed at which processes the intermediate products have been manufactured or transformed from other intermediate products and elementary flows. Finally, each intermediate product can be traced back to its basically constituting material and energy resources. When following the process tree in the other direction, more and more branches join until the tree top is reached. This tree top represents the final process of the product system, at which the final product is generated.

In the step of LCI all flows shown in Figure 3-4 including the output flows, which are released as emissions into air, water and soil, are identified and quantified for each process of the considered

product system. A fully elaborated and quantified process chain analysis finally highlights to what extent each process of the process chain contributes to the overall emissions as well as the energy and material demand of the product system.

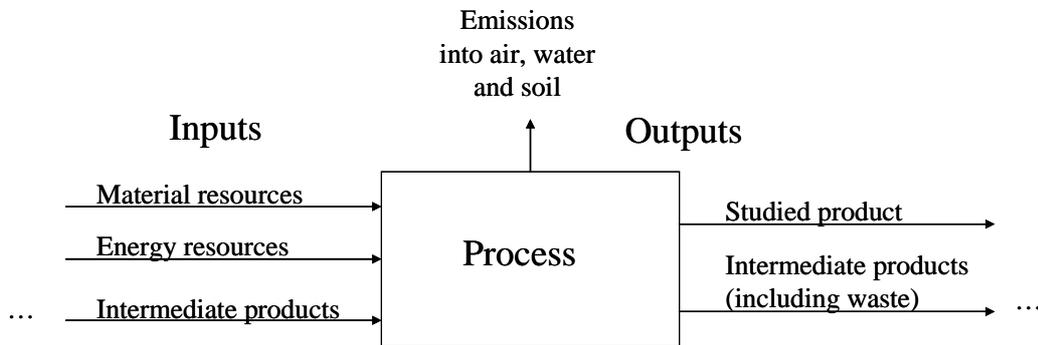


Figure 3-4: Simplified illustration of a generic process within a process flow chain analysis

3.2.3 Life Cycle Impact Assessment (LCIA)

Subject of the LCIA is the evaluation of the magnitude and the significance of potential environmental impacts that are caused by the investigated product system.

According to ISO 14043 an LCIA is made up of three mandatory steps /6/. Starting point is the selection of environmental impact categories that are to be investigated within the LCA study (first step). Based on this choice, the input and output flows from the LCI (quantified elementary flows and release of emissions) are assigned to those impact categories they are contribution to (classification – second step). Thereby it is possible that some flows contribute to more than one impact category. Each environmental impact category is characterised by a reference substance and the impact, which is caused by one unit of this reference substance. The environmental impact category ‘global warming potential’ (GWP) for instance is characterised by the reference substance CO₂ and the global warming potential, which is caused by one kilogram of this substance. The contribution of other substances to the GWP is expressed by quantification of their global warming potential in relation to the reference given by CO₂. This is done by so-called conversion factors, which convert greenhouse gas emissions into CO₂-equivalents. This characterisation of environmental impact categories based on reference substances and the quantification by means of conversion factors can be followed in Table 5-2 in chapter 5.1.3 of this study. For the overall quantification of an environmental impact category, all contributing substances are converted into the damage relation of the reference substance and finally added up. This third and final step of an LCIA is referred to as ‘conversion’.

3.2.4 Life Cycle Interpretation

In this concluding step of an LCA study, the results of the LCI and the LCIA are discussed, conclusions are drawn and recommendations are made. The final task of the life cycle

interpretation is the publication of a readily understandable, complete and consistent presentation of the LCA results in accordance with the goal and scope definition of the study /7/.

3.3 LCA of Electricity Generation Technologies (EGTs)

The environmental performance of electricity generation significantly varies between different EGTs. This variation appears not only in terms of the type and the amount of emissions released and resources used, but also the contribution from the individual life cycle phases is very diverse. The operation of wind, water and photovoltaic power plants is practically free of emissions into air, quite contrary to the electricity generation from hard coal, lignite, natural gas and biomass, which features significant emissions. However, there are emissions assigned to electricity from wind, water and solar energy, which arise from the construction and dismantling of the associated power plants /129/. In case of nuclear electricity generation, the supply of uranium and its processing to fuel elements has to be taken into account beside the construction and dismantling of the nuclear power plant /19/ /20/ /21/.

This indicates that a comparison of the environmental performance of different EGTs is only feasible when referring to the entire life cycle. The approach of LCA ensures such a holistic view as well as analysis and thus facilitates a comparison between different EGTs.

3.3.1 Emissions over the Life Cycle

Electricity generation involving combustion processes (electricity generation based on hard coal, lignite, natural gas, biomass etc.) is generally associated with emissions into air that are generated during the operation of the power plant and are usually released from a stack at the power plant site. These emissions are referred to as direct emissions. All other emissions released over the life cycle are summarised as indirect emissions. These include all emissions, which are released during the life cycle phases of the construction and the dismantling of the power plant. Also emissions along the supply of construction materials and transport services contribute to these indirect emissions.

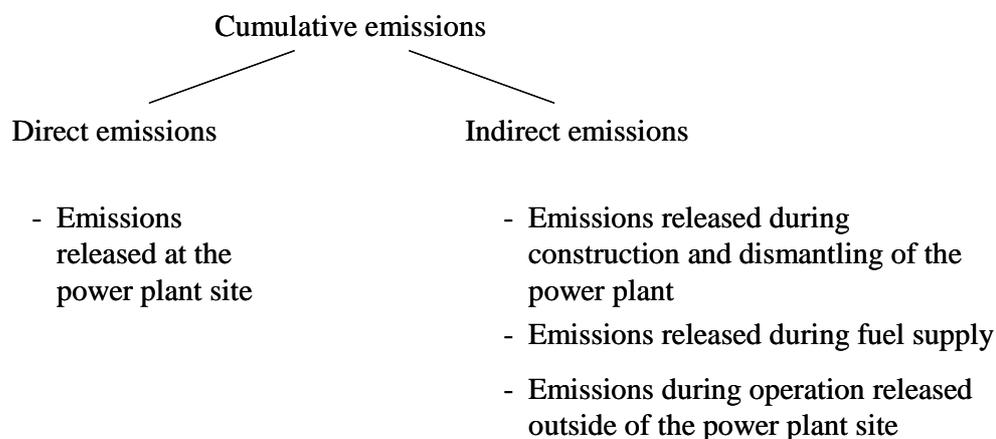


Figure 3-5: Emissions over the life cycle of electricity generation

Further indirect emissions stem from all processes during power plant operation, which cause the release of emissions at locations different from the power plant site. For EGTs based on hard coal, lignite, natural gas, biomass, uranium etc. the fuel supply is a significant source of indirect emissions. Less indirect emissions originate from the supply of operating supplies and spare parts during the power plant operation.

The sum of direct and indirect emissions represents the emissions, which are released over the life cycle of electricity generation. In this study these aggregated life cycle emissions are termed as ‘cumulative emissions’, as shown in Figure 3-5.

3.4 Introduction of the Methodological Concept of this Study in Contrast to Limitations and Problems of Existing LCA Studies

There are plenty of studies on LCA of EGTs, among them /18/ /19/ /22/ /23/ /25/ /26/ etc.. These studies are based on sound scientific work and are well documented. However, it is often difficult or even impossible to compare their LCI and LCIA results. This is due to limitations, which LCA studies on EGTs inherently feature. Figure 3-6 gives an overview of such limitations, whereas it is basically distinguished between methodological and study-specific limitations. Both sources for limitations are to be avoided or reduced by application of the methodology outlined in this study.

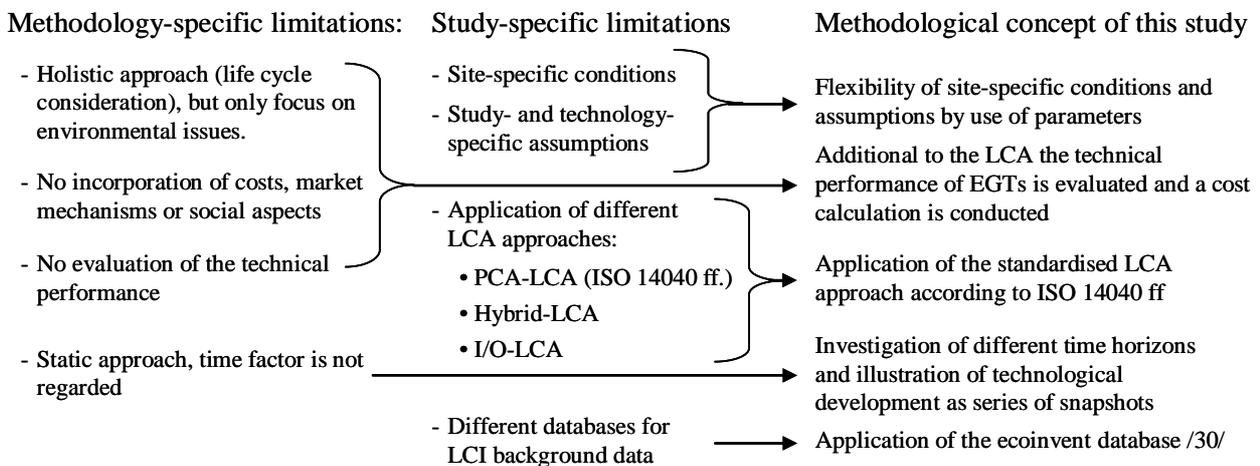


Figure 3-6: Methodological concept of this study aiming at reducing limitations of LCA studies

The methodology of LCA is a holistic approach in terms of analysing the entire life cycle of a product system. However, the content of investigation is restricted to environmental aspects and impacts only. Other fields are not accounted for in an LCA study, as for instance economic issues, social aspects /4/ /13/ or technical performance /13/ /18/ /31/. Thus, for a more thorough evaluation of EGTs this study includes a cost calculation and an analysis of technical aspects additionally to the LCA.

A further methodological limitation of LCA is being a steady-state rather than a dynamic approach /13/. The investigation of a product system is always bound on a specific location and time. The time horizon considered in most studies is the present situation. However, there are an increasing number of prospective studies investigating future technical concepts, as for instance /22/ /23/ /24/ and /26/. These studies present single snapshots of future time horizons. This study follows this snapshot approach, but intends to go further in giving a series of snapshots on future time horizons in order to picture an outlined technical development like a flip-book.

The other part of limitations is study-specific. As LCA studies are conducted for individual locations, there are differences in site-specific conditions. This aspect of being place bound is to be overcome in this study by the possibility to vary site-specific conditions by means of parameters. This parametrisation approach is also intended to facilitate modifications in assumptions on technical specifications of the investigated product systems in LCA studies.

In general, the LCI and LCIA results on EGTs strongly depend on the frame conditions, which exist or are assumed for the investigated product system. The capacity, efficiency, load factor (full load hours) and technical life time of the analysed technology are only some parameters with considerable influence on the results. Furthermore, local conditions like the characteristics of the used fuel alter the outcome of an LCA study, as investigations of fuels originating from different countries show /28/ /29/.

The application of parameters within LCA, as elaborated in this study, allows LCA studies to be flexibly adapted to different conditions in terms of place, technological configuration and general assumptions. With appropriate modification of parameters also the consideration of different time horizons can be achieved. Furthermore, if such a parameter modification is done in terms of adjusting or matching the frame conditions and assumptions of other LCA studies on similar EGTs, a proper comparison of LCI and LCIA results is facilitated. Such a comparison to LCA results of other studies is illustrated in chapter 7.1 and chapter 7.2 for the results of this study.

A study-specific limitation not able to be overcome is the use of different databases for LCA background data. In almost all LCA studies the LCI data of basic processes within the investigated product system are taken from different LCA databases. Table 11-1 in the annex gives an overview of currently existing databases for LCA background data. As in most LCA studies only aggregated results are published without given insight in the detailed process flow diagram, it is only seldom possible to substitute the processes, which have been taken from a LCA background database, by LCI data from other databases.

Finally, the use of different LCA approaches is a study-specific limitation often contributing to major discrepancies in LCI and LCIA results /21/ /32/ /129/. Starting from standard LCA approach according to ISO 14040ff, a variation of the results by 5-73 % /32/ is reported for the application of the hybrid LCA approach. The use of a third LCA approach being solely based on an economic input/output analysis, which is referred to as EIO-LCA, causes even more discrepancy in the LCA results. Here, deviations by 30-100 % /27/ or even 300-2,000 % /21/

have been observed. These different approaches for LCA are shortly characterised in the following chapter.

3.4.1 LCA (ISO 14040 ff.) and Hybrid-LCA

The standardised LCA approach according to ISO 14040 ff. entails a slight underestimation of the real situation in its LCI results /33/ /32/ /27/. This is due to the aspect that cut-off criteria are defined, which exclude processes from the product system that are of negligible relevance for the overall results. In order to compensate for this limitation due to the definition of the system boundary and in order to face the often observed shortage of reliable data on processes in LCA studies, the approach of EIO-LCA was developed /32/ /34/. EIO-LCA is a top-down approach, which takes the whole economy as system boundary and obtains its data from economic input-output tables /36/. These statistical data in combination with data from the environmental economic accounting (in German: Umweltökonomische Gesamtrechnung – UGR) provide information on the release of selected emissions and the use of selected resources in different economic sectors. In an EIO-LCA all processes within the process chain analysis are classified into these different economic sectors. Based on cost data of the individual processes and the sector specific environmental data, LCI data are derived. However, since the economic sectors are very unspecific, the EIO-LCA approach does not match the original goal of LCA as a precise bottom-up approach /27/ and features only rough results.

To improve the quality of the EIO-LCA results, the approach of hybrid-LCA evolved, which combines the approaches of LCA and EIO-LCA. In a hybrid LCA the statistical data from input / output-tables (I/O-tables) and UGR are used to complement processes that lack data on material flows on the one hand and to derive data for processes, which have been excluded from the product system due to cut-off criteria on the other hand /18/ /27/ /33/ /35/. This methodology promises further approximation of the LCA results to fully comprise an investigated product system, but at the same time causes new inaccuracy.

In a hybrid LCA all surveyed material and energy flows and also the processes are monetised using market prices. The price of all process inputs is compared to the price sum of its material and energy flows. The revealed price difference is accounted for by statistical information from I/O-tables and UGR, which is added to the LCI data /18/ /33/ /35/. This proceeding, however, involves uncertainty due to possible double counting of LCI data, which was firstly taken into account in the material survey and secondly regarded within the statistical information of I/O-tables and UGR /21/ /27/ /32/. Furthermore, the attribution of prices to the surveyed flows is involved with some uncertainty. And finally, a limiting factor is that information from I/O-tables and UGR is only available for selected emissions and resources, which makes an investigation of the bulk of possible inventories unable to be investigated in a hybrid LCA.

Leading projects investigating current and future EGTs at national and international level, as for instance /26/ /43/ /55/ /42/ /56/, apply the approach of LCA according to ISO 14040 ff. This

approach clearly specifies the release of emissions and the resource use of each process over the process chain. This generation of accurate and detailed results is especially important in LCA studies on those EGTs, which feature cumulative emissions and resource use mainly from the construction of the power plant and other use of infrastructure (electricity generation from wind, solar and water power). The accuracy in LCA results is further promoted by the existence and continuous development of LCA background databases /27/.

In line with the recent projects of the European Commission on LCA of EGTs, in this study the LCA methodology according to ISO 14040ff is applied.

3.5 Methodology Expansion to Parametrised LCA

In order to overcome some of the limitations of current LCA studies, which have been outlined in chapter 3.4, the approach of 'Parametrised LCA' (P-LCA) has been developed in this study. The following sections of this chapter give an introduction of P-LCA and discuss this methodology in differentiation to other scientific concepts in this field. The examples given within the following sections for the application of P-LCA refer to investigations of fossil fuelled EGTs.

3.5.1 Structure and Concept, Objectives and Features of P-LCA

The innovative feature of P-LCA is the possibility to modify assumptions and technical settings within the process chain of an LCA study, whereas the impact of this modification on the individual processes and finally on the entire product system is automatically calculated. Prerequisite for this approach is the modelling and mathematical quantification of all material and energy flows within the investigated product system by mathematic formulae. These formulae contain parameters, which have been elaborated in order to illustrate and quantify influence factors on the respective material and energy flows. Furthermore, these parameters facilitate to model coherences and interrelations to other flows and processes within the investigated product system.

The application of parameters allows investigating technologies in a much broader field of application. By modification of the numerical values standing behind the parameters it is possible to illustrate different site-specific conditions and different technical performances of a technology within the same process chain analysis. This, as another significant benefit of P-LCA, enables comparisons of LCA results from different studies. Often LCA studies on similar technologies show considerably deviating results, which is due to different frame conditions within the investigated product systems. By adaptation of the parameters in order to reach compliance to assumptions and technical settings of the compared LCA study, similar frame conditions can be approximated as prerequisite for a proper comparison.

This flexibility due to parameter modification makes P-LCA appropriate for sensitivity and uncertainty analyses as well as for estimative LCA. Especially the possibility for sensitivity

analyses is to be highlighted, as this supports the gain of knowledge on coherences and parameter relevance already during the conduction of an LCA study.

3.5.2 Scenario Modelling in Prospective LCA Studies

The investigation of technology development and future technical concepts is topic of an increasing number of LCA studies. This highlights the importance to provide timely information on the environmental performance of innovative technologies for decision makers in industry and policy. However, the necessity to anticipate future developments confronts the LCA practitioner with a particular challenge, as there are mostly no reference system and data available. This data problem is tackled in most prospective LCA studies by the development and investigation of scenarios, which embed the investigated technology into assumptions and frame conditions of a future time horizon. Ekvall illustrates this approach by his recommendation to apply scenario modelling for the investigation of uncertain or prospective developments as well as assumptions in LCA /14/. From these scenarios finally LCI data for the investigated future technology can be derived.

In 1998, the SETAC responded to the first applications of scenario modelling within prospective LCA studies by launching of the Working Group 'Scenario Development in LCA'. This working group set out to find possible solutions for problems arising from the conduction of prospective LCA. Starting point of the collective work was the development of procedures for modelling those parts of product systems, which are unknown, uncertain or ambiguous due to several alternatives /47/. The outcome of the first working phase was published in the report 'Scenarios on Life-Cycle Assessment' in 2004 /48/. Therein basic definitions and principals of scenario modelling were introduced, at which also the scenario methodology applied in this study is oriented. One fundamental reference is the definition of the term 'scenario in LCA studies', which according to the SETAC working group is the description of a possible future situation relevant for specific LCA applications based on specific assumptions about the future and (when relevant) also including the presentation of the development from the present to the future /48/.

Such scenarios are basically subdivided into so-called 'What-if-scenarios' and 'Cornerstone-Scenarios', as pictured in Figure 3-7. The scenarios within this study correspond to the category of cornerstone-scenario, which according to /47/ includes investigations of open research plans on complex objects featuring different alternatives in terms of design and development. The central intention of cornerstone-scenarios is to gain knowledge on the environmental performance of an object in order to provide strategic information to decision makers.

Research problems, which appear more specific and cover a short to medium time horizon, are usually modelled in 'What-if' scenarios /47/.

Within the two basic scenario approaches shown in Figure 3-7, the SETAC Working Group 'Scenario Development in LCA' distinguishes three types of scenario applications: Technology scenarios, which are developed within the LCI, as well as environment and valuation scenarios,

which are developed in the LCIA /47/. According to this definition the scenarios within this study can be clearly categorized as technology scenarios.

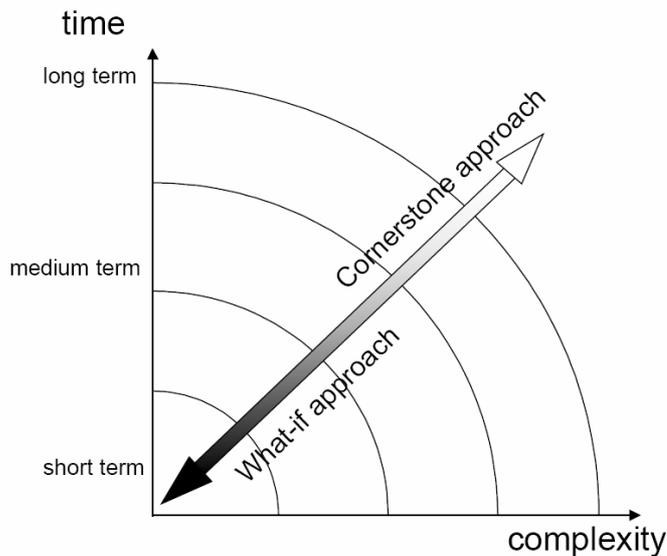


Figure 3-7: Two basic approaches to scenario development at LCA research

3.5.3 Application of P-LCA in Scenario Modelling of Future Energy Technologies

The approach of scenario modelling is applied in several representative prospective LCA studies on the future development of energy technologies, as for instance in /37/ and /38/ investigating future fuel cell systems or in /26/ and /42/ analysing different future EGTs. However, in these studies, the scenario modelling is done for only one specific future time horizon, which in /26/ /38/ /42/ is the year 2010 and in /37/ is the year 2020. Even if LCA methodology investigates the entire life cycle of a technology, the investigation done in these studies still represents a snapshot of one stage of technological development at one particular time horizon. However, only a series of snapshots will be able to sketch technology development over time. This methodology of providing snapshot series of most important steps of technology development is already inherently implemented within the scenario definition of the SETAC working group on scenarios within LCA /47/. Therein the description of the evolution from present conditions to future time horizons is explicitly mentioned as possible element of a scenario. However so far, this extended scenario approach has been applied only in retrospective LCA studies. In /38/, for instance, the evolution of a technology up to its present state is illustrated by providing an LCA snapshot series of most important steps of technological development.

As a first step directing to the investigation of future technology development in LCA, recent prospective LCA studies embark upon investigating future technology development over more than only one time horizon, as for instance /22/ /23/ /43/. This is a new dimension in prospective LCA studies on future energy technologies, as different scenarios have to be modelled. Especially the project 'New Energy Externalities Development for Sustainability' (NEEDS) /43/ within the sixth framework program of the European Commission sets new standards in using scenarios within prospective LCA. It investigates the future development of EGTs from today by the time horizons 2025 and 2050, thereby analysing three technology scenarios for each of these

time horizons. These scenarios within ‘NEEDS’ illustrate diverse drivers and frame conditions, which involve different velocities of technical development of EGTs by 2025 and 2050. Such an LCA investigation of different scenarios requires a profound and flexible modelling of the process chain of EGTs. To meet this need, the methodology of P-LCA was developed and successfully established within the contribution of the Institute of Energy Economics and the Rational Use of Energy (IER) to the project ‘NEEDS’.

3.5.4 Parametrisation Methodology in the Scientific Discussion

Several LCA studies on future technology concepts call for flexible process chain analyses in order to incorporate the multitude of changes in technology development over time.

- Hillman emphasizes the importance of including time- and scale-related factors in prospective LCA studies /24/ /52/.
- Spielmann highlights the importance of scenario modelling in prospective LCA and elaborates examples for the investigation of transport systems /44/. This scenario development is based on parameters.
- Hellweg applies scenario modelling in order to take time and site dependency of the LCA results on thermal waste treatment processes into account /46/.
- Pehnt shows the necessity and relevance of a dynamic LCA in his investigation of renewable energy technologies over future time horizons /22/. In different scenarios he investigates improvements of both the technologies and the background system and applies parameters to characterise changes between the scenarios.
- Not for prospective, but for comparative LCA the application of parameters is shown by Cooper /45/, who calculates reference flows for comparable alternatives, which can be regarded as different scenarios.

In the study of Spielmann, Pehnt and Cooper parameters are used for scenario characterisation. However, they are not integrated in the process chain analyses of the LCI. The approach of P-LCA on the other hand puts this parameter integration into practice and enables a more flexible scenario modelling in prospective LCA.

The use of parameters within the methodology of LCA is not new, but was already applied by Mueller /41/. He describes the generic principle of parameter integration into an LCI. Thereby he outlines the use of parameters for improved data management and calculation as well as for approximate LCA. As example of this approach he presents LCI studies for applications in the car industry. In his calculations design parameters of components are used as input into formulae for the calculation of LCI data. The idea of this approach is basically comparable to the approach of P-LCA. This is as Mueller takes responsibility for all parameter applications within LCI by emphasizing that the use of parameters is not restricted to his design parameters, but possible for any user-defined quantitative and qualitative specification /41/. However, the scope of P-LCA is targeted at flexible scenario modelling in prospective LCA rather than on the application within

comparative LCA on product alternatives with different design. This gets obvious when looking at the different ways of parameter application in P-LCA, which are introduced in the following sections and methodically exceed Mueller's approach.

3.5.5 Integration of Parameters into the Process Chain Analysis

For more flexible calculation of LCI data, parameters are integrated into the process chain analysis of an investigated product system. Parameters in this context represent any user-defined specification, which is of interest of being modified in an LCA study.

How this integration is done, is displayed in Figure 3-8. The processes within a process chain analysis are interconnected by energy and material flows, which are represented by arrows. In conventional LCI these flows are quantified by absolute numbers. In P-LCA, however, this quantification is done by numbers, which have been calculated from parametrised formulae displayed by f_1 to f_6 in Figure 3-1. Therein the letters a,b,c,d etc. represent parameters, which are involved in the calculation of flows. A special case is f_6 , which is a function without parameters and thus represents the conventional way of flow quantification by an absolute number.

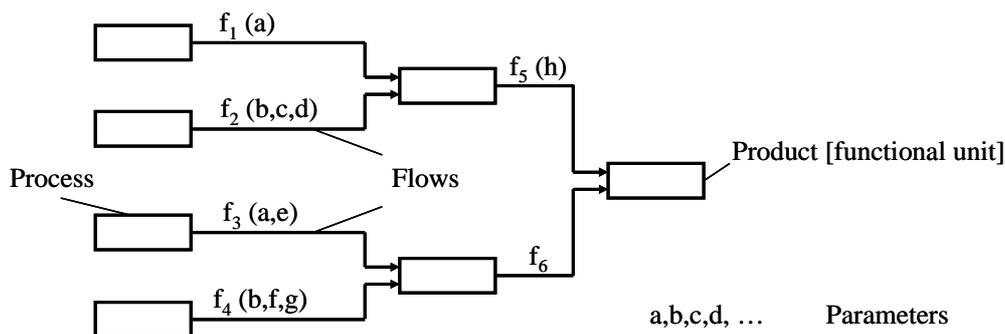


Figure 3-8: Parametrised formulae in a process flow diagram of P-LCA

It is obvious that the generation of a framework of parametrised formulae is laborious to be initially generated, but this effort will be paid back in the further application of the parametrised process chain analysis. Once parametrised formulae are established, the calculation of LCI data is automated and can be easily adapted to different parameter specifications. A modification of the numerical values behind the parameters entails an immediate recalculation of the entire process chain and updates all LCI data. This means that for both each individual process and the entire product systems the influence of a modification is immediately highlighted by revised results for the considered material and energy flows, extraction of natural resources and emissions release. Such an update finally also refers to the results of the LCIA. The aspect, that parametrisation affects not only the phase of LCI but also the LCIA, is the reason to name this methodology P-LCA instead of P-LCI.

The application of parameters within the process chain of an LCA simplifies the calculation of LCI data, which also was the main driver for Mueller to develop his parametrisation approach /41/. Furthermore, P-LCA makes the calculation more flexible. It enables to perform quick and

straightforward revisions of the LCA results in order to take changes in assumptions and technical specifications into account or to perform sensitivity analyses on the significance of singular parameters.

Finally, it is to be highlighted that the integration of parameters solely complements the calculation within LCA, but does not change the fundamental LCA methodology, so that the approach of P-LCA still is in accordance to the standards of ISO 14040ff.

Parameters in the P-LCA of this Study

The parameters within P-LCA can be distinguished into input parameters and system parameters. Input parameters are quantified by the user and thus are those parameters, which can be modified. System parameters on the other hand cannot be influenced by the user, but are automatically calculated from the information given by the input parameters. A selection of input and system parameters that are integrated in the investigated product systems of EGTs in this study are shown in Table 3-2 and Table 3-3.

Table 3-2: Selected input parameters within P-LCA on EGTs in this study

Input parameters	Shortcut
Electric net capacity	$P_{el,Net}$
Electric net efficiency (LHV)	$\eta_{el,Net}$
Penalty of the electric net efficiency due to	
- Energy demand of auxiliary systems	$effpen_{Net,el, auxiliary\ systems}$
- CO ₂ capture	$effpen_{Net,el, CO_2\ capture}$
Load factor	α
Technical lifetime of	
- Power plant	$LT_{Power\ plant}$
- Individual components	$LT_{Component}$
CO ₂ capture rate	CO ₂ Capture rate
Fuel characteristics	
- Lower heating value	$LHV_{Steam\ coal}$
- Ash content	c_{Ash}
- Sulphur content	$c_{Sulphur}$
Transport distances	d_x
Pressure loss in CO ₂ pipeline	$\Delta p_{Pipeline}$
Depth of CO ₂ injection	$d_{CO_2\ injection}$
Overpressure for CO ₂ injection	$p_{Overpressure\ CO_2\ injection}$

Generally, it is not possible to define all parameters as input parameters. This gets apparent, when looking at equation 3-1, which describes the calculation of the electric gross capacity of a power plant.

$$P_{el,Gross} = \frac{P_{el,Net}}{\eta_{el,Net}} \cdot \eta_{el,Gross} = \frac{P_{el,Net}}{\eta_{el,Net}} \cdot \left(\eta_{el,Net} + \text{effpen}_{Net,el,auxiliary\ systems} \right) \quad (3-1)$$

If in this equation the three parameters $P_{el,Net}$, $\eta_{el,Net}$ and $\text{effpen}_{Net,el,auxiliary\ systems}$ are available as input parameters, the fourth parameter, in this case the electric gross capacity $P_{el,Gross}$ will be automatically defined. This means, that not all parameters can be arbitrarily modified at the same time and thus be categorised as input parameters, but at least one parameter of this equation has to necessarily be a system parameter. Within this mathematic boundary condition of having a unique defined equation, however, the choice of the system parameter from an equation is principally flexible. In this study those parameters are chosen as input parameters, which are most commonly used and reported as technical specifications of power plants.

Table 3-3: Selected system parameters within P-LCA on EGTs in this study

System parameters	Shortcut
Electric gross capacity	$P_{el,Gross}$
Electric net capacity with CO ₂ capture	$P_{el,Net,CO_2\ capture}$
Electric gross capacity with CO ₂ capture	$P_{el,Gross,CO_2\ capture}$
Electric gross efficiency (LHV)	$\eta_{el,Gross}$
Thermal firing capacity	$P_{th,Firing}$
Cooling capacity	$P_{th,Cooling}$
Steam turbine capacity	$P_{el,Steam\ turbine}$
Gas turbine capacity	$P_{el,Gas\ turbine}$
Specific CO ₂ emission factor	Spec. CO ₂ -factor _{Steam coal}

One important aspect to be mentioned here, is, that the net and gross capacities of power plants with CO₂ capture are categorised as system parameters in this study (see Table 3-3). This is, since all mathematical calculations are established to start from power plants without CO₂-capture. The addition of capture facilities and their operation reduces the initial electrical net capacity $P_{el,Net}$ to the electrical net capacity with CO₂ capture $P_{el,Net,CO_2\ capture}$, which can be automatically calculated from the given input parameters $P_{el,net}$, $\eta_{el,Net}$, $\text{effpen}_{Net,el,auxiliary\ systems}$ and $\text{effpen}_{Net,el,CO_2\ capture}$ as shown in equation 3-2.

$$P_{el,Net,CO_2\ capture} = \frac{P_{el,Net}}{\eta_{el,Net}} \cdot \left(\eta_{el,Net} - \text{effpen}_{Net,el,auxiliary\ systems} - \text{effpen}_{Net,el,CO_2\ capture} \right) \quad (3-2)$$

3.5.6 Different Ways of Parameter Application in P-LCA

The integration of parameters in a process chain as described in the previous chapter offers the opportunity to apply parameters for different purposes. In this study basically three ways of parameter application are distinguished. Besides the calculation of flows and emissions by means of parametrised formulae, there are parameter applications secondly for the scaling of components and facilities within the product system and thirdly for the automated calculation of

transport and disposal services. These parameter applications are presented in the following sections.

Calculation of Energy and Material Flows as well as Release of Emissions

As described before, parametrised formulae are developed in order to quantify energy and material flows as well as emissions release within the investigated product system. Starting from the parameters presented in Table 3-2, some of the fundamental parametrised formulae within the process chains of fossil fuelled EGTs in this study are shown by the following equations.

First of all, the electricity, which is generated by the investigated power plant during its technical lifetime, is quantified in equation 3-3:

$$electricity_{Lifetime} = P_{el,Net} \cdot \alpha \cdot LT_{Power\ plant} \quad (3-3)$$

The electricity_{Lifetime} again is direct input into equation 3-4, which calculates the specific steam coal demand (mass) per generated kWh of electricity:

$$specific\ steam\ coal\ demand = \frac{P_{th,Firing} \cdot \alpha \cdot LT_{Power\ plant}}{LHV_{Steam\ coal} \cdot electricity_{Life\ time}} \quad (3-4)$$

The specific carbon dioxide emissions of EGTs are calculated by equation 3-5 and 3-6 distinguished in facilities with and without CO₂ capture. Equation 3-7 shows the specific CO₂ emissions, which are captured in power plants with CO₂ capture. The specific CO₂-factor of steam coal is calculated in reference to the respectively applied lower heating value of the steam coal, since the latter was chosen as input parameter in this study.

$$m(CO_2)_{without\ CO_2\ capture} = \frac{spec.\ CO_2 - factor_{Steam\ coal}}{\eta_{el,Net}} \quad (3-5)$$

$$m(CO_2)_{with\ CO_2\ capture} = \frac{spec.\ CO_2 - factor_{Steam\ coal}}{\eta_{el,Net,CO_2\ capture}} \cdot \left(1 - CO_{2,Capture\ Rate}\right) \quad (3-6)$$

$$m(CO_2)_{captured} = \frac{spec.\ CO_2 - factor_{Steam\ coal}}{\eta_{el,Net,CO_2\ capture}} \cdot CO_{2,Capture\ Rate} \quad (3-7)$$

Equation 3-7 has considerable significance for the CCS chain, as the amount of captured CO₂ defines the energy and material flows and thus the emission releases along the following CO₂ transportation.

Less than 10 % of the incombustible constituents in the steam coal leave the combustion process as slag. The rest of the incombustible constituents are released as fly ash, which subsequently is separated in electrostatic precipitators (ESP). Based on the input parameter j, which according to the type of combustion process quantifies the relation between slag and fly ash, equation 3-8 and 3-9 calculate the residues of electricity generation from steam coal.

$$mass_{Slag} = mass\ steam\ coal_{Lifetime} \cdot c_{Ash} \cdot j \quad (3-8)$$

$$mass_{Fly\ ash} = mass_{steam\ coal} \cdot c_{Ash} \cdot (1 - j) \quad (3-9)$$

The equations shown above represent some of the core parametrised formulae, which can be applied to all technologies for electricity generation from hard coal. There are many more parametrised formulae, which have to be individually developed for each investigated power plant concept and CO₂ capture technology. Since each power plant has a unique structure with individual components, also the operating supplies and spare parts during the operation are different. Thus, the parametrised formulae for these energy and material flows as well as emissions have to be tailored to the investigated power plant concept and its specifications.

Scaling of Components and Facilities

A particular challenge at P-LCA is the investigation of parameter modifications, which involve a change in the size of power plant components. An increase of the power plant capacity for instance automatically requires larger combustion chambers, heat exchangers, turbines and a change in the size of several other power plant components. In order to calculate such size changes due to modified power plant characteristics, scaling functions have been developed for each power plant component.

Starting point of scaling always is the reference material framework of a component. This reference material framework is the summary of construction materials, construction services as well as the constructive energy demand, which was balanced for the installation of a reference power plant component. In the scaling approach of this study it is assumed that for all sizes of a power plant component the composition of this reference material framework remains constant. The quantity of the materials and services within the material framework, however, will change in accordance to the size of the power plant component. Size modifications are modelled by multiplication of the reference material framework of power plant components with a scaling factor. This scaling factor is calculated by a scaling function $f_{comp}(a,b,c, \dots)$, which is tailored to the respective power plant component and comprises its most important dimensioning factors as input parameters. If the dimensioning factors for the reference case are applied as input parameters to the scaling function, the resulting scaling factor is one. For other input parameters, the scaling factor is calculated to results higher than one for up-scaling and results lower than one for down-scaling. This generic concept of scaling is illustrated in Figure 3-9.

In Table 3-4 scaling functions and their respective dimensioning parameters together with the underlying basic principles of power plant engineering are shown for selected power plant components. An extended list of scaling functions is included in Table 11-2 in the annex of this study.

The scaling approach in this study does not aim at exactly picturing the material framework of power plant components in larger or smaller sizes, but rather at giving an approximation of the construction materials, construction services and constructive energy demand required in case of modification of dimensioning factors. This investigation of changes in the infrastructure due to possible changes in future power plant configuration methodologically refers to the approach of

consequential LCA as introduced in chapter 3.2.1. Thereby it is primarily important to highlight the dimension of changes and trends that modifications have on the LCI results. A very detailed analysis of the design of modified power plant components and a precise specification of LCI results is of subordinate importance for this type of investigations.

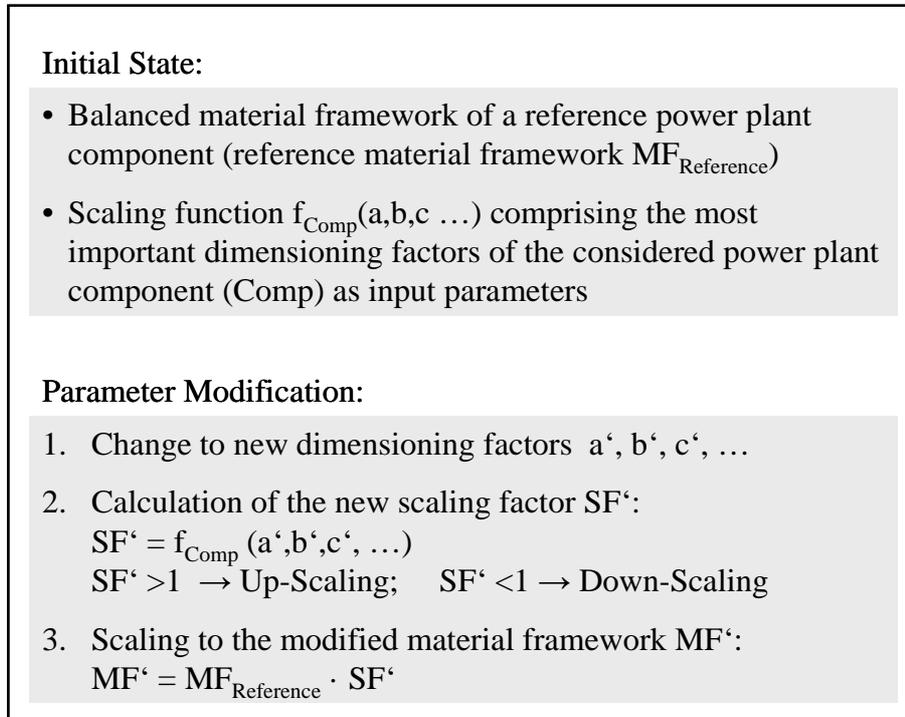


Figure 3-9: Concept of component scaling in P-LCA

The approximations, which in this study are generated by means of the developed scaling functions, feature two basic limitations. Firstly, it is not taken into account that for some power plant components changes in the dimensioning are involved with changes to other construction materials or at least with changes in the relative material composition. Secondly, it is neglected that each power plant component features a certain capacity, at which further up-scaling gets unfeasible due to technical, material or other reasons. At such a point, further increases in the capacity are achieved by the replacement of the considered power plant component by two or more components of lower capacity. These both limitations, however, are of minor relevance for the overall results provided that the scaling is not applied for excessive size modifications. In this study scaling factors always remain between 0.5 and 1.5, which corresponds to size increases or decreases of maximal 50 %.

Furthermore, the scaling approach has to be seen against the background that in hitherto existing LCA studies, either no scaling at all or scaling by linear factor multiplication has been applied. In contrast, this study introduces a scaling approach, which applies scaling at the level of power plant components with tailored, partly complex and non-linear scaling functions rather than scaling the power plant as a fixed unit. The incorporation of scaling in LCA studies is object of

current research. Caduff-Dinkel investigates different approaches of up-scaling in prospective LCA /50/. Part of this research is also economies of scale, which in accordance to some scaling factors in Table 3-4 are calculated by the relation of different power plant capacities. In a similar way, the scale-up from demonstration facilities to large-scale plants is investigated by Shibasaki in /53/.

Table 3-4: Scaling functions of selected power plant components

Power plant component (abbreviation)	Parametrised scaling function P_{Comp} with $Comp \in \{\text{SteamG, Gen, ST, ...}\}$	Basic correlation to power plant engineering
Steam generator (SteamG)	$f_{\text{SteamG}} = \frac{P_{th, \text{Firing}}}{P_{th, \text{Firing}, \text{reference}}}$	Constant heat flow density in heat transfer systems
Steam generator house (SteamGH)	$f_{\text{SteamGH}} = \sqrt[3]{\frac{P_{el, \text{Steam turbine}}}{P_{el, \text{Steam turbine}, \text{reference}}}}$	Constant heat flow density in heat transfer systems. Surface of building corresponds to the squared cube root.
Steam turboset (SteamTS)	$f_{\text{SteamTS}} = \sqrt{\frac{P_{el, \text{Steam turbine}}}{P_{el, \text{Steam turbine}, \text{reference}}}}$	Constant steam flow per cross-sectional area
Condenser (Cond)	$f_{\text{Cond}} = \frac{P_{th, \text{Cooling}}}{P_{th, \text{Cooling}, \text{reference}}}$	Constant heat flow density in heat transfer systems
Generator (Gen)	$f_{\text{Gen}} = \frac{P_{el, \text{Gross}}}{P_{el, \text{Gross}, \text{reference}}}$	Constant electricity density in conductors
Transformer (Trans)	$f_{\text{Trans}} = \frac{P_{el, \text{Gross}}}{P_{el, \text{Gross}, \text{reference}}}$	Constant electricity density in conductors
Piping and fittings (Pipe)	$f_{\text{Pipe}} = \sqrt{\frac{P_{th, \text{Firing}}}{P_{th, \text{Firing}, \text{reference}}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Cooling tower - construction materials (CoolTC)	$f_{\text{CoolTC}} = \sqrt[3]{\frac{P_{th, \text{Cooling}}}{P_{th, \text{Cooling}, \text{reference}}}}$	Constant relation between cooling tower volume and cooling power. Mass of cooling tower predominantly determined by the surface of the cooling tower
Cooling tower - mechanical components (CoolTM)	$f_{\text{CoolTM}} = \frac{P_{th, \text{Cooling}}}{P_{th, \text{Cooling}, \text{reference}}}$	Constant heat flow density in heat transfer systems

Automated Calculation of Transport and Disposal Services

The life cycle investigation of a product system comprises the survey of all energy and material flows within the considered product system. Within the analysis of the material flows reaching from extraction of natural resources up to the end-of-life treatment of used products, transport services play a decisive role. This is exemplarily highlighted in Figure 3-10 showing the life cycle of materials for construction of the power plant.

Starting from raw material extraction over the processing to different materials, over the manufacturing of intermediate products and power plant components, finally the construction at the power plant site follows. All these individual steps of the construction phase are interconnected by transport services. During the operation phase the construction materials remain at the power plant site until the end of the technical life time of either individual power plant components or the power plant as a whole is reached. Then, with the beginning of the dismantling phase, the power plant and its individual components are deconstructed to basic material fractions. These material fractions are transported to different places for individual end-of-life treatment. Thereby basically two streams can be distinguished: Materials or material fractions that are able to be reutilized go for recycling, the other materials and material fractions follow diverse paths of material-specific waste management. The transportation to the place of the recycling is included within the system boundaries, whereas the recycling process itself is not. This is referred to as open loop recycling /5/. The different paths for waste management are not specified in detail in Figure 3-10, as these are described in this study by datasets for disposal services fromecoinvent, which already incorporate all these transportation services /51/.

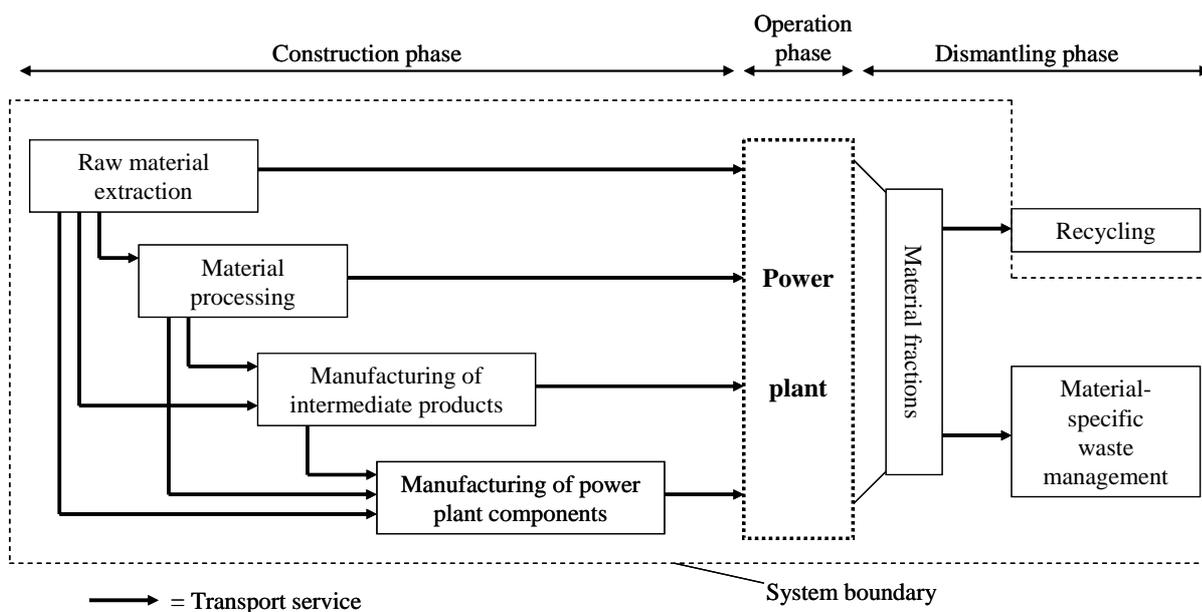


Figure 3-10: Transport services over the life cycle of materials for power plant construction

According to equation 3-10, the quantity of transport services depends on the transport distances as well as on the mass of the transported materials, intermediate products, power plant components or material fractions. Transportation services are usually measured in the unit ‘tkm’ (ton-kilometre), which illustrates the transportation of a mass of one ton over a distance of one kilometre (equation 3-10).

$$\text{Transport service [tkm]} = \text{transport distance [km]} \cdot \text{transport charges [t]} \quad (3-10)$$

From Figure 3-10 it becomes apparent, that transport distances are determined by the respective locations of the raw material extraction, the processing and manufacturing facilities, the power plant site and finally the place of the end-of-life treatment. As these distances are hardly known for all individual materials and intermediate products, in LCA studies and LCA databases commonly standard transportation distances are applied.

As default setting in this study, the standard transportation distances applied in the LCA database ecoinvent /30/ are adopted (see Table 3-5). These transportation distances are basically implemented as parameters. This means that by virtue of the methodology P-LCA, the transport distance parameters of the investigated product systems are able to be modified.

In case of such a modification the resulting changes in the transportation services are automatically quantified. In equation 3-11 it is illustrated, how the transportation services for different transport means on rail, street and water are calculated.

$$TS_i = \sum_x \left[\left(\sum_j MF_{x,j} \right) \cdot sd_{x,i} \right] \quad (3-11)$$

TS – Transport service [tkm]

i – Transport means: train, truck, barge etc.

MF – Mass of a material flow [kg]

j – Any process within the investigated process chain

sd – Standard transport distance [km]

x – Any considered material flow

Equation 3-11 in the first instance aggregates the mass of one considered material flow MF_x over all processes of the investigated product system. This is necessary, as the same material often is constituent in the material frameworks of diverse processes. Different power plant components, which in the investigated product systems are generally treated as individual processes, may for instance require diverse quantities of aluminium. Thus the overall material flow of aluminium is calculated as sum of all aluminium flows from all processes ($\sum_j MF_{x,j}$).

Following, this total sum of one specific material flow is multiplied by the standard transport distance $sd_{x,i}$, which is characteristic for the considered material. Final step is the calculation of the transport service TS_i of one transport means i, which is obtained by the aggregation of the described transport service calculation over all materials x.

From equation 3-11 it arises that transport services within the P-LCA approach of this study basically are system parameters. Input parameters for this calculation are the surveyed material flows and the transport distances. A particular advantage of this parameter application comes into play, when parameters on power plant characteristics as for instance the power plant capacity are modified. As described above, such a modification implies an automated adaptation of power plant components by means of scaling of their respective material frameworks. Following, these modified quantities within the material flows are inserted into equation 3-11 resulting in an automatic recalculation of all transport services. This means that all transport services within the parametrised process chains of this study are automatically calculated and also automatically revised in case of parameter modification.

Table 3-5: Densities and standard transport distances (from place of production to its use) of selected materials in this study
(source: /30/ /49/ /53/)

	Density [kg/m ³]	Standard transport distance in Europe	
		Freight train [km]	Lorry 32t [km]
Mineral products			
Gravel / sand	2,000	-	50
Cement	3,150	100	100
Concrete (w/o reinforcing steel)	2,200	-	50
Float glass	2,500	600	100
Metals			
Steel/ cast iron	7,900	200	100
Copper	8,900	200	100
Aluminium	2,700	200	100
Plastics			
PVC	1,400	200	100
PE	950	200	100
PP	900	200	100
Wood (from Swiss forests)			
Sawn timber (softwood)	450 ⁱ⁾	100	50
Structural timber (softwood)	450 ⁱ⁾	-	100
Particle board	680 ⁱ⁾	200	50
Basic chemicals, inorganic ⁱⁱ⁾			
Caustic soda	1,045	600	100
Soda (sodium carbonate)	2,532	600	100
Hydrochloric acid	909	200	100
Sulphuric acid	1,840	600	100
Nitric acid	1,383	600	100
Phosphoric acid	1,685	600	100
Hydrofluoric acid	993	600	100
Basic chemicals, organic			
Ethylene		600	100
Naphtha		600	100
Refrigerants		600	100
Organ. solvents		600	100
Pesticides		600	100
Gases (if not produced on the spot)			
Oxygen		100 ⁱⁱⁱ⁾	50 ⁱⁱⁱ⁾
Nitrogen		100 ⁱⁱⁱ⁾	50 ⁱⁱⁱ⁾
Hydrogen		100 ⁱⁱⁱ⁾	50 ⁱⁱⁱ⁾
Helium		100 ⁱⁱⁱ⁾	50 ⁱⁱⁱ⁾
ⁱ⁾ absolutely dry			
ⁱⁱ⁾ carrier substance to be considered additionally			
ⁱⁱⁱ⁾ if bought in cylinders: doubling of transport distances (due to tare weight)			

This optimisation and simplification by means of automated LCI data calculation also applies to the calculation of disposal services, which illustrate the end-of-life treatment of materials or material fractions. Basic condition within a life cycle investigation is, that all constructed and used materials, which were not changed in their consistency during their usage, have to be disposed at the end of their life time. For most construction materials this is done in the dismantling phase, which starts after the technical life time of the power plant. Thereby deconstructed materials and basic material fractions are assigned to diverse disposal services. The disposal services used within this study are taken from the disposal process portfolio of the LCA database ecoinvent /30/ and have been selected based on recommendations made in /49/. Table 11-3 in the annex gives an overview of the applied disposal services.

A disposal service is quantified by the sum of the masses that are to be disposed. Starting from the given condition that all constructed and used materials, which have not been changed in their consistency during the analysed life cycle, have to be disposed in the dismantling phase, disposal services are calculated according to equation 3-12:

$$DS_x = \left(\sum_j MF_{x,j} \right) \quad (3-12)$$

DS – Disposal service [kg]

j – any process within the investigated process chain

MF – mass of a material flow [kg]

x – any considered material flow

Both the disposal during the dismantling phase and the disposal during the operation phase are calculated according to equation 3-12. Operating supplies and spare parts obey the same principle as the materials for power plant construction, solely the point in time for the disposal can be different.

Like transportation services also the disposal services are automatically calculated and immediately revised in case of changes in the material flows due to parameter modification. Thus, in the approach of P-LCA these services constitute system parameters.

3.5.7 Field of Application for P-LCA

The use of parameters and thus the possibility to change assumptions and frame conditions of LCA studies opens up further fields of application for LCA. The flexibility in the modelling and calculation of LCI data by means of parameter modification allows scenario modelling of product systems, which is a promising means for prospective LCA in the investigation of future time horizons. Especially for the analysis of technology development, P-LCA constitutes a helpful tool to derive LCI and LCIA data for different capacity levels, designs and other anticipated technical specifications. Further advantage of P-LCA is the application of parameter modification for sensitivity analyses or the comparison to other LCA studies by adaption of study-specific assumptions and frame conditions.

Summarizing, by means of P-LCA it is possible to model and picture the environmental performance of future EGTs.

4 The LCA Software BALANCE

The conduction of an LCA study involves the collection and management of large amounts of data. Especially the modelling of a product system over its life cycle, which comprises diverse flows of materials and energy as well as releases of emissions, requires proper data management.

Table 4-1: Extract of the reference list of the software BALANCE
(source: IER)

Project name	Contracting institution	Finalisation of project	BALANCE version	Reference
CASES (Cost Assessment for Sustainable Energy Systems)	European Commission	2009	4.0	/55/
NEEDS (New Energy Externalities Developments for Sustainability)	European Commission	2008	4.0	/43/
Guidelines on the generation and update of a harmonised dataset on the German electricity mix (in German)	BMWA	2007	4.0	/57/
EUSUSTEL (European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply)	European Commission	2007	4.0	/56/
LCA of selected future EGTs (in German)	BMWA	2004	3.5	/26/
ECLIPSE (Environmental and Ecological Life Cycle Inventories for Present and Future Power Systems in Europe)	European Commission	2004	3.5	/42/
Pathway to sustainable consumption – an interdisciplinary analysis	BMBF	2002	3.5	/58/
Fundamentals on the evaluation of sustainability of energy systems in Baden-Württemberg	BWPlus	2001	3.0	/59/
Scientific supervision of the operation of the RME-fired energy supply facilities of the Lower House of German Parliament in Berlin	FNR	2001	3.0	/60/
Macroeconomic evaluation of energy generation from biomass	FNR	2000	3.0	/61/
LCA of energy and material flows of energy supply technologies	PEF	2000	2.0	/62/
Systematic comparison of journeys in passenger transportation with respect of environmental and climatic impacts of different transport means	BWPlus	2000	2.0	/63/
Technical, economic and environmental assessment of solar tower power plants	IER	2000	2.0	/64/
Energetic utilisation of hydrothermal geothermal sources in Germany – an energy-economic assessment	IER	2000	2.0	/110/
LCA of electricity generation from regenerative energy sources	IER	2000	2.0	/66/
BMWA – German Federal Ministry of Economics and Labour BMBF – German Federal Ministry of Education and Research BWPlus – Baden-Württemberg Environmental Ministry’s program ‘living basis environment and its protection’ FNR – Agency for Renewable Resources PEF – Project European Research Centre				

Therefore, nowadays different kinds of LCA software are available supporting the user in structuring and evaluating the data during the performance of an LCA study.

In this study the non-commercial software BALANCE is applied, which had been developed at IER by Thorsten Marheineke from 1994 to 1996. He established the LCA methodology according to ISO 14040ff in BALANCE and within the scope of his PhD complemented the software by the methodology of hybrid LCA /33/.

Since then BALANCE was continually improved and adapted to developments within LCA methodology (version 2 to 3.5) and was utilised within several national and international LCA projects. Table 4-1 shows a reference list of some of these LCA projects conducted by means of the software BALANCE. In the course of this PhD project for this study, the software BALANCE was updated to the version BALANCE 4.0 featuring the implementation of current database technology, windows-based software-structure and the adaptation to 32-bit-based operating systems. Furthermore, the methodological expansion to P-LCA offering the possibility to integrate parameters into LCA according to ISO 14040ff was integrated. Equipped with the current LCA database ecoinvent 1.2, BALANCE 4.0 was successfully applied at several LCA projects, as it can be seen from Table 4-1.

4.1 BALANCE 4.0

In the following sections an introduction of the structure and the basic functions of BALANCE 4.0 is given.

4.1.1 Database System

The software BALANCE 4.0 constitutes a tool that guides the user through all phases of an LCA study. It provides a user environment for the modelling of the investigated product system, the generation and quantification of individual processes, the calculation of LCI and LCIA data and finally the analysis as well as assessment of these data. The system standing behind this user environment primarily comprises interaction and data management by two databases, a so-called user database and a main database. This database system is shown in Figure 4-1.

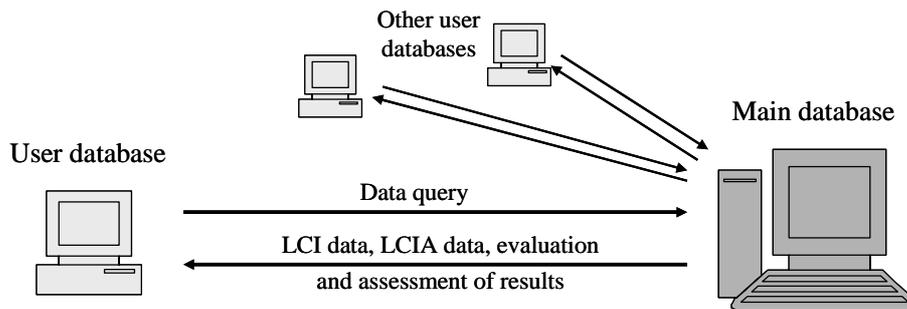
The main database contains LCI data and LCIA data on LCA background processes, which in other studies are also referred to as processes of the up- and downstream chains. These LCA background processes constitute a large variety of already balanced processes for the

- supply of materials
- supply of energy carriers
- basic services as for instance the generation of heat or electricity
- transport services
- disposal services

These LCA background processes in the main database of BALANCE 4.0 originate from the database ecoinvent in the version 1.2 /30/ comprising approximately 3,200 different processes with about 2,800 inventories belonging to each process.

The other database, the user database, contains all data of the modelled product system, which are entered by the user. This comprises all surveyed material frameworks and energy requirements as well as direct emissions of all processes within the modelled product system.

After selection of the set of background processes by the user, all required data on these processes are copied from the main database and are transferred to the user database. Furthermore, all calculated LCI and LCIA data of the investigated product system as well as the analysis and assessment of these LCA data are saved at the user database.



- Data of the investigated product system (process flow diagram and process modelling)
- LCA background data: LCI and LCIA data on supply chains of materials and energy carriers as well as on basic services (around 3,200 processes)
- Appr. 2,800 different inventories (emission releases, resource demand) for each process

Figure 4-1: Database system in BALANCE 4.0

4.1.2 Process Diagram

The conduction of an LCA study in BALANCE 4.0 involves numerous interactions of user database and main database. The sequence of these interactions is shown in the process diagram in Figure 4-2 highlighting the contribution of the respective databases to central steps of an LCA study.

In the following paragraphs some screenshots of BALANCE 4.0 are shown in order to further illustrate central steps of the conduction of an LCA study in BALANCE 4.0. These screenshots are identified by Roman numbers referring to the steps in Figure 4-2 that are marked by bracketed numbers. Since BALANCE 4.0 is established on basis of a German data base program, in all spread sheets and calculations not the international, but the German notation with comma is used for the decimal places of numbers, as it becomes apparent in the following screen-shots.

