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The potential role of Carbon Capture and Storage, under different policy options

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The potential role of Carbon Capture and Storage, under different policy options

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Foreword

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This project is part of CATO, a Dutch collaboration between companies, NGOs and knowledge institutes in the field of carbon dioxide capture and storage. It aims to identify whether and how CCS can contribute to a sustainable energy system in the Netherlands. This report is the outcome of a project conducted in 2008.

The authors wish to thank Geert Verbong and Fred Lambert (Eindhoven University of Technology) for their valuable input and feed-back. Finally, we owe thanks to Bart Wesselink, Kornelis Blok, Ruut Brandsma, Ela Wojcik-Gront and Erika de Visser (Ecofys) for their contributions.

Summary

CO_2 Capture and Storage (CCS) is indicated as an important pillar in the Dutch climate change working program 'Schoon & Zuinig'. However, the working program does not yeat contain policies to stimulate CCS. Scientific literature provides analyses on the effectiveness of a limited number of policy options, mainly focusing on carbon tax. This research project explores a broader range of policy options. For this, a bottom-up simulation model of the Dutch electricity supply sector was developed. The central question in this report is:

What is the potential role of CO_2 Capture and Storage in the Netherlands under different policy options on the mid term (2030)?

Methodology

We analysed different policy scenarios, with use of the Ecofys energy model. This model is a bottom-up simulation model of the Dutch electricity supply sector up to 2030, with a high level of technological detail. The model simulates replacement of electricity generation capacity, and calculates the related societal costs and CO_2-emissions.

The main characteristics of the model are:

- ***Exogenous electricity demand.*** Electricity demand is taken from the PRIMES 2007 baseline scenario.
- ***Load duration curve*.** The curve is divided into five load levels. For each load level different investment decisions are made.
- ***Stock turnover.*** For each of the five load levels the pace of retirement of standing stock in addition to exogenous electricity demand, determine how much additional electricity generation capacity is needed.
- ***Least cost technology.*** The investment decision rule comprehends that the least cost technology is chosen.
- ***Distribution of three discount rates.*** The cost calculations are based on a distribution of discount rates, reflecting different investor preferences and behaviour.
- ***Intermittent energy sources.*** The costs of producing electricity from solar and wind are evaluated against average electricity costs. The resulting wind and solar capacity is deducted from demand for new capacity. Costs due to back-up and supply-demand mismatch are included.
- ***Cost supply curves.*** For renewable energy sources and CCS, different categories of potential, with different characteristics are distinguished.

- ***Learning curves.*** With increased implementation, the cost of technologies will go down as a result of technological learning. Every technology is characterized with a progress ratio.
- ***Limit to growth.*** Various factors can limit growth of technologies, e.g. shortage in materials or limited production capacity. Therefore costs increase if the annual growth rate of a technology exceeds 30%.
- ***CCS.*** Seven different types of CCS plants are included in the model. The model takes into account economies of scale in CO_2-transport and distinguishes between different types of storage, with different characteristics and timing of availability.

We analyzed a range of different policy scenarios, including the following policy options:

- CO_2-prices
- investment subsidies
- feed-in tariffs for renewables and CCS
- CCS standards (obliging CCS for newly built coal and/or gas plants)
- Combinations of those policy options

Main findings

1 *At gradual increases of carbon prices, the share of CCS is modest*

Different CO_2-price scenarios with different rates of gradual increase result mainly in large shares of gas fired capacity at the expense of coal. The role of CCS stays limited. If no restrictions are imposed, CCS is implemented from a CO_2-price of €38,-/ton, but it does not contribute to more than 15% of electricity generation capacity. The gradual CO_2-price that we assumed results in a lock-in of fossil-fuel fired capacity and therefore limits the potential for CCS up to 2030 under the ETS. Note that early retirement and retrofit with CCS were not taken into account.

2 *Biomass plants with CCS might play a role in CO_2-mitigation under the ETS, if biomass CCS can produce emission allowances*

A considerable part of the CCS capacity at moderate CO_2-prices is formed by biomass fired CCS plants. If allowances are given to the negative emissions from biomass with CCS, this becomes attractive. If negative emissions are not acknowledged, as in the current ETS, the role of CCS is more limited. This implies that biomass CCS might play an important role in greenhouse gas mitigation. Therefore emissions that are indirectly abstracted from the atmosphere through biomass should be acknowledged in the ETS.

3 *Reducing initial CO_2 transport costs has a significant positive impact on the implementation of CCS*

An important factor in the limited potential of CCS is the high costs for CO_2-transport at small scale. The first CCS projects will be very expensive and the moment of first implementation is relatively late, since a high CO_2-price is needed to make CCS competitive. Once this hurdle is overcome, costs will drop and CCS is more attractive. Scenarios in which the costs for small scale transport are reduced to economies of scale level, show a considerably higher share of CCS. Government support for transport costs in an early phase is therefore a promising policy option.

4 *Different types of policies stimulate different CCS technologies*

In addition to a CO_2-price, also scenarios are analyzed taking different investment subsidies, different feed-in tariffs and CCS standards for coal and/or gas plants into account. Figure 1 shows the shares of different types of CCS in the electricity generation mix, for different policy options. A distinction is made between the fuel types used.

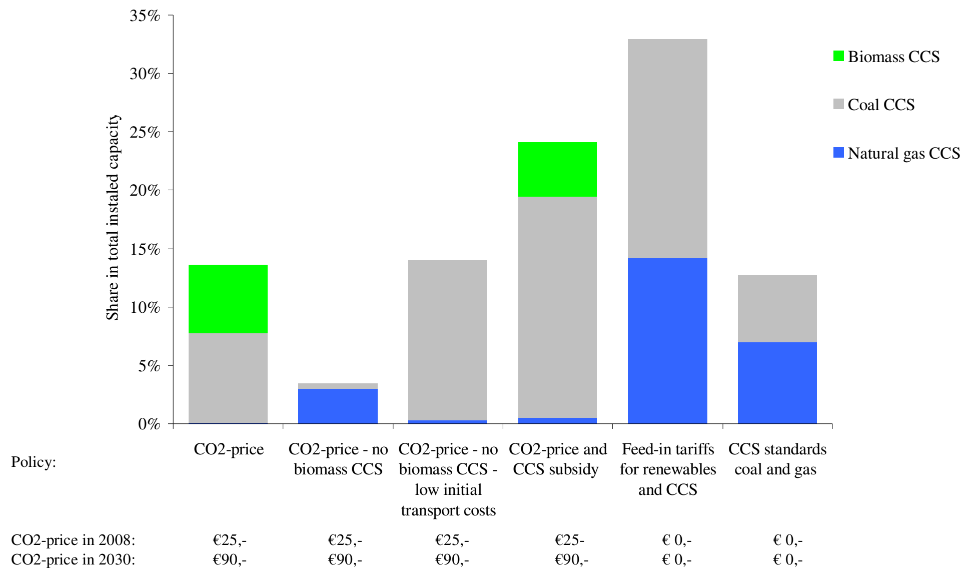

Figure 1: Shares of different types of CCs in 2030 for different policy scenarios

Different types of policies stimulate different types of CCS. Biomass CCS is only adopted when a CO_2-price is included and negative emissions are acknowledged in the ETS. Investment subsidies are most favourable to coal fired CCS, because the share of investment costs in total costs is relatively high for this technology. Feed-in tariffs and CCS standards are stimulating both coal and gas fired CCS.

5 *It is most cost-effective in the long-term to stimulate both renewable energy sources and CCS*

Societal costs and CO_2-emissions are calculated for scenarios with different policy combinations. Figure 2 shows the societal costs and CO_2-emissions in a number of scenarios. We distinguish three types of scenarios: scenarios with one single policy option, which are relatively less effective, policy combinations that stimulate CCS and policy combinations that stimulate both CCS and renewable energy sources.

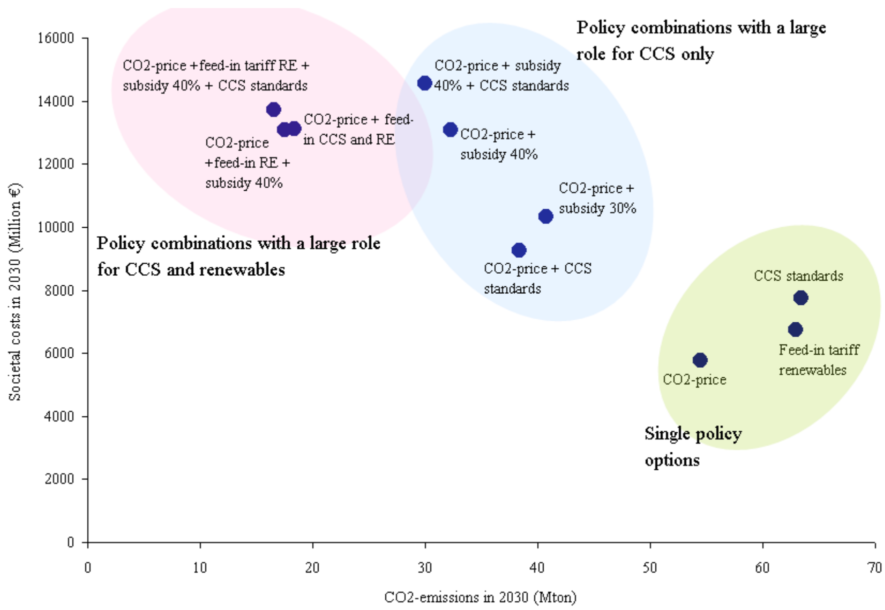

Figure 2: The societal costs in 2030 and CO_2-emissions in 2030 for a selection of policy scenarios (RE=renewable energy sources)

Because of the large learning potential for renewable energy sources, the costs go down relatively fast. This results in societal costs in 2030 that are at comparable level for scenarios stimulating CCS and renewables and scenarios stimulating CCS only, while the reduction potential is higher if renewable energy sources are stimulated in addition to CCS.

6 *The modelling approach chosen represents a weak incentive ETS*

The study is compared to the work of Van den Broek et al. (2007b). The difference in results between the two studies is that Van den Broek et al. (2007b) find higher deployment of CCS, with lower CO_2-prices than our study. This can be explained by two main differences in approach: Increase in CO_2-price is foreseen in the optimisation model with perfect foresight used by Van den Broek et al., while the Ecofys model (a simulation model without foresight) only reacts to present CO_2-prices. Groenenberg and de Coninck (2008) refer to an ETS with foresight as strong incentive CCS, and to an ETS without foresight as weak incentive ETS. This is consistent with the observation that the CO_2-price as modelled by Van den Broek et al. (2007b) provides a stronger incentive to CCS than in our study. In addition early retirement and retrofit play an important role in the study by Van den Broek et al. (2007b), while we do not take those options into account.

Recommendations

Based on our findings, we recommend policy makers to implement policies additional to ETS to stimulate CCS. We recommend supporting transport costs in an early phase. To have a cost effective mitigation policy, renewable energy sources should be stimulated simultaneously. For researchers it is recommended that further research is done on reducing initial transport costs and the potential of biomass CCS.

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List of abbreviations

CATO	CO_2 Afvang Transport en Opslag (CO_2 Capture Transport and Storage)
CBS	Centraal Bureau voor de Statistiek (Netherlands statistics office)
CC	Combined Cycle
CCS	Carbon Capture and Storage
CFF	Clean Fossil Fuel
CHP	Combined Heat and Power
CO_2	Carbon dioxide
COE	Cost Of Electricity
cum	Cumulative installed capacity
EC	European Commission
ECN	Energy Centrum Nederland (Energy research Centre of the Netherlands)
ECS	Energy and Climate Strategies
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Scheme
EU	European Union
FLH	Full Load Hours
GDP	Gross Domestic Product
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
LDC	Load Duration Curve
LPG	Liquified Petroleum Gas
MEP	Milieukwaliteit van de elektriciteitsproductie (Environmental quality of electricity production)
NEA	Nuclear Energy Agency
NGCC	Natural Gas Combined Cycle
NGO	Non-Governmental Organization
NO_x	Nitrogen oxide
O&M	Operation and Maintenance
OECD	Organisation for Economic Co-operation and Development

PC	Pulverised Coal
PV	PhotoVoltaics
RE	Renewable Energy
R&D	Research and Development
RD&D	Research Development and Demonstration
SDE	Stimulering Duurzame Energieproductie (Stimulating Sustainable Energy production)
SO_x	Sulfur oxide
WP	Work Package

1 Introduction

1.1 Background

The growing concern for climate change has led to ambitious greenhouse gas abatement targets in the European Union. In 2020 should be achieved (EC, 2008a):

- 20% reduction in greenhouse gas emissions (relative to 1990)
- 20% share of renewable energy in EU energy consumption
- 20% saving of energy consumption through energy efficiency (relative to 1990)

As a result, national governments will need to identify the potential and accompanying costs of possible abatement options, and the best policy design to stimulate those options. The Dutch government has expressed its ambition to make the Netherlands one of the cleanest and most efficient countries in Europe. One of the pillars in the Dutch climate mitigation strategy is the introduction of Carbon Capture and Storage (CCS). However, being a new, not widely applied technology, CCS is accompanied with many uncertainties. One of the issues of debate is how to stimulate the introduction of CCS technology. The Dutch government has taken the position that CCS should be competitive under the EU Emissions Trading Scheme (EU ETS) in the long run. In the short run, other policy options should stimulate the rapid introduction of CCS in the Dutch electricity system.

1.2 CATO

CATO is a strong consortium of Dutch companies, research institutes, universities and environmental organisations. With a budget of over €25 million, CATO can be regarded as the Dutch national research program on CCS. Half of the costs is subsidized by the Dutch government. The aim of the CATO programme is to identify whether and how CCS can contribute to a sustainable energy system in the Netherlands.

This study is part of Work Package 1 of the Dutch research project called CATO[1]. Work package 1 focuses on system analysis, infrastructure and transition management. Within this work package, WP1.4 focuses on "*identification of optimal systems and strategies for large-scale deployment of Clean Fossil Fuel (CFF) systems on the long term (…)*".

[1] Information on CATO can be found on www.co2-cato.nl

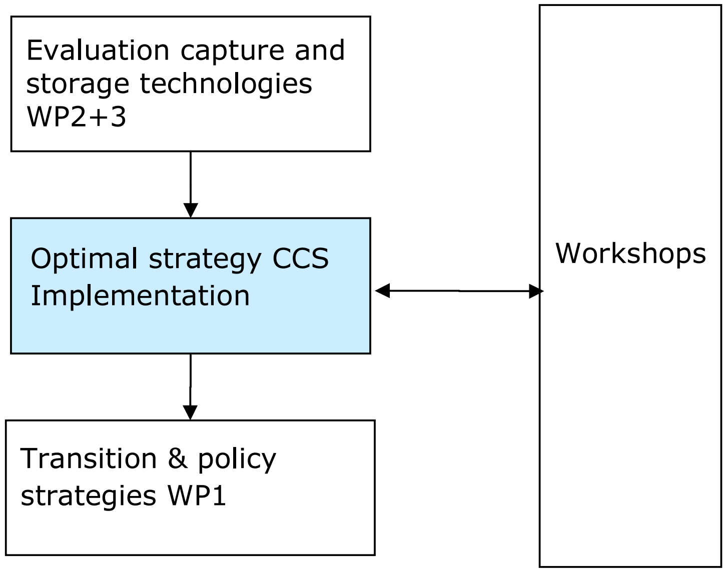

Figure 3: Overview of relations of the research project with other CATO Work Packages

Figure 3 presents the relation of this study with other CATO activities. Data input is used from WP 2 and 3 on CCS technology characteristics. The work is presented in a CATO workshop for policy makers, and improved as a result of comments. Finally, it provides input into other activities within WP1, regarding transition and policy strategies. The work is complementary to the CATO work of Van den Broek et al. (2007a,b). This will be further elaborated in Chapter 5.

1.3 Objectives of the study

Within the policy context and the CATO-project described above, research is needed on the costs and impacts of policy options to stimulate CCS. This study will address this by answering the following research question:

What is the potential role of CO_2 Capture and Storage in the Netherlands under different policy options on the mid term (2030)?

A dynamic simulation model of the Dutch electricity market will be used, to explore the effect of policy options and combinations of policy options on the electricity generation mix up to 2030.

We provide an overview of the effect of separate policy options and a selection of policy combinations. The outcomes assess the effects of different policy options in terms of CO_2-emissions, costs and technologies adopted. We will not evaluate existing or planned policy schemes; neither an optimal pathway to meet CO_2 mitigation targets. The results of the study are intended to provide input into the discussion related to CCS policy design in the Netherlands.

1.4 Dutch climate policy

As described above, the EU has set ambitious climate targets. The Netherlands has set even more stringent targets for itself. In the Dutch working program: Schoon en zuinig (2007) the Dutch government states:

"The Netherlands aims for one of the most clean and efficient energy systems in Europe in 2020." (Schoon en zuinig, 2007, p. 27)

The Netherlands aim to achieve in 2020 (Schoon en zuinig, 2007):

- 30% reduction of greenhouse gases (relative to 1990)
- Energy efficiency improvement of 2% per year (currently 1% per year)
- A 20% share of renewable energy sources in energy supply (currently 2 to 3%)

In order to reach its targets, the Dutch government is to a certain extent restricted by EU policy and legislation. The key pillar in EU policy is the Emissions Trading Scheme (ETS). The ETS puts a limit (CO_2-cap) on total CO_2-emissions of the electricity supply sector and other sectors. The EU issues allowances to emit CO_2, of which the sum equals the CO_2-cap. Every actor is obliged to surrender allowances equal to its CO_2-emissions. Emission allowances can be traded. As a result the emission of CO_2 has a price. This scheme has started in 2005 and is currently in its second trading period. The EU is still improving the scheme. For instance, allowances will probably be auctioned rather than assigned from 2012 onwards. Also, in 2008 the European commission decided that CO_2 stored through CCS, can already be considered as not emitted in the ETS, in the current trading period, up to 2012 (EC, 2008b). The Dutch government aims at influencing the design of the scheme through diplomacy. They plead among others for raising the emission cap for 2020 (Schoon en Zuinig, 2007). Although, the EU ETS is the main policy instrument, other policies are implemented in the Netherlands as well.

The Dutch climate policy strategy can be categorized as follows

- Market incentives (e.g. EU ETS)
- Setting standards
- Instruments aimed at innovation
- Temporary incentives (subsidies and taxes)
- International climate and energy diplomacy

The Dutch working program for climate change mitigation: 'Schoon en zuinig', will be reviewed in 2010. Based on this review a new policy agenda will be set to achieve the targets for 2020. The policy analyses done in this project can be used as input in the review process.

1.4.1 CCS policy

CCS is an important pillar in both the EU and the Dutch climate change policy. The EC considers CCS to be "a crucial element in the portfolio of existing and emerging technologies with the potential to bring the cuts of CO_2 emissions needed for meeting targets beyond 2020" (EC, 2008b). Since it is believed that the EU targets cannot be reached without CCS, considerable attention is paid to CCS stimulation policy. Moreover, the European Commission sees the early development of CCS as an opportunity to become a technological leader and to set the standard for CCS legislation (EC, 2008b).

CCS is also an important pillar in the Dutch working program 'Schoon en zuinig'. In principle a transition from coal to gas fired power plants in the Dutch electricity sector could reduce a substantial amount of greenhouse gases. But the government aims for a varied technology mix in order to secure energy supply and keep energy affordable. This is the main motivation for aiming for large scale implementation of CCS.

Both the EU and the Dutch point of view on CCS stimulation policy is that CCS should be competitive under the ETS and this is the main policy instrument to stimulate it. In order to make CCS competitive by 2020 the European commission aims to have at least 12 large scale CCS demonstration plants ready by 2015 (EC, 2008c). The Dutch government wants to build two of those large scale CCS demonstration plants before 2015 and supports those financially. At least 91,8 mln Euro is available from existing funds and additional money will be available from 2010 onwards.

The Dutch government lobbies for an EU-wide obligation of CCS in new coal fired power plants, once CCS can be considered as state of the art. Currently new coal plants in the Netherlands should already be built capture ready, with the purpose that CCS technology can easily be added to the power plant at a later stage (Schoon en zuinig, 2007). However, there is no clear definition on 'capture ready' and critics place question marks with the possibility of adding CCS technology to a 'capture ready' power plant. The costs for retrofitting a power plant with CCS are believed to be considerably higher than for including CCS in a new to be built plant.

In addition to the ETS, the Dutch government uses binding covenants to stimulate operators of new coal fired power plants to substantially reduce its emissions by 2015.

Further policies implemented in the energy sector are the SDE, a subsidy scheme for renewable energy (with an emphasis on wind and biomass), a subsidy for combined heat and power (CHP) plants and a large extension of the electricity grid to be able to handle the growing share of fluctuating energy sources like solar and wind energy. A clear viewpoint on nuclear energy is given by the current government. They state that nuclear energy is not sustainable and not necessary to reach the targets. During the current coalition period no new nuclear power plants will be built.[2] No statement has been made about the years after the coalition period.

1.5 Structure of the report

The report is structured as follows: In Chapter 2 the bottom-up simulation model is described in detail. Chapter 3 presents the results of the policy analyses. Chapter 4 describes sensitivity analyses. In Chapter 5 the results will be discussed. Finally in Chapter 6 the conclusions are presented.

2 Recently (2008) the Dutch coalition partner CDA has announced that nuclear energy should be implemented in the Netherlands. This has put the discussion on nuclear energy on the agenda again in the Netherlands. The Dutch electricity company Delta, announced on 10 September 2008 that it had started the application procedure for a building permit for a new nuclear power plant.

2 The Ecofys model

The study is performed using the electricity supply module of the Ecofys model. This module provides bottom-up simulations of the Dutch electricity supply sector. The model is Excel-based and programmed in Visual Basic. This chapter describes the different components of the model. In Section 2.1 a general overview of the model is provided. In Section 2.2 through 2.5 the model will be described in more detail.

2.1 General overview

Key characteristics of the model and the technologies included are shown in Table 1.

Table 1: Characteristics of the Ecofys energy model, as it has been used in this study

Scope:	**The Ecofys model**	
Classification:	Bottom-up Simulation	
Time-period: Reference period: Actual model run:	1990-2030 1990-2005 2006-2030	
Geographical coverage:	The Netherlands	
Power supply technologies included:	Large hydro Small hydro Wind on-shore Wind off-shore Solar thermal Solar PV Geothermal Conventional Coal Normal Conventional Coal Normal CCS Conventional Coal Advanced Conventional Coal Advanced CCS	Coal gasification/ CC Coal gasification/CC CCS Oil Steam Electric CC (gas) CC (gas) CCS Gas turbines (small) Gas turbines (small) CCS Biomass combustion Biomass combustion CCS Biomass gasification Biomass gasification CCS

The basic model mechanism is outlined in Figure 4. The model evaluates how much and what type of power plant capacity should be built. The quantity of electricity generation capacity that should be built is based on:

- The annual electricity demand (adopted from PRIMES baseline 2007, Section 2.2.2)
- Load duration curve (Section 2.2.1)
- The timing of the retirement of power plants (Stock turnover[3], Section 2.2.3)

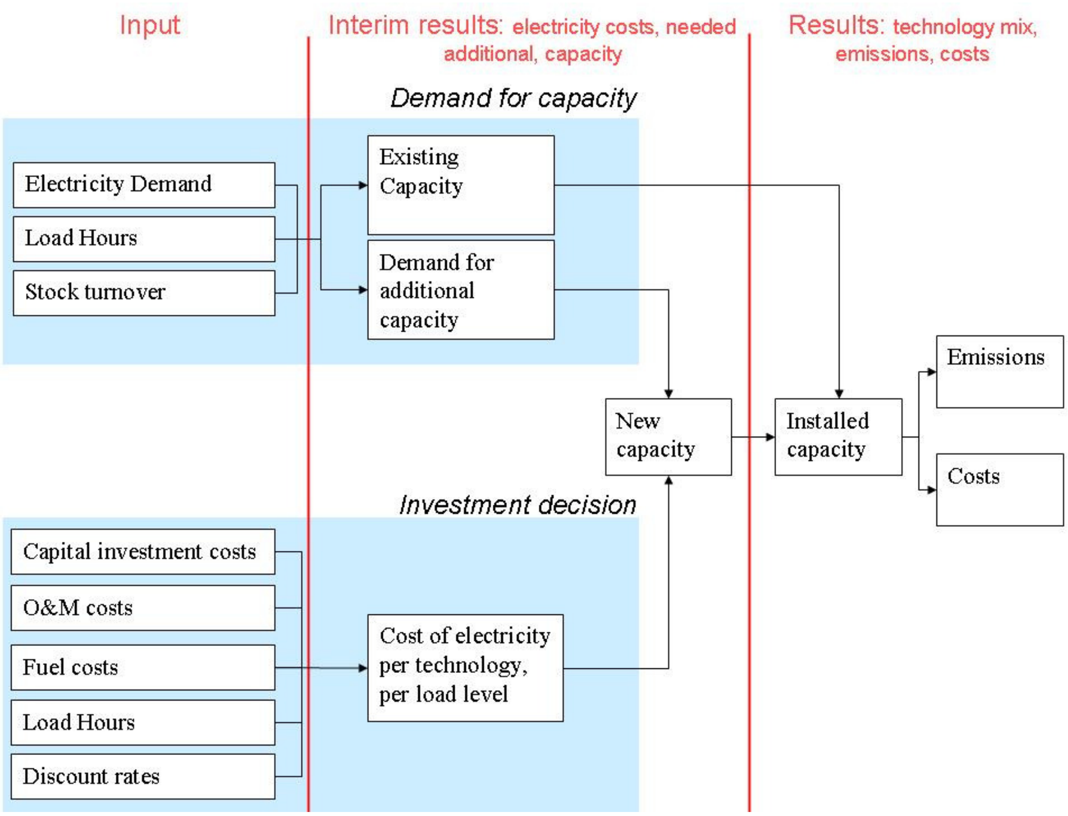

Figure 4: Overview of the model

The assumed investment decision for new capacity is that the least expensive technology is built (in terms of electricity generation costs). The costs of electricity generation are based on:

- The costs of building a new power plant
- The costs for operation and maintenance of the power plant

[3] We make assumptions on the lifetime a plant is in operation until it retires. Based on these assumptions and the years of construction of the power plants, we can derive how much capacity is annually retired. In the remaining of the report this is referred to as stock turnover.

