Modelling approaches to assess and design the deployment of CO_2 capture, transport, and storage

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Modelling approaches to assess and design the deployment of CO_2 capture, transport, and storage

Modelleermethodes voor evaluatie en ontwerp van CO_2 afvangst, transport en opslag

(met een samenvatting in het Nederlands)

Proefschrift

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Contents

Abbreviations

ASU	Air separation unit
AZEP	Advanced Zero Emission Power plant
CATO	CO_2 Capture, transport, and Storage (in Dutch)
CBS	Statistics Netherlands
CC	CO_2 Capture
CCC	Carbon Constraint scenario in the WETO-H2 study (2006)
CCS	CO_2 Capture, transport, and Storage
CCR	CO_2 Capture Ratio
CHP	Combined Heat and Power generation plant
CMU	Carnegie Mellon University
COE	Levelised Cost Of Electricity
CPB	Netherlands Bureau for Economic Policy Analysis
CRRF	Capture Ready RetroFit
ECBM	Enhanced Coalbed Methane Recovery
EIA	Energy Information Administration in the United States
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute
ESP	ElectroStatic Precipitator
ETS	Greenhouse gas Emission allowance Trading Scheme
EU	European Union
FCF	Fixed Charge Factor
Ft	Terrain Factor
FGD	Flue Gas Desulphurisation
GE	General Electric Company
GHG	GreenHouse Gases
GIS	Geographic Information System
GTCC	Gas Turbine Combined Cycle power block
HRSG	Heat Recovery Steam Generator
HHV	Higher Heating Value
IEA	International Energy Agency
IEA-GHG	International Energy Agency Greenhouse Gas R&D programme
IECM	Integrated Environmental Control Model
IGCC	Integrated coal (with possibly biomass) gasification Combined Cycle power plant
IGCC-CC	Integrated coal (with possibly biomass) Gasification Combined Cycle power plant, with pre-combustion CO_2 Capture
IPCC	Intergovernmental Panel on Climate Change
LHV	Lower Heating Value
LWR	Light Water Reactor
MARKAL	(Acronym for Market Allocation), a linear optimisation energy bottom-up model generator
MEA	Monoethanolamine

NEMS	the National Energy Modelling System at the US Energy Information Administration
NGCC	Natural Gas Combined Cycle power plant
NGCC-CC	Natural Gas Combined Cycle power plant with post-combustion CO_2 capture
NL	The Netherlands
NPV	Net Present Value
NRW	North Rhein-Westfalian
O&M	Operating and Maintenance (non-fuel)
O&M&M	Operation, Maintenance, and Monitoring
PC	Pulverised Coal-fired power plant, with possibly co-firing of biomass
PC-CC	Pulverised Coal-fired power plant, with possibly co-firing of biomass with post-combustion CO_2 Capture
POLES	(Acronym for Prospective Outlook on Long-term Energy Systems), a partial equilibrium model
ppmv	Parts Per Million by Volume
PR	Progress Ratio
PV	Photovoltaic System
R&D	Research and Development,
RD&D	Research, Development and Demonstration
REF	Reference scenario in the WETO-H2 study (2006)
RES	Reference Energy System
RF	RetroFit
SCR	Selective Catalytic Reduction
SE	Strong Europe scenario
SEC-CC	Specific Energy Consumption of the CO_2 Capture process
SOFC-GT	Solid Oxide Fuel Cell with Gas Turbine
SPC	Supercritical Pulverized Coal-fired power plant
SRES	Special Report on Emissions Scenarios, published by IPCC (2000)
TCR	Total Capital Requirement
TIT	Turbine Inlet Temperature
T&S	Transport and Storage
UU	Utrecht University
UK	United Kingdom
US	United States
WEO	World Energy Outlook, published annually by IEA (each year)
WETO-H2	A study of the European Commission: World Energy Technology Outlook (2006)
WGS	Water Gas Shift reaction
WLO	Welfare, Prosperity, and Quality of the Living Environment report (in Dutch, 2006)

Chapter 1
Introduction

1.1 Background

The United Nations Framework Convention on Climate Change signed by 165 countries is stating that stabilisation of greenhouse gas concentrations in the atmosphere needs to be achieved at a level that would prevent dangerous anthropogenic interference with the climate system (UN, 1992). Based on scientific assessments of dangerous anthropogenic interferences for different temperature increases (IPCC, 2001; IPCC, 2007a; Climate congress, 2009; Smith et al., 2009), public institutions have set targets for a maximum increase of the mean global temperature. The European Union (European Union, 2007) and the Conference of the Parties (COP), which is responsible for the international efforts to implement the UNFCC (COP15, 2009), aim to keep global temperature increase below 2°C.[1]

To keep temperature increase between 2-2.4°C above pre-industrial level, it is estimated that GHG emissions have to stabilise at 445-490 parts per million CO_2-equivalent (IPCC, 2007b). This requires greenhouse gas (GHG) emissions to be cut back with 50-85% annually in 2050 compared to the 2000 level (IPCC, 2007b). Also, the need to take stringent measures in the short term has been stressed by several studies. For instance, Meinshausen et al. (2009) put a limit to the cumulative amount of CO_2 emitted in the period 2009-2050 of around 700 $GtCO_2$. This requires already significant GHG emission reduction in the near future. If global GHG emissions are more than 25% above 2000 levels in 2020, they indicate that 2°C increase (above pre-industrial level) is very likely to be exceeded[2].

According to many scenario studies, a portfolio of technologies will be needed to achieve very large GHG emission reduction. One technology that could be included in such a portfolio is CO_2 capture and storage (CCS), defined as the separation of CO_2 from industrial and energy-related sources, transport of the CO_2 to an (underground) storage site, and long-term isolation of the CO_2 from the atmosphere (IPCC, 2005). CCS can significantly cut back CO_2 emissions from burning carbon-containing fuels. These fuels, especially fossil fuels, are expected to dominate the primary energy supply until at least the middle of the 21st century

[1] The EU explicitly compares the temperature of 2°C increase to pre-industrial levels. COP 15 did not provide a clear reference date, but most probably pre-industrial levels are used as a reference. The difference between the temperature of pre-industrial levels and of the period 1990-2000 is around 0.6°C (IPCC, 2007).
[2] In 2008, global CO_2 emissions from fossil fuels and the cement industry were already 25% higher than in 2000 (PBL, 2009).

(IPCC, 2005; IEA, 2009). The potential key role of CCS in national and global portfolios of mitigation measures has been made evident in several studies. For example, in the Energy Technology Perspectives study of the International Energy Agency (IEA, 2008), CCS contributes with around 20% to the total CO_2 emission reduction in 2050 in a scenario aiming at stabilisation of CO_2 concentration at 450 ppm. In a similar scenario in the World Energy Outlook 2009 of IEA, CCS contributes 10% to the CO_2 emission reduction in the global power sector in 2030 (IEA, 2009).

1.2 Gaps in knowledge

If CCS is to play a significant role in a national portfolio to reduce GHG emissions, in-depth knowledge is essential on how, when, where, and to what extent, CCS can contribute cost-effectively to CO_2 emission reduction (IEA, 2004). Energy modelling is a key tool to get quantitative answers to these questions. However, new or improved modelling approaches are required, because CCS distinguishes itself from other CO_2 mitigation technologies (e.g. solar power, wind power, co-firing of biomass) with respect to the following combination of aspects:

- It consists of a chain of activities: CO_2 capture at a CO_2 emission source, transport to a storage site, and storage in the underground. Therefore, introduction of CCS requires several pre-conditions to be fulfilled at the same time.
- It is not yet applied on a commercial scale. Consequently, its cost development is quite uncertain.
- It needs a dedicated infrastructure to connect CO_2 sources and CO_2 sinks at the right place and time.
- It has a trans-boundary scope. Neighbouring countries may cooperate in developing a CO_2 infrastructure in order to achieve economies of scale.
- Unlike other CO_2 emission reduction measures, its sole purpose is the reduction of CO_2 emissions. As a consequence, to realise CCS at large scale, specific policy measures may be required.

Below, it is described why these five specific characteristics of CCS need to be addressed using new or improved assessment tools.

Chain of activities

First, the chain-characteristic of CCS makes introduction of, for example, power plants with CCS more complicated than conventional power plants. Whether CCS is implemented on large scale depends on five conditions which should be fulfilled at the same time. First, appropriate climate policy should be in place before energy companies will invest in power plants with CCS. Next, CCS must be a cost-effective technology. In addition, CO_2 transport infrastructure must have been built. Also, CO_2 sinks must be available over time. Finally, there should be a need for new power plants on which CCS can be implemented on a large scale, although retrofitting existing plants might also be an option. Most global, regional, and national studies do not analyse in detail nor in a dynamic way, how the development of CCS depends on these conditions. In general, global or regional studies are not able to address them, because data are dealt with at a low spatial resolution, see e.g. (IEA, 2004; IPCC, 2005; Odenberger et al., 2009). National studies often take into account only some of the conditions. They focus, for example, on the total potential of CCS, on a development pathway of CCS, or on the CO_2 storage potential (Menkveld, 2004; Marsh, 2005; Praetorius and Schumacher, 2009; Bistline and Rai, 2010). An assessment taking into account all conditions in an integrated manner would support CCS planning activities better.

Uncertain development of the costs of CO_2 capture technology

Secondly, the development of the costs of CO_2 capture technology is quite uncertain as power and industrial plants with CCS are new in the energy system. A common way to estimate such cost development is to use the concept of experience curves, e.g. (McDonald and Schrattenholzer, 2001). This concept is based on the empirically observed phenomenon that unit costs often tend to decline by a constant percentage for each doubling of produced or installed capacity. Applying this method to CO_2 capture asks for several innovations. First, this method is usually applied to identify and estimate the reduction of capital costs of energy technologies. For technologies for which the capital costs are indeed the decisive factor, like wind turbines (Junginger, 2005) and photovoltaic (Zwaan and Rabl, 2003), cost developments of power generation can thus be estimated. However, in the case of power plants with CCS, not only developments on capital costs, but also improvements in the power plant efficiency and the energy requirements of the CO_2 capture process can have a significant impact on cost developments. In recent studies this has not sufficiently been taken into account (Riahi et al., 2004; Rubin, 2007). Therefore, it is important to get insights into the future trends of capital cost as well as performance variables. In addition, because components of power plants with CCS (e.g. combined cycle power block, CO_2 post-combustion capture unit) can be found in different types of power plants (Rubin, 2007), cost reductions and performance improvements as a function of time will depend on the capacity

growth of all these power plants together. This spillover effect should be addressed. Finally, it is important to understand when technologies can become cost-effective due to learning in contrast to getting insight into specific learning rate figures. A solution is to combine learning rates with cumulative capacity projections, so that cost trends can be extrapolated into the future. This can be done in techno-economic models with endogenous learning and large geographical coverage[3] like the West European MARKAL model (Smekens, 2005), the global POLES model (EC, 2006), or the NEMS model of the US (EIA-DOE, 2006). However, studies that use these models do not report the cost reduction over time. Instead, they usually report the share of penetration of the different technologies. Consequently, data on cost reductions are not available for assessments at a regional or national level.

A dedicated infrastructure

Thirdly, large-scale implementation of CCS will require the development of *a dedicated infrastructure* to connect CO_2 sources and CO_2 sinks at the right place and time. Transport and storage are responsible for a relatively small share of total costs of CCS compared to capture of CO_2. Capture is expected to be responsible for 60-75% of CCS costs per tonne CO_2 avoided (IEA GHG, 2005; IPCC, 2005; Damen et al., 2009). However, transport and storage facilities are key requirements for the implementation of CCS. Thus, if required upfront investments for pipelines and storage facilities are delayed, because their future usage is uncertain, CCS deployment may be slowed down. A sound long term planning and design of these infrastructures may help to overcome these barriers. For planning and design it is necessary to take into account developments of the energy system and industrial sector as well as timing and spatial aspects (i.e. when and where will CO_2 capture, transport, and storage take place), while at the same time assuring the cost-effectiveness of CCS. Most studies do not address all these aspects at once. For example, a number of studies cover routing of CO_2 pipelines, but do not match the availability of sources (the period when CO_2 capture units are operational at these sources) and the availability of sinks (the period when CO_2 can be stored in the sinks) over time (Christensen, 2004; IEA GHG, 2005; Geus, 2007; Middleton and Bielicki, 2009). These studies also exclude the development of the energy system as a whole, which can lead to new CO_2 sources. In quantitative energy scenario studies, the cost-effectiveness of CCS in the coming decades is assessed by comparing this option to other CO_2 emission reduction options (e.g. energy efficiency, renewables, nuclear). However, in these studies, location aspects are only addressed in a limited way, generally by assuming average transport and storage costs. In studies that dealing with both spatial aspects and CCS implementation pathways (Cremer, 2005; Damen et al., 2009), sinks and

[3] Because learning is often achieved at a global level nowadays.

sources are matched on a first-come-first-serve basis. Thus, the design of the infrastructure does not take into account long term CO_2 transport or storage requirements.

Trans-boundary scope

Fourthly, for the design of a national CO_2 infrastructure, it is important to take possible trans-boundary CO_2 flows into account. For example, for North West European countries, it could be an option to store their CO_2 in a very large formation under the North Sea, called the Utsira formation. This formation is located in the Norwegian part of the North Sea and has an estimated potential storage capacity of 42 Gt CO_2 (Bøe et al., 2002). Storage in this formation would require large investments in a major trunkline across the North Sea. Collecting CO_2 flows from different North West European countries could make such an investment more affordable. So far, most assessments of trans-boundary transport crossing the North Sea have concentrated on the use of CO_2 for enhanced oil recovery (EOR) to reduce CCS costs (Markussen, 2002; BERR, 2007; Hoog, 2008). However, recent analyses (Broek et al., 2008; Damen et al., 2009) show that CO_2 storage in very large geological storage reservoirs, can make CO_2 trans-boundary transport for the mere purpose of CO_2 storage an interesting option as well. Expanding the scope of analysis and modelling these potential flows can support the design of a trans-boundary CO_2 infrastructure which is ready to incorporate these flows in the future.

Sole purpose is CO_2 emission reduction

Finally, CCS is a technology whose only purpose is emission reduction. In contrary to other CO_2 emission reduction measures which clearly have other drivers and co-benefits, like energy saving and renewable energy that reduce dependency on (often imported) fossil fuels. This characteristic implies that specific policy measures, such as a GHG emission trading system, are required to realise CCS at large scale. So far, the European Union (EU) has enabled CCS as a CO_2 reduction technology under the Directive for the Geological Storage of CO_2 (European Union, 2009c). The EU also adapted a directive that regulates the GHG emission allowance trading scheme (EU-ETS) so that the deployment of CCS on a commercial scale can be driven (ultimately) by a CO_2 price (European Union, 2009b)[4]. However, it is uncertain whether such a trading system (or a global emission allowance trading scheme) leads to sufficiently high CO_2 prices and stable investment environment for CCS deployment at large scale[5]. In addition, the EU has a renewable energy target of 20% in 2020 of total EU

[4] CO_2 emissions captured, transported and safely stored will be considered as not emitted under the EU ETS, but allowances will have to be surrendered for any leakage.

[5] The price of the EU emission allowances fluctuated between 10 and 15 €/tCO_2 in 2009 (European Climate Exchange, 2010). In 2008 a higher figure of around 28 €/t CO_2 was achieved (Cozijnsen, 2010).

energy use (European Union, 2009a). While part of this target will be met through the 10% target for energy from renewable sources in transport in 2020, it is estimated that more than half of the 20% renewable energy target will come from EU-ETS sectors including the electricity sector (EC, 2008). This renewable energy target can lower the price of CO_2 emission allowances and thus decrease the market potential for CCS. This would happen if the renewable target goes without a cutback in the CO_2 emissions cap of the EU-ETS, and if it stimulates power producers to use more renewable energy sources than they would without such a target for renewables. In summary, the (uncertain) development of international climate policy is likely to have a major influence on the deployment of a key mitigation technologies and CCS in particular. Insights into this influence may help to formulate strategies and to design policies which lead to a CCS deployment trajectory as aimed for by different stakeholders at a regional or national scale, see e.g. (Rotterdam Climate Initiative, 2009).

Table 1 Research questions

	Content-related research questions	Modelling approach-related research questions	Chapters dealing with questions
I.	Could the key pre-conditions of CCS deployment be met at the same time (CO_2 capture and storage options available, CCS cost-effective, and transport infrastructure and climate policy in place)?	Can a bottom-up energy model integrate all relevant dynamic data regarding key pre-conditions for CCS deployment?	**2,** see also 3, 4, 5, and 6
II.	What could be the cost and performance developments of power plants with CCS?	Can the concept of experience curves be applied on cost as well as performance variables, incorporate learning spill-over effects, and be integrated with cumulative capacity projections to gain insights into the performance development of power plants with CCS?	**3**
III.	What could be the (optimal) design of large-scale CO_2 infrastructure taking into account location, and time-path of individual infrastructural elements?	Can a bottom-up energy model be integrated with a geographical information system (GIS) to model when and where it would be cost-effective to construct elements of a CO_2 infrastructure?	**4,** see also 5
IV	How could the design of a Dutch CO_2 infrastructure take into account trans-boundary CO_2 flows, for example, to store CO_2 in a very large formation under the North Sea?	Can trans-boundary CO_2 flows be included in a national bottom-up energy model to generate knowledge on the development of a national CO_2 infrastructure?	**5**
V.	What could be the impact of different international climate policies on the implementation of CCS in a national energy system?	Can general equilibrium models of the world economy and national bottom-up energy models be combined to analyse the impact of international climate policies on national CCS deployment?	**6**

1.3 Objective of thesis

The overall aim of this thesis is threefold. First to develop new and improved modelling approaches that overcome the gaps in knowledge and analysis capabilities as described above. Secondly, to provide quantitative insights into timing, spatial issues, costs, and investments in CCS deployment trajectories, taking the Netherlands as a case study. Finally, to demonstrate the usefulness of the model approaches developed in this thesis to assess and design future deployment of CCS.

The specific gaps in knowledge are subdivided into 5 content related and 5 modelling related research questions as presented in Table 1.

1.4 General approach and scope

For most part of this thesis, MARKAL (an acronym for MARKet ALlocation), a tool providing a technology-rich basis for estimating energy dynamics over a multi-interval period (Loulou et al., 2004), forms the basis of the modelling approaches. MARKAL is an internationally recognised model generator that was developed within the Energy Technology Systems Analysis Programme (ETSAP) and has been used in numerous studies, e.g. (Das and Ahlgren, ; Larson et al., 2003; Chen et al., 2007; IEA, 2008; Contreras et al., 2009). The focus in this thesis is on the electricity supply sector and the CO_2 intensive industry of the Netherlands. This is a suitable case study to study CCS deployment in detail for the following reasons: first, the small size of the Netherlands allows for a detailed assessment of deployment trajectories of CCS. Second, in the Netherlands many large CO_2 point sources in the power sector and industry (Damen et al., 2009) can be found close to each other. Thirdly, there is significant potential storage capacity onshore as well as offshore. Finally, the Netherlands has the potential to act as a CO_2 hub for neighbouring countries. This Dutch case or North West Europe case may be typical for other large industrial regions worldwide like the East coast of China, the south of the United States, and the San Paulo region in Brazil.

1.5 Outline of thesis

Chapter 2 presents a quantitative scenario study for the electricity and cogeneration sector in the Netherlands using MARKAL-NL-UU. This model is specifically developed for this research and is a dynamic bottom-up energy model with special CCS features generated with MARKAL. The focus of this chapter is on assessing how conditions essential for the introduction of CCS, occur at the same time. These conditions involve climate policy, the

need for new power plants, cost-effectiveness of CCS technology compared to competing CO_2 reduction options, and the availability of CO_2 transport infrastructure and CO_2 sinks.

In chapter 3 cost reductions and performance improvements are identified for different power plants and CCS technologies. Since the development of these power plants is closely related to that of their counterparts without CCS, these are also included in this analysis. In addition, this chapter demonstrates how experience curve models with projections of future global power plant capacity can be combined to derive pathway dependent estimates of future plant costs and CO_2 mitigation costs over time.

Chapter 4 describes the design of a toolbox which allows assessments of the spatially explicit development of a CO_2 infrastructure over time. This toolbox takes into account location, and time-path of individual infrastructural elements. It integrates ArcGIS, a geographic information system with spatial and routing functions, and MARKAL-NL-UU. Besides the electricity and cogeneration sector, also the CO_2 intensive industry is included in the analysis.

In chapter 5, the cost-effectiveness of applying CCS and storing the CO_2 in a very large formation under the North Sea around 800 km away from the Netherlands, is assessed by making use of the toolbox developed in chapter 4. This toolbox takes into account the competition with CO_2 storage in smaller onshore and nearby offshore formations, and the competition with other CO_2 mitigation options. Furthermore, the influence of CO_2 flows from neighbouring countries on the CO_2 infrastructure in the Netherlands is analysed.

In chapter 6, a general equilibrium model for global policy analysis applied by the Netherlands Bureau for Economic Policy Analysis (CPB), called WorldScan, is linked to MARKAL-NL-UU. The combined models are used to gain insights into impacts of a European or global emission trading system on the deployment of CCS in the Netherlands.

Finally, in chapter 7, the objectives, approaches, discussions, and results of this thesis are summarised. This chapter also highlights the findings in this thesis with respect to the five content-related and modelling approach related research questions, and suggestions for further research.

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Chapter 2

Planning for an electricity sector with carbon capture and storage, case of the Netherlands

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Abstract

Before energy companies will invest in power plants with CCS, appropriate climate policy should be in place, a need for new power plants must exist, CCS technology should be cost-effective, and CO_2 transport infrastructure and CO_2 sinks must be available. In order to get more grip on planning, we carried out a quantitative scenario study for the electricity and cogeneration sector in the Netherlands using the energy-bottom up model generated with MARKAL. We analysed strategies to realise a 15% and 50% reduction of CO_2 emissions in respectively 2020 and 2050 compared to the 1990 level. We found that, if nuclear energy is excluded as a mitigation option, CCS can be sufficiently cost-effective in 2020 to avoid 29 Mt/yr in 2020 in the Dutch electricity sector (which is half of the CO_2 emission abatement necessary in this year). We identified the following important factors for planning. In a postponement strategy in which CO_2 is reduced from 2020, CO_2 can be abated at less than 30€/t up to 2020. A gradual reduction of 2.5% annually from 2010, asks for a climate policy that makes expenditures possible of 50 €/t CO_2 before 2015. Construction of coal-fired power plants without CCS are preferably not built or, in the postponement strategy, only to a limited extent. Finally, early planning is required to realise the construction of a transport infrastructure with a length of around 450 km before 2020.

2.1 Introduction

Most scientists agree that CO_2 emissions need to be reduced worldwide by 30%-60% in 2050 compared to 2000 in order to keep CO_2 concentration in the atmosphere below 450 ppmv. This would keep temperature raise between 2.4 and 2.8°C compared to pre-industrialised levels (IPCC, 2007). Currently, the Kyoto Protocol states that the European Union (EU) should reduce its greenhouse gas (GHG) emissions by 8% in 2012 compared to 1990 level (UNFCCC, 1997). The EU considers a follow-up necessary and states that developed countries need to reduce greenhouse gas emissions by 30% in 2020 and 60% – 80% in 2050 compared to 1990. The EU is willing to commit to 30% reduction in 2020 if other developed countries also commit themselves to comparable emission reductions, and makes a firm independent commitment to achieve at least a 20% reduction compared to 1990 (EU, 2007a).

Carbon dioxide Capture and Storage (CCS) is a CO_2 abatement option that can contribute substantially to these ambitious targets. Especially the electricity sector, with large point sources of CO_2, offers opportunities to apply CCS at a large scale (IPCC, 2005). However, in the development towards an electricity sector with CCS, planning may be important. For example, an investment decision for a power plant with CCS will probably only be made if the following events coincide:

- new power plants are needed, because old power plants are dismantled or due to growth in electricity demand,
- climate policy which imposes restrictions on CO_2 emissions of power plants for at least the next decade, is in place,
- CCS is competitive (with or without external financial support) compared to other mitigation options,
- CO_2 transport infrastructure is available or construction of such an infrastructure can be built within the foreseeable future, and
- sinks in which the CO_2 can be stored are available.

In earlier studies estimates have been made about the extent to which CCS can contribute to a worldwide CO_2 reduction in certain regions and periods. For example, IPCC has shown that the economic global reduction potential of CCS may vary between 0-70 Gt CO_2/yr in 2050[1] (IPCC, 2005). The IEA expects this potential to be between 8-25 Gt CO_2/yr in 2050 (IEA, 2004). These worldwide studies cannot address specific planning issues with respect to the energy infrastructure, because data are dealt with at a low spatial resolution. However, studies at the national level also do not deal with planning sufficiently. The Department of Trade and Industry in the UK calculated the British CCS economic reduction potential to be

[1] The wide range is a consequence of using different SRES and different models.

between 50-180 Mt CO_2/yr for the period 2040-2050 (Marsh, 2005)[2]. The Energy research centre of the Netherlands (ECN) estimated this potential to be between 12-15 Mt in 2020 in the Dutch electricity sector (Daniëls, 2006). Another ECN study reports a technical potential of 46 Mt in 2050 in this sector (Menkveld, 2004)[3]. These national studies did not analyse how above described events can coincide, and thus do not provide insight whether it is difficult to realise these figures. And even when the studies show a growth pathway of the CCS potential, they do not investigate whether this potential matches the availability of sinks over time or how climate policy should evolve. The interaction between the dynamic factors that play an important role in CCS development remains obscure. Consequently, planning a CCS trajectory is not a straightforward task. To overcome this gap of knowledge, we, therefore, investigate the following research question: **How may a trajectory towards an electricity sector with CCS look like, and how does it depend on the events described above**? Answering this question may help to know to what extent planning is necessary and possible.

For this purpose, we carry out a scenario study in which we integrate and vary dynamic data on:

- Electricity demand development
- Data on costs and efficiencies of different CCS technologies and developments in these parameters
- Data on costs of transport and storage of CO_2
- The vintage structure of the electricity park
- The CO_2 storage potential and the timing when storage sites become available
- Climate policy reduction targets

We study the influence of dynamic data within a scenario that is characterised by international cooperation and social motivations. Scenario variants have been studied by building and running a model of the electricity and cogeneration supply sector of the Netherlands generated with MARKAL (MARKAL-NL-UU). This is an interesting sector for CCS deployment because the Netherlands has good CO_2 storage possibilities, and relatively short distances between large point sources and potential sinks for CO_2. Furthermore, because the Netherlands is a small country, it is considered a suitable region to study timing aspects in detail. In 2005, the Dutch electricity park had a total installed capacity of around 21.8 GWe

[2] This UK study used a detailed MARKAL model to estimate the CCS potential. It studied the consequences of timing on the development of CCS trajectories. However, it did not look at the consequences of timing of events such as sinks becoming available or decommissioning of existing power plants.
[3] CO_2 emissions from the Dutch public electricity and heat sector amounted to circa 55 Mt in 2003 (Klein Goldewijk, 2005).

consisting of 19% coal-fired plants, 47% central gas-fired, 2% nuclear, 23% gas-fired cogeneration, and 8% other (solar, wind, biomass-only, waste incineration). See for more details on the vintage structure section 2.3.5.

The structure of this paper is as follows. Details about the adopted methodology can be found in section 2. Section 3 deals with the input data. Results and discussion are presented in Section 4 and 5. Finally, in the last section conclusions are drawn with respect to CCS implementation trajectories. In this study, the costs are discounted back to the year 2000 with a discount rate of 5%, prices are given in $€_{2000}$ unless otherwise stated, and Mt always refers to Mt CO_2.

2.2 Methodology

2.2.1 Overview

In order to investigate CCS implementation trajectories, a quantitative analysis of a specific scenario for the electricity sector in the Netherlands is carried out. The focus of this study is on large scale production of electricity. We choose the scenario Strong Europe (SE) to investigate CCS trajectories. SE is one of the four scenarios recently developed by the Netherlands Bureau for Economic Policy Analysis (CPB)[4]. CPB formulated four qualitative storylines for Europe by highlighting two characteristics of the world[5]. The first characteristic deals with the extent to which international cooperation exists in the world versus a regional focus. The second characteristic makes a distinction between a social versus an individualistic-driven world. This resulted in four views of Europe, called Global Economy, Strong Europe (SE), Transatlantic Markets, and Regional Communities. SE is based on prevalence of international cooperation and social motivations (Mooij, 2003). SE creates an environment in which it is likely that international agreements regarding climate change are made. Since large scale implementation of CCS is likely to happen in this scenario, it is regarded as an appropriate scenario to work with in this study (see section 2.3.1 for relevant figures on SE).

[4] These scenarios were further quantified by CPB for Europe (Lejour, 2003), by CBS and RIVM-MNP for the Dutch demographic developments (Jong, 2004) and by CPB for the Dutch economy (Huizinga, 2004). In addition, the Strong Europe and Global Economy scenario were translated to energy scenarios for the Netherlands in Reference projections for 2005 - 2020 (Dril, 2005). In the Welfare and Environmental Quality report (Janssen et al., 2006), energy scenarios for 2000-2040 were constructed for all four scenarios.

[5] This is analogue to the way IPCC had developed its scenarios in the Special Report on Emission scenarios (IPCC, 2000).

We specify different variants of the SE scenario in order to explore the influence of two dynamic factors. First, since CCS is not a cost-effective technology without a climate policy being in place, we aim to study different emission reduction pathways in detail: a non-reduction variant, a DirectAction variant with CO_2 reduction targets from 2010 onwards, and a PostponedAction variant with targets from 2020 onwards. In this study we set a cap on the CO_2 emissions from electricity generation and cogeneration units[6]. We choose this sector cap so that the emissions will be reduced at a slightly more lenient rate (15% in 2020, 50% in 2050 compared to 1990) than the EU reduction ambition (20% in 2020, 60% in 2050 compared to 1990), because we consider the possibility that part of the emission reduction will take place abroad[7]. Secondly, the life time of power plants is varied from 30 years for power plants to 40 and 50 years for respectively gas- and coal-fired power plants. Life time is an important issue, because it may turn out to be much longer than is generally assumed, as is demonstrated in the liberalised energy markets in the United States (IEA, 2004). Thus, with the energy markets being liberalised in Europe, longer life spans should be taken into account.[8] The variation of these two factors results in six main variants (see Table 1).

We use the MARKAL-NL-UU technical economic model of the Dutch electricity and cogeneration supply sub-system to find the CCS deployment trajectory of each variant for the period 2000 to 2050. In this period CCS can develop from the research phase to a well-established commercial technology. The analysis is done at the 2050 time horizon with eleven five-year time step to provide sufficient insight into possible implementation trajectories of CCS. Apart from studying the effect of the CO_2 reduction targets and the life time of power plants, we also explore the influence of the following factors in a sensitivity analysis: energy prices, potential of competing technologies (cogeneration and nuclear), development rate of CCS technology, discount rate, and the strictness of climate reduction targets (see section 2.2.6).

[6] i.e. units in the public electricity and heat sector (including cogeneration units that are joint-ventures of public electricity companies and private industrial companies) and cogeneration units in other sectors (industry, commercial, and agricultural sector).

[7] Under the Kyoto protocol CO2 reductions in the Netherlands will be mainly realised by acquiring CO_2 rights abroad: in developing countries with Clean development mechanism projects and in central and eastern European countries with Joint implementation projects. This way, although the Dutch GHG emissions have to be reduced with 6% on average in the target period 2008-2012, the Dutch allocation plan allows a CO_2 emission increase from 158 Mt in 1990 to 186 Mt in the target period (VROM, 2004). Note that we also assume that the CO_2 reduction target will be evenly distributed over all sectors.

[8] Already the trend to extend the lifetime of power plants has started. The 11 large electricity producing units (>200 MWe) that have been decommissioned until now in the Netherlands had been operating during 24 years on average, while current units will probably operate for 32 years on average.

Table 1 Main characteristics of the variants of the SE scenario

Name	Vintage structure	Upper limit of CO_2 emissions in the power and heat sector compared to 1990[a] (in %)		
		2010	2020	2050
BAU NV	Power plants have a life time according to the plans[b] of utility companies or if plans are unkown life time is assumed to be 30 years (**Normal Vintage**). [c]	-	0	0
DirectAction NV		+9[d]	-15	-50
PostponedAction NV		-	-15	-50
BAU EV	Coal-fired power plants have a life time of 50 years and the gas-fired power plants of 40 years (**Extended Vintage**).[e]	-	0	0
DirectAction EV		+9 [d]	-15	-50
PostponedAction EV		-	-15	-50

[a] From the national greenhouse gas inventory report (Klein Goldewijk, 2005), we deduced that around 54 Mt of CO_2 was emitted from electricity generation and cogeneration units in 1990 (corresponding to 34% of the total national CO_2 emissions). This figure was not reported as a separate entity, but is the sum of 39.8 Mt (Public electricity and heat sector), 13 Mt (cogeneration industry), 0.4 Mt (cogeneration commercial sector), and 0.6 Mt (cogeneration agricultural sector).
[b] The average life time of the 20 current large units in the Dutch electricity park of which utility plans are known, will be on average 32 years (excluding the nuclear power plant).
[c] 1.1 GW of the capacity existing today will still be in place in 2035. In 2035 all existing power plants have been replaced.
[d] Emissions in the Dutch power and heat sector have increased by 24% in 2005 compared to 1990 due to the growth in electricity demand. Thus, an increase of +9% in 2010 compared to 1990 already requires an annual reduction of 2.5% from 2005.
[e] 6.7 GW of the capacity existing today will still be in place in 2035.

2.2.2 The MARKAL-NL-UU model

The MARKAL (an acronym for MARKet ALlocation) methodology provides a technology-rich basis for estimating energy dynamics over a multi-interval period (Loulou et al., 2004). It is an international recognised model generator that has been used in numerous studies. Typical examples are a study on energy technology strategies in China (Larson et al., 2003), a world-wide study on the potential of key energy technologies (IEA, 2006a), and a study on UK 60% CO_2 abatement scenarios (Strachan, 2007).

MARKAL generates economic equilibrium models formulated as linear (or non linear) mathematical programming problems. It calculates the technological configuration of an energy system by minimising the net present value of all energy system costs. Linear programming bases its decisions on ‘perfect foresight’, which means that the model can ‘look ahead’ to the end of the model period to find the least-cost energy configuration over the whole period. The energy system in MARKAL consists of two building elements: technologies and commodities. Commodities are energy carriers or materials. Technologies

convert commodities into other commodities. Commodities flow from one technology to another thus creating a network structure. The resulting Reference Energy System (RES) can be depicted as a network diagram. In this study, we use technologies that convert primary energy carriers (e.g. coal or gas) into final energy carriers (electricity and heat), and we modelled CO_2 transport and sink technologies.[9] The cost and performance characteristics of the technologies need to be specified as well as the costs and availability of primary energy resources. Values for these parameters should be given for each five-year time step in the model period. The energy system is optimised so that it can satisfy the annual energy demand (also an average figure for a five-year time interval) against the least cost.

Our MARKAL-NL-UU model of the Dutch electricity sector builds on the West European (WEU) MARKAL model developed by ECN (Smekens, 2005). This model deals with the pre-2004 EU-15 countries plus Norway, Iceland and Switzerland. This ECN model provides the RES as well as data on costs and performance of energy conversion and demand technologies.[10] In our model, all relevant data have been updated. This concerns data on large scale conversion technologies in the electricity sector, and CO_2 capture, transport, and storage technologies. Furthermore, the vintage structure of the Dutch electricity park, and the Dutch electricity and heat demand were specified.

The WEU MARKAL model can deal with endogenous learning (Seebregts, 2000). However, learning in energy technologies mostly takes place at world level whereas we focus on the Netherlands only. Therefore, our MARKAL-NL-UU model does not run with endogenous learning. Instead technology development is an exogenous input based on projections from literature. The improvement in cost and performance of technologies is implemented by specifying several variants of power plants for different points in time (2010, 2020, 2030, and 2040).

[9] Technologies that convert final energy carriers to energy services (e.g. the demand for lighting, cooling, or transport) can also be modelled in MARKAL. However, in this study we do not use this feature. Also technologies that convert energy carriers into materials or vice versa can be defined. We used this feature to model capture, transport, and storage of CO_2.

[10] The base data in the model is described in several publications of ECN: data on power plants can be found in (Lako, 1998), data on the use of biomass for energy in (Feber, 1999), data on CCS in (Smekens, 2005).

2.2.3 Scenario-driven parameters

Final electricity and heat demand

The total Dutch final demand for electricity as well as heat from cogeneration is the driving force in the model and is based on the SE scenario[11]. This demand includes the heat and electricity generated by decentralised cogeneration units and used at location. The final electricity and heat demand excludes transport losses. These losses are modelled separately for the centralised power plants.

In MARKAL the energy carriers, electricity and heat, are treated in a special way, since they are not easily stored. These energy carriers are tracked for different time-slices. Electricity demand is differentiated for the following six time-slices: day and night for summer, winter, and the intermediate period[12]. A reserve factor is used to take care that enough capacity is available to fulfil the peak demand. This reserve factor is also used to insure against possible electricity shortfalls due to uncertainties such as unplanned down time of equipment. Heat demand is differentiated for three time-slices: winter, summer, and the intermediate period.

2.2.4 Power plant technologies

Selection of technologies

A portfolio of power plant technologies is included in the model. A wide range of possible technologies is represented in the model by considering the following aspects:

- Fuel type: coal, gas, coal/biomass, biomass, solar, wind, and nuclear.
- State-of-the-art technologies and a diverse range of advanced technologies which are available from 2020, 2030, and 2040 onwards.
- With and without CO_2 capture technologies. CO_2 capture technologies which we include are post-combustion capture, pre-combustion capture, and retrofit of existing and new (capture-ready) power plants.[13]

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[11] It is outside the scope of this study to analyse whether the factors that influence the energy demand (e.g. economic or population growth) will change due to the CO_2 cap we introduce into the SE scenario.

[12] Summer goes from 1st of June to 1st of September, winter from 1st of December to 1st of March. Intermediate period is the remaining part of the year. The day-period covers the period from 7 to 23 hours and the night period from 23 to 7 hours.

[13] We assume that all new coal-fired power plants are built capture-ready. We define capture ready power plants as power plants for which small adaptations have taken place in the design and construction phase (without additional investment costs) to make it easier to add a capture unit later on. To model retrofit of power plants in MARKAL, two technologies need to be specified: a power plant technology plus a capture

Cost parameters

In order to make a fair comparison in the optimisation process, it is very important that the technology cost data in MARKAL refer to similar expenses (see Annex I for a description of the cost composition). Based on literature search, we specified for each technology the investment costs (€/kW), the fixed operating and maintenance (O&M) costs (€/kW), and the variable O&M costs without fuel expenses (€/kWh).

Life time of power plants

In MARKAL only one life time per technology can be specified. This life time represents both the economic and the technical life time. The economic life time determines over how many years the investment costs are spread. In the *EV* variants O&M costs are probably too low for old power plants, because MARKAL does not provide any feature to increase O&M costs with aging of power plants. However, with longer life times we simulate more according to reality when there are opportunities to invest in a completely new power plant.

Base load and flexible power plants

In MARKAL the operation pattern of power plants can be determined during a model-run, or it is indicated beforehand whether a power plant can provide base load power and/or peak load power. To overcome the limitation of six time-slices, we assume that all nuclear and coal/biomass-fired power plants (pulverised coal-fired power plants, PCs, as well as integrated coal-gasification combined cycle power plants, IGCCs) are operated in base load mode[14]. However, because coal-fired power plants could also be operated in a more flexible way, a sensitivity analysis is carried out on this input parameter (see section 2.2.6). Furthermore, the availability of renewable energy technologies (onshore and offshore wind turbines, and solar energy) needs to be specified per time-slice.

Deployment of competing CO_2 reduction technologies

The extent to which CCS competes with other technologies to reduce CO_2 emissions (such as cogeneration, nuclear and renewable energy) is analysed in broad outlines. In the main

technology. A user-constraint is added to assure that the capture technology only operates when the base plant is being operated.

[14] Coal fired power plants in the Netherlands used to operate in a flexible mode, even with a turn-down ratio of 20%. Due to low natural gas prices in the latest decennia, the natural gas combined cycle power plant power plants (NGCCs) were deployed in full load. However, with current high gas prices coal-fired power plants will preferably be operated in base load mode. Also power plants with CCS most likely provide base load power, because then the CO_2 emissions will be reduced to the highest degree. Furthermore, if a CCS plant with post combustion is turned down, the lower pressure may become too low for the regeneration of amines (Ploumen, 2006a).

variants the deployment of these competing technologies is based on data reported for the SE scenario in the study 'Welfare and Environmental Quality, a scenario study for the Netherlands in 2040' (WLO) (Janssen et al., 2006). In the sensitivity analysis it was explored to what extent these bounds on competing technologies influence the results (see section 2.2.6).

2.2.5 Transport and storage of CO_2

CO_2 pipelines

CO_2 transport cost data depend on the length and diameter of the pipeline (IEA GHG, 2005b; IPCC, 2005). The diameter depends on the desired flow rate of CO_2. Furthermore, also type of terrain matters, i.e. onshore transport is usually cheaper than offshore (IPCC, 2005). We explicitly model two transport alternatives:

- CO_2 is transported from a power plant to the vicinity of onshore or offshore reservoir(s) through a dedicated pipeline and then via a satellite line to a reservoir.
- It is transported from a power plant via a short connector pipeline to an onshore or offshore trunk line and then via a satellite line to a reservoir.

In this study choices had to be made with respect to distances and CO_2 flow rates that are appropriate for the Dutch situation. In a study about CO_2 transport in the vast US booster stations were not considered necessary (IEA GHG, 2005b). Following this example, we also assume that these will not be required in the Dutch situation, and are thus not included in the model. Because in the Netherlands onshore CO_2 transport may be rather expensive due to the large number of obstacles that may be encountered (Warmenhoven, 2006), a sensitivity analysis is done on the onshore transport costs (see section 2.2.6).

Sinks

In MARKAL-NL-UU we model five Dutch storage types: onshore and offshore empty gas/oil fields, onshore aquifers[15], and coal fields combined with enhanced coal bed methane production (ECBM). Most storage sites in the Netherlands do not have the potential to store the total emissions of a power plant over its whole life time[16] and are small compared to

[15] We do not consider offshore aquifer traps (TNO, 2007), because very little is known about these. This option will be interesting if one or more large offshore aquifers will be found.

[16] For example, you need more than 100 Mt CO_2 storage capacity for a 1000 MW coal-fired power plant with a life time of 30 years. Only one offshore and 6 onshore fields (including the Groningen gas field) have over 100 Mt of storage capacity.

some saline aquifers abroad[17]. Therefore, we also include the Norwegian Utsira aquifer as storage option in our model. For each Dutch storage type, we model an average sink technology (with an average size[18], average life time, average number of wells, average costs, etc.). We assume that reservoirs will be filled at maximum rate (limited by the number of wells and the maximum injection rate per well) and will thus be full after a limited number of years (we use this number as the life time of the storage type in MARKAL-NL-UU). Then a switch needs to be made to new reservoirs. Consequently, investments in new storage capacity will be a continuous process during the life of a power plant

We assume that 80% of the Dutch storage potential in the five storage types will be available for CO_2 storage. This way we take into account amongst others competing storage options such as natural gas storage[19] or the possibility that fields will not be fit for CO_2 storage due to safety risks. From the MARKAL-NL-UU model runs we acquire information on the required size and the type of CO_2 storage reservoirs over time. Next, if the model has chosen to store the CO_2 in gas fields, we verify whether these reservoirs are actually available at the right time. This verification step is not necessary when the CO_2 is stored in aquifers or coal bed layers, because they are available from the start. Finally, in the sensitivity analysis we analyse how important the availability of CO_2 storage in the Netherlands is for the competitiveness of CCS. For this purpose, we do a model run in which CO_2 can only be stored in an aquifer abroad.

2.2.6 Sensitivity analysis

A sensitivity analysis is carried out on one of the main reduction variants. For this purpose, we choose the *DirectAction EV* variant (see Table 1) with extended vintage and climate policy starting from 2010[20]. In the sensitivity analysis we are interested in the influence of two types of parameters. First, parameters which we expect to have a crucial role (such as energy prices, climate policy targets, and cost developments of competing technologies). Secondly, parameters that are relevant specifically for CCS (e.g. CCS development rate, transport costs,

[17] e.g. aquifers in the Bunter sandstone formation or in the Utsira formation in respectively the UK and the Norwegian part of the North Sea (Bentham, 2006)

[18] The average size per storage option is based on the total storage capacity divided by the number of reservoirs of this option.

[19] In the WLO report it is foreseen that around 2.7 billion m^3/yr of natural gas will be stored underground (Janssen et al., 2006).

[20] We choose this *DirectAction* variant, because the EU aims for a post-2012 climate regime (EU, 2007b). Thus it is likely that there will be new CO_2 reduction targets from 2012 onwards.

sink availability) in order to get more insight into important bottlenecks or stimuli in a CCS development trajectory.

Table 2 lists all sensitivity variants that are run with MARKAL-NL-UU. We look at two periods: the first period (2015 – 2030[21]) in which CCS could play an important role in the energy system (medium term) and the period (2035 – 2050) in which CCS could have settled as a mature technology in the energy system (the long term). We assess how the following three aspects differed from *DirectAction EV*:

- The three power plant technologies that produce the most electricity (on average) in the medium and long term. In this way we get insights whether the configuration of the electricity park really looks different.
- The average yearly amount of CO_2 stored in the medium and long term. This way we could verify how robust a CCS strategy might be.
- The objective function in order to asses to what extent the parameters influence the costs.

[21] When we mention a specific year like 2030 in relation to input or result data of the MARKAL model, we usually refer to the five-year time step '2030' starting halfway 2027 and ending halfway 2032. An input or result data for the year 2030 can be considered as an average figure for the five-year time step '2030'.

Table 2 List of categories and variants used in the sensitivity analysis

Category	Variant	Why
Capture of CO_2	Flexible-load operation	To asses to what extent more CCS would be deployed, if it can also be operated in a flexible mode.
	Slow development of CCS	CCS is not in a mature phase yet. The speed at which CCS develops with respect to costs and performance can be a determining factor.
Transport and storage	Storage abroad	It might be possible that many Dutch sinks are not available for storage, but storage abroad is available. We explored the consequences.
	Higher onshore transport costs	Onshore transport costs can be much higher than the default values because of art works.
Short term strategy of utilities	Almost half of the plans to build PCs and the IGCC plan are realised before 2012	Currently many plans exist to build coal-fired power plants. It is interesting to evaluate how much the results of the analysis change when these plans are actually realised
	Almost half of PC plans and the IGCC are realised before 2012, but with capture units.	It can be investigated how the results change when the new PCs will be immediately equipped with CCS.
Competition	Nuclear is allowed	It is important to explore to what extent nuclear competes with CCS.
	Nuclear is allowed, but with high waste fee	It is important to explore to what extent nuclear competes with CCS.
	Slow development of CCS plus nuclear	If the development of CCS is not as described in the base variant, it is especially interesting to analyse to what extent nuclear competes with CCS.
	Cogeneration may increase	It is important to explore to what extent cogeneration (without CCS) competes with CCS
	Higher onshore transport costs plus nuclear	If onshore transport costs are much higher, it is interesting to assess what happens when nuclear bound is released.
	Biomass price remains high	In the SE scenario the increasing demand for biomass may keep the biomass price high.
CO_2 targets	very strict climate policy	Since the EU opts for GHG reduction of 30% in 2030 and 80% in 2050 compared to 1990, we assess the consequences of such high CO2 reduction targets.
Economic	High discount rate	Studies have published evidence arguing that the discount rate is a very determinant factor.
	Coal price higher	In the main variants, especially IGCC-CCS power plants are used as a mitigation option. It is important to know how much this depends on the coal price.
	Gas and coal price higher	In the main variants, prices of natural gas and coal are lower than current prices. Therefore, also a variant is run with overall high energy prices.

2.3 DATA

2.3.1 Scenario-driven parameters

This section describes all scenario related inputs (see Table 4 for a summary).

Development of the final electricity demand

The demand for electricity and heat from 2000 to 2050 has to be determined outside the model and is based on GDP and demographic developments. For the SE scenario CPB projected that the Dutch economy would annually grow with 1.6% on average (Huizinga, 2004). Statistics Netherlands (CBS) and the Netherlands Environmental Assessment Agency (MNP) expect that in this scenario, the Dutch population will grow from 16.3 million people to 19.2 million in 2050 (Jong, 2004). The projected electricity demand for SE can be obtained from the WLO study (Janssen et al., 2006). This study assumes annual growth rates of 1.5% until 2020, and 0.8% until 2040. Next, the demand growth is extrapolated with 0.8% until 2050, resulting in an electricity demand of 175 TWh in the year 2050. The scenario characteristics are presented in Table 3 in relation to their historic developments.

Table 3 Characteristics of the Strong Europe scenario in the Netherlands

Population growth per year (%)		GDP growth per year (%)		Projected: final electricity growth per year (%)
Projected	Historic	Projected	Historic	
0.4 (2005- 2050)	0.6 (1980-2000)	1.6	2.6 (1971-2001)	1.5 (2005-2020) 0.8 (2020-2050)

Load curve of the electricity demand

Although the load duration curve could change over time, we assume in this paper that it will not[22]. Therefore, we use data for the years 2005-2006 (TenneT, 2006b) to generate the load duration curve for the whole study period (2000-2050). Because TenneT provides data at a rather detailed level (for each quarter of an hour), and we only have 6 time-slices in our

[22] In 1990, van Wijk also presented a load duration curve for the Netherlands based on 1987 data (Wijk, 1990). This curve looks quite similar as the load duration curve based on 2006 data. We consider, therefore, a reasonable assumption that the curve does not change over time.

model, aggregation was necessary. Figure 1 presents the load duration curve per quarter-hourly and per MARKAL time-slice. The step downwards just before 6000 hours in the right picture is caused by the difference in average daily and nightly load. Because we use the aggregated load duration curve, we use the reserve factor to take care that an extra 20% of capacity will be built to address the peak demand[23]. Furthermore, in the Netherlands, usually a reserve capacity above the maximum peak load of around 20% is used to meet contingencies (Scheepers, 2004). By adding these two elements, we arrive at a reserve factor of 40%.

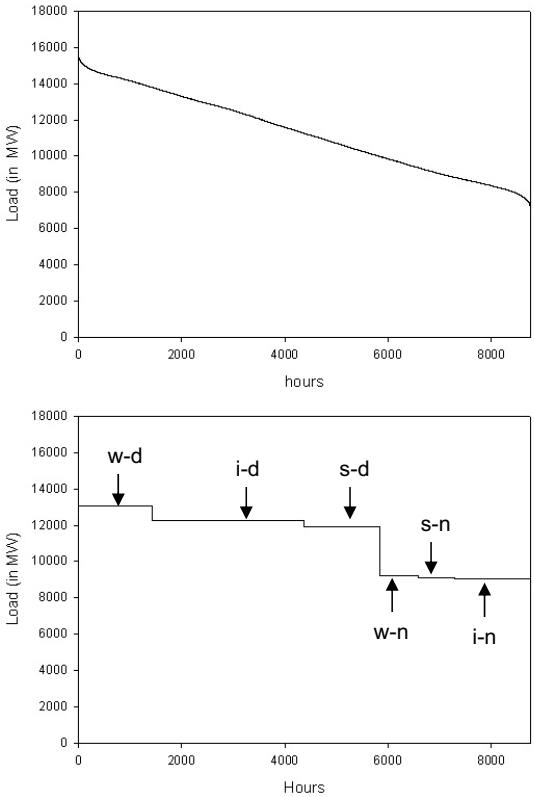

Figure 1 Yearly load duration curve sampled per 15 minutes (a) and per MARKAL time-slice (b) i=intermediate (fall+spring), s=summer, w=winter, d=day, n=night

[23] We deduce this value of 20% from the difference between the maxima in the aggregated and the detailed load duration curves

Final heat demand (from cogeneration) development

CBS reports that in the year 2000 the heat production by cogeneration was 220 PJ. Of this heat, households consumed 16 PJ and the commercial sector 49 PJ. The remaining 155 PJ was consumed by the industry including the oil refineries and agriculture sector. 33 PJ of the heat was produced by central cogeneration units which includes the district heating power plants, and the remaining by decentral units.

According to the WLO report (Janssen et al., 2006), growth of the electricity production by cogeneration units in the SE scenario is expected to increase from 37 TWh (133 PJ) in 2000 to around 51 TWh in 2040 (of which 44 TWh produced by decentral units and 7 TWh by centralised units). However, the heat from cogeneration is expected to grow at a lower pace or not at all, because it is assumed that the heat/power ratio of decentral cogeneration units will decrease from around 2/1 to around 1/1 (Dril, 2005). Because an in-depth analysis of the development of cogeneration is outside the scope of this study, the heat produced by cogeneration has been kept constant over time. Additionally, it is assumed that the division between heat from decentral and central cogeneration is kept constant.

Table 4 Summary of scenario specific input data in MARKAL

Description	Units	Years					
		2000	2010	2020	2030	2040	2050
Electricity demand[a]	TWh	101	119	138	149	162	175
Decentral cogeneration upper bound [a]	GWe	5.0	5.8	7.0	7.5	8.1	8.7
Onshore wind upper bound[a]	GW	0.5	1.4	1.9	2.0	2.0	2.1
Offshore wind upper bound[a]	GW	-	0.7	3.0	6.5	10.0	12.0
Nuclear energy[a]	GW	0.45	0.45	0.45	0.45	0[b]	0
Uranium oxide	€/GJe	1.25	1.25	1.28	1.34	1.41	1.48
Gas price	€/GJ	2.1	4.0[c]	4.0	4.4	5.0	5.6
Coal price	€/GJ	0.9	1.3	1.4	1.5	1.6	1.7
Biomass price	€/GJ	6.0	6.0	5.5	4.5	4.0	4.0
Net import electricity	TWh	19	23	0	0	0	0

a SE WLO + extrapolation to 2050 (Janssen et al., 2006).
[b] from 2035
[c] 3.8 in 2015

Influence of cross-boundary electricity transport

A determining factor for the development of the Dutch electricity park is whether the Netherlands will be a net-importer or exporter of electricity and to what extent. In the last decades the Netherlands has been a net importer of electricity. In 2000, 18 TWh of electricity were imported, about 18% of the final electricity use (KEMA, 2002). It is expected that in the short term the Netherlands will import more, because in Europe still an overcapacity of power plants exists. In the long term, due to liberalisation and the closing of nuclear power plants, this overcapacity will decrease. In 2002, KEMA presented scenarios in which the Netherlands will remain an importer, but also one where it becomes a net exporter (KEMA, 2002). The authors of the WLO report (Janssen et al., 2006) assume an export of electricity in the Strong Europe scenario. In an electricity park with hardly any nuclear power and with a stringent climate policy, we consider this assumption rather unlikely. Therefore, we keep the net import at 0 TWh from 2020 onwards.

Energy prices

We use the latest available energy price projections of the reference scenario in the World Energy Outlook (WEO) 2006 (IEA, 2006b).[24] In this scenario, it is assumed that oil prices remain high (47 $\$_{2005}$/barrel in 2012 and 55 $\$_{2005}$ in 2030) [25] compared to the figures for the year 2000. We assume that oil prices will continue to increase upto 70 $\$_{2005}$/barrel in 2050. Gas prices will follow the oil price, because of inter-fuel competition and the widespread oil-price indexation in long-term gas-supply contracts, and analogue to WEO 2006 we set the gas price at 3.9 €/GJ in 2005 up to 4.4 €/GJ in 2030.[26] After 2030 it increases at a similar rate as the oil price to 5.6 €/GJ in 2050. Spot prices of coal were 2.4 €/GJ in 2004. However, the WEO 2006 expects that coal prices will decrease again to 1.3 €/GJ in 2010 and then slightly increase to 1.5 €/GJ in 2030. We adopt this coal price scenario and let the price gradually increase up to 1.7 €/GJ from 2030 to 2050.

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[24] Although specific oil and gas prices (3.4 $€_{2000}$/GJ in 2030) are given for the SE in the WLO publication, we choose to use the more recent WEO projections. The SE prices in the WLO publication were lower, because of declining energy demand due to climate policy. However, the IEA used the same prices in the reference scenario as well as the alternative scenario with climate policy. They argue that the effect of declining energy demand on energy prices cannot be estimated.

[25] This high oil price scenario seems reasonable. Prices have already been for 2 years above $35/barrel and even reached levels of about $70/barrel (= 8 $€_{2000}$/GJ). Also, prices in the Annual energy outlook 2006 of EIA-DOE are high: oil prices are projected to increase from 40$\$_{2004}$/barrel (=4.8 $€_{2000}$/GJ) in 2004 to 57$\$_{2004}$/barrel (=6.9 $€_{2000}$/GJ) in 2030 (EIA-DOE, 2006).

[26] These prices seems relatively low compared to the oil price of 6.5 €/GJ and the gas price of 5 €/GJ (=22 ct_{2006}/m^3) in 2006 (Gasunie, 2006). Therefore, we do a sensitivity run with a 25% higher gas price than in the base variants.

We base the biomass price on the wood pellet price. Although pellets are more expensive than other biomass fuel input, they do not require extra investment or O&M costs when used for co-firing in coal-fired power generating units. Thus, these cost factors compensate each other (Sambeek, 2004). In our MARKAL-NL-UU model we apply, therefore, no extra investment or O&M costs on the biomass-co-firing technologies. Wood pellets were 7-7.5 $€_{2004}$/GJ at the gate of the power plant in 2004 and the price is estimated to stabilise between 5.6-6.4 $€_{2004}$/GJ in the mid term (Sambeek, 2004). We assume that due to cost reductions in production, transport, and pre-treatment, prices will decrease over time to 4 €/GJ[27].

As in the studies (University of Chicago, 2004; IEA, 2006a), we took the uranium oxide price to be 1.25 €/GJe (5.6 $\$_{2003}$/MWhe) including a nuclear waste fee of 0.24 €/GJ. This price increases slightly to 1.5 €/GJe in 2050. In the sensitivity analysis, we analyse the consequence of using advanced nuclear fuel cycles for an additional 10 €/MWhe[28] in order to reduce the amount and the radioactive lifetime of the nuclear waste.

Deployment of competing CO_2 reduction technologies

In the WLO report, it was assumed that in SE subsidies for wind energy will continue up to 2040, and that consequently, 10 GW offshore and 2.0 GW onshore wind energy will be installed by the year 2040. In our study we consider these capacities to be the maximum amount that can be installed, and we extrapolate this upper bound to respectively 12 GW and 2.1 GW in 2050. The model decides to which extent these potentials will be used. With respect to cogeneration, WLO assumes that electricity production from decentral units will be 44 TWh in 2040 which agrees with 8.1 GW of installed capacity with a capacity factor of 62%[29]. Again we adopted this capacity as upper bound for decentral cogeneration. Central cogeneration is constrained by the limited demand for district heating. According to WLO the capacity of photovoltaic cells (PV) will grow to 3 GW in 2040. However, we just let the model decide on the deployment of PV based on its cost-effectiveness.

[27] The report 'Pre-treatment technologies, and their effects on the international bioenergy supply chain logistics' declares that pellet costs delivered to Europe can be 3.6 €/GJ (for torrified pellets) and 4.9 €/GJ for normal pellets (Uslu, 2006).

[28] Additional costs of different advanced nuclear cycles (e.g. with transuranic waste burning in a fast reactor or accelerator driven systems) are estimated to be between 4 and 16 euro/MWh (OECD-NEA, 2002).

[29] With CBS statistics data we calculate that decentral cogeneration units are operated with a capacity factor of 62% on average (CBS, 2006)

2.3.2 Data for power plant technologies

Cost and performance

Data for the most important power plant technologies are presented in Table 5. We adopt the data for new and advanced gas- and coal-fired power plant technologies (with and without CCS) from two studies of Damen (Damen et al., 2006; Damen, 2007), because the authors have collected cost and performance data in a consistent manner. We derive the data which are needed to split the O&M costs into a variable and a fixed cost part, from the original references. For NGCC and IGCC from (IEA GHG, 2003), for PC from (IEA GHG, 2004). To assure the quality of data, we verify the data against data from various other studies (Hendriks, 2004; Menkveld, 2004; IPCC, 2005; Peeters, 2007). All coal-fired power plants have a flexible input of either coal or biomass.[30] The WLO study assumes that in all coal-fired power plants 20% co-firing of biomass is happening in SE. We let the model free to decide to what extent it will use biomass for mitigation purposes. Data for PV are derived from (EU PV Technology Platform, 2007), for wind from the CPB study Wind energy on the North Sea, the Fact sheets report presented by ECN in 2004, and Junginger's article about the global experience curves for wind farms (Menkveld, 2004; Junginger, 2005; Verrips, 2005). For the nuclear power plant we take data from the study The economic future of nuclear power (University of Chicago, 2004; IEA, 2006a).[31]

We used the same dataset for the *DirectAction* and *PostponedAction* variants. Although, for the *PostponedAction* variants, it is the question, if also in the rest of the world action is postponed and thus experience with large scale CCS is lacking, whether the technologies advance at similar rates.[32]

[30] Because it was outside the scope of this paper to analyse biomass co-firing in detail, we did not adjust the efficiency or other cost and performance data of the power plants with biomass co-firing, but used the more expensive wood pellets as input (see also section 2.3.1). However, costs and performance will change with other biomass input. For example, a biomass-fired IGCC has a somewhat lower efficiency (1% point) than an IGCC, because of moisture and larger volumes (lower energy density) (Hendriks, 2004).

[31] The nuclear power plant Borssele is a Pressurised light water reactor plant. A new power plant in the Netherlands will probably be of the same type, i.e. the EPR (European Pressurised light water Reactor) (Menkveld, 2004).

[32] Empirically it is shown that there is a relation between the cumulative capacity of a technology and costs of the technology: unit costs decrease with increasing experience. This can be referred to as learning by doing (McDonald et al., 2001).

Life time

A life time of 30 years is chosen for coal-fired and gas-fired power plants, 20 years for wind turbines, 20 years for PV, and 40 years for nuclear power plants in the normal vintage variants.[33] In the *EV* variants we prolong the life times to 40 years for gas-fired, 50 years for coal-fired, and 60 years for nuclear power plants.

Availability factor

The availability factor is the difference between the actual capacity and the available capacity. Usually the difference is caused amongst others by environmental conditions, technical defects, maintenance, fulfillment of environmental permits, and disposal of heat (TenneT, 2006a). The availability factor does not equal the capacity factor. This latter factor is an output of the MARKAL model and depends on the load duration curve of the electricity demand. TenneT data show that in the Netherlands availability is on average 89% for the power plants and 90% for the nuclear power plant (TenneT, 2006a). We adopt these figures. Furthermore, we expect that the availability of a power plant with capture is a little lower (85% at most) because of increased complexity of the power plant. Finally, we assume an average yearly capacity factor for wind onshore, offshore and PV of respectively 25%, 38%, and 10%[34]. In the model the availability of the renewable technologies are differentiated per time-slice.

Summary

In order to put the cost and performance data of the different technologies into perspective, we present three technology indicators in Table 6: the specific CO_2 emissions (in kg/kWh), the cost of electricity (COE), and the CO_2 avoidance costs compared to a reference technology. Note, that in the MARKAL model runs the actual values will deviate from these figures.

[33] In current energy markets these life times seem relatively short. However, many MARKAL studies still use lifetimes between 25 and 30 years for fossil-fuelled power plants because MARKAL does not make a distinction between the economic and technical life time, and because it is not possible to increase the operating and maintenance costs with aging of a power plant.

[34] Capacity factor of onshore wind is derived from the website of Wind Service Holland (Wind Service Holland, 2008). Capacity factor of offshore wind increases from 38% in 2000 to 40% in 2010 (Verrips, 2005). Capacity factor of PV increases from 8.6% in 2000 to 10.3% in 2050 (Holland Solar, 2005).

Table 5 Technology cost and performance data

	Technology[a]	2010	2020	2030	2040
Efficiency (in %)	NGCC	58%	60%	63%	64%
	PC	46%	49%	52%	53%
	IGCC	46%	50%	54%	56%
	NGCC-CCS	49%	52%	56%	58%
	PC-CCS	36%	40%	44%	47%
	IGCC-CCS	38%	44%	48%	50%
	PC-RF	28%	29%	29%	29%
	PC-CRRF	36%	37%	37%	37%
	IGCC-CRRF	38%	39%	39%	39%
Investment costs (in €/kW)	NGCC	500	450	450	450
	PC	1182	1100	1053	1000
	IGCC	1457	1330	1230	1125
	NGCC-CCS	848	751	694	620
	PC-CCS	1851	1701	1550	1400
	IGCC-CCS	1900	1600	1400	1300
	PC-RF	850	850	850	850
	PC-CRRF	700	700	700	700
	IGCC-CRRF	500	500	500	500
	Wind onshore	908	795	714	641
	Wind offshore	1800	1500	1420	1400
	Nuclear	1961	1961	1961	1961
	PV	3200	2000	1000	700
Fixed O&M costs (in €/kW)	NGCC	15	13	13	13
	PC	61	57	52	48
	IGCC	56	52	47	42
	NGCC-CCS	26	19	17	15
	PC-CCS	75	64	59	54
	IGCC-CCS	73	60	55	50
	PC-RF	11	11	11	11
	PC-CRRF	15	15	15	15
	IGCC-CRRF	17	17	17	17
	Wind onshore	25	20	18	16
	Wind offshore	76	72	68	64
	Nuclear	52	52	52	52
	PV	32	20	10	7

Table 5 continued

	Technology[a]	2010	2020	2030	2040
Variable O&M costs (in €/GJ)	NGCC	0.01	0.01	0.01	0.01
	PC	0.26	0.26	0.25	0.25
	IGCC	0.22	0.18	0.15	0.14
	NGCC-CCS	0.30	0.30	0.27	0.26
	PC-CCS	0.96	0.92	0.80	0.70
	IGCC-CCS	0.38	0.30	0.20	0.20
	PC-RF	0.69	0.69	0.69	0.69
	PC-CRRF	0.69	0.69	0.69	0.69
	IGCC-CRRF	0.16	0.16	0.16	0.16
	Nuclear	0.51	0.51	0.51	0.51
Availability	All conventional plants	89%	89%	89%	89%
	all CCS plants	85%	85%	85%	85%
	Wind onshore	26%	26%	26%	26%
	Wind offshore	40%	40%	40%	40%
	Nuclear	90%	90%	90%	90%
	PV	9%	9%	10%	10%
Capture ratio (in %)		85%	90%	90%	90%

[a] integrated gasification combined cycle power plant (IGCC), natural gas combined cycle power plant (NGCC), pulverised coal-fired power plant (PC), photovoltaic power (PV), retrofit (RF), capture ready retrofit (CRRF). Costs of retrofit technologies are additional costs for capture unit.

Table 6 Technology indicators

		Technology	2010	2020	2030	2040
Specific CO_2 emissions (in kg/kWh)		NGCC	0.348	0.337	0.321	0.316
		PC	0.740	0.699	0.655	0.643
		IGCC	0.740	0.681	0.631	0.608
		NGCC-CCS	0.062	0.058	0.036	0.035
		PC-CCS	0.142	0.127	0.077	0.072
		IGCC-CCS	0.134	0.077	0.071	0.068
		PC-RF	0.122	0.117	0.117	0.117
		PC-CRRF	0.095	0.092	0.092	0.092
		IGCC-CRRF	0.090	0.087	0.087	0.087
		Wind onshore	0	0	0	0
		Wind offshore	0	0	0	0
		Nuclear	0	0	0	0
		PV	0	0	0	0

Table 6 continued

		Technology	2010	2020	2030	2040
COE[a] (in €/MWh)		NGCC	31	29	31	34
		PC	29	28	26	26
		IGCC	31	28	27	25
		NGCC-CCS	42	38	38	39
		PC-CCS	43	39	36	34
		IGCC-CCS	40	34	31	30
		PC-RF	52	52	52	54
		PC-CRRF	45	45	46	47
		IGCC-CRRF	42	42	43	44
		Wind onshore	43	37	33	30
		Wind offshore	63	55	52	50
		Nuclear	27	28	28	28
		PV	324	196	95	65
CO_2 avoidance costs[b] (in €/t)	**compared to**					
	NGCC	NGCC-CCS	36	30	25	21
	PC	PC-CCS	23	20	17	14
	IGCC	IGCC-CCS	16	10	8	9
	PC-2000	PC-RF	37	39	44	48
	PC-2010	PC-CRRF	24	26	30	32
	IGCC-2010	IGCC-CRRF	17	19	22	25
	PC	NGCC	5	5	13	23
	PC	IGCC-CCS	19	11	8	7
	PC	Wind onshore	19	13	10	6
	PC	Wind offshore	46	39	39	38
	PC	Nuclear	-2	0	2	3
	PC	PV	398	241	105	60
	NGCC	PC-CCS	58	47	22	2
	NGCC	PC-RF	90	101	107	103

[a] These values must be considered as an indication for the cost of electricity (COE). In the calculation of these COEs we assume that capacity is utilised to the maximum extent, that only coal is burned in PC and IGCC plants, and that energy prices remain constant over the life time of the technologies (for example the COE of a PC built in 2040 is based on coal prices in 2040). In the MARKAL model runs these conditions will be different.

[b] The costs of CO_2 avoidance can only be determined in comparison to costs and emissions of a reference technology. In most cases PC is taken as the reference technology. Also the CO_2 avoidance costs are just an indication for the same reasons as for the COE.

Table 7 Data overview of CO_2 storage options in the Netherlands

	Unit	Gas fields onshore	Gas fields offshore	Aquifers onshore	ECBM
Cumulative Storage potential[a]		1421	863	440	172
Timing: how much storage capacity gets depleted around					
2010	**Mt CO_2**	491	137	available from start	available from 2020
2015		439	170		
2020			550		
2025		478	336		
Average reservoir characteristics					
Reservoir depth[b]	**km**	2.6	3.5	2	1
Reservoir thickness[c]	**m**	125	125	125	200
Well capacity[c]	**Mt CO_2/year**	1.25	1.25	1	0.01
number of wells[c]		2	2	2	6
Horizontal drilling[c]	**m**	1000	1000	1000	800
average lifetime storage option		16	9	22	20
CO_2 storage capacity over lifetime	**Mt CO_2**	39	23	44	1.2
Average investment costs[c]					
site development costs	**m€**	1.6	1.8	1.6	0.18
drilling costs per meter 2000	**€/m**	1750	2500	1750	500
drilling costs per meter 2020	**€/m**	1200	1750	1200	350
surface facilities	**m€**	0.4	25	0.4	0.4
monitoring investments	**m€**	0.2	0	2	2
total investment costs	**m€**	17	52	18	11
O&M (as share of investment costs)[c]	**%**	7%	8%	7%	7%
MARKAL input[d]					
Investment costs 2000-2020	**m€ per Mt CO_2/yr**	7.6	22	9.2	183[d]
Investment costs 2020-2050	**m€ per Mt CO_2/yr**	5.5	19	7	141[d]
Fixed costs 2000-2020	**m€ per Mt CO_2/yr**	0.5	1.8	0.6	12.8
Fixed costs 2020-2050	**m€ per Mt CO_2/yr**	0.4	1.5	0.5	9.9
Costs per tonne CO_2 2000-2020[e]	**€/t CO_2**	1.5	5.6	1.7	34
Costs per tonne CO_2 2020-2050[e]	**€/t CO_2**	1.1	4.7	1.3	26

[a] Storage potentials for the gas fields and aquifers are from (TNO, 2007) and includes gas fields of > 10 Mt and ten aquifer traps of >10 Mt. The conservative estimates of (Hamelinck, 2001) were used in which ECBM recovery is limited to a depth range of 500 – 1500. In the MARKAL model we take 80% of these storage potential figures.

[b] Average depth of gas fields and aquifers is based on TNO study (TNO, 2007).

[c] Data taken from (IEA GHG, 2005a). Possible cost reductions when sinks are close to each other have not been considered.

[c] Values relate to storage facilities that can store 1 Mt CO_2 per year.

[d] Investment costs per Mt CO_2/year are very high because of low injection rate. However, these costs will partly be offset by the yield of methane. It is assumed that 2 molecules of CO_2 replace one molecule of CH_4 (IEA GHG, 2005a).

[e] Costs per tonne CO_2 in case the sink is used to its maximum. However, the MARKAL model decides itself to which extent the reservoir will be used.

2.3.3 Data for storage of CO_2

Table 7 presents the MARKAL-NL-UU inputs for CO_2 storage and the data on which these values are based. Cost data were taken from the IEA report 'Building the cost curves for CO_2 storage: European sector' (IEA GHG, 2005a). This report presents distinct data for investment and O&M costs. The base data to calculate the average reservoir size is derived from (TNO, 2007) and is for onshore and offshore fields, respectively, 39 and 23 Mt. When two wells per reservoir are drilled and the full injection rate of 1.25 Mt/yr per well is used[35], these will be filled in respectively 16 and 9 years[36]. We only consider the 10 onshore aquifers with a storage capacity > 10 Mt. These aquifers have an average storage capacity of 44 Mt, a filling capacity of 2 Mt/yr (with two wells and a well capacity of 1 Mt/yr), and are thus filled in 22 years. An ECBM site has six wells and a life time of 20 years.

Table 8 Data on CO_2 transport for the Dutch situation

		Offshore				Onshore				Utsira Norway
		Direct line	Line to trunk or direct line	Trunk line	Satellite line	Direct line	Line to trunk or direct line	Trunk line	Satellite line	Trunk line
distance	km	200	20	200	30	100	10	100	15	800
flow	Mt/yr	6	6	20	2.5	6	6	20	2.5	28
lifetime	years	25	25	25	9	25	25	25	16[a]	25
Investment costs	m€/Mt/yr	18.5	1.4	8.1	6.6	9.5	0.6	4.5	1.7	38.5
Fixed costs	m€/Mt/yr	0.40	0.03	0.12	0.18	0.20	0.01	0.09	0.03	0.33
transport cost[b]	€/t	1.72	0.13	0.69	1.11	0.87	0.05	0.41	0.19	3.06

[a] Satellite pipelines to aquifers and coal beds have a longer life time. However, this hardly has an effect on the average transport costs.
[b] Costs per tonne CO_2 in case the pipeline is used to its maximum capacity. However, the MARKAL model decides itself to which extent the pipeline capacity is used.

[35] To capture all CO_2 emissions of a coal-fired power plant, injection will need to take place in two to three reservoirs at once.
[36] Using two wells and filling the offshore reservoir in 9 years is cheaper per tonne CO_2 (4.7 €/t CO_2) than filling the reservoir with only one well in 18 years (5.9 €/t CO_2). For storage onshore it does not matter whether the reservoir is filled with one well in 32 years or two wells in 16 years (1.1 €/t). The difference is due to the fact that O&M costs are more expensive offshore than onshore.

2.3.4 Data for transport of CO_2

CO_2 transport cost data are derived from (IEA GHG, 2002) and (Hendriks et al., 2003). These studies have been used to sketch the range in transport cost data in the IPCC special report on Carbon Dioxide Capture and Storage (IPCC, 2005).

