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Policy instruments for advancing CCS in Dutch power generation

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Preface

This report is made for the European Climate Foundation (ECF). The ECN project number is 5.5059. The ECN contact person for questions on this report is Ad Seebregts (seebregts@ecn.nl). The previous contact persons at ECN for ECF were Pieter Boot (now at the Dutch Ministry of Economic Affairs, Agriculture and Innovation) and Heleen Groenenberg (now at Ecofys).

The study was basically performed in the period January 2010-April 2010, with the report being finalised in the autumn of 2010. The authors are grateful to a number of persons for sharing their views on effective policies for CCS, including Simon Skillings (E3G), Mark Johnson (WWF), Saeda Moorman and Ron Wit (Stichting Natuur en Milieu), Kathreen Newell (DECC), Rebecca Collyer and Matt Phillips (ECF), Heleen de Coninck, Jeroen van Deurzen (ECN) and Meg Gottstein (RAP).

Abstract

Decarbonisation policy in the Netherlands is heavily dependent on the success of carbon capture and storage (CCS). This report discusses several ways to stimulate CCS in the power sector after the round of demonstration activities that are to start around 2015. It describes recent policy developments in the UK, the US and Germany. It concludes that a policy package is the most useful way forward, including a financial incentive to cover additional costs of CCS and a regulatory instrument such as an emissions performance standard (EPS) or other regulation for new coal-fired power plants. It investigates the impact of different variants of policy packages on the Dutch electricity market, including wholesale market prices, CO_2 emissions and export. It looks at pros and cons of various financial instruments and considers possible restrictions the EU legal framework might pose.

Contents

List of tables

List of figures

Summary

Many studies [1] on the long-term developments of low carbon energy systems show that Carbon Capture and Storage (CCS) is needed in addition to energy saving, renewable energy and nuclear energy. Power generation is the most important sector to deploy CCS at fossil plants. The first demonstration projects in the European Union (EU) will be up and running by 2015, sponsored by the European Commission and national governments e.g. the Dutch ROAD project planned in the Rotterdam area. After 2020 CCS has to be deployed on a larger scale.

Two key barriers exist for deploying CCS timely at large scale: (1) power producers do not have long-term investment certainty; (2) the current EU Emission Trading System (ETS) will not deliver sufficiently high and certain CO_2 prices to make CCS cost-effective. CCS is a high cost investment.

ECN examined a policy package as suggested by the European Climate Foundation (ECF) consisting of: (1) an environmental performance standard (EPS) and (2) financial incentives to cover the uneconomical part of CCS and (3) efforts to strengthen the EU ETS. This policy package is meant to provide more certainty to investors and to advance the large-scale deployment of CCS in Dutch power generation in the period 2020 to 2030, as a next step after the demonstration phase. The EPS involves a steadily lowering CO_2 emission factor of 350 g/kWh in 2020 to 150 g/kWh or less in 2030.

ECN has been asked to assess the consequences of this policy package. From this assessment, ECN concludes that:

1) This package provides more long-term certainty to investors in carbon capture for coal-fired power plants currently being built.
2) The package provides more certainty about the CO_2 supply for the CO_2 transport and storage chain, thus facilitating investment in the CO_2 transport infrastructure needed to accommodate large flows of CO_2.
3) An EPS provides an incentive that investments in CCS will be made in time directly after the demonstration phase.
4) The package stimulates an earlier commercial viability and availability of CCS, thus facilitating CCS to become a Best Available Technique. It can then result in a faster decline of the CO_2 ETS cap after 2020. Negotiations for a new cap will start in 2017.
5) The budgets needed for financial support in the period 2020 to 2030 have been assessed. ECN has made calculations in the context of the recent Dutch Reference Projection.
    a) The support needed is about €300 million per year, corresponding with a net electricity production of 18 TWh by three coal power plants, in the period 2020 to 2030, at a CO_2 price of 20 €/ton. [2] This indicative amount depends on the used assumptions; however, the order of magnitude will be hundreds of millions of Euros. The support

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[1] Studies showing the need for CCS include: IPCC, 2007 (4th Assessment Report); IEA, 2010 (Energy Technology Perspectives); Eurelectric, 2009 (Power Choices); ECF, 2010 (Roadmap 2050); PBL, 2009a (Schoon en Zuinig in breder perspectief - De effecten op het luchtbeleid en de betekenis voor de lange termijn); ECN/NRG, 2007 (De belofte van een duurzame Europese energiehuishouding; Energievisie van ECN en NRG); Green4Sure, 2007. The last study excludes nuclear power (Green4Sure).

[2] Other assumptions: Coal price of about 2.3 €/GJ; Gas price: about 6 €/GJ. Wholesale market electricity price under these conditions: 61 €/MWh. 100% coal. With 20% co-firing of biomass, the support needed for the additional cost of co-firing would be about 100 million.. ECN/KEMA calculations show that 20% of co-firing would lead to a financial gap of about 6 €/MWh (based on use of agricultural residues), see (ECN/KEMA, 2009).
Net efficiencies of coal power plants with CCS: 35 to 39% depending on when retrofit CCS will be applied. First demos: 35%. For CCS on new coal power plants after 2025, 39%. Loss in net MW_e capacity: 20% for first demos.

needed decreases with increasing CO_2 prices for instance as a result from strengthening the EU ETS.

b) Without financial compensation for the additional costs of CCS, the cost of electricity production by these plants is between 78 €/MWh (100% coal) and 84 €/MWh (with the additional assumption of 20% co-firing of biomass). The average wholesale market price is 61 €/MWh. Consequently, the financial gap is between 17 and 23 €/MWh.

c) CCS can be deployed cost-effectively, from a producers' perspective, at a CO_2 price of about 75 €/ton CO_2. The cost of production by the coal power plant with CCS then would approximately be equal to the (higher) market price of electricity (break-even point). The financial gap will then be zero. CCS at gas-fired power plants requires an even higher CO_2 price, based on the assumptions made.

6) The competitive position of Dutch electricity producers and large Dutch consumers of electricity is not significantly affected by the policy package:[3]

   a) The wholesale market electricity price will only change slightly. The changes will be equal to or less than 1%, i.e. on an average wholesale market electricity price of about 60 €/MWh, the change is between -0.1 to +0.6 €/MWh (-0.01 to 0.06 ct/kWh).

   b) The consequences for the net exporting position are modest, between 6 and 10%. The net export changes are less than 1.5 TWh compared to net export electricity figures ranging from 15 to 25 TWh in the period 2020-2030.

7) The policy package may induce additional CCS investments in the Netherlands. This does not only relate to investments in CO_2 capture, but also in CO_2 infrastructure, offshore activities and CO_2 storage. Knowledge and innovation in the Netherlands with regard to CCS technology can benefit from these investments. The extent to which these potential economic benefits can materialize requires further research.

Policy package needs careful design

The policy package as suggested by ECF requires a careful design, e.g. it should take into account interactions with other policy instruments such as the EU ETS, the IPPC Directive, national renewable energy subsidy schemes or renewable energy obligations. In addition, the actual energy market conditions and outlooks should be taken into consideration when establishing the amount of financial support. This is similar to the current SDE feed-in premiums, which are established on a yearly basis.

[3] Findings 6 a) and b) are based on electricity market model calculations. These include among others, merit order effects in dispatching the power plants. The model treats the Netherlands in detail with interconnections to neighbouring countries in Northwest Europe.

1. Introduction

1.1 Background

Many studies [4] on the long term developments of low carbon energy systems show that Carbon Capture and Storage (CCS) is needed in addition to energy saving, renewable energy and nuclear energy. Power generation is the most important sector to deploy CCS at fossil plants. CO_2 capture and storage technology is anticipated to play an important role in the Dutch climate mitigation portfolio. Climate mitigation requires on the one hand the reduction of greenhouse gas emissions on the short term using cheap abatement options, and on the other the development of promising technologies that may significantly contribute to emissions reductions on the medium and long term. It also requires a suite of effective government policies to drive change. CCS may be able to reduce emissions in the Netherlands by tens of megatons per year. A scenario might be the capture of 4-10 Mt CO_2 per year in the Netherlands by 2020 (ECN/PBL, 2007; 2009) and up to 80-100 Mt in 2050 (McKinsey, 2009)[5]. It follows that effective technology policies are required to advance the timely introduction and diffusion of CCS technologies.

This is particularly important in view of plans tabled in the last few years for the construction of four new coal plants in the Netherlands[6], adding up to an additional 4.7 GW and giving rise to concerns about increasing CO_2 emissions. These four proposals have been permitted already. As a result the Dutch economy runs the risk of a lock-in in a carbon-intensive mode. At the same time however, the ambition from the Dutch government to link up to international efforts and realize CO_2 capture and storage (CCS) technology has been substantiated.

In the Clean and Efficient program two CCS demonstrations were foreseen, and the Dutch government has committed to contributing financially to the CCS demo in the Rotterdam area (new E.ON coal power plant). The Dutch government has granted a subsidy of 150 million €, in addition to a contribution of 180 million € from the European Commission, as part of the European Economic Recovery Plan (EERP). More policies were announced in the June 2009 Policy Letter to the Dutch Lower House from the Ministry of Economic Affairs (Beleidsbrief CCS, 23 June 2009). The letter underlined that both safety and communication and public participation are important issues to address before CCS can be deployed at a large scale. Furthermore, policies were presented that should contribute to meeting as much as five preconditions including:

- decrease of the costs of CO_2 capture technology,
- effective organization of CO_2 infrastructure and storage,
- sufficient legal underpinning of responsibility and liability,
- safeguarding of potential storage locations,
- adequate financial support.

This letter made reference to early investment subsidies for CCS demonstrations. These have been announced for some demonstrations of CCS. In the European Economic Recovery Plan (EERP; EC 2009) 180 M€ was reserved for a CCS demonstration in the Netherlands. The joint

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4 Studies showing the need for CCS include: IPCC, 2007 (4th Assessment Report); IEA, 2010 (Energy Technology Perspectives); Eurelectric, 2009 (Power Choices); ECF, 2010 (Roadmap 2050); PBL, 2009 (Schoon en Zuinig in breder perspectief - De effecten op het luchtbeleid en de betekenis voor de lange termijn); ECN/NRG, 2007 (De belofte van een duurzame Europese energiehuishouding; Energievisie van ECN en NRG); Green4Sure, 2007. The last study excludes nuclear power (Green4Sure).