Within the scope definition of an LCA study, the inventories are selected, which are to be calculated and evaluated. Figure 4-3 displays this selection step and highlights that there are several life cycle inventories for one substance, which is emitted. As shown in the screenshot, carbon dioxide emissions are distinguished into carbon dioxide emissions originating from fossil energy carriers on the one hand and from biogenic energy carriers on the other hand.

Furthermore, the settlement density, at which the carbon dioxide emissions take place, is specified.

User database	Main database
Scope definition	
Description of the product system	Selection of inventories to be integrated (I)
Specification of system boundaries and the functional unit	Selection of environmental impact categories to be analysed
Modelling of the product system	
Generation of processes and a process tree structure	Selection of LCA background processes (supply of materials and energy carriers, services (transport, disposal) etc.) (II)
Quantification of product flows by parametrised formulae (III)	
Calculation	
Calculation of parametrised formulae	Transfer of the specified LCI and LCIA data of all selected LCA background processes
Calculation of LCI and LCIA data for all processes of the product system	
Preparation, evaluation and assessment of the LCA results	
Graphical and tabular display, evaluation and assessment of LCA results (IV)	Selection of evaluation and assessment methods
	Transfer of calculation factors and formulae for the selected methods to the user database

Figure 4-2: Process diagram of the database system in BALANCE 4.0

The selection of LCA background processes from the main database is pictured in Figure 4-4. Ordered by categories, the background processes provided by the main database are alphabetically listed showing further specifications by country code, time horizon of the data and the indication of infrastructure processes. Datasets of infrastructure processes comprise only the infrastructure of a process without material and energy flows for the operation of this process. LCA background processes that are not classified as infrastructure process comprise all data of a process including infrastructure, operation and dismantling.

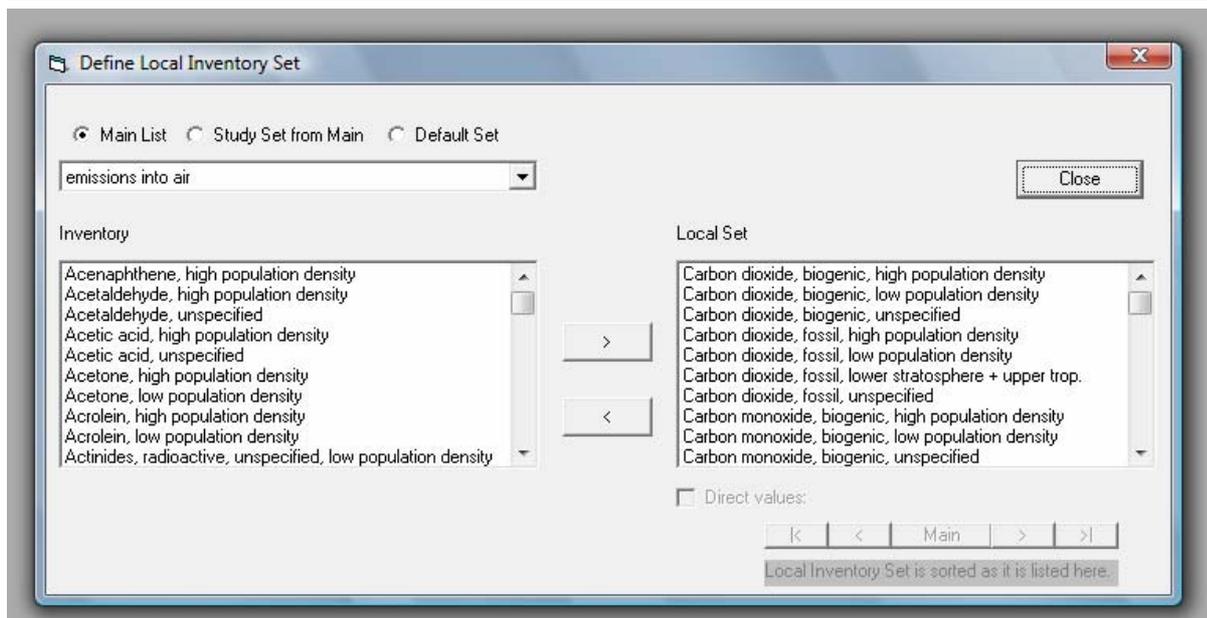


Figure 4-3: Selection of inventories from LCA main database in BALANCE 4.0

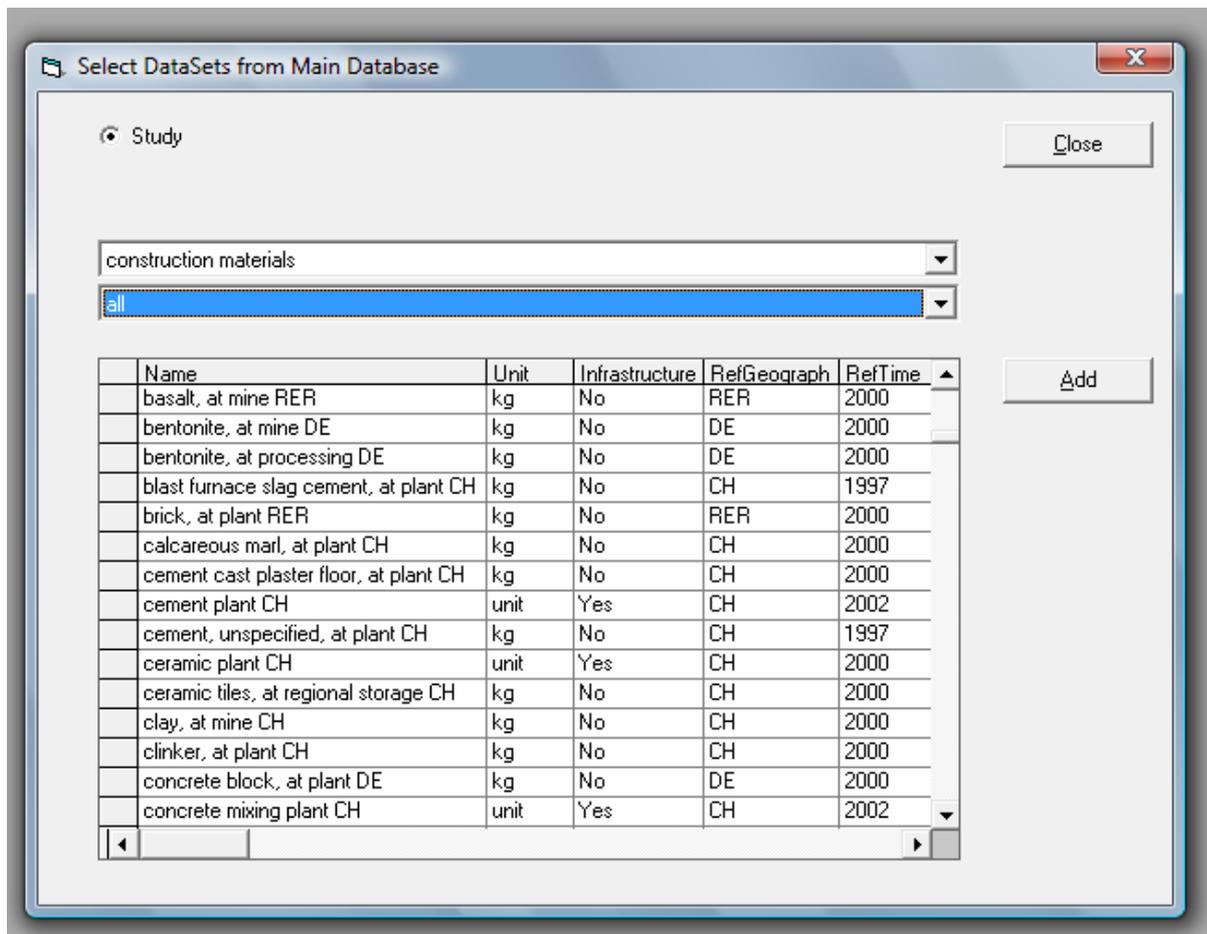
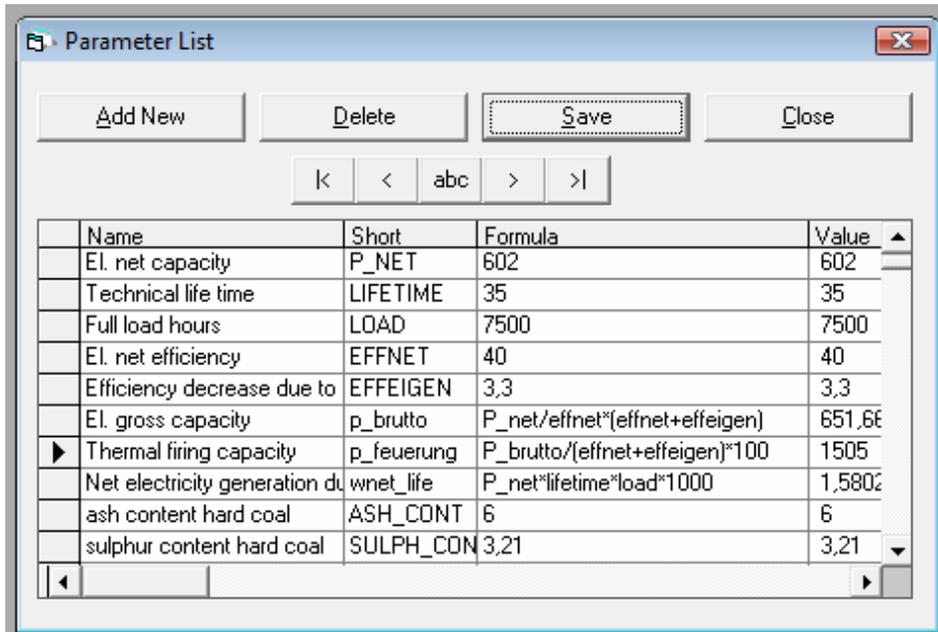


Figure 4-4: Selection of LCA background processes from LCA main database in BALANCE 4.0

BALANCE 4.0 has a separate area and windows structure for the administration of parameters. The window shown in Figure 4-5 allows the user to define and specify parameters for an LCA study. Thereby the numeric value standing behind the parameter can be defined by the user either

as an absolute number or as the result of a parameter-based formula, which in Figure 4-5 is the case for the parameter 'El. gross capacity' and the following two parameters.



Name	Short	Formula	Value
El. net capacity	P_NET	602	602
Technical life time	LIFETIME	35	35
Full load hours	LOAD	7500	7500
El. net efficiency	EFFNET	40	40
Efficiency decrease due to	EFFEIGEN	3,3	3,3
El. gross capacity	p_brutto	$P_{net}/effnet*(effnet+effeigen)$	651,6€
Thermal firing capacity	p_feuerung	$P_{brutto}/(effnet+effeigen)*100$	1505
Net electricity generation du	w_net_life	$P_{net}*lifetime*load*1000$	1,5802
ash content hard coal	ASH_CONT	6	6
sulphur content hard coal	SULPH_CON	3,21	3,21

Figure 4-5: Administration of parameters in BALANCE 4.0

Figure 4-6 shows the window for the modelling and quantification of processes of the investigated product system. The input quantification, which is selected by the radio button in the screenshot, shows the contributions from other processes (in this case a list of different materials). The quantity of these material flows is specified by parametrised formulae.

For the presentation of the LCI and LCIA results in BALANCE 4.0, either a tabular structure or the graphical illustration in the modelled process tree can be chosen. In tabular structure high information density is achieved by presentation of rows with selected processes opposed to columns of selected LCI or LCIA results. In this form also the analyses of LCA results, for instance the aggregation or disaggregation of LCI and LCIA results, can be displayed. Furthermore, the assessments of the LCA results, as for instance the calculation of external costs can be tabulated.

The same presentations, analyses and assessments of LCA result are possible as graphical illustration in the modelled process tree as shown in Figure 4-7. Thereby, the contribution of selected processes to the overall LCA results, analyses or assessments is highlighted. Figure 4-7 shows the percentile contribution of processes to the specific CO₂ emissions of a hard-coal-fuelled IGCC power plant in such a graphical process chain analysis.

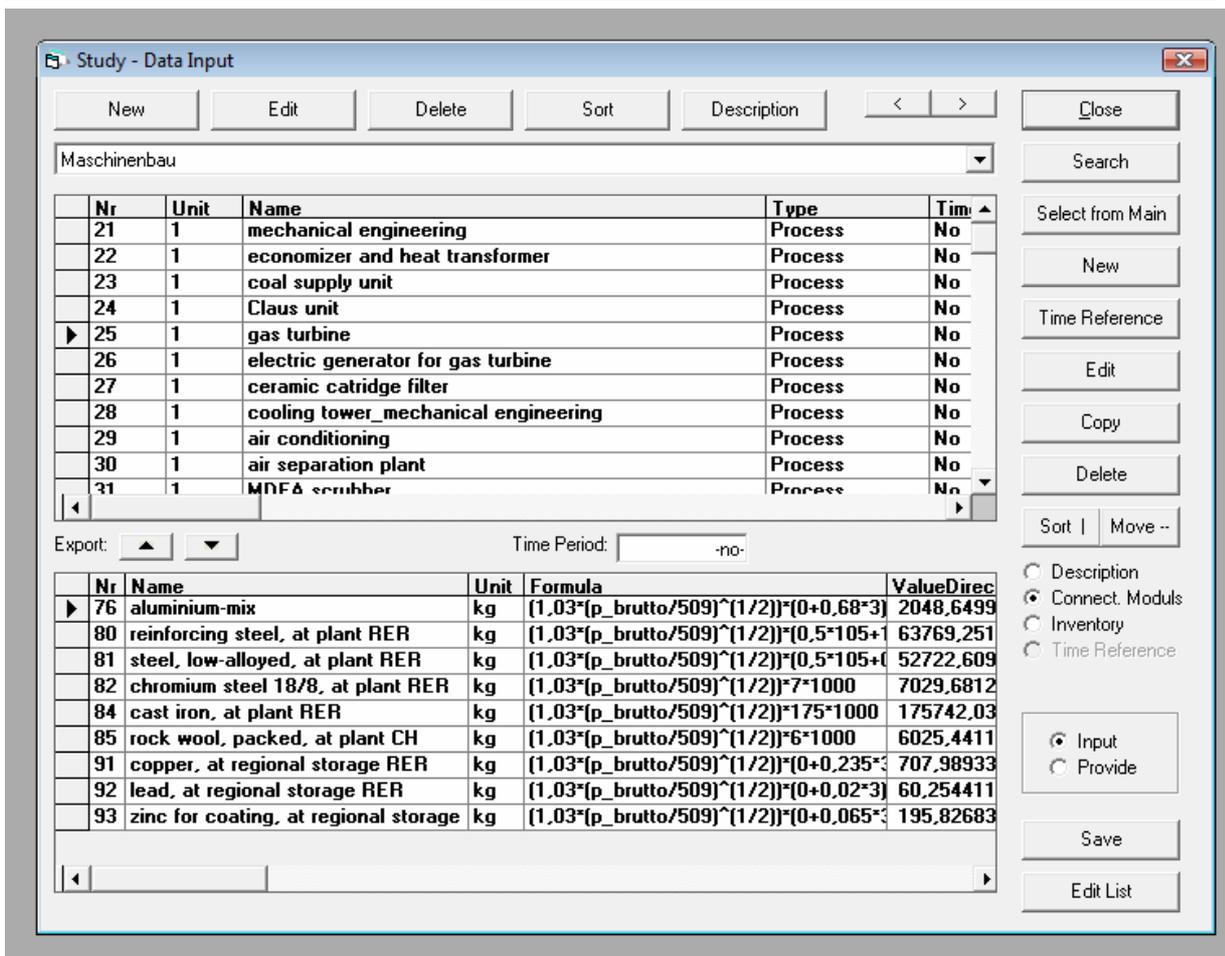


Figure 4-6: Modelling of processes in BALANCE 4.0

4.2 Transfer of LCA Data

In BALANCE 4.0, data preparation of LCI and LCIA for export according to the EcoSpold format /66/ has been integrated. The EcoSpold format is an electronic format for data exchange of different kinds of LCA data, which had originally been developed for the communication of LCI data within the Swiss ecoinvent project. The basic exchange format of EcoSpold constitutes XML-files, which however also can be converted into HTML and Excel documents. In BALANCE, the transfer of LCI and LCIA data to the Excel format of EcoSpold is integrated. For finalisation of the EcoSpold format, the user has to add meta information into the exported Excel file. Meta information in this context constitutes the labelling of the LCI or LCIA data by information on the balanced time period, the geography, technology, validations on the used data sources, and finally on the balancing person. The EcoSpold software for conversion between XML, Excel and HTML format is publicly available. By means of this software, communication to other LCA software like SimaPro, Umberto, GaBi or Team is possible, which themselves feature an interface to the EcoSpold for the exchange of LCA data.

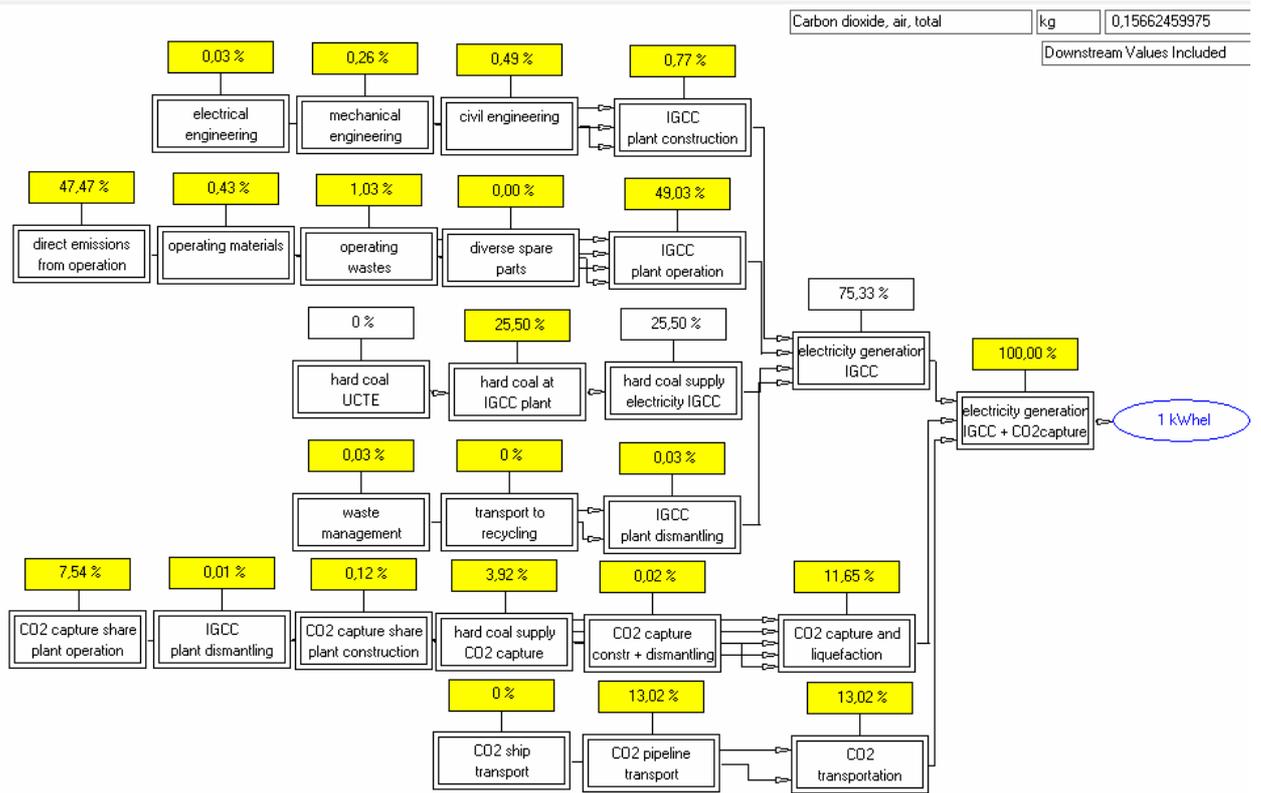


Figure 4-7: Graphical presentation, analysis and assessment of LCA results in BALANCE 4.0

5 Parametrised LCA of Electricity Generation in Hard-coal-fuelled Power Plants with CCS

This part of the study comprises the environmental, economic and technical analysis of current and future hard-coal-fuelled EGTs with and without CCS. In the following chapters firstly an introduction to the generic frame conditions of this study is given. Subsequently, a specification of the investigated technology scenarios paves the way for the presentation and discussion of the results.

5.1 Goal and Scope Definition

In this study, the approach of P-LCA is applied, which in accordance to the LCA methodology of ISO 14040ff follows the process diagram shown in Figure 3-2.

5.1.1 Goal Definition

The goal of this study is an analysis of the economic, environmental and technical performance of hard-coal-fuelled electricity generation with and without CCS. As product system the technical state-of-the-art of three different power plant concepts for CO₂ capture is modelled and evaluated for both current conditions and future time horizons. By means of LCA the impact of these product systems on resources, climate, ecosystems and human health is evaluated. Additionally, economic analyses are conducted by means of calculation of average life-cycle levelised electricity generation costs, external costs and CO₂ avoidance costs.

5.1.2 Specification of the Product System, Generic Assumptions and Functional Unit

The investigated product system is sketched in Figure 5-1. Starting from German steam coal supply, the hard-coal-fuelled electricity generation in different power plants with CO₂ capture is investigated. The captured CO₂ is compressed at the power plant site before it is transported and injected into a geological storage formation.

The system boundary of the investigated technology is represented by the dotted border around the power plant site in Figure 5-1. This shows that the life cycle of the captured CO₂ within the investigated product system is only considered up to the point, when the CO₂ is injected into the storage site. This means that the long-term storage of the CO₂ is not covered in this study. Currently, only few CO₂ storage sites have been used so far, which do not feature any leakage of CO₂ and thus no negative impact from CO₂ storage. This exclusion from CO₂ leakages at the same time is a prerequisite for the commissioning of CO₂ storage sites. Starting from this basic requirement and due to missing data on long-term experiences and monitoring results, the CCS chain in this study is not considered beyond the step of injection.

The product output of the investigated system is the supply of the electricity into the electricity grid, as shown in Figure 5-1. As functional unit within this study the kWh of generated electricity is considered.

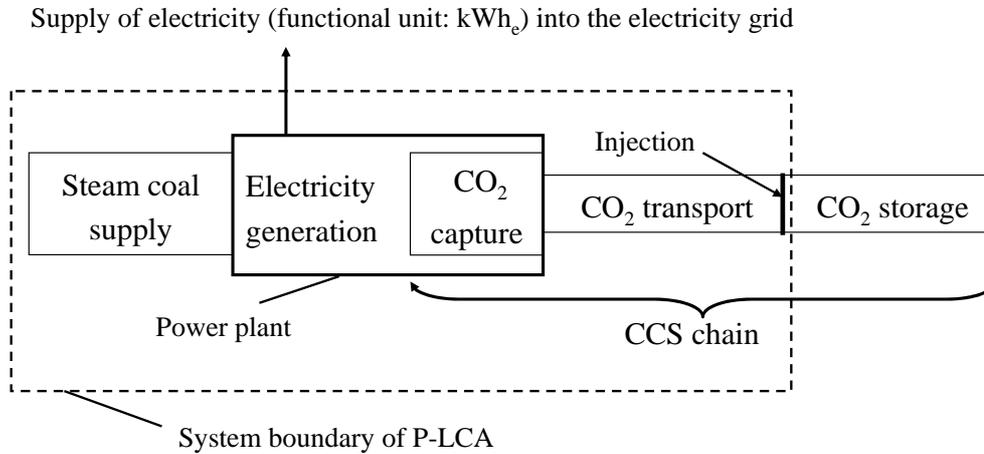


Figure 5-1: Investigated product system in this study

The system boundary of P-LCA includes the supply of all required materials and energy carriers for the entire life cycle of the product system. Thereby also the infrastructure of the supply chains and the power plant construction itself are accounted for. All material flows are individually followed from extraction from nature resources up to the end-of life treatment, whereas in case of recycling, the open loop approach as suggested by ISO 14041 is applied.

Apart from the long-term storage not being considered, there are no explicit cut-off criteria applied in this study. For consistency reasons, the approach of the ecoinvent database is adopted, which refers the judgement in compiling LCI data on whether or not to include the production of a certain input or whether or not to include the release of a certain pollutant to the environmental knowledge of the people involved in the study /87/.

In order to reach comparability between the investigated technologies and time horizons, the technical life time of all analysed hard-coal-fuelled power plants is assumed to be 35 years. The operational mode of these plants is considered to be consistently at 7,500 full load hours per year. These full load hours represent base load conditions, which are deemed to be a prerequisite for CCS systems /126/. The location of the analysed power plant concepts constitutes a typical power plant site in Germany.

Starting from present conditions, the future time horizons 2015, 2025 and 2050 are investigated. This analysis of future time horizons together with the modelling of new technological approaches like the different CO₂ capture technologies in comparison to current technology makes this study a prospective consequential LCA study.

For the modelling of the process chain analysis and the integration of parameters into this LCA study, the software BALANCE 4.0 is used (see chapter 4). The data for LCA background processes are obtained from the ecoinvent database in the version 1.2.

5.1.3 Life Cycle Inventories and Environmental Impact Categories

The LCI is performed for around 80 to 100 individual elementary flows, which represent different material or energy resources or released emissions. Table 5-1 shows a selection of these life cycle inventories, which are explicitly analysed in this study. The demand for material resources is exemplarily quantified by means of the elementary flows shown in the first category. By the elementary flows of the second category the demand for energy resources is identified, which finally is also used to calculate the cumulated energy demand (CED) of the individual life-cycle phases from the steam coal supply chain over the power plant construction and electricity generation with CCS up to the end-of life treatment.

Table 5-1: Analysed elementary flows in the LCI of this study

Material resources			
Aluminium	Basalt	Clay	Chromium
Copper	Dolomite	Granite	Gravel
Gypsum	Iron	Lead	Sand
Zinc			
Energy resources			
Crude oil	Hard coal	Lignite	
Natural Gas	Peat	Uranium	
Emissions into air			
Carbon dioxide, fossil (CO ₂)		Non-methane volatile organic compounds (NMVOC)	
Carbon monoxide (CO)		Particulate matter < 2.5 µm (PM _{2.5})	
Sulphur dioxide (SO ₂)		Particulate matter < 10 µm (PM ₁₀)	
Nitrogen oxides (NO _x)		Dinitrogen monoxide (N ₂ O)	
Methane (CH ₄)			

The emissions into air in the third category of Table 5-1 contribute to different environmental impact categories, which are displayed in Table 5-2 for the categories investigated within this study. The applied characterisation factors of the environmental impact categories applied in this study originate from /13/ and /88/ and represent the current state of research.

The global warming potential (GWP), which is measured in CO₂-equivalents, is an index quantifying the contribution to global warming of a substance that is released into the atmosphere. The substances contributing to GWP modify the absorption of thermal radiation in the Earth's atmosphere. As a consequence, thermal radiation remains within the Earth's atmosphere and increases the equilibrium temperature of the Earth.

The acidification potential (AP) measures the contribution of an emitted substance to acidification. This occurs when oxides as SO₂ (reference substance), NO_x and other substances

react with water vapour in the atmosphere to form acids, which fall down to the Earth in the form of rain or snow or as dry depositions.

Table 5-2: Specification of the analysed environmental impact categories in this study
(source: /13/ /88/)

Environmental impact category	Contributing life cycle inventory [kg]	Characterisation factor	Reference unit
Global warming potential (100a) (GWP)	Carbon dioxide (CO ₂)	1	kg CO ₂ -equivalents
	Methane (CH ₄)	23	
	Dinitrogen monoxide (N ₂ O)	296	
	
Acidification potential (AP)	Sulphur dioxide (SO ₂)	1	kg SO ₂ -equivalents
	Nitrogen oxides (NO _x)	0.7	
	Ammonia (NH ₃)	1.88	
	
Eutrophication potential (EP)	Phosphate (PO ₄ ³⁻)	1	kg PO ₄ ³⁻ -equivalents
	Nitrate, nitrite	0.1	
	Nitrogen oxides (NO _x)	0.13	
	Ammonia (NH ₃)	0.35	
	Phosphorus (P)	3.06	
	
Human toxicity potential (100a) (HTP)	Ammonia (NH ₃)	0.1	kg 1,4-DCB-equivalents
	Particulates < 10 µm	0.82	
	Nitrogen oxides (NO _x)	1.2	
	
Photochemical ozone creation potential (POCP)	Carbon monoxide (CO)	0.037	kg formed ozone
	Methane (CH ₄)	0.009	
	
Stratospheric ozone depletion potential (SODP)	Diverse chlorofluorocarbons (CFC)	...	kg CFC-11-equivalents
Cumulated energy demand (CED)	Diverse energy resources	...	MJ _{Prim} -equivalents

1,4-DCB – Dichlorobenzene (C₆H₄Cl₂)

CFC-11 – chlorofluorocarbon (CFCl₃)

MJ_{Prim} – Primary energy content

The eutrophication potential (EP) quantifies the nutrient enrichment by the release of phosphorus compounds and nitrogen into water or soil. Nutrients accelerate the growth of algae and other vegetation in water. The degradation of this organic material consumes oxygen resulting in oxygen deficiency, fish kill and silting of lakes.

The human toxicity potential (HTP) expresses the potential harm of toxic chemicals, which are released into the environment. The harm of these chemicals is compared to the relative toxic impact of the reference substance dichlorobenzene (1,4-DCB). The calculation of the human toxicity potential is based on a generic fate and exposure model (CalTox), which determines the distribution of a chemical in a model environment and accounts for a number of exposure routes,

including inhalation of gases and particles, ingestion of produce, fish, and meat, and dermal contact with water and soil /94/.

The photochemical ozone creation potential (POCP) measures the contribution of a substance to the formation of photochemical ozone at ground level. This environmental impact category is often also referred to as indication for ‘summer smog’, as it describes the reaction of volatile organic compounds and nitrogen oxides to form ozone in the presence of heat and sunlight, which frequently takes place in urban regions during hot summer weather.

The stratospheric ozone depletion potential (SODP) quantifies the contribution of substances to the depletion of the stratospheric ozone layer. A reduction of the stratospheric ozone layer density results in increased UV-radiation at ground level of the Earth, which is detrimental to plants, animals and human beings. The ozone layer depletion caused by one kilogram of chlorofluorocarbon (CFC-11) constitutes the reference of this environmental impact category.

The cumulative energy demand (CED) quantifies the entire energy demand, valued as primary energy, which arises in connection to the production, use and disposal of an economic good (product or service) or which may be attributed to it in a causal relation /94/. In this study the calculation of the CED is done according to the German VDI guideline 4,600 /94/. Thereby, the contribution of fossil energy resources is quantified based on their net calorific value when extracted from natural resources. The contribution of energy and electricity from renewable energy sources is taken into account with respect to the physical quality of energy conversion. In this study, net calorific values of fossil fuels are derived from the documentation of theecoinvent database /88/. For the calculation of the CED of nuclear and renewable electricity generation, different net efficiencies of presently used technologies are applied for nuclear power (33 %), wind power (25 %), photovoltaic (15 %) and hydro power (100 %). Biomass including wood is taken into account by its net calorific value.

5.1.4 Risks to Human Health

The impact on human health can be specified by the indication of a loss in life expectancy of human beings. Epidemiological studies revealed a correlation between exposure to particulates and total mortality /93/. Starting from these investigations on acute mortality (short-term) and chronic mortality (long-term), the impact pathway approach was developed /89/ /90/ /92/, which allows to quantify the impact of pollutants as for instance particulates, SO₂, NO_x as well as the impact of radionuclides and carcinogens on human health. Characterisation factors for several pollutants were developed and attributed to different impact pathway categories so that from pollutant exposure health risks could be quantified as years of life lost (YOLL). Within the European project series ‘ExternE’, the list of characterisation factors was advanced /90/ and recently updated again within the European ‘NEEDS’ project /43/. The YOLL characterisation factors of the ‘NEEDS’ project are used for the calculation of the health risks in this study and are displayed in Table 5-3. The YOLL characterisation factors of the impact pathway category ‘Lethal cancer due to ionising radiation’ are listed in Table 11-4 of the annex.

Table 5-3: YOLL characterisation factors applied in this study
(source: /43/)

Impact pathway category	Contributing LCI, emission into air [kg]	Geographic reference	Characterisation Factor in YOLL / kg
Acute and chronic mortality due to primary and secondary particles	Particulates < 2.5 µm	Germany	$6.90 \cdot 10^{-4}$
	Particulates > 2.5 µm, < 10 µm	Germany	$1.94 \cdot 10^{-6}$
	Nitrogen Oxides (NO _x)	Germany	$1.71 \cdot 10^{-4}$
	Sulphur Dioxide (SO ₂)	Germany	$1.68 \cdot 10^{-4}$
	Ammonia (NH ₃)	Germany	$1.48 \cdot 10^{-4}$
	NMVOG	Germany	$8.11 \cdot 10^{-7}$
	Formaldehyde	Germany	$5.00 \cdot 10^{-6}$
Lethal cancer due to cancerogens	Arsenic (As)	Europe	$2.10 \cdot 10^{-4}$
	Cadmium (Cd)	Europe	$9.8 \cdot 10^{-4}$
	Chromium (Cr)	Europe	$7.88 \cdot 10^{-4}$
	Chromium VI (Cr VI)	Europe	$6.00 \cdot 10^{-3}$
	Nickel (Ni)	Europe	$1.00 \cdot 10^{-4}$
	Dioxins and Furans	Europe	$9.25 \cdot 10^2$

5.2 Economic Analysis

The evaluation of the economic performance of hard-coal-fuelled electricity generation with and without CCS is done by quantification of average lifetime levelized electricity generation costs on the one hand and external costs on the other hand. Furthermore, for an economic assessment of CCS as measure for CO₂ abatement, technology-specific CO₂ avoidance costs are calculated. In the following paragraphs the applied methodologies and approaches for the calculation of these cost types are illustrated.

5.2.1 Average Lifetime Levelized Electricity Generation Costs (ALLEGC)

The approach of average lifetime levelized cost calculation illustrates the total life-cycle expenses of a product system in relation to the product output during the life time of the production facilities. In case of electricity generation all expenses along construction, operation and dismantling of a power plant are accounted for and related to the overall generation of electricity. Due to the life-cycle perspective, this calculation of ALLEGC allows an immediate and objective economical comparison between different EGTs /98/ /56/. The formula for the calculation of ALLEGC is shown in equation 5-1 and is similarly applied at calculations of the OECD in /97/ and in the European project 'EUSUSTEL' /56/.

The total investment costs in equation 5-1 include both the overnight investment costs and the interest costs during construction. The overnight investment costs again comprise the total costs incurred for building the plant including owner's own cost contribution (fees, tax payments, engineering consultants etc.) and are accounted for as if they were spent immediately on the day of commissioning. For the calculation of the interest costs during construction the overnight investment costs are assumed to be split over the construction period of three years with 25 % in

the first, 40 % in the second and 35 % in the third year. During this construction period a construction interest rate of 8.5 % is applied.

$$ALLEGC = \frac{\sum_t (I_t + OM_t + F_t) \cdot (1+r)^{-t}}{\sum_t P_{el,Net} \cdot \alpha_t \cdot LT_{Power\ plant}} \quad (5-1)$$

I_t – Total investment costs in the year t
 F_t – Fuel costs in the year t
 α_t – Load factor in the year t
t – Indication of the considered year

OM_t – Operation and maintenance costs in the year t
 $P_{el,Net}$ – Net electrical capacity of the analysed power plant
 $LT_{Power\ plant}$ – Technical lifetime of the analysed power plant
r – Discount rate over the technical lifetime

The expenses in the numerator of equation 5-1, namely total investment costs, operation and maintenance costs as well as fuel costs, are calculated on an annual basis (as annuities) and are expressed in the present value of a specified base year. This base year for all scenarios is considered to be the year of commissioning. For the calculation of the present value in the commissioning year a discount rate r is applied, which for this study is assumed to be 10 % in accordance to similar calculations of ALLEGC as illustrated in /56/ /97/ /98/. Generally, calculations of levelized costs are carried out in real values, which means that inflation is not taken into account between the different analysed time horizons. Nevertheless, the escalation or decrease in prices of goods, services, salaries and fuels is to be regarded at the cost calculation.

In order to account for these price changes, the development of steam coal prices is estimated in this study according to the base price scenario shown in Table 5-4. This development of steam coal prices is derived from an IER report on electricity generation costs /172/, in which a base-price and a high-price scenario for steam coal were developed based on price projections of several representative sources. Thereby steam coal price projections are independent from oil price development. However, due to increasing steam coal demand, steam coal prices are projected to increase. The prices shown in Table 5-4 comprise the projected steam coal world-market prices as well as expenses for transportation from world market trading places to a typical German power plant site.

Table 5-4: Scenarios on the development of steam coal prices for Germany
(source: derived from /172/)

Steam coal, Germany	Unit	2007	2010	2015	2025	2050
Base-price scenario	€ ₂₀₀₅ / GJ	1.99	1.64	1.75	1.75	1.95
High-price scenario	€ ₂₀₀₅ / GJ	2.06	1.96	1.99	2.08	2.35

Annual operation and maintenance costs are calculated to constitute 5 % of the total investment cost. In accordance to the LCA assumptions, ALLEGC are calculated for all investigated power plant concepts with and without CCS with a load factor α_t of 7,500 full load hours per year, which is determined to represent base load. Likewise consistent, the life time $LT_{Power\ plant}$ of all investigated power plants is assumed to be 35 years.

ALLEGC generally include specific overheads or insurance premiums of a power plant, R&D expenditures initiated by the producer and expenses for environmental protection measures /97/, which for instance also comprises the installation of abatement technologies such as CCS technology.

5.2.2 External Costs

There are damages to human health, to the environment and to the climate due to the release of emissions from power plants, which are not covered by the ALLEGC. Thus, these costs are not paid by electricity supply companies, but are imposed on the members of the society. This, for instance, refers to the release of CO₂ emissions, which contribute to the global warming effect, or to the release of SO₂ emissions, which cause acid rain and thus entail crop loss and material damages to buildings. When these damages are monetised, these are referred to as external costs of electricity generation.

A more generic definition is given within the 'ExternE' project series of the European Commission in that external costs arise when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted, or compensated for, by the first group /90/.

The aim of the external cost approach is to firstly identify and secondly monetise the damages, which are caused by an investigated product system, but are not accounted for within the price of the generated product. Final objective is to internalise the quantified external costs. This means, economic instruments as taxes or subsidies are to be implemented in order to cover the external costs. That way it is ensured that the prices of a product incorporate both the expenses for manufacturing and the costs of caused damages. The sum of manufacturing costs (ALLEGC) and external costs is referred to as 'total costs' of a product (electricity).

In this study, the methodology for external cost calculation is applied, which was developed within the 'ExternE' project series of the European Commission /99/ and further elaborated in the following projects 'NewExt' /101/ /91/, 'ExternE-Pol' /100/ and 'NEEDS' /43/. Basis of this external cost methodology is the approach of impact pathway assessment, which is summarized in Figure 5-2. Thereby the pathway of the emissions is followed from the source (which in case of electricity generation predominantly is the stack of a power plant) over different routes of dispersion and physical or chemical conversion within air, soil and water up to physical impacts on ecosystems, climate, human beings or other affected items. This bottom-up approach takes different concentration levels and pathways of emitted pollutants into account. Physical impacts (damages) are identified and quantified by means of dose-response models, which were compiled and critically reviewed within several European projects on external cost calculation /103/.

These dose-response models illustrate the impact of traditional air pollutants, but also incorporate the exposure to heavy metals and some important organic substances (e.g. dioxins), which accumulate in water and soil compartments and lead to significant exposure via the food chain

/102/. Final step of the impact pathway assessment is the evaluation of the quantified damages in monetary terms (monetisation). For some damages, as for instance crop loss and material damage and partly also damages to human health, market prices can be applied for this monetisation. For damages on climate and ecosystems, where no market-prices exist, monetary evaluation is carried out on basis of the willingness-to-pay or willingness-to-accept approach, which is based on individual preferences /103/. These individual preferences were surveyed by large-scale interviews of people and so-called avoidance factors are quantified in order to calculate external costs.

The damage and avoidance costs calculated in this study are derived from factors that were developed within the European project 'NEEDS' project and are listed in Table 5-5. Within 'NEEDS', damage factors were developed for time horizons before 2020 on the one hand and after the year 2020 on the other hand. Thus for application of these factors to the scenarios of this study, the investigated time horizons 2007 / 2015 and 2025 / 2050 are assigned to the respective damage factors, as illustrated in Table 5-5. For the impact category climate change, avoidance factors on decade level were generated within 'NEEDS' as shown in Table 5-5.

The impact category climate change is quantified by the global warming potential of the investigated product system, which in accordance to 'NEEDS' is assessed with an avoidance factor between 19 and 55 €₂₀₀₅ / ton of CO₂-equivalents for the respective time horizons. Literature reveals that there is a wide margin of CO₂-avoidance costs due to high uncertainty in the economic assessment of climate change and the influence of different value judgements /103/. In order to account for a dynamic cost development, the avoidance cost factors in 'NEEDS' and thus also in Table 5-5 are discounted to the year of emission.

The impact category human health was intensively analysed within the last decade and thus features the highest number of damage factors among the impact categories shown in Table 5-5. However, it has to be highlighted that these factors are strongly dependent on the considered locations and thus feature considerable fluctuation between different studies /102/. The impacts of ionising radiation are also quantified within the impact category human health, but due to space reasons are shown in Table 11-4 of the annex.

The biodiversity of ecosystems can be dramatically influenced by changes in the soil chemistry and the nutrition supply. Acid rain caused by SO₂ emissions entails changes in the root growth and the intake of nutrients. Nitrogen compounds that are infiltrated into the soil result in eutrophication.

The impact category crop loss relies on the aspect that the exposure of air pollutants like SO₂, NO_x, ozone (O₃) and Peroxyacetyl nitrate (PAN) has a toxic impact on crops. Especially immissions of SO₂ and ozone (included within NMVOC) result in biochemical and physiological reactions that can be damaging to the crops /103/.

Natural weathering causes material damages to buildings and monuments. More significant damage, however, originates from immissions of air pollutants. SO₂ and acid rain entail

corrosion on metallic and inorganic materials, ozone damages organic materials and particulate emissions soil exposed materials.

The contribution of all impact categories is finally summed up to make for the external costs.

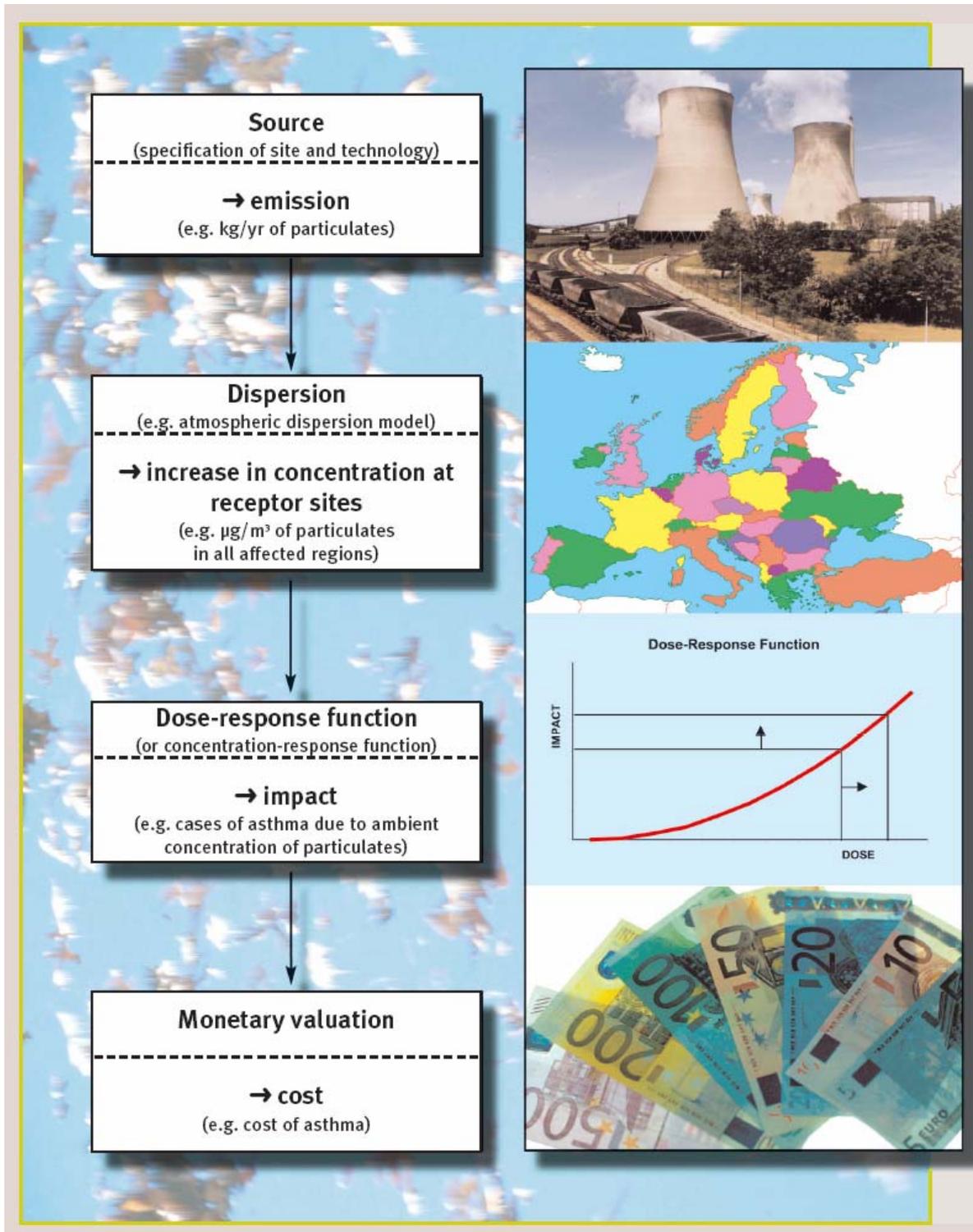


Figure 5-2: Principal steps of an impact pathway assessment for the case of air pollutants of fossil-fuelled electricity generation (source: /102/)

Table 5-5: Damage and avoidance cost factors [€₂₀₀₅ per ton of pollutant] of external cost calculation in this study ordered by analysed impact categories
(Source: derived from 'NEEDS' /43/ and 'ExternE' methodology /102/)

Impact categories	Human health		Loss of biodiversity		Crop loss		Material damage		Climate change			
	Damage costs								Avoidance costs			
External cost approach												
Time horizon	2007 2015	2025 2050	2007 2015	2025 2050	2007 2015	2025 2050	2007 2015	2025 2050	2007	2015	2025	2050
Effects	Reduction in life expectancy, cancers		Acidification, eutrophication		Yield change, increased need for liming		Ageing and soiling of building materials		Global warming			
Air pollutants												
SO ₂	8,318	9,871	580	410	-71	-96	441					
NO _x	8,947	10,686	1,503	1,485	462	626	96					
NH ₃	13,070	8,617	5,999	6,154	-63	-58						
NM VOC	831	269	-203	-83	280	144						
PM _{2.5-10}	2,066	2,109										
PM _{2.5}	39,768	40,719										
Cd	39,000											
As	80,000											
Ni	4,000											
Pb	600,000											
Hg	8,000,000											
Cr	31,500											
Cr-VI	240,000											
Formaldehyde	200											
CO ₂									19	19	21	55
CH ₄									399	399	427	1,006
N ₂ O									5,890	5,890	6,291	14,843
SF ₆									593	837	1,036	1,776

5.2.3 Technology-specific CO₂ Avoidance Costs

CO₂ avoidance costs quantify the economic effort necessary to avoid one ton of CO₂ from being released into the atmosphere. In case of CCS technology, CO₂ avoidance costs constitute the costs for capture, transportation and storage per ton of CO₂. The calculation of CO₂ avoidance costs necessitates a reference power plant as a cost reference. In this study, the reference point for CO₂ avoidance costs in a power plant for hard-coal-fuelled electricity generation with CCS

constitutes a power plant with the same technology, but without CCS. This constitutes a relative reference point, which in the same way is applied for the calculation of CO₂ avoidance costs in similar studies on CCS technologies as for instance in /23/ and /134/. Also there an absolute reference point is avoided, since the choice of the reference power plant will have considerable influence on the CO₂ avoidance costs and is very difficult to be reasoned on a scientific basis. A relative reference point on the other hand is unbiased and more objective for the evaluation of any CCS technology. Furthermore, a relative reference is advantageous for the assessment of the calculated CO₂ avoidance costs, since these can be put in direct reference to the price levels of CO₂ allowances within the European carbon emissions trading. If the price of CO₂ allowances reaches the level of the CO₂ avoidance costs, the considered power plant with CCS will feature the same economic performance as its reference power plant without CCS.

In this study, the calculation of CO₂ avoidance costs is conducted according to equation 5-2, for which ALLEGC of a power plant without CCS are subtracted from ALLEGC of the same power plant with CCS. This difference is subsequently divided by the amount of avoided CO₂ and thus quantifies technology-specific CO₂ avoidance costs. The avoided amount of CO₂ is calculated from the difference in CO₂ emissions of the considered power plant with and without CO₂ capture.

$$\text{CO}_2 \text{ avoidance costs} = \frac{ALLEGC_{\text{with CO}_2 \text{ capture}} - ALLEGC_{\text{without CO}_2 \text{ capture}} + C_{\text{transp}} + C_{\text{storage}}}{\text{amount of CO}_2 \text{ avoided}} \quad (5-2)$$

C_{transp} – Costs of CO₂ transportation [€₂₀₀₅ / t CO₂]

C_{storage} – Costs of CO₂ storage [€₂₀₀₅ / t CO₂]

5.3 Present and Future Upstream Chains

The availability of up-to-date data is a prerequisite not only for data on the investigated product system, but also for LCA background data, which constitute LCI data on the supply of materials, energy carriers or services. In order to apply accurate LCA background data in this prospective LCA study, the supply of basic materials, energy carriers and services is individually analysed for the investigated future time horizons, as it is shown in the following sections.

5.3.1 German Steam Coal Supply Chain

Hard coal can be processed to steam coal, coke or coking coal. For electricity generation in German power plants predominantly steam coal is used. The German steam coal supply chain describes the hard-coal mining, the processing to steam coal and its transportation to a typical German power plant site. In order to generate LCA data for this process chain, the energy consumption, the material flows and the release of emissions of the individual processes over the steam coal supply are analysed.

The steam coal used in German power plants originates from both domestic hard-coal mining and imports from other countries. The origin and the imported amount of the steam coal are

published annually by the German Coal Importer Federation /105/. A summary of these data for the years 1990 to 2005 is listed in Table 5-6 and Table 5-7.

Due to uncompetitive costs of German hard-coal mining in the world market, the share of domestic steam coal was continuously declining during the last decades and was gradually replaced by cheaper imports of steam coal. In 2007 finally the German government decided to phase-out the German domestic hard coal mining by the year 2018. This decision will cause further changes to the German steam coal supply in that the current steam coal from domestic mining will be completely replaced by imports within the following decade.

Starting from the background shown in Table 5-6 and Table 5-7 and the anticipated phase-out of German domestic hard coal mining, LCI data for the German steam coal supply for both current and future time horizons are generated. This principle of coupling the modelling of LCI data to ongoing reporting activity is also used in the guidance on generating LCI data of the German Network on Life Cycle Inventory Data /106/.

Based on the aspect that the overall annual German steam coal demand has been almost constant at around 50,000 to 55,000 Mt during the past fifteen years, it is assumed that this level will also stay constant for the following years. Changes in the overall hard coal demand, however, would anyway not be significant for the results of LCA data on the German steam coal supply chain, since due to the generation of specific LCI data predominantly the composition and the origin of the steam coal are relevant, but not the quantity of the German steam coal demand. For the composition of the steam coal imports it is assumed that the last reported import share of the respective countries in 2005 will persist for the following years. Based on these assumptions, the composition of the German steam coal supply chain is projected for the years 2015 and 2018 as shown in the dark grey, right-hand columns in Table 5-7. For the years after 2018, the German steam coal supply will be only made up of imports. Thus in this study, the LCI data of the German steam coal supply in 2018 are maintained for the following future time horizons between 2018 and 2050.

The process chain of the German steam coal supply chain is structured according to the hard coal supply chain in the ecoinvent database, which is described in /28/. A simplified picture of this process chain of the modelled steam coal supply is given in Figure 5-3.

Infrastructure data, information on operating supplies and direct emissions during mining processes originate from ecoinvent data. However, the energy requirement and the transportation services within the steam coal supply chain are newly balanced, whereas parameters are applied.

The electricity required for mining is assumed to be generated by a hard coal power plant located close to the mine. In accordance to ecoinvent, the heat for the mining is provided by hard coal, which is combusted in an industrial furnace in the power range of 1-10 MW_{th}.

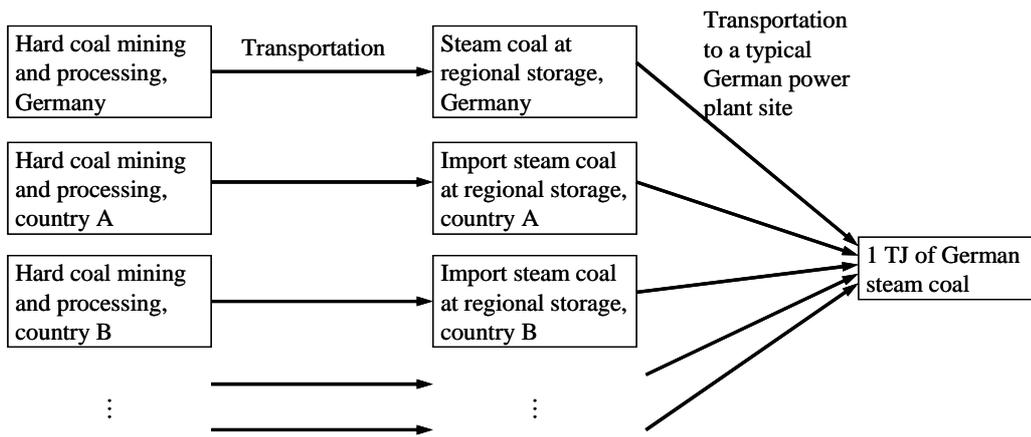


Figure 5-3: Simplified process chain of the German steam coal supply

After processing of mined hard coal to steam coal at the mine site, the steam coal is transported to a country-specific regional storage. This regional storage is the starting point for the transportation to Germany and a typical German power plant site. From /105/ and /107/ as well as by means of maps and public available distance calculators, distances and transport means for transportation from the respective regional storage sites in steam coal exporting countries to Germany were surveyed, which are displayed in Table 5-8. Transoceanic freight ships are used for offshore transportation. Onshore transportation is done by freight trains. Finally all steam coal is transported to a typical power plant site within Germany, whereas average distances of 120 km by train transportation and 140 km by barge transportation are assumed.

Table 5-8: Assumed transport distances for steam coal transportation from different countries (source: /105/, /107/)

	Transport distance transoceanic freight ship [km]	Transport distance freight train [km]	Transport distance barge [km]
Germany	-	120	140
South Africa	12,500	700	140
Poland and Czech Republic	-	670	140
Russia and CIS	3,500	4,120	140
Columbia and Venezuela	9,500	320	140
Norway	1,200	370	140
Australia	23,000	320	140
Indonesia	24,000	270	140
USA and Canada	7,500	1,120	140
China	29,000	720	140

The net calorific values of steam coal from different countries assumed in this study according to /107/ are listed in Table 5-9.

Table 5-9: Net calorific value of steam coal imported from different countries in this study
(source: derived from /107/)

Country	Net calorific value of the produced steam coal [MJ/kg]	Country	Net calorific value of the produced steam coal [MJ/kg]
Germany	29.3	USA	27.6
Poland	26.6	Columbia	24.7
Czech Republic	28.9	Venezuela	28.9
Norway	27.6	South Africa	26.4
Russia	26.6	Australia	27.6
China	26.4	Indonesia	22.2

5.3.2 Electricity Mixes

For the generation of LCI data on future electricity mixes in this study, data from energy system modelling of the European ‘NEEDS’ project are applied. In ‘NEEDS’, the development of electricity generation technologies and electricity mixes is modelled for 29 countries with a Pan-European energy system model /173/. In this model country-specific electricity mixes are generated in five-yearly intervals from 2005 to 2050. In order to evaluate CCS technologies and their performance within the current German electricity generation mix with considerable contribution from fossil fuels, the business as usual scenario from the modelling in ‘NEEDS’ is applied. The application of the ‘440 ppm’ scenario in ‘NEEDS’ would have been no neutral reference due to the already incorporated several climate protection measures including CCS.

The contribution of different energy sources to the German electricity mix in the ‘business as usual scenario’ is shown for the investigated time horizons in Table 5-10.

Table 5-10: Contribution of different energy sources to the German electricity mix of investigated time horizons
(source: /173/)

[%]	2007	2015	2025	2050
Hard coal	22.4	26.9	28.2	21.4
Lignite	24.9	22.2	32.9	35.2
Oil	1.0	0.4	0	0
Natural gas	12.7	14.2	18.8	16.5
Nuclear	27.1	16.8	0	0
Hydro	3.4	3.8	3.7	3.7
Wind	4.8	9.2	9.3	15.0
Solar	0.2	0.8	1.0	1.7
Others	3.5	5.7	6.0	6.4

In a next step LCI data on the German electricity mix for the respective time horizons are calculated. Thereby datasets on electricity generation from different energy sources are

developed and composed according to the shares in Table 5-10. The technical development and efficiency improvement of the individual electricity generation technologies over the time horizons are derived from the energy system model applied in 'NEEDS'.

In the following LCA study, the LCI data on German electricity mixes are mainly applied for processes within the CCS chain, as for instance the operation of CO₂-pipeline compressors and for the CO₂-injection. The electricity for operation of auxiliary systems of the investigated power plants is generated by the respective power plant itself and not taken from the electricity grid.

5.3.3 Material Supply

The LCI data on future material supply is derived from the research conducted within the 'NEEDS' project. Therein, the LCI data on the supply of materials as well as on basic services were developed for the future time horizons 2025 and 2050 /111/. These datasets are applied for LCI calculation in this study. Since for the time horizon 2015 only minor changes in the LCI data on the supply of materials are expected, only for the time horizon 2025 and 2050 future LCI data on the material supply are generated and applied.

5.4 Electricity Generation in Power Plants with Pulverized Coal Combustion (PCC) and CO₂ Post-combustion Capture

CO₂ Post-combustion capture involves the separation of CO₂ from the flue gases of large-scale combustion processes of fossil fuels. This capture approach is independent of the combustion process itself and constitutes an end-of-pipe technology, which can be added to the flue gas cleaning of any fossil fuelled power plant.

5.4.1 Background on Electricity Generation in PCC Power Plants

The combustion technology most widely used for electricity generation from hard coal is PCC. More than 90 % of the total coal-fired capacity worldwide is based on PCC technology /115/. Starting from many decades of experience, PCC combustion is a mature technology, which can be applied to different kinds of coal. The output capacities of PCC power plants are oriented to the capacity of the operated steam turbines and range between 50 and 1,300 MW_e, whereas most new power plants now feature capacities exceeding 300 MW_e.