Table 8 presents the data used in our MARKAL-NL-UU model. They represent different CO_2 transport pipelines in the Dutch situation. The distances are based on measurements between potential sources and sinks with a GIS system. The ages of the transport lines are by default 25 years. Only the satellite pipelines have the same life time as the reservoirs they go to.

2.3.5 Vintage structure in the Netherlands

In order to assess when new power plants will be needed, the capacity and construction year of current power plants and cogeneration units in the Netherlands have been collected. How the vintage structure develops over time, depends on the expected life time of the power plants. We base these life times on the plans of energy companies and otherwise on an average life time of 30 years for centralised units and 25 years for decentralised units. Data were obtained from (SEP, 1996; Essent, 2005; Nuon, 2005; Seebregts, 2005). Finally, the websites of the major energy companies active in the Netherlands, Essent, Nuon, Electrabel, Delta, Eneco, E.On were scanned for the latest news on, for example, new power plants and life extension plans of existing power plants. Data were completed and verified with online data of CBS (CBS, 2006). With respect to Figure 2, in which the development of the vintage structure is depicted, we make the following remarks:

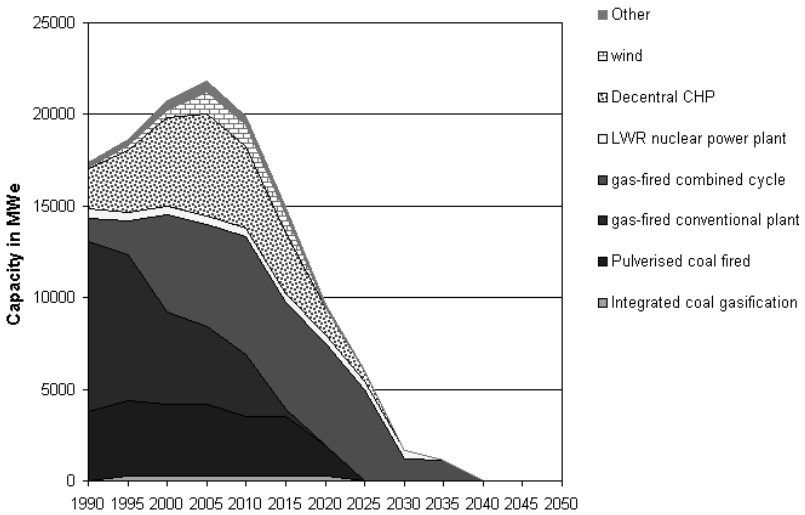

Figure 2 Vintage structure of Dutch electricity park 'normal vintage'

- Many power companies have plans to build new power plants in the Netherlands. Plans for which the final investment decisions have been taken, are included. In the sensitivity analysis it is analysed what happens when part of the other plans will also be carried out.
- Biomass is not shown as a separate category. 950, 1750, 3350 GWh was produced in respectively 2003, 2004, and 2005 from biomass. This corresponds to a growth from 1% to more than 3% of total annual electricity production (Junginger, 2006). In 2005, around 70% of this electricity was produced in coal-fired power plants, 18% in gas fired power plants and 11% in a biomass only plant. Feed stocks varied from palm oil, sawdust, pellets, palm pit shells to demolished uncontaminated wood[37]. Because subsidies for biomass have been lowered since mid 2006, electricity from biomass is expected to decrease in the short term as long as no new policy measures are taken.
- Although 'combi' gas-fired power plants can be found in the Netherlands, we do not model them as a separate category. A 'combi' uses exhaust gases from the gas turbine as combustion air in the boiler. It can be considered as a predecessor of an NGCC[38] which uses the exhaust gas to heat up the water directly without using additional fuel (Gijsen, 2001). Since the efficiency of the 'combi' is lower than NGCC, we included them into the conventional condensing power plant category.

[37] It is not allowed to use contaminated wood in the Netherlands.
[38] NGCC is usually called STEG (Steam and gas turbine) in the Netherlands

2.4 Results and discussion

2.4.1 Electricity generation technologies with and without CO2 capture

In this section the results of the MARKAL-NL-UU runs are discussed. Figure 3 depicts the resulting capacities (in GW) of the different technologies over time for the *BAU*, *DirectAction*, and *PostponedAction NV* variants in which the power plants are decommissioned after 30 years[39]. With respect to the composition and dispatch of the electricity park, the following conclusions can be drawn from the MARKAL-NL-UU runs:

Business as usual

The *BAU* variants show that, if there would be no CO_2 reduction targets, the electricity park will consist for a large part out of PC plants (almost half of the total capacity in 2050). A quarter of the park consists of CHPs and the remaining quarter is covered by NGCCs to fulfil the peak demand of electricity. In total, a little over 33 GW in 2050 is necessary. CO_2 emissions for power generation rise to 93 and 102 Mt/yr in 2020, and 113 and 117 Mt/yr in 2050 for, respectively, the *BAU NV* and *BAU EV* variant (see already Figure 8). This implies an increase of more than 110% compared to the 1990 CO_2 emission level. In the *EV* variants less efficient power plants stay longer in operation, and thus cause the higher CO_2 emissions.

Long term mitigation strategy

All reduction variants (i.e. the *DirectAction* and *PostponedAction* variants) depict the same mitigation strategy at the end of the model horizon. This strategy can be characterised as follows:

- The **total electricity generation capacity** will amount up to 35 GW (6% more than the *BAU* variants) in 2050, because the average availability of the park has decreased due to the wind energy.
- In the long-term (2050) the **technologies** that play the most **dominant** role in the CO_2 reduction strategy are IGCC-CCS (13-14 GW), gas-fired power plants, and CHP. NGCC-CCS is not part of the solution.

[39] The variants with the extended life times are discussed in the text, but not presented in Figure 3. The installed capacities of these variants are quite similar to the variants presented in the graphs. Only in the period between 2010-2020 there are remarkable differences, but these are shown in Figure 4.

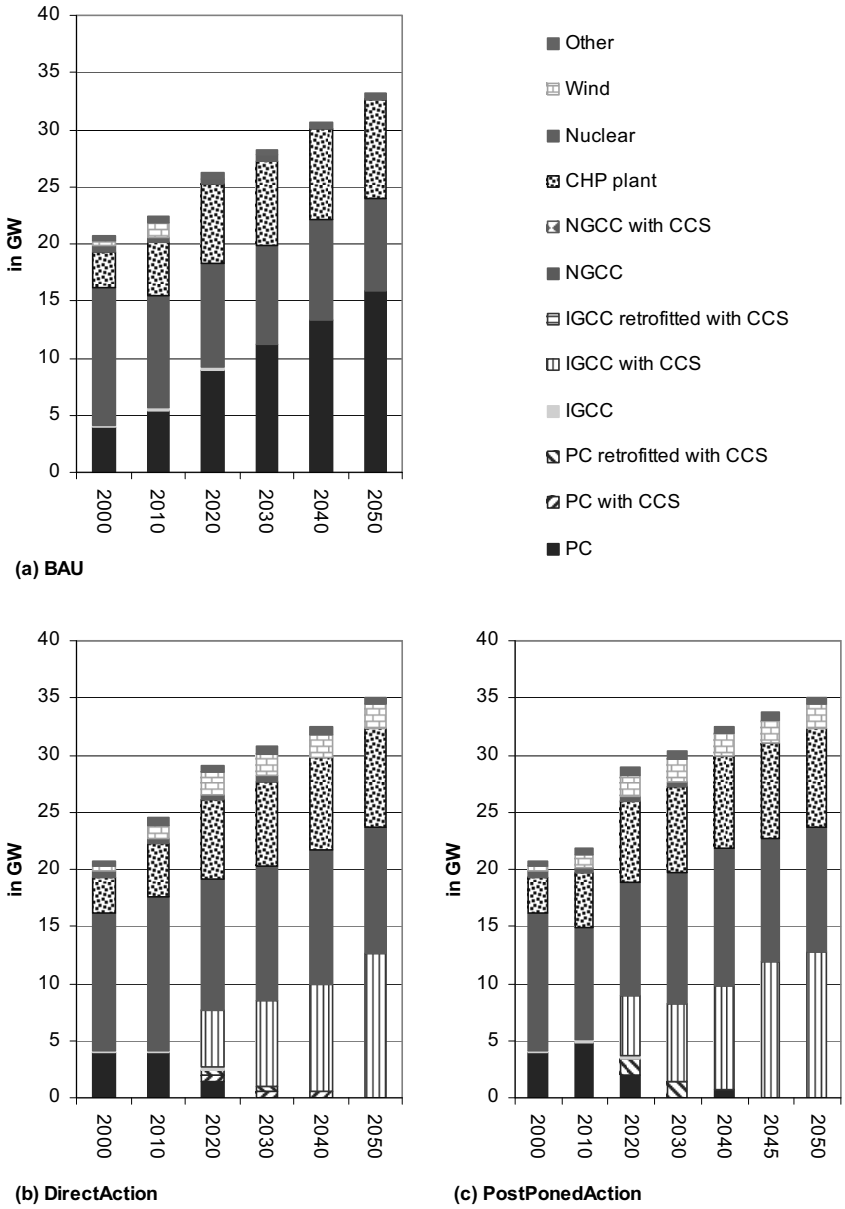

Figure 3 Total installed capacity of different technologies for the 'normal' vintage variants

- **Wind energy** plays a modest role. The capacity of onshore wind is restricted by the upper bound of 2.1 GW and will cover the electricity demand for less than 3%. Offshore wind energy does not become competitive during this period[40].
- In 2050, between 24% and 30% of primary energy input in the coal-fired power plants consists of **biomass**.
- Currently, there are in the Netherlands a few PC and NGCC power plants delivering **district heat**. In the reduction variants the PC plants will be replaced by IGCC with CCS. However, in these variants, the heat produced for district heating units will in the end come from NGCC units. The reason is that power plants with CO_2 capture cannot deliver district heat, because 50% to 66% of the low pressure steam will be needed for regeneration purposes (Ploumen, 2006b). It is the question if at the location of the current PC power plants that provide district heating, NGCC units will be built. Therefore, it should be investigated in more detail how an electricity park with large scale CCS can be combined with district heating.
- The primary energy use for electricity generation which is presented in Figure 6, also provides information on the long term strategy. The share of coal will grow from 24% in 2005 to 37% in 2050 and the share of biomass will increase to 17% in 2050. Although the share of gas (natural gas and blast furnace gas) decreases, it still remains substantial with 43% in 2050.

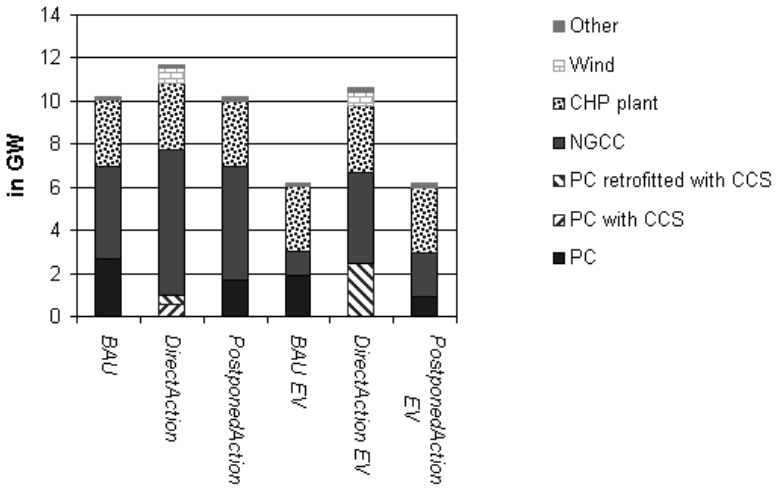

Figure 4 Investments in new capacity in the periods 2010 and 2015 per main variant[41]

[40] The outcome of the linear optimisation process shows that the investment costs of wind energy need to be reduced by 560 – 940 €/kWh in order to become a competitive technology in a reduction variant.
[41] Note that in the *DirectAction EV* variant, it seems that much more power plants will be constructed than in the *BAU EV* variant. However this is not the case: the 'PC retrofitted with CCS' category refers to the retrofit of

Short term mitigation strategy

Figure 4 presents the investments in electricity generation capacity for 2010 and 2015 for all main variants. It can be deduced from the figure that the investment strategies in the main variants especially vary at the beginning of the model horizon. However, we can identify a few main conclusions about a short-term strategy to reach the CO_2 abatement target in 2020.

- At the beginning of the model period one could expect that there still may be some investment in conventional IGCC or PC plants, because at that time reduction targets are not so strict yet. However, results show that there is hardly any investment in these types of plants. Only in the *PostponedAction* variants in which CO_2 emissions may still increase up to 2015, **capture ready power PC plants** play a limited role. A PC plant(s) of 1.5 and 1 GW will be built between 2010 and 2015 in respectively the *PostponedAction NV* and *EV* variant which will be retrofitted with capture units in 2020. This investment of 1-1.5 GW PC is small in comparison to existing plans of electricity companies.[42]
- In all variants around 3 GW of **CHP** units will be constructed in 2010 and 2015, mostly this is to replace existing units (2.2 GW) and the remaining is to build additional CHP units. Except for the 300 MW CHP unit which is being built by Air Liquide/Shell in Pernis and will become operational in 2007, we are not aware of other large scale CHP construction plans.
- With respect to **NGCC**, we note that in the *NV* variants 3 GW more NGCC needs to be built to replace existing gas-fired power plants than in the *EV* variants in 2010 and 2015 due to the longer life times in the latter variants. To reach the CO_2 targets in the *PostponedAction* and *DirectAction* variants additional investments in NGCCs are required in 2010 and 2015: *PostponedAction* requires an additional investment of 1 GW in these periods, and *DirectAction* requires even 3 GW more compared to the *BAU* variants. Current NGCC construction plans of the energy companies for the time step '2010' amount up to 3.6 GW (Delta, 2006; ECN, 2006; Electrabel, 2006; Essent, 2006; Eneco, 2007). These plans are presented as additional capacity rather than as replacement for old power plants. Thus, if these plans are actually taken on and if the existing gas-fired power plants remain in operation, there will be sufficient NGCC capacity for a strategy to reduce CO_2 emissions from 2010 onwards.

existing power plants. The retrofit capacity in the graph should, therefore, not be interpreted as additional capacity.

[42] Plans amount up to 1200 MW IGCC and 3300-4100 MW PC (Ploumen, 2006a).

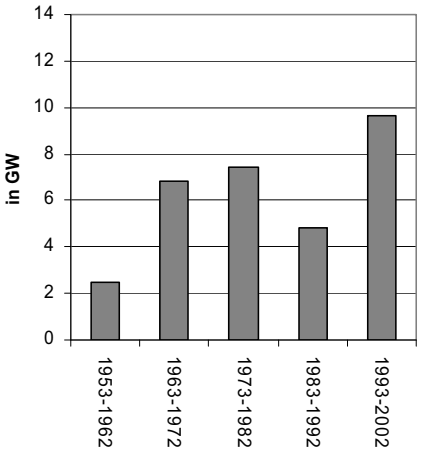

Figure 5 New built capacity historically (per 10 years)

- In the *PostponedAction* variants, no **retrofitting** of current PC power plants takes place. In the *DirectAction* variants, already in 2010 and 2015 CO_2 capture is deployed as a solution to reach the CO_2 abatement targets. The model prefers at this point to invest in 0.5 GW of PC with post-combustion and 0.5 GW in retrofit of existing PC in the *NV* variant, while in the *EV* variant 2.5 GW of existing PC is retrofitted with post-combustion. Apparently, retrofitting of existing coal-fired power plants plays a considerable role in the *DirectAction EV* variant: in this variant, it is worthwhile to retrofit an existing power plant because the capture unit will be used over a long time (from around 2010 to 2030). An overall analysis of all reduction variants shows us that in 2020 only between 3% and 8% of the electricity comes from coal-fired power plants without CCS. Ergo, most PC plants which exist today are either decommissioned, not operated anymore, or have been retrofitted in 2020.
- In all variants, major power plant construction is necessary for replacement of old power plants compared to historic construction activities (compare model results in Figure 4 with historic data in Figure 5). In the reduction variants, these replacement activities are to a large extent used to switch to a less CO_2 intensive electricity park. In the *DirectAction* variants additional capacity needs to be constructed to make up for the lower availability of wind energy. Furthermore, in the *DirectAction* variants, additional capacity needs to be built compared to *BAU*, because old power plants will be operated less.
- With respect to the primary energy for electricity generation (Figure 6), it is a cost-effective strategy not to increase the share of coal in 2010 and 2015 in the *DirectAction NV* variant. Moreover, 50% of this coal already will be fired in a power plant with CO_2 capture. In the *PostponedAction NV* variant the share of coal may rise on the short term.

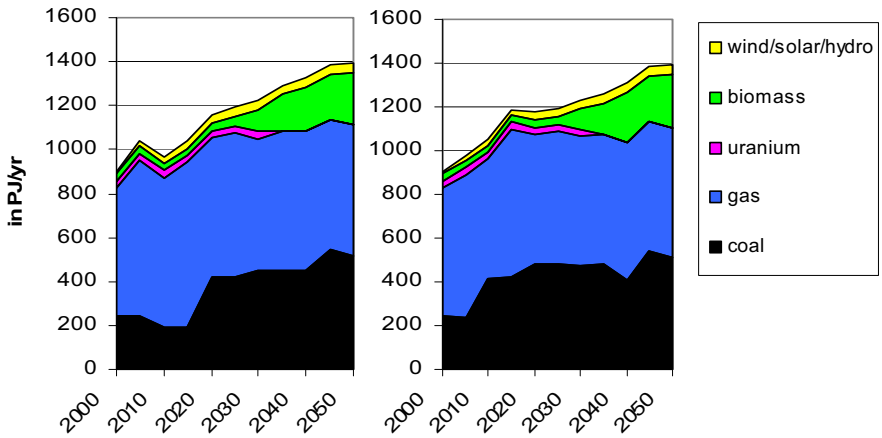

Figure 6 Primary energy use per year for *DirectAction* (left) and *PostponedAction* (right)[43]

Early decommissioning. Since the life time of power plants are fixed in MARKAL, we need to look at the MARKAL results with respect to the capacity factor to get an indication when power plants may be phased out early. Figure 7 shows that the power plants in the *DirectAction* reduction variants operate on average fewer hours than in the *BAU* variants. In the *DirectAction NV* variant, the current PC plants, which are not retrofitted, will operate not more than 30% of the yearly hours from 2010 due to their high specific CO_2 emissions (this can also be achieved by phasing out one or two of the older coal-fired power plants). In the *DirectAction EV* variant, the current PC power plants which are retrofitted, will still be operated around 75% of their time from 2010 (but less than in the *BAU* variant). However, from 2030 even retrofitting is not sufficient to keep these plants in operation. Consequently, the average capacity factor of the total electricity park will temporarily decrease with more than 4 percent point in 2030 compared to *BAU* (see the *DirectAction EV* variant in Figure 7). The model rather chooses to build new more efficient power plants to replace the electricity production from these old plants. We conclude that when a severe reduction path is followed, it will be highly unlikely that the life time of current PC plants will be extended to 50 years. Only in the case that these PC plants will already be retrofitted in 2015, an extension of their life time from 30 years to 40 years (till 2025) may still be sensible.

[43] The primary energy use of the EV variants follow about the same pattern as their analogue NV variants

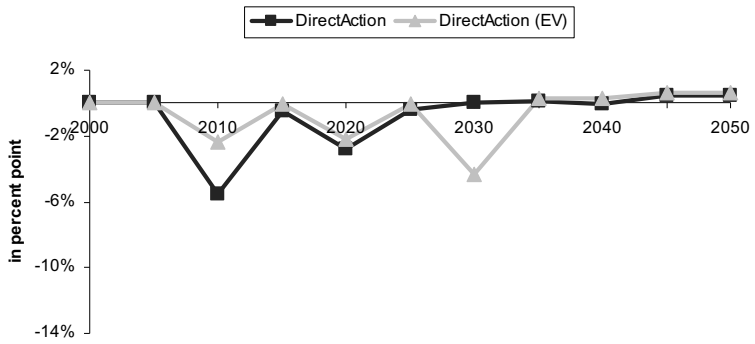

Figure 7 Average capacity factor in two reduction variants compared to *BAU* variants

2.4.2 CO_2 storage

The amount of CO_2 stored varies between 33 Mt (*DirectAction NV*) and 44 Mt (*DirectAction EV*) per year in 2020 and comes from 6-7 GW of power plants. This corresponds to on average 29 Mt CO_2 avoided[44]. Figure 8 shows the amounts of CO_2 avoided in comparison to other mitigation options. In the *DirectAction EV* variant most CO_2 is stored and avoided due to the large scale retrofitting of existing PCs. In the *DirectAction NV* variant the least CO_2 is stored, because retrofitting is not cost-effective and short-term mitigation strategy is based more on the use of NGCCs. The figures which Damen presented for the power sector (excluding retrofitting) amount to only 11-14 Mt CO_2 avoided/yr in 2020 (Damen, 2007) are lower. However, he did not design an overall strategy to reduce CO_2 emissions up to a certain level. Since we assume a binding target of 15% CO_2 reduction in 2020 compared to the 1990 level, the deployment of large scale CCS appears to be, within the framework of our assumptions on prices and competing technologies, the most cost-effective strategy to realise this target. In 2050 about 63 Mt CO_2/yr is stored from the electricity sector, which corresponds to around 54 Mt CO_2 avoided/yr, and stems from 13-14 GW power plant capacity.[45] Menkveld reported a slightly lower figure of 46 Mt CO_2 avoided/yr in 2050

[44] The difference between the amounts of CO_2 stored and CO_2 avoided is caused by the efficiency loss of power plants due to the additional energy required for CO_2 capture and compression: a larger amount of CO_2 is produced per kWh electricity output in a power plant with capture than in one without capture (IPCC, 2005). On the basis of capture rate, and efficiency of power plants with and without capture, we calculated the average ratio of CO_2 avoided to CO_2 stored in the year 2020 (78%) and 2050 (85%). Over time the difference between these amounts becomes smaller due to more efficient capture processes

[45] Average storage figures for the period 2015-2030 is 31 Mt CO_2/yr and for 2035-2050 56 Mt CO_2/yr.

(Menkveld, 2004). Damen reported higher figures of 60-84 Mt CO_2 avoided/yr (Damen, 2007) probably due to a higher electricity demand in 2050 (210 TWh) than in our study (175 TWh).

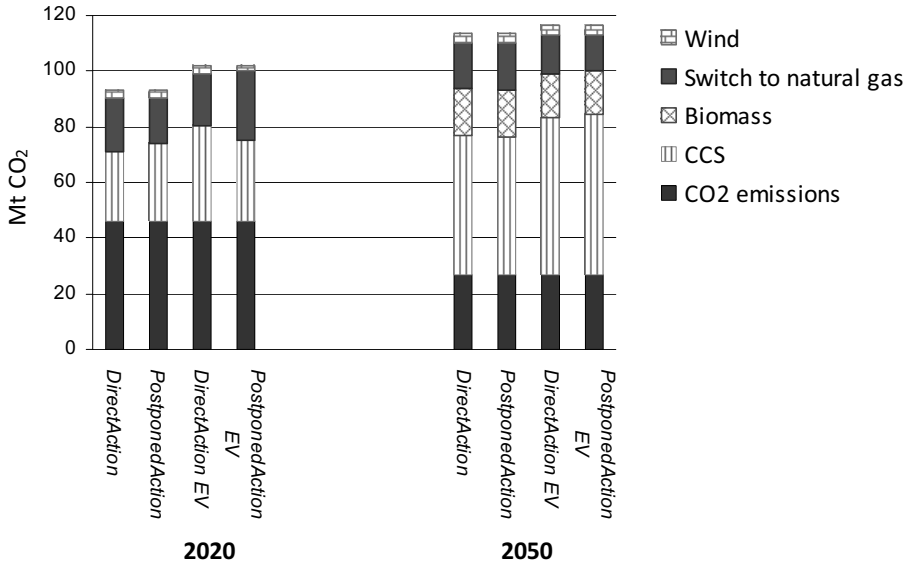

Figure 8 Amount of CO_2 avoided by CCS and other mitigation options

Depending on the reduction variant, storage of CO_2 starts between 2010 and 2020 in onshore empty gas fields, and next storage is continued in onshore aquifers. This is understandable, because the onshore sinks are, on average, twice as large as the offshore gas fields, which make costs of storage cheaper. Also, distances to the onshore storage sites are shorter and thus the construction of pipelines to these locations will be cheaper. However, it is doubtful whether all CCS plants can be located in such a way that they can be easily connected with onshore storage sites. Furthermore, the onshore fields will be almost filled up with CO_2 by 2045 (except for the Groningen field) and only then the model starts using offshore gas fields[46].

The timing when the onshore gas fields become available does not appear to be a problem for the storage of CO_2 emissions from the power sector.[47] The storage capacity in the

[46] This study assumed that offshore fields that have been abandoned 20-35 years earlier, will still be suitable for storage.
[47] The cumulative stored CO_2 emissions in the different variants have been compared with the availability data in Table 7.

medium term could even be sufficient to store CO_2 from other sectors as well. However, it may be a problem, that the onshore fields are already filled by 2045. If the Groningen field would be available by 2040 instead of 2050, a switch to small offshore gas fields may not be necessary.

2.4.3 CO_2 transport

Of course, also a CO_2 infrastructure needs to be constructed in time to transport around 38 Mt/yr in 2020 and 63 Mt/yr. Before 2020 around 480 km of pipelines must be laid down, next before the year 2035 another 360 km, and finally before 2050 yet another 1930 km. The latter figure is high, because of the transport to numerous small offshore gas fields[48]. However, it still remains more cost-effective to store the CO_2 to the Dutch offshore fields than transporting it to the Utsira aquifer formation in the Norwegian North Sea.

If we look at the short term strategy, we see that in the *DirectAction* variants, the construction of infrastructure is a more gradual process: facilities for 7-20[49] Mt/yr will be built in 2015 and 20-26 Mt/yr in 2020, whereas in the *PostponedAction* variants a similar infrastructure is built in around 5 years. Considering the history of Gasunie which constructed 2050 kilometres of main gas pipelines and 2350 kilometres of regional pipelines between 1964 and 1972 (Gasterra, 2007), the actual construction of an infrastructure in a short period is possible. However, legislative procedures have changed since this period and may slow down the process of building a CO_2 infrastructure. Therefore, we presume that a more gradual process is preferable.

2.4.4 CO_2 reduction costs

Figure 9 depicts the marginal cost of CO_2 reduction over the model horizon for the *NV* variants.[50] The marginal cost in a specific time step refers to the amount of money the objective function in the linear optimisation process will decrease, if the CO_2 reduction target in this time step is lowered by 1 Mt of CO_2[51]. Thus, the marginal cost provides an indication of how high a CO_2 price in an emission-trading scheme (ETS) should be to realise the entire

[48] Currently, there is around 3000 kilometres of pipelines on the Dutch continental plate for exploration of gas and oil (Productschap Vis, 2004).
[49] Infrastructure for 20 Mt in 2015 is required in the *EV* variant in which PC plants are retrofitted.
[50] The marginal CO_2 prices in the *EV* variants only slightly differ from those in their analogue *NV* variants.
[51] It will decrease by the *discounted* marginal cost.

CO_2 target and does not provide information about the average cost of CO_2 mitigation[52]. The reduction variants obviously differ significantly in 2015, because in the *PostponedAction* variant, reduction targets are only imposed from 2020 onwards. The high marginal cost in the *DirectAction* variant (50 €/t) is a result of the expensive measure to reduce emissions with CO_2 capture and storage in 0.5 GW of PC-CCS power plant and at the same time underutilising existing PC power plants.

Notice that the marginal cost in 2020 is lower than the one in 2025. The reason is that, because many power plants need to be built around 2020, already then investments will be made to reach the reduction target in 2025. As a result of these investments, it is relatively 'cheap' to reduce the last Mt of CO_2 in 2020.

We see that the marginal cost of CO_2 gradually reduces after 2025 due to the development of IGCC-CCS technology, and the phasing out of older power plants. Apparently, these developments more than compensate extra costs, which might be necessary to decrease the average CO_2 emissions/kWh over time. The marginal cost in 2050 is based on the reduction of CO_2 emissions by using an IGCC-CCS power plant with co-firing of biomass.

Finally, we conclude from Figure 9 that for the direct action strategy, a gradual increase of a CO_2 price in an ETS system would not be sufficient to gradually decrease CO_2 to –15% compared to the 1990 level between 2010 and 2020. Since it is not expected that the CO_2 price in an ETS system will be so high in the near future[53], this strategy would require additional subsidies or other incentives by the government.

[52] For example, it might be possible to achieve the reduction of the majority of CO_2 against relative cheap costs, while mitigating the last tonnes could be very expensive. The marginal price only refers to the abatement of the very last tonne of CO_2.

[53] In the WLO study, the CO_2 price is only 11 €/t in 2020 (Janssen et al., 2006). In the World Energy Outlook of the European Commission, CO_2 price is estimated to be 10 $€_{2005}$/t in 2010 increasing linearly to 20 $€_{2005}$/t in 2030 (EC, 2006).

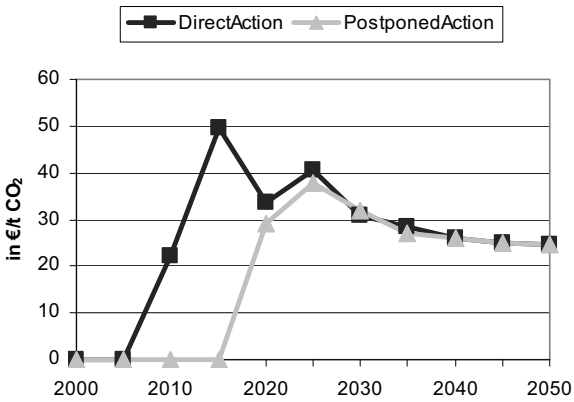

Figure 9 Marginal cost of CO_2 reduction

2.4.5 Electricity generation costs

Figure 10 shows the cost of electricity (COE) over the model horizon for the *NV* variants[54]. The following conclusions can be drawn from this graph.

- In all variants[55] the COE increases considerably from 2000 to 2005[56]. This is mainly due to substantial rise in prices of both coal and gas during this period.
- After 2010 in the *BAU* variant the COE decreases to a level lower than in 2000 due to the decommissioning of older less efficient power plants. Between 2020 and 2050 the COE hardly changes, because the impacts of technical improvements and cost reductions in power generating technologies counterbalance the increase in coal and gas prices.
- Obviously, the COE starts deviating from the *BAU* case as soon as CO_2 needs to be reduced (from 2010 in *NV* variants and from 2020 in *EV*). In 2050 the COE price is around 20% higher than the COE in the *BAU* variant in 2050. In the *DirectAction EV* variant the COE is highest in 2015 due to major retrofitting activities in this period.

[54] We have used the total undiscounted annualised cost results of MARKAL for the calculation of the COE. Because at first, these annualised costs could not be related to the objective function, we improved the MARKAL GAMS code with respect to this point. The problem was that two different annuity factors were used: one for the objective function and another for the annualised costs. We took care that the same annuity factor was used for both outcomes. Furthermore, in order to get the electricity costs we need to subtract the costs for heat production by cogeneration units from the total annualised costs. For this purpose, we suppose that the heat also could have been produced by a boiler with an efficiency of 0.9 and, therefore, subtract the heat demand (in PJ)/0.9 * gas price (in €/PJ) from the total costs.

[55] The *PostponedAction EV* variant is not presented, because it almost shows a similar pattern as the analogue *NV* variant.

[56] These model results reflect the real life trend that energy prices have increased considerably between 2000 and 2005 (SenterNovem, 2005).

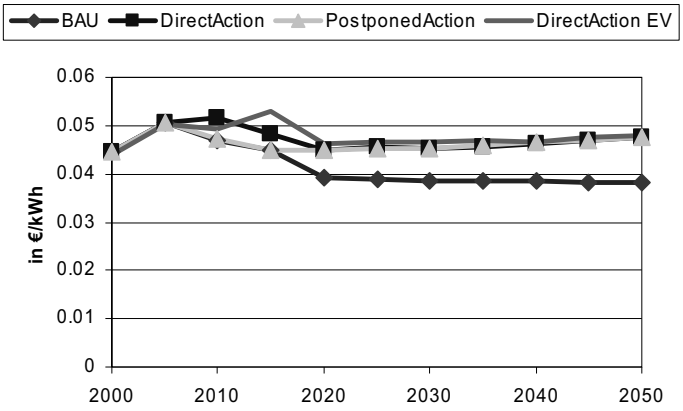

Figure 10 Cost of electricity

- Because the reduction targets are only set from 2020 onwards, the COE in the *PostponedAction* is naturally lower than in the *DirectAction* variants before 2020. From 2020 the COE of the *PostponedAction* variants remains equal to those of the *DirectAction*. So no extra effort has to be made to achieve the 50% reduction target in 2050. However, the total cumulative CO_2 emissions over the whole model period of the *PostponedAction* variants are around 200 Mt higher compared to the *DirectAction* variants (which have cumulative CO_2 emissions of 2.7 Gt).
- In the reduction variants the total electricity and heat generation costs in 2050 have doubled compared to 2000 due to the higher COE, higher gas prices, and because of the increase in final electricity demand from 101 TWh to 175 TWh in 2050. However, in 2050 the GDP also has doubled compared to 2000. The net effect is that the CO_2 reductions in the electricity and cogeneration sector in 2050 can be realised with the same share of GDP as in 2000.
- Finally, Figure 11 depicts the extra undiscounted annual costs that have to be spent in order to achieve the reduction targets compared to the *BAU* variants. For the *DirectAction NV* and *EV* variant respectively around 7% (≈ 410 m€/year) and 14% of the electricity production costs in 2015 is spent on mitigation measures and this share grows to around 17% in 2050 (≈ 1600 m€/year). Again we see that in 2015 the costs in the *EV* variant are much higher, because of massive retrofitting activities in this period. *PostponedAction* variants show similar cost developments from 2020 onwards.

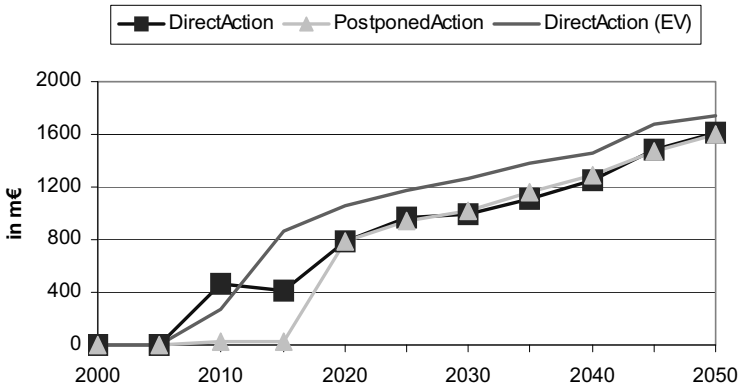

Figure 11 Undiscounted extra annual costs of reduction variants compared to *BAU* variant

2.4.6 Sensitivity analysis

Table 9 presents the results from the MARKAL-NL-UU runs that were made for the sensitivity analysis. All results are compared to the main variant *DirectAction EV*. The results are presented for the medium (period I: 2015 – 2030) and the long term (period II: 2030 – 2050). In the *DirectAction EV* variant, CHP produces most electricity in the medium term, NGCC is on second, and IGCC-CCS is on third place with respect to electricity generation. The contribution of PC (without retrofit) is minimised to 5% of total electricity production in 2020. In the long term IGCC-CCS takes over the first place. In many sensitivity variants, this pattern is repeated: a higher coal price, higher transport costs, a higher discount rate, no storage availability in the Netherlands, more flexibility of coal-fired plants, or the construction of coal-fired power plants in 2010 do not change the order of importance for electricity generation. However, in the following variants this order changes:

When nuclear power is not restricted and no special nuclear waste fee is charged, IGCC-CCS is hardly used for climate mitigation over the whole model horizon. When a nuclear waste fee of 1 €ct/kWh is charged, nuclear and CHP are mainly deployed for CO_2 mitigation in the medium term and CCS does not play a major role yet. In the long term IGCC-CCS and nuclear will contribute about equally to the electricity production.

Table 9 Summary sensitivity analysis runs

Variant	How	P[a]	Three technologies that produce the most electricity (at the left: highest electricity production technology)			CO_2 stored	NPV total system[b]
			1	2	3	% compared DirectAction EV	positive, negative or neutral effect[c]
DirectAction EV		**I.**	**CHP**	**NGCC**	***IGCC-CCS***	**39 Mt/yr**	**124 billion euros**
		II.	***IGCC-CCS***	**CHP**	**NGCC**	**58 Mt/yr**	
Flexible-load operation	Coal-fired technologies can operate in flexible mode instead of only base-mode	I.	CHP	NGCC	*IGCC-CCS*	2%	0
		II.	*IGCC-CCS*	CHP	NGCC	-5%	
Slow development of CCS	Advanced CCS technologies are 10 years later available	I.	CHP	NGCC	PC-CCS	-33%	-
		II.	*IGCC-CCS*	CHP	NGCC	-2%	
Storage abroad	No Dutch storage is available. However, storage options in Norway are available.	I.	CHP	NGCC	*IGCC-CCS*	-34%	-
		II.	*IGCC-CCS*	CHP	NGCC	-2%	
Higher onshore transport costs	Investment of onshore pipelines are tripled	I.	CHP	NGCC	*IGCC-CCS*	-3%	0
		II.	*IGCC-CCS*	CHP	NGCC	-4%	
Almost half of the plans to build PCs and the IGCC plan are realised before 2012	min. bound PC-2015 = 2.0 GW, min. bound IGCC-2015 = 1.2 GW (in 2010)	I.	CHP	NGCC	*IGCC-CCS*	9%	-
		II.	*IGCC-CCS*	CHP	NGCC	2%	
Almost half of PC plans and the IGCC are realised before 2012, but with capture units.	min. bound PC-post-2010 = 2.0 GW (in 2010), min. bound IGCC-pre-2015 = 1.2 GW	I.	CHP	NGCC	*IGCC-CCS*	5%	0
		II.	*IGCC-CCS*	CHP	NGCC	4%	
Nuclear is allowed	No maximum bound on nuclear capacity	I.	NUCLEAR	CHP	NGCC	-97%	++
		II.	NUCLEAR	CHP	NGCC	-89%	
Nuclear is allowed, but with high waste fee	no maximum bound on nuclear capacity and 1 euro cent/kWh waste fee	I.	CHP	NUCLEAR	NGCC	-69%	0
		II.	CHP	NUCLEAR	*IGCC-CCS*	-49%	

Variant	How	P[a]	Three technologies that produce the most electricity (at the left: highest electricity production technology)			CO_2 stored	NPV total system[b]
			1	2	3	% compared DirectAction EV	positive, negative or neutral effect[c]
DirectAction EV		**I.**	**CHP**	**NGCC**	***IGCC-CCS***	**39 Mt/yr**	**124 billion euros**
		II.	***IGCC-CCS***	**CHP**	**NGCC**	**58 Mt/yr**	
Slow development of CCS plus nuclear	Advanced CCS technologies are 10 years later available + no nuclear bound	I.	NUCLEAR	CHP	NGCC	-98%	++
		II.	NUCLEAR	CHP	NGCC	-89%	
Cogeneration may increase	no cogeneration bound	I.	CHP	*IGCC-CCS*	NGCC	-35%	++
		II.	CHP	*IGCC-CCS*	NGCC	-34%	
Higher onshore transport costs plus nuclear	No maximum bound on nuclear capacity and investments of onshore pipelines are tripled	I.	NUCLEAR	CHP	NGCC	-98%	++
		II.	NUCLEAR	CHP	NGCC	-89%	
Biomass price remains high	biomass price remains at 6 Euro/GJ over the whole period	I.	CHP	*IGCC-CCS*	NGCC	0%	0
		II.	*IGCC-CCS*	CHP	NGCC	5%	
very strict climate policy	CO2 bound is -80% instead of -50% (in 2050 compared to 1990)	I.	CHP	*IGCC-CCS*	NGCC	4%	-
		II.	*IGCC-CCS*	CHP	NGCC	1%	
High discount rate	Discount rate is 10% instead of 5%	I.	CHP	NGCC	*IGCC-CCS*	-11%	
		II.	*IGCC-CCS*	CHP	NGCC	-17%	
Coal price higher	Coal price increases to 2.0 euro/GJ in 2050 (+20%)	I.	CHP	NGCC	*IGCC-CCS*	-5%	0
		II.	*IGCC-CCS*	CHP	NGCC	-4%	
Gas and coal price higher	Coal price increases to 2.0 euro/GJ in 2050 (+20%) and gas price increases to 6.7 euro/GJ in 2050 (+20%)	I.	CHP	*IGCC-CCS*	NGCC	0%	--
		II.	*IGCC-CCS*	CHP	NGCC	0%	

[a] I. refers to the period 2015 – 2030 and II. refers to the period 2035 – 2050

[b] 'NPV (= Net present value) total system' stands for 'total discounted costs of the electricity generation sector' and is the end-value of the objective function after the linear optimisation process.

[c] Marks in this column refer to difference between NPV of specific variant and NPV of *DirectAction EV* in % (Diff_NPV). Mark is '0' when –1% < Diff_NPV < 1%, '+' when –5% < Diff_NPV < -1%, '++' when Diff_NPV < -5%, '-' when +1% < Diff_NPV < +5%, or '--' when Diff_NPV > 5%.

- When the development of power plants with capture is slow, PC-CCS will play an important role in the medium term instead of IGCC-CCS. Improvements in costs and performance that can be achieved for IGCC-CCS are relatively high compared to PC-CCS, because IGCC itself is still in an early stage of commercialization. However, these improvements are only realised when more IGCC plants are built. Since CO_2 capture is an important reason to switch from IGCC power plants to PC power plants, a slow development in CO_2 capture would also have a large negative impact on the cost development of IGCC-CCS.
- In some cases IGCC-CCS takes over second place in the medium term instead of NGCC. This is the case when gas prices are higher, so it is more expensive to operate NGCC plants. Also when biomass prices are higher, IGCC-CCS will be deployed more to reduce the CO_2 emissions in the medium term and large-scale biomass use starts only from 2035.
- When cogeneration is not restricted, it keeps its dominant role in the electricity generating park.

How much CCS is actually used in the different variants, can be deduced from the amount of CO_2 stored per year. In the *DirectAction EV* variant, 39 Mt/year is stored on average in the medium term and 58 Mt/year in the long term. In the following cases we find major deviations from these figures:

- When bounds on nuclear without a nuclear waste fee of 1 €ct/kWh and cogeneration energy are released, the CO_2 stored reduces by respectively 90% and 35% per year compared to the *DirectAction EV*.
- When progress in CCS technology is slow CO_2 storage is reduced by 33% in the medium term. However, in the long term it hardly makes a difference.
- When storage locations are only available abroad, 34% less CO_2 is stored in the medium term compared to the *DirectAction EV* variant. Apparently, it is still worthwhile to store 25 Mt CO_2/yr in this period, although the transport costs have increased from 0.7 to 3.1 €/t CO_2 on average. Again, the difference in the long term can be neglected.
- The sensitivity variant in which PC power plants are constructed in 2010, shows that around 9% more CO_2 needs to be stored yearly to realise the CO_2 targets in the medium term because of less efficient coal-fired power plants which need to be retrofitted. In the *DirectAction* variants, construction of new coal-fired power plants is rather postponed to 2020 at which moment right away power plants with CO_2 capture are constructed.
- Also, in the variant in which PC-CCS plants and an IGCC-CCS are built in the short term, more CO_2 needs to be stored due to the less developed capture process.

In Table 9 we also compare the NPV (= value of the objective function) of the sensitivity variant with the NPV of the *DirectAction EV* variant. A change of parameter can have an effect that ranges from a very positive effect (NPV decreases by more than 6200 m€) to a very negative effect (NPV increases by more than 6200 m€). As can be deduced from the

table, especially the raise in gas price (a very negative effect), and the release of bounds on CHP and nuclear without a nuclear waste fee of 1 €ct/kWh (a very positive effect) have a large effect on the NPV. In other cases, there is a slight negative effect (between 1% and 5% higher NPV) or hardly any effect. Note that a slight negative effect still may mean 100 million of additional yearly expenses for over many years. For example, the negative effect in the case that half of the PC plans and one IGCC are built in the short term, implies that around 2010 16 m€/yr has to be spent less for electricity generation, but from 2015 to the end of the model horizon 100-200 m€/yr needs to be spent extra.

2.5 Discussion

When we compare our results with outcomes of policy reports, the share of renewable energy in 2020 is low. In our study renewable energy is only applied for 5%-6% in 2020, and, except for onshore wind energy, does not appear to be a cost-effective measure to realise GHG reduction targets in the electricity sector. However, the Dutch government has an overall target of 20% renewable energy in the Netherlands for 2020 (CDA-PVDA-ChristenUnie, 2007). Therefore, special incentives will be necessary to ensure that energy companies invest in renewable energy: a follow-up of the Dutch feed-in tariff system as proposed by a combination of environmental organisations and unions, will be required (Green4Sure-project, 2007). This is even more important, if it is necessary to realise a larger share than 20% renewable energy in the electricity sector in order to achieve the national 20% renewable target. This may be the case, because it is relatively easy to introduce renewable energy in the electricity sector compared to other sectors such as industry or households.

We did not find the same conclusion as Viebahn who argued that in Germany a mix of renewable energy may be cheaper around 2033 than fossil-fired power plants with CCS (Viebahn et al., 2007). Partly, this may be caused by the fact that CCS is cheaper in the Netherlands, because of better storage opportunities, another reason is that for this study we did not consider thermal solar power from North Africa as an option for the Netherlands. Furthermore, assumptions on learning rates and performance developments are crucial in this type of analyses. A more in-depth comparison of these factors may give insight into the differences for Germany and the Netherlands.

In this analysis we have ignored a few factors that may have an impact on the results. We only looked at CO_2 reduction measures in the Dutch power sector that generate electricity for Dutch consumers only. As our study shows, it is possible to store 31 Mt CO_2/yr in the

period 2015-2030 and 56 Mt CO_2/yr between 2035 and 2050 from this sector alone. However, when also GHG reduction targets in other sectors and power generation for export are taken into account, it is most likely that it is cost-effective to store more CO_2 per year. As a consequence the Dutch onshore sinks will be filled quicker and a call upon the more expensive storage locations offshore (either on the Dutch continental plate or abroad) is necessary before 2045. The option to store another 50-100 Mt/yr from foreign CO_2 sources in the Dutch territory, as was put forward by the Workgroup Clean Fossil on CCS in the Netherlands (Workgroup Clean Fossil, 2007), would also imply that less 'cheap' storage is available for Dutch sources and a dense network to offshore gas fields is even needed earlier. Also the sensitivity analysis demonstrates that the competitiveness of CCS will decrease with less Dutch CO_2 storage available. Another question is whether it is not more cost-effective to generate electricity with CCS (or other CO_2-free products) in the Netherlands and to export this instead of storing CO_2 from abroad.

The load duration curve in this study is a simplified version of the real load duration curve. The curve is so to speak flattened. The reserve factor in the model makes up partly for this model caveat, because it ensures that sufficient capacity is installed to cover the peak load. However, the dispatch of the capacity is not according to real life: base load capacity will be dispatched more in the model, and peak load capacity less. The consequence of this caveat may be that the deployment of IGCC-CCS base load units is overestimated, which would make this option cheaper than in reality. A study with a more detailed load duration curve and more insight into how a power plant with CCS may be dispatched, can provide information to what extent the competitiveness of CCS may change.

Finally, in this study the calculation of the cogeneration potential does not take into account spatial variation of the heat demand. In the main variants we solved this problem by adhering to the cogeneration potential of the SE scenario. However, the sensitivity analysis showed that a larger role of cogeneration can reduce the need for CO2 storage by around one third. Also EnergieNed, a foundation for energy companies argued that the role of cogeneration may be bigger (EnergieNed, 2007). Although MARKAL-NL-UU does not deal with spatial aspect of cogeneration, more detailed cost-curves based on the spatial variation of heat demand, can be implemented into the model. More detailed cogeneration modelling, will also give more insight into the combination of district heating and CCS.

2.6 Conclusions

In this paper we investigated how a trajectory towards an electricity sector with CCS may look like, and how it depends on climate policy, CCS technology development, competitiveness with other mitigation options, the need for new power plants, and availability of CO_2 transport and sinks. We carried out a quantitative scenario study for the electricity sector in the Netherlands using the bottom-up, dynamic, linear optimisation model MARKAL-NL-UU, generated with MARKAL. On the basis of cost minimisation, this model provided configurations of the electricity park for the period 2000 to 2050. We analysed strategies to realise a 15% and 50% reduction of CO_2 emissions in respectively 2020 and 2050 compared to the level of 1990. Model results show that, if the Netherlands excludes nuclear power as a mitigation option and potential of cogeneration and onshore wind energy is limited, CCS is a cost-effective measure to avoid a considerable amount of CO_2 per year (around 29 Mt/yr in 2020 and 63 Mt/yr in 2050) in the electricity sector alone. In a direct action strategy in which CO_2 is reduced by 2.5 % annually from 2010, the marginal cost of CO_2 is 50 €/t in 2015 and decreases to 25 €/t CO_2 in 2050. In a postponement strategy in which CO_2 is reduced from 2020, the high marginal CO_2 cost of 50 €/t CO2 is avoided and will be 30 €/t CO_2 in 2020. In the first case the construction of the necessary infrastructure to transport around 38 Mt CO_2 annually (in 2020) may be spread over 10-15 years and in the latter case over 5 years.

The findings highlight four important factors that stakeholders need to consider in planning climate change mitigation with CCS.

At first glance, it seems wise for policy makers to wait with a severe **climate policy** till 2020. At that moment all CO_2 probably can be abated at less than 30€/t CO_2. If one already starts in 2010, abatement costs increase to 50€/t CO_2 in order to reach the reduction targets. Since it is not expected that the CO_2 price in the ETS system will be so high in the near future, this strategy would require additional subsidies or other incentives by the government. However, there are two possible disadvantages of a postponement strategy. First, the cumulative CO_2 emissions over the period 2000-2050 will be higher (around 7.4%) than when a strict climate policy is enforced from 2010. Secondly, we saw that in the postponement strategy, in a short period an infrastructure needs to be set in place for the transport and storage of around 37 Mt CO_2 per year. We expect that it is better to spread the construction over a longer period. Finally, it most likely depends on international agreements whether the Netherlands postpones action or not. In a worldwide postponement strategy, CO_2 capture technology may not improve as quickly as modelled in our study, and hence advanced capture technologies will not be available by 2020. In this case the model results shows that on average 33% less CO_2 from the Dutch electricity park, will be stored between 2015 and 2030.

Concluding, if the Netherlands aims for substantial CO_2 reductions within its own boundaries before 2020, excludes nuclear, and has limited options to increase the share of cogeneration, cheap biomass, onshore wind energy, and energy saving, a climate policy is required that makes expenditures of 50€/t CO_2 possible rather at the short term than later: a gradual increase of a CO_2 price would not be sufficient to gradually decrease CO_2 to –15% compared to the 1990 level between 2010 and 2020.

In view of the current plans of energy companies to build coal-fired power plants in the Netherlands in the short term, it may be of importance to realise that in a cost-effective CO_2 reduction strategy only between 3% and 8% of the electricity comes from coal-fired **power plants** without CCS in 2020. Ergo, most PC plants which exist today are either decommissioned, not operated anymore, or have been retrofitted in 2020. Furthermore, we conclude from the sensitivity analysis that, if PC power plants are constructed in 2010 (as is currently planned by energy companies), around 9% more CO_2 needs to be stored yearly to realise the CO_2 targets in the medium term because these 'less' efficient coal-fired power plants need to be retrofitted. According to our study it is more cost-effective to postpone the construction of new coal-fired power plants to 2020. Therefore, we conclude that long term certainty about CO_2 policy will improve planning of CCS, especially in a liberalised energy market in which energy companies tend to make investment decisions based on short term priorities.

In the case that 80% of the Dutch CO_2 sinks is indeed available for **CO_2 storage**, the timing when these sinks become available does not seem to be a bottleneck for the storage of CO_2 emissions of the Dutch electricity sector according to the model results: sufficient storage remains available over the whole period. However, already by 2040 all onshore sinks have been filled (except for the Groningen field that will not be available before 2050) and a switch needs to be made to the small offshore fields. The availability of the Utsira field in Norway instead of Dutch sinks, does not change the deployment of CCS in the long term. Between 2015 and 2030 34% less CO_2 will be stored, however, this still amounts up to 25 Mt CO_2/yr. It may, therefore, be valuable to explore the options to construct a trunk pipeline to one of the immense fields abroad.

Higher **transport** costs in the Netherlands itself have a limited impact on the cost-effectiveness of CCS. Most important is that the infrastructure is actually present when needed. Since already around three years are needed for legal procedures (Gasunie, 2005), and on top of that time for route selection and construction is required, early preparation for an infrastructure of some 450 km of CO_2 pipelines before 2020, is a pre-requisite for CCS to play a role as envisioned in this study.

Of course, in this analysis we also ignored factors that are probably of importance for the planning of CCS. First, although the electricity sector is the most likely sector for CCS to play a role, a study about planning of CCS needs to include CO_2 reduction measures in other sectors as well, especially to grasp the consequences for CO_2 storage capacity and infrastructure. Insight into the competition with other measures, can be refined by including more details on the potential of cogeneration, and by considering several development pathways of renewable energy. Finally, how power plants can be dispatched in an electricity park in which intermittent renewable energy plays an important role, requires further investigation.

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Annex I Description of cost parameters

The investment costs equal the total capital requirement (TCR) which includes the following three components (Damen et al., 2006) and (EPRI, 1993).

- The total plant costs which is the costs to erect the plant, engineering costs and contingencies (due to estimation errors or omissions). These costs also include auxiliary processes such as flue gas desulphurisation and dust removal.
- The owner costs which are the costs to develop and start up the plant.
- The interest costs that are made during the construction period. In MARKAL the construction lead period is not explicitly modelled, therefore the investment costs should include interests during construction. For the technologies taken from (Damen et al., 2006), the assumptions were that a coal power plant is built in three years (for building years 1, 2, and 3 respectively 30%, 30%, and 40% of the expenditure) and a gas fired power plant in two years (for building years 1, and 2 respectively 40%, and 60% of the expenditure). With a discount rate of 5%, this leads to respectively 5% and 2% extra costs on top of the investment costs of coal and gas-fired power plants.

The fixed operating and maintenance (O&M) costs include the costs that are related to the installed capacity. These include:

- Direct labour costs (for operation of the power plant). Often an average cost of an employee is estimated at €50000/year (IEA GHG, 2003).
- Administrative and general overhead (usually 30% of direct labour costs: EPRI).
- Maintenance costs (a percentage of installed capital costs: EPRI). Maintenance costs include maintenance materials as well as hired maintenance labour costs. If maintenance materials are classified as variable costs such as in (EPRI, 2000), than this should be transferred to fixed costs.

Variable O&M costs are those costs that are relative to the activity level. These include consumables such as water, solvents, chemicals, and waste disposal. Fuel costs are not included in the variable O&M costs, but are calculated by the model by combining the marginal price of the input fuel and the efficiency of the plant. Possible benefits from selling by-products can be subtracted from the variable costs.

Chapter 3

Effects of technological learning on future cost and performance of power plants with CO_2 capture

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Abstract

This paper demonstrates the concept of applying learning curves in a consistent manner to performance as well as cost variables in order to assess the future development of power plants with CO_2 capture. An existing model developed at Carnegie Mellon University, which had provided insight into the potential learning of cost variables in power plants with CO_2 capture, is extended with learning curves for several key performance variables, including the overall energy loss in power plants, the energy required for CO_2 capture, the CO_2 capture ratio (removal efficiency), and the power plant availability. Next, learning rates for both performance and cost parameters were combined with global capacity projections for fossil-fired power plants to estimate future cost and performance of these power plants with and without CO_2 capture. The results of global learning are explicitly reported, so that they can be used for other purposes such as in regional bottom-up models. Results of this study show that IGCC with CO_2 capture has the largest learning potential, with significant improvements in efficiency and reductions in cost between 2001 and 2050 under the condition that around 3100 GW of combined cycle capacity is installed worldwide. Furthermore, in a scenario with a strict climate policy, mitigation costs in 2030 are 26, 11, 19 €/t (excluding CO_2 transport and storage costs) for NGCC, IGCC, and PC power plants with CO_2 capture, respectively, compared to 42, 13, and 32 €/t in a scenario with a limited climate policy. Additional results are presented for IGCC, PC, and NGCC plants with and without CO_2 capture, and a sensitivity

analysis is employed to show the impacts of alternative assumptions on projected learning rates of different systems.

3.1 Introduction

Carbon dioxide capture and storage (CCS) is a CO_2 abatement option that can contribute substantially to achieve ambitious CO_2 reduction targets. The electricity sector especially, with large point sources of CO_2, offers opportunities to apply CCS at a large scale (IPCC, 2005). Results of techno-economic energy models[1] show that power plants combined with CCS can indeed compete from a mitigation perspective with other non- or low-emitting CO_2 technologies such as nuclear energy or renewable energy. Necessary pre-conditions are strict climate policies, a decrease in the cost of CCS, and more specifically, an improvement in the performance of capture technologies by technological learning (IPCC, 2005; EC, 2006; IEA, 2006a; MIT, 2007).

In various energy models, the assessment of CO_2 capture (CC) technology development in relation to changing market conditions and policies is an important, but uncertain factor (Rubin et al., 2004a; Berglund and Soderholm, 2006). One way to estimate the future costs of power plants with CC is to use bottom-up techno-economic engineering models[2] (David and Herzog, 2000; Gray et al., 2004; IEA GHG, 2004; Peeters et al., 2007) which are based on in-depth analysis of possible technical innovations. Another method is to use the concept of learning curves as applied, for example, by Riahi (Riahi et al., 2004) and more recently by Rubin (Rubin et al., 2007b). The learning curve method is based on the empirically observed phenomenon that unit costs often tend to decline by a constant percentage for each doubling of production or capacity.[3] This method provides insights into the pace at which a technology can improve and how this depends on market developments.

[1] A wide variety of techno-economic models is available that calculate the least costing electricity generating mix in context of a socio-economic changing environment with constrains on carbon emissions. Examples of these models are MARKAL at ETSAP, MESSAGE at IIASA, NEMS at EIA, POLES at Enerdata (Uyterlinde et al., 2006). Technological change of energy technologies is also represented in top-down models as described by McFarland et al. (McFarland et al., 2004).

[2] Bottom-up engineering estimates are based on expert judgements on the potential development of disaggregated components of power plants.

[3] Wright already described in 1936 that unit labor costs for the manufacture of airplanes declined at a constant rate per doubling of cumulative output by cumulative experience of the workers (Junginger et al., 2005). This phenomenon is now described in many other case studies such as for energy technologies (McDonald and Schrattenholzer, 2001) and CCS (Riahi et al., 2004; Rubin et al., 2007b).

However, the methodology to assess the rate at which CC technology develops could be improved with respect to the following aspects:

- Often the learning curve method is applied to identify and estimate cost reduction trends in the capital costs of energy technologies. For technologies of which the capital cost is indeed the decisive factor, like wind turbines (Junginger et al., 2005) and photovoltaic (Zwaan and Rabl, 2003), this is sufficient. However, for CC, it is also necessary to get insight into the future trends of performance variables such as power plant efficiency, availability[4], CO_2 capture ratio (CCR), and the energy requirements of the CO_2 capture process, because performance improvements in these parameters can have a significant impact on electricity and CO_2 mitigation costs.
- While early publications of learning curves were actually based on physical measures such as labour efficiency (Sharp and Price, 1990), they are nowadays mostly applied to identify cost trends. However, Yeh and Rubin (2007) also used them to assess the efficiency improvements of pulverised coal-fired power plants. Asymptotic limitations to the improvement of efficiency were not yet taken into account.
- Although research has been done to identify learning curves in efficiency (Yeh and Rubin, 2007) and availability (Joskow and Rozankski, 1979; Lofe and Richwine, 1985), no effort has been undertaken to integrate learning curves of performance variables with those of cost variables. This combined effect may have a significant influence on the development of CO_2 mitigation costs and, thus, on the future deployment of CCS.
- It is more interesting to know "when technologies become cost-effective due to learning" than getting insight into specific learning rate figures. Learning rates are, therefore, used in techno-economic models[5] to determine the penetration of technologies and the accompanying reduction in capital costs. Because learning is often achieved at a global level nowadays[6], learning rate models typically apply to large markets and geographical areas (such as all of Europe or the entire world). Unfortunately, techno-economic modelling studies usually report the resulting penetration of technologies on this large scale, and not the resulting cost reductions over time. Consequently, data on cost reductions are not available for models at a regional or national level. However, also at this level, it would be useful to know how learning may affect the penetration of technologies. A solution is to combine learning

[4] In this article, "efficiency" refers to the "net efficiency of power plants based on lower heating value", and "availability" to the "availability of the power plants".
[5] Examples of models with endogenous learning are MARKAL (Smekens, 2005), POLES (EC, 2006), and NEMS (EIA, 2004).
[6] The world markets of gas and steam turbines for power plants are, dominated by a few leading players among which Siemens, GE, Alstom, and Mitsubishi (Beckjord, 2003; McGovern and Hicks, 2004). When companies supply all over the world, their knowledge and technology is applied on a global level, and, therefore, as Junginger argues for the wind turbine market (Junginger et al., 2005), we can conclude that one can speak to a large extent of "global" learning.

rates with cumulative capacity projections, so that cost trends can be extrapolated to the future. However, this has only been done to a limited extent such as for wind energy (Verrips et al., 2005).

- Learning in components that are shared by different applications has an influence on cost reductions and performance improvement in all these applications. These technology spillover effects should be addressed in the model.

The objective of this paper is to investigate whether the concept of learning curves can be applied in a consistent manner to performance as well as cost variables so that learning in all relevant variables is coherently taken into account for the assessing the future development in CC power plants. Our focus is to identify cost reductions and performance improvement in natural gas-fired combined cycle (NGCC) and pulverised coal-fired (PC) power plants with post-combustion CC as well as in integrated coal-gasification combined cycle (IGCC) power plants with pre-combustion CC. Since the development of these power plants is closely related to that of their counterparts without CC, these are also included in this analysis. This paper also demonstrates how learning curve models with projections of future global power plant capacity can be combined to derive estimates of future plant costs and CO_2 mitigation costs.

Our approach consists of three steps. First, the effect of technological learning on the performance variables is quantified, specifically, plant-level energy loss (instead of efficiency), CCR, energy use of CC, and availability. Whenever possible, we base these learning trends on existing literature. Otherwise, we attempt to collect historical data on the performance variables, and the cumulative installed capacity of power plants to analyse whether a log-linear relation exists between the performance improvement and the cumulative installed capacity. In the second step, we extend the spreadsheet CMU model developed by Rubin et al. (IEA GHG, 2006) at Carnegie Mellon University (CMU) that provided insight into the potential learning of cost variables in power plants with CC. We add learning in several key performance variables to this model so that the combined impact of cost and performance improvements can be quantified. Furthermore, power plants without CC are included in the model to calculate the CO_2 mitigation costs. The extended CMU model will be further referred to as CMU/UU model. In the final step, projections of capacity growth from global energy modelling studies are added in order to make time-based trends of performance improvement and cost reductions for power plants with and without CC. Finally, a sensitivity analysis sheds light on the uncertainty of the results.

The structure of this paper is as follows. Section 3.2 covers the methodology of how learning trends are analysed and how projections of power plant capacities are used to make time-based trends. Section 3.3 describes historical trends based on empirical data, and how these lead to learning parameters used as input in the CMU/UU model. Section 3.4 presents the

results of the CMU/UU model and a sensitivity analysis. Finally, this paper concludes with a discussion of the results and methodology (Section 3.5) and overall conclusions (Section 3.6).

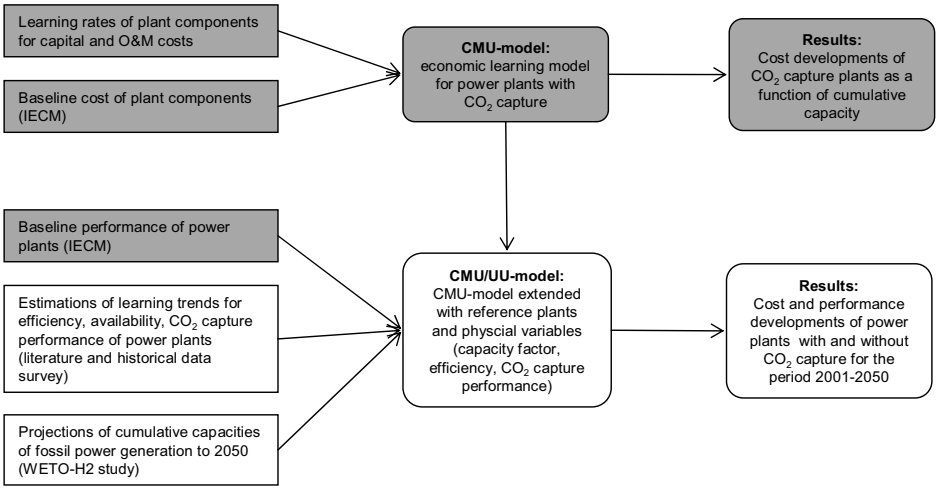

Figure 1 Schematic of how CMU model is extended in this paper (grey boxes refer to previous CMU study and white ones to this paper)

3.2 Methodology

3.2.1 Overview

Figure 1 shows how this research builds on the CMU model developed earlier by Rubin et al. (IEA GHG, 2006) to estimate learning trends in costs of power plants with CC. In this model learning trends were appraised by splitting up power plants into different components (e.g. power block, air pollution control, or CC unit) for which the learning potential was assessed[7]. The authors derived the learning parameters for these components from the developments of seven technologies[8] that match or resemble power plant components, and they based

[7] Insight in learning mechanisms can be provided by splitting up a learning system in different subsystems (Junginger et al., 2005). This component learning method was also applied for cost reduction estimations of photovoltaic systems (Schaeffer et al., 2004), offshore wind farms by (Junginger et al., 2005), and CC (Riahi et al., 2004; IEA GHG, 2006).

[8] Flue gas desulphurisation system (FGD), selective catalytic reduction system (SCR), gas turbine combined cycle power plant (GTCC), pulverized coal boiler (PC-boiler), liquefied natural gas production plant (LNG), oxygen production plants, and steam methane reforming system (SMR) for hydrogen production (IEA GHG, 2006).

costs on the Integrated Environmental Control Model (IECM, 2007)[9]. In this research we extend the CMU model to include several power plant performance variables which also influence future costs. Next, learning parameters for these performance variables are assessed (section 3.2.3). Then, projections of capacity growth from a modelling study are added to estimate learning effects during the analysis period from 2001 to 2050 (section 3.2.4), taking into account technology spillover effects (section 3.2.5). Finally, alternative assumptions regarding relevant learning parameters are explored in a sensitivity analysis (section 3.3.9).

In this study, a fixed capital charge factor of 11%[10] is used, prices are given in $€_{2005}$ unless otherwise stated, and "t" always refers to "t CO_2". All efficiencies are based on the lower heating values of the fuels.

3.2.2 Theoretical background

This section includes a brief overview of the concepts and definitions that underlie the results of this paper.

3.2.2.1 Performance parameters

Single-factor learning curve model

The concept of a technological learning curve, or experience curve, is based on the empirically observed phenomenon that unit costs often tend to decline by a constant percentage for each doubling of production (Equation 1 to Equation 4) (Junginger et al., 2005). If the unit costs are plotted against the cumulative production on a log-log scale this relationship is then a straight line (Equation 2). This curve is commonly called the experience curve.

$$C_{Cum} = C_0 \, Cum^b \qquad \text{Equation 1}$$

$$\log C_{Cum} = \log C_0 + b \log Cum \qquad \text{Equation 2}$$

[9] The IECM is developed at the CMU with support of the National Energy Technology Laboratory of the US Department of Energy. The IECM is subject to continuous development with the latest version (5.2.2) being able to assess the economic, environmental and physical performance of GTCC, PC, IGCC, and Oxyfuel power plants with addition of various modules for NO_x, SO_2 and CO_2 (IECM, 2007; Rubin et al., 2007b). The model calculates the outcomes using basic laws of thermodynamic and chemical relations. More complex processes, like the gasification process, are modelled in ASPEN+ and integrated in the IECM model as data tables for a wide range of conditions (Rubin et al., 2007a).

[10] The fixed charge factor is based on a 10% discount rate, and 30 year life time.

PR = 2^b Equation 3

LR = $1-2^b$ Equation 4

C_{Cum} = Costs for the last unit[a]
Cum = Cumulative production
C_0 = Costs for first unit
b = Experience index
PR = Progress ratio
LR = Learning rate

[a] In this study, costs are either expressed in €/kW for the investment costs or €/MWh for the operating and maintenance costs (O&M), and Cum is measured in GW. Furthermore, apart from applying this formula to the costs, it is also applied to the net efficiency of power plants.

Availability

The availability factor of a power plant is defined as the amount of time that a power plant is able to produce electricity divided by a reference period as in Equation 5 (Boyce, 2002). It is one of the most important indicators of power plant performance, both from a technical and economic perspective (WEC, 2004). A power plant is unavailable when it is offline for scheduled maintenance (planned outage) or if unexpected problems occur (forced outage).

$$A = \frac{P - S - F}{P}$$ Equation 5

A = availability
P = period of time (usually 8760 hours per year)
S = scheduled outage (hours per year)
F = forced outage (hours per year)

For the availability factor, another model is used to estimate the trend in availability over time. This so-called time constant model (Equation 6) was developed by Towill (Towill, 1990; Naim and Towill, 1993).

$$Y_{M(t)} = Y_c + Y_f(1 - e^{-t/\tau})$$ Equation 6

$Y_{M(t)}$ = availability at time t
Y_c = initial availability
Y_f = maximum amount the availability can increase
$Y_c + Y_f$ = maximum achievable availability
τ = time constant (a measure of the speed of improvement)

Capacity factor

To calculate electricity generating costs, the actual amount of electricity generated over a period of time is required. This is normally represented by the plant capacity factor (Equation 7), which is a measure that defines the energy a plant generates as a fraction of the maximum generating capacity during a reference period (typically one year) (VGB, 2006). Note that the plant capacity factor cannot exceed the plant availability over any given period.

$$CF = \frac{E_{out}}{E_{\max}} \qquad \text{Equation 7}$$

CF = capacity factor
E_{out} = net amount of electricity produced per year (MWh)
E_{max} = net plant capacity (MW) * reference period (hours per year)

Plant efficiency

The efficiency of a power plant is defined as the fraction of net useful electricity output to the total energy input to the plant (Equation 8). An important distinction must be made between the efficiency expressed in lower heating value (LHV) and in higher heating value (HHV). The HHV includes the condensation energy of water produced during combustion in the energy content of the fuel while in case of the LHV, the energy content is given with water in gaseous form (Blok, 2007). Efficiencies in this paper are expressed as net generating efficiencies on a LHV basis if not mentioned otherwise. It should be noted, however, that this factor depends on fuel properties. We used a factor of HHV/LHV = 1.04 for coal and HHV/LHV = 1.11 for natural gas to calculate the LHV efficiencies of the power plants in the Integrated Environmental Control Model (IECM) which employs HHV (IECM, 2007).

$$\eta = \frac{E_{out}}{E_{in}} \qquad \text{Equation 8}$$

η = net plant efficiency
E_{in} = total energy input per unit of time (MWhth)
E_{out} = net amount of electricity produced per unit of time (MWh)

CO_2 capture ratio

The CO_2 capture ratio (CCR) is defined as the amount of CO_2 captured divided by the amount of CO_2 produced when the used fuel is combusted (Dijkstra et al., 2006).

$$CCR = \frac{Amount\ of\ CO_2\ captured}{Amount\ of\ CO_2\ produced\ when\ combusting\ the\ fuel\ used} \qquad \text{Equation 9}$$

CCR = CO_2 capture ratio

Efficiency and energy penalty in power plants with CO_2 capture

The efficiency of an NGCC or PC with post-combustion CO_2 capture depends on the efficiency of the reference plant, being an NGCC plant for NGCC-CC, and a PC plant for PC-CC. From this reference efficiency, the equivalent electrical energy needed for capturing and compressing the CO_2 from the flue gas is subtracted (Equation 10). Although a large amount of thermal energy for CO_2 capture is used in the form of low temperature steam, that energy requirement for capture can be expressed as a loss in electricity produced for a fixed energy input to the plant.

$$\eta_{CCS} = \eta_{reference} - (Q_{capture}\alpha + W_{compr}) * CCR * EF_{CO_2}$$ Equation 10

$Q_{capture}$ = thermal energy requirement (MJ_{th}/t CO_2 captured)
α = thermal energy to electricity ratio (MJ_e/MJ_{th})
$W_{compr.}$ = CO_2 compression energy (MJe/t CO_2 captured)
CCR = CO_2 capture ratio
EF_{CO2} = emission factor CO_2 from coal or natural gas (t CO_2/MJ_{th})

The efficiency for the reference IGCC plant is based on the combined cycle efficiency fueled with syngas multiplied by the cold gas efficiency minus the energy requirement for other processes, see Equation 11. The efficiency for IGCC with pre-combustion CO_2 capture is similar to the reference IGCC but is based on the combined cycle efficiency fueled with H_2 and additional energy losses due to the CO_2 capture (i.e. for the water gas shift reaction and the Selexol capture unit).

$$\eta = \eta_{GTCC}\eta_{coldgas} - \frac{W_{aux}}{E_{in}}$$ Equation 11

η = net efficiency of IGCC power plant.
η_{GTCC} = combined cycle efficiency (fueled with syngas in reference IGCC and with hydrogen in IGCC with CO_2 capture).
$\eta_{coldgas}$ = cold gas efficiency
W_{aux} = energy requirement for air separation unit (ASU), sulphur removal, and gasification in reference IGCC per unit of time (expressed as loss in electricity output in MWh). In IGCC with CO_2 capture also for capture process using Selexol minus energy recovered from water gas shift (WGS) reaction.
E_{in} = total energy input per unit of time (MWh_{th})

Efficiency and energy penalty in power plants with CO_2 capture

The energy penalty of a power plant with CCS is defined as the change compared to the net plant efficiency of the reference plant (Equation 12) due to the capture unit (Rubin et al., 2004b).

$$EP = 1 - \left(\frac{\eta_{CCS}}{\eta_{reference}} \right) \qquad \text{Equation 12}$$

EP = energy penalty
η_{CCS} = efficiency of power plant with carbon capture
$\eta_{reference}$ = efficiency of power plant without carbon capture

3.2.2.2 Cost parameters

Power plant cost factors include capital investments, O&M cost and the cost of fuel which are used to calculate the electricity generation cost. We used the IECM model to provide the baseline costs of the power plants after comparing them with cost estimates in publications from IPCC, IEA, and Utrecht University (see section 3.3.7). The cost factor categories in the IECM model are based on the EPRI Technology Assessment Guide (EPRI, 1993) [11].