* The costs of fuel input
* The number of hours a plant is in operation annually
* Discount rates. The investment costs are divided over the total electricity that will be produced during the economic lifetime of the power plant.

Finally the new capacity is added to the existing capacity (installed capacity). From the installed capacity, annual CO_2-emissions (Emissions) and annual costs (Costs) are calculated.

2.2 Basic principles

In this Section we will describe in detail the basic structure of the model, as outlined in Figure 4.

2.2.1 Load duration curve

In this section we define five categories of electricity demand, based on the demand structure of the Netherlands. The demand structure is represented by the load duration curve. Electricity demand per hour is ordered and plotted as shown by the black curve in Figure 5. The curve is normalized by dividing electricity demand per hour by average electricity demand per hour over the whole year.

Although the level of demand shifts over time, there is always a basic level of demand, referred to as base load and shown as load 1 in Figure 5. Only a small part of the time there is peak load demand (Load 5 in Figure 5). The difference between the load levels causes a difference in the type of plants that are chosen to operate in the different load levels. Base load plants operate almost fulltime during a year. Power plants with relative high fixed costs but low variable costs are preferred. In the peak load, plants with low fixed costs but relatively high variable costs are preferred.

The shape of the load duration curve is assumed to stay constant over time. Annual electricity demand figures are divided over the load levels according to this shape.

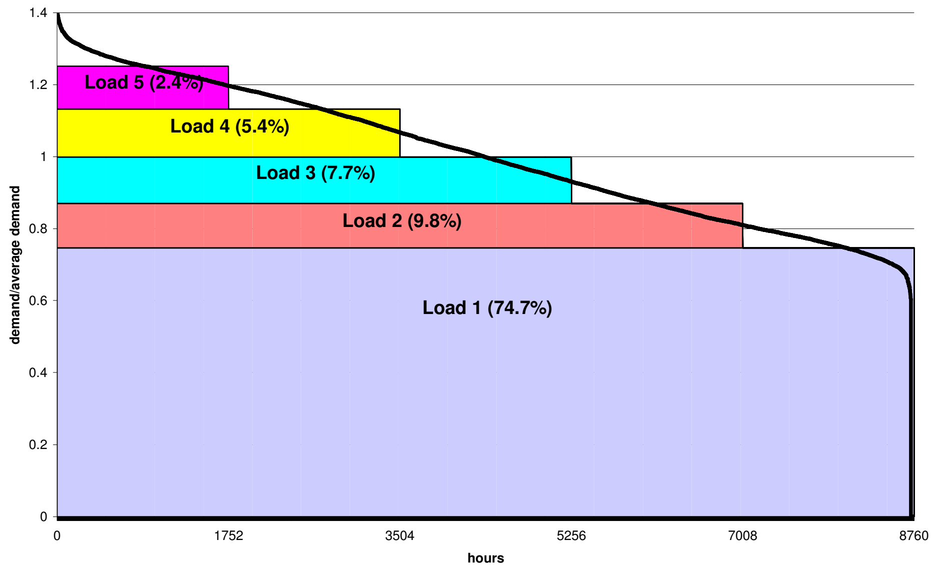

Figure 5: Normalized load duration curve of electricity demand in the Netherlands. Hours are sorted according to demand. The blocks represent base load (load 1) to peak load (load 5). The percentages represent the load level's share in total demand.

The five load levels described in this section represent five levels of electricity demand in which decisions are made. When the decision is made, a power plant is built in a certain load level and generates the amount of hours that there is electricity demand in this load level. The plants do not shift between load levels during their lifetimes. Energy models usually make a distinction between decisions on what types of plants should be built (planning), and an operational strategy based on merit order, using operating costs (van Vuuren, 2007). The method described in this section, of dividing the load duration curve into five levels combines the decision making on installed capacity and merit order. An advantage of this method is a reduction in calculation steps done by the model. A disadvantage is that capacity is built statically in one load level and cannot shift between them, over time.

2.2.2 Electricity demand as exogenous input

The model does not dynamically simulate changes in electricity demand. Instead, the development of electricity demand over time (up to 2030) is an exogenous input into the model and adopted from the PRIMES baseline scenario (2007). The PRIMES model is a model of the European energy system, producing results for each country individually, up to 2030. Its development started in 1993 and is successfully peer reviewed by the European Commission in 1997-1998. It has become the default model used by the European Commission for its policy analyses. PRIMES focuses on market-related mechanisms and technology penetration. It includes the energy supply and demand side. It is designed to serve as an "energy policy markets analysis tool". The mechanism used by PRIMES is to find a static equilibrium between supply and demand for one time period and repeat this under dynamic relationships. The equilibrium is based on a price mix in which the best quantity to supply for producers matches the best quantity to use for consumers (Capros, 1999). Both the Ecofys model and the PRIMES model are simulation models and are therefore compatible.

2.2.3 Stock turnover

How much additional electricity generation capacity is needed every year in the different load levels, is determined by electricity demand and stock turnover. Electricity demand is adopted from the PRIMES baseline scenario (2007) as an exogenous input. This section describes how stock turnover is modelled in more detail.

Stock turnover represents the gradual retirement of electricity generation capacity and the installation of new plants. The main assumption is the plant lifetime. The PLATTS database provides a global list of power plants and their characteristics from 1882 to 2005. This database is used to determine the existing installed generation capacity. The stock turnover pattern is based on assumptions on the lifetimes of power plants. The sensitivity analysis on those assumptions is discussed in Section 4.4. The development of the capacity for the Netherlands is shown in Figure 6. From 2006 onwards the standing capacity from PLATTS database gradually decreases, because of retirement (stock turnover). Annually the new required capacity (Capacity to be built) is calculated based on the retired capacity and the increase in electricity demand.

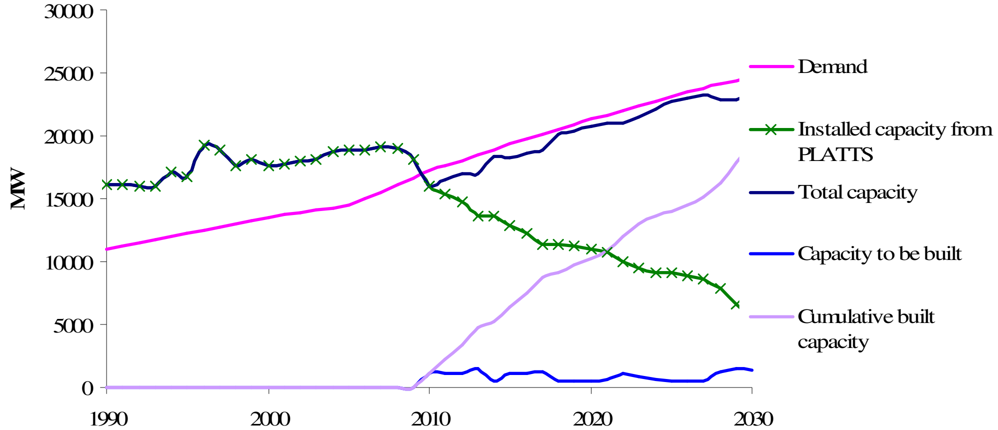

Figure 6: Demand, total capacity, capacity from PLATTS and capacity to be built during the modelling period for the Netherlands.

In order to determine the needed installed capacity in every load level, the existing installed capacity needs to be divided over the load levels. This division is made according to a preference order from typical base load to typical peak load technologies (Table 2).

Table 2: List of technology categories from PLATTS included in the model, ordered by base load vs. peak load preference order.

	Technologies
Base Load ↑	Landfill gas[4]
	Wind on-shore
	Wind off-shore
	Nuclear*
	Other renewables*
	Small hydro
	Conventional Coal Normal
	Coal gasification/ CC
	Biomass combustion
	Biomass gasification
	Oil Steam Electric
	CC (gas)
	Solar thermal
	Solar PV
	Geothermal
↓ Peak load	Large hydro
	Gas turbines (small)

The installed capacity of those technologies is distributed proportional over the load levels according to this preference order. This shows how much electricity generation capacity is installed in every load level.The needed capacity per load level is calculated using Equation 1 and reduced with the installed capacity per load level to determine how much new generation capacity should be built.

Equation 1: $$Cap_i = \frac{Demand * Conv * S}{H_i} * (1 + BC)$$

i = number of load level (1 to 5)
Capi = Needed Capacity in Load i [MW]
Demand = Yearly electricity demand from PRIMES [ktoe]
Conv = Conversion factor ktoe to MWh = 11630 [MWh/ktoe]
S = Share of surface of load block i of total LDC surface (Figure 5) [%]
Hi = The amount of hours in load i (the width of the load block) [hours]
BC = Backup Capacity [%]

4 Landfill gas and other renewables are included in the historical data for stock turnover, but cannot return as new capacity in the model.

The Ecofys model does not dynamically simulate changes in the import/export balance. Instead we adopt both electricity demand data as import/export figures from the PRIMES 2007 baseline scenario, in which import/export dynamics are included. The calculations presented are based on electricity demand, which is adjusted for import and export. In other words, only the electricity demand which is assumed to be produced in the Netherlands is taken into account.

2.2.4 Decision making

In the previous section it is determined how much new electricity generation capacity should be built in each load level. In this section we will describe how the decision is made on what type of power plants should be built, to meet this demand for additional capacity.

We determine what type of power plants should be built, based on the decision rule, implying the least expensive technology to be adopted. The evaluation of the costs is done separately in each of the five load levels (Figure 5). In every load level costs are evaluated for a distribution of discount rates. 25% percent of the capacity to be built is evaluated with a discount rate of 10%, 50% with a discount rate of 15% and 25% with a discount rate of 20% (Figure 7). This division represents the difference in preferences and strategy of different parties. The discount rates represent interest rates and risks. In a public owned electricity sector risks are low and discount rates are typically 5-6%. In a privatised market, firms have become price takers, resulting in higher risks and higher discount rates (Anderson, 2007).

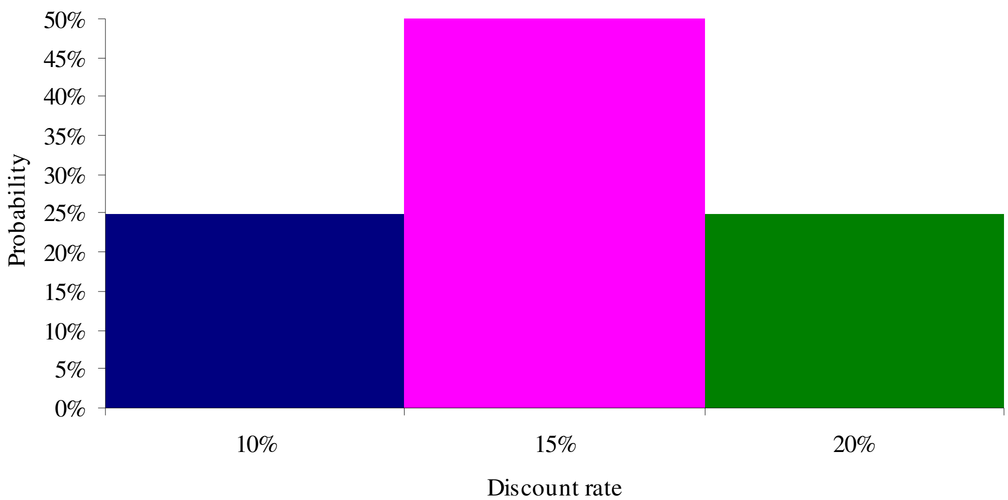

Figure 7: Probability density function of discount rates as assumed in the model

Table 3: Overview of input data on efficiency, progress ratio, specific investment costs, O&M costs and fullload hours (SERPEC-CC, 2008; PLATTS, 2006; Rafaj and Kypreos, 2007; Green-X, 2003; Green-X, 2008; Kahouli-Brahmi, 2008; Messner, 1997; Barreto and Kypreos, 2004; Rubin et al., 2006; IPCC, 2006 uranium-stocks.net, 2008)

Type of plant	Efficiency[a]	Progress Ratio[b]	Specific Investment Costs (€/kW)	O&M costs (% of SIC)	Full load hours
Large hydro	100%	99%	1800	3%	3500
Small hydro	100%	99%	2350	2%	3500
Wind on-shore	100%	93%	1114	4%	[d]
Wind off-shore	100%	91%	[c]	4%	3500
Solar thermal	100%	85%	4336	4%	[d]
Solar PV	100%	82%	5271	1%	[d]
Geothermal	100%	95%	2800	7%	6500
Conventional Coal Normal	46%	87%	1100	4%	8000
Conventional Coal Normal CCS	36%	98%	1800	5%	8000
Conventional Coal Advanced	47%	98%	1163	4%	8000
Conventional Coal Advanced CCS	35%	95%	1600	5%	7000
Coal gasification/CC	46%	98%	1600	4%	7000
Coal gasification/CC CCS	37%	95%	2350	4%	7000
Oil Steam Electric	42%	100%	800	3%	3000
CC (gas)	58%	90%	500	4%	7000
CC (gas) CCS	50%	98%	920	5%	7000
Gas turbines (small)	30%	87%	610	4%	5000
Gas turbines (small) CCS	28%	98%	1852	2%	5000
Biomass combustion	36%	95%	1800	5%	7000
Biomass combustion CCS	33%	98%	2400	5%	7000
Biomass gasification	44%	90%	2652	5%	7000
Biomass gasification CCS	38%	92%	3500	5%	7000

a Efficiency of converting fuel energy input into electricity. SERPEC provides figures for efficiency, investment costs and full load hours. Missing data for conventional coal normal, with and without CCS, oil steam electric and small gas turbines with and without CCS is taken from Green-X (2003).
b Progress ratios are used for learning curves (Section 2.3.2)
c For wind off-shore cost supply curves are applied to specific investment costs (see Section 2.3.3).
d For wind on-shore, solar thermal and solar PV cost supply curves are applied to full load hours (see Section 2.3.3).

As in most energy models, the decision rule is based on costs (the same accounts for a.o. IEA's MARKAL model (Anderson, 2007) and the PRIMES model (Capros, 2003)). The electricity price volatility, induced by market liberalisation is taken into account in the range of discount rates used.

2.2.5 Costs of electricity production

The decision making rule described in Section 2.2.4 is based on the costs of electricity generation. For every technology this cost is calculated and the least expensive technology is built. This section describes how the costs of generating electricity are calculated.

It is common to use the average annual kWh cost to make investment decisions. This cost includes annualised capital costs, operation and maintenance costs, fuel costs and if applicable additional costs like tradable permits (Anderson, 2007). As described in Section 2.2.1, there is a difference in full load hours between the load levels and thus a difference in costs (Anderson, 2007). The mentioned cost factors are included in Equation 2.

The costs of electricity (COE) are calculated using the following formulas:

Equation 2: $$COE = \frac{\alpha * Isp + O\&M * Isp}{loadhours} + F$$

Equation 3: $$\alpha = \frac{r}{1-(1+r)^{-L}}$$

Equation 4: $$F = \frac{Fp * CONV_{GJ/kWh}}{\eta}$$

COE = Cost of Electricity production [€/kWh]
r = discount rate
L = economic lifetime [year]
Isp = specific Investment costs [€/kW]
Loadhours = hours that a plant will be in operation = the minimum of max full load hours of the specific technology and the load hours in the specific load level [hours]
O & M = Operating and maintenance costs [% of Total investment costs]
α = annuity factor / annual depreciation
F = Fuel price [€/kWh]
η = conversion efficiency
Fp = Primary fuel price [€/GJ]
CONVGJ/kWh = Conversion factor of GJ to kWh (=0.0036 GJ/kWh)

As a result of the focus on cost of electricity (rather than price); the cost outcomes represent societal costs. The data input for the costs of electricity are shown in Table 3 and Table 4.

Table 4: Overview of input data on economic lifetime, emission coefficient, capture efficiency, nominal capacity, cumulative installed capacity and the Dutch share of cumulative installed capacity in the Netherlands (SERPEC-CC, 2008; PLATTS, 2006; Rafaj and Kypreos, 2007; Green-X, 2003; Green-X, 2008; Kahouli-Brahmi, 2008; Messner, 1997; Barreto and Kypreos, 2004; Rubin et al., 2006; IPCC, 2006 uranium-stocks.net, 2008)

Type of plant	Economic Lifetime (year)	Emission coefficient (kg CO_2/ GJ)	Capture efficiency[e]	Nominal capacity (MW)[f]	Cumulative installed capacity (MW)[g]	Share of cum[h]
Large hydro	50	0		100	803466	0.1%
Small hydro	50	0		1	43061	0.1%
Wind on-shore	20	0		2	42054	1.8%
Wind off-shore	20	0		5	690	3.0%
Solar thermal	30	0		50	390	3.0%
Solar PV	25	0		10	179	2.9%
Geothermal	20	0		22	10276	6.3%
Conventional Coal Normal	35	95		446	1335759	0.5%
Conventional Coal Normal CCS	35	95	90%	446	500	0.5%
Conventional Coal Advanced	35	95		446	500	0.5%
Conventional Coal Advanced CCS	35	95	95%	446	10000	0.5%
Coal gasification/CC	35	95		400	2376	6.6%
Coal gasification/CC CCS	35	95	90%	400	500	6.6%
Oil Steam Electric	30	73		24	558023	0.2%
CC (gas)	30	56		179	1002506	1.6%
CC (gas) CCS	25	56	90%	179	10	1.6%
Gas turbines (small)	30	56		2	25571	2.1%
Gas turbines (small) CCS	20	56	90%	2	10	2.1%
Biomass combustion	30	110		12	27896	1.5%
Biomass combustion CCS	30	110	90%	12	300	1.5%
Biomass gasification	30	91		2	74	1.5%
Biomass gasification CCS	30	91	90%	2	50	1.5%

e Part of the CO_2-emission that is captured and stored
f Nominal capacity represents the size of an average plant. The growth limit from Section 2.3.4 is only applied after four times the nominal capacity has been built.
g The global all-time cumulative installed capacity is used in the learning curve formula (Section 2.3.2)
h The part of cumulative installed capacity which is Dutch. It is assumed that this part stays constant over time.

2.2.6 CO_2-emissions

From the calculations in the previous sections, the new installed capacity is derived. This new installed capacity includes existing power plants, which are not retired according to the stock turnover and power plants that are built as a result of the decision making process. Based on the modelled electricity generation stock and the load hours in the specified load level, the model calculates annual CO_2-emissions, using Equation 5 and Equation 6.

Equation 5: $$CO_2 = FF * e * o$$

Equation 6: $$FF = \frac{Cap * OT}{\eta * CONV_{GW/MWh}}$$

CO_2 = CO_2-emissions [ton CO_2]
FF = fuel flow [TJ]
e = emission factor [ton CO_2/TJ]
o = oxidation factor
Cap = power plant capacity [MW]
OT = operational time of power plant
η = conversion efficiency
CONVGJ/MWh = Conversion factor of GJ to MWh (=3.6 GJ/kWh)

The most important factors, influencing CO_2-emissions are the efficiency, which is plant specific (SERPEC-CC, 2008; Table 3) and the emission factor, which is fuel specific (IPCC, 2006; Table 4). The emission factor reflects the full carbon content of the fuel used. Though, a small fraction of carbon is retained in ash, particulates or soot. This is reflected by the oxidation factor (IPCC, 2006). The operational time is dependent on the load level (Section 2.2.1) and the maximum time a plant can be in operation annually.

Figure 8 shows the emissions calculated by the model, based on the basic principles, for the reference period: 1990-2006. For comparison statistical data from CBS and IEA is added. It is shown that the model provides a rather good estimate of the CO_2-emission.

The model as described so far is able to simulate replacement of capacity in the electricity supply sector and calculate the related CO_2-emissions and costs. However, some important refinements should be made to let the model better reflect the electricity supply sector. These refinements are discussed in Section 2.3.

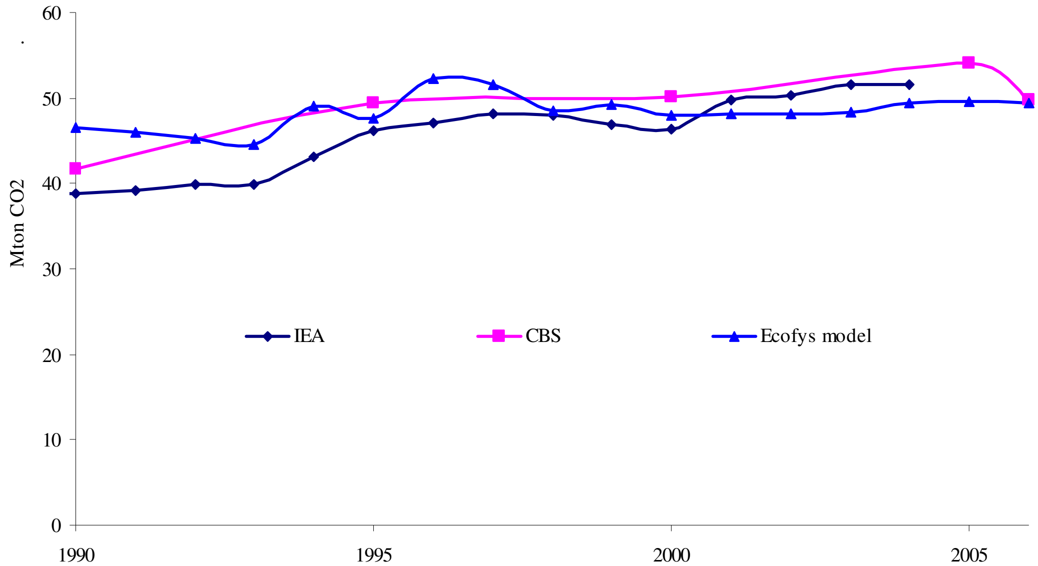

Figure 8: CO_2-emissions from IEA, CBS and model simulations.

2.3 Refinements in the model

This section describes a number of refinements in the model, additional to the basic principles discussed in Section 2.2. Although the model is able to simulate replacement of electricity generation capacity with the basic principles, some refinements are needed to make the model more realistic and to include interesting possible consequences of policies. First the model is refined for intermittent energy sources. The load level structure is based on electricity generation capacity that can produce electricity whenever there is demand. However, intermittent energy sources cannot be planned. Therefore, the decision making procedure is adapted for intermittent energy sources in Section 2.3.1. In Section 2.3.2 the concept of technological learning is discussed. As a result of learning the costs of a certain type of plant will go down with increased penetration. New technologies with high potential for learning are often subject to policies and cost decrease through learning might be an interesting consequence of policies. In Section 2.3.3 cost supply curves are presented to reflect limitations that are faced by certain technologies, and Section 2.3.4 describes a limit to growth, which is implemented because the general decision rule allows especially new technologies to increase at an unrealistic growth rate.

2.3.1 Solar and wind energy in the load level structure

Solar and wind energy are intermittent energy sources. The delivery of their electricity depends on weather conditions and cannot be planned. As a result, they cannot be placed in a single load level. Figure 9 shows the average full load hours solar and wind per load level and the load duration curve. During hours with high electricity demand (peak load) little solar electricity is available, while during hours with low demand, much solar electricity is available. Although the availability of wind matches better with the load duration curve, it can also not be planned according to the load level structure. Investment decisions for those technologies are treated different from other technologies in the model.

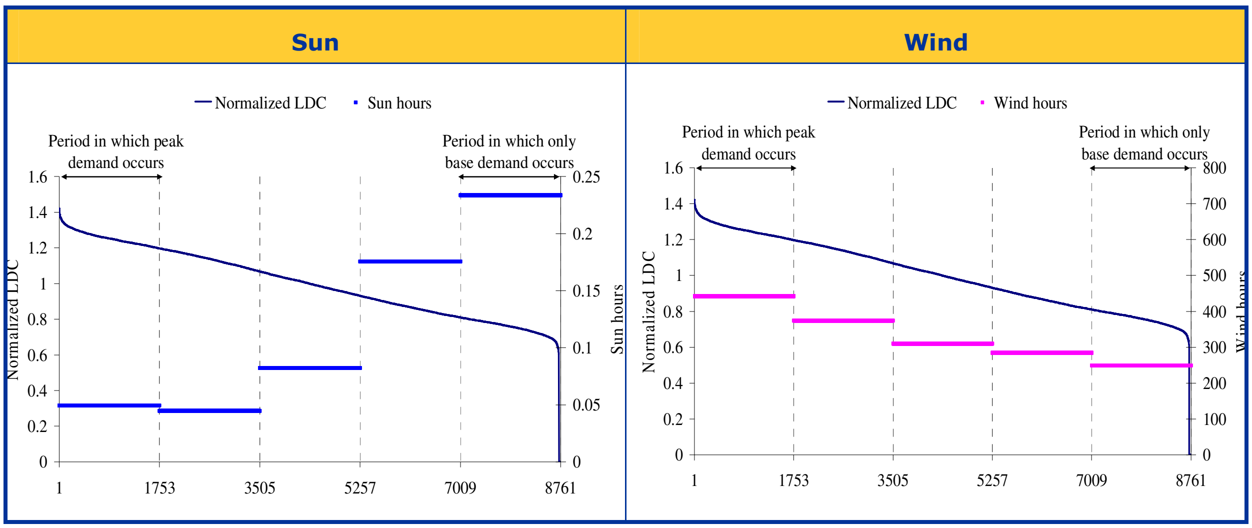

Figure 9: The average of full load sun (left) and wind (right) hours in each load level.

Instead of evaluating wind and solar in the specific load levels, the costs of new wind/solar installations are evaluated against average electricity costs, based on the installed capacity in the previous year. If their price is below average, new capacity is installed. The installation of new wind/solar capacity is limited by four factors:

- a limited growth of 30% per year (Section 2.3.4)
- increasing costs because of depleting potential (cost supply curves, Section 2.3.3)
- increasing need for backup capacity
- increasing supply-demand mismatch

In addition, the competitiveness of solar and wind energy is positively influenced by technological learning. As a result of technological learning, investment costs decrease with increased penetration (Section 2.3.2). The way intermittent energy sources are treated in the model is summarized in Figure 10.