The efficiency of a PCC power plant is mainly determined by the efficiencies of the steam cycle and the boiler, which again are mainly influenced by the applied steam conditions. Most PCC power plants worldwide operate at subcritical conditions, which refer to steam pressures below 220 bar and temperatures below 540 °C /114/. These units feature efficiencies for electricity generation between 35 and 39 % as shown in Table 5-11. The overall thermal efficiency of some older, relatively small subcritical units can be even lower at around 30 % /115/. The range of net efficiencies achievable in PCC power plants is influenced by the coal quality, the local cooling conditions and the operation mode (part-load versus base load). Already different cooling conditions as for instance the utilisation of a cooling tower instead of direct sea water cooling can

result in a difference of about two percentage points in the efficiency of a power plant /116/. This is because power plants operate more efficiently with lower temperatures of both the cooling water and the ambient air.

Table 5-11: Steam conditions and net efficiencies of current and future PCC power plants (derived from /117/ /112/ /114/)

Steam conditions	Net efficiency* [%]	Temperature level [°C]	Pressure level [bar]
Sub-critical	35 – 39	< 540	< 220
Supercritical	40 – 45	540 – 566	220 – 270
Ultra-supercritical	46 – 55	> 566	> 270

Nowadays, PCC power plants using steam in supercritical conditions have become the system of choice for new commercial coal-fired power plants in many industrialized and developing countries /112/. More than 240 supercritical units are currently in operation worldwide /117/. Net efficiencies of 40 to 45 % are achievable with these power plants as shown in Table 5-11. Proceeding to even more advanced power plants operating at ultra-supercritical steam conditions, there are more than 24 units operating worldwide, which have been commissioned in Denmark, Germany, Japan, the Netherlands and USA /117/.

Table 5-12: State-of-the-art of PCC power plants in Europe (source: /118/ /174/)

Power plant unit	Country	Year of commissioning [year]	Net capacity [MW]	Steam temperature [°C]	Net efficiency [%]
Studsrup 3&4	DK	1984/1985	2x350	540	42.0
Avedøreværket 1	DK	1990	250	545	42.4
Fynsværket 7	DK	1991	385	540	43.5
Esbjergværket 3	DK	1992	385	560	45.0
Staudinger 5	D	1992	500	562	43.0
Rostock 1	D	1994	500	562	43.0
Hemweg 8	NL	1994	630	563	43.0
Amer 9	NL	1994	600	568	42.6
Nordjyllandsværket 3	DK	1998	400	582	46.8
Avedøreværket 2	DK	2002	400	600	46.8
Westfalen D/E	D	2011 (planned)	2x800	600/610	> 46
Moorburg	D	2012 (planned)	820	600	46.5

DK -Denmark; D - Germany; NL – Netherlands

Table 5-12 provides an overview of the state-of-the-art of the most modern PCC power plants in Europe. This table reveals that the power plant with the currently highest efficiency in Europe is the unit Nordjylland 3 in Denmark with an efficiency of almost 47 % and a capacity of 400 MW_e /118/.

In Germany the most advanced PCC power plant Rostock 1 commissioned in 1994 with a net efficiency of 43 % is reported. After a break of more than one decade without any commissioning of new hard-coal-fuelled power plants in Germany, new power plant units are currently planned to be commissioned by 2011 / 2012, which are dimensioned for a net efficiency above 46 % /174/, as shown in Table 5-12.

5.4.2 Future Development of PCC Technology

The main objective of future development of PCC technology is directed at further efficiency enhancements of ultra-supercritical power plants. The main prerequisite for higher efficiencies is the operation at even more elevated steam conditions than applied in current power plants. For steam conditions in the range of 700 °C net efficiencies in the range of 50 to 55 % (depending on inland or coastal sites) could be achieved /119/. However, the aspired increases in power plant efficiencies requires the development of advanced materials especially for the steam turbine and the boiler, since steel, as used today, does not tolerate steam temperatures and pressures in the range of 700 °C and above 350 bar. The European project 'THERMIE 700' aims to develop nickel alloys (also called super alloys) required for superheaters and steam pipework at this temperature level. In the project 'COMTES 700', plant operation at a temperature of 700 °C is investigated at an existing hard-coal-fired 750 MW_e power plant. Thereby the super alloys are being tested for high-temperature applications and new austenite materials are being applied in the medium temperature range. Furthermore, in this project, experience on steam oxidation, expansion and also flue gas corrosion is gained /119/.

Apart from the material development for higher steam operating conditions, there are several measures to increase the thermal efficiency of the steam cycle relative to current design practice. Such measures are intermediate superheating, regenerative feedwater preheating and a further lowering of the condenser pressure /115/. Currently, hard-coal-fuelled steam condensing power plants normally feature single intermediate superheating and up to ten feedwater preheating stages.

In order to reach higher efficiencies within all processes of a PCC power plants, the losses outside of the steam cycle process have to be minimised, e.g. combustion and flue gas losses. Measures to utilize the flue gas enthalpy are air preheating, cold end optimisation and flue gas release through a wet cooling tower. Furthermore, the power consumption of all auxiliary systems has to be optimised. In modern power plants, all these measures for efficiency enhancement will be applied.

5.4.3 Background on Systems for CO₂ Post-combustion Capture

There are several different technologies for the separation of CO₂ from the flue gases of power plants based on principles such as absorption, adsorption, cryogenics and membranes. The selection of the preferred capture technology depends on flue gas properties as for instance the temperature, pressure, concentration and volume flow rate /77/. Flue gases of combustion

systems are usually released at atmospheric pressure and due to the large presence of nitrogen feature CO₂ concentrations ranging between 3 and 14 % /72/. For these flue gas conditions the most favourable performance in CO₂ post-combustion capture in terms of high selectivity, capture efficiency as well as lowest energy requirement and costs is currently achieved by chemical absorption processes /72/.

The absorption processes based on MEA or related amines are currently the only commercially available CO₂ post-combustion capture technologies /122/. However, deployment for large-scale power generation has not yet been achieved /72/ /77/. The production capacity of present facilities applying CO₂ post-combustion capture at coal- or gas-fired power plants for the purpose of CO₂ production for food/beverage applications ranges between 6 and 800 tons of CO₂ per day /72/. The capture of 90 % of the CO₂ generated by a power plant with a capacity of 500 MW_e at a net efficiency of 45 %, however, would produce about 7,000 tons CO₂ per day. Table 5-13 provides an overview of current plants with commercial CO₂ post-combustion capture.

Table 5-13: Commercial power plants with CO₂ post-combustion capture
(source: /77/)

Operator	Location	Capacity (tons CO ₂ per day)	Energy technology	CO ₂ usage	Year of commis- sioning
IMC Global	Trona, California	800	Coal boiler	Carbonation of brine (soda ash)	1978
Mitchell Energy	Bridgeport, Texas	493	Gas heaters, engines, turbine	EOR	1991
Northeast Energy Associates	Bellingham, Massachusetts	320	Gas turbines	Food-grade	1991
Applied Energy Systems	Poteau, Oklahoma	200	Gas boiler (fluidized bed)	Food-grade	1991
Sumitomo Chemicals	Chiba, Japan	165	Gas boilers plus oil / coal boiler	Food-grade	1994
Luzhou Natural Gas	China	160	NH ₃ plant reformer exhaust	Urea	1998
Indo Gulf Fertilizer Co.	India	150	NH ₃ plant reformer exhaust	Urea	1988
Prosint	Rio de Janeiro, Brasil	90	Gas boiler	Food-grade	1997
Liquid Air Australia	Australia	2 x 60	Gas boiler	Food-grade	1985
AES, Shady Point Power Station	Panama, Oklahoma	190	Coal-fired CFB boiler	Food-grade	1991
AES, Warrior Run Power Station	Cumberland, Massachusetts	150	Coal-fired CFB boiler	Food-grade	1999

With amine based absorption processes, generally 80 to 95 % of the CO₂ is able to be scrubbed /72/ /124/ depending on the design of the absorber /77/.

5.4.4 Future Development of the Technology for CO₂ Post-combustion Capture

Research on CO₂ post-combustion technology mainly aims to reduce the energy requirement of the absorption process. Therefore, new solvents are tested, which feature higher CO₂ loading capacities, reduced energy demand in the regeneration process or less sensitivity to NO₂ and SO₂ and thus reduced the solvent degradation. These solvent properties would increase the efficiency of the overall capture process and at the same time would allow a smaller dimensioning of the capture facilities. Solvents with promising properties, which are close to commercialisation, are ammonium and potassium /122/. However, the main development of new solvents is concentrated on the optimisation of amine blends, as amines have proven to have so far the most advantageous characteristics for CO₂ absorption /72/.

Besides absorption processes, membranes are under development for CO₂ post-combustion capture from flue gases. Membrane technology is already commercially used at present for CO₂ removal from natural gas at high pressure and at high CO₂ concentration, but at flue gas conditions of PCC power plants, considerable energy is necessary as a driving force for CO₂ separation, which results in higher energy penalties than for chemical absorption processes /72/. Improvements in membrane technology can be made, if more selective membranes become available.

Other areas of development are improvements and optimisation of the auxiliary systems for CO₂ capture. An optimal integration of the CO₂ capture unit into the electricity generation processes is a prerequisite for operational availability and reliability at different load levels /77/.

5.4.5 Specification of Investigated Technological Development of PCC Power Plants with and without CCS

The ultra-supercritical PCC technology currently operated in hard coal power plants in Europe and also worldwide is taken as reference for the LCA study. For the investigated hard-coal-fired PCC power plant the steam parameters of the currently planned German hard-coal-fired power plant units Westfalen D/E, namely 600 °C and 285 bar /174/, are applied. Since these steam cycle conditions allow operation at electrical net efficiencies above 46 % (see Table 5-12), for the investigated PCC power plant a net efficiency of 46 % is assumed. This power plant is analysed for 600 MW_e representing an average capacity of hard-coal-fired PCC power plants. The capture of CO₂ is performed based on chemical absorption processes, which constitutes a proven and commercially available technology in the oil and gas industry /72/ /77/. Thereby the most proven and commercially applied amine, monoethanolamine (MEA), is applied to scrub the CO₂ from the flue gas.

Starting from the anticipated future development of both ultra-supercritical PCC and CO₂ post-combustion capture technology, power plant data for future time horizons have been derived in

accordance to the ‘NEEDS’ project. The technical specifications of PCC power plants for the time horizons 2015, 2025 and 2050 are summarized in Table 5-14. In principle, the same PCC power plant with a gross capacity of 643 MW_e is analysed for different technical settings with and without CCS. The applied CO₂ capture rate and the associated efficiency penalties are derived from [120]. Since the technology for CO₂ post-combustion capture is expected to be technically mature for large-scale application in PCC power plants not until the future time horizon 2015, PCC power plants with CCS are investigated only for future horizons.

Table 5-14: Technical specification of investigated current and future PCC power plants with and without CO₂ post-combustion capture

Post-combustion capture		2007	2015	2015	2025	2025	2050	2050
CCS		without	without	with	without	with	without	with
El. gross capacity	[MW _e]	643	643	643	643	643	643	643
El. net capacity	[MW _e]	600	602	477	603	517	603	543
El. gross efficiency	[%]	49.3	51.3	51.3	52.3	52.3	56.3	56.3
Efficiency penalty due to auxilliary systems	[%]	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Efficiency penalty due to CO ₂ capture	[%]	-	-	10 (7.7)	-	7	-	5
El. net efficiency	[%]	46.0	48.0	38.0 (40.3)	49.0	42.0	53.0	48.0
Technical life time	[a]	35	35	35	35	35	35	35
Load	[h/a]	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Net electricity generation over the life time	[TWh _e]	157.5	158.0	125.2	158.3	135.7	158.3	142.5
CO ₂ capture rate	[%]	-	-	90	-	90	-	90
SO ₂ emissions	[mg/Nm ³]	200	150	10	130	10	50	10
NO _x emissions	[mg/Nm ³]	200	150	40	140	40	60	40
PM ₁₀ emissions	[mg/Nm ³]	20	10	5	8	3	5	2

In brackets: Technical specification in case of CO₂ barge transportation instead of CO₂ pipeline transportation (see chapter 5.7.9)

The efficiency increases shown for future time horizons in Table 5-14 predominantly originate from elevations of the live steam parameters. Influence factors of second importance are the integration of further intermediate superheating and the reduction of combustion and flue gas losses. Finally also improvements of auxilliary systems are incorporated in the efficiency increases of future power plants. In Table 5-14 the efficiency penalty due to auxiliary systems remains constant for all PCC power plants at 3.3 %. This constancy, however, actually reflects an efficiency increase in the auxilliary systems, since it has to be referred to concurrently increasing net electricity generation.

The reduced efficiency penalty due to CO₂ capture takes the development of solvents with lower energy requirement and higher CO₂ loading capacities into account.

5.4.6 Investigated Hard-coal-fired PCC Power Plants with and without CO₂ Post-combustion Capture

The generic principle of electricity generation in the investigated ultra-supercritical hard-coal-fired PCC power plant with and without CO₂ post-combustion capture can be followed in Figure 5-4 showing a simplified process flow diagram. Since CO₂ post-combustion capture constitutes an end-of-pipe technology, facilities for the capture of CO₂ can be integrated downstream to the flue gas cleaning as shown by the facilities within the dotted border in Figure 5-4.

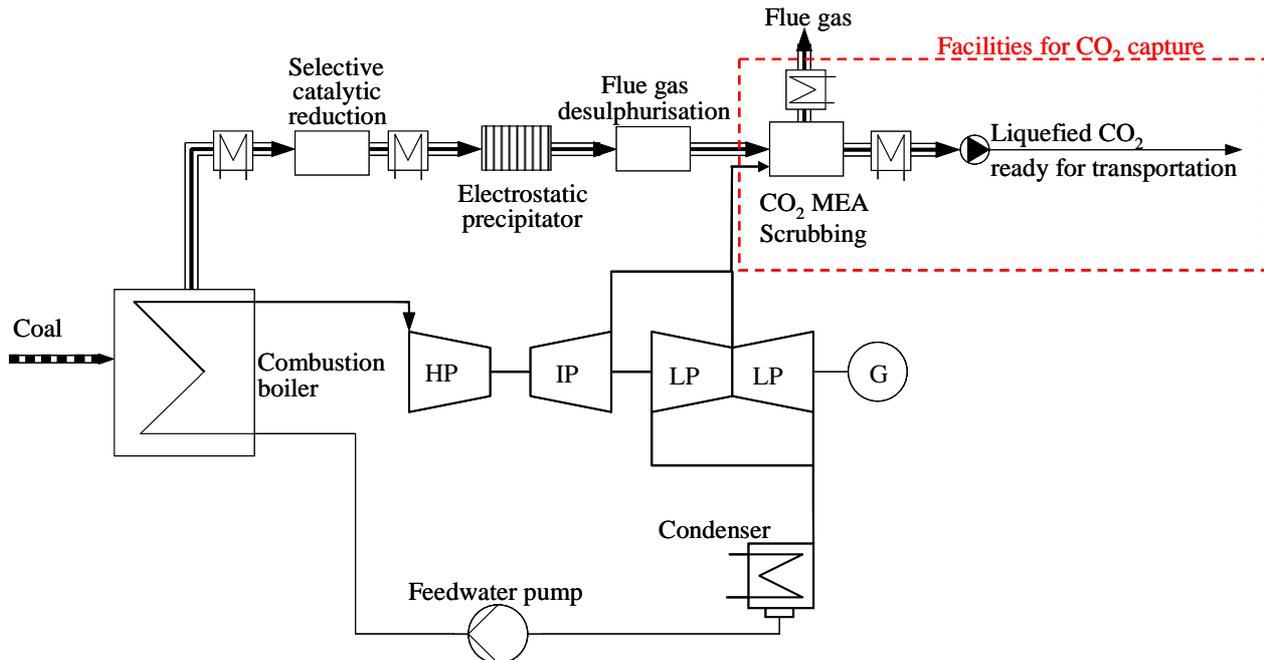
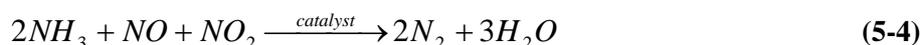
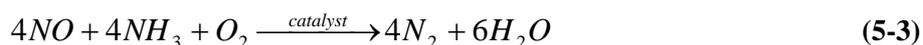


Figure 5-4: Simplified process flow diagram of the investigated ultra-supercritical PCC power plants with and without CO₂ post-combustion capture

In the PCC power plant, the coal is crushed and milled to fine powder, which is burned at atmospheric pressure. In case of bituminous coal, 70 to 75 % of the coal powder feature particle sizes smaller than 75 μm , while only less than 2 % are larger than 300 μm /113/. These particle sizes are small enough to be injected through burners together with combustion air directly into the combustion chamber. The fine coal particles heat up rapidly, undergo pyrolysis and finally ignite so that the particle residence time in the combustion chamber is typically between 2 and 5 seconds /113/ /114/. Thereby combustion temperatures between 1,500 and 1,700 $^{\circ}\text{C}$ are obtained. The generated heat is lead through the boiler, whereas live steam is produced in the boiler tubes of the heat exchangers. This live steam drives a steam cycle consisting of high-pressure, medium-pressure and low-pressure turbines that are coupled to an electric generator. The flue gas leaving the boiler undergoes several steps of gas cleaning and is finally released into the atmosphere. In PCC power plants with CO₂ post-combustion capture the flue gas is furthermore scrubbed in a CO₂ capture unit, whereas the CO₂ is separated from the flue gas.

Flue Gas Cleaning From Nitrogen Oxides, Particulates and Sulphur Dioxide

In the first step of the flue gas cleaning, nitrogen oxides (NO_x) are removed by selective catalytic NO_x reduction (SCR). Thereby ammonia vapour is injected into the flue gas stream, which downstream the boiler after cooling by a heat exchanger features temperatures between 300 and 400 °C. The reaction of the reducing agent ammonia with the NO_x of the flue gas is enabled at these temperature conditions by the presence of a catalyst. This catalyst is embedded in the tubes of the SCR unit and is passed by the flue gas stream during the reaction. The reactions taking place in the SCR unit are shown by the equations 5-3 and 5-4:



In presence of the catalyst ammonia reduces NO_x, which in the flue gas primarily comprises nitrogen oxide (NO) and nitrogen dioxide (NO₂), to pure nitrogen and water. Thereby the first reaction (equation 5-3) is of major importance, since 90 % of the nitrogen oxides in the flue gas consist of NO.

Following to the SCR, an electrostatic precipitator (ESP) separates particulates from the flue gas stream. The basic principle of this technology, which is most widely used on coal-fired power units, is that the flue gas is passed through an electric field. Thereby the particles in the gas stream are initially charged by means of a corona discharge. The charged particles are immediately deflected by the electric field and finally deposit on collecting electrodes, from where they can be removed.

Downstream to the particulate removal in the process flow diagram in Figure 5-4, the flue gas desulphurisation (FGD) unit is installed. This unit applies the concept of wet scrubbing, which currently constitutes the most widely used FGD technology for SO₂ removal in PCC power plants /121/. Thereby the flue gas stream is scrubbed by a sorbent, which is limestone slurry. Calcium carbonate from the limestone reacts with the SO₂ and oxygen (O₂ from air) according to equation 5-5 to ultimately produce gypsum. This gypsum precipitates from the solution in the sump of the FGD unit and can be sold as by-product.



Specifications on the released concentrations of SO₂, NO_x and particulates are derived from the 'Reference Document on Best Available Techniques (BREF) for Large Combustion Plants' /169/, which was developed in the course of the direction on Integrated Pollution Prevention and Control (IPPC) of the European Commission. This document outlines currently applied power plant technology, state-of the art technology and best available technology (BAT). Furthermore, thresholds and estimations on emission levels are reported for the mentioned technology levels of different large combustion plants. These references of the BREF for SO_x, NO_x and particulate emissions are applied in the scenario modelling of this study, whereas references for currently operated plants are assumed for 2007, references for new built power plants are assumed for 2015 and references for BAT are assumed for 2025. Further

improvements are modelled for 2050 according to Theloke et al. /170/, who outline possible measures for even further reduction of SO_x and NO_x emissions from PCC technology.

Specifications on NO_x and SO_2 emissions for PCC power plants with CO_2 capture are taken from /72/, which reports emission levels to avoid a major degradation of the solvent MEA.

Scrubbing and Compression of CO_2

The investigated unit for CO_2 post-combustion capture in this study is oriented to the pilot facility operated within the European project ‘ CO_2 from Capture to Storage’ (CASTOR) at the Danish power plant Esbjerg. In this pilot facility 0.5 % of the flue gas from the 400 MW_e power plant is scrubbed, whereas at a CO_2 capture rate of 90 % approximately one ton of CO_2 per hour is produced /122/. For this study this pilot facility has been scaled-up in order to scrub the entire flue gas of the investigated PCC power plant.

The fundamental underlying principle of CO_2 scrubbing in this CO_2 capture unit is the exothermic and reversible reaction between a weak acid (CO_2) and a weak base (MEA) to form a soluble salt. In the process flow diagram of the analysed CO_2 capture unit, which is shown in Figure 5-5, this reaction takes place, when the flue gas is counter-currently contacted with the lean solvent MEA in the absorber.

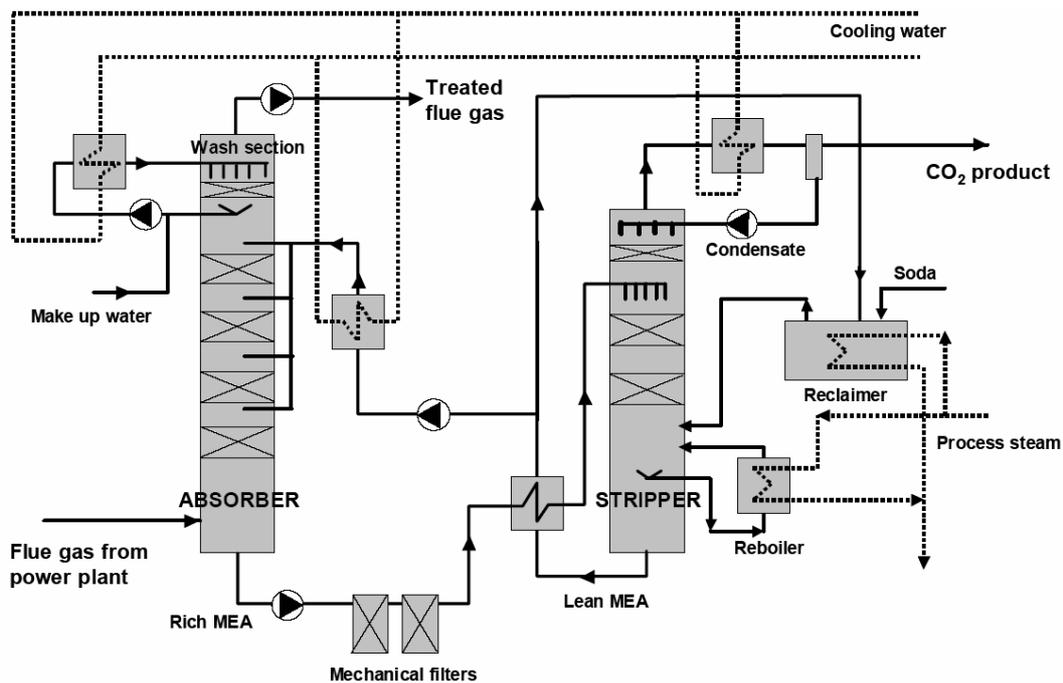


Figure 5-5: Flow diagram of the unit for CO_2 post-combustion capture derived from the CASTOR pilot plant at Esbjerg power plant (source: /122/)

Since hot flue gases cause solvent degradation and reduce the absorber efficiency, the absorber temperature typically ranges between 40 and 60 °C /72/. After the absorption, at which 90 % of the CO_2 is bound by the solvent, the flue gas undergoes a water wash in order to remove remaining solvent droplets before it is finally released. The rich solvent loaded by absorbed CO_2

is pre-heated and pumped to the stripper, where the CO₂ is released from the solvent again. This reversion of the absorption process (desorption) in the stripper takes place at elevated temperatures of 100 – 140 °C. Thereby gaseous CO₂ with a purity of 99.9 % (dry basis) is released and leaves at the top of the stripper [124/ 72/ 77]. The regenerated solvent is led back to the absorber.

The heat energy required by the stripper in order to provide the elevated temperature conditions for the regeneration of the rich solvent is typically provided by low-pressure steam, which was extracted from the steam cycle prior to the last expansion stage of the steam turbine [77/ 72].

Additional energy is required for the compression and liquefaction of the captured CO₂. For most cases in this study the captured CO₂ is compressed to a pressure of 110 bar and as a fluid injected into a CO₂ transportation pipeline. Both the bleed of steam and the electricity for CO₂ compression (see chapter 5.7.9) are taken from the electricity generation process and thus reduce the overall efficiency of the power plant. This is referred to as efficiency penalty due to CO₂ capture.

In few cases the CO₂ transportation by barge is investigated, which takes place at a pressure of 7 bar. This means that the captured CO₂ has to be compressed to a lower pressure level, so that less energy is required. This means that less energy is taken from the process of electricity generation and thus the efficiency penalty of the power plant is lower, which is shown by the bracketed numbers in in Table 5-14.

The use of MEA as a scrubbing solvent requires low levels of NO_x and SO₂ in the flue gas to be scrubbed. This is because NO_x and SO₂ react with the amine to form heat-stable, non-regenerable salts and thus cause a solvent loss. An SO₂ concentration of around 10 ppm is reported to keep the solvent consumption at around 1.6 kg of MEA per ton of CO₂ [72]. In the case of NO_x, a NO₂-level smaller than 20 ppm is recommended, as it is primarily the NO₂ that reacts with the solvent [77]. Thus, according to [72] an NO_x-level of around 40 ppm is more than sufficient to fulfil this requirement. Summarizing, a prerequisite for CO₂ post-combustion capture is a previous flue gas cleaning by means of SCR and FGD, which is able to reach the cited flue gas pollutant limits.

5.5 Electricity Generation in Hard-coal-fired Power Plants with Oxyfuel Combustion

The main component of the flue gases of conventional PCC technology is nitrogen, since it constitutes approximately 79 % by volume of the air used in combustion. In these flue gases, CO₂ is present as a dilute gas with a volume of 3 to 14 % [72]. This low CO₂ concentration makes CO₂ capture energy intensive and costly [75]. Therefore, in case of oxyfuel combustion, the dilution of the CO₂ concentration by nitrogen in the flue gas is avoided by using oxygen for combustion instead of air. By means of an air separation unit (ASU), almost pure oxygen (95 – 99.7 % [73]) is produced and supplied to the combustion process. That way, CO₂ concentrations

in the cleaned flue gases of oxyfuel combustion can reach 95 % and above /75/ /72/. This enables the direct capture of the entire flue gas stream instead of just scrubbing the CO₂.

5.5.1 Background on Oxyfuel Combustion

Oxyfuel combustion does not constitute an entirely new technology, but has been used for several years in the metal and glass manufacturing industries /72/ /73/. The combustion in pure oxygen was applied in furnaces in order to reach higher temperatures combined with improved efficiency and reduced emissions /73/ /75/. This means that all the major components of oxyfuel combustion have already gained first experiences and are principally available /73/.

The feasibility of coal-fired oxyfuel combustion for electricity generation in conventional steam boilers has been demonstrated in several pilot-scale studies /72/ /73/ /75/. Thereby, the possibility of CO₂ capture was tested, as first proposed by Abraham in 1982 in order to use the captured CO₂ for enhanced oil recovery /4/. Combustion experiments on small commercial stoker furnaces and pilot boilers in the USA, Japan, Canada and Europe did not reveal any major barriers /73/ and thus paved the way for future large-scale applications of the oxyfuel technology. In the most recent development, the energy supply company Vattenfall commissioned a demonstration oxyfuel power plant featuring an capacity of 30 MW_e at its power plant site Schwarze Pumpe in Germany in 2008.

5.5.2 Oxyfuel Technology in Hard-coal-fired Power Plants

As the flame temperature of coal combustion in pure oxygen at near-stoichiometric conditions can reach up to 3,500 °C, which is far too high for typical power plant materials, in oxyfuel power plants part of the flue gas is recycled back to the boiler in order to reduce the flame temperature to about 1,900 °C /72/. Recycling in this context means that, downstream of the economizer, a part of the flue gas, which at this stage consists mainly of CO₂ and water vapour, is separated and fed back to the boiler. Besides temperature control, this flue gas recycling replaces the volume of the missing nitrogen and ensures that there is enough gas to carry the heat through the boiler /75/.

The flue gas of oxyfuel combustion consists mainly of CO₂ (about 90 % on a dry basis), water vapour, minor amounts of noble gases and some excess oxygen, which is required to ensure complete combustion of the fuel /73/. Additionally, there are minor amounts of SO₂, NO_x, metals and particulates originating from impurities in the coal. The non-recycled part of the flue gas undergoes water condensation and removal of impurities. The remaining gas stream of almost pure CO₂ is compressed to liquid state for transportation and storage.

Differences between PCC and oxyfuel technology

There are three key elements that distinguish the process flow of a coal-fired oxyfuel power plant from a similar power plant based on conventional PCC technology:

- An air separation unit (ASU) is added for generating high-purity oxygen for combustion

- Technical equipment for recirculating a part of the flue gas back to the boiler is established
- The flue gas treatment comprises dehydration and compression of the flue gas as preparation for CO₂ transportation

Oxyfuel power plants feature lower efficiencies than conventional PCC power plants. This is due to the increased auxiliary power consumption mainly by the ASU /76/.

In the following sections possible concepts and properties for the boiler and the ASU in oxyfuel power plants are described.

Boiler and Flue Gas Recirculation

The combustion of coal in an environment of mainly oxygen, carbon dioxide and water vapour affects the combustion performance and the heat transfer patterns in the boiler. Studies showed that a combustion with 30 % oxygen in CO₂ (compared to an oxygen concentration of 21 % in air) would still allow the same boiler design to be used /74/. The combustion in higher concentrations of oxygen, however, requires a modification of the boiler, mainly at the heat transfer surfaces and burners /73/. Higher concentrations of oxygen and thus higher flame temperatures are achieved, when the flue gas recycling rate is further reduced. The same adiabatic flame temperature as for a conventional PCC is achieved with oxyfuel combustion at a recycling rate of approximately 60 % of the flue gas /75/.

Experiences from pilot studies showed that the repowering of an existing boiler to oxyfuel combustion is feasible /75/. However a new boiler design is preferable, since it allows an optimisation of the oxygen concentration in the feed gas and also yields a slightly higher combustion efficiency /73/. The application of oxyfuel technology to new and modern ultra-supercritical boilers is even more advantageous, since their increased efficiency reduces the oxygen demand per kWh of generated electricity and thus reduces the energy demand by the ASU /73/. Another obstacle for the retrofit of existing boilers to oxyfuel combustion is the control of the air-in-leakage. Current boiler systems normally feature air-in-leakages of 8 to 16 %, which are difficult to be completely eliminated /73/.

Air Separation Unit

There are different technologies for separating the individual constituents of air. Commercial technologies that are applied mostly in air separation facilities worldwide are cryogenic distillation, pressure swing adsorption (PSA) and vacuum swing adsorption (VSA). PSA and VSA are designed and utilized for small-scale oxygen production (< 200 t O₂ / d), whereas cryogenic distillation can be applied to large-scale oxygen production /73/. Cryogenic distillation constitutes the separation of the individual constituents of air by the difference in their boiling points taking place at cryogenic temperature level. The largest oxygen production plant currently operating based on cryogenic distillation features a capacity of 4,000 t O₂ / d, however design

studies for the generation of 7,000 t O₂/d have already been performed /73/. Figure 5-6 summarizes the range of application for the respective air separation technologies.

A hard-coal-fired oxyfuel power plant featuring a capacity of 600 MW_e and an efficiency of 45 % requires an oxygen supply of around 8,000 – 9,000 tons of oxygen per day /67/. MitsuiBabcock reports a demand of 10,400 t O₂ per day for the operation of an oxyfuel power plant with a net capacity of 677 MW_e /74/. This highlights that cryogenic air separation is currently the only technology for oxygen production available on an industrial scale /72/ /73/ /74/ /75/ /76/. After one century of application, cryogenic distillation is considered a mature and proven technology with high reliability and without any major safety or maintenance problems /72/ /73/. An electricity demand of 0.21 to 0.29 kWh_e / kg oxygen (at 99.5 % volume share) is required for oxygen production in these processes /178/.

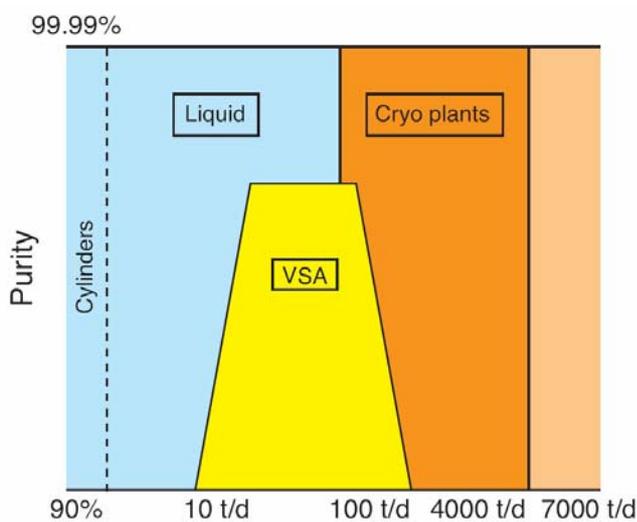


Figure 5-6: Capacities of different technologies for oxygen production from air (source: /73/)

Flue Gas Treatment

Due to the absence of nitrogen in the feed gas, there is almost no formation of thermal NO_x. The only NO_x emissions originate from fuel-bound nitrogen, whereas approximately 50 % of this generated NO_x is reduced to nitrogen (N₂) in the course of the flue gas recycling /76/. In addition, reducing interaction between recycled NO_x, fuel bound nitrogen and hydrocarbons released from coal may further decrease the formation of NO_x /75/. Due to this low level of NO_x in the flue gas, in most oxyfuel concepts no SCR units are established for the flue gas cleaning /73/.

The generation of SO₂ originates from sulphur bound in the coal and on a quantitative basis is similar to that of PCC technology. Thus the flue gas treatment of oxyfuel power plants can similarly to PCC power plants comprise FGD units for the removal of the remaining SO₂. In some oxyfuel concepts, however, FGD units are omitted, since the remaining SO₂ in flue gas could also be potentially left to be stored alongside the CO₂ /73/ /74/.

5.5.3 Future Development of Oxyfuel Technology

Major improvements in oxyfuel technology are expected from future development of the ASU. Considering the maturity of cryogenic air separation, improvements to reduce the energy requirement and also costs of this technology are possible, but limited /73/. Thus, the development of new technologies for large-scale oxygen production with high energy efficiency is followed /77/. Promising technologies like oxygen transport membranes (OTM), which selectively transport oxygen across a membrane and thus achieve air separation, are intensively researched. However, currently OTM feature efficiencies that are considerably lower than those of cryogenic air separation and are at pilot plant stage, but large-scale production is projected to be available after industrial demonstration within the next decade /72/.

Another investigated process transferring oxygen directly from air to a solid material is chemical looping combustion, but still is at early stage of development. Thereby metal oxide particles are used for oxygen transfer from combustion air to fuel and thus CO₂ is obtained in a separate stream without any gas separation needed.

The process of oxyfuel combustion itself offers further potential for optimisation and efficiency improvement. Investigations on ignition characteristics, flame stability and heat transfer are required for further improvements of the boiler technology /75/. Furthermore, combustion chemistry and kinetics need to be analysed in detail in order to provide enhanced boiler design data. Another field of research is the investigation of dynamic behaviour as well as start-up and shut-down procedures for oxyfuel combustion /73/. Long-term availability and reliability have to be investigated at the operation of large-scale oxyfuel power plants.

5.5.4 Specification of Investigated Technology Development of Hard-coal-fired Oxyfuel Power Plants with CCS

According to the previously described technology development large-scale oxyfuel power plants are assumed to be firstly available in 2015. Starting from the anticipated future technical development of oxyfuel combustion, power plant data for the time horizons 2015, 2025 and 2050 have been derived, which are summarized in Table 5-15. The investigated hard-coal-fired oxyfuel power plants constitute newly built power plants, which are always dimensioned for CO₂ capture. The PCC power plants without CO₂ capture are considered the reference power plants for the oxyfuel power plant with CO₂ capture. Thus all these power plants feature the same gross capacity of 643 MW_e. The process flow diagram of the investigated hard-coal-fired oxyfuel power plants is displayed in Figure 5-7.

The applied CO₂ capture rate and the associated efficiency penalties of the investigated hard-coal-fired oxyfuel power plants are derived from /120/. The remaining non-captured two respectively three percent of the CO₂ emissions are assumed to be lost in the TEG unit, which is explained in more detail in the following sections. The other gaseous emissions of the electricity generation process are almost entirely captured together with the flue gas stream of the oxyfuel

power plant. Only one percent of these emissions are assumed to be lost and thus released into the atmosphere during the flue gas treatment. Since particulates are usually removed before the flue gas treatment, no losses but an entire capture are assumed for particulate emissions.

Table 5-15: Technical specification of investigated future oxyfuel power plants with CO₂ capture

Oxyfuel combustion		2015	2025	2050
CCS		with	with	with
El. gross capacity	[MW _e]	643	643	643
El. net capacity	[MW _e]	602	603	603
El. gross efficiency	[%]	51.3	53.3	56.3
Efficiency penalty due to auxiliary systems	[%]	3.3	3.3	3.3
Efficiency penalty due to CO ₂ capture	[%]	8 (7.5)	8	7
El. net efficiency	[%]	40.0 (40.5)	42.0	46.0
Technical life time	[a]	35	35	35
Load	[h/a]	7,500	7,500	7,500
Net electricity generation over the life time	[TWh _e]	158.0	158.3	158.3
CO ₂ capture rate	[%]	97	97	97
SO ₂ emissions	[mg/Nm ³]	2 (1% loss)	1.3 (1% loss)	0.5 (1% loss)
NO _x emissions	[mg/Nm ³]	2 (1% loss)	1.4 (1% loss)	0.6 (1% loss)
PM ₁₀ emissions	[mg/Nm ³]	captured	captured	captured

In brackets: Technical specification in case of CO₂ barge transportation instead of CO₂ pipeline transportation (see chapter 5.7.9)

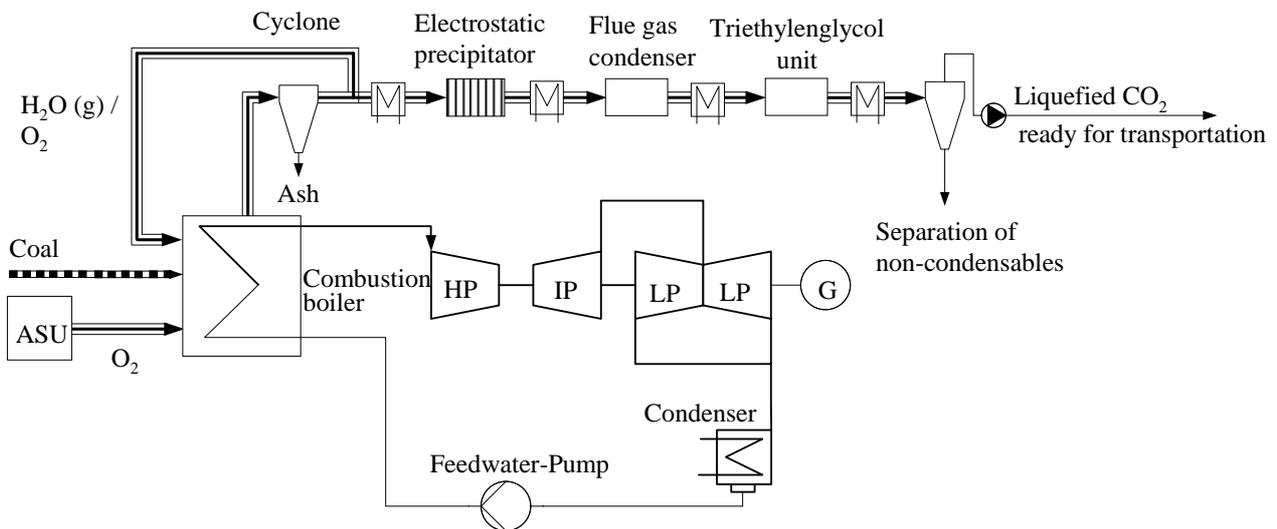


Figure 5-7: Process flow diagram of the investigated oxyfuel power plants with CO₂ capture

Similarly to PCC technology, the increases in the net efficiency of power plants for future time horizons mainly originate from the possibility to operate at higher live steam conditions, the installation of intermediate superheating and the reduction of combustion and flue gas losses. Furthermore, optimisations at the flue gas recirculation as well as improvements at the design as

well as the materials for oxyfuel boilers are responsible for the net efficiency increase of oxyfuel technology. The reduction of the efficiency penalty due to CO₂ capture in 2050 reflects improvements at the ASU.

ASU, Boiler and First Particulate Removal

In the investigated hard-coal-fired oxyfuel power plant oxygen is produced in the ASU by cryogenic distillation of air. This oxygen is used for combustion of pulverized coal in an oxyfuel boiler. Following the outlet from the boiler, a cyclone is installed, which removes the major part of the flue gas particulates. This cyclone is placed before the bypass for the flue gas recycle flow in order to avoid ash enrichment of the boiler /76/. More than half of the flue gas stream is fed back to the boiler.

Flue Gas Treatment

For the non-recycled part of the flue gas, removal of fine particles is necessary in order to protect the following heat exchangers and in particular the equipment for CO₂ compression /74/. This fine particulate removal is carried out in an ESP.

For the next step, a complete dehydration of the flue gas is performed, which is important for the CO₂ transportation. A dry CO₂ stream will inhibit corrosion and the precipitation of hydrates in the CO₂ pipeline and furthermore reduce the transported mass flow /76/. The flue gas is dehydrated in two steps. Firstly, it is passed through a traditional flue gas condenser, where most of the water is removed. Thereby a major part of the electrolytes (SO₂, chlorides and fluorides) are absorbed in the condensing water, which subsequently has to be cleaned by water treatment /76/. Secondly, leaving the condenser at a pressure of approximately 30 bar, the flue gas is further dehydrated in a tri-ethylene glycol (TEG) unit leaving a water residual of up to 60 ppm. The dehydration by TEG, which is exemplarily illustrated by the plant scheme shown in Figure 5-8, constitutes a well known and technically approved process, which is commercially and widespread used in the oil and gas industry /76/.

In the glycol contactor of the TEG unit not only water, but also some CO₂ is dissolved into the TEG liquid. This CO₂ is released when TEG solution is regenerated and thus lost from the flue gas stream. The amount of lost CO₂ depends upon the pressure and temperature levels in the TEG unit. At 30 bar and 25 °C, approximately 75 kg CO₂ / m³ TEG are dissolved and lost /76/, which represents the loss of 3 % of CO₂ emissions in the investigated oxyfuel power plant.

Due to the pressure increase up to around 58 bar at 20 °C in the TEG unit, the main part of the flue gas (CO₂ and SO₂) is in a liquid state after dehydration /76/. However, at the same time, remaining non-condensable gases (nitrogen, NO_x, oxygen, noble gases etc.) are still in a gaseous state. Taking advantage of this gaseous state, they are then separated in a conventional gas liquid separator /75/.

Finally, the cleaned flue gas is further compressed by a high-pressure pump in order to increase the pressure from 58 bar to CO₂ transport conditions of 110 bar. The flue gas stream leaving the

oxyfuel power plant after flue gas treatment is in a liquid state and features a CO₂ concentration of at least 97 %. This CO₂ capture rate is a very optimistic figure, which is based on theoretic studies and estimations done for the European project NEEDS in 2006 /43/. Currently, with further practical experience from pilot studies and labor scale experiments a CO₂ capture of 90 % appears more realistic. Since this study is oriented at the technical data of the NEEDS project, the CO₂ capture rate is maintained in the described analyses. However, the methodology of parametrisation allows the analyses of this study to be performed with other, CO₂ capture rates.

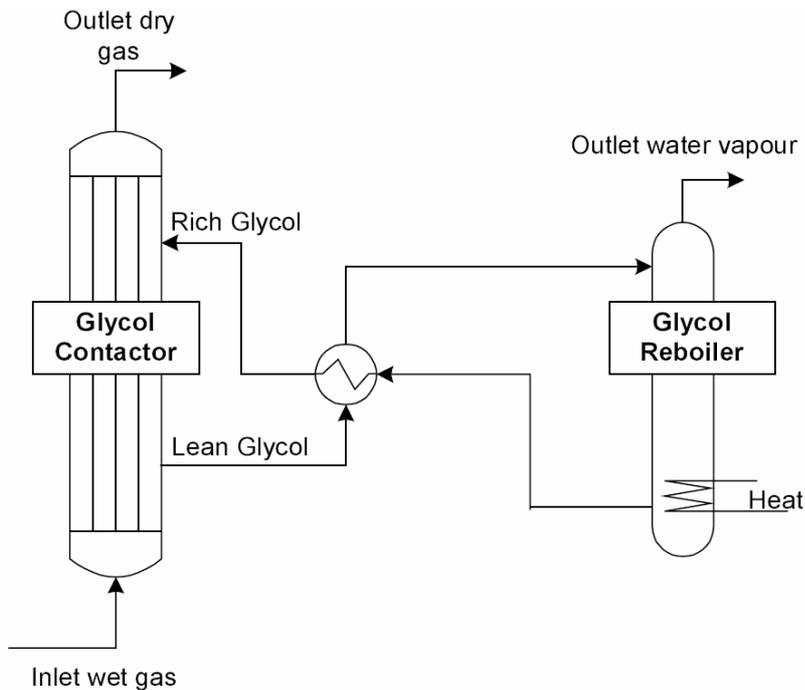


Figure 5-8: Plant scheme for a TEG dehydration unit
(source: /76/)

At the flue gas treatment of the investigated oxyfuel power plant no SCR unit for NO_x reduction and also no FGD unit is installed, since most of SO₂ and NO_x is already captured by the water condensing.

5.6 Electricity Generation in Hard-coal-fuelled IGCC Power Plants with CO₂ Pre-combustion Capture

Integrated gasification combined cycle (IGCC) is an emerging advanced power generation technology having the potential to generate electricity from coal with higher efficiency and lower emissions than other current coal technologies. Emission levels of NO_x, SO₂, CO and PM₁₀ emissions into air are considerably reduced and are expected to approach the emission levels of natural gas-based electricity generation /71/.

The concept of IGCC is derived from the natural gas combined cycle (NGCC) technology, which constitutes a combination of a gas turbine cycle and a steam turbine cycle. This use of two thermodynamic cycles in cascade, which gives the name of "combined cycle" to this technology,

allows generating electricity with higher efficiency compared to conventional PCC power plants, which are only based on a steam turbine cycle.

For the application of coal to the combined cycle technology, coal has to be gasified, since gas turbines cannot be charged with solid feedstock. The gasification product is a high temperature coal gas, which is often referred to as synthesis gas or syngas. After an exhaustive gas cleaning, this syngas is fired in a gas turbine for electricity generation. The hot exhaust of the gas turbine still has enough heat to generate super-heated steam, which is used for electricity generation in a steam turbine cycle. This simplified process structure of an IGCC power plant is pictured in Figure 5-9.

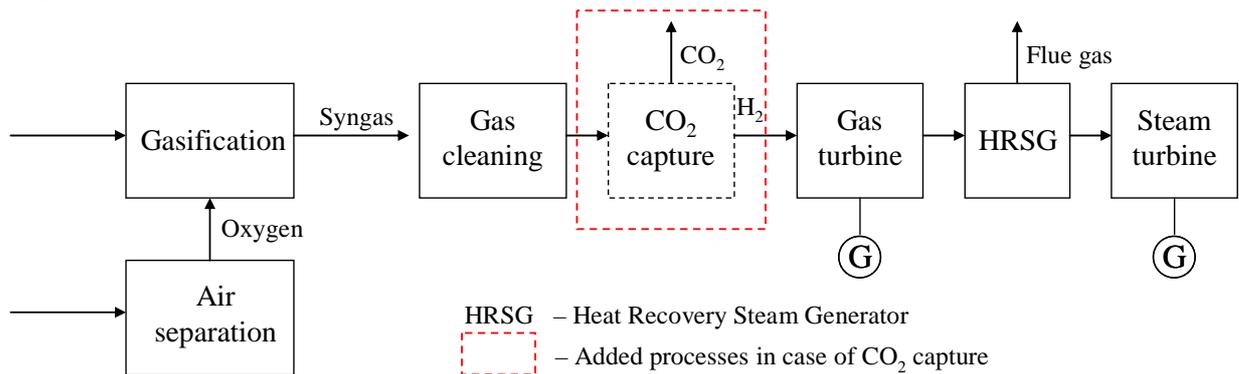


Figure 5-9: Simplified process structure of IGCC technology with and without CO₂ pre-combustion capture

IGCC plants are characterized by the oxidant fed to the gasifier (oxygen or air) and the type of gasifier /84/. There are moving-bed gasifiers, fluidized-bed gasifiers and entrained-flow gasifiers. Most IGCC plants in operation or under construction use entrained flow gasifiers, which are oxygen blown /78/. Since pure oxygen is not diluted by the large quantities of nitrogen present in air, oxygen-blown coal gasifiers are more efficient, produce a syngas stream with a higher concentration of CO₂ and thus enable CO₂ capture at lower energy expenditure /72/. However, making oxygen for this type of gasifier typically involves an ASU with an energy-intensive cryogenic process to extract oxygen from the air.

For CO₂ capture at IGCC technology a CO₂ capture unit is integrated after the process of gas cleaning, as shown in Figure 5-9. IGCC technology allows CO₂ pre-combustion capture, which constitutes the removal of the carbon content of the fuel prior to combustion. Thereby, the CO₂ is captured from syngas, which has higher partial pressures (20–30 bar) and a higher concentration of CO₂ (30 %) than the diluted flue gas of conventional PCC power plants (1 bar, 14 % CO₂ concentration) /72/ /77/. The preferred technique for CO₂ capture at such pressures and concentrations is currently physical absorption /85/. Physical solvents commonly used in commercial processes include cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor solvent process) and sulfolane. In IGCC power plants due to the higher partial pressures and higher concentrations of CO₂ in the syngas less energy for the separation of CO₂ is required, which entails lower efficiency penalties due to

CO₂ capture compared to CO₂ post combustion capture systems of conventional PCC power plants.

5.6.1 Background on Hard-coal-fuelled Electricity Generation in IGCC Power Plants

IGCC technology is based upon technologies, power plant components and materials that are already technically proven and available /72/. The gasification of coal is a mature technology with long-term experience. Large-scale syngas production for industrial generation of ammonium, different chemicals and synthetic fuels is technically state-of-the-art. The second core technology necessary for IGCC, is electricity generation by NGCC technology, which has also gained worldwide experience. Currently, there are still increasing growth rates of NGCC power plants. However, despite worldwide commercial use and acceptance of both gasification processes and NGCC power systems, coal-fuelled IGCC technology is still cited as not being established as a mature technology for electricity generation /78/. It is characterized to be ‘at demonstration stage’ /79/ or to constitute a ‘near commercial technology’ /69/.

Each major component of IGCC has been broadly utilized in industrial and power generation applications, but, so far, the integration of a gasification unit with a combined cycle power block for the purpose of electricity generation has only been demonstrated at a few facilities around the world. These milestone facilities of coal-fuelled IGCC technology for electricity generation are listed in Table 5-16.

Table 5-16: Coal-fuelled IGCC power plants for electricity generation worldwide (source: /78/ /80/)

	Cool Water demonstration power plant	Wabash power plant	Willem Alexander power plant	Polk power plant	Vresova power plant	Puertollano power plant
Location	California, USA	Indiana, USA	Buggenum, Netherlands	Florida, USA	Czech Republic	Spain
Net capacity (MW_e)	120	262	253	250	350 (430) ¹	298
Gasifier	Texaco	Conoco Phillips	Shell	Chevron Texaco	Lurgi	Prenflo
Gas turbine	GE 7E	GE MS 700IFA	Siemens V 94.2	GE MS 700IFA	GE 209E	Siemens V 94.2
Efficiency (% HHV)	33	39.7	41.4	37.5	41 (44) ¹	41.5
Feedstock	Bituminous coal	Bituminous coal / pet coke	Bituminous coal	Bituminous coal/ pet coke	Lignite	Bituminous coal / pet coke
Start of operation	1984	1995	1994	1996	1996 (2005) ¹	1998

¹ Numbers in brackets show a power plant retrofit and optimisation conducted in 2005

In 1984, the technical feasibility of coal-fuelled IGCC technology was first demonstrated at the Cool Water IGCC plant in California being regarded as a power plant of the first IGCC generation. Approximately ten years later, the commercial feasibility of second generation IGCC technology was demonstrated at the Polk Tampa power plant in Florida. On a commercial prototype scale, two IGCC power plants were built in Europe, namely in Buggenum (Netherlands) and in Puertollano (Spain). Both plants operate reasonably reliably at efficiencies of over 42 %. The unit in Puertollano is widely regarded as state-of-the-art for operational hard coal fuelled-based IGCC power plants /81/.

According to a recent status report on IGCC power plants by the World Coal Institute (WCI), there are currently around 160 IGCC plants installed worldwide. Furthermore, around 16,500 MW_e of IGCC capacity is expected to be operating in the USA by 2020 /70/ /82/. However, these figures predominantly refer to IGCC power plants based on oil, refinery residues and other feedstock different from coal. Less than 1 GW_e of the total installed IGCC capacity of 4 GW_e is operated based on coal /72/. These hard-coal-fuelled IGCC power plants have gained only limited operational experience and have not demonstrated sufficient availability so far, which has impeded a major commercial break through of IGCC technology /72/. The process complexity of IGCC technology and the considerable efforts in order to achieve high efficiencies led to a very integrated and complicated design, which goes in line with poor availability and high costs. /72/

This explains, why all coal-fuelled IGCC plants built so far were subsidised /72/. The European plants were part of the ‘Thermie program’ of the European Commission, whereas in the USA the Department of Energy (U.S. DOE) was partly funding the design and construction of the hard-coal based IGCC power plants as well as the operating costs for the first few years.

IGCC technology has not been very widely deployed due to availability concerns and strong competition from still cheaper PCC and NGCC power plants (wherever natural gas is readily available at low prices) /72/. However, during the last few years, major steps in terms of availability improvement and load-follow capacity were achieved, as recent experiences from the IGCC power plant in Puertollano show /68/.

According to the R&D programs funded by the U.S. DOE, the next phase of major improvements in IGCC technology is expected to be commercially available as third-generation-IGCC by 2010 /77/.

5.6.2 Future Development of IGCC Technology

The main disadvantages of IGCC technology are its high technological complexity, low operational flexibility, and relatively high specific investment costs. IGCC power plants have to be designed for a specific type of coal or solid fuel in order to achieve a high reliability. These aspects, as well as further efficiency enhancements, will be addressed in future technical research and development.

Improvement for coal gasification are expected from the development of less energy intensive methods to produce the oxygen required for gasification process. One possible way is the application of ceramic membranes to separate oxygen from the air at elevated temperatures /130/. Membranes may also become an important new technology for pre combustion capture of CO₂. Currently membranes are explored and developed that are able to selectively remove hydrogen from shifted syngas leaving behind a highly concentrated CO₂ stream.

Further substantial increases in the efficiency of IGCC technology will evolve from the application of hot gas clean-up. Currently, the gas cleaning stages for particulates and sulphur removal can only operate at relatively low temperatures, which limits the overall efficiency obtainable by IGCC /131/.

Efficiency improvements are also expected from advances in gas turbine technology (higher pressure ratios, higher turbine entry temperatures, reheat). Already with recent advances in gas turbine technologies and the current state-of-the-art of all other power plant components, IGCC power plants offering efficiencies close to 50 % are technically feasible /70/ /69/.

According to studies within the Carnot program of the European Union an efficiency of 51 – 53 % is expected for IGCC in 2015 (EC 2001). The coal industry anticipates IGCC power plants with future net efficiencies of 56 % /70/. In a similar vein the U.S. DOE is citing that in future IGCC technology may be able to achieve efficiencies approaching 60 % /131/. Very optimistic are also the forecasts by the German COORETEC (CO₂ reduction technologies) project: Starting from a current efficiency of 45 – 48%, an efficiency of 54 – 57 % is forecasted between 2010 and 2020. Past 2025 an IGCC efficiency of 62 % is expected /132/.

5.6.3 Background on CO₂ Pre-combustion Capture

CO₂ capture technology is well established for gasification systems that produce chemicals and synthetic fuels /86/. About 3,500 tons of CO₂ are daily generated in power plants for ammonium production worldwide. Large streams of nearly pure CO₂ are furthermore separated in South African plants producing Fischer-Tropsch fuels and chemicals as well as from a plant producing synthetic natural gas from coal in North Dakota /72/. Thereby, the physical solvent Rectisol is mostly used. The majority of the CO₂ captured in these power plants is vented. However not in North Dakota, where yearly about 1.5 megatons of CO₂ are compressed and transported via pipeline to the Weyburn field in Canada for the purpose of enhanced oil recovery (EOR) (see chapter 5.8.3). This shows that CO₂ pre-combustion capture can be considered a commercially ready technology. However, no IGCC plant with precombustion CO₂ capture has been built yet nor is under construction /72/.

5.6.4 Specification of Investigated Technology Development of IGCC Power Plants with and without CO₂ Pre-combustion Capture

The latest hard-coal-fuelled IGCC power plant for electricity generation installed in Europe is located in Puertollano, Spain, and was commissioned in 1998. This IGCC power plant has been

taken as the basis for the IGCC power plant investigated in this study. However, as the Puertollano IGCC power plant, to some extent, features power plant components dating back to 1998 and thus does not represent the current state-of-the-art of IGCC technology, some modifications were assumed for the investigated IGCC power plant.

Several possible improvements for the Puertollano power plant had already been investigated in the European JOULE III program, whereas based on more advanced power plant components and enhanced materials an optimised IGCC concept with higher capacity and higher efficiency called 'IGCC 2000' had been developed /83/ /68/. Both IGCC concepts have been taken as basis and have been further developed to the investigated hard-coal-fuelled IGCC power plant for the time horizon 2007 with an electric net efficiency of 450 MW_e (instead of 300 MW_e in Puertollano). The efficiency of the investigated IGCC power plant has been increased to 45 % instead of 42.2 % net efficiency in Puertollano. This efficiency increase originates from improvements in state-of-the-art power plant components, a change in the feedstock used and better cooling conditions due to assumed German conditions with lower temperatures. The reference IGCC power plant is fuelled by German steam coal instead of the current Puertollano mix of hard coal and bitumen.

Starting from the anticipated future development of IGCC technology, power plant data on future time horizons have been derived in accordance to the 'NEEDS' project. The technical specification of IGCC power plants for the time horizons 2015, 2025 and 2050 is summarized in Table 5-17.

Table 5-17: Technical specification of investigated current and future IGCC power plants with and without CO₂ pre-combustion capture

Pre-combustion capture		2007	2015	2015	2025	2025	2050	2050
CCS		without	without	with	without	with	without	with
El. gross capacity	[MW _e]	483	483	483	483	483	483	483
El. net capacity	[MW _e]	450	454	401	455	405	455	413
El. gross efficiency	[%]	48.3	54.3	54.3	57.3	57.3	60.3	60.3
Efficiency penalty due to auxilliary systems	[%]	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Efficiency penalty due to CO₂ capture	[%]	-	-	6 (4.9)	-	6	-	5
El. net efficiency	[%]	45.0	51.0	45.0 (46.1)	54.0	48.0	57.0	52.0
Technical life time	[a]	35	35	35	35	35	35	35
Load	[h/a]	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Net electricity generation over the Life Time	[TWh _e]	118.1	119.2	105.3	119.4	106.3	119.4	108.4
CO₂ capture rate	[%]	90	90	90	90	90	90	90
SO₂ emissions	[mg/Nm ³]	20	10	10	5	5	5	5
NO_x emissions	[mg/Nm ³]	80	40	40	25	25	25	25
PM₁₀ emissions	[mg/Nm ³]	-	-	-	-	-	-	-

In brackets: Technical specification in case of CO₂ barge transportation instead of CO₂ pipeline transportation

(see chapter 5.7.9)

In principle the same IGCC power plant with a gross capacity of 483 MW_e is analysed for different technical specifications with and without CO₂ pre-combustion capture. The applied CO₂ capture rate and the associated efficiency penalties are derived from /120/. Power plants with CO₂ capture are assumed to be firstly available in the time horizon 2015.