Capital cost

Calculations on technology investment cost are based on the total capital requirement (TCR), including total plant investment and royalty fees, startup costs and initial inventories of stock feed. The TCR of power plant technologies in this paper are calculated using the IECM model. A detailed description of the assumptions of the TCR can be found in the IECM manual or the IECM-model itself (IECM, 2007). For example, details with respect to IGCC are described in (Rubin et al., 2007a), and for amine-based CO_2 capture systems in (Rao et al., 2004).

O&M cost and fuel cost

The O&M cost or annual cost consists of three factors: fixed O&M cost, variable O&M cost and fuel cost. The fixed O&M cost includes cost of labor for operating, maintenance and administration & support, and cost of materials for maintenance. The variable O&M cost consists of consumable products like chemicals, water and electricity. Also cost for waste disposal and credits for by products like sulfur or gypsum are included in the variable cost component. The cost of fuel is considered a separate factor from the variable O&M cost due to its large impact on total O&M cost and its direct relation with the net plant efficiency. To

[11] EPRI's cost categories have not changed since 1993, however EPRI (1993) is the last publicly available version of the Technology Assessment Guide. Later versions are proprietary (Rothwell, 2004).

address for changing plant utilization, O&M cost are subdivided into a variable and fixed component.

Levelized cost of electricity generation

The levelized cost of electricity (COE) generation is calculated using Equation 13.

$$COE = \frac{(TCR * \alpha + FOC)}{8.76 * CF} + \frac{COF * 3.6}{\eta} + VOC \qquad \text{Equation 13}$$

$$\text{with } \alpha = \frac{r}{1-(1+r)^{-L}} \qquad \text{Equation 14}$$

COE	=	levelized cost of electricity (€/MWh)
TCR	=	total capital requirement (€/kW)
α	=	capital recovery factor (Equation 14)
FOC	=	Fixed O&M cost (€/kW per year)
COF	=	cost of fuel (€/GJ)
VOC	=	variable O&M cost (€/MWh)
CF	=	capacity factor
η	=	net plant efficiency
r	=	discount rate (fraction)
L	=	plant life time (years)

CO_2 mitigation cost

The mitigation cost of CO_2[12] is expressed as the incremental cost of electricity generation for a CCS plant compared to a reference plant without CCS, divided by the difference in CO_2 emission rates per kwh of net plant output (Equation 15) (Damen et al., 2006). For the reference plant we chose the same technology without CO_2 capture.

$$\mathrm{MC}_{\mathrm{CO}_2} = \frac{COE_{capture} - COE_{reference}}{m_{CO_2,reference} - m_{CO_2,capture}} \qquad \text{Equation 15}$$

MC_{CO2}	= CO_2 mitigation cost (€/t CO_2)
$COE_{capture}$	= COE capture plant (€/MWh)
$COE_{reference}$	= COE reference plant (€/MWh)
$m_{CO2,reference}$	= CO_2 emissions reference plant (t CO_2/MWh)
$m_{CO2,capture}$	= CO_2 emissions capture plant (t CO_2/MWh)

[12] Note that transport and storage (T&S) costs of CO_2 are excluded.

3.2.3 Assessment of learning parameters for performance variables

Historical data on values of the performance variables and the corresponding cumulative installed capacity of the relevant power plant components are searched for in literature and databases. These data are used to analyse whether there is a (log-linear) relation between each variable and the cumulative installed capacity. If so, the progress ratio is determined; otherwise, alternative assumptions are made to model the improvement of the performance variables in the CMU/UU model. In the CMU model a lower bound and upper bound for the progress ratio of capital and O&M cost were defined to characterize the uncertainty in these ratios. Similarly, we choose for each progress ratio, a best estimate or the "nominal" value, a conservative and an optimistic one. In combination with projections of future capacities, this results in a learning uncertainty range for cost reductions and performance improvement of the power plants in the CMU/UU model.

Cost during early commercialisation of technologies may increase rather than decrease[13], due to technological optimism and uncertainties in scale-up estimations based on pilot and prototype data. To address this issue, (Rubin et al., 2007b) argues that learning only starts when a certain amount of experience is gained. The length of such a pre-learning phase is dependent on the complexity, maturity and scale of the technology. Rubin based these pre-learning phases on empirical trends of selective catalytic reduction (SCR) and flue gas desulphurization (FGD) capital costs plus judgements of technology maturity (Rubin et al., 2004a; IEA GHG, 2006) resulting in a pre-learning phase of 3 GW installed capacity for NGCC-CC, 5 GW for PC-CC, and 7 GW for IGCC-CC. We use these figures and add a 6 GW[14] pre-learning period for the IGCC reference plant, while for the mature NGCC and PC reference plants we assume that learning continues from current costs.

3.2.4 Future projections of fossil-fired power plants

To estimate future cost reductions and performance improvements with learning curves, cumulative capacity projections of technologies are required. Since learning in this domain happens on a global level[15], we need global projections. These can be found in integrated

[13] Similar to (Colpier and Cornland, 2002; Rubin et al., 2004a) observed progress ratios >100% for capital and O&M cost during early stages of commercialisation for FGD and SCR in coal-fired power plants.

[14] We assume that the pre-learning phase of an IGCC without capture is slightly less than of an IGCC with capture.

[15] The production and development of energy technologies takes place in range of multinational companies that operate on a global market. Nevertheless, the majority of historic capacity (see section 3.3.1), is deployed in Western Europe, the US and Japan, while a large part of the future deployment of new power generation

global assessment studies, particularly in studies that use energy bottom-up models in which individual energy technologies are represented (McFarland et al., 2004). Unfortunately, results of such bottom-up models rarely report the capacity growth of specific energy technologies. Instead results like the total amount of CO_2 captured (IPCC, 2005) or the aggregated capacity of CCS power generation in 2050 (IEA, 2006a), are usually reported.

Global capacity projections of fossil-fired power plants with and without CCS up to 2050 are, however, available from the WETO-H_2 study (EC, 2006; Kitous, 2007). We therefore use these as input for the CMU/UU model. In that study a reference scenario (REF), a carbon constraint scenario (CCC), and a hydrogen technology scenario were implemented in the POLES model to explore technology options and climate policies. In this paper, we use the results of REF in which a continuation of existing economic and technological trends is assumed, along with a carbon tax to discourage CO_2 emissions, and CCC with more stringent policies that aim to stabilize the CO_2 concentration in the atmosphere at 500 ppmv by 2050. These cases differ mainly with respect to the level of a carbon tax: in the REF scenario the CO_2 tax increases from 5-10 €/t in 2010 to 30 €/t in 2050 for Annex B countries, and from 0 to 15 €/t CO_2 for non-Annex B countries. In the CCC scenario, the CO_2 tax increases from 10 €/t CO_2 in 2010 to 200 €/t CO_2 in 2050 globally.

Table 1 Power plants and their components

Plant Type \ Component	GTCC power block	PC-boiler/ steam turbine generator area	CO_2 capture (amine system)	CO_2 capture (WGS/Selexol)	CO_2 compression	Air separation unit	Gasifier area	Sulphur removal/ recovery	Air Pollution controls (SCR, ESP, FGD)
NGCC	x	-	-	-	-	-	-	-	-
NGCC-CC	x	-	x	-	x	-	-	-	-
IGCC	x	-	-	-	-	x	x	x	-
IGCC-CC	x	-	-	x	x	x	x	x	-
PC	-	x	-	-	-	-	-	-	x
PC-CC	-	x	x	-	x	-	-	-	x

x = component is part of power plant; - = component is not part of power plant

capacities will be in rising economies like China and India. It is outside the scope of this paper, to take into account that regions may contribute in a different way to the global learning trends.

3.2.5 Technology spillover

To account for technology spillover between different types of power plants[16], a method developed for the MARKAL model is used (Feber et al., 2003). Similar methods are also applied in the NEMS model of EIA (EIA, 2004). The power plants are divided into components each capable of performing a certain function. In order to estimate the learning potential, the capacity of individual components applied in different type of power plants is summed. Table 1 depicts which components are distinguished per power plant type. The GTCC power block component is part of both NGCCs and IGCCs, because in this paper it is assumed that future designs of hydrogen or syngas-fired GTCCs in IGCCs are similar to natural gas-fired GTCCs (IEA GHG, 2006). However, the GTCC power block is represented as one component instead of a separate steam and gas turbine, since data on costs and performance of these separate components are less readily available. Thus, technology spillover from the PC steam turbine to the GTCC steam turbine cannot be addressed.

In this method the experience of components in the power plants with CC is slightly underestimated, because their capacities are measured on the basis of net electricity generating output. However, gross capacity of the power block of power plants with CC is larger than that of those without CC when their net capacity is the same.

[16] In this paper, we only consider technology spillover between power plants, and leave out experience from other applications. Thus, the experience of gasifiers in syngas production is not taken into account. Furthermore, it is assumed that gas turbines do not share experience with jet engines or industrial gas turbines. However, the overall effect is expected to be small, because including gas turbines from different markets would also result in a larger current experience base.

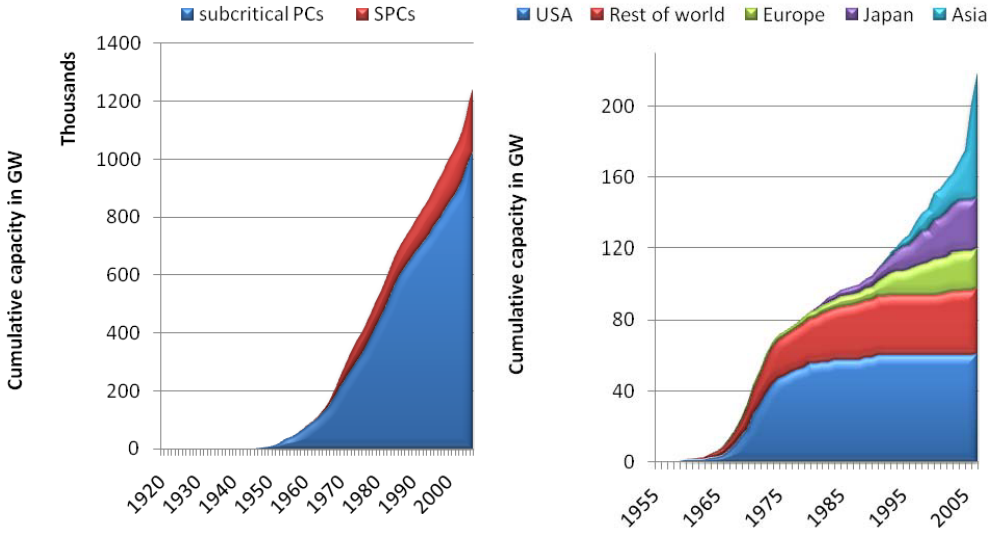

Figure 2 Global cumulative capacity of all PC power plants (top) and SPCs only (bottom) based on data from (IEA Clean Coal Centre, 2007)

3.3 Data and assumptions

This section describes the data that underlie the input parameters of the CMU/UU model, with emphasis on the assessment of the progress ratios for the performance variables.

3.3.1 Historic development of power plant capacities

3.3.1.1 Pulverized coal plants

According to Yeh et al. (2007), the growth of PC capacity was high in the United States (US) from the 1950s due to the growing economy and peaked globally in the late 1960s and 1970s. In the 1980s and 1990s, a downturn in economic activity resulted in less growth of electricity demand and consequently new power plant capacity in the US and later in Europe. Furthermore, the interest shifted from PC towards NGCC (Watson, 1997; Lako, 2004), (see section on NGCC). However, global PC capacity continued to grow due to the demand in developing economies: as shown in Figure 2, the total PC capacity grew to almost 1200 GW in 2005 (EIA-DOE, 2008), and, for example, in China it increased rapidly with 70 GW additional capacity in 2005 (MIT, 2007) and 105 GW in 2006 (EPRI, 2007).

Supercritical pulverized-coal-fired power plants - SPCs

Although the first PCs with supercritical[17] steam cycles were already commissioned in the 1960s, reliability problems, low coal prices and decreasing demand for new capacity, hampered the growth of these units in the US. While between 1970 and 1974, 63% of new installed PC capacity was supercritical, these units were practically abandoned in the 1980s (IEA GHG, 2006). However, later in Europe and Japan high coal prices and a better coal quality justified a renewed development of SPCs. With almost 180 GW of cumulative experience in 2005 (see Figure 2), proven reliability[18], and efficiencies up to 46%, SPC is now also regaining interest in the US (IEA GHG, 2006).

[17] Supercritical PC plants operate at steam temperatures >540 ^{o}C at which water and steam have the same density and water does not “boil” anymore making steam and water indistinguishable (ASME, 2003). Steam plants operating at steam temperatures >580 ^{o}C are called ultra supercritical (IEA, 2006a).

[18] For example, the availability of the SPC Hemweg 8 plant in the Netherlands averaged 92% between 1998 and 2000 (DTI, 2006).

3.3.1.2 IGCC plants

The first IGCC power plant was commissioned in 1984, and currently only four IGCC utility plants, each between 250 and 300 MW in size, are in commercial operation (with some governmental financial support) (MIT, 2007), with a total capacity of around 1.5 GW (IEA Clean Coal Centre, 2007). Experience in IGCC technology has been gained more rapidly in the industrial sector (mainly petrochemicals) where these units are fuelled with refinery wastes, asphalt, or petroleum coke to produce heat, electricity and other products (MIT, 2007). If the industrial units that generate electricity are also taken into account, the IGCC electricity generation capacity amounts to 5.5 GW[19] (DOE and NETL, 2007). Since the technology is still in the early stages of commercialisation, it is not yet possible to create a learning curve supported by empirical data.

3.3.1.3 NGCC plants

Figure 3 shows the cumulative capacity growth of NGCCs. The first NGCC power plant was installed in the US in 1949 (Chase and Kehoe, 2001). After large power blackouts in the United Kingdom (UK) and US in the mid-1960s, interest in gas turbine technology grew because of its relative short construction time and flexibility. NGCC capacity began to grow after 1978, when the US government launched the Public Utility Regulatory Policies Act to stimulate more efficient and environmentally-friendly electricity production, (Watson, 1996). When oil and gas prices dropped in 1986, and many electricity markets were privatized (starting in the UK), interest in NGCC increased even more rapidly. Its relatively low capital cost, short construction time and efficiencies reaching 55% in the 1990s, made NGCC a popular choice in competitive electricity markets. In most of the world, increased natural gas prices and less growth in capacity demand restrained the popularity of NGCCs in the 2000s. However, global capacity continued to grow due to the construction of 200 GW of NGCCs from 2000 to 2004 mainly in the US (IEA, 2006b). In 2003, the global installed NGCC capacity was over 350 GW (IEA, 2006a).[20]

[19] According to the National Energy Technology Laboratory (DOE and NETL, 2007), 144 gasification plants were installed in 2007 including 427 gasifier units with a capacity of 56 GWth which is roughly equivalent to 29 GW. 19% of this capacity (5.5 GW) is used for electricity production (26 units).

[20] In 2003, the total gas-fired electricity generation capacity was 915 GW (IEA, 2006a), which consisted of 38% NGCCs, 25% gas turbines, 36% steam turbines, and 1% internal combustion engines.

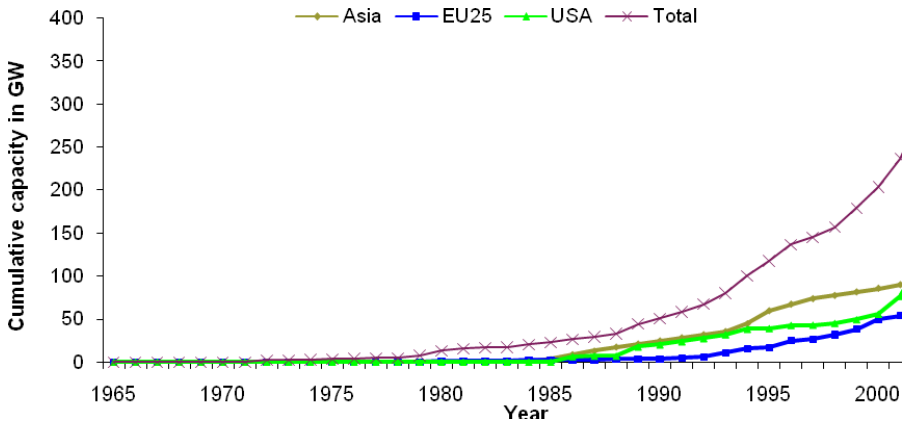

Figure 3 Cumulative capacity of NGCC. Data for OECD countries based on (Argiri, 2007; IEA, 2007b), corrected for non-OECD countries based on (Watson, 1996; Watson, 1997; Colpier and Cornland, 2002; Watson, 2004)[21]

3.3.2 Future power plant capacities

3.3.2.1 Capacity projections per power plant type

Kitous (2007) provided detailed projections for new capacity of different types of fossil-fuel-fired power plants for the WETO-H_2 scenarios noted earlier (see Figure 4).[22] In this study, the global electricity demand of 15000 TWh in 2001 (57% generated by fossil-fired power plants) grows to ~59000 TWh (35-48% generated by fossil-fired power plants) in 2050. In the REF scenario, fossil-fired generation capacity will be constructed will grow from ~1300 GW in 2001 to ~3600 GW in 2050 to fulfil this demand. Deployment of coal-fired power plants with CO_2 capture (mainly IGCC-CC) starts in 2025 due to the CO_2 tax[23] while NGCC-CC is not constructed at all. By 2050 13% of the capacity is equipped with CO_2 capture.

21 The world cumulative capacity of NGCCs is based on a variety of sources because no single accurate database appears to be available. Furthermore, NGCC manufacturers consider the deployment rate of NGCCs confidential (Siemens, GE).

[22] This figure also includes available data on existing power plants. Decommissioning of the PCs is based on the following assumptions: according to (Lako, 2004) around 30% of these coal-fired power plants were older than 30 years in 2005, and the replacement rate may need to be between 20-40 GW per year in the period after 2005.

[23] Note that also in the REF scenario a CO_2 tax is applied that increases to 30 €/t CO_2 in 2050 for Annex B countries and 15 €/tonne CO_2 for non-Annex B countries.

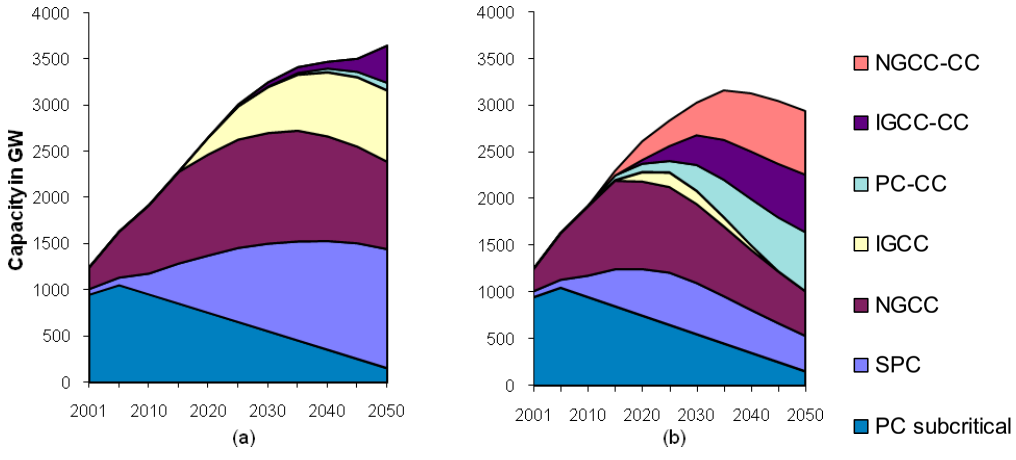

Figure 4 Capacity 2001 and future capacity for scenarios REF (a) and CCC (b) based on data from (IEA GHG, 2006; Kitous, 2007)

In the CCC scenario, although ambitious CO_2 abatement policies are initiated, power generation from fossil fuels continues to grow from ~1300 GW in 2001 to ~3200 GW in 2035 and then starts to decrease. The share of fossil fuel power generation capacity with CO_2 capture is 66% in 2050. Table 2 displays the maximum cumulative capacity (including replacement capacity) that is reached, and the number of capacity doublings per power plant type in the analysis period. These doublings only give an indication of the learning potential of each power plant type, because the added effects of technology spillover (which are taken into account in the CMU/UU model) are not shown.

Table 2 Number of doublings based on the WETO-H_2 scenarios

	Reference scenario			CCC scenario		
	Cumulative capacity		Number of doublings[b]	Cumulative capacity		Number of doublings[b]
-	Year[a]	GW		Year[a]	GW	
SPC	2050	1385	4.5	2025	601	3.3
PC-CC	2050	81	4.0	2050	635	7.0
IGCC	2050	769	7.0	2025	153	4.7
IGCC-CC	2050	403	5.8	2050	615	6.5
NGCC	2050	2059	3.1	2050	1578	2.7
NGCC-CC		0	0.0	2050	680	7.8

[a] Year after which the maximum cumulative capacity is reached.
[b] Doublings when learning starts after 5 GW for PC-CC, 6 GW for IGCC, 7 GW for IGCC-CC, and 3 GW for NGCC-CC

3.3.2.2 Capacity projections per technology component

To account for technology spillover, the capacity projections of the power plant technologies are converted to projections per technology component (see Figure 5). The GTCC power block, which is part of both the NGCCs and IGCCs (with and without CC), has a combined experience of more than 3250 GW in both scenarios in 2050. The additional experience of the GTCC power block (~3100 GW) is due to different additional capacities

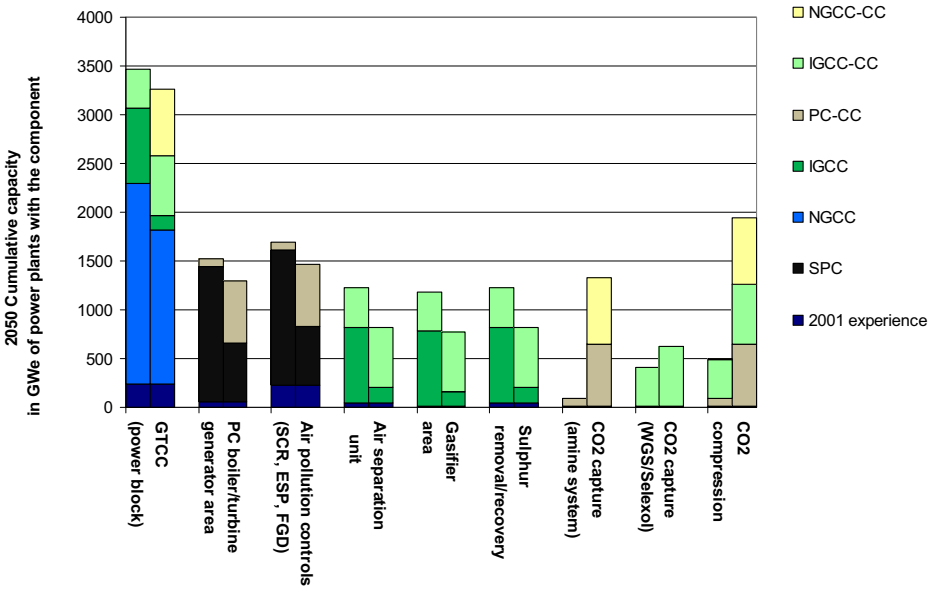

Figure 5 2050 cumulative capacity projections for technology component: REF (left columns), CCC (right columns) including the 2001 experience (excluding capacity for subcritical PC)

of NGCC, NGCC-CC, IGCC, and IGCC-CC power plants in the two scenarios. The SPC boiler gets an additional experience of ~1300 GW between 2001 and 2050 in both scenarios. Whereas in REF this is mainly a result from the capacity growth of SPCs without capture, in CCC it is half from the growth of SPCs without capture and half with capture. The REF and CCC scenarios differ especially for specific capture plant components (amine and Selexol CO_2 capture and CO_2 compression) since these components are more dependent on a strict climate policy. Finally, the cumulative capacities of SPC components (PC boiler and air pollution controls) are higher than those of IGCC components (ASU and gasifiers) in both scenarios.

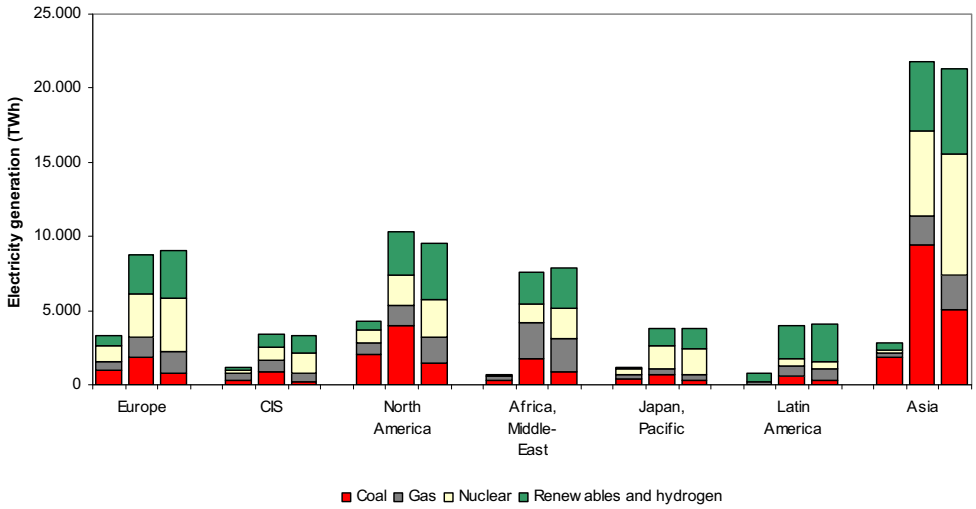

Figure 6 Electricity generation per region in 2001 (left bars) and 2050 projections for REF (middle bars) and CCC (right bars) based on data from (EC, 2006)

3.3.2.3 Location of projected power generation capacities

As we assume learning to occur on a *global* level, we base learning curves on *global* cumulative capacities and extrapolate the learning trends into the future with global capacity projections. However, it is important to realise that the increase in capacities differ quite substantially per world region. Figure 6 provides insight into division of current and future electricity generation over the world regions as reported in WETO-H_2 (EC, 2006)[24]. In 2001, North America produced most electricity (almost 4500 TWh per year) followed by Europe (almost 3500 TWh per year). Together, they were responsible for 51% of global electricity generation. Due to the economic growth of mainly India and China, Asia becomes the largest producer of electricity in these scenarios, with over 36% of world power generated in Asia in 2050. Estimates of future learning in this study, could be overly optimistic, if, for example, Asia's contribution to global learning would diminish due to a lack of competition and the construction of only mature technologies in this region.

[24] As capacity projections are not reported, electricity generation data is used as an indication of the growth in capacity.

3.3.3 Power plant efficiency

3.3.3.1 PCs

Historic development

Yeh et al. (2007) analysed the efficiency improvement of PCs (IEA GHG, 2006) for the period 1920-1972. In the US, the PC efficiency had improved incrementally to a peak of 42% in the early 1960s when the first demonstration PCs were built with supercritical steam circulation (IEA GHG, 2006). Then in the beginning of the 1970s, a plateau was reached because steam pressure and temperature with natural steam circulation (subcritical) could not be increased, and corrosion and other metallurgical problems caused low availability and high O&M costs in SPCs (IEA GHG, 2006). Efficiency of new plants even decreased slightly in the 1970s due to the Clean Air Act, which enforced emission control technologies for SO_2 and NO_x reduction, and the introduction of cooling towers reducing the thermal discharge to rivers or lakes (ASME, 2003). In the mid-1980s, when SPCs started to be built in Europe and Asia (mainly Japan), the efficiency plateau was overcome.

Yeh et al. (2007) already found a log-linear relation between the $efficiency_{HHV}$ in the US and the global cumulative installed capacity (with a PR of 103%). However, in order to take into account the physical limitations of improvement in efficiency, we analysed whether there exists a log-linear relation between the $energy_{HHV}$ loss (1-$efficiency_{HHV}$) in a power plant and the cumulative capacity. Figure 7 shows this is indeed the case and a PR of 98% was found with a correlation factor of R^2=0.92. This indicates a slightly lower rate of efficiency improvement than Yeh et al.'s study. There are two reasons for this PR. First, introduction of an asymptote slows continued improvements when higher efficiencies are reached. Secondly, due to an update of the IEA's CoalPower database[25] the cumulative capacity of PC turned out to be 1033 GW in 2002 instead of 882 GW used earlier.

[25] The CoalPower database contains detailed information on almost 7000 coal-fired units (including decommissioned units) throughout the world (IEA Clean Coal Centre, 2007).

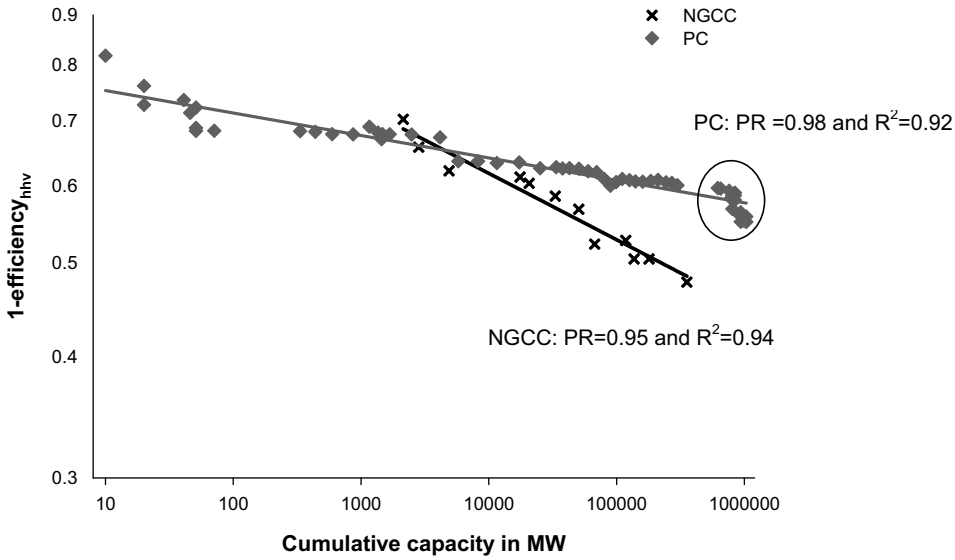

Figure 7 Learning curve of the PC efficiency loss between 1920 and 2002 based on data from (Lako, 2004; DTI, 2006; IEA Clean Coal Centre, 2007) for European plants and the learning curve of the NGCC efficiency loss from 1970 and 2003 based on efficiency data from (Chase and Kehoe, 2001; IEA, 2006a).

The circle in Figure 7 further demonstrates the conclusion formulated by Rubin et al. (IEA GHG, 2006) that the shift from subcritical to supercritical steam conditions seems to be a discontinuity in the learning curve of the PC efficiency. For this reason, we also investigate whether there is a log-linear relation between the efficiency of state-of-the-art[26] SPCs as a function of the cumulative SPC capacity if learning starts with SPC as a 'new' technology. Because the first SPC plant, commissioned in 1957 (ASME, 2003), had similar[27] performance to Studsrup, a SPC plant commissioned in Denmark in 1985, we assume that learning in SPC efficiency started when the supercritical units were first deployed in Europe and Japan from 1984. This learning curve for SPCs suggests a PR of 98% for the efficiency loss. However, the correlation is lower with an R^2 of 0.68.

[26] Only efficiencies of European plants are included, because SCPCs located in Japan have lower net efficiencies than similar plants located in Northern Europe due to higher seawater temperatures (~10 K). According to the (IEA, 2007c), 10 K increase in cooling water temperature decreases the efficiency with one percent point. The most efficient plants found are therefore located in Europe and in particular Denmark.

[27] A thermal efficiency of 41% is reported for the Philo 6 Generating Unit commissioned in 1957 as the first unit with supercritical steam circulation (ASME, 2003), while Studsrup had a reported efficiency of 42%.

Future development

With an efficiency of 47%, the Danish Nordjylland power station, commissioned in 1998, is currently the most efficient PC worldwide. This plant reaches such high performance due to steam conditions of 290 bar/582°C/580°C/580°C (double reheat) and the availability of cold seawater (~10°C) for the cooling system (Lako, 2004; IEA, 2007c). Efficiencies of 46% are anticipated for PCs located inland in Northern Europe with steam conditions of 300 bar/600°C/620°C (heat and reheat steam temperature) (DTI, 2006). The Isogo Unit 2 in Japan, operational in 2009, will be the first PC with these steam conditions (IEA, 2007c).

High coal prices and strict environmental constraints per unit of output are reasons for the efficiency of PCs to improve, mainly by development of advanced alloys that allow for higher steam temperatures. The European AD700 programme aims to achieve efficiencies up to 50% with steam conditions of 700°C/720°C shortly after 2010 (DTI, 2006). Lako (2004) estimated the PC efficiency will be around 48-50% in 2010, 50-53% in 2020 with steam temperatures reaching 775°C, and 51-55% in 2050. Also (IEA, 2006a) estimated 50 to 55% to be achievable in 2020. Besides environmental constraints and high fuel prices, sufficient RD&D expenditures are required to reach these efficiencies. More factors influencing the PC efficiency are coal quality (ash, sulphur, moisture content), the availability of cooling water and other local circumstances[28].

As input to the CMU/UU model we take a PR of 98% for efficiency loss in SPCs based on the above analysis. For the conservative bound we assume no further improvement in efficiency, while for the optimistic bound, we use a PR of 95% (see Table 3 summarising all input data of the CMU/UU model regarding the learning assumptions of the performance variables).

3.3.3.2 NGCC

Historic development of NGCC performance

The development of NGCC performance is different from PC technology. While PCs pioneered in the technological development for electricity generation from the beginning of the 20th century, NGCC technology started as a combination of two mature technologies: the steam turbine and the industrial gas turbines (Watson, 1997). The first NGCC was installed in the US in 1949, though the gas turbine was small (3.5 MW) and ran on the energy of exhaust gases from boiler-feed water heaters of a 35 MW conventional steam unit (Chase and Kehoe, 2001). This first-generation NGCC, mainly built during the 1950s-1960s, used

[28] According to the IEA (IEA, 2006a), the average efficiency of hard-coal PCs in 2003 ranges from 33% in China to 39% in Western Europe and 42% in Japan.

conventional boilers that were (partially) heated by the exhaust gasses of the gas turbine, and could thus reach efficiencies up to 37-39% (Maslak and Tomlinson, 1994).

During the first boost of NGCC construction from the mid-1960s (see section 3.3.1.3), heat recovery systems were introduced using finned tubes. These systems were initially meant for cogeneration of heat and power, but could also be applied as heat recovery steam generator (HRSG) for combined cycles (Maslak and Tomlinson, 1994). In the 1970s, air-cooled turbine blade technology and advanced materials, derived from the aircraft industry, and better heat recovery improved the efficiency up to 40% for NGCCs with a capacity of 100 MW (Watson, 1996). However, because of growing size and complexity, the availability of these first units was lower than 80% (Watson, 1997) (see section 3.3.6). Although the oil crisis in 1973/74 hampered further expansion of the NGCC market, it stimulated companies to develop more efficient technologies (Chase and Kehoe, 2001).

During the second boost of NGCC construction from the late 1970s, the high fuel prices resulted in the third-generation designs that were optimized for combined cycles, whereas the first- and second-generations were based on optimal single cycles (Chase and Kehoe, 2001). The first third-generation gas turbine was installed in 1990.

In Figure 7, also the efficiency loss of state-of-the-art NGCCs, based on the performance of General Electric (GE) units (Chase and Kehoe, 2001) is given as a function of the cumulative installed capacity of NGCCs between 1970 and 2003. The observed learning trend has a PR of 95%.

Future development

The second- and third-generations use air from the compressor to cool turbine blades. This open-loop air-cooling causes a temperature drop in the gas turbine and increases the compressor work due to higher air requirement (Chase and Kehoe, 2001). However, in the fourth generation, closed-loop steam-cooling of turbine blades are being introduced in order to avoid pressure drops and make higher turbine inlet temperatures (TIT) possible without having to increase combustion temperatures (Chase and Kehoe, 2001)[29]. This results in higher turbine outlet temperatures which can be used for more efficient (supercritical) steam cycles. A first demonstration of the closed-loop steam cooling with the H-type turbines of GE in 2003, showed that 60% is attainable due to a TIT of 1430°C and a pressure ratio of 1:23 (Peeters et al., 2007).

[29] This combustion temperatures in state-of-the-art NGCCs is currently limited by materials and the formation of NO_x to of 1475°C.

Future development of advanced turbine materials and firing technologies could allow for an even higher TIT. According to Rao (NETL, 2006) a TIT of 1700°C or higher could be possible in combination with pressure ratios below 1:30. Thus, an efficiency of 65% could be reached with a turbine inlet temperature of 1850°C and supercritical HRSG technology (Peeters et al., 2007). For efficiencies higher than 65%, other technologies like fuel cells have to be included (NETL, 2006).

For the future performance of the NGCCs, it is assumed in the CMU/UU model that efficiency loss continues to decrease by 5% for each doubling of installed capacity (see NGCC efficiency in Table 3). As lower and upper bound, we take a PR of 98% (similar to PC power plants) and a PR of 93%, respectively.

3.3.3.3 IGCC

With ~5.5 GW of total installed capacity (DOE and NETL, 2007), learning in IGCC has hardly begun. Therefore, it is not possible to conduct a historic trend analysis of the overall efficiency improvement of IGCCs. However, the approach of component learning used in this study allows us to investigate the efficiency improvement potential per subsystem of the IGCC, i.e. the air separation unit (ASU), the gasifier, the gas cleaning section and the GTCC power block. We estimate and apply PRs at this level (see Table 3).

ASU

The electricity use for cryogenic oxygen production in an ASU decreased from 350-400 kWh/tonne oxygen in 1980 to 300-325 kWh/tonne oxygen in 2003 (IEA GHG, 2006). This was the result of the optimization of the distillation column by using structured packing instead of perforated distillation trays and of the reuse of energy by advanced heat exchangers. Further optimization was possible due to computer simulation tools and economies of scale.

Although the oxygen separation process is a mature technology, a breakthrough could still decrease its energy consumption. For example, new methods for air separation are being developed such as selective ceramic membrane technologies. The ion transport membrane technology could, for example, decrease the energy consumption by 25 to 35% compared to cryogenic process (IEA GHG, 2006), and will probably be commercially available for IGCCs after 2010 (Gray et al., 2004; IEA GHG, 2006). In the CMU/UU model we apply a PR of 95% for the reduction of electricity use in the ASU based on a learning curve of this specific development published in (IEA GHG, 2006).

Table 3 Learning assumptions for the performance variables in the CMU/UU model*

Plant Type	Baseline[a]	Learning rates (in %)			
		Nominal	Range		
PC (PC-CC) efficiency	45% (35%)				
Energy loss PC boiler/turbine	55%	2 [b]	0	-	5
CO_2 capture efficiency (MJe/t CO_2)	*1210*	*5 [e]*	*2[c]*	-	*7*
NGCC (NGCC-CC) efficiency	56% (48%)				
Energy loss GTCC	44%	5 [d]	2 [c]	-	7
CO_2 capture efficiency (MJe/t CO_2)	*1771*	*5 [e]*	*2 [c]*	-	*7*
IGCC (IGCC-CC) efficiency	39% (33%)				
Energy loss GTCC (fired with syngas)	46%	5 [d]	2 [c]	-	7
Cold gas energy loss	22%	5 [e]	2 [c]	-	7
Energy loss for other processes[f]	4.6%point	5[e]	2 [c]	-	7
Energy loss GTCC (fired with hydrogen)	*49%*	*5 [d]*	*2 [c]*	-	*7*
Energy loss other processes[f]	*6.1%point*	*5 [e]*	*2 [c]*	-	*7*
CCR		*CCR in 2050[g]*			
Post-combustion	*90%*	*90%*	*90%*	-	*95%*
Pre-combustion	*90%*	*95%*	*90%*	-	*100%*

* Cells in italic relate to the power plants with CO_2 capture
[a] Baseline data come from the IECM model. The power plant efficiencies agree with the ranges found in (IEA GHG, 2003; IEA GHG, 2004; IPCC, 2005; Damen et al., 2006). Note that the IGCC(-CC) efficiencies correspond with values for the IGCC with the GE Energy (formerly Texaco) gasifier, and not the more efficient dry feed gasifier of Shell. The cold gas efficiency of 78% corresponds published data for the GE gasifier with a Pittsburgh no. 8 type coal (EPRI, 2002) which was also chosen in the IECM model for this study.
[b] Learning rate for PC plant energy loss as found in section 3.3.1.1.
[c] We base lower learning rate of the energy losses on the conservative learning rate found for the PC plant efficiency loss.
[d] Learning rate for GTCC energy loss as found in section 3.3.3.2.
[e] In this paper, energy loss of CO_2 capture and other auxiliary processes are based on the progress ratio of oxygen production plant energy consumption (IEA GHG, 2006). See for more details sections 3.3.3.3 and 3.3.4.
[f] Energy use for ASU, sulphur removal, and gasifier. For CC-plant: also for Selexol capture minus energy recovered from WGS reaction.
[g] If 2050 value is higher than baseline, an improving logarithmic trend over the additional capacity between 2001 and 2050 is assumed.

Gasifier

The cold gas efficiency (the amount of chemical energy in fuel that is converted into chemical energy in the syngas) from solid coal to syngas and latent heat loss due to water in the slurry feed, has a major impact on the overall efficiency of the IGCC. The gasifier type for current and future IGCCs is expected to be an entrained-bed oxygen-blown technology (Gray et al., 2004; Chen, 2005), but may also be another one, e.g. an air-blown gasifier. Gray et al. (Gray et al., 2004) expects current single slurry-feed gasifiers with a carbon utilization of 95% to be replaced by dry-feed entrained-bed gasifiers with a carbon utilization of 98%.The higher carbon utilization results in a higher cold gas efficiency, thus improving the efficiency by one

percentage point. The lower water content in the syngas due to dry-feed of the coal improves the net power generation efficiency of the IGCC by four percentage points. Because the diversity and technological complexity of gasifiers make it difficult to quantify its efficiency improvement, we only make a rough estimate of 95% for the PR of the reduction in chemical energy loss in the CMU/UU model.

Gas cleaning

When the syngas leaves the gasifier, it is contaminated with hydrogen sulfide (H_2S) and carbonyl sulfide (COS). The COS is hydrolyzed in a catalytic reactor to CO_2, H_2S and CO after particles are removed e.g., in a water-based quench system (IEA GHG, 2006). The H_2S is scrubbed with a physical absorption Selexol unit and sulphur is recovered with a Claus/Scot process (Chen, 2005). An alternative process, which is not commercially available yet, is selective catalytic oxidation of H_2S (SCOHS). By injection of air into the syngas stream over a catalyst, H_2S is oxidized and the condensed stream of sulphur can be removed easily from the syngas because it falls to the bottom of the reactor by gravitational forces (Gray et al., 2004). Because this process does not require a regenerative H_2S scrubber process, it reduces cost and increases the net efficiency. Again, we assume a PR of 95% for the reduction in energy use.

GTCC power block

The potential for improvement of the GTCC power block in an NGCC shown in Section 3.3.3.2 also gives insights into the learning potential in an IGCC. In the CMU/UU model we assumed that these improvements are coupled. However, the efficiency of the GTCC power block fired with syngas or hydrogen in IGCCs is lower than in NGCCs.

Future development overall efficiency

Current state-of-the-art IGCCs can reach efficiencies of 45% (Lako, 2004), which is a little lower than advanced supercritical PCs (46%). However, higher efficiencies are expected from process optimization and integration, and the introduction of advanced technologies (IEA, 2007c). Gas turbine technology development, which is also stimulated by the development of NGCCs, will be the most important factor. For the short term (2010), it is anticipated that IGCCs can reach net efficiencies of 50-52% with advanced (H-type) gas turbines (Lako, 2004). H-type turbines running on syngas probably become commercially available in 2012 (Gray et al., 2004). For 2020, (Lako, 2004) estimated the maximum efficiency to be around 53-56% if sufficient R&D takes place in all relevant technologies. Also Gray et al. (Gray et al., 2004) estimates around 53% to be feasible with H-frame gas turbines, gas cleaning by selective

catalytic oxidation of H_2S and an ion transport membrane for air separation after 2010. For 2050, efficiencies of 55-60% are expected (Lako, 2004). To achieve even higher efficiencies, a solid oxide fuel cell/gas turbine hybrid design will be required. Such a combination could lead to efficiencies of around 67% (Gray et al., 2004).

3.3.4 Energy use in CO2 capture process

Historic development

The concept of capturing CO_2 from gaseous substances at atmospheric pressure with regenerative alkanolamines[30] was patented by (Bottom, 1930) and its first commercial application was reported in 1941 (Willmott et al., 1956). The process, also known as natural gas sweetening, still remains the process of choice for removal of acid gases (CO_2 and H_2S) from natural gas to avoid corrosion, and freeze-out in pipelines and process equipment, and to increase the heating value of gas (Rao et al., 2004). In the mid 1970s, increasing energy prices due the oil crisis and stricter environmental regulations stimulated the development of this capture process. For example, due to restrictions on sulphur emissions, it became necessary to capture and recycle the sulphur from the acid gas stream. This resulted in a shift from non-selective CO_2 and H_2S removal with MEA to selective diethanolamine and other more complex amines for selective removal of H_2S (Bullin and Polasek, 1982). In the same period, MEA gained popularity from the oil sector for the bulk removal of CO_2 for enhanced oil recovery (EOR) (Rubin et al., 2004a). In 1982, a MEA system was built that captured CO_2 from a gas-fired power plant with a capacity of 1100 t/day for EOR, but due to decreasing oil prices this plant was abandoned in 1984 (Yokoyama, 2006). However, bulk CO_2 removal regained interest in the 1990s as a potential GHG emission reduction technology.

Current experience with large-scale projects is still limited to EOR and a few industrial projects like the Sleipner gas field at which approximately 1 Mt CO_2 per year is recovered - about half the capacity needed for a 500 MW gas-fired power plant (Rao et al., 2004). Other amine-based CO_2 scrubber experience can be found in the chemical and food industry (see Table 4).

[30] Scrubbing systems with aqueous alkanolamine solvents are mainly used for the removal of H_2S (hydrogen sulfide) and CO_2 from gases (Mokhatab et al., 2006). It depends on the gas properties and process conditions what kind of amine solvent or mixture of solvents has to be used. Amine solvents consist of ammonia molecules from which one, two or three hydrogen atoms are replaced by a hydrocarbon group to form primary, secondary or tertiary amines respectively, each having its specific properties. An example of a primary amine is monoethanolamine (MEA), a secondary: diethanolamine and a tertiary: methyldiethanolamine (Mokhatab et al., 2006).

Table 4 Use of flue gas CO_2 amine scrubbers (IEA, 2004)

CO_2 end use	Max. capacity (t CO_2/day)	Number built*	Feed source
EOR	1000	3	Natural gas
Food/beverage	300	More than 20	Natural gas
Chemicals	800	5	Natural gas/coal

*) many more small scale units are in operation from which no data is available, especially in the food industry.

Regeneration energy

The energy requirement for CO_2 capture dropped from almost 9.5 GJ/t in the 1950s to 4.2 GJ/t in 1982[31] (Rubin et al., 2004a) by adding inhibitors and stabilizers to the solvents. Thus, the allowable[32] concentration of MEA could increase from 5-12 wt% in 1950 to 30 wt% in 1980 with a CCR of 85-95%. Although no major improvements in MEA are observed between 1982 and 2002, continuous R&D has resulted in several innovations using other solvents. For example, a new solvent composition with sterically hindered amines by Mitsubishi Heavy Industries reduced the regeneration energy to 2.8 GJ/t (Mimura et al., 1997). This so-called KS-1 solvent is already in use at a pilot scale in Japan since 1990 with a CO_2 capture capacity of 2 t/day and in Malaysia with a capacity of 160 t/day since 1999 for the production of urea (MHI, 2003). The Econamine FG process (3.9 GJ/t), developed by Dow for EOR and sold to Fluor Daniel, finds its successor in the Econamine FG Plus™ process, which reduces the regeneration energy to 3.3 GJ/t, though a more complex system with split flow and absorber cooling is necessary (Svendsen et al., 2007).

The energy requirement for CO_2 capture can be decreased most effectively by improvements in solvents (IEA GHG, 2000). However, measures such as a better absorber design[33] or reuse of compression energy[34] can also lower the energy requirement for capture. Because these

[31] Values are based on the limited available data on historic energy requirement for CO_2 capture, because performance data were considered confidential and the energy consumption was not an issue (Bullin and Polasek, 1982). A learning trend could, therefore, not be identified.

[32] When oxygen is present, it can react with MEA forming glycine, glycolic acid or oxalic acid. Accumulation and further interaction of these components leads to solvent degradation and corrosion (Svendsen et al., 2007). The corrosiveness depends on the solvent concentration, which can be higher if inhibitors or sterically hindered amines are used to prevent corrosion and solvent loss.

[33] The electricity requirement for solvent pumps and for the flue gas fan to overcome the pressure drop in the absorber column can be lowered by improved packing material and the design of the absorber column.

[34] The development potential of CO_2 compression is expected to be marginal because the compression train is based on mature and optimized technology (IEA GHG, 2006; Peeters et al., 2007). According to Peeters et al. (2007), improvements in energy use of CO_2 compression for post-combustion CC can be made by reuse of compression heat in the capture unit by integrating the compression and the CO_2 capture train. Savings of 25% in 2020 and 35% in 2030 in low temperature steam are calculated for a NGCC-CC.

factors are interrelated (e.g. solvent improvement also lowers the energy consumption of the solvent pumps), learning in energy use of CO_2 capture is addressed as a single learning factor. Furthermore, because a learning curve for energy losses could not be developed due to the limited amount of historic data, we use a PR of 95% based on the rate for oxygen production systems as in (IEA GHG, 2006). For the pre-combustion capture process with Selexol the same PR is also assumed for the energy losses (see Table 3).

3.3.5 CO_2 capture ratio - CCR

The CCR depends on solvent circulation and concentration, reactor scale and partial pressure of CO_2 in the flue gas. According to Dijkstra (2006), the energy penalty for an 85% CCR at a PC power plant with MEA capture results in an energy penalty of 12.5 percentage points, while a 99% CCR in one of 19.5 percentage points compared to 46% efficiency for the reference plant[35]. Thus, the economic optimum of CCR of power plants with post-combustion will probably be below 90% due to an increase in the energy penalty and investment costs with higher CCRs (Dijkstra et al., 2006). Therefore, most studies consider a CCR of 85-90%, and only a few studies take into consideration that future improvements in CC technology might result in higher CCR [36].

A trend analysis of the SO_2 capture ratio of FGD shows a learning-like curve starting at 70% in 1969 and increasing to around 92% in 1995 (Rubin et al., 2004a). Because this trend was probably driven by the introduction of stricter environmental policies, we cannot deduce that the CCR will also increase in the future due to technology development. Thus, expecting that the CCR probably will depend more on economic criteria or environmental regulation, we keep the CCR constant in the CMU/UU model (see Table 3), except in the optimistic case where the CCR improves to 95% for post-combustion capture and 100% for pre-combustion capture[37]. In a sensitivity analysis we investigate the effect of other CCRs (see section 3.3.9).

[35] The energy penalty per tonne of CO_2 does not increase linearly with the amount of CO_2 captured due to higher recirculation and leaner MEA requirements at the top of the scrubber, and relatively larger pressure drop over the scrubber section (Dijkstra et al., 2006).
[36] Pacific Northwest National Laboratory (PNNL) in the US assumed that the CCR increases from 91% in 2020 to 94% in 2095 (Clarke et al., 2006).
[37] In the pre-combustion process, the higher partial pressure of CO_2 allows for higher CCRs in the future (Gray et al., 2004).

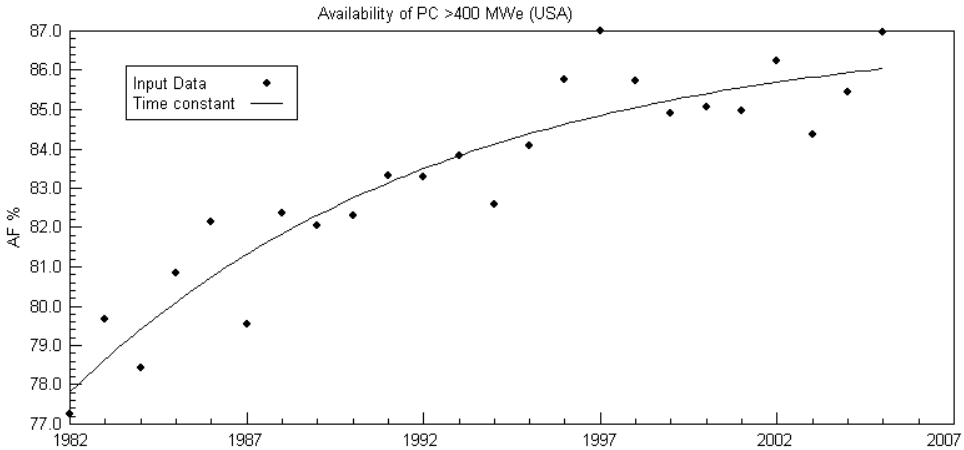

Figure 8 Availability of PC in the US (>400 MW) based on data from (NERC, 1991).

3.3.6 Power plant availability

PC Plants

As revealed in Figure 8, the average availability factor of PCs in the US derived from the NERC-GADS database (NERC, 1991) improved significantly from 77% in 1982 to 87% in 2005. These data are not well-described by a log-linear learning curve based on cumulative installed capacity, rather the improvement in the availability seems to follow a time-dependent learning curve (see Figure 8) reaching a maximum value of ~88% when extrapolated to the future. As can be seen in Figure 9, the availability of German PCs also fluctuates around this value in the period 1996-2005.

Figure 9 further illustrates that the average availability factor of subcritical and supercritical PCs is almost equal (around 88%). Thus, as predicted by Lofe (1985), they are equally reliable due to experience gained in the past. However, the average capacity factor of supercritical PCs with lower operating costs (69%) was substantially higher than of subcritical units (57%). In the US with only subcritical plants in operation during this period, this was 63% (NERC, 1991).

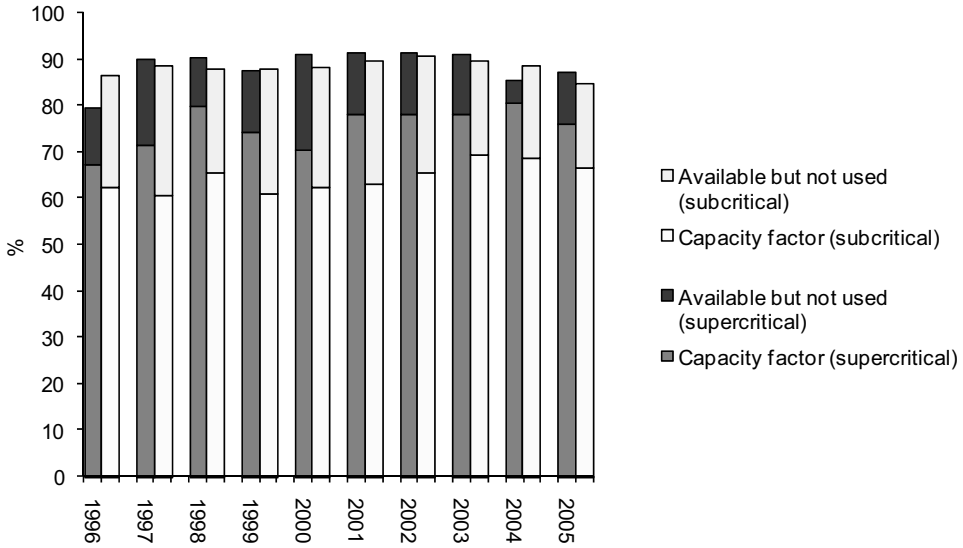

Figure 9 Availability and capacity factor of subcritial and supercritical PC in Germany in the period 1996-2005 based on data from (VGB, 2006).

NGCC Plants

The early stages of commercialization of NGCC were beset by reliability problems. While the first NGCCs were used for small industrial applications, increasing size, complexity, and use for medium-load applications in the 1970s forced manufacturers to put more emphasis on reliability (Watson, 1996)[38]. In the mid-90s, competition between the four major suppliers[39] of NGCCs and the need for state-of-the-art efficient technology, forced the suppliers to bring new plants on the market before they were sufficiently tested. As a consequence, delays in operation and serious breakdowns[40] causing low reliability were reported for all suppliers in the second half of the 1990s (Watson, 1998).

According to GE, however, an average availability of 95.6% for base load plants was already achieved in 1994 (Maslak and Tomlinson, 1994). Although more NGCC manufacturers report availability factors over 95%, Watson criticized that these values were 'selective at best' (Watson, 1998). Another GE study (GE Power Systems, 1999) reported an average availability

[38] From the mid-1970s, programs were initiated in the US to improve the NGCC reliability involving manufacturers and institutes like EPRI (Electric Power Research Institute) (DellaVilla et al., 1992). The GE Gas Turbine Division started the ORAP (Operational Reliability Analysis Program) to enhance feedback and share experience in order to improve NGCC reliability over 95%.
[39] General Electric, Westinghouse/Mitsubishi, ABB and Siemens (Colpier and Cornland, 2002).
[40] e.g. GE had problems that its high efficient plants suffered from turbine vibration problems.

of 87% for F-class turbines while the average for mature NGCCs was 94% during the same period.

The problems that occurred in the 1990s made NGCC manufacturers more conservative in bringing new technology on the market (Bolland, 2007). Extensive testing and experience gained from three generations of NGCC technology should, therefore, make the newest H-type gas turbine more reliable. GE expects availability levels of 90% and higher for new turbines regardless of their complexity (GE Energy, 2007).

NGCCs are often used for peak loads which make it easier to plan an outage for maintenance. In Germany, for example, the average capacity factor of NGCCs was only 22% between 1996 and 2005 (VGB, 2006) (see Figure 10), while the availability factor was fluctuating around 90%.

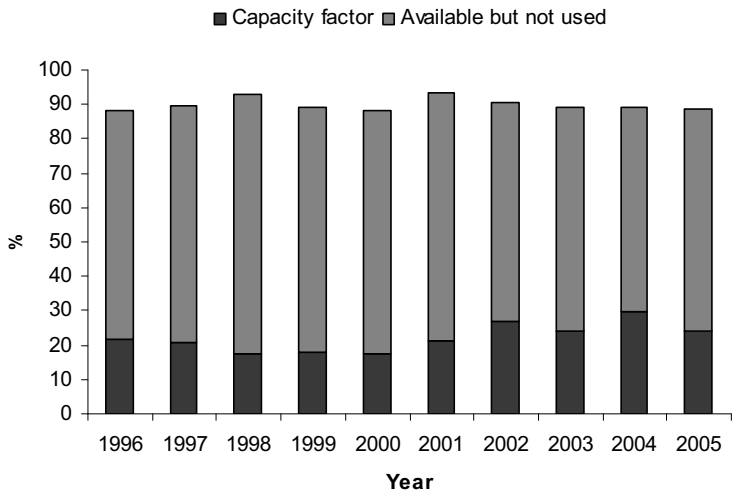

Figure 10 Availability of NGCC power plants in Germany (> 65 MW) in the period 1996-2005 based on data of (VGB, 2006).

IGCC Plants

Present IGCCs without CO_2 capture had a range of problems which made them very unreliable, especially in the first five years of operation (MIT, 2007). However, these plants were initially constructed as demonstration plants (IEA, 2007c) to gain experience with factors such as different kinds of fuel, rather than producing electricity at the lowest cost. Now, IGCCs are considered to be a reliable technology with improved designs and materials and can be deployed on a commercial scale (GE Energy, 2007) with expected availabilities of around 85% (MIT, 2007) or even up to 90% (Gray et al., 2004).

Table 5 Baseline capital and O&M of power plants and learning assumptions for capital and O&M costs of power plants in the CMU/UU model (Source: IEA GHG, 2006, corrected for €$_{2005}$ with IECM, version 5.2.1)

Plant type	Technology	Capital costs (€/kW)		O&M costs €/MWh		Learning Rates (in %)								2001 Capacities (GW)
						Capital Costs				O&M costs				
		No CC	CC	No CC	CC	Nominal	Range			Nominal	Range			
PC	PC boiler/turbine - generator area	983	*1197*	4.2	*4.9*	6	3	-	9	15	7	-	30	61
	Air pollution controls (SCR, ESP, FGD)	185	*215*	2.7	*3.3*	12	6	-	18	22	10	-	30	230
	CO_2 capture (amine system)		*318*		*6.0*	*11*	*6*	-	*17*	*22*	*10*	-	*30*	*10*
	CO_2 compression		*77*		*0.3*	*0*	*0*	-	*10*	*0*	*0*	-	*10*	*10*
NGCC	GTCC	535	*621*	1.5	*1.8*	10	5	-	15	6	0	-	10	237
	CO_2 capture (amine system)		*212*		*1.7*	*11*	*6*	-	*17*	*22*	*10*	-	*30*	*10*
	CO_2 compression		*37*		*0.1*	*0*	*0*	-	*10*	*0*	*0*	-	*10*	*10*
IGCC	ASU	244	*310*	1.2	*1.4*	10	5	-	15	5	0	-	10	50
	Gasifier area	487	*562*	3.6	*4.0*	14	7	-	21	12	5	-	20	10
	Sulphur removal/recovery	77	*105*	0.4	*0.5*	11	6	-	17	22	10	-	30	50
	CO_2 capture (WGS/Selexol)		*234*		*1.3*	*12*	*6*	-	*18*	*22*	*10*	-	*30*	*10*
	CO_2 compression		*44*		*0.2*	*0*	*0*	-	*10*	*0*	*0*	-	*10*	*10*
	GTCC	533	581	1.4	*1.6*	10	5	-	15	6	0	-	10	237

The italic cells are specific to the power plants with CO_2 capture.
[a] Based on the GE Energy (formerly Texaco) gasifier.

Inputs to the CMU/UU model

It can be concluded from the historic development of PCs and NGCCs that during the introduction of new, more complex technologies, as happened with supercritical PCs in the 1960s and F-type NGCCs in the 1990s, reliability issues can be expected. However, with average learning-by-doing, availability improves and appears to level off when the availability approaches 90%. Also in power plants with CO_2 capture availabilities may be lower in the beginning and increase later on. Since we did not find a trend for the rate at which this can occur, we assume the same capacity factor for all power plants in the CMU/UU model and investigate the sensitivity of the results to this capacity factor (see 3.3.9).

3.3.7 Economic learning parameters

Besides the learning assumptions for the performance variables, we applied learning rates for the capital and O&M (non-fuel) costs in the CMU/UU model. Cost data for the different plant types (see Table 5) were taken from the IECM model (IECM, 2007), which are based on plants with air pollution control systems and a size of ~500 MW. Plants with CO_2 capture remove 90% of the CO_2 produced and compress it to 13.8 MPa. The total capital cost data in IECM agree with figures presented in other studies (IPCC, 2005; Damen et al., 2006). The experience curves in Table 5 are taken from the CMU model for which they were specifically developed in the IEA-GHG study (IEA GHG, 2006), except for the NGCC learning rates which were adopted from a study by Colpier and Cornland (Colpier and Cornland, 2002). The learning rates vary between 6-14% for the investment costs, and 5-22% for the O&M costs. It is not feasible to compare these learning rates of cost developments in NGCCs and PCs with other recent sources, as experience curves for these power plants are hardly published in open scientific literature (Neij, 2008)[41]. However, the learning rates can be compared to those for the investment costs of alternative electricity generation technologies like 17-26% for PV (Parente and Goldemberg, 2002; Nemet, 2006; Sims et al., 2007; Sark et al., 2008), 4-11% (on country level) (Neij., 2003), and 15-23% (on global level) (Junginger et al., 2005; Sims et al., 2007) for wind turbines, and 7-10% for fluidized bed combustion plants (Koornneef et al., 2007).

[41] Neij (2008) lately reviewed literature on learning rates for electricity generating technologies and found that recent literature (e.g. Kouvaritakis et al. referred to in McDonald) present “assumed” learning rates for fossil-fired power plants rather than learning rates based on data collection. She suggested using learning rates of 5%±2%, and 10% ±2% for cost reductions in coal-fired power plants and in gas-fired power plants, respectively (without clearly indicating whether these apply on the COE or the investment costs). Her suggestions were based on the same publications underlying the learning rates in the CMU-model.

3.3.8 Fuel prices and financing

The base case of CMU/UU model assumes energy prices of 2.2 $€_{2005}$/GJ for coal and 8.0 $€_{2005}$/GJ for natural gas, as in the reference scenario of the World Energy Outlook in 2007 (IEA, 2007b). Gas prices had doubled between 2000 and 2006 because of increasing oil prices and higher demand for natural gas because of stricter environmental constraints (IEA, 2007b). Also from 2006 till mid 2008, the energy prices kept increasing, but thereafter fell down sharply. Therefore, we investigate the effect of other fuel prices in the sensitivity analysis (see section 3.3.9).

A fixed charge factor (FCF)[42] of 0.11 is assumed for all technologies in the model based on a discount rate of 10%, and 30 year lifetime of power plants. However, it is arguable whether the same financial assumptions should apply for all power plants. For example, because IGCC technology is relatively new and uncertain, a risk premium could be considered for financing this type of technology. On the other hand, the stimulation of cleaner fossil technology could result in financing that is favorable to this technology (Rubin et al., 2007b). The impact of other financing assumptions is, therefore, explored in the sensitivity analysis (see section 3.3.9). Costs are reported in $€_{2005}$, and are based on IECM output data in $US\$_{2005}$ with a US$ to € exchange rate of 0.80 (OANDA, 2007).

3.3.9 Sensitivity analysis assumptions

In addition to the base case, we explore the sensitivity of results to more optimistic and pessimistic progress ratios of cost as well as performance variables. Also the effect of a slower or faster growth of the cumulative capacity is examined by moving the results forward or backward in time. The effect of the uncertainty in a few additional key variables (i.e., capacity factor, CCR, fuel prices, and fixed charge factor) also is analyzed (see Table 6):

The lower bound of the **capacity factor** is based on the subcritical PCs in the US and Germany (section 3.3.6), because CO_2 capture will probably not be applied on peak load power plants due to its large capital investment. As an upper bound the value of 94% is chosen.

For **CCR** we take 81% as lower bound which is comparable to the lowest estimate of 80% found in literature (Thomson and Geleff, 2002). A CCR of 99% is comparable to current performance of state-of-the-art FGD units (Rubin et al., 2004a).

Although prices of coal are more stable than prices of natural gas, we investigate a **fuel price** range of -50% to + 200% for both fuels.

[42] Required annual revenue factor of the capital investment (Rubin et al., 2007b) which can also include taxes.

The **fixed charge factor** may vary by region and plant technology due to difference in discount rates, tax policy, and economic lifetime of the technology. A range of ±50% is considered.

Table 6 Key variables and their uncertainty ranges

Variable		Nominal	Range of values			Range (% of Nominal)		
Capacity factor		85%	60%	-	94%	70	-	110
CCR	PC-CC and NGCC-CC	90%	81%	-	99%	90	-	110
	IGCC-CC	95%	86%	-	99%	90	-	104
Fixed charge factor		11%	6%	-	17%	50	-	150
Natural gas price (€/GJ)		8.0	4.0	-	16	50	-	200
Coal price (€/GJ)		2.2	1.1	-	4.4	50	-	200

3.4 Results and discussion

This section presents the CMU/UU model results combining the projected learning rates and future deployment of each technology component over the period 2001-2050. This leads to performance improvements and cost reductions for the power plants with and without CC. Table 7 - Table 9 show the resulting development of efficiency, energy penalty, and key cost parameters. The tables also depict how these results change when more pessimistic or optimistic learning rates are used. The resulting reductions in COE and mitigation costs for the CC-plants are summarized in Figure 11 and Figure 12.

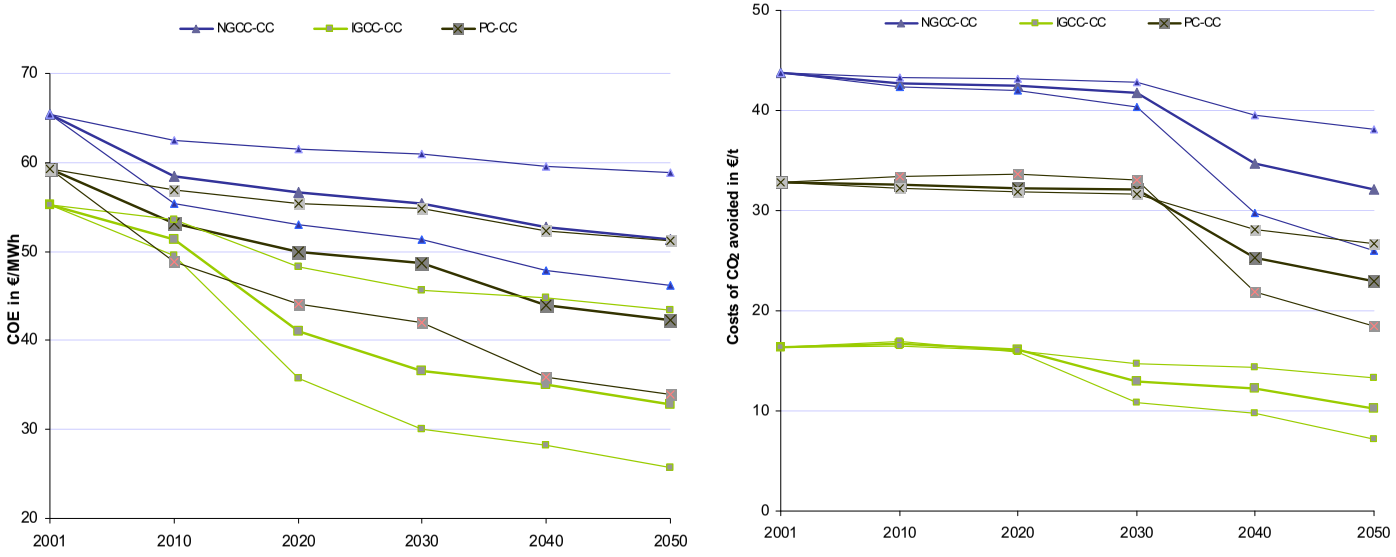

Figure 11 Projections of COE and CO_2 mitigation cost (excluding T&S costs) of power plants with CCS for the REF scenario. To calculate the CO_2 mitigation costs the costs for PC-CC, NGCC-CC, and IGCC-CC are compared to the costs of their own counterparts without CO_2 capture.

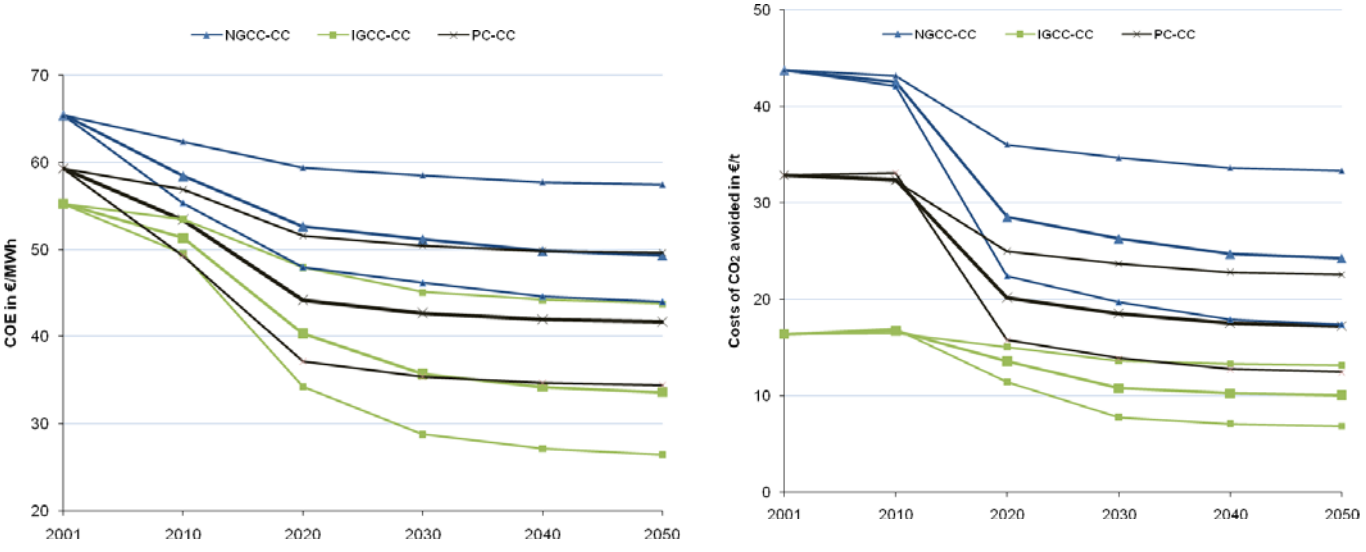

Figure 12 Projections of COE and CO_2 mitigation costs (excluding T&S costs) for power plants with CCS for the CCC scenario.

Table 7 Cost and performance of NGCCs with and without CO_2 capture for 2001 to 2050*

	Parameter	Sce-nario	Year 2001	2010	2020	2030	2040	2050	Range in 2050	% Change 2001-2050 Base	Range
NGCC	**Efficiency (%)**	REF	56	61	63	64	64	65	59 - 69	17	7 - 24
		CCC	56	61	63	63	64	65	59 - 69	16	7 - 24
	Capital cost (€/kW)	REF	535	426	398	381	368	356	285 - 439	-33	-18 - -47
		CCC	535	426	398	382	366	359	289 - 441	-33	-18 - -46
	O&M cost (€/MWh)	REF	1.5	1.3	1.3	1.2	1.2	1.2	1.0 - 1.5	-21	0 - -33
		CCC	1.5	1.3	1.3	1.2	1.2	1.2	1.0 - 1.5	-21	0 - -33
	Fuel cost (€/MWh)	REF	42	38	37	37	36	36	34 - 39	-14	-6 - -20
		CCC	42	38	37	37	36	36	34 - 39	-14	-6 - -19
	COE (€/MWh)	REF	51	46	44	44	43	42	39 - 47	-17	-8 - -24
		CCC	51	46	44	44	43	42	39 - 47	-17	-8 - -24
NGCC-CC	**Efficiency (%)**	REF	48	53	54	55	57	58	52 - 62	22	9 - 31
		CCC	48	53	56	57	59	59	52 - 64	24	10 - 34
	Energy penalty (%)	REF	15	13	13	13	11	11	10 - 13	-27	-11 - -32
		CCC	15	13	10	10	9	9	8 - 12	-40	-17 - -48
	Capital cost (€/kW)	REF	871	746	712	689	629	599	471 - 722	-31	-17 - -46
		CCC	871	745	620	588	559	549	411 - 687	-37	-21 - -53
	O&M cost (€/MWh)	REF	3.6	3.3	3.3	3.2	2.5	2.3	1.8 - 3.1	-37	-14 - -50
		CCC	3.6	3.3	2.1	1.9	1.8	1.8	1.4 - 2.7	-50	-25 - -62
	Fuel cost (€/MWh)	REF	49	44	43	42	41	40	37 - 45	-18	-8 - -24
		CCC	49	44	41	41	40	39	37 - 45	-20	-9 - -25
	COE (€/MWh)	REF	65	58	57	55	53	51	46 - 59	-22	-10 - -30
		CCC	65	58	53	51	50	49	44 - 57	-25	-12 - -33
	Fuel cost (€/t CO_2 avoided)	REF	22	21	20	20	17	15	13 - 21	-30	-5 - -40
		CCC	22	21	15	14	13	12	10 - 19	-44	-13 - -55
	Mitigation cost (€/t CO_2 avoided)	REF	44	43	42	42	35	32	26 - 38	-27	-13 - -41
		CCC	44	43	29	26	25	24	17 - 33	-44	-24 - -60

* Note: All CC plant costs exclude the cost of CO_2 transport and storage. The ranges refer to the results for more pessimistic and optimistic learning rates than in the base case. Finally, by moving results forward or backward in time, the effect of a slower or faster growth in cumulative capacity can be assessed.