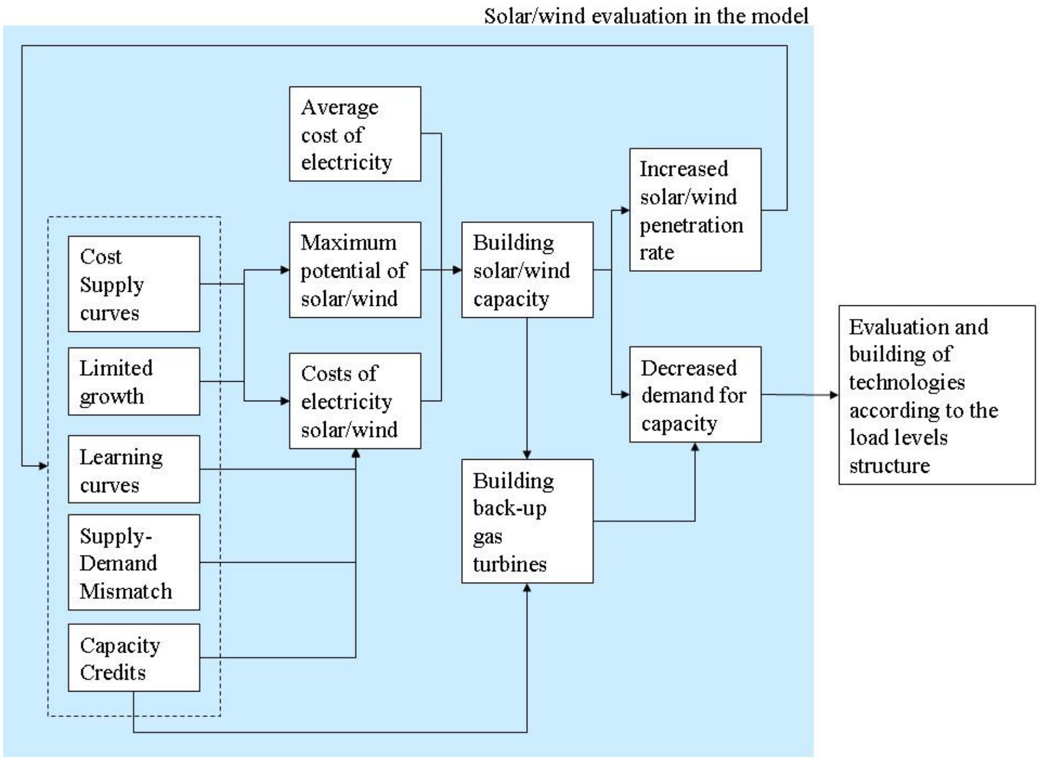

Figure 10: The implementation of solar and wind energy.

Because of the intermittent nature of solar and wind, back-up capacity needs to be installed to limit the risk of blackouts during peak load. We use the capacity credit to reflect this. The capacity credit represents the conventional power plant capacity that can be replaced with one MW of capacity of wind technology is built. Equation 7 shows how the capacity credit for wind is calculated according to Voorspools and D'haeseleer (2006). For solar PV the capacity credit is assumed to be equal to the load factor[5].

Equation 7: $$CC = \frac{23.8}{0.306+\partial} \cdot \frac{CF}{R_{system}} (1 + 3.26 \cdot \partial \cdot e^{-0.1077(0.306+\partial)(x-1)})$$

CC = Capacity Credit in % of installed rated wind power
x = penetration level of wind as % of peak load
CF = Capacity factor of wind (average)
Rsystem = Reliability of conventional plants in % (85% (Voorspools and D'haeseleer, 2006))
ð = dispersion coefficient, 0 < ð < 1 (0.56 in the Netherlands (Van Wijk, 1990))

[5] The capacity credit for solar electricity will drop with very high implementation rates. Since we consider high implementation rates of solar capacity in the Netherlands to be unlikely, this is a valid assumption.

Equation 7 shows that the capacity credit is influenced by a number of factors. The penetration level (x) indicates the share of wind in the total electricity generation mix, as a percentage of peak load. Second, the capacity factor (CF) indicates the average share of full load wind hours per year. Third, the reliability of conventional plants (R) also influences the capacity factor. Fourth, the dispersion coefficient (∂) indicates the spread in wind regime in a country that is analyzed. A dispersion coefficient of 1, means that the output of all wind turbines is perfectly correlated. A dispersion coefficient of 0, means that all turbines provide a constant combined output. The lower the dispersion coefficient, the less risk that electricity supply cannot be met with wind capacity and the higher the capacity credit.

Wind/ solar capacity is built as long as it is profitable. Simultaneously small gas turbines are built as back-up capacity for the part of the wind/solar supply that is not covered by the capacity credit, according to Equation 8. They are most suitable to react fast to fluctuations in wind and solar, and investment costs are relatively low. They form a cheap option for capacity that is in principle not used. This capacity can also be used in the operational strategy. Therefore, only part (30-50%) of the investment costs are allocated to the wind turbines, as was also done by Hoogwijk et al. (2007. The remaining part of the investment costs is allocated to the overall capacity mix and is divided over the load levels. In the comparison between wind electricity costs and average electricity costs, those (high) costs are not taken into account.

Equation 8: $Backup\_Capaciy = (1 - CC) * Wind / solar\_Capacity$

Backup_Capacity = Extra back-up capacity needed due to the intermittency of wind [MW]
CC = Capacity Credit as % of installed rated wind power (Equation 7)
Wind/solar_Capacity = Installed wind/solar capacity

The capacity credit for wind decreases with increased penetration rate of wind. As a result more backup capacity is needed and costs increase. In addition, costs of wind increase because an increasing share of produced wind electricity cannot be supplied to the grid, due to a mismatch between supply and demand. To cover the discarded electricity, we use a mismatch coefficient (Hoogwijk et al., 2007). Holttinen and Pederson (2003) simulated the Danish situation and found that discarded electricity is no issue until a penetration rate of 20% (consistent with Hoogwijk et al., 2007). After this penetration rate the discarded electricity will increase rapidly to 16% with a penetration rate of 40%, as shown in Figure 11.

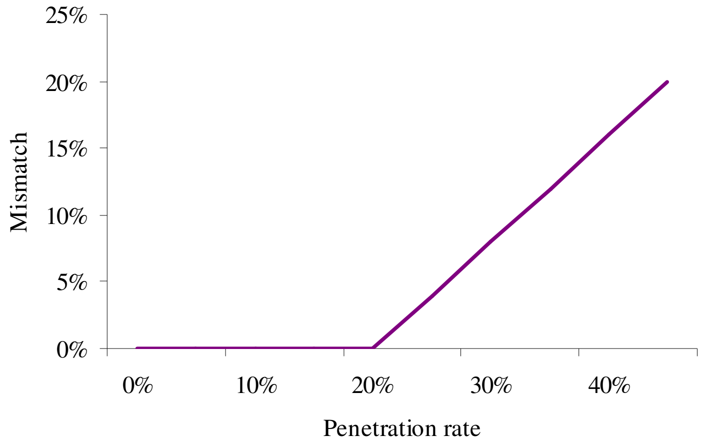

Figure 11: Mismatch between demand and electricity supplied by wind increases with increasing penetration rate (Based on Holttinen and Pederson (2003))

2.3.2 Learning curves

We take technological progress into account by applying learning curves on specific investment costs in the model. A learning curve describes the cost reduction of power plants as a result of increased experience. New technologies will experience a relatively rapid decline in investment costs on the left side of the curve in Figure 12, while older technologies are on the right side of the curve and experience slower cost reductions.

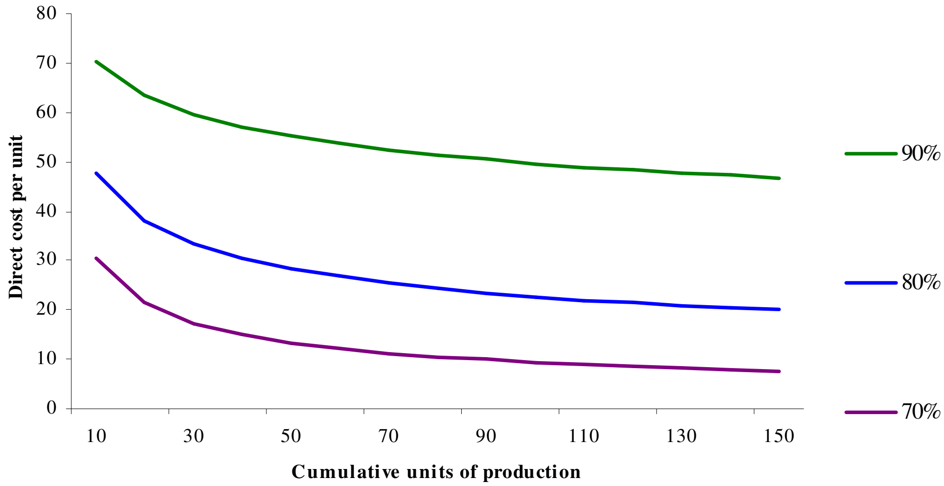

Figure 12: Example of a 'learning' or 'experience' curve with a progress ratio of 90%, 80% and 70%.

The model for 'learning by doing' was introduced by Wright (1936). He described a learning curve by the following equations (Wright, 1936, Riahi et al., 2004, Junginger, 2005):

Equation 9: $$Isp = C_{cum} = C_0 * Cum^b$$

Equation 10: $$PR = 2^b$$

Isp = specific investment costs
Ccum = cost per unit = Specific investment cost
Cum = cumulative production
PR = progress ratio, 0 <PR < 1 (this is the cost reduction when the cumulative installed capacity is doubled)
C0 = cost of first unit produced
b = experience index, -1 < b < 0

Learning curves are derived by fitting a curve (Equation 9) through (cumulative) installed capacity and the related cost level at different time intervals. The results (progress ratio and y-axis intercept) are extrapolated into the future. This approach takes all cost reducing factors into account and thus no distinction can be made between 'learning by doing', 'learning by searching' (RD&D), 'learning by using' or 'learning by interacting' (Junginger, 2005). This use of learning curves automatically incorporates scale effects in the concept of learning (Neij, 1999; Junginger, 2005).

We apply the learning curve to investment costs (and implicitly on O&M costs, which are represented as a share of investment costs). Technological performance (e.g. plant efficiency) is assumed to stay constant over time, independent of increased implementation rates. PLATTS database (which represents power plants from 1882 onwards) provides data on (global) initial cumulative installed capacity, needed in the calculations. New (modelled) plants are added to the cumulative installed capacity. It is assumed that the share of the Netherlands and the EU in global cumulative installed capacity per technology stays constant.

Table 3 provides an overview of the progress ratios in the model. Progress ratios are provided by SERPEC-CC (large hydro, small hydro, wind-onshore, wind off-shore, Solar PV), Rafaj and Kypreos, 2007 (conventional coal advanced, coal gasification and CC gas, with and without CCS). Green-X, 2008 (biomass combustion, biomass gasification), Kahouli-Brahmi, 2008 (small gas turbines, conventional coal normal), Messner, 1997 (solar thermal), and Barreto and Kypreos, 2004 (oil steam electric). Progress ratios of CCS plants and the starting point of the learning curve are calibrated based on data from Rubin et al. (2006) and expected future costs from SERPEC-CC (2008).

2.3.3 Cost supply curves

We apply cost supply curves to represent the potential of a technology that is available at a certain cost level (Blok, 2007). Cost supply curves are required to indicate costs for renewable energy sources. For those technologies there is often limited potential (depending on the country and its climate) and the total potential is non-uniform in terms of quality and costs. We assume that locations are chosen in order of optimal performance. For instance, locations with a highly favourable wind regime will be chosen first, to build wind turbines. Once those locations are used, locations with somewhat less wind will be chosen, etc. The decrease in full load hours (Figure 13) causes an increase in electricity production costs (Figure 14).

We apply a discretized cost supply curve (an example is shown in Figure 14) to the technologies listed in Table 5, based on data from SERPEC-CC (2008). As indicated in this table, the variables through which electricity costs are influenced vary between technologies. For hydropower and geothermal energy the cost supply curves represent maximum annual electricity production, at constant cost level.

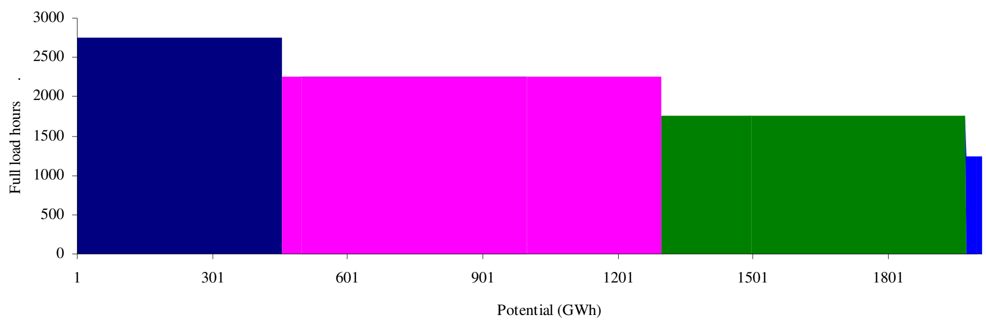

Figure 13: Potential of wind onshore in the Netherlands in 2006 and the related full load hours (Based on data from SERPEC-CC (2008))

The model calculates for each time step the available lowest cost potential. Once this potential is fully used, the model withdraws new production potential from the next 'block' on the cost supply curve (see Figure 10). An overview of the cost supply curve data as implemented in the model is shown in Table 5.

Table 5: Overview of data for cost supply curves for the Netherlands[6]

		Potential (GWh)						
Wind on-shore	Full load hours	2000	2005	2010	2015	2020	2025	2030
	2750	0	454	1963	8003	26591	56298	75448
	2250	0	842	2364	6524	17179	40503	77691
	1750	0	675	1896	5230	13773	32473	62288
	1250	0	37	103	285	750	1769	3394
		Potential (GWh)						
Solar PV	Full load hours	2000	2005	2010	2015	2020	2025	2030
	1781	0	0	0	0	0	0	0
	1500	0	0	0	0	0	0	0
	1266	0	0	0	0	0	0	0
	1078	0	5	95	347	1165	3098	2369
		Potential (GWh)						
Solar thermal	Full load hours	2000	2005	2010	2015	2020	2025	2030
	5606	0	0	0	0	0	0	0
	2716	0	0	0	0	0	0	0
		Potential (GWh)						
Wind off-shore	Specific investment costs (€)	2000	2005	2010	2015	2020	2025	2030
	1856	0	59	256	1102	4599	17091	45648
	2068	0	0	0	597	3756	23208	129571
	2280	0	0	618	3886	24012	134059	489948
	2546	0	0	2808	2808	2808	2808	2808
		Potential (GWh)						
	No cost factor	2000	2005	2010	2015	2020	2025	2030
Large hydro	-	0	88	88	88	88	88	88
Small hydro	-	0	0	0	0	0	0	0
Geothermal	-	0	0	0	0	0	0	0
		Potential (EJ/year)						
Biomass	Fuel price (Euro/GJ)	2000	2005	2010	2015	2020	2025	2030
	3	0.10	0.10	0.10	0.12	0.07	0.08	0.08
	6	0.01	0.01	0.01	0.02	0.02	0.03	0.03

[6] The technical potential comes gradually available, through an S-curve.

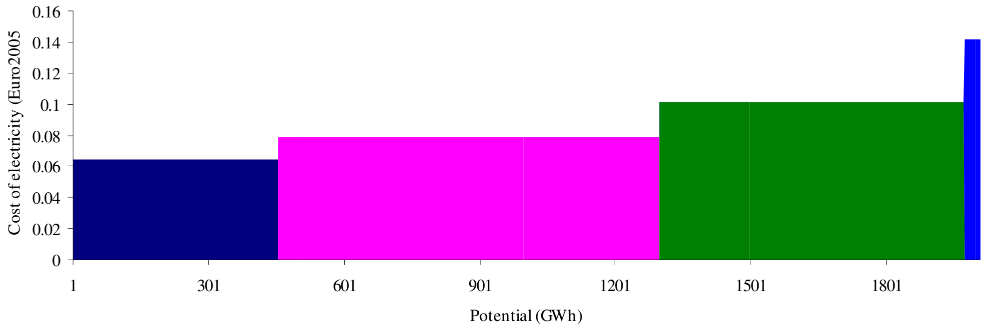

Figure 14: Cost supply curve of on-shore wind in the Netherlands in 2006 (Discount rate = 15%) (Based on data from SERPEC-CC, 2008)

The cost supply curves are derived from SERPEC-CC (2008). Biomass potential is divided in two categories: bio-energy crops and residues. The category 'bio-energy crops' includes oil, starch and sugar crops (Nikolaou, 2003; de Wit and Faaij, 2008). The category 'residues' includes grass, wood, agricultural residues and waste (Nikolaou, 2003). Biomass prices are average values derived from Nikolaou (2003) and calibrated with de Wit and Faaij (2008). Biomass potentials are derived from SERPEC-CC (2008). Cost supply curves are also applied to CCS storage- and transport costs. This is further elaborated in Section 2.4.

2.3.4 Growth limit

Various factors can limit growth of technologies, e.g. shortage in materials or limited production capacity. We apply an exogenous growth limit in the model, by raising costs at high growth rates. Figure 15 shows the development of electricity generation costs as a function of growth rate. The model allows technologies to grow without consequences up to an annual growth of 30%. Costs increase linearly when annual growth exceeds 30%, until other technologies can compete.

Growth is limited when installed capacity of a technology exceeds four times its nominal capacity. The nominal capacities of renewable energy technologies are provided by SERPEC-CC (2008) and are typically small. For the other technologies the average nominal capacity of the PLATTS Europe database is used (see Table 4).

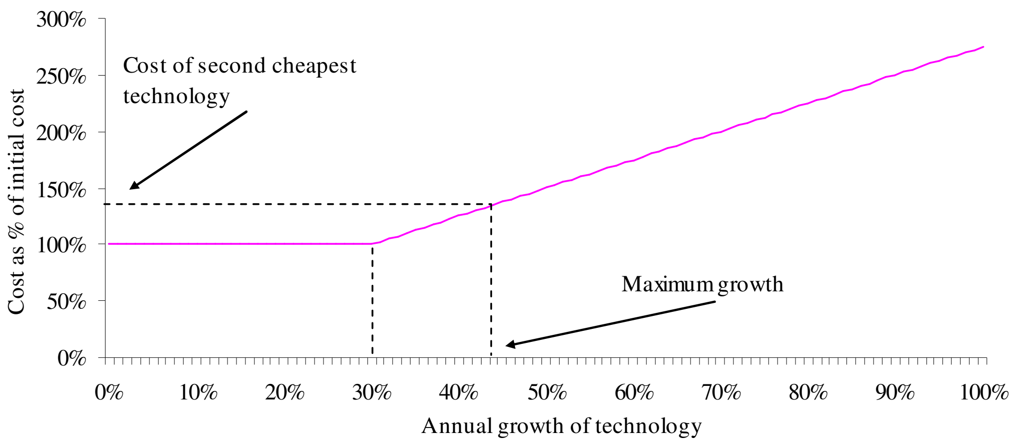

Figure 15: Development of the level of specific investment costs as a function of growth rate.

2.4 Carbon Capture and Storage

So far we described the model to simulate the replacement of electricity generation capacity. This section describes how the three components of CCS: capture (Section 2.4.1), transport (Section 2.4.2) and storage (Section 2.4.3), are implemented.

2.4.1 Capture

The model includes seven types of plants with CCS (see Table 1). Gasification plants (coal and biomass) are equipped with pre-combustion CCS. All other CCS plants are equipped with post-combustion CCS.

The incremental costs for electricity production related with CCS, are mainly due to the costs of capture (IPCC, 2005). Investment costs and operation and maintenance costs are increased by the costs of the capture facility. The reduced energy efficiency of a plant (the energy penalty) raises the electricity generation costs. CO_2 capture can raise the costs of electricity by 10% to 50% (IPCC, 2005; Damen, 2007). With a discount rate of 10% and 2008 fuel prices, capture costs are approximately €0.02/kWh for natural gas fired plants and €0.03/kWh for coal fired power plants. The cost parameters of CCS and reference plants are shown in and Table 4. The costs of compressing CO_2 to a pressure suitable for storage are included in the capture costs. Booster stations to retain pressure during transport are included in transport costs.

2.4.2 Transport

The costs of CO_2-transport are primarily determined by transport distance and economies of scale. Although some case studies exist on the costs of CO_2 transport, most modelling studies assume constant transport costs per ton CO_2 (McCoy and Rubin, 2008; van den Broek et al., 2007b). We assume a constant transport distance of 200 km, which is at the high range of Dutch transport distances (Damen, 2007). However, we include price differences as a result of economies of scale. Economies of scale decrease transport cost through pipeline diameter and decreased pressure losses. With higher annual CO_2 flows, pipelines with larger diameters, lower pressure losses become feasible. As a result transport costs decrease. Transport costs for on-shore pipelines are adopted from Lysen, Jansen and van Egmond (2006) and shown in Table 6. The data is consistent with Lako (2006) and Hendriks et al. (2004). According to IPCC (2005) offshore pipelines are 40% to 70% more expensive than onshore pipelines (IPCC, 2005). An average value of 55% is assumed in the model.

Table 6: Transport costs of CO_2 in the Netherlands (based on data from Lysen, Jansen and van Egmond, 2006).

Annual CO_2 flow (on-shore and off-shore)	Transport cost: €/ton CO_2 (200 km)	
	On-shore	Off-shore
< 1 Mton/year	13.6	21.1
1 t 4 Mton/year	6.8	10.5
>4 Mton/year	3.4	5.1

The additional kWh-costs of large scale CO_2-transport are at most €0.002/kWh (Model calculations; Damen, 2007).

2.4.3 Storage

The Dutch annual CO_2 emission was about 180 Mt CO_2/year in 2007, of which 100 Mt by the energy and industry sectors (Damen, 2007). The total Dutch storage potential is estimated to be between 3500 and 4000 Mt CO_2. This is enough to store 35 years of emissions from energy and industry (by constant emission levels). The Dutch storage potential consists mainly of gas fields, but also other types of storage are available. In our model we make a distinction between 12 types of reservoirs. Storage potential and costs differ between those types of reservoirs. We use the cost supply curve approach (Section 2.3.3) to take the range of storage potentials and costs into account. The different types of reservoirs are used in order of increasing costs.

The storage potential for the Netherlands is based on data from TNO (Simmelink et al. 2007). The 12 different types of reservoirs become available in different years. We do not include the Groningen gas field, since it is expected to become available after 2040, and reservoirs with a capacity smaller than 4 Mt CO_2 (Simmelink et al., 2007; Damen, 2007). The annual available storage potential is shown in Figure 16.

The total storage potential included in the model is 3910 Mt CO_2. Including the Groningen gas field would add another 7350 Mt CO_2 to the Dutch storage potential.

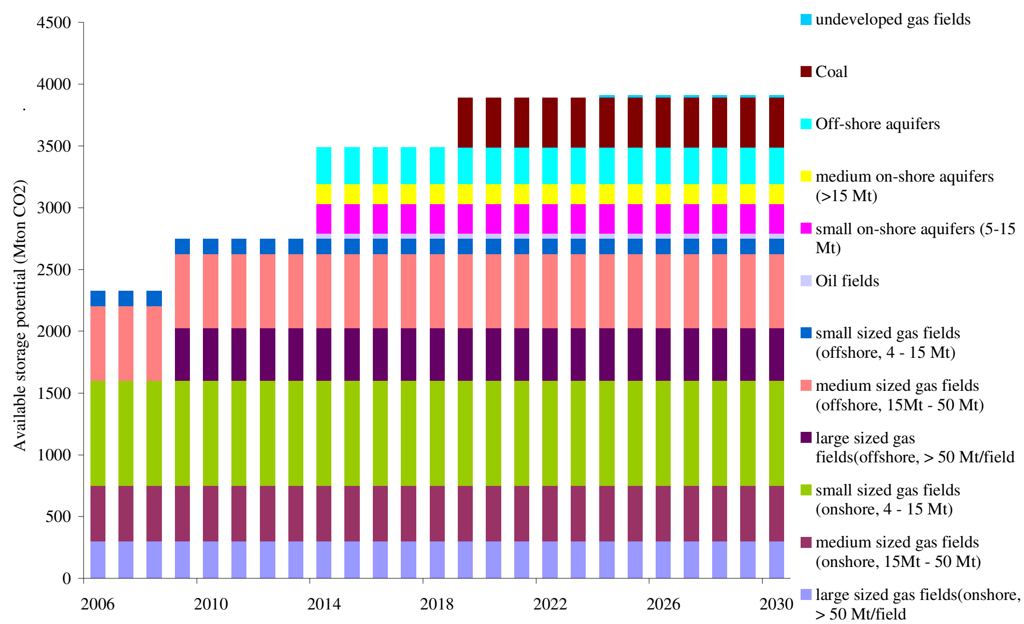

Figure 16: CO_2 storage potential subdivided into types of storage for the Netherlands (based on Simmelink et al. (2007))

We assume that a CCS power plant will store its emissions in the same reservoir during its lifetime. This implies that the model assigns the CO_2-emissions that will be stored over the whole lifetime of the plant to one reservoir. The available storage capacity is reduced accordingly.

The costs of storage are provided by Hendriks et al. (2004) for different storage depths (see Table 7). In the Netherlands most storage locations are at a depth of 2000-3000 m (Simmelink et al., 2004). We assume all CO_2 will be stored at 2000 m depth. The costs of storage in coal seams are based on Hamelinck et al. (2002) and Wildenborg and van der Meer (2002). Storage costs increase electricity costs by approximately € 0.001/kWh.