The main factors for the improvement of the net efficiency of future IGCC power plants are firstly the introduction of the hot gas clean-up, which avoids a cooling and reheating of the synthesis gas and secondly improvements of gas turbine technology. Finally enhancements at the ASU contribute to higher efficiencies.

At the CO₂ capture process only minor improvements are expected, since the use of physical solvents for CO₂ capture is already presently applied at medium scale. Further enhancements of the solvents and optimisations of shift reaction and CO₂ scrubbing are modelled to slightly reduce the efficiency penalty due to CO₂ capture by 2050.

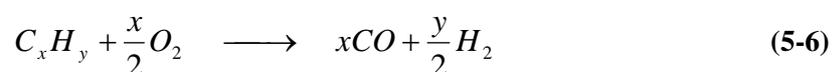
In order to avoid major degradation of the solvent for CO₂ scrubbing, the release of SO₂ and NO_x is oriented towards the concentration reported in /72/. For the IGCC power plants without CCS a more conservative assumption is made for the release of SO₂ and NO_x, which however will be met by the current state-of-the-art of syngas gas cleaning technology. For the time horizons 2025 and 2050 the concentration of BAT for IGCC reported in the BREF is taken as reference /169/.

The process flow diagram of the investigated IGCC power plant is shown in Figure 5-10, whereas for cases with CO₂ pre-combustion capture, components framed by the dashed lines are integrated. In the following sections the concept and the main components of this IGCC power plant are introduced.

Coal Gasification

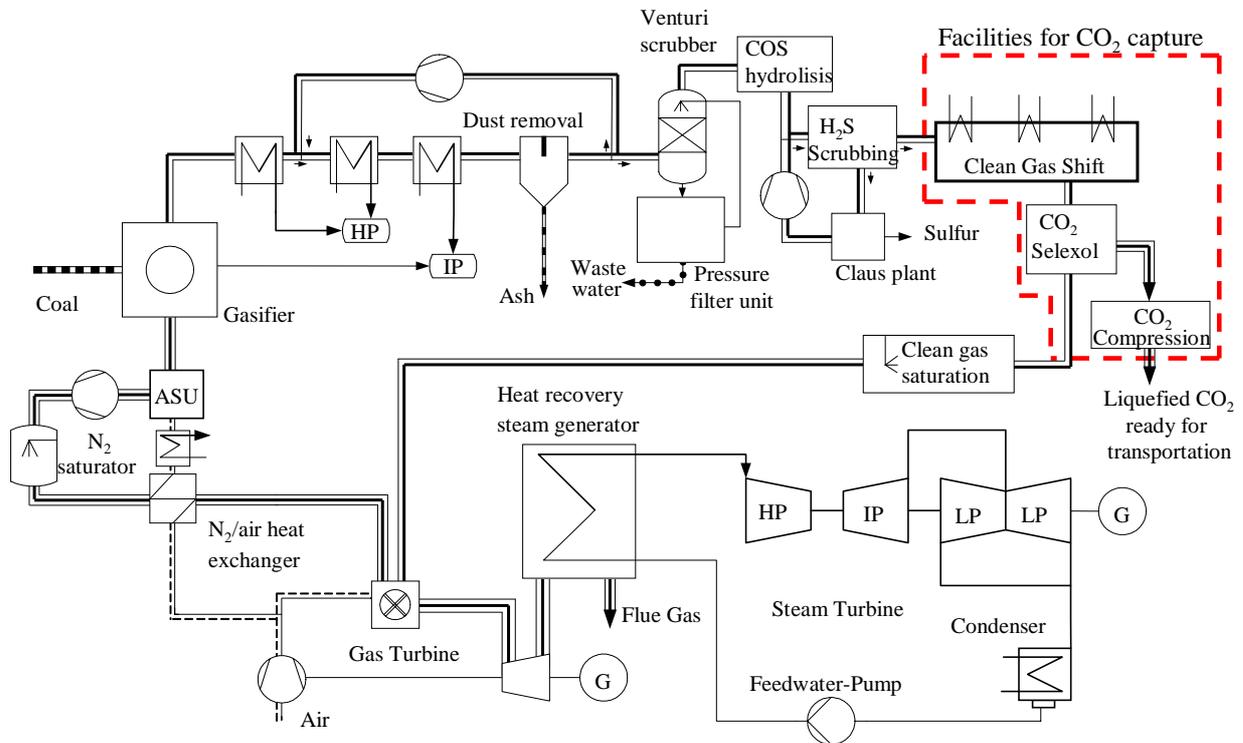
The conversion of coal into gaseous components takes place in a pressurized and heated environment in the presence of oxygen or steam and is referred to as gasification. In this study a pressurised entrained flow gasifier operating at 25 bar and 1,200 to 1,600 °C is applied, which is fed by pulverized steam coal and oxygen from a cryogenic ASU. A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is carefully controlled to facilitate partial oxidation. Only a relatively small portion of the fuel is completely burned, the main reaction is the generation of incomplete burned hydrocarbons, which are released as gaseous constituents from the feedstock. These gaseous constituents primarily are hydrogen, CO and CO₂, which together with water and impurities (e.g., N₂, COS, H₂S, HCN, NH₃ and volatile trace minerals) make up the produced syngas.

The typical gasification reactions of a hydrocarbon like coal with oxygen can be summarized by the chemical reaction shown in equation 5-6.



Due to the high pressure and temperature conditions in the gasifier as well as due to the constricted oxygen feeding a reducing environment is generated, which prevents the generation of CO_2 and water vapour (H_2O). Main products of this gasification are CO and hydrogen (H_2).

Figure 5-10: Process flow diagram of the investigated hard-coal-fuelled IGCC power plants with and without CO_2 capture
(source: modified from /83/)



Minerals in the fuel, i.e. rocks and other impurities, which do not gasify, are separated during gasification and for the most part leave the bottom of the gasifier either as an inert glass-like slag or as other marketable solid products. Only a small fraction of the mineral matter is blown out of the gasifier as fly ash requiring downstream removal. This cleaning of particulates from the produced syngas is necessary before its combustion in a gas turbine. Following particulate removal, the syngas is cleaned of other impurities. For the following syngas cleaning, wet scrubbing under cold conditions is applied. The wet scrubbing process is commercially proven and established in other industries. However it goes hand-in-hand with an efficiency reduction by some two to three percentage points /83/. This energy loss is caused by gas quench, whereby the high-temperature syngas leaving the gasifier at around $1,550\text{ }^\circ\text{C}$ is mixed with a recirculated quench gas ($235\text{ }^\circ\text{C}$), thereby reaching a temperature level of around $800\text{ }^\circ\text{C}$ /68/. Further cooling down to $235\text{ }^\circ\text{C}$ for the wet scrubbing process is achieved with heat exchangers that produce high-pressure and medium-pressure steam from the dissipated heat.

Gas quenching and thus the bulk of the efficiency loss could be reduced by syngas cleaning under hot conditions. Hot gas cleanup, however, is presently still under development and not yet

commercially applicable. Thus it is assumed to be applied in the investigated IGCC power plant not until the time horizon 2025.

At the currently applied wet scrubbing process, the cooled syngas passes through a cyclone, where most of the particulates are removed. Further cleaning of particulates along with the initial removal of acidic gaseous pollutants (HCl, HF, NH₃, HCN and partially H₂S and CO₂) is accomplished in a following Venturi scrubber /68/.

During coal gasification, sulphur impurities in the feedstock predominantly form gaseous carbonyl sulphide (COS) and hydrogen sulphide (H₂S). For the third step of the syngas cleaning, COS hydrolysis, a catalyst is applied to convert the COS of the syngas into H₂S, which at this stage remains as only sulphur component in the syngas (see equation 5-7).



Next follows the Rectisol scrubbing, where H₂S is removed from the syngas. After being stripped by the solvent Rectisol by means of pressure swing, the H₂S is released into a Claus unit, in which it is converted to sulphur. The tail-gases of the Claus unit are recycled back to the main syngas flow. That way, in the Claus unit over 99 % of the sulphur bound in the coal can be recovered as chemically pure sulphur, which constitutes a marketable by-product /69/.

Up to this stage in the syngas cleaning, only a few NO_x emissions are present in the syngas due to the reducing environment of the gasifier. Instead of NO_x, predominantly ammonia was created in the gasifier by reaction of hydrogen with the nitrogen bound in the steam. However, the most part of this ammonia was stripped out during the cleaning of the syngas /72/.

After syngas cleaning, the bulk of the NO_x and SO₂ has been removed from the syngas /70/. However, before the cleaned syngas enters the gas turbine for combustion, it is humidified in order to reduce the generation of NO_x emissions.

CO₂ Pre-Combustion Capture

When carbon capture is required, two power plant components, a shift-reactor and facilities for CO₂ capture and compression are added to the process flow of a conventional IGCC power plant. In Figure 5-10, these added components for CO₂ capture are highlighted by dashed lines. In the shift reactor, which is placed downstream of the syngas cleaning, the carbon monoxide of the syngas is reacted with steam in a catalytic environment to build CO₂ and more hydrogen. This shift reaction is characterised by equation 5-8.



The gas stream leaving the shift reactor at a pressure of 20 – 30 bar consists of mainly hydrogen and CO₂, the latter featuring concentrations of around 30 % (dry basis) /72/.

After the scrubbing of CO₂ from shifted syngas by the solvent Selexol, hydrogen remains as a clean fuel, which is combusted in the gas turbine for the purpose of electricity generation. The captured CO₂ is compressed to 110 bar for pipeline transportation and storage.

5.7 Transport of CO₂

In most cases, the captured CO₂ cannot be stored at the power plant site itself, but has to be transported to an appropriate storage site, where it is injected into geological formations for long-term isolation from the atmosphere. This chapter illustrates the transport conditions of CO₂, possible transport means for CO₂ transportation and technical specifications for injection into different geological storage sites. Finally the technology and specifications applied to the quantification of LCI data for CO₂ transportation and storage in this study are outlined.

5.7.1 Background on CO₂ Transportation

There are different technical possibilities for the transportation of CO₂. Some of them are already in use today for applications of enhanced oil recovery (EOR) or within the food industry. EOR involves the injection of CO₂ into almost exploited oil fields in order to boost the production of the remaining oil (see chapter 5.8.3). In the USA within the scope of EOR, more than 40 million tons of CO₂ from primarily natural CO₂ sources are transported annually via pipelines and injected into oil fields [77]. Therefore a network of CO₂ pipelines with a length of more than 3,100 km has been built [134].

Smaller quantities of CO₂ are transported within the food industry. In the German food industry approximately 100,000 tons of CO₂ are stored annually at high-pressure or in a liquefied state in steel tanks, which are then transported by train or lorry.

5.7.2 Transport Properties of CO₂

At ambient conditions, CO₂ appears as a colourless and odourless gas. In this gaseous state CO₂ is not appropriate for transportation, as it occupies enormous volumes. This volume is reduced when the CO₂ is compressed or converted into a liquid or solid state. From Figure 5-11, which constitutes a phase diagram of CO₂, it can be seen that at an ambient pressure of 1,013 bar CO₂ appears only in a gaseous or solid state. The solid state of CO₂, which is also named dry ice, however, is inappropriate as a transport condition for CO₂. This is because the cryogenic production of dry ice constitutes an energy intensive process, which is not economically applicable for large-scale transportation of CO₂ [135].

The most advantageous properties for an economically and technically feasible transport of CO₂ on a large scale is offered by liquefied CO₂ [77]. CO₂ in a fluid or dense-fluid state features a density of more than 200 kg / m³ and offers appropriate transport conditions. As shown in Figure 5-11, the dense-fluid state constitutes the fluid state at a super-critical pressure level, which is existent at pressures above 73.3 bar.

According to current experiences, the fluid state is considered most appropriate for loading and transportation of CO₂ in steel tanks, which are then used for transportation by train, lorry, barge or tanker. For transportation in pipelines on the other hand, CO₂ in a dense-fluid state is preferred [77]. The dense-fluid state of CO₂ requires a higher pressure level and thus more energy than the

liquid state, but it ensures stable conditions along the entire pipeline infrastructure. This is especially important in order to avoid cavitations in the pipeline as well as in the pumping and compressor stations /77/.

In most geological storage sites for CO₂ capture, the pressure conditions due to the depth of the formations resemble the transportation conditions so that the stored CO₂ is kept in a fluid or dense-fluid state /135/.

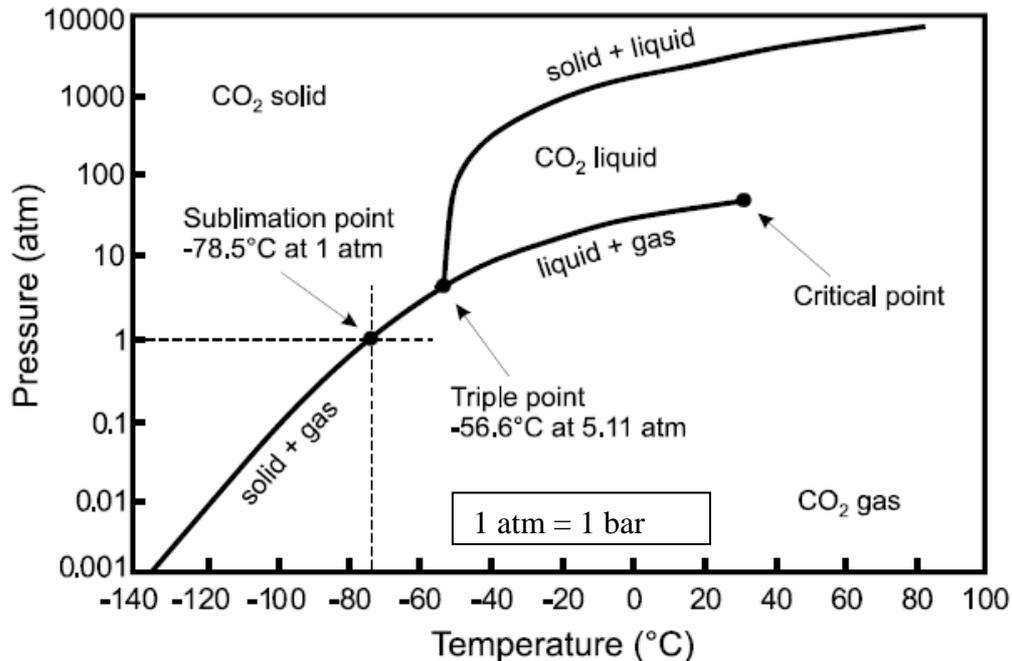


Figure 5-11: Phase diagram of CO₂
(source: /72/)

5.7.3 Compression and Liquefaction of CO₂

To reach the transport conditions for CO₂, the captured CO₂ has to be compressed to a liquid state. Current technology for liquefaction of CO₂ is multi-staged compression with intermediate cooling /136/ /124/. Both CO₂ at liquid and liquid-dense state can be obtained by this method. For the production of liquefied petrol gas (LPG), this technology is already applied on a large scale and thus constitutes a mature and established technology, which can be transferred to CO₂ /72/.

In most power plant concepts for large-scale capture of CO₂, the liquefaction of CO₂ is integrated into the power plant and occurs directly after the process of CO₂ capture. The electricity required for the compression is taken from the electricity output of the power plant. This means that the compression of CO₂ constitutes an auxiliary unit of the power plant, which reduces the overall net electricity generation and thus contributes to an efficiency penalty due to CO₂ capture.

To avoid negative impacts on transportation infrastructure, the CO₂ stream has to be cleaned of water and some impurities before it is compressed. Especially water implicates a danger for corrosion and at the same time constitutes additional transportation mass /77/ /124/. To remove

the water, all power plant concepts for CO₂ capture include either a condensation step or a TEG-dehydration unit or both in order to dry the captured CO₂ stream. Furthermore, any remaining water is removed at the intermediate cooling by condensation during the single steps of the CO₂ compression /136/.

Depending on the means for CO₂ transportation different pressure and temperature levels have to be reached for compression and liquefaction of CO₂. These differences and the resulting effect on the overall efficiency of the investigated power plant concepts are explained in the paragraph 5.7.9.

5.7.4 Transport Options for Liquefied CO₂

Principally CO₂ can be transported by various means, whereas it is to be distinguished between onshore and offshore as well as continuous and discontinuous transportation. An example for discontinuous transportation of CO₂ is the storage of CO₂ in steel tanks, which subsequently are transported by ship, train or lorry. Continuous transportation on the other hand is achieved by utilisation of CO₂ pipelines, which can be installed both on-shore and off-shore in order to constantly convey liquefied CO₂. Figure 5-12 summarizes these options of CO₂ transportation.

Basically, the infrastructure for the first transportation of CO₂ from a large-scale power plant with CO₂ capture has to be dimensioned for continuous transportation of CO₂. This is because these power plants are primarily operated at base load in order to achieve optimal performance and availability, which means that there is virtually a continuous generation of electricity and, at the same time, capture of CO₂, which has to be removed. The generated CO₂ stream is injected into a pipeline at the power plant site, from where it can be either directly injected into an on-site geological storage formation or be transported to a distant storage site.

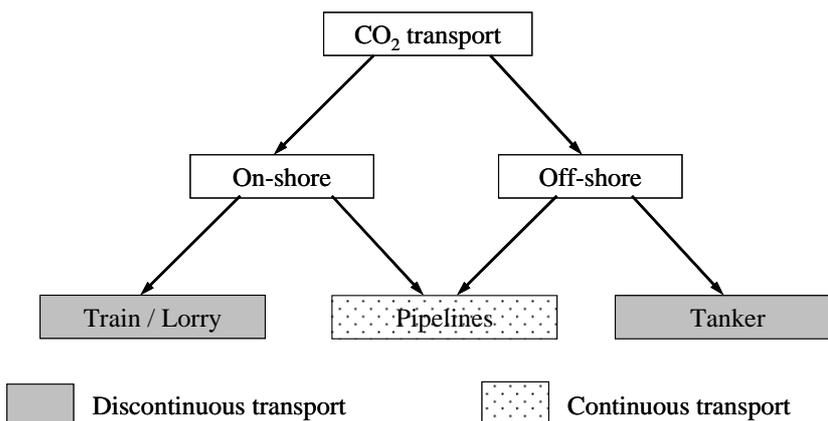


Figure 5-12: Continuous and discontinuous transport of CO₂
 (source: /137/)

The continuous CO₂ pipeline transportation leaving the power plant can be coupled to a system with discontinuous CO₂ transportation as for instance the transportation by train, lorry or ship. Prerequisites for such discontinuous transportation is the installation of facilities for an intermediate storage of CO₂ at the exit of the pipeline. Such an intermediate storage can be

realized either by means of steel tanks or by use of an appropriate underground storage formation /77/.

5.7.5 CO₂ Transportation by Train and Lorry

The prevalent means of CO₂ transportation in the food industry is by train or lorry. The liquefied CO₂ is stored in steel tanks, which are loaded and transported like containers. In the steel tanks, temperatures of around -20 °C and pressures of around 20 bar are maintained in order to keep the CO₂ in a fluid state /72/.

However, this discontinuous transportation of CO₂ in steel tanks is unlikely to be applied to the large-scale transportation of CO₂ from power plants with CO₂ capture /72/. As already mentioned before, about 7,000 tons of captured CO₂ per day have to be transported from a power plant having a capacity of 500 MW_e, a net efficiency of 45 % and a CO₂ capture rate of 90 %. Under the assumption of a loading capacity of 5 tons of CO₂ per lorry /137/, 100 lorries a day would be required to transport the captured CO₂ of this power plant. Trains would reduce this amount of daily transportation tours due to their higher loading capacity. However, altogether, the infrastructure for both lorries and trains seems not appropriate for transporting of such large amounts of CO₂. Furthermore, these means of transportation are not economic, as costs for lorry transportation, which are reported to 25 Euro / ton CO₂ in /135/, but also train transportation would significantly increase the price of the generated electricity.

5.7.6 CO₂ Transportation in Pipelines

The current technology of choice for large-scale CO₂ transportation is the use of CO₂ pipelines. Most of the currently installed pipeline capacity for CO₂ transportation is located in the USA /72/. Table 5-18 lists currently existing CO₂ pipelines in North America together with their capacities and the year of commissioning as far as this is known. These pipelines are applied within the scope of EOR (see chapter 5.8.3).

In the USA, these pipelines are governed by the Department of Transportation, which determines standards for construction, operation and monitoring of CO₂ pipelines /72/. As a central element of the safety regulations for CO₂ pipelines, systems for supervisory control and data acquisition (SCADA) are mandatory for the measuring pressure drops.

The pressure within a CO₂ pipeline must be kept clearly above the critical pressure of 73.9 bar in order to avoid cavitation and a two-phase system in the pipeline /72/ /23/. Thus, with regard to an added safety margin, a minimum pressure of 80 bar is recommended along an entire pipeline /138/.

Due to pipeline friction there will always be a drop in the pressure level along the length of a pipeline. In order to sustain the minimum pressure, recompressor and pumping stations have to be installed at regular intervals along the pipeline. Depending on the mass flow, the roughness of the pipeline and the chosen initial pressure, such compressor stations are installed at intervals between 150 and 400 km for currently operated CO₂ pipelines /72/.

Table 5-18: Existing CO₂ pipelines in North America
(source: /72/, /171/)

Name of the pipeline	Operator	Origin of the CO ₂	Length [km]	Diameter [mm]	Capacity [Mt CO ₂ /year]	Start-up year
Cortez	Kinder Morgan	McElmo Dome	808	762	19.3	1984
Sheep Mountain	BP Amoco	Sheep mountain natural	660	610	9.5	unknown
Bravo	BP Amoco	Bravo dome natural	135	508	7.3	1984
Canyon Reef Carriers	Kinder Morgan	Gasification plants	87	406	5.2	1972
Val Verde	Petrosource	Val Verde Gas Plants	51	254	2.5	1998
McElmo Creek	ExxonMobil	McElmo Dome	25	25	1.3	unknown
Llano Lateral	Trinity Pipeline	Cortez dome	33	325	1.7	unknown
Choctaw	Denbury Resources	Jackson Dome	115	508	8.8	unknown
Weyburn	North Dakota Gasification Co.	Gasification plant	328	356/305	4.9	2000

Design and Construction of Pipelines for CO₂ Transportation

CO₂ pipelines are constructed based on the same technology as natural gas pipelines. For the main material, steel pipes are used, which for protection from external corrosion are wrapped in a layer of tar /142/. Usually, the CO₂ pipelines are installed below the surface at depths of one meter or in critical areas somewhat deeper. Figure 5-13 shows two pictures on the installation of pipelines.



Figure 5-13: Installation of pipelines
(source: /137/)

Normally carbon-manganese steels are used for the pipelines, as this material is resistant to gaseous impurities in the CO₂ stream such as O₂, H₂S, SO₂ or NO_x. Problematic is only the transportation of moist CO₂, which causes corrosion. In this case, an inner polymer coating of the pipelines and the use of high-alloyed steels for the tubes or a further dehydration step is necessary /142/.

5.7.7 CO₂ Transportation by Tanker or Barge

Another means of large-scale transportation of CO₂ is by tanker or barge. Tanker transportation is applied at sea, whereas barges carry out the transportation on inland waterways. The infrastructure for ship transportation of fluidized substances is mature and currently already in use for the transportation of liquefied petrol gas (LPG). LPG is stored at atmospheric pressure and at a temperature of -162 °C in steel tanks, which are then shipped on a tanker or barge. A similar infrastructure can be applied for CO₂ transportation and would involve the following six components:

- Tanks for the intermediate storage of liquefied CO₂, which is delivered in pipelines from power plants with CO₂ capture
- Facilities for loading the steel tanks that are integrated into the tanker or barge
- CO₂ tankers or barges
- Facilities for unloading the tanker or barge
- Tanks for the intermediate storage of the shipped liquefied CO₂
- Pipeline infrastructure for further transportation of the CO₂ to a storage site

CO₂ is filled into steel tanks in a fluid state. Therefore a pressure of 7 bar and a temperature of minus 50 °C are required /139/. This is different from the conditions at LPG transportation, however, the energy requirement for the maintenance of these CO₂ transport conditions is similar to that for the transportation of LPG /139/. Although, on the one hand, CO₂ transportation involves a higher energy demand due to the elevated pressure of 7 bar, on the other hand, this is compensated for by a reduced effort in sustaining a relatively higher temperature level.

Due to a limited demand, CO₂ tanker and barge transportation is currently restricted only to applications in north-western Europe and features an annual transportation capacity of around 300,000 tons /139/.

For the future, it is expected that CO₂ transportation by tanker or barge will gain in importance. One promising scenario is the retransportation of CO₂ from fossil power plants to places, where by the mining and extraction of fossil fuels potential CO₂ storage sites have been created /135/. Many OECD countries produce CO₂ from oil or gas, which originally was imported from middle-east or Russia. This CO₂ could be stored in the depleted oil and gas fields or used for EOR and EGR (see chapter 5.8.3) in these countries. Such a scenario would involve a transportation of CO₂ on a large scale, which due to the long distances could be better realised by tanker transportation than by CO₂ pipeline /135/.

The construction of CO₂ tankers is similar to the technically mature production of tankers for LPG transportation /132/. Investigations have already been conducted on whether the same tanker can be used for both the transportation of CO₂ and LPG. Instead of empty return trips of LPG tankers, the return voyage could be used for the transportation of CO₂. However, it was revealed that a change in the transport media between CO₂ and LPG in the steel tanks involves

an exhaustive cleaning process in order to avoid impurities in the respective substances and thus is not recommended for large-scale application /139/.

Similar to other ships, CO₂ tankers and barges are fuelled by diesel oil. This fossil energy source is primarily used for propulsion, however, a small part of the diesel consumption is generated by maintaining the pressure and temperature conditions in the steel tanks. The combustion of diesel oil releases major amounts of CO₂, SO₂, NO_x as well as other air pollutants.

5.7.8 Safety Aspects for the Transportation of CO₂

At low concentrations, the gas CO₂ is nontoxic and appears under ambient conditions with concentrations of around 0.04 % in the air. However, in air, at concentrations above 10 vol. %, it can and will cause asphyxiation in human beings. Exposure to CO₂ at these levels of concentration can occur, when CO₂ is released in high quantities, as may happen with leakages during CO₂ transportation or due to eruptions of CO₂ from natural sources.

In the past, such incidents have only been observed from natural CO₂ sources, mainly from volcano eruptions. One example is the CO₂ outgassing at the Nyos lake in Kenia in 1986, which caused the death of 1,700 people /141/. Because CO₂ has a higher density than air, it accumulates at ground level. In and around such a lake, a CO₂ concentration of 10 % is quickly exceeded. This highlights why safety issues for CO₂ transportation is of such high importance. In order to avoid risks, it is not recommended to direct CO₂ pipeline routes or other means of CO₂ transportation through densely populated areas /135/.

Safety Aspects for CO₂ Pipelines

From experience within the scope of EOR, it can be referred that CO₂ pipelines feature lower leakage rates than pipelines for the transport of natural gas /140/. From the existing CO₂ pipeline network, less than 5 E-5 recorded incidents per km per year are reported /72/. To date, no fatalities or injuries have been observed. The consequences of accidents at CO₂ pipelines are expected to be less severe than similar accidents at pipelines of natural gas or other dangerous substances because CO₂ is not toxic and non-flammable /72/.

According to the regulations of the US Department of Transportation CO₂ pipelines are monitored during operation both inside by devices sent through the pipelines (pigs) and outside by inspection from helicopter and foot patrols /72/.

Safety Aspects for CO₂ Transportation by Tanker or Barge

There are various scenarios for the failure of shipping systems, which also include damage to the transported freight. Both technical failure and human factors are reasons for collisions, foundering, strandings, fires etc. whereas long-term investigations show that purely technical factors are relatively uncommon /72/.

The risks for the release of CO₂ in ship transportation can be minimised, when high standards in terms of technical safety systems, monitoring and personnel training are applied. Normally,

tankers feature higher safety standards than ships in general /72/. Very high standards for construction and operation of tankers and terminals currently exist for LPG and LNG transportation. With similar standards for CO₂ tanker and barge transportation it is expected that the frequency of incidents will be similar to that for LPG tankers (9.1 E-4 incidents per ship per year) and for LNG tankers (3.7 E-1) /72/.

5.7.9 LCA of CO₂ Transportation and Storage

In this study, the large-scale transportation of CO₂ is investigated for both pipeline and barge, which are expected to be the technologies of choice for CO₂ transportation under German conditions. The CO₂ captured from a German hard-coal-fuelled power plant is transported to a domestic storage site, which is assumed to be a saline aquifer at a depth of 800 m. The distance for CO₂ transportation, which is modelled as a parameter in P-LCA, is assumed to be 350 km for the investigated technology scenarios.

The simplified process diagram of the two pathways for CO₂ transportation investigated in this study is shown in Figure 5-14. In case of pipeline transportation, the captured CO₂ is compressed to a pressure of 110 bar and injected into a pipeline, which directly leads to a CO₂ storage site. For barge transportation, it is assumed that both the power plant and the pipeline connection to the CO₂ storage site are accessible from an inland waterway. At the power plant site, the captured CO₂ is intermediately stored in steel tanks at conditions of 7 bar and -50 °C, before it is transferred into the steel tanks of a CO₂ barge. The loaded CO₂ is subsequently shipped to a CO₂ storage site, into which the CO₂ is injected.

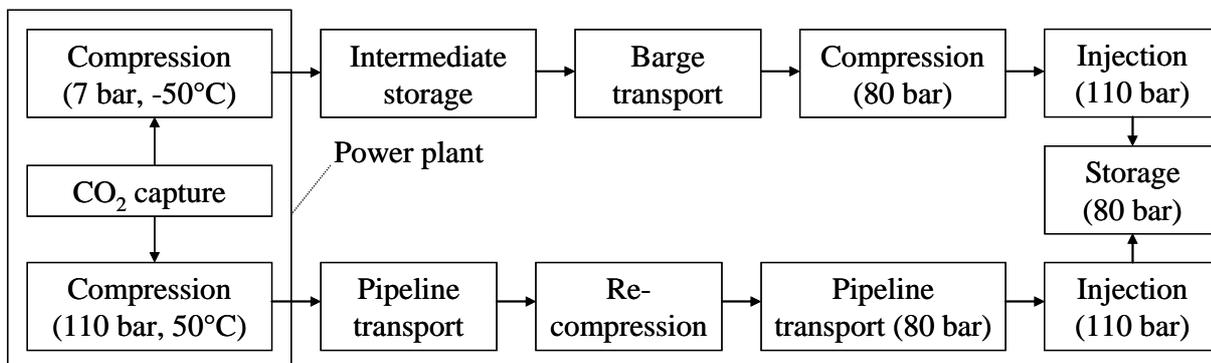


Figure 5-14: Simplified process diagram of CO₂ transportation by pipeline and barge in this study

For both the CO₂ transportation and storage, LCI data is quantified with reference to one ton of captured CO₂. This is the functional unit, which is commonly used by technical references and also for cost figures on the CCS chain and thus is applied in this study for the CCS chain. For the final calculation of LCI data in this study, one ton of captured CO₂ is linked to the generated kilowatt hour of electricity in a hard-coal-fuelled power plant with CO₂ capture, which is the functional unit of the investigated technology scenarios. Such a link is achieved by calculation of the CO₂ captured per generated kWh_e.

In order to keep the amount of LCI data at a manageable level, the investigation of both transport means has not been performed for all technology scenarios. Pipeline transportation, which is expected to be applied in more future CCS power plant projects in Germany, has been investigated as default means for CO₂ transportation in this study, whereas CO₂ barge transportation has been investigated only for the time horizon 2015 in order to facilitate a comparison between the different means of CO₂ transport. The results of this comparison, however, are not restricted to the time horizon 2015, but can be transferred also to the other time horizons 2025 and 2050.

As already mentioned before and indicated in brackets in Table 5-14, Table 5-15 and Table 5-17, the investigated power plants with CO₂ capture and following barge transportation feature elevated power plant net efficiencies compared to power plants with CO₂ capture and following CO₂ pipeline transportation. This results from the aspect that the compression of captured CO₂ for intermediate storage in steel tanks and the following barge transportation (at 7 bar) is significantly less energy-intensive than the compression for pipeline transportation (at 110 bar). This means that the efficiency penalty due to CO₂ capture is lower in technology scenarios with CO₂ barge transportation due to the lower pressure level of the fluidized CO₂ and thus the net efficiencies in these technology scenarios are higher.

The lower energy requirement for CO₂ compression in CO₂ barge scenarios is quantified according to equation 5-10, which is presented in the next chapter, and results in an increase of the power plant efficiency by 2.3 % for the PCC, by 1.1 % for the IGCC and by 0.5 % for the oxyfuel power plant. IGCC technology features a lower efficiency increase, since the produced synthesis gas and, therefore, the captured CO₂ are already available at an elevated pressure level (around 30 bar /72/) so that there is less energy saved when only reduced CO₂ compression is required for barge transportation. Oxyfuel technology features an even lower efficiency decrease in the technology scenario with barge transportation, as after the TEG unit, the compressed CO₂ stream is already available at a pressure of around 40 bar.

CO₂ Pipeline Transport

Within the analysed technology scenarios, annual CO₂ flow rates of between 2.1 and 3.8 Mt of CO₂ are transported by CO₂ pipeline. Calculation of a CO₂ pipeline diameter by equation 5-9 according to /171/ revealed a pipeline diameter of 350 mm being appropriate for such a CO₂ transport capacity. As can be followed from equation 5-9, this pipeline diameter allows CO₂ transportation for capacities up to 4.2 Mt of CO₂ at a velocity of up to 2 m/s. Lower CO₂ transport capacities are able to be transported within the same pipeline at lower velocities. This allows to use the same pipeline diameter of 350 mm for all technology scenarios and thus the same infrastructure for the CCS chain.

In this study the materials for CO₂ pipeline construction are considered to be similar to the material framework of natural gas pipelines, as it is also assumed in /143/ /171/. Therefore, dimensioning and material data are obtained from the database ecoinvent /29/. According to this

source, a low-alloyed steel with a wall thickness of 8 mm is used for the pipeline, which for protection is coated, firstly, by a 2.2 mm thick layer of low-density polyethylene (LD-PE) and, secondly, by a 3 mm thick layer of bitumen. For the pipeline, a 1.7 m deep and 1 m broad trench is excavated, which for up to a depth of 1.2 m is filled with sand. Onto this sand layer the pipes are placed before being finally covered by the excavated soil. This pipeline infrastructure is used over the technical lifetime of the power plants.

$$D_{Pipeline} = \sqrt{\frac{F_{CO_2}}{v \cdot \pi \cdot 0.25 \cdot \rho_{CO_2}}} \quad (5-9)$$

$D_{Pipeline}$ – Pipeline diameter [m]

F_{CO_2} – CO₂ flow [kg/s]

v – transport velocity [m/s] (2 m/s)

ρ_{CO_2} – density of CO₂ [kg / m³] (800 kg / m³)

π – 3.1415

The liquefied CO₂ leaving the power plant enters the pipeline at a pressure of 110 bar, which constitutes an overpressure of 30 bar above the minimum pressure of 80 bar for pipeline transportation. In close correlation to case studies and calculations in /143/ /145/ /136/, a pressure drop during transportation of 20 bar / 100 km is assumed in this study. In order to keep the minimum pressure of 80 bar in the pipeline, the pressure drop is compensated for by recompression stations installed at intervals of 150 km. Thus, for a pipeline distance of 350 km two electrically driven compressor stations are modelled in the investigated scenarios.

The electricity demand for compression at these compressor stations is calculated according to equation 5-10, which was developed in /136/ for CO₂ pipelines. The required electricity is supplied from the German electricity grid, which is quantified by LCI data on the German electricity mix of different time horizons specified in chapter 5.3.2. The pipeline recompression is dimensioned in order to ensure the minimum pipeline pressure of 80 bar at the pipeline outlet, which at the same time is the inlet of the injection unit.

$$E_c = C_{el} \cdot \ln\left(\frac{P_{outlet}}{P_{inlet}}\right) \cdot F_{CO_2} \quad (5-10)$$

E_c – Electricity demand for compression [kJ_e/s]

C_{el} – Constant (87.85 kJ_e/kg)

P_{outlet} – Outlet pressure [Pa] (110,000 Pa)

F_{CO_2} – CO₂ flow [kg/s]

P_{inlet} – Inlet pressure [Pa] (80,000 Pa)

As for the leakage of the investigated CO₂ pipeline, the leakage rates published by the American CO₂ pipeline operator Kinder Morgan are applied /146/. From experiences of pipeline monitoring, an average CO₂ spill of 0.29 barrels per mile (appr. 0.054 kg CO₂ / km) is reported and is used within in this study. During the operation of CO₂ pipelines, regular monitoring for leakages by helicopter is taken into account. Fortnightly, helicopters overfly and inspect the entire pipeline route.

CO₂ Barge Transport

In the technology scenarios with CO₂ barge transportation, steel tanks with a capacity of 140,000 m³ are used for the intermediate storage of CO₂ compressed 7 bar and -50 °C. From these tanks, which in this study are able to store an average of five days of CO₂ capture, the liquid CO₂ is transferred to the storage tanks of the CO₂ barge. Infrastructure data for the CO₂ barge tanker are derived from the material framework of an LPG tanker in the database ecoinvent /29/. This source is also used for data on the operation and maintenance of the modelled CO₂ barge. Furthermore, the use of ports and inland waterways is quantified according to ecoinvent. The amount of diesel oil for the operation of the CO₂ barge is derived from /147/, whereas an additional diesel oil consumption of 5 % is assumed in order to take the maintenance of the CO₂ transport conditions into account.

As for the leakage rate of the barge transportation, a higher CO₂ spill compared to pipeline transportation is likely to occur during the transfer of CO₂ between different steel tanks. Thus, a conservative assumption for of a five times higher leakage rate of 1.33 E-7 kg CO₂ / km is made.

5.7.10 Costs of CO₂ Transportation

The costs for pipeline construction are primarily determined by the length of the pipeline, the amount of CO₂ to be transported as well as the topography and specifications of the traversed landscape. The crossing of mountains, rivers, streams as well as routing around national parks or densely populated areas is involved with additional costs, which are capable of doubling the specific pipeline construction costs (per kilometre) /124/ /142/. The same applies for digging and installing the pipeline in difficult soil conditions, as for instance in rock or permanently frozen soil.

For cost calculation of CO₂ pipeline transportation in this study, the approach outlined in /171/ is applied. Starting from costs of natural gas pipelines, which is a common procedure (see /143/), in /171/ investment costs as well as operational costs for pipelines and compressor stations are calculated. This is done via mathematical relations and empiric factors, which had been derived for the construction and operation of pipelines based on used materials, applied manufacturing processes and required services. According to these equations the investment costs for a CO₂ onshore pipeline with a diameter of 350 mm along a distance of 350 km is calculated for an average terrain to around 72,500,000 €₂₀₀₅. For compressor stations investment costs of around 7 M€₂₀₀₅ per station are quantified.

Furthermore annual operation and maintenance costs are determined to 3 % of the pipeline investment costs and 5 % of the investment costs of the compressor stations.

Based on these cost factors, an assumed operational life time of 35 years, specific costs for CO₂ pipeline transportation are calculated for a discount rate of 10 %, which for different transport distances and annual CO₂ throughputs are displayed in Figure 5-15.

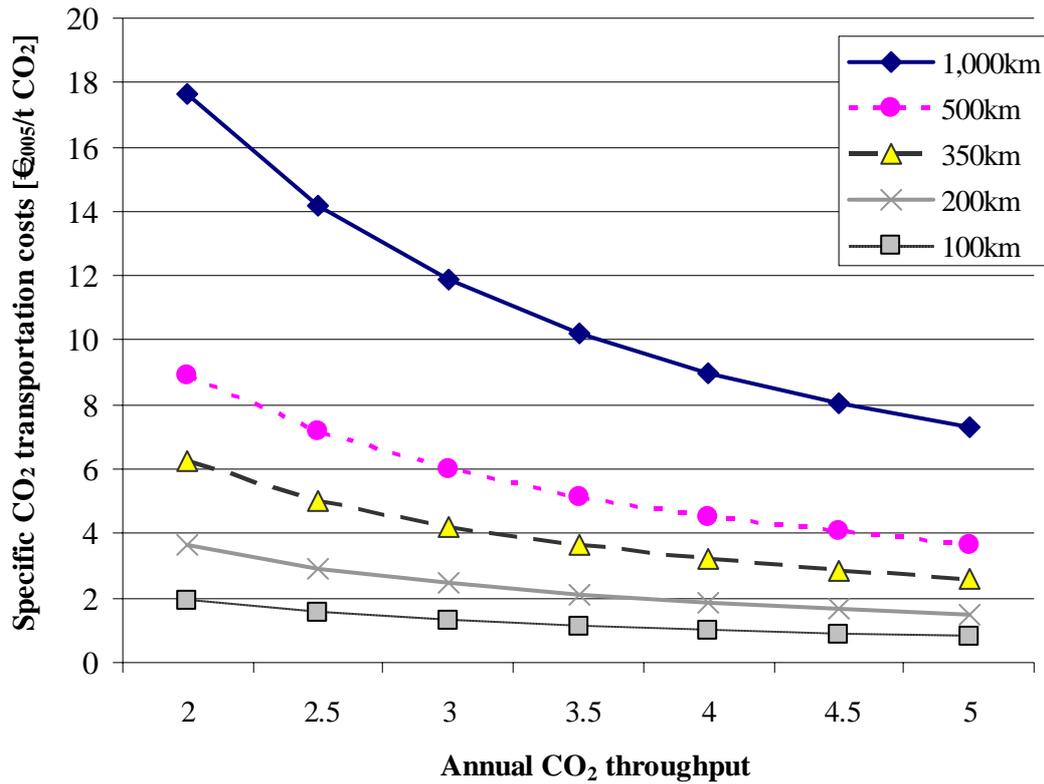


Figure 5-15: Costs of CO₂ pipeline transportation with pipeline diameter of 350 mm (source: /171/)

Based on these cost curves for each investigated technology scenario CO₂ transportation costs are derived, which altogether are in a range of between 3.6 to 6.0 €/t CO₂.

The investment costs dominate the specific pipeline transportation costs. At an average transportation distance of 350 km, investment costs for CO₂ pipeline and compressor stations contribute 73 to 75 % of the overall costs. The remaining costs originate from operation and maintenance, whereas 2 to 5 % of the transportation costs account for electricity costs of the compressor stations.

Summarizing, it can be stated that costs of CO₂ pipeline transportation are predominantly determined by the transport distance and secondly by the transported mass flow /137/.

The costs of CO₂ tanker and barge transportation feature even higher investment costs than pipeline transportation due to the material intensive infrastructure for the ships, the loading and unloading facilities as well as the steel tanks for intermediate storage. However, the specific operating costs per kilometre of ship transportation, which are mainly influenced by the costs for the ship's diesel oil, are slightly lower than the operating costs of CO₂ pipeline transportation /139/ /135/. This entails, that for short and medium distances CO₂ pipeline transportation features lower full costs, whereas for transportation over long-distances CO₂ ship transportation is more economic. As shown in Figure 5-16, at a distance of approximately 1,500 km a break even point is reached, at which ship and pipeline transportation of CO₂ feature the same level of transportation costs /142/. At this point it has to be stated that CO₂ barge transportation, which is

expected to be mainly applied for distances below 1,500 km, will in most cases be less economic than CO₂ pipeline transportation. For the transportation distance of 350 km in this study, transportation costs of 8.3 €₂₀₀₅ / ton CO₂ have been calculated according to the cost figures and equations in /139/.

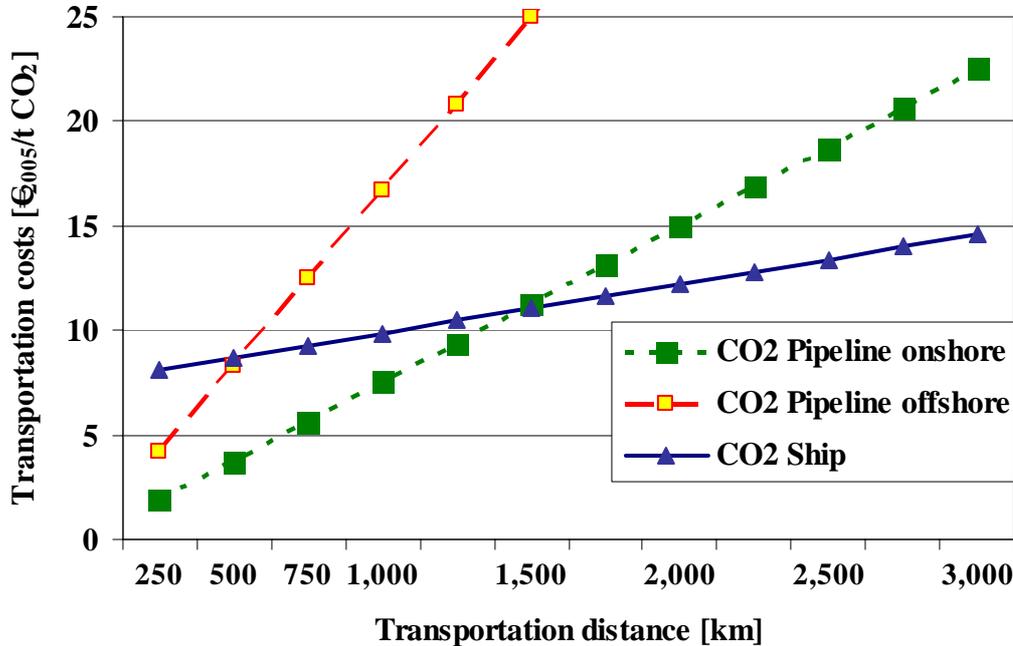


Figure 5-16: Comparison of costs of CO₂ ship and pipeline transportation (source: /139/)

5.8 Storage of CO₂

Basic requirement for the application of CCS technology is the availability of safe and permanent CO₂ storage sites. Thereby different geologic formations are considered appropriate for CO₂ storage, which are outlined in the following paragraphs.

5.8.1 CO₂ Storage in Geologic Formations

CO₂ can be injected into geological formations, which feature sufficient storage capacity, an adequate sealing by a cap rock and stable geological conditions. Porous rock formations provide storage capacity for CO₂ and are used most efficiently, when CO₂ is stored at dense-fluid state. Appropriate conditions for such storage with high ambient pressures are existent in rock formations at a depth of 800 m or more /126/.

Deep Saline Aquifers

The most abundant CO₂ storage capacity is offered by deep saline aquifers, which constitute porous rock formations that contain water or brines with a high salinity/72/ /77/. Due to the depth and the high salinity of these aquifers, the water is not suitable for use as drinking water or for agriculture. Usually, aquifers are made up of sandstone and dolomite and are sealed by cap rocks of anhydrite or shale. According to the current levels of knowledge, CO₂ injected into saline

aquifers is firstly stored as a liquid CO₂ plume (in small parts also in a gaseous state) before it is dissolved into the brine and over a long term reacts with the aquifer rock (mineralisation) /126/.

Depleted Oil and Gas Reservoirs

CO₂ can be injected into depleted oil and gas reservoirs, which have proven their suitability and safety for storage over geological time periods. As a result of previous oil or gas production, the underground reservoirs have been intensively studied. This information can be used for capacity and safety estimates for the storage of CO₂. Depleted gas fields feature a higher CO₂ storage capacity than oil fields, because gas fields are more abundant and normally larger in volume /126/.

5.8.2 Other Options for CO₂ Storage

There are other options for the storage of large amounts of CO₂, which are considered as subordinate solutions, since they are either controversial (storage of CO₂ in the ocean) or currently not applicable on a large scale (mineralisation of CO₂)

Ocean Storage

Basically, there are two concepts for the storage of CO₂ in the ocean:

- Storage as a CO₂ lake on the floor of the ocean:
Liquid CO₂ is injected at depths of around 3,000 m. At this depth due to high ambient pressure CO₂ features a higher density than water and sinks to the sea floor. At this pressure, dissolution of fluid CO₂ is low and due to slow circulation of deep ocean water most of the CO₂ will remain in the ocean /144/.
- Dissolution of CO₂ in the ocean:
When injected at depths between 1,000 m and 2,000 m, fluid CO₂ forms a plume, which dissolves in the ocean water without being released as gaseous CO₂.

Both concepts have only been tested on a laboratory scale. Experiences on a large scale are not available, especially since pilot projects in Hawaii and Norway were cancelled because of protests from environmentalists /126/.

In Germany, ocean storage is not being pursued, because possible impacts on the oceanic ecosystem are not predictable with current levels of knowledge /132/.

Mineralisation of CO₂

The concept of mineralisation is based on the reaction of CO₂ with ground magnesium and calcium silicate rock to build carbonates. This chemical reaction, which has been tested on a laboratory scale, ensures long-term storage of CO₂, but requires enormous quantities of material rock and this is in line with low reaction rates. Thus, only an improvement in the reaction kinetics will facilitate mineralisation being used as an option for large-scale storage of CO₂ /126/.

5.8.3 Use of CO₂ for Economic Benefit

There are concepts, which use CO₂ to generate economic benefits. The following paragraphs outline how fossil fuels can be produced by injection of large amounts of CO₂.

Enhanced Oil Recovery (EOR)

EOR involves the injection of CO₂ into oil fields, which are almost exploited. The injection of the inert CO₂ gas restores the declining pressure in the oil field and at the same time improves the viscosity of the remaining oil by building an oil-CO₂ mixture. During the extraction of this oil-CO₂ mixture, more than 50 % and up to 67 % of the injected CO₂ is returned to the surface /126/. To minimise EOR operating costs this CO₂ is usually separated from the extracted oil-CO₂ mixture and reinjected into the reservoir.

For an average oil field, only around 5 to 40 % of the oil is able to be recovered by conventional primary oil production /72/. The injection of CO₂ entails an additional oil recovery of from 8 – 15 % of the total quantity of original oil in place, which increases total recovery by 50 % /126/. This boost of oil production by CO₂ injection opens up the possibility for using large quantities of CO₂ with economic benefit. In the USA, the transportation and injection of CO₂ within the scope of EOR has been applied for more than three decades and constitutes a technically mature and economic technology /72/.

Enhanced Gas Recovery (EGR)

Similar to EOR, CO₂ can be injected into almost exploited gas fields for the purpose of enhanced gas recovery. Different to oil fields, up to 95 % of the original gas in place can be extracted from a gas field, however, the injection of CO₂ can be used to repressurize the gas field and thus enable the remaining gas to be extracted /72/. Since CO₂ in gaseous, liquid and even super-critical state is notably denser than methane, it will flow downwards, fill the bottom of the gas field and force the natural gas above it, where it can be extracted. According to different studies, the potential for CO₂ injection is larger for EGR than for EOR /126/ /72/, as is also shown in Table 5-19. The revenue per ton of CO₂, however, is substantially lower for EGR than for EOR. So far, EGR has only been applied on a pilot scale /72/.

Enhanced Coal Bed Methane (ECBM)

Unmined coal seams usually contain considerable amounts of methane (up to 25 m³ per ton of coal /72/), which is stored in the pores and fractures of the seam. When CO₂ is injected into such coal seams, it displaces the stored methane due to higher CO₂ adsorptivity. This production of methane and simultaneous storage of CO₂ is referred to as enhanced coal bed methane (ECBM) recovery. This technique is capable of recovering 90 % or more of the methane in the coal seam compared to conventional coal seam methane recovery, which by reservoir-pressure depletion allows only 50 % of the stored methane to be extracted /72/ /126/.

5.8.4 Potentials for CO₂ Storage in Germany

Starting from the described options for CO₂ storage, CO₂ storage capacities can be derived for geologic formations, regions and countries. Also in Germany, such studies on the CO₂ storage potential have been performed, however, with, in part, very differing results. Due to the difficulty in estimations on the size of geologic formations and their potential to store CO₂, most studies report minimum and maximum ranges. Table 5-19 provides an overview of storage potential for different CO₂ storage options in Germany, which were developed under the different studies. The highest potential for CO₂ storage was revealed for saline aquifers, which allow between 16 and 44 billion tons of CO₂ to be stored. Starting from current German annual CO₂ emissions from hard coal of 319 million tons, this CO₂ storage potential of saline aquifers would allow to store the release of these CO₂ emissions for 51 to 140 years.

Table 5-19: Summary of studies on the German CO₂ storage potential
(source: /144/)

German CO ₂ storage potential [Mt CO ₂]		Depleted gas fields + EGR		Depleted oil fields + EOR		Deep saline aquifers		Enhanced coal bed methane (ECBM)		Sum	
		min	max	min	max	min	max	min	max	min	max
1	May et al. 2003 /149/ Gerling et al. 2004 /148/	2,560		81	110	16,000		3,100	8,300	22,551	27,780
2	COORETEC, 2004 /132/	2,560				33,000		5,500		41,060	
3	RWEPower/Vattenfall, 2003 /150/	2,600		100		22,800	43,500	400	1,700	26,750	47,900
4	GESTCO, 2004 /151/	2,227		103		23,000	43,000			25,330	45,330
5	Gerling et al. 2004 /148/	2,563		81		39,400		2,500	6,600	45,272	49,372

5.8.5 Injection of CO₂

For storage, the transported CO₂ stream is to be injected into CO₂ storage sites, which are at depths of 800 m or more. As mentioned before, due to the high ambient pressure at this depth, CO₂ will remain in the supercritical state and thus features a high density, which is the preferred

state for storage with a low volume requirement. The hydrostatic pressure gradient of 0.098 bar / m illustrates the increase in pressure with depth /145/. However, due to different characteristics of individual storage sites and abnormalities of geological layers, some variability of reservoir pressures can be found. For CO₂ injection the reservoir pressure has to be overcome and furthermore some overpressure is necessary to feed the CO₂ into the reservoir.

5.8.6 LCA of CO₂ Storage

For Germany, the storage options considered most promising are the storage in selected depleted gas fields and deep saline aquifers /23/. Within the scope of the European project CO₂ SINK, a first test storage of CO₂ in an 800 m deep saline aquifer is being performed in Ketzin, which is located close to Berlin. Longer experience with CO₂ storage in a saline aquifer is available at the Sleipner project under the North Sea, where since 1996 annually approximately 1 Mt of CO₂ is injected into the Utsira formation /72/. Corresponding to these CO₂ storage projects, a saline aquifer at depths of around 800 m is considered as storage site in this study.

For this storage site, it is assumed that there is no leakage, as this is the prerequisite for a safe CO₂ storage site. From /145/, an ambient pressure of 80 bar in this aquifer at a depth of 800 m and an overpressure of 30 bar for injection of CO₂ into this aquifer are adopted. This is in accordance to /72/, where as a safe injection pressure a pressure is recommended, which is 1.35 times the hydrostatic pressure at depths down to 1,000m and 2.4 times the hydrostatic pressure for depths of 1,000 – 5,000 m. This is, since the application of very high additional pressures may be disadvantageous for the safety of a CO₂ storage site /126/ and involve fractures of the cap rock.

Both the ambient pressure in the CO₂ storage site and the overpressure are modelled as parameters in P-LCA and thus are flexibly modifiable. According to /126/, the injection pressure is a function of the injection depth and the pressure profile found in underground.

Besides infrastructure for CO₂ injection also LCI data on infrastructure for monitoring of the CO₂ storage has been quantified.

As mentioned before, the quantification of LCI data for CO₂ storage in this study is confined to the injection of the liquid CO₂ into the aquifer. Long-term storage of CO₂ is not investigated, but it is assumed that there will be no CO₂ leakage within the CO₂ storage site, so that no further interactions of the CO₂ with the environment at the Earth's surface will occur.

Table 5-20 summarizes the assumptions for the injection and storage of CO₂ in this study.

Table 5-20: Technical specification of CO₂ injection and storage in this study

Parameter	Specification in this study
CO ₂ storage site	Deep saline aquifer
Depth of the storage site	800 m
Ambient pressure at the storage site	80 bar
Overpressure for injection	30 bar
Leakage rate	0 %

Infrastructure of CO₂ Injection

For the injection of CO₂ into the 800 m deep aquifer, an injection well is drilled. Due to similarity to the oil well drilling the LCI dataset ‘well for exploration and production, onshore’ fromecoinvent is taken in this study /30/. Additionally to the vertical well, a subsurface horizontal well drilling of another 800 m is assumed to be installed in order to improve the CO₂ injection, as it is recommended in /72/. Furthermore, a vertical monitoring well is drilled along half the length of the vertical injection well (400 m). So, altogether the total well drilling sums to 2,000 m. Additionally, LCI data on compressor stations and a piping system to run the injection site are quantified. By the compressors and pumps a pressure level of 110 bar is generated, which covers the reservoir pressure of the saline aquifer of 80 bar and the overpressure of 30 bar.

CO₂ Injection after Pipeline Transportation

At the outlet of the pipeline the CO₂ stream features the minimum pipeline pressure of 80 bar. Consequently, an additional pressure increase of 30 bar is necessary in order to reach the injection pressure level of 110 bar. This pressure increase is provided for by the electrical driven injection facilities. The required electricity for injection is obtained from the German electricity grid and is calculated according to equation 5-10.

The pressure loss in the wells along the injection depth is considerably lower than the required pressure to be overcome for injection into the storage site /145/ and thus is considered to be included in the overpressure of 30 bar.

CO₂ Injection after Barge Transportation

The CO₂ transported by barge is delivered under the transport conditions of 7 bar and -50 °C. As indicated before, for injection, however, a pressure level of 110 bar is required. The pressure difference is met by the compressors and pumps at the injection site. The electricity demand for compression and injection is calculated according to equation 5-10.

5.8.7 Costs of CO₂ Storage

The geological storage of CO₂ is involved with capital costs for the well drilling, the pumps and the overall injection infrastructure. Furthermore, there are operational costs for the injection. The overall costs for CO₂ capture are very much dependant on the chosen type of geological storage, of its local characteristics and its depth. Comprehensive cost studies on well drilling and also estimations for geological CO₂ storage in different regions have been made, which have been categorized and summarized in /72/. This compilation of CO₂ storage cost estimates is shown in Table 5-21 and includes capital, operating and site characterisation costs for different storage options and regions.

Not accounted for in Table 5-21 are monitoring costs and costs for remediation and additional efforts to address long-term liabilities /72/, which are very site-specific and difficult to estimate on a scientifically proven basis.

For this study specific CO₂ storage costs of 2.2 €₂₀₀₅ / t CO₂ stored are assumed, which represents average storage costs in a saline formation in Europe. Within the GESTCO project /151/ specific CO₂ storage costs were developed for project cases with aquifer storage in Germany. These cost data are ranging both below and above 2.2 €₂₀₀₅ / t CO₂, so that this cost figure can also be considered as an average for Germany.