Table 8 Cost and performance of IGCCs with and without CO_2 capture for 2001 to 2050*

	Parameter	Scenario	Year 2001	2010	2020	2030	2040	2050	Range 2050	% Change 2001-2050 Base	Range
IGCC	**Efficiency (%)**	REF	39	42	47	49	50	51	43 - 56	31	12 - 44
		CCC	39	42	47	49	50	50	43 - 55	29	11 - 42
	Capital cost (€/kW)	REF	1341	1233	883	783	745	706	515 - 969	-47	-28 - -62
		CCC	1341	1233	907	794	754	737	547 - 992	-45	-26 - -59
	O&M cost (€/MWh)	REF	6.6	6.4	4.4	3.9	3.7	3.6	2.4 - 5.3	-46	-20 - -63
		CCC	6.6	6.4	4.6	4.0	3.8	3.7	2.6 - 5.4	-44	-18 - -61
	Fuel cost (€/MWh)	REF	16	15	14	13	13	13	11.4 - 14.7	-23	-11 - -30
		CCC	16	15	14	13	13	13	11.6 - 14.7	-23	-10 - -29
	COE (€/MWh)	REF	43	40	31	29	28	27	21 - 34	-38	-20 - -50
		CCC	43	40	32	29	28	27	22 - 35	-36	-19 - -48
IGCC-CC	**Efficiency (%)**	REF	33	37	42	44	45	46	38 - 52	39	15 - 55
		CCC	33	37	42	44	45	46	38 - 51	37	15 - 53
	Energy penalty (%)	REF	14	12	11	10	9	9	7 - 11	-38	-18 - -51
		CCC	14	12	10	9	9	9	11 - 7	-38	-51 - -19
	Capital cost (€/kW)	REF	1836	1718	1307	1128	1070	981	701 - 1337	-47	-27 - -62
		CCC	1836	1718	1281	1091	1034	1010	727 - 1358	-45	-26 - -60
	O&M cost (€/MWh)	REF	9.1	8.9	6.6	5.4	5.1	4.6	3.1 - 7.0	-49	-23 - -66
		CCC	9.1	8.9	6.2	5.1	4.9	4.8	3.2 - 7.1	-47	-22 - -65
	Fuel cost (€/MWh)	REF	19	17	15	14	14	14	12 - 17	-28	-13 - -36
		CCC	19	17	15	14	14	14	12 - 17	-27	-13 - -35
	COE (€/MWh)	REF	55	51	41	37	35	33	26 - 43	-41	-22 - -53
		CCC	55	51	40	36	34	34	26 - 44	-39	-21 - -52
	Fuel cost (€/t CO_2 avoided)	REF	3.5	3.0	2.8	2.4	2.3	2.0	1.4 - 3.2	-43	-9 - -60
		CCC	3.5	3.0	2.5	2.1	2.0	2.0	1.4 - 3.1	-44	-11 - -60
	Mitigation cost (€/t CO_2 avoided)	REF	16	17	16	13	12	10	7 - 13	-38	-19 - -56
		CCC	16	17	14	11	10	10	7 - 13	-39	-20 - -58

* Note: All CC plant costs exclude the cost of CO_2 transport and storage. The ranges refer to the results for more pessimistic and optimistic learning rates than in the base case. Finally, by moving results forward or backward in time, the effect of a slower or faster growth in cumulative capacity can be assessed.

Table 9 Cost and performance of PCs with and without CO_2 capture for 2001 to 2050*

	Parameter	Scenario	Year 2001	2010	2020	2030	2040	2050	Range 2050	% Change 2001-2050 Base	Range
PC	**Efficiency (%)**	REF	45	47	49	49	50	50	45 - 57	10	0 - 27
		CCC	45	47	48	49	49	49	45 - 55	8	0 - 21
	Capital cost (€/kW)	REF	1168	1016	933	897	878	869	743 - 1010	-26	-14 - -36
		CCC	1168	1015	948	933	928	926	819 - 1042	-21	-11 - -30
	O&M cost (€/MWh)	REF	6.9	5.0	4.0	3.6	3.4	3.3	1.8 - 5.0	-52	-27 - -74
		CCC	6.9	5.0	4.2	3.9	3.8	3.8	2.3 - 5.3	-45	-23 - -67
	Fuel cost (€/MWh)	REF	14.1	13.4	13.0	12.9	12.8	12.7	11.1 - 14.1	-9	0 - -21
		CCC	14.1	13.4	13.1	13.0	13.0	13.0	11.6 - 14.1	-7	0 - -17
	COE (€/MWh)	REF	38	33	31	30	29	29	24 - 34	-24	-11 - -38
		CCC	38	33	31	31	31	31	34 - 51	-20	34 - -11
PC-CC	**Efficiency (%)**	REF	35	37	39	39	41	41	36 - 49	18	3 - 39
		CCC	35	37	41	41	42	42	37 - 48	19	6 - 36
	Energy penalty (%)	REF	22	21	20	20	18	17	15 - 20	-23	-10 - -32
		CCC	22	21	16	15	15	14	13 - 17	-35	-21 - -43
	Capital cost (€/kW)	REF	1806	1624	1524	1480	1386	1349	1120 - 1560	-25	-14 - -38
		CCC	1806	1624	1404	1364	1344	1337	1113 - 1543	-26	-15 - -38
	O&M cost (€/MWh)	REF	14.5	12.3	11.1	10.6	7.9	7.0	4.3 - 10.6	-52	-27 - -70
		CCC	14.5	12.3	7.0	6.3	6.0	5.8	3.3 - 9.5	-60	-35 - -77
	Fuel cost (€/MWh)	REF	18.1	16.9	16.3	16.1	15.6	15.4	13.0 - 17.6	-15	-3 - -28
		CCC	18.1	16.9	15.6	15.4	15.3	15.2	13.3 - 17.0	-16	-6 - -26
	COE (€/MWh)	REF	59	53	50	49	44	42	34 - 51	-29	-14 - -43
		CCC	59	53	43	42	41	41	33 - 49	-31	-17 - -44
	Fuel cost (€/t CO_2 avoided)	REF	6	6	6	6	5	5	4 - 6	-22	3 - -42
		CCC	6	6	4	4	4	4	3 - 5	-38	-17 - -53
	Mitigation cost (€/t CO_2 avoided)	REF	33	33	32	32	25	23	18 - 27	-30	-19 - -44
		CCC	33	33	20	19	17	17	12 - 22	-48	-32 - -62

* Note: All CC plant costs exclude the cost of CO_2 transport and storage. The ranges refer to the results for more pessimistic and optimistic learning rates than in the base case. Finally, by moving results forward or backward in time, the effect of a slower or faster growth in cumulative capacity can be assessed.

NGCC Projections

The capital cost per kilowatt of the NGCCs falls by 33% (Table 7) over the analysis period due mainly to a large increase of cumulative capacity of the GTCC power block from 237 GW in 2001 to around 3400 GW in 2050 (~3.8 doublings). Non-fuel O&M costs decrease by 21% but this has little impact on the COE of the NGCC plants (<1%). By contrast, 66% of the reduction in the COE is accounted for by a reduction in fuel cost. Because these costs represent the largest share (82%) of the total COE in 2001, a projected efficiency improvement from 56% in 2001 to 65% in 2050 is the key determining factor.

According to Peeters et al. (Peeters et al., 2007) a 65% efficiency could be achieved with a turbine inlet temperature of 1850°C and once-through supercritical HRSG technology. They estimated NGCC efficiencies of 57% in 2010, 60% in 2020 and 62% in 2030. The values in this study for 2010 and 2020 are somewhat higher because of the large growth of GTCC capacity in the WETO-H_2 projections. Furthermore, Peeters et al. assumed an F-type GTCC for the short term (2010), whereas in this study, an F-type GTCC is already applied in 2001.

NGCC-CC Projections

The 31-37% reduction in unit capital cost for NGCC-CC plants in Table 7 depends on three components. First, as with NGCCs, the capital cost of the power block decreases by ~33% over the study period. Secondly, although no NGCC-CCs are built in the REF scenario, three doublings of post-combustion capture capacity are realised in the analysis period for that scenario, as noted earlier. This spillover effect results in a capital cost reduction of the NGCC-CC capture unit from 264 €/kW in 2001 to 183 €/kW in 2050. In the CCC scenario, with 6.7 doublings, these costs decrease to 117 €/kW in 2050. The CO_2 compression system does not become cheaper due to an assumed PR of 100%. However, the efficiency of NGCC-CCs increases from 48% in 2001 to 58-59% in 2050. This is due to ~16% improvement of the GTCC efficiency and a 15% and 30% reduction in the energy consumption for the capture unit in the REF and CCC cases, respectively. The more efficient capture unit in CCC thus reduces the energy penalty from 15% to 9%, versus 11% in REF.

For the same reasons as with NGCC, the NGCC-CC efficiency in this study (53%) in 2010 is higher than the 49% in Peeters et al. (2007). However, Peeters' efficiencies of 55% for 2020 and 58% for 2030 are comparable with the values found in this study (54-56% in 2020 and 55-57% in 2030).

IGCC Projections

Rapid deployment of IGCC technology (138-184 GW by 2020) in combination with its current low operating capacity of ~1.5 GW results in steep cost reductions and efficiency improvements before 2020. Capital costs decrease from 1341 €/kW to 883-907 €/kW, resulting in lower costs than for a PC (Table 8). Other studies, though, indicate that costs of IGCCs will be 10% higher than PCs in 2020 (Gray et al., 2004, IEA, 2006a). Efficiency in our model increases from 39% in 2001 to 42% in 2010. This is in line with current IEA-GHG estimates of IGCC efficiency being 42.3% (IEA GHG, 2007). However, the model outcome of 47% in 2020 is lower than expectations in literature: by then IEA (2006a) expects an efficiency of 50%, Lako (2004) an efficiency of 56% (if sufficient RD&D efforts are undertaken), and Gray et al. (2004) estimates it to be over 62% if a solide oxide fuel cell topping cycle is added. One reason for these differences may be the lower cold gas efficiency of 78% for the slurry-fed gasifier in the baseline case. If the Shell gasifier with dry feed and a cold gas efficiency of 84% (IEA GHG, 2007) was taken as baseline, the results would yield higher efficiencies as in some other bottom-up studies.

IGCC-CC Projections

Learning has a big impact on IGCC-CCs due to its current low level of maturity. Therefore, the COE of IGCC-CCs decreases by ~40% between 2001 and 2050 while the COE of NGCC-CCs and PC-CCs only decreases by 22-31%. Also efficiency increases by ~38% compared to ~23% for NGCC-CC and ~18% for PC-CC. The share of fuel costs in the COE is ~34% in 2001 and increases to ~41% despite a fuel cost decline of ~28%. The reason is that the reduction in specific capital costs is even larger. The share of fuel costs in the CO_2 mitigation costs stays in the range of 19-21%.

The observed trends for IGCC-CC for both the REF and CCC scenarios are similar, because the cumulative capacity of an important component in the IGCC power plant, the GTCC power block, is in the same range in both scenarios. Only the CO_2 mitigation costs decline a little faster in the CCC scenario.

PC Projections

Even though PC plants do not benefit as much from technology spillover as IGCCs and NGCCs, the PC boiler capacity still experiences around 4.5 doublings over the analysis period under the assumption that PC development restarted with the introduction of supercritical PC. As a consequence, the capital costs of PCs decrease by 21% to 26% over the analysis period (see Table 9). These cost reductions are less than for NGCCs and IGCCs because of the lower learning rate (6%) for the PC boiler than for the GTCC power block (10%). The O&M

cost falls by 45-52% as a result of a better PR for the O&M of the PC boiler (85%) and the environmental control system (78%). The estimated capital cost of ~900 €/kW in 2020 and ~700 €/kW in 2050 are lower than those of (Lako, 2004), who estimated capital cost of 1100 €/kW in 2020, and 1000 €/kW in 2050. The efficiency of PCs improves from 45% in 2001 to 49-50% in 2050. These projections are lower than other estimates in the literature, such as 50-55% which could be reached in ultra-supercritical PC plants by 2020 according to IEA (2008). The reason is that historical trends demonstrate a low PR of only 98% for efficiency improvement. However, if a more optimistic PR of 5% becomes viable, efficiencies of 55-57% could be reached in 2050.

PC-CC Projections

Capital costs of PC-CCs decrease by ~25% over the analysis period which is slightly more than estimated by (Lako, 2004). His expectations were 1700 €/kW in 2020, and 1500 €/kW in 2050 compared with 1433-1561 €/kW in 2020 and 1368-1392 €/kW in 2050 in this study. For PC-CCs, efficiency improves from 35% in 2001 to ~41% in 2050. Similar to PCs, these estimates are more conservative than those of Lako (2004), who estimated a PC-CC efficiency of 41% in 2010, 44% in 2020, and 46% in 2050. However, if more optimistic values for future learning rates are assumed in the CMU/UU model, the efficiency reaches ~48% in 2050.

Development of COE and CO2 mitigation costs

Figure 11 shows the developments of the COE and CO_2 mitigation costs (excluding T&S costs) for the REF scenario (in which CO_2 prices do not exceed 30 €/t). The thick lines depict the trends for the baseline estimates of progress ratios and the thin lines for the lower and upper bound progress ratios. The COE of IGCC-CC is the lowest from the start and remains lowest when the baseline path is followed.[43] Only, when higher learning rates are achieved in PC development and worse ones in IGCC, does the COE of a PC-CC plant become cheaper than the IGCC-CC plant. Although there is hardly any CC-capacity built before 2020-2030 in REF, the COE nonetheless decreases due to spillover experience in base plants without capture. On the other hand, no additional experience is gained in capture technology during this period, so CO_2 mitigation costs only decline later on in the analysis period.

In the CCC scenario, the deployment of power plants with CC starts in 2010 as a result of the higher CO_2 price. This results in more rapid decreases in COE and mitigation costs from 2010 onwards (see Figure 12). However, the COE trend for IGCC-CC plants hardly differs between

[43] Note that the assumed capacity factor of 85% may be too optimistic for IGCC at the start. Furthermore, CO_2 mitigation costs are rather low for IGCC-CC at the start, because it is calculated compared to its IGCC counterpart which is more expensive than PC at that time.

the REF and CCC scenarios. The reason is that two developments offset one another: on the one hand, less total IGCC capacity (with and without capture) is built in the CCC scenario, which results in less learning (and less cost reduction) for the base plant compared to the REF case. On the other hand, the number of IGCCs with capture units is higher in the CCC case, resulting in more efficient and less costly CO_2 capture. Note that in the long term (2050) the COEs in the REF and CCC cases are only slightly different because learning effects level off as more capacity is needed to achieve each new doubling and thus the same cost reduction.

While CO_2 capture hardly started by 2030, in the REF scenario, already ~900 GW with CO_2 capture is built in CCC. As a consequence, the mitigation costs in 2030 are 37%, 17%, and 42% cheaper in CCC than in REF for NGCC-CC, IGCC-CC, and PC-CC respectively. In all cases, the mitigation costs are lowest for the IGCC-CC (16 €/t CO_2 in 2001 and 10 €/t CO_2 in 2050). Mitigation costs of the PC-CC decrease from 33 €/t in 2001 to 17 and 23 €/t CO_2 in 2050 in the REF and CCC scenario, respectively. The mitigation costs remain the highest for NGCC-CC (in REF, 32 €/t and in CCC 24 €/t in 2050) as less CO_2 is avoided and the energy penalty results in higher fuel cost, per unit of electricity generated (amounting to12-15 €/t CO_2 avoided).

3.4.1.1 Uncertainty in key variables

The spider diagrams in Figure 13 show the sensitivity of COE and mitigation costs (excluding T&S costs) to the key variables, fixed charge factor, availability, fuel price, and CO_2 capture ratio. The centres (100%) of each diagram are the base case results for CCC. Lower fuel cost and FCF results in lower COE and mitigation cost to avoid CO_2. On the other hand, lower capacity factors increase the specific investment cost and fixed O&M cost per unit of electricity generated, resulting in higher COE and mitigation costs. Note that changing fuel cost, capacity factor and FCF also affects the COE of the reference plants; otherwise, the change in COE of the CC plants relative to the reference plant would have been larger, as would the mitigation costs.

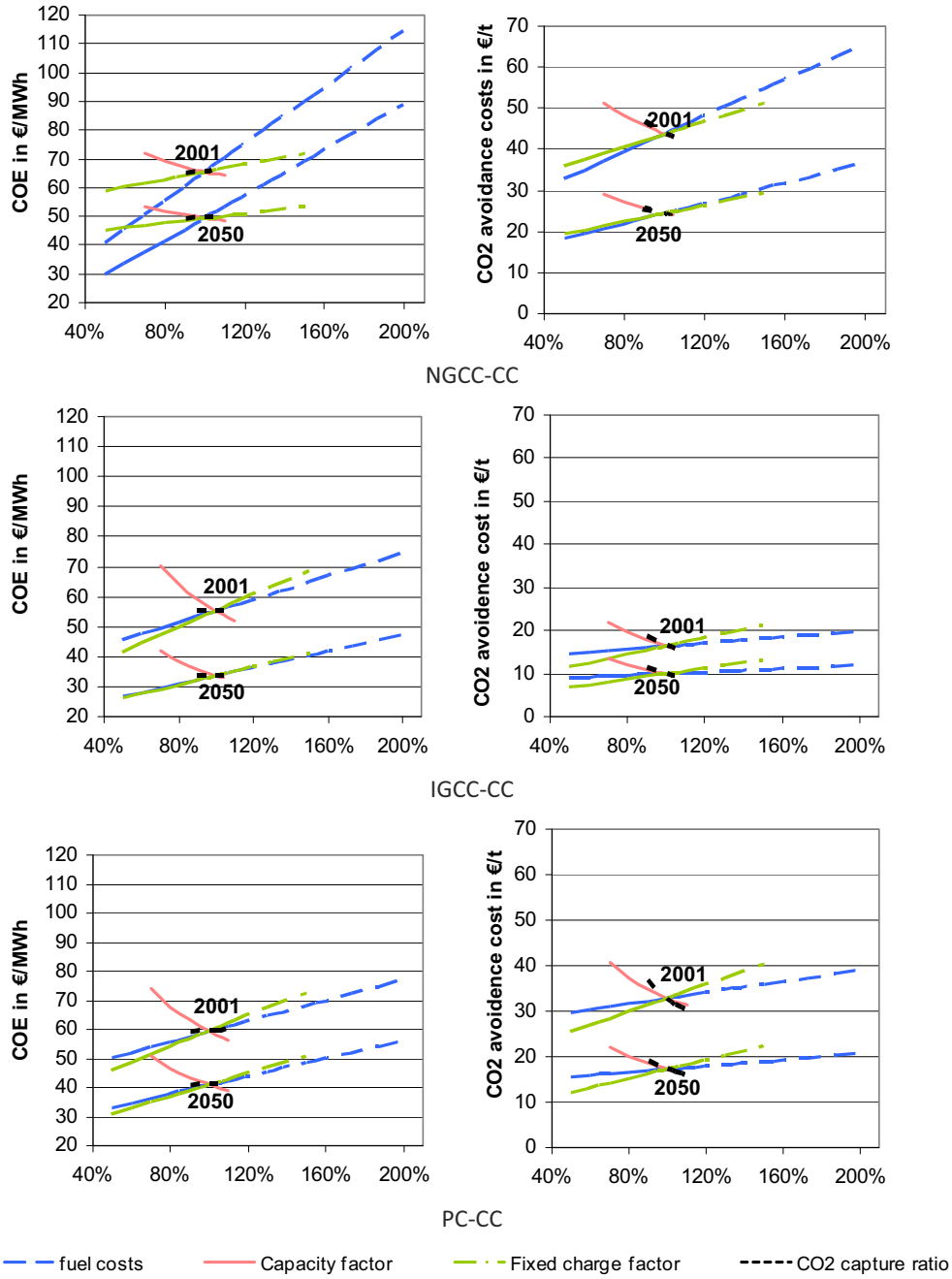

Figure 13 Sensitivity of COE (left) and mitigation cost (right) in the CCC scenario (excluding T&S costs)

Fuel prices have a major influence on the COE of CC plants. A 100% increase in fuel prices results in COE increases of 80% for NGCC-CC, 41% for PC-CC and 37% for IGCC-CC in 2050. The coal-fired plants are less sensitive to fuel prices as COE is heavily influenced by capital costs.

For all technologies, changing the capacity factor impacts the COE and mitigation cost significantly, with the capital intensive PC-CC and IGCC-CC plants being most sensitive to CF changes. For the baseline assumptions of this study, in 2050 IGCC-CC plants with a capacity factor as low as 60% still have a lower COE (42 €/MWh) and mitigation cost (13 €/tonne CO_2) than both the NGCC-CC plant and PC-CC plant with a capacity factor of 94% (COE of 39 €/MWh and mitigation costs of 17 €/tonne CO_2). This is because IGCC plants experience larger cost reductions over the study period, which offset the effect of lower plant utilization. Only if future natural gas prices become cheaper does NGCC-CC compete favourably with IGCC-CC.

The spider diagrams show that results are also sensitive to the FCF, meaning that, apart from technological learning, financing factors have a major influence on the costs. With a lower CCR the energy penalty of the CO_2 capture unit decreases, resulting in a lower COE. However, the mitigation cost increases rapidly as less CO_2 is avoided. Uncertainty in CCR is therefore important when technologies are compared for mitigation cost and environmental performance.

3.5 Discussion

In this section, we discuss a number of issues in order to put the study results concerning the impact of technological learning in power plants into perspective.

The observed learning trends for efficiency of NGCC and PC are based on state-of-the-art technologies applied worldwide. In reality, less efficient and cheaper technologies are deployed more often, especially in regions where fuel prices are lower (IEA, 2006a). The efficiency trends projected in this study may, therefore, be too optimistic as worldwide averages for newly-built power plants without CCS. However, CO_2 capture will probably be applied mainly on state-of-the-art power plants to minimize the additional cost and negative impact on plant efficiency.

The efficiency improvement for IGCCs is partly based on observed development of analogous technologies due to the limited availability of empirical data on all IGCC components. Furthermore, the applied methodology with separate experience curves for different components could not deal with the integration of subsystems within IGCC. Thus, possible

feedbacks from the improvement in one component to another are not reflected in this analysis. This may be a reason why the efficiency of the IGCC plant in the base case (47% in 2020) in this study is less optimistic than those (50-62% in 2020) in bottom-up studies. A further analysis can provide insights whether IGCC rather needs to be treated as a compound learning system in which feed-forward and feedback loops between individual components dominate the learning process (IEA, 2000).

Although bulk removal of CO_2 from flue gases is an energy intensive process, little historical data appeared to be available on energy intensity trends for this process. Therefore, the PR of 95% for the energy requirements for oxygen production was used as a surrogate, because this also represents an energy intensive industrial process. More research on learning trends of efficiency improvements in these types of processes could provide better estimates of learning rates for CC technologies.

The sensitivity analysis showed that a higher CO_2 capture ratio lowers the CO_2 mitigation cost. However, that analysis did not include the change in energy penalties for different CCRs, so only applies locally to small changes in CCR. Indeed, other studies have shown that a higher CCR is not always advantageous.

To estimate future power plant costs using learning curves we used projections of future capacity growth from the WETO-H_2 modelling study (EC, 2006). While the impact of projections from other modelling studies also would be interesting to explore, these were not readily available or not detailed enough. For example, the estimated 2050 global electricity demand of WETO-H_2 is much higher than that of the Energy Technology Perspectives study of IEA (IEA, 2006a), resulting in larger amounts of new fossil-fired plant capacity and greater cost reductions from learning, even for mature technologies like PC and NGCC.

The WETO-H_2 assumptions regarding technology developments may not necessarily agree with our assumptions on technological change. In all cases, however, this was impossible to verify because detailed assumptions were not explicitly reported.

Another issue is that historical learning curves are based on experience in industrialised countries, while it is expected that two-thirds of new power plant capacity by 2050 will be built in developing countries (DTI, 2006). Although state-of-the-art technology is also deployed in these countries, so far the majority of installations realized are mature technologies like subcritical PC plants (IEA Clean Coal Centre, 2007). Consequently, global projections may overestimate the amount of advanced technologies deployed in future years.

While we were unable to derive a historical learning rate for power plant availability from the aggregated data at our disposal, we suspect that a time-dependent model might be suitable to estimate the availability improvement[44]. For purposes of the present analysis, we assumed that plant designs achieved an availability that equalled or exceeded the assumed capacity factor.

In this paper, the CO_2 transport and storage costs were excluded in the CO_2 mitigation costs because of our focus on technological learning effects at power plants. Including these cost would raise the mitigation costs roughly by 5-10 €/t and the COE by roughly 5-10% (assuming no significant change for T&S costs for these scenarios).

3.6 Conclusions

This paper has extended the concept of technology learning curves to simultaneously consider improvements in key system performance parameters as well as cost variables in assessing the future development of power plants with CO_2 capture. This study further combined learning curve models with projections of future global power plant capacity to derive estimates of future plant costs and CO_2 mitigation costs for two policy scenarios. Sensitivity analysis also was used to explore the implications of alternative assumptions.

Learning curves for performance variables

First, we tried to identify learning curves for the performance variables. In order to take into account asymptotic limitations to the improvement of efficiency, learning curves were created for the development of the energy loss (1-efficiency$_{HHV}$). The progress ratio for PCs was based on the development of the world wide capacity of subcritical and supercritical units resulting in 1240 GW of cumulative capacity in 2007. The progress ratio turned out to be 98% implying a 2% decrease in energy loss per doubling of installed capacity. For NGCCs with a cumulative capacity of 389 GW in 2004, we found a progress ratio for the energy loss in NGCCs of 95%. For IGCCs, the current installed capacity (~1.5 GW) was not sufficient to identify specific learning trends. However, since we assumed technology spillover between NGCCs and IGCCs for the GTCC power block, no separate PR for this component was necessary. With respect to the variables of energy use for CO_2 capture, CO_2 capture ratio,

[44] However, it is uncertain whether a learning trend can be determined at all, let alone extend it to the future. The reason is that availability for 75% to 80% dependent on plant management, and for 20% to 25% on design according to Richwine (WEC, 2004). Although management could also “learn”, it is probably sensitive to external factors. For example, the privatisation in the electricity sector had a significant influence on plant management, with economic indicators now becoming more important (WEC, 2001).

and plant availability, it was not feasible to create learning curves due to a lack of data. Furthermore, more research is necessary to quantify the relation between the increasing complexity of new technologies and the necessary experience required to reach availabilities of mature power plants (around 85-90%).

Cost and performance projections

We combined the learning curves for plant components with projections of capacity growth from the World Energy Technology Outlook H_2. According to these projections, the global fossil-fired electricity generation capacity grows from ~1300 GW to ~3600 GW in 2050 (of which 13% with CO_2 capture) in the REF scenario with a limited climate policy. In the CCC scenario with a stricter climate policy it grows to ~3200 GW in 2035 and then decreases to ~2900 GW in 2050 (of which 66% with CO_2 capture).

When technology spillover is taken into account, the new power plants without CO_2 capture also stimulate the improvement in power plants with CO_2 capture as they consist largely of similar technologies. For example, the SPC boiler gets an additional experience of ~1300 GW between 2001 and 2050 in both scenarios. Whereas in REF this is mainly a result from the capacity growth of SPCs without capture, in CCC it is half from the growth of SPCs without capture and half with capture. In both the REF and CCC scenarios, the additional experience (including replacement capacity) of the GTCC power block is around ~3100 GW in 2050, but in each scenario this total reflects different additional capacities of NGCC, NGCC-CC, IGCC, and IGCC-CC power plants. The components that are specific to CO_2 power plants improve faster in CCC than in REF, because in 2030 CO_2 capture has hardly begun in the REF scenario while in CCC ~900 GW of power plants with CO_2 capture is installed. As a result, the mitigation costs in the CCC scenario in 2030 are 26, 11, 19 €/t (excluding CO_2 transport and storage costs) for NGCC-CC, IGCC-CC, and PC-CC power plants, respectively, compared to 42, 13, and 32 €/t in the REF scenario.

IGCC-CC has the largest learning potential of the power plants with CO_2 capture. Its efficiency improves from 33% in 2001 to 46% in 2050, while the efficiency of PC-CC increases from 35% to ~42% in 2050. The NGCC-CC remains the most efficient plant with capture as its efficiency improves from 48% to ~59% in 2050.

Study Methodology

The approach in this paper can give additional insights into possible cost developments as well as power plant efficiency developments over time. Furthermore, the results of global learning and its effect on cost and performance of technologies are explicitly reported, whereas these have been rarely published in other modelling studies which include

technological learning for cost developments (e.g. MARKAL, POLES, and NEMS). Finally, by introducing the impact of technology spillover between different types of power plants, insights are gained on how the developments of power plants with capture depend on developments in power plants without CC.

Of course, this study also has limitations. First, the results of this study are sensitive to the baseline input data which, for example, did not include recent price increases. Secondly, we only used projections of power plant capacities from one study in order to extrapolate the learning trends to the future. If other sufficiently detailed projections become available, it would be good to use these as well to be able to assess the effect of different model projections. Thirdly, we assumed that learning takes place at a global level as power plants are generally built by large multinationals. Because a large fraction of the projected capacities is estimated to be built in rising economies like China and India, it is necessary to gain insights into the likely contribution of the growing markets in these economies to the technological development. Fourthly, it needs to be further assessed how the learning processes in individual components of power plants influence each other. This analysis can indicate to what extent the method to treat components as individual learning units instead of a compound learning system is legitimate. Finally, more understanding and quantification of technology spillover from applications outside the power sector (e.g. from syngas-based fuel production) to the development of power plants can improve the results of this study.

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Chapter 4

Designing a cost-effective CO_2 storage infrastructure using a GIS based linear optimization energy model

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Abstract

Large-scale deployment of carbon capture and storage needs a dedicated infrastructure. Planning and designing of this infrastructure require incorporation of both temporal and spatial aspects. In this study, a toolbox that integrates ArcGIS, a geographical information system with spatial and routing functions, and MARKAL, an energy bottom-up model based on linear optimization has been developed. Application of this toolbox led to blueprints of a CO_2 infrastructure in the Netherlands. The results show that in a scenario with a 20% and 50% CO_2 reduction targets compared to 1990 level in respectively 2020 and 2050, an infrastructure of around 600 km of CO_2 trunklines may need to be built before 2020. In this phase, investment costs for the pipeline construction and the storage site development amount to around 720 m€ and 340 m€, respectively. The results also show the implication of policy choices such as allowing or prohibiting CO_2 storage onshore on CCS and infrastructure development. This paper illustrates how the ArcGIS/MARKAL-based toolbox can provide insights into a CCS infrastructure development, and support policy makers by giving concrete blueprints over time with respect to scale, possible pipeline trajectories, and deployment of individual storage sites.

4.1 Introduction

Carbon dioxide capture and storage (CCS) may play a significant role in greenhouse gas mitigation policies if stabilisation targets of 450 ppmv or less for the concentration of CO_2 in the atmosphere are to be reached (IPCC, 2007; IEA, 2008b). CCS involves the separation of CO_2 from industrial and energy-related sources, transport to a (underground) storage location and long-term isolation from the atmosphere (IPCC, 2005). Extensive research, development and demonstration efforts are needed to further develop this technological option, improve the performance, and reduce its costs. Large-scale implementation of CCS will require the deployment of a whole new infrastructure to transport and store the CO_2 (Odenberger et al., 2009). Although transport and storage are relatively cheap activities in the CCS chain compared to capture of CO_2 which is roughly responsible for 60-75% of CCS costs per tonne CO_2 avoided[1], the required upfront investments needed for construction of trunklines and storage facilities, and the uncertainty on their future usage can delay necessary investments in CO_2 infrastructure. A sound planning and design of this infrastructure may help to overcome these barriers. For planning and design it is necessary to take into account synergies and interferences between the infrastructure development and the development of the energy supply system and carbon intensive industrial sectors (e.g. refineries, ammonia, iron and steel). This involves taking into account the following timing and spatial aspects, while at the same time assuring the cost-effectiveness of CCS:

Timing aspects:

- A CO_2 sink (e.g. an empty gas field) should be available when a capture unit becomes operational (e.g. at a power plant).
- The amount of CO_2 captured needs to be matched to the storage potential and the maximum injectivity rate of the sinks available.
- Short-term matching between sinks and sources should not prevent cost-effective matching in the longer-term.
- The CO_2 transport flows over time should determine to what extent the CO_2 infrastructure can be over-dimensioned when pipelines are laid down.

Spatial aspects:

- Distances between sources and sinks determine CO_2 transport costs.

[1] IPCC estimated transport costs of 1-8 US$/t for 250 kilometers, 0.6-8.3 US$/t for storage, and 13-74 US$/t for capture in power plants (IPCC, 2005). Damen et al. gave ranges of 2-17 €/t for transport and storage in aquifers or hydrocarbon fields, and 5-100 €/t for capture at power plants and industrial units in the Netherlands (Damen et al., 2009). IEA GHG estimated that almost 30 Gt of CO_2 can be transported and stored in Europe for less than 20 €/t when all confined aquifers, and hydrocarbon fields are available (IEA GHG, 2005).

- The exact trajectory of a pipeline gives more insight into the transport costs, and thus into the feasibility to make that connection.
- To take advantages of economies of scale, appropriate clusters of sources and sinks may be defined that can more easily be connected by trunklines.

Cost-effectiveness of CCS:

- The design of the infrastructure affects the costs of CO_2 transport and storage (since storage costs are site-specific), and could, therefore, influence the competitiveness of CCS in the energy system as a whole.
- Policies with respect to transport and storage of CO_2 (e.g. allowing CO_2 to be stored only offshore) influence the cost-effectiveness of CCS at large, and thus its potential role in the total energy system.

Most studies conducted until now only address a limited number of these aspects. For example, routing of CO_2 pipelines has been dealt with in the EU research project GESTCO (1999-2003) (Christensen, 2004), the IEA GHG study "Building the cost curves for CO_2 storage: European sector" (IEA GHG, 2005), and a study by Middleton and Bielicki (2009). These studies used a Geographic Information System (GIS), to estimate CO_2 transport costs. Whereas in GESTCO a least-cost route was found by taking into account aspects like land use, rivers and existing pipeline corridors (Egberts et al., 2003), the IEA study based its costs calculations on the length of a straight line between sinks and sources multiplied by a factor of 1.15 in order to correct for the actual trajectory. Middleton and Bielicki (Middleton and Bielicki, 2009) developed a tool that not only determines where to build and connect pipelines, but also selects the sources and sinks where to capture and store CO_2 on the basis of cost-minimization. However, in these three studies the availability of sources (the period when CO_2 capture units are operational at these sources) and the availability of sinks (the period when CO_2 can be stored in the sinks) were not matched over time. Among others, the future development of the energy system including new CO_2 sources was not taken into account. In the follow-up project of GESTCO, GeoCapacity (2006-2008) (Geus, 2007), timing aspects are not considered; instead it is being estimated whether the storage potential is sufficient for potential capture sources in the neighbourhood.

In quantitative energy scenario studies of greenhouse gas mitigation options at the national (Marsh, 2005; Broek et al., 2008), or world level (IEA, 2008b), the cost-effectiveness of CCS over the coming decades is assessed compared to other CO_2 mitigation options (e.g. energy efficiency, renewables, nuclear). In these studies, location aspects are addressed generally by assuming average transport and storage costs for different types of sinks (aquifers, empty gas and oil fields, coal seams). Therefore, these studies do not sufficiently address the spatial constrains of a CO_2 transport infrastructure. Nevertheless, in the literature some attempts have already been made to include (at some level) temporal and spatial aspects. In the

European CASTOR research project (CASTOR project, 2004) for instance, spatial aspects like clusters of sources and sinks representing areas with relatively high density of power plants and hydrocarbon fields, and trunklines between them, were considered. However, the level of spatial detail was limited since GIS was not used to find specific pipeline trajectories. Furthermore, although a development pathway of CCS was taken into account, the timing and structure of the CO_2 infrastructure was pre-determined by user input without considering different alternative infrastructure implementations. Damen et al. (2009) took into account spatial aspects into CCS implementation pathways by differentiating transport costs between clusters of sinks and sources without the use of a GIS. Cremer (2005) dealt with spatial and temporal aspects by integrating a GIS with an energy bottom-up model. In both studies, sinks and sources were matched on a first-come-first-serve basis. Thus, the design of the infrastructure did not take into account long term CO_2 transport or storage requirements.

We conclude that existing tools and studies mostly focus on either the spatial aspects, temporal aspects or cost-effectiveness of CCS. However, planning and designing the development of a CO_2 infrastructure, requires dealing with all of them at once. Doing so is important to support policy makers and market players with decision-making on long term infrastructural issues.

This article aims to assess blueprints for the development of a large-scale CO_2 infrastructure in the Netherlands for the analysis period 2010-2050. Such blueprints must reveal succeeding cost-effective combinations of sources, sinks, and transport lines over this period. Moreover, they should provide insights into the costs, location, and time-path of the individual infrastructural elements. The scope of this study is limited to sources that emit more than 100 kt CO_2 a year in the industrial, electricity and cogeneration sector in which CO_2 capture can be applied[2].

The structure of this paper is as follows. Section 2 describes main aspects of the methodology and the input data used. Results and discussion are presented in Section 3 and 4 respectively. Finally, in the last section conclusions are drawn with respect to the role of CO_2 transport for the deployment of CCS in the Netherlands.

[2] This threshold is also applied by IPCC in their Special report on CCS (IPCC, 2005), because CO_2 capture from smaller sources is more costly, and the emissions from the stationary CO_2 sources (excluding the residential sector) represent only a small fraction of total CO_2 emissions.

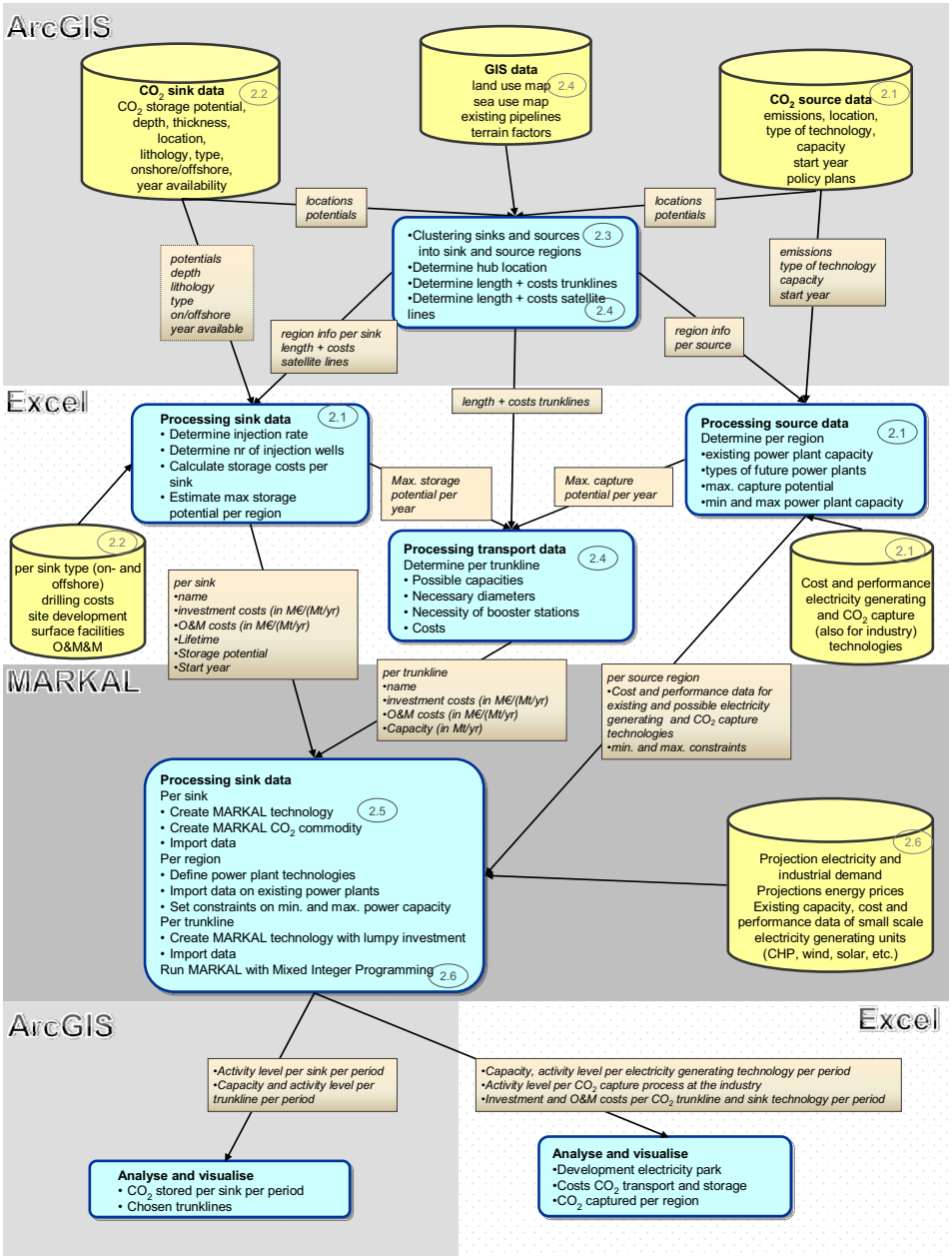

Figure 1 **Scheme of the methodology applied in this study including data flows between ArcGIS, a spreadsheet interface, and MARKAL (the numbers refer to relevant sections in this paper)**

4.2 Methodology

The techno-economic MARKAL model of the Dutch electricity and cogeneration sector, MARKAL-NL-UU, that was applied to assess possible CCS deployment trajectories in the Netherlands (Broek et al., 2008) is the starting point of this study. The MARKAL (an acronym for MARKet ALlocation) methodology provides a technology-rich basis for estimating dynamics of the energy system over a multi-interval period. This MARKAL energy system consists of two standard building elements: technologies and commodities. Commodities may be energy carriers or materials. Technologies which are implemented in the model by techno-economic data (e.g. required input, efficiency, investment costs) convert commodities into other commodities. Commodities flow from one technology to another thus creating a network structure. MARKAL translates the techno-economic data and possible flows of the energy system into a linear mathematical programming problem and then minimises the net present value of all system costs (Loulou et al., 2004). However, in the MARKAL methodology the possibilities to include spatial aspects are limited. For example, unless explicitly specified, MARKAL cannot account for differences between transport costs according to distances and terrain types between sources and sinks.[3] Also, the closeness of different sinks to each other cannot be investigated in MARKAL. However, ArcGIS, a geographical information system (GIS), offers elaborate spatial functions e.g. to assess distances, or to find cost-effective pipeline trajectories through different terrains from one point to another. Therefore we developed a toolbox that combines MARKAL (version 5.7e) with ArcGIS (version 9.2). Besides temporal and spatial aspects, this toolbox takes into account techno-economic criteria (e.g. costs, efficiency data) as well as policy criteria (e.g. CO_2 targets, allowing CO_2 storage offshore only).

Another important aspect is the choice of the network type in which sources can be connected to sinks in the model. In real life, CO_2 transport can be organised in different forms: point-to-point connection between one source and one sink, via a hub-spoke network, or via a mature transport network[4]. These forms may be developed as subsequent steps in the CO_2 infrastructure (McKinsey&Company, 2008): i.e. in a demonstration-stage

[3] MARKAL is able to model trade of energy carriers or materials between different regions with the multi-regional feature. However, the modeller is responsible for choosing the right transport costs (e.g. depending on distances) between these regions.

[4] A hub and spoke network pattern is a radial system of routes. The hub could be considered the hub of a wheel with spokes to the outlying locations (Toh and Higgins, 1985). By acting as collection and dissemination points, hubs allow for indirect connections between sources and sinks. A mature transport network is a complex network structure composed of multiple connections between sources and sinks via pipelines of various sizes in diverse ways.

(point-to-point), early commercialization stage (hub-spoke), and commercial stage (mature network). A point-to-point network is very expensive, because it would consist of separate pipelines for each relevant source-sink combination. In this study we opt for the hub-spoke network form[5] to be able to cover at least the economies of scale of the commercialization-stage[6] of transporting CO_2 from various sources through trunklines to various sinks. In order to model this hub-spoke network, CO_2 sources and sinks need to be clustered into source and sink regions. The CO_2 captured at individual sources in one source region is then transported through so-called satellite pipelines to and collected in the hub of the source region. From there it is transported through a trunkline to a hub in a sink region from where it is distributed via satellite pipelines to several sinks of the sink region.

The research methodology applied in our study can be summarised into seven steps:

1. Inventory of potential CO_2 sinks and their costs (ArcGIS, spreadsheet interface).
2. Inventory of potential CO_2 sources and their costs (ArcGIS, spreadsheet interface).
3. Clustering of sources and sinks into source and sink regions[7] and assessing appropriate locations for the hubs (ArcGIS).
4. Identification of possible trunkline routes between the hubs in the source regions and the hubs in the sink regions, satellite routes within the regions, and estimation of costs per pipeline (ArcGis).
5. Extension of MARKAL-NL-UU model to incorporate spatial data that are of importance for the design of a CO_2 infrastructure. These data are imported from ArcGis into MARKAL-NL-UU via a spreadsheet interface that creates extra MARKAL building elements: technologies for potential regional sources, pipelines, and sinks, and extra commodities for all potential CO_2 flows[8] (MARKAL-NL-UU).
6. Running of MARKAL-NL-UU for different variants (e.g. with respect to policy options) to find cost-effective pathways to reach specific CO_2 reduction targets. The model calculates the deployment of CCS and other CO_2 mitigation measures like photovoltaic systems, wind turbines, or biomass co-firing. Furthermore, it assesses which sources, sinks, and transport options will be used over time and to what extent. The analysis period 2010-2050 is divided into 5-year time steps.

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[5] Also, the IEA states that a hub spoke network structure would be the most efficient way to connect many emitters to large storage sites (IEA, 2008a).

[6] In an IEA GHG study, it was calculated that although large-scale infrastructures with trunklines and satellite connections will have high initial investment costs, they may eventually lead to lower costs than the gradual evolution of individual pipelines growing to a larger system (IEA GHG, 2005). One reason is that the transport costs per tonne of CO_2 decline in pipelines with higher CO_2 mass flow rates (IPCC, 2005), because the increase in diameter of a pipeline and related material costs is less than the increase in mass flow rate.

[7] A region is defined as a collection of sink or source locations.

[8] To apply this methodology, the MARKAL equations do not need to be modified.

7. Presentation and analysis of results (spreadsheet interface, ArcGIS).

The remaining part of this section describes the seven steps in more detail. Figure 2 presents how the steps are linked via various data flows between ArcGIS, the spreadsheet interface, and MARKAL. Finally, note that in this study a discount rate of 5% is applied, prices are given in $€_{2007}$ unless otherwise stated, and "t" always refers to "tonne CO_2".

4.2.1 Inventory of sources

We assume that CO_2 capture will be applied at locations where large-scale sources are currently situated. To determine where CO_2 capture units in principle can be installed, data have been gathered on locations of existing CO_2 point sources in the Dutch power sector and CO_2 intensive industry[9]. The sources selected emit more than > 100kt CO_2 per year in 2004 and are suitable for either retrofit with CO_2 capture or replacement with a CO_2 capture unit. The inventory resulted in 43 locations: 24 existing power plants, and 15 industrial sources. Besides these locations, also four possible new locations at the coast are included[10]. The data on locations are used to cluster sources into "source regions" so that transport options from these regions can be determined (see section 4.2.3). Besides location, we collected the following data on the existing sources:

- **Age** of power plants in order to estimate their decommissioning dates. Once a power plant is decommissioned, there are opportunities to build new ones (gas, coal and/or biomass-fired) with or without CO_2 capture units. For industrial units, we assume that the industrial production continues at today's level, and ignore costs for necessary replacement of these units. Figure 2 Scheme of the methodology applied in this study including data flows between ArcGIS, a spreadsheet interface, and MARKAL (the numbers refer to relevant sections in this paper).
- **Capacity** data of power plants to determine the current electric capacity in a "source region". This gives an indication of the minimum future power generation capacity in a region, since it is expected that most existing power generating capacity will be replaced

[9] Data were collected from the following sources: (1) the Pollutant Release and Transfer Register, the Dutch national register that administrates among others the CO_2 emissions of the industrial and electricity producing sector. (2) GESTCO, an EU research project (1999-2003) that carried out an extensive inventory of industrial and energy related CO_2 sources larger than 0.1 Mt/yr for seven European countries (Christensen, 2004). (3) GeoCapacity (2006-2008), the follow up of GESTCO covering 22 European countries (Geus, 2007). (4,5) Broek et al. (2008) and (Damen et al., 2009), who collected recent data on the electricity park and industrial CO_2 sources.

[10] Three of these are based on energy company plans for new power plants. In the draft of the new structure plan for electricity supply, the Dutch Government also permits power plants at new locations close to the coast (EZ and VROM, 2008).

(Pelgrum, 2008). However, the capacity at a location may increase in the future. Capacity data on industrial units (in tonnes product) and associated CO_2 emissions are used to calculate the amount of CO_2 that can potentially be captured at these units.

- **Type** of CO_2 source. The large scale power plants are either natural gas combined cycle ower plants (NGCC), subcritical or supercritical pulverised coal-fired power plants with possible co-firing of biomass (PC), integrated coal (and biomass) gasification power plants (IGCC), or gas-fired combined heat and power generation plants (CHP). On the basis of these categories, the locations of power plants that can be retrofitted with CO_2 capture are identified assuming that only existing supercritical PCs can be retrofitted. This parameter also determines the possible types of new power plants (with and without capture, and each with their own costs) for a "source region". Most types of power plants can be built anywhere, except for coal-fired power plants that can only be constructed in regions where these already exist or at the new locations at the coast-side. Industrial sources include: ethylene plant, ethylene oxide plant, ammonia plant, hydrogen plant, cement plant, refinery, or iron and steel plant. Depending on the type of industrial plant, costs of a CO_2 capture and compression unit at these different plants are determined.

Table 1 Investment costs and efficiency of electricity generating technologies

	Total capital requirement (€/kW)				Efficiency (energy output of electricity/energy input of fuel)			
	2010	2020	2030	2040	2010	2020	2030	2040
NGCC	676	608	608	608	58%	60%	63%	64%
PC	1598	1487	1448	1352	46%	49%	52%	53%
IGCC	2005	1798	1691	1521	46%	50%	54%	56%
NGCC-CCS	1146	1014	938	838	49%	52%	56%	58%
PC-CCS	2546	2328	2110	1892	36%	40%	44%	47%
IGCC-CCS	2769	2374	2130	1956	38%	44%	48%	50%
Wind onshore	1227	1075	965	866				
Wind offshore	2433	2028	1919	1892				
Nuclear	2652	2652	2652	2652				
Photovoltaic systems	4325	2703	1352	946				

[a] Abbreviations used: NGCC - natural gas combined cycle power plant, PC - pulverised coal-fired power plant including possibly co-firing of biomass, IGCC - integrated coal with possibly biomass gasification combined cycle power plant.

Cost data of CO_2 capture units for the industrial units are derived from Damen (Damen et al., 2009) and of existing and future power plant technologies from the MARKAL-NL-UU model (Broek et al., 2008) and (Vosbeek and Warmenhoven, 2007) (see Table 1 for investment

costs and efficiency input data). The capture units at power plants can be post-combustion units at NGCCs or PCs, or pre-combustion units at IGCCs. Finally, since in the last years a steep increase in prices have occurred, all cost data are updated to $€_{2007}$ monetary units by using the CEPCI index (Chemical Engineering, 2008)[11].

4.2.2 Inventory of sinks

To determine where and how much CO_2 can be stored in the Netherlands and the Dutch continental plate, CO_2 capacity inventories of hydrocarbon fields and aquifer traps[12] are used. The resulting sink inventory is based on data compiled by (Christensen, 2004; Kramers, 2007; TNO, 2007c; TNO, 2007a). In the Netherlands there are over 500 oil, gas fields and aquifers. Because not all of them are suitable for CO_2 storage (e.g. they are situated shallower than 800 meters or have reservoir rocks with porosity less than 10%), the total amount of options considered is 172 excluding the large Slochteren field[13]. The selection is based on a number of threshold values for specific characteristics of the CO_2 storage reservoirs as shown in Table 2 (Ramírez et al., 2009).

Of the 172 fields 35 are aquifers, 131 are gas fields, 5 are oil fields and 1 field contains both oil and gas. Three of the sinks are “stacked” sinks in which separate fields lay on top of each other. There are slightly more offshore (87) than onshore (81) sinks. Despite this, the potential onshore storage capacity (1.8 Gt) is larger than the offshore storage capacity (1.3 Gt). Potential storage capacities per sink are on average 26 Mt onshore, and 15 Mt offshore. The storage potential of aquifers amounts to 0.3 Gt onshore and 0.1 Gt offshore. Furthermore, to study the possibility of storage outside the Netherlands, also a large aquifer in the Norwegian part of the North Sea is included: the Utsira formation with an estimated capacity of 42.4 Gt (Bøe R., 2002). For each sink the following data have been collected:

[11] The Chemical Engineering magazine provides a weighted average index for cost developments called the CEPCI (Chemical Engineering Plant Cost Index), which is widely used for estimating cost of power plant construction, e.g. (Rubin, 2007).

[12] The option to store CO_2 in coal bed seams with enhanced methane recovery is not taken into account as unmined coal seams are assumed to have a limited potential in the investigated time frame in the Netherlands considering the current state of technology.

[13] The gas producing field Slochteren in Groningen has an estimated CO_2 storage capacity of about 7 Gt., but is considered unavailable for storage before 2050 (TNO, 2007).

Table 2 Threshold values applied in this study for selecting CO_2 storage reservoirs

Parameter	Threshold
Capacity	4 Mt CO_2 for gas/oil and 2 Mt CO_2 for aquifers
Thickness reservoir	>10m
Depth top reservoir	≥800m
Porosity reservoir (the fraction of void space in the reservoir)	Aquifers: >10%
Permeability reservoir (a measure of the ability of the reservoir to transmit fluids)	Aquifers: an expected permeability of 200mD or more
Thickness seal	≥10m
Seal composition	salt, anhydrite, shale or claystones
Reservoir composition	Aquifers: sandstones. Hydrocarbon fields: limestone, sandstone, siltstone, carbonates
Initial pressure	Overpressure areas excluded
Salt domes	Relevant for aquifers. Traps located alongside/near salt domes/ walls have been excluded because there is a high risk of salt cementation.

- **Location.** Locations of the potential sinks are determined by X and Y coordinates, which represent the centroids of the sinks. Here CO_2 could be stored in the future. These locations are also used to cluster sinks into sink regions to determine transport options to these regions.
- **Type.** The sink can be a deep saline aquifer formation, an (almost) empty oil or gas field. CO_2 storage costs (see Table 3) as well as injectivity rate depend on the type of sink.
- **On- or offshore.** The sink is either located on or offshore. CO_2 storage costs depend strongly on this parameter (CASTOR project, 2004; IEA GHG, 2005).
- **Start year of injection.** Year from which CO_2 can be stored in the sink. It is assumed that aquifers can be used right away. However, CO_2 storage in the oil and gas fields can only start after the economic viable part of these reserves has been exploited. This moment is estimated based on the end year reported in the current winning schemes in the online database, the "Dutch oil and gas portal" (TNO, 2007a).

Table 3 Costs of individual components for underground CO_2 storage[a]

	Unit	Hydrocarbon onshore	Hydrocarbon offshore	Aquifer onshore	Aquifer offshore
Drilling costs	€ per meter	3000	4000	3000	4000
Site development costs[b]	m€	3.0	3.0	24	24
Surface facilities[c]	m€	1.53	15.3	1.53	61.2
Monitoring costs	m€	0.2	0[d]	1.5	1.5
Operating, maintenance, and monitoring costs (O&M&M)[e]	% of investment costs per year	5	5	5	5

[a] The lifetime of the investments are set to a maximum of 25 years. However, many sinks can be filled in a period shorter than 25 years, and for these sinks lifetimes are set accordingly.

[b] Data on the geological structure and reservoir properties of hydrocarbon fields are available, but are scarce for aquifers.

[c] The surface facility costs for offshore aquifers are 4 times higher than those for offshore hydrocarbon fields due to the assumption that no old platforms can be re-used for aquifers.

[d] Data are based on two studies without specific monitoring investments when CO_2 is stored in offshore gas fields.

[e] All fields have the same percentage for O&M&M costs, because according to (TNO, 2007c) higher costs for O&M offshore (IEA GHG, 2005) may be offset by higher costs for monitoring onshore due to stricter health, safety and environmental requirements (Egberts et al., 2005).

- **Potential capacity of storage.** Maximum amount of CO_2 that can be stored in the sink. Potential storage capacity for gas and oil fields are estimated based on the Dutch ultimate recoverable methane and oil volumes and area per field.[14] The minimum storage capacity in aquifers is based on the area, average aquifer thickness, porosity, storage efficiency, fraction of porous permeable rock of the aquifer and CO_2 density at reservoir conditions. The methodologies used to calculate the potentials have been described in detail in (TNO, 2007c).
- **Depth, thickness.** Depth is the height of the overburden, and thickness is the height of the reservoir. The drilling costs for the wells are calculated on basis of these parameters and an average cost per meter drilled.
- **Injectivity rate.** The injectivity rate determines how much Mt CO_2 can be injected per well per year. The injectivity rate depends on the reservoir type and the lithology of the reservoir rock and varies between 0.1 and 1 Mt per year per well. This rate is assumed to be constant during the CO_2 injection period. Furthermore, this rate together with the storage capacity is used to calculate the number of wells that are needed.

[14] Although it would be better to base the storage potentials on specific ultimate recoverable volumes and depth data per field, these are not publicly available.

Investment costs and yearly costs for each sink are determined based on CO_2 storage cost values reported in the European CASTOR project (CASTOR project, 2004). Costs for activities in the oil and gas exploration and production sector, which are similar to CO_2 storage activities, have risen tremendously since 2005 up to the end of 2008. The reason was an increase in the number of activities leading to a shortage of necessary equipment and services. Therefore, we increase the costs provided in the CASTOR study to $€_{2007}$ costs using the CERA (Cambridge Energy Research Associates) Upstream Capital Costs Index (UCCI)[15]. The resulting costs per reservoir type are shown in Table 3.

4.2.3 Clustering of sources and sinks into source and sink regions

The choice to use a hub-spoke network form to include scale-advantages of transporting CO2 has implied that sources and sinks have to be first clustered into regions (see above). Ideally, MARKAL-NL-UU could calculate optimal regions itself (e.g. by combining close-by sources where CO2 will be captured around the same time). However, to feed MARKAL-NL-UU with an appropriate data set for many possible combinations of sources and sinks go beyond the processing capacity of the model as it stands right now[16]. To avoid this problem, the clustering of sources and sinks into regions is done before the MARKAL-NL-UU runs by seeking a cost-effective trade-off between trunkline costs and satellite pipeline costs. Using ArcGIS, we calculate the total annual transport costs for several plausible regional configurations by totalling up the costs of all potential satellite lines within the regions and of the necessary trunklines to or from these regions. Next, we select the configurations with the lowest costs, thus, seeking an optimum between many small regions (short satellite lines and many trunklines) or a few large regions (long satellite lines and few trunklines).

The current geographical distribution of power plants, industrial sources and sinks already form natural clusters of CO_2 sources (because of access to feedstock supplies, access to distribution channels, or other historical reasons to concentrate economic activities, see figure 2a) and CO_2 sinks (because of the geological history of The Netherlands, see Figure 2b). Despite this, alternative configurations are possible. For example, in a few cases it is the question whether remote sources can better be assigned to a separate region or be added to another region in the neighbourhood. In three cases (around Rijnmond, IJmond and

[15] This index tracks nine key cost areas for both offshore and land-based projects. The CERA-IHS index amounts to 1.67 for the period 2000-2007 and 1.53 for the period 2005-2007 (Offshore Source Magazine, 2007).

[16] The solving time of MARKAL-NL-UU ranges from one hour to 1 day (depending on the variant) Even two alternative sets of regions would increase the solving time of MARKAL-NL-UU in an undesirable way.

Eemsmond, see figure 2a) clustering the sources into one large region was assessed versus clustering them into two smaller regions. According to this assessment, it is cheaper[17] to collect the CO_2 in one hub with one trunkline to a sink region than in two hubs with two trunklines to a sink region if this is more than 100 km away from the source region(s). Since most sink regions are more than 100 km away from the source regions, the configuration with the large source regions is chosen. Note that the choice to model a hub-spoke network has limitations: in a mature distributed network, a small trunkline could have a connection to two smaller source regions, which then could be connected to a sink region with a large trunkline. Clustering of sinks is done in a similar manner. In Figure 2a, the result of the source clustering is shown. The 43 sources are clustered into 7 source regions and 173 sinks are clustered in 8 sink regions with the Utsira formation being considered as a separate sink region.

Finally, by means of the Mean Centre tool of Spatial Statistics function of ArcGIS the location of the regional centres (or hubs), which are the connection points to the trunklines, are determined. This Mean Centre Tool finds the mean centre which is the weighted X and Y coordinate of all sinks or sources in a region. As weight we used the current emissions or storage capacity of the sources or sinks in a region to take care that the large ones are closer to the hub. Thus, for cost-efficient reasons the thicker satellite pipelines needed for the larger CO_2 flows are shorter.

[17] The costs to transport the CO_2 from individual sources to the hubs in a sink region for a configuration with one large source region is 1 to 26 M€ per year cheaper than a configuration with two small ones. In the calculation it is assumed that the CO_2 from all sources is captured and transported to a sink region 100-250 km away.

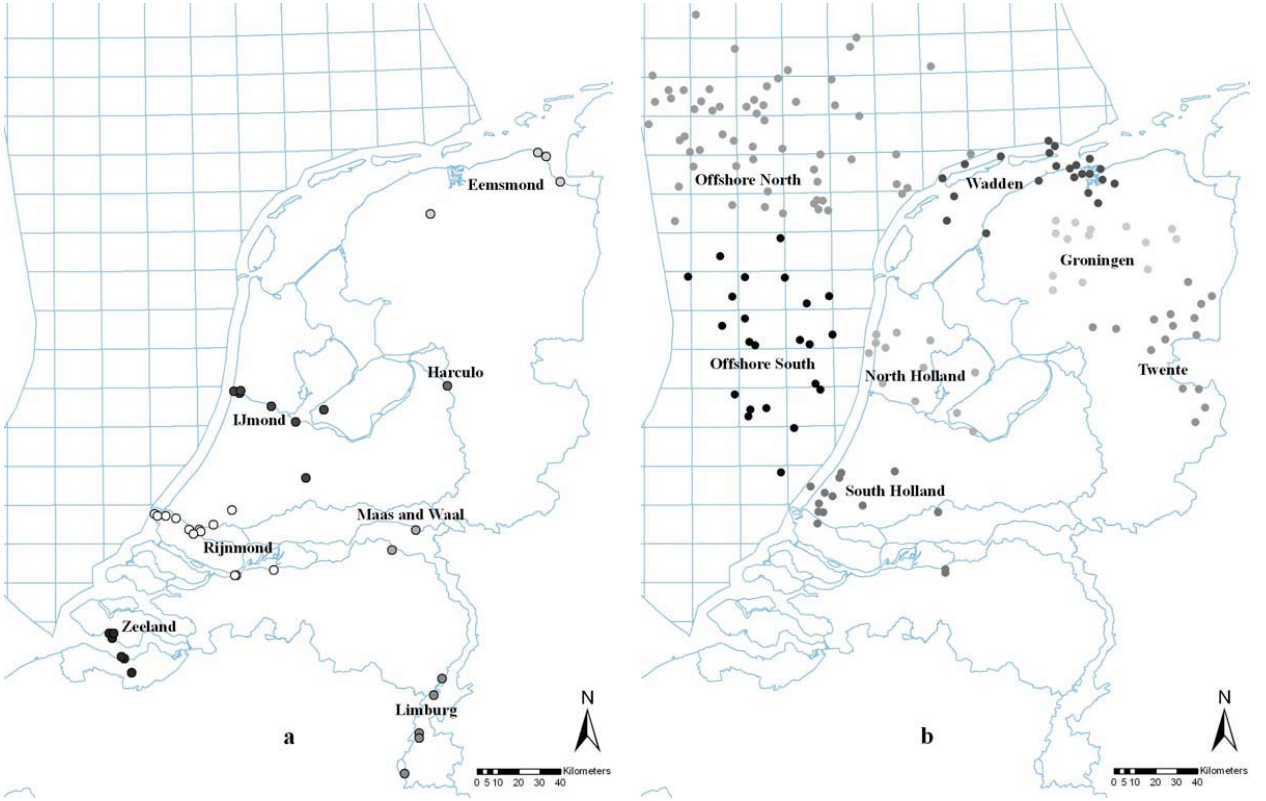

Figure 2 **Source (a) and sink regions (b). Note that the names of the regions are specified in the maps, and all sources and sinks belonging to one region have the same colour**

4.2.4 Routing of CO_2 pipelines

In order to estimate the costs of potential CO_2 satellite-lines and trunklines[18], it is necessary to include two basic aspects. The first one is that the costs of construction of CO_2 pipelines differ per land use type. For example, it is more expensive in nature or populated areas than in agricultural areas (IEA GHG, 2002; Egberts et al., 2003). Secondly, placing pipelines in pipeline corridors is favoured because of legal and engineering advantages (Hendriks et al., 2007; Buisleidingenstraat Nederland, 2008). To account for these factors, geographical data on current and future land-use, sea-use, and existing pipeline corridors are included by using the following maps (see Annex I):

- A 2010 and 2040 land-use map published by the Netherlands Environmental Assessment Agency. These GIS maps depict areas for living, working, agriculture, horticulture, cattle breeding, infrastructure and nature (MNP, 2007; Kuiper and Bouwman, 2009). For this study, we use the 2040 map based on the "trend" scenario in which current trends in society are extrapolated.
- A map of projected use of the Dutch continental shelf for 2050, developed by a joint project of several Dutch ministries (IDON, 2005). This map depicts areas for military purposes, sand extraction, pipelines and cables, wind turbine parks, shipping, and nature.
- A map with existing gas (40 and 60 bar), oil and chemical pipelines published by the Dutch Ministry of Housing, Spatial Planning and the Environment (Speel, 2007).
- A map with landfall possibilities (locations where onshore and offshore pipelines can be connected) from the Dutch Policy Plan Pipelines (EZ et al., 1984). Even though new locations can be chosen in the future, the government stimulates the usage of existing landfall possibilities (EZ et al., 1984). Currently, four landfall possibilities are pointed out: near Eemshaven, Den Helder, IJmond, and Rotterdam.

4.2.4.1 Transport investment costs

In this research the investment costs depend on the distance, and therefore, the pipeline trajectory. Determination of this trajectory - the routing - is done using a model in ArcGIS

[18] Costs will be based on the construction of new pipelines. Re-use of pipelines is not considered in this study, because this would require an in-depth assessment of the existing (natural gas) pipelines, their suitability for CO_2 transport, and an estimation of the time they will be available for CO_2 transport. Furthermore, it is expected that only a few pipelines may be re-used, because most of them will still be needed for gas transport (NOGEPA, 2008).

that calculates the least-cost path between two specific points. This model consists of the following steps:

- Two terrain factors are assigned to each location (a grid cell of 100x100 meter) depending on the terrain type and presence of pipeline corridors, respectively.
- The pipeline investment costs are calculated for each location according to Equation 1.
- The least costs between one specific point (e.g. the hub in a source region) and all other points on the map is calculated using the algorithm as described in (Adriaensen et al., 2003; ESRI, 2007a).
- The least-cost path is chosen between two specific points (e.g. between the hub in a source region and the one in a sink region) (ESRI, 2007b).
- The result of the model consists of the trajectory for the least-cost pipeline and its investment costs.

Thus, by minimising costs certain routes (e.g. through nature and along pipeline corridors) are discouraged and others encouraged (e.g. through agriculture land).

$$I = Ft_{land\text{-}use} * Ft_{corridors} * C * D * L \qquad \text{(Eq. 1)}$$

Where:

I	=	Investment costs pipeline (€).
$Ft_{land\text{-}use}$	=	Terrain factor for crossing different types of land-use.
$Ft_{corridors}$	=	Terrain factor for following or deviating from existing pipeline corridors.
C	=	Constant cost factor (1600 $€_{2007}/m^2$) [19]
D	=	Diameter (m) [20]
L	=	Length (m).

In Table 4 the terrain factors used in this study can be found. These values were verified by an expert panel of four pipeline engineers (Pipeline engineers, 2008). The terrain factors were not based on specific literature references, since terrain factors for CO_2 transport in literature do not seem to be supported by robust arguments. For example, the source of the terrain factors used in the DSS tool of the GESTCO project (Egberts et al., 2003) is not

[19] Many methods exist to calculate the costs of CO_2 transport (McCollum and Ogden, 2006). We use an adapted version of the formula in Hendriks, et al., 2003(a) which was the basis for the CO_2 transport cost calculations in a Dutch case study (Hendriks et al., 2007). Thus, we can derive the constant cost factor from this case study by subtracting the costs that depend on terrain factors (e.g. for crossing artworks being 17-20% of the total costs) from their Constant cost factor (1900 – 2000 $€_{2007}/m^2$) which included the costs to cross specific terrains (Hagedoorn, 2007).

[20] The diameter is calculated on the basis of the length and maximum mass flow rate through a trunkline. For one trajectory, two or three pipeline options are defined, each with a different capacity (e.g. 5, 10, 15, 20, or 25 Mt per year).

mentioned, and in the PH4/6 transmission report of the IEA GHG R&D (2002) the data are based on terrain factors developed for overhead electricity transmission which differ substantially from pipeline infrastructure. The latter terrain factors were also used by the CASTOR project.

Table 4 Overview of the terrain factors compiled for this study (based on expert opinion)

	Terrain type	factor
$Ft_{land\text{-}use}$	Working/living/horticulture/infrastructure: 'populated'	1.4
	Recreation/agriculture/cattle breeding: 'remote'	1.0
	Rivers and lakes	1.8
	Offshore[a]	0.9
	Nature/wind mill park	10
$Ft_{corridors}$	Following the corridors onshore	1.0
	Following the corridors offshore	0.9
	Deviating from the corridors onshore	1.5
	Deviating from the corridors offshore	1.0

[a]Although, investment costs for offshore pipelines are in general higher than for onshore ones, in the Netherlands due to the complex onshore situation, it appears to be the other way around. Three possible reasons are [Hendriks et al., 2007]:

- The Dutch soil with a lot of peaty soil complicates the construction of pipelines considerably.
- Numerous concessions to local authorities and landowners have to be made.
- The Netherlands is densely populated and has numerous artworks such as waterways and freeways.

Finally, the ArcGIS least-cost routing model results in a list of trajectories and investment costs of all possible source and sink regions pipeline connections. Table 5 shows two or three[21] pipeline options defined per trajectory, each with a different capacity (i.e. 5, 10, 15, 20, or 25 Mt per year). The choice of capacities depends on the maximum CO_2 capture and storage potential per year for the sink and source regions. Because experience with natural gas pipelines show that pipelines can be used for 40 years, a lifetime of 40 years is assumed for the CO_2 pipelines (Pipeline engineers, 2008).

[21] The selection is limited to two or three capacities per trajectory because of computational constraints.

Table 5 Examples of modelled trunkline options between hubs in source and sink regions. Length and costs result from the least-routing model

Source region	Sink region	Length	Booster station	Investment costs for selected capacities in M€			
		km		5 Mt/yr	10 Mt/yr	15 Mt/yr	25 Mt/yr
Rijnmond	Twente	194	yes	169		256	311
Rijnmond	Offshore South	104	no	109		152[a]	
Rijnmond	Offshore North	215	yes	187		268	320
Eemsmond	Wadden	70	no	59		92	113
Eemsmond	Groningen	53	no	38		59	73
Limburg	Twente	227	yes	188	244[b]		
Ijmond	Offshore South	69	no	78		105[a]	
Ijmond	Offshore North	167	yes	145		202	238

[a] A trunkline of 20 Mt/yr or more would not be sensible, because even if all sinks in the Offshore South region are used simultaneously less than 15 Mt per year can be injected into these sinks.

[b] A trunkline of more than 10 Mt/yr from Limburg would not be sensible, because even if capture would be applied on all (future) sources in the region, the amount of CO_2 would not exceed 10 Mt per year.

In the first model runs, some trunklines were chosen that although they connected different regions, they followed for a large part the same trajectory. Because it would be more realistic to build one trunkline that connects several source regions with several sink regions than these parallel trunklines, we also design via-routes trunklines which can be built in stages. Based on the results of the first model runs, the following four via-routes are selected:

- The "*via-Limburg*" route connects three source regions (Limburg, Maas and Waal, and Harculo) with the sink regions in the North East of the Netherlands (Twente, Groningen, and Wadden).
- The "*via-Rijnmond*" route connects the source regions in the West of the Netherlands and Harculo with the sink regions in the North East.
- The "*via-IJmond*" route connects the source regions in the West with 4 sink regions (North Holland, the offshore, and Wadden).
- A central *collection point* for all CO_2 source regions is located offshore in the North of the Netherlands near the island Vlieland (on a junction of multiple existing gas pipelines) from where a major trunkline can transport CO_2 to the Utsira formation.