5 McKinsey, 2009: Large scale roll-out scenario for CCS in the Netherlands: 2020-2050. Final report for the Ministry of Economic Affairs and the Ministry of Housing, Spatial Planning and the Environment, October 2009.

6 E.ON (1070 MW) and Electrabel (800 MW) in the Rotterdam area. RWE (1560 MW) and Nuon (1200 MW) in the Eemshaven. The Nuon Magnum power plant is a natural gas fired power plant in the first phase. The second phase will make it a multi-fuel gasification CCGT plant, with coal, biomass and natural gas as primary fuels.

proposal from Eon and Electrabel for a CCS operation in the Rijnmond area was selected, and in its letter from 18 November 2009 the Dutch government has committed to contributing to this project as well. Furthermore, 300 Mt emission allowance units have been made available for twelve demonstrations of CCS or innovative renewable energy in the EU, and it is anticipated that a CCS demonstrations in the Netherlands will be among those twelve. Apart from these early investments, the Ministry announced an initial assessment of measures to stimulate CCS alongside the EU ETS.

In her November 2009 letter, the Minister of Economic Affairs again committed to realizing large scale deployment of CCS, and announced some sort of a legal obligation to ensure that CO_2 capture and storage will be applied in the Netherlands, alongside the EU ETS (Tweede Kamer, vergaderjaar 2009-2010, 31209 nr. 103): “Ideally, EU-ETS will finance CCS after 2020 (..) But, in order to be certain that the implementation of CCS will be guaranteed, in addition to ETS some kind of legal obligation will be drafted”. Parliament would be informed in Spring 2010.

The EU Emissions Trading Scheme has been advocated widely as the prime instrument for advancing CCS. Indeed, the EU ETS has been designed as an instrument to reduce GHG emissions cost-effectively and as such has gained widespread support. Recently however, doubts were raised within both the public and private sector concerning the effectiveness of the EU ETS in its current form as an instrument to also induce long term technological change, because the CO_2 price level so far has been low and volatile and because a perspective on a high and stable CO_2 price is still lacking. Sceptics argue that the ubiquitous availability of low cost abatement options in EU ETS sectors against a background of low CO_2 price levels holds back investors from making early investments in immature technologies, such as CO_2 capture and storage. Indeed, with a project cost of CCS from coal-based capacity of around 48 €/tCO_2 in 2020 and a CO_2 price on the order of 30 €/tCO_2, as suggested by McKinsey (2009), the EU ETS indeed does not provide an effective signal to invest in CCS. ECN’s own analyses indicate a higher value of 70 to 90 €/ton CO_2 for the cost, and an even lower CO_2 price of 20 €/ton CO_2 (Van Dril et al., 2009, Seebregts and Groenenberg, 2009).

If one would succeed in further improving the EU ETS with an ambitious long term target technologies like CCS would benefit more. This technology and others may be in their infancies today, but need to be further developed timely if they are to contribute significantly to curbing emissions decades from now. These technologies are not only important for the power sector itself. They are also crucial to underpin the electrification of transport and heat on the medium and long term. Improvements to the EU ETS cannot be decided by the NL alone, however.

Consequently, a major point of debate concerns the question how to ensure investor confidence, and which complementary policies, besides the EU ETS may be applied to stimulate the implementation of CCS, in particular during its pre-commercial phase. Both regulation-based policies and financial instruments have been advocated to help avoid a lock-in in carbon intensive technologies. The first group includes instruments such as a CCS mandate or an emissions performance standard (EPS) at the plant level, while examples of the later are a feed-in subsidy or tariff or a tender system. Initial assessments of these instruments have been carried out in a number of studies (Groenenberg & De Coninck, 2008; Working Group ‘Schoon Fossiel’, 2007; McKinsey, 2009).

The United Kingdom and the United States are active players in the formulation of proposals for effective incentives for CCS. CCS policies proposed in the UK and US combine both carrot and stick, including financial and regulatory instruments. Regulations ensure that eventually widespread deployment of CCS is guaranteed (and that investors in CCS cannot be undercut), while financial instruments ensure that economic damage to the industries at stake is reduced. As a consequence, these so-called integrated policy packages might be acceptable to a wide range of stakeholders, including both industry and NGO’s. The composition of such integrated policy packages may change over time, with regulations becoming more stringent and/or subsidies more constrained.

Even so, ample scope remains for a debate on timing and stringency or level of the regulations and incentives in possible integrated policy package for CCS in the Netherlands. Therefore, insight into the environmental and cost effectiveness of these policy packages is indispensable. There is also a need for an enhanced understanding of their implications for electricity cost and market prices, the composition of the electricity park and the competitive position of the Dutch power generation sector, which might be affected if electricity costs in the Netherlands would increase substantially following the introduction of CCS policies. In particular the position of the Dutch power sector vis-à-vis Germany is considered important, since the Dutch electricity market is connected most closely to the German one. Prices in the German electricity market are therefore important when determining the limits of the level playing field in the power sector, and German policies for stimulating CCS must be considered as well.

1.2 Objective and research questions

This study does not investigate whether CO_2 capture and storage technology (CCS) is needed in the Netherlands. It assumes that - globally and in the Netherlands - CCS is a necessary part of a pathway towards a power system with significantly reduced CO_2 emissions. It aims to assess what the implications are of different instruments for advancing CCS in the Dutch power generation, including financial instruments and CCS.

This study intends to describe possible implications of a policy package of a combination of CCS regulation and financial instruments (within the context of a strengthening of the EU emissions cap) in order to support reflections in this issue in policy making. By means of modelling, indicative illustrations of possible outcomes will be provided. As such, it tries to offer guidance to policy makers seeking to develop a policy package that will help ensure both investor confidence in the economic viability of CCS projects, and confidence that CCS indeed will find its way to the market in a timely fashion. It deals with the power sector and not with CCS options in industrial processes.

In view of the objective formulated above, the following relevant research questions need to be answered:

1) What are current developments in the UK, the US and Germany regarding the introduction of complementary policies for CCS?
2) What may different policy choices for CCS regulation imply for the deployment in the Netherlands of conventional coal and natural gas based capacity, co-fired biomass, CHP and CCS?
3) How might the price of electricity in the Netherlands alter following the introduction of such policies and considering other relevant cost factors, and how does this compare to electricity prices in Germany?
4) How do the pros and cons of various financial instruments, to be used alongside CCS regulatory instruments and the EU ETS, compare, and in particular how may the costs for the various policy packages be split between industry, government and consumers?
5) What restrictions does the EU legal framework pose against the introduction of complementary policies for CCS in the Netherlands, and against the combination of such policies with financial instruments?

Chapter 2 deals with recent policy developments in the United Kingdom, United States and Germany. Chapter 3 discusses whether a policy package may be useful. Chapter 4 compares different financial instruments and Chapter 6 analyzes some legal restrictions for the introduction of relevant regulation. Chapter 5 looks at the implications of policy packages for the Dutch electricity market. Chapter 7 discusses the results and concludes which policy approaches could be suggested to Dutch policy makers.

2. Policies for incentivizing CCS outside the Netherlands

2.1 Introduction

Policies for CO_2 capture and storage on coal-based power generation are increasingly being discussed in countries around the world. Policies have been proposed or are being discussed *inter alia* in the United Kingdom, at the federal and state level in the United States, and to a minor extent in Germany. The share of coal is considerably lower in the Netherlands: 28% of the fuel mix, against 40% in the United Kingdom, 49% in Germany and 52% in the United States (2007).

2.2 United Kingdom

2.2.1 Introduction

The United Kingdom is a frontrunner in the debate on and formulation of policies for advancing CCS, and the UK government has taken a range of initiatives to speed up introduction and deployment of the technology. Contrary to the Dutch government, the UK has not consented any unabated coal plants. Instead, it proposed a pipeline for CO_2 and prevented 13 GW of planned unabated coal capacity, thus strengthening prospects for the viability of four commercial scale demonstration programmes.

In 2007 a competition was launched to build one of the world's first commercial scale CCS power plants in the UK. The project aims to demonstrate post-combustion CCS on a <u>new</u> coal-fired power station with CO_2 stored offshore, capturing CO_2 from 300MW net (around 400MW gross) of the power station's capacity. The plant should be up and running by 2014. At this stage, On 30 June 2008 bidders successful at the pre-qualification stage of the demonstration project were announced, and the selection process continues. Two candidate demonstrations remain, but oddly neither of the two fully meets the tender criteria. The proposal from Scottish Power (Iberdrola) at Longannet regards a retrofit of CCS to an existing operation. whereas the investment decision for the facility planned by Eon in Kingsnorth has been postponed and cannot be operational by 2014. In March 2010 funding was awarded to both applicants for design and development studies as part of the competition. The UK government may want to align the selection with the allocation of the funds available for CCS demonstrations under the New Entrants Reserve, to avoid compromising EC demonstration support again, as happened with funds from the European Economic Recovery Plan for a UK CCS demonstration. These funds were allocated to an IGCC project at Hatfield. However, since this operation will demonstrate pre-combustion capture technology, the post-combustion tender could not be used to provide the additional national support that was a precondition for EC funding. Recently (March 2010), the UK government in its strategy paper *Clean coal: an industrial strategy for the development of carbon capture and storage across the UK* pursued CCS as a 'UK growth sector' with potential benefits worth up to billions of Pounds, sustaining jobs for up to 100,000 people by 2030.