Table 5-21: Compilation of CO₂ storage cost estimates for different storage options
(source: /72/)

Option type	On- or offshore	Location	€ ₂₀₀₅ /t CO ₂ stored		
			Low	Mid	High
Saline formation	Onshore	Australia	0.2	0.4	4.1
Saline formation	Onshore	Europe	1.9	2.2	5.0
Saline formation	Onshore	USA	0.3	0.4	3.6
Saline formation	Offshore	Australia	0.4	2.7	24.2
Saline formation	Offshore	North Sea	3.8	6.2	9.6
Depleted oil field	Onshore	USA	0.4	1.0	3.2
Depleted gas field	Onshore	USA	0.4	1.9	9.8
Disused oil or gas field	Onshore	Europe	1.0	1.4	3.0
Disused oil or gas field	Offshore	North Sea	3.0	4.8	6.5

6 Results

In this chapter, the results of the P-LCA study are presented. The main objective thereby is to give an overview of the results and to highlight significant outcomes of the study. The results presentation underlies the challenge of providing a complete and, at the same time, detailed illustration of results on LCA background data and 17 investigated technology scenarios, for which each comprises a major quantity of LCI and LCIA data in each of the six analysed life cycle phases.

To provide a clear structure for the presentation of LCA results, the following sections separately illustrate the outcomes of the investigated material resources, energy resources, emissions and environmental impact categories. Thereby, for each of these categories, a contribution analyses to the individual life cycle phases is made, a result evaluation for individual investigated technology scenarios is given and, finally, sensitivity analyses are performed in order to highlight the significance of the presented results.

In order to keep the LCA results at a manageable level, the transportation of CO₂ by either pipeline or barge is not investigated for all scenarios. For the time horizon 2015, at which all power plant concepts for large-scale CO₂ capture are anticipated to be in operation, exemplarily both CO₂ transportation technologies are analysed and compared. The results of this comparison of CO₂ transport means can be transferred to the time horizons 2025 and 2050, at which only the CO₂ transportation by pipeline is investigated.

6.1 Results on LCA Background data

The introduction to the result presentation is given in the following sections illustrating the main results of LCA background data for current and future time horizons.

6.1.1 German Steam Coal Supply Chain

The continuous substitution of the German domestic steam coal by steam coal imports from other countries shows a clear influence on the LCI data of the German steam coal supply chain. The increase of imports goes in line with a higher amount of transportation services and thus an increase in both resource demand and release of emissions, as it can be followed from the emissions in to air pictured in Figure 6-1. Between the year 1990 and the entire phase-out of German hard-coal mining in 2018 specific CO₂ emissions are expected to increase from 84 to 204 g CO₂ / kg steam coal. Similar increases in specific emissions are anticipated for the substances SO₂, NO_x and CO.

The increase in NO_x and SO₂ emissions is strongly influenced by the transportation via transoceanic freight ships. Due to diesel oil with high sulphur content and pollutant-intensive combustion in ship engines, the emissions of these substances will increase with the amount of steam coal imports and the distance to the exporting countries. Thereby constant emissions from transoceanic freight ships for future time horizons have been assumed.

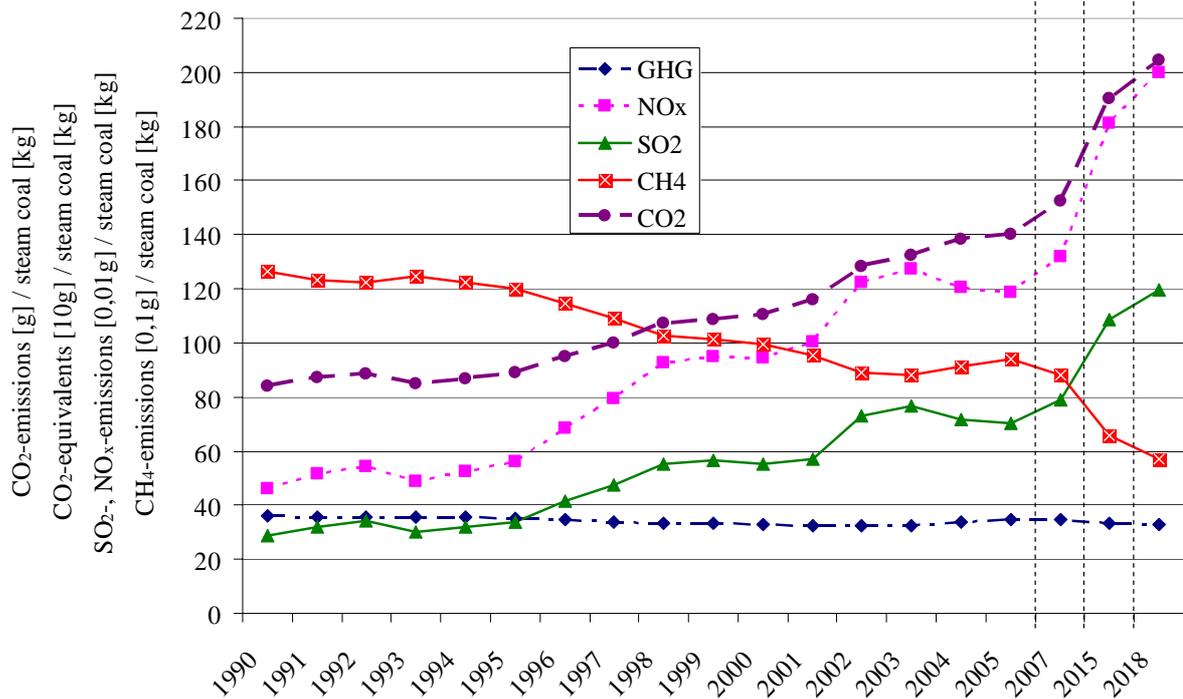


Figure 6-1: Annual time series of selected emissions of the German steam coal supply chain

Table 6-1: Emissions into air and cumulated energy demand over the transport chain of the German steam coal supply in the year 2007

	Unit	Value	Mining and processing	Regional storage	Freight train	Oceanic freight ship	Barge
Emissions							
CO₂	kg / TJ steam coal	5,500	41.4 %	7.0 %	20.0 %	27.5 %	4.1 %
CH₄	kg / TJ steam coal	320	98.6 %	0.6 %	0.4 %	0.3 %	0.1 %
N₂O	kg / TJ steam coal	0.29	64.9 %	4.3 %	11.4 %	13.6 %	5.8 %
SO₂	kg / TJ steam coal	29	13.6 %	3.8 %	11.2 %	70.2 %	1.2 %
NO_x	kg / TJ steam coal	48	36.8 %	1.5 %	12.1 %	44.2 %	5.4 %
NH₃	kg / TJ steam coal	2.4	91.4 %	0.6 %	1.4 %	6.4 %	0.2 %
CO	kg / TJ steam coal	13	46.0 %	1.6 %	25.3 %	24.5 %	2.6 %
NM VOC	kg / TJ steam coal	5.3	53.7 %	1.2 %	13.1 %	28.0 %	4.0 %
Dust	kg / TJ steam coal	98	59.8 %	37.4 %	1.7 %	1.0 %	0.1 %
PM₁₀	kg / TJ steam coal	4.8	29.1 %	17.1 %	29.9 %	22.0 %	1.9 %
Cumulated energy demand (CED)*							
CED_{Prim}	TJ / TJ steam coal	0.085	55.8 %	2.8 %	15.2 %	22.7 %	3.5 %

* without energy content of the steam coal itself (27.68 MJ / kg)

The only LCI results revealing a slight decline over the considered time period are specific methane emissions. The methane emissions mainly originate from the mining and vary strongly between different mining sites and countries. According to the literature, German mines feature comparably high methane emissions so that a substitution of German steam coal by imports

results in a decline of methane emissions /28/. This decline in specific methane emissions on the one hand and the increase in both CO₂ emissions and emissions of other green house gases on the other hand results in an almost constant level of the global warming potential (CO₂-equivalents) of the German steam coal supply chain as shown in Figure 6-1 .

In Table 6-1 the specific emissions into air of the German steam coal supply chain and their local spreading over the entire process chain from mining and transportation up to the power plant site are shown. This highlights that a major contribution to several emissions into air and also to the CED is caused by transportation services.

Table 6-2: LCI results of present and future LCA background data (I)

Name	Unit	Concrete, normal, at plant [m ³]			German electricity mix [kWh _e]				German steam coal supply [kg]		
		2007 / 2015	2025	2050	2007	2015	2025	2050	2007	2015	2025 / 2050
CO ₂	kg	2.6 E+2	2.5 E+2	2.4 E+2	6.0 E-1	5.9 E-1	7.2 E-1	6.2 E-1	1.5 E-1	1.9 E-1	2.0 E-1
CO	kg	2.1 E-1	1.1 E-1	1.0 E-1	1.4 E-4	1.4 E-4	1.4 E-4	1.3 E-4	3.7 E-4	5.0 E-4	5.5 E-4
SO ₂	kg	1.5 E-1	8.5 E-2	7.5 E-2	5.0 E-4	4.9 E-4	4.7 E-4	4.3 E-4	7.9 E-4	1.1 E-3	1.2 E-3
NO _x	kg	4.7 E-1	2.7 E-1	2.0 E-1	5.3 E-4	5.3 E-4	5.1 E-4	4.8 E-4	1.3 E-3	1.8 E-3	2.0 E-3
NM VOC	kg	6.5 E-2	6.3 E-2	6.0 E-2	4.5 E-5	4.3 E-5	4.2 E-5	3.3 E-5	1.5 E-4	2.0 E-4	2.2 E-4
PM _{2,5}	kg	2.3 E-2	2.0 E-2	1.8 E-2	3.7 E-5	3.5 E-5	3.4 E-5	3.1 E-5	4.9 E-5	6.6 E-5	7.2 E-5
PM ₁₀	kg	4.8 E-2	5.4 E-2	4.9 E-2	4.9 E-5	4.8 E-5	4.6 E-5	4.3 E-5	1.3 E-4	1.8 E-4	2.0 E-4
CH ₄	kg	2.1 E-1	1.8 E-1	1.5 E-1	1.2 E-3	1.2 E-3	1.1 E-3	1.0 E-3	8.8 E-3	6.6 E-3	5.7 E-3
N ₂ O	kg	1.1 E-3	1.2 E-3	1.2 E-3	2.2 E-5	2.2 E-5	2.2 E-5	2.1 E-5	8.2 E-6	1.1 E-5	1.1 E-5
Lignite	kg	2.3 E+0	3.9 E+0	3.9 E+0	3.1 E-1	2.8 E-1	3.5 E-1	4.0 E-1	1.4 E-2	1.9 E-2	2.0 E-2
Hard Coal	kg	1.7 E+1	1.5 E+1	1.2 E+1	1.4 E-1	1.7 E-1	2.1 E-1	1.3 E-1	1.1 E0	1.1 E0	1.1 E0
Natural Gas	Nm ³	2.2 E+0	3.1 E+0	3.4 E+0	2.7 E-2	3.4 E-2	3.0 E-2	2.4 E-2	4.5 E-3	6.0 E-3	6.6 E-3
Crude Oil	kg	1.4 E+1	1.2 E+1	1.0 E+1	1.2 E-2	2.7 E-3	3.1 E-3	2.4 E-3	2.0 E-2	2.8 E-2	3.1 E-2
Peat	kg	2.3 E-4	2.1 E-4	2.1 E-4	8.8 E-8	1.4 E-7	1.4 E-7	1.6 E-7	2.5 E-7	3.5 E-7	3.8 E-7
Uranium	kg	4.6 E-4	4.3 E-4	4.2 E-4	5.9 E-6	3.5 E-6	2.0 E-7	1.7 E-7	7.0 E-7	9.3 E-7	1.0 E-6
Aluminium	kg	9.3 E-2	1.1 E-1	1.1 E-1	2.9 E-5	4.4 E-5	4.5 E-5	5.4 E-5	2.3 E-4	3.1 E-4	3.5 E-4
Basalt	kg	9.4 E-2	9.4 E-2	9.4 E-2	6.0 E-6	6.1 E-6	6.1 E-6	5.7 E-6	9.2 E-6	1.2 E-5	1.3 E-5
Chromium	kg	1.3 E-2	1.3 E-2	1.3 E-2	2.3 E-5	2.9 E-5	2.7 E-5	3.7 E-5	1.6 E-5	2.2 E-5	2.4 E-5
Clay	kg	1.2 E+2	1.2 E+2	1.2 E+2	4.5 E-4	4.4 E-4	4.3 E-4	4.1 E-4	1.7 E-3	2.0 E-3	2.1 E-3
Copper	kg	1.3 E-2	1.1 E-2	1.1 E-2	1.1 E-5	1.4 E-5	1.6 E-5	1.9 E-5	1.3 E-5	1.8 E-5	1.9 E-5
Dolomite	kg	2.2 E-3	2.2 E-3	2.2 E-3	4.3 E-6	5.9 E-6	6.6 E-6	8.2 E-6	8.3 E-6	1.1 E-5	1.2 E-5
Granite	kg	8.9 E-6	9.0 E-6	9.0 E-6	7.0 E-9	1.1 E-8	1.1 E-8	1.2 E-8	1.2 E-8	1.6 E-8	1.8 E-8
Gravel	kg	2.0 E+3	2.0 E+3	2.0 E+3	1.1 E-2	1.2 E-2	1.3 E-2	1.1 E-2	9.1 E-2	1.2 E-1	1.3 E-1
Gypsum	kg	1.0 E-5	1.1 E-5	1.1 E-5	3.5 E-8	3.8 E-8	4.6 E-8	4.0 E-8	2.3 E-8	2.6 E-8	2.7 E-8
Iron	kg	9.3 E-1	7.5 E-1	7.5 E-1	9.7 E-4	1.1 E-3	1.1 E-3	1.1 E-3	3.6 E-3	4.7 E-3	5.2 E-3
Lead	kg	2.5 E-2	2.1 E-2	2.1 E-2	1.5 E-5	1.2 E-5	1.1 E-5	1.2 E-5	1.4 E-5	1.8 E-5	2.0 E-5
Sand	kg	3.4 E-5	4.0 E-5	4.0 E-5	5.8 E-6	9.9 E-6	1.1 E-5	1.6 E-5	6.2 E-8	8.1 E-8	8.8 E-8
Zinc	kg	1.5 E-2	1.5 E-2	1.5 E-2	1.0 E-6	1.5 E-6	1.5 E-6	1.9 E-6	5.8 E-6	7.7 E-6	8.4 E-6

6.1.2 LCI data on Current and Future Upstream Chains

The LCI results of some other upstream process chains are shown in Table 6-2. Further LCI results on LCA background data are shown in Table 11-5 to Table 11-7 in the annex. Thereby it becomes apparent that most LCI data on material supply show decreasing release of emissions and decreasing resource demand for future time horizons. This is due to improvements in the manufacturing process on the one hand, but also due to efficiency improvements in the background system on the other hand.

As shown in chapter 6.1.1 the increase of imports in the German steam coal supply chain goes in line with an increase in the demand for material and energy resources as well as with an increase in emissions. This can be followed in Table 6-2 for the future time horizons of the steam coal supply chain.

The German electricity mix for future time horizons reveals a reduction of the uranium demand due to the phase-out of nuclear electricity generation in Germany. At the same time more electricity from lignite is generated, which can be seen at the demand for lignite and the development of the CO₂ emissions. The increased electricity generation based on renewable energy sources as well as the efficiency improvement of electricity generation technologies entails that most of the LCI data of the German electricity mix are declining for future time horizons.

6.2 Presentation and Analysis of Life Cycle Inventory Data of Investigated CCS Technologies

The environmental performance of CCS has an impact on all life cycle phases of the investigated hard-coal-fuelled technologies for electricity generation. There are life cycle phases like the transportation and injection of CO₂, which are solely induced by CCS. But also the life cycle phases of the electricity generation process itself such as the construction, operation and dismantling of the power plant are influenced by CCS, namely by the facilities for CO₂ capture and compression. Besides the influence from the construction and dismantling of these facilities, the operation of these facilities has a considerable impact on the LCI data. As CO₂ capture goes in line with an efficiency penalty for the process of electricity generation in the power plant, less electricity is generated along the overall life time of the product system. This entails an increase of all LCI and LCIA data, since these data are referred to a reduced amount of life-cycle electricity generation, which is the functional unit in this LCA study. This means that there is a first increase in LCI and LCIA data due to additional infrastructure and a second increase due to a reduction in the functional unit. This influence of CCS on LCI data can be followed in the following sections, which present and evaluate the LCI results on material resources, energy resources and emissions.

6.2.1 Demand for Material Resources

The demand for material resources arises from the infrastructure, which is built or used within the technology scenarios. Table 6-3 summarizes how this demand for different material resources is split over the individual life cycle phases. The margins shown for the contribution to the individual life cycle phases constitute the result ranges between all investigated technology scenarios with and without CCS.

Table 6-3: Contribution analysis of the demand for material resources over the life cycle

[%]	Life cycle phases					
	Steam coal supply	Power Plant Construction	Power Plant Operation	Power Plant Dismantling	CO ₂ transportation	CO ₂ injection
Aluminium	80.1 - 90.2	8.3 – 18.6	0.48 - 0.85	0.02 – 0.03	0.54 – 0.81	0.18 – 0.27
Basalt	23.0 - 34.7	57.5 – 69.8	5.3 – 9.2	0.03 – 0.06	1.4 – 2.0	0.23 – 0.31
Chromium	28.8 – 39.7	58.2 – 69.1	1.4 – 2.5	0.03 – 0.05	1.6 – 2.8	0.52 – 1.0
Clay	66.2 – 75.6	12.0 – 21.0	9.3 – 13.9	0.04 – 0.06	1.7 – 2.3	0.39 – 0.85
Copper	30.4 – 47.4	47.9 – 67.0	1.8 – 3.0	0.05 – 0.07	1.1 – 2.2	0.40 – 0.84
Dolomite	69.3 – 85.9	11.2 – 20.9	0.36 – 0.71	0.03 – 0.07	12.4 – 16.5	0.68 – 1.1
Granite	82.4 – 88.3	2.9 – 5.3	4.7 – 8.2	2.4 – 5.2	3.1 – 4.2	0.78 – 1.1
Gravel	85.1 – 94.4	3.8 – 8.0	0.73 – 1.3	0.32 – 0.68	6.0 – 8.1	0.12 – 0.17
Gypsum	5.7 – 8.4	89.1 – 93.0	1.1 – 1.5	0.01 – 0.02	0.40 – 0.77	0.14 – 0.27
Iron	71.1 – 86.6	10.8 – 19.6	0.34 – 0.78	0.04 – 0.08	11.6 – 15.5	0.36 – 0.42
Lead	63.5 – 90.2	3.6 – 20.7	2.6 – 5.3	1.0 – 2.4	14.0 – 20.2	0.66 – 0.89
Sand	4.6 – 82.1	0.86 – 20.1	0.27 – 59.8	0.01 – 0.28	23.4 – 63.6	9.8 – 26.9
Zinc	78.6 – 85.6	7.2 – 12.4	5.5 – 8.9	0.09 – 0.16	1.7 – 2.4	0.25 – 0.38

The bulk of most material resources shown in Table 6-3 originate from the supply of steam coal. This means that most material demand over the life-cycle of electricity generation from hard coal is not required at the power plant site, but for the infrastructure of the steam coal supply. Only for basalt, chromium, copper and gypsum is the main demand accounted for during the construction of the power plant. The demand for these materials represents the high quantities of concrete, copper and different types of high-alloyed steel, which are required for the manufacturing of the power plant components.

The spare parts required during power plant operation and the use of the infrastructure during power plant dismantling show only minor contributions to the overall demand for materials. Even less is the share of material demand from CO₂ injection.

Noteworthy material demand apart from the steam coal supply chain and the power plant construction only originates from the transportation of CO₂. Therefore, the main contribution arises from steel, which is the main constituent of the pipeline infrastructure together with sand. For steel production, high quantities of iron and also dolomite are required. Further material demand is generated by the electricity demand of the pipeline compressors and pumps.

Absolute figures on the demand of material resources within the investigated scenarios are summarized in Table 11-8 and Table 11-9 in the annex. Therein, it can be seen that scenarios with CCS basically feature a higher material demand than scenarios without CCS. In a direct comparison of the individual technologies for CO₂ capture, IGCC technology shows the lowest demand for material resources followed by oxyfuel combustion and PCC technology.

The highest demand for material resources in all scenarios for electricity generation from hard coal is surveyed for gravel and iron. A detailed contribution analysis of the latter is shown in Figure 6-2 highlighting that the bulk of the specific iron demand arises from the steam coal supply. The iron-intensive infrastructure of train, barge and ship transportation is partly accounted for each transported ton-kilometer of steam coal. Due to the large amount of required steam coal along the life cycle of a power plant and the far distances at the steam coal supply, this demand for iron sums up to an amount, which finally is higher than the iron demand from power plant construction.

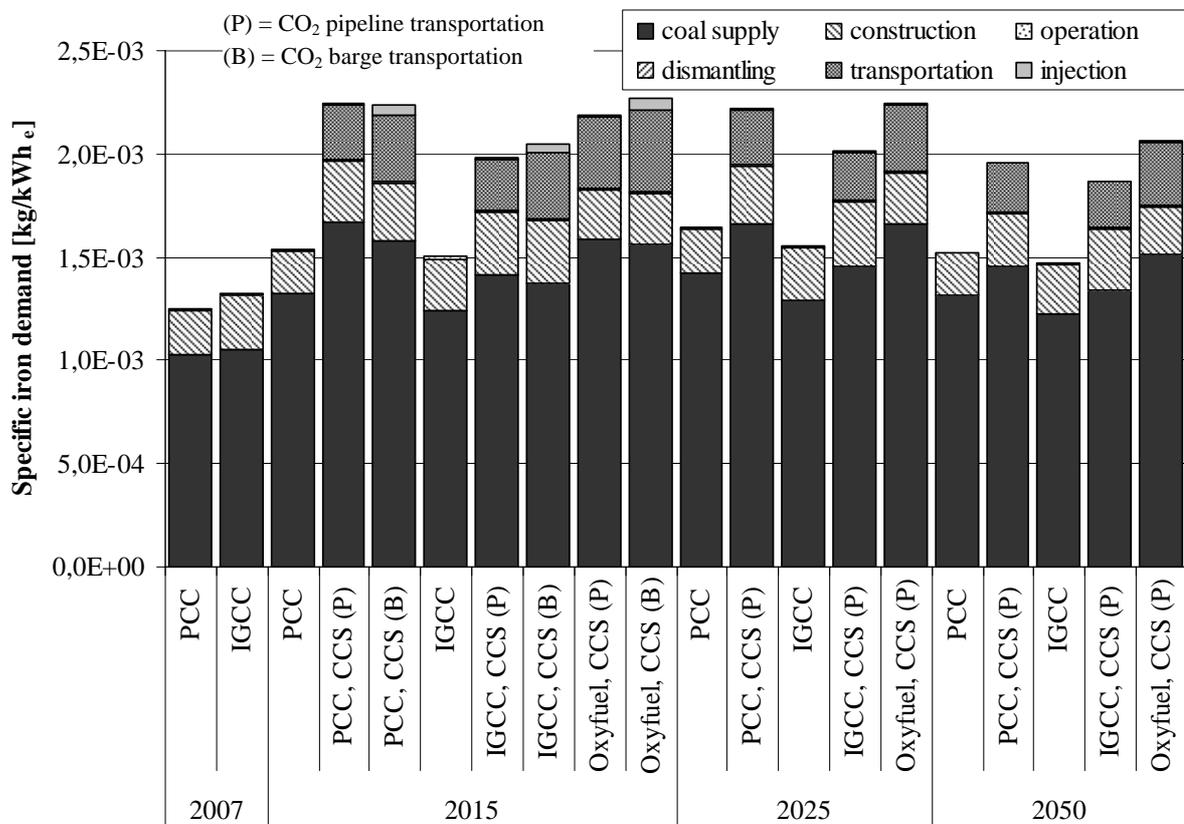


Figure 6-2: Contribution analysis of the iron demand

Furthermore, it is illustrated that CCS technology is involved with an elevated iron demand, whereas the highest specific demand for iron is calculated for scenarios using barge transportation. In the case of barge transportation, the advantage of a lower efficiency penalty due to CO₂ capture is outweighed by the material-intensive infrastructure of the barge system and especially by the electricity-intensive operation for additional compression before CO₂ injection. It can be deduced from Figure 6-2 that the decrease in the specific iron demand due to efficiency increases of the power plants for future time horizons is outweighed by the higher material demand originating from the steam coal supply. Not only the iron demand, but also all specific demand on other material resources show an increase for future time horizons by 20 to 50 %. This is due to the replacement of the declining German domestic steam coal production, which goes in line with transportation of steam coal over longer distances and thus causes a higher demand for material resources.

Evaluation of the Power Plant Construction

Since LCI data on construction materials of power plant components are often required in reference to the power plant capacity, which is the commonly applied functional unit when talking about power plant construction, a further evaluation of the construction phase of the investigated power plant technologies has been made, which is shown in Table 6-4.

Table 6-4: Material demand of power plant construction related to the installed power plant capacity. Sensitivity analysis for three different capacity levels

$\left[\frac{kg}{kW_e} \right]$	PCC			PCC			Oxyfuel		
	Without			With			With		
CCS	429	643	965	429	643	965	429	643	965
Gross Power Plant Capacity [MW_e]	429	643	965	429	643	965	429	643	965
Aluminium	+14.1%	2.58	-12.2%	+14.3%	3.38	-12.4%	+14.2%	2.74	-11.9%
Basalt	+12.9%	2.02	-11.2%	+13.2%	2.65	-11.4%	+13.1%	2.24	-11.0%
Chromium	+16.1%	2.82	-13.7%	+16.8%	4.06	-14.3%	+16.8%	3.52	-13.8%
Clay	+14.4%	27.70	-12.6%	+14.5%	41.32	-12.7%	+14.5%	30.91	-12.3%
Copper	+1.5%	1.47	-1.2%	+1.4%	2.06	-1.1%	+1.6%	1.67	-1.3%
Dolomite	+15.1%	0.14	-12.9%	+15.6%	0.20	-13.3%	+15.4%	0.16	-12.7%
Granite	+16.8%	5.5 E-5	-14.2%	+17.0%	7,3 E-5	-14.3%	+16.7%	6.0 E-5	-13.7%
Gravel	+14.4%	429.82	-12.6%	+14.5%	641.62	-12.7%	+14.5%	480.00	-12.3%
Gypsum	+22.0%	0.03	-18.1%	+22.0%	0.03	-18.1%	+22.0%	2.5 E-2	-17.5%
Iron	+15.1%	54.12	-12.9%	+15.6%	78.02	-13.3%	+15.4%	63.09	-12.8%
Lead	+15.1%	9.4 E-2	-12.9%	+15.3%	0.13	-13.1%	+15.2%	0.11	-12.6%
Sand	+3.4%	1.1 E-3	-2.9%	+3.6%	1.5 E-3	-3.0%	+3,2%	1.4 E-3	-2.6%
Zinc	+13.5%	6.0 E-2	-11.4%	+14.0%	8.0 E-2	-11.7%	+13.4%	6.3 E-2	-10.9%

$\left[\frac{kg}{kW_e} \right]$	IGCC			IGCC		
	Without			With		
CCS						
Gross Power Plant Capacity [MW_e]	322	483	725	322	483	725
Aluminium	+14.0%	3.92	-12.2%	+14.1%	4.52	-12.2%
Basalt	+12.0%	1.45	-10.2%	+12.4%	1.70	-10.5%
Chromium	+18.5%	2.33	-15.4%	+18.8%	2.97	-15.6%
Clay	+14.5%	38.23	-12.7%	+14.5%	47.90	-12.7%
Copper	+1.2%	2.16	-1.0%	+1.1%	2.74	-0.9%
Dolomite	+16.1%	0.16	-13.6%	+16.3%	0.20	-13.7%
Granite	+15.0%	4.4 E-5	-12.8%	+15.2%	5.3 E-5	-12.9%
Gravel	+14.5%	599.55	-12.7%	+14.5%	750.39	-12.7%
Gypsum	+21.9%	0.02	-18.0%	+21.9%	0.03	-18.0%
Iron	+16.1%	64.94	-13.6%	+16.3%	80.91	-13.7%
Lead	+14.9%	0.11	-12.8%	+15.1%	0.13	-12.9%
Sand	+3.4%	1,2 E-3	-2.9%	+3.4%	1.4 E-3	-2.9%
Zinc	+11.6%	6.6 E-2	-9.9%	+11.9%	7.9 E-2	-10.1%

From the tables, it can be deduced that PCC technology requires lower specific material resources than oxyfuel combustion. However, the addition of CO₂ capture facilities increases the material demand for the PCC power plant over that of the oxyfuel power plant.

Depending on the material investigated, the lowest material demand is either for the PCC or the IGCC power plant. The installation of facilities for CO₂ capture and compression on the other hand requires a lower increase in specific material demand for IGCC than for PCC power plants. In Table 6-4, a sensitivity analysis is shown for an up and downscaling of the power plant capacity by 50 %, which is represented by the figures on the right-hand and left-hand side of the bold printed columns. This scaling, which is possible in P-LCA by implementing scaling functions for power plant components, reveals that the material demand is greatly reduced for power plants with a higher capacity than it is increased for power plants with a lower capacity. The strongest scaling effect is found for gypsum, which mainly originates from the declining demand for concrete in facilities with higher mass flows. Sand is also required in connection with the production of polymers such as polyvinylchloride, which is, for instance, required for electrical components in the power plant and is scarcely reduced at specific level when upscaling to higher power plant capacities. The same is true for copper, which is predominantly required for wiring.

CO₂ Transportation and Injection

A detailed analysis of the demand for different material resources is also made for the phases of CO₂ transportation and CO₂ injection. In sensitivity analyses, the impact of transportation distance and the injection overpressure on the LCI results are investigated as shown in Table 6-5.

Table 6-5: Demand for material resources at transportation and injection of CO₂, complemented by a sensitivity analysis on the transportation distance and the injection overpressure

$\left[\frac{kg}{t CO_2} \right]$	1. row: CO ₂ pipeline transportation				1. row: CO ₂ injection (pipeline)			
	2. row: CO ₂ barge transportation				2. row: CO ₂ injection (barge)			
	In brackets: contribution from infrastructure only							
Transport distance [km]	100	350	700	1,400	-	-	-	-
Overpressure, injection [bar]	-	-	-	-	30	60	90	150
Aluminium	-71%	1.1 E-3 (29%)	+100%	+300%	3.5 E-4 (4%)	+73%	+132%	+223%
	-71%	1.6 E-3 (82%)	+91%	+280%	2.9 E-3 (0.5%)	+5%	+12%	+22%
Basalt	-71%	3.3 E-4 (67%)	+100%	+300%	5.3 E-5 (10%)	+68%	+123%	+209%
	-72%	1.7 E-3 (90%)	+92%	+283%	4.1 E-4 (1%)	+5%	+12%	+22%
Chromium	-71%	6.7 E-4 (22%)	+100%	+300%	2.3 E-4 (1%)	+75%	+135%	+229%
	-71%	7.8 E-4 (90%)	+91%	+281%	1.9 E-3 (0.1%)	+5%	+12%	+22%
Clay	-71%	2.6 E-2 (69%)	+100%	+300%	5.2 E-3 (35%)	+50%	+89%	+152%
	-72%	8.3 E-1 (95%)	+93%	+285%	3.1 E-2 (6%)	+5%	+11%	+21%
Copper	-71%	3.3 E-4 (21%)	+100%	+300%	1.2 E-4 (2%)	+74%	+134%	+226%
	-70%	1.2 E-3 (91%)	+89%	+274%	9.6 E-4 (0.3%)	+5%	+12%	+22%
Dolomite	-71%	1.0 E-3 (90%)	+100%	+300%	5.3 E-5 (13%)	+66%	+119%	+201%
	-65%	1.1 E-3 (91%)	+84%	+258%	4.0 E-4 (2%)	+5%	+12%	+22%
Granite	-71%	3.4 E-7 (44%)	+100%	+300%	8.3 E-8 (2%)	+74%	+134%	+227%
	-71%	5.3 E-7 (87%)	+91%	+280%	7.0 E-7 (0.3%)	+5%	+12%	+22%
Gravel	-71%	4.6 E+0 (95%)	+100%	+300%	9.6 E-2 (3%)	+74%	+133%	+225%
	-72%	1.1 E+1 (95%)	+93%	+286%	8.0 E-1 (0.3%)	+5%	+12%	+22%
Gypsum	-71%	9.0 E-7 (24%)	+100%	+300%	3.0 E-7 (3%)	+73%	+132%	+224%
	-72%	4.3 E-5 (96%)	+93%	+286%	2.5 E-6 (0.4%)	+5%	+12%	+22%
Iron	-71%	4.2 E-1 (95%)	+100%	+300%	1.1 E-2 (27%)	+56%	+100%	+170%
	-65%	4.9 E-1 (91%)	+84%	+258%	7.3 E-2 (4%)	+5%	+11%	+21%
Lead	-71%	2.4 E-3 (90%)	+100%	+300%	9.6 E-5 (4%)	+73%	+131%	+222%
	-70%	7.2 E-4 (69%)	+89%	+275%	7.9 E-4 (1%)	+5%	+12%	+22%
Sand	-71%	1.8 E-4 (2%)	+100%	+300%	7.7 E-5 (0.04%)	+76%	+137%	+232%
	-71%	2.7 E-6 (76%)	+91%	+281%	6.6 E-4 (0.01%)	+5%	+12%	+22%
Zinc	-71%	9.0 E-5 (70%)	+100%	+300%	1.3 E-5 (92%)	+70%	+125%	+212%
	-71%	2.4 E-4 (60%)	+91%	+281%	1.0 E-4 (1%)	+5%	+13%	+22%

Thereby, the LCI results are related to the functional unit of the CCS chain, which is one ton of stored CO₂. A direct comparison between CO₂ transportation by pipeline and barge, as shown in Table 6-5, reveals that CO₂ pipeline transportation generally features a lower specific demand for material resources. Due to a higher operational material demand, when taking into account the infrastructure contributions shown in brackets, pipeline transportation features a lower specific demand for material resources than CO₂ barge transportation.

The CO₂ transportation by barge requires facilities for the intermediate storage of CO₂, which are independent of the transportation distance. This part of the fixed infrastructure makes the barge transportation non-proportional to the transport distance, as can be seen from the figures for longer transport distances in Table 6-5.

In contrast to CO₂ transportation by barge or pipeline, which, for specific demand on material resources feature a major contribution from the infrastructure, the injection phase is dominated by the demand for material resources for the operation of the electrical pumps and compressors. Despite identical injection infrastructure for all technology scenarios of this study, the injection following CO₂ barge transportation features higher material demand. This arises from the necessity for an additional CO₂ compression at 110 bar following barge transportation at a CO₂ pressure level of around 7 bar.

Since most CO₂ storage sites will be deeper than 800 m, which is the case for the investigated aquifer in this study, a higher pressure level will be required for injection, which has to be generated additionally to the pipeline pressure. This means that starting from the pressure at the end of the pipeline of 80 bar an overpressure of clearly more than 30 bar (this study) could be necessary. As shown in Table 6-5, higher pressures increase the material demand for a logarithmic scale according to equation 5-10.

6.2.2 Demand for Energy Resources

Each process in the process chain requires energy to run. This energy is taken from primary or secondary energy carriers, which can be traced back to the use of energy resources. Table 6-6 shows a contribution analysis of the demand for different energy resources over the life cycle of the investigated technologies in this study. Absolute figures on the demand for energy resources are listed in Table 11-10 and Table 11-11 in the annex. From these tables, it can be deduced that the highest demand for energy resources is for hard coal, which, in the form of steam coal, is used as a fuel for the electricity generation process in the power plant. This steam coal input to the power plant is also used as feedstock for CO₂ capture and compression.

The life cycle phase of the steam coal supply in Table 6-6 comprises both the inherent energy resources in the steam coal, which is solely hard coal, and the energy resources required for mining, processing and transportation of the steam coal. The latter contributes only marginally to the specific demand on hard coal, but for all other energy resources it makes up bulk of their demand over the steam coal supply chain. For these energy resources their specific demand over

the steam coal supply chain are considerably higher than the specific demand from the life cycle phases construction, operation and dismantling of the investigated power plants.

Further noteworthy demand on energy resources arise from pipeline transportation and injection of CO₂, both of which are operated by means of the secondary energy carrier electricity. This electricity, which is obtained from the German electricity grid, is generated by different technologies using different energy resources, which can be seen from the LCI data of the German electricity mix in Table 6-2. As reflected by Table 6-6, considerably more electricity is required for CO₂ transportation than for CO₂ injection.

Table 6-6: Contribution analysis of the demand for energy resources over the life cycle

[%]	Life cycle phases					
	Steam coal supply	Power Plant Construction	Power Plant Operation	Power Plant Dismantling	CO ₂ transportation	CO ₂ injection
Lignite	43.7 – 95.7	0.79 – 2.8	1.2 – 3.8	0.01 – 0.04	28.1 – 38.2	11.9 – 16.2
Hard coal	4.64 – 5.01	0.06 – 0.12	94.3 – 94.9	(3 – 5) E-4	0.46 – 0.86	0.18 – 0.35
Natural gas	68.5 – 93.6	2.8 – 5.7	1.9 – 4.1	0.05 – 0.13	12.1 – 19.3	4.4 – 7.3
Crude oil	94.6 – 97.5	1.1 – 2.3	1.1 – 1.9	0.12 – 0.26	1.5 – 2.1	0.18 – 0.23
Peat	51.7 – 88.2	6.1 – 14.9	1.1 – 2.9	0.06 – 0.17	32.5 – 39.9	0.32 – 0.44
Uranium	76.9 – 95.4	1.6 – 3.0	2.1 – 4.1	0.05 – 0.10	1.5 – 13.7	0.31 – 5.5

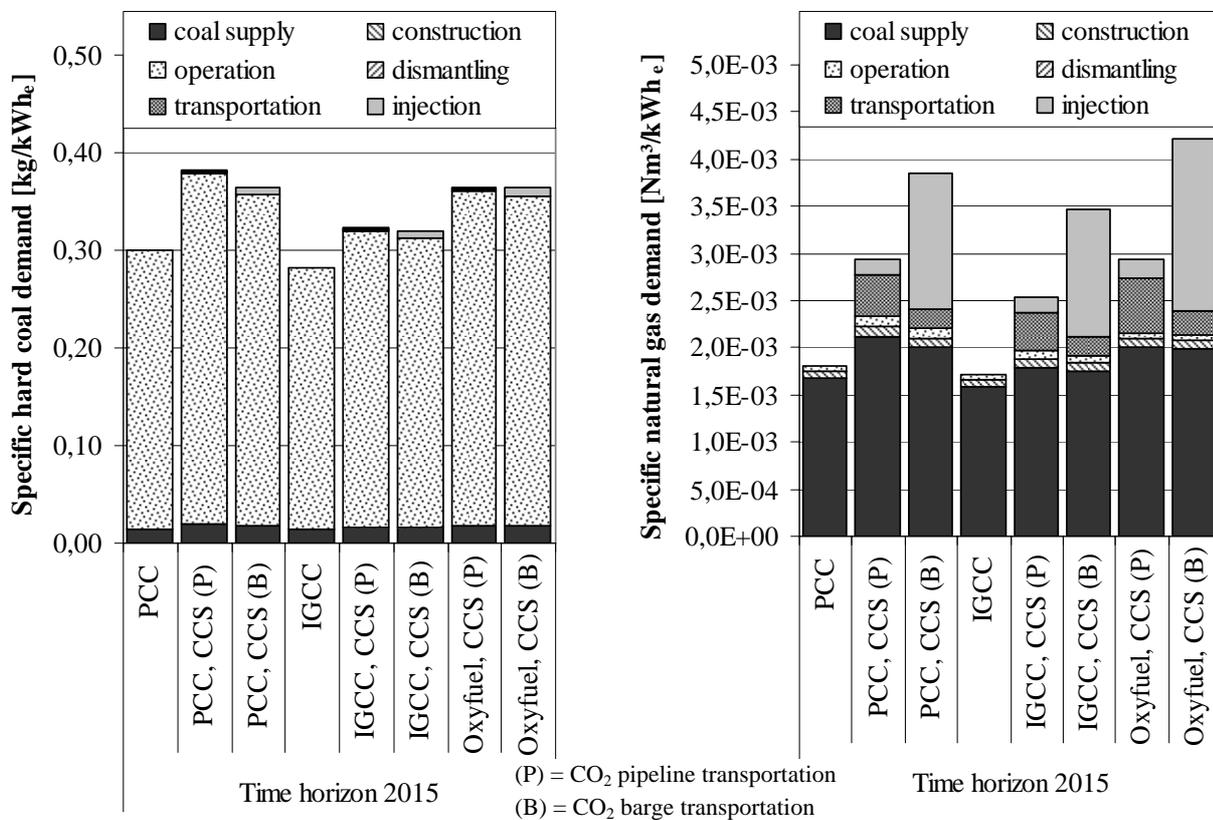


Figure 6-3: Contribution analysis of the demand for hard coal and natural gas for the time horizon 2015

A more detailed analysis of the hard coal demand for the investigated technologies is shown in Figure 6-3. The main factor influencing the demand for hard coal is the overall efficiency of the power plants, which increases between 2007 and 2050 due to improvements in power plant technologies. This results in a reduction of the specific demand for hard coal for future time horizons.

The increasing imports in the German steam coal supply chain and thus increased levels of transportation have an impact on the demand for energy resources. The demand for energy resources besides steam coal are increased by 22 to 39 %. For instance, for natural gas, an increase of 33 % over the steam coal supply chain is quantified between 2007 and 2025.

Transportation and Injection of CO₂

A detailed analysis of the demand for energy resources arising from the transportation and injection of CO₂, as depicted in Table 6-5, illustrates the contribution from the infrastructure and shows all figures with reference to the functional unit of the CCS chain, which is the ton of captured CO₂.

Table 6-7: Demand for energy resources for transportation and injection of CO₂, complemented by a sensitivity analysis on the transportation distance and the injection overpressure

$\left[\frac{1}{t \text{ CO}_2} \right]$	1. row: CO ₂ pipeline transportation				1. row: CO ₂ injection (pipeline)			
	2. row: CO ₂ barge transportation				2. row: CO ₂ injection (barge)			
In brackets: contribution from infrastructure only								
Transport distance [km]	100	350	700	1,400	-	-	-	-
Overpressure, injection [bar]	-	-	-	-	30	60	90	150
Lignite [kg]	-71% -71%	5.1 E0 (1.8%) 4.2 E-1 (76.3%)	+100% +91%	+300% +280%	2.2 E0 (0.2%) 1.8 E+1 (0.02%)	+76% +5%	+136% +12%	+231% +22%
Hard coal [kg]	-71% -70%	3.2 E0 (5.2%) 4.8 E-1 (84.7%)	+100% +89%	+300% +275%	1.3 E0 (0.3%) 1.1 E+1 (0.03%)	+76% +5%	+136% +12%	+231% +22%
Natural gas [Nm ³]	-71% -71%	7.0 E-1 (12.4%) 3.3 E-1 (44.4%)	+100% +91%	+300% +280%	2.6 E-1 (0.7%) 2.2 E0 (0.1%)	+75% +5%	+136% +12%	+230% +22%
Crude oil [kg]	-71% -72%	2.5 E-1 (80.5%) 3.8 E0 (6.7%)	+100% +93%	+300% +286%	2.8 E-2 (24.1%) 1.9 E-1 (3.6%)	+58% +5%	+104% +11%	+176% +22%
Peat [kg]	-71% -72%	1.1 E-4 (97.7%) 3.0 E-5 (95.1%)	+100% +92%	+300% +284%	1.1 E-6 (2.4%) 9.4 E-6 (0.3%)	+74% +5%	+133% +12%	+226% +22%
Uranium [kg]	-71% -71%	6.8 E-5 (6.6%) 2.4 E-5 (78.1%)	+100% +91%	+300% +280%	2.7 E-5 (0.8%) 2.3 E-4 (0.1%)	+75% +5%	+136% +12%	+230% +22%

For CO₂ pipeline transportation the highest demand for energy resources arises from electricity generation for operating the pump and compressor stations.

For the operation of CO₂ barge transportation, ship diesel oil is used, which was refined from crude oil and also accounts for the use of some natural gas resources.

Thus, the infrastructure contribution is low for crude oil and somewhat reduced for natural gas.

As shown in Table 6-5, the manufacturing and installation of the wells and pumps for CO₂ injection require less energy resources than the electrical operation of these facilities. Thereby, the demand for electricity is higher for injection after barge transportation due to the additional CO₂ compression.

The comparably higher share of crude oil required for the infrastructure originates from the use of lubricating oil used during drilling and well installation and appears as high as 24 % due to the low demand for crude oil within the German electricity mix.

The result of scalings show the relationship between the CO₂ pipeline transportation and the transportation distance. However, this is not entirely the case for barge transportation due to the additional infrastructure required for intermediate CO₂ storage.

The structure of the results on the variation of the transport distance and the injection overpressure is similar to the sensitivity analysis for the demand for material resources in Table 6-5 so that they are not discussed in further detail here.

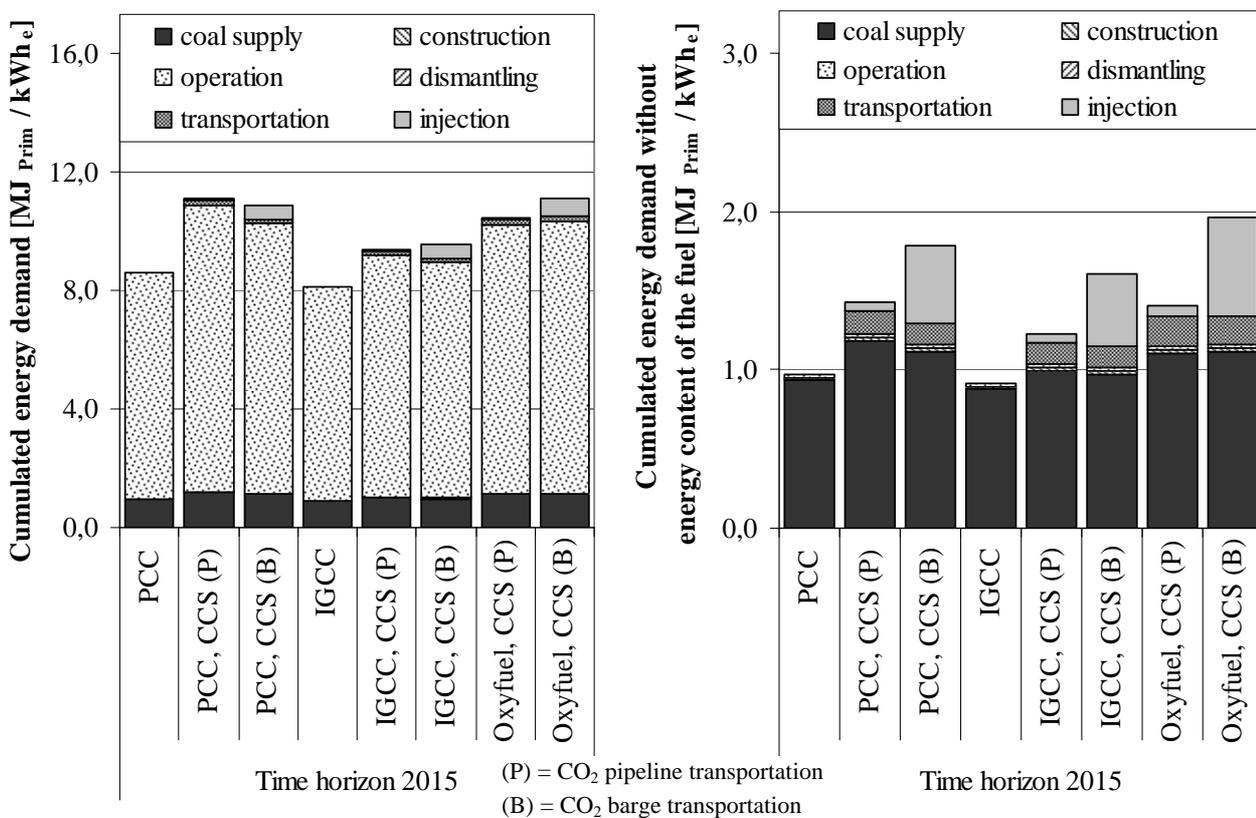


Figure 6-4: Contribution analysis of the cumulated energy demand

6.2.3 Cumulated Energy Demand (CED)

Most contributions to the CED of the investigated technologies arises from the power plant operation as shown in Figure 6-4. For a more detailed analysis of the CED, the contribution from the energy content of the fuel has been subtracted for the figure on the right hand side. In this figure, contribution from the steam coal supply primarily reflects the energy demand for the mining and transportation of the steam coal. The life-cycle phases of construction and dismantling of the power plant show negligible contribution to the CED.

The CED of CO₂ transportation is almost equivalent for the electrically operated pipeline on the one hand and the CO₂ barge, which is fuelled by diesel oil, on the other hand. Again, however, the technology scenarios with barge transportation features higher figures, as the injection after barge transportation requires an additional compression of the transported CO₂ and thus is involved with a higher CED.

Pipeline transportation and injection of CO₂ contribute between 2.0 to 2.7 % to the overall CED when compared to technology scenarios without CO₂ capture. The contributions from the entire CCS chain increases the CED by between 12 to 29 %.

6.2.4 Release of Emissions into Air

The supply of steam coal and the power plant operations are the main sources of emissions released by the investigated technologies for hard-coal-fuelled electricity generation. These results can be derived from the contribution analysis shown in Table 6-8, where large fluctuations of specific emissions into air between the individual technology scenarios are revealed. This fluctuation is mainly caused by very low specific emissions into air for technology scenarios with oxyfuel power plants when compared to the other technologies. In power plants with oxyfuel combustion the flue gas stream features considerably less air pollutants than the flue gas of PCC power plants and is almost completely captured after the gas cleaning. This means that the operational emissions into air from oxyfuel power plants result solely from the use of operating supplies, the manufacturing of spare parts and from leakages during combustion and flue gas treatment.

According to Table 6-8, the other life-cycle phases, being the construction and dismantling of the power plants as well as the transportation and injection of CO₂, make only minor contributions to the specific emissions into air within the investigated technology scenarios.

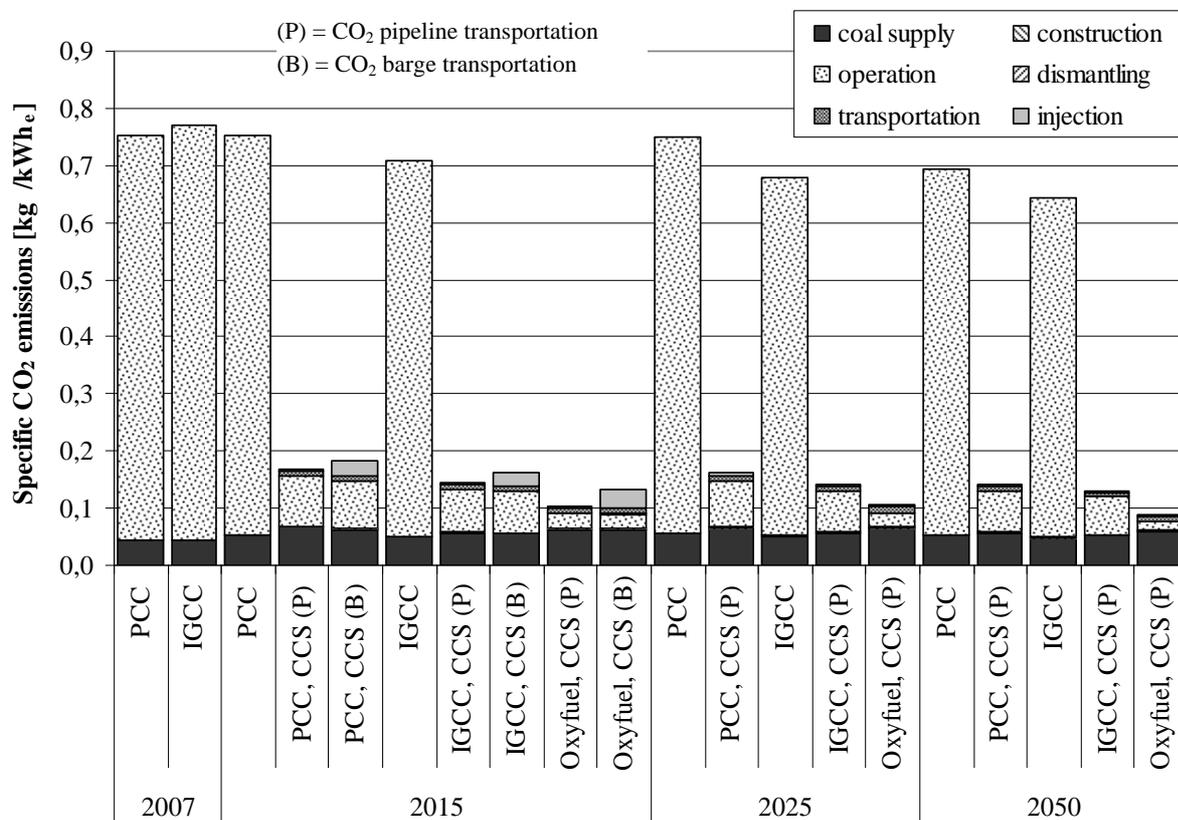
On a quantitative basis, the highest emissions into air among the investigated technology scenarios are made up of CO₂ followed by NO_x and SO₂. Absolute figures on emissions into air within the respective technology scenarios are listed in Table 11-12 and Table 11-13 in the annex.

Table 6-8: Contribution analysis of the release of emissions into air over the life cycle

[%]	Life cycle phases					
	Steam coal supply	Power Plant Construction	Power Plant Operation	Power Plant Dismantling	CO ₂ transportation	CO ₂ injection
CO ₂	5.7 – 66.8	0.13 – 1.2	18.0 – 94.2	0.01 – 0.06	4.5 – 10.2	1.7 – 4.0
CO	42.8 – 88.7	1.9 – 6.6	1.3 – 54.3	0.04 – 0.12	2.7 – 6.5	0.25 – 0.59
SO ₂	29.1 – 95.7	0.46 – 1.6	2.8 – 70.4	0.01 – 0.03	1.6 – 2.3	0.53 – 0.78
NO _x	40.9 – 95.8	0.29 – 0.67	1.3 – 58.8	0.03 – 0.09	1.5 – 2.2	0.40 – 0.60
NM VOC	75.1 – 95.7	0.75 – 1.3	0.98 – 23.9	0.08 – 0.17	1.4 – 2.4	0.25 – 0.44
PM _{2.5}	64.7 – 95.1	3.1 – 6.2	0.76 – 32.0	0.19 – 0.50	3.1 – 5.0	0.67 – 1.1
PM ₁₀	56.6 – 94.5	3.0 – 5.6	0.48 – 40.1	0.23 – 0.61	2.3 – 3.8	0.33 – 0.54
CH ₄	97.4 – 99.4	0.06 – 0.17	0.06 – 0.85	0.002 – 0.004	0.75 – 1.4	0.30 – 0.56
N ₂ O	7.0 – 79.0	0.06 – 0.49	8.9 – 92.9	0.003 – 0.03	0.72 – 9.1	0.29 – 3.7

Specific CO₂ Emissions

A separate analysis of the specific CO₂ emissions as shown in Figure 6-5 highlights the heavy reduction in CO₂ emissions, which is achieved by CO₂ capture. This reduction, however, only pertains to the operational CO₂ emissions of the investigated power plants. For other life-cycle phases, CCS technology is involved with additional CO₂ emissions due to the higher demand for steam coal and the added necessity for transportation and injection of the captured CO₂.

**Figure 6-5:** Contribution analysis of specific CO₂ emissions

Comparing different technological alternatives over the CCS chain, pipeline transportation followed by CO₂ injection is involved with less specific CO₂ emissions than barge transportation followed by CO₂ injection, as the latter includes an additional CO₂ compression stage.

Among the investigated technology scenarios, the lowest specific CO₂ emissions are quantified for scenarios with oxyfuel combustion, since this technology features the highest CO₂ capture rate (97 %) of the investigated CO₂ capture technologies. For PCC and IGCC technology, a CO₂ capture rate of 90 % is achieved, which results in a reduction of the specific CO₂ emissions of between 75.6 by 79.8 % as shown in Figure 6-5.

Specific SO₂ Emissions

PCC power plants without CCS revealed the highest specific SO₂ emissions among the investigated technology scenarios, which becomes apparent in Figure 6-6. PCC power plants with CCS are equipped with more efficient FGD systems in order to achieve clearly lower SO₂ emissions, since the MEA solvent used for CO₂ post-combustion capture shows a degradation in presence of high SO₂ concentrations.

For coal gasification in IGCC power plants, inherently less SO₂ emissions are generated, which are further reduced by syngas scrubbing. Thus, considerably lower specific SO₂ emissions are achieved compared to PCC technology.

Technology scenarios for oxyfuel combustion feature the lowest specific SO₂ emissions due to the capture of the entire flue gas stream (except for some losses).

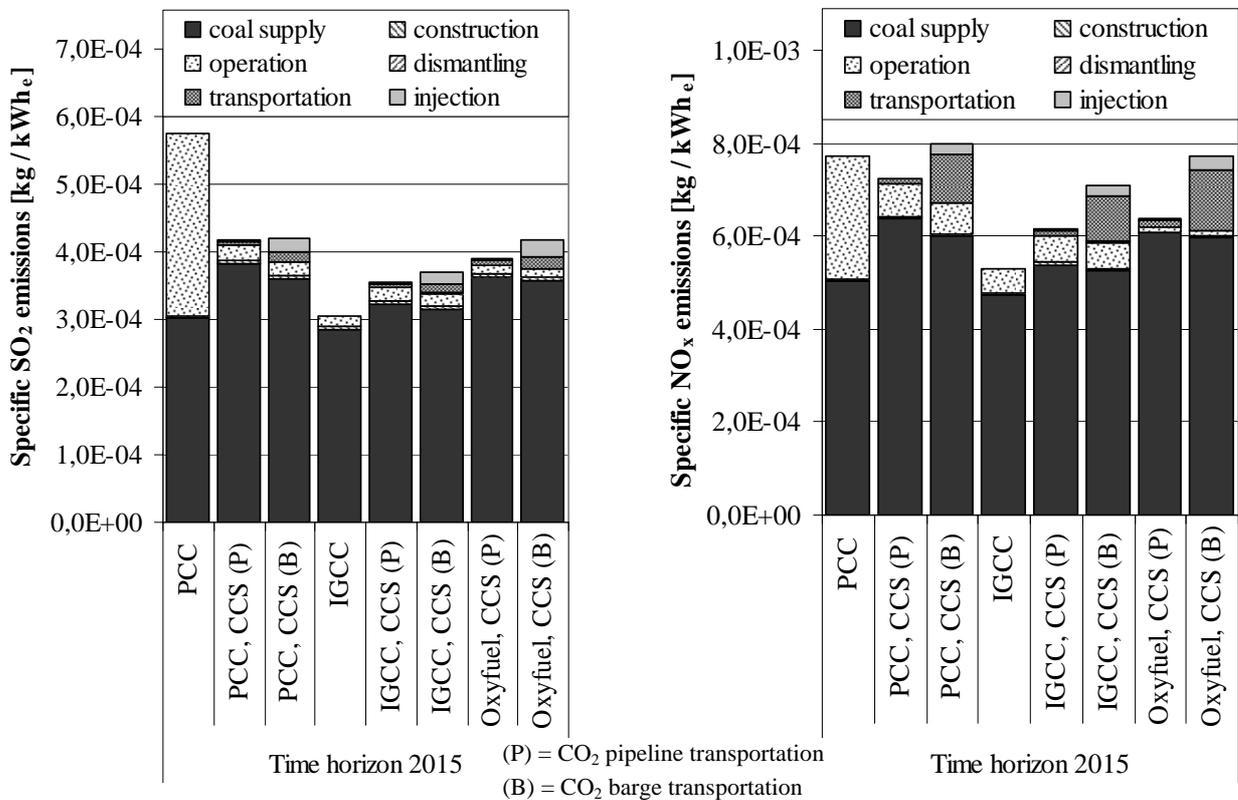


Figure 6-6: Contribution analysis of specific SO₂ and NO_x emissions

Specific NO_x Emissions

Similarly to the results for specific SO₂ emissions, the specific NO_x emissions are highest for PCC power plants without CO₂ capture and lowest for oxyfuel power plants as pictured in Figure 6-6. Since MEA scrubbing requires low NO_x concentrations in the flue gas to avoid degradation, PCC power plants with CO₂ capture are equipped with SCR units featuring higher NO_x removal rates than PCC power plants without CO₂ capture. This advanced equipment for NO_x removal explains the reduction of NO_x emissions with the integration of CO₂ capture in PCC power plants.