4.2.5 Extending MARKAL-NL-UU for the design of a CO_2 infrastructure

The developed ArcGIS/MARKAL interface ensures that MARKAL-NL-UU is extended, so that in a model run:

- Each sink can be selected (or not) on the basis of its investment and O&M&M costs, availability, potential CO_2 storage capacity, injection rate, and costs for the satellite lines from the region hub to the sink. To accomplish this, each sink is modelled as a separate technology in MARKAL-NL-UU.
- The role of the power sector and CO_2 intensive industry over time, including the role of CCS, can be determined per source region. Since this depends among others on the age of the existing electricity park in a region, this existing park is specified per region in MARKAL-NL-UU. Furthermore, large scale future electricity generating technology options are defined per region, so that the model can select in which regions it builds new power plants.
- Potential trunklines (including the via-routes) can be selected in a model run to be constructed at a certain moment in the analysis period when there is a need for CO_2 transport. Also, the optimal capacity of a selected trunkline is then chosen based on the amount of CO_2 to be transported. To avoid that the model chooses the cheaper - but in real life impossible option - of building half of a pipeline with a 20 Mt/yr capacity when a pipeline with a 10 Mt/yr capacity is required, trunklines need to be modelled with lumpy investments in MARKAL-NL-UU. This takes care that either a pipeline can be built as a whole in a certain period or not at all. In this case, the solution domain for the pipeline capacity is an integer (e.g. a pipeline can be built once, twice, but not half), and, therefore, the mixed integer programming algorithm[22], a solver for models with integer variables, has to be used (Loulou et al., 2004). In contrast, the usual linear programming algorithm finds solutions in which all variables can take any (non-negative) value.

4.2.6 Scenario assumptions for MARKAL-NL-UU model runs

The last step in the methodology is running MARKAL-NL-UU to determine the role of CCS and the associated CO_2 infrastructure within the national portfolio of mitigation options for a given year. The scenario inputs that underlie these runs are the following:

- The Dutch electricity demand increases from 101 TWh in 2000 to 175 TWh in 2050. These values are based on the Strong Europe scenario of the Dutch planning agencies (Janssen et al., 2006; Broek et al., 2008).

[22] Mixed integer programming problems require substantially more time and internal memory to solve than pure linear programs (GAMS, 2005). In this study, the CPLEX solver, and a computer with a quad core central processing unit (2.66 GHz each) and an internal memory of 8 Gb are used.

- In 2020 and in 2050, 20%[23] and 50% less CO_2 is emitted, respectively, in the Dutch CO_2 intensive industry and energy sector compared to 1990 levels.
- The Netherlands changes from an electricity importing country towards a self sufficient electricity producing country in 2020.
- CO_2 streams coming from other countries are not taken into account.
- The share of renewable electricity increases to at least 27% in 2020 and 41% in 2050.
- Nuclear energy phases out.
- The current plans to build two pulverised coal plants in the Rijnmond area (1.8 GW) before 2015 materialise.
- The increase in coal and gas prices up to 2030 is based on the "high growth" scenario in World Energy Outlook by IEA (IEA, 2007). From 2030, we assume that price keep rising at similar rate until 2050[24]. This results in a gas price of 5.5 €/GJ in 2010 to 11.7 €/GJ in 2050, and a coal price of 2.5 €/GJ in 2010 to 4 €/GJ in 2050.

4.2.7 Alternative variants to analyse effects of policy measures and sensitivity analysis

Finally, variants of the base scenario are created to investigate the impact of various policy measures (i.e. CO_2 targets, or renewable energy policy), availability of storage capacity on the infrastructure development costs, and role of CCS (e.g. exclusion of a certain reservoir type such as CO2 storage onshore), and to explore the sensitivity of the results to parameters such as the terrain factor, and constant cost factors for pipelines. The following variants are presented in this paper:

- *Base case*: All sinks can be used.
- *Only offshore*. To diminish the risk of storage and public opposition to CCS, it is assumed that CO_2 is only allowed to be stored in offshore sinks (including Utsira).
- *Only offshore - No Utsira*:This is the Only offshore variant without the option to store CO_2 in the Norwegian Utsira aquifer.
- *Low renewables*: *Base case* without renewable lower bounds.
- *R_30/80*: High CO_2 reduction. 30% and an 80% CO_2 reductions compared to 1990 levels in 2020 and 2050, respectively, are required.

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[23] The CO_2 reduction target of the Dutch government is 30% less CO_2 emissions in the year 2020 compared to 1990 levels. Several sectors together aim to reduce their emissions of which the electricity sector and industry are part. Hence, the reduction constraints in this study contain a part of the total Dutch emission reduction target.

[24] Although IEA in the Energy Technology Perspectives 2008 report (IEA, 2008b) assumed that prices remain stable after 2030, we consider it plausible that prices increase further due to growing energy demand.

- *R_20/80*: High CO_2 reduction from 2020. 20% and an 80% CO_2 reductions compared to 1990 levels in 2020 and 2050, respectively, are required.
- *CF_1120*: The constant cost factor is set to 1120 €/m^2 instead of 1600 €/m^2.
- *C_2080*: The constant cost factor is set to 2080 €/m^2 instead of 1600 €/m^2.

4.3 Results

4.3.1 Base case

4.3.1.1 Development of the electricity generation sector

In the *Base case*, the power generation capacity grows with more than 100% between 2010 and 2050 in order to meet the growing electricity demand and to offset the lower availability of wind and solar capacity. The 50% CO_2 reduction target for 2050 is for a large extent met by the deployment of 8.2 GW of IGCC with CCS and 1.5 GW of PC retrofitted with CO_2 capture (together 20% of the total capacity). Furthermore, due to co-firing of biomass in the coal-fired power plants, biomass energy input will grow to 16% of the primary energy input for electricity generation in 2050. Finally, model results show that onshore wind is cost-effective from the start, and photovoltaic systems (without subsidies) around 2050. To reach the renewable targets of 27% in 2020 and 41% in 2050 renewable electricity, also offshore wind power is being deployed up to 13 GW in 2050. In this reduction scenario in which nuclear power is phased out, CCS contributes on average 26% to the CO_2 reduction in the electricity sector compared to a model run without any CO_2 targets.

4.3.1.2 CO_2 captured at industry and power plants

Figure 4 shows the annual amount of CO_2 captured at power plants and industry per region in the Netherlands. A significant amount of CO_2 is transported from the *Rijnmond* region from 2020 onwards. In this region the 1.8 GW of PC capacity built in 2010 is retrofitted with CO_2 capture in 2020, and early opportunities for CO_2 capture at hydrogen, ethylene, and ethylene oxide production facilities are utilised (7.4 Mt per year). In *Zeeland* and in *Limburg,* CO_2 is captured at an ethylene and ammonia factory and transported through the *via-Rijnmond* and *via-Limburg* route. Furthermore, a power plant of 0.3 GW with capture is installed in the *Maas and Waal* region, because it is easy to connect from there to the *via-Limburg* route. Finally, in *IJmond* CO_2 is captured at the steel plant Corus and (part of) a power plant of 0.2 GW. From 2030, large scale electricity generating capacity with capture is

being installed in *Eemsmond* driven by the presence of the onshore gas fields nearby (4.1 GW IGCC-CCS by 2050), and from 2040 also in *IJmond* which is in the vicinity of the offshore fields (2 GW IGCC-CCS). Also in *Rijnmond*, an IGCC-CCS of 1.7 GW is built around 2040. In the end of the analysis period the *Eemsmond*, *Rijnmond* and *IJmond* regions generate all three substantial amounts of CO_2 that needs to be stored (between 10 and 22 Mt per year).

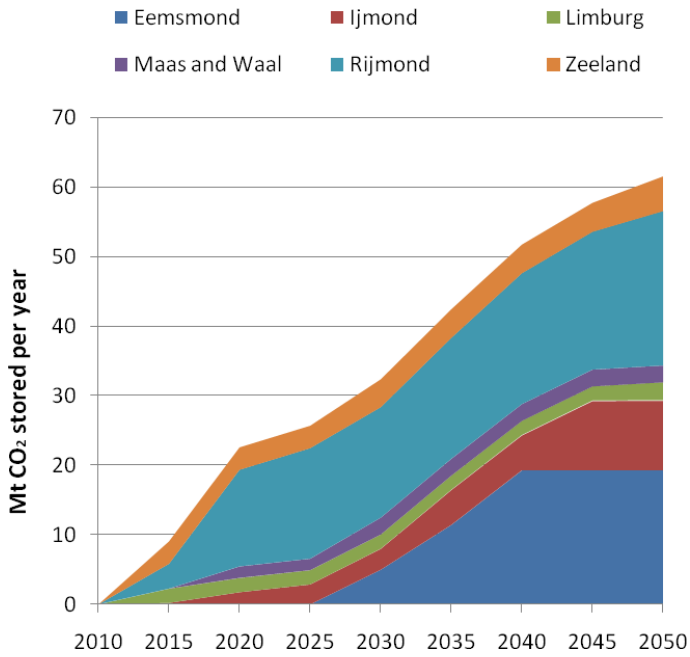

Figure 4 Annual amount of CO_2 captured at power plants and industry per period per region (Base case)

4.3.1.3 Design of the trunkline infrastructure

Figure 5 depicts the trajectory and the CO_2 flow rate of the trunklines in the years 2020, 2035 and 2050. The flow rate can vary as long as it remains below the chosen trunkline capacity. This chosen capacity depends on the maximum flow rate during the whole period. Consequently, the pipelines are usually underutilised at the beginning. In 2020 the basis for the infrastructure is laid down. There is one direct connection between *IJmond* and *North Holland*. Furthermore, the *via-Rijnmond* route is used to transport the bulk CO_2, with a flow rate of 17 Mt per year from *Zeeland* and *Rijnmond* to the sinks in the *Twente* and *Groningen* regions. Finally, the via-Limburg route is used to transport annually a modest 2 Mt CO_2 captured from the industry in *Limburg* and 2 Mt from a power plant in the *Maas and Waal*

region towards the sinks in the *Twente* region. In total 603 km trunkline are constructed of which 283 km for small CO_2 flows from *Limburg, Maas and Waal,* and *Zeeland*. In 2035 the infrastructure slightly changes. Only two direct connections between *Eemsmond* and *Groningen*, and *Eemsmond* and *Wadden* have been added to the pipeline network. The flow rates in the already existing pipelines increase slightly. By 2050, also the *via-IJmond* route has been constructed making a 15 Mt connection from *Rijmond* and a 5 Mt connection from *IJmond* to the sinks in the *Offshore North* region. Again the flow rate from the *Zeeland*, and *Limburg* only increase slightly as these regions are not in the vicinity of a landfall possibility or onshore sinks.

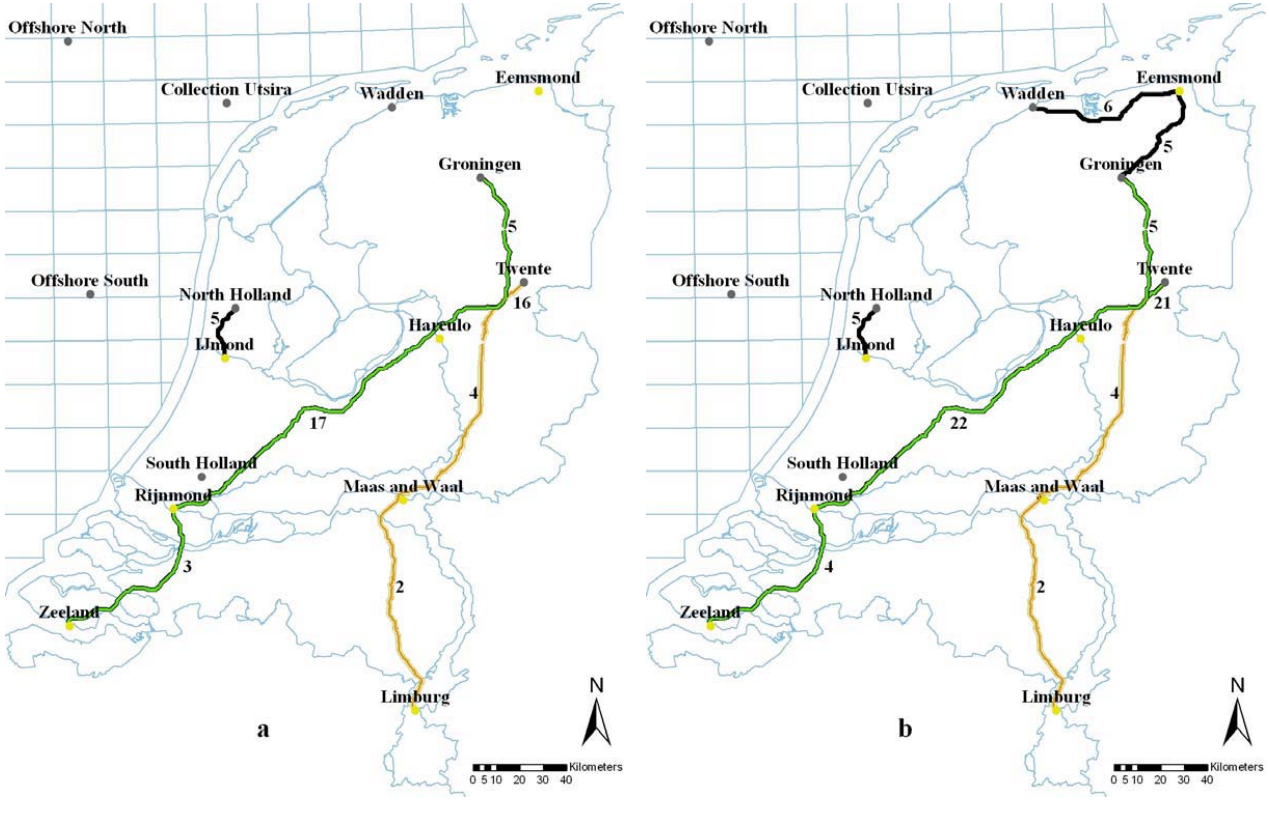

Figure 5 Trajectories and flow rates (in Mt per year) of trunklines in 2020 (a), 2035 (b), and 2050 (c) for the Base case

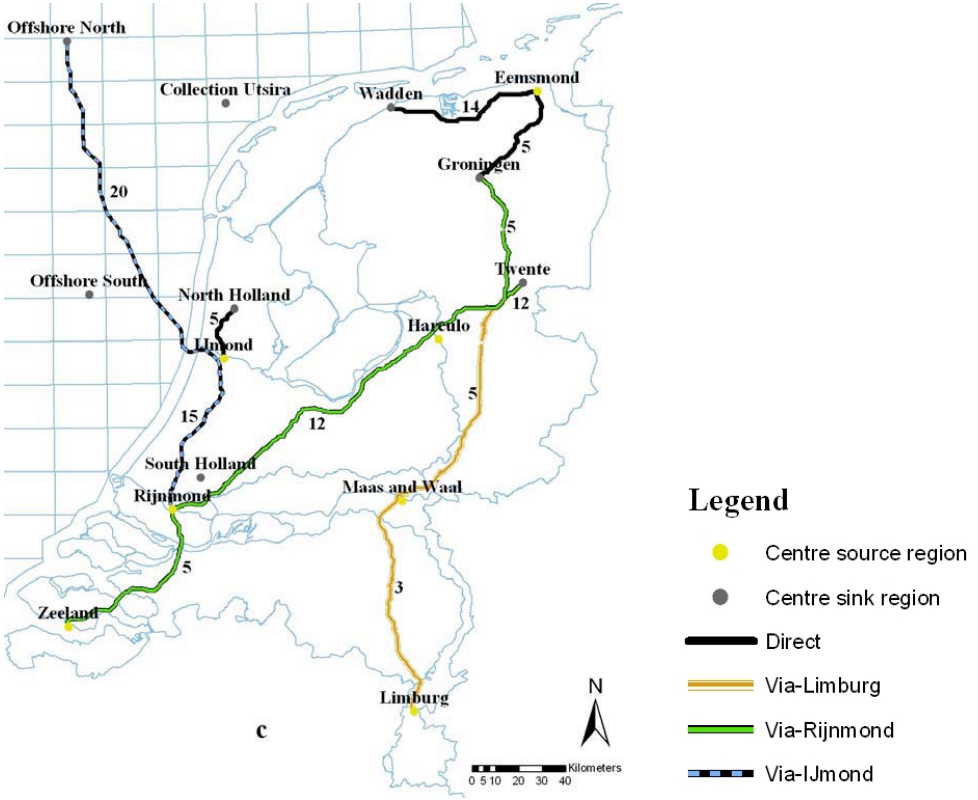

Figure 5 Trajectories and flow rates (in Mt per year) of trunklines in 2020 (a), 2035 (b), and 2050 (c) for the Base case

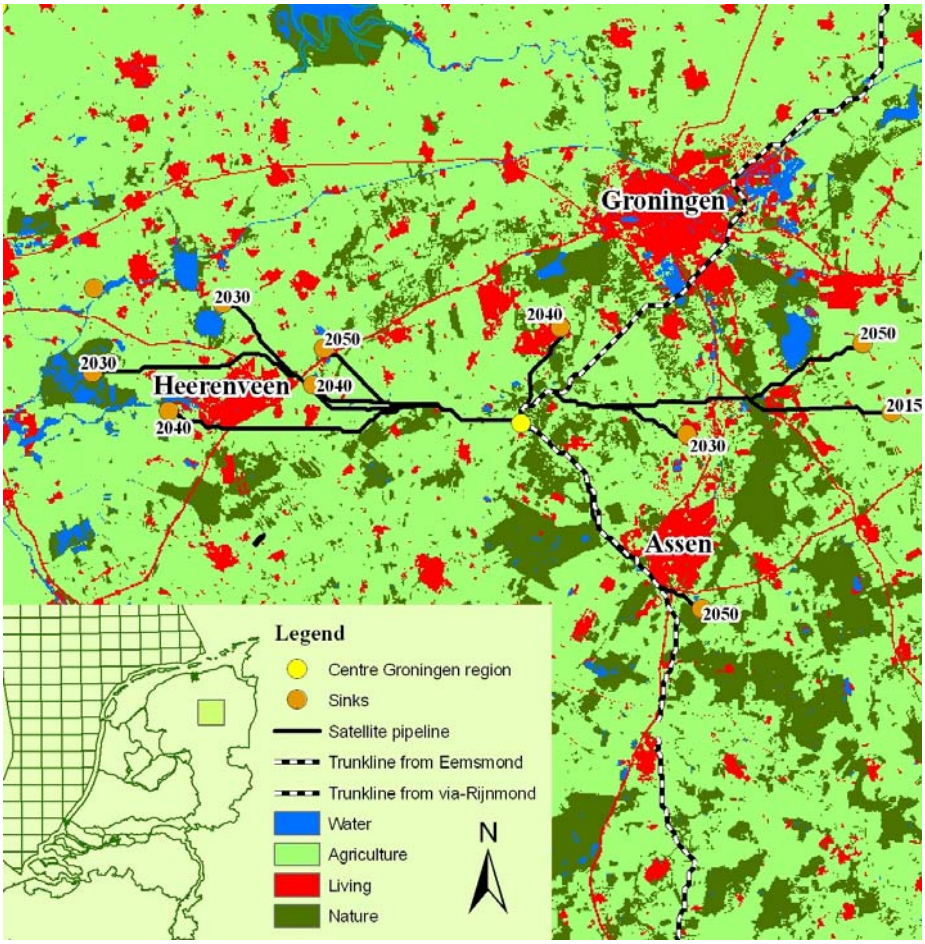

Figure 6 Trajectories of the satellite pipelines in the Groningen region based on the projected land use map of MNP. Also the periods in which CO_2 storage at the individual sinks start, are shown. All 10 sinks that are used are depicted with a satellite line to the hub, while the remaining 4 unused sinks (of which 3 are located under the legend) are not

4.3.1.4 Trajectories of trunklines and satellite lines

With respect to the trajectories of the trunklines, we find that in general they follow the existing pipeline corridors, except for a few diversions in case a shortcut turns out to be more cost-effective. In order to illustrate how the routing of the transport network takes into

account the projected land use, Figure 6 shows the trajectories of the satellite pipelines in the *Groningen* sink region. A trunkline delivers CO_2 to the hub in the region from where it can be distributed among 14 potential sinks. However, four of them are not chosen by the model as storage location during the analysis period. The storage activities start in one large field (154 Mt). In 2030 three storage locations are added (between 20-73 Mt). In 2040 another two sites of 9 and 10 Mt, and finally in 2050 another 3 small fields are needed. In most cases the size of the storage location, which is a determinant factor for the storage costs (ranging between 1.3 and 9.8 €/t), is more important for the selection of storage sites than the satellite line costs (ranging between 0.4-4.8 €/t). Routing through nature (dark green), water (blue) and populated area (red) is preferably avoided as they are assigned with higher terrain factors of respectively 10, 1.8 and 1.4, compared to a terrain factor of 1 for remote areas. The flow rate of the satellite pipelines is in the order of 1 – 6 Mt/yr and depends fully on the injection rate of the individual sinks.

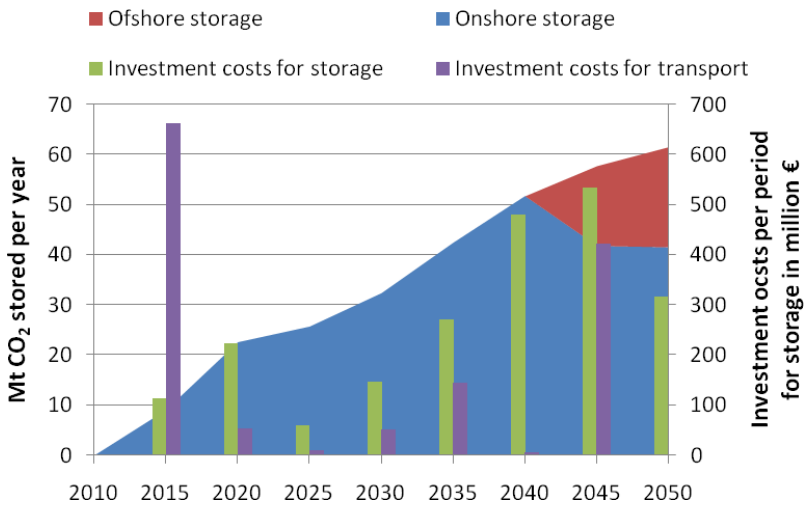

Figure 7 Annual amount of CO_2 stored and investment costs for transport and storage (including costs for satellite lines) in the period 2010-2050 (Base case)

4.3.1.5 CO_2 storage over time

Due to a fairly steep increase of CCS deployment in the Netherlands, the amount of CO_2 stored will be around 23 Mt per year in 2020 (see Figure 7). From 2020 onwards, CCS

deployment grows towards 62 Mt/yr in 2050. The cumulative amount of CO_2 captured, transported and stored in 2050 is 1.4 Gt, which is 44% of the Dutch storage capacity.

Figure 8 shows the geographical location of the sinks and the amount of CO_2 stored in Mt over the analysis period. In total, 10 offshore and 42 onshore sinks out of 172 sinks are selected in the analysis period. Furthermore, only 4 fields with an effective storage capacity smaller than 10 Mt are used. After 2050 more than 1.2 Gt storage capacity is left unused in offshore reservoirs, and 0.6 Gt in onshore reservoirs. The selected sinks have storage costs (including satellite line costs) of less than 8 €/tonne CO_2. However, not all sinks with costs lower than 8 €/tonne have been chosen either because the CO_2 transported to a region could still be stored in other sinks (e.g. in the *Wadden* region) or they are in an area that was too expensive connecting a trunk line to (e.g. *Offshore South)*. In the *Groningen* region, on the other hand, almost all available sinks will be filled. Offshore sinks are only utilised for storage after 2040 due to higher storage and transport costs and not to sink unavailability[25]: storage costs offshore (including satellite line costs) begin at costs of 3.4 €/t while onshore this is 1.5 €/t.

[25] Note that although in practice it may be preferred to start injecting CO_2 shortly after the field stops producing gas or oil, in the current MARKAL-NL-UU sinks can be selected any time after the production of the field.

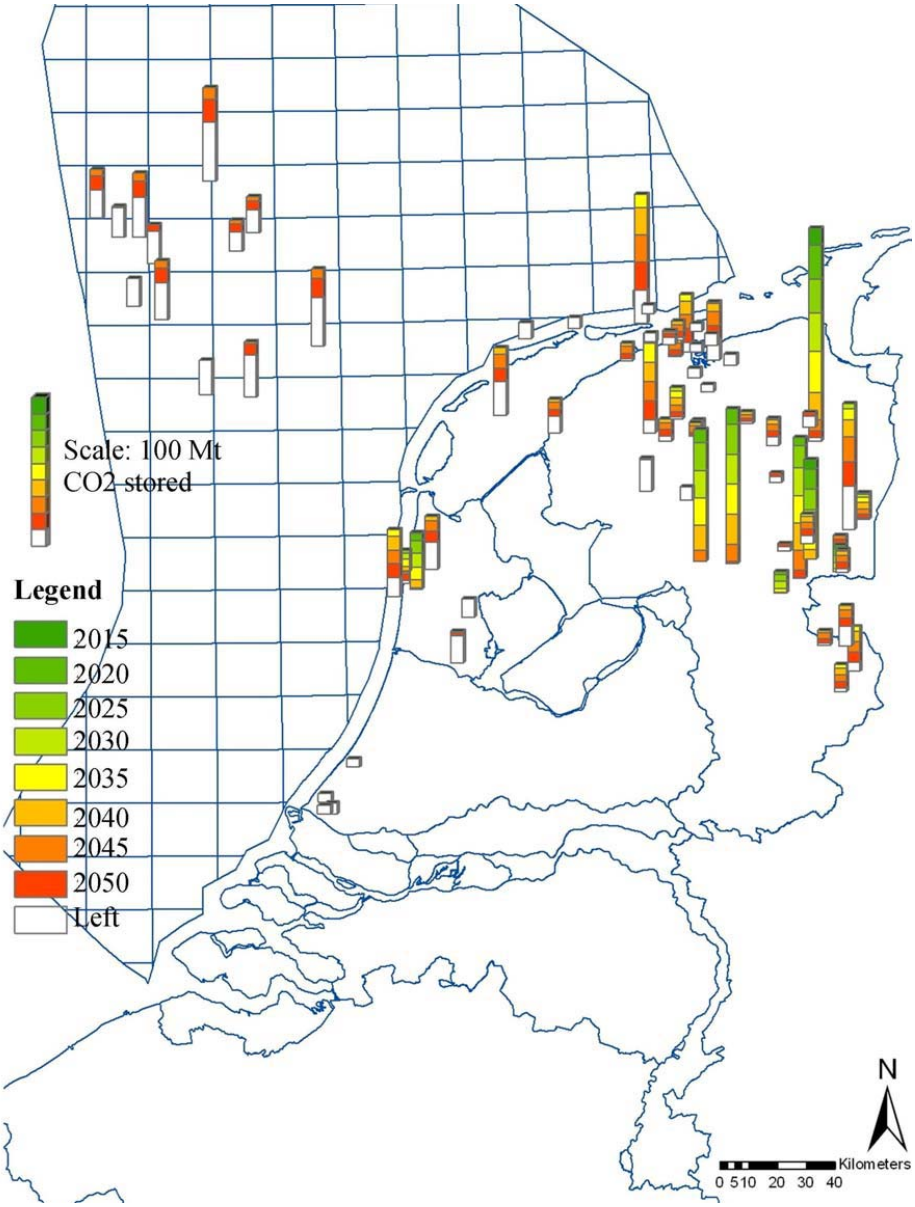

Figure 8 **CO_2 storage over the time period 2015-2050 (Base case). Each stacked bar represents a sink. The size and colours relate to respectively the amount and timing of the stored CO_2. A white bar represents the storage capacity that is still available. Note that only the sinks used for storage in the analysis period are depicted. The star indicates the stacked gas field near Emmen**

Not all large fields are used immediately. For example, the stacked gas field Emmen-Zechstein and Emmen-Carboon (see Figure 8) with a total effective capacity of 92 Mt is used from 2030 onwards, even though it is available for CO_2 storage from the beginning of the analysis period. The seven gas fields in the *Twente* region that are deployed earlier are more cost-effective, because they are even larger (3 out of 7), or because they have higher injectivity rates and/or are located at less depth in the underground (the other 4) compared to Emmen-Zechstein. In this *Base case* with an imposed renewable energy target, no CO_2 is stored in the Utsira aquifer in Norway: the CO_2 storage locations in the Netherlands can cover the CO_2 storage needs against competitive costs.

4.3.1.6 CO_2 transport and storage costs

In the periods 2015 and 2020, large investments[26] (718 m€) have to take place to build a CO_2 pipeline network in order to meet projected CO_2 transport. Around 2045, a trunk line to the *Offshore North* region is built, which involves an investment of 233 m€. The total investment costs in trunklines between 2010-2050 amounts to 1.4 billion euro. The average transport costs for the trunklines are the highest in 2015 (with 6.2 €/t) due to the limited amount of CO_2 that is transported in this period (see Figure 7), and then decrease rapidly to 2.1 € in 2030. For the remaining of the analysis period, they vary between 1.5 and 2 €/t.

Figure 7 also shows the annual amount of CO_2 stored. Until 2040 all CO_2 is stored in onshore reservoirs. Around 2040 the share in onshore storage declines, whilst the offshore storage becomes cost-effective. Moreover, Figure 7 shows that early investments for drilling, site-development and surface facilities, and the construction of satellite pipelines in the sink region, are needed around 2015-2020 for the preparation of onshore sinks. Around 2040-2045, a substantial investment is required for the preparation of offshore sinks. The total investment costs for storage over the analysis period is 2.2 billion €. Furthermore, the average storage costs increase from 1.4 €/t in 2015 to 3.3 €/t in 2050, because at first CO_2 is stored in large gas fields onshore with low CO_2 storage costs, and later a switch is made to the more expensive smaller and/or offshore gas fields

[26] The transport costs include the costs associated with the trunklines and the satellite lines in the source region. However, the costs for satellite lines in the sink regions are included in the storage costs.

4.3.2 Results of alternative variants and sensitivity to main parameters

The sensitivity of the results towards availability of storage capacity, policy measures, and constant cost factor are presented in this paper. The sensitivity towards alternative terrain factors can be found in (Brederode, 2008). In Table 6 the results of the variants are summarised with respect to the infrastructure (transport and storage) costs, and the cumulative amount of CO_2 stored.

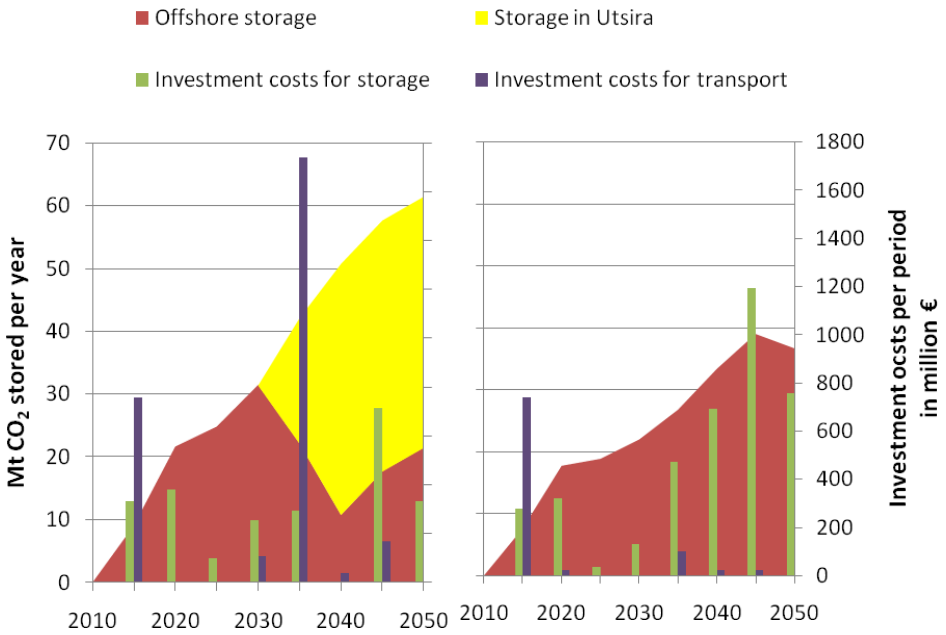

Figure 9 The annual amount of CO_2 storage and investment costs for transport and storage (including costs for satellite pipelines) in the period 2010-2050 for the Only offshore variant (left) and Only offshore - No Utsira variant (right)

First we highlight a few results per variant. In the *Only Offshore* variant the cumulative amount of CO_2 over the total analysis period is almost equal to the *Base case*. However, the majority of the CO_2 (700 Mt) is stored in the Utsira formation from 2033 onwards (see Figure 9). The contribution of CCS to CO_2 reduction remains on average 26%, although the transport costs are in some time steps almost three times higher. The low storage costs (being 1 €/t when 40 Mt per year is injected based on the assumptions in this study) in the Utsira formation ensure that CCS remains a competitive option. On the other hand, in the *Only*

Offshore - No Utsira variant, the amount of CO_2 stored diminishes by 33% due to limited availability of storage locations. Instead an energy mix with more offshore wind energy is found to be more cost-effective to reach the CO_2 target. In this variant costs of transport plus storage increase substantially (with 72-121%).

Table 6 CCS deployment and transport and storage costs for different variants

Variant	Transport costs			Storage costs			CCS deployment			Average contribution of CCS to CO_2 reduction in electricity sector from 2015 to 2050[a]
	€/t CO_2			€/t CO_2			Mt cumulative			%
	2020	2035	2050	2020	2035	2050	2020	2035	2050	
Base	2.7	1.9	1.9	1.7	2.1	3.3	102	555	1363	26
Offshore	3.0	5.3	3.9	4.0	3.0	3.0	99	494	1341	26
Offshore - No Utsira	3.7	2.7	2.1	4.0	4.8	9.4	82	359	917	13
Low renewables	2.1	1.6	3.8	1.9	2.4	1.8	142	732	1670	37
Reduction: 30/80	2.0	1.5	4.5	2.1	2.9	1.8	158	942	2226	45
Reduction: 20/80	2.7	1.6	4.5	1.9	2.7	1.8	120	804	2061	40
Cost factor: 2080	3.4	2.3	2.3	1.8	2.2	3.6	102	555	1363	26
Cost factor: 1120	2.0	1.4	3.1	1.7	2.0	1.4	104	572	1392	27

[a] This refers to the share of CO_2 avoided in the electricity sector by CCS compared to the total amount of CO_2 that need to be mitigated (this total amount is based on a model run without a CO_2 cap).

In the high reduction variants *R_30/80* and *R_20/80*, the cumulative amount of CO_2 stored is 63% and 51% higher than in the *Base case*, because the total amount of CO_2 that needs to be avoided in these variants is much larger. On the other hand, the transport costs up to 2040 are lower because pipelines are used to the full extent. However, from 2040 onwards, the Dutch storage capacity becomes scarce and a pipeline to Utsira needs to be constructed causing transport costs to be 141% higher than in the *Base case* (from 1.9 to 4.5 €/t).

In the variant without a lower bound for renewable electricity, CCS contributes with 37% to the CO_2 reduction instead of 26% in the *Base case*. In this variant, the share of renewable electricity is 16% in 2020 and 30% in 2050 compared to 27% and 41% in the *Base case*.

In the variant with constant cost factor of 2080 €/m^2 instead of 1600 €/m^2, transport costs increase with more than 23% compared to the *Base case*. In the *CF_1120 variant*, transport costs decrease with over 26% in 2015 and 2035. In this variant, in contrary to the *Base case*, a CO_2 pipeline to the Utsira formation is constructed in 2045 due to the lower CO_2 transport costs. Consequently, in 2050 CO_2 transport costs are higher, but CO_2 storage costs are lower than in the *Base case*. Finally, a change of 30% in the constant cost factor does not have any noticeable effect on the extent of CO_2 reduction by CCS.

Considering the outcome of all variants, we make some observations with respect to costs, necessary pipelines, and contribution of CCS to CO_2 reduction. First costs of the infrastructure vary between 3.4 and 11.5 €/t with 1.4 - 5.3 €/t for transport and 1.4 – 9.4 €/t for storage of CO_2. Total investment costs for the infrastructure range from 3.5 to 8.1 billion € during the whole analysis period. The results also point out that already in 2015, it seems worthwhile to invest in a trunkline from the *Rijnmond* region to either the North East of the Netherlands (with an estimated investment of about 350 m€) or, when no onshore storage is allowed, to the *North Sea offshore* region (for about 330 m€). In the variants two pipeline construction phases are identified: one between 2015 and a second one around 2040. The variants also show that it is cost-effective to over-dimension pipelines in the beginning, so that after 5-10 years the amount of CO_2 transported and stored can increase rapidly. Furthermore, in all variants, trunklines are built to transport the CO_2 from the almost 100%-pure CO_2 streams from sources in Limburg and Zeeland at an early stage. Apparently, since at these sources no major investments are needed for capturing the CO_2, it is worthwhile to invest in these long trunklines to the far off sinks. Additionally, in all onshore variants the *Eemsmond* region is connected to *Groningen* and then to the *Wadden* region, and *IJmond* is connected to the *North Holland* region.

Finally, in many variants (very ambitious reduction targets, limited renewable electricity, or limited storage capacity), the contribution of CCS depends strongly on the availability of the Utsira formation. Without this reservoir, the combined transport and storage costs can not be kept sufficiently low and the contribution of CCS to the reduction of CO_2 in the electricity sector reduces to 13% on average (compared to 26-45% in variants in which the Utsira formation is available). It is expected that the continuation of CCS deployment after the analysis period (2005-2050) will also depend on whether a very large CO_2 storage reservoir remains or becomes available after 2050 (e.g. the Slochteren field).

4.4 Discussion

In this section we discuss some of the main limitations of this study. The first point to be highlighted is the choice of the hub-spoke form as starting point for the development of the CO_2 pipeline network. This choice is of importance for two reasons. First, it requires that sources and sinks are clustered into regions with central hubs which are then determining factors in the layout of the infrastructure. However, in the case of CCS, the extent to which sources and sinks could be clustered in completely different way is limited due to the existence of natural clusters of sources and sinks resulting from historical economic or geological factors. The applied modelling approach would, therefore, be harder to apply to other types of transport problems where the locations for supply and demand are completely free to choose or need to be scattered all over the country (e.g. in the case of a hydrogen infrastructure, hydrogen fuelling stations need to be placed at many places). Second, modelling a more complex network with several minor hubs within regions instead of a hub-spoke network could reduce transport costs within regions and thus make a region more attractive. With regard to the second factor, model runs have been done without satellite costs in the North Sea region (Brederode, 2008). The attractiveness of these offshore regions did not seem to change. Furthermore, to take into account the (possible) complexity of the network, this study includes via-routes linking several source regions with several sink regions. Thus, transport costs between regions were reduced by combining several trunklines from several source regions to the same sink region(s) into one trunkline.

Still more insights can be obtained into the design of the infrastructure, when also the following aspects will be addressed:

- In this study we do not include the fact that foreign countries with small CO_2 storage potential like Belgium consider storing their CO_2 in Dutch reservoirs (Wildenborg, 2008). The influence of taking these flows into account is not clear. On the one hand, this additional CO_2 may force up the storage costs as the relative more expensive sinks need to be deployed for CO_2 storage as well. On the other hand, it may lower transport costs from the *Limburg* and *Zeeland* region, because pipelines can be constructed with larger capacities to transport CO_2 from, respectively, Germany and Belgium as well. The pipeline network may thus be designed differently when foreign CO_2 flows must be accommodated by the infrastructure.
- In this research most timing aspects have been taken into account with respect to the availability of sinks and sources. Only the time that a sink remains available after oil or gas production has ceased, was not restricted. However, preferably CO_2 storage should start within 2 years after production in order to avoid abandonment of the field and keep costs of mothballing a platform to a minimum. Taking this aspect into account will probably change the cost-effective design of the CO_2 infrastructure. For example, offshore sinks may be chosen before 2040.

- CO_2 storage potentials of this study were based on the TNO database which is in turn based on publicly available data (TNO, 2007c). However, the storage potential per sink may be either overestimated or underestimated due to lack of sufficient site specific data (TNO, 2007c). For example, a sink may not be suitable for CO_2 storage due to its performance characteristics (e.g. well integrity, faults, permeability). More detailed data from field operators on the ultimate recovery per field, and site characteristics can improve the quality or change the outcome of this study. Preferably, data should be obtained from local feasibility studies of individual sites. Furthermore, stakeholders may decide to use fields for other purposes such as natural gas storage (Taqa, 2008) or waste water injection from oil production (NAM, 2004; Drenthe Province, 2007). These aspects could diminish or increase the potential storage capacity of the country and hence affect the role of CCS in the mitigation portfolio as was demonstrated in the alternative variants in this paper.
- Taking external safety of CO_2 pipelines explicitly into account may affect the results for two reasons. First, mitigating the risk of a CO_2 pipeline is possible, but would add costs to the pipeline infrastructure (Koornneef et al., 2009). Secondly, it may be necessary to avoid CO_2 pipelines in certain areas. E.g. according to Turner et al. (2006) risk criteria could under certain conditions lead to zoning the land surrounding the pipeline in order to avoid a pipeline closer than 100 metres to residential buildings.
- The results are based on the input data in MARKAL-NL-UU and ArcGIS, which are based on the best available knowledge at this moment. However, experience with capture and storage of CO_2 is still limited, and therefore, data on costs and performance can still be improved. Furthermore, prices of equipment and energy are undergoing turbulent changes these days, which makes it hard to have an up-to-date database. Finally, data on CO_2 storage potential and costs need to be assessed further, once more experience is gained with actual CO_2 storage projects.

4.5 Conclusions

In this paper, we investigated how a CCS infrastructure could be developed within a portfolio of CO_2 mitigation measures to realise a 20% and 50% reduction target in the electricity and heat generation sector and CO_2 intensive industry compared to 1990 level in respectively 2020 and 2050. For this purpose, we carried out a quantitative scenario study for the Netherlands with the energy model MARKAL-NL-UU to assess the development of the CCS infrastructure over time, and the geographic information system ArcGIS for its spatial aspects. On the basis of the assumptions in this study, infrastructure consisting of around 600 km of CO_2 trunklines may need to be built before 2020 to reach the CO_2 reduction target of 20% when no additional nuclear power is constructed and the share of renewable electricity is 27% in 2020. In this phase, investment costs for the pipeline construction and the storage site development amount to around 720 m€ and 340 m€, respectively. In the

variant without renewable energy target, (which results in 16% renewable electricity), an additional investment of 244 m€ in the CO_2 infrastructure is necessary before 2020, especially to prepare more sinks for CO_2 storage (182 m€). Finally, a sensitivity analysis was employed to show the impact of alternative assumptions on the CO_2 infrastructure development. Costs in the different sensitivity variants ranged between 4.0 and 11.5 €/t with 1.5 - 5.3 €/t for the transport and 1.7 – 9.4 €/t for storage.

Several conclusions which are of importance for stakeholders involved in CCS can be drawn. First, results show that the policy choice to allow the storage of CO_2 onshore or not, is of major importance for the design of the infrastructure. If allowed, a CO_2 transport pipeline from *Rijnmond* to the sinks in the North-East of the Netherlands seems a cost-effective option. If not, a trunkline to a mega structure abroad (e.g. the Utsira formation) from around 2030-2035 has to be considered in order keeping CCS costs competitive. Secondly, such a policy decision should be taken as soon as possible because already now preparations should be on the way for constructions of a few large trunklines (planning routes, acquiring permits and licenses) to facilitate the CO_2 storage in the future. For example, it seems worthwhile to already invest around 2015 in a trunkline from the *Rijnmond* region to either the North East of the Netherlands (for around 350 M€) or, when no onshore storage is allowed, to the *North Sea offshore* region (for around 330 M€). Thirdly, the necessary investment decisions need to be underpinned by policy strategies, specific CO_2 reduction targets, and sink evaluations in order to reduce uncertainties with respect to future pipeline use. Although in the variants presented, the average amount of CO_2 stored up to 2025 ranged from 15-32 Mt/yr, this may be less (e.g. when CO_2 reduction targets are less strict, nuclear power is considered acceptable, or specific sinks turn out to be unsuitable for CO_2 storage). Fourthly, it should be studied how to take advantage of the early opportunities in *Limburg* and *Zeeland*, which are further away from potential sinks. Although the model results show that it could be cost-effective to construct long pipelines from these locations, other solutions such as storage in the nearby coal seams may also be considered. Alternatively, additional CO_2 flows from Belgium or Germany can make these pipelines more worthwhile to invest in. Finally, although currently capture costs take the major share in the total CCS costs, storage can become the restricting factor for the cost-effectiveness of CCS in the medium term (2035-2045) if cheap storage locations are filled or not available. It is recommended to seek ways to reduce these costs. For example, by making optimal use of existing wells and platforms, by integrating sinks into one storage facility, and additional search for large aquifers.

With regard to the methodology developed for this study, the results show that an ArcGIS/MARKAL-based toolbox can provide additional insights into the development of a CCS infrastructure. This approach can deliver concrete blueprints over time with respect to scale,

possible pipeline trajectories, and deployment of individual storage sites. It can also demonstrate how different policy choices lead to other designs of a cost-effective CCS infrastructure. This toolbox could, therefore, be used to support policy makers and companies in their decisions on CCS-related issues. Consequences of measures, such as the use of a pipeline for CO_2 transport in the Rotterdam region, the construction of capture ready power plants at specific locations can be evaluated with this toolbox.

Further research is required as this study has a number of caveats. The international context of CO_2 transport (e.g. CO_2 flows through or into the Netherlands), specific timeslots when sinks are available, CO_2 from small installations, possibilities to re-use wells and pipelines, and site-specific geological data, were missing. Finally, taking the hub-spoke network as basis imposes limitations to the structure of the network.

4.6 Acknowledgement

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ANNEX I GIS maps used in this study

Figure 1 Existing pipeline corridors in the Netherlands (in red gas 60 bar, in blue gas 40 bar, in green oil and in yellow chemicals). Source: (Speel, 2007).

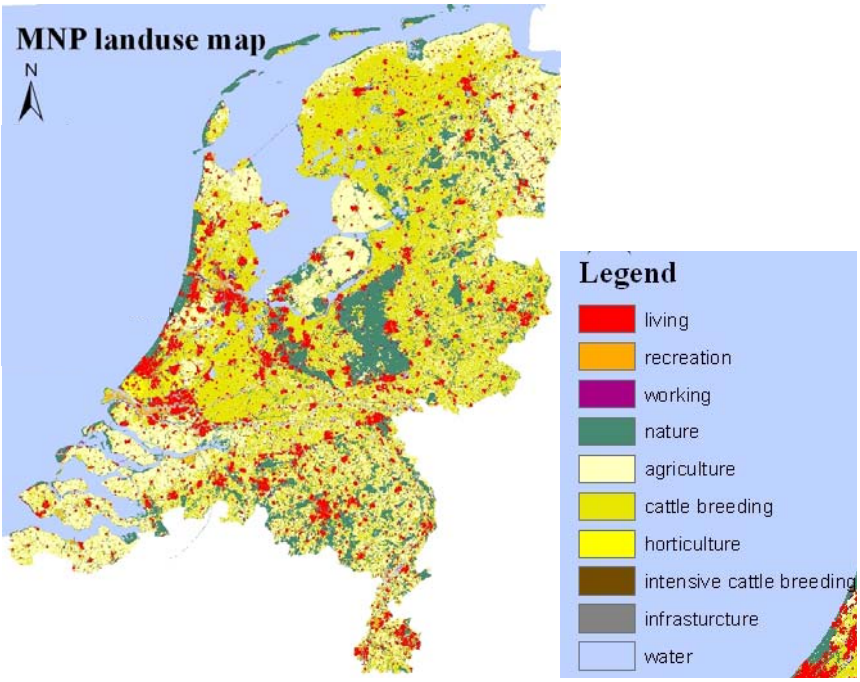

Figure 2 2040 land-use map in the Netherlands. Source: (MNP, 2007).

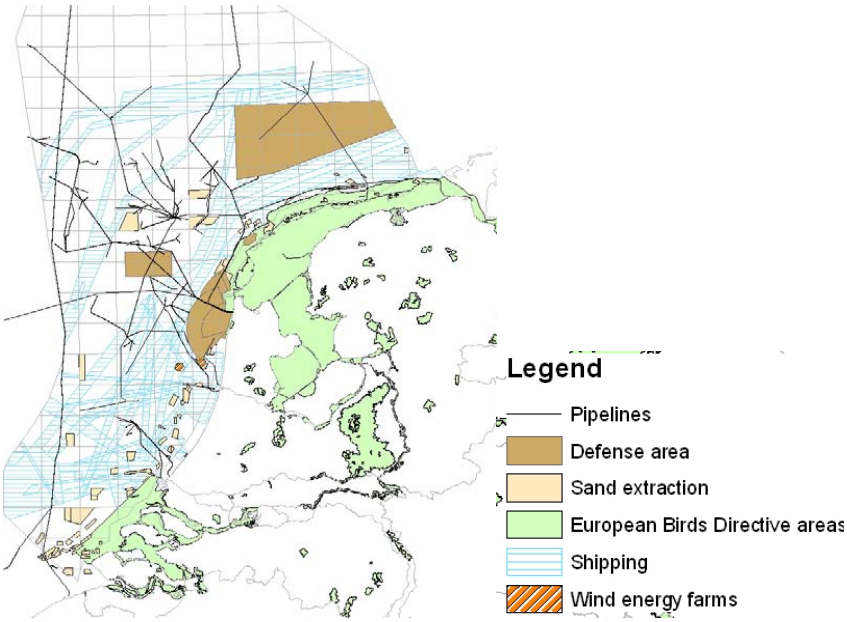

Figure 3 Projected use of the Dutch continental shelf for 2050. Source: (IDON, 2005).

Chapter 5

Feasibility of storing CO_2 in the Utsira formation as part of a long term Dutch CCS strategy, an evaluation based on a GIS/MARKAL toolbox

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Abstract

This study provides insight into the feasibility of a CO_2 trunkline from the Netherlands to the Utsira formation in the Norwegian part of the North Sea, which is a large geological storage reservoir for CO_2. The feasibility is investigated in competition with CO_2 storage in onshore and near-offshore sinks in the Netherlands. Least-cost modelling with a MARKAL model in combination with ArcGIS was used to assess the cost-effectiveness of the trunkline as part of a Dutch greenhouse gas emission reduction strategy for the Dutch electricity sector and CO_2 intensive industry. The results show that under the condition that a CO_2 permit price increases from €25 per tCO_2 in 2010 to €60 per tCO_2 in 2030, and remains at this level up to 2050, CO_2 emissions in the Netherlands could reduce with 67% in 2050 compared to 1990, and investment in the Utsira trunkline may be cost-effective from 2020-2030 provided that Belgian and German CO_2 is transported and stored via the Netherlands as well. In this case, by 2050 more than 2.1 $GtCO_2$ would have been transported from the Netherlands to the Utsira formation. However, if the Utsira trunkline is not used for transportation of CO_2 from Belgium and Germany, it may become cost-effective ten years later, and less than 1.3 $GtCO_2$ from the Netherlands would have been stored in the Utsira formation by 2050. On the short term, CO_2 storage in Dutch fields appears more cost-effective than in the Utsira formation,

but as yet there are major uncertainties related to the timing and effective exploitation of the Dutch offshore storage opportunities.

5.1 Introduction

5.1.1 Overview

CO_2 capture and storage (CCS) is increasingly considered a crucial technology for mitigating climate change (IPCC, 2007). An important precondition for the implementation of CCS, however, will be the realisation of a CO_2 transport and storage infrastructure. In North West Europe part of this infrastructure may be constructed in the North Sea because of the large CO_2 storage potentials that have been identified there. For example, in the Norwegian part of the North Sea, storage capacity has been estimated to be 148 $GtCO_2$ in aquifers, 4.4 $GtCO_2$ in gas fields, and 4.8 $GtCO_2$ in oil fields (Bøe et al., 2002; BERR, 2007). In the part of the North Sea that belongs to the United Kingdom (UK), the storage potential has been estimated to be 14.5 $GtCO_2$ in aquifers, 6.0 $GtCO_2$ in gas fields, and 4.2 $GtCO_2$ in oil fields (BERR, 2007).

The geological reservoirs under the North Sea with very large CO_2 storage potentials (e.g. large reservoirs in the Bunter Sandstone formation in the UK part of the North Sea, or the Utsira formation in the Norwegian part of the North Sea) may be indispensable when large amounts of CO_2 need to be stored (Damen et al., 2009). A North Sea pipeline network could connect CO_2 sources in countries around the North Sea to such a geological storage reservoir. So far most studies of trans-boundary transport crossing the North Sea have concentrated on the use of CO_2 for enhanced oil recovery (EOR). For example, Markussen et al. (2002) looked at the use of large volumes of CO_2 from the UK, Denmark, and Norway for EOR on the North Sea continental shelf. According to them it is cost-effective to sequester around 680 $MtCO_2$ in the North Sea while at the same time producing an additional amount of two billion barrels of oil. More recently, a study in the UK (BERR, 2007), which examined a CO_2 infrastructure for storing CO_2 from UK and Norwegian sources in the North Sea, found that only for the purpose of EOR, it would be worthwhile to transport CO_2 from the UK to Norway.[1] Also in the Netherlands, a study of the Rotterdam Climate Initiative to reduce CO_2 emissions in the Rotterdam region, considered CO_2 transport to Norway only for EOR purposes (Hoog, 2008). Furthermore, the authors of the IEA GHG study, which calculated cost curves of CO_2 transport and storage for Europe (IEA GHG, 2005a), did not include the aquifers with large CO_2 storage potentials such as the Utsira formation in their analysis. However, recent broader analyses (Broek et al., 2008; Broek et al., 2009; Damen et al., 2009) showed that CO_2 storage in very large geological storage reservoirs, can make CO_2 trans-boundary transport for the mere purpose of CO_2 storage an interesting option as well.

[1] For the purpose of CO_2 storage only, they found that sufficient storage capacity is available for the UK on its own territory. Most of the UK sources which are in the region of East Midlands and South Yorkshire, are even close to the sinks (gas fields as well as saline aquifers) on the UK territory in the Southern part of the North Sea.

Yet, a decision to invest in a major trunkline across the North Sea to such a reservoir, requires additional insights into its feasibility with respect to costs and organisation.

In this paper, we, therefore, aim to assess the cost-effectiveness of CCS and CO_2 storage in a very large formation under the North Sea in competition with CCS and CO_2 storage in smaller nearby formations or in competition with other CO_2 mitigation options. We also try to identify the boundary conditions that make investments in a major CO_2 pipeline across the North Sea worthwhile, and to assess suitable routings for this pipeline. Finally, we will make a first inventory of organisational issues related to its construction.

We will investigate these issues by investigating the specific case of a CO_2 trunkline from the Netherlands to the Utsira formation. This formation has already been used for CO_2 injection from 1996 in the Sleipner project, the first commercial project to store CO_2 in a saline aquifer (Gale et al., 2001; Torp and Gale, 2004; Hermanrud et al., 2009). This formation consisting of sand and sandstone, is located east of Norway from ca 58ºN to 62ºN and covers an area of up to 470 km in North-South direction and up to 100 km in East-West direction, the thickness is probably not more than 250 m, and is located at a depth of 500-1500 m below the sea floor (Bøe et al., 2002) and a water depth of 80-100 meters (Torp and Brown, 2004). The formation is of special interest due to its enormous theoretical CO_2 storage potential (42 $GtCO_2$) and its high permeability (Bøe et al., 2002). The permeability is in the order of 3500 mD, and the porosity ranges from 27% to 42% (Torp and Gale, 2004). By using a general storage efficiency of 6% for open aquifers, the pore volume that can be used for CO_2 storage is estimated to be 55 km^3 (Bøe et al., 2002). Furthermore, it is overlain by the Nordland shale (Bøe et al., 2002) consisting of fine-grained clays or silty clays, through which it is unlikely that CO_2 will leak (Kemp et al., 2002).

The structure of this paper is as follows. Details about the adopted methodology and input data can be found in section 2. Results are presented and discussed in Section 3 and 4. In section 5 we discuss a few organisational issues, and finally in section 6 conclusions are drawn with respect to the feasibility of a CO_2 trunkline from the Netherlands to the Utsira formation. It should be noted that the scope of the study is limited to sources that emit more than 100 $ktCO_2$ in the industrial, electricity and cogeneration sector in which CO_2 capture can be applied. In this paper, a discount rate of 7% is used, and all costs are in $€_{2007}$.

5.2 Methodology

5.2.1 Overview

To evaluate the techno-economic feasibility of a CO_2 trunkline from the Netherlands to the Utsira formation, temporal and spatial dimensions need to be taken into account explicitly. Therefore we use a toolbox integrating ArcGIS, a geographical information system (GIS) with elaborated spatial and routing functions, and the MARKAL (an acronym for MARKet ALlocation) tool, which can generate energy bottom-up models to calculate energy

technology configurations over time (Loulou et al., 2004). More specifically, we apply the MARKAL implementation of the Dutch electricity and cogeneration sector, MARKAL-NL-UU, that was used earlier to assess possible CCS deployment trajectories in the Netherlands (Broek et al., 2008). In MARKAL-NL-UU, technologies that convert primary energy carriers (e.g. coal, gas, uranium) or renewables (e.g. wind, biomass, and solar) into final energy carriers (electricity and heat), are modelled. Furthermore, MARKAL-NL-UU includes CO_2 transport and sink technologies, and industrial technologies that produce other types of products (e.g. steel, hydrogen). The model can determine the deployment of CCS and other CO_2 mitigation measures like photovoltaic cells, wind turbines, or biomass co-firing by minimising the net present value of all system costs. Furthermore, it assesses which sources, sinks, and transport options will be used over time and to what extent. The period of analysis is 2010-2050, and a time step of 5-years is used.

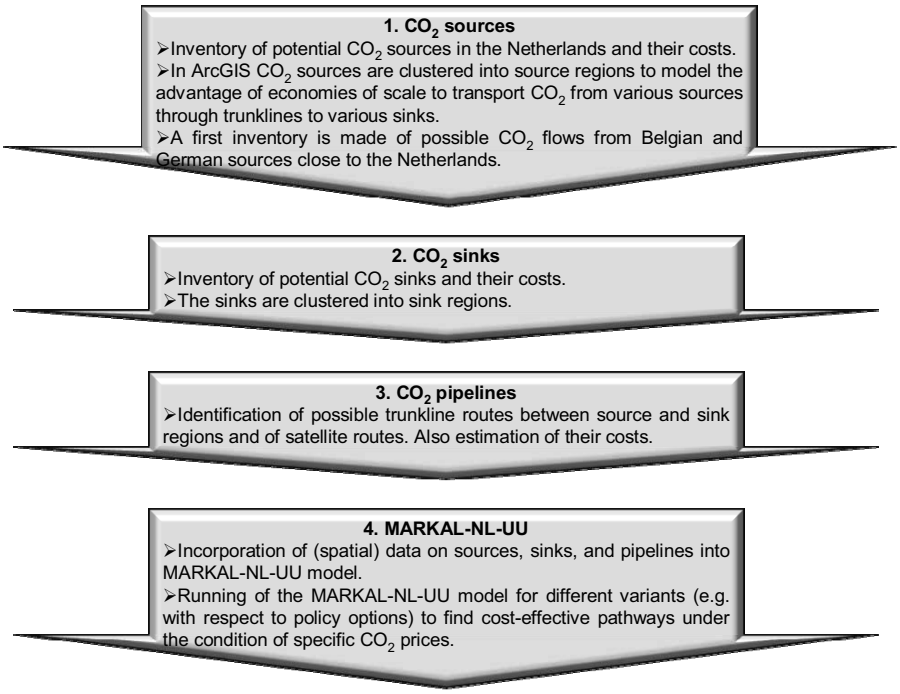

Figure 1 Schematic representation of the methodological approach in this analysis

The application of this toolbox provides blueprints of the development of a CO_2 infrastructure in the Netherlands taking into account CO_2 emission sources in Germany and Belgium. Insights can be obtained into possible CO_2 pipelines routings and their associated costs, and the amounts of CO_2 that can be captured in different Dutch regions and stored in Dutch sinks (onshore or near-offshore) or in the Norwegian Utsira formation. The methodology, which is described in detail by (Broek et al., 2009), can be summarized in four

main steps related to processing data for CO_2 sources, CO_2 sinks, and pipelines. The fourth step concerns the specification and running of MARKAL-NL-UU (see Figure 1).

In the rest of this section, we describe the individual steps in more detail with a focus on relevant issues for assessing the specific case of an Utsira trunkline from the Netherlands.

5.2.2 Inventory of sources

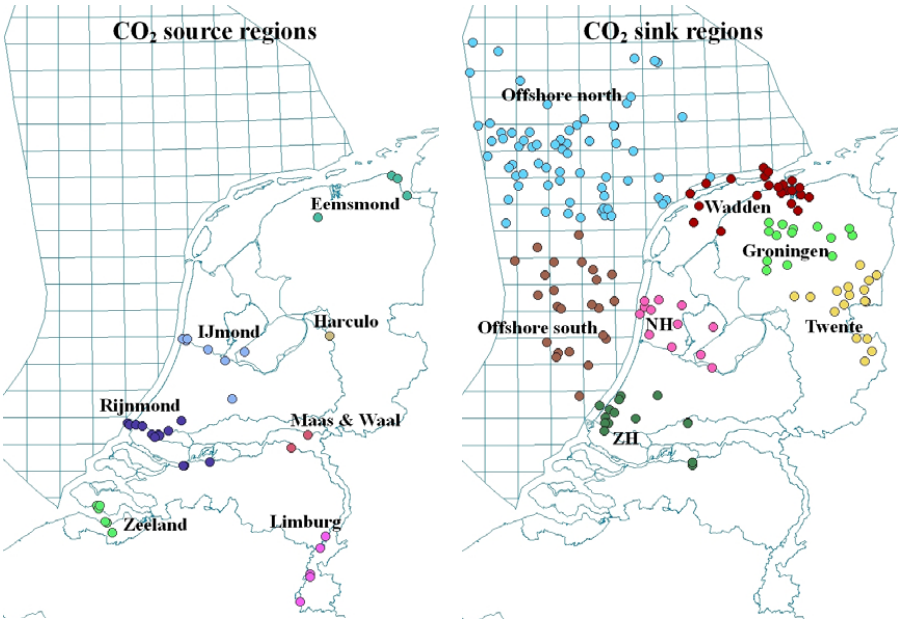

Figure 2 Clustering of potential CO_2 source locations into source regions (a) and potential CO_2 sinks into sink regions (b). The names of the regions are specified in the maps. Note that some sources are almost at the same location, and thus cannot be distinguished from each other on the map. The Utsira formation offshore Norway is not shown

CO_2 from inside the Netherlands

Under the condition of a strict climate policy, CO_2 emissions can be reduced by capturing them at large scale fossil-fuelled power plants, industrial processes generating small quantities of pure CO_2 (e.g. hydrogen, ammonia, or ethylene oxide production units) or large quantities at a single site (e.g. steel industry, refineries, or ethylene production units) (Damen et al., 2009). Therefore, the inventory of potential sites for CO_2 capture in the Netherlands in the period 2010-2050 includes the sites of the 24 large scale power plants, 15 industrial plants, and 4 probable locations for new power plants (43 sources in total). The capture units at power plants can be post-combustion units at natural gas combined cycle power plants (NGCC) or pulverised coal-fired power plants with possibly biomass co-firing

(PC), post-combustion retrofit units for PCs, or pre-combustion units at integrated coal (with possibly biomass) gasification combined cycle power plants (IGCC)[2]. Figure 2 shows the 43 locations where CO_2 may be captured in the future, and how they are clustered into seven source regions as described in (Broek et al., 2009). Per region it is known when the existing power plants will be decommissioned[3]. Consequently, MARKAL-NL-UU can calculate when in the Netherlands new power plants (see section 5.2.5 for more details) are needed to meet the future electricity demand, selects the types of power plants, and selects the source regions where these new power plants will be constructed. For the industrial units, it is assumed that the industrial production continues at today's level, and the costs for necessary replacement of these units are not included in MARKAL-NL-UU.

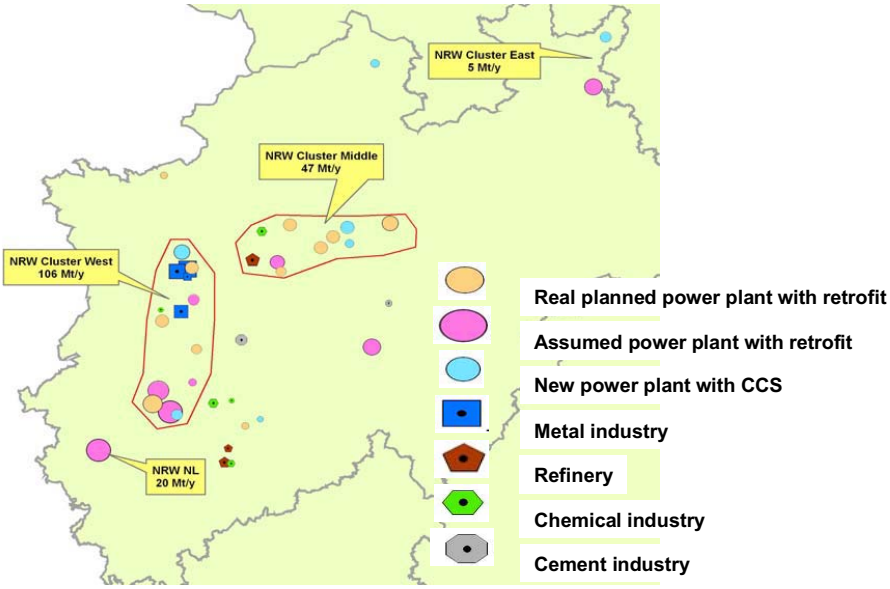

Figure 3 Locations of CO_2 sources in North Rhine Westphalia. Assumptions on CCS made by the authors (Viebahn et al., 2009b)

CO_2 from outside the Netherlands

In the Belgian part close to the Zeeland region, the German part close to the Eemsmond region, and the North Rhein-Westfalian (NRW) part of Germany (close to the Limburg and

[2] Pulverised coal-fired power plants with oxyfuel combustion and CO_2 removal were not included, because they are not clearly different from PC power plants with a post-combustion CO_2 capture unit with respect to cost-effectiveness (Damen et al., 2006).

[3] Based on the age of existing power plants, plans of energy companies and/or a life time of 40 years for NGCC and IGCC, and 50 years for PC. For more details on the vintage structure of the electricity sector see (Broek et al., 2008).

Maas and Waal region), many large point sources of CO_2 exist, but nearby storage sites for these sources are limited. While the total storage potential for Germany was first estimated to be in the order of 10 to 40 $GtCO_2$ (May et al., 2005), the most recent assessment (EU Geocapacity, 2009) results in 17 $GtCO_2$ storage capacity (mainly in aquifers) which would be sufficient for 37 years of emissions from the existing large point sources in Germany. Unfortunately, although the large stationary sources in the Ruhr area in NRW emit nearly 50% of the German CO_2, NRW has only one aquifer with a storage capacity of some more than 100 $MtCO_2$ (with a 90% probability) and in total, a capacity of 348 $MtCO_2$ in aquifers could exist there (GD and BGR, 2005)[4]. Therefore, an enormous pipeline infrastructure would be required to store the CO_2 from NRW sources in the German sinks, which are mainly located in the North of Germany. For Belgium, the recent CO_2 storage assessment (EU Geocapacity, 2009) yields a storage capacity of only 199 $MtCO_2$ compared to 58 Mt of annual CO_2 emissions from large Belgian sources. For these reasons, storage outside the German and Belgian territories should be taken into consideration. Possible options would be to transport the CO_2 to Dutch sinks or via the Netherlands to the Utsira formation.

Data on the CO_2 capture potentials from CO_2 sources in NRW, were derived from recent studies of a CCS infrastructure in NRW (Viebahn et al., 2009b; Viebahn et al., 2009a) (Figure 3). Although NRW plans to replace most old power plants by highly-efficient new ones before 2020, this is not sufficient to reach an 80%[5] reduction of greenhouse gas emissions compared to the 1990 level by 2050 in Germany. A part of the solution could be the application of CCS. In the mentioned NRW studies, the infrastructural requirements necessary to realise such a scenario, were assessed. The maximum CO_2 flows were calculated that can be captured under the condition that the CO_2 permit price is high enough. It was investigated which power plants could be retrofitted with post-combustion CO_2 capture or replaced as thermal or IGCC power plants with CCS from 2020 in NRW. For economic reasons, only power plants were considered for retrofit with a CO_2 capture unit that will not be older than 12 years in 2020[6]. Furthermore, the CO_2 capture potential at big industrial emitters was assessed.

Data on CO_2 capture potentials from sources in Belgium close to Zeeland and in Germany close to Eemsmond are derived from the GESTCO project (Hendriks and Egberts, 2003)[7]. It is

[4] In the NRW area, also a maximum of 160 $MtCO_2$ may be stored in coal seams with enhanced coal-bed methane recovery (ECBM). However, the application of ECBM is restricted due to the low permeabilities and large depth of the coal deposits (Kronimus et al., 2008).

[5] To reach a greenhouse gas concentration below 500 ppm CO_2-equivalent, which is needed to keep global mean surface air temperature increase around 2.0-2.4°C, worldwide CO_2 emissions need to reduce by 50-85% compared to 2000 levels and CO_2 emissions should peak before 2015 (IPCC, 2007). Furthermore, the CO_2 emission reduction in developed countries need to be substantially more than in developing countries (IEA, 2008), up to 80% compared to 1990 level (EU, 2005).

[6] According to (McKinsey&Company, 2008), only power plants not older than 12 years will be retrofitted from 2020, because they estimated total CCS costs to be at least 30 percent higher for older (same scale) plants, and possibly much more, depending on the specific case.

[7] Sources are considered with pure CO_2 streams or emissions of more than 2 $MtCO_2$/yr. Furthermore, Belgian sources are included which are located at latitude > 51°N and longitude < 4.6°E, and German sources (close to Eemsmond) that are located at latitude > 53°N and at longitude < 8.8°E.

assumed that in Belgium a pure CO_2 emission stream of 1 $MtCO_2$/yr can be stored from 2015, and CO_2 from the other Belgian sources after 2020. Furthermore, it is assumed that a new coal-fired power plant according to E.ON's plan (E.ON, 2007) will be built and can be equipped with a CO_2 capture unit (6 $MtCO_2$/yr) before 2020. Table 1 presents the resulting CO_2 capture potentials from the different foreign regions.

Table 1 CO_2 capture potential at existing CO_2 sources in Germany and Belgium for different timeframes

Region abroad	Nearest source region in the Netherlands	Estimated CO_2 capture potential (in $MtCO_2$ per year)			
		2015	2020	2025	2030 onwards
Belgium (around Antwerp)[a]	Zeeland	1	7	22	22
Germany (NRW) [b]	Maas and Waal		30	104	104 (from 2040 112)
Germany (NRW) [c]	Limburg		21	21	21
Germany (Niedersachsen) [d]	Eemsmond		3	10	11

Source: (Hendriks and Egberts, 2003; Viebahn et al., 2009a; Viebahn et al., 2009b)
[a] Data on existing sources (>2$MtCO_2$ per year) and CO_2 pure streams are derived from (Hendriks and Egberts, 2003). Furthermore, the plan of E.ON to build a coal-fired power plant with capture of 6 $MtCO_2$ per year is added. It is assumed that the 1 $MtCO_2$ of pure CO_2 available in this area could already be stored from 2015. Around 2020, the E.ON power plant could be online, and then the other sources could be equipped with CO_2 capture.
[b] Based on studies by Viebahn (2009b; Viebahn et al., 2009a), which provide insights into the timing of CCS at different power plants in the German State North Rhine-Westphalia (cluster Middle and cluster West in **Figure 3**). The industrial emitters are responsible for around 20% of the CO_2 capture potentials. Only sources >1 $MtCO_2$ are considered.
[c] Based on studies by Viebahn (2009b; Viebahn et al., 2009a). The CO_2 close to the Limburg region in the Netherlands originates from the Weisweiler power plant (see NRW NL cluster in **Figure 3**).
[d] Based on data about existing sources in the GESTCO database (Hendriks and Egberts, 2003). The rate by which these sources become available is similar to that in North Rhine-Westphalia close to Maas and Waal. These data exclude any plan to build new coal-fired power plants in this region because no details were available on the status of these plans.

5.2.3 Inventory of sinks

In this study 172 Dutch sinks are considered for CO_2 storage. Only hydrocarbon fields are considered with a storage capacity > 4 $MtCO_2$, and aquifers with a storage capacity > 2 $MtCO_2$. Together these sinks are assumed to have an effective capacity potential of 1.8 $GtCO_2$ (81 sinks) onshore and 1.3 $GtCO_2$ (87 sinks) offshore[8,9]. From these fields 35 are

[8]The Slochteren field in the province Groningen has an estimated CO_2 storage capacity of about 7 $GtCO_2$. This gas producing field is considered unavailable for storage before 2050 and therefore it is not considered in this project (NLOG, 2007).
[9] NOGEPA (2008) recently published a study with slightly different storage potentials due to different techno-economic thresholds. They estimated Dutch offshore storage capacity to be around 0.9 Gt. The study did not include any storage in offshore aquifers (0.14 $GtCO_2$). Furthermore, the NOGEPA study only included fields with

aquifers, 131 are gas fields, 5 are oil fields and 1 field contains both oil and gas. The storage potential of aquifers amount to 0.25 $GtCO_2$ onshore, and 0.15 $GtCO_2$ offshore. Apart from the Dutch fields, the large aquifer in the Utsira formation in the Norwegian part of the North Sea with an estimated capacity of 42 $GtCO_2$ (Bøe et al., 2002) is investigated. Clustering the sinks into sink regions (Broek et al., 2009) resulted in three onshore regions in the North East of the Netherlands, two onshore regions in the West of the Netherlands, two offshore regions in the Dutch part of the North Sea, and the Utsira formation offshore Norway (see Figure 2). In this paper we will refer to the Dutch offshore fields as near-offshore fields because they are located between 20 km and 200 km away from the Dutch coast while the Utsira formation is more than 750 km away. Finally, CO_2 storage in German or Belgian sinks is not considered as an option in this paper.

Per sink, investment, and operating, maintenance, and monitoring (O&M&M) costs are specified on the basis of depth, thickness, CO_2 storage capacity, and injectivity per well. A distinction is made between storage in onshore fields and near-offshore fields, and between hydrocarbon fields (gas and oil) and aquifers. Specific cost data are used for storage in the Norwegian Utsira formation. It is assumed that aquifers are available from the start, and gas fields become available when gas production has ceased. These dates are based on the production reports of the oil and gas exploration companies and are sometime between 2005 and 2025[10]. Near-offshore CO_2 injection facilities can be installed on existing platforms, thus limiting expenditures to the costs of conversion of the platform and well workovers. However, the period in which a platform may be re-used, *the window-of-opportunity*, is limited. Once most of the resources within reach of a platform have been produced, it is often not economic to continue the production activities at this platform because of its high operating costs[11]. Then, when production activities cease, the platform needs to be removed as required by Dutch legislation (EZ, 2002a; EZ, 2002b) following international regulation[12]. If it is later decided to store CO_2 in these fields, new platforms and new wells would need to be constructed for the CO_2 storage activities. Also onshore, there is the possibility to re-use wells and facilities. To model the window-of-opportunity, we take care that in MARKAL-NL-

more than 2.5 $MtCO_2$ storage capacity that were still producing, fields with temporarily ceased production, or with a Field Development Plan. Abandoned fields were left out. In addition, to ensure a reasonable injectivity, only fields, for which the product of permeability and thickness was higher than a chosen threshold value of 0.25 Darcy meter, were considered. NOGEPA, which is the association of companies holding licences to explore for, develop and produce hydrocarbons on- and offshore in The Netherlands, has access to confidential production data to make such injectivity estimations per field.