Table 7: Costs of CO_2-storage (Hendriks et al., 2004; Costs of storage in coal seams is based on data from Hamelinck et al., 2002 and Wildenborg and van der Meer, 2002)

€/tonne CO_2	Depth of storage (m)		
	1000	2000	3000
Aquifer onshore	1.8	2.7	5.9
Aquifer offshore	4.5	7.3	11.4
Gas field onshore	1.1	1.6	3.6
Gas field offshore	3.6	5.7	7.7
Oil field onshore	1.1	1.6	3.6
Oil field offshore	3.6	5.7	7.7
Coal seams		15	

2.5 Implementation of policies in the model

The model provides extensive possibilities to perform policy analyses. The policy options that are implemented in the model are:

- CO_2-price
- Subsidies
- Feed-in tariffs
- CCS standards
- Regulations on storage options
- Variable discount rates

An overview of the different policy options and how they are implemented in the model is shown in Figure 17. This section describes how the policy options are implemented in the model. Regulations on storage options and variable discount rates are not discussed, since they are not included in the policy analyses.

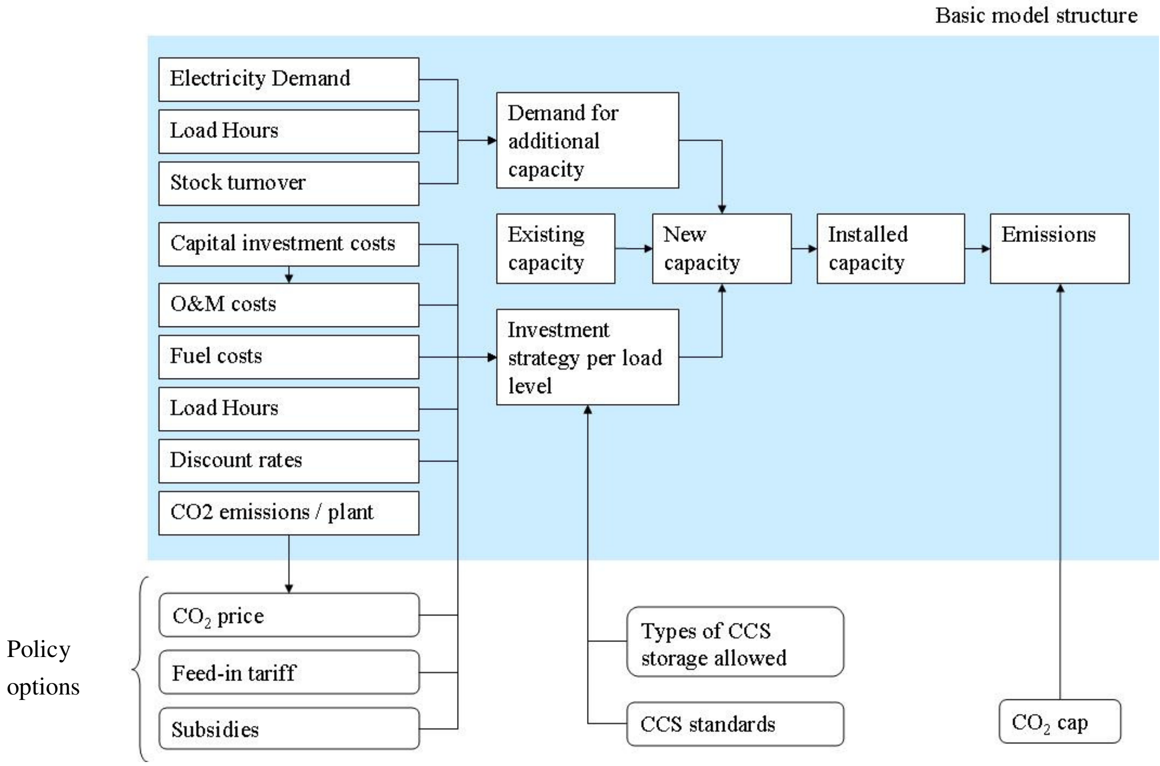

Figure 17: Schematic overview of the basic model structures and of policy options and their positioning relative to the basic structure.

2.5.1 CO_2-price

As described in Section 1.4, the EU ETS is an important policy instrument in the EU and Dutch climate policy portfolio. The model includes the CO_2-price as a price per tonne CO_2 emitted, with which the costs of electricity are increased. The initial value of the CO_2-price, as well as its annual growth can be varied. The value of the CO_2-price is assumed to be €25,-/ ton CO_2 in 2008, which is the actual CO_2-price in August 2008 (PointCarbon, 2008). In specific CO_2-price scenarios, many different annual growth rates are implemented between 0% and 10%. In combination scenarios a default annual CO_2-price growth is assumed of 2%. This results in a CO_2-price of €39,-/ton in 2030. This reflects estimates of CO_2-price development (i.e. Vosbeek and Warmenhoven, 2007).

2.5.2 Subsidies

The model includes subsidies to all renewable and CCS technologies in two different ways; demonstration subsidies and investment subsidies. Both subsidies are implemented as a share of total investment costs. Demonstration subsidies are specifically aimed at financing CCS demonstration plants, and have a limited budget. Investment subsidies are in general lower and run for a specified time period, without budget limitations.

The limited budget for the CCS demonstration subsidy is based on the EU target of 10-12 CCS demonstration plants running by 2015 and the Dutch ambition to contribute with 2 plants (Eemshaven and Rijnmond: Schoon en zuinig, 2007), with a size of 1200 MW each (Didde, 2008). The public (inc. EU and national government budget) expenditure available to finance CCS is estimated to be in the order of 250 millions € for a 400 MW plant (EC, 2008c). Based on those estimates we use the Dutch demonstration budget of €1.5 billion. The EC investment estimates are based on a 50/50 distribution of public and private sources. Another €1.5 billion is assumed to be spent by private parties. This leads to a scenario in which €3 billion is available to finance investment costs for CCS plants between 2008 and 2020. The demonstration subsidy provides at the most the full investment costs of the CCS part of the plant (approximately 40% of the total plant investment costs).

2.5.3 Feed-in tariffs

In the Dutch policy scheme feed-in tariffs are used to stimulate renewable energy. The MEP subsidy scheme was terminated in 2006, because expenditure had become too high. Provided the success of the policy, it was expected that the target of 9% renewables in 2010 would be easily reached. In 2008 the MEP subsidy scheme is replaced by a comparable feed-in tariff scheme, the SDE (Stimulation of sustainable energy production). The Netherlands does not consider the use of feed-in tariffs for the stimulation of CCS yet. However its effectiveness and its usability for the demonstration as well as the up-scaling phase, make it a potential policy option for CCS stimulation (Groenenberg and de Coninck, 2008).

We include a feed-in system in the model, based on the Dutch SDE system. A fixed subsidy per kWh is donated to renewable electricity. We adopted the tariffs of the SDE for renewables: wind on-shore: €0.028 /kWh, solar PV: €0.33 /kWh and biomass: €0.053 /kWh. Tariffs for wind off-shore are not yet determined. We assume a tariff of €0.047 /kWh, which is the sum of the wind on-shore tariff and the cost-difference between off-shore and on-shore wind by a discount rate of 10%. Apart from the sensitivity analyses we implement a feed-in tariff for CCS of €0.02 /kWh. Feed-in tariffs run either until 2020 or 2030. When a feed-in tariff is implemented in combination with a CO_2-price, no feed-in tariff is assigned to biomass CCS options, since the negative emissions already provide a kind of feed-in tariff under the ETS.

2.5.4 CCS standards

One of the policy options mentioned in the CCS discussion is the obliged implementation of CCS in new coal and/or gas fired power plants (EC, 2008b; Schoon en Zuinig, 2007). We include scenarios in which CCS is obliged on three levels of stringency. CCS standards is applied to: new coal fired power plants; new coal and gas fired power plants; or new coal, gas and biomass fired power plants. CCS standards runs for the period 2020-2030. Intermittent energy sources are usually evaluated against the average cost of electricity that is actually delivered to the grid in the previous year. Since CCS standards inhibits that some cheap technologies cannot be built anymore, renewables suddenly compete with more expensive technologies. This is not reflected in the average electricity price, and thus in case of CCS standards wind and solar energy are evaluated against the price of the cheapest CCS technology (in the base load).

3 Results

The model described in Chapter 2 is used to generate a range of policy scenarios, aiming to stimulate CCS. The results of those analyses are described in this chapter.

A baseline scenario, without policies, is produced as a reference to the policy scenarios (Section 3.1). We analyze four policy options separately, to make clear what the effect is of those single policy options. A number of scenarios with CO_2-prices is produced in Section 3.2, with different boundary conditions. Different rates of subsidies for CCS are applied in addition to a CO_2-price in Section 3.3. Section 3.4 describes different scenarios with feed-in tariffs for renewable energy sources and CCS. Section 3.5 discusses scenarios with CCS standards. Different policies are combined in Section 3.7; to explore what the role of CCS might be when policies are combined. The cost effectiveness of policies is discussed in Section 3.8. In this chapter we present among others the societal costs of a number of scenarios. Societal costs represent the total costs of generating electricity with the installed capacity that is a result of the model calculations. To calculate the societal costs we use a societal discount rate of 6% (Based on Joode et al., 2004 and own expertise). Note that our analysis does not include the possibility to retrofit or early retire a power plant. The results reflect the effect of policies on new to be built power plants. Nuclear energy is assumed to be no viable option.

3.1 Baseline

We compare the results of the policy scenarios to the baseline scenario. The baseline scenario is a scenario without any kind of policy option. Without policies, the Dutch electricity generation mix would shift from a natural gas dominated sector to a coal dominated sector. In this scenario gas fired power plants are strictly built to be used in the peak load hours and renewable technology is not competitive. The competitive advantage of coal can be explained by the low coal price and the high natural gas price.

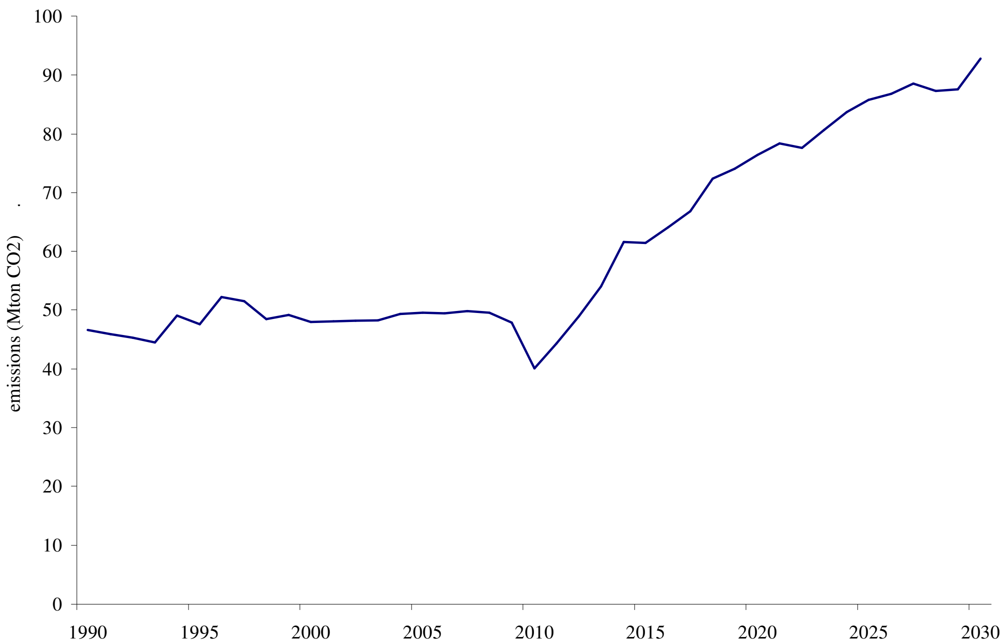

Figure 18: CO_2-emissions in the baseline scenario (no policy)

Figure 18 shows the CO_2-emissions in the baseline scenario, and Figure 19 shows the development over time of the electricity generation mix in this scenario. From 2010 onwards, the emissions increase considerably as a result of the rapid expansion of coal fired generation capacity. The CO_2-emissions show a sudden breakdown in 2010, followed by a rapid increase. In the Netherlands, currently more capacity is installed than needed. The model will only start implementing new power plants if demand for capacity exceeds available capacity. Based on our assumptions on power plant lifetimes, in 2010 the Maasvlakte power station (2 coal fired units of 520 MW each) will retire. The contribution of this large plant to CO_2-emissions is such that emissions drop immediately when it retires and a higher share of electricity is produced by gas plants. From 2010 onwards, there is no overcapacity and the model builds additional capacity to meet (increasing) demand.

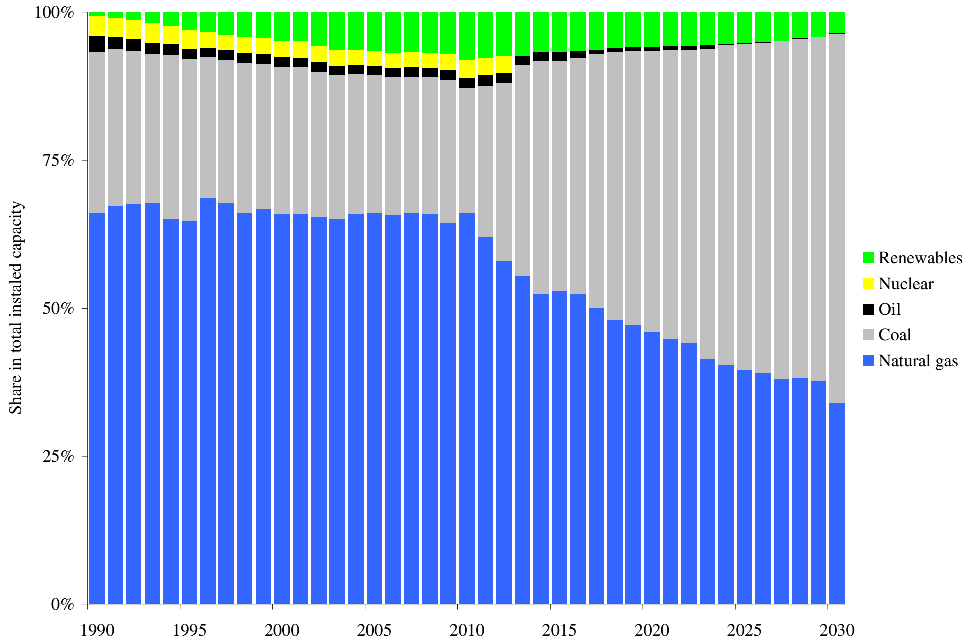

Figure 19: The development of the electricity generation mix according to the baseline scenario.

The CO_2-emissions in the baseline scenario gradually rise from 47 Mton CO_2 in 1990 to 76 Mton CO_2 in 2020 to 93 Mton CO_2 in 2030. While the target for 2020 is 37.6 Mton.

3.2 CO_2-price

The CO_2-price is implemented in eleven scenarios with the same initial (2008) CO_2-price of €25,-/ton CO_2. The pace at which the CO_2-price grows annually is varied between 0% and 10%. This analysis (consisting of eleven scenarios) is repeated for several cases:

1. No restrictions
2. Emissions stored through biomass CCS are not acknowledged as negative emissions in the EU ETS
3. Case 2 in addition to reduction of small-scale transport costs to the level of large scale transport

Figure 20, Figure 22 and Figure 23 show the resulting technology mix in 2030 for case 1 to 3 respectively, in the different CO_2-price scenarios. Each bar represents one of the scenarios. The range of CO_2-prices in the scenarios is shown under the graphs.

3.2.1 Case 1 – No restrictions

The electricity generation mix in 2030 is shown in Figure 20. Every column shows a scenario with a different annual increase in CO_2-price. Gas remains an important fuel in those scenarios. The share of renewable energy sources increases with increasing CO_2-price. CCS is first implemented with a CO_2-price of €38,-/ton CO_2. The share of CCS gradually increases up to an annual CO_2-price increase of 7% (from €25,- in 2008 to €111,- in 2030). For higher CO_2-price growth rates, its share decreases again. With high CO_2-prices, the part of the emissions that is not captured and has to be paid through a CO_2-price (about 10% - 15% of the total emissions) increases the costs substantially, so that CCS is less competitive to renewable energy sources.

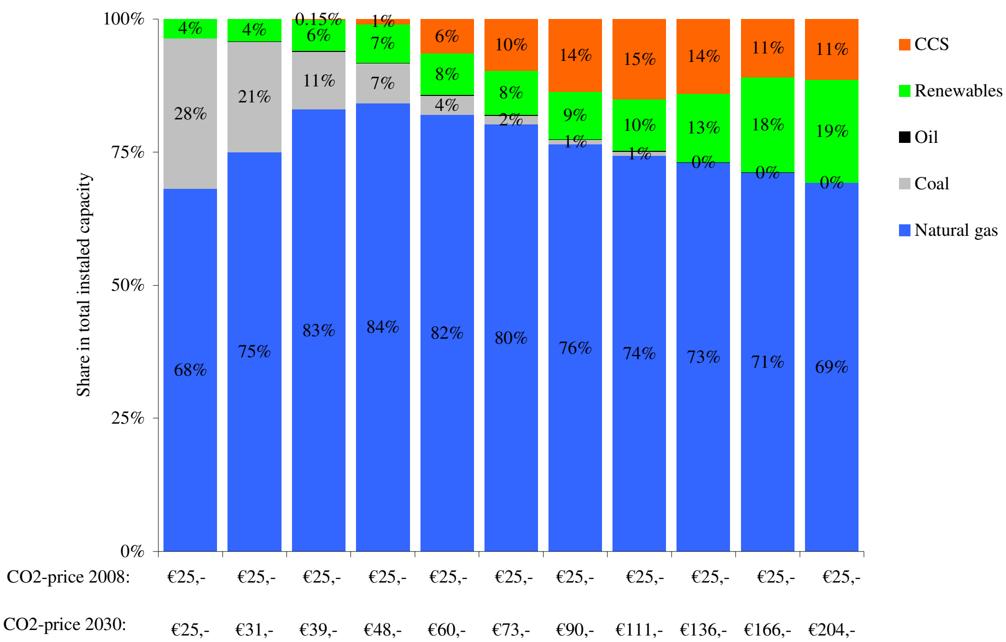

Figure 20: The electricity generation mix in 2030 for different rates of CO_2-price increase.

For the same scenarios, Figure 21 shows the shares of different types of CCS. The graph illustrates the favourable effect of a CO_2-price for biomass fired plants with CCS. This is a result of the way emissions from biomass CCS plants are modelled. Emissions from biomass combustion or gasification are reported as zero in the ETS. If the CO_2 emitted by a biomass plant is captured through CCS, over the whole CO_2 cycle CO_2 is actually abstracted from the atmosphere. This means that the emissions from a biomass plant with CCS, as reported in the ETS system, become below zero. In other words, a biomass plant can produce European Emission Allowances (EUA's; IPCC, 2006). The costs of generating electricity, using this technology might become below zero, when the CO_2-price is high enough. But biomass potential is limited, by the cost supply curve (Section 2.3.3). Note that there is no system yet to let power plants produce EUA's.

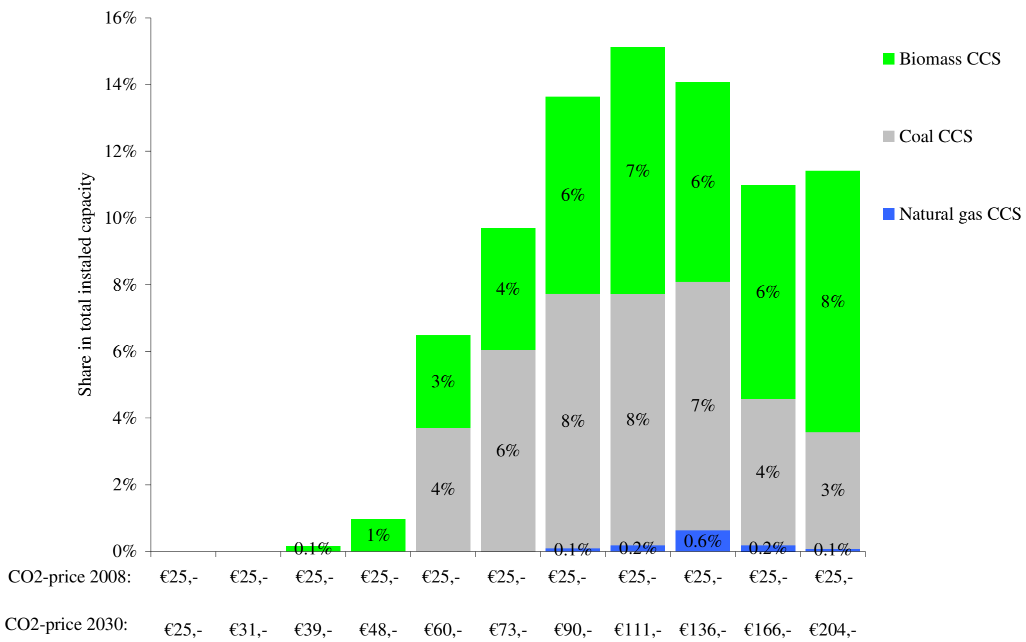

Figure 21: The share of different types of CCS in total installed capacity for different rates of CO_2-price increase.

3.2.2 Case 2 – Negative emissions are not acknowledged through the EU ETS

The same analysis of a range of CO_2-price scenarios is repeated without the acknowledgement of CO_2 captured by biomass CCS plants. The results are shown in Figure 22. In this case, something remarkable occurs. In a case 1 scenario where the CO_2-price increases from €25,- in 2008 to €60,- in 2030, 4% of the installed capacity in 2030 is CCS coal (see Figure 21). In a scenario with the same price range, but for case 2, there are no CCS plants built at all. This can be explained by the scale advantages in transport cost that biomass CCS imposed in the scenarios from Figure

20. The first Mtons to transport are much more expensive (see Section 2.4.2) and the CO_2-price has to be relatively high to overcome this hurdle. Since biomass had already reduced these costs in the scenarios where it could produce EUA's, the costs of generating electricity from CCS coal and gas were smaller and they became competitive sooner. In the scenarios where biomass CCS could not produce EUA's, the hurdle of the first transport costs still had to be taken and a much higher CO_2-price was needed to make CCS (coal and gas) competitive.

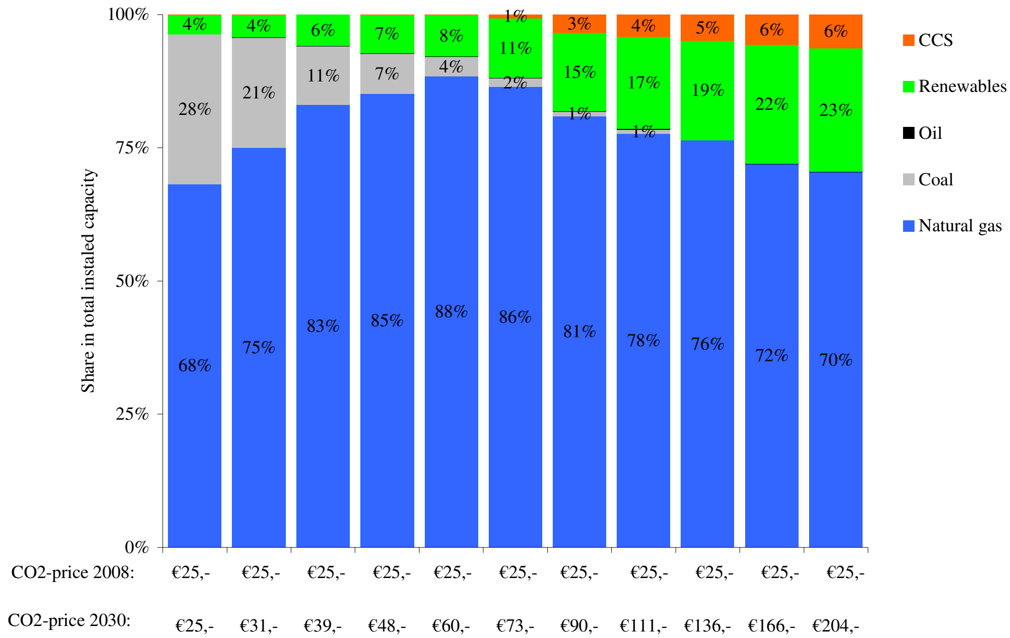

Figure 22: The electricity generation mix in 2030 for different rates of CO_2-price increase when negative emissions are not acknowledged.

3.2.3 Case 3 – Costs for small scale transport are reduced

Figure 23 shows the same scenarios for a case in which biomass CCS is not acknowledged as in case 2 and in addition, CO_2-transport costs are from the start at the (low) level of large scale transport. Figure 23 shows the electricity generation mix in 2030 for the different CO_2-price scenarios. In this case, CCS is first implemented with a CO_2-price of €37,-/ton CO_2. This implies that initial support/funding for transport facilities is an effective option to stimulate CCS. How this support best is designed is outside the scope of this research and further research is recommended. Several authors make suggestions on possible transport support mechanisms, like government or EU construction of a pipeline network (Vosbeek and Warmenhoven, 2007), spatial planning of new power plants (Damen, 2007) or reusing infrastructure (Damen, 2007).

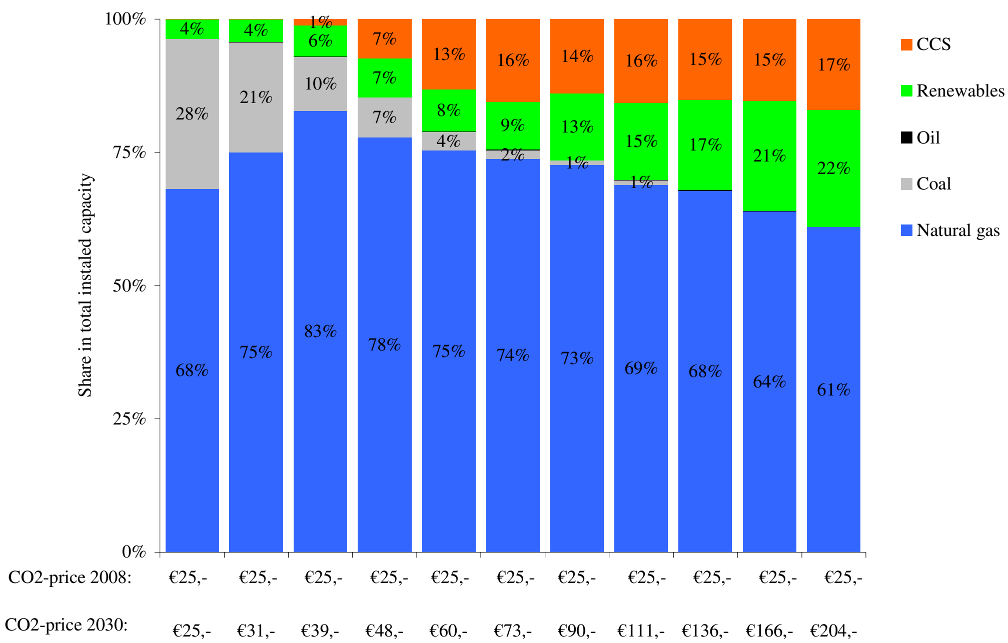

Figure 23: The electricity generation mix in 2030 for different rates of CO_2-price increase when biomass CCS cannot produce EUA's and initial transport costs are assumed to be low.