Furthermore, following the announcement of the annual budget the Government announced several proposals related to CCS on 23 April 2009. A consultation was launched on 17 June to inventory views on these proposals, and a government response to it was issued in November. The proposed framework consisted of both financial and regulatory policies. The regulatory part would include a requirement for demonstrating CCS, a requirement for the retrofit of CCS, and some contingency measure. The financial part would include the continuation of the CCS demonstration competition launched in 2007, and the design of a new mechanism to support CCS

demonstrations. The various elements of the proposals will be elaborated further below and complemented with relevant stipulations from the November government response.
The proposals are now (December 2010) elements of the Energy Act 2010.[7]

2.2.2 Regulation

Requirement to demonstrate CCS
The first regulatory stipulation in the UK framework requires the demonstration of CCS for coal plants (both pulverized coal plants and coal gasifiers) on at least 300 MW net of its capacity (slightly higher for IGCC). Operations should capture and store at least 20 Mt CO_2 over a period of 10 to 15 years. A levy was also introduced to help finance up to four 300MW demonstration projects. The combination of this regulatory requirement and a financial incentive was intended to enable up to four new coal power stations to be built by 2020. Regarding permitting procedures, the proposal stipulated that whereas to date CCS demonstrations must apply for a permit under the Electricity Act 1989, from 2010 onwards permits they would need to be granted by the Infrastructure Planning Commissions, under the Planning Act 2008. This should help ensure independent evaluation of planning and environmental issues, unconnected to any decision-making on funding.

Requirement to retrofit CCS
On top of this, the UK government proposed that new coal power stations should be required to retrofit CCS to their full capacity within some five years of CCS having been independently judged economically and technically proven. Following a judgement that CCS is proven, a retrofit requirement could take the form of the requirement for a specific technology, or an emission performance standard.

An independent evaluation of the technical and economic maturity of CCS was proposed to take place by 2020. This judgement should be made by or based on advice from an independent body. It should be based on evidence both from the UK demonstration programme and from other EU and global experiences. It should be informed by experts and other stakeholders. The European Commission has scheduled a review of the implementation of the Storage Directive in the light of technological progress as early as 2015 (2009/31/EC, Art 38), and the Committee for Climate Change (2009) recommended that an evaluation of the maturity of CCS would take place as early as 2016. However, following the consultation the UK government decided that the UK review of CCS will take place in 2018. Also, the review should not only involve focus on a narrow comparison between technology costs and carbon price, but involve a broader assessment of the status of CCS and its role in decarbonisation of the electricity mix. Such a wider focus with a stronger emphasis on the technological maturity of CCS would help reflecting that a key factor in driving early CCS deployment is likely to be the availability of (additional) financial support.

The UK proposal considered that the retrofit requirement may need to apply to existing coal plants as well. However, since these were not designed carbon capture ready and are much less efficient than new plants, a retrofit requirement may well enforce closure of the plant. Other options therefore would be to exclude existing plants from the retrofit requirement, assuming that air quality regulation and the relatively costly operation of inefficient old plants will limit operation anyway, or to include only units of coal plants that have been upgraded to supercritical. Furthermore, an alternative measure could be considered for existing plants, such as one of the contingency measures discussed below. Indeed, in its November response to the consultation the UK government decided that existing coal power stations that are upgraded to supercritical boiler technology should be required to demonstrate CCS as well.

[7] See http://www.legislation.gov.uk/ukpga/2010/27/part/1.

Contingency
The third regulatory requirement proposed stipulates that while the preliminary assumption is that CCS will be proven by 2020, contingency measures must be considered in case it does not prove to be a viable approach either technically or economically. These should ensure that deep emission reductions from power plants will be realized. Options include a cap on CO_2 emissions from individual coal power stations, a running hours limit, or an emissions performance standard. In its response to the consultation the UK government suggested 'an emissions performance standard by way of a plant level cap' as a possible contingency measure. The UK government view is that such a measure can be introduced under the planning regime, to avoid a conflict with the IPPC Directive (see also Section 6.2).

Role of emissions performance standards
In its proposals the UK government suggested that an emissions performance standard could support each of the three regulatory elements listed above. An indicative EPS could be set (i) at a level that reflected the expected reduction in emissions as a result of operating a CCS demonstration; (ii) at a level that reflected the retrofit of CCS on new (and existing) coal based power plants; (iii) with a view to ensure that substantial emission reductions are realized anyhow in case CCS is not proven technology by 2020. Broadly, two alternative approaches to an EPS were suggested. The first approach would link timing and level of any EPS implementation to CCS technological and economical progress. The second approach would set out the levels and timing of an EPS in advance and independently of knowledge on CCS development. The latter involves a financial risk for the operator, but at the same time provides greater regulatory certainty. Either way, an EPS would need to be consistent with EU legislation, notably the IPPC directive, which excludes the introduction of emissions limit values for CO_2.

In its third reading stage of the Energy Bill, an attempt was made to introduce an emissions performance standard in the Energy Bill. The move was narrowly defeated. The government defended its proposal not to introduce an EPS by now by arguing that it would have blocked development of new coal-fired power plants, "and thus the demonstration of CCS and the development of clean coal. Introducing an EPS today would be premature and undermine investment", Minister of State for Energy Joan Ruddock said (*EU Energy*, March 12, 2010).

2.2.3 Financial incentives

Collecting resources for funding
The UK government proposed financial measures to support CCS demonstrations and to complement regulation. In the April 2009 proposal two approaches are distinguished to collect the financial means needed to support CCS demonstrations: an obligation to supply CCS electricity, and a levy on electricity suppliers. The UK government in its proposal very explicitly preferred the levy, which would involve placing an order on suppliers to pay a specified amount per unit of electricity supply to support CCS demonstrations. In its response to the consultation the UK government made clear that resources will be collected indeed through a levy, which was previously applicable only to coal-fired power generation but has been extended to include gas-fired demonstration projects. The House of Commons accepted this proposal on February 25, 2010. It now is law and part of the Energy Act 2010.

The reason for this preference was that a levy mechanism would avoid a number of problems associated with an obligation. A supplier obligation would for instance require setting a buyout price in case there is not sufficient electricity produced with CCS available in the market, which is difficult. It would also involve transaction costs that are relatively high, considering the amount of CCS electricity that is available. Furthermore, an obligation is likely to trigger a strong preference for the lowest cost CCS demonstrations and hamper the application of other selection criteria.

Mechanisms of payment to demonstrations
Further to the collection of funds for CCS demonstrations, three mechanisms were put forward that may be used to distribute these funds: a feed-in tariff, additional payments (also referred to as a feed-in premium scheme), and a contract for difference. The UK proposal indicated a clear preference for a contract for difference. This was based primarily on the larger risk of windfall profits under a feed-in premium scheme (see also the comparison of financial instruments in Section 4.5).

In its response to the consultation however, the UK government stipulated that funding of the CCS demonstrations will be arranged in so-called ‘CCS Assistance Schemes’. These will work in much the same way as traditional contractual arrangements, with a view to allow the government to select the CCS demonstrations and work together with developers to set the terms for financial support. Monitoring and operation of the financial support to the projects will be undertaken by an (existing) agency.

2.2.4 Lessons from the United Kingdom policy practices
To sum up, the UK government has chosen to base its policies for incentivizing CCS on a broad stakeholder consultation. Key elements of these policies include the requirement to demonstrate CCS at commercial scale on every new coal plant over 300 MW_e; the requirement to implement CCS to the full scale once CCS can be considered a mature technology for the decarbonisation of the power sector and is economically proven, and some contingency measure to ensure that no unabated coal will be realized beyond 2020. Financial support provided by the UK government will focus on four selected demonstrations. The UK explicitly considered ways to fund this financial scheme, and has opted for a levy on electricity suppliers.

Beyond the ruling out of entirely unabated (and only ‘capture ready’coal) coal under planning regulations, at this stage, no final decision has been taken on the final contingency regulation for 2020 onwards- both a CCS mandate and an EPS are still open. Nevertheless, a clear message on the end of unabated coal was sent out. Furthermore, no definitive decisions were made on additional funding schemes, such as a contract for difference, so as to avoid making the power sector heavily reliant on subsidies. The legally-binding review remains a critical moment for concluding CCS policies after 2020 (i.e. the phase of first wave full scale CCS deployment).

The UK plans offer a number of useful elements to consider when drafting policies for CCS in the Netherlands. These include: a broad stakeholder consultation; a timely review of the maturity of CCS technology and introduction of no-regret measures; and a contingency measure to exclude unabated coal should CCS prove insufficiently mature.

2.3 United States

2.3.1 Introduction
Much of the legislative work on CCS in the United States regards the regulation of the risk of underground storage, and matters of liability and long term stewardship. However, several initiatives have also been taken to actively stimulate the decarbonisation of the power sector, both on the state and on the federal level, as will be described in the remainder of this section.

2.3.2 Action at State level

California

In California, Senate Bill 1368 (Chapter 598) was signed into law on September 29, 2006. The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an EPS. Following adoption of the bill, the California Energy Commission elaborated more detailed regulations. These established a standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1100 lbs CO_2/MWh, or around 500 g CO_2//kWh. To put this in perspective, in October 2009 only 177 MW was coal-fired.

In principle, investments that must be in compliance with the EPS include:

- Construction or purchase (turnkey agreements) of *new* power plants designed and intended for baseload generation.
- Purchase of *existing* power plants designed and intended for baseload generation, or ownership shares thereof, other than combined cycle natural gas power plants in operation or permitted prior to June 30, 2007.
- Capital *investments in existing*, utility-owned power plants designed and intended for baseload generation, other than those for routine maintenance, that:
  - for combined-cycle, natural gas power plants permitted before June 20, 2007, increase the generation capacity by 50 megawatts (MW) or more,
  - for other power plants, are intended to extend the life of one or more units by five years or more,
  - are intended to increase the rated capacity of the power plant,
  - are intended to convert a non-baseload power plant into a baseload power plant.

SB 1368 required the California Public Utility Commission to adopt a methodology to account for additional emissions associated with heat production in combined heat and power generation.