[10] The year in which gas field are released, however, shifts ahead, because gas production continues longer due to higher revenues and new production technologies (TNO, 2007). Because it is not known beforehand how much longer production will continue in specific fields, we did not take this shift into our analysis.

[11] For example, in Ireland, it is estimated that after 30 years of production 95% of the ultimate recoverable gas reserves has been produced from the Kinsale Head gas field, and that it approaches the end of its economic lifetime. The overhead costs of the platform are considered too high to produce small amounts of gas (CSA Group, 2008). Consequently, without any other purpose for the infrastructure in the near future, the platform needs to be decommissioned.

[12] In 1998, the OSPAR decision 98/3 was adopted that prohibits to dump disused offshore installations, and/or leave them wholly or partly in place within the maritime area (OSPAR convention, 1998).

UU the facilities of a sink can only be re-used if CO_2 storage starts within 5 years after the estimated year in which gas (or in some cases oil) production will cease.

The investment costs to develop a specific sink for CO_2 storage are calculated using Equation 1 and the input data for the different types of sinks in Table 2. The O&M&M costs of a sink are always based on a fixed percentage (see Table 2) of the investment costs for the development of the sink from scratch, because in the case of re-use the existing equipment also needs to be operated and maintained.

Equation 1 $$I = W * (C_d * H + C_w) + C_{sf} + C_{sd}$$

Where:

I	=	Investment costs sink (€).
W	=	Number of wells per sink. The number of wells depend on the storage potential of the sink and the injectivity per well for the sink.
C_d	=	Drilling costs (€ per meter). $C_d = 0$ if old wells can be re-used.
H	=	The drilling distance being the depth of the reservoir starting at the bottom of the sea (for offshore sinks) or the ground surface (for onshore sinks) plus the thickness of the reservoir (in meter)
C_w	=	Fixed costs per well (in €). In case of re-use, these are the costs for the workovers of the old wells.
C_{sf}	=	Investment costs for the surface facilities on the injection site and investments for monitoring (e.g. purchase and emplacement of permanent monitoring equipment) (in €)
C_{sd}	=	Investment costs for the site development costs. E.g. site investigation costs, costs for preparation of the drilling site and costs for environmental impact assessment study. In general it is expected that for 'empty' gas and oil fields geological and geophysical data are available (in €).

In order to illustrate the range in costs for the different sink types, Table 2 also shows the CO_2 storage costs in € per tCO_2 for illustrative sinks.

Table 2 Storage cost data used in this study

	Parameter	Unit	Hydrocarbon onshore	Hydrocarbon onshore with re-use[a]	Hydrocarbon near-offshore	Hydrocarbon near-offshore with re-use[a]	Aquifer onshore	Aquifer near-offshore	Utsira Formation
Input data	Drilling costs (Cd)	€ per meter	3000[b]		5314		3000[b]	5314	14600[c]
	Fixed well costs (Cw)	M€ per well		1	8.2	2		8.2	18[cd]
	Site development costs (Csd) e	M€	3.3	3.3	3.3	3.3	25.5	25.5	4.5[f]
	Surface facilities costs (Csf)	M€	1.5	0.4	61	15	1.5	61	
	O&M&M costs	% of investment[g] per year	5	5	5	5	5	5	5
	Depth + thickness reservoir (H)	meter	800-4190		1979-4429		1150 -3800	1550-3900	1250
	Injection rate per wellh	$MtCO_2/yr$	0.2-1	0.2-1	0.2-1	0.2-1	0.2-0.5	0.2-0.5	2
An example sink[i]	Depth + thickness reservoir	meter	2500		3600		2500	3000	1250
	Injection rate per well	$MtCO_2/yr$	1	1	1	1	1	0.5	2
	Levelised storage costs	€/tCO_2	1.7	1.0	12.5	6.4	9.4	30.1	2.8

Sources: (CASTOR project, 2004; BERR, 2007; Serbutoviez et al., 2007; Torp, 2008; Wildenborg et al., 2008)

[a] Re-use of wells and platform. The fixed costs per well are the estimated costs to convert a production well into a CO_2 injection well. [b] For the onshore wells, the fixed costs per well are included in the drilling costs (these costs assume reservoir depths of around 3000 m). [c] Costs for storage into the Utsira formation were given in $€_{2008}$. A factor of 0.73 based on the IHS/CERA Upstream Capital Cost Index (IHS, 2008) is used to convert them to $€_{2007}$. Costs of, for example, renting drilling rigs had risen tremendously in 2008 due to the high oil prices; in 2009 these costs are again falling rapidly (IHS, 2009). [d] Instead of injecting CO_2 from a platform into the Utsira formation, CO_2 can be injected from systems on the sea bottom (subsea completion systems). A subsea frame with subsea completion systems for 4 wells costs ca 100 million $€_{2008}$ (18 $M€_{2007}$ per well). These costs include costs for engineering, transport of the subsea frame to the right location, installation, and a reserve of 25% for contingency costs (non-budgeted expenses). Although the injection itself takes place at the sea bottom, the control of the injection will take place at a nearby existing platform (Torp, 2008). [e] Including monitoring investment costs in pre-operational phase. [f] Site development costs for the Utsira formation are much lower than for the Dutch near-offshore aquifers, because the Utsira formation is already used for CO_2 injection. [g] As a fixed percentage of the investment costs for the development of the sink from scratch (also in the case of re-use of equipment). [h] The injectivity rate depends on the reservoir type and the lithology of the reservoir rock. [i] In the model storage costs are calculated per individual sink depending on type, CO_2 storage capacity, depth, and injection rate of the sink. However, to get an impression of the storage costs per type of sink, the levelised costs are shown for a sink with a specific depth, a typical injection rate expected for Dutch sinks, and lifetime of 25 years for the storage facilities. The calculation is based on a 7% discount rate.

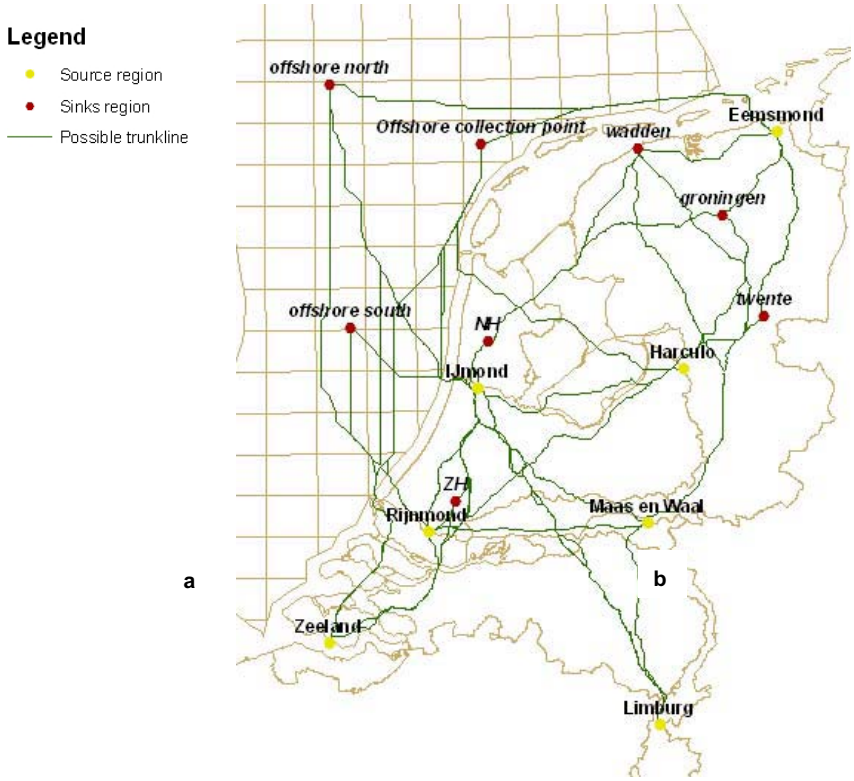

Figure 4 Possible trunklines between source and sink regions in the Netherlands

5.2.4 Inventory of pipeline routes

In ArcGIS, routings of possible trunklines between the Dutch source and sink regions are identified with least-cost routing functions (see Figure 4). The investment and operational costs of a pipeline are influenced by terrain conditions such as land use or roads to be crossed (Vandeginste and Piessens, 2008). Therefore, we differentiate the CO_2 pipeline construction costs per land-use type by using terrain factors, and a preference is given for following the existing hydrocarbon pipeline corridors resulting in investment costs varying between 1300 and 4300 € per meter length and per meter diameter for a specific location (Broek et al., 2009)[13]. Future land-use is taken into account via a GIS map for 2040 developed by the Netherlands Environmental Assessment Agency (MNP, 2007). We use Equation 2 of

[13] The calculations to determine the requirements for the pipelines are based on transport of pure CO_2. In reality, the CO_2 will contain a certain level of impurities which may change the behaviour of CO_2 at a given pressure and temperature. These impurities may also have an impact on the pipeline requirements to prevent corrosion, which may affect investment costs.

Hendriks et al. (2003) rearranged by McCollum and Ogden (2006) [14] to calculate the diameters of the CO_2 pipelines for all the trajectories and several capacities per trajectory (e.g. for a maximum of 5, 15, or 25 $MtCO_2$ flow per year).

Equation 2

$$D^5 = \frac{8 * \lambda * m^2}{\pi^2 * \rho * \frac{\Delta P}{L}}$$

Where:

	D	= Diameter pipeline (m)
	λ	= friction coefficient (0.015)
	m	= mass flow rate ($ktCO_2$/day)
	ρ	= CO_2 density (800 kg/m^3)
	ΔP	= pressure drop ($3*10^6$ Pa) assuming an inlet pressure of 110 bar and a delivery pressure of 80 bars at the injection site.
	L	= length of pipeline (m)

Finally, we select four options for a trunkline from the Netherlands to the Utsira formation taking into account the locations of CO_2 source regions and the existing Dutch landfalls (i.e. locations where pipelines are preferred to go from onshore to offshore) which are preferably used for new pipelines as well (EZ et al., 1984). Figure 5 shows the routings found by the ArcGIS least-cost routing functions and Table 3 shows the technical and economic details of these pipelines.

5.2.5 MARKAL-NL-UU scenario assumptions

The role of CCS and the associated CO_2 infrastructure within the total portfolio of mitigation options for a given year can be determined in the context of a scenario. The base scenario inputs that underlie the runs of MARKAL-NL-UU are the following:

- The Dutch electricity demand will increase from 110 TWh in 2005 to 175 TWh in 2050. This value is in line with the electricity demand growth in the "Strong Europe" scenario used by the Dutch planning agencies (Janssen et al., 2006).
- The permit price of CO_2 increases from 25 €/tCO_2 in 2010 to 60 €/tCO_2 in 2030, and remains at this level up to 2050.

Nuclear power phases out in 2033 when the existing nuclear power plant in Borssele of 450 MW has to shut down (VROM, 2006).

[14] As can be seen in the model comparison analysis by (McCollum and Ogden, 2006), the resulting diameters lay within the range of diameters calculated by models in other studies (IEA GHG, 2002; Heddle et al., 2003; Ogden et al., 2004; IEA GHG, 2005a; IEA GHG, 2005b).

Table 3 Technical and economic details of four possible trunklines to Utsira

					Pipeline capacity (in $MtCO_2$/yr)			
Collection point	**Length (in km)**	**Landfall**	**Parameter**	**Unit**	**20**	**40**	**60**	**80**
Eemsmond	750	Existing landfall in the municipality of Warffum (near Eemsmond).	Pipeline diameter [b]	Inch	36	42	48	48
			Power pumping station [c]	MW	17	65	114	464
			Pressure before transport [c]	bar	100	115	120	160
			Investment [d]	M €	1250	1530	1820	2140
At sea North West of the Netherlands[a]	750	The landfall would be at existing locations in Rotterdam, or at the second Maasvlakte as in the RCI plan (Hoog, 2008).	Pipeline diameter	Inch	36	42	48	48
			Power pumping station	MW	17	65	114	464
			Pressure before transport	bar	100	115	120	160
			Investment	M €	1250	1530	1820	2140
IJmond	830	Existing landfall location near IJmuiden.	Pipeline diameter	inch	36	42	48	48
			Power pumping station	MW	19	75	130	493
			Pressure before transport	bar	100	120	125	165
			Investment	M €	1380	1690	2010	2340
Rijnmond	890	Existing landfall near Rotterdam or at the second Maasvlakte as in the RCI plan (Hoog, 2008).	Pipeline diameter	inch	36	42	48	48
			Power pumping station	MW	21	83	143	514
			Pressure before transport	bar	105	125	130	170
			Investment	M €	1480	1810	2160	2480

Source: (Buit, 2009)

[a] Or onshore close to an existing landfall possibility near Den Helder at Callantsoog (starting point for a gas pipeline to the United Kingdom, the BBL pipeline).

[b] A dedicated physical model has been used to determine the dimensions of the pipeline and the pumping station. The mass flow of CO_2 and the pressure specifications determine the possible diameters of the pipeline. Pipeline diameters of 30, 36, 42 and 48 inch are available. The pipeline material must be able to withstand high pressures, so the material of choice is X70 pipeline steel.

[c] It is assumed that the CO_2 delivered to the collection point at the start point of the Utsira trunkline is in the dense phase (at 80 bars). At the collection point, there is a station pumping the CO_2 and thus increasing the pressure. Pressure loss along the pipeline must be limited, to keep the CO_2 at or above 80 bars. At the storage site, a pressure of 80 bars is sufficient to inject the CO_2.

[d] Estimations of CO_2 transport costs are based on available data of oil and gas pipelines at the Gasunie company which is responsible for the operation and development of the Dutch natural gas transmission grid (Buit, 2009). Operating and maintenance costs of the trunkline and pumping station (excluding electricity costs for the pumping station) are estimated at 3.5% of the investment. Costs for electricity in the pumping station are assumed to be 60 €/MWh.

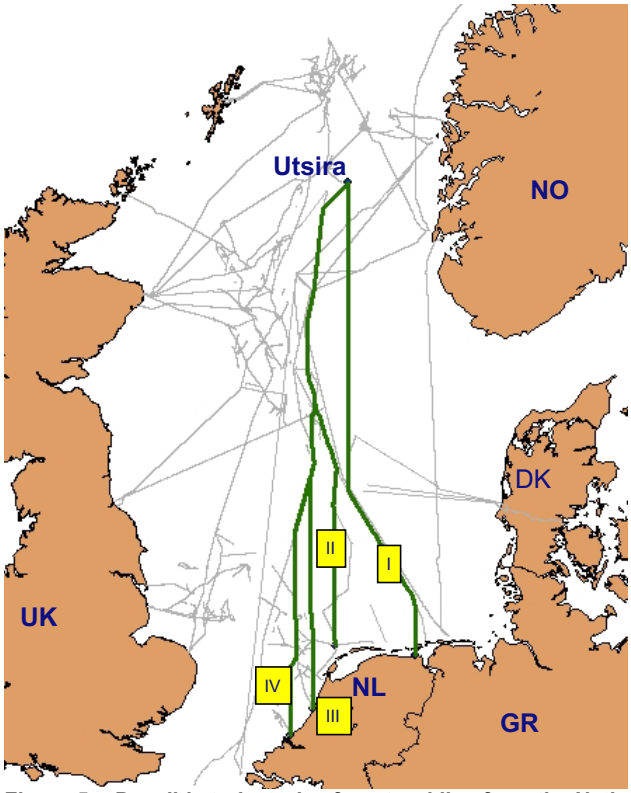

Figure 5 Possible trajectories for a trunkline from the Netherlands to the Utsira formation (see also Table 3)

- Input data for the development of costs and performance characteristics of the electricity generating technologies (including power plants with CCS, nuclear power plants, and renewable electricity generation technologies) and of CO_2 capture units in the industry are described in (Broek et al., 2008; Damen et al., 2009)[15] In these studies, the data for new and advanced gas- and coal-fired power plant technologies (with and without CCS were adopted from (IEA GHG, 2003; IEA GHG, 2004; Damen et al., 2006). Data from other electricity generating technologies were taken from various other studies, e.g. (University of Chicago, 2004; Junginger, 2005; EU PV Technology Platform, 2007).
- The Netherlands changes from an electricity importing country towards a self sufficient electricity producing country in 2020. Import of electricity decreases from 18 TWh in 2005 to 0 in 2020 because of the expected increase in electricity generation capacity in the coming years. However, the amount of electricity produced in the Netherlands may

[15] All cost data are updated to $€_{2007}$ monetary units by using the CEPCI index.

be higher than assumed in this study. According to various studies the Netherlands may even become a net exporter following the increase in production capacity until 2020 (Özdemir et al., 2008; Seebregts and Daniëls, 2008; Seebregts and Groenenberg, 2009). Also, TenneT (2008), the Dutch Transmission System Operator, has indicated that this could happen.

- The share of electricity from renewable sources in the final electricity consumption increases from 29% in 2020 to 43% in 2050.[16]
- The current plans to build two pulverised coal-fired power plants in the Rijnmond area (the E.ON plant of 1.1 GW, and the Electrabel plant of 0.7 GW), and one in the Eemsmond region (the RWE plant of 1.6 GW) before 2015 materialise.
- Increases in coal and gas prices up to 2030 are based on the "high growth" scenario in the World Energy Outlook by the IEA (IEA, 2007). From 2030 on, we assume that prices keep rising at similar rates until 2050. This results in a gas price increase from 5.5 €/GJ in 2010 to 11.7 €/GJ in 2050, and a coal price increase from 2.5 €/GJ in 2010 to 4 €/GJ in 2050.
- CO_2 from Belgium and/or Germany can be transported and stored via or in the Netherlands. In this study the costs for CO_2 capture from German and Belgian stationary CO_2 sources and transport to the collection point in the Netherlands (in the Zeeland, Limburg, Maas and Waal or Eemsmond region) are not included. These costs would be driven by climate policies in those countries which lie outside the modeling being done here which focuses on CCS adoption in the Netherlands. However to explore how the export of captured CO_2 from these countries would affect the economics of using CCS in the Netherlands, we exogenously specify maximum amounts that can be captured from large stationary point sources in these two countries which might be transported to the Netherlands (see table 1). Based on the assumption that these countries are willing to pay 7.5 €/tCO_2 to the Netherlands to transport and store their CO_2, the model decides how much CO_2 is imported into the Netherlands.
- Sinks are only allowed to be used for CO_2 storage if they can be developed into a safe and effective storage site. Therefore, they need to fulfil a number of criteria, for example, with respect to seismicity, integrity of existing wells, faults, overburden, and seals. To take this type of criteria into account, we used the indicator developed by Ramírez et al. (2009), which ranked the Dutch CO_2 storage options with respect to the required effort to manage risks (on a ranking scale of 0-100, with 0 indicating a storage site requiring the "most" effort to manage risks, and 100, the "least"). We chose a threshold value of 70 below which the sinks are not considered suitable. This criteria results in a decrease in Dutch storage capacity for onshore from 1.8 to 1.2 GtCO_2, and for

[16] In order to stimulate the use of renewable energy, the EU has stipulated that the Netherlands must obtain 14% of the final energy consumption from renewable energy sources by 2020 (Council of European Union, 2008; EC, 2008). However, to achieve this target, the share of renewable electricity in the final electricity consumption must be higher than the overall national renewable target. E.g. (Menkveld, 2007; Harmsen and Hoen, 2008) mention shares of 39-41% to reach the Dutch national renewable target of 20%.

near-offshore from 1.3 to 1.0 $GtCO_2$. In addition to be conservative, we have disregarded all Dutch aquifers (0.4 $GtCO_2$), because there is little published about these formations.

In order to study the feasibility of a North Sea trunkline to the Utsira formations under different conditions, the following scenarios are studied:

1. *Base case*. This scenario is based on the base scenario assumptions above.
2. *CO_2 storage offshore only.* CO_2 can either be stored in the Dutch near-offshore sinks or in the Utsira formation offshore Norway.
3. *CO_2 flows from Dutch sources only.*
4. *CO_2 flows from Dutch sources only and CO_2 storage offshore only.* A combination of scenario 2 and 3.
5. *Low CO_2 permit price - low electricity demand scenario*. In this scenario, the electricity demand grows less (from 110 TWh in 2005 to 137 TWh in 2050) as in the Regional Communities scenario (Janssen et al., 2006), the CO_2 permit price increases from €25/tCO_2 in 2010 to €45/tCO_2 in 2030, and remains at this level up to 2050. Germany and Belgium will pay only 5 €/tCO_2 for transport and storage of their CO2 from the collection point in the Netherlands.

5.3 Results

5.3.1 Base case

In this section the results of the MARKAL-NL-UU runs are described for the base case. In order to meet the growing electricity demand and to offset the lower availability of wind and solar capacity, the power generation capacity more than doubles over the analysis period. Due to the assumed CO_2 permit price (€43/tCO_2 in 2020 and €60/tCO_2 from 2030 onwards) and the renewable energy target, CO_2 emissions are reduced by 29% and 67% compared to the 1990 level in the electricity generation sector and CO_2 intensive industry in 2020 and 2050, respectively. On average 31% of the reduction of emissions in the power sector (compared to a scenario without a CO_2 permit price or renewable targets) can be attributed to CCS. Over the whole analysis period a cumulative amount of 1.8 $GtCO_2$ of CO_2 from the Netherlands and 1.5 $GtCO_2$ from abroad will be captured and stored.

In 2020, the PC power plant capacity installed before 2015 (i.e. the RWE, E.ON, and Electrabel power plants) will have been retrofitted with CO_2 capture, and by 2050 a total of 6.8 GW of IGCC with CCS, and 2.9 GW of NGCC with CCS will have been constructed. Furthermore, from 2030 the share of biomass co-firing in coal-fired power plants will be 30% of fuel energy input. Finally, model results indicate that onshore wind is cost-effective from

the start, and photovoltaic cells from 2050 onwards. To reach the renewable targets, also offshore wind power would be deployed up to 11 GW in 2050.

The annual amount of CO_2 captured per region in the Netherlands is presented in Figure 6. In 2015, only CO_2 from industrial units (5 $MtCO_2$) is captured and stored in Dutch onshore fields. In 2020 44% of the CO_2 is captured in the Rijnmond (15 $MtCO_2$) and 32% in the Eemsmond region (11 $MtCO_2$)[17]. During the rest of the analysis period, the amount of CO_2 captured grows to around 65 $MtCO_2$ per year. In 2050, the Eemsmond, Rijnmond and IJmond regions all generate substantial amounts of CO_2 that need to be stored (21, 14, and 20 $MtCO_2$ per year, respectively). IJmond is a favoured location for CO_2 capture, because in this scenario it is also the location where the CO_2 is collected for transport to Utsira[18].

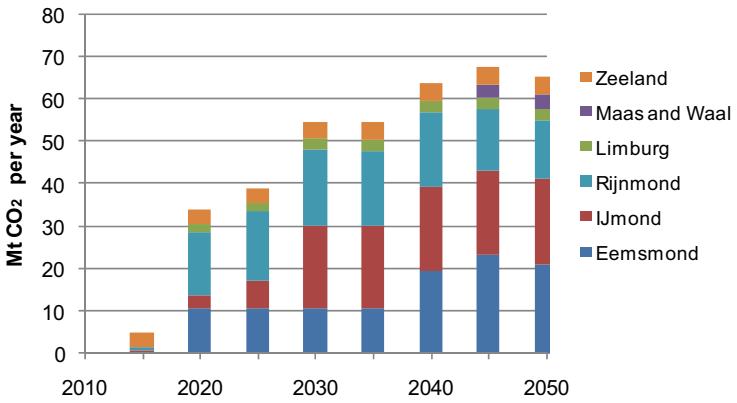

Figure 6 Annual amount of CO_2 captured at power plants and industrial units per region in the Netherlands in the base case

Figure 7 presents the total amount of CO_2 stored per year including the CO_2 from Germany and Belgium, and Figure 8 shows that from 2030 onwards storage in the Utsira formation is considered a cost-effective option by the model (60 $MtCO_2$ per year is transported from the Netherlands to Utsira). From 2040, the CO_2 flow to Utsira increases to 120 $MtCO_2$ per year.

[17] These results are in agreement with the plans of the Rotterdam Climate Initiative and the "Kern Team" Consortium in the North of the Netherlands. The Kern Team assumes that the RWE power plant, which is probably built as a CO_2 capture ready plant before 2014, may be retrofitted before 2020, and that CO_2 capture partly takes place at another plant, the NUON IGCC plant, which also is planned to be constructed.

[18] In this study, only approved plans for new power plants in the Rotterdam harbour are taken into account. However, Rotterdam may increase its industrial activities and electricity generating technologies even more in the coming decades. As a consequence more CO_2 capture could be needed in this area than this study shows. For example, the physical space in the Rijmond harbour allows for around 8000-9000 MW of power plants. Currently, electricity generation capacity in the Rotterdam harbour amounts to 3000-3500 MW, and capacity planned on the short term is around 3000 MW.

The investment costs are distributed unevenly over the analysis period (Figure 8): in 2015-2020, the basis of the CO_2 infrastructure in the Netherlands is laid down, in 2030 one trunkline is built to the Utsira formation, and in 2040 a second one.

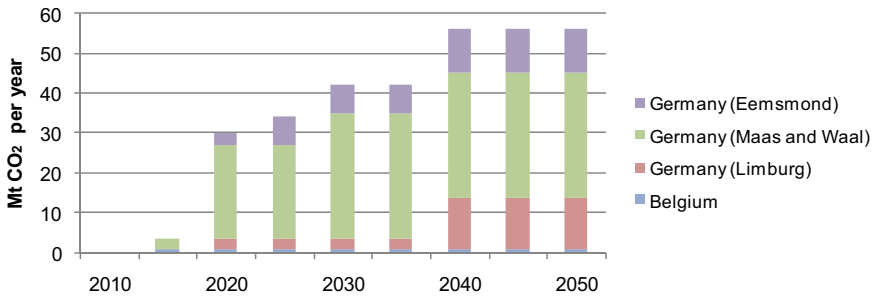

Figure 7 Annual amount of foreign CO_2 captured at power plants and industrial units per region and transported to the Netherlands

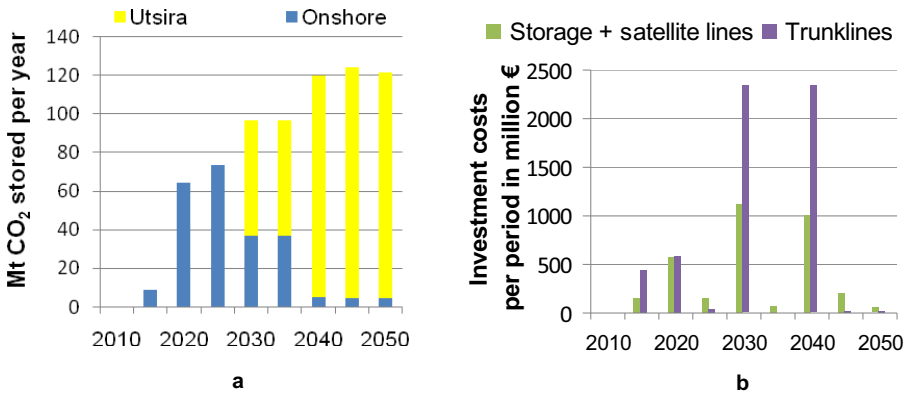

Figure 8 Total annual amount of CO_2 stored (Dutch and foreign CO_2) in Dutch onshore sinks and the Utsira formation (a) and upfront investment costs for transport and storage in the period 2010-2050 (b)

Figure 9 depicts the development of CO_2 storage over time in Dutch sinks. Note that, once most Dutch onshore sinks have been filled, CO_2 is stored in the Utsira formation. The near-offshore sinks are not selected by the model, because at the beginning of the analysis period they are not cost-effective compared to the Dutch onshore sinks. At a later stage the existing gas infrastructure (e.g. platforms) has been decommissioned, and the window-of-opportunity (see section 5.2.3) for reuse of infrastructure has thus passed, making CO_2

storage in the Dutch near-offshore fields even more expensive. Furthermore, in these fields, the amount of CO_2 stored per well (over its entire lifetime) is limited due to the on average small size of the sinks and the injectivity rate never being higher than 1 $MtCO_2$/yr per well. On the contrary, storage in the Utsira formation is cost-effective, because there 50 $MtCO_2$ can be stored per well over its lifetime due to the enormous storage potential of the Utsira formation and the higher injectivity rate of 2 $MtCO_2$/yr per well.

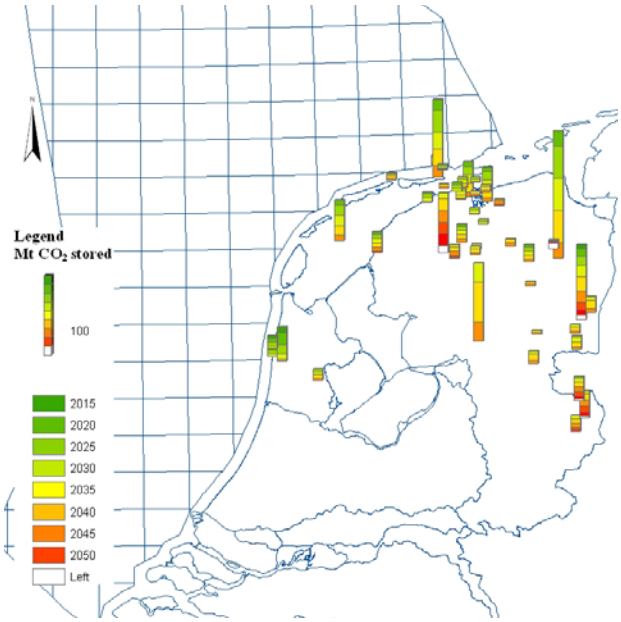

Figure 9 **CO_2 storage over the time in the base case. Each stacked bar represents a sink. The size and colours relate to respectively the amount and timing of the stored CO_2. A white section represents the storage capacity that is still available. Note the sinks that are not used for CO_2 storage during the analysis period, are not depicted on the map. Furthermore, the map does not show that 2.1 $GtCO_2$ is stored in the Utsira formation from 2030 onwards, because this formation is located around 650 km to the North of the map.**

Finally, Figure 10 and Figure 11 depict the trunklines that may be built and used around 2020 and 2040[19]. CO_2 from Limburg is stored in the Twente region, from Eemsmond in the Groningen region, and from the other source regions in the Wadden region and (to a small extent) in the North Holland region.

[19] Model outcomes are also available for other periods (i.e. for each 5-year time step).

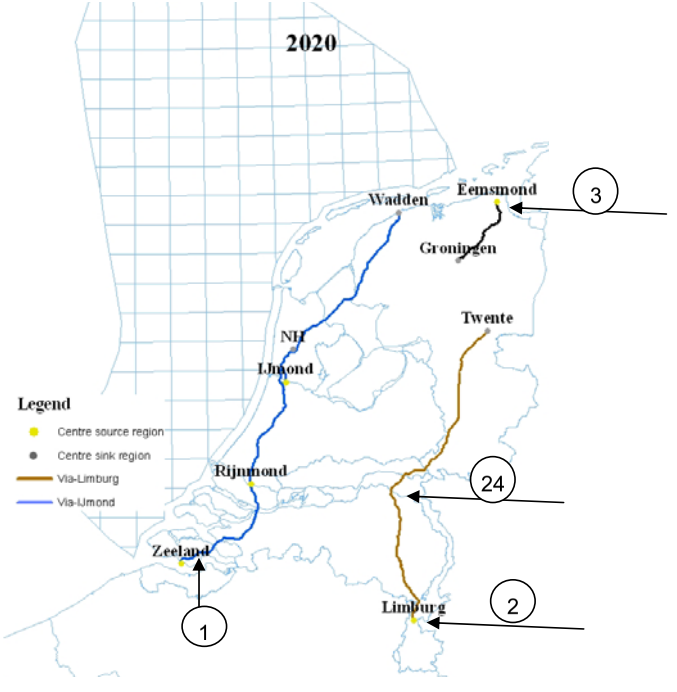

Figure 10 **CO_2 infrastructure in 2020 for the Base case. The numbers represent the amount of CO_2 transported from abroad (in $MtCO_2$/yr)**

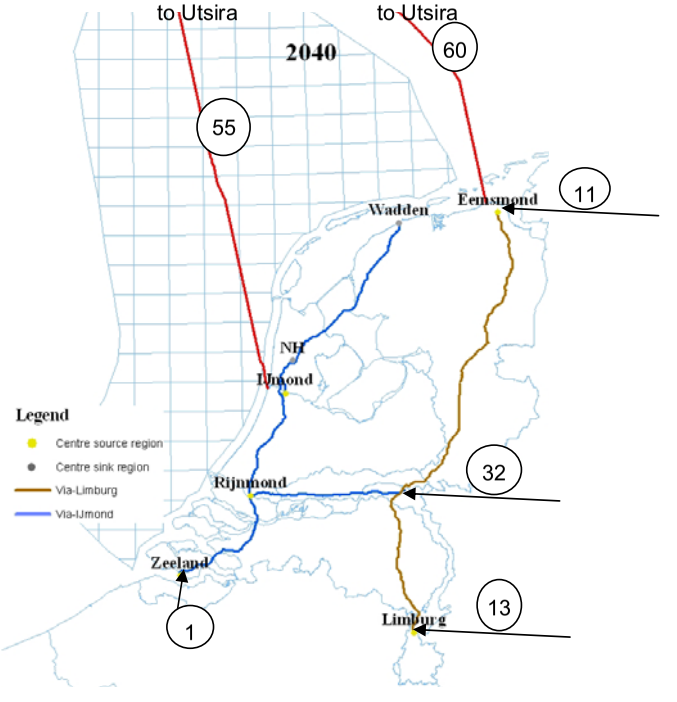

Figure 11 **CO_2 infrastructure in 2040 for the Base case. The numbers represent the amount of CO_2 transported from abroad and to the Utsira formation (in $MtCO_2$/yr)**

5.3.2 Comparison of scenarios

Table 4 summarizes the main results for all scenarios investigated. These results are: the development of transport and storage costs (€/tCO_2), the cumulative amounts of CO_2 stored over time, the year when storage in the Utsira formation would become cost-effective, the capacity and starting point in the Netherlands of the trunkline to the Norwegian Utsira formation, and the total amount of CO_2 stored in the Utsira formation in 2050.

The results from the scenarios led to the following insights:

Scenarios with CO_2 storage offshore only in near-offshore sinks or the Utsira formation (scenarios 2 and 4)

In absence of possibilities to store CO_2 onshore (Figure 12), CO_2 from Rijnmond is transported via Eemsmond to Utsira from 2020. In fact, CO_2 from all Dutch regions except from the IJmond region is transported to Utsira via this collection point. A pre-requisite for the Utsira pipeline to be cost-effective at this stage is that it also needs to transport CO_2 from Germany.

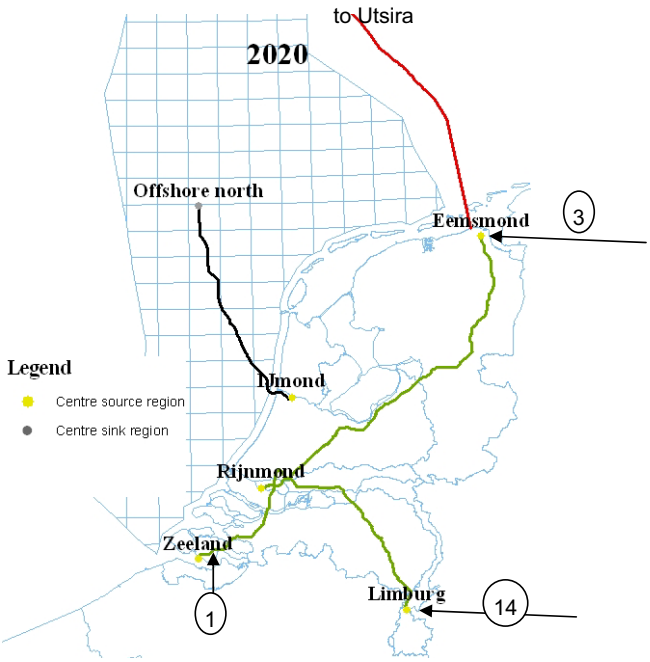

Figure 12 CO_2 infrastructure in 2020 for CO_2 storage offshore only scenario in near-offshore fields and the Utsira formation. The numbers represent the amount of CO_2 transported from abroad (in MtCO_2/yr)

Table 4 Overview of results per scenario

	Scenario	Average transport and storage costs			Total amount of CO_2 stored			Origin CO_2		Trunkline to Utsira			Total amount of CO_2 stored in Utsira formation
								NL	Belgium/ Germany				
		€/tCO_2			MtCO_2 until			Total MtCO_2 stored until 2050		Construction period	Capacity (Mt/year)	Starting point	MtCO_2
		2020	2035	2050	2020	2035	2050						2050
1	Base case	3.5	7.0	8.5	202	1451	3212	1751	1461	2030/2040	60/60	IJmond/Eemsmond	2054
2	CO_2 storage offshore only	8.8	8.1	8.3	139	1164	2977	1747	1230	2020/2040	60/60	Eemsmond/Rijnmond	2678
3	CO_2 flows from Dutch sources only	4.1	4.2	8.8	121	868	1846	1846	0	2040	60	Eemsmond	750
4	CO_2 flows from Dutch sources only and CO_2 storage offshore only	8.3	10.6	9.2	89	697	1675	1675	0	2030	60	IJmond	1229
5	Low CO_2 permit price - low electricity demand	4.2	5.3	10.8	126	738	1438	1236	202	2050	40	Eemsmond	100

- Storage in the near-offshore fields is mainly cost-effective when already existing wells and platforms can be re-used. In none of the scenarios more than 20 $MtCO_2$ is stored in near-offshore fields that had to be re-opened. Planning the offshore CO_2 infrastructure on the Dutch continental shelf is therefore important, but difficult. On the one hand it is not certain when gas production in individual fields will cease and thus, when CO_2 storage can start[20]. On the other hand, once gas production has ceased, the infrastructure around the gas fields need to be mothballed to keep them suitable for CO_2 storage. This mothballing activity would encounter two difficulties. First, an exemption needs to be made from the current Dutch legislation which requires platforms to be dismantled when production activities have been stopped (EZ, 2002b; EZ, 2002a). Secondly, exploration companies may not be willing to pay the mothballing costs, but instead opt for abandoning the gas fields, when there is uncertainty about the supply of CO_2. Finally, an issue could be whether exploration companies will provide guarantees on the availability of storage capacity over long time periods to energy companies which need to store their CO_2. In case of the Utsira formation, this may be easier to guarantee.

Scenarios with CO_2 flows from Dutch sources only (scenarios 3 and 4)

- Before 2040 the Netherlands has sufficient cost-effective onshore storage options to fulfil its own storage demand and the Utsira formation is not yet needed (scenario 3). Therefore, compared to the scenario which includes CO_2 flows from Germany and Belgium (scenario 1), the construction of a pipeline to the Norwegian Utsira formation becomes cost-effective 10 years later (i.e. in 2040 instead of 2030).
- However, if due to lack of public support, the use of the Dutch fields onshore is not allowed (scenario 4), an Utsira pipeline for CO_2 from Dutch sources becomes again cost-effective 10 years earlier (in 2030). Note that in the scenario with the German and Belgian CO_2 flows and offshore storage only (scenario 2), the Utsira trunkline would already be cost-effective from 2020.
- Furthermore, in scenario 4, costs for CO_2 transport and storage are 8.3 €/tCO_2 and CCS will contribute with 21% to the CO_2 avoidance in the electricity sector in 2020 compared to 4.1 €/tCO_2 and 31%, respectively, in the scenario with onshore storage (scenario 3). The increase in costs is mainly due the higher investment and O&M&M costs needed for CO_2 storage costs in the offshore fields (see Table 2). Although CO_2 avoidance costs of CCS are mainly determined by the CO_2 capture costs, the increased transport and storage costs have an impact on the competiveness of CCS in the short term.
- In the long term, the impact of only allowing CO_2 storage offshore on the role of CCS in the portfolio of mitigation measures in the Netherlands, is limited, if the CO_2 can be stored in the Utsira formation (or another large formation under the North Sea). Without this possibility, there would not be enough cost-effective offshore Dutch sinks to store

[20] For example, when gas prices rise or mining costs decrease, production from almost depleted gas fields remains profitable for a longer time period.

the CO_2 produced in the Netherlands over time and consequently the share of CCS in the portfolio would significantly decrease.

Low CO_2 permit price - low electricity demand scenario (scenario 5)

- The role that CCS can play in the portfolio of Dutch mitigation measures will depend mainly on the permit price of CO_2. If the only policy measure applied is the emission trading system (ETS), if the CO_2 permit price stays below €45/tCO_2 by 2030, and if the energy demand grows less, CCS will be implemented to a lesser extent than in the base case. Reason is that whereas in the base case coal-fired power plants, which could be equipped with CCS, were built after 2015 to meet the growing electricity demand, there is no need for them in this scenario (except for one in 2040). Furthermore, in the *base case* (scenario 1) NGCC plants were equipped with CCS, which is too expensive under the given CO_2 permit price of 45 €/tCO_2. The average contribution of CCS to the reduction of emissions in the power sector (compared to a scenario without a CO_2 permit price and renewable targets) decreases from 31% in the base case to 17% in this scenario. However, because the energy demand is also lower (119 TWh instead of 137 TWh in 2020), the total CO_2 emission in 2020 is similar to that in the base case.
- If the CO_2 permit price increases to €45/tCO_2 instead of €60/tCO_2, constructing a trunkline to Utsira appears only cost-effective around 2050. Furthermore, if Germany and Belgium pay a fee of 5 €/tCO_2 for transport and storage of their CO_2, it is hardly attractive to store their CO_2. In that case, only small flows (<3 MtCO_2 per year) from Belgium and Germany are passing through the Netherlands, and are used to fill up spare[21] capacity in the Dutch CO_2 pipelines[22].

Overall findings

The analysis of the scenarios led to a number of important findings with respect to a CO_2 trunkline from the Dutch coast to the Utsira formation:

- Investment costs for the chosen trunklines to Utsira vary between 1.8 and 2.2 billion €. The most cost effective transport capacity for the Utsira pipeline seems to be 60 MtCO_2/yr[23]. Lower (20 or 40 MtCO_2/yr) or higher (80 MtCO_2/yr) values are not chosen in the model runs[24].
- From an economic and infrastructure development point of view, there is no clear preference for the location of the collection point from where CO_2 is transported to

[21] Note that MARKAL-NL-UU can only choose between a limited amount of pipeline capacities which may not match entirely the CO_2 flow from Dutch sources.
[22] However, MARKAL-NL-UU takes care that a CO_2 flow from Germany or Belgium to the Netherlands, once started, cannot be reduced within 40 years.
[23] Note that in the Base case and Offshore only scenario two trunklines of 60 MtCO_2/yr are constructed.
[24] Nevertheless, a 40 MtCO_2/yr pipeline may also be an option depending on CO_2 permit prices, since its levelised transport costs are less than 1 €/tCO_2 more than the transport costs through a 60 MtCO_2/yr pipeline (and assuming an electricity price of 60 €/MWh for the pumping station).

Utsira. In the three coast locations (Eemsmond, IJmond, and Rijnmond), it is possible to collect the necessary amount of around 50-60 $MtCO_2$/yr to make a trunkline to Utsira from these locations profitable.

- Pipelines transporting German CO_2 flows can either cross the Netherlands from East to West and then go to a starting point of a trunkline at IJmond or Rijnmond to Utsira, or they can stay east and go to the starting point at Eemsmond. The CO_2 flows from Belgium and Germany, where a maximum amount of 22 $MtCO_2$/yr and 144 $MtCO_2$/yr, respectively, could be captured, help to reach 60 $MtCO_2$/yr flows at an earlier stage.
- In the scenarios on average 8 fields need to be used simultaneously to store 10 $MtCO_2$/yr in the Netherlands due to the limited storage potential of the individual sinks (on average 26 $MtCO_2$ onshore, and 15 $MtCO_2$ offshore). In the beginning of the period usually the larger fields are chosen and around 4-6 fields suffice for 10 $MtCO_2$/yr, at the end of the period 12-17 smaller fields may be needed to store the same amount of CO_2. In this case, it requires a good logistic plan to choose the CO_2 sinks at the right time (so that equipment can be re-used), to match the CO_2 flows from different CO_2 sources to the different CO_2 sinks, and to switch timely to new sinks. In comparison logistics of the CO_2 transport and storage would be rather easy when a trunkline to Utsira is built and all CO_2 can be stored in this one formation which is available all the time.

5.4 Discussion of the outcomes

In this paper the development of a Dutch CO_2 infrastructure that would include an offshore trunkline to the Utsira formation was investigated taking into account policy to mitigate CO_2 emissions. The applied model MARKAL-NL-UU in combination with ArcGIS indicates that CO_2 capture and storage in the Netherlands may increase steeply around 2020. Projections of total volume captured are in the range of 26 to 39 $MtCO_2$/yr. These figures are in line with regional plans in the Netherlands. In the Rijnmond region the "Rotterdam Climate Initiative" aims for an increase of CO_2 storage from 1 $MtCO_2$/yr in 2010 and 5 $MtCO_2$/yr in 2015 to 15 $MtCO_2$/yr in 2020 and 20 $MtCO_2$/yr in 2025 (Hoog, 2008). In the Eemshaven region a consortium called the "Kern team", recently published an action plan in which they aim for around 10 $MtCO_2$ storage per year by 2020 (Kernteam CCS Noord-Nederland, 2009). However, this fast increase is not envisioned by other studies (Menkveld (Ed.), 2007; Daniëls et al., 2008) evaluating present Dutch climate policy measures (VROM, 2007). According to these studies CO_2 storage of at most 10 $MtCO_2$/yr will be achieved by 2020 in the Netherlands[25]. The difference with the findings of this paper can be explained by the fact that MARKAL-NL-UU does not take into account political, legal, business-related, or organisational barriers that can delay the implementation of the capture units or even prevent it. The projected steep increase should, therefore, only be considered as a techno-

[25] Although, it is assumed that large scale CO_2 storage is feasible before 2020, it is not argued why this remains limited to 10 $MtCO_2$/yr.

economic potential (based on the model input data regarding costs and performance, and a discount rate of 7%). It must also be noted that the model opts for a quick growth so that transport costs are lowered by full utilisation of large trunklines at an early stage (resulting in transport costs of 1.6-3.2 €/tCO_2 in 2020, and 5.9 €/tCO_2 in the scenario in which a trunkline to Utsira is already built in 2020). A slower growth in capture capacity would lead to higher transport costs (e.g. model results show that the costs in 2015 are varying between 4.0 and 9.7 €/tCO_2 because of underutilisation of the pipelines).

Other aspects that could change the cost-effectiveness of a trunkline to Utsira over time are:

- Electricity production in the Netherlands for export has not been modeled in this study. Inclusion of electricity production for foreign use will imply greater revenues for plant operators and thus could facilitate the financing of CO_2 infrastructures.
- We departed from a fee of 7.5 €/tCO_2 for transporting CO_2 from German and Belgian parties. A higher fee (e.g. 8.5 €/tCO_2 instead of 7.5 €/tCO_2) would also help to make a trunkline to Utsira cost-effective earlier.
- Higher costs for the pumping station as a result of increased energy or capital costs (i.e. more than 60 €/MWh) would delay cost-effectiveness of a CO_2 trunk pipeline to Utsira.
- In this study, the whole portfolio of measures including CCS would result in CO_2 emission reduction of less than 70% in 2050 compared to 1990 levels in the electricity generating and CO_2 intensive industrial sectors. This may not be in line with a worldwide climate strategy to keep global mean surface air temperature increase around 2°C. In such a strategy emission reductions of up to 80% are necessary in developed countries, and the power sector needs to be virtually decarbonised (IPCC, 2007; IEA, 2008). This strategy would increase the demand for CCS, and bring forward the need for an Utsira pipeline.
- Finally, the costs of CO_2 storage in the Utsira formation may be underestimated. Costs for possible extra wells that produce water out of the aquifer to avoid pressure build up, which could jeopardise the integrity of the sealing rock as investigated by Lindeberg et al. (2009), are not included.

Furthermore, this paper investigated the development of a CO_2 infrastructure which will favour the national strategy of the Netherlands to reduce its CO_2 emissions. As a consequence specific interests of neighbour countries are not taken into account. For instance,

- In this study, it is assumed that the Netherlands has unhindered access to storage capacity in the Utsira formation. In the scenarios up to 2.7 GtCO_2 from (and via) the Netherlands is stored in the Utsira formation by 2050 filling 6% of the total storage capacity of 42 GtCO_2 according to (Bøe et al., 2002). However, there may well be a need to store CO_2 from other countries in the Utsira formation apart from CO_2 coming from Norwegian sources (Bergmo et al., 2009). UK, on the contrary, may be less interested in storing CO_2 there, because a recent study which investigated a North Sea CCS

infrastructure for the UK and Norway (BERR, 2007) stated that sufficient storage capacity is available for the UK on its own territory[26].

- MARKAL-NL-UU may choose the German and Belgian flows so that larger CO_2 pipelines with lower unit costs become profitable or to fill up spare capacity in the Dutch CO_2 pipelines. Belgium and Germany, if they decide to transport and store their CO_2 via or into the Netherlands, probably have specific requirements about the amounts of CO_2 that need to be transported. Since currently no German or Belgian strategy is known about reducing CO_2 emissions using CCS, only data on maximum possible CO_2 flows from Germany and Belgium have been applied in our study as boundaries for the model runs.
- In this paper it is assumed that Germany and Belgium pay a fee of 5-7.5 €/tCO_2 for transport from a collection point in the Netherlands and storage of their CO_2. It is not investigated whether the CO_2 permit price is attractive enough for them to capture and transport CO_2 to the collection point in the Netherlands.
- We do not consider the opposite case that Germany wants to import CO_2 from the Netherlands. For example, CO_2 from Eemsmond may be transported to Emden in Germany, which is close-by and could be a potential CO_2 collection point for CO_2 storage in the North sea[27].

Another point to be taken into account is that the results related to CO_2 storage in specific sinks should be viewed with care, because input assumptions on the storage potentials per sink are uncertain:

- CO_2 storage potentials in this study were based on the TNO database using publicly available data and may have been either underestimated or overestimated (TNO, 2007). More detailed data from local feasibility studies (e.g. from field operators on the ultimate recovery of hydrocarbon fields, and site characteristics) can improve the estimates of the storage potentials and associated cost-effectiveness of the individual sinks (in a positive or negative way).
- Also the storage capacity of the Utsira formation is still in debate. Lindeberg et al. (2009) state that there is no exact limit of the storage capacity in the Utsira formation, and estimate a cost-effective storage capacity range of 20-60 GtCO_2. According to them an economic optimisation of the well and infrastructure would determine the optimal filling over a very long time perspective. A higher capacity may be reached by closer well spacing. Conversely, other studies indicate that the CO_2 storage capacity may be lower than expected because of e.g. inadmissible pressure built up when CO_2 is injected in aquifers (Meer and Yavuz, 2008).

[26] However, in this study, they did not consider the entire Utsira formation as an option for CO_2 storage.
[27] Emden was considered a CO_2 collection point in a study by Holt et al. (2009), who investigated a CO_2 infrastructure for EOR in the North Sea..

5.5 Discussion of some organisational issues

From a Dutch perspective, a number of options are conceivable for setting up a CO_2 transport network. These options can include (or are a combination of) a network connecting CO_2 sources to onshore storage sites, to Dutch near-offshore hydrocarbon fields, or to a huge reservoir underneath the North Sea (in this study the Utsira formation). Some organisational implications of the different options are pointed out:

CO_2 storage onshore. Our analysis shows that storage of CO_2 onshore is preferred from an economical point of view (scenarios 1, 3, 5). In this case governmental intervention is needed to promote the realisation of a large CO_2 pipeline connecting regions with major CO_2 point sources to the North East of the Netherlands. The sizeable investment related to this pipeline makes it unlikely that a private company would build it on its own. The government may encourage and involve the private sector in constructing such a pipeline, for instance, by issuing a tender for a preferred trajectory such as Rijnmond-Eemsmond. Private companies may design, build and operate the pipeline, while the investment will most likely need to be co-financed by industry and government. As a consequence, ownership of the pipeline may be both public and private.

Once Dutch onshore capacity has been filled up, it is probably too costly to exploit the Dutch near-offshore capacity, as pointed out in this study. In this case (after 2040) a trunkline towards Utsira would need to be ready.

CO_2 storage in Dutch near-offshore fields. Storage of CO_2 offshore near the Dutch coast or elsewhere may be preferred if the public acceptance of storage onshore would be negative, and/or because permitting procedures will be shorter (scenarios 2, 4). In this case, the government could advance full exploitation of storage capacity in near-offshore depleted hydrocarbon fields (NOGEPA, 2008). The government would need to have a greater role in the selection of storage locations offshore, and take care that platforms of near-offshore depleted gas fields are kept in good condition until they can be used for CO_2 storage. It is unlikely that this would happen in absence of public intervention, since mothballing platforms would involve expenditures in the order of millions of euros. As in the case of onshore storage design, construction and operation may be done effectively by private companies, while both funding and ownership could be shared by the public and private sector. Once near-offshore capacity has been filled up, a trunkline towards Utsira (or another major storage formation) would need to be ready, and some sort of Initiative taken by North Sea countries is needed to realise such a (joint) pipeline.

CO_2 storage in the Utsira formation. Storage of CO_2 before 2030 in the Utsira formation is a possibility if CO_2 may not be stored onshore and neighbouring countries will pay for the transport of their CO_2 via the Netherlands (scenario 2). However, it could also be necessary if CO_2 may not be stored onshore, and at the same time the Dutch government prefers not to coordinate utilisation of near-offshore transport and storage capacity. In these cases immediate realisation of a CO_2 trunkline towards Utsira will be necessary. Finally, the organisational implications of CO_2 storage in the Utsira formation differ somewhat from the storage in onshore or near-offshore fields. A large number of public and private parties (e.g. CO_2 suppliers) from countries neighbouring the North Sea need to be engaged, for example,

in choosing the trajectory of the pipeline towards Utsira. Thus, routings and dimensions can be chosen which are preferred from a socio-economic and strategic point of view. Next, the governments may request a tender for the construction of this pipeline, and design and construction will be in the hands of private companies. Funding, on the other hand, may need to be shared between governments and private companies, because of the sizeable investment of 1-2 billion € and uncertainty in future CO_2 permit prices. Ownership could be with the private sector from the start or public assets could be sold to a private company at some point during operation of the project. Finally, a private entity may be responsible for the operation of pipeline infrastructure. This may be the operator of the storage site, or a gas transport company.

5.6 Conclusions

In this research we combined the energy bottom-up model MARKAL and the geographic information system, ArcGIS, to assess the feasibility of using the Utsira formation as part of a long-term Dutch strategy to develop a CO_2 infrastructure. We strived to determine suitable technical configurations for such a pipeline, to assess the boundary conditions making its investment worthwhile, and to make a first inventory of the organisational implications around the construction of this pipeline.

Application of the ArcGIS/MARKAL toolbox shows that an offshore pipeline to the Utsira formation as part of a regional solution (transporting CO_2 from the Netherlands, Belgium and Germany) appears a cost-effective option in the medium term (after 2020). A main condition for the pipeline to Utsira is the existence of a high CO_2 permit price (increasing from around €43/tCO_2 in 2020 to €60/tCO_2 in 2030). If the price stays below €45/tCO_2 by 2030 and the growth of the electricity demand is limited, CCS will be implemented less, and constructing a pipeline to Utsira is only considered cost-effective by the model from 2050 onwards.

Model results suggest that an investment in a CO_2 trunk pipeline towards the Utsira formation may even be cost-effective from 2020 onwards, provided that onshore storage capacity is not permitted or used and that Belgian and German CO_2 is transported as well. Exploitation of onshore capacity and exclusion of Belgian and German CO_2 will each push back cost-effectiveness of a trunkline to Utsira by 10 years. From a national perspective, on the short term storage in Dutch near-offshore fields is more cost-effective than in Utsira, but as yet there are major uncertainties related to the timing and effective exploitation of near-offshore CO_2 storage opportunities.

The ArcGIS/MARKAL toolbox proved to be valuable to get more insights into the boundary conditions of a CO_2 trunkline from the Netherlands to Utsira, because it matches multiple sources to multiple sinks with respect to costs, availability, and location as a function of time. Furthermore, it investigates how and when CO_2 flows from the Netherlands, Germany and Belgium could be transported and stored via a Dutch CO_2 infrastructure. Finally, by adding the spatial aspect into a typical energy system study, the toolbox can support policy makers to tackle the spatial issues relevant for CO_2 infrastructure development and the timeframes

involved. The resulting maps that make the development of a CO_2 infrastructure more visible, may also be used as communication tool among stakeholders.

Nevertheless, in this research there are important caveats that need to be addressed in future work. For instance, the national strategies of Belgium and Germany to develop a CO_2 infrastructure were not taken into account. Also, the possibility to transport and store CO_2 via Germany should be considered. Finally, cost data need to be periodically updated (e.g. due to additional costs for water production wells, or impurities in the CO_2 pipelines) and checked by industrial partners in order to assure that modelling results are close to real developments.

Prioritisation of CO_2 storage in onshore fields, near-offshore fields, and/or in the Utsira formation is an important aspect for the optimal design of a Dutch CO_2 infrastructure. Furthermore, suboptimal use of public resources available for developing CO_2 transport networks, can and need to be avoided while fast deployment of CCS is facilitated. The type of public responsibility during the development of CO_2 networks would mainly depend on the storage location. For onshore storage, greater public involvement is required in the permitting process for CO_2 storage sites and pipeline trajectories, especially if CO_2 storage is perceived unfavourably by the local public. Furthermore, pipeline trajectories onshore may be defined in generic terms, while private companies can design the precise layout after a tender procedure. For storage near-offshore, greater public involvement is required in order to fully exploit the near-offshore storage capacity since CO_2 storage in these fields is only cost-effective when gas and oil production platforms are preserved for CO_2 storage. Finally, CO_2 storage in the Utsira formation (or another large formation under the North Sea) would require a major consortium of public and private parties near the North Sea to render this option cost-effective, and to decide on a preferred trajectory by all stakeholders involved.

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Chapter 6

Impact of international climate policies on CO_2 capture and storage deployment, illustrated in the Dutch energy system

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Abstract

A greenhouse gas emission trading system is considered an important policy measure for the deployment of CCS at large scale. However, more insights are needed whether such a trading system leads to a sufficient high CO_2 price and stable investment environment for CCS deployment. To gain more insights, we combined WorldScan, an applied general equilibrium model for global policy analysis, and MARKAL-NL-UU, a techno-economic energy bottom-up model of the Dutch power generation sector and CO_2 intensive industry. WorldScan results show that in 2020, CO_2 prices may vary between 20 €/tCO_2 in a GRAND COALITION scenario, in which all countries accept greenhouse gas targets from 2020, to 47 €/tCO_2 in an IMPASSE scenario, in which EU-27 continues its one-sided emission trading system without the possibility to use the Clean Development Mechanism. MARKAL-NL-UU model results show that an emission trading system in combination with uncertainty does not advance the application of CCS in an early stage, the rates at which different CO_2 abatement technologies (including CCS) develop are less crucial for introduction of CCS than the CO_2 price development, and the combination of biomass (co-firing and CCS seems an important option to realise deep CO_2 emission reductions.

6.1 Introduction

The Fourth Assessment report of the IPCC published in 2007 (IPCC, 2007a) as well as other recent publications like the synthesis report of the scientific congress "Climate change: Global Risks, Challenges & Decisions" (Climate congress, 2009) underpin the necessity to limit the human induced increase of the mean temperature on earth to maximum 2°C or even stricter. These studies also show the tremendous effort which is needed to reach this goal of limiting greenhouse gas (GHG) emissions. This is illustrated by the fact that human induced CO_2 emissions (excluding CO_2 emissions due to deforestation) were increasing by 0.8% on average in the period 1990-2000, while they increased with 3.3% on average over the period 2000-2006 (Boden et al., 2009). As a consequence the CO_2 emissions are at the high end of the range of the IPCC emission scenarios (Weyant et al., 2006; IPCC, 2007b). In a recent publication by Meinshausen et al. (2009) it is argued that diminishing the annual global CO_2 emissions to 50% of the 2000 level in 2050, is not sufficient to mitigate the proposed mitigation as discussed in the political arena (COP15, 2009). Instead they state that the cumulative amount of CO_2 emitted in the period 2009-2050 should not be more than about 700 $GtCO_2$ to have a 75% probability of global warming to stay below 2°C. Using this cumulative CO_2 emission approach, they state that also short term action is required, because the probability of exceeding the 2°C increases to 53-87%, if global GHG emissions are more than 25% above 2000 levels in 2020.

It is expected that CO_2 capture and storage (CCS) may play an important role in realising the necessary emission reductions. For example, in the last ETP study of the International Energy Agency (IEA) (2008), CCS is one of the key technologies in the Blue Map scenario[1] contributing for 19% to the total CO_2 emission reduction in 2050. The European Union (EU) has enabled CCS as a CO_2 reduction technology under the Directive for the Geological Storage of CO_2 (European Union, 2009c). The EU also adapted the Directive that regulates the GHG emission allowance trading scheme (EU-ETS) such that the deployment of CCS on a commercial scale will be driven (ultimately) by a CO_2 price (European Union, 2009b)[2]. Though this EU-ETS instrument can provide the necessary stable investment environment, it is uncertain whether the EU-ETS (or a global emission allowance trading scheme) will be sufficient to actually realise CCS at large scale and in time for the following reasons:

[1] The Blue Map scenario is the most far reaching scenario in terms of emission reductions in the ETP study. In this scenario CO_2 emissions will decrease to 14 Gt CO_2 per year in 2050 in order to stabilise CO_2 concentration at 450 ppm.

[2] CO_2 emissions captured, transported and safely stored will be considered as not emitted under the EU ETS, but allowances will have to be surrendered for any leakage.

- In an optimal trading scheme[3], all GHG emissions will be included and long-term targets will be set such that welfare is maximised by realising emission reduction at the lowest possible cost. To obtain a carbon price in all major emitting countries, an effective international coalition is needed. So far, such a coalition has not materialised and it is uncertain this coalition will ever be formed. The United Nations Climate Change conference in Copenhagen (COP15) in December 2009 also failed to produce an effective international agreement on further emission reductions. And even if an agreement will be successfully negotiated in Mexico in 2010, it remains to be seen whether this is sufficient to meet the long-term goal to restrict the increase in temperature due to human activities to 2°C above pre-industrial level.
- It is questionable whether the CO_2 price resulting from the EU-ETS will be high enough to finance CCS in time. In a study by McKinsey, it is estimated that the CO_2 price may only be high enough from 2030 onwards (McKinsey&Company, 2008). Furthermore, the CO_2 price development is quite uncertain in the post-Kyoto period 2013-2020, also called Phase III[4], and especially thereafter.
- The ETS, as it was introduced in 2005, did not realize emission reductions within the EU in a cost-effective way (Böhringer et al., 2006; Aalbers, 2007; Koutstaal and Veenendaal, 2008). Inefficiencies were, for example, the incomplete coverage of the ETS, the rules concerning the allocation of allowances to existing and new firms, and rules concerning this allocation in case firms close. While some of these inefficiencies have been addressed in the plans for the EU-ETS after 2012, others remain (European Union, 2009b), such as a lack of stable investment environment, uncertainty about the future of the Clean Development Mechanism (CDM) and the additional target for contribution of renewable energy in the year 2020.
- It is difficult for EU-ETS to create a stable investment environment for firms with a clear, long-term commitment to GHG emission reduction. Currently, the emission cap for the EU-ETS is depending on the outcome of an international agreement on climate change policy. The EU intends to reduce the GHG emissions with 30% compared to 1990 by 2020 if other developed countries commit themselves to comparable emission reductions, and otherwise with 20% (Council of the European Union, 2007). In the latter case, the cap for GHG emission allowances in EU-ETS is 21% lower compared to the 2005 GHG emissions in 2020 (European Union, 2009b).
- For the period after 2020, a cap has not yet been set and a long-term goal such as the 2°C target is not specific enough to formulate expectations about future caps. Consequently, it is difficult to formulate expectations about the post-2020 price of GHG

[3] A scheme in which marginal abatement costs are equalised for all major emitting countries and installations, so that all technologies which are cost efficient at a given CO_2 price will be used.

[4] One of the reasons for the uncertainty is that it unknown how many non-used EU emission Allowances (EUA) of the Kyoto period 2008-2012, Phase II, of the Kyoto Protocol will be used in Phase III (=banking of EUAs). Estimates of the surplus of EUAs of Phase II that may be transferred to Phase III, vary from 90 $MtCO_2$ (Szabo, 2009) to 166 Mt (CommodityOnline, 2010).

allowances. This uncertainty will influence the investment decisions of firms. Especially for long-term capital intensive emission reduction options such as CCS, the lack of a long-term ceiling will reduce their attractiveness vis-à-vis emission reduction options which having a shorter time horizon.

- From 2012, it is still unknown to what extent Certified Emission Reductions (CER), which can be obtained by CO_2 emission reduction in developing countries through the Clean Development Mechanism (CDM), can be used in the ETS. This depends on an international agreement. However, the use of CERs may have major influence on the price of CO_2.
- In addition to the CO_2 emission target, the EU has a renewable energy target of 20% in 2020 of total EU energy use (European Union, 2009a). While part of this target will be met through the 10% target for energy from renewable sources in transport in 2020, it is estimated that more than half of the 20% renewable energy target will come from EU ETS sectors (EC, 2008a). This will limit a priori the scope for CCS because part of the fossil fuel based generation will diminish. Furthermore, assuming that the total cap for the ETS sectors is not reduced, a renewable target will lower the price of the allowances if it compels power producers to use more renewable energy sources than they would without the renewable target.

In summary, the (uncertain) development of international climate policy may have a major influence on the deployment of a key technology such as CCS. In order to be able to deploy CCS effectively in a national climate mitigation strategy, we need more insight in this influence. Therefore, we investigate the following research question: what could be the impact of different international climate policy frameworks (e.g. whether there is effective international coordination or not and whether CDM is allowed in future climate policies) on the implementation of CCS in a national energy system like the system of the Netherlands?

In general, two type of models can be used to investigate the impact of energy and climate change policies (Frei et al., 2003; McFarland et al., 2004; Dagoumas et al., 2006; Böhringer and Rutherford, 2008; van Vuuren et al., 2009):

- Top-down computable general equilibrium models, which represent economy-wide interactions, including international trade, energy supply and demand, inter-industry demand and supply for goods and services, factor markets, and consumer demands. They are suitable to assess the influence of energy and environmental policy on the economy, but usually cannot provide technological details which may also be relevant for policy making.
- Energy bottom-up models, which focus on the energy system itself and uses disaggregated data of existing and emerging technologies. They can investigate the implementation of a specific technology such as CCS in detail, but they neglect potentially important interactions of the energy sector with the rest of the economy.

In this study, both types of models have been combined to enhance their strengths and to reduce their weaknesses. Several solutions exist to achieve that (Hourcade et al., 2006). One solution is to incorporate more technological detail in a CGE model. However, in practice the results with respect to technological detail remain limited: usually not more than a general overview of the resulting energy mix is presented or only some numerical examples (Frei et al., 2003; McFarland et al., 2004; McFarland and Herzog, 2006; Böhringer and Rutherford, 2008). A second solution is to extend an energy bottom-up model with economic interactions, see, for example, the MARKAL-MACRO model (Chen, 2005; Strachan and Kannan, 2008). In this approach some aspects of the economy are modelled, like an endogenous energy demand or a GDP which depends on developments in the energy system, but other macro-economic interactions are not included. A third solution is to combine the strengths of both type of models by soft-linking them. For example, in studies by Hoefnagels et al. (2009) and Altamarino et al. (2008), the results from bottom-up models are used in a CGE model to evaluate the macro-economic impacts of a shift in fuel and/or technology mix. Examples of the opposite direction (i.e. to assess the impact of policy on the technology mix) are two MIT studies by Schäfer et al. (Schäfer and Jacoby, 2005; Schäfer and Jacoby, 2006) which exports developments of energy demand and energy prices from a CGE model, EPPA, into MARKAL, to assess the impact of climate policy on the transport sector in the United States. In this study, we aimed to do a similar exercise with two models having different geographical scopes in order to assess the impact of *global* climate policy on the introduction of CCS in a *national* energy system.

In our study, we used WorldScan (Lejour et al., 2006), a model for international economic policy analysis to determine the consequences of alternative GHG emission mitigation scenarios up till 2050. This generated consistent time profiles of energy demand, energy prices, and CO_2 emission prices on world, regional, and national level. By feeding these into MARKAL-NL-UU (Broek et al., 2008), a techno-economic model of the Dutch power generation sector and CO_2 intensive industry, we were able to explore the prospects of CCS on a national level. The Netherlands is an interesting country for CCS deployment, because it has good CO_2 storage possibilities, and relatively short distances between large point sources and potential sinks for CO_2.

The structure of this paper is as follows. Details about the adopted methodology and input data can be found in section 2. Results and discussion are presented in Section 3 and 4. Finally, in the section 5 conclusions are drawn with respect to the impact of international climate policy on the implementation of CCS.

6.2 Methodology

6.2.1 Overview

Figure 1 depicts a scheme of the methodology applied in this analysis. The WorldScan model was used to investigate four alternative global climate policy scenarios described below (Lejour et al., 2006; Manders and Veenendaal, 2008). The WorldScan runs resulted in time series for the international CO_2 price, energy prices, and the development of the electricity and energy demand in Europe and the Netherlands. Next, the MARKAL-NL-UU techno-economic model of the Dutch power generation sector was used to investigate the effect of the CO_2 price on CCS deployment in the Netherlands for the period 2000 to 2050. The driving forces in the MARKAL-NL-UU model were the total Dutch final demand for electricity and the CO_2 price.

Figure 1 Scheme of the methodology applied in this analysis

6.2.2 WorldScan

6.2.2.1 Modelling approach and input data

The macroeconomic consequences of climate policy scenarios were assessed using the applied general equilibrium model, WorldScan. This model has global coverage and in particular detailed regions within Europe; in total 14 regions and countries are specified. Furthermore, it distinguishes between 25 markets for goods and services and factor markets for labour, capital, land and natural resources in the regions (see Appendix I). With respect to climate policies, four categories of regions were distinguished: EU-27 (1), other developed countries (2), fast developing countries (3), and least developing countries (4). The first two groups are referred to as Annex I, and the last two groups as the non-Annex I countries to the Kyoto Protocol (UNFCCC, 1997).

The WorldScan model was calibrated to the base year 2004, for which data were mainly taken from the Global Trade Analysis Project-7 (GTAP-7) database (Narayanan (Editors) and Walmsley, 2008)[5]. This static calibration relied on the following exogenous inputs: elasticities

[5] This database contains integrated data on bilateral trade flows and input-output accounts for 57 sectors and 113 countries and regions.

of substitution in production (that are compatible with those in similar models, see (Lejour et al., 2006) for details), substitution elasticities in demand for varieties from different geographical origins (taken from (Hertel et al., 2007), and income elasticities of consumer demand at sectoral level (taken from the GTAP-database). Figure 2 shows the nested structure of Constant Elasticity of Substitution - aggregates that were used to describe production techniques in WorldScan. Each aggregate allowed for a different elasticity of substitution for the underlying inputs.

Furthermore, WorldScan was calibrated to a baseline time path with exogenous projections of population, labour participation, GDP growth rates (that were adopted in the model by adjusting total factor productivities), and energy use in volume terms (see description of BASELINE scenario below). The energy volumes were adopted by adjusting the energy efficiencies indices of the energy carriers at the regional level: a change in the index was compensated by changing the capital requirements (e.g. an increase in the index required an increase in capital inputs such that the energy carrier price was maintained at the level of the previous year).

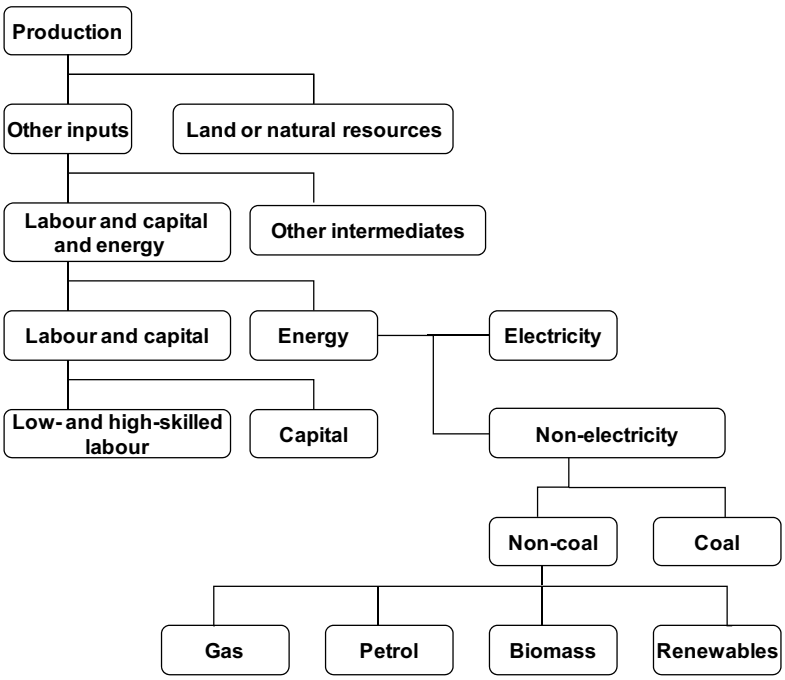

Figure 2 Constant Elasticity of Substitution production nest in WorldScan

In WorldScan, seven energy carries were distinguished: coal, petroleum, natural gas, solid biomass, bio-ethanol, biodiesel, and other renewables without any further subclassifications. Only the first three contributed to the CO_2-emissions simulated in the model. CCS was not included in WorldScan. The following six sectors were assumed to be covered by the EU-ETS: electricity; ferrous metals; chemical, rubber, and plastic products; mineral products; paper products and publishing; and non-ferrous metals[6].

In WorldScan all agents take prices as given and thus decide on optimal consumption and production and investment quantities. These decisions affect the quantities demanded for imports and production inputs. Changes in demand and supply will affect prices. In equilibrium all prices will have adjusted such that all markets are clearing and no agents can improve their objective anymore[7]. In particular, price formation of energy carriers is affected by the production costs, demands for the energy carriers, and the availability of natural resources[8].