In Figure 23 the share of CCS is slightly varying. This is caused by the annual differences in demand for new capacity and the different years in which CCS implementation peaks, before declining due to increased CO_2-costs. Although electricity demand rises gradually, in some years many plants are retired, whereas in other years only little new capacity is needed. In the scenarios where the CO_2-price increases rapidly, at some point the competitiveness of CCS declines, due to the costs of the remaining emissions. As a result, the installed capacity declines.

Figure 24 shows the share of CCS in the capacity that is built over time. The grey bars in the figure represent the total capacity in MW that is built every year. If the peak in the share of CCS that is to be built overlaps with years with high level of capacity that is built, the share of CCS can be higher than in other scenarios, even if the CO_2-price is that high that CCS becomes less competitive. The peak in the building of new CCS capacity differs between the scenarios and the fluctuations in demand for new capacity cause the variations in the share of CCS in Figure 23. If the peak in to be built CCS capacity, overlaps with high demand for new capacity, the scenarios will have relatively more CCS.

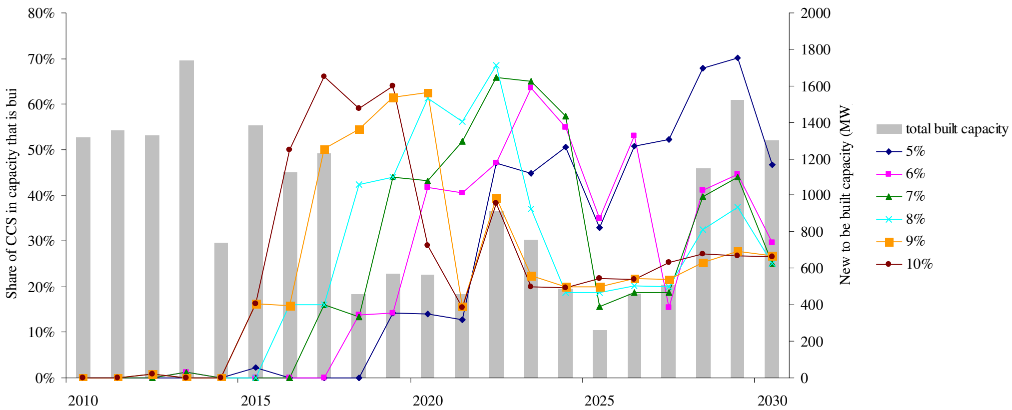

Figure 24: The annual share of CCS capacity in total built capacity for different rates of CO_2-price increase and the annual capacity to be built.

Figure 20 through Figure 23 show that the penetration of CCS is moderate in the CO_2-price scenarios we included in the analysis. The CO_2-price increases gradually from the current (2008) price level, €25/ton CO_2. Since CCS only becomes competitive at €40/ton CO_2 (case 1, no restrictions), much capacity has been built before CCS is implemented. Fossil fuels can still compete with renewable energy sources at current CO_2-price levels. In scenarios with a gradual increase of CO_2-prices, there is a lock-in of fossil fuel technology (Note that retrofit and early retirement are not included in the analysis). Groenenberg and de Coninck (2008) state that the ETS forms a weak incentive, in the current form with short time periods and high uncertainty, and that additional policy is needed to stimulate CCS. If an energy supplier would expect CO_2-prices to increase in the future, he would probably invest sooner in CCS than when there was high uncertainty, about whether the price would rise as well. In the model analysis there is no foresight mechanism with respect to expected CO_2-prices. This reflects a situation with uncertainty. Our findings support the conclusion of Groenenberg and de Coninck (2008), that additional policy is needed to the ETS system to implement CCS.

We compare the results to three target levels. First the 20% share of renewable energy sources in 2020, second a CO_2-emission reduction of 20% compared to the 1990 level in 2020, which is equal to 37.6 Mton for the centralized power sector as defined in this report, third a calculated CO_2-emissions target for 2030, based on linear interpolation between the 2020 and 2050 (50%) target of the EU (resulting in a

30% reduction target in 2030). Table 1 shows the lowest CO_2-price scenarios for which targets are met. Most of the scenarios analysed in this section are not effective in reaching the targets imposed by the European commission and the Dutch government. This is illustrated by Table 1, which shows the rates of CO_2-price increase required to meet the targets. In none of the scenarios analysed the targets for renewable energy sources or the 2020 emission targets were met. The calculated target for 2030 was met when the CO_2-price increased with an annual rate of 6% from €25,-/ton CO_2 in 2008 to €90,-/ton CO_2 in 2030. In case 2, where biomass CCS could not produce EUA's, the 2030 target was only met when initial CO_2 transport costs were kept low. In this case a CO_2-price increase of 9% was needed to reach the target (from €25,-/ton CO_2 in 2008 to €166,-/ton CO_2 in 2030).

Table 1: Minimum levels of CO_2-price increase, required to reach mitigation targets for the three cases analysed.

Case		2020 renewables target	2020 emission target	Calculated 2030 emission target
4	No restrictions	-	-	6%
5	No production of EUA's by biomass CCS	-	-	-
6	No production of EUA's and low initial transport costs	-	-	9%

The assumption that the CO_2-price rises gradually, starting at the actual level has significant effect on the achievement of emission targets. A sudden increase in CO_2-price would impose earlier abatement and higher likelihood that targets will be met. It should be emphasized that we do not include possibilities for early retirement of power plants or retrofit. Both possibilities might become feasible at high CO_2-prices. However, the possibilities of retrofit and early retirement are subject to discussion (see Chapter 5).

Figure 25 shows the range of CO_2-emissions for the different cases. For every case, the scenario with a constant CO_2-price of €25,- is shown, and the scenario with the highest CO_2-price increase from €25,- in 2008 to €204,- in 2030. The arrows on the left side point out the range of the different cases. Case 1, without restrictions, results in the lowest CO_2-emissions. The highest CO_2-emissions result from case 2 scenarios.

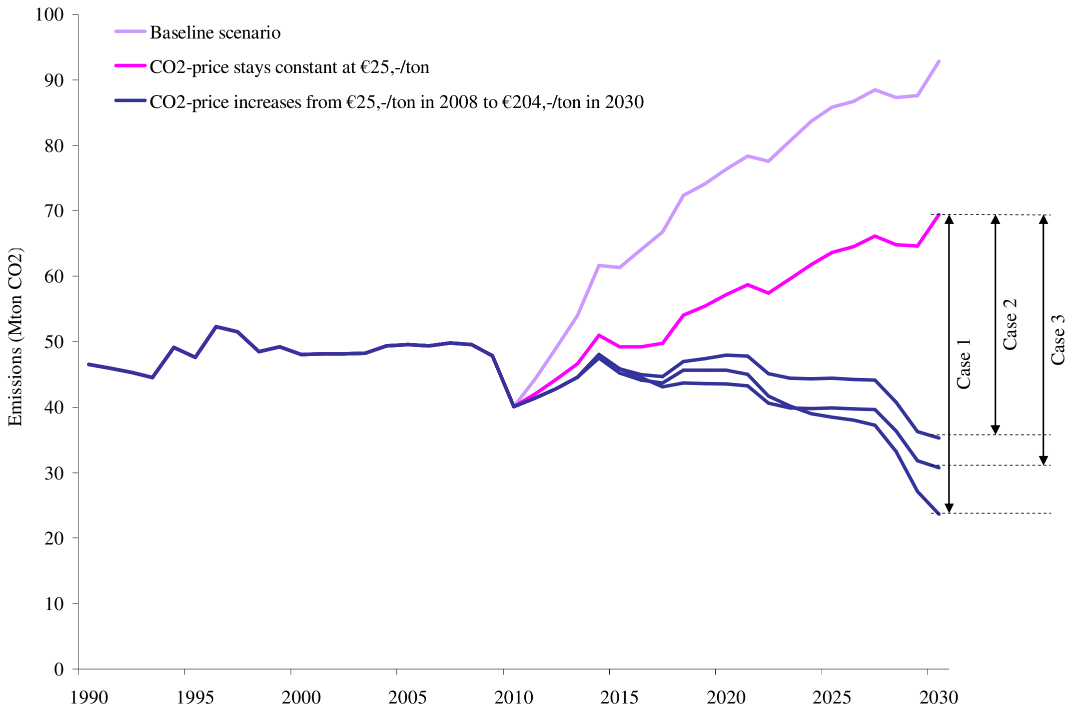

Figure 25: CO_2-emissions in two different CO_2-price scenarios for the three cases discussed

Figure 26 shows the annual societal costs of generating electricity for the three cases discussed in this section and a CO_2-price increase of 6% per year. At this level, the CO_2-price increases from €25,-/ton CO_2 in 2008 to €90,-/ton CO_2. Case 2 imposes the least societal costs. Case 1 imposes the highest societal costs, since it is beneficial for biomass CCS, which has very high costs of generating electricity. From case 2 and 3, case 3 is most expensive since more CCS capacity is built in this scenario.

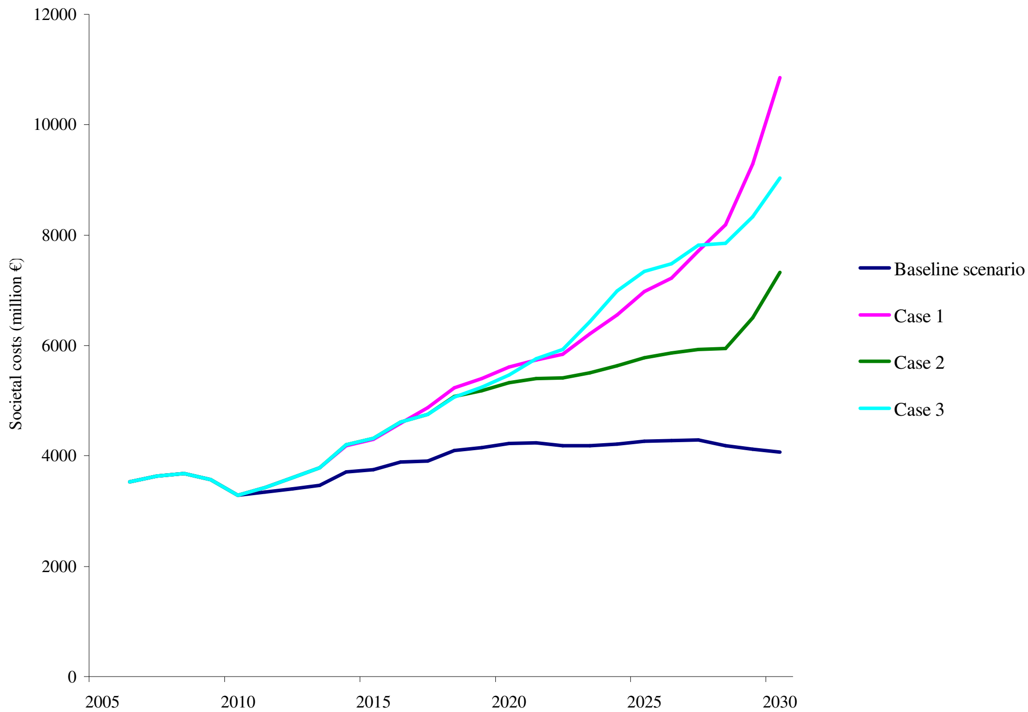

Figure 26: Annual societal costs (CO_2-price not included) for the three cases with a CO_2-price increase of 6% per year.

3.3 Subsidies

In order to analyze the effect of CCS demonstration subsidies, we created four scenarios, with different subsidies. In those scenarios, the CCS part of the capital investment costs of a plant is subsidized, at different rates. The amount of money spent on subsidies is restricted at € 3.000.000.000,- (derived from EC, 2008c, see Section 2.5.2). In those scenarios we assume a CO_2-price of €25,-/ton CO_2, which gradually rises with 2% per year to €39,-/ton CO_2 in 2030. The subsidy is available from 2010 onwards. Figure 27 shows the share of CCS in 2030 for scenarios, with different subsidy levels. In combination with a CO_2-price which increases with 2% per year, 10% investment subsidy, imposes enough incentive to introduce CCS. This percentage is based on total plant investment costs, and is equivalent to about 25% of capture investment costs. CCS is introduced in 2025 at a CO_2-price of €35,-/ton CO_2. In this scenario gas fired CCS plants form the largest share of CCS. With increased investment subsidies, coal fired and biomass fired power plants gain momentum, since investment costs for those plants are relatively high. When all CCS investment costs are subsidized (40% of total investment costs), CCS is introduced in 2016 at a CO_2-price of €29,-/ton CO_2.

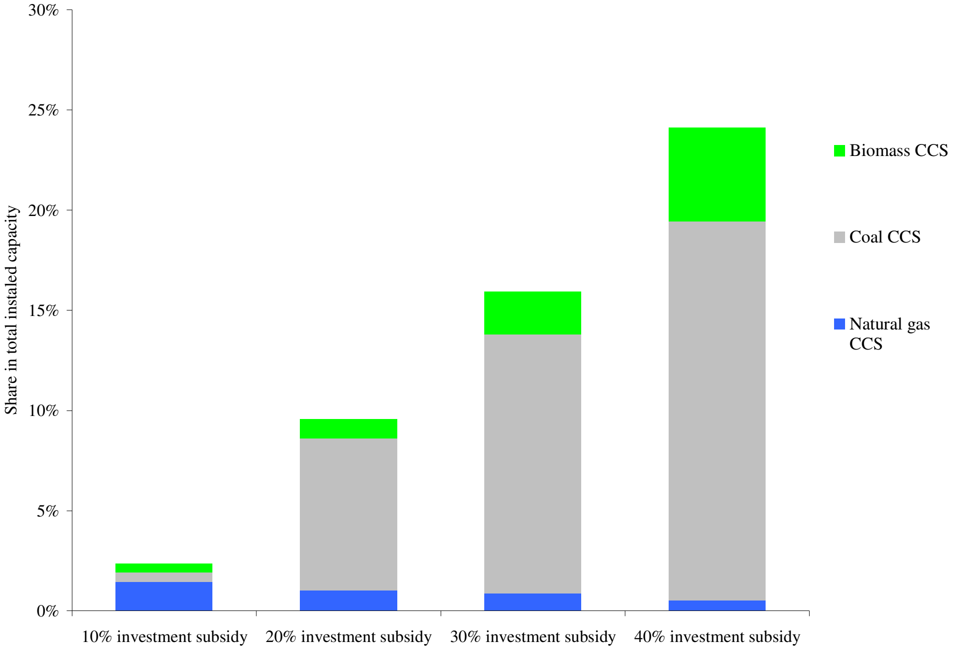

Figure 27: The share in total installed capacity in 2030 of different types of CCS for different investment subsidies.

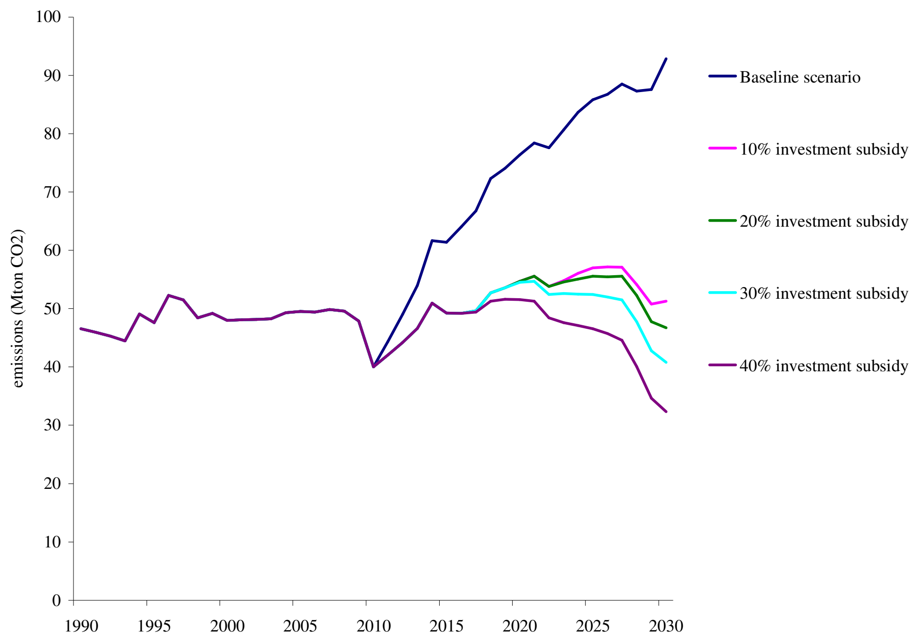

Figure 28: CO_2-emissions for different CCS investment subsidies scenarios.

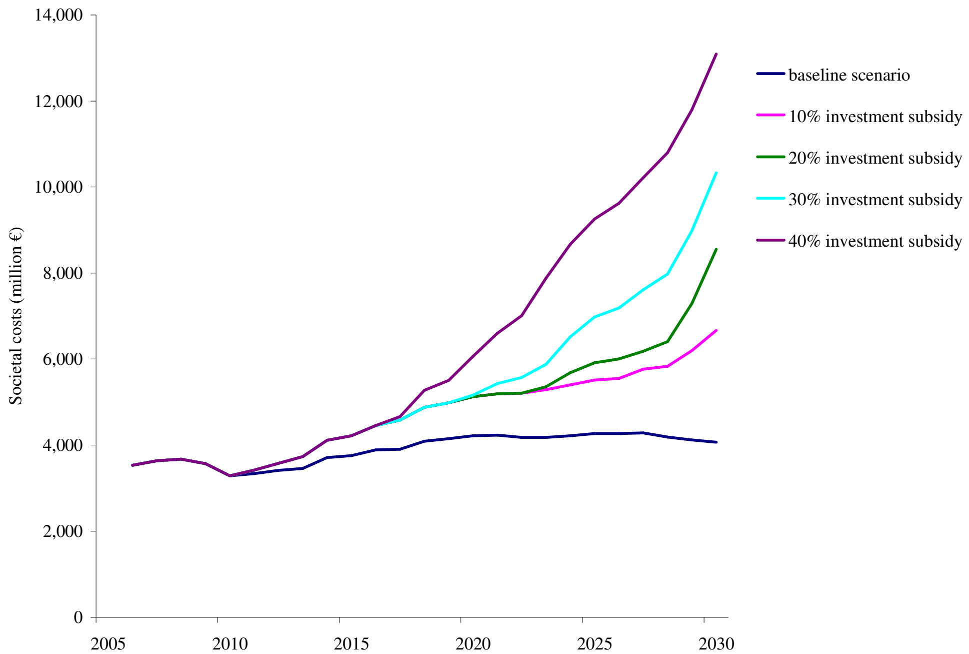

Figure 29: Annual societal costs for different CCS subsidies. In all scenarios the CO CO_2-price rises linearly from €25,- in 2008 to €39,- in 2030.

3.4 Feed-in tariffs

A third policy option we include in the analysis is a feed-in tariff on electricity generated in CCS plants. Figure 30 shows the electricity generation mix of five scenarios with feed-in tariffs from 2010 onwards. In all scenarios the tariffs for renewables are kept constant at the level of the Dutch SDE scheme, as described in Section 2.5.3. The feed-in tariffs for CCS are respectively €0.02/kWh, €0.03/kWh, €0.04/kWh or €0.05/kWh. Those scenarios do not include a CO_2-price. We find that a feed-in tariff for CCS of €0.025/kWh is not sufficient to stimulate CCS. A feed-in tariff of €0.03/kWh or more does stimulate CCS. Figure 30 shows that, with a feed-in tariff of €0.03/kWh, CCS competes mainly with coal and only little with gas, but not with renewables. With higher feed-in tariffs, CCS competes with renewables as well and gains large market shares. A feed-in tariff for CCS of €0.03/kWh (in combination with the SDE subsidy scheme) would be sufficient to be on schedule for the 2050 target in 2030, with a CO_2-emission of 30 Mton CO_2. Note that we assumed that CCS can be implemented on a large scale from 2010 on. This is regarded as being an optimistic assumption. Figure 31 shows the CO_2-emissions for a selection of feed-in tariff scenarios. The societal costs are shown in Figure 32. For feed-in tariffs that impose large scale implementation of CCS, societal costs are high.

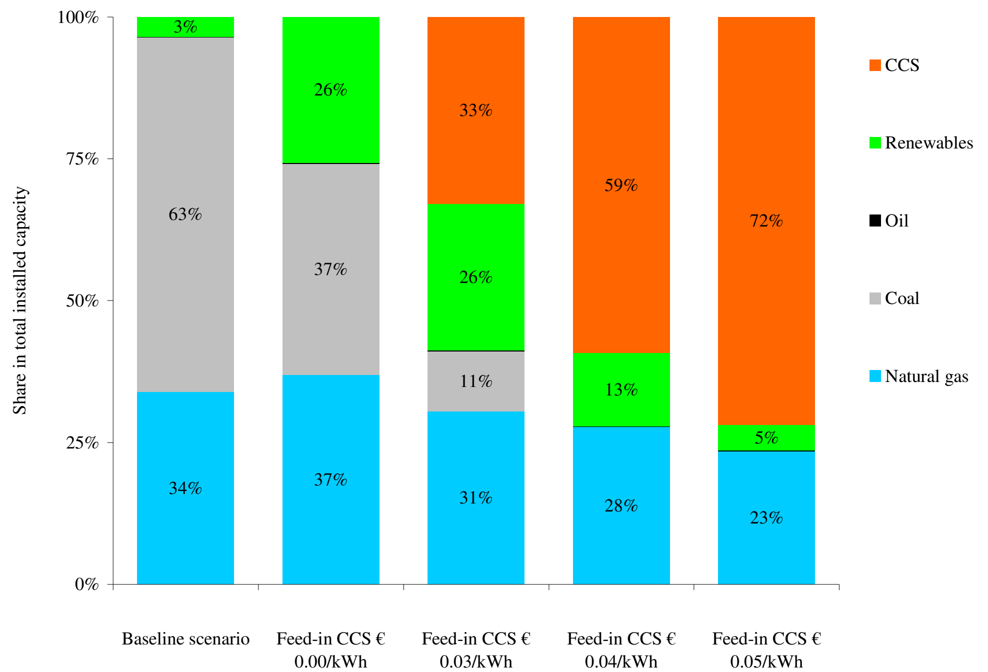

Figure 30: The electricity generation mix in 2030 according to the baseline scenario and four feed-in tariff scenarios. Renewables receive feed-in tariffs in all feed-in scenarios.

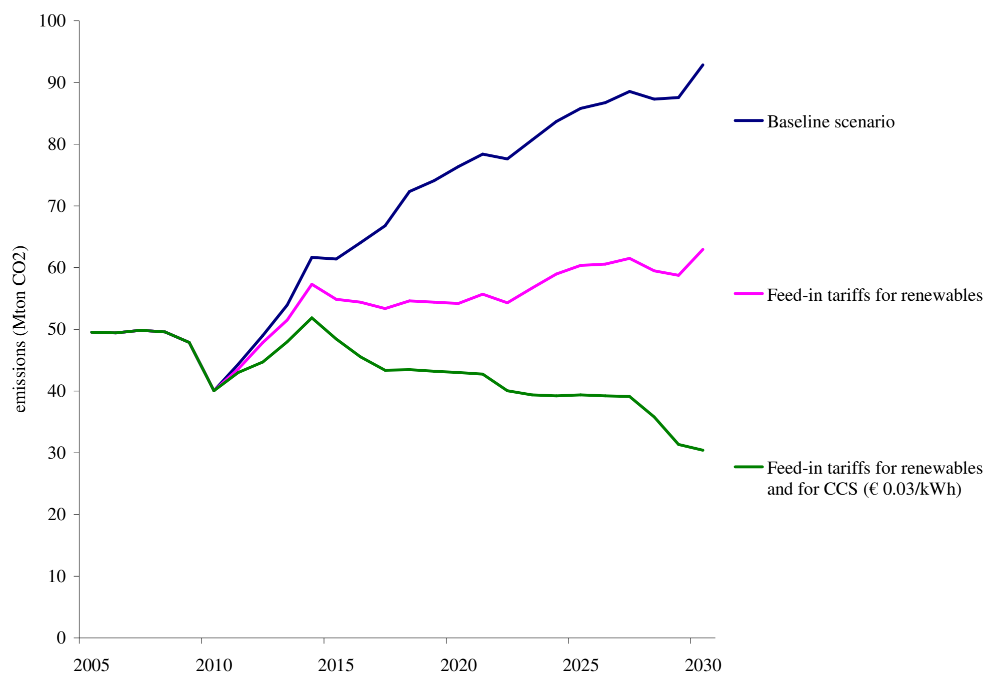

Figure 31: CO_2-emissions for the different feed-in tariff scenarios.

A striking result is obtained from the analyses: with increasing feed-in tariffs, CCS can increasingly compete at higher load levels, with less load hours. As a result, more capacity is built, but the amount of CO_2 stored is actually reduced. The growth of new technologies is restricted proportionally over the load levels. Because of this, increasing competitiveness at higher load levels (e.g. peak load) induces a shift from capacity to higher load levels. As a result the average number of hours a CCS plant is in operation is reduced. However, this occurs only in extreme cases, for instance with high feed-in tariffs. The conclusions (Chapter 6) are based on the scenario with a feed-in tariff of € 0.03/kWh in which this is not relevant.