Washington

In October 2009, 929 MW of coal-fired plants could be observed in Washington. The State of Washington introduced an EPS with the adoption of SSB 6001 in 2007. The EPS amounts to 1100 lbs CO_2/MWh, or the average available GHG emissions of NGCC turbines, whichever is the lowest. As of July 1, 2008 an EPS applies for all baseload electric generation (i.e. capacity with an annual load factor of at least 60%) for which electric utilities enter into long-term financial commitments. Such commitments may include: (i) a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or (ii) a new or renewed contract for baseload electric generation with a term of five or more years for the provisions of retail or wholesale power to end-users.

Electricity from renewable resources or from CHP based on natural gas or waste gas is considered in compliance with this EPS. An output-based methodology will be established to correct for the emissions from CHP related to heat production. Furthermore, three categories of emissions were identified that will be disregarded when determining compliance with the EPS, namely (i) emissions injected into geological formations, (ii) emissions that are permanently sequestered by some other approved means, and (iii) - should geological storage prove infeasible for technical or economical reasons - emissions mitigated by purchasing verifiable GHG emissions reductions from an electric generating facility located within the western interconnection.

The sequestration plan will be evaluated by the energy facility site evaluation council and the responsible department in Washington on the basis of a number of criteria. These include financial provisions, technical specifications of the sequestration, monitoring provisions, penalties for failure to implement the plan, provisions for purchasing credits in case sequestration fails, and communication to the public on sequestration plans.

Montana

The State of Montana had 1096 MW of coal-fired plants by October 2009. Montana's law regarding constraints on coal plants (HB 25) was passed in May 2007. It stipulates that - until the State or Federal Government has adopted uniformly applicable state-wide standards for CCS - applications for the acquisition of an equity interest or lease in a coal-based facility or equipment for electricity generation, built after January 1, 2007, may not approved unless 50% of the CO_2 is capture and stored offsite. Remarkably, there is no explicit reference to geological storage. The law does also not include any references to renewable energy.

Oregon

In October 2009, 420 MW was coal-fired. Oregon's EPS law (SB 101) was signed by the Governor on July 22, 2009 and will take effect in 2010. The bill stipulates that the EPS that applies to electric companies and electricity service suppliers is 1100 lbs CO_2/MWh for a generating facility. An electric company, electricity service supplier, or governing board of a consumer-owned utility may not enter into a long-term financial commitment unless the base load electricity acquired under the commitment is produced by a generating facility that complies with this standard. Also, the Oregon Public Utility Commission (OPUC) may not acknowledge in an integrated resource plan, or allow in customer rates, the costs of a long-term financial commitment by and electric company or by an electricity service supplier unless the facility complies with the EPS. The OPUC must withdraw the certificate of an electricity service supplier if it serves customers in the state with baseload electricity from a facility that does not comply with the EPS.

Various exceptions apply. The EPS does not apply to GHG emissions produced by a generating facility owned by an electric company or electricity service supplier or contracted through a long-term financial commitment if the emissions stem from (i) renewable energy sources, (ii) from a CHP installation fuelled by natural gas, synthetic gas, distillate fuels, waste gas or a combination of these fuels, or (iii) from a generating facility that has in place a plan to be a low-carbon emissions resource, pursuant to sufficient technical documentation, within seven years of commencing plant operations. An output based methodology shall be established to ensure that the calculation of emissions of greenhouse gases for CHP includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy. The latter may well refer to coal plants with a plan to capture and sequester carbon emissions within a designated period of time. There are no explicit references to CCS in SB 101.

In case of unanticipated electricity system reliability needs or catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances the EPS does not apply. Finally, an electric company may also enter into a long-term financial commitment that does not meet the EPS if it does not seek recovery of the costs in retail sales in this state.

Illinois

Illinois is a State in which coal is important (7641 MW coal-fired capacity in October 2009). Its January 2009 legislation (SB 1987) therefore was highly relevant. It consists of two parts:

- From 2009-2015 new coal-fuelled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016-17 70% must be captured and stored and after 2017, 90% must be captured and stored.
- SB 1987 also establishes a goal of having 25 percent of electricity used in the state to come from coal-fuelled power plants that capture and store CO_2 emissions by 2025 (this is comparable with the way renewable energy is stimulated in many US States). To support the commercial development of CCS technology, the legislation guarantees purchase agreements for the first Illinois coal facility with CCS technology, the Taylorville Energy Center (TEC). Illinois utilities are required to purchase at least 5 percent of their electricity supply from the TEC, provided that customer rates experience only 'modest' increases (not more than 2%). Based on 2008 estimates, project costs are expected to meet this requirement, unless there is

a sustained weakening of gas prices. The TEC is expected to be completed in 2014 with the ability to capture and store at least 50 percent of its CO_2 emissions. Based on Illinois' expected power supply requirements, an additional 800 MW of CCS could be needed. A candidate could be a former proposed Future Gen site.

2.3.3 Federal action

EPA action

The US Environmental Protection Agency (EPA) has published its finding that greenhouse gases threaten public health in the Federal Register by 15 December 2009. The endangerment finding took effect on January 14, 2010. Now a permit is needed with regard to the greenhouse gas emission to construct any major emitting facility or to modify an existing facility. The permitting authority is usually the responsible State agency; EPA offers advice. EPA is expected to roll out its first round of greenhouse gas rules by March 2010, the first-ever US federal standards for greenhouse gases. However, it is expected that it will take some years before the regulation will be in place.

These standards would automatically trigger requirements that stationary sources install 'best available control technology' (BACT). BACT represents an emission limitation based on the maximum degree of reduction of regulated pollutants, taking into effect energy, environmental and economic impacts and other costs. The Agency has proposed a separate rule to shield smaller facilities from those requirements, which is also expected to be in place by March.

It is still unknown how EPA will define BACT for stationary sources like power plants. There is divergence of opinion as to what BACT would likely be. BACT will be site-specific and may vary by type of facility and from state to state. It is likely that BACT will include high efficiency standards. If this does not force a major redesign of the plant, also co-firing with biomass or coal drying could be imposed. Less certain is whether IGCC or CCS could be obliged. Opponents claim that this would imply a redesign of the plant, which is not the intention of BACT. In an important recent decision, however, EPA suggests that IGCC technology cannot be ruled out as BACT for a pulverized coal power plant without an examination of whether IGCC would alter design elements 'inherent' to the purpose of the proposed project or would achieve pollution reductions 'without disrupting (the applicants') basic business purpose'. Therefore, once available and depending on a case by case analysis, IGCC could be BACT for greenhouse gas emissions (Zygmont 2010). The issue of CCS is also interesting because under BACT the geographical location of a project has to be taken into consideration. Most observers do not expect CCS will be imposed immediately; this will depend on whether CCS technology deployment will be available, cost effective and whether storage sites are available. However, it could be done later. The position of performance emission standards in BACT is unclear. In any case it is expected that EPA endangerment finding and the definitions of BACT will be legally contested whatsoever,

Climate action in the House - ACES or Waxman Markey

On June 26 2009, the US House of Representatives passed the American Clean Energy and Security Act of 2009 (ACES; H.R.2454) by a vote of 219 over 212. The Act is named after representatives Waxman and Markey, who introduced it. It establishes a GHG cap-and-trade system and important additional measures to help mitigate climate change and transform energy supply and demand into a sustainable system. The bill contains five distinct titles: I) clean energy, II) energy efficiency, III) reducing global warming pollution, IV) transitioning to a clean energy economy and V) agriculture and forestry related offsets.

Title I on clean energy establishes a renewable electricity standard, and sets performance standards for new coal-fired power plants and CCS. It also addresses investments in clean energy technologies. As to the performance standards for coal, these would effectively make the implementation of CCS technology mandatory at new coal-fired power stations, as specified in Table 2.1. The 2025 deadline referred to in the table may be brought forward in the event that more than 4GW of CCS is installed before this date, or it may be extended by up to 18 months on a case by case basis, at the discretion of the EPA.

New coal-fired power stations that implement CCS technologies would be eligible to receive federal financial assistance in the form of freely allocated emission allowances, under certain conditions. Funds of US$1 billion per year would be made available for CCS demonstration and deployment - the proceeds to come from a levy or 'wire charge' on electricity produced from fossil fuels.

Thus, the incentives to CCS provided by the Waxman-Markey bill would consist of three elements: (i) a long term cap-and-trade system, which would also provide (ii) emission allowances to be allocated freely and to financially support new coal plants, and (iii) regulation to prevent that initiatives for implementing CCS by individual industries, incentivized by the previous two elements, are undermined. These elements of the package were considered complementary rather than opposing.

Table 2.1 *Emission performance standards in Waxman-Markey bill*

When	Performance standard	Remarks
Coal-fired plant permitted between 2009 and 2015.	Must achieve a 50 percent reduction in emissions by 2025.	Would be eligible for federal financial assistance if CCS is implemented within 5 years of commencement of operations.
Coal-fired plant permitted between 2015 and 2020.	Must achieve a 50 percent reduction in emissions by 2025.	Would be eligible for federal financial assistance if CCS is implemented upon commencement of operations.
Coal-fired plant permitted after 2020.	Must achieve a 65 percent reduction in emissions upon commencement of operations.	

Climate action in the Senate - ACELA

Energy and climate legislation is also under consideration in the US Senate. The Senate Energy and Natural Resources Committee passed the American Clean Energy Leadership Act of 2009 (S.1462; ACELA) on June 17, 2009. This bill addresses several energy issues, including many addressed under the ACES Act (section above).

ACELA addresses CCS in subtitle F, section 371. It stipulates that the US Department of Energy shall carry out a program of up to 10 competitively selected projects to demonstrate CCS from industrial sources, including power plants. Furthermore, it authorizes DOE to indemnify demonstration project owners against liability for damages from carbon storage projects in excess of financial insurance required of projects. It also allows DOE to collect a fee from projects in order to cover expected costs associated with this indemnification.

Thus, ACELA is more limited in scope than the Waxman-Markey bill passed in the House of Representatives. It does not include any emission performance standards, nor a consumer levy on electricity produced with CCS.