6.2.2.2 International climate change policy scenarios

The most recent study using WorldScan to investigate climate change policies is (Manders and Veenendaal, 2008). This study builds upon scenarios developed by Boeters et al.(2007). From this study, we derived four global policy scenarios, namely the BASELINE, IMPASSE, IMPASSE - NO CDM, and GRAND COALITION scenario.

BASELINE

Manders and Veenendaal (2008) use as baseline a so-called middle-course scenario without climate policy developed by the Dutch Environmental Assessment Agency (van Vuuren et al., 2007). This scenario is based on estimates of trends, and is comparable to the reference scenario used by the IEA (2004) and the so-called B2 scenario used by the IPCC (2000). According to this baseline, the global population continues to expand to 9 billion in the middle of this century, and decreases slightly thereafter. Combined with a worldwide economic growth of around 2.7% per year, the global demand for energy will increase significantly: doubling current consumption in 2050, and tripling it in 2100. This expansion

[6] The coverage of these sectors is somewhat broader than actual coverage by EU-ETS. Most emissions issued by the combustion of fossil fuels in the sectors Electricity and Ferrous metals can be considered to be subject to the EU-ETS emission ceiling, but the remaining sectors comprise also activities that are not covered by EU-ETS (such as publishing as opposed to paper production).

[7] Imperfect markets caused by organisations with monopoly power (e.g. OPEC) were not modelled in WorldScan.

[8] In this WorldScan version, it was assumed that new natural resources are found at same rate at which they are depleted.

takes place primarily in emerging developing countries, thus reducing current gaps between their energy consumption per capita and that in industrialized countries.

GRAND COALITION

The Grand Coalition scenario results from an 'ideal' development of climate policies. In this scenario, international negotiations succeed in forming a "grand coalition" that includes not just the Annex I countries, but also large, fast-growing developing countries such as China, India and Brazil. A new climate mitigation regime follows the so-called 'multi-stage approach' (Elzen et al., 2006), and stipulates specific efforts such that the 2°C target is expected to remain feasible. The present level of development and GHG emissions per capita of the various participating countries determine the extent of the mitigation efforts and the type of commitment (absolute, relative or no commitment at all). Initially, up to 2020, emissions of some least-developed countries are not restricted; whereas more advanced developing countries commit themselves to relative targets. All Annex I countries accept absolute emissions reduction targets. After 2020 all countries accept relative or absolute targets.

The costs of significant emissions reductions remain limited because emission trading is used on a large scale. Not just the countries with absolute targets (Annex I), but also the nations with relative targets (China, India and Brazil) use the Common Trading Scheme (CTS), at least for the energy-intensive sectors. Using opportunities created by the Clean Development Mechanism (CDM) is an option in countries with no restrictions on emissions. But since the greatest potential for relatively inexpensive mitigation options is in the fast-developing countries and can be reached via emissions trading, CDM is negligible.

IMPASSE

Despite intensive negotiations, the developed and the larger, fast-developing countries fail to achieve post-2012 climate agreements. In particular, key countries (i.e. USA, Russia, and China) do not consider global warming urgent enough. This leads to an "impasse", and no follow-up agreements are made for the post-2012 period. The USA continues a policy of encouraging technology development, and participation in the Asian Pacific Partnership. The EU tries internally to keep its ETS alive – at its stated minimum reduction level of 20% below 1990. Thus, it is hoped that in the long run, when climate policy would rank higher on the international policy agenda, it will be relatively easy to switch over to much more stringent emission restrictions. CDM is used with some restraint and the use of CDM continues to increase slightly after 2020. The other Annex I countries hardly implement climate policies – any policies they put in place are integrated where possible into other policy areas, such as those focusing on security of energy supplies and local pollution. Japan, Australia and Canada

fall back on the Asian Pacific Partnership, where the voluntary agreements have little effect. The developing Asian countries also continue to participate in Asian Pacific Partnership. These developing countries take no new initiatives, but are prepared to continue with CDM. In this scenario achieving the 2°C maximum objective is highly improbable.

IMPASSE - NO CDM

This scenario is similar as IMPASSE, except that the ETS does not allow for CO_2 reduction measures in developing countries by CDM.

Renewable energy target

In the GRAND COALITION as well as the IMPASSE scenarios the renewable energy target (20% of EU energy usage in 2020) is imposed at the EU-level. The 20% renewable target is maintained as a lower bound in physical terms at the level reached in 2020 in the years thereafter. The burden over member states is shared by trading renewable energy certificates. Consequently, the marginal costs of meeting the renewable energy target are equal in all member states.

Further details on the WorldScan scenarios used in this study are presented in Table 1.

Table 1 Implementation of CO_2 emission reduction in WorldScan

Scenario		EU – 27	Other Annex I countries	Fast developing countries	Least developing countries
All scenarios		World population grows to 9.1 billion people in 2050. The population in the EU-27 and the Netherlands decreases from 489 to 457 and from 16.3 to 15.7 million people between 2004 and 2050, respectively.			
BASELINE		Average economic growth of 1.7% per year in EU27, 2.2% in other Annex I countries, 4.5% in fast developing countries and 3.9% in least developing countries. Global economic growth amounts to 2.7%. No CO_2 emission reduction targets			
GRAND COALITION	2012-2020	Overall CO_2 emission reduction target of 20-30% in 2020 compared to 1990 levels. Emission allocations per country based on per capita emissions.		Brazil and China reduce CO_2 emissions by 1% annually compared to the baseline scenario (i.e. they are approximately 5% below baseline after 5 years), and India, Other Southeast Asia, and Other Latin America by 0.5% per year. Participation in CTS after 2012	Middle-East, North-Africa, and Rest of World have no GHG emission reduction commitment and do not contribute via CDM either
		No distinction between ETS and non-ETS in the EU after 2012. All sectors become then subject to the single emissions ceiling of the CTS. Target of 20% renewable energy use in 2020.			
	2020-2050	A worldwide target of 13.5 $GtCO_2$ in 2050. Emission allocations per country based on per capita emissions.			
		Floor of 20% renewable energy use.			

Scenario		EU – 27	Other Annex I countries	Fast developing countries	Least developing countries
IMPASSE	2012-2020	Emission target of 20% overall CO_2 emission reduction compared to 1990 levels in 2020. Distinction between ETS and non-ETS sectors: non-ETS sectors have to meet national reduction targets by national carbon taxation. No trade in emissions allowances outside the EU-ETS. Limited use of CDM-credits: (for ETS-sectors one third of reduction below BASELINE; for non-ETS sectors 3 percent of 2005 emissions). Target of 20% renewable energy use in 2020.	Reduction of CO_2 emissions by 0.25% per year, compared to the BASELINE scenario.	No reduction commitment at all. Voluntary contribution via CDM in ETS-sectors.	No reduction commitment and no contribution via CDM either
	2020-2050	Emission target of 20% overall CO_2 emission reduction compared to 1990 levels from 2020 to 2050. Limited use of CDM-credits (limits as in period 2012-2020). Floor of 20% renewable energy use.	Reduction of CO_2 emissions by 0.25% per year, compared to the BASELINE scenario.	No reduction commitment at all. Voluntary contribution via CDM in ETS-sectors.	No reduction commitment and no contribution via CDM either
IMPASSE - NO CDM		Same as Impasse, except no CDM			

6.2.3 MARKAL-NL-UU

6.2.3.1 Modelling approach and input data

MARKAL-NL-UU is based on the MARKAL (an acronym for MARKet ALlocation) methodology that provides a technology-rich basis for estimating energy dynamics over a multi-interval period (Loulou et al., 2004). MARKAL generates economic equilibrium models formulated as linear (or non linear) mathematical programming problems. It calculates the technological configuration of an energy system by minimising the net present value of all energy system costs. With this model we evaluated the impact of the different CO_2 price paths by looking at the resulting CO_2 emissions from the electricity sector, and the contribution of CCS to this CO_2 emission reduction. In our study the period 2005-2050 was investigated using a time step of 5 years. Prices are given in $€_{2007}$ unless otherwise stated.

The main input data of MARKAL-NL-UU were the following:

- Development of costs and performance characteristics of electricity generating technologies (including power plants with CCS, nuclear power plants, and renewable electricity generation technologies) and of CO_2 capture units in the industry. The large scale power plants are either natural gas combined cycle power plants (NGCC), pulverised coal-fired power plants with possible co-firing of biomass (PC), integrated coal (and biomass) gasification power plants (IGCC), or gas-fired combined heat and power generation plants (CHP). We assumed that NGCCs can operate in flexible mode, while coal-fired power plants in base load mode only. Key data are shown in Appendix II, and a detailed description can be found in (Broek et al., 2008; Damen et al., 2009; Broek et al., 2010)[9]. Data for combined heat and power generation (CHP) units were based on two reports in which the profitability of new and old CHP units in the Netherlands is estimated (Hers et al., 2008b; Hers et al., 2008a).
- CO_2 storage potentials, and costs for CO_2 transport and storage. The sink inventory is based on data compiled by (Christensen, 2004; Kramers, 2007; TNO, 2007c; TNO, 2007a; Ramírez et al., 2009) and resulted in a selection of 123 CO_2 hydrocarbon fields and aquifers which are considered suitable for CO_2 storage (e.g. deeper than 800 meters, reservoir rocks with porosity more than 10%) with a total estimated CO_2 storage capacity of 1.2 $GtCO_2$ onshore and 1.1 $GtCO_2$ offshore.[10] Furthermore, we assumed that the large aquifer in the Utsira formation in the Norwegian part of the North Sea with an estimated capacity of 42 GtCO2 (Bøe et al., 2002) is available for storage of Dutch CO_2. Based on several sources, we estimated average CO_2 storage costs for onshore and offshore

[9] All costs were updated to $€_{2007}$ by using the CEPCI index.

[10] The Slochteren field in Groningen with an estimated capacity of about 7 $GtCO_2$ was not included in the inventory, because it is probably unavailable for CO_2 storage before 2050 (TNO, 2007).

storage in the hydrocarbon fields and aquifers (see Appendix II). We also distinguished between costs for CO_2 storage when facilities of the gas production activities can be re-used, and when this is not the case (i.e. if there is a gap of more than 5 years between gas production and CO_2 storage activities). Average CO_2 transport costs for transport to onshore sinks, offshore sinks, or the Utsira formation were derived from (Broek et al., 2010), a study which specifically investigates the development of the CO_2 infrastructure (see Appendix II).

- Assumptions on import and export of electricity. In the model runs, it is assumed that electricity may be exported from 2010 to 2020, but not in the years thereafter in order to keep the analysis focussed on the Dutch electricity market. In a recent report of TenneT[11] investigating the security of electricity supply in the Netherlands, the Dutch net electricity export grows from 0 GW in 2008 to 4.6-16 GW in 2016 depending on the variant. In the low export variant, the electricity demand in the Netherlands does not decrease due to the economic recession, and not all planned power plants will be built (only around 10 GW). In this variant, the export potential has its maximum in 2013 and then decreases again. In the high export variant, the Dutch electricity growth is less and an additional 18.5 GW power plants will be built between 2009 and 2016, and 2.3 GW wind power. 4.6 GW would mean an export potential of around 30 TWh (assuming an average capacity factor of 75%) (TenneT, 2009). According to Tennet this export potential may either increase or decrease after 2015.
- A limit to the deployment of nuclear power in the Netherlands. Nuclear power phases out in 2033 when the existing 450 MW nuclear power plant in Borssele has to shut down (VROM, 2006). In the sensitivity analysis, the effect of extra nuclear capacity is presented.
- The vintage structure of the electricity generation sector. The vintage was updated with all the plans for new capacity which are in the realisation phase. These include 3.6 GW of PCs (of E.ON and Electrabel in Rotterdam, and RWE in the Eemshaven), and 5.1 GW of NGCCs (see Figure 3).
- Assumptions on the deployment of photovoltaic systems (PV) and wind turbines (see Table 2). This includes the offshore wind energy and PV capacity proposed by the current government (EZ, 2008) as part of its regular energy policy and its additional policy to stimulate the economy (i.e. extra subsidy for a capacity of 500 MW offshore wind energy) (Ministry of General Affairs, 2009).
- Assumptions on biomass availability for the electricity generation sector (i.e. biomass for waste incineration, CHP units and co-firing in coal-fired power plants). Based on a global biomass potential assessment study and a study on the economic impact of biomass use in the Netherlands (Hoefnagels et al., 2009; Dornburg et al., 2010), a maximum bound was derived for the availability of biomass for electricity generation (see Table 3).

[11] TenneT is the Dutch transmission system operator who is responsible for administering the national transmission grid and safeguarding the reliability and continuity of the Dutch electricity supply.

Furthermore, it was assumed that 30% biomass can be co-fired in coal-fired power plants built before 2015, and 50% in newer coal-fired power plants[12].

- Costs were discounted with a discount rate of 7%.

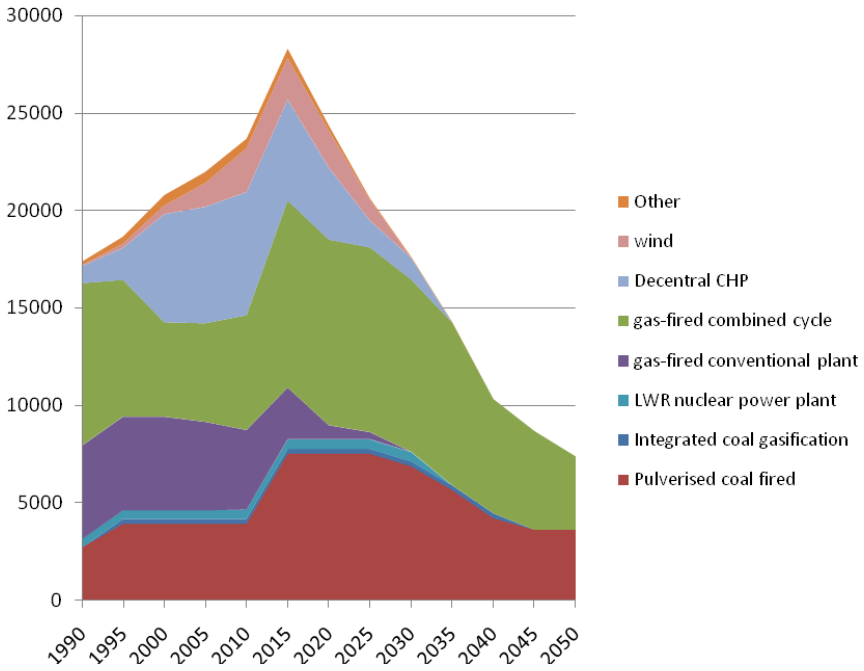

Figure 3 Development of existing electricity generation capacity in the Netherlands (in MW). It includes planned capacity in the realisation phase

[12] Meerman et al. (2009) state that co-firing of 100% biomass in an IGCC with existing technology is possible, but diminishes the thermal input efficiency of an IGCC by 15%. New (advanced) combustion technologies (e.g. circulating fluidized bed) could have higher flexibility. A study which includes details on flexible co-firing in coal-fired power plants, could assess the potential of the biomass co-firing further.

Table 2 Data for PV, wind capacity, and biomass availability as applied in MARKAL-NL-UU

			To be installed		Upper bound	
Type	**Unit**	**2008**	**2010**	**2015**	**2020**	**2050**
Wind offshore capacity	MW	228	200[a]	250[a]+500[b]	6000[a]	
Wind onshore capacity	MW	2022	(1550)[c]	(520)[c]	6000[d]	6000 [d]
PV capacity	MW	50	45[a]	25[a]		11600[e]

[a] source: EZ (2008). The government has made concrete plans to finance the mentioned capacities before 2010 and 2015. These figures were therefore implemented as lower investment bounds in MARKAL-NL-UU. For 2020, the government indicated an ambition of 6000 MW offshore wind energy. [b] source: Ministry of General Affairs (2009). [c] By 2011 wind capacity on land should have doubled to 4000 MW (VROM; EZ; LNV, 2008). However, the government plans for onshore wind energy were not implemented as lower investment bound, because recent requests for subsidy for wind on land have been very limited (EZ, 2009). [d] The government also indicates an ambition of 6000 MW onshore wind capacity by 2020 (VROM; EZ; LNV, 2008). However, in an evaluation of the government plans 4000 MW of onshore wind energy is considered to be the maximum under current spatial planning procedures and net capacity (Menkveld (Ed.), 2007). It was assumed that due to spatial limitations this is the maximum amount of wind capacity that can be placed onshore in the Netherlands. In a study that investigates the relation between energy and spatial use (Hugo Gordijn, 2003), it is recommended to reserve space for wind energy offshore. They estimate that for 20.000 MW wind energy, a surface of 2400 km^2 would be needed offshore on the Dutch continental shelf. Although this space is available, the locations of wind farms must be carefully planned so that they do not conflict with other sea uses. [e] According to the Dutch energy scenario in the WLO study (Janssen et al., 2006), PV may grow from 200 MW in 2020 to 3 GW in 2040. The value of 11.6 GW is obtained with geometric extrapolation.

Table 3 Data biomass availability in MARKAL-NL-UU

				Upper bound			
	Biomass available	**Unit**	**2008**	**2020**	**2030**	**2040**	**2050**
1.	worldwide [a]	EJ	9 (2005)	66	114	181	290
2.	for the Netherlands [b]	PJ	88	448	517[13]	823	1320
3.	for the electricity sector of which [c]	PJ	49 [14]	137	158[15]	252	404
	biomass fired in waste incineration installations [d]	PJ	29	31	32	34	35

[a] In the global biomass potential assessment study (Dornburg et al., 2010) the biomass potential is estimated to be around 290 EJ in 2050 in a medium development scenario without high levels of learning in agriculture and restraining pressure on natural habitats. In our study, we assumed an average development over time in which the global potential increases from 9

[13] In (Hoefnagels et al., 2009), the biomass use in 2030 varies between 150 and 1450 PJ per year.
[14] The amount of biomass used for electricity generation (excluding organic waste) has fallen from 31 PJ in 2005 to 20 PJ in 2008.
[15] The study by Hoefnagels et al. (2009) suggests a biomass use of 120 PJ in the electricity generation sector in 2030 in the high biomass scenario.

EJ for modern bioenergy use in 2005[16] to 290 in 2050. The biomass availability for each 5-year time step was based on the average figures for a development with linear growth and one with a growth rate of 8% per year. Note that the choice of growth type has a large consequence for biomass potential estimates over time: e.g. the potential ranges from 29 EJ with 8% growth per year to 103 EJ with linear growth in 2020. [b] The availability of biomass for the Netherlands was derived by applying the egalitarian fairness principle (i.e. equal biomass supply per capita) and the sovereignty principle (the biomass is divided according to the current percentages of national energy use in the global energy use). Until 2025 the sovereignty principle was applied, and from 2025, an average of the two principles. [c] Based on the Dutch biomass study (Hoefnagels et al., 2009), in which on average 31% of the primary biomass is used for electricity generation in the different scenarios. The other part of the biomass is used in the transport sector, and chemical industry. [d] Part of the biomass is available in the form of organic waste. In the Netherlands 29 PJ organic waste was used in waste incinerations in 2008. We assumed that this will grow at the same rate as the population to 35 PJ in 2050.

6.2.3.2 Scenarios in MARKAL-NL-UU

BASELINE, GRAND COALITION, IMPASSE, and IMPASSE - NO CDM scenarios

The results of the four different WorldScan scenarios were translated to four analogue scenarios in MARKAL-NL-UU: BASELINE, GRAND COALITION, IMPASSE, and IMPASSE - NO CDM. As WorldScan generated results for the development of the Dutch electricity demand, the CO_2 price, and the energy prices, these were used as input in MARKAL-NL-UU. The CO_2 price was implemented as a tax on CO_2 emissions originating from electricity generation from fossil fuels in MARKAL-NL-UU[17]. Consequently, all mitigation measures with lower cost than this tax will be implemented in a model run. Also the contribution of the Netherlands to achieve the renewable 20% EU-target in 2020 was taken from WorldScan. This contribution was set as a lower bound in MARKAL-NL-UU for the period 2020-2050.

GRAND COALITION - RENEWABLE+ scenario

Furthermore, in order to investigate the cost-effectiveness of renewable energy versus CCS, we investigated a fifth scenario GRAND COALITION - RENEWABLE$^+$. Given the deep emission cuts and the consequently high CO_2 prices towards 2050, renewable energy use increases substantially in the WorldScan scenario. In the GRAND COALITION - RENEWABLE$^+$ scenario, we took over this high share (on top of the 20% EU renewable target) into MARKAL-NL-UU for the whole period 2020-2050.

[16] In 2005, also 37 EJ non-commercial biomass (charcoal, wood, and manure for cooking and space heating) was used (Dornburg et al., 2008).

[17] Currently in the Dutch national allocation plan for the Kyoto-period 2008-2012 at least 16.5 GW is included in the ETS system (EZ and VROM, 2007) of a total of 23.0 GW in 2006 (CBS, 2009). This amount is based on combining the installations in the national allocation plan with the capacities of the database made for (Broek et al., 2008) and the Dutch National Allocation Plan (EZ and VROM, 2007). Not included in the ETS system are the nuclear power plant (0.5 GW), wind turbines (1.6 GW), small scale CHP units like gas engines (2.4 GW), small gas turbines, and small steam turbines (e.g. in the waste incineration sector).

Sensitivity analysis

In the sensitivity analysis, we examined two aspects: the impact of uncertainty of CO_2 emission ceilings after 2020 on CCS deployment in the near term, and the sensitivity of CCS deployment versus alternative assumptions of key parameters.

Uncertainty of CO_2 price

The uncertainty about future CO_2 emission ceilings and associated CO_2 prices was investigated through the inclusion of two *hedging cases*. In the *first case* it was assumed that CO_2 prices up to 2020 are high (IMPASSE - NO CDM), and in the *second case* low (as in GRAND COALITION). After 2020, the CO_2 price could follow three different price paths depending on alternative post-2020 caps. These price paths are based on the three scenarios, BASELINE, GRAND COALITION, and IMPASSE - NO CDM, and were assumed to be equally probable. The purpose of this analysis was to investigate what may happen with CCS deployment up to 2020 if the CO_2 price can go into various directions after 2020. The stochastic modelling method in the MARKAL model was used for this purpose (Loulou et al., 2004).

Alternative assumptions of key parameters

In the sensitivity analysis, we explored the influence of alternative developments of various CO_2 reduction measures (i.e. of PV, CCS, and nuclear), fuel prices, and CO_2 storage potential, as these factors affect the introduction of CCS. Their influence was compared to another scenario, namely the GRAND COALITION scenario. This scenario was chosen as reference, because it is more interesting to investigate in detail how the Netherlands can contribute to a global reduction strategy with considerable global CO_2 emissions reduction than one without.

6.3 Results

6.3.1 WorldScan results

6.3.1.1 Developments of GDP and energy demand

For each scenario, GDP and energy demand projections as calculated by WorldScan are presented in Table 4.

- In the GRAND COALITION scenario GDP growth in the EU-27 is lowest resulting in a 1.0% lower GDP in 2050 compared to the BASELINE. In the IMPASSE – NO CDM scenario, it is 0.4%

lower in 2050, while the use of CDM in the IMPASSE scenario limits GDP loss to 0.3%. Note that WorldScan does not include any negative economic effects of climate change itself which occur according to Stern (2006).

- In GRAND COALITION and IMPASSE - NO CDM energy demand in the EU-27 peaks in 2020 and then reduces, and in the IMPASSE scenario it almost stabilizes from 2020. Note that none of the scenarios have a reduced energy demand by 2020 as aimed for by the European Union with their energy package[18], According to a strategic energy review, this package should lead to a reduction of 5-8% primary energy consumption (EC, 2008b). Also the WorldScan projections for the growth of electricity demand of 2.4% per year are higher than aimed for by the European Union. The strategic review expects an 0.5-0.6% per year electricity demand growth with the energy package and 1.6% per year without (EC, 2008b).

Table 4 Development of GDP and the growth of energy and electricity demand in four scenarios as calculated by WorldScan

Scenario		GDP		Energy demand growth		Electricity demand growth	
	Unit	% per year		% per year		% per year	
		2004-2020	2020-2050	2004-2020	2020-2050	2004-2020	2020-2050
BASELINE	EU-27	2.41	1.37	1.47	0.46	2.50	1.07
	NL	2.31	1.26	2.30	0.36	2.55	1.05
GRAND COALITION	EU-27	2.39	1.35	1.26	-1.59	2.23	-0.11
	NL	2.27	1.10	1.47	-2.18	2.16	-0.77
IMPASSE	EU-27	2.37	1.38	0.86	0.09	2.17	1.03
	NL	2.21	1.26	0.50	0.09	1.97	1.02
IMPASSE - NO CDM	EU-27	2.36	1.38	0.38	-0.02	1.91	0.96
	NL	2.17	1.26	-0.04	0.01	1.60	0.94

The Dutch electricity demand shown in Figure 4, grows from 110 TWh in 2005 to 200 and 185 TWh in 2050 for IMPASSE and IMPASSE - NO CDM, respectively. Only in the GRAND COALITION scenario, the electricity demand starts decreasing after 2020. In this scenario, the electricity demand grows to 152 TWh in 2020 and, then, decreases to 120 TWh in 2050.

[18] This energy package encompasses a set of policy measures which must support the achievement of the 20-20-20 targets set by the European Council (Council of the European Union, 2007): 20% reduction of GHG emissions by 2020 compared to 1990, a 20% share of renewable energies in the final overall EU energy consumption, and 20% savings on the EU's energy consumption compared to projections for 2020 as estimated in the Green paper on energy efficiency by the European Commission (EC, 2005).

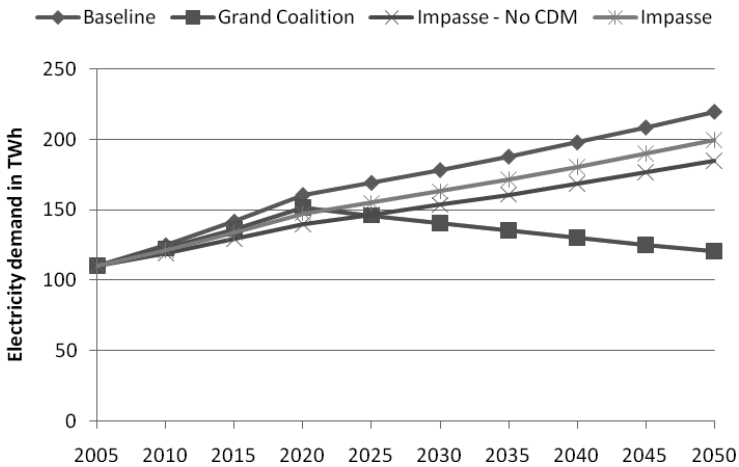

Figure 4 Development of the Dutch electricity demand for the four scenarios as calculated by WorldScan

6.3.1.2 Development of energy prices

The energy prices resulting from the WorldScan runs are presented in Table 5. The results show that:

- Coal price increases with 63% between 2005 and 2050 in the Baseline scenario. Gas prices increase with 15% between 2005 and 2025 and then decrease slightly. While population grows with 43%, and economy with 240% over the period 2004-2050 in the BASELINE, energy demand grows with not more than 50%. As prices mainly depend on production costs and energy demand developments (scarcity of natural resources is assumed in WorldScan), it is conceivable that the price of natural gas does not increase very much. On the other hand, the price of coal increases more because of an increased demand for this cheaper fuel.
- In GRAND COALITION coal and natural gas prices are 40% and 20%, respectively, lower than in the BASELINE due to lower energy demand. However, because CCS is not included in WorldScan, there is also no demand for fossil fuels used in power plants with CCS. Consequently, the prices may have been underestimated.
- The coal price development in WorldScan agrees with values in the World Energy Outlook (WEO) 2009 in which the coal price is 2.5 and 1.5 €/GJ in 2030 in their reference and 450 ppm scenario, respectively (IEA, 2009). However gas prices in WorldScan are lower than the WEO projections of 8.9 and 7 €/GJ in these WEO scenarios (IEA, 2009).
- The wood pellet price decreases from 7.0 €/GJ in 2005 to around 5.4 €/GJ in 2050. This decline is in line with (Uslu et al., 2008) who assess the costs to produce and deliver wood pellets to the Rotterdam harbour in the Netherlands at 4.7 €/GJ.

Table 5 Development of energy prices for the four scenarios as calculated in WorldScan (in €$_{2007}$/GJ)

		2005	2010	2020	2030	2040	2050
BASELINE	coal	1.8	1.9	2.1	2.3	2.6	2.9
	gas	4.7	5.0	5.3	5.4	5.3	5.2
	wood pellets	7.0	6.8	6.2	5.8	5.6	5.5
GRAND COALITION	coal	1.8	1.8	1.9	1.8	1.8	1.8
	gas	4.7	4.8	5.1	4.7	4.4	4.1
	wood pellets	7.0	6.8	6.0	5.6	5.4	5.3
IMPASSE	coal	1.8	1.8	2.0	2.2	2.4	2.7
	gas	4.7	4.8	5.2	5.3	5.3	5.2
	wood pellets	7.0	6.8	6.0	5.6	5.5	5.3
IMPASSE - NO CDM	coal	1.8	1.8	1.9	2.1	2.3	2.6
	gas	4.7	4.8	5.2	5.3	5.3	5.2
	wood pellets	7.0	6.8	6.0	5.6	5.5	5.4

6.3.1.3 Development of CO_2 emissions and CO_2 price

Although in the IMPASSE scenarios, a European climate policy is implemented, the global CO_2 emissions almost increase as fast as in the BASELINE (about 55 $GtCO_2$/yr in IMPASSE versus 59 $GtCO_2$/yr in the BASELINE in 2050). Only in the scenario GRAND COALITION, global emissions are reduced to 13.5 $GtCO_2$ per year in 2050, and the cumulative amount of CO_2 emissions over the period 2009-2050 is 964 $GtCO_2$. This is about 270 $GtCO_2$ higher than the 700 $GtCO_2$ needed to have a high probability of warming to stay below 2°C (see section 1.1). Furthermore, note that WorldScan models CO_2 emissions from fossil fuel firing only (being 22 $GtCO_2$ in 2004). The total amount of CO_2 emissions was already around 27 $GtCO_2$ in 2000 (Olivier et al., 2005; IPCC, 2007c)[19].

The outcomes of WorldScan are coherent with outcomes from other studies. For example, the ETP study by IEA estimates 62 $GtCO_2$/yr in 2050 in their Baseline scenario (IEA, 2008), and the CO_2 emissions in the SRES scenarios, which are summarised in (IPCC, 2007a), vary between 35 and 49 $GtCO_2$ in 2030.

[19] These emissions exclude post-burn CO_2 emissions from the remainings of biomass after forest fires (around 2.2 $GtCO_2$ in 2000) (JRC and PBL, 2009).

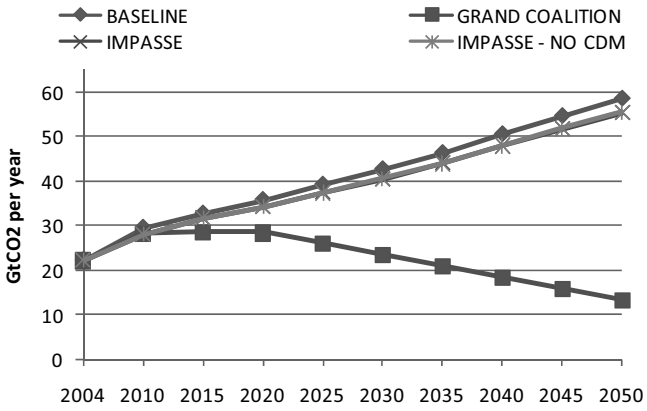

Figure 5 Worldwide CO_2 emissions from fossil fuel firing for the four scenarios as calculated by WorldScan

In the IMPASSE and GRAND COALITION scenarios with CDM, the CO_2 prices increase to 23 €/tCO_2 in 2020 while in the IMPASSE- NO CDM scenario it increases to 46 €/tCO_2.. These projections are in line with current forecasts of the CO_2 price for the 3rd ETS phase (2013-2020) presenting prices between €20 and €40 per tCO_2 (Gorina, 2009)[20].

In the GRAND COALITION scenario CO_2 prices increase sharply to 502 €/tCO_2 in 2050 when 45 GtCO_2/yr need to be abated compared to the BASELINE. These figures are very high compared to cost estimates of CO_2 reduction in other studies. For example, in the (IPCC, 2007a) report it is stated that around 30 GtCO_2/yr may be reduced for less than 124 €/tCO_2[21] in 2030[22], whereas in GRAND COALITION a similar reduction requires an emission price of about 186 €/tCO_2 in 2039. In the ETP study, 35 GtCO_2/yr could be reduced for less than 83 €/tCO_2[23] in 2050, whereas in WorldScan such a reduction would cost 258 €/tCO_2 in 2043. However, in the ETP study it is also pointed out that marginal costs beyond 35 GtCO_2/yr may increase to 200-660[24] €/tCO_2 if CO_2 emissions need to be reduced with 50 GtCO_2/yr. One of the reasons for the higher estimates from WorldScan may be that other models incorporate the

[20] The sources mentioned are Deutsche Bank, Point Carbon, UBS, and Barclays Capital (Carbon New Finance, 2009; Platts, 2009).
[21] i.e. 100 \$/tCO_2. We assumed that the IPCC data are reported in $\$_{2000}$.
[22] In an evaluation of the energy models used for the IPCC report, it is shown that the results from different models varies between 17 and 30 GtCO_2/yr which could be reduced for less than 124 €/tCO_2 in 2030 (van Vuuren et al., 2009). The differences can be explained by differences in baseline, model types, and data input.
[23] i.e. 100 $\$_{2005}$/t$CO_2$.
[24] The higher end estimate of 660 €/tCO_2 is due to pessimistic assumptions about the costs of CO_2 reduction, especially in the transport sector. The analysis did not include backstop options such as (co-)firing biomass in power plants with CCS (IEA, 2008).

simulation of cost reductions of abatement technologies through learning-by-doing. These mechanisms are not included in WorldScan.

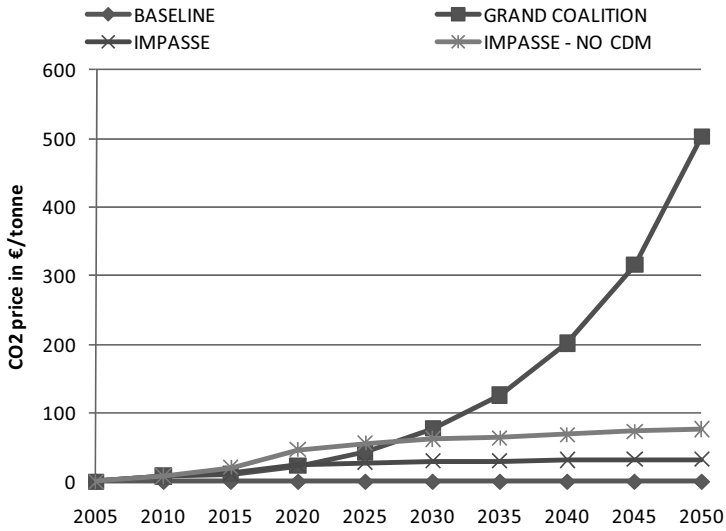

Figure 6 CO_2 price development for the different scenarios as calculated in WorldScan

6.3.1.4 Renewable energy

In WorldScan it is found that the contribution of the Netherlands to the EU renewable energy target in 2020 leads to a share of 23-27% of renewable energy in the primary energy input (on input basis) of electricity generation in the reduction scenarios. Furthermore, in WorldScan the share of renewable energy in the primary energy input increases to 61% in the GRAND COALITION scenario. We use this value as lower bound in the GRAND COALITION - RENEWABLE$^+$ scenario in MARKAL-NL-UU.

6.3.2 MARKAL-NL-UU results

6.3.2.1 Development of the power sector and CCS in the Netherlands

Figure 7 summarises the electricity generating capacity for all scenarios. In this section we focus on two points in time in the analysis period 2005-2050, namely one in the short term "2020" and one in the long term "2040".

In general it can be observed that while in the BASELINE, coal-fired power plants play a dominant role over the whole analysis period, this role is less in all CO_2 emission reduction scenarios. The short term strategy is to switch from coal to natural gas and wind energy, the

long term strategy is to introduce CCS at large scale in all reduction scenarios except for the IMPASSE scenario. In this latter scenario with a CO_2 price remaining around 30 €/tCO_2, the main strategy is to switch from coal to natural gas.

Specifically about the deployment of CCS, it is found that:

- *In the short term, CCS plays a role in the electricity generation sector in the* IMPASSE - NO CDM *scenario only.* In 2020, one power plant of 1.8 GW has been built with CCS, and 2.6 GW of PCs have been retrofitted with CO_2 capture in this scenario.
- *From 2030, CCS takes off* leading to an IGCC-CCS capacity between 5.9 and 7.1 GW in 2040. Additionally, in the IMPASSE - NO CDM and GRAND COALITION scenarios 9.5 and 9.0 GW of NGCC-CCS has been constructed in 2040, respectively. In GRAND COALITION - RENEWABLE$^+$ only 4.1 GW NGCC-CCS is deployed because of the high share of renewable energy, and in the IMPASSE scenario with a CO_2 price of 30 €/tCO_2 NGCC-CCS is not cost-effective at all. Biomass is co-fired in the CCS coal-fired power plants for 24% in 2020 and between 34 and 48% in 2040 (on the basis of energy input).
- *Retrofitting with CO_2 capture units remains limited, considering that 3.6 GW of new PCs will be built around 2015.* Besides the 2.6 GW retrofitted in the IMPASSE - NO CDM scenario, retrofitting remains below 0.9 GW in the other scenarios. In the BASELINE without any CO_2 price, the coal-fired power plants keep emitting CO_2, and in the GRAND COALITION scenarios, it is more cost-effective to build IGCCs with CCS compared with retrofitting the older coal-fired power plants.

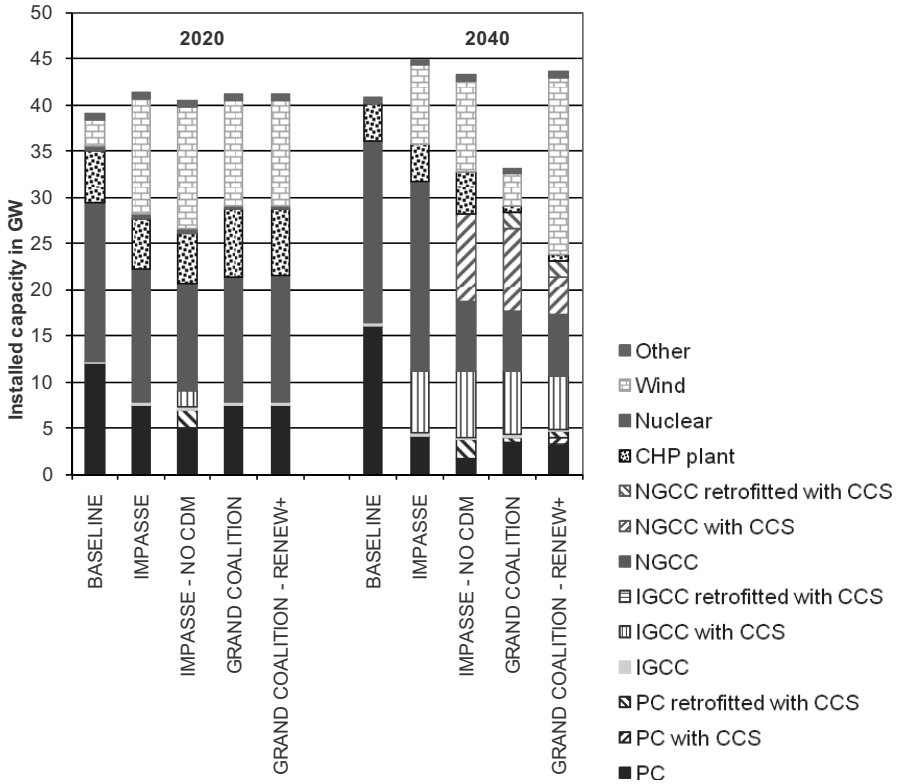

Figure 7 Total installed electricity generating capacity in the Netherlands in 2020 and 2040 for five scenarios as calculated with MARKAL-NL-UU

Figure 7 also shows two alternative strategies to reach low CO_2 emissions (see section 1.1.1.11) in the GRAND COALITION scenarios. In GRAND COALITION - RENEWABLE$^+$, it is a strategy combining wind energy, CCS in NGCCs, and CCS in biomass-coal fired power plants, which generate 40%, 15%, and 33% of the electricity in 2040, respectively. In the GRAND COALITION the strategy consists of mainly CCS: 39% output from biomass-coal fired power plants, 49% from NGCCs, and 5% from wind turbines in 2040. This latter strategy is a business as usual scenario in the sense that the electricity generation sector keeps depending on large scale power plants. Note that in our study, it was assumed that NGCC-CCS can operate in a flexible mode, and that there is additional NGCC capacity which can be used as backup or spinning reserve capacity in both scenarios. However, fuel use requirements and extra CO_2 emissions of these units were not taken into account in our analysis.

In Figure 8, the primary energy use in the power sector for the years 2020 and 2040 is summarised. This figure supports the observation that coal is the dominant energy source for power generation in the BASELINE, while for all reduction scenarios it is natural gas. The figure also shows the biomass use of which most is co-fired in coal-fired power plants with CCS. In all reduction scenarios, the total amount of available biomass (i.e. 106 PJ) is used in 2020 to reach the EU renewable target. After 2020, the restricted availability of biomass remains the limiting factor for further biomass use in all periods in the GRAND COALITION - RENEWABLE+ scenario, and in the other reduction scenarios it is the limiting factor in half of the periods.

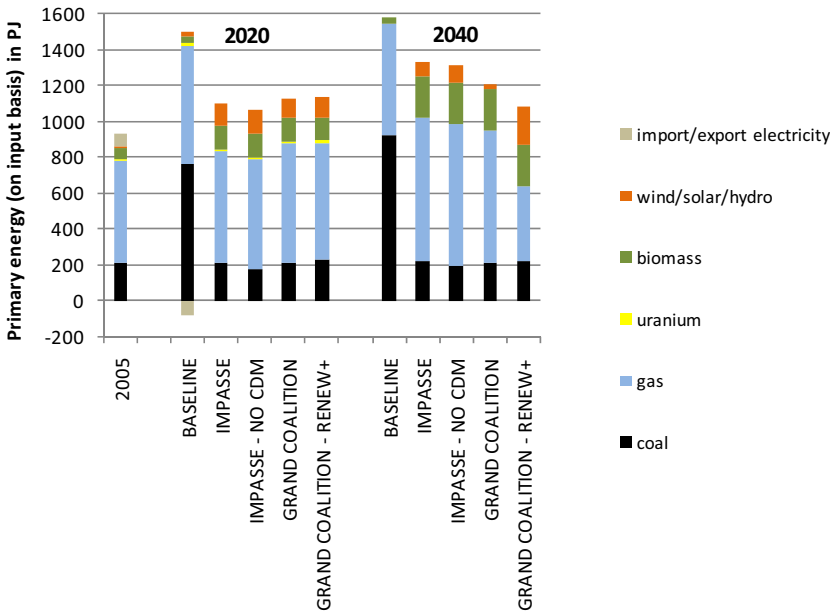

Figure 8 Primary energy use in the power sector of the Netherlands in 2020 and 2040 per scenario as calculated with MARKAL-NL-UU. Note that it was assumed that for wind/solar/hydro 1 PJe = 1 PJ primary energy

6.3.2.2 Development of CO_2 emissions

Figure 9 shows the development of the CO_2 emissions from the power sector and the CO_2 intensive industry in the Netherlands for the different scenarios. At first the CO_2 emissions rise from 80 to around 113 $MtCO_2$/yr in 2015 because the Netherlands is switching from being an electricity importing country to an exporting one with an export of 5 - 14 TWh in 2015. Next, the scenarios follow different CO_2 emission pathways. In the BASELINE, they keep

increasing to 156 $MtCO_2$/yr, while in GRAND COALITION they fall to negative emissions of 2 $MtCO_2$/yr in 2050. Negative CO_2 emissions are achieved by co-firing biomass in coal-fired power plants with CCS. Also in the GRAND COALITION scenario - RENEWABLE$^+$ scenario, zero emissions should be achievable given the CO_2 price of 500 €/tCO_2. However, the CO_2 emissions are reduced to 10 $MtCO_2$/yr because in this scenario the biomass-CCS combination is limited: the high renewable target of 61% in GRAND COALITION - RENEWABLE$^+$ restricts the option of biomass co-firing which is bounded to 50% of the input in this study. In the IMPASSE scenario the CO_2 emissions only reduce to 52 $MtCO_2$/yr in 2050 due to the low CO_2 prices. Finally, while in the IMPASSE - NO CDM scenario worldwide emissions hardly decrease, the Dutch emissions diminish to 11 $MtCO_2$/yr.

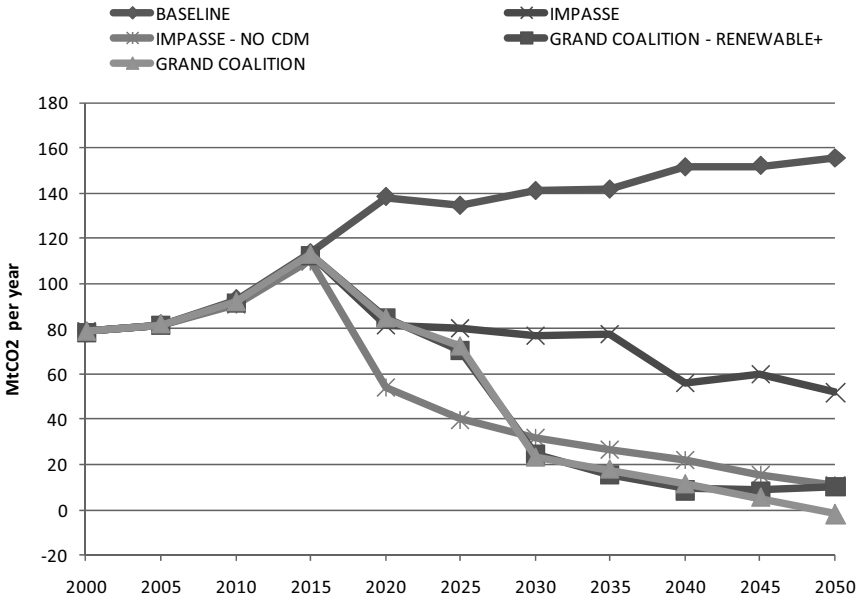

Figure 9 CO_2 emissions from the power sector and CO_2 intensive industry in the Netherlands per scenario as calculated with MARKAL-NL-UU

6.3.2.3 Contribution of CCS to CO_2 reduction

Figure 10 presents the amount of CO_2 stored over time per scenario. In most scenarios the amount of CO_2 stored in 2020 is very limited: some CO_2 from the ammonia and hydrogen manufacturing units is stored in the GRAND COALITION scenarios. The only CO_2 capture at power plants in this period is realised in IMPASSE - NO CDM with a CO_2 price of 47 €/tCO_2 in 2020 and 26 $MtCO_2$/yr stored at this point in time. Next, in this scenario the application of

CCS increases fast to 43 $MtCO_2$/yr in 2025, while only 14 and 8 $MtCO_2$/yr is stored in the GRAND COALITION scenarios, and IMPASSE scenario, respectively. Around 2030, the GRAND COALITION scenarios catch up with the IMPASSE - NO CDM scenario. Given that CCS is the main CO_2 mitigation measure in the IMPASSE - NO CDM and GRAND COALITION - RENEWABLE$^+$ scenario's, storage continues to grow in these two scenarios to around 90 $MtCO_2$/yr. In the end, 1.8-2.0 $GtCO_2$ is stored of which 0.5-0.6 $GtCO_2$ in the Utsira formation. A prerequisite for such a scenario to continue is that a huge CO_2 storage reservoir remains available. From 2040 in GRAND COALITION, the role of CCS diminishes in favour of wind energy (see below). In IMPASSE CO_2 storage remains lower over the whole period, reflecting the lower targets and CO_2 prices.

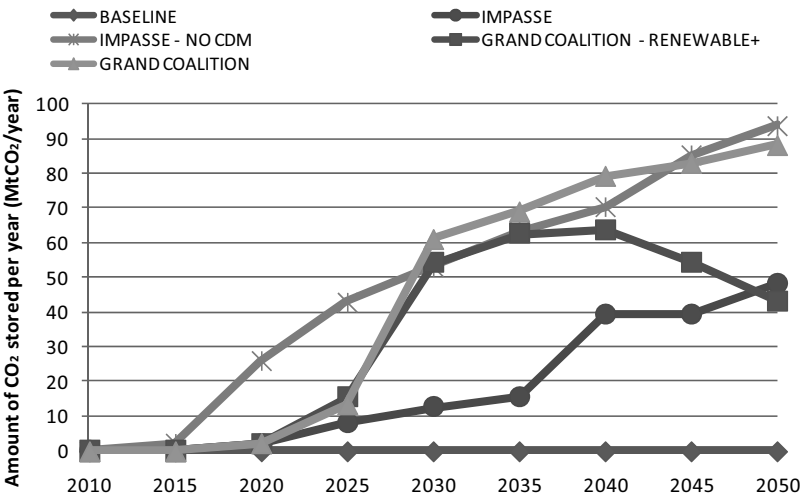

Figure 10 Annual amount of CO_2 stored in the period 2010-2050 per scenario as calculated in MARKAL-NL_UU

Figure 11 summarises the cumulative amount of CO_2 emissions in the Dutch power sector and the CO_2 intensive industry over the period 2009-2050 in the different scenarios. Also the contributions of the different abatement measures to the CO_2 reduction are depicted. In this period, the cumulative CO_2 emissions for the electricity sector and the CO_2 intensive industry is 5.7 $GtCO_2$ in the BASELINE , 3.2 $GtCO_2$ in the IMPASSE, and around 2 $GtCO_2$ in the other scenarios[25]. In the reduction scenarios between 2.5 and 3.8 $GtCO_2$ is avoided to which CCS

[25] A translation of the worldwide cumulative CO_2 limit of about 700 $GtCO_2$ to keep temperature increase below 2°C (see section 6.1) over the period 2009-2050 of (Meinshausen et al., 2009) would translate into a Dutch

contributes the most with 27-47%[26]. The use of biomass contributes with 10-15% to the CO_2 avoidance, and this mostly takes place in power plants with CCS. Only in the GRAND COALITION - RENEWABLE$^+$ scenario, part of the CO_2 avoidance by biomass is realised in CHP units.

In Figure 11 also the total undiscounted additional energy system costs due to the CO_2 reduction (as calculated in MARKAL-NL-UU) over the period 2009-2050 are presented. However, these figures do not include other GDP losses as determined in WorldScan (see section 1.1.1.6). The CO_2 reduction costs of the IMPASSE scenario with only modest CO_2 reduction are evidently lowest. Although the cumulative CO_2 emissions are slightly lower in IMPASSE - NO CDM than in the GRAND COALITION scenarios, the total costs for the CO_2 reduction costs are less (77 instead of 88 or 111 billion € over the period 2009-2050). The reason is that in GRAND COALITION, in order to avoid the very high CO_2 taxes at the end of the period, far reaching CO_2 measures are taken resulting in negative CO_2 emissions. Furthermore, in GRAND COALITION -RENEWABLE$^+$ the high share of renewable energy is responsible for the higher costs.

emission space of 1.5 - 4.0 $GtCO_2$ in total. 4.0 $GtCO_2$ was calculated by using the ratio of Dutch to global CO_2 emissions in 2006, and 1.5 $GtCO_2$ by using the ratio of Dutch to global population (in the WorldScan scenarios of this study). In the first case, the sovereignty fairness principle was applied (i.e. the percentage reduction of current emissions is equal for all countries) and in the second case, the egalitarian fairness principle (i.e. equal emissions per capita are allowed) (Ringius et al., 2002). Note that in a global trading system, national emission spaces can be enlarged by reducing emissions elsewhere.

[26] The amount of CO_2 avoided by CCS was calculated by comparing the emissions of the power plant with CCS with those of the same type of power plant without CCS.

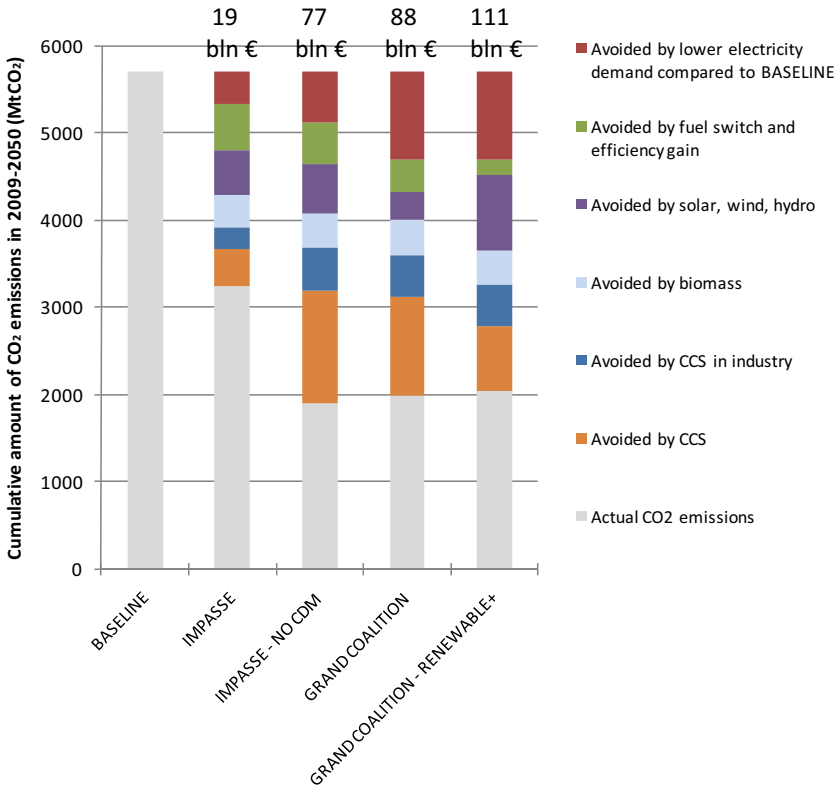

Figure 11 Contribution of CCS and other abatement measures to CO_2 emission reduction in the Dutch electricity and heat generation sector over the period 2009-2050 for the different scenarios. Total CO_2 reduction costs, in billion €, are also presented.

6.3.2.4 Electricity prices and abatement costs

Table 6 presents the costs for electricity generation and for CO_2 reduction for each scenario. Electricity costs range between 56 and 71 €/MWh in 2020 with highest costs for the IMPASSE - NO CDM scenario due to its high emissions permit price.

Table 6 Overview of electricity and CO_2 reduction costs for the different scenarios

		BASELINE	IMPASSE	IMPASSE - NO CDM	GRAND COALITION	GRAND COALITION - RENEWABLE+
Average electricity demand (TWh)		177	163	153	134	134
Electricity expenses (€/MWh)[a]	2020	56	67	71	65	65
	2030	55	64	72	73	74
	2040	54	64	71	69	79
Cumulative amount of CO_2 stored ($GtCO_2$)		0.0	0.6	1.9	1.7	1.3
CO_2 average emission reduction expenses (€/tCO_2)[b]	2020	0	16	38	29	28
	2030	0	21	39	45	48
	2040	0	25	38	42	60

[a] We used the total undiscounted annualised cost results of MARKAL-NL-UU for the calculation of the cost of electricity (COE). We distributed the costs to the electricity and heat output on exergy basis (i.e. using a factor of 1 for electricity, 0.15 for district heat, and 0.35 for industrial heat) based on typical figures described in (Blok, 2009).

[b] The costs for CO_2 reduction in each scenario were based on the total undiscounted annualised cost results and CO_2 emissions of MARKAL-NL-UU in relation to the costs and CO_2 emissions of an analogue version of the scenario without a CO_2 price. Only, the GRAND COALITION - RENEWABLE+ scenario was compared to the GRAND COALITION scenario without a CO_2 price.

6.3.2.5 Sensitivity analysis

Figure 12 presents the amount of CO_2 stored for the GRAND COALITION and IMPASSE – NO CDM scenario with uncertainty about the development of the CO_2 price after 2020. From this year, the CO_2 price will either follow the BASELINE, GRAND COALITION, or IMPASSE – NO CDM price path. The analysis shows that in 2020 under uncertainty 21 $MtCO_2$ less is stored compared to the "certain" IMPASSE – NO CDM scenario, and no CO_2 at all in the GRAND COALITION scenario. Instead extra CO_2 emission allowances are bought. For example, in the uncertainty variant of IMPASSE - NO CDM, the 21 $MtCO_2$ are emitted in 2020 resulting in 1 billion € extra costs for CO_2 emission allowances, but in the same year 0.8 billion € less is spent on abatement costs. More generally, with uncertainty about the future price of carbon, investments in abatement options with long life spans will be postponed. For introduction of CCS on the short term, complementary measures besides the EU ETS or CTS are needed as confirmed by Groenenberg and de Coninck. They state that the limited time horizon and short-trading periods of EU ETS probably do not lead to substantial CCS diffusion (Groenenberg and de Coninck, 2008).

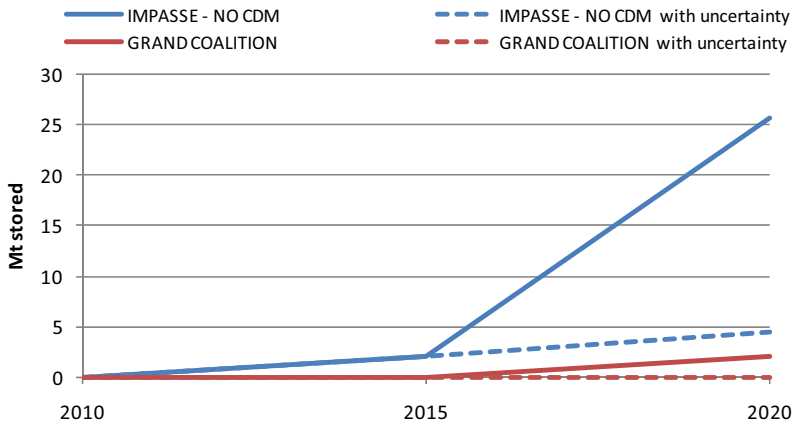

Figure 12 CO_2 stored under uncertainty about the development of the CO_2 price from 2020

Table 7 Overview of the MARKAL-NL-UU sensitivity variants

Variant of GRAND COALITION	Implementation
High fossil prices	Coal and gas price are around 35%, 65%, and 100% higher in 2010, 2015, and 2020 onwards, respectively, compared to those in GRAND COALITION. This results in a coal price of 3.5 instead of 1.8 €/GJ, and a gas price of 8.2 instead of 4.1 €/GJ in 2050.
High biomass price	Wood pellet price is around 30%, 65%, and 100% higher in 2010, 2015, and 2020 onwards, respectively, compared to the one in Grand Coalition. This results in a price of 10.6 instead of 5.3 €/GJ in 2050.
Slow CCS	CCS development is delayed with 10 years. I.e. the CCS power plants of 2010 with its specific costs and performance are available from 2020 (see Appendix II), the 2020 plants from 2030, etcetera.
Limited availability CO_2 storage reservoirs	Utsira is not available for Dutch CO_2 and onshore storage is restricted to 600 $MtCO_2$ instead of 1200 $MtCO_2$
Optimistic development PV	Costs of PV decrease faster (1550, 875, and 675 €/kW in 2020, 2030, and 2040, respectively)
No CCS	No CCS is allowed.
No bound on nuclear	Expansion of nuclear power is not restricted.
Nuclear - no CCS	Nuclear power is not restricted and no CCS is allowed.
Less biomass	Biomass availability for the Dutch electricity sector is halved (i.e. 69, 79, 126, 202 PJ in 2020, 2030, 2040, and 2050, respectively).
NGCC-CCS baseload	NGCC-CCS cannot be operated in a flexible mode

In the sensitivity analysis, also a number of MARKAL-NL-UU runs were undertaken as listed in Table 7. Figure 13 illustrates the variation in these runs resulting from changes in key parameters regarding the development of energy prices, competing technologies, or the availability of CO_2 storage. In the variants without any CCS the cumulative CO_2 emissions in the period 2009-2050 are substantially higher (0.8 -1.3 $GtCO_2$ higher). In almost all other variants CCS plays an important role avoiding between 0.9 and 1.6 $GtCO_2$ in the period investigated. The contribution of CCS is the least in the variant with limited CO_2 storage (0.9 $GtCO_2$ avoided), and limited biomass availability (1.3 $GtCO_2$ avoided). Note, that in the limited CO_2 storage variant this is partly due to the CO_2 emissions in the CO_2 intensive industries for which no alternative CO_2 mitigation measures are defined in MARKAL-NL-UU. In the limited biomass variant, CCS becomes less attractive, because less biomass is available for co-firing in the CCS power plants. Finally, in the variant with NGCC-CCS operating as base load and the one with unrestricted nuclear power, 1.4 $GtCO_2$ is avoided by CCS compared to 1.6 $GtCO_2$ in GRAND COALITION. In most variants, it holds that there are more cumulative CO_2 emissions with less CCS except for the nuclear variant (more CO_2 with less CCS) and the variant with expensive fossil fuels (more CO_2 with more CCS due to a larger share of coal-fired power plants). The variant Slow CCS shows that under a relatively low CO_2 price of 23 €/t in 2020, the rate at which CCS develops does not reduce the amount of CO_2 avoided by CCS. However, if the CO_2 price follows the IMPASSE – NO CDM path with high CO_2 prices in 2020, 0.4 $GtCO_2$ less would be avoided over the period 2009-2050 in a Slow CCS variant. In this case the slow CCS technology advancement reduces the amount of CO_2 avoided by CCS, but the CO_2 price remains the most important factor for the introduction of CCS as confirmed by (Jakobsen et al., 2008).

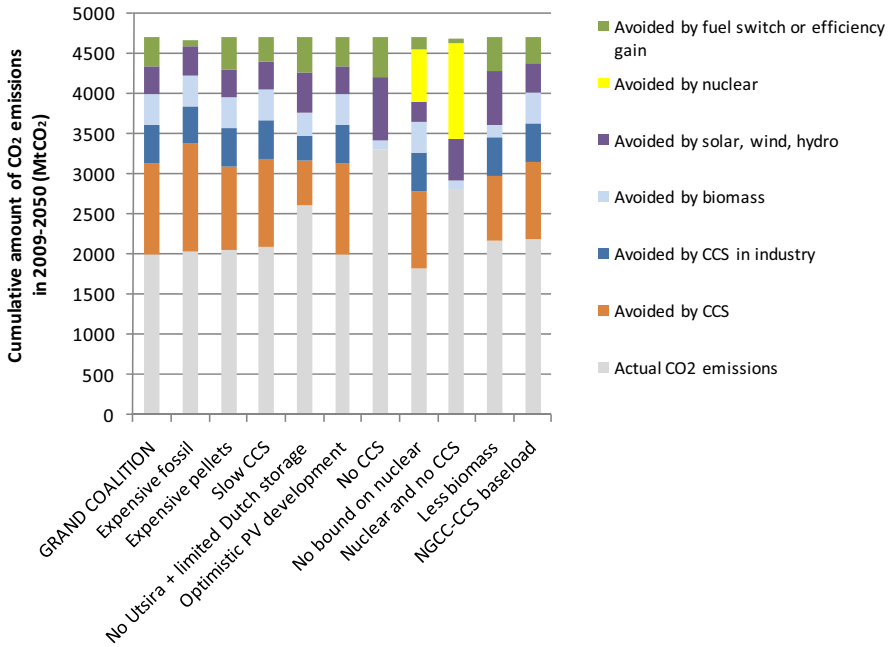

Figure 13 Contribution of CCS and other abatement measures to the CO_2 reduction in the Dutch electricity and heat generation sector over the period 2009-2050 for different variants of the GRAND COALITION scenario

6.4 Discussion

In this paper we combined the applied general equilibrium model WorldScan with the techno-economic energy model MARKAL-NL-UU in order to evaluate the impact of international climate policies on the deployment of CCS on a national level. One of the results shows that the CO_2 price in most scenarios is too low in the short term for large scale introduction of CCS. In GRAND COALITION, for example, options for CO_2 emission reduction abroad are less costly, and the need for large scale introduction of CCS only takes off at large scale from 2030 when the CO_2 price increase above 70 €. However, it is important to note that none of the scenarios seem to achieve sufficient CO_2 emission reductions to keep temperature increase below 2°C with a high probability according to the latest insights. In the GRAND COALITION scenarios, cumulative CO_2 emissions for energy fuel combustion only were about 964 $GtCO_2$, while total cumulative CO_2 emissions are required to stay below 700 $GtCO_2$ over the period 2009-2050. Investigating scenarios with stricter CO_2 cap developments in WorldScan, would provide additional insights into the consequences of

deep reduction strategies. The CO_2 price in such a "grand coalition" scenario may be significantly higher than the 23 €/tCO_2 in our GRAND COALITION scenario in 2020, making CCS commercial at an earlier stage.

This first endeavour to soft-link the global WorldScan model with the national MARKAL-NL-UU model provides a consistent method to investigate the consequences of international climate policy on the cost-effectiveness of a technology at a national level. However, there is still potential for improvement. So far, the energy and CO_2 prices fed from WorldScan into MARKAL-NL-UU determine the cost-effectiveness of the energy technologies in a national context. In principle WorldScan should also receive the power generation package generated by a bottom-up model as well as the use that is made of CO_2 reduction technologies like CCS. Next, Worldscan can calculate the implications of this package for the electricity demand, prices of primary energy carriers and the emissions price and send these back to a bottom-up model like MARKAL-NL-UU. It should be noted that for the IMPASSE scenario, WorldScan should get the power generation package from a bottom-up model including an extended technology database with learning rates that covers the whole of EU27. Similarly, to verify the validity of high CO_2 prices approaching 600 €/tCO_2 in the GRAND COALITION scenario, a bottom-up model with global coverage could provide the right input for WorldScan. Such a joint analysis of top-down and bottom-up models at the global level would probably show that at a CO_2 price of 600 €/tCO_2 even deeper CO_2 reductions than in this study would be feasible and/or against lower costs.

In MARKAL-NL-UU, insights into the following aspects could improve the results:

- CO_2 reduction measures to replace cogeneration technologies. More CO_2 reduction measures need to be included to assess the CO_2 reduction potential accurately for high CO_2 prices. For example, geothermal heat generation technologies could replace existing district heating systems. Furthermore, a study by Kuramochi et al. (Kuramochi et al., 2010) showed that post-combustion CO_2 capture from 50-400 MWe may be feasible at costs of 35 – 60 $€_{2000}$/tCO_2 in the midterm (2020-2025). Including this option into MARKAL-NL-UU would require amongst others an in-depth analysis of the scale and heat power ratio's of the cogeneration facilities in the Netherlands.
- Co-firing of biomass in power plants. In this paper co-firing of biomass in coal-fired power plants was limited to 50% of the input. Because the combination of CCS and biomass-co-firing shows up as a cost-effective CO_2 emission reduction measure, a further study could provide insights into the cost-effectiveness of power plants that are fully flexible to switch from coal to biomass or vice-versa.
- Contribution of CCS in the transport sector. The inclusion of the transport sector into the model would give more insights into the total CO_2 capture potential as CCS can be applied at production units of final energy carriers for vehicles (i.e. at synfuel, hydrogen production units or power plants).

- Flexibility of an energy system with both a high percentage of renewable energy and large scale deployment of CCS power. For example, the GRAND COALITION - RENEWABLE$^+$ is characterised by a high share of wind energy in combination with power plants equipped with CCS. Further study should point out whether the electricity system is flexible enough to handle these high shares.

6.5 Conclusions

In this study we combined the applied general equilibrium model WorldScan used for international economic policy analysis with the techno-economic energy model MARKAL-NL-UU in order to evaluate the impact of international climate policies on the deployment of CCS at a national level. To demonstrate this, we focussed on the Dutch electricity generation sector and CO_2 intensive industries.

Main results from our modelling are:

- In 2020 CO_2 prices in the EU-27 may vary between 23 €/tCO_2 in a GRAND COALITION scenario, in which all countries accept relative or absolute greenhouse gas targets from 2020, to 47 €/tCO_2 in an IMPASSE – NO CDM scenario, in which EU-27 countries continue their one-sided European emission trading system without having the possibility to use the Clean Development Mechanism.
- Due to the high CO_2 price in the IMPASSE – NO CDM scenario development of CCS on a national level, in the Netherlands, is earlier than in all other scenario's: 26 and 43 MtCO_2 per year are stored in the Netherlands in 2020, and 2025, respectively. However, this is not efficient since in this scenario high costs of abatement within the EU are applied while low cost abatement options are left unused outside the EU.
- In the more successful GRAND COALITION scenarios, CCS is not deployed at large scale in an early stage: 2 and 14 MtCO_2 per year are stored in 2020 and 2025, respectively. Thereafter CCS is scaled up fast to more than 50 MtCO_2 in 2030.
- If the CO_2 price is 47€/tCO_2 in 2020, uncertainty about the development of the CO_2 price after 2020, reduces the CO_2 storage from 26 to 4 MtCO_2 per year.
- Over the whole period (2009-2050), total cumulative CO_2 emissions of the Dutch power sector and CO_2 intensive industry decrease from 5.7 GtCO_2 in a business as usual scenario to around 2 GtCO_2 in IMPASSE – NO CDM, and GRAND COALITION scenarios (one with low and one with a high share of renewables). In these scenarios CCS contributes between 34% (GRAND COALITION - RENEWABLE$^+$) and 47% (IMPASSE – NO CDM) of the total CO_2 avoided. CO_2 emissions reduce to around 10 MtCO_2/yr and even negative emissions of 2 MtCO_2/yr in GRAND COALITION in 2050. Due to the different reduction pathways the total undiscounted costs of the CO_2 reduction range from 77 to 111 billion € (GRAND COALITION - RENEWABLE$^+$). The sensitivity analysis showed that in the successful GRAND COALITION

scenario, restricted availability of biomass and CO_2 storage potential may be limiting factors for the deployment of CCS.

Based on this case study and modelling results we can conclude that:

- International climate policy in combination with uncertainty does not advance the application of CCS in an early stage. For an earlier start of CCS complementary policy making is indispensable.
- The rates at which different CO_2 abatement technologies (including CCS) develop, are less crucial for introduction of CCS than the CO_2 price development if the introduction of CCS depends on an emission trading system.
- The combination of biomass (co-)firing and CCS seems an important option to realise deep CO_2 emission reductions. In our reduction scenarios for the Netherlands, this option avoids around 30 $MtCO_2$ in 2040.

With respect to the applied methodology we conclude that a global economic policy analysis tool as WorldScan can be used to obtain an appropriate context to assess the impact of international climate policies on a national level. Its global scope and its approach which seeks equilibriums in energy and CO_2 markets, give insights into the relation between developments of the energy demand, CO_2 prices, and fuel prices. On the other hand, the use of an energy bottom-up model can generate more detailed insights into the effectiveness of different CO_2 reduction strategies. This type of analysis is important, because national governments depend to a large extent on global climate policies for the success of their domestic reductions and vice versa.

Finally, it is concluded that further research is needed with respect to the following issues:

- In order to stay below the 2°C degrees warming, it is important to study pathways of the energy system with more and quicker reduction of global CO_2 emissions than presented in this study.
- Modelling these deep reduction scenarios poses additional requirements to the models. For example, pathways to even negative CO_2 emissions in some sectors must be modelled properly. This requires that more mitigation options are included in the models in order not to underestimate the potential to reduce CO_2 emissions or overestimate the reduction costs. Also, more detailed modelling is necessary to investigate the conditions under which new configurations of the energy system can function, such as an energy system with a high deployment of renewable energy in combination with power plants equipped with CCS.
- The linkage between a top-down model like WorldScan and a bottom-up model can be improved by an iterative approach. WorldScan should receive different energy technology configurations generated by bottom-up models, and next, calculate the implications of these configurations for the electricity demand, prices of energy carriers,

and the emissions price. These results can be fed into a bottom-up model like MARKAL-NL-UU.

6.6 Acknowledgement

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Annex I WorldScan classification

Table 8 Overview of regions, sectors and production inputs in WorldScan

Regions[a)]	*Sectors*[b)]	*Inputs*[b)]
1. Netherlands	Cereals	*Factors*
EU-15 (old member states) minus the Netherlands	Oilseeds	Low-skilled labour
EU-12 (new member states)	Sugar crops	High-skilled labour
2. Other Europe	Other agriculture	Capital
Former Soviet Union	Minerals	Land
United States	Oil	Natural resources
Other OECD (ex Mexico)	Coal	
3 Brazil	Petroleum and coal products	*Primary energy carriers*
Mexico, Central and other Latin America	Natural gas	Coal
Middle East and North Africa	Electricity	Petroleum, coal products
China and Hong Kong	Ferrous metals	Natural gas
India	Chemical, rubber, plastic products	Modern biomass
4. Other South and South -East Asia	Mineral products	Renewables
Rest of World	Paper products, publishing	
	Non-ferrous metals	*Other intermediates*
	Vegetable oils and fats	Cereals
	Other consumer goods	Oilseeds
	Capital goods and durables	Sugar crops
	Road and rail transport	Other agriculture
	Other transport	Minerals
	Other services	Oil
	Biodiesel	Electricity
	Ethanol	Ferrous metals
	Modern biomass	Chemical, rubber, plastic products
	Renewables	Mineral products
		Paper products, publishing
		Non-ferrous metals
		Vegetable oils and fats
		Other consumer goods
		Capital goods and durables
		Road and rail transport
		Other transport
		Other services
		Biodiesel
		Ethanol

[a] The numbers refer to the different groups of countries as mentioned in Table 1. Non-Annex I regions are denoted in italics

[b] ETS-sectors and inputs are denoted in bold

Annex II Input data MARKAL-NL-UU

Table 8 Technical and economic parameters of electricity generating technologies modelled in MARKAL-NL-UU [a]

	Technology	2010	2020	2030	2040
Investment costs (in €/kW)	NGCC	676	608	608	608
	PC	1598	1487	1448	1352
	IGCC	2005	1798	1691	1521
	NGCC-CCS	1146	1014	938	838
	PC-CCS	2546	2328	2110	1892
	IGCC-CCS	2769	2374	2130	1956
	Wind onshore	1227	1075	965	866
	Wind offshore	2433	2028	1919	1892
	Nuclear	2652	2652	2652	2652
	PV	4325	2703	1352	946
Fixed O&M costs (in €/kW)	NGCC	19	17	16	16
	PC	58	52	50	49
	IGCC	71	66	60	53
	NGCC-CCS	33	24	22	19
	PC-CCS	86	63	58	53
	IGCC-CCS	92	76	70	63
	Wind onshore	32	25	23	20
	Wind offshore	96	91	86	81
	Nuclear	66	66	66	66
	PV	40	25	13	9
Variable O&M costs (in €/GJ)	NGCC	0.02	0.02	0.02	0.02
	PC	0.36	0.35	0.33	0.33
	IGCC	0.29	0.25	0.20	0.19
	NGCC-CCS	0.41	0.40	0.36	0.35
	PC-CCS	1.29	1.25	1.08	0.95
	IGCC-CCS	0.51	0.41	0.27	0.27
	Wind onshore	0.00	0.00	0.00	0.00
	Wind offshore	0.00	0.00	0.00	0.00
	Nuclear	0.69	0.69	0.69	0.69
	PV	0.00	0.00	0.00	0.00
Efficiency (in %)	NGCC	58%	60%	63%	64%
	PC	46%	49%	52%	54%
	IGCC	46%	50%	53%	56%
	NGCC-CCS	49%	52%	56%	58%
	PC-CCS	36%	40%	44%	47%
	IGCC-CCS	38%	44%	48%	52%

[a] Source of performance and cost data: (IEA GHG, 2003; Hendriks, 2004; IEA GHG, 2004; Menkveld, 2004; University of Chicago, 2004; IPCC, 2005; Junginger, 2005; Verrips, 2005; Damen et al., 2006; IEA, 2006; Damen, 2007; EU PV Technology Platform, 2007; Peeters, 2007; Graus and Worrell, 2009; NETL, 2009; Prins et al., 2009)

Table 9 CO_2 transport and storage costs assumed in this study

		investment	Fixed O&M	Lifetime	CO_2 storage capacity
		M€/(Mt/yr)	M€/(Mt/yr)	years	Gt
Transport[A]	to fields offshore	31	0.9	40	
	to fields onshore	20	0.6	40	
	to the Norwegian Utsira field	42	1.5	40	
Storage[b]	aquifers offshore	196	9.6	21	0.0
	aquifers onshore	83	3.8	28	0.0
	depleted gas fields offshore	32	1.4	19	1.0
	depleted gas fields offshore without re-use	111	5.3	19	
	depleted gas fields onshore	11	0.4	22	1.2
	depleted gas fields onshore without re-use	23	1.0	22	
	Norway, Utsira field, off-shore	18	0.9	25	42

[a] In the CO_2 infrastructure study by Broek et al. (2010), each pipeline is modelled separately, CO_2 transport costs are assumed to be proportional to meter length and per meter diameter of the pipeline as suggested by (Hendriks et al., 2003; Hendriks et al., 2007) and varies between 1300 and 4300 €/m^2 for a specific location depending on the land-use type, and whether there is an existing hydrocarbon pipeline corridor or not. In this paper, we did not model each pipeline, but pipelines with average CO_2 transport costs were derived from the CO_2 infrastructure study (Broek et al., 2010).