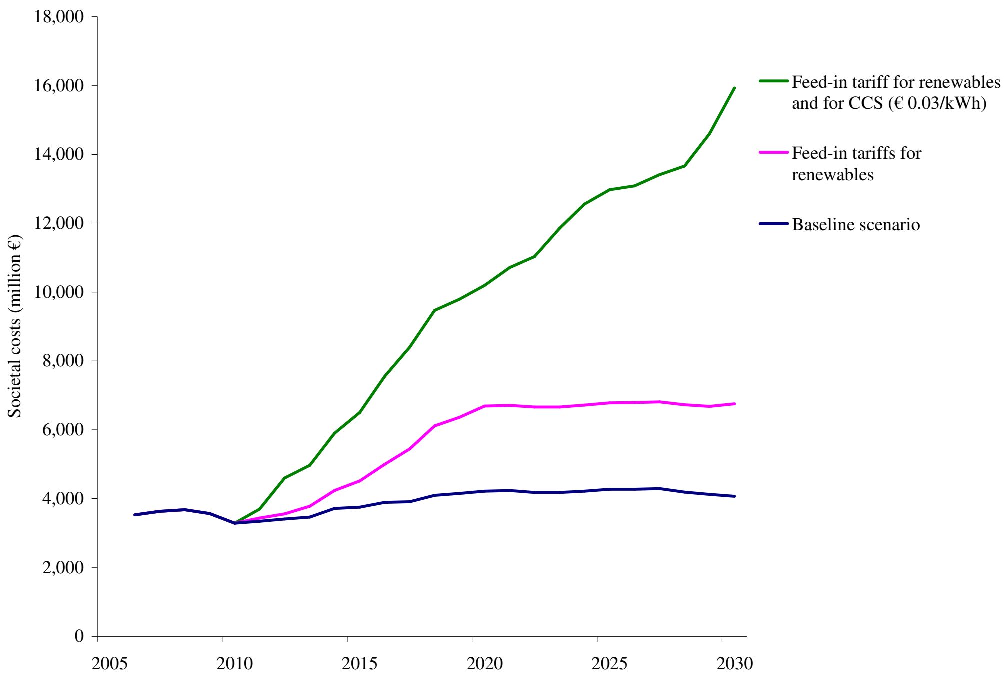

Figure 32: Annual societal costs for different CCS feed-in tariffs.

3.5 CCS standards

Obliging CCS for newly built power plants from 2020 onwards is considered by both the European Commission and the Dutch government. We analyzed three scenarios with CCS standards. The three variants include: a CCS obligation for coal power plants, for coal and gas power plants and for coal, gas and biomass plants. In all scenarios, CCS standards is imposed from 2020 onwards, because CCS should be considered 'state of the art' (Schoon en Zuinig, 2007) before CCS standards can be implemented. Figure 33 shows the technology mix in 2030 for those scenarios. CCS standards for coal plants does not lead to the implementation of CCS. Gas fired power plant are installed instead of coal fired power plants. When gas fired plants are imposed to CCS standards as well, CCS becomes a competitive option. Adding biomass to the CCS standards legislation has no effect, since biomass was not competitive in the baseline scenario.

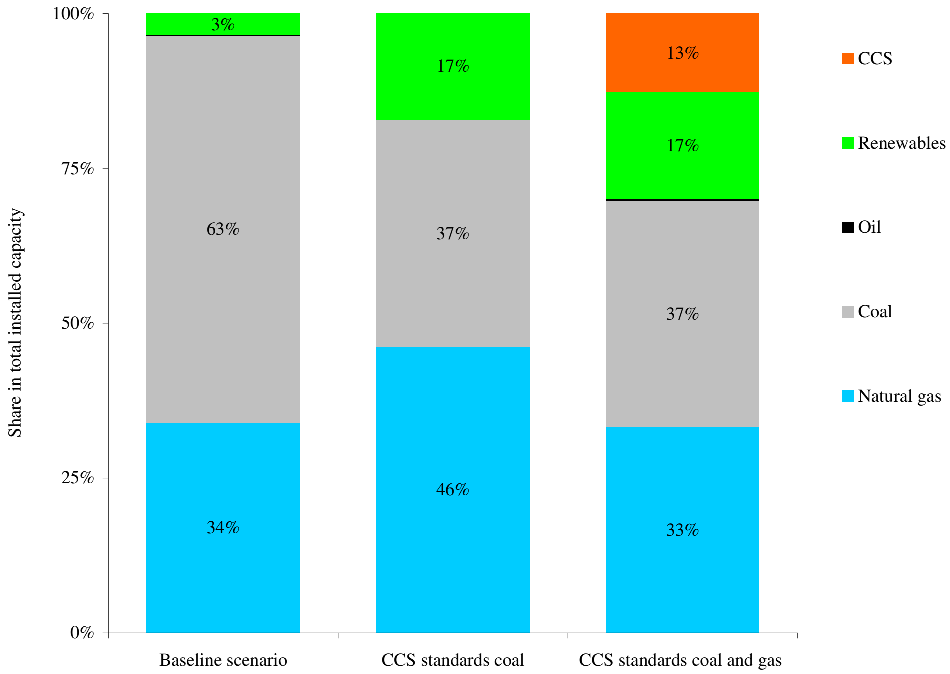

Figure 33: Electricity generation mix in 2030, in the baseline scenario, and two CCS standards scenarios

CCS standards is also applied in combination with a CO_2-price (increasing from €25,- in 2008 to €39,- in 2030). Figure 34 shows the CO_2-emissions for the different CCS standards scenarios, with and without a CO_2-price. CCS standards is very effective in reducing CO_2-emissions, since it eliminates the technologies with the highest CO_2-emissions. However, the policy can only be implemented from 2020 onwards. As a result of lock-in of high emitting technologies before 2020, the effect of the policy is limited within the timeframe chosen, until 2030.

Figure 35 shows the annual societal costs for the CCS standards scenarios. The costs of CCS standards coal are moderate, since coal is replaced with the relatively cheap gas technology. When both coal and gas technology are not allowed costs rise fast, since only expensive technologies are allowed to be built.

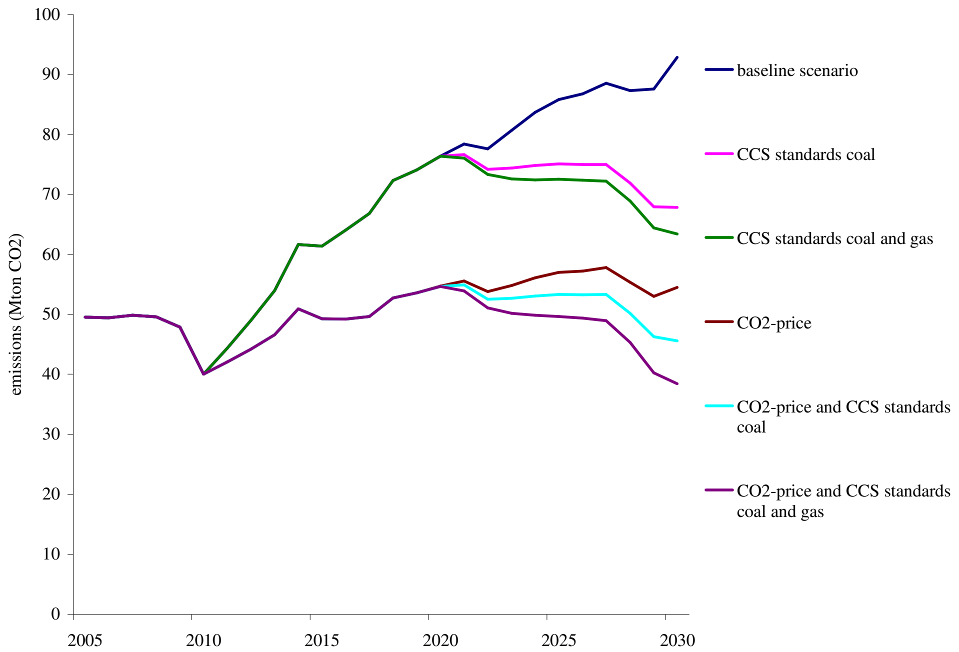

Figure 34: CO_2-emissions for the CCS standards scenarios.

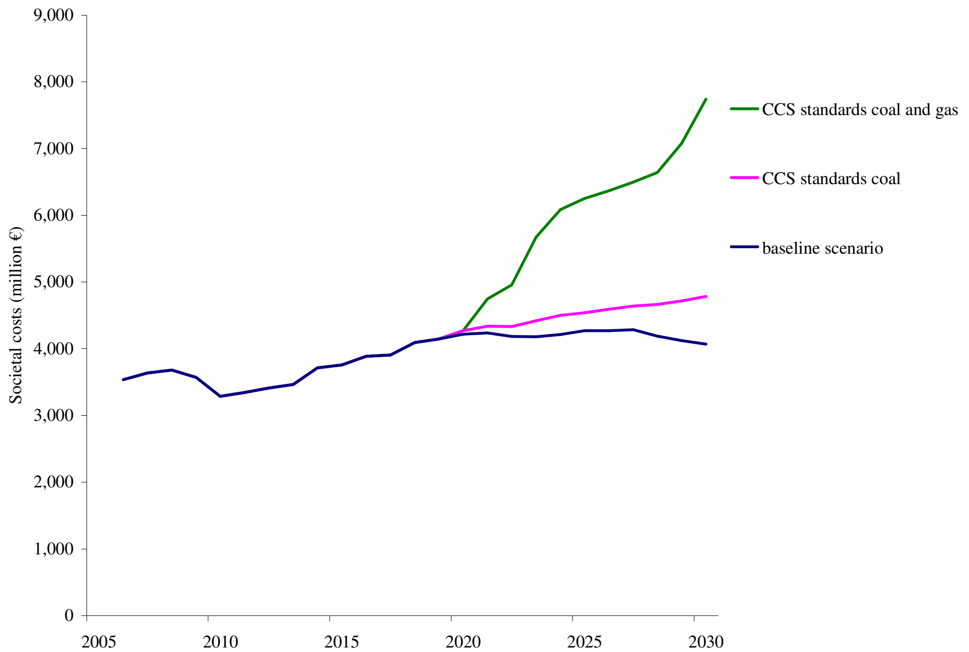

Figure 35: Annual societal costs for different CCS standards scenarios.

3.6 Effects of policies on types of CCS

In the sections above four policy options are discussed. In the results, CCS is presented as a single technology category. However, the model analyses include 7 types of CCS technologies. The analyses on different policy options that stimulate CCS adoption show that different policies impose incentives for different types of technology. In this section we distinguish between the three fuel types only, to analyse the effect of policies on the type of CCS adopted.

In most scenarios different types of CCS are adopted. This shows that there is not one most favourable technology. Figure 36 shows the fuel mix of CCS capacity adopted for a selection of scenarios.

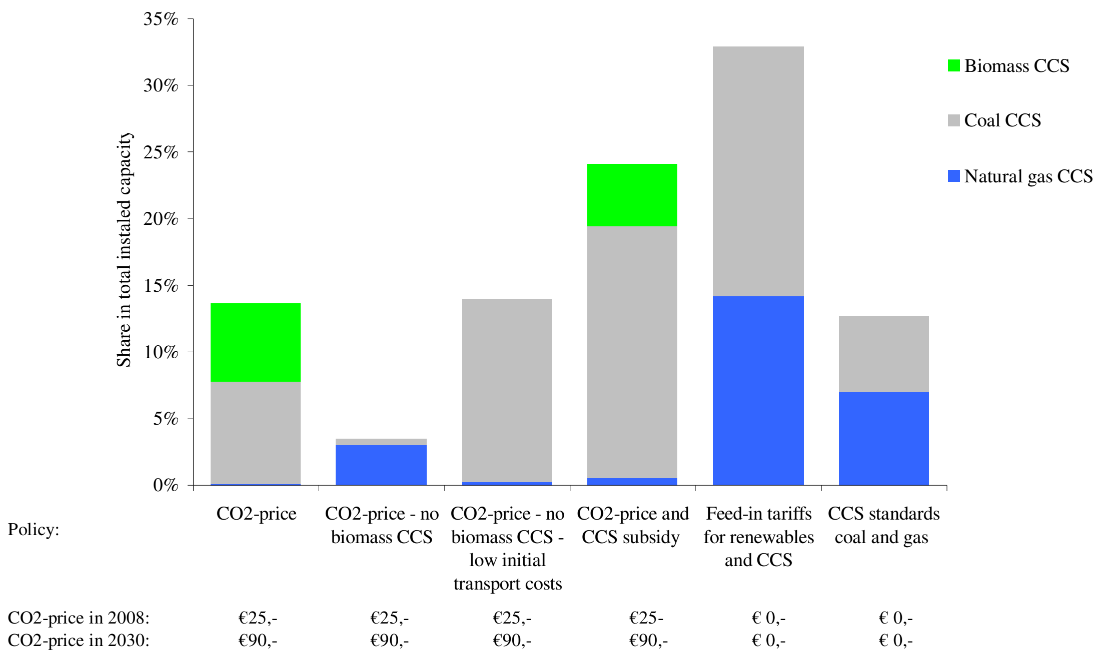

Figure 36: Shares of different types of CCS in 2030 for different policy scenarios. The CCS subsidy presented here, is equal to total investment costs of the CCS part of the plant. The feed-in tariff for CCS is €0.03/kWh.

The high costs of biomass CCS make it a less interesting option, but the possibility for biomass CCS to produce emission allowances in the ETS system make it competitive in scenarios where a CO_2-price is imposed. Investment subsidies are beneficial to coal technology, for which investment costs form the larger share of the electricity generation costs. As discussed in Section 3.3, a small subsidy (10% on total investment costs), combined with a CO_2-price, is rather beneficial for CCS gas. With higher subsidies gas plants with CCS become a less interesting option.

Both feed-in tariff for CCS and CCS standards stimulate gas and coal power plants with CCS simultaneously. This can be explained by the different characteristics and different cost structures of CCS gas and CCS coal. In different load levels and for different discount rates either gas or coal is more competitive. Another factor that plays a role is the gradually rising gas price over the modelling period (adopted from PRIMES 2007 baseline). With stimulation options that provide strong incentives for CCS early in the modelling period, gas is more competitive than if stimulation options provide incentives later in the modelling period.

From these differences, it can be derived that an important consideration in policy design is the type of CCS that is stimulated.

3.7 Policy combinations

In Section 3.6 the effect of different policy options on the implementation of CCS is discussed. In this section we will discuss a selection of policy combination scenarios.

3.7.1 Dual policy combinations with a CO_2-price

First a CO_2-price is combined with an additional policy option in a number of scenarios. Figure 37 shows the installed capacity in 2030 for those scenarios, and the related CO_2-emissions. From the graph follows that, combining a CO_2-price with a demonstration subsidy is beneficial for CCS, but the share of renewables stays relatively small. A scenario with a CO_2-price and a feed-in tariff for both renewables and CCS is effective in meeting emissions and renewables targets, but also expensive.

The CO_2-emissions and annual societal costs from scenarios that combine a CO_2-price with one other policy are shown in Figure 38 and Figure 39 respectively. Since the feed-in tariff on renewable energy sources starts in 2010, emissions are reduced from this year onwards. CCS is imposed from 2015 onwards.

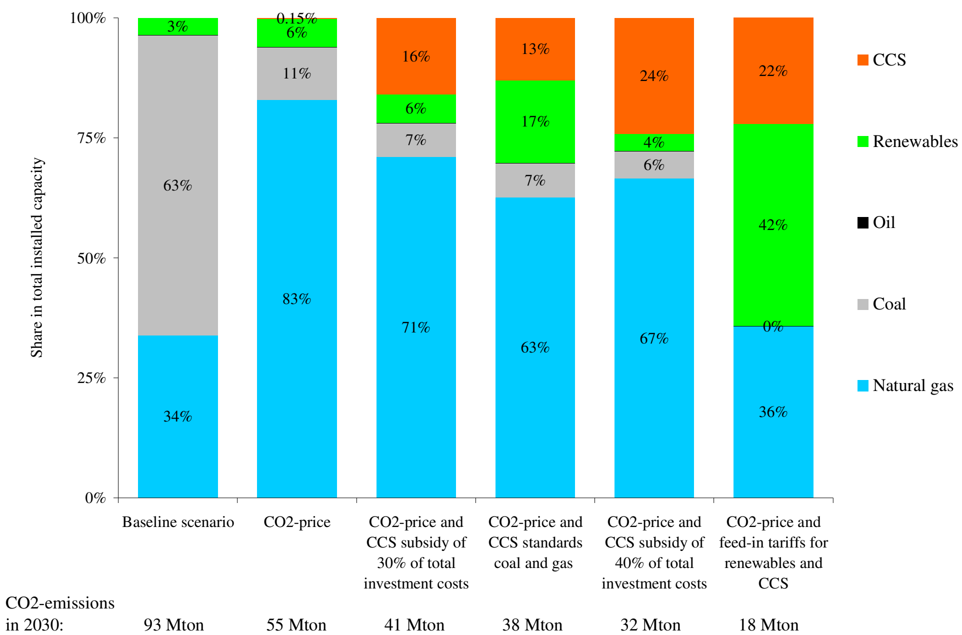

Figure 37: The electricity generation mix in 2030 for different policies, combined with a CO_2-price.

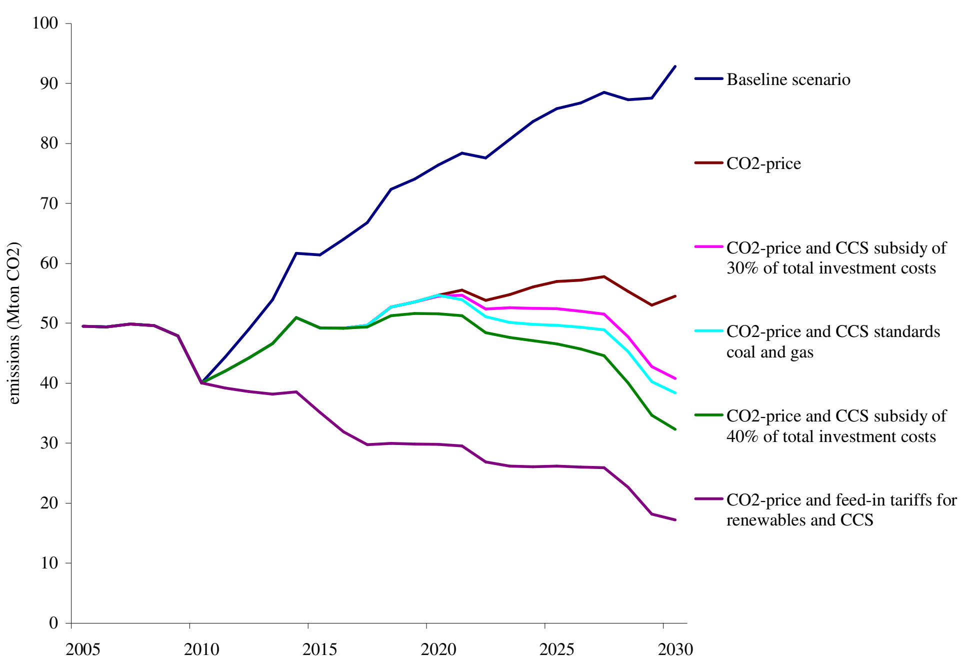

Figure 38: CO_2-emissions for different scenarios with a CO_2-price and one additional policy.

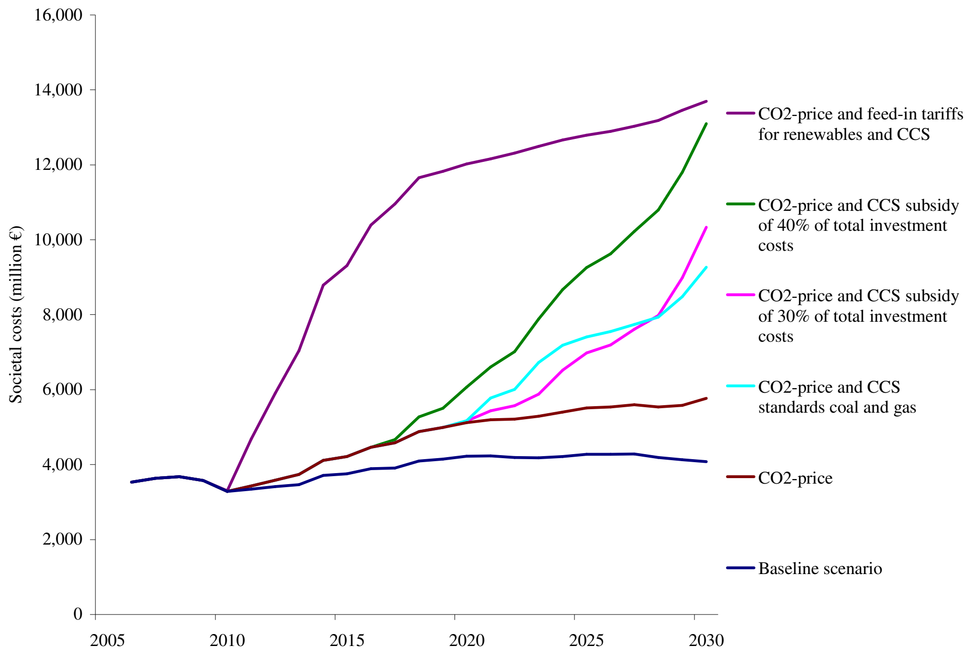

Figure 39: Annual societal costs of generating electricity in 2030, for different policy scenarios.

3.7.2 Policy packages

In addition to the analyses above, we developed a number of more extensive policy packages. In this section we will discuss a selection of those packages.

3.7.2.1 Policy package 1

In the first policy package, the following policy options are included:

1. A CO_2-price that increases from €25,-/ton CO_2 to €39,-/ton CO_2 in 2030 (2% increase per year)
2. Feed-in tariffs for renewable energy sources (based on the Dutch SDE system)
3. CCS demonstration subsidy on the full capture part of the investment costs

The first two policy options are currently in action in the Netherlands (apart from assumptions on CO_2-price development). Option 3 is considered by the Dutch government.

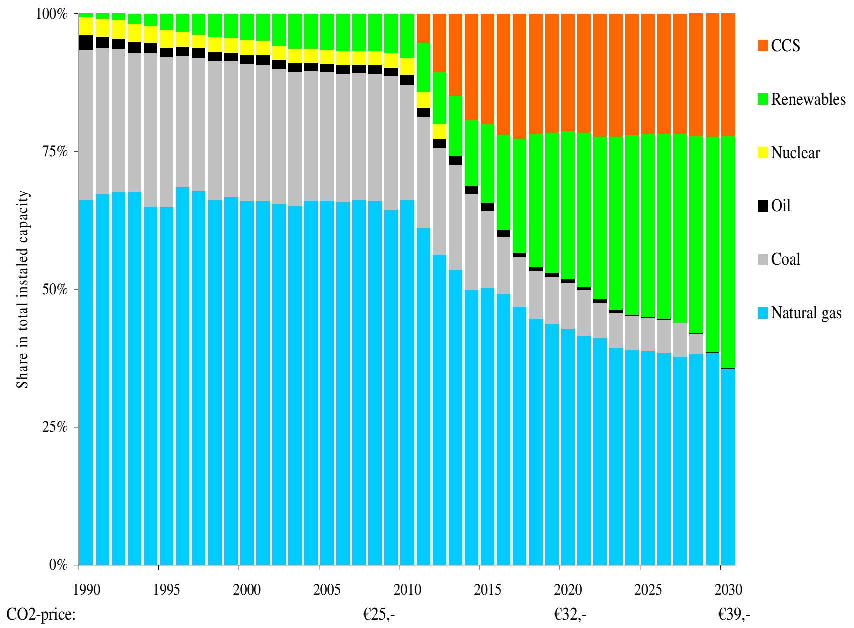

Figure 40: The electricity generation mix over time, for a policy package, including a CO_2-price with an annual increase of 2%, a demonstration subsidy for CCS and a feed-in tariff for renewables.

Figure 40 shows the electricity generation mix for this policy package. The 2020 emission target is met with 30 Mton CO_2, and the target for 2050 is already met in 2030, with 18 Mton CO_2-emission. In this scenario the target for renewable energy sources is also met. However, particularly the assumptions on the SDE scheme were optimistic. We assumed the feed-in tariffs for renewable energy sources to stay constant up to 2030. It is more realistic to assume that the feed-in tariffs will be terminated at some point or that the tariffs will be reduced. As a result, the scenario presented in Figure 40 represents a policy mix with a very strong incentive for renewable energy sources.

3.7.2.2 Policy package 2

The second policy package includes policies 1 to 3 from policy package 1, plus:

4 CCS standards for coal and gas plants

Because CCS standards is also considered by the Dutch government, we analyse a scenario in which CCS standards is added to the mix. Because the share of CCS is already considerable in the first policy package, CCS standards show little additional effect. The development of the technology mix is equal in both scenarios until 2020. In 2030 the share of CCS is higher for the scenario with CCS standards (28% vs. 24%), at the expense of gas. The share of renewables stays equal.

3.7.2.3 Policy package 3

The third policy package includes policy options 1, 3 and 4 from the previous policy packages, but excludes policy option 2, incentives for renewables.

In a scenario with policy package 3, the 2020 emission targets are not reached. The CCS adopted in this scenario is sufficient to reach the 2030 emission targets.

3.7.2.4 General information on policy packages

The policy packages presented here show that CCS can play a considerable role in CO_2 emission reduction. Without renewables the 2020 CO_2-abatement target in the Netherlands is not met, but the 2030 can still be met. The CO_2-emissions for the three policy packages discussed in this section are shown in Figure 41. In policy package 3, no separate policies on renewables are implemented. The share of renewables is considerably smaller than in the other policy packages. As a result, the CO_2-emissions are higher in this scenario.