Climate action in the Senate - the Kerry-Boxer bill

On November 5 2009, the Senate Environment and Public Works Committee, chaired by senator Barbara Boxer, passed the Clean Energy Jobs and American Power Act of 2009 (S.1733; the Kerry-Boxer Bill). The bill draws heavily from the ACES Act and establishes a cap-and-trade system. While the House bill is a comprehensive clean energy and climate bill, the Kerry-Boxer bill focuses primarily on reducing U.S. greenhouse gas (GHG) emissions. The bill reflects an important part of Senate deliberations.

The bill includes a CO_2 emissions standard for coal-fuelled power plants. The standard applies to plants initially permitted after Jan 1, 2009 and that derive at least 30 percent of annual heat input from coal or pet-coke or some combination thereof. The performance standard is:

- 65% reduction in annual CO_2 emissions for plants initially permitted after Jan 1, 2020.
- 50% reduction in annual CO_2 emissions for plants initially permitted between 2009 and 2019.

The section further directs that plants initially permitted between 2009 and 2019 must comply with the performance standard by:

- January 1, 2020, or
- four years after the date that EPA determines that:
  - there is at least 10 GW of capacity operating with CCS in the US (where up to 3 Mt CO_2 per year from industrial CCS can count as up to 1 GW),
  - at least two 250+ MW_e generating units are operating with CCS and not using oil and gas fields for sequestration, and
  - at least 12 Mt CO_2 per year is captured and sequestered nationally; whichever date is first.

The deadline may be extended on a case-by-case basis by up to 18 months if entities can show that it is technically infeasible to comply. In addition, a report shall be issued by the end of June 2017 on the status of CCS deployment, which shall include a finding regarding the possible extension of the 2020 deadline for two years.

The Kerry-Boxer bill furthermore allows the power sector to investigate the possibility to establish a Carbon Storage Research Corporation, which would aim to support at least five commercial scale CCS demonstrations, including the transformation of CO_2 into a valuable commodity.

Federal action - outlook

Legislative initiatives in both the House and the Senate seemingly give rise to some optimism with regard to federal action to stimulate CCS. Yet, it must be noted that although significant money is involved and stringent standards have been proposed, CCS technology is not always specified in the proposals. Also, proposed emission reductions are oftentimes made contingent on a minimum capacity with CCS being in place, which implies an inherent risk that eventually no CCS will be in place at all.

Various Senate committees hold jurisdiction over the energy and climate legislation at the federal level. Therefore, the timing of the climate change debate within the Congress is not clear. However, action in the Senate advances as Senators continue to introduce climate change bills. Majority leader Reid is expected to combine the various elements put forward so far into a comprehensive bill that he will bring to the Senate floor in the first half of 2010. If the Senate passes this combined bill, differences between the Senate and House bills would have to be reconciled, with the final bill passed by both houses, before the bill could be sent to President Obama and signed into law.

2.3.4 Lessons from the United States policy practices

To sum up, initiatives for decarbonising the power sector have been taken both at the federal level and in a number of states, mostly on the Western coast, but also in Illinois which is more dependent on coal. While the emissions reductions proposed in the Waxman Markey (in the House) and in the Kerry Boxer bills (Senate) are more stringent than the emission performance standards at the State level, the final outcome on these proposals is as yet undecided. No financial support schemes have been proposed.

Introduction of the EPS of 500g/kWh for baseload facilities in a number of States was possible partly since compliance is generally required only when utilities enter into new long term commitments, such as a new ownership interest, an upgrade or a new contract for baseload electric generation. Thus, there is no requirement to retrofit all existing facilities from day 1.

Three messages can be taken home from these US policies for decarbonising the power sector. Firstly, provided that regulation is considered, at present a type of generic regulation may be preferred over a specific CCS mandate. A generic type of regulation, such as an EPS, would allow for greater flexibility for the operator of a baseload installation. Secondly, regulation that will have a bearing only later in time may well be more acceptable to industries, and hence be easier to introduce than measures that have an immediate impact. Thirdly, some states with coal interests have adopted a package approach. They expect this makes sense as capture and storage might present an economic opportunity for them. They combine greenhouse gas reduction policies with CCS policies as they "stand to benefit economically by maintaining the value of their coal deposits in the face of carbon constraints, taking advantage of EOR opportunities, and developing geologic sequestration as a new industry" (Pollak et al, 2009). This does not differ so much from the position of the Netherlands.

2.4 Germany

Germany is still considering its position with regard to CCS policies because of four reasons: the strong position of coal interests; the possible interaction with renewable energy and with nuclear energy; and the strong political position of local interests.

The position of coal in German energy policy is strong. Lignite and hard coal have by far the largest share in the German power fuel mix (45% in 2008, of which 25% lignite and 20% hard coal, slightly declining from 50% in 2000; this has to be compared with 38% in the UK and 27% in the Netherlands; although Germany is perceived of the stronghold of renewable energy, the 2008 share of renewable energy in 2008 was only 7%). National production of hard coal is still subsidized (2.3 billion EUR annually) and the policy aim is to continue this until the end of 2018. Lignite production is fully commercial and some new lignite plants have been built in the past decade. Large utilities RWE, Eon and Vattenfall have been investing in demonstration plants as they consider CCS to be an important aspect of keeping coal open in a responsible way. Vattenfall has built an oxyfuel demonstration plant of 30 MW near its Schwarze Pumpe lignite plant; if all goes well this will enable the company to build a 300 MW demonstration plant in the middle of the next decade. RWE has (in cooperation with Linde and BASF) built a small post-combustion demonstration plant that has been opened in August 2009. The actual government stated that the construction of highly efficient coal-fired power plants is acceptable.

However, not everybody in Germany agrees about the position of coal in a sustainable fuel mix. The German Advisory Board for Environment (Sachverstandigenrat fur Umweltfragen) argued strongly (Weichenstellungen fur eine nachhaltige Stromversorgung, 2009) that, due to intermittency issues of the increasing share of wind energy, coal and nuclear energy are not flexible enough. New investments in base-load cannot be coal or nuclear. The country has to prepare for a 100 per cent renewable energy fuel mix. The Council also is of the opinion that due to a scarcity of storage capacity in Germany it is unacceptable to depend on fossil fuel plants with CCS. It could well be possible that CCS storage options are even less than currently estimated (equivalent to 30 - 60 years with the actual power production and fuel mix), as they might be needed in the future for biomass with CCS, or they might compete with geothermal. Elements of this vision are shared widely in Germany. The actual government is strongly in favour of a fast increase of the share of renewable energy.

Thirdly, the position of nuclear energy asks for more political attention than CCS. The former government had agreed upon an opt-out of nuclear, which has been withdrawn by the actual one. Details of the nuclear energy policy have to be agreed with industry, however, this task is relatively urgent as the oldest plants would have to close rather soon and a new policy has to be in place on time. This political debate is considered to be more urgent than the future of CCS. Fourthly, local and regional communities are strongly against storage in their backyard. As legislation has to be accepted in the German Council of Regional governments as well (Bundesrat), this is a political factor that cannot be neglected. On the other hand, the governments in regions dominated by hard coal and lignite are in favour of CCS.

The German federal government has not been able to define a clear policy in this respect. In early 2009 the former government presented a CCS Law that tried to regulate storage and transport issues. However, due to opposition from the regions this was withdrawn and considered to be an issue for the next - actual - government. Without legislation no European funding for demonstration projects can be taken for granted. The actual government is still considering its position as the political leadership of the Ministry of Environment has moved to another party. Some elements might be (speech of Staatssekretar Jochen Homann of the Ministry for Economy and Technology) at the 2nd CCS Congress, 28 January 2020):

- CCS is necessary at a global level; whether this is also the case for Germany is still uncertain.
- Renewable energy will provide more than 50% of the power fuel mix by 2050.
- CCS might be an option of German climate policy, but is certainly a potentially important offspring of industrial policy and might be a strong export opportunity.
- CCS is mainly an element of technology policy, more than of energy policy per se. Public R&D budget of CCS has been increased for the year 2010. Demonstration investments are needed to prove what technologically is feasible.
- Decisive will be public acceptance.

At this moment even capture-readiness is legally not obliged in Germany. We have to wait how the legislative procedure will continue, but strong policies to regulate the CO_2 emission of coal-fired power generation are not to be expected. The federal government expects to draft an integrated ‘energy concept’ before the end of the year.

3. Integrated policy packages for incentivizing CCS

3.1 Examples of integrated policy packages

The policies for advancing CCS in the United Kingdom and the United States may serve as examples for advancing CCS in the Netherlands. A striking feature of the policies introduced or proposed in these countries is the combination of various policy instruments to force the introduction and upscaling of CCS technologies. Such combination of policy instruments is not uncommon in the Netherlands, and is applied for the energy-intensive industry, for the built environment, and for renewable energy (Van Dril et al, 2009).

For the *energy-intensive industry* the EU ETS is leading. Apart from this, industry participates in a sustainability agreement with the Dutch government. In it they committed to improve energy efficiency by 20% in 2020 over 2005 levels, and expressed the ambition to save 10% of fossil fuels. For several industrial sectors a technology road map has been made. For each sector energy savings, CO_2 reductions and applicable sustainable technology will be elaborated. Where possible green and sustainable resources will be used to replace fossil fuels. Waste streams, co products from the food industry, as well as fertilizer and wood may be used as biomass for energy supply. Finally, an effective exchange of information, energy savings along the chain (i.e. outside the installation), and encouragement of front runner sectors are important.

In the *built environment* a range of measures is applied simultaneously. As of 2008 and EPC label (Energy Performance Coefficient) can be made available when buildings are sold or rented out. The government subsidizes the stimulation of energy savings in dwellings, as well as of the advancement of sustainable energy in buildings (solar heating, PV and heat pumps). Furthermore, owners may use the Energy Investment Tax Deduction (Energie-investeringsaftrek, EIA) to exploit fiscal benefits. Other possible measures are being explored.

Also for *renewable energy* various instruments were and are being used simultaneously. Alongside the regulation Stimulation Sustainable Energy (SDE) and previously the regulation Environmental Quality Energy Production (MEP), the Energy Investment Tax Deduction (EIA) may be used when realizing renewable energy. There has also been a voluntary agreement for coal-based power generation (kolenconvenant) which addressed renewable energy, next to the MEP.