[b] Unit costs of setting up and maintaining CO_2 storage facilities (e.g. costs for site exploration and development, an offshore platform, drilling costs per meter) were based on several sources (BERR, 2007; Serbutoviez et al., 2007; Torp, 2008; Wildenborg et al., 2008). Based on these unit costs and the characteristics of the individual sinks (e.g. depth, location), we estimated average costs for the different CO_2 storage categories.

Table 10 Technical and economic parameters of CHP technologies modelled in MARKAL-NL-UU (excluding units for district heating)[a]

	efficiency		Investment	O&M costs	Capacity factor	Capacity	Scale
	electric %	Thermal %	€/kW	€ct/kWh		GW (in 2005)[b]	MW
NGCC-CHP existing	32	48	721	0.65	66%	2.8	< 250
NGCC-CHP new	43	31	1040	0.78	67%		< 250
Steam turbine small	10	74	471	0.56	38%	0.3	~15
Gas turbine-CHP existing	32	46	979	0.66	64%	0.6	~25
Gas turbine-CHP new large	28[c]	61	971	0.53	75%		~45
Gas turbine-CHP small	25[c]	64	1470	1.10	75%	0.3	~8
Gas engine-CHP existing	41	49	550	0.74	46%	1.8	< 2
Gas engine-CHP new	41	49	578	0.68	46%		< 2

[a] Source of performance and cost data: (Hers et al., 2008b; Hers et al., 2008a), and for steam turbines (Energy Nexus Group, 2002).

[b] Source: (CBS, 2009)

[c] The electrical efficiency of the new gas turbines is lower than of the existing gas turbines, because the new ones include the possibility of supplemental firing of the heat recovery unit (Hers et al., 2008b). Thus, the gas turbine can be sized to meet the base load demand while the load swings upward can be met by supplemental firing of the heat recovery unit (Boyce, 2005)

Chapter 7
Summary and highlights

7.1 Introduction

Based on scientific assessments of dangerous anthropogenic interferences for different temperature increases (IPCC, 2001; IPCC, 2007; Climate congress, 2009; Smith et al., 2009), (inter)governmental bodies have set targets for a maximum increase of the mean global temperature. The European Union (EU) and the Conference of the Parties (COP), which is responsible for the international efforts to implement the United Nations Framework Convention on Climate Change (UNFCCC) (European Union, 2007; COP15, 2009), aim to keep global temperature increase below 2°C.[1] Achieving this target requires far reaching reduction of greenhouse gas (GHG) emissions in which CO_2 capture and storage (CCS) is expected to play an important role (IEA, 2008; IEA, 2009). CCS can be defined as the separation of CO_2 from industrial and energy-related sources, transport of the CO_2 to a (underground) storage location and long-term isolation of the CO_2 from the atmosphere (IPCC, 2005).

If CCS is to play a significant role in a national portfolio of CO_2 emission reduction measures, in-depth knowledge is needed on how, when, where, and to what extent, CCS can contribute cost-effectively to CO_2 emission reduction (IEA, 2004). Energy modelling is a key tool to get quantitative insights into these aspects. However, for that purpose new or improved modelling approaches are required, because CCS distinguishes itself from other CO_2 mitigation technologies (e.g. energy saving, solar power, wind power, and the use of biomass) with respect to the following combination of aspects:

- It consists of a chain of activities: CO_2 capture at a CO_2 emission source, transport of the CO_2 to a storage site, and storage of the CO_2 in the underground. Therefore, introduction of CCS requires several pre-conditions to be fulfilled at the same time.
- CCS is not yet applied on a commercial scale. Consequently, its cost development is quite uncertain.

[1] The EU explicitly compares the temperature of 2°C increase to pre-industrial levels. COP does not provide any explicit reference date. The difference between the temperature of pre-industrial levels and of the period 1990-2000 is around 0.6°C (IPCC, 2007).

- It needs a dedicated infrastructure to connect CO_2 sources and CO_2 sinks at the right place and time.
- CCS has a trans-boundary scope. For example, neighbouring countries may cooperate in developing a CO_2 infrastructure in order to achieve economies of scale.
- Unlike other CO_2 emission reduction measures, its sole purpose is the reduction of CO_2 emissions. As a consequence, to realise CCS at large scale, specific policy measures may be required.

Table 1 Research questions

	Content-related research questions	Modelling approach-related research questions	Chapters dealing with questions
I.	Could the key pre-conditions of CCS deployment be met at the same time (CO_2 capture and storage options available, CCS cost-effective, and transport infrastructure and climate policy in place)?	Can a bottom-up energy model integrate all relevant dynamic data regarding key pre-conditions for CCS deployment?	**2,** see also 3, 4, 5, and 6
II.	What could be the cost and performance developments of power plants with CCS?	Can the concept of experience curves be applied on cost as well as performance variables, incorporate learning spill-over effects, and be integrated with cumulative capacity projections to gain insights into the performance development of power plants with CCS?	**3**
III.	What could be the (optimal) design of large-scale CO_2 infrastructure taking into account location, and time-path of individual infrastructural elements?	Can a bottom-up energy model be integrated with a geographical information system (GIS) to model when and where it would be cost-effective to construct elements of a CO_2 infrastructure?	**4,** see also 5
IV.	How could the design of a Dutch CO_2 infrastructure take into account transboundary CO_2 flows, for example, to store CO_2 in a very large formation under the North Sea?	Can transboundary CO_2 flows be included in a national bottom-up energy model to generate knowledge on the development of a national CO_2 infrastructure?	**5**
V.	What could be the impact of different international climate policies on the implementation of CCS in a national energy system?	Can general equilibrium models of the world economy and national bottom-up energy models be combined to analyse the impact of international climate policies on national CCS deployment?	**6**

Objective

The overall aim of this thesis is three-fold. First to develop new and improved modelling approaches that can overcome the gaps in knowledge related to the five specific aspects described above (see also table 1). Secondly, to provide quantitative insights into timing, spatial issues, costs, and investments in CCS deployment trajectories, taking the Netherlands as a case study. Finally, to demonstrate the usefulness of the model approaches developed in this thesis to assess and design future deployment of CCS.

The specific gaps in knowledge are subdivided into 5 content-related and 5 modelling approach-related research questions as presented in Table 1.

This chapter continues with a brief summary of the thesis per chapter. It concludes with highlights of the thesis regarding the different content- and modelling approach related questions, and suggestions for further research.

7.2 Summary per chapter

Chapter 2 explores the dependence of large scale CCS deployment in the electricity sector on a number of issues: climate policy development, CCS technology development, competitiveness of CCS versus other mitigation options, demand for new power plants on which CCS can be implemented, and availability of CO_2 transport facilities and sinks. We carried out a quantitative scenario study for the electricity sector in the Netherlands using a bottom-up, dynamic, linear optimisation model, generated by MARKAL and called MARKAL-NL-UU. In this model, we integrated dynamic data on the electricity demand development, the developments of costs and performance of various technologies (power generation technologies with and without CO_2 capture, CO_2 transport pipelines, and CO_2 storage facilities), the vintage structure of the power generation sector, the availability of CO_2 storage potential over time, and climate policy reduction targets. On the basis of cost minimisation and the expectations about electricity generation costs of different technologies, this model provided configurations of the Dutch electricity park for the period 2000 to 2050. We analysed strategies to realise a 15% and 50% reduction of CO_2 emissions for power generation in the Netherlands in, respectively, 2020 and 2050, compared to the 1990 level. Furthermore, we assumed that nuclear power is phased out, growth of decentral cogeneration units is limited (i.e. it may grow from 5.4 GW in 2005 to 8.7 GW in 2050), onshore wind energy is limited to around 2 GW, and electricity demand grows from 110 TWh in 2005 to 175 TWh in 2050. In this scenario, we found that CCS may avoid 29 Mt per year in

2020 in the Dutch electricity sector (which is half of the CO_2 reduction in that year). The results of a sensitivity analysis show among others that if nuclear power is allowed, there would probably be hardly any CCS before 2030, and if CO_2 storage is only possible abroad, or CCS development is delayed by 10 years, CCS deployment may be reduced by one third before 2030. With respect to planning, the findings highlight among others the following factors. First, if CO_2 needs to be reduced by 15% in the power generation sector by 2020 compared to the 1990 level, coal-fired power plants without CCS are preferably not built or only to a limited extent. In the model runs, only 3-8% of the electricity comes from coal-fired power plants without CCS in 2020. Secondly, early planning is required to realise the construction of a CO_2 transport infrastructure before 2020. Finally, assuming that around 3 Gt of the Dutch CO_2 storage potential identified can actually be used for CO_2 storage, the individual sinks become available in time for the storage of CO_2 from the Dutch electricity sector. However, already by 2040 most onshore sinks may have been filled with CO_2 and a switch to the offshore fields (in which it is more expensive to store CO_2) is required to accommodate further storage after 2040.

Chapter 3 applies the experience curve approach to investigate potential developments in performance as well as cost variables of power plants with CO_2 capture. We first identified progress ratios for the development of the energy loss. The progress ratio for PCs was based on the development of the world wide capacity of subcritical and supercritical units resulting in 1240 GW of cumulative capacity in 2007. The progress ratio turned out to be 98% implying a 2% decrease in energy loss per doubling of installed PC capacity. For NGCCs with a cumulative capacity of 389 GW in 2004, we found a progress ratio for the energy loss in NGCCs of 95%. For IGCCs, the current installed capacity (~1.5 GW) was not sufficient to identify specific learning trends. A model developed at Carnegie Mellon University provides insights into the impact of technological learning on cost variables in power plants with CO_2 capture. We extended the model with experience curves for several key performance variables, namely the overall energy loss in power plants, the energy required for CO_2 capture, the CO_2 capture ratio (removal efficiency), and the power plant availability. Next, the learning rates for both performance and cost parameters were combined with global capacity projections for fossil-fired power plants. This resulted in cost and performance projections of power plants with and without CO_2 capture over time that can be used for other purposes such as a national or regional evaluation of CO_2 emission mitigation strategies. The study results show that IGCC power plants with CO_2 capture have the largest learning potential compared to PC and NGCC power plants. Significant improvements in efficiency (from 33% to 46%) and reductions in investment cost (from 1800 to 1000 €/kW) between 2001 and 2050 may be realised under the condition that in this period capacities of

around 3100 GWe[2] of combined cycle power blocks and around 1000 GWe[2] of gasifiers are installed worldwide. Furthermore, in a scenario with a relatively strict climate policy[3], CO_2 capture costs in 2030 are calculated at 26, 11, 19 €/t CO_2 for NGCC, IGCC, and PC power plants with CO_2 capture, respectively, compared to 42, 13, and 32 €/t CO_2 in a scenario with a moderate climate policy[4].

In *chapter 4,* a spatially explicit toolbox that is able to support planning and design of an infrastructure for large scale deployment of CCS, is presented. To investigate both temporal and spatial aspects, this toolbox integrates ArcGIS, a geographical information system with spatial and routing functions, and MARKAL-NL-UU, the bottom-up energy model of the Dutch electricity sector extended with the CO_2 intensive industry. Application of this toolbox led to spatially explicit blueprints of an infrastructure for transport and storage of CO_2 in the underground (onshore and/or offshore) in the Netherlands in the period 2010-2050. The results show that in a scenario with a 20% and 50% CO_2 emission reduction targets in the power generation sector and CO_2 intensive industry compared to 1990 level in respectively 2020 and 2050, an infrastructure of around 600 km of CO_2 trunklines may need to be built before 2020. In this phase, investment costs of pipeline construction and storage site development can amount to around 720 m€ and 340 m€, respectively. Results also show that the policy choice to allow the storage of CO_2 onshore or not, is of major importance for the design of the infrastructure. If allowed, it seems worthwhile to already invest before 2020 in a trunkline from the Rijnmond region to North East of the Netherlands (for around 350 million €) or, otherwise, to the North Sea (for around 330 million €). In the first case average costs to transport and store CO_2 are around 4 €/tCO_2 while in the second case costs are around 8 €/tCO_2.

Chapter 5 focuses on the feasibility of a CO_2 trunkline from the Netherlands to the Utsira formation in the Norwegian part of the North Sea, which is a potential large geological storage reservoir for CO_2. The feasibility of this trunkline was investigated in competition with CO_2 storage in onshore and near-offshore sinks in the Netherlands. Least-cost modelling with a MARKAL model in combination with ArcGIS was used to assess the cost-effectiveness of the trunkline. The results show that CO_2 emissions in the electricity sector and CO_2 intensive industry could reduce with 67% in 2050 compared to 1990 under the condition that a CO_2 permit price increases from €25 per tCO_2 in 2010 to €60 per tCO_2 in 2030 and remains

[2] In GWe of the power plants with the component
[3] A climate policy aiming at long-term stabilisation of CO_2 concentration in the atmosphere to 500 ppm by 2050. CO_2 tax increases from 10 €/tCO_2 in 2010 to 200 €/tCO_2 in 2050.
[4] Under this policy CO_2 tax increases from 5-10 €/tCO_2 in 2010 to 30 €/tCO_2 in 2050 for Annex B countries and to 15 €/tCO_2 for non-Annex B countries.

at this level up to 2050. The analysis also shows that an investment in the Utsira trunkline may be cost-effective from 2020-2030 provided that German CO_2 is transported and stored via the Netherlands which achieves necessary economies of scale. In this case, by 2050 more than 2.1 GtCO2 would have been transported by the trunkline. However, if the Utsira trunkline is not used for transportation of CO_2 from Germany, it may become cost-effective 10 years later, and less than 1.3 $GtCO_2$ from the Netherlands would have been stored in the Utsira formation by 2050. On the short term, CO_2 storage in Dutch fields appears more cost-effective than in the Utsira formation.

In *chapter 6,* it is investigated whether a greenhouse gas emission trading system leads to a sufficient high CO_2 price and stable investment environment for CCS deployment. For this purpose, we combined WorldScan, a general equilibrium model for global policy analysis applied at the Netherlands Bureau for Economic Policy Analysis (CPB), and MARKAL-NL-UU. WorldScan results show that in 2020, CO_2 prices may vary between 0 €/t CO_2 in a BASELINE scenario without any climate policy, to 20 €/t CO_2 in a GRAND COALITION scenario, in which all countries accept greenhouse gas targets from 2020, and 47 € per t CO_2 in an IMPASSE scenario, in which EU-27 continues its one-sided emission trading system without the possibility to use the Clean Development Mechanism (CDM). Only in the GRAND COALITION scenario CO_2 emissions are reduced significantly resulting in a worldwide cumulative amount of around 1000 Gt CO_2 from energy fuel combustion alone in the period 2009-2050 (compared to 1800 $GtCO_2$ in the BASELINE). In the GRAND COALITION scenario, 2 Mt CO_2 per year is stored in the Netherlands in 2020, while in the IMPASSE scenario without CDM, this was 26 Mt CO_2 per year (around 20 Mt CO_2 avoided). Electricity costs range between 56 and 71 €/MWh in 2020 with the lowest costs in the BASELINE and highest in the IMPASSE scenario without CDM. If the development of the CO_2 price in the IMPASSE scenario is uncertain after 2020, the analysis points out that CO_2 storage is limited to 4 instead of 26 Mt CO_2 in this year. The results also shows that the rate at which CCS technologies develop is important for the deployment of CCS (i.e. 0.4 Gt CO_2 less may be stored over the period 2009-2050 if CCS development is slowed down with 10 years), but less crucial than the development of the CO_2 price. Another outcome of the analysis was that the combination of biomass (co-firing) with CCS could become an important option to realise deep CO_2 emission reductions (e.g. in 2040, this option may avoid around 30 Mt CO_2 per year).

7.3 Highlights

7.3.1 Content-related questions

Based on the results in chapters 2-6, we describe highlights with respect to the five content-related questions formulated at the start of the thesis.

I. Could the key pre-conditions of CCS deployment be met at the same time (CO_2 capture and storage options available, CCS cost-effective, and transport infrastructure and climate policy in place)? Under a strict climate policy aiming at significant CO_2 emission reduction in the Netherlands in the short term (e.g. more than 15% emission reduction in the Dutch power generation sector in 2020 compared to 1990 level), capture and storage (onshore as well as offshore) options are available in time to avoid at least 20 Mt CO_2 per year in 2020, while CCS costs may stay below 50 €/tCO_2 and electricity costs may be around 70 €/MWh. Furthermore, to transport and store the CO_2, an investment in pipelines and storage facilities of at least 0.8 billion is needed[5]. Of the five pre-conditions, it seems to be most uncertain that a strict climate policy is met (see below).

Furthermore, with respect to timing the following aspects are noteworthy:

Scenario assumptions with a slower CCS development (a postponement of 10 years) showed only an avoidance of 4 Mt CO_2 by CCS in 2020.

Under a strict climate policy (as described above), our model results show that coal-fired power plants (including the ones constructed in the period 2010-2015) hardly generate electricity without CO_2 capture in 2020.

Although enough CO_2 storage capacity is in principle available in time in the short term, timing may become an issue for the offshore fields which can only re-use platforms and wells if CO_2 storage starts soon after the gas production activities cease. Our results show that without re-use the offshore fields are most probably too expensive (around 13 instead of 6 €/t CO_2) to be used for CO_2 storage.

II. What could be the cost and performance development of power plants with CCS? Learning-by-doing can have a big impact on integrated coal gasification combined cycle power plants with pre-combustion CO_2 capture due to its current low level of maturity. This is

[5] Of course, the results are based on scenario assumptions of among others developments of energy prices, and investments of power generation technologies (with and without CCS).

demonstrated in this thesis for both a moderate and a relatively strict climate policy. In both scenarios the costs of electricity of IGCC-CCS decrease by ~40% between 2001 and 2050, while these costs of NGCC-CCS and PC-CCS only decrease by 22-31%. Furthermore, the energy efficiency of IGCC-CCS increases by ~38% in this period compared to ~23% for NGCC-CCs and ~18% for PC-CCS. The development of CO_2 emission reduction costs differs per scenario: in the scenario with the relatively strict climate policy (with 940 GW CCS capacity in 2030), CO_2 capture costs in 2030 are calculated at 26, 11, 19 €/t CO_2 for NGCC, IGCC, and PC power plants with CO_2 capture[6], respectively, compared to 42, 13, and 32 €/t CO_2 in the scenario with the moderate climate policy (with 50 GW CCS power plants in 2030).

III. What could be the (optimal) design of large-scale CO_2 infrastructure taking into account location, and time-path of individual infrastructural elements? CCS is a mitigation option that could expand rapidly under a strict climate policy from avoiding around 20 Mt/year in 2020 to 45-55 Mt/year in 2030 and 40-80 Mt/year in 2050. Such a rapid deployment requires the construction of key elements of a CO_2 network at an early stage, especially, a major trunkline from Rijnmond to a cluster of sinks elsewhere, either onshore or offshore.

If only a trunkline to the onshore storage sites in the Netherlands is chosen, 1 out of the 1.2[7] Gt CO_2 of onshore storage capacity may have been filled by 2040. By that time, the offshore capacity is not-cost effective for CO_2 storage (with storage costs of on average 13 €/t CO_2), because the platforms and wells at the offshore gas fields cannot be re-used anymore. The Netherlands would then largely become dependent on a large CO_2 storage reservoir like the Utsira formation. Without such a reservoir the role of CCS is restricted (for example, in one scenario CO_2 storage increases to around 60 Mt CO_2 stored per year in 2050, but in the same scenario without the Utsira formation of Norway, CO_2 storage remains below 40 Mt CO_2 per year up to 2050).

Finally, note that infrastructure design needs to take into account that for each 10 Mt CO_2 per year that is stored in the Netherlands, on average 8 fields have to be used simultaneously for CO_2 storage due to the limited storage potential of the individual fields (on average 26 MtCO_2 onshore, and 15 MtCO_2 offshore). The design also needs to allow for CO_2 storage activities to be shifted from one field to another, once they are filled within 5 to 25 years.

[6] Compared to their counterpart without CO_2 capture.
[7] In order to take into account that not all sinks may be suitable for CO_2 storage, the estimate of CO_2 storage capacity was already lowered from 1.6 to 1.2 GtCO_2 based on criteria with respect to seismicity, integrity of existing wells, faults, overburden, and seals.

IV. How could the design of a Dutch CO_2 infrastructure take into account transboundary CO_2 flows, for example, to store CO_2 in a very large formation under the North Sea? Results show that policy choices concerning CO_2 storage onshore in the Netherlands and joining forces with neighbouring countries to set up a CO_2 infrastructure, can play a key role on when a trunkline to Utsira may be built. If onshore CO_2 storage is allowed to be used for CO_2 storage, an 800 km pipeline to the Utsira formation in the Norwegian part of the North Sea (with an at present estimated total storage capacity of 42 $GtCO_2$) may be constructed around 2040 when storage capacity in the Dutch territory in which CO_2 can be stored against lower costs than in Utsira, is almost filled. A restriction on onshore storage in the Netherlands (transport to and storage in the onshore sinks amount to around 4 €/t CO_2) could make this pipeline already cost-effectiveness in 2030. Also, a trans-boundary effort to arrange joint transport of CO_2 from Dutch and German sources to the Utsira formation (assuming that Germany would pay 7.5 €/t CO_2), could make the construction of this pipeline possible in 2030.

V. What could be the impact of different international climate policies on the implementation of CCS in a national energy system? According to the results, a global GHG emission trading system aiming at 50% CO_2 reduction in 2050 does not generate a sufficient high and certain CO_2 price for large scale CCS deployment in the short term (e.g. avoiding more than 20 Mt CO_2 per year by CCS in the Netherlands). Obtained results indicate that this can happen with a guaranteed CO_2 price of at least 47 €/tCO_2 from 2020. However, such a high CO_2 price appears only feasible in an EU emission trading system without the option to use CDM, or a more ambitious global CO_2 reduction strategy in which global cumulative CO_2 emissions are limited to 700 $GtCO_2$ in the period 2009-2050. Both do not seem likely to happen in the short term. Therefore, if complementary policy like an obligation to add CCS to fossil fired power plants is not implemented, large scale CCS will only take place from 2030 instead of 2020. This implies that 10 years in the first half of the 21st century, the period in which CCS is especially meant to play a role are lost for substantial CO_2 reduction by CCS.

7.3.2 Modelling approach-related questions

With respect to the five modelling approach-related questions, we mention the following highlights.

I. Can a bottom-up energy model integrate dynamic data regarding key pre-conditions for CCS deployment? This thesis shows that a bottom-up energy model based on MARKAL is

suitable to integrate dynamic data of key pre-conditions with respect to climate policy, potential options of CO_2 capture in, for example, the power generation sector, the availability of sinks, and the construction of a CO_2 infrastructure. However, the analysis was not complete yet, because among others the need for CO_2 emission reduction in other sectors like the transport sector was not included. Furthermore, although the broad outlines of load demand patterns of the electricity and heat demand, and load supply patterns of the power generation technologies were taken into account, a more in-depth analysis of these patterns on hourly basis could provide insights into the flexibility of power generation by large scale CCS combined with intermittent renewable energy sources.

II. Can the concept of experience curves be applied on cost as well as performance variables, incorporate learning spill-over effects, and be integrated with cumulative capacity projections to gain insights into the performance development of power plants with CCS? The thesis shows that applying experience curves to performance as well as cost variables of power plants with CCS can give insights into potential improvements of investment cost, efficiency, CO_2 mitigation costs, and electricity costs. By combining the experience curves with cumulative capacity projections of power plants with and without CCS, figures for the performance of power plants with CCS over time were obtained. The experience curves were determined at component level of the power plants (e.g. combined cycle power block, CO_2 post-combustion capture unit). Therefore, it could be taken into account that the improvements of the components depend on the total cumulative capacity growth of several types of power plants (with and without CCS) together. In this thesis, it was assumed that learning takes place at a global level as power plants are usually built by large multinationals. Because a large fraction of the projected capacities is estimated to be built in rising economies like China and India, it needs to be assessed to what extent they will build state-of-the-art power plants and, in this way, actually contribute to technology development. Furthermore, it needs to be assessed how learning processes related to individual technology components of power plants influence each other. Further, analysis should indicate to what extent the method to treat components as individual learning units instead of a compound learning system is legitimate.

III. Can a bottom-up energy model be adapted to model when and where it would be cost-effective to construct elements of a CO_2 infrastructure? A toolbox based on ArcGIS and a MARKAL-based model can provide insights into the development of a CCS infrastructure in a specific region. We were able to match multiple sources to multiple sinks with respect to costs, availability, and location as a function of time. In contrast to other studies, this toolbox

provided relevant outcomes with respect to the development of a CO_2 infrastructure at the level of specific CO_2 infrastructural elements (e.g. a pipeline, a gas field) which are both spatially and temporally explicit. It resulted, among others, in maps of the CO_2 infrastructure with pipeline trajectories, and the deployment of individual storage sites over time. The toolbox also demonstrated possible impact of policy choices on the design of a CCS infrastructure. Nevertheless, the developed modelling approach can still be refined. For example, as basis for the development of the CO_2 network, a hub-spoke form was used which posed limitations to the structure of the network. Furthermore, more detailed data on the CO_2 storage potential based on local studies of individual sites would improve the outcomes. Finally, taking into account the option to transport CO_2 per ship and the periods needed for legal procedures could better support planning of the development of a CO_2 infrastructure.

IV. Can transboundary CO_2 flows be included in a national bottom-up energy model to generate knowledge on the development of a national CO_2 infrastructure? The ArcGIS/MARKAL tool is able to investigate how and when CO_2 flows from neighbouring countries can be transported and stored via a Dutch CO_2 infrastructure to Dutch sinks or to a reservoir abroad. However, in this thesis national strategies of the neighbouring countries (i.e. Belgium and Germany) to develop a CO_2 infrastructure were not taken into account. Also the possibility to transport and store CO_2 via Germany was excluded.

V. Can general equilibrium models of the world economy and national bottom-up energy models be combined to analyse the impact of international climate policies on national CCS deployment? Based on our findings, we conclude that the combination of a national energy bottom-up model based on MARKAL, and a global applied general equilibrium model can be used to assess the impact of international climate policies on CCS deployment at a national level. The modelling of global energy and CO_2 markets by WorldScan provides projections of energy demand, CO_2 prices, and fuel prices for different international climate policies. Given this context, the CCS deployment at a national level can be further analysed with a bottom-up energy model. Modelling deep CO_2 emission reduction scenarios, however, poses additional requirements to the models. More mitigation options need to be included in order not to underestimate the potential to reduce CO_2 emissions or overestimate the mitigation costs. Furthermore, the introduction of more bottom-up information on technologies including learning rates (e.g. CCS or biomass-based technologies) into WorldScan could give more insights into the impact on energy demand, and energy prices of different portfolio's to mitigate CO_2 emissions.

7.3.3 Further research

Finally, in this thesis a number of topics were highlighted that need to be investigated further:

- To assess the need for CO_2 storage capacity and infrastructure, CCS options that can be applied in other sectors should be investigated in addition to the power sector and the CO_2 intensive industry. In particular, CCS could be applied in fuel production for the transport sector.
- For the same reason further insight is required into the technology and costs of CO_2 capture options that can be applied at smaller installations (e.g. cogeneration units or boilers).
- Because the combination of CCS with biomass turned out to be an important option allowing negative CO_2 emissions, the costs and performance of this option needs to be investigated in detail.
- To plan a CO_2 infrastructure, it is crucial to have more knowledge on CO_2 storage potentials in individual gas fields and aquifers. Further research is needed that link realistic and site specific storage potentials and availability to the supply of CO_2 over time.
- In order to create synergies between different (North West European) countries in the development of a CO_2 infrastructure, the scope of the study with a toolbox like the ArcGIS/MARKAL toolbox can be expanded from the Netherlands to several neighbouring countries. Furthermore, it could be applied in other similar regions in the world.
- The ArcGIS/MARKAL toolbox could be adapted to deal with necessary periods for legal procedures, transport of CO_2 by ships, and the inclusion of capture at smaller scale CO_2 sources.
- Because ultimately CCS is limited by the potential to store CO_2, a high penetration of e.g. renewable energy is indispensable for far reaching CO_2 emission reduction. Therefore, it needs to be investigated in detail how power plants with CCS and intermittent renewable energy sources can maintain a secure, flexible, and reliable electricity supply.

7.4 References

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Hoofdstuk 8

Samenvatting en highlights

8.1 Inleiding

Wetenschappelijke studies over mogelijke gevaren van – door mensen veroorzaakte – temperatuursstijging (IPCC, 2001; IPCC, 2007a; Klimaat congres, 2009; Smith et al., 2009), hebben ervoor gezorgd dat nationale en internationale overheidsinstanties de verhoging van de mondiale temperatuur willen beperken. Onder andere heeft de Conferentie van Partijen (COP) die verantwoordelijk is voor de uitvoering van het VN klimaatverdrag (United Nations Framework Convention on Climate Change), en de Europese Unie (EU) zich ten doel gesteld om de wereldwijde temperatuur met niet meer dan 2°C te laten stijgen[1] (Europese Unie, 2007; COP15, 2009). Om deze doelstelling te halen moet de uitstoot van broeikasgassen sterk verminderd worden. Hierbij kan CO_2-afvangst en opslag (CCS) naar verwachting een belangrijke rol spelen. CCS wordt gedefinieerd als de afscheiding van CO_2 uit industriële en energiegerelateerde puntbronnen, transport van CO_2 naar een (ondergrondse) opslaglocatie en tenslotte langdurige isolatie van de CO_2 uit de atmosfeer (IPCC 2005).

CCS kan een belangrijke rol spelen in een nationaal portfolio van CO_2 emissiereductie-maatregelen. Daarvoor is diepgaande kennis nodig over hoe, wanneer, waar en in welke mate, CCS kosteneffectief kan bijdragen aan het verlagen van de CO_2-emissies (IEA, 2004). Het gebruik van energiemodellen is daarbij een belangrijke methode om kwantitatief inzicht te krijgen. Er zijn daarvoor echter nieuwe of verbeterde modelleermethodes nodig, omdat CCS zich onderscheidt van andere CO_2-emisssiereductietechnologieën (bijv. energiebesparing, zonne-energie, windenergie, en het gebruik van biomassa) door de volgende combinatie van aspecten:

- CCS bestaat uit een keten van activiteiten: CO_2-afvangst bij een CO_2-puntbron, het transport van CO_2 naar een opslaglocatie, en opslag van de CO_2 in de ondergrond. Daarom is het voor de invoering van CCS vereist dat aan een aantal randvoorwaarden tegelijkertijd wordt voldaan.

[1] De EU bekijkt de verhoging van de temperatuur met 2°C ten opzichte van het pre-industriële niveau. COP noemt geen expliciete referentiedatum. Het verschil tussen de temperatuur van het pre-industriële niveau en van de periode 1990-2000 is ongeveer 0,6°C (IPCC, 2007a).

- CCS is nog niet toegepast op commerciële schaal. Daarom is kostenontwikkeling vrij onzeker.
- Er is een speciale infrastructuur nodig die CO_2-puntbronnen en opslaglocaties met elkaar verbindt op het juiste moment en op de meest daarvoor in aanmerking komende plaats.
- CCS heeft een grensoverschrijdend karakter. Buurlanden kunnen bijvoorbeeld samenwerken om schaalvoordelen te bereiken bij de ontwikkeling van een CO_2-infrastructuur.
- In tegenstelling tot andere CO_2-emissiereductiemaatregelen, is het enige doel van CCS het verminderen van de CO_2-uitstoot. Daarom kunnen specifieke beleidsmaatregelen nodig zijn om CCS op grote schaal te realiseren.

Tabel 1 Onderzoeksvragen

	Inhouds-gerelateerde onderzoeksvragen	**Modelleermethode-gerelateerde onderzoeksvragen**	**Hoofdstukken die ingaan op de vragen**
I.	Kunnen de belangrijkste randvoorwaarden voor CCS tegelijkertijd plaatsvinden (CO_2-afvangst en opslag opties beschikbaar, CCS kosteneffectief, CO_2 transportinfrastructuur klaar, en een adequaat klimaatbeleid)?	Kan een bottom-up energiemodel alle relevante dynamische gegevens integreren betreffende de belangrijkste randvoorwaarden voor CCS?	**2,** zie ook 3, 4, 5 en 6
II.	Wat zijn de ontwikkelingen van kosten en prestaties van elektriciteitscentrales met CCS?	Kan het concept van leercurves worden toegepast op zowel kosten- als prestatie-variabelen, kan het spill-over effecten meenemen en kan het worden geïntegreerd met cumulatieve capaciteitprojecties om inzicht te verkrijgen in de ontwikkeling van elektriciteitscentrales met CCS?	**3**
III.	Wat is een (optimaal) ontwerp van een grootschalige CO_2-infrastructuur, rekening houdend met de locatie en het tijdspad van individuele infrastructurele elementen?	Kan een bottom-up energiemodel worden geïntegreerd met een geografisch informatiesysteem (GIS) om te kunnen modelleren waar en wanneer het kosteneffectief zou zijn om elementen van een CO_2-infrastructuur te bouwen?	**4,** zie ook 5
IV.	Hoe kan het ontwerp van een Nederlandse CO_2-infrastructuur rekening houden met grensoverschrijdende CO_2 stromen, bijvoorbeeld om CO_2 op te slaan in een zeer grote formatie onder de Noordzee?	Kunnen grensoverschrijdend CO_2-stromen worden meegenomen in een nationaal bottom-up energiemodel om kennis te vergaren over de ontwikkeling van een nationale CO_2-infrastructuur?	**5**
V.	Wat kan de impact zijn van verschillende vormen van internationaal klimaatbeleid op de toepassing van CCS in een nationaal energiesysteem?	Kunnen algemene evenwichtsmodellen van de mondiale economie en nationale bottom-up energiemodellen worden gecombineerd om de impact van internationaal klimaatbeleid op de nationale inzet van CCS te bepalen?	**6**

Doelstelling

Het algemene doel van dit proefschrift is drieledig. Ten eerste het ontwikkelen van nieuwe en verbeterde modelleermethodes om kennishiaten met betrekking tot de vijf bovengenoemde punten te dichten (zie ook tabel 1). Ten tweede, het verkrijgen van kwantitatieve inzichten in de timing, ruimtelijke aspecten, kosten en investeringen van CCS trajecten, waarbij Nederland als case studie wordt genomen. Tenslotte om het nut van de in dit proefschrift ontwikkelde modelleermethodes aan te tonen bij de evaluatie en het ontwerp van de toekomstige inzet van CCS.

De specifieke kennishiaten zijn onderverdeeld in 5 inhouds-gerelateerde en 5 modelleermethode-gerelateerde onderzoeksvragen zoals weergegeven in Tabel 1.

In de volgende paragrafen wordt per hoofdstuk eerst een korte samenvatting van dit proefschrift gegeven. Vervolgens wordt afgesloten met highlights uit het proefschrift als antwoord op de verschillende inhouds- en modelleermethode-gerelateerde onderzoeksvragen, en met suggesties voor verder onderzoek.

8.2 Samenvatting per hoofdstuk

Hoofdstuk 2 verkent op welke wijze grootschalige CCS in de elektriciteitssector afhankelijk is van de volgende punten: ontwikkeling van klimaatbeleid, technologie-ontwikkeling van CCS, concurrentievermogen van CCS ten opzichte van andere CO_2-emissiereductietechnologieën, de vraag naar nieuwe centrales waarop CCS kan worden toegepast, en de beschikbaarheid van CO_2-transportpijpleidingen en opslagvelden. We hebben de Nederlandse elektriciteitssector geanalyseerd door middel van kwantitatief scenario-onderzoek. Hiervoor hebben we een bottom-up, dynamische, lineair optimalisatie model gebruikt, dat gegenereerd is met MARKAL en we MARKAL-NL-UU noemen. In dit model integreerden we dynamische gegevens van de elektriciteitsvraag, de kosten en prestaties van de verschillende technologieën (d.w.z. elektriciteitsopwekkingstechnologieën met en zonder CO_2 afvangst, CO_2 transportpijpleidingen en opslagfaciliteiten), de huidige structuur van de elektriciteitssector, de leeftijd van de centrales, de beschikbaarheid van het CO_2-opslag potentieel door de tijd, en emissiereductiedoelstellingen. Op basis van kostenminimalisatie en gebruik makend van kostenverwachtingen voor verschillende elektriciteitsopwekkingstechnologieën, berekende het model configuraties van het Nederlandse elektriciteitspark voor de periode 2000 tot 2050. We analyseerden strategieën om de CO_2-uitstoot in 2020 met 15% te verminderen ten opzichte van het niveau in de Nederlandse elektriciteitssector in 1990 en met 50% in 2050. Bovendien zijn we ervan uitgegaan dat kernenergie wordt afgebouwd, de groei van decentrale WKK-eenheden beperkt plaats vindt (d.w.z. het kan groeien van 5,4 GW in 2005 tot 8.7 GW in 2050), windenergie op land maximaal 2 GW kan zijn, en de elektriciteitsvraag toeneemt van

110 TWh in 2005 tot 175 TWh in 2050. In dit scenario vinden we dat CCS in 2020 ongeveer 29 Mt CO_2 kan vermijden in de Nederlandse elektriciteitssector (de helft van de gerealiseerde CO_2-reductie in dat jaar). Een gevoeligheidsanalyse laat onder andere zien dat als kernenergie is toegestaan, er waarschijnlijk nauwelijks CCS voor 2030 wordt gebouwd. Ook wordt gevonden dat als CO_2-opslag alleen mogelijk is in het buitenland, of de ontwikkeling van CCS-technologie met 10 jaar wordt vertraagd, de CCS-inzet met één derde verminderd zou worden in deze period. Op basis van onze bevindingen, benadrukken we de volgende factoren ten aanzien van de planning. Ten eerste, als de uitstoot van CO_2 in de elektriciteitssector in 2020 met 15% ten opzichte van 1990 moet worden verminderd, worden poederkoolcentrales (PC) zonder CCS bij voorkeur niet gebouwd of slechts in beperkte mate: In het model is in 2020 slechts 3-8% van de elektriciteit afkomstig van deze centrales. Ten tweede is vroegtijdige planning nodig om voor 2020 over een CO_2-infrastructuur te kunnen beschikken. Tot slot, als we ervan uitgaan dat ongeveer 3 Gt CO_2 van het geschatte Nederlandse CO_2-opslagpotentieel daadwerkelijk gebruikt kan worden voor CO_2-opslag, lijkt het dat de individuele velden op tijd beschikbaar komen voor opslag van CO_2 afkomstig van de Nederlandse elektriciteitssector. In 2040 kunnen de meeste velden op land reeds gevuld zijn met CO_2 waardoor een overstap naar velden op zee (waar het opslaan van CO_2 duurder is) nodig is om CO_2 op te kunnen slaan na 2040.

Hoofdstuk 3 past de leercurvebenadering toe om mogelijke ontwikkelingen in zowel prestatie- als kostenvariabelen van centrales met CO_2-afvangst te onderzoeken. We hebben eerst de "progress ratio's" (PR) voor de vermindering van energieverlies geïdentificeerd. Voor poederkoolcentrales (PC) was deze gebaseerd op de ontwikkeling van de mondiale capaciteit van subkritische en superkritische eenheden. In 2007 hebben deze een cumulatief geïnstalleerd vermogen van 1240 GW. De PR bleek 98% te zijn, wat betekent dat het energieverlies van PCs met 2% daalt bij elke verdubbeling van het geïnstalleerde PC vermogen. Voor aardgasgestookte centrales met stoom- en gasturbines (STEGs) en een cumulatieve capaciteit van 389 GW in 2004, vonden we een PR van 95%. Voor kolenvergassingscentrales met een stoom- en gasturbine (KV-STEG), is de huidige geïnstalleerde capaciteit (~ 1.5 GW) onvoldoende om specifieke leertrends te kunnen identificeren. Een model ontwikkeld aan de Carnegie Mellon universiteit geeft inzicht in de leertrends van kostenvariabelen in centrales met CO_2-afvangst. Dit model hebben we uitgebreid met leercurves voor een aantal belangrijke prestatievariabelen, namelijk het energieverlies in elektriciteitscentrales, de energie die nodig is voor de CO_2-afvangst, de CO_2-afvangstratio (ofwel verwijderingpercentage), en de beschikbaarheid van centrales. Vervolgens werden de leercurves voor zowel de prestatie- als de kostenvariabelen gecombineerd met prognoses van wereldwijde groei van fossiel gestookte centrales. Dit

resulteerde in kosten- en prestatie-projecties van centrales met en zonder CO_2-afvangst. Die projecties kunnen gebruikt worden voor andere doelen, zoals bijvoorbeeld het maken van een nationale of regionale evaluatie van CO_2-mitigatiestrategieën. Uit de studieresultaten blijkt dat KV-STEGs met CO_2-afvangst het grootste leerpotentieel hebben vergeleken met PCs en STEGs. Forse rendementsverbeteringen (van 33% tot 46%) en verlagingen van investeringskosten (van 1800 naar 1000 €/kW) zouden gerealiseerd kunnen worden in de periode 2001-2050 als in die periode wereldwijd ongeveer 3100 GWe[2] aan stoom- en gasturbine capaciteit en rond de 1000 GWe[2] aan vergassers wordt gebouwd. Verder werden de kosten van CO_2-afvangst in 2030 berekend op 26, 11, 19 €/t CO_2 voor, respectievelijk, STEGs, KV-STEGs, en PCs met CO_2-afvangst in een scenario met een relatief streng klimaatbeleid[3]. In een scenario met een gematigd klimaatbeleid[4] waren deze kosten 42, 13, en 32 €/ton CO_2.

Hoofdstuk 4 presenteert een toolbox dat de ruimtelijke planning en het ontwerp van een infrastructuur voor grootschalige CCS kan ondersteunen. Om zowel tijds- als ruimtelijke aspecten te onderzoeken, integreert deze toolbox ArcGIS, een geografisch informatiesysteem met ruimtelijke en routefuncties, en MARKAL-NL-UU, het bottom-up energiemodel van de Nederlandse elektriciteitssector uitgebreid met de CO_2 intensieve industrie. Toepassing van deze toolbox leidde tot ruimtelijke blauwdrukken voor een infrastructuur voor transport en opslag van CO_2 in de ondergrond (op land en/of op zee) in Nederland in de periode 2010-2050. De resultaten tonen aan dat in een scenario met 20% en 50% CO_2-emisssiereductiedoelstellingen ten opzichte van 1990 in respectievelijk 2020 en 2050 in de elektriciteitssector en de CO_2-intensieve industrie, het nodig kan zijn om een infrastructuur van ongeveer 600 km CO_2 pijpleidingen aan te leggen voor het jaar 2020. In deze fase kunnen de investeringen voor de aanleg van pijpleidingen en de ontwikkeling van opslagfaciliteiten respectievelijk neerkomen op rond de 720 en 340 miljoen €. De resultaten tonen ook aan dat de beleidskeuze ten aanzien van het toestaan van CO_2-opslag op land van groot belang is voor het ontwerp van de infrastructuur. Indien toegestaan, lijkt het zinvol om al voor 2020 te investeren in een pijpleiding van de regio Rijnmond naar het Noord-Oosten van Nederland (voor ongeveer 350 miljoen €), of anders naar de Noordzee (voor ongeveer 330 miljoen €). In het eerste geval zijn de gemiddelde kosten voor transport en opslag van CO_2 rond de 4 €/t CO_2 tegenover 8 €/t CO_2 in het tweede geval.

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[2] In GWe van de elektriciteitscentrales met desbetreffende technologie.
[3] Een klimaatbeleid die lange termijn stabilisatie van de CO_2 concentratie op 500 ppm in 2050 beoogt. CO_2 belasting neemt toe van 10 €/tCO_2 in 2010 tot 200 €/tCO_2 in 2050.
[4] Met dit beleid neemt de CO_2 belasting toe van 5-10 €/tCO_2 in 2010 tot 30 €/tCO_2 in de Annex B landen en 15 €/tCO_2 in de non-Annex B landen in 2050.

Hoofdstuk 5 onderzoekt of het economisch haalbaar is om een CO_2-pijpleiding vanuit Nederland naar de Utsira formatie aan te leggen. De Utsira formatie is een groot CO_2-opslag reservoir in het Noorse deel van de Noordzee dat mogelijk voor CO_2 uit Nederland toegankelijk is . De haalbaarheid van deze pijpleiding is onderzocht in concurrentie met CO_2-opslag in velden op land en op zee in Nederland. Kostenoptimalisatie door middel van een MARKAL model in combinatie met ArcGIS werd gebruikt voor de beoordeling van de kosten van de pijpleidingen. De resultaten tonen aan dat de CO_2-uitstoot in de elektriciteitssector en de CO_2 intensieve industrie kunnen verminderen met 67% in 2050 ten opzichte van 1990 onder de voorwaarde dat de CO_2-prijs stijgt van €25/t CO_2 in 2010 naar €60 /t CO_2 in 2030, en op dit niveau blijft tot 2050. De analyse toont ook aan dat een investering in een pijpleiding naar Utsira kosteneffectief kan zijn van 2020-2030 op voorwaarde dat Duitse CO_2 wordt getransporteerd en opgeslagen via Nederland omdat dit schaalvoordelen biedt. In dit geval zou in 2050 meer dan 2,1 Gt CO_2 zijn vervoerd door de pijpleiding. Maar als de Utsira pijpleiding niet wordt gebruikt voor het transport van CO_2 uit Duitsland, dan is het pas 10 jaar later kosteneffectief, en wordt minder dan 1,3 Gt CO_2 uit Nederland in de Utsira formatie opgeslagen tot 2050. Op de korte termijn lijkt CO_2-opslag in de Nederlandse velden meer kosteneffectief dan in de Utsira formatie.

In *hoofdstuk 6 wordt* onderzocht of een handelssysteem voor broeikasgasemissierechten tot een voldoende hoge CO_2-prijs en een stabiel investeringsklimaat voor CCS leidt. Voor dit doel, hebben wij WorldScan, een algemeen evenwichtsmodel voor mondiale beleidsanalyse dat toegepast wordt bij het Centraal Plan Bureau, en MARKAL-NL-UU gecombineerd. WorldScan resultaten laten zien dat in 2020 de CO_2 prijzen kunnen variëren tussen 0 €/t CO_2 in een BASELINE scenario zonder klimaatbeleid, tot 20 €/t CO_2 in een GRAND COALITION scenario waarin alle landen broeikasgasemissie-reductiedoelstellingen accepteren vanaf 2020, en 47 €/t CO_2 in een IMPASSE scenario waarin de EU-27 doorgaat met een éénzijdig emissiehandelssysteem zonder de mogelijkheid om het Clean Development Mechanism (CDM) te gebruiken. Alleen in het GRAND COALITION scenario wordt de CO_2-uitstoot aanzienlijk verminderd hoewel dit nog steeds resulteert in een wereldwijde cumulatieve uitstoot van ongeveer 1000 Gt CO_2 door de verbranding van fossiele brandstoffen in de periode 2009-2050 (in vergelijking tot 1800 Gt CO_2 in het BASELINE scenario). In het GRAND COALITION scenario wordt 2 Mt CO_2 per jaar opgeslagen in Nederland in 2020, terwijl dat in het IMPASSE scenario zonder CDM 26 Mt CO_2 per jaar (ongeveer 20 Mt vermeden CO_2) is. Elektriciteitsproductie-kosten variëren tussen 56 en 71 €/MWh in 2020 met de laagste kosten in de BASELINE en de hoogste in het IMPASSE scenario zonder CDM. Als het verloop van de CO_2-prijs in het IMPASSE scenario na 2020 onzeker is, wijst de analyse uit dat CO_2-

opslag beperkt wordt tot 4 Mt CO_2 in plaats van 26 Mt CO_2 in dit jaar. De studie toont ook aan dat de snelheid waarmee CCS-technologieën zich ontwikkelen belangrijk is voor de mogelijke inzet van CCS (er zou 0,4 Gt CO_2 minder opgeslagen worden in de periode 2009-2050 als CCS-ontwikkeling wordt vertraagd met 10 jaar), maar minder belangrijk dan de ontwikkeling van de CO_2-prijs. Een ander resultaat van de analyse is dat de combinatie van biomassa (-bijstook) met CCS een belangrijke optie zou kunnen worden om een vergaande CO_2-emissiereductie te realiseren (in 2040 kan deze optie bijvoorbeeld rond de 30 Mt CO_2 per jaar aan uitstoot vermijden).

8.3 Highlights

8.3.1 Inhouds-gerelateerde vragen

Op basis van de resultaten in de hoofdstukken 2-6, beschrijven we hieronder de highlights met betrekking tot de vijf inhouds-gerelateerde onderzoeksvragen die aan het begin van het proefschrift zijn geformuleerd.

I. Kunnen de belangrijkste randvoorwaarden voor CCS tegelijkertijd plaatsvinden (CO_2-afvangst en opslag opties beschikbaar, CCS kosteneffectief, CO_2 transportinfrastructuur klaar, en een adquaat klimaatbeleid)?

Onder een streng klimaatbeleid gericht op een significante CO_2-uitstoot vermindering in Nederland op de korte termijn (bijvoorbeeld meer dan 15% emissiereductie in de Nederlandse elektriciteitssector in 2020 vergeleken met het niveau van 1990), zijn afvangst- en opslagopties (zowel op land als op zee) op tijd beschikbaar om minstens 20 Mt CO_2 per jaar te vermijden in 2020, terwijl de CCS-kosten beneden de 50 €/t CO_2 zouden kunnen blijven en de elektriciteitskosten rond de 70 €/MWh. Bovendien zijn er investeringen in pijpleidingen en opslagfaciliteiten nodig van ten minste 0,8 miljard € om CO_2 te transporteren en op te slaan.[5] Van de vijf randvoorwaarden lijkt de realisatie van een voldoende streng klimaatbeleid het meest onzeker (zie hieronder).

Met betrekking tot timing zijn de volgende aspecten ook van belang:

Onder de aanname van een trage CCS-ontwikkeling (vertraagd met 10 jaar) werd in onze scenarioanalyses slechts 4 Mt CO_2 door CCS vermeden in 2020.

[5] Natuurlijk zijn de resultaten gebaseerd op scenario-aannames van onder andere ontwikkelingen van energieprijzen en investeringskosten van elektriciteitsopwekkings-technologieën (met en zonder CCS).

Onder een streng klimaatbeleid (zoals hierboven beschreven), laten onze modelresultaten zien dat kolengestookte elektriciteitscentrales (met inbegrip van diegene die gebouwd worden tussen 2010 en 2015) nauwelijks elektriciteit produceren zonder CO_2-afvangst in 2020.

Hoewel in principe voldoende CO_2-opslagcapaciteit beschikbaar is op de korte termijn, kan timing een probleem worden voor de velden op zee waar bestaande platforms en putten alleen maar kunnen worden hergebruikt als er met CO_2-opslag begonnen wordt direct nadat de gasproductie is gestopt. Onze resultaten laten zien dat zonder hergebruik de velden op zee zeer waarschijnlijk te duur zijn (opslagkosten zijn ongeveer 13 in plaats van 6 €/t CO_2) om voor CO_2-opslag te gebruiken.

II. Wat zijn de ontwikkelingen van kosten en prestaties van elektriciteitscentrales met CCS?

"Learning-by-doing" kan een groot effect hebben op de kosten van KV-STEGs met pre-combustion CO_2-afvangst vanwege hun huidige lage niveau van volwassenheid. Dit wordt in dit proefschrift gedemonstreerd aan de hand van een mondiale energiescenario met een gematigd klimaatbeleid en één met een relatief streng klimaatbeleid. In beide scenario's verminderen de elektriciteitskosten bij KV-STEGs met CCS met ongeveer 40% tussen 2001 en 2050, terwijl dit voor aardgasgestookte STEGs en PCs met CCS tussen de 22-31% ligt. Bovendien kan in deze periode het elektrisch rendement van de KV-STEGs met CCS met ongeveer 38% stijgen, met ongeveer 23% voor STEGs met CCS en 18% voor PCs met CCS. De mate waarin CO_2-emissiereductiekosten verminderen verschilt per scenario: in het scenario met een relatief streng klimaatbeleid (met 940 GW CCS capaciteit in 2030), worden de CO_2-afvangstkosten[6] in 2030 berekend op 26, 11, 19 € per t CO_2 voor respectievelijk STEGs, KV-STEGs en PCs met CO_2-afvangst, vergeleken met 42, 13, en 32 €/t CO_2 in het scenario met een gematigd klimaat beleid (met 50 GW CCS capaciteit in 2030).

III. Wat is een (optimaal) ontwerp van grootschalige CO_2-infrastructuur rekening houdend met de locatie en het tijdspad van individuele infrastructurele elementen?

CCS is een CO_2 reductiemaatregel die zich snel zou kunnen ontwikkelen onder een streng klimaatbeleid. Daarmee kan in Nederland een hoeveelheid CO_2-uitstoot worden vermeden van ongeveer 20 Mt CO_2 per jaar in 2020, tot 45-55 Mt CO_2 per jaar in 2030, en 40-80 Mt CO_2 per jaar in 2050. Om zo'n snelle groei te kunnen realiseren is het nodig om in Nederland kernelementen van een CO_2-netwerk in een vroeg stadium te bouwen, zoals met name een

[6] In vergelijking met hun tegenhanger zonder CO_2-afvangst.

grote CO_2 pijpleiding van het Rijnmond gebied naar een cluster van velden elders, ofwel op land ofwel op zee.

Als er alleen wordt gekozen voor een pijpleiding naar de opslagplaatsen op land in Nederland, zou 1 van de 1.2[7] Gt aan CO_2-opslagcapaciteit op land gevuld kunnen zijn voor 2040. Tegen die tijd is CO_2-opslag op zee niet meer rendabel (kosten bedragen daar gemiddeld 13 €/t CO_2) omdat de platforms en putten van de gasvelden op zee niet meer beschikbaar zijn. Nederland zou dan grotendeels afhankelijk worden van een groot CO_2-opslag reservoirs elders zoals de Utsira formatie waarover Noorwegen beschikt. Zonder een dergelijk reservoir wordt de rol van CCS beperkt. In een van onze scenario's neemt CO_2-opslag bijvoorbeeld toe tot ongeveer 60 Mt CO_2 per jaar in 2050, maar in hetzelfde scenario zonder de Utsira formatie optie blijft CO_2-opslag onder de 40 Mt CO_2 per jaar tot 2050.

Tenslotte kan worden opgemerkt dat er bij het ontwerp van de infrastructuur rekening gehouden moet worden met het feit dat voor elke 10 Mt CO_2 per jaar die in Nederland wordt opgeslagen, gemiddeld 8 velden gelijktijdig gebruikt moeten worden, omdat de opslagcapaciteit[8] en injectiesnelheid per individueel veld beperkt is. Bij het ontwerp moet er ook rekening mee gehouden worden dat als de velden gevuld zijn (binnen 5 tot 25 jaar) de CO_2-opslag-activiteiten van het ene veld naar het andere verschoven dienen te worden.

IV. Hoe kan het ontwerp van een Nederlandse CO_2-infrastructuur rekening houden met grensoverschrijdende CO_2 stromen, bijvoorbeeld, om CO_2 op te slaan in een zeer grote formatie onder de Noordzee?

De resultaten laten zien dat beleidskeuzes met betrekking tot de CO_2-opslag op land in Nederland en het mogelijk bundelen van inspanningen met buurlanden om een CO_2-infrastructuur aan te leggen, medebepalend zijn voor het tijdstip waarop een pijpleiding naar Utsira gebouwd kan worden. Als het in Nederland is toegestaan om CO_2 op land op te slaan, zou een 800 km lange pijpleiding naar de Utsira formatie in het Noorse deel van de Noordzee (met een nu ingeschat totale opslagcapaciteit van 42 Gt CO_2) rond 2040 gebouwd kunnen worden, omdat dan de opslagcapaciteit in Nederland, waar CO_2-opslag goedkoper is dan in de Utsira formatie, grotendeels gevuld is. Een restrictie op de opslag op land[9] in Nederland, kan deze pijpleiding al in 2030 kosteneffectief maken. Ook zou een

[7] Omdat niet alle velden geschikt zijn voor CO_2-opslag, was de raming van de CO_2-opslagscapaciteit al verlaagd van 1,6 tot naar 1,2 Gt CO_2 op basis van criteria met betrekking tot de seismiek, de integriteit van de bestaande putten, breuken, de bovenliggende lagen, en afdichtingen.

[8] In de database die voor dit proefschrift is gebruikt is de opslagcapaciteit op land gemiddeld 26 Mt CO_2 per veld en op zee gemiddeld 15 Mt CO_2.

[9] Kosten van transport naar en opslag in deze velden op land bedragen rond de 4 €/t CO_2.

grensoverschrijdende inspanning om bijvoorbeeld CO_2 van Nederland en Duitsland[10] gezamenlijk te vervoeren naar de Utsira formatie, de bouw van deze pijpleiding al in 2030 mogelijk kunnen maken.

V. Wat kan de impact zijn van verschillende vormen van internationaal klimaatbeleid op de toepassing van CCS in een nationaal energiesysteem?

Volgens de studieresultaten zorgt een wereldwijd handelssysteem van broeikasgasemissierechten met het doel om 50% CO_2-reductie in 2050 te behalen niet voor een voldoend hoge en stabiele CO_2-prijs om grootschalige CCS op de korte termijn te realiseren (bv. het vermijden van meer dan 20 Mt CO_2 uitstoot per jaar door CCS in Nederland). Verkregen resultaten geven aan dat dit wel zou kunnen gebeuren met een gegarandeerde CO_2-prijs van minstens 47 €/t CO_2 vanaf 2020. Een dergelijke hoge CO_2-prijs lijkt alleen haalbaar in een EU-systeem van emissiehandel zonder de mogelijkheid van het CDM gebruik te maken. Een andere mogelijkheid is dat er een ambitieuzere wereldwijde CO_2-emissiereductie-strategie wordt ontwikkeld, waarbij de cumulatieve wereldwijde CO_2-uitstoot beperkt blijft tot 700 Gt CO_2 in de periode 2009-2050. Beide zijn niet waarschijnlijk op de korte termijn. Daarom zal grootschalige CCS zonder aanvullend beleid, zoals een verplichting om CCS te installeren op centrales die gestookt worden op fossiele brandstoffen, alleen toegepast worden vanaf 2030 in plaats van 2020. Dit houdt in dat er 10 jaar in de eerste helft van de 21e eeuw, de periode waarvoor CCS speciaal bedoeld is, verloren gaan.

8.3.2 Modelleermethode-gerelateerde vragen

Met betrekking tot de vijf modelleermethode-gerelateerde vragen, noemen we de volgende highlights.

I. Kan een bottom-up energiemodel alle relevante dynamische gegevens integreren betreffende de belangrijkste randvoorwaarden voor CCS?

Dit proefschrift laat zien dat een bottom-up energiemodel, gebaseerd op MARKAL, geschikt is voor het integreren van dynamische gegevens betreffende de belangrijkste randvoorwaarden. Deze randvoorwaarden hebben betrekking op het klimaatbeleid, de CO_2-afvangst mogelijkheden in onder andere de elektriciteitssector, de beschikbaarheid van opslagvelden, en de bouw van een CO_2-infrastructuur. Toch is de analyse niet compleet, omdat onder andere de noodzaak van CO_2-emissiereductie in andere sectoren, zoals de

[10] Aannemend dat Duitsland 7,5 €/t CO_2 zou betalen voor CO_2 transport en opslag.

transportsector niet is meegenomen. Bovendien, alhoewel globaal rekening is gehouden met de patronen in de vraag naar elektriciteit en warmte en het aanbod door het geïnstalleerd elektrisch vermogen, kan een meer diepgaande analyse van deze patronen op uurbasis inzicht geven in de flexibiliteit van een elektriciteitsproductiesysteem waarin grootschalige toepassing van CCS wordt gecombineerd met een grootschalig gebruik van intermitterende hernieuwbare energiebronnen.

II. Kan het concept van leercurves worden toegepast op zowel kosten- als prestatievariabelen, kan het spill-over effecten meenemen, en kan het worden geïntegreerd met cumulatieve capaciteitsprojecties om inzicht te verkrijgen in de ontwikkeling van elektriciteitscentrales met CCS?

Het proefschrift laat zien dat het inschatten van leercurves voor zowel prestatie- als kostenvariabelen van centrales met CCS inzicht kan geven in de mogelijke ontwikkeling van investeringskosten, elektrische rendementen, CO_2-emissiereductie-kosten en elektriciteitsproductiekosten. Door de leercurves te combineren met cumulatieve capaciteitsprojecties van centrales met én zonder CCS, kunnen waarden voor de prestaties van de centrales met CCS door de tijd heen worden verkregen. In dit proefschrift zijn de leercurves bepaald per component van de centrales (bv. op basis van een stoom- en gasturbine eenheid of CO_2 post-combustion afvangunit). Zo kon worden meegenomen dat verbeteringen van componenten afhankelijk zijn van de totale cumulatieve capaciteitsgroei van verschillende types centrales (met en zonder CCS) tezamen. In dit proefschrift werd ervan uitgegaan dat er mondiaal geleerd wordt omdat energiecentrales meestal gebouwd worden door grote multinationals. Omdat verwacht wordt dat een groot deel van de capaciteitsgroei in opkomende economieën zoals China en India zal plaatsvinden, moet worden ingeschat of daar ook state-of-the-art energiecentrales gebouwd zullen worden waarmee daadwerkelijk wordt bijgedragen aan de technologische ontwikkeling. Voorts dient te worden onderzocht hoe leerprocessen met betrekking tot individuele technologische componenten van centrales elkaar beïnvloeden. Een verdere analyse kan aangeven in welke mate de methode om componenten als afzonderlijke leereenheden in plaats van als een samengesteld leersysteem te behandelen legitiem is.

III. Kan een bottom-up energiemodel worden geïntegreerd met een geografisch informatiesysteem (GIS) om te kunnen modelleren waar en wanneer het kosteneffectief zou zijn om elementen van een CO_2-infrastructuur te bouwen?

Een toolbox gebaseerd op ArcGIS en een MARKAL-gebaseerd model kan inzicht geven in de ontwikkeling van een CCS-infrastructuur in een specifieke regio. We konden voor Nederland

meerdere bronnen aan meerdere opslaglocaties matchen op basis van kosten, locatie en beschikbaarheid als functie van de tijd. In tegenstelling tot andere studies, bood dit instrumentarium zowel ruimtelijke als tijdsspecifieke uitkomsten van de ontwikkeling van een CO_2-infrastructuur op het niveau van specifieke CO_2-infrastructurele elementen (bijvoorbeeld een pijpleiding, een gasveld). Het resulteerde onder meer in landkaarten voor de CO_2-infrastructuur met pijpleidingtrajecten en de inzet van individuele opslaglocaties in de loop van de tijd. De toolbox liet ook de mogelijke effecten van beleidskeuzes op het ontwerp van een CCS-infrastructuur zien. Echter, de ontwikkelde modelleermethode kan nog verder worden verfijnd. Bijvoorbeeld, kan de mogelijke netwerkstructuur worden uitgebreid door niet alleen uit te gaan van een sternetwerk-structuur. Bovendien zouden meer gedetailleerde gegevens over het CO_2-opslag potentieel op basis van lokale studies van individuele sites de resultaten kunnen verbeteren. Tenslotte zou het meenemen van zowel de mogelijkheid om CO_2 per schip te transporteren, als de tijdpaden die nodig zijn voor juridische procedures, beter de planning van een CO_2-infrastructuur kunnen ondersteunen.

IV. Kunnen grensoverschrijdende CO_2-stromen worden meegenomen in een nationaal bottom-up energiemodel om kennis te vergaren over de ontwikkeling van een nationale CO_2-infrastructuur?

De ArcGIS/MARKAL toolbox is in staat om te onderzoeken hoe en wanneer de CO_2-stromen uit naburige landen kunnen worden vervoerd en opgeslagen via een Nederlandse CO_2-infrastructuur naar Nederlandse gasvelden of een reservoir in het buitenland. Echter, in dit proefschrift is geen rekening gehouden met de nationale strategieën van deze naburige landen (België en Duitsland) om hun CO_2-infrastructuur te ontwikkelen. Ook de mogelijkheid om CO_2 via Duitsland te transporteren en in bijvoorbeeld de Utsira formatie op te slaan werd uitgesloten.

V. Kunnen algemene evenwichtsmodellen van de mondiale economie en nationale bottom-up energiemodellen worden gecombineerd om de impact van internationaal klimaatbeleid op de nationale inzet van CCS te bepalen?

Op basis van onze bevindingen, concluderen we dat een combinatie van een nationaal bottom-up energiemodel gebaseerd op MARKAL, en een wereldwijd toegepast algemeen evenwichtsmodel, kan worden gebruikt om het effect van internationaal klimaatbeleid op de inzet van CCS op nationaal niveau te bepalen. Door wereldwijde energie- en CO_2-markten te modelleren geeft WorldScan prognoses van de energievraag, CO_2-prijzen, en brandstofprijzen voor verschillende vormen van internationaal klimaatbeleid. Binnen deze context kan de CCS-inzet op nationaal niveau worden geanalyseerd met een bottom-up energiemodel. Echter, het

modelleren van diepe CO_2-emissiereductie scenario's stelt aanvullende eisen aan de modellen. Meer mitigatie-opties moeten worden opgenomen om de mogelijkheden voor vermindering van de CO_2-uitstoot niet te onderschatten of om de reductiekosten niet te overschatten. Bovendien zou WorldScan op basis van meer detail-gegevens en leercurves van technologieën (bijv. over CCS of over biomassa centrales) meer inzicht kunnen geven in het effect van verschillende portfolio's om CO_2-uitstoot te beperken op het verloop van de energievraag en van energieprijzen.

8.3.3 Verder onderzoek

Tenslotte zijn in dit proefschrift een aantal onderwerpen belicht die verder onderzoek behoeven, waaronder:

- Om de behoefte aan CO_2-opslag capaciteit en infrastructuur goed in te schatten, moeten ook CCS-opties worden onderzocht die kunnen worden toegepast in andere sectoren dan de elektriciteitssector en de CO_2-intensieve industrie. Met name bij de productie van brandstoffen voor de transportsector zou CCS toegepast kunnen worden.
- Om diezelfde reden is meer inzicht nodig in de technologie en kosten van CO_2-afvangstopties die toegepast kunnen worden op kleine installaties (bijvoorbeeld WKK-eenheden en ketels).
- Omdat de combinatie van CCS met biomassa een belangrijke optie bleek te zijn om negatieve CO_2 emissies mogelijk te maken, moeten de kosten en prestaties van deze optie in detail worden onderzocht.
- Om een CO_2-infrastructuur te plannen, is het van cruciaal belang om meer kennis over het CO_2-opslag potentieel in individuele gasvelden en aquifers te verkrijgen. Verder onderzoek is nodig om reële en locatie-specifieke opslagmogelijkheden te matchen met het beschikbaar komen van CO_2-stromen door de tijd heen.
- Om te zorgen voor synergie tussen de verschillende (Noord-West-Europese) landen bij de ontwikkeling van een CO_2-infrastructuur, kan de reikwijdte van de studie met een toolbox zoals ArcGIS/MARKAL worden uitgebreid van Nederland naar verschillende buurlanden. Voorts zou dit instrument kunnen worden toegepast in andere vergelijkbare regio's in de wereld.
- De ArcGIS/MARKAL toolbox kan worden toegepast om om te gaan met noodzakelijke termijnen voor juridische procedures, met transport van CO_2 door schepen, en met de afvangst van CO_2 van kleinere puntbronnen.
- Omdat uiteindelijk CCS wordt beperkt door de mogelijkheden van het opslaan van CO_2, is een hoge penetratie van bijvoorbeeld duurzame energie onmisbaar om CO_2-uitstoot fors terug te brengen. Daarom moet o.a. in detail worden onderzocht hoe elektriciteitscentrales met CCS en het gebruik van intermitterende hernieuwbare energiebronnen tezamen een veilige, flexibele en betrouwbare elektriciteitsvoorziening kunnen blijven garanderen.

Dankwoord

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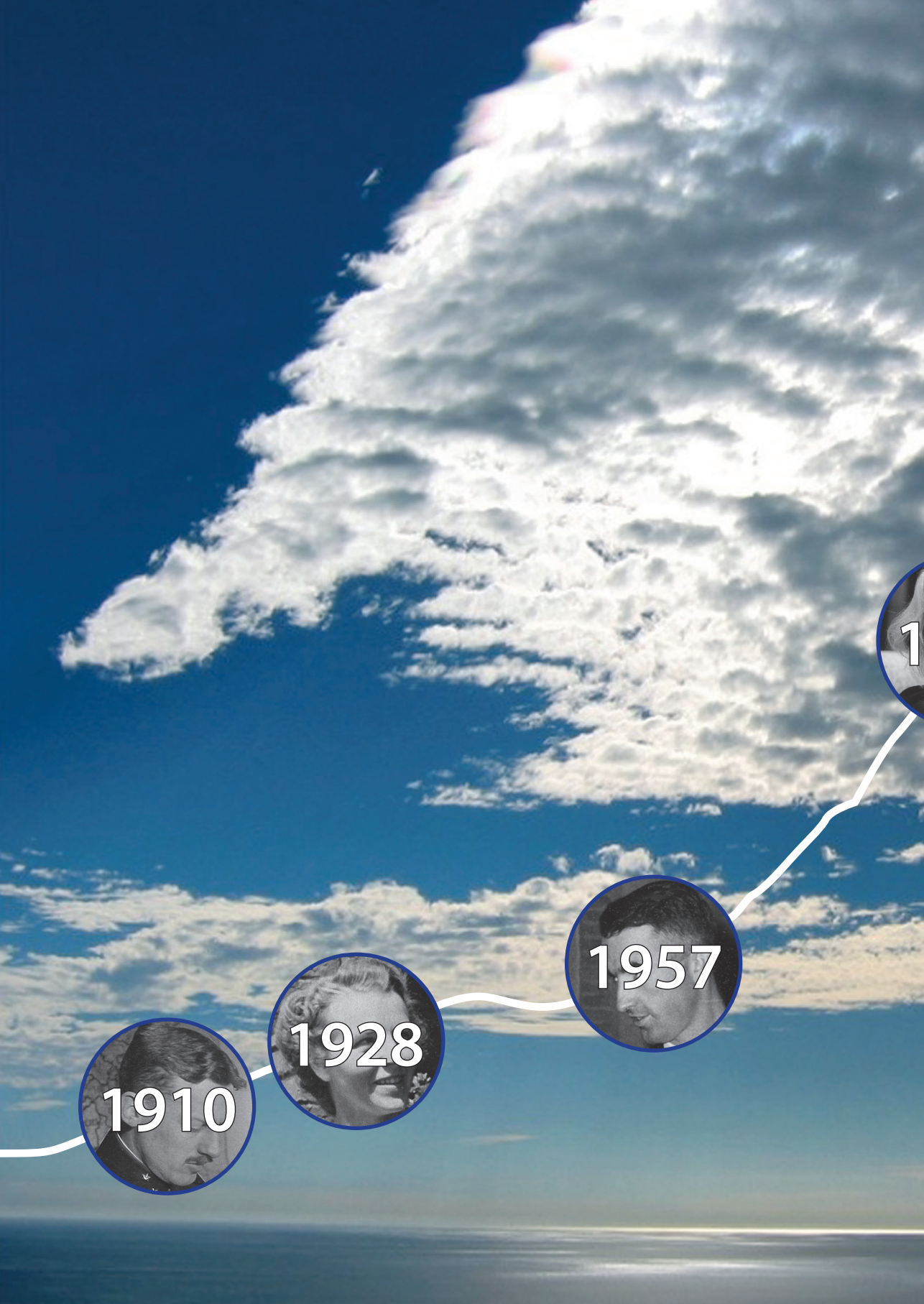
Curriculum vitae

I was born in Deventer on the 12th of October 1965. After high school, I went one year to Hollins College in the United States. I studied electrical engineering at the Technical University of Delft where I specialised in systems and control engineering. I began may career at the Policy Studies department of the Energy research Centre of the Netherlands (ECN). There I developed and applied energy models for the Netherlands and several Eastern European countries. Then I worked for UNESCO in New Delhi, India. I was responsible for the technical programme for South and Central Asia. Next, as a consultant and researcher in various organizations, I coordinated and gave advise on the design, development, and application of knowledge systems. At Alterra, the research institute for our green living environment, these were knowledge systems in the field of environment and energy.

In recent years, I worked within the CATO programme, the Dutch national research programme on CO_2 Capture and Storage (CCS), at the Utrecht University. I investigated how much CO_2 emissions could be reduced by CCS in the Netherlands, how CCS can be introduced at large scale, and what kind of CO_2 infrastructure would be needed. For this purpose, I used scenario studies, energy models, and geo-information systems.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