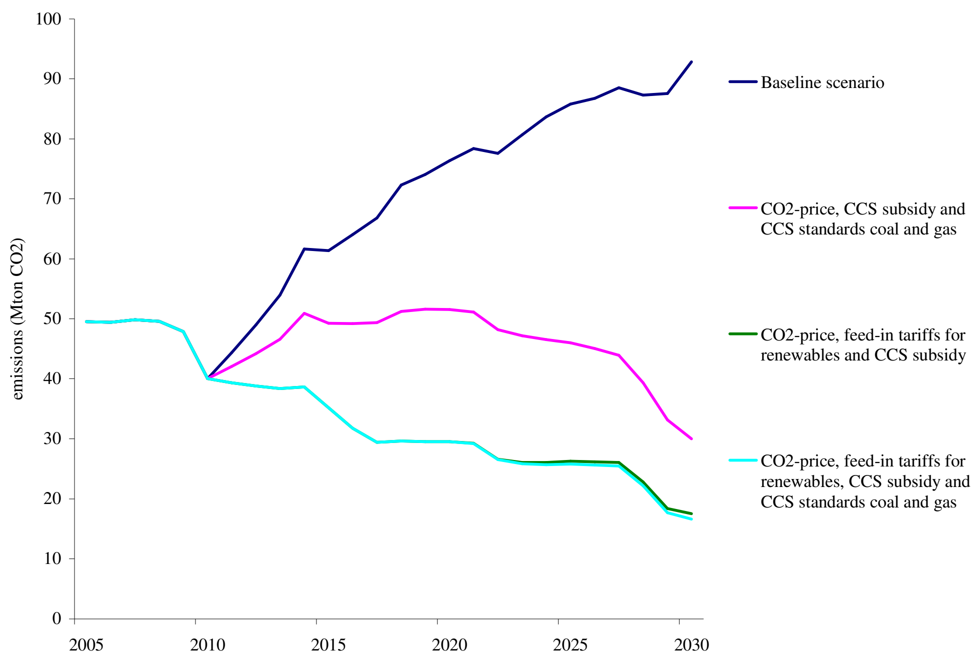

Figure 41: CO_2-emissions for three different policy packages.

The societal costs are shown in Figure 42. The costs for policy package 3, without renewables policy, increase gradually with increasing share of CCS. The costs of the policy package with renewables policy increase rapidly from the start of the scenario, as a result of the feed-in tariffs for renewables. In 2030, the cost for the policy package with renewables policy ends up less expensive than policy package 3. Renewable energy sources provide greater opportunities for technological learning than CCS and their potentials (in the cost supply curve) for low cost generation increases over time. As a result the increase in societal costs decreases over time, whereas the growth rate of low carbon technologies (CCS and renewable energy sources) stays relatively constant.

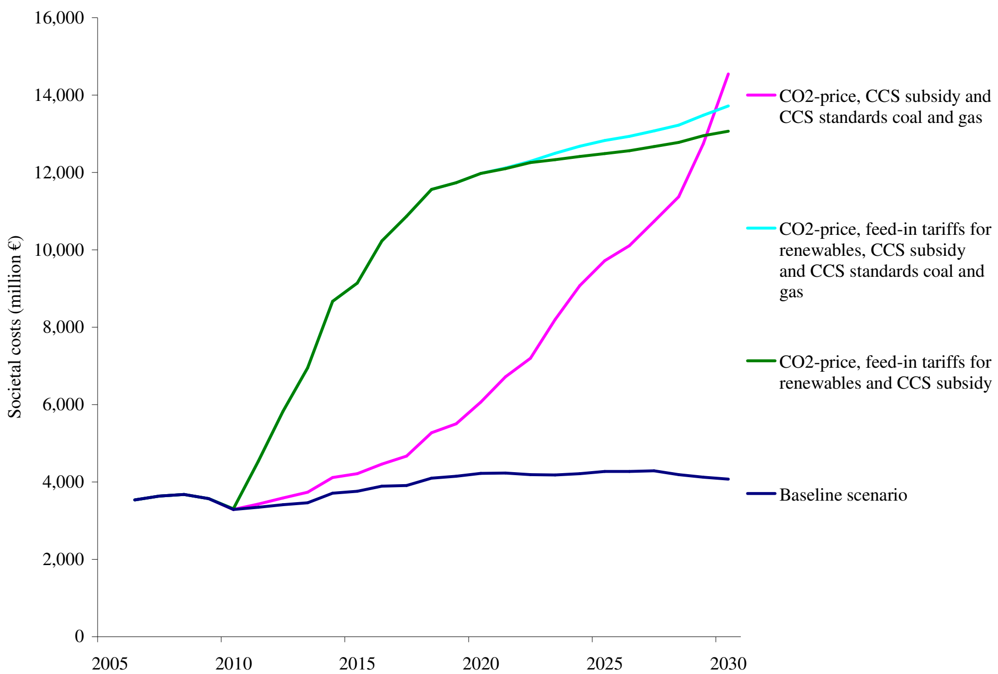

Figure 42: Annual societal costs for three different policy packages.

3.8 Cost effectiveness of policies

An important factor in policy evaluation is the cost effectiveness. We calculated the costs of CO_2-abatement in €/ton CO_2 avoided for the policy options analyzed in this chapter, based on societal costs with a discount rate of 6%.

By comparison to the baseline scenario, for every policy scenario the cost per ton CO_2 avoided is determined. Figure 43 shows the results of this calculation for different scenarios with different final CO_2-emissions. Single policy options are represented with the green circle. They save little CO_2-emissions. From those policy options, the CO_2-price is most cost-effective. CCS standards for coal and gas plants and feed-in tariffs for renewables are expensive options, since they stimulate expensive technologies. Subsidies for CCS are not included, since they do not reduce CO_2-emissions if not combined with a CO_2-price. The blue area represents policy scenarios with a considerable share of CCS as result, but a small role for renewables. The pink area shows policy scenarios with a large role for both CCS and renewables.

The scenarios including renewables lie slightly below the trend line in Figure 43. Policy scenarios in which renewables are stimulated from the start of the modelling period are relatively less expensive, since this provides the opportunity for extensive learning (as also observed in Section 3.7).

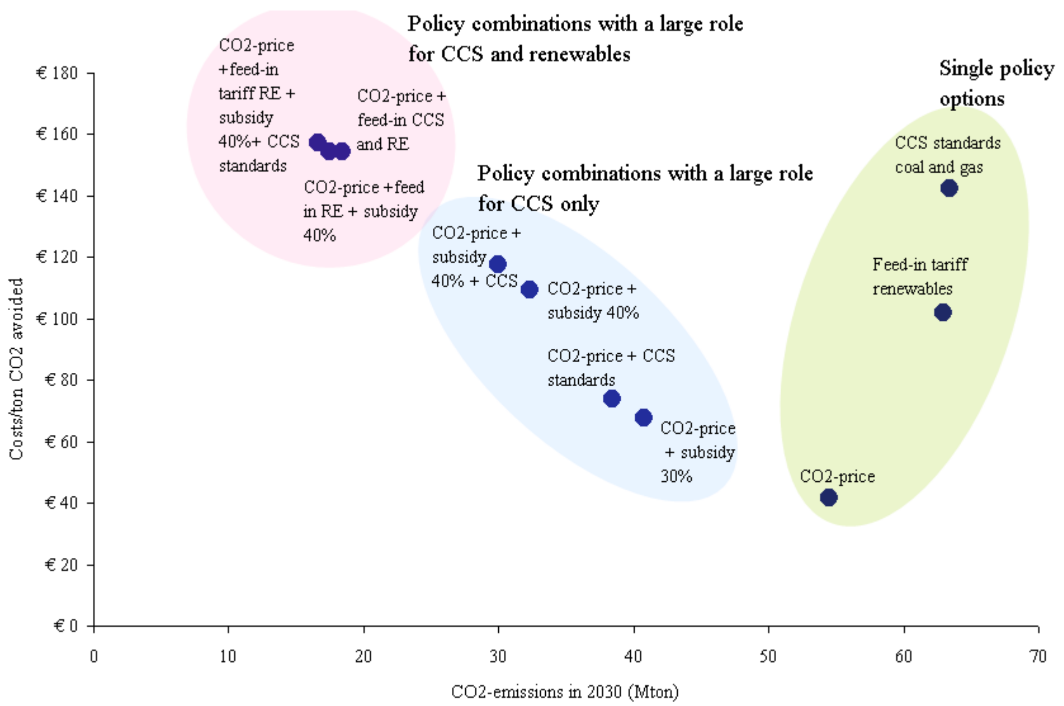

Figure 43: The costs/ton CO_2 avoided (between 2006 and 2030) and CO_2-emissions in 2030 for a selection of policy scenarios (RE = renewables)

In Figure 44 the societal costs and CO_2-emissions in 2030 are shown for the scenarios from Figure 43. The scenarios with a large role for CCS and renewable energy sources are most effective and the costs are comparable to the most effective policy options with a large role for CCS only. This is a result of the rapid cost reductions for renewable energy sources. The costs of renewable energy sources in those scenarios will decrease further after 2030, although with decreasing pace as a result of the shape of the learning curve (Section 2.3.2). As a result, those scenarios will become most cost-effective in the long-term.

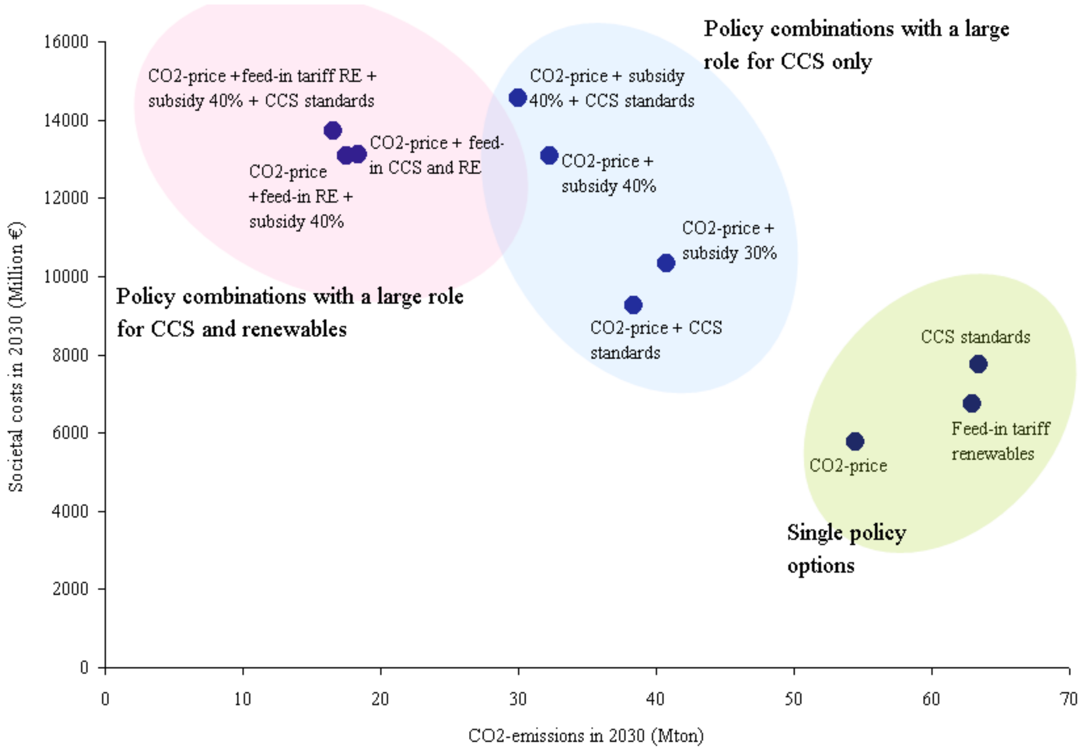

Figure 44: The societal costs in 2030 and CO_2-emissions in 2030 for a selection of policy scenarios (RE = renewable energy sources)

This implies that renewable energy sources should be stimulated in addition to CCS. In our scenarios, renewable energy sources are stimulated through feed-in tariffs. A large disadvantage of the Dutch feed-in tariffs is that they impose a heavy burden on government budget (ECN, 2007). The German system, in which the costs for the feed-in tariff are charged on to the consumer as a tax on electricity consumption, might be a feasible option.

4 Sensitivity analysis

In this chapter sensitivity analyses are shown for the most important or uncertain assumptions. The fuel prices are discussed in Section 4.1. The impacts of the assumptions on which the costs of electricity are based are assessed in Section 4.2. The sensitivity analysis for discount rates is discussed in Section 4.3. Operational lifetime and the maximum level of growth are assessed in Section 4.4 and 4.5 respectively. In addition, we performed sensitivity analyses on progress ratios and more detailed sensitivity analysis on specific investment costs. Those analyses showed no significant impact on the results and are not presented in this report.

4.1 Fuel prices

The model uses fuel prices from the PRIMES 2007 baseline scenario. The future development of fuel prices is very hard to predict, which is illustrated by Figure 45. In this graph, the oil prices from the previous PRIMES (2003) version are shown together with the PRIMES 2007 oil prices and the 2008[7] (EIA, 2008a) oil price. PRIMES 2003 didn't foresee the high oil price rise after 2003. PRIMES 2007 oil prices are higher, but the oil price in the first half of 2008 has again been almost twice the PRIMES oil price. Since fuel price is a very important parameter in the model we investigate the sensitivity of fuel prices on the electricity generation mix.

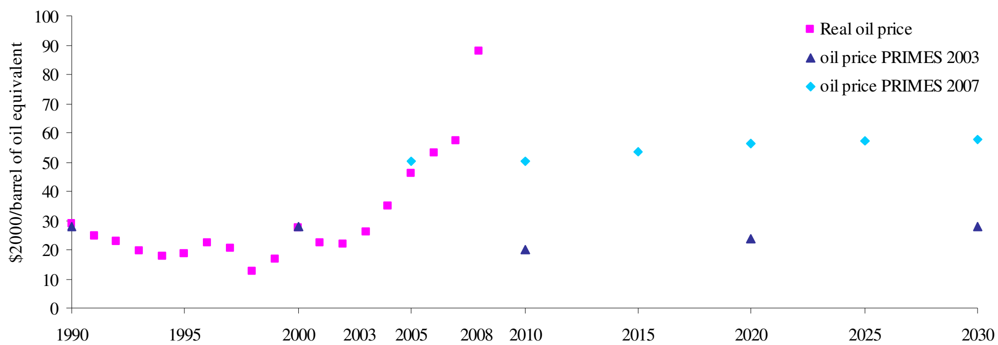

Figure 45: Actual oil prices in contrast with oil prices from PRIMES 2003 and PRIMES 2007 (Actual oil price 1990 -2007: WTRG Economics, 2008; Actual oil price 2008: IEA, 2008)

We tested the model with 8 fuel price scenarios (Table 2). Except for the PRIMES fuel price scenarios, five fuel price scenarios based on current fuel prices (average over the first half of 2008) were used (EIA, 2008). In one scenario fuel prices stay constant at

[7] Projected average over 2008

2008 levels, the other scenarios show constant annual increase or decrease of the fuel prices (coal, gas and oil simultaneously) from 2008 on. Fuel prices before 2008 are based on historic values. The PRIMES 2007 scenario was used as input for electricity demand. The only exception is one run with the PRIMES 2003 fuel price scenario. This scenario is run with both its own demand scenario and the (higher) PRIMES 2007 demand scenario. The difference in demand between PRIMES 2003 and PRIMES 2007 is small and does not change the results significantly.

Table 2: Scenarios used in the sensitivity analysis of fuel prices

Scenario:	Fuel prices	Demand
1.	PRIMES 2007	PRIMES 2007
2.	PRIMES 2003	PRIMES 2007
3.	PRIMES 2003 fuel prices and demand	PRIMES 2003
4.	Constant level of 2008 fuel prices	PRIMES 2007
5.	2008 fuel prices with a decrease of 2% / year	PRIMES 2007
6.	2008 fuel prices with a decrease of 4% / year	PRIMES 2007
7.	2008 fuel prices with an increase of 2% /year	PRIMES 2007
8.	2008 fuel prices with an increase of 4% /year	PRIMES 2007

The coal, gas and oil prices for the different scenarios are shown in Figure 46.

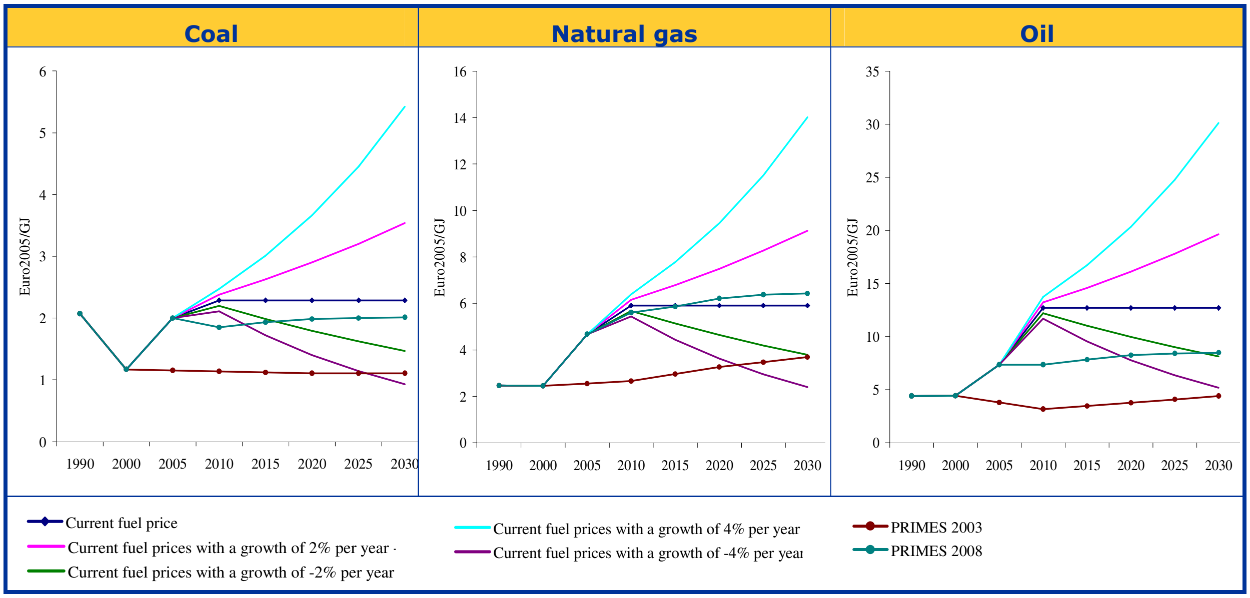

Figure 46: Fuel prices for the scenarios used in the sensitivity analysis

The results of the sensitivity analysis for fuel prices are shown in Figure 47 and Figure 48. The oil (and natural gas) price is very low in the PRIMES 2003 scenario, as illustrated in Figure 45. This results in a better position for gas fired power plants and thus a higher share of gas, relative to the baseline scenario. The current fuel prices show less difference with the baseline scenario. Even more coal is built at the expense of gas. The scenarios in which fuel prices gradually decline are favourable for natural gas, since the share of fuel costs is high for natural gas. The scenarios in which the fuel price gradually increases are favourable for renewables, at the expense of coal.

The gas price in the PRIMES 2003 scenarios is very low and coal fired power plants are replaced with gas fired power plants, resulting in low emissions. The scenarios with PRIMES 2003 fuel prices combined with PRIMES 2003 demand and PRIMES 2007 demand show little difference.

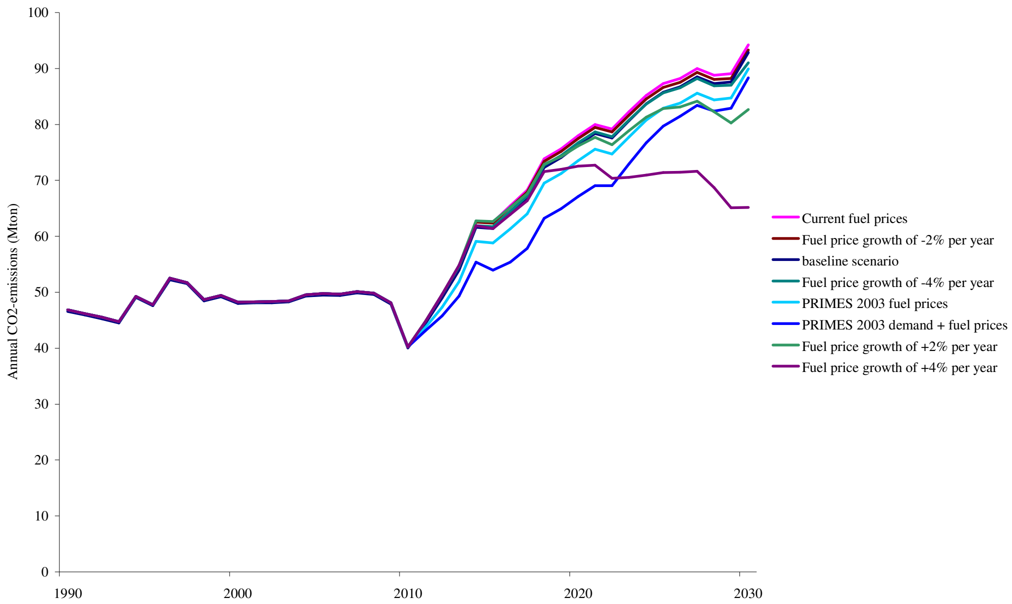

Figure 47: The development of CO_2-emissions for different fuel price scenarios

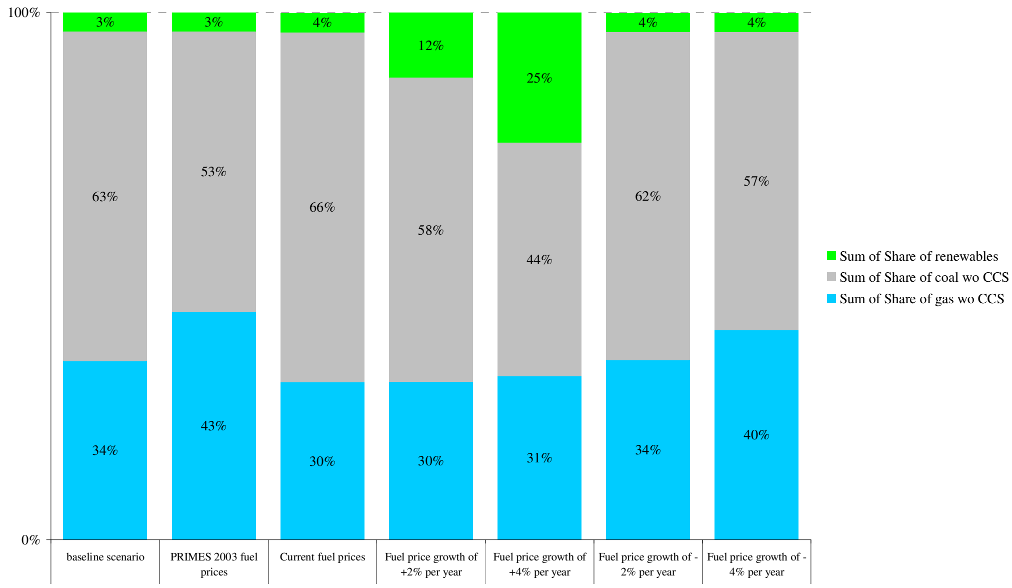

Figure 48: The share of renewable, coal and gas electricity generation technology in the total installed capacity in 2030 for different scenarios.

When the fuel prices increase, renewables substitute part of the coal capacity. The share of gas also increases slightly, while fuel costs are dominant in the electricity costs of gas. This is caused by the backup capacity needed for wind, which is formed by small gas turbines. Thus, both an annual increase in fuel prices as an annual decrease in fuel prices reduces CO CO_2-emissions. Decline is positive for gas technology, while very high fuel prices are positive to the share of renewables.

4.2 Electricity generation costs

Electricity generation costs have a number of different input variables. To asses the sensitivity of the electricity generation costs to different parameters, all parameters are increased and decreased with 10% and 20%, while the other parameters stay constant at their default value. We present the results of four technologies, which are representative to the complete list of technologies included in the model. In Figure 49 and Figure 50 the increase in cost of electricity is presented as a function of increase in different cost parameters for conventional coal normal, conventional coal normal CCS, CC (gas) and wind on-shore.

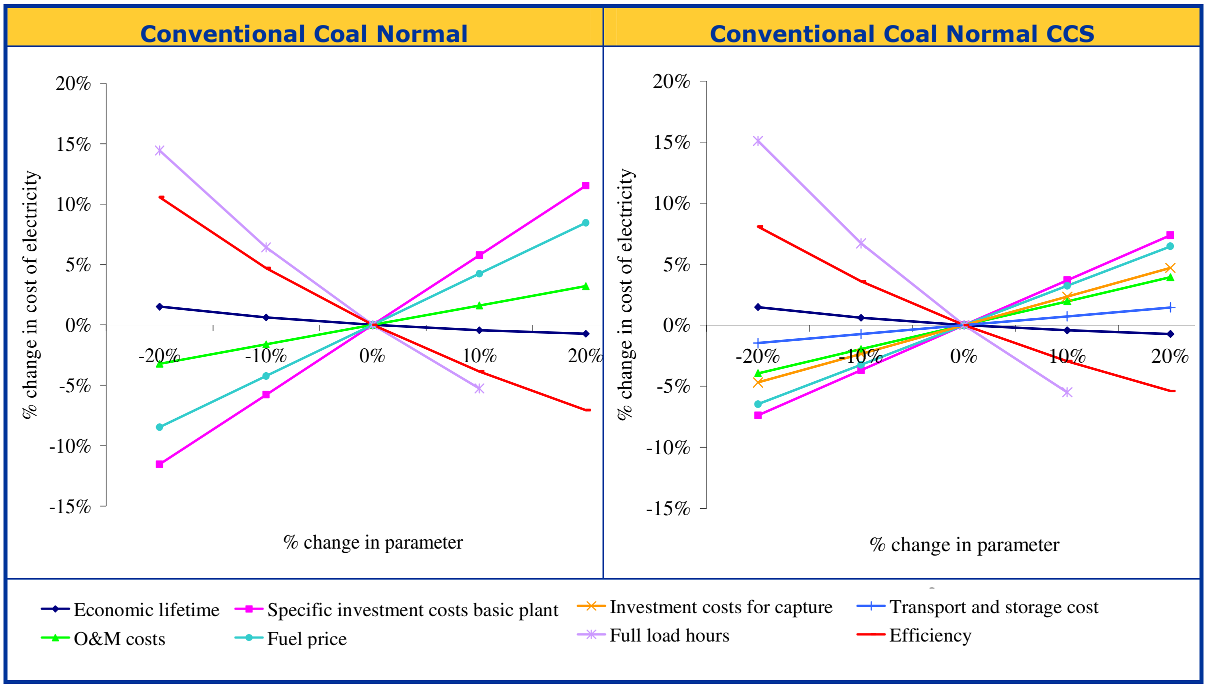

Figure 49: Sensitivity of the cost of electricity from a conventional coal normal plant (left) and the same plant with CCS (right) to different input parameters. The results are representative to other coal fired power plants (without CCS).