In brief, objectives are combined with voluntary measures (in industry), voluntary measures are used simultaneously with fiscal measures (in buildings), and subsidies are combined with fiscal and some voluntary measures (for stimulating renewables). Combinations of policy instruments also concern the simultaneous use of mandatory measures and subsidies: in these cases the mandatory measures define the minimum obligation and the subsidies incentivize additional investments. This kind of package approach often has a dynamic effect: the minimum standard is gradually getting stricter and the subsidies stimulate new technologies that, after having been proved, later become part of the standard. Up to now no experience has been gained in using simultaneously subsidies and obligations that stimulate respectively oblige the same level of performance.

3.2 Rationale for combining policy instruments

The examples introduced in Section 3.1 illustrate that a number policy instruments may be used simultaneously to address multiple obstacles to the introduction and diffusion of technologies. However, this does not always imply however that such a combination represents an optimal solution, or that instruments should be used simultaneously.

Yet, the requirements to CCS policies listed in Section 3.3 do not rule out the possibility that using multiple instruments in series may be useful.

In this assessment of policies for advancing CCS in the Netherlands we will therefore focus on two groups of instruments that may be used consecutively. We will consider both financial and regulatory instruments. The different characteristics of financial and regulatory instruments imply that a consecutive use of financial and regulatory instruments allows for more certainty in reaching multiple objectives.

Financial instruments are usually temporary, and are intended to evoke immediate or short term investments. Examples include a feed-in scheme or a tender system. A financial instrument may warrant greater assurance among industrial stakeholders that the financial risks involved are minimized. A weak point of financial instruments in general may be that transaction costs are likely to be higher than for regulatory instruments, because more information from industry will need to be processed by the state before subsidies can be handed out.

Regulatory instruments on the contrary can be considered more structural, and may be for instance a technology mandate or an emissions performance standard. They may provide the long term horizon usually required in board rooms to decide on strategic changes. A CCS mandate may be a better guarantee that investments are directed towards CCS, whereas an EPS would allow greater flexibility to the operator to choose from other technologies as well, notably the cofiring of biomass, while CCS technology is developed further. Although regulatory instruments will not reduce the costs of CCS, it will ensure a level playing field for plant operators in the Netherlands. Thus, the innovation objective of realizing widespread deployment of CCS may well be met by a regulatory instrument. Note that regulation will not improve the environmental effectiveness of the EU ETS, unless the emission ceiling is adjusted. Moreover, it is likely to increase social costs of emissions reductions, since a more expensive technology will be implemented with preference (Sijm, 2005).

Interaction with ETS. A defining feature of an emissions cap and trade system, such as the EU ETS, is that, assuming adequate monitoring and enforcement, there is certainty that total covered emissions will be equal to the aggregate cap (the next section is adopted from Boot & van Bree, 2010). Environmental effectiveness is guaranteed. In principle, the scheme will result in the target to be met in the most cost-effective way. In practice, however, market failures are usually widespread, in particular in the markets for energy efficiency and carbon saving technologies. Moreover, the social and political process that leads to the setting of the ETS cap and its corresponding carbon price is unlikely to reflect any 'social optimum' for carbon externalities. Therefore, there may be legitimate grounds for introducing other policy instruments, such as: improving the static efficiency of ETS by overcoming market failures other than CO_2 externalities; improving the dynamic efficiency of ETS by overcoming market failures in the area of technology innovation and diffusion; delivering other objectives than carbon efficiency (e.g., security of supply), or addressing deficiencies of the ETS design (such as mitigating the risks of allowance price uncertainty).
The fact that positive combinations between an ETS and other instruments are possible does not guarantee that they will result in a better social optimum. Moreover, once the cap is set over a certain period, the justification for introducing such other instruments must rely upon one or more of the grounds mentioned above, rather than on the contribution to overall emission reductions.
The interaction of ETS with carbon regulation or financial instruments is of particular importance. The interaction with carbon regulation includes some objections:

- Carbon regulation next to the EU ETS does not improve the environmental effectiveness of the scheme, while a risk exists that it will increase overall social costs as it reduces the flexibility in finding solutions to decrease emissions.

- If carbon regulation is binding and the ETS cap is fixed, it reduces the demand for emission allowances and, hence, lowers the price for these allowances, thereby reducing the incentive for carbon abatement by all other installations not covered by the regulation.
- It is questionable whether carbon regulation, in particular an EPS, will be effective in stimulating CCS and reaching a certain CCS target, notably if CCS is still technologically risky or not yet proven at a large scale, not economically viable or still very expensive, and/or hardly socially acceptable. If this is the case, rather than encouraging investments in CCS, carbon regulation may actually stimulate investments in other carbon saving technologies. This regards the timing of regulation.
- Carbon regulation usually refers only to a specific category of installations such as (new) coal-fired power plants. So, even in the best case it will only be a very partial approach.

These objections refer in particular to an Emissions Performance Standard (EPS) besides EU ETS, but most of them also apply to the coexistence of a CCS mandate and a cap-and-trade system. A major exception is that, compared to an EPS, a CCS mandate can be more easily stipulated and implemented for a large variety of different installations. In addition, a mandate is most likely more effective in actually implementing more investments in CCS. On the other hand it is difficult to imagine the introduction of a CCS mandate when CCS is not a proven technology.

In order to stimulate investments such as CCS, the interaction of the EU ETS with financial instruments, compared to carbon regulation, offers some advantages. Financial instruments are more cost-effective in reaching a certain CCS target than regulation because they (i) address the economic constraints of CCS investments, i.e., low/uncertain carbon prices, more directly, (ii) offer higher market liquidity and flexibility, (iii) may reduce ‘unintended’ side-effects such as stimulating nuclear power generation or co-firing of coal and biomass, and (iv) may reduce the risk of losing sectoral competitiveness to foreign countries.

Finally, a combination of carbon regulation and financial incentives could be considered. The potential advantage of such a combination is that it would ensure that all investors would have to apply to the rules (which is not necessarily the case if a financial instrument is used separately) and no free-riders are accepted. In the current financial situation of the Dutch government it cannot be imagined that a financial incentive would be applied for a longer time than strictly necessary: the temporariness has to be guaranteed. This will be part of the deal between a coal-fired plant generator and the government in concluding the contract for financial support, but additional regulation could underline the temporariness: it could be announced in a timely way how and to which extent the regulation would replace the financial incentive.

3.3 Requirements for CCS policies

In order to formulate effective policies for advancing CO_2 capture and storage it is necessary to identify the various conditions that such policies meet. These include obviously the innovation and environmental objectives to which CCS policies should contribute, but also a number of economic and other prerequisites. Policies for advancing CCS should:

1) contribute to a rapid diffusion of CCS technologies on the short term (up to and beyond 2015),
2) contribute to certain and substantial CO_2 emission reductions on the medium term (2025-2030),
3) be consistent and predictable, so as to provide clear regulatory signals to industry,
4) be sustainable over a prolonged timeframe from a public budgetary perspective,
5) avoid perverse outcomes, such as wind fall profits or a reduced incentive for ongoing innovation,
6) be acceptable to multiple groups of stakeholders, including both industry and NGOs,

7) be flexible to take into account the rate at which CCS technologies mature, both technically and economically.

A precondition underlying several of the points listed here is that policies for CCS should be formulated in a critical and urgent timeframe. Slow action is likely to frustrate meeting innovation and environmental objectives timely. It will also reduce the existing momentum in government and industry to take CCS technologies forward and may lead to the cancellation of existing plans for CCS operations.

3.4 Elements of integrated policy packages for CCS

The policies proposed and adopted in the United Kingdom and the United States were considered before defining integrated policy packages for CCS for the purpose of this study. A number of elements may be considered important for any CCS policy package in the Netherlands.

These include:
I. Investment subsidies in the demonstration phase (i.e. prior to 2020) and some other financial instrument in the up-scaling phase (after 2020).
II. A staged and increasingly stringent emission performance standard, which eventually is replaced by a mandate for CCS until the point at which CCS is recognized as Best Available Technique (BAT).

Element I comprises financial instruments whereas II is regulatory. Note that we assume that the package will be considered in the context of the European emissions trading scheme. A decrease of CO_2 emissions due to CCS is primarily a technology approach. From an environmental view it only makes sense if the additional CO_2 reduction leads to more stringency in the emissions cap.

A financial instrument is needed to alleviate the financial risk from operators to embark on CCS technology. Apart from early investment subsidies for selected demonstrations (see introduction) an instrument is needed that will reduce the financial uncertainty to any CCS project developer willing to invest in CCS. Various financial instruments may be deployed to this effect, such as:
- a feed-in tariff or premium,
- a contract for difference (also dubbed a CO_2 price guarantee), or
- a tender system.

Eventually, financial support could be replaced by regulation. The choice for an increasingly stringent EPS, eventually followed by a mandate, may be justified for two reasons. Firstly, it provides a very clear long term investment horizon to operators willing to invest in CCS. Secondly, it allows operators from coal-based facilities flexibility to choose from a number of alternative technologies for generating electricity from fossil fuels while reducing CO_2 emissions, namely:
- a switch from coal to natural gas,
- co-firing of biomass,
- greater use of combined heat and power generation, and
- CO_2 capture and storage.

This flexibility also allows for more time for the technological development and cost reduction of CCS technologies. Obviously, the eventual introduction of a CCS mandate should be made contingent on the maturity of CCS technologies, also taking into account the ambition of what regulators are expecting the market to deliver. If necessary, the mandate should be postponed.

Best Available Techniques (maybe in the framework of updated IPPC Directive?) have also been considered. This is also a form of regulation but takes technology development and state-of-the-art better into account. The rationale is that regulation can only be applied to proven technology. It poses less risks to investors and retains a level playing field. It is valid for all EU Member States. A drawback is that it will not stimulate innovation and new technology. So, BAT is more for a second phase or even third phase, once technology has been proven on large scale.