Even less NO_x emissions are generated in IGCC power plants, since there is no diluting nitrogen from the air due to gasification by almost pure oxygen and only limited amounts of nitrogen during combustion of the syngas respectively hydrogen in the gas turbine. The same absence of nitrogen from the air is the reason for the low NO_x emissions of oxyfuel power plants, which, however, are further reduced by capturing the entire flue gas stream.

Transportation and Injection of CO₂

The CCS chain contributes between 6 to 14 % to the specific CO₂ emissions of hard-coal-fuelled electricity generation with CCS. The contribution of the CCS chain to most other emissions into air is much less and mostly below 5 %. One exception is a contribution of between 1 to 13 % in the specific N₂O emissions, which shows high percentage within the scenarios for oxyfuel combustion. For these scenarios, due to the capture of the entire flue gas stream already a very low level of N₂O emissions during CO₂ transportation considerably increases the percentage share of the CCS chain.

In order to analyse in more detail the small contribution of the CCS chain to the specific cumulative emissions into air, all emissions are related to the functional unit of the CCS chain and listed in Table 6-9.

This table shows that CO₂ barge transportation is involved with more specific emissions than the transportation of CO₂ by pipeline. Only specific methane emissions are higher for CO₂ pipeline transportation. As shown by the contribution due to the infrastructure, these emissions originate from the pipeline transportation and therefore from the German electricity mix. In this mix, more than half of the electricity is generated from coal, which goes in line with major specific methane and N₂O emissions from mining. The operation of barge transportation on the basis of ship's diesel oil combustion, on the other hand, involves mainly CO₂, NO_x, SO₂ and particulate emissions, but only a little CH₄ emissions. This explains the lower CH₄ emissions for barge transportation and also the lower contribution by the infrastructure to the specific emissions of the just cited pollutants. The contribution by the infrastructure to the specific emissions of CO₂ pipeline transportation is reduced for the pollutants, which are emitted by the generation of the German electricity mix.

The contribution by the infrastructure to CO₂ injection is clearly lower than it is for CO₂ transportation. This means that the bulk of the specific emissions from CO₂ injection arises from the German electricity mix, which is used for the operation of the pumps and compressors. Highest specific emissions have been quantified for CO₂ injection (barge) due to the additional CO₂ compression after barge transportation.

The importance of scaling the transportation distance and injection overpressure to the specific emissions is similar to that already evaluated for material and energy resources.

Table 6-9: Release of emissions into air at transportation and injection of CO₂, complemented by a sensitivity analysis on the transportation distance and the injection overpressure

$\left[\frac{kg}{t CO_2} \right]$	1. row: CO ₂ pipeline transportation				1. row: CO ₂ injection (pipeline)			
	2. row: CO ₂ barge transportation				2. row: CO ₂ injection (barge)			
In brackets: contribution from infrastructure only								
Transport distance [km]	100	350	700	1,400	-	-	-	-
Overpressure, injection [bar]	-	-	-	-	30	60	90	150
CO ₂	-71% -72%	1.2 E+1 (10%) 1.4 E+1 (22%)	+100% +92%	+300% +284%	4.6 E0 (0.7%) 3.9 E+1 (0.1%)	+75% +5%	+136% +12%	+230% +22%
CO	-71% -69%	1.5 E-2 (83%) 2.5 E-2 (57%)	+100% +88%	+300% +271%	1.3 E-3 (16%) 9.8 E-3 (2%)	+64% +5%	+115% +11%	+194% +22%
SO ₂	-71% -72%	1.1 E-2 (27%) 2.3 E-2 (25%)	+100% +92%	+300% +283%	3.5 E-3 (3%) 2.9 E-2 (0.3%)	+74% +5%	+133% +12%	+226% +22%
NO _x	-71% -72%	1.7 E- 2 (43%) 1.6 E-1 (4%)	+100% +93%	+300% +286%	4.4 E-3 (5%) 3.6 E-2 (0.7%)	+72% +5%	+129% +12%	+219% +22%
NM VOC	-71% -72%	2.1 E-3 (62%) 1.6 E-2 (54%)	+100% +92%	+300% +284%	3.9 E-4 (14%) 2.9 E-3 (2%)	+66% +5%	+118% +12%	+200% +22%
PM _{2.5}	-71% -72%	1.5 E-3 (58%) 4.3 E-3 (21%)	+100% +92%	+300% +283%	3.1 E-4 (10%) 2.4 E-3 (1%)	+68% +5%	+123% +12%	+209% +22%
PM ₁₀	-71% -70%	3.1 E-3 (71%) 6.4 E-2 (38%)	+100% +90%	+300% +277%	4.1 E-4 (10%) 3.2 E-3 (1%)	+68% +5%	+123% +12%	+209% +22%
CH ₄	-71% -71%	2.8 E-2 (6%) 9.9 E-3 (39%)	+100% +92%	+300% +282%	1.1 E-2 (0.7%) 9.6 E-2 (0.1%)	+75% +5%	+136% +12%	+230% +22%
N ₂ O	-71% -72%	4.8 E-4 (6%) 1.1 E-3 (73%)	+100% +93%	+300% +286%	2.0 E-4 (1%) 1.7 E-3 (0.1%)	+75% +5%	+135% +12%	+229% +22%

6.3 Environmental Impact Assessment

Starting from the LCI results shown in the previous chapter, the environmental impact of hard-coal-fuelled electricity generation with and without CCS is investigated for selected environmental impact categories.

6.3.1 Global Warming Potential (GWP)

The GWP is dominated by the specific CO₂ emissions, which contribute more than 90 % to the CO₂ equivalents of this environmental impact category. As shown in the contribution analysis in Figure 6-7, CCS considerably reduces the GWP, but also goes in line with additional CO₂ equivalents from the CCS chain and the steam coal supply.

For PCC and IGCC technology, a CO₂ capture rate of 90 % reduces the CO₂ equivalents by between 71.1 to 74.7 %. The difference in relation to the CO₂ capture rate mainly originates from additional CO₂ equivalents from methane emissions of additional steam coal demand. Additional emissions from CO₂ transportation and injection account for only 1.4 – 1.7 % of this difference.

The CO₂ capture technology with the best environmental performance, in terms of GWP, is oxyfuel combustion, since this technology achieves the highest CO₂ capture rate.

Comparing CO₂ transportation technologies ends up with advantages for pipeline transportation, which features a clearly lower GWP compared to barge transportation.

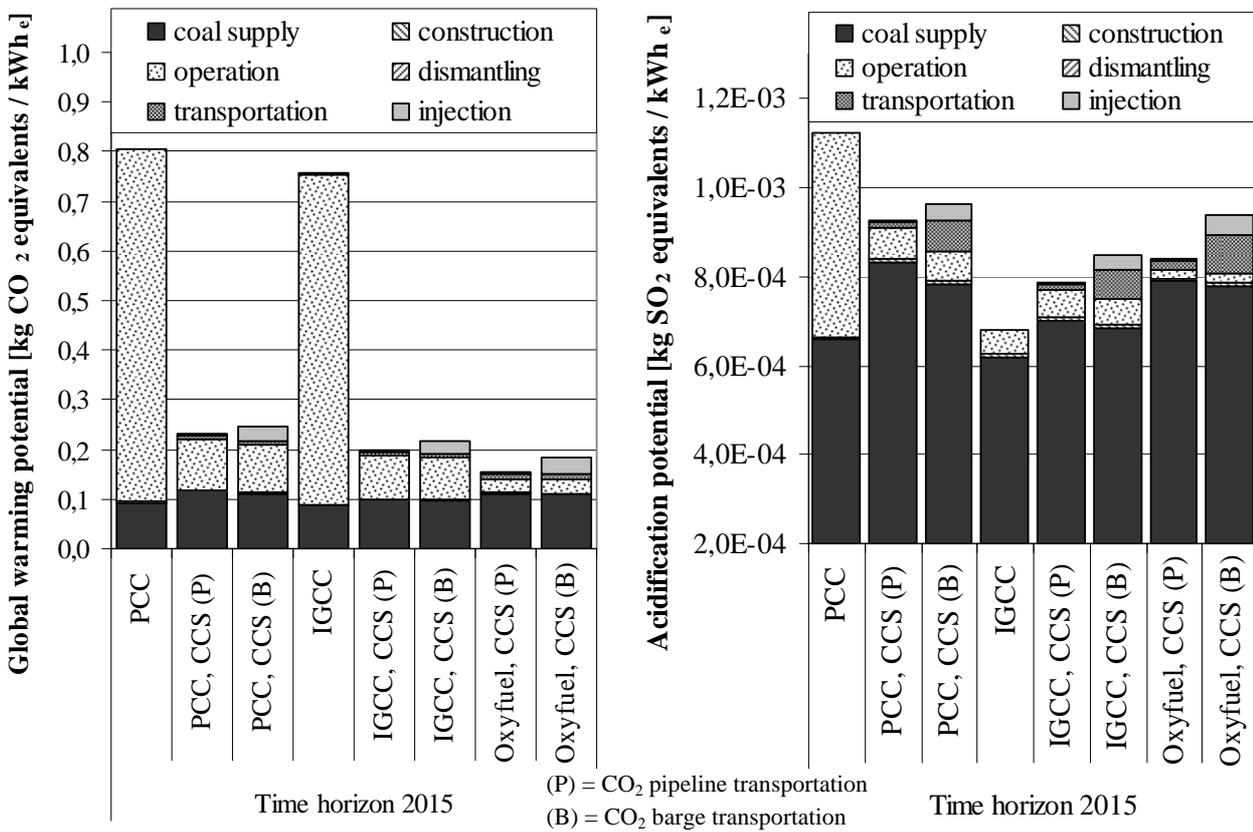


Figure 6-7: Contribution analysis of the global warming as well as the acidification potential

6.3.2 Acidification Potential (AP)

The AP is predominantly influenced by the specific SO₂ emissions and a subordinate contribution from NO_x emissions within the investigated scenarios. As the contribution analysis in Figure 6-7 shows, highest AP is quantified for PCC power plants without CCS due to their comparably high operational emissions of NO_x and SO₂. Due to the dominant contribution from the steam coal supply, the scale in Figure 6-7 was altered in order to provide a

better overview of the contributions from life cycle phases different from steam coal supply. This change of scale applies also to some of the following figures, which feature a dominating contribution from the steam coal supply.

When CO₂ capture facilities are installed at PCC power plants, SO₂ and NO_x emissions are heavily reduced, which results from the more effective flue gas scrubbing applied in order to avoid degradation of the MEA solvent. This reduction in SO₂ and NO_x emissions results in an AP level, which is similar to that of IGCC power plants. Even lower operational SO₂ emissions, and thus a more reduced AP, is revealed by oxyfuel power plants due to the capture of almost the entire flue gas stream from power plant operation.

The best environmental performance in terms of AP, however, is achieved by scenarios on IGCC power plants without CCS. In these scenarios, low operational AP is combined with a very low up-stream AP due to the lowest demand for steam coal.

In comparing of CO₂ transportation alternatives, again pipeline transportation shows better performance despite the reduced efficiency penalty due to CO₂ capture in the power plants of the scenarios with barge transportation.

6.3.3 Eutrophication Potential (EP)

As shown in Figure 6-8, EP features a similar picture to AP presented in the previous section. However, for this environmental impact category, the main influence originates from the NO_x emissions alone without any contribution from SO₂. Thus, the maximum EP arising from operational NO_x emissions is somewhat lower than the respective AP. The environmental performance between the investigated technology scenarios and also the conclusions drawn from this are similar to the above evaluated AP. The best environmental performance revealed is for IGCC power plants without CCS. For CO₂ transportation, pipeline transportation turns out to be the better alternative.

6.3.4 Human Toxicity Potential (HTP)

The HTP gets its highest contribution from the steam coal supply, mainly from mining (particulate emissions) and transportation (NO_x emissions). This explains why HTP increases for the future time horizons, whereas steam coal demand is decreasing due to improved power plant efficiencies.

The second largest contributor to the overall HTP for the investigated technology scenarios is the operational emissions, whereas the highest impact results from emissions of arsenic, PAH, benzene and Chromium IV.

As third a major source of the HTP the power plant construction is identified, where, in Figure 6-8 it can clearly be seen that PCC power plants require the largest facilities for CO₂ capture. This at the same time goes along with the highest amount of emissions at their installation.

The contribution of CO₂ transportation and injection to the HTP is small and ranges between 2.0 – 3.4 % for pipeline transportation. Higher contributions arise from CO₂ barge transportation

and injection (6.6 – 10.1 %), which, however, is partly compensated for in these technology scenarios by lower impact from the reduced steam coal demand and also lower operational emissions by the power plant.

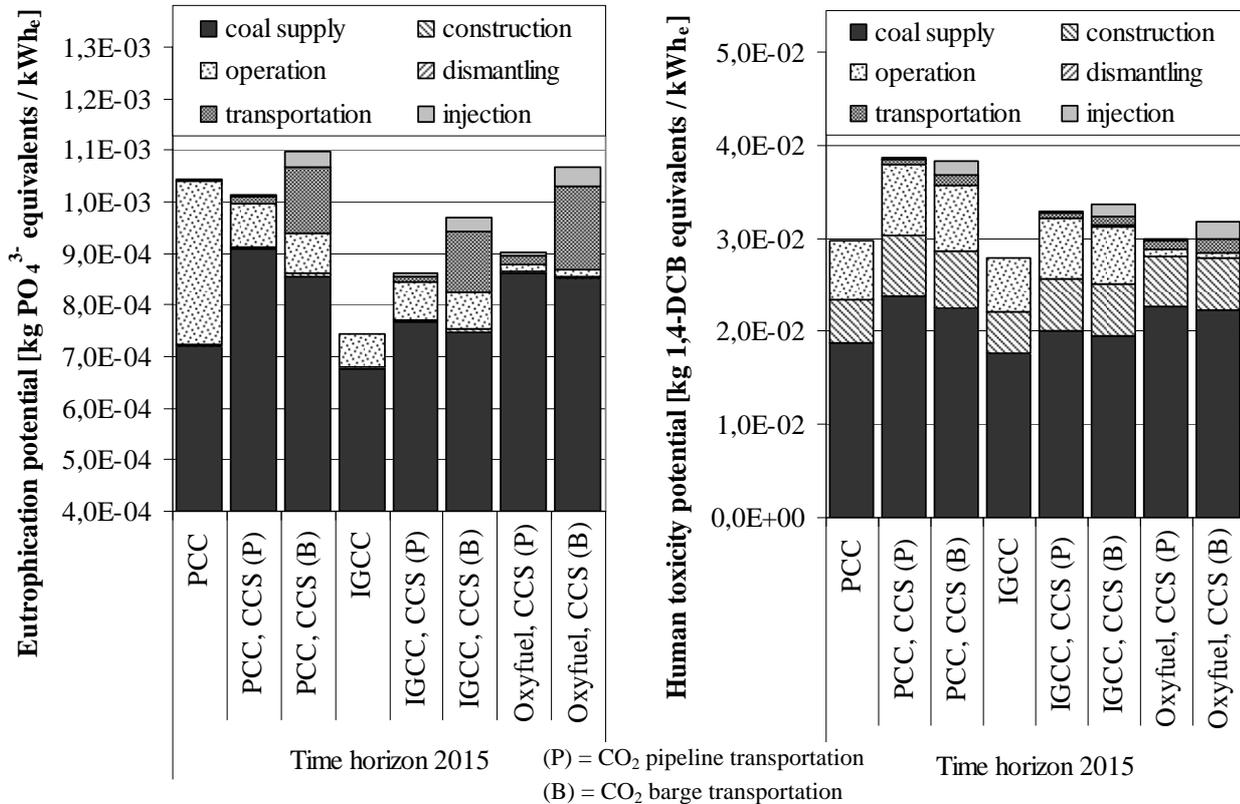


Figure 6-8: Contribution analysis of the eutrophication and the human toxicity potential

Considering the entire contribution from the CCS chain, an increase in HTP of up to 29 % revealed for the PCC and IGCC power plants with pipeline transportation, as shown in Figure 6-8, compared to the power plants without CCS. For oxyfuel power plants, even a small reduction is quantified when compared to the PCC power plant without CCS. This is due to the high capture rate for all substances of the flue gas at oxyfuel power plants, which also includes the main HTP contributors arsenic, PAH, benzene and Chromium VI.

6.3.5 Photochemical Ozone Creation Potential (POCP)

The steam coal supply chain is responsible for the most part of the POCP as shown in Figure 6-9. Here, it is revealed that, for future time horizons, the POCP shows a stronger decline than the steam coal demand itself. This is due to the reduction in specific methane emissions from mining, which amongst all emissions contribute most to the POCP of the steam coal supply. As shown in chapter 6.1.1, German hard-coal mining comes with higher specific methane emissions than hard-coal mining in other countries. In the course of the phasing out of German domestic hard-coal mining, the increasing imports consequently result in lower specific methane emissions.

For operational emissions, the CO emissions predominantly contribute to the POCP, which are highest for PCC power plants. The contribution of CO₂ pipeline transport and injection ranges between 1.7 and 3.3 %. For CO₂ barge transportation and injection, this contribution is somewhat higher, but again partly compensated for by the efficiency advantage in the power plants of these technology scenarios.

The addition of CCS increases the POCP for technology scenarios with PCC and IGCC power plants by up to 29 %. For technology scenarios with oxyfuel power plants, almost no increase in POCP is revealed.

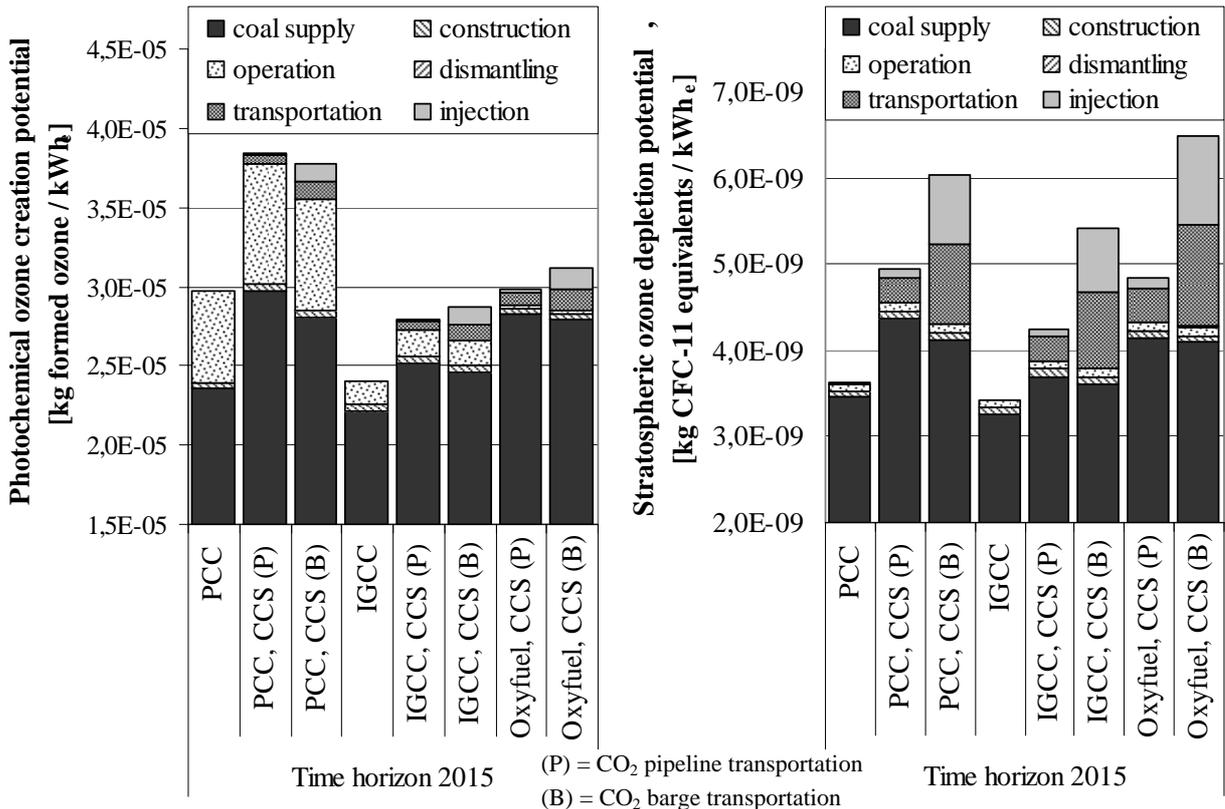


Figure 6-9: Contribution analysis of the photochemical ozone creation and the stratospheric ozone depletion potential

6.3.6 Stratospheric Ozone Depletion Potential (SODP)

The SODP is caused by the emission of diverse chlorofluorocarbons (CFC) into air. As shown in Figure 6-9, most of these CFC emissions in the technology scenarios under investigation originate from the steam coal supply chain. Thereby, more than half of the CSC emissions are released by the tanker transportation of steam coal.

This considerable contribution to the SODP by ship transportation also becomes apparent in the three scenarios with CO₂ barge transportation. In direct comparison, pipeline transportation and injection of CO₂ is involved with a lower SODP, since less specific CSC emissions are released by electricity generation for operating the pipeline compressors.

Due to rising imports and thus increasing transportation within the German steam coal supply chain, the SODP increases over future time horizons. Apart from the technology scenarios with barge transportation highest SODP levels are revealed for technology scenarios with

oxyfuel power plants and PCC power plants with CCS due to the increased steam coal demand. Altogether, CCS technologies increase the SODP by between 17 to 36 % compared to their reference power plants without CO₂ capture.

6.3.7 Risks to Human Health

The most relevant parameters for quantifying the risks to human health are the release of particulates, SO₂ and NO_x. In the investigated technology scenarios these emissions predominantly originate from the steam coal supply chain, as is illustrated in Figure 6-10 . Only in technology scenarios for PCC power plants without CCS is there a major contribution from the power plant operation due to elevated SO₂ and NO_x emissions.

Despite higher characterisation factors of particulate emissions (see Table 5-3), SO₂ and NO_x emissions are more influential for the risks to human health, since higher quantities of these substances are released.

The lowest risks to human health are involved with IGCC power plants without CCS. Also, in the direct comparison of CCS technologies, technology scenarios on IGCC power plants show less years of life lost than technology scenarios on oxyfuel and PCC power plants.

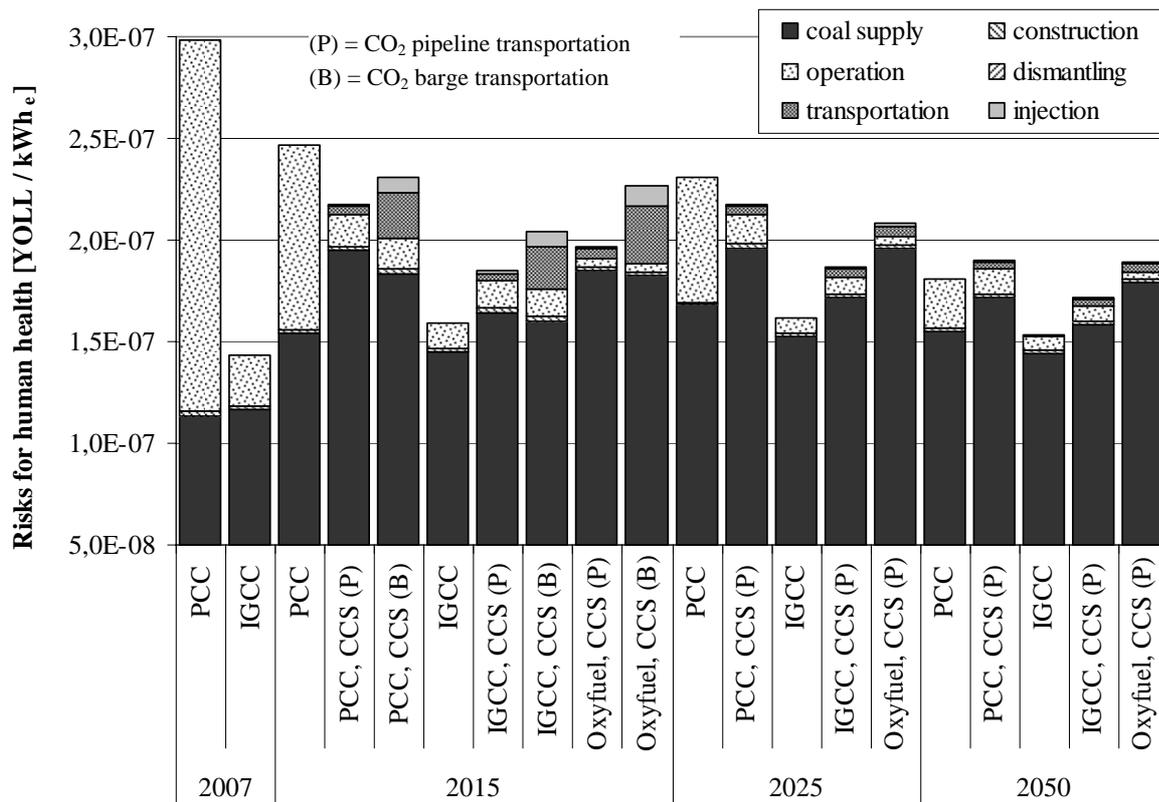


Figure 6-10: Contribution analysis of risks to human health

6.4 Economic Analysis

In the following section a full cost analysis of hard-coal-fuelled electricity generation with and without CCS is made. After a literature survey on cost data of CCS technologies, firstly direct costs and secondly external costs of the investigated technologies are illustrated and discussed.

6.4.1 Cost Development of Investigated Technologies for Hard-coal-fuelled Electricity Generation with CO₂ Capture

In the literature, different technology roadmaps and cost projections for hard-coal-fuelled power plants with CO₂ capture have been published over the last few years. In Table 6-10, Table 6-11 and Table 6-12 this reporting of technical and cost data from selected sources is summarized. In the columns of these tables data on power plants with CO₂ capture in reference to the same power plant without CO₂ capture are shown, as it is reported in the literature. Thereby specific cost data are reported in reference to the net electric capacity of the respective power plant. In the three bottom lines of the tables ALLEGC and CO₂ avoidance costs are shown, which have been calculated from the reported cost data according to the approaches shown in chapter 5.2.1 and 5.2.3. In order to allow better comparability between the individual power plants, the ALLEGC and CO₂ avoidance costs in Table 6-10, Table 6-11 and Table 6-12 only comprise the process of electricity generation with CO₂ capture in the power plant, but are calculated without transportation and storage of the captured CO₂.

Table 6-10: Cost data and technical specification of hard-coal-fired power plants with CO₂ post-combustion capture

Time horizon		1999	2000	2002	2004	2005	2006	2006	2006
Year of publication		1999	2002	2007	2007	2005	2006	2006	2006
Reference		/136/	/165/	/114/	/114/	/72/	/156/	/157/	/162/
Subreference				/164/	/163/				
Net electric efficiency	[%]	33.4	30.9	35.4	31.3	32.5	36.0	34.8	28.1
Efficiency penalty	[%]	11.6	10.3	9.7	9.8	10.5	10.0	9.2	12.1
CO ₂ capture efficiency	[%]	90	90	90	90	85	85	85	90
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,770	1,850	2,080	1,480	1,940	1,450	1,650	1,890
Total investment costs	[€ ₂₀₀₅ /kW _e]	2,070	2,160	2,430	1,740	2,260	1,690	1,930	2,210
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	689	830	883	560	790	528	476	809
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	103	108	121	87	113	85	58	111
ALLEGC with CO ₂ capture*	[€ ₂₀₀₅ /MWh _e]	61.82	65.35	68.27	56.33	66.46	52.73	54.76	68.50
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	42.65	43.02	46.14	39.87	45.35	37.95	45.85	44.93
CO ₂ avoidance costs*	[€ ₂₀₀₅ /tCO ₂]	29.47	31.37	33.79	23.03	33.48	24.86	14.29	32.75

* without transportation and storage of the captured CO₂

Time horizon		2006	2006	2006	2007	2010	2012	2015	2020
Year of publication		2006	2006	2006	2007	2007	2002	2007	2006
Reference		/158/	/123/	/159/	/43/	/120/	/165/	/43/	/158/
Subreference									
Net electric efficiency	[%]	33.8	25.3	35.3	36.0	37.0	36.1	38.0	40.0
Efficiency penalty	[%]	10.5	20.7	8.7	10.0	10.0	6.3	10.0	9.0
CO ₂ capture efficiency	[%]	88	90	90	85	88	90	90	85
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	2,110	1,730	1,680	1,450	1,730	1,520	1,510	1,520
Total investment costs	[€ ₂₀₀₅ /kW _e]	2,460	2,030	1,970	1,690	2,020	1,780	1,770	1,780
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	805	648	533	528	673	550	610	805
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	123	101	98	85	101	89	88	89
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	80.09	67.19	58.74	57.67	59.14	54.55	53.69	46.67
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	48.73	42.44	44.15	38.72	41.56	40.53	37.51	33.69
CO ₂ avoidance costs *	[€ ₂₀₀₅ /tCO ₂]	49.13	41.12	21.67	29.52	28.81	19.90	26.27	23.04

* without transportation and storage of the captured CO₂

Time horizon		2020	2020	2020	2025	2030	2030	2040	2050
Year of publication		2007	2006	2007	2007	2006	2007	2007	2007
Reference		/23/	/134/	/120/	/43/	/134/	/120/	/23/	/43/
Subreference									
Net electric efficiency	[%]	40.0	37.4	43.0	43.0	44.0	48.0	44.0	48.0
Efficiency penalty	[%]	9.0	11.6	7.0	7.0	8.0	5.0	8.0	5.0
CO ₂ capture efficiency	[%]	88	90	90	90	90	90	90	90
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,540	1,750	1,510	1,400	1,600	1,370	1,410	1,370
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,810	2,050	1,770	1,630	1,870	1,600	1,650	1,600
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	706	750	481	500	650	384	617	475
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	94	102	88	82	94	80	87	80
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	54.36	60.06	51.92	49.48	54.40	47.40	51.03	48.73
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	36.30	40.37	39.84	36.95	38.56	38.11	35.22	37.45
CO ₂ avoidance costs *	[€ ₂₀₀₅ /tCO ₂]	30.67	32.82	20.21	20.95	27.60	16.37	27.55	19.86

* without transportation and storage of the captured CO₂

The figures in the tables are ordered by the time horizon, which is reported for the power plant data in the respective literature source. As some literature sources refer to figures from other, mostly older studies (sub-references) or to updates of older reference data, a distinction between the time horizon of the reported data and the year of publication is made.

The dark grey coloured columns represent the power plants with CO₂ capture, which are investigated in this study. The cost data of these power plants originate from the energy system modelling in the project 'NEEDS' of the European Commission /43/. An evaluation of these cost

data and a comparison to other reported cost references in Table 6-10, Table 6-11 and Table 6-12 is presented in the following chapter 6.4.4.

As a graphical illustration, Figure 6-11, Figure 6-12 and Figure 6-13 show a literature review of specific investment costs of different power plants with CO₂ capture and thereby highlight the investment cost penalty due to CO₂ capture.

Ultra-supercritical PCC Power Plants with CO₂ Post-combustion Capture

PCC is considered a mature technology, which primarily will gain improvements and efficiency increases by operation at elevated steam conditions. Investment costs of ultra-supercritical PCC are clearly higher than that of super-critical and sub-critical power plants. The operation at elevated steam conditions involves more advanced materials, which go in line with additional costs. In the following decades, super alloys based on nickel will be required, which are even more expensive and thus result in increasing investment costs for future ultra-supercritical PCC power plants. However, at the same time ultra-supercritical power plants feature considerable savings in energy costs, since less coal is needed due to the higher power plant efficiencies. Furthermore, future investment costs of PCC power plants will be influenced by cost savings due to improvements and experiences gained from manufacturing and operation. In this study it is assumed that cost increases due to the more expensive materials are compensated by cost decreases resulting from efficiency improvement and learning.

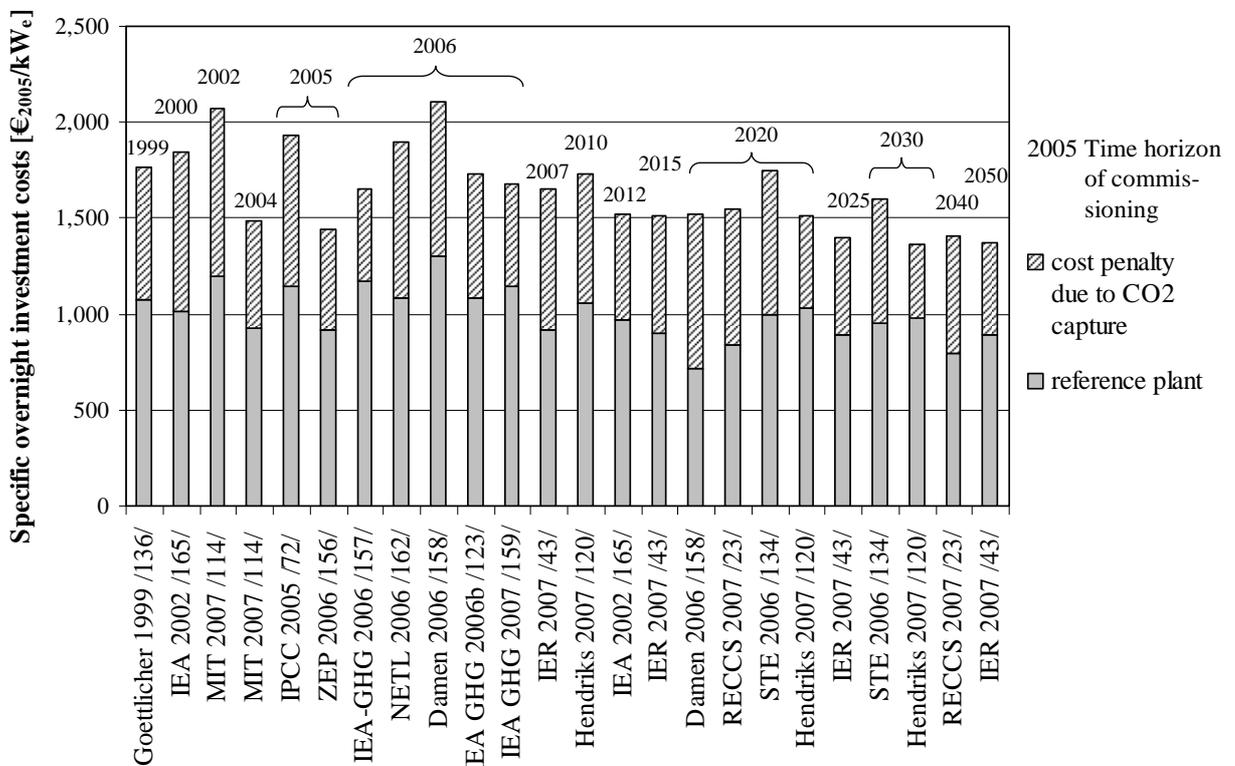


Figure 6-11: Composition of specific investment costs of hard-coal-fired PCC power plants with CO₂ post-combustion capture

PCC power plants with CO₂ post-combustion capture feature higher investment costs due to the additional installation of both a CO₂ capture unit and facilities for CO₂ compression. This is referred to as investment cost penalty due to CO₂ capture. Especially, the unit for CO₂ post-combustion capture causes a substantial investment cost penalty due to its large dimensions, which are expected to exceed the sizes of other units for flue gas cleaning /127/. However, since post-combustion technology features still considerable potential for learning, a decrease of these costs is anticipated for future time horizons /123/.

Table 6-11: Cost data and technical specification of hard-coal-fired oxyfuel power plants

Time horizon		1999	2002	2002	2005	2006	2006	2006	2006
Year of publication		1999	2007	2006	2005	2006	2006	2006	2006
Reference		/136/	/114/	/123/	/72/	/156/	/157/	/158/	/159/
Subreference			/154/		/155/				
Net electric efficiency	[%]	35.6	30.6	26.3	35.4	36.0	35.4	34.5	35.4
Efficiency penalty	[%]	9.4	8.5	19.7	8.8	10.0	8.6	10.5	8.6
CO ₂ capture efficiency	[%]	99	90	90	91	91	90	95	90
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,450	1,780	2,140	1,580	1,750	1,840	1,850	1,800
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,700	2,080	2,500	1,850	2,050	2,150	2,160	2,110
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	374	787	1050	507	640	663	557	656
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	85	104	125	92	102	64	108	105
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	53.03	63.92	75.96	56.20	60.03	56.72	65.43	61.66
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	41.55	43.15	43.85	42.13	42.95	45.26	47.43	44.58
CO ₂ avoidance costs *	[€ ₂₀₀₅ /tCO ₂]	15.46	27.53	52.89	20.49	26.24	17.01	25.68	25.35

* without transportation and storage of the captured CO₂

Time horizon		2015	2020	2020	2025	2030	2030	2050
Year of publication		2007	2006	2007	2007	2006	2007	2007
Reference		/43/	/134/	/120/	/43/	/134/	/120/	/43/
Subreference								
Net electric efficiency	[%]	40.0	41.0	42.0	42.0	45.0	46.0	46.0
Efficiency penalty	[%]	8.0	8.0	8.0	8.0	7.0	7.0	7.0
CO ₂ capture efficiency	[%]	97	95	100	97	95	100	98
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,410	1,850	1,510	1,350	1,700	1,370	1,300
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,640	2,160	1,770	1,580	1,990	1,600	1,520
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	505	850	481	455	750	384	405
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	82	108	88	79	99	80	76
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	50.30	60.91	52.29	48.77	56.46	48.03	47.72
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	37.14	40.72	39.84	36.79	38.91	38.11	37.20
CO ₂ avoidance costs *	[€ ₂₀₀₅ /tCO ₂]	19.35	31.10	18.40	18.35	28.63	15.55	16.86

* without transportation and storage of the captured CO₂

Additional operational costs due to CO₂ post-combustion capture are caused by expenditures for solvents like MEA, which are reported to be around 1.56 €₂₀₀₅ per kg of MEA /72/. The dominating increase of costs, however, originates from the increased fuel costs caused by the efficiency penalty due to CO₂ capture.

6.4.2 Cost Development of Oxyfuel Technology

The cost penalty due to CO₂ capture of an oxyfuel power plant, which constitutes the difference in costs between an oxyfuel power plant with CO₂ capture and the costs a conventional coal-fired PCC power plant without CO₂ capture, are similar to /72/ or even less expensive than the additional costs for the installation of other CO₂ capture technologies /75/. This cost penalty originates from an advanced oxyfuel boiler system as well as from additional components such as an ASU, a dehydration unit and flue gas compression facilities. These increases in costs outweigh the cost savings due to the not required facilities for NO_x removal and the FGD as well as the smaller dimensions of flue gas treatment facilities /76/. This downsizing to smaller dimensions for the flue gas treatment is possible, since the flue gas volume in an oxyfuel power plant is considerably reduced in comparison to the flue gases in conventional combustion processes, which still contain nitrogen.

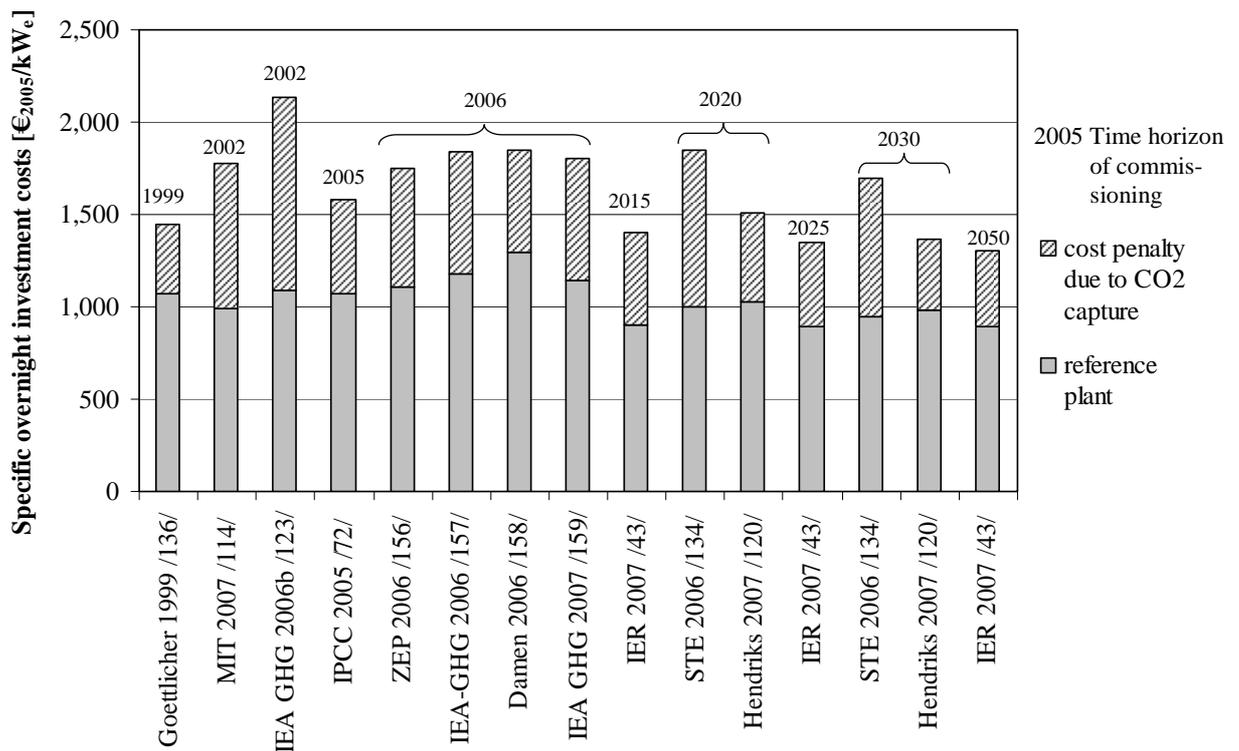


Figure 6-12: Composition of specific investment costs of hard-coal-fired oxyfuel power plants

6.4.3 Cost Development of IGCC Technology

Investment costs of IGCC power plants are difficult to be quantified, as this technology is still not perceived to be a mature technology and cost reductions due to learning effects are most probable. Currently, IGCC power plants feature higher investment costs than conventional PCC

power plants /133/. The quantification of cost ranges however is difficult, since IGCC technology is applied within different technical configurations due to different applied gasifier concepts, feedstock or local conditions. Most studies indicate that IGCC plants are slightly more costly without CO₂ capture and slightly less costly with CO₂ capture than respective PCC power plants of similar capacity /72/.

Table 6-12: Cost data and technical specification of hard-coal-fuelled IGCC power plants with CO₂ pre-combustion capture

Time horizon		1999	2000	2002	2003	2003	2004	2005	2006
Year of publication		1999	2002	2007	2004	2003	2007	2005	2006
Reference		/136/	/165/	/114/	/160/	/161/	/114/	/72/	/156/
Subreference			/166/	/164/			/163/		
Net electric efficiency	[%]	42.8	36.1	39.4	34.2	31.5	33.9	35.5	36.0
Efficiency penalty	[%]	8.7	6.1	5.6	5.8	6.5	5.3	6.7	10.0
CO ₂ capture efficiency	[%]	90	90	90	89	85	90	86	92
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,700	1,690	1,660	1,380	1,320	1,340	1,590	1,580
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,950	1,970	1,940	1,620	1,540	1,590	1,870	1,850
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	377	449	466	536	272	335	411	659
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	98	99	97	98	77	78	93	92
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	55.30	58.50	56.40	55.75	53.57	51.29	56.56	55.62
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	44.99	46.67	44.74	39.23	44.24	41.80	45.22	38.23
CO ₂ avoidance costs*	[€ ₂₀₀₅ /tCO ₂]	17.85	15.58	17.53	22.41	12.83	12.44	15.04	26.33

* without transportation and storage of the captured CO₂

Time horizon		2006	2006	2006	2006	2006	2007	2010	2012
Year of publication		2006	2006	2006	2006	2007	2007	2007	2002
Reference		/157/	/162/	/158/	/a8/	/a10/	/43/	/120/	/165/
Subreference									/166/
Net electric efficiency	[%]	31.5	34.1	34.8	31.5	34.8	39.0	37.0	43.5
Efficiency penalty	[%]	6.5	6.3	8.2	6.5	8.2	6.0	8.0	4.3
CO ₂ capture efficiency	[%]	85	90	90	90	90	90	90	90
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,510	1,560	1,620	1,520	1,620	1,650	2,120	1,290
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,770	1,820	1,890	1,770	1,890	1,930	2,470	1,510
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	313	313	445	328	445	350	577	277
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	88	91	95	89	95	97	124	75
ALLEGC with CO ₂ capture *	[€ ₂₀₀₅ /MWh _e]	58.43	56.38	57.50	56.97	57.50	56.30	68.42	45.94
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	48.21	46.99	44.79	46.72	44.79	46.88	53.43	38.88
CO ₂ avoidance costs*	[€ ₂₀₀₅ /tCO ₂]	14.02	12.71	18.21	13.09	18.43	14.14	22.69	11.20

* without transportation and storage of the captured CO₂

Time horizon		2015	2020	2020	2020	2025	2030	2030	2040	2050
Year of publication		2007	2007	2006	2007	2007	2006	2007	2007	2007
Reference		/43/	/23/	/134/	/120/	/43/	/134/	/120/	/23/	/43/
Subreference										
Net electric efficiency	[%]	45.0	42.0	44.3	43.0	48.0	46.5	47.0	46.0	52.0
Efficiency penalty	[%]	6.0	8.0	8.8	6.0	6.0	7.5	5.0	8.0	5.0
CO ₂ capture efficiency	[%]	90	88	90	90	90	90	95	92	90
Overnight investment costs	[€ ₂₀₀₅ /kW _e]	1,500	1,760	1,900	2,020	1,370	1,500	1,830	1,590	1,370
Total investment costs	[€ ₂₀₀₅ /kW _e]	1,760	2,060	2,220	2,360	1,600	1,760	2,140	1,860	1,600
Cost penalty in overnight investment costs	[€ ₂₀₀₅ /kW _e]	300	617	700	577	270	350	481	529	270
Annual O&M costs	[€ ₂₀₀₅ /kW _e ·a]	88	99	111	118	80	88	107	91	80
ALLEGC with CO ₂ capture*	[€ ₂₀₀₅ /MWh _e]	50.77	57.95	60.93	64.23	47.23	51.13	58.85	53.82	47.53
ALLEGC without CO ₂ capture	[€ ₂₀₀₅ /MWh _e]	42.87	43.17	44.00	50.43	40.08	41.84	47.52	40.79	40.69
CO ₂ avoidance costs*	[€ ₂₀₀₅ /tCO ₂]	13.43	25.47	30.06	22.55	12.85	16.78	18.44	22.95	12.94

* without transportation and storage of the captured CO₂

Operating and maintenance costs are similar to those of conventional PCC power plants /133/. The highest cost reduction potential in IGCC technology is seen at the ASU for oxygen production /77/. Similar to oxyfuel technology, more efficient and lower-cost technologies are able to reduce both investment and operating costs of IGCC power plants.

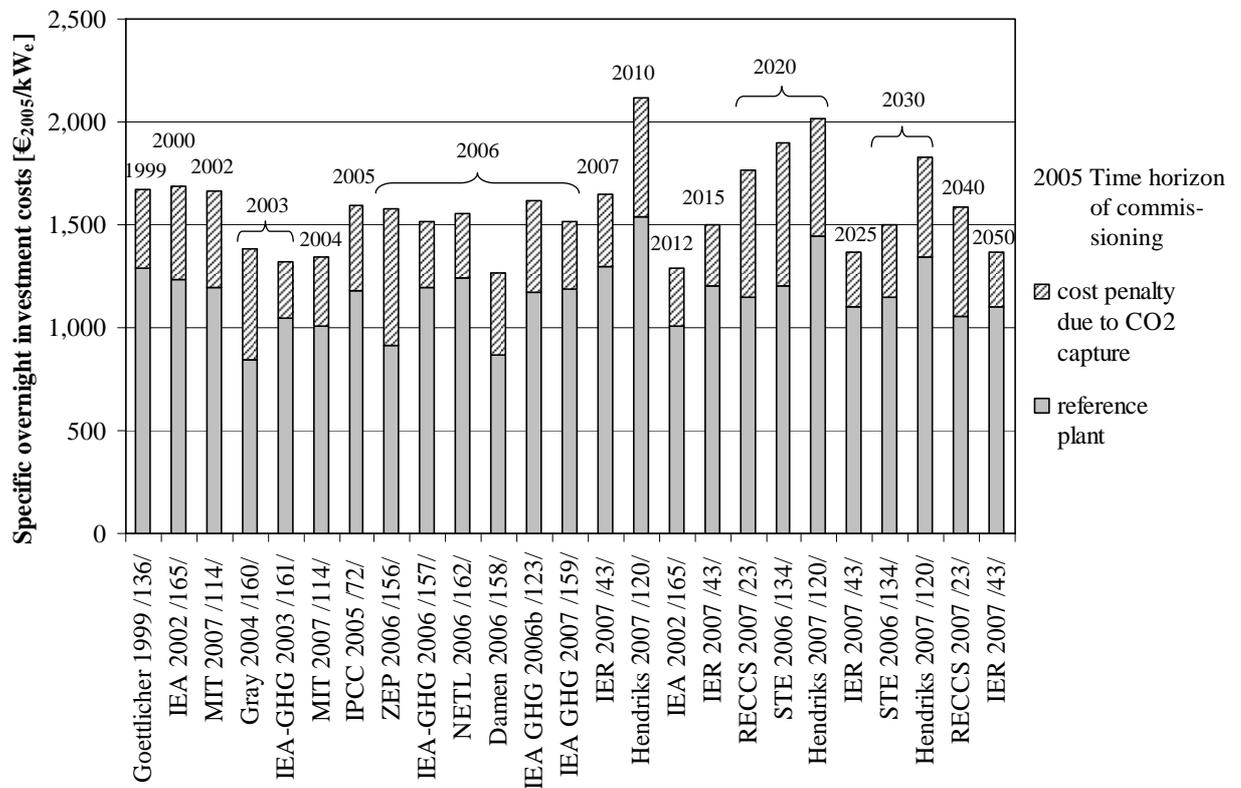


Figure 6-13: Composition of specific investment costs of hard-coal-fuelled IGCC power plants with CO₂ pre-combustion capture

6.4.4 Evaluation Cost Data of Investigated Power Plants

The cost tables Table 6-10, Table 6-11 and Table 6-12 show a considerable range of cost data for ALLEGC and also CO₂ avoidance costs. Thereby the power plants investigated in this study to a large extent reveal lower CO₂ avoidance costs than most other power plants. The ALLEGC on the other hand, reveal much less variance for all power plants. Thereby the cost data of this study clearly are within the interval of other ALLEGC. The reason for the different results and variance on ALLEGC and CO₂ avoidance cost is the different ratio between cost penalty due to CO₂ capture and overnight investment costs. As shown in Figure 6-11, Figure 6-12 and Figure 6-13 cost data of this study feature comparably low cost penalties due to CO₂ capture on the one hand, but a higher share of overnight investment costs than other power plants on the other hand. All cost data are decreasing for future time horizons with cost data of this study well within the cost range of other cost data in literature. This becomes even more apparent when referring the costs of the investigated power plants to cost data, which are reported for the years 1999 to 2006.

6.4.5 Average Lifetime Levelized Electricity Generation Costs (ALLEGC)

The ALLEGC calculated for electricity generation with and without CCS for the investigated technology scenarios with CO₂ pipeline transportation are shown in Figure 6-14. Thereby it becomes apparent that ALLEGC are increased by between 17 to 43 %, when CCS technology is integrated into the technology scenarios. Thereby the CO₂ capture process itself contributes by between 60 to 79 % of these additional CCS costs. A further 14 to 31 % arises from transportation of the captured CO₂ and between 6 to 8 % from its injection into the storage site.

PCC technology features the lowest ALLEGC of all technology scenarios without CCS, since it goes in line with the lowest specific investment costs. However, in technology scenarios with CCS technology PCC power plants show higher ALLEGC than both technology scenarios with IGCC and oxyfuel power plants. The better economic performance of the latter technologies originates from lower penalties in specific investment costs at the installation of CO₂ capture facilities as well as the lower efficiency penalty due to CO₂ capture.

Lowest ALLEGC are calculated for IGCC technology due to the best net efficiency of all investigated technologies and the lowest efficiency penalty due to CO₂ capture. Advantages of oxyfuel technology arise from the higher CO₂ capture rate, which increases the transported CO₂ volume flow and thus entails lower specific costs for transportation and injection of CO₂.

In order to further analyse the results shown in Figure 6-14, a sensitivity analysis for the major influential factors of the ALLEGC calculation is performed. Figure 6-15 presents a variation of the net efficiency, the technical lifetime, the total investment and the fuel costs of the investigated technology concepts for hard-coal-fuelled electricity generation with and without CCS and reveals the impact of this variation on ALLEGC. The major influence arises from total investment and the fuel costs, whereas the lifetime and the net efficiency of the investigated power plants are of minor importance. This sensitivity analysis, which covers a broad range of

uncertainty for all four modified parameters and is only exemplarily done for the time horizon 2015, is also able to be transferred to technology scenarios for other time horizons.

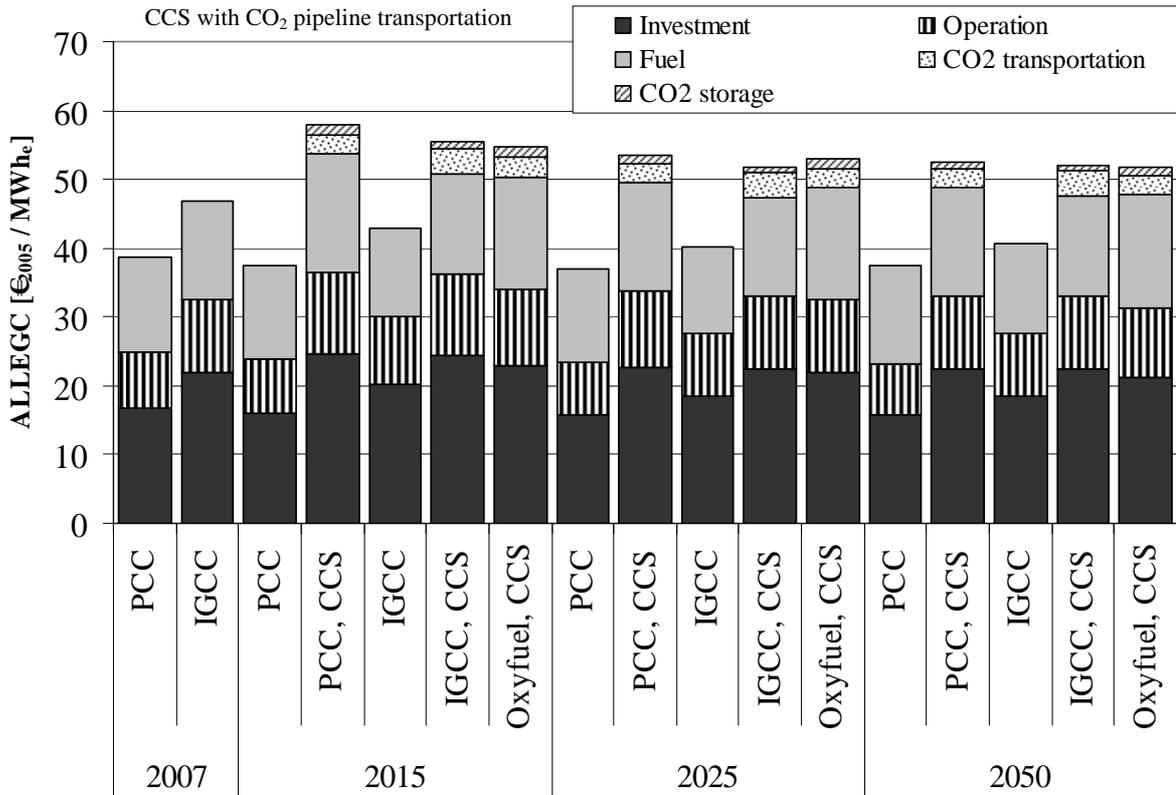


Figure 6-14: ALLEGC of hard-coal-fuelled electricity generation with and without CCS

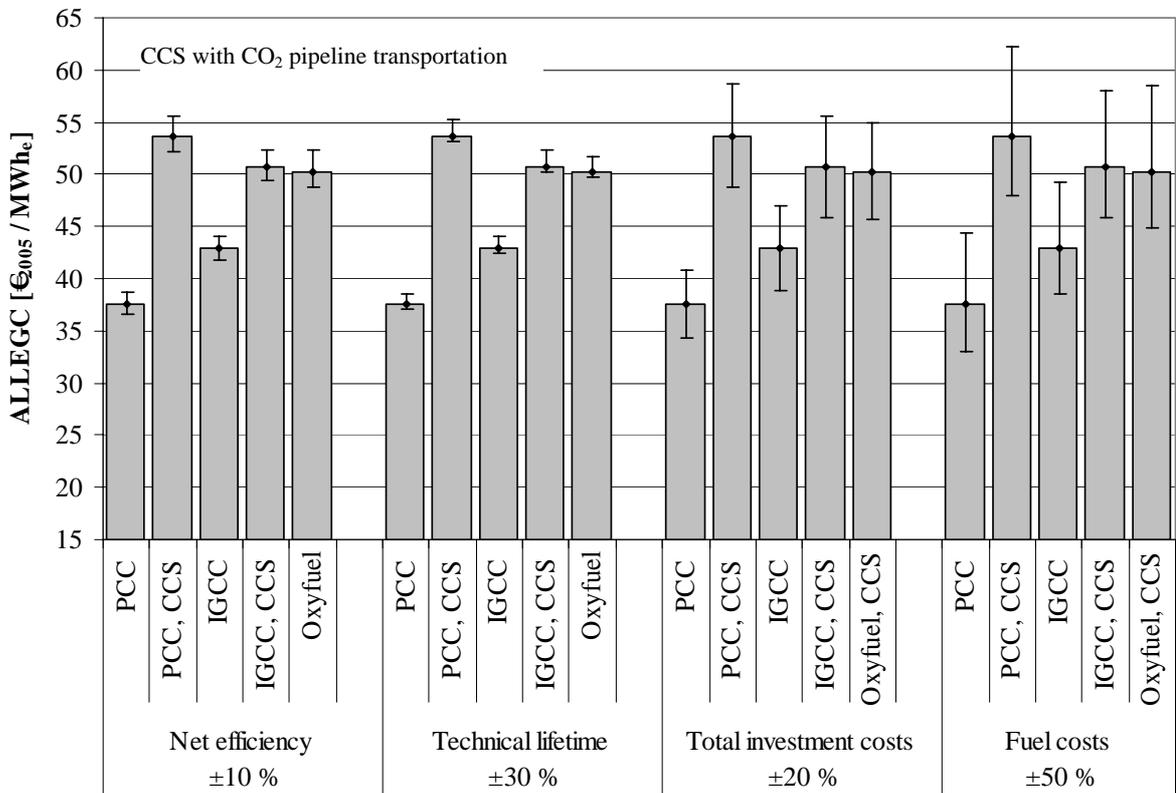


Figure 6-15: Exemplary sensitivity analysis on ALLEGC for investigated scenarios with time horizon 2015

6.4.6 Technology-specific CO₂ Avoidance Costs

An analysis of the technology-specific CO₂ avoidance costs, pictured in Figure 6-16, reveals a cost range of between 20 to 32 €₂₀₀₅ per ton of avoided CO₂ for the investigated technology scenarios with CCS. Thereby the reference for each power plant with CCS constitutes the same power plant without CCS.