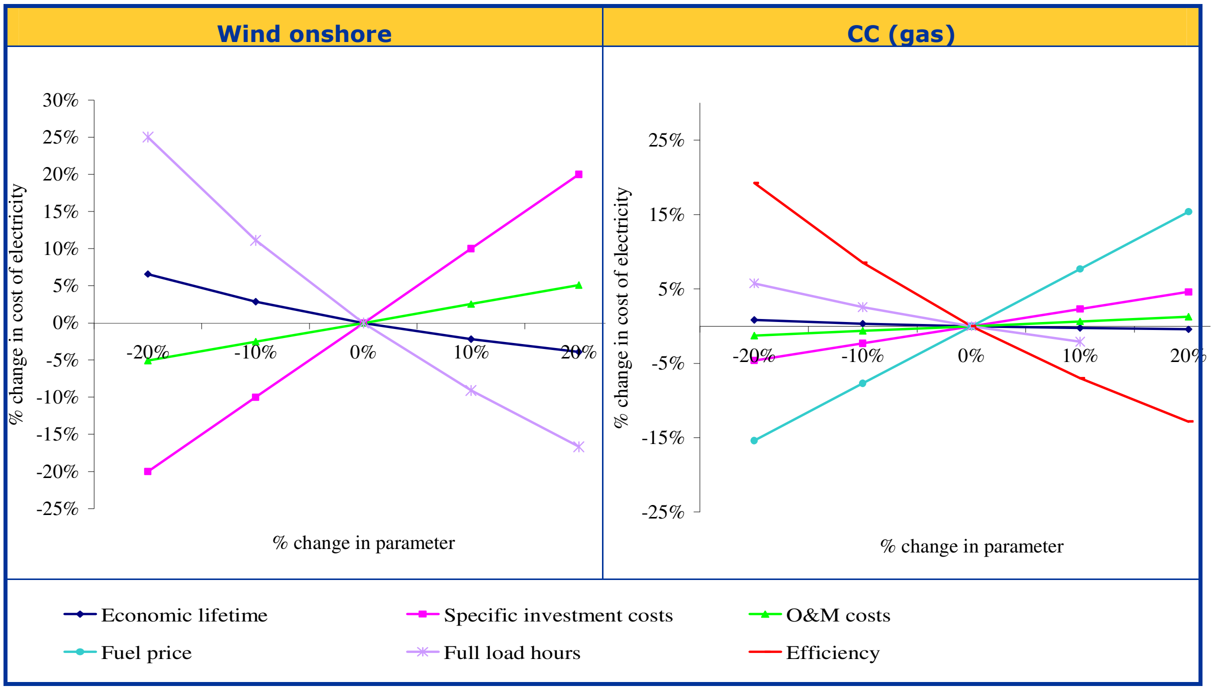

Figure 50: Sensitivity of the cost of electricity from a wind on-shore facility (left) and a CC gas plant (right) to different input parameters.

Coal plants, with and without CCS, are mainly sensitive to full load hours and specific investment costs. This shows that that they are typical base load plants. Those parameters are also important to wind, because the full load hours of wind are relatively small. Gas fired plants are much more sensitive to fuel prices. For CCS plants transport and storage costs are combined, but their influence on electricity costs is still quite small. The cost of electricity is more sensitive to capture (investment) costs. Note that we assumed transport costs for large scale transport in the sensitivity analysis. The costs for small scale transport are much higher (see Section 2.4.2). If transport costs are raised to the level of small scale transport, the impact on the cost of electricity becomes 5%. In this case transport costs have a larger impact than the extra investment costs for capture facilities. The most important parameters, investment costs and fuel prices were subject to more extensive analysis. What the effect is of transport costs on model outcomes is described in Section 3.2.3. The sensitivity of model results on investment costs didn’t show large deviations or changed conclusions. Therefore, they are not presented here. The sensitivity analysis of fuel prices is discussed in Section 4.1.

4.3 Discount rates

We include three different discount rates in the model, each representing part of the investment decisions. The effect of the discount rate assumptions is explored by running the model several times using one, instead of three, discount rate, being one of the default discount rates in the model; 10%, 15% and 20%. The model is also run for a discount rate of 5%, to represent a societal discount rate.

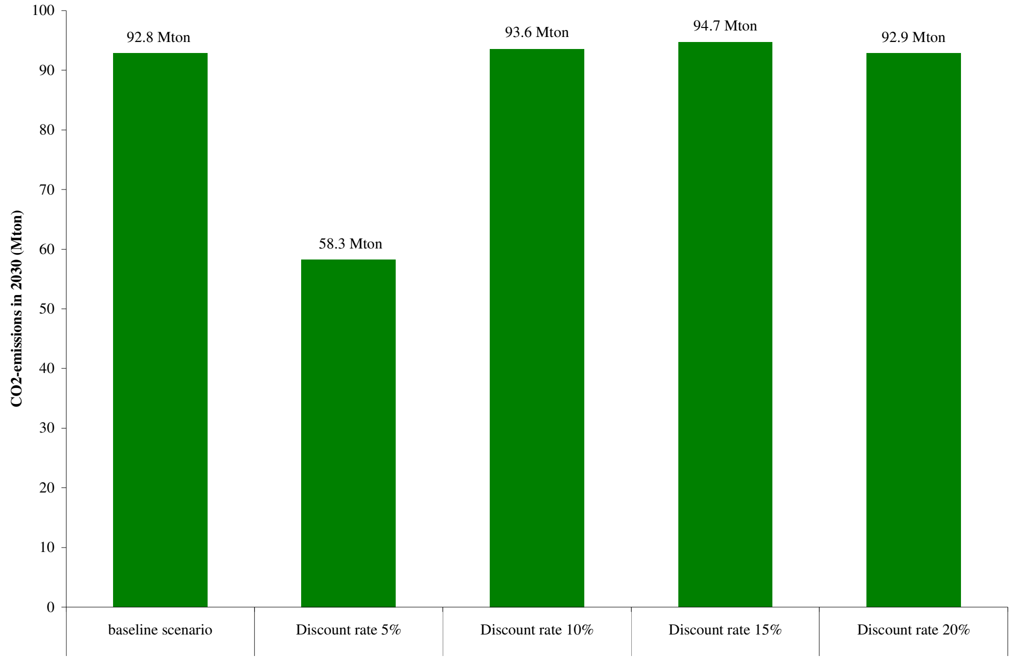

Figure 51: CO_2-emissions in 2030 for five cases: the baseline scenario in which the costs are assigned according to three different discount rates, one single discount rate of 5%, 10%, 15% and 20%.

Figure 51 shows the CO_2-emissions in 2030 for the different scenarios. A low discount rate of 5% is especially favourable for wind, at the expense of gas and coal power plants, whereas with a discount rate of 10% or 15% the wind capacity shifts towards coal capacity. With a discount rate of 20% the share of gas increases, because of the low investment costs. In Figure 52 the share in installed capacity of wind, gas and coal capacity is shown for the different discount rate scenarios. It shows that the model results are quite robust to discount rates within the commercial spectrum. A societal discount rate increases the share of renewables considerably. This indicates that the electricity generation mix in a state owned electricity sector (i.e. lower discount rates) would be very different.

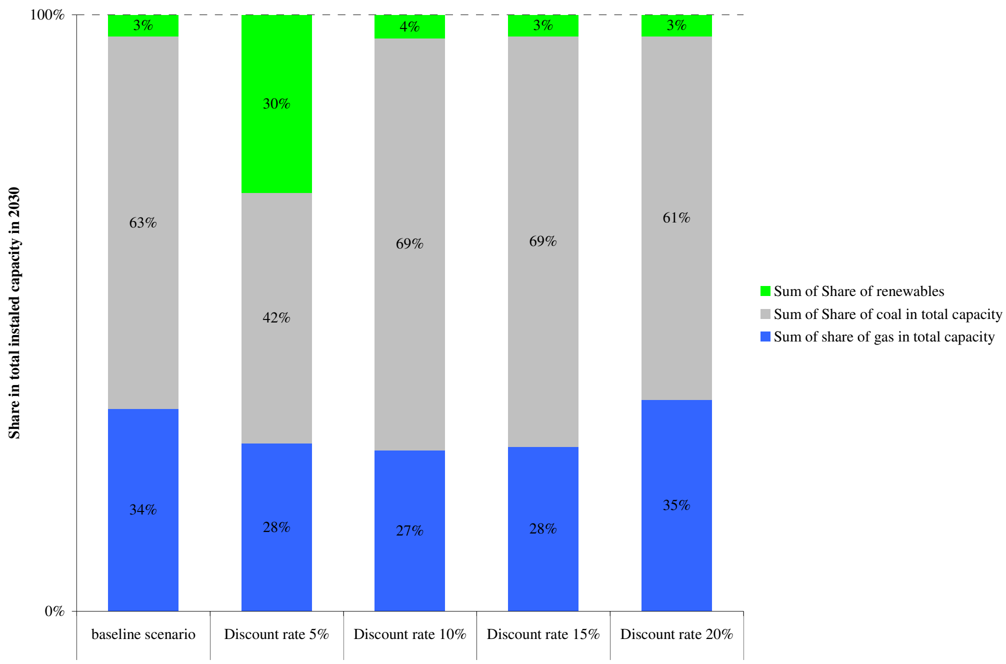

Figure 52: The share of the three largest technology categories: gas, wind and coal, in 2030, for four different discount rate scenarios.

4.4 Operational lifetime

To estimate the stock turnover of existing capacity, we made assumptions on operational lifetimes. We divided the assumptions on lifetimes into two periods, since operational lifetimes tend to increase, as a result of liberalisation trends. Liberalisation made profit maximization more important and as a result power plants were retired later.

We make the shift between two lifetime periods in 2000 (based on calibration with CBS data). We assume pre-2000 operational lifetimes of 35 years for coal fired power plants, 40 years for nuclear plants, an infinite lifetime for large hydro and geothermal and 30 years for all other power plants. Post-2000 operational lifetimes are 40 years for nuclear and 35 years for all other power plants. Plants that are not retired before 2000, based on the pre-2000 lifetimes, were assigned a post-2000 lifetime.

The assumption on operational lifetime is uncertain and therefore we performed a sensitivity analysis. The post-2000 lifetime was varied between 35 and 70 years. Figure 53 shows the total existing capacity, during the model period for those different lifetime scenarios. From a lifetime of 60 years on, the existing capacity stays constant (excluding model-built capacity). This indicates that no power plants retire after 2006. With a lifetime of 50 or 40 years power plants start retiring after 2022 or 2013 respectively. Note that CBS data in Figure 54 is higher than PLATTS data in 2006 because PLATTS represents plants that started operation before or in 2005. From 2006 on the capacity is completed by model results.

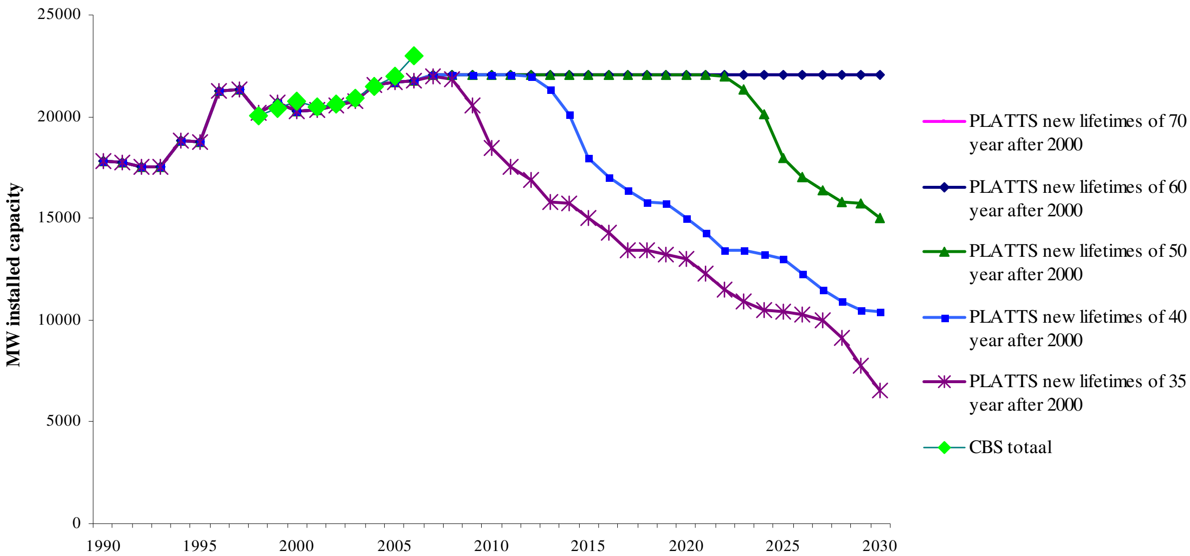

Figure 53: Installed capacity (including industrial plants) according to CBS and PLATTS with lifetimes of 30 years for plants that are retired before 2000 and lifetimes of respectively 60, 50, 40 and 35 years for plants that are retired after 2000.

4.5 Growth limit

We limited the annual growth of technologies by increasing the costs when annual growth exceeds 30% (see Section 2.3.4). A sensitivity analysis is done by varying the 'growth limit' between 5% and 50%. The corresponding CO_2-emissions are shown in Figure 54. Very low growth rates of 5% and 10% cause an increased variety in the energy portfolio. Because of its stringent character all technologies, including conventional plants are limited and this provides opportunities to cleaner alternatives. With a growth limit above 20% CO_2-emissions stay relatively constant. Above 40% the technology mix does not change anymore. With the default option, 30% growth limit coal is still slightly restricted. In a scenario with a growth limit exceeding 40%, additional coal capacity is built.

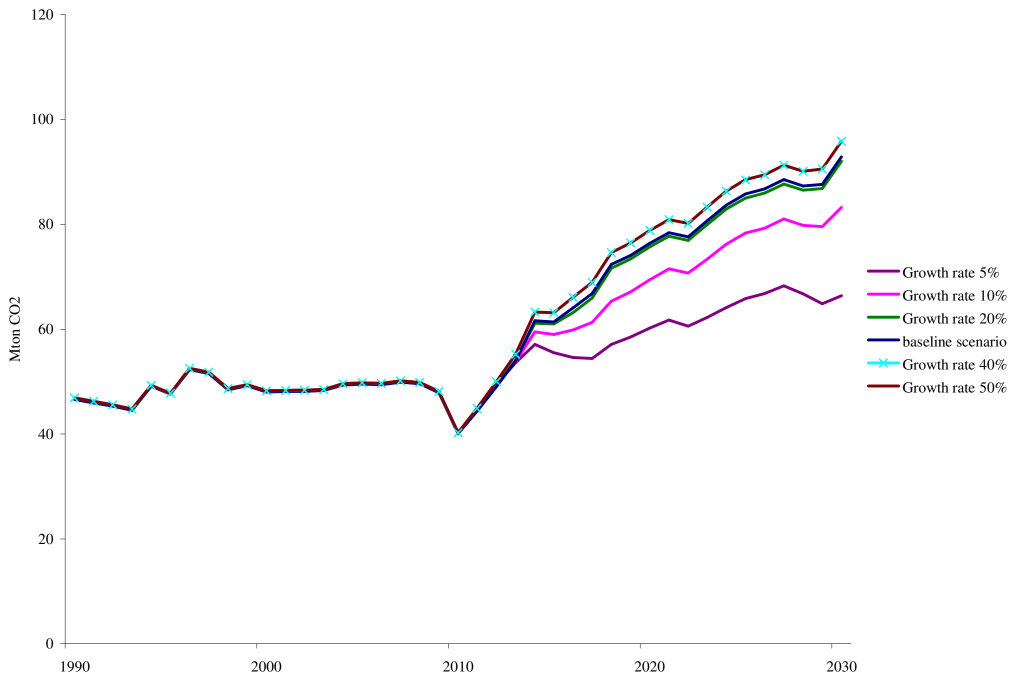

Figure 54: CO_2-emissions for different maximum growth rates. Maximum growth in the baseline is 30%. The curves of the baseline scenario and max growth of 20% and 50% overlap.

5 Discussion

This study is part of CATO work package 1.4. Within this work package another modelling study on CCS pathways is performed by van den Broek et al. (2007a,b). In this chapter we compare our study to this work and discuss our results.

Van den Broek et al. (2007b) use the bottom-up optimization model with perfect foersight, MARKAL-NL-UU, to do a study on CCS implementation trajectories in the Netherlands. Their research focuses on planning issues in emission target setting. The three pathways analyzed in detail are: a non-reduction variant, a DirectAction variant with CO_2-reductions from 2010 onwards and a postponed action variant, with targets from 2020 onwards. A trajectory is found for the different variants by cost optimizing the pathway over the whole period, for a dictated emission target. The approach, as well as the results of our study differs substantially with Van den Broek et al. (2007b). Table 2 shows the most important differences between both studies. For a more detailed description of the methodology, we refer to van den Broek et al. (2007b).

Table 1: Overview of the most important differences in assumptions between our study and Van den Broek et al. (2007b)

Van den Broek et al. (2007b)	Current research
Optimization	Stimulation
Perfect foresight	No foresight
Early retirement and retrofit play an important role	No early retirement and retrofit
One policy option: CO_2-tax	Four policy options, plus combinations as input variables

The purpose of our study is different from the study of Van den Broek et al. (2007b). We analyse the share of CCS as a results of policy options, while Van den Broek et al. (2007b) analyse cost-optimal pathways to reach a specified target. Comparison of the two approaches increases the understanding of various policy options and the parameters influencing the potential role of CCS. However, both studies are based on different assumptions and therefore a comparison can only provide a moderate increase in understanding.

The findings of Van den Broek et al. (2007b) indicate that a CO_2-price of €50,-/ ton CO_2 up to 2015 is needed to reach direct action (2020) targets of 15% CO_2-reduction. In a postponed action scenario in which only 2050 targets have to be reached, only €30,-/ton CO_2 is needed. In the direct action scenario in 2020, 6-7 GW CCS is installed and in both the direct action scenario and the postponed action scenario in 2050, 13-14 GW CCS is installed.

Our results show that a gradually rising CO_2-price does not provide an incentive to large scale deployment of CCS or any other CO_2-mitigation potential, even if the annual increase in the CO_2-price is high. The highest implementation level of CCS is 4GW in 2030 in a scenario with low initial transport costs of CO_2 and a CO_2-price rising from €25,-/ton in 2008 to €73,-/ton in 2030 (€45,-/ton in 2020). The highest implementation rate in 2020 was 3 GW, and reached with a CO_2-price increase from €25,-/ton in 2008 to €78,-/ton in 2020.

The general difference between the results of the two studies is that Van den Broek et al. (2007b) find higher deployment of CCS, with lower CO_2-prices. The more optimistic results of Van den Broek et al. (2007b) can be explained by the more optimistic methodology and assumptions.

First, the MARKAL-NL-UU model, used by van den Broek et al. (2007b) is a perfect foresight optimisation model. Decisions are optimized in the electricity supply sector, based on knowledge over the whole modelling period. In other words: increase in CO_2-price is foreseen, in contrast to the Ecofys model. Groenenberg and de Coninck (2008) refer to an ETS with good foresight possibilities as strong incentive ETS. A strong incentive ETS is effective in stimulating CCS. ETS with limited foresight possibilities is referred to as weak incentive ETS and needs additional policy to stimulate CCS. We interpret the ETS as modelled by van den Broek et al. (2007b) as strong incentive ETS and the ETS in the Ecofys model as weak incentive ETS. The current ETS system corresponds to a weak incentive ETS, but proposals have been made and the discussion is ongoing to improve the ETS system (ECN, 2007). Most likely, additional policy is needed to stimulate innovation (ECN, 2007).

The second difference between the two studies concerns retrofitting power plants with CCS. In the trajectories found by van den Broek et al. (2007b) early retirement and retrofit play an important role. In our model, there is no possibility of retrofitting power plants, or early retirement. The option of retrofit is characterized by uncertainty. Critics question the possibilities of retrofitting power plants with CCS. Although, new coal plants should already be built ‘capture ready’ in the Netherlands, no satisfactory definition of ‘capture ready’ is available (EnergieCentrum, 2008). Moreover, the costs of building a conventional plant and retrofitting it in a later stage are higher than for plants that are directly built with CCS (Vosbeek and Warmenhoven, 2007).

In our analyses we have assumed that nuclear is not an option. In the Netherlands, the political climate and public opinion have made large scale deployment of nuclear energy unlikely so far, but recently the political and public discussion is intensified. For understanding of the competition between nuclear energy and CCS, additional research is needed, in particular on the costs of electricity production by nuclear plants in the Netherlands.

We find that biomass CCS, although expensive, is a feasible climate change mitigation option with a CO_2-price, if it can produce emission allowances in the EU ETS. Rhodes and Keith (i.e. 2002) describe in their work the technological opportunities of biomass CCS. Other modelling exercises do not include biomass CCS (i.e. van den Broek et al.

2007b; Otto and Reilly, 2007). A number of remarks should be made about biomass CCS. First, building a biomass CCS plant imposes very high risks, which might limit the competitiveness of the technology. Second, sustainability discussions regarding biomass and the limited available potential of 'sustainable' biomass make large scale deployment of biomass CCS a less feasible option. Limited potentials are included in our analysis, and they do indeed limit the role of biomass CCS. Third, the ETS does not include a system yet to let power plants produce emission allowances. Among others the sustainability discussion related to biomass might make producing emission allowances by biomass CCS plants politically not acceptable. In addition, it might drive the CO_2-price down and thereby reduce the incentive for other CO_2-mitigation options. Fourth, biomass CCS is an expensive option, compared to other CCS and renewable options, and deployment of this option increases the societal costs of generating electricity considerably. Therefore, it is questionable whether stimulation of this technology is desired. In spite of those limitations, our findings make visible an interesting but underexposed research area. With respect to all the issues raised, further research is needed.

6 Conclusions

In the debate on abating climate change, the technology carbon capture and storage has recently received much attention. It is perceived as a promising CO_2-abatement option. In the Dutch as well as EU plans on climate change mitigation, CCS plays a large role. However, CCS is a new technology and is currently not competitive with other (conventional) ways of electricity generation. Additional policy is needed to stimulate the implementation of CCS and thereby facilitate technological development in this field. The discussion on how to shape a policy program on CCS is still in an early phase. In this study a first exploration was made on CCS stimulation policies.

The study is performed using a bottom-up simulation model of the Dutch electricity supply sector. Four policy instruments were analyzed: a CO_2-price, a demonstration subsidy, CCS standards and a feed-in tariff for CCS and renewable energy sources. Three policy mix scenarios, showed the combined effects of the policies.

The results show that there are effective policy options available to stimulate the implementation of CCS. Furthermore, some additional interesting implications, for policy design, have been found. The main conclusions from the study are:

1 At gradual increases of carbon prices, the share of CCS is modest.

The share of CCS remains modest with gradually increasing CO_2-prices. A CO_2-price of €166,-/ton CO_2 is needed to reach CO_2-mitigation targets. It is to be noticed that the model does not include perfect foresight. Therefore, our results are based on a weak incentive ETS. Better foresight opportunities, by increasing stability of the ETS design and improved predictability of the CO_2-price, will probably increase the effectiveness of the emissions trading scheme.

2 *Reducing initial CO_2 transport costs has a significant positive impact on the implementation of CCS.*

Initial CO_2 transport costs are relatively high, as a result of the small scale of most of the pipelines. Reducing CO_2 transport costs to levels associated with economies of scale make CCS technologies competitive at lower CO_2-price levels and advance the moment of CCS adoption.

3 *Biomass plants with CCS might play a role in CO_2-mitigation under the ETS, if biomass CCS can produce emission allowances.*

Biomass CCS is a technology that extracts CO_2 from the atmosphere. Under the present EU ETS system, emissions extracted from the atmosphere are not acknowledged. If in the future, those 'negative' emissions will be acknowledged under the ETS, biomass CCS might become an attractive option. Without this acknowledgement, biomass CCS is estimated to be too expensive to be adopted on a large scale.

4 *Different types of policies stimulate different CCS technologies.*

A CO_2-price is stimulating biomass CCS, under the condition that emissions extracted from the atmosphere are acknowledged under the EU ETS. Policies directed at investment costs (CCS subsidy) would result in more coal-based CCS. Policies directed at overall costs (feed-in tariffs) would result in both gas- and coal-based CCS. Obliging CCS in new fossil fuel fired power plants stimulates both coal and gas fired CCS plants.

5 *It is most cost-effective in the long-term to stimulate both renewable energy sources and CCS.*

Policy combinations with a large role for CCS and renewable energy technologies result in similar annual costs as policy combinations mainly stimulating CCS, but also much higher reduction potential. This is a result of the extensive possibilities of technological learning for renewable energy sources.

The above stated findings should be considered in the discussion on policy formulation for CCS. In addition, it reveals interesting input and questions to other research areas. Therefore we derive recommendations for both policy makers and researchers:

For policy makers it is recommended that:

- additional policies are designed next to includion of CCS in the EU ETS.
- support is provided on CO_2 transport costs in an early phase of CCS deployment.
- the production of allowances by biomass CCS plants in the ETS will be considered.
- the type of CCS which is stimulated is considered in policy design.
- renewable energy sources are stimulated in addition to CCS, e.g. through feed-in tariffs.

For researchers it is recommended that:

- further research is done on nuclear energy in the Netherlands and possible competition between nuclear and CCS.

- further research is done on how initial transport costs can be reduced.
- additional research is done on the potential of biomass CCS, taking issues into account that might temper the potential of biomass CCS.
- additional research is done to determine which types of CCS are preferred, and what are the advantages and disadvantages of every CCS type, with respect to technological characteristics, security of energy supply, competition with other CO_2-mitigation measures etc.
- further research is done on whether our results are applicable when decentralized electricity generation of renewable energy sources is included.

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