Clearly, the outcome of any integrated policy package for CCS will critically depend on the precise aims of policy makers and on the elaboration of the design characteristics of its elements. Individual policy instruments can be designed in multiple ways. Start and end of a policy may be varied, just as the level of the standard or subsidy or the categories of technologies, fuels or installation sizes to which it is applied.

Basically, two scenarios will be sketched in Chapter 5. Both start with the assumption that the coal-fired demonstration projects which are being built and planned are sufficiently successful to enable a next step by 2020. In the first scenario only regulation will be used. To illustrate the impact of an EPS without financial compensation, the impact of a 500 gram CO_2 per kWh will be sketched. The second scenario models the impact of a combination of financial compensation and EPS in four variants. In the variant Slow Coal one large scale demonstration project has been developed by 2015 and all new coal-fired power plants built in 2012-15 will have been retrofitted to include CCS before 2030. This has been financed externally and is being enforced by an emissions performance standard of 350 g CO_2/kWh valid from 2020. In the Fast Coal variant two demonstration projects have been completed by 2015, the financial incentive and EPS results in CCS retrofit before 2025 and a new coal-fired plant with CCS has been completed before 2030. ECN has not modelled a more stringent EPS. It is assumed that the demonstration projects will show whether additional policies can be formulated by 2018. Additionally, two variants include CCS activities with regard to gas-fired plants. The Slow Coal and Gas variant is comparable with the Slow Coal, but includes a gas-fired demonstration facility to be built by 2020 and 1000 MW gas-fired plants with CCS after 2025. It has not been considered which precise type of regulation is needed to enforce this - ECN does not think enough experience has been made with EPS in the case of gas-powered plants. It is assumed that in the next years some kind of policy regulation approach will be found to enforce a small share of CCS in gas-fired plants if regulation is deemed necessary. In the Fast Coal and Gas variant the Fast Coal variant is combined with two gas-fired demonstration plants around 2020 and 2000 MW of gas-fired plants with CO_2 capture before 2030. It could be imagined that this has been incentivized by a combination of financial incentives and a stricter emissions performance standard for gas-fired plants. It has to be underlined that this is a purely technical assumption. No experience is available to guarantee that this is feasible at large-scale. A sequence of demonstration investments is needed to show that and how this standard may be used in a responsible way.

These variants look only at new coal (and gas-fired) plants - including those who received a permit recently and are being built capture-ready - as retrofit of older plants would be extremely costly. It is assumed that older coal-fired plants will phase-out gradually due to the increasing price of CO_2 emission allowances and by their position in the merit order, as new plants (coal and gas) and low marginal cost technologies (in particular wind energy) will start to produce. The increasing CO_2 price after 2020 and increasing wholesale electricity prices will change the emphasis in the package towards a decrease of additional financial support as well. No financial support is needed from the moment in which the CO_2 price covers additional costs of CCS. It will be illustrated at which price level that might be the case.

4. Comparison of financial instruments

4.1 Feed-in schemes

Feed-in schemes have been successful in advancing renewable energy in various EU member states, including Germany, Denmark, Spain and The Netherlands. A distinction can be made between feed-in tariffs (FIT) and feed-in premiums (FIP; Van Lensink et al 2007). In feed-in tariff systems, the electricity producer sells electricity against a fixed tariff to an electricity distribution company. In feed-in premium systems the producer will sell the electricity on the market himself. He receives an additional premium to make up for the uneconomic top, i.e. the difference between the costs of producing electricity using fossil fuels and the costs of producing electricity from renewable energy.

A fixed tariff will provide more certainty to producers, because the uncertainty in the income per kilowatt hour delivered is removed. The greater stability of income in a feed-in tariff system vis-à-vis a feed-in premium system tends to lead to more favourable conditions for external finance. Still, projects may involve certain risks, including technological risks (for instance a standstill of the installation) or risks related to fluctuations of fuel prices. Furthermore, a third party such as a transmission or distribution system operator will need to resell the electricity purchased against a fixed tariff.

In a feed-in premium system the producer will take on the risks of electricity price variations himself. He receives a premium on top of the price for conventional electricity, but, no adjusted prices are applied for electricity produced with renewable energy or CCS. As a consequence, this variant can be considered more in line with a liberalized electricity market.

In brief, the choice for a fixed tariff or a premium has a bearing on the attribution of risk. Indirectly, this may affect the environmental effectiveness of the scheme. While a feed-in premium system may seem more in agreement with a liberalized electricity market, a fixed tariff may bring more favourable financing conditions.

4.2 Contract for difference

In the context of CO_2 markets a contract for difference (CFD) is a contract between two parties, stipulating that one party (e.g. the Dutch government) will pay to the other (a project developer) the difference between a preset level for the CO_2 price, equal to a level needed to make up for the costs of CCS technology, and the CO_2 price that will be realized. A contract for difference may thus be used to overcome the uncertainties in the value of emission allowance units while CO_2 prices are still low and volatile. This instrument is also referred to as a CO_2 price guarantee.

4.3 Tender systems

Tender systems are used widely to induce industry to propose and realize specific objectives as defined by a national government or other public authority. In the context of CCS they may be used equally for the realization of CO_2 capture installations, CO_2 pipeline trajectories, or CO_2 storage locations. The European Commission already launched a call for tender to select CCS demonstrations that would benefit from the 1.05 G€ available for CCS in the European Economic Recovery Plan. Clearly, the selection involved substantial efforts to carefully select these demonstrations. Eligible operations would need to capture over 80% of CO_2 from power plants with a capacity over 250 MW_e, and transport and store this safely. Knowledge sharing was another crucial precondition. Selection criteria included a well-considered plan, both technically and financially, the expenditure of substantial amounts before the end of 2010, and the availability of a strategy to collect the required permits. In a final step, candidate demonstrations were ranked according to the anticipated delay caused by a lack of finance, the required contribution from the EC per ton of CO_2 in the first five years, complexity and innovation of the operation, and the quality the plan with respect to information and data used. Selection efforts might be more modest in future national tenders, in particular when calls regard specific pre-defined CCS projects.

4.4 Criteria for comparing financial instruments

The financial instruments introduced above may be compared using a number of criteria, including:

- *Environmental effectiveness*, i.e. effectiveness to reduce CO_2 emissions and stimulate innovations such as CCS. In general, environmental effectiveness of an instrument will go up as the level and/or duration of a subsidy increases, although this effect is likely to level off.
- *Cost effectiveness*, i.e. the amount of CO_2 reduced or the CCS capacity realized for a given amount of subsidy. Cost effectiveness of a subsidy probably increases as a subsidy starts to reach a level high enough to induce new investments. However, it will most likely fall again if levels of subsidies increase further, possibly resulting in wind fall profits for project developers.
- *Interaction and compatibility with the EU ETS*, notably the effect on the CO_2 price. In general, any policy instrument used alongside the EU ETS will lead to the deployment of a technology that would not have been preferred in absence of the instrument. Consequently, if the EU ETS emissions ceiling is not adjusted downwards, the demand for CO_2 credits under the EU ETS will drop, as well as the CO_2 price.
- *Distribution of costs* among industry, government and consumers or tax payers. For all financial instruments the same principle applies. The lower costs are to industry, the smaller the need is to pass on costs to the consumer, but the greater the burden for the tax payer.
- *Incentive to innovate.* For an effective stimulation of ongoing innovation and cost reduction it is important that the party paying for the technology also disposes of the means to reduce these costs. For financial instruments this is not possible by definition. However, at least a government should have access to correct cost information. Otherwise, the government may find itself paying too much for stimulating a technology, and this would remove the incentive for industry to further bring down costs.
- *Windfall profits.* These are excessive profits that may arise if the prices for emission allowance units or for fossil fuels are lower than anticipated.
- *Transaction costs* or ease of implementation.
- Perceived *support among industrial stakeholders.*
- Perceived *support among NGOs.(Non-governmental organisations)*

Clearly, all of these are important criteria. However, without further information on the duration or the level of a subsidy it is difficult to resolve in generic terms on most of these criteria, including differences in environmental and/or cost effectiveness of the financial instruments discussed, as well as on their effect on the CO_2 price or on distributional effects. Such a comparison would require detailed insight in the business cases for CCS operations, and this is beyond the scope of the present study. Also, support among industrial stakeholders is unlikely to distinguish between the various subsidy instruments. Presumably, any kind of financial support is welcome to industrial project developers as long as it helps to make a business case.

Still, it is possible to compare the financial instruments in generic terms on the basis of three remaining criteria, namely the incentive to innovate, transaction costs, and support among key stakeholders, including both industry and NGOs.

4.4.1 Cost effectiveness (public budget)

The three financial instruments introduced have different implications for the information on the cost of the technology that the government would dispose of.

1. Under a feed-in scheme, the government would depend on reliable information on technology costs from industry to estimate the difference between the cost price of electricity with and without CCS, i.e. the uneconomic top. Even if the cost of electricity produced with CCS is estimated conservatively (on the low side), inputs from industry are indispensable. This implies the risk that subsidies might be too high, which would reduce the incentive for industry to further innovate. Note however that a feed-in scheme may also offer the possibility to tender, as for instance in the Dutch SDE system for renewable energy.

2. This is different from the situation under a contract for difference. Since this instrument covers the difference between the actual and a previously anticipated CO_2 price level, there is no need for the government to have insight into the costs of CCS technology. It will only need to know the volume of CO_2 that will be captured and stored by individual CCS operations.

3. A tender system takes an intermediate position in this respect. While the technology costs involved in developing a (part of the) CCS chain would clearly be important to a government that launched a call for tender, it is only one of the factors in deciding on the winning proposal.

4.4.2 Potential for excessive profits

Excessive or windfall profits could arise if the prices for emission allowance units or for fossil fuels are higher than anticipated.

In a scheme of feed-in tariffs the cost of electricity from CCS projects is influenced by the price of fossil fuels and the costs of CO_2 emissions as set by the EU ETS. Thus, risks related to fossil fuel and carbon prices could lead to overly high feed-in tariffs. This may lead to unexpectedly high profits should fuel or CO_2 prices remain on the high side. However, in case of very low fuel or CO_2 prices the opposite is the case.