The bulk of the CO₂ avoidance costs are caused by the CO₂ capture process, which is particularly expensive for PCC power plants. Also oxyfuel power plants are involved with a high cost contribution from the CO₂ capture process (with reference to the PCC power plant without CO₂ capture), but, however, go along with the lowest CO₂ avoidance costs for transportation and injection of CO₂. Due to the highest CO₂ capture rate among the investigated CO₂ capture technologies, oxyfuel scenarios feature the highest transported volume flow of CO₂ and thus reach the cheapest specific CO₂ transportation costs. Lowest overall CO₂ avoidance costs, however, are revealed for IGCC power plants despite their highest specific CO₂ transportation costs.

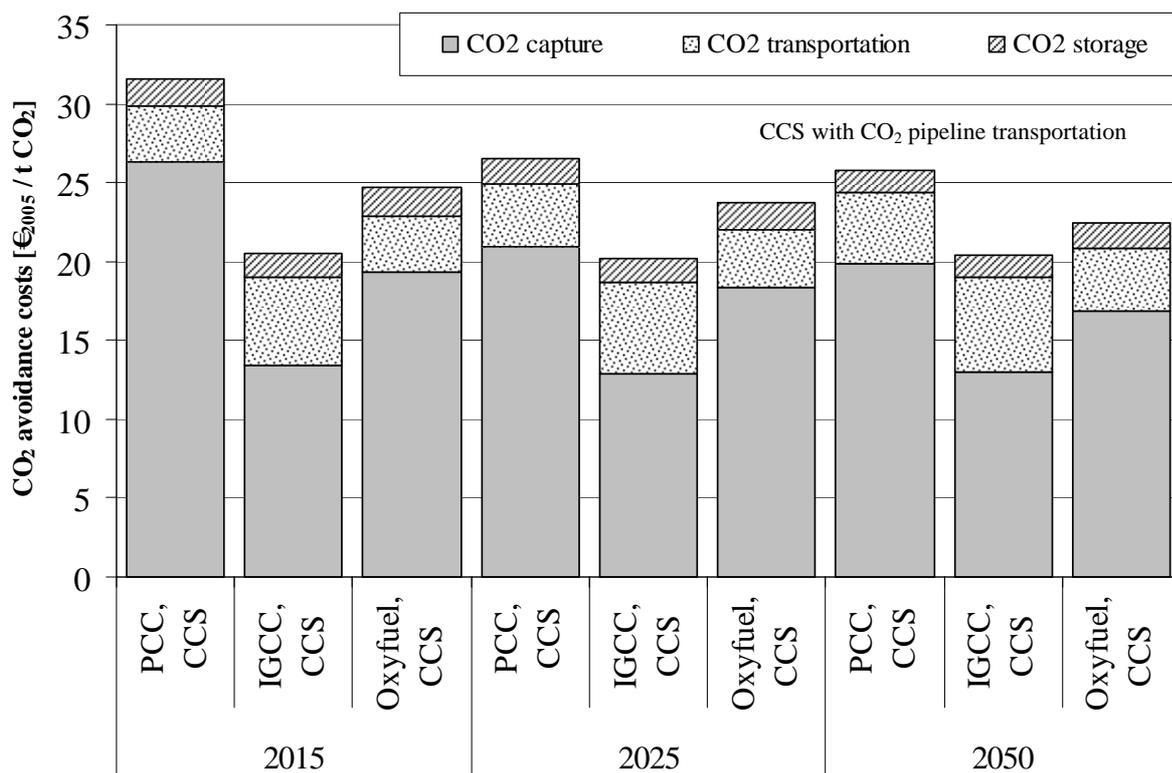


Figure 6-16: CO₂ avoidance costs within the investigated scenarios on hard-coal-fuelled electricity generation with CCS

6.4.7 External Costs

Starting from the calculated cumulated emissions within the investigated technology scenarios, external costs are quantified, and are pictured in Figure 6-17. This figure illustrates the different categories of external costs and shows that a high contribution arises from avoidance costs to

climate change, which are predominantly caused by the release of CO₂ emissions. CCS technology strongly reduces these CO₂ emissions and thus entails a reduction in avoidance costs of between 71 to 75 % for PCC scenarios, between 74 to 76% for IGCC scenarios and between 81 to 83 % for oxyfuel scenarios. Due to the discounting of avoidance cost factors for future time horizons, there is an increase in CO₂ avoidance costs, which becomes especially significant for PCC and IGCC power plants without CO₂ capture in 2025 and even more so in 2050.

The damage costs to human health, which constitute the second largest contribution to the overall external costs, predominantly originate from the release of SO₂, NO_x, NH₃, NMVOC, particulate and heavy metal emissions into air and are highest for PCC scenarios without CO₂ capture due to elevated operational emissions. The addition of CO₂ capture facilities for PCC power plants requires a more intensive flue gas cleaning for SO₂ and NO_x, which explains the reduced specific damage costs to human health in PCC scenarios with CCS.

In this category, an even better performance is achieved by IGCC power plants, which feature lower operational SO₂ and NO_x emissions than PCC power plants. Due to the highest net efficiency among the investigated technologies, IGCC power plants go hand-in-hand with the lowest emissions from the steam coal supply chain.

Technology scenarios on oxyfuel technology are involved with higher damage costs to human health than IGCC power plants due to their lower power plant efficiency.

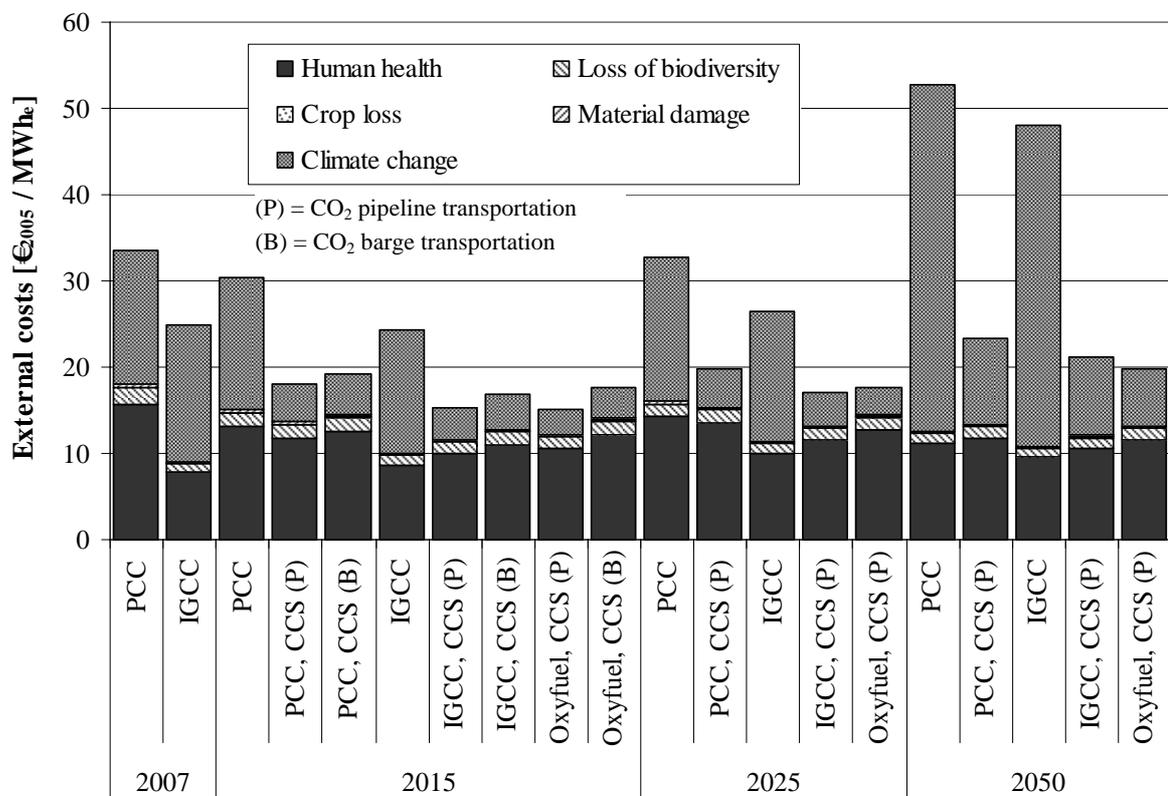


Figure 6-17: Contribution analysis of the external cost calculation

The same ranking of technology scenarios with CCS reveals the sum of specific damage costs to materials, crop loss and loss of biodiversity. All these cost factors of external cost calculation,

which show only minor relevance to the overall external costs, are clearly influenced by the release of SO₂ and NO_x emissions. The lowest operational emissions of these substances are featured by oxyfuel power plants. However, the least damage costs in the above mentioned categories are involved with technology scenarios with IGCC technology due to higher net power plant efficiencies and thus the lowest emissions from the steam coal supply chain.

A detailed list of the individual cost factors contributing to the overall external costs is provided by Table 11-14 and Table 11-15 in the annex.

6.4.8 Full Costs

The addition of the ALLEGC presented in chapter 6.4.5 and the external costs presented in chapter 6.4.7 results in the full costs of hard-coal-fuelled electricity generation with and without CCS as shown in Figure 6-18. It reveals that the full costs are at an almost equal level for all investigated technology scenarios and are slowly declining over future time horizons. Only the high avoidance costs on climate change of power plants without CO₂ capture in 2025 and 2050 deviate from this generic reduction of full costs. Technology scenarios with CCS feature marginally lower full costs than the respective scenarios without CCS. This means that in technology scenarios with CCS, the increase in ALLEGC is more than counterbalanced by the reduction in the external costs.

For a direct comparison between CCS technologies, oxyfuel and IGCC power plants are involved with the lowest full costs followed by PCC power plants.

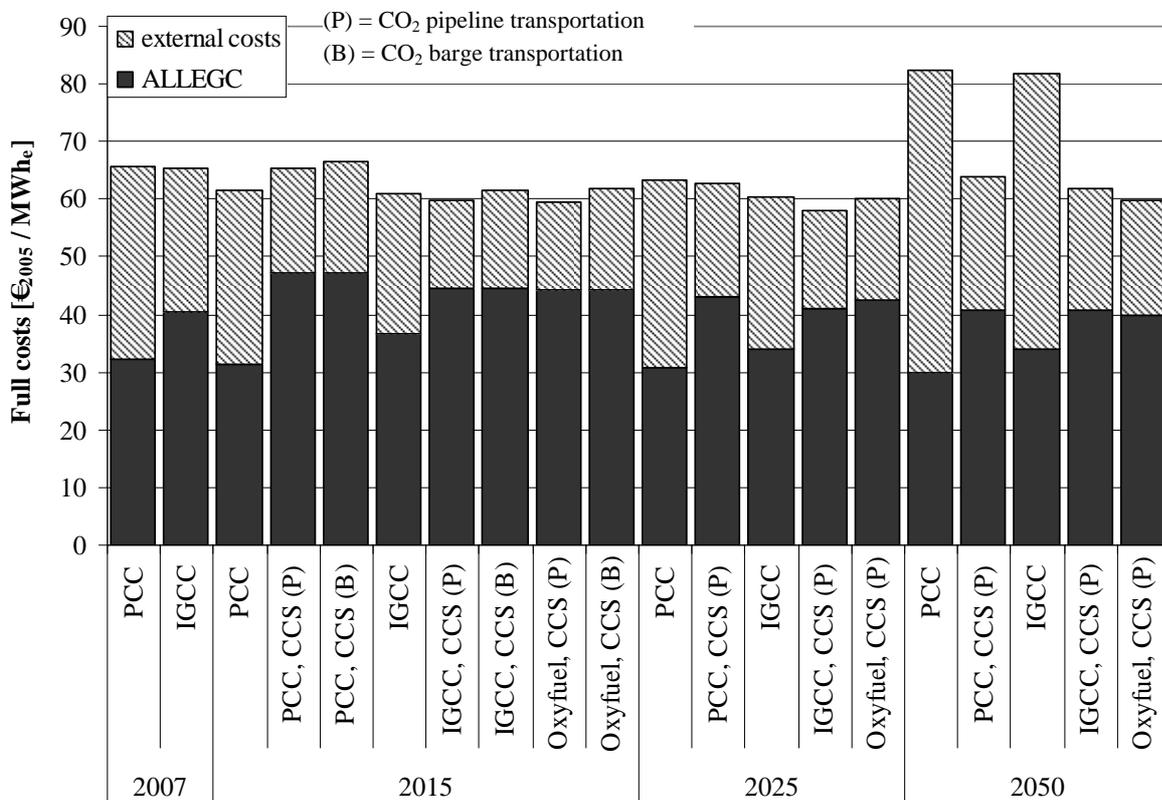


Figure 6-18: Full cost analysis

7 Discussion

In the following chapters the results of the study are analysed and discussed in relation to the results of other studies on CCS technologies as well as in relation to LCI data of other electricity generation technologies.

7.1 Comparison of Results of Other LCA Studies on CCS Technology

In this section the results obtained from this P-LCA study, as well as the economic evaluation of hard-coal-fuelled electricity generation with and without CCS, are compared to the outcome of similar studies analysing CCS technologies.

There are many studies on CCS technologies as well as on the potential for CO₂ capture and storage, but only few studies that apply the methodology of LCA in this field of research. Currently, there is only one LCA study, which analyses CCS technologies over the entire life cycle and thereby besides CO₂ also quantifies other life cycle inventories. This study is entitled RECCS – Structural-economic Comparison of **R**egenerative Energy Technologies with **C**CS (in German). It was commissioned by the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and conducted by a working group of different German research institutes in 2007 /23/. In the RECCS study different CCS technologies and their life cycle have been analysed with particular focus on German conditions.

Another recent study, which investigates future electricity generation under application of CCS technologies for German conditions, was performed by the Forschungszentrum Jülich in 2006 /134/. This study has its focus on the balancing of CO₂ emissions as well as on the economic performance of CCS technologies.

The results of the RECCS and Jülich studies are introduced in more detail within the following sections and are referred to within the final discussion of the results of this P-LCA study. To identify this P-LCA study against the RECCS and the Jülich study in the following graphs and tables it is labelled by the initials OMS.

7.1.1 Evaluation of LCA Results

In the above mentioned RECCS study, as well as the Jülich study, the three promising concepts for CO₂ capture, namely CO₂ post-combustion capture, CO₂ pre-combustion capture and oxyfuel combustion, are investigated. These CO₂ capture concepts, as well as the transportation and storage of the captured CO₂, are analysed for exemplary power plants. These power plants feature different technical specifications, which for the RECCS and Jülich studies are exemplarily illustrated in Table 7-1 for the time horizon 2025. This time horizon is revealed as the best reference for a proper comparison of study results, since this time horizon is also investigated in the OMS study and is either reported by the RECCS or the Jülich study or can be derived from these studies by a linear interpolation of the reported specifications for the time horizons 2020 and 2030.

In the RECCS study, no explicit technical and economic specification of oxyfuel technology is given. However, for this technology, also LCA results show up in the result diagrams, whereas an electrical net efficiency of 38.0 % and a CO₂ capture rate of 99.5 % is noted. Due to this reporting, the oxyfuel technology is also listed in Table 7-1.

Since a full-scale LCA is only performed in the RECCS study and the Jülich study does not reveal any LCA results (CO₂ emissions are investigated as single and only life cycle inventory, but results are not reported and are only used internally for the calculation of CO₂ avoidance costs), the comparison of LCA result is only drawn in reference to the RECCS study.

Table 7-1: Technical specification of investigated power plant concepts with CCS in the RECCS study and the Jülich study for the time horizon 2025
(source: /23/ /134/)

Reference technologies of different studies		PCC	PCC	IGCC	IGCC	Oxy-fuel	PCC	PCC	IGCC	IGCC	Oxy-fuel
Study		RECCS					Jülich				
CCS		with-out	with	without	with	With	with-out	with	with-out	with	with
El. net capacity	[MW _e]	700	570	700	590	700	-				
El. net efficiency	[%]	49.0	40.0	50.0	42.0	49.0	50.5	40.7	53.5	45.4	43.0
Efficiency penalty due to CO₂ capture	[%]	-	9.0	-	8.0	11.0	-	9.8	-	8.1	7.5
CO₂ capture rate	[%]	88				99.5	-	90	-	90	95
Technical life time	[a]	25					20				
Load	[h/a]	7,000					6,000				
Net electricity generation over the life time	[TWh _e]	122.5	99.8	122.5	103.3	-	-				
Total investment costs	[€ ₂₀₀₅ /kW _e]	950	1,750	1,300	2,000	-	975	1,675	1,188	1,700	1,775
Fuel costs (steam coal)	[€ ₂₀₀₅ / t]	2.37				-	1.68				
Interest rate	[%]	10				-	5				

For a thorough evaluation of the results of the OMS and RECCS studies a twofold comparison is performed. Firstly, the LCI and LCIA results of both studies are directly compared. Secondly, a comparison is performed after adapting the OMS study to the technical specification of the reference technologies in the RECCS and STE studies. As mentioned in chapter 3.5.1 the approach of P-LCA facilitates such a flexible adaptation of the reference power plants of the OMS study to other technical specifications. The adaptation of the OMS reference technologies to the technical specifications of the RECCS study is referred to as OMS-RECCS and is shown in Figure 7-1 alongside the LCA results of both the RECCS study and the unmodified OMS study.

The comparison of the LCA results shown in Figure 7-1 reveals that the LCA results of the OMS and the RECCS study are quite close for PCC technologies and also for IGCC power plants without CCS. Some deviation, however, is shown for the results on oxyfuel technology and on IGCC power plants with CCS. This deviation is mainly caused by different specifications of the investigated power plants, which can be predominantly traced back to different efficiencies and different efficiency penalties due to CO₂ capture. When the same specifications were assumed for these technologies, the deviation is almost entirely eliminated, as is illustrated by the results for OMS-RECCS. As shown in Figure 7-1, OMS-RECCS features slightly higher figures for CED results, slightly higher figures for results on specific CO₂ emissions and slightly lower figures for GWP results. However, altogether OMS-RECCS correlates very well to the results of the RECCS study. This illustrates that the power plant modelling of the OMS study reveals LCA results in accordance to other LCA calculations and, furthermore, can be flexibly adapted to different technical specifications.

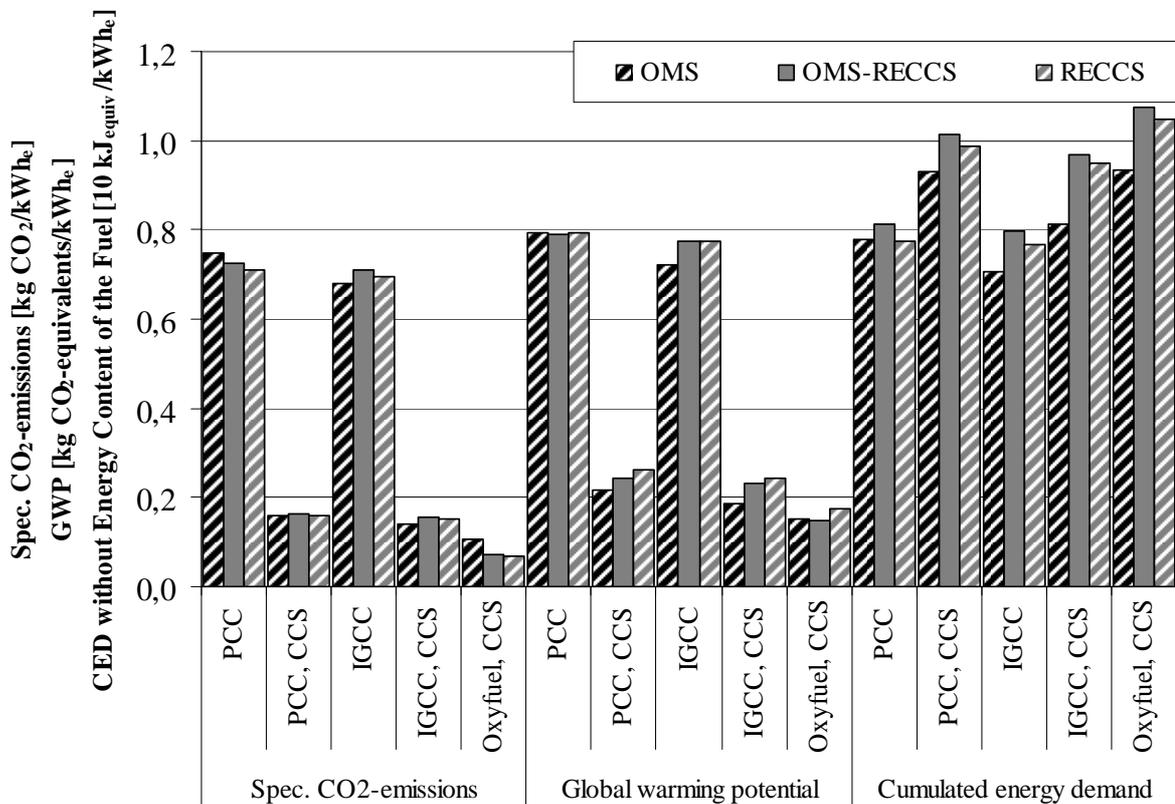


Figure 7-1: Comparison of LCA results between this study (OMS) and RECCS study (source: /23/)

In Figure 7-1 differences between OMS-RECCS and RECCS originate from the application of different LCI background data and the non-identical power plant infrastructure. Since major changes in the LCA results for the future time horizons of the OMS study originate from changes within the German steam coal supply chain, which is not the case in the RECCS study, the calculation of the OMS-RECCS results with time horizon 2020 data was performed based on the current German steam coal supply chain for the year 2007.

7.1.2 Evaluation of Cost Figures

The comparison of cost figures is drawn in a similar manner to the comparison of LCA results. Firstly, the cost figure of the OMS, RECCS and Jülich studies are directly compared. Secondly, the assumptions and specifications of the cost calculation in the RECCS study as well as the Jülich study are adapted to the cost calculation model of the OMS study. Thereby, the cost data labelled OMS-RECCS and OMS-Jülich are quantified. The cost figures of both the original studies and the hybrid calculations are illustrated in Figure 7-2. Missing bars result from missing cost reporting on oxyfuel technology and also partly on IGCC power plants in the RECCS study.

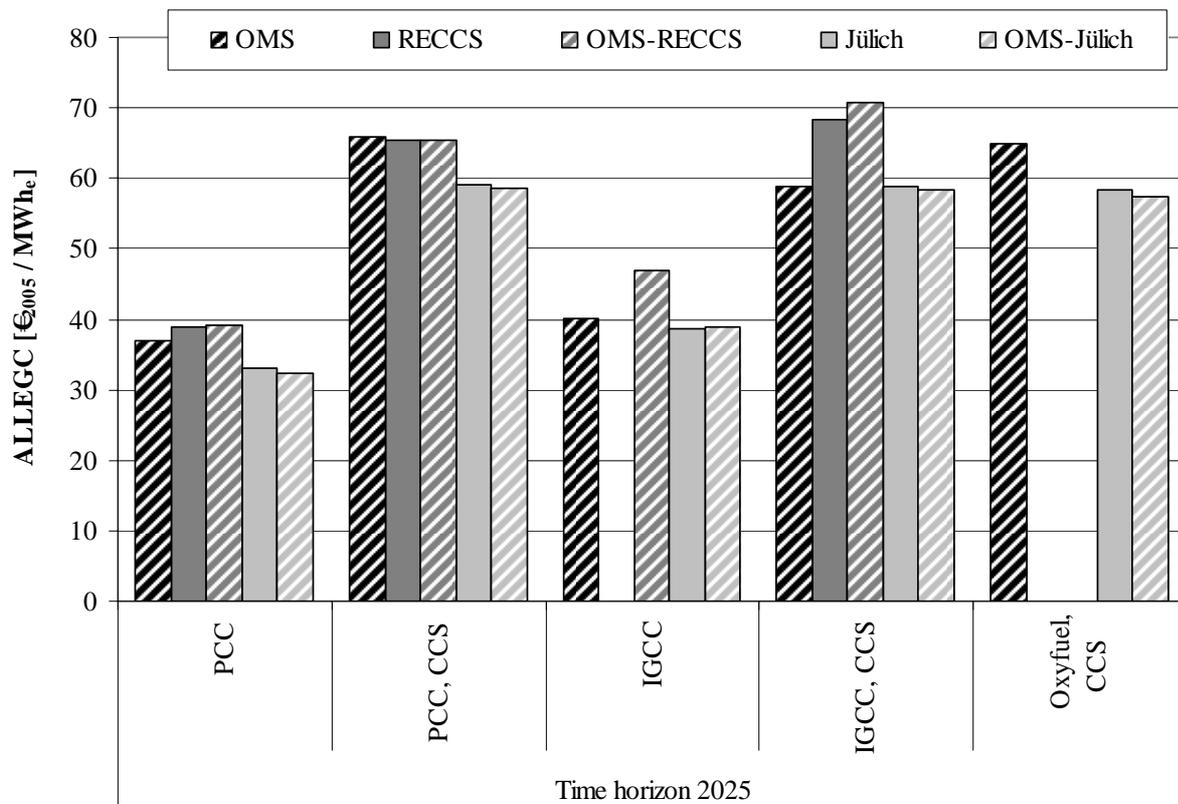


Figure 7-2: Comparison of ALLEGC between this study (OMS), RECCS study and Jülich study (source: /23/ /134/)

Figure 7-2 shows that the cost figures, which deviate between the OMS study and the other two studies, are revealed as almost identical, when the same comparison is made between RECCS and Jülich studies and the hybrid calculations. This means that differences in the cost figures of OMS, RECCS and Jülich study predominantly originate from different assumptions and different basic data in the ALLEGC calculation. Main differences thereby constitute the cost penalties on investment costs due to CO₂ capture, which for instance for IGCC power plants deviates by around factor of 2 between RECCS and OMS study.

Furthermore, it is revealed that in the RECCS and Jülich studies no owner's own costs are accounted for. Thus, it is assumed that these costs are already incorporated into the power plant investment costs. Additionally, in the RECCS and Jülich studies lower technical lifetimes, lower load levels and partly higher fuel costs are assumed resulting in higher ALLEGC.

As shown in Figure 7-3, major differences in cost figures are revealed when comparing the CO₂ avoidance costs, which are reported in the OMS, RECCS and Jülich studies. Again the technology specifications of the RECCS and Jülich studies were applied to the cost calculation of the OMS study and resulted in cost figures for the hybrid labels OMS-RECCS and OMS-Jülich. Hereby, it becomes apparent that the difference in CO₂ avoidance costs is considerably more significant between the figures of the OMS study and other two studies than between figures of the hybrid studies and the RECCS respectively Jülich study.

This means, that the CO₂ avoidance costs of the OMS study are clearly lower than all other compared figures due to different assumptions in the cost calculation. The above mentioned considerable differences in the cost penalties of investment costs due to CO₂ capture as well as the different efficiencies of the reference technologies are responsible for this gap in the CO₂ avoidance costs.

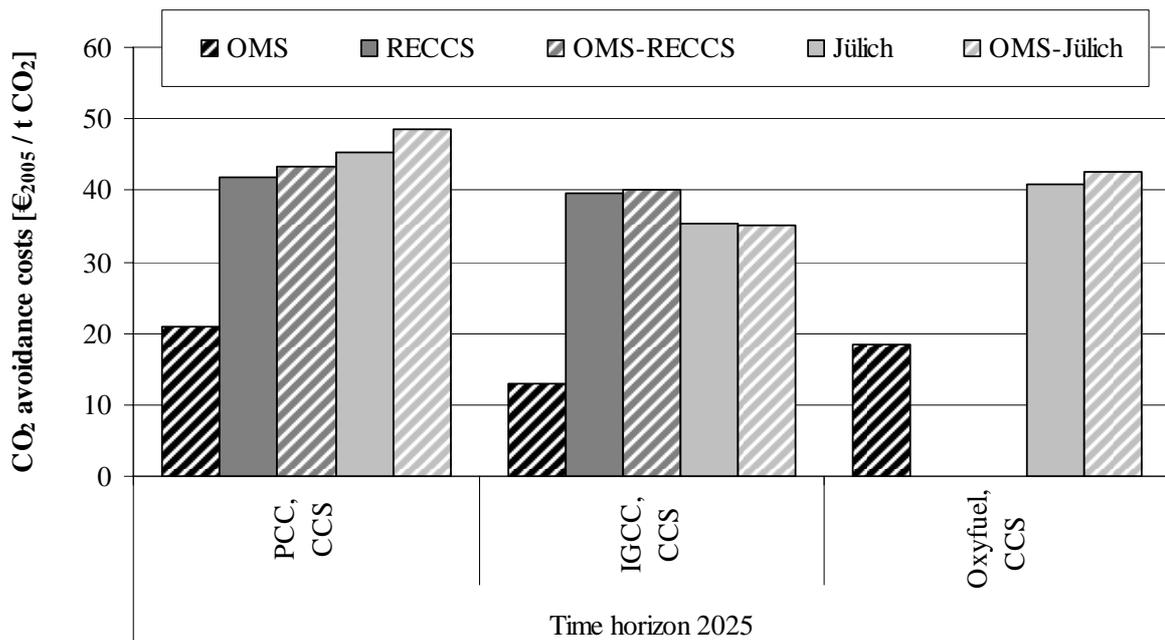


Figure 7-3: Comparison of CO₂ avoidance cost between this study (OMS), RECCS study and Jülich study
(source: /23/ /134/)

7.2 Comparison to Other Electricity Generation Technologies (EGTs)

In order to thoroughly evaluate the environmental performance of hard-coal-fuelled electricity generation with and without CCS, the obtained LCI results are compared to the environmental performance of other EGTs. Table 7-2 shows a portfolio of different EGTs including the PCC power plants investigated in this study as technologies for electricity generation from hard coal.

Apart from PCC technology with CCS, which is analysed for the time horizon 2015, all other reference EGTs represent current technical state of the art and are typical technologies contributing to the German electricity mix. The comparison of these current EGTs is performed with reference to the hard-coal-fuelled PCC technology with CCS for the time horizon 2015, since currently no commercial large-scale application of CCS technology is available nor anticipated before 2015 (see chapter 5.4.6). Nevertheless, this comparison to the future time horizon appears representative and reaches the same relative hierarchy between the investigated technologies, even if an efficiency improvement for the current EGTs were assumed. For reasons of comparison EGTs based on fossil fuels and nuclear are assumed to be operated at base load with 7,500 full load hours per year.

Table 7-2: Different reference technologies for electricity generation

Energy source	Technology	Installed net capacity [MW _e]	El. net efficiency [%]	Technical lifetime [years]
Hard coal	Pulverized coal combustion (PCC)	602	46	35
Hard coal	PCC with CO ₂ capture	477	38	35
Lignite	PCC	1,050	44	35
Natural gas	Natural gas combined cycle (NGCC)	1,000	60	30
Nuclear	Pressurized water reactor (PWR)	1,600	36	60
Photovoltaic	Polycrystalline	0.002	13 ¹⁾	25
Wind offshore	Horizontal axis wind turbine	5	2,450 h/a ²⁾	20
Wind onshore		2	1,680 h/a ²⁾	20
Hydro	Run-of-river	3.1	85 ³⁾	60

¹⁾ system efficiency; annual electricity yield: 796 kWh_e/kW_{peak}
²⁾ full load hours
³⁾ 5,100 full load hours per year

Release of Emissions into Air

A comparison of the specific CO₂, SO₂ and NO_x emissions released by the mentioned EGTs is shown in Figure 7-4 and illustrates the benefit of CCS technology when applied to conventional hard-coal PCC power plants. Specific CO₂ emissions are considerably reduced, though still remain at a level, which is clearly above that of photovoltaic and still is a multiple higher than that of EGTs based on other renewables and nuclear.

Also the specific NO_x and SO₂ emissions are mitigated, when CCS technology is applied, but still remain at a comparably high level. This level is only exceeded by hard-coal-fuelled PCC technology without CCS and in case of SO₂ emissions also by electricity generation from lignite. Hard-coal-fuelled PCC technology without CCS features higher specific SO₂ and NO_x emissions

than lignite PCC technology, since the better operational performance of hard-coal PCC technology is worsened by additional emissions from steam coal supply. As lignite PCC power plants are mine-mouth operated, there are no major emissions from fuel supply.

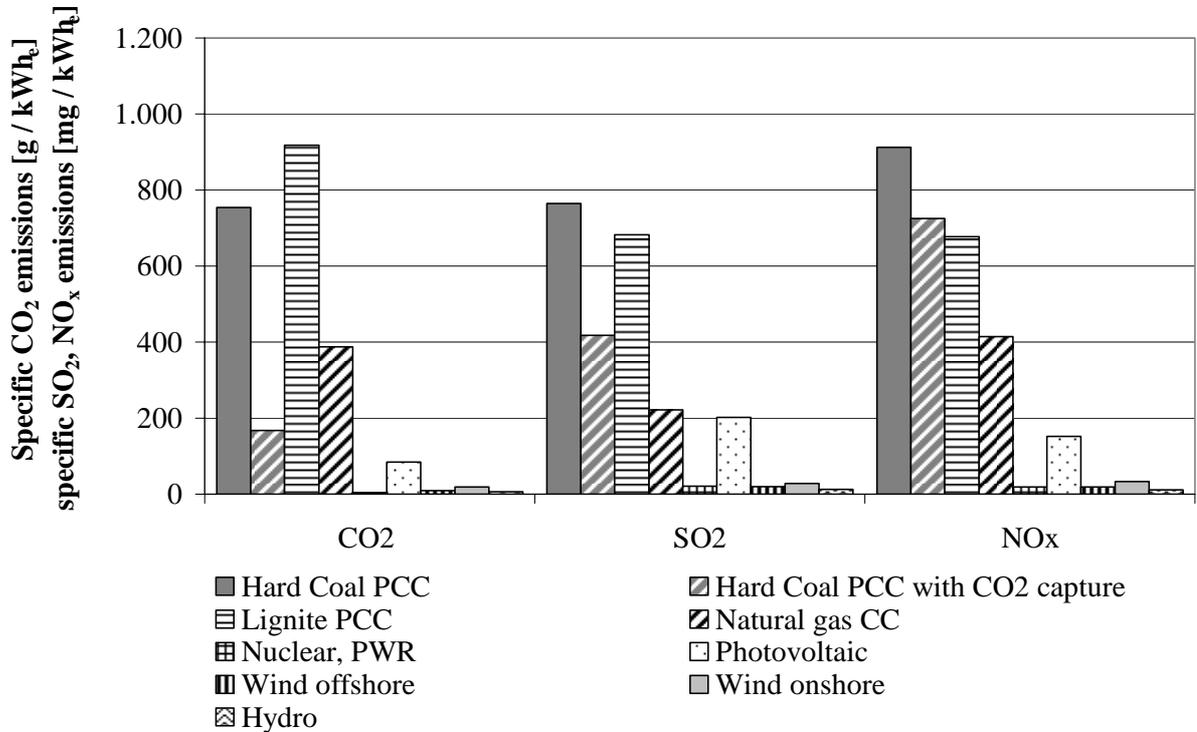


Figure 7-4: Comparison of specific emissions into air of different EGTs

Demand for Material Resources

The specific demand for material resources of the compared EGTs is largely dominated by the high figures for photovoltaic as shown in Figure 7-5. In order to picture in one figure the wide range of quantities in the demand for the three resources iron, copper and aluminium, which is difficult due to their different orders of magnitude, a percentile illustration in reference with photovoltaic has been chosen.

As shown in Figure 7-5, photovoltaic clearly features the highest specific resource demand for aluminium and copper. In the case of aluminium, the frame of the photovoltaic module, which is installed on a tilted roof, is a major contributor and is especially noteworthy, since the specific aluminium demand in Figure 7-5 is shown in a different scale. This high specific resource demand for photovoltaic primarily arises from the comparably low electricity generation over the lifetime when being compared against other EGTs.

The specific copper demand can be traced back to the wiring of the photovoltaic module. Second and third rankings in the specific demand for copper and aluminium are held by hard-coal PCC power plants. Thereby, CCS technology goes along with a higher specific demand due to the additional installation of CO₂ capture facilities, additional contribution from transportation as well as storage of CO₂ and finally a lower electricity generation over the lifetime.

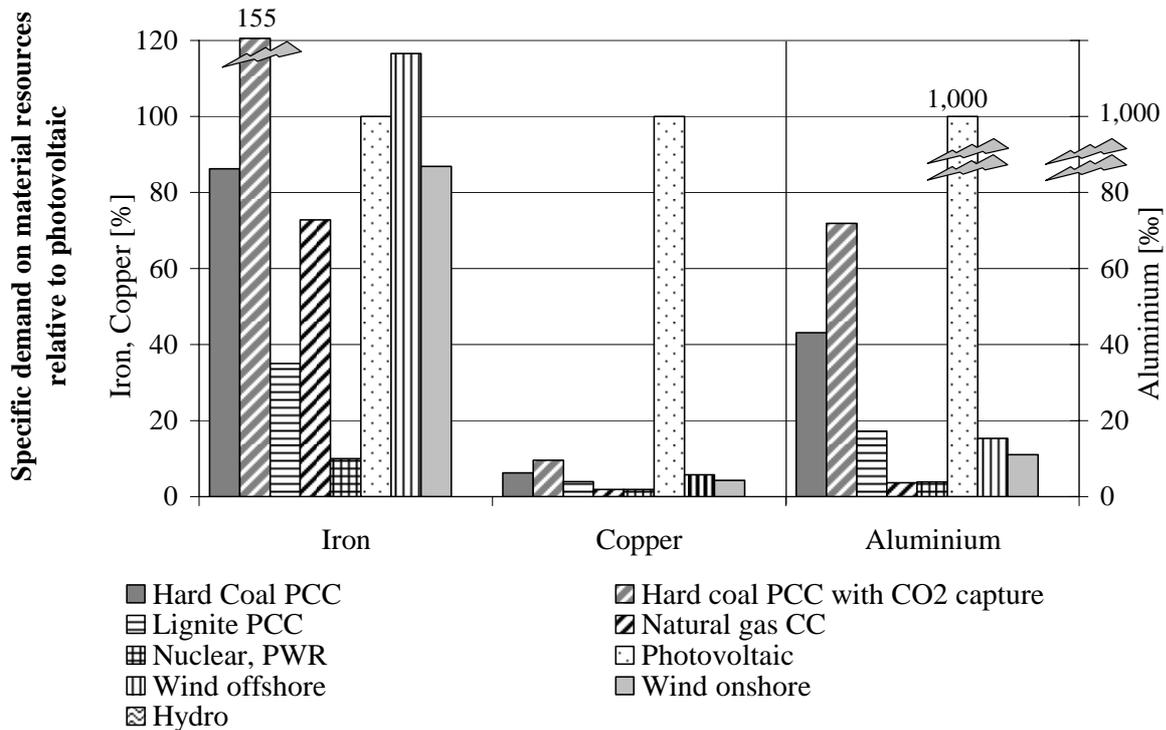


Figure 7-5: Comparison of the specific demand for material resources of different EGTs

Only the comparison of the specific demand for iron reveals the highest figures not for photovoltaic, but for hard coal-fuelled PCC with CO₂ capture. The specific iron demand for hard-coal-fuelled PCC technology predominantly originates from the steel requirements over the steam coal supply chain as was already shown in Figure 6-2. This requirement is even higher for PCC power plants with CCS due to the increased demand for steam coal. Furthermore, additional infrastructure for the facilities for CO₂ capture as well as transportation and injection of the captured CO₂ contribute to a higher demand for iron. Altogether, the addition of CCS technology increases the specific resource demand of PCC technology by 80 % for steel, 52 % for copper and 67 % for aluminium.

Demand for Energy Resources

For EGTs based on fossil fuels a major contribution to the demand for energy resources is caused by the fuel supply as shown in Figure 7-6 presenting an overview of the specific cumulated energy demand (CED). Thereby it becomes apparent that both hard coal and natural gas constitute fuels, which have to be transported over large distances and thus are involved with a major specific CED. The energy requirement for construction and dismantling of the power plant are of minor importance for EGTs based on fossil fuels and on nuclear, but for renewable EGTs it constitutes the major part of the specific CED. Altogether, the specific CED is lowest for electricity generation from nuclear, wind and hydro power. An exception among the renewable EGTs is photovoltaic, which due to the lower electricity generation over the life time features a specific CED in the range of hard-coal-fuelled electricity generation.

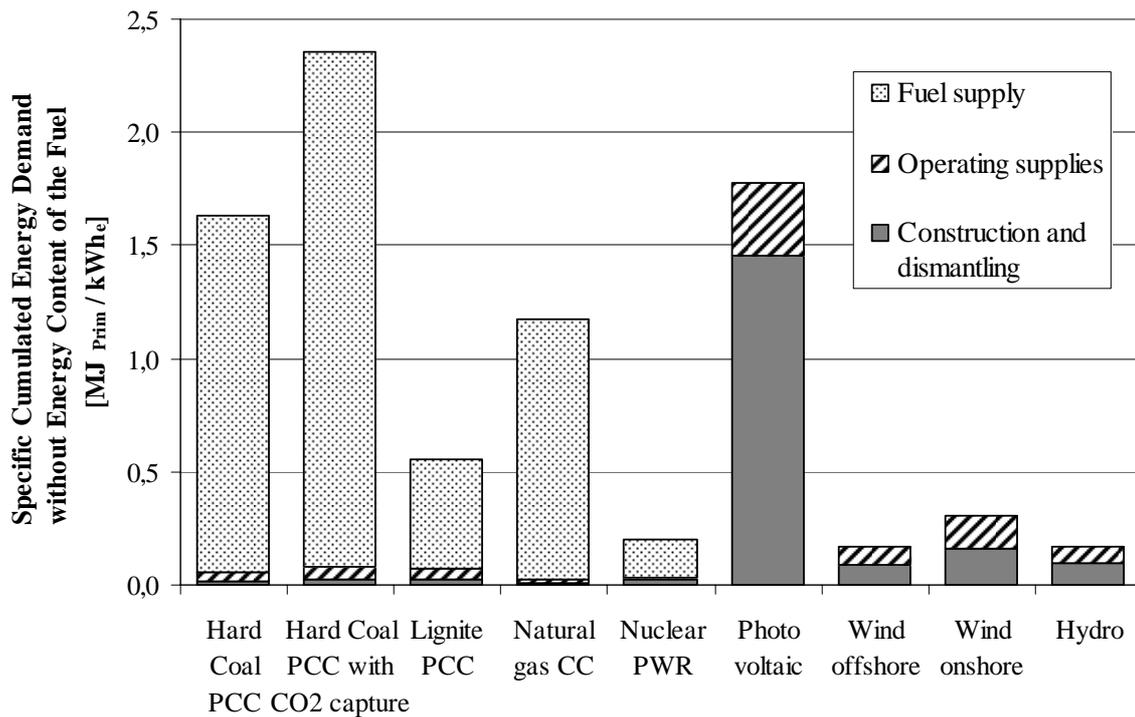


Figure 7-6: Comparison of the specific CED (without energy content of the fuel) of different EGTs

Risks to Human Health

For a comparison of the risks to human health caused by the different EGTs a disaggregation in the contribution from the direct emissions, on the one hand, and from the indirect emissions of the up- and downstream processes, on the other hand, is made as pictured in Figure 7-7.

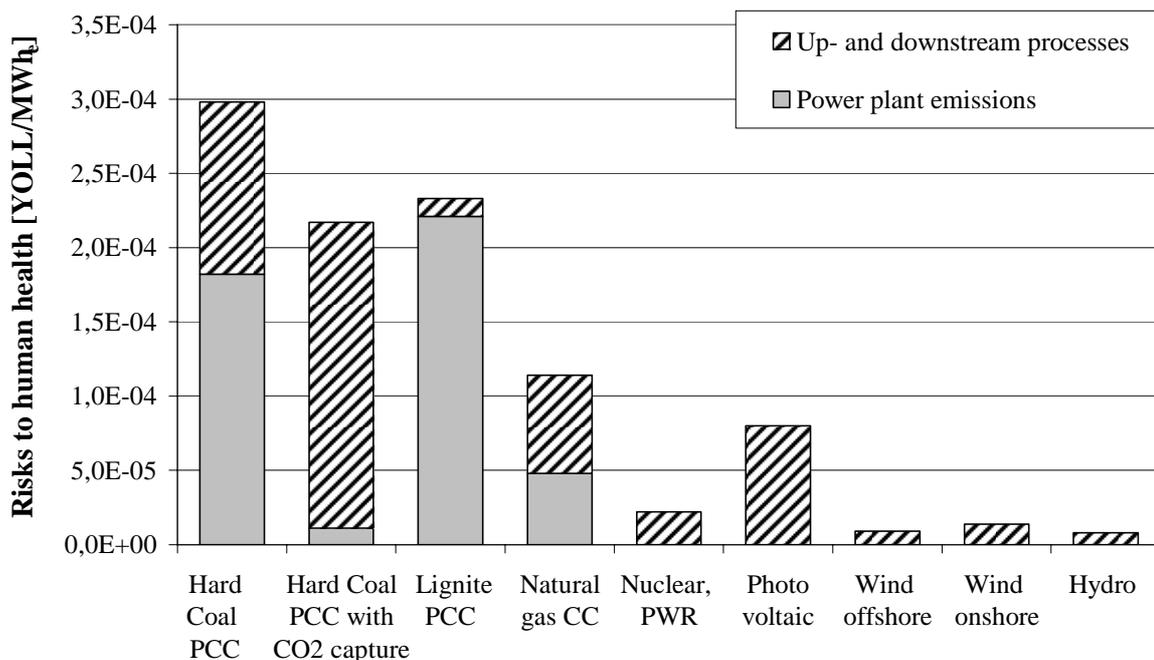


Figure 7-7: Comparison of risks to human health arising from different EGTs

From this figure, it is revealed, that hard-coal-fuelled electricity generation in PCC power plants is involved with the highest risks to human health. CCS technology reduces the years of life lost by around 12 %, but still features relatively high risks, which are only exceeded by electricity generation from lignite.

Lowest risks to human health go in line with EGTs that are based on non-fossil energy resources and thus do not feature any direct emissions. Only photovoltaic deviates from this and shows risks to human health being higher than NGCC technology.

Economic evaluation

The comparison of different EGTs reveals highest external costs for electricity generation from fossil fuels as illustrated in Figure 7-8. PCC technology with CCS shows clearly reduced external costs mainly due to the reduction of the avoidance costs for global warming. The lowest external costs for fossil-fuelled electricity generation are achieved by NGCC power plants, which in their cost figures range somewhat higher than photovoltaic. All other EGTs reveal external costs, which are at least one order of magnitude smaller than those of hard-coal PCC power plants without CCS.

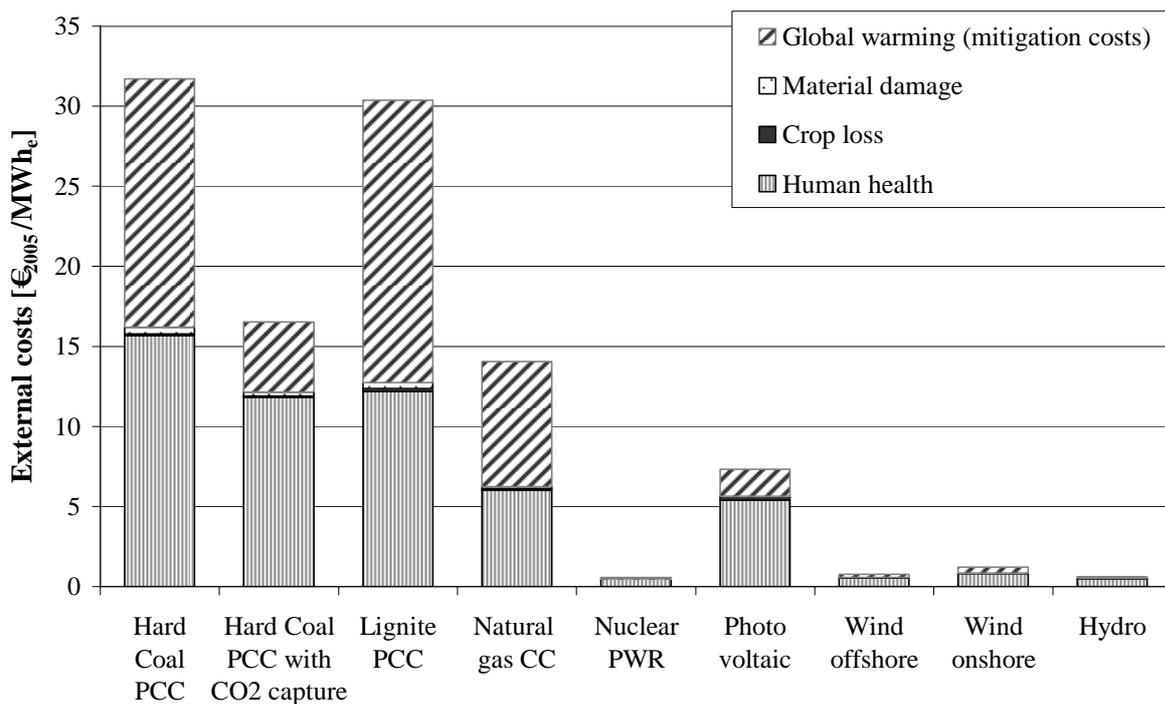


Figure 7-8: Comparison of external costs of different EGTs

An analysis of the full costs of the compared EGTs shows a very broad range of cost figures as illustrated in Figure 7-9.

The lowest full costs of the compared EGTs shown in Figure 7-9 go in line with electricity generation from nuclear (45 €₂₀₀₅ / MWh_e). Somewhat higher full costs in the range of 65 to 89 €₂₀₀₅ / MWh_e are involved with electricity generation from fossil fuels, whereas NGCC power plants feature the best economic performance (but worst economic performance in terms of

ALLEGC). Fossil fuelled EGTs go in line with major contributions from external costs, which is particularly high for lignite and hard-coal PCC due to having the highest operational emissions of CO₂, SO_x and NO_x.

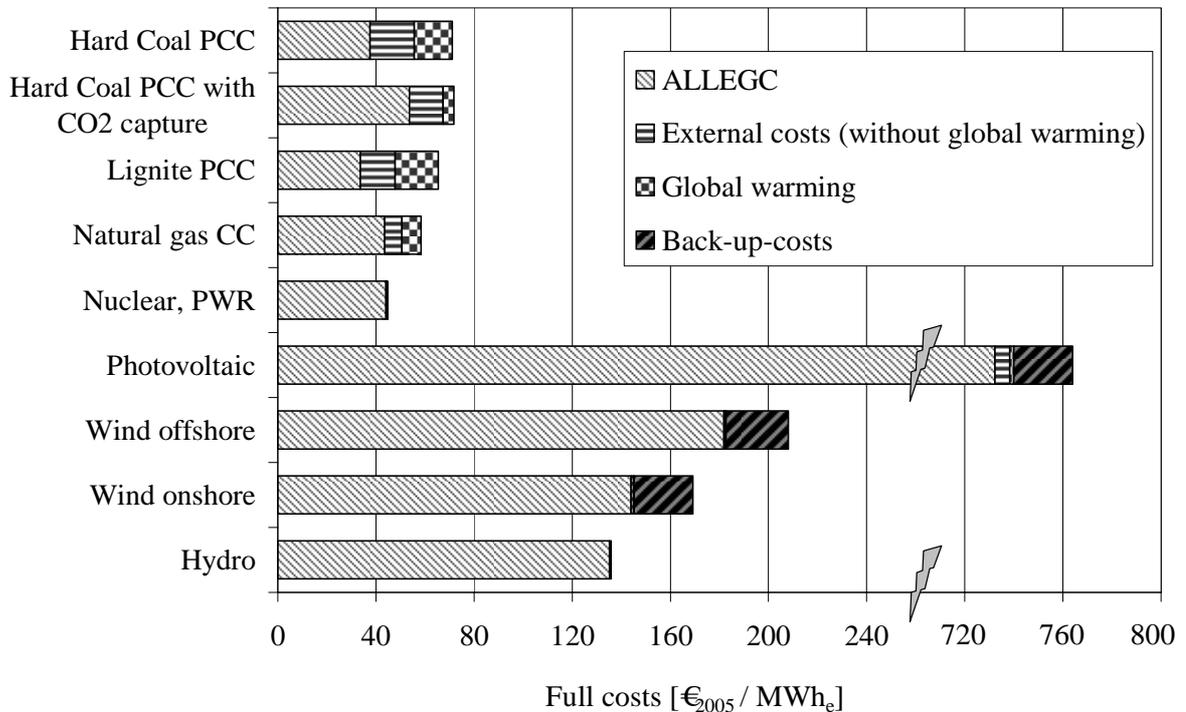


Figure 7-9: Comparison of full costs of different EGTs
(source: /172/)

Despite of high contributions from external costs, fossil-fuelled EGTs still go hand-in-hand with considerably less full costs than regenerative EGTs, which clearly feature higher ALLEGC in the range of 136 to 772 €₂₀₀₅ / MWh_e. The ALLEGC presented in Figure 7-9 are derived from /172/ except the ALLEGC for the hard-coal-fuelled power plants, which have been quantified within this study. Also in /172/, an interest rate of 10 % is applied to the annuity based calculation of ALLEGC.

Since photovoltaic as well as wind power only provide a fluctuating electricity generation, back-up-costs are quantified in order to integrate these technologies into the German electricity grid. Back-up-costs represent the costs of fossil-fuelled electricity generation, which are necessary to provide electricity in periods of no electricity generation from photovoltaic or wind power. Photovoltaic, by far, features the worst economic performance of the compared EGTs, which ranges almost one order of magnitude above the full costs of fossil fuelled electricity generation.

8 Conclusions

In this section, the findings of the investigated technology scenarios are summarized and overall conclusions for this study are drawn.

8.1 Environmental Performance of Investigated CCS Technologies

The environmental performance of CCS technologies involves improvements on the one hand, but also deteriorations on the other hand, as will be shown in the following paragraphs. Therein, firstly, the advantages of CCS technologies are presented for the release of different emissions into air. Secondly, disadvantages are highlighted, which especially refer to the increased demand for both energy and material resources. After a presentation of the predominantly deteriorating contribution of the German steam coal supply a final evaluation of the environmental performance of the investigated CCS technologies is conducted.

Reduction in Specific CO₂ Emissions

From a life-cycle perspective, CCS technology is able to entirely fulfil its purpose of achieving a major reduction in CO₂ emissions of fossil-fuelled electricity generation. The specific cumulative CO₂ emissions of the investigated technologies for hard-coal-fuelled electricity generation (680 – 770 g CO₂ / kWh) reveal a reduction by 76 – 87 %, when CCS technologies are installed and operated. Altogether, specific CO₂ emissions between 89 and 183 g CO₂ / kWh_e remain, which is clearly below the emission level of other fossil fuelled EGTs (best performance is shown by NGCC technology with 387 CO₂ / kWh_e, according to Figure 7-4).

The lowest specific CO₂ emissions are achieved by power plants with oxyfuel combustion, since this technology is able to reach the highest CO₂ capture rate among the investigated CO₂ capture technologies. Oxyfuel power plants almost attain the specific CO₂ emissions of photovoltaic, which are around 89 g CO₂ / kWh_e.

However, for a thorough evaluation of the specific CO₂ emissions it has to be clearly pointed out that a considerable amount of the remaining CO₂ emissions within the investigated technology scenarios with CCS constitute additional CO₂ emissions from the CCS chain. Solely the technologies for capture, transportation and injection of CO₂ produce specific CO₂ emissions in the range of 17 – 44 g CO₂ / kWh_e. These specific CO₂ emissions are clearly higher than those of EGTs based on wind, hydro or nuclear power as shown in Figure 7-4.

The largest part of the additional CO₂ emissions from the CCS chain (33 to 44 %) originates from the efficiency penalty due to CO₂ capture and thus constitute higher operational CO₂ emissions. Furthermore, the higher demand for steam coal and its supply contributes between 23 – 31 % to the additional specific CO₂ emissions for scenarios with CCS technology. Another 17 – 31 % originates from the transportation of CO₂ and, finally, the contribution from the injection of CO₂ is comparably low at between 3 – 12 %.

Altogether, it can be concluded that CCS technologies reduce the bulk of the specific CO₂ emissions from hard-coal-fuelled electricity generation. This reduction also strongly mitigates the GWP of these EGTs. In the investigated technology scenarios a mitigation of the GWP between 71 – 75 % has been revealed.

Mitigation of Specific SO₂ and NO_x Emissions

Another improvement in the environmental performance of hard-coal-fuelled electricity generation that comes with CCS technologies is a reduction in the specific SO₂ and NO_x emissions. Since the operation of facilities for CO₂ capture requires lower concentrations of SO₂ and NO_x than achieved by currently operated power plants without CO₂ capture, CCS technologies constitute a driver for the development of more advanced flue gas cleaning systems. The highest reductions in SO₂ and NO_x emissions are necessary for PCC technology. IGCC technology inherently features lower emission levels of these substances, but also here the capture of CO₂ goes in line with a further reduction. The lowest operational release of NO_x and SO₂ and also of other emissions into air occurs in technology scenarios with oxyfuel power plants, since almost the entire flue gas stream of these power plants is captured.

The best overall environmental performance over the entire life-cycle in terms of specific SO₂ and NO_x emissions is achieved by IGCC power plants due to their having the best power plant efficiencies and lowest efficiency penalties due to CO₂ capture amongst the investigated technologies. This advantage in power plant efficiencies and the advanced environmental performance of electricity generation after coal gasification is the reason why IGCC technology with and without CCS reaches the lowest emission levels for almost all investigated emissions into air. As mentioned before, only the specific emissions of CO₂ and N₂O are lower for oxyfuel power plants due to a lower release of these pollutants during the operation of the power plant.

Deterioration of the Environmental Performance when using CCS Technologies

There are also disadvantages when using CCS technologies. For most life-cycle inventories under investigation the installation and operation of CCS technologies involve a deterioration (increase) in their specific cumulative figures. As CO₂ capture goes hand-in-hand with an efficiency penalty for the power plants, less electricity is generated over the overall life time of the product system. This entails, that besides the deteriorations during the installation and operation of facilities for capture, transportation and injection of CO₂, all LCI data of an investigated technology with CCS are referred to a reduced life-cycle electricity generation and thus feature higher specific figures.

This deterioration of the environmental performances relates to all types of emissions released and also to the demand for both energy and material resources. However, for some life-cycle inventories this deterioration is compensated or even outweighed by improvements that come along with CCS technologies. This is the case for the release of CO₂, SO₂ and NO_x, as shown above, but also for particulate emissions, for which an enhanced removal is modelled over future

time horizons. A further exception from this generic deterioration constitute the technology scenarios on oxyfuel power plants, for which all operational emissions into air are considerably reduced due to the capture of almost the entire flue gas stream. This capture either strongly mitigates or in case of CO and N₂O emissions outweighs the above mentioned deteriorations.

Taking into account the deteriorations and the direct contributions from CCS technologies, an increase in the specific demand for the investigated material resources aluminium, basalt, chromium, clay, copper, dolomite, granite, gravel, gypsum, iron, lead and zinc by between 11 – 51 % compared to their respective technology scenarios without CCS has been revealed. There are even higher increases in the specific demand for the energy resources lignite, natural gas, crude oil, peat and uranium, which ranges at between 12 – 280 %. This, in part, considerable increase originates from the aspect that, during power plant operation without CCS, almost the entire energy demand is met by hard coal, but in technology scenarios with CCS other energy sources are required to provide the energy for the operation of transportation and injection of CO₂.

Contribution from Upstream Processes

Looking over future time horizons from 2005 to 2025 there is an increasing contribution from the German steam coal supply chain to emissions into air and to the demand for both energy and material resources within the investigated technology scenarios. This increase is independent of the environmental performance of the analysed technologies in scenarios with and without CCS, but originates from the phasing out of German domestic hard-coal mining. The replacement of German steam coal by imported steam coal from different countries goes in line with additional transportation services and a reduction of the efficiency over the steam coal supply chain. These aspects, as well as the lower net efficiencies in mine-mouth operated power plants in other countries, entail a higher release of emissions and a higher demand for both material and energy resources, which strongly influences the figures of several investigated life-cycle inventories in the investigated technology scenarios. For all emissions into air except methane, for all energy resources as well as for all material resources except gypsum, dolomite and clay, the improvement in the environmental performances by declining power plant efficiencies over future time horizons is outweighed by the deterioration arising from the steam coal supply chain. This constitutes a major influence of the steam coal supply chain on the overall LCI results and highlights that also significant improvements in power plant technology can be annihilated by changes in background processes of the analysed product systems. For some life-cycle inventories as, for instance, aluminium and granite, the deteriorations brought about by the steam coal supply chain are even worse than the deteriorations due to the installation and operation of CCS technologies.

Environmental Impact Categories

The release of emissions and the demand for both material and energy resources are the basis for the quantification of different environmental impact categories. Based on the above summarized results and conclusions, environmental impact categories are either lowest for IGCC power plants due to their highest power plant efficiencies, which is the case for the AP, EP, POCP, ODP and CED or are lowest for oxyfuel power plants due to the almost entire capture of operational emissions, which refers to the GWP and the HTP.

Risks to human health are predominantly influenced by the release of SO₂ and NO_x emissions and thus are lowest for IGCC power plants with and without CCS.

Final Evaluation of Investigated CCS Technologies

By a direct comparison of technologies with CO₂ capture, the most disadvantageous environmental performance is revealed for PCC technology with CO₂ post-combustion capture. This technology shows the highest release of emissions into air, the highest demand for both material and energy resources and thus features the most serious impacts on the environment.

The evaluation of two different means for CO₂ transportation reveals a clearly better environmental performance for CO₂ pipeline transportation against CO₂ barge transportation. Especially, the required additional compression of CO₂ after barge transportation involves a higher release of emissions into air and a higher demand for both material and energy resources than CO₂ pipeline transportation. Thus, it is concluded that for German conditions CO₂ pipeline transportation is the most favourable option for CO₂ transportation. Only when transportation over very long distances is considered, ship transportation of CO₂ may also become attractive.

The best environmental performance of the investigated technologies with CO₂ capture is revealed to be for either IGCC power plants with CO₂ pre-combustion capture or for oxyfuel power plants. For several investigated life-cycle inventories and environmental impact categories oxyfuel power plants show the most favourable results due to their high capture rate for CO₂ as well as due to the capture of other operational emissions into air. However, the majority of results are most advantageous for IGCC power plants, since this technology is anticipated to feature the highest power plant efficiencies and definitely involves the lowest generation of emissions during the electricity generation process. Both latter aspects are also the reasons, why IGCC power plants show a clearly better environmental performance than PCC power plants when comparing power plants without CO₂ capture.

8.2 Economic Performance of Investigated CCS Technologies

In the following paragraphs, the economic performance of the investigated technology scenarios with and without CCS is evaluated in terms of ALLEGC, CO₂ avoidance costs, external costs and full costs before final conclusions are drawn.

ALLEGC (Average Lifetime Levelised Electricity Generation Costs)

Hard-coal-fuelled electricity generation in technology scenarios with CCS technologies is involved with higher ALLEGC than in technology scenarios without CO₂ capture. The efficiency penalty due to CO₂ capture entails a higher demand for steam coal and thus increases the fuel costs. Furthermore, ALLEGC are increased by additional costs for investment, operation and dismantling of facilities for capture, transportation and injection of CO₂. Finally, the lower quantities of electricity generated over the life time of the power plant result in an increase in ALLEGC.

Altogether, the ALLEGC of the hard-coal-fuelled electricity generation technologies with CCS investigated range between 47.2 and 53.7 €₂₀₀₅ / MWh_e, which constitutes an increase of between 17 % to 43 % compared to the ALLEGC of the technologies without CCS. Despite this cost increase when integrating and operating CCS facilities, the investigated technology scenarios with CCS show ALLEGC, which are still lower than the ALLEGC of electricity generation from photovoltaic (732 €₂₀₀₅ / MWh_e), wind power (144 – 182) and hydro power (135), according to Figure 7-9. However, the deterioration of ALLEGC by CCS technologies becomes significant, when a comparison is drawn with EGTs based on nuclear power (44), lignite (34) or natural gas (44). Thus, it becomes obvious that the integration and operation of CCS facilities increases the ALLEGC of hard-coal-fuelled electricity generation to become the highest cost level among nuclear and fossil-fuelled EGTs.

A comparison of the economic performance between the individual investigated CCS technologies reveals CO₂ pre-combustion capture in IGCC power plants to be involved with lowest ALLEGC. This is because the two main factors increasing ALLEGC within technology scenarios with CCS are most favourable for IGCC technologies. These factors are, on the one hand, the investment cost penalties due to CO₂ capture and, on the other hand, the cost penalty in fuel costs, which is caused by the efficiency penalties due to CO₂ capture. Oxyfuel technology featuring higher cost penalties due to CO₂ capture than IGCC technology reveals somewhat higher ALLEGC, but is still better than PCC technology, which shows the highest cost penalties due to CO₂ capture and thus the highest ALLEGC.

The same ranking of ALLEGC for CO₂ capture technologies is reported in the STE study /134/. A somewhat better performance for oxyfuel technology compared to IGCC technology is found in the RECCS study /23/. However, this can be traced back to different assumptions for the cost penalties due to CO₂ capture for these technologies.

Comparing hard-coal-fuelled electricity generation without CCS reveals lower ALLEGC for PCC power plants than for IGCC power plants. This result is reached within both this study and the RECCS and STE studies due to the clearly lower investment costs for PCC power plants.

CO₂ avoidance costs

The additional costs for integrating and operating CCS technologies are illustrated by the CO₂ avoidance costs. These CO₂ avoidance costs, which summarize the costs for the capture, transportation and storage of CO₂ in relation to the quantity of avoided CO₂ emissions, range between 20 and 32 €₂₀₀₅ / t of avoided CO₂ within the investigated technology scenarios. Compensating for these CO₂ avoidance costs by, for instance, having CO₂ allowances at the same price level that can be sold within the European emission trading scheme, would enable the same economic performances to be reached in power plants with CCS as in power plants without CO₂ capture. The lowest price level for CO₂ allowances would be required for IGCC power plants with CCS, whilst the highest price level would be for PCC power plants with CCS. This forces the conclusion that, today, the prices of CO₂ allowances within the second trading period between 2008 to 2012, which are currently fluctuating between 15 and 28 €/ t CO₂, are for the upper range able to facilitate an economic operation of IGCC power plants with CCS as well as oxyfuel power plants (for the assumptions considered in the cost calculations). PCC power plants with CCS would require CO₂ allowances with higher prices.

CO₂ avoidance costs are predominantly influenced by the investment cost penalties due to CO₂ capture, which, in this study, are highest for PCC power plants. With reference to the other sources of cost data, which partly state higher figures for the investment cost penalties due to CO₂ capture, both the RECCS and STE studies report higher CO₂ avoidance costs for the CCS technologies investigated. However, at the same time in these two studies, lower cost figures for investment costs for power plants without CO₂ capture are assumed, which results in generating similar ALLEGCC to this study for the technologies considered. Together, both the RECCS and STE studies show the same ranking of CCS technologies for CO₂ avoidance costs. IGCC power plants come first with the lowest CO₂ avoidance costs followed by oxyfuel power plants and PCC power plants with CCS.

External costs

An advantageous aspect for the economic performance of CCS technologies is revealed by the external costs, which have been quantified within the technology scenarios investigated. The avoidance costs on climate change are greatly reduced by between 71 to 83 % due to the capture of the bulk of CO₂ emissions. All other external cost components, these being damage costs to human health, loss of biodiversity, crop loss and material damage, are increased due to the above mentioned deterioration of specific figures for hard-coal-fuelled electricity generation with CCS. However, the reduction in avoidance costs for climate change outweighs this cost increase of the other cost components and entails an overall reduction in external costs of between 36 to 62 %.

The lowest avoidance costs for climate change are revealed for oxyfuel power plants due to the highest CO₂ capture rate among the investigated CO₂ capture technologies. However, the lowest overall external costs go in line with electricity generation at hard-coal-fuelled IGCC power

plants with CCS, since this technology features the highest efficiency and thus the lowest indirect emissions. In power plants with CCS, the contribution from indirect emissions, especially emissions from the steam coal supply chain, turn out to be more decisive for the external cost calculation than the contributions from direct emissions at the power plant site.

Full costs

When looking at the full costs of the technology scenarios investigated, the integration and operation of CCS technologies show lower figures and thus are advantageous when compared to technology scenarios without CO₂ capture. The addition of ALLEGC and external costs to the full costs reveals that, for scenarios with CCS, the decrease in external costs is more significant than the increase in ALLEGC. This means that technology scenarios with CCS show an improved economic performance when the economic evaluations were made on the basis of full costs. However, an economic evaluation is predominantly made on the basis of only direct costs, which are ALLEGC. The only way to take external costs into account for economic evaluation is by the internalisation of such costs due to legal regulations. This, for instance, is the case for the European emission trading scheme, which via CO₂ allowances internalises the avoidance costs on climate change into ALLEGC. By means of this approach, the integration and operation of CCS technologies may become competitive to hard-coal-fuelled power plants without CO₂ capture.

However, even without the internalisation of avoidance costs on climate change by CO₂ allowances the hard-coal-fuelled EGTs with CCS investigated are competitive with EGTs based on regenerative energy sources. In this respect, they revealed lower ALLEGC and lower full costs than regenerative EGTs, as shown in Figure 7-9.

Apart from the economic competitiveness a crucial aspect for the market penetration of CCS technologies will be the societal acceptance of this technology, especially the long-term safety of geological CO₂ storage sites.

All CCS technologies investigated are anticipated to be ready for large-scale commissioning within the next decade. For hard-coal-fuelled electricity generation, this means that future power plant capacities are able to greatly contribute to a mitigation in the release of anthropogenic CO₂ emissions, as and when they are commissioned in order to replace outdated power plant units.

9 Outlook

Considering the technically immature state-of-the-art for current CCS technologies and the availability of several different technology roadmaps on their future development, this study provides a reasonable prospective LCA study within this field of research and firstly quantifies LCI data for several material and energy resources as well as emissions. By using parameters, the ability to change the assumptions and frame conditions for this P-LCA study opens up the possibilities to easily adapt the results to other CCS projects along with any new developments. Initial experiences for current pilot facilities with CCS would allow further tuning of the applied key parameters.

The major level of detail in this study, which includes the technical specifications for individual power plant components, enables the generated parametrised LCI models to be used for the simulation and analysis of power plants with CCS featuring different capacity levels and different technical specifications. However, notwithstanding this flexible approach, these parametrised LCI models are able to be further elaborated, as for instance by investigation of advanced power plant components.

One field of LCI research, which is covered in this work and goes beyond other studies, but still features potential for improvement, is the elaboration of scaling factors for different power plant components. Hereby, cooperation with the power plant industry, which currently develops LCA-based environmental product declarations (EPD) for their products, would provide valuable new projects and at the same time enhancements to LCI modelling. Furthermore, this cooperation in developing very accurate LCI data for power plant components could provide a more detailed specification for the materials used. The development and usage of advanced materials for alloys, plastics etc. becomes more and more important when striving for further efficiency improvements, as for instance in the case of the 700 °C power plants. However, the production of these materials is scarcely covered by relevant data in current LCI databases.

Further basic research is required for storing CO₂ in different geological storage sites and monitoring the injected CO₂. Thus, more data on injection and monitoring infrastructure could be obtained in order to specify the LCI data further. Based on a detailed investigation of current CO₂ storage activities by the power plant industry, by producers of natural gas or by European projects, the storage of CO₂ as the final step in the life-cycle of fossil-fuelled electricity generation with CCS could be modelled by empiric and proven LCI data.

The analysis of the steam coal supply chain at an annual level reveals that changes over time in the supply of materials or energy carriers are able to influence the overall LCA results. Starting with this experience, it is recommended to conduct further LCA studies in order to analyse changes over time for the supply of other materials, products and resources. There are several supply chains, which are of minor importance for this study but show a higher relevance over the life cycle of other energy technologies or product systems and thus offer a promising field of investigation.

Further developments in the field of power plant parameters could focus on the integration of different stoichiometric specifications for the electricity generation processes in the gasifiers and boilers of the power plants investigated in order to specify the generated operational emissions. The quantification of LCI data for different stoichiometric parameters would then allow integrating different load levels or profiles of power plants in LCA.

The cost modelling in this study is based upon a framework of assumptions, which are very likely to change over future time horizons. Already, today's prices for fuel and material resources are changing quite rapidly, so that the cost calculations have to be regularly adapted to current market conditions. Hereby, a scenario modelling for different price development pathways would enable the market penetration of CCS technologies to be sketched under different frameworks.

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11 Annex

Table 11-1: LCA databases worldwide
(source: /168/)

Database + version	Supplier	Database Languages
CML-IA 2.7	Leiden University, Institute of Environmental Sciences (CML)	English
DEAM™	Ecobilan - PricewaterhouseCoopers	English
DEAM™ Impact	Ecobilan - PricewaterhouseCoopers	English
DIM 1.0	ENEA - Italian National Agency for New Technology, Energy and the Environment	English, Italian
ecoinvent Data v1.2	ecoinvent Centre	Japanese, English
ecoinvent Data v1.3	ecoinvent Centre	Japanese, English
EIME V8.0	CODDE	English, French, Spanish
esu-services database v1	ESU-services Ltd.	English, German
Eurofer data sets	EUROFER	English
GaBi databases 2006	PE International GmbH	Japanese, English, German
GEMIS 4.4	Oeko-Institut (Institute for applied Ecology), Darmstadt Office	Czech, English, German, Spanish,
IO-database for Denmark 1999	2.-0 LCA consultants	English
IVAM LCA Data 4.04	IVAM University of Amsterdam bv	English
KCL EcoData	Oy Keskuslaboratorio-Centrallaboratorium Ab, KCL	English
LCA Database for the Forest Wood Sector	Bundesforschungsanstalt für Forst- und Holzwirtschaft (BFH)	
LCA_sostenipra_v.1.0	Universitat Autònoma de Barcelona (UAB)	English, Catalan, Spanish
MFA_sostenipra_v.1.0	Universitat Autònoma de Barcelona (UAB)	English, Catalan, Spanish
Option data pack	National Institute of Advanced Industrial Science and Technology (AIST)	Japanese,
PlasticsEurope Eco-profiles	PlasticsEurope	English,
ProBas	Umweltbundesamt	German,
Sabento library 1.1	ifu Hamburg GmbH	English, German
SALCA 061	Agroscope Reckenholz-Tänikon Research Station ART	English, German
SimaPro database	PRé Consultants B.V.	English
sirAdos 1.2.	LEGEP Software GmbH	German
The Boustead Model 5.0.12	Boustead Consulting Limited	English
Umberto library 5.5	ifu Hamburg GmbH	English, German
US Life Cycle Inventory Database	Athena Sustainable Materials Institute	English
Waste Technologies Data Centre	UK Environment Agency	English

Table 11-2: Further scaling functions of power plant components
(source: own)

Power plant component (abbreviation)	Parametrised scaling function P_{Comp} with $Comp \in \{GT, ST, ASU, \dots\}$	Basic correlation to power plant engineering
Construction Engineering		
Transformer House (TransH)	$f_{TransH} = \sqrt[3]{\frac{2}{3} \frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	Constant electricity density in conductors Surface of building corresponds to the squared cube root.
House for Emergency Power Supply (HEPS)	$f_{HEPS} = \sqrt[3]{\frac{2}{3} \frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	Constant electricity density in conductors Surface of building corresponds to the squared cube root.
Gate Keepers House (GKH)	$f_{GKH} = 1$	unchanged
House for Feed Pump and Water Treatment (FPWTH)	$f_{FPWTH} = \sqrt[3]{\frac{P_{el,Steam Turbine}}{P_{el,Steam Turbine,reference}}}$	Constant heat flow density in heat transfer systems. Surface of building corresponds to the squared cube root.
Feedstock Storehouse (FeedS)	$f_{FeedS} = \sqrt[3]{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant specific fuel feed ratio. Surface of building corresponds to the squared cube root.
Machine House (MachH)	$f_{MachH} = \sqrt[3]{\frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	Power Plant Capacity as reference for machine volume. Surface of building corresponds to the squared cube root.
Administration House (AdmH)	$f_{AdmH} = 1$	unchanged
Other Buildings (OBuild)	$f_{OBuild} = \frac{2}{3} \cdot \sqrt[3]{\frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	1/3 of the remaining buildings remain unchanged
Street Pavin (Street)	$f_{Street} = \frac{1}{2} \cdot \sqrt[3]{\frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	50% of the street network is basic requirement and remains unchanged. Streets are one-dimensional, thus changes correspond to the cube root
Floor and Roof Covering (FRCover)	$f_{FRCover} = \frac{1}{3} \cdot \sqrt[3]{\frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	Roof and floor are together only 2/6 of the surface of a building
Mechanical Engineering		
Feed-Water Pumps (FWP)	$f_{FWP} = \frac{P_{el,Steam Turbine}}{P_{el,Steam Turbine,reference}}$	Steam Turbine determines the steam cycle, the amount of feed-water and thus the dimensioning of the feed-water pumps
Gas Turbine (GT)	$f_{GT} = \sqrt{\frac{P_{el,Gas Turbine}}{P_{el,Gas Turbine,reference}}}$	Constant gas volume flow per cross-sectional area
Fuel Supply System (FSS)	$f_{FSS} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe

Mechanical Engineering (continued)		
Air Conditioning System (ACS)	$f_{ACS} = \frac{2}{3} \cdot \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	1/3 of the air conditioning systems are independent from power plant capacity
Air Separation Unit (ASU)	$f_{ASU} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Claus Unit (CU)	$f_{CU} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
MDEA-Scrubber (MDEAS)	$f_{MDEAS} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Shift Reactor (ShiftR)	$f_{ShiftR} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Selexol-Scrubber (SelexolS)	$f_{SelexolS} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Cyclon (Cyclon)	$f_{Cyclon} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Venturi-Scrubber (VentS)	$f_{VentS} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Ceramic Candle-Filter (CCF)	$f_{CCF} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density through filter; mass of filter is predominantly determined by the surface of the filter
Heat Exchanger (HeatEx)	$f_{HeatEx} = \sqrt{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Water Treatment Facilities (WTF)	$f_{WTF} = \sqrt{\frac{P_{th,Cooling}}{P_{th,Cooling,reference}}}$	Constant mass flow density in pipes; mass of pipes is predominantly determined by the surface of the pipe
Gasifier (Gasifier)	$f_{Gasifier} = \sqrt[3]{\frac{P_{th,Firing}}{P_{th,Firing,reference}}}$	Constant mass flow density. Gasifier volume corresponds to firing capacity. Surface of building corresponds to the squared cube root.
Other Auxilliary Systems (OAS)	$f_{OAS} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Basic reference to the overall power plant capacity

Electrical Engineering		
Cable and Pallets (Cable)	$f_{Cable} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Constant electricity density in conductors
Control and Communication Systems (Control)	$f_{Control} = \sqrt[3]{\frac{P_{el,Gross}}{P_{el,Gross,reference}}}$	Mostly one-dimensional systems in accordance to the power plant capacity Changes correspond to the cube root.
Generator Conduction (GCond)	$f_{GCond} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Constant electricity density in conductors
Switching Station (SwitchingS)	$f_{SwitchingS} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Constant electricity density in conductors
Emergency Power Supply (EPS)	$f_{EPS} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Constant electricity density in conductors
Electric Motors (EMotor)	$f_{EMotor} = \frac{P_{el,Gross}}{P_{el,Gross,reference}}$	Constant electricity density in conductors

Table 11-3: Disposal processes of the ecoinvent database applied in this study
(source: derived from /49/)

Disposal service	Unit
Final disposal	
disposal, building, concrete, not reinforced, to final disposal	kg
disposal, building, reinforced concrete, to final disposal	kg
disposal, building, reinforcement steel, to final disposal	kg
disposal, building, emulsion paint on walls, to final disposal	kg
disposal, building, mineral wool, to final disposal	kg
disposal, building, polyethylene/polypropylene products, to final disposal	kg
Sorting / Recycling	
disposal, building, concrete, not reinforced, to recycling	kg
disposal, building, concrete, not reinforced, to sorting plant	kg
disposal, building, reinforcement steel, to recycling	kg
disposal, building, reinforcement steel, to sorting plant	kg
disposal, building, reinforced concrete, to recycling	kg
disposal, building, reinforced concrete, to sorting plant	kg
disposal, building, bulk iron (excluding reinforcement), to sorting plant	kg
disposal, building, mineral wool, to recycling	kg
Incineration	
disposal, municipal solid waste, 22.9% water, to municipal incineration	kg
disposal, plastic, industr. electronics, 15.3% water, to municipal incineration	kg
disposal, plastics, mixture, 15.3% water, to municipal incineration	kg
disposal, polyethylene, 0.4% water, to municipal incineration	kg
disposal, copper, 0% water, to municipal incineration	kg
disposal, steel, 0% water, to municipal incineration	kg
disposal, glass, 0% water, to municipal incineration	kg
disposal, polyvinylchloride, 0.2% water, to municipal incineration	kg
disposal, polystyrene, 0.2% water, to municipal incineration	kg
disposal, wood untreated, 20% water, to municipal incineration	kg
Hazardous waste incineration / deposition	
disposal, used mineral oil, 10% water, to hazardous waste incineration	kg
disposal, hazardous waste, 25% water, to hazardous waste incineration	kg
disposal, hazardous waste, 0% water, to underground deposit	kg
Inert material landfill	
disposal, concrete, 5% water, to inert material landfill	kg
disposal, inert waste, 5% water, to inert material landfill	kg
disposal, steel, 0% water, to inert material landfill	kg
disposal, glass, 0% water, to inert material landfill	kg
Sanitary landfill	
disposal, aluminium, 0% water, to sanitary landfill	kg
disposal, inert material, 0% water, to sanitary landfill	kg
disposal, tin sheet, 0% water, to sanitary landfill	kg
disposal, polystyrene, 0.2% water, to sanitary landfill	kg
disposal, polyvinylchloride, 0.2% water, to sanitary landfill	kg
Waste water treatment	
treatment, sewage, from residence, to wastewater treatment, class 2	m ³
treatment, inorganic production effluent, to wastewater treatment, class 3	m ³
treatment, organic production effluent, to wastewater treatment, class 3	m ³

Table 11-4: External costs and YOLL characterisation factors of the impact pathway category 'Lethal cancer due to ionising radiation'
(source: /43/)

Radionuclide	Emission into	[manSv / PBq]	[YOLL / kBq]	[Euro / kBq]
Aerosols, radioactive	air	2.0 E3	2.0 E-9	2.6 E-4
Carbon-14	air	9.2 E4	9.1 E-8	1.2 E-2
Carbon-14	water	1.0 E3	9.9 E-10	1.3 E-4
Cesium-137	air	7.4 E3	7.3 E-9	9.5 E-4
Cesium-137	water	9.8 E1	9.7 E-11	1.3 E-5
Hydrogen-3, Tritium	air	4.1 E0	4.0 E-12	5.3 E-7
Hydrogen-3, Tritium	water	8.5 E-1	8.4 E-13	1.1 E-0
Iodine-129	air	6.4 E4	6.3 E-8	8.2 E-3
Iodine-131	air	2.0 E4	2.0 E-8	2.6 E-3
Krypton-85	air	2.1 E-1	2.1 E-13	2.8 E-8
Noble gases, radioactive	air	4.3 E-1	4.2 E-13	5.5 E-8
Radon-222	air	2.5 E0	2.5 E-12	3.2 E-7
Thorium-230	air / water	3.0 E4	3.0 E-08	3.9 E-3
Uranium-234	air / water	8.0 E3	7.9 E-09	1.0 E-3
Uranium-238	air / water	7.0 E3	6.9 E-09	9.0 E-4
Sr-90	unspecified	4.7 E0	4.6 E-12	6.1 E-7
Ru-106	unspecified	3.3 E0	3.3 E-12	4.3 E-7
Pb-210	unspecified	1.0 E3	9.9 E-10	1.3 E-4
Po-210	unspecified	1.0 E3	9.9 E-10	1.3 E-4
Ra-226	unspecified	6.0 E2	5.9 E-10	7.7 E-5

Table 11-5: LCI results of present and future LCA background data (II)

Name	Unit	Aluminium production mix, at plant [kg]			Steel, low-alloyed, at plant [kg]			Transport, lorry 32t [tkm]		
		2007 / 2015	2025	2050	2007 / 2015	2025	2050	2007 / 2015	2025	2050
CO ₂	kg	6.7 E+0	7.3 E+0	6.9 E+0	1.5 E+0	1.4 E+0	1.4 E+0	1.6 E-1	1.3 E-1	1.3 E-1
CO	kg	6.7 E-2	3.7 E-3	3.5 E-3	2.3 E-2	2.1 E-2	1.9 E-2	7.4 E-4	6.5 E-4	6.4 E-4
SO ₂	kg	2.7 E-2	2.3 E-2	1.9 E-2	4.6 E-3	4.5 E-3	4.3 E-3	2.6 E-4	2.2 E-4	2.1 E-4
NO _x	kg	1.4 E-2	1.5 E-2	1.4 E-2	4.6 E-3	4.4 E-3	4.3 E-3	1.3 E-3	6.0 E-4	5.7 E-4
NMVOOC	kg	1.9 E-3	2.6 E-3	2.4 E-3	9.4 E-4	1.0 E-3	1.0 E-3	2.8 E-4	3.1 E-4	3.0 E-4
PM _{2,5}	kg	3.5 E-3	2.6 E-3	1.8 E-3	1.8 E-3	1.8 E-3	1.6 E-3	9.0 E-5	3.7 E-5	3.6 E-5
PM ₁₀	kg	8.5 E-3	1.0 E-2	8.2 E-3	5.1 E-3	5.7 E-3	5.4 E-3	1.3 E-4	8.3 E-5	8.0 E-5
CH ₄	kg	1.1 E-2	1.6 E-2	1.5 E-2	3.0 E-3	4.7 E-3	4.6 E-3	1.5 E-4	1.4 E-4	1.4 E-4
N ₂ O	kg	1.9 E-4	2.0 E-4	1.9 E-4	3.7 E-5	3.6 E-5	3.5 E-5	5.3 E-6	5.4 E-6	5.1 E-6
Lignite	kg	9.0 E-1	1.6 E-1	1.5 E-1	1.9 E-1	1.9 E-1	1.8 E-1	3.0 E-3	3.8 E-3	3.8 E-3
Hard Coal	kg	1.4 E+0	2.2 E+0	2.0 E+0	3.8 E-1	7.1 E-1	6.8 E-1	3.3 E-3	4.0 E-3	4.0 E-3
Natural Gas	Nm ³	3.6 E-1	4.9 E-1	4.7 E-1	1.4 E-1	1.4 E-1	1.3 E-1	4.4 E-3	4.2 E-3	4.1 E-3
Crude Oil	kg	8.4 E-1	7.5 E-1	7.3 E-1	9.0 E-2	7.4 E-2	7.3 E-2	5.2 E-2	4.2 E-2	4.0 E-2
Peat	kg	1.3 E-5	4.8 E-6	4.8 E-6	2.6 E-6	2.1 E-6	2.1 E-6	3.7 E-7	4.0 E-7	4.0 E-7
Uranium	kg	4.4 E-5	1.9 E-5	1.8 E-5	1.0 E-5	9.7 E-6	9.6 E-6	2.6 E-7	5.2 E-7	5.2 E-7
Aluminium	kg	1.5 E+0	1.5 E+0	1.5 E+0	2.0 E-3	1.9 E-3	1.9 E-3	1.8 E-4	1.8 E-4	1.8 E-4
Basalt	kg	4.9 E-4	4.9 E-4	4.9 E-4	6.4 E-4	6.3 E-4	6.3 E-4	1.4 E-5	1.5 E-5	1.5 E-5
Chromium	kg	2.6 E-4	2.6 E-4	2.6 E-4	9.2 E-3	9.2 E-3	9.2 E-3	6.9 E-6	1.5 E-5	1.5 E-5
Clay	kg	3.6 E-2	3.5 E-2	3.5 E-2	3.3 E-2	2.3 E-2	2.3 E-2	1.3 E-3	1.4 E-3	1.4 E-3
Copper	kg	2.4 E-3	2.4 E-3	2.4 E-3	1.4 E-4	1.3 E-4	1.3 E-4	2.1 E-5	2.4 E-5	2.4 E-5
Dolomite	kg	6.4 E-5	6.4 E-5	6.4 E-5	2.0 E-3	2.0 E-3	2.0 E-3	7.8 E-6	7.8 E-6	7.8 E-6
Granite	kg	4.6 E-7	4.6 E-7	4.6 E-7	2.1 E-7	1.3 E-7	1.3 E-7	2.5 E-7	2.5 E-7	2.5 E-7
Gravel	kg	7.2 E-1	7.2 E-1	7.2 E-1	2.8 E-1	2.1 E-1	2.1 E-1	1.7 E-1	1.7 E-1	1.7 E-1
Gypsum	kg	8.6 E-6	1.3 E-5	1.3 E-5	2.6 E-7	2.3 E-7	2.3 E-7	1.2 E-7	1.2 E-7	1.2 E-7
Iron	kg	3.2 E-2	3.2 E-2	3.2 E-2	8.1 E-1	8.4 E-1	8.4 E-1	4.6 E-3	4.7 E-3	4.7 E-3
Lead	kg	1.2 E-3	1.2 E-3	1.2 E-3	4.1 E-4	1.7 E-4	1.7 E-4	7.9 E-4	8.0 E-4	8.0 E-4
Sand	kg	9.6 E-7	9.6 E-7	9.6 E-7	1.5 E-6	1.4 E-6	1.4 E-6	9.6 E-8	1.0 E-7	1.0 E-7
Zinc	kg	1.1 E-2	1.1 E-2	1.1 E-2	9.3 E-5	8.6 E-5	8.6 E-5	2.3 E-5	2.3 E-5	2.3 E-5

Table 11-6: LCI results of present and future LCA background data (III)

Name	Unit	Cast iron, at plant [kg]			Reinforcing steel, at plant [kg]			Chromium steel 18/8, at plant [kg]		
		2007 / 2015	2025	2050	2007 / 2015	2025	2050	2007 / 2015	2025	2050
CO ₂	kg	1.6 E+0	1.5 E+0	9.1 E-1	1.2 E+0	1.2 E+0	1.1 E+0	4.8 E+0	4.6 E+0	4.4 E+0
CO	kg	2.5 E-2	2.2 E-2	3.3 E-3	2.3 E-2	2.1 E-2	1.9 E-2	1.9 E-2	1.8 E-2	1.7 E-2
SO ₂	kg	5.3 E-3	5.3 E-3	3.2 E-3	3.6 E-3	3.5 E-3	3.3 E-3	1.8 E-2	1.8 E-2	1.7 E-2
NO _x	kg	4.8 E-3	4.7 E-3	2.4 E-3	3.2 E-3	3.0 E-3	2.9 E-3	1.3 E-2	1.2 E-2	1.2 E-2
NMVOOC	kg	6.0 E-4	7.9 E-4	4.0 E-4	7.2 E-4	8.0 E-4	7.9 E-4	2.0 E-3	2.3 E-3	2.3 E-3
PM 2,5	kg	1.0 E-3	1.0 E-3	4.2 E-4	7.7 E-4	7.7 E-4	6.9 E-4	9.7 E-3	9.1 E-3	8.5 E-3
PM ₁₀	kg	4.0 E-3	4.6 E-3	7.0 E-4	3.3 E-3	3.9 E-3	3.7 E-3	1.7 E-2	1.8 E-2	1.6 E-2
CH ₄	kg	3.1 E-3	5.6 E-3	1.8 E-3	2.4 E-3	4.2 E-3	4.1 E-3	1.0 E-2	1.1 E-2	1.0 E-2
N ₂ O	kg	3.8 E-5	3.7 E-5	2.9 E-5	2.2 E-5	2.1 E-5	2.1 E-5	1.0 E-4	9.6 E-5	9.3 E-5
Lignite	kg	2.9 E-1	2.8 E-1	2.6 E-1	1.6 E-1	1.5 E-1	1.5 E-1	6.4 E-1	6.2 E-1	6.0 E-1
Hard Coal	kg	4.3 E-1	8.4 E-1	1.7 E-1	3.1 E-1	6.4 E-1	6.2 E-1	1.2 E+0	1.4 E+0	1.3 E+0
Natural Gas	Nm ³	1.1 E-1	1.1 E-1	1.0 E-1	1.1 E-1	1.1 E-1	1.1 E-1	5.2 E-1	5.0 E-1	4.8 E-1
Crude Oil	kg	1.2 E-1	1.3 E-1	1.0 E-1	7.8 E-2	6.4 E-2	6.4 E-2	2.3 E-1	2.2 E-1	2.1 E-1
Peat	kg	1.3 E-6	1.4 E-6	1.4 E-6	1.2 E-6	1.2 E-6	1.2 E-6	9.8 E-6	1.8 E-6	1.8 E-6
Uranium	kg	1.5 E-5	1.5 E-5	1.4 E-5	8.2 E-6	7.9 E-6	7.8 E-6	3.3 E-5	3.2 E-5	3.1 E-5
Aluminium	kg	6.8 E-4	5.2 E-4	3.6 E-4	4.7 E-4	3.9 E-4	3.9 E-4	3.1 E-2	3.1 E-2	3.1 E-2
Basalt	kg	2.6 E-4	2.6 E-4	2.4 E-4	3.2 E-4	3.2 E-4	3.2 E-4	3.1 E-3	3.1 E-3	3.1 E-3
Chromium	kg	5.8 E-4	5.7 E-4	5.6 E-4	2.4 E-4	2.3 E-4	2.3 E-4	2.4 E-1	2.4 E-1	2.4 E-1
Clay	kg	2.2 E-2	9.5 E-3	6.2 E-3	2.6 E-2	1.6 E-2	1.6 E-2	8.5 E-2	7.9 E-2	7.9 E-2
Copper	kg	1.5 E-4	1.3 E-4	1.2 E-4	1.0 E-4	9.0 E-5	9.0 E-5	4.7 E-4	4.7 E-4	4.7 E-4
Dolomite	kg	2.4 E-5	1.7 E-5	1.2 E-5	1.9 E-3	1.9 E-3	1.9 E-3	1.9 E-3	1.9 E-3	1.9 E-3
Granite	kg	2.8 E-7	1.5 E-6	1.5 E-6	1.6 E-7	8.0 E-8	8.0 E-8	9.2 E-7	8.5 E-7	8.5 E-7
Gravel	kg	3.2 E-1	2.1 E+0	2.0 E+0	2.1 E-1	1.4 E-1	1.4 E-1	1.3 E+0	1.3 E+0	1.3 E+0
Gypsum	kg	3.2 E-7	2.6 E-7	8.1 E-8	2.3 E-7	1.9 E-7	1.9 E-7	4.8 E-7	4.4 E-7	4.4 E-7
Iron	kg	9.3 E-1	9.3 E-1	5.1 E-3	8.0 E-1	8.3 E-1	8.3 E-1	5.2 E-1	5.5 E-1	5.5 E-1
Lead	kg	8.6 E-4	3.9 E-4	2.8 E-4	4.0 E-4	1.6 E-4	1.6 E-4	6.1 E-4	3.7 E-4	3.7 E-4
Sand	kg	1.3 E-6	1.5 E-6	1.4 E-6	7.6 E-7	7.0 E-7	7.0 E-7	3.3 E-6	3.2 E-6	3.2 E-6
Zinc	kg	9.8 E-5	8.8 E-5	7.9 E-5	7.2 E-5	6.5 E-5	6.5 E-5	2.8 E-4	2.7 E-4	2.7 E-4

Table 11-7: LCI results of present and future LCA background data (IV)

Name	Unit	Copper, at regional storage [kg]			Zinc for coating, at regional storage [kg]			Flat glass, uncoated, at plant [kg]		
		2007 / 2015	2025	2050	2007 / 2015	2025	2050	2007 / 2015	2025	2050
CO ₂	kg	1.6 E+0	1.5 E+0	1.4 E+0	2.3 E+0	2.2 E+0	2.1 E+0	5.0 E-1	9.4 E-1	8.6 E-1
CO	kg	6.5 E-3	5.7 E-3	5.6 E-3	4.4 E-3	3.6 E-3	3.5 E-3	4.2 E-4	3.6 E-4	3.4 E-4
SO ₂	kg	1.0 E-1	7.4 E-2	4.6 E-2	2.6 E-2	2.1 E-2	1.7 E-2	5.2 E-3	4.3 E-3	3.3 E-3
NO _x	kg	2.0 E-2	1.8 E-2	1.8 E-2	1.4 E-2	1.3 E-2	1.3 E-2	4.0 E-3	3.3 E-3	2.6 E-3
NMVOOC	kg	3.5 E-3	3.3 E-3	3.2 E-3	2.1 E-3	2.3 E-3	2.3 E-3	2.8 E-4	3.5 E-4	3.2 E-4
PM _{2,5}	kg	1.1 E-2	9.8 E-3	9.7 E-3	3.2 E-3	3.1 E-3	3.0 E-3	2.6 E-4	1.8 E-4	1.1 E-4
PM ₁₀	kg	1.9 E-2	2.4 E-2	2.4 E-2	6.0 E-3	8.9 E-3	8.8 E-3	3.6 E-4	4.6 E-4	3.0 E-4
CH ₄	kg	2.4 E-3	2.3 E-3	2.3 E-3	4.0 E-3	3.9 E-3	3.7 E-3	1.2 E-3	1.2 E-3	1.2 E-3
N ₂ O	kg	2.3 E-4	2.1 E-4	2.1 E-4	1.3 E-4	1.3 E-4	1.2 E-4	6.1 E-6	6.1 E-6	5.6 E-6
Lignite	kg	2.1 E-1	1.9 E-1	1.9 E-1	3.2 E-1	3.1 E-1	2.9 E-1	2.9 E-2	2.9 E-2	2.6 E-2
Hard Coal	kg	2.3 E-1	2.3 E-1	2.3 E-1	4.5 E-1	4.3 E-1	4.1 E-1	5.1 E-2	5.3 E-2	5.1 E-2
Natural Gas	Nm ³	1.6 E-1	1.5 E-1	1.5 E-1	2.2 E-1	2.1 E-1	2.1 E-1	1.5 E-1	1.5 E-1	1.6 E-1
Crude Oil	kg	1.8 E-1	1.6 E-1	1.6 E-1	1.7 E-1	1.6 E-1	1.5 E-1	9.6 E-2	9.5 E-2	6.2 E-2
Peat	kg	2.5 E-5	8.0 E-6	8.0 E-6	1.1 E-5	1.1 E-5	1.1 E-5	1.2 E-5	1.2 E-5	1.2 E-5
Uranium	kg	1.1 E-5	1.0 E-5	9.9 E-6	1.7 E-5	1.6 E-5	1.6 E-5	1.6 E-6	1.6 E-6	1.5 E-6
Aluminium	kg	9.3 E-3	9.3 E-3	9.3 E-3	4.2 E-3	4.2 E-3	4.2 E-3	3.1 E-4	3.1 E-4	3.1 E-4
Basalt	kg	4.8 E-3	4.8 E-3	4.8 E-3	2.5 E-3	2.5 E-3	2.5 E-3	5.3 E-4	5.3 E-4	5.3 E-4
Chromium	kg	9.6 E-3	9.6 E-3	9.6 E-3	1.8 E-4	1.8 E-4	1.8 E-4	7.7 E-5	7.7 E-5	7.7 E-5
Clay	kg	1.0 E-1	1.0 E-1	1.0 E-1	2.1 E-1	2.1 E-1	2.1 E-1	1.3 E-2	1.9 E-3	1.9 E-3
Copper	kg	6.9 E-1	6.9 E-1	6.9 E-1	4.2 E-4	4.2 E-4	4.2 E-4	8.8 E-5	1.1 E-5	1.1 E-5
Dolomite	kg	1.1 E-4	6.3 E-5	1.1 E-4	4.2 E-5	4.2 E-5	4.2 E-5	8.0 E-6	8.0 E-6	8.0 E-6
Granite	kg	2.3 E-7	2.3 E-7	2.3 E-7	5.1 E-7	5.1 E-7	5.1 E-7	5.0 E-8	5.0 E-8	5.0 E-8
Gravel	kg	8.1 E-1	8.1 E-1	8.1 E-1	5.8 E0	5.8 E+0	5.8 E+0	6.8 E-1	6.8 E-1	6.8 E-1
Gypsum	kg	8.2 E-7	8.2 E-7	8.2 E-7	2.9 E-7	2.9 E-7	2.9 E-7	1.0 E-6	1.0 E-6	1.0 E-6
Iron	kg	3.5 E-2	3.5 E-2	3.5 E-2	1.5 E-1	1.5 E-1	1.5 E-1	3.4 E-3	3.4 E-3	3.4 E-3
Lead	kg	1.8 E-4	1.8 E-4	1.8 E-4	9.1 E-4	9.1 E-4	9.1 E-4	8.3 E-5	8.3 E-5	8.3 E-5
Sand	kg	1.1 E-5	1.1 E-5	1.1 E-5	6.6 E-6	6.6 E-6	6.6 E-6	2.6 E-7	2.6 E-7	2.6 E-7
Zinc	kg	3.1 E-4	3.1 E-4	3.1 E-4	1.6 E+0	1.6 E+0	1.6 E+0	1.1 E-4	1.1 E-4	1.1 E-4

Table 11-8: Specific demand for material resources of the investigated technologies scenarios for the time horizons 2007 and 2015

$\left[\frac{kg}{kWh_e} \right]$	2007		2015							
	PCC	IGCC	PCC	PCC	PCC	IGCC	IGCC	IGCC	Oxy-fuel	Oxy-fuel
CCS	with-out	with-out	with-out	with / pip.	with / ship	with-out	with / pip.	with / ship.	with / pip.	with / ship
Aluminium	7.5 E-5	8.2 E-5	9.8 E-5	1.3 E-4	1.2 E-4	9.8 E-5	1.1 E-4	1.1 E-4	1.2 E-4	1.2 E-4
Basalt	1.1 E-5	9.3 E-6	1.2 E-5	1.5 E-5	1.6 E-5	9.4 E-6	1.1 E-5	1.2 E-5	1.4 E-5	1.5 E-5
Chromium	1.6 E-5	1.4 E-5	1.7 E-5	2.4 E-5	2.4 E-5	1.5 E-5	1.8 E-5	1.9 E-5	2.2 E-5	2.3 E-5
Clay	6.7 E-4	7.2 E-4	7.4 E-4	9.6 E-4	1.4 E-3	7.5 E-4	8.7 E-4	1.4 E-3	9.1 E-4	1.6 E-3
Copper	9.6 E-6	1.2 E-5	1.1 E-5	1.5 E-5	1.5 E-5	1.3 E-5	1.6 E-5	1.7 E-5	1.3 E-5	1.4 E-5
Dolomite	2.9 E-6	3.1 E-6	3.5 E-6	5.3 E-6	5.3 E-6	3.5 E-6	4.6 E-6	4.8 E-6	5.1 E-6	5.4 E-6
Granite	4.0 E-9	4.1 E-9	5.2 E-9	6.7 E-9	6.9 E-9	4.9 E-9	5.8 E-9	6.1 E-9	6.5 E-9	7.1 E-9
Gravel	2.8 E-2	2.9 E-2	3.5 E-2	4.8 E-2	4.9 E-2	3.4 E-2	4.1 E-2	4.4 E-2	4.6 E-2	5.1 E-2
Gypsum	1.1 E-7	1.1 E-7	1.1 E-7	1.4 E-7	1.6 E-7	9.9 E-8	1.1 E-7	1.4 E-7	1.1 E-7	1.4 E-7
Iron	1.2 E-3	1.3 E-3	1.5 E-3	2.2 E-3	2.2 E-3	1.5 E-3	2.0 E-3	2.1 E-3	2.2 E-3	2.3 E-3
Lead	4.5 E-6	4.7 E-6	5.7 E-6	8.7 E-6	7.8 E-6	5.5 E-6	7.6 E-6	7.1 E-6	8.7 E-6	8.0 E-6
Sand	2.3 E-8	2.4 E-8	2.8 E-8	4.9 E-7	7.4 E-7	2.7 E-8	2.9 E-7	4.7 E-7	2.4 E-7	5.7 E-7
Zinc	2.0 E-6	2.1 E-6	2.5 E-6	3.3 E-6	3.2 E-6	2.4 E-6	2.8 E-6	2.9 E-6	3.1 E-6	3.3 E-6

Table 11-9: Specific demand for material resources of the investigated technologies for the time horizons 2025 and 2050

$\left[\frac{kg}{kWh_e} \right]$	2025					2050				
	PCC	PCC	IGCC	IGCC	Oxy-fuel	PCC	PCC	IGCC	IGCC	Oxy-fuel
CCS	with-out	with / pip.	with-out	with / pip.	with / pip.	with-out	with / pip.	with-out	with / pip.	with / pip.
Aluminium	1.1 E-4	1.2 E-4	1.0 E-4	1.2 E-4	1.2 E-4	9.9 E-5	1.1 E-4	9.8 E-5	1.1 E-4	1.1 E-4
Basalt	1.2 E-5	1.4 E-5	9.4 E-6	1.1 E-5	1.4 E-5	1.1 E-5	1.3 E-5	9.1 E-6	1.0 E-5	1.3 E-5
Chromium	1.7 E-5	2.3 E-5	1.5 E-5	1.8 E-5	2.2 E-5	1.6 E-5	2.0 E-5	1.4 E-5	1.7 E-5	2.1 E-5
Clay	7.6 E-4	9.2 E-4	7.4 E-4	8.6 E-4	9.1 E-4	7.1 E-4	8.2 E-4	7.1 E-4	8.0 E-4	8.4 E-4
Copper	1.1 E-5	1.4 E-5	1.3 E-5	1.6 E-5	1.3 E-5	1.1 E-5	1.3 E-5	1.3 E-5	1.6 E-5	1.3 E-5
Dolomite	3.8 E-6	5.2 E-6	3.5 E-6	4.7 E-6	5.2 E-6	3.5 E-6	4.6 E-6	3.4 E-6	4.4 E-6	4.9 E-6
Granite	5.6 E-9	6.7 E-9	5.1 E-9	5.9 E-9	6.8 E-9	5.2 E-9	6.0 E-9	4.8 E-9	5.5 E-9	6.3 E-9
Gravel	3.8 E-2	4.7 E-2	3.5 E-2	4.2 E-2	4.7 E-2	3.5 E-2	4.1 E-2	3.3 E-2	3.9 E-2	4.3 E-2
Gypsum	1.1 E-7	1.3 E-7	9.6 E-8	1.1 E-7	1.0 E-7	1.1 E-7	1.2 E-7	9.4 E-8	1.0 E-7	1.0 E-7
Iron	1.6 E-3	2.2 E-3	1.6 E-3	2.0 E-3	2.2 E-3	1.5 E-3	2.0 E-3	1.5 E-3	1.9 E-3	2.1 E-3
Lead	6.1 E-6	8.5 E-6	5.7 E-6	7.6 E-6	8.8 E-6	6.4 E-6	8.4 E-6	6.4 E-6	8.2 E-6	8.9 E-6
Sand	2.9 E-8	5.0 E-7	2.7 E-8	2.9 E-7	2.6 E-7	2.7 E-8	5.3 E-7	2.6 E-8	3.2 E-7	3.3 E-7
Zinc	2.7 E-6	3.2 E-6	2.5 E-6	2.9 E-6	3.2 E-6	2.5 E-6	2.9 E-6	2.4 E-6	2.7 E-6	3.0 E-6

Table 11-10: Specific demand for energy resources of the investigated technologies for the time horizons 2007 and 2015

$\left[\frac{kg}{kWh_e} \right]$	2007		2015							
	PCC	IGCC	PCC	PCC	PCC	IGCC	IGCC	IGCC	Oxy-fuel	Oxy-fuel
CCS	with-out	with-out	with-out	with / pip.	with / ship	with-out	with / pip.	with / ship.	with / pip.	with / ship
Lignite	4.3 E-3	4.4 E-3	5.5 E-3	1.1 E-2	1.8 E-2	5.2 E-3	1.0 E-2	1.7 E-2	1.2 E-2	2.2 E-2
Hard coal	3.0 E-1	3.1 E-1	3.0 E-1	3.8 E-1	3.6 E-1	2.8 E-1	3.2 E-1	3.2 E-1	3.6 E-1	3.6 E-1
Natural gas	1.4 E-3	1.4 E-3	1.8 E-3	2.9 E-3	3.8 E-3	1.7 E-3	2.5 E-3	3.5 E-3	2.9 E-3	4.2 E-3
Crude oil	5.9 E-3	6.1 E-3	8.0 E-3	1.0 E-2	1.2 E-2	7.5 E-3	8.7 E-3	1.1 E-2	9.8 E-3	1.3 E-2
Peat	8.7 E-8	8.9 E-8	1.1 E-7	2.1 E-7	1.6 E-7	1.1 E-7	1.9 E-7	1.4 E-7	2.2 E-7	1.6 E-7
Uranium	2.1 E-7	2.2 E-7	2.7 E-7	4.0 E-7	4.9 E-7	2.6 E-7	3.5 E-7	4.4 E-7	4.1 E-7	5.3 E-7

Table 11-11: Specific demand for energy resources of the investigated technologies for the time horizons 2025 and 2050

$\left[\frac{kg}{kWh_e} \right]$	2025					2050				
	PCC	PCC	IGCC	IGCC	Oxy-fuel	PCC	PCC	IGCC	IGCC	Oxy-fuel
CCS	with-out	with / pip.	with-out	with / pip.	with / pip.	with-out	with / pip.	with-out	with / pip.	with / pip.
Lignite	5.8 E-3	1.2 E-2	5.3 E-3	1.1 E-2	1.4 E-2	5.4 E-3	1.2 E-2	5.0 E-3	1.1 E-2	1.4 E-2
Hard coal	3.0 E-1	3.5 E-1	2.7 E-1	3.1 E-1	3.5 E-1	2.8 E-1	3.1 E-1	2.6 E-1	2.8 E-1	3.2 E-1
Natural gas	1.9 E-3	2.9 E-3	1.8 E-3	2.5 E-3	2.9 E-3	1.8 E-3	2.4 E-3	1.7 E-3	2.3 E-3	2.6 E-3
Crude oil	8.7 E-3	1.0 E-2	7.9 E-3	9.1 E-3	1.0 E-2	8.0 E-3	9.0 E-3	7.5 E-3	8.4 E-3	9.4 E-3
Peat	1.2 E-7	2.1 E-7	1.1 E-7	1.8 E-7	2.2 E-7	1.1 E-7	1.9 E-7	1.0 E-7	1.7 E-7	2.1 E-7
Uranium	3.0 E-7	3.5 E-7	2.7 E-7	3.1 E-7	3.5 E-7	2.7 E-7	3.1 E-7	2.6 E-7	2.9 E-7	3.2 E-7

Table 11-12: Specific emissions into air of the investigated technologies for the time horizons 2007 and 2015

$\left[\frac{kg}{kWh_e} \right]$	2007		2015							
	PCC	IGCC	PCC	PCC	PCC	IGCC	IGCC	IGCC	Oxy-fuel	Oxy-fuel
CCS	with-out	with-out	with-out	with / pip.	with / ship	with-out	with / pip.	with / ship.	with / pip.	with / ship
CO ₂	7.5 E-1	7.7 E-1	7.5 E-1	1.7 E-1	1.8 E-1	7.1 E-1	1.4 E-1	1.6 E-1	1.0 E-1	1.3 E-1
CO	2.5 E-4	1.3 E-4	2.8 E-4	3.6 E-4	3.6 E-4	1.5 E-4	1.8 E-4	1.9 E-4	1.9 E-4	2.0 E-4
SO ₂	7.7 E-4	2.6 E-4	5.7 E-4	4.2 E-4	4.2 E-4	3.1 E-4	3.6 E-4	3.7 E-4	3.9 E-4	4.2 E-4
NO _x	9.1 E-4	5.0 E-4	7.7 E-4	7.3 E-4	8.0 E-4	5.3 E-4	6.1 E-4	7.1 E-4	6.4 E-4	7.7 E-4
NM VOC	5.5 E-5	5.0 E-5	7.0 E-5	9.0 E-5	9.5 E-5	6.0 E-5	6.9 E-5	7.7 E-5	7.1 E-5	8.3 E-5
PM _{2.5}	1.5 E-5	1.6 E-5	2.9 E-5	2.6 E-5	2.8 E-5	1.9 E-5	2.2 E-5	2.5 E-5	2.5 E-5	2.9 E-5
PM ₁₀	6.6 E-5	4.1 E-5	6.5 E-5	8.5 E-5	8.4 E-5	5.0 E-5	5.9 E-5	6.1 E-5	6.6 E-5	7.0 E-5
CH ₄	2.5 E-3	2.6 E-3	1.8 E-3	2.4 E-3	2.3 E-3	1.7 E-3	2.0 E-3	2.0 E-3	2.2 E-3	2.3 E-3
N ₂ O	3.3 E-5	3.2 E-5	3.3 E-5	4.2 E-5	4.1 E-5	3.0 E-5	3.4 E-5	3.5 E-5	4.5 E-6	6.2 E-6

Table 11-13: Specific emissions into air of the investigated technologies for the time horizons 2025 and 2050

$\left[\frac{kg}{kWh_e} \right]$	2025					2050				
	PCC	PCC	IGCC	IGCC	Oxy-fuel	PCC	PCC	IGCC	IGCC	Oxy-fuel
CCS	with-out	with / pip.	with-out	with / pip.	with / pip.	with-out	with / pip.	with-out	with / pip.	with / pip.
CO ₂	7.5 E-1	1.6 E-1	6.8 E-1	1.4 E-1	1.1 E-1	6.9 E-1	1.4 E-1	6.4 E-1	1.3 E-1	8.9 E-2
CO	2.9 E-4	3.5 E-4	1.6 E-4	1.9 E-4	2.0 E-4	2.7 E-4	3.0 E-4	1.5 E-4	1.7 E-4	1.8 E-4
SO ₂	5.1 E-4	4.2 E-4	3.1 E-4	3.6 E-4	4.1 E-4	3.7 E-4	3.7 E-4	3.0 E-4	3.3 E-4	3.8 E-4
NO _x	7.4 E-4	7.3 E-4	5.4 E-4	6.2 E-4	6.7 E-4	5.9 E-4	6.3 E-4	5.1 E-4	5.7 E-4	6.1 E-4
NM VOC	7.5 E-5	8.9 E-5	6.2 E-5	7.1 E-5	7.5 E-5	6.9 E-5	7.8 E-5	5.9 E-5	6.6 E-5	6.8 E-5
PM _{2.5}	2.1 E-5	2.6 E-5	1.9 E-5	2.3 E-5	2.6 E-5	1.9 E-5	2.9 E-5	1.8 E-5	2.1 E-5	2.4 E-5
PM ₁₀	7.4 E-5	8.4 E-5	5.2 E-5	6.1 E-5	7.0 E-5	5.9 E-5	7.4 E-5	4.9 E-5	5.6 E-5	6.3 E-5
CH ₄	1.6 E-3	1.9 E-3	1.4 E-3	1.7 E-3	1.9 E-3	1.5 E-3	1.6 E-3	1.4 E-3	1.5 E-3	1.7 E-3
N ₂ O	3.3 E-5	3.9 E-5	2.9 E-5	3.3 E-5	4.7 E-6	3.0 E-5	3.4 E-5	2.7 E-5	3.0 E-5	4.3 E-6

Table 11-14: Specific external costs of the investigated technologies for the time horizons 2007 and 2015

$\left[\frac{€}{MWh_e} \right]$	2007		2015							
	PCC	IGCC	PCC	PCC	PCC	IGCC	IGCC	IGCC	Oxy-fuel	Oxy-fuel
CCS	with-out	with-out	with-out	with / pip.	with / ship	with-out	with / pip.	with / ship.	with / pip.	with / ship
Human health	1.6 E+1	7.8 E+0	1.3 E+1	1.2 E+1	1.3 E+1	8.6 E+0	1.0 E+1	1.1 E+1	1.1 E+1	1.2 E+1
Loss of Bio-diversity	1.9 E+0	1.0 E+0	1.6 E+0	1.5 E+0	1.6 E+0	1.1 E+0	1.3 E+0	1.4 E+0	1.4 E+0	1.6 E+0
Crop loss	1.1 E-2	5.4 E-2	3.2 E-2	6.1 E-2	9.6 E-2	4.3 E-2	4.9 E-2	8.4 E-2	3.4 E-2	8.3 E-2
Material Damage	4.3 E-1	1.6 E-1	3.3 E-1	2.5 E-1	2.6 E-1	1.9 E-1	2.2 E-1	2.3 E-1	2.3 E-1	2.6 E-1
Climate Change	1.6 E+1	1.6 E+1	1.5 E+1	4.4 E+0	4.6 E+0	1.4 E+1	3.7 E+0	4.1 E+0	2.9 E+0	3.5 E+0

Table 11-15: Specific external costs of the investigated technologies for the time horizons 2025 and 2050

$\left[\frac{€}{MWh_e} \right]$	2025					2050				
	PCC	PCC	IGCC	IGCC	Oxy-fuel	PCC	PCC	IGCC	IGCC	Oxy-fuel
CCS	with-out	with / pip.	with-out	with / pip.	with / pip.	with-out	with / pip.	with-out	with / pip.	with / pip.
Human health	1.4 E+1	1.4 E+1	1.0 E+1	1.2 E+1	1.3 E+1	1.1 E+1	1.2 E+1	9.5 E+0	1.1 E+1	1.2 E+1
Loss of Bio-diversity	1.5 E+0	1.4 E+0	1.1 E+0	1.2 E+0	1.4 E+0	1.2 E+0	1.3 E+0	1.0 E+0	1.1 E+0	1.2 E+0
Crop loss	1.2 E-2	6.5 E-2	4.4 E-1	5.0 E-2	3.8 E-2	2.1 E-2	5.8 E-2	4.2 E-2	4.7 E-2	3.5 E-2
Material Damage	2.9 E-1	2.5 E-1	1.9 E-2	2.2 E-1	2.5 E-1	2.2 E-1	2.2 E-1	1.8 E-1	2.0 E-1	2.2 E-1
Climate Change	1.7 E+1	4.4 E+0	1.5 E+1	3.9 E+0	3.1 E+0	4.0 E+1	9.9 E+0	3.7 E+1	9.1 E+0	6.7 E+0

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