In a scheme of feed-in premiums the uncertainty in CO_2 prices still exists, but the uncertainty in fossil fuel prices is less important, because the scheme only covers the additional cost of producing electricity with CCS, and not the full cost of electricity. The risk of windfall profits is therefore somewhat smaller.

Under a contract for difference system the operator of a CCS demonstration is covered for the difference in CO_2 price that is needed to enable CCS, and the CO_2 value that is realized. This scheme does not involve a CO_2 price risk, because the higher the CO_2 price is, the less the operator gets reimbursed. As in a FIP scheme, there is a small remaining fossil fuel price risk related to the fossil fuel requirement for capturing the CO_2.

In a tender system risks related to both fossil fuel and to CO_2 prices exist. Typically, assumptions on these variables are made explicit in project proposals, but usually funding under a tender system is not made contingent on fossil fuel and/or CO_2 price developments.

4.4.3 Transaction costs

Furthermore, the financial instruments introduced here differ with respect to the ease by which they may be implemented and the associated transaction costs.

A major advantage of a feed-in scheme would be that it would link up to the current practice of stimulating renewable energy projects through the SDE. Methods and procedures may to some or to a large extent be similar to the practices for renewable energy.

Introducing contracts for difference on the contrary would involve an entirely different instrument. While in theory this does not need to be a problem, in practice it may complicate its introduction.

Tender systems are used widely for inter alia infrastructural projects, including renewable energy, and can be used easily for CCS projects as well. It will however require processing a lot of detailed project information and therefore put a greater burden on the public sector then for instance a feed-in scheme.

4.4.4 Incentive to innovate

The different schemes have different effects on innovation. Both a feed-in tariff and premium can be quite effective in stimulating innovation, if the tariffs are announced timely and the subsidy decreases in such a way that cost reductions are almost forced. This is the case in the - in this respect - successful German feed-in tariff scheme. In the Dutch SDE feed in premium, however, this long-term approach is not taken, although in principle it could be done. The ranking therefore is somewhat lower. An innovative approach is more difficult to implement in a contract for differences scheme, as in that scheme the amount to be paid depends on the difference between the expected and actual CO_2 price. A CFD does not stimulate innovation in the way well designed feed-in tariffs or premiums do. A tender system could be organized in a comparable way as the feed-in tariff with ex ante annunciation of decreasing minimum prices. Furthermore, because of the competition between the applicants, innovation will be stimulated. As we assume a tender system would be based upon the actual legislation of the SDE, we do not rank it higher than the feed-in tariff, but higher than the feed-in premium scheme.

4.4.5 Stakeholder support

Support for any CCS policy among a range of stakeholders, including industry and NGOs, is important. This is even more so since the technology itself has turned out to be controversial. A number of Dutch NGO's appeared reluctant in accepting CCS, while others, notably the Stichting Natuur en Milieu (SNM) take a more neutral or positive stance. The position of NGOs is important in particular because they have an impact on perceptions of CCS among the public at large. Negative evaluations of CCS on their behalf, as well as of related policy incentives may well negatively influence public views of the technology.

Any policy for stimulating CCS will most likely be considered carefully by the NGOs and assessed in particular for repercussions it might have for other climate policies, notably the competition of CCS policies with resources for advancing renewable energy. Therefore, in general financial instruments are likely to meet greater resistance than regulatory instruments. To what extent one financial instrument may be preferred over the other, is a matter of speculation, but some observations can be made.

The prevailing feed-in premium system scheme in the Netherlands, the SDE, has been designed to stimulate energy from renewable sources. Its precursor, the MEP, was closed in 2006 because the number of applications outran the available budget. Budgetary constraints are therefore an important issue in the evaluation of this instrument for advancing CCS. Expansion of the portfolio of technologies covered by the SDE to include CCS is likely to affect the budget available for renewable energy projects, and may well meet serious resistance among NGOs.
Similarly, NGOs may be concerned that a tender system meant to induce and help realize CCS projects will have a negative effect on the resources available for renewable energy. Concerns

might be somewhat smaller then when CCS is to be supported by the same regulation. Note however that these concerns may not be justified. Additional budget for CCS does not need to have a bearing on the financial support for renewable energy, but may be collected by for instance an increase of the electricity prices.

A contract for difference will most likely not be able to account on great enthusiasm from the NGO community either. Although in principle this instrument could be applied to (a selection of) CCS technologies only, it might prove politically unfeasible to reserve it for CCS only. Proponents of renewable energy could argue with some reason that a CFD should be equally applicable to other technologies, and would not want to accept the instrument if it is designed to advance CCS only.

4.5 Conclusion

The outcome of this comparison is presented in a semi-quantitative way in Table 4.1. Based on the above it may seem difficult to express an explicit preference for one or the other financial instrument.

Stimulating CCS in the Netherlands with a feed-in scheme, notably when based on an (additional) premium, has the advantage that the instrument could be linked to the existing scheme for renewable energy, the Stimulering Duurzame Energie (SDE). On the downside, it requires processing possibly biased cost information from industry by the state, it involves the risk of excessive profits should CO_2 and fossil fuel prices is lower respectively higher than anticipated, and it may render the energy sector dependent on subsidies.

A contract for difference on the contrary will not require evaluation by the state of possibly underestimated cost information. It would however require the introduction of an entirely new policy instrument, which possibly will involve higher transaction costs and most likely give rise to questions as to why a dedicated instrument would be required for CCS and not for other abatement technologies.

A tender system has an intermediate position. It is being used widely in Dutch energy policy, and competition will discourage project developers to overestimate costs. It will involve a minor risk of windfall profits in case fossil fuel prices are lower than anticipated, and require efforts from a state agency to evaluate the project.

Table 4.1 *Comparison of financial instruments for stimulating CCS on the basis of three criteria (FIT = feed-in tariffs, FIP= feed-in premiums, CFD =contract for difference)*

Criterion *Instrument*	Cost effectiveness (public budget)	Risk of excessive profits	Transaction costs	Incentive to innovate	Support stakeholders
FIT	**-/o** project developer provides information on cost of technology to government, however competitive tendering possible	**-** uncertainty in price of fossil fuels and price EUAs	**+** link up to existing SDE	+/o if defined in timely way	**-** concerns about competition with RES in SDE
FIP	**-/o** project developer provides information on cost of technology to government, however competitive tendering possible	**-/o** uncertainty in price of fossil fuels (limited) and price EUAs	**+** link up to existing SDE	o + if defined in timely way (but not the case in SDE)	**-** concerns about competition with RES in SDE
CFD	**+** no need for government to dispose of information on cost technology	**o** uncertainty in price of fossil fuels (limited)	**-** entirely different instrument	o ex post result will not stimulate innovation	**-** limited or absent (if only for CCS
Tender system	**o** competition hampers the use of overly high estimates of cost technology	**-/o** uncertainty in price of fossil fuels (possibly limited) and price EUAs	**o**/+ more labour-intensive, but widely used	o/+ dependent on degree of competition of applicants and long-term approach of government	**-** concerns about competition with RES

All in all, the differences between the instruments are small. No really preferred one can be distinguished. At least on the short term a tender system could be preferred slightly for providing subsidies. It stimulates competition and also may allow the state to have a say in operating conditions, should this be desirable. On the medium term, feed-in premiums may be the preferred instrument for reducing the financial risk of a CCS operation. The most important reason for this is that it would be difficult to make the argument as to why CCS, contrary to other carbon abatement technologies in the power sector, would need to be stimulated with a dedicated instrument. If cost effectiveness is ranked highest, a contract for differences might be the best option.

5. Implications of CCS regulation for the Dutch electricity production system and electricity market

5.1 Introduction

The implications of the combination of financial incentives and regulation of the four policy packages introduced in Section 3.4 will be explored in this chapter. The emphasis will be on possible compositions of the Dutch electricity production system, and on the impacts on the resulting fuel mix and CO_2 emissions, and import and export flows, the cost of production, and on the level of wholesale electricity market prices. As background scenarios the new reference projections (here denoted as 'NRP-NL') for the Netherlands have been used (ECN/PBL, 2010). Assumptions for economic growth, electricity demand, fuel and CO_2 prices, for these projections and the resulting composition of the electricity production system are given in Section 5.2. Prior to showing the cost impacts of individual measures and the policy packages, the technical feasibility of the EPS values is discussed in Section 5.3. Besides CCS, also co-firing of biomass in new coal-fired power plants is addressed. The combination of biomass co-firing and CCS may lead to very low and even negative CO_2 emission values. In addition, Section 5.3 also reports indicative results of the extreme 'Only EPS' case which is compared to the NRP-NL-SVV reference case. It also refers to findings of recent assessments of individually proposed policy measures in the Netherlands, a.o., an EPS of 350 gram/kWh for new power plants in the Netherlands.

Section 5.4 summarises the assumptions for the four policy packages analysed quantitatively. Cost estimates are important to consider in conjunction with market behaviour and for calculation of financial gaps or needed subsidies to compensate for the higher costs of CCS. These cost considerations are given in Section 5.5.
The results of the quantitative analyses for the four policy packages are given in Section 5.6. The results focus on the changed impacts to:
- wholesale electricity prices in the Netherlands,
- net export of electricity,
- competitiveness of Dutch power generation sector,
- CO_2 emitted and other emissions (notable NO_x, SO_2 and particulate matter), and
- renewable electricity by biomass co-firing.

Section 5.7 is devoted to indicative calculations of the cost of additional financial measures.
Supporting numerical details of both NRP-NL-SVV reference cases are given in an Annex to this report. If not indicated otherwise all monetary values in this chapter are expressed in €2008.

Due to the limited scope of the ECF study, ECN did not explore a broad envelope of other assumptions. The NRP-NL projections include integrated uncertainty and sensitivity analyses which could add to the robustness of the conclusions in this chapter. These sensitivity analyses will not be reported here. With regard to the cost estimates in the Annex, ECN addresses some of the uncertain factors (fuel prices and CO_2 prices).

It is assumed that the additional use of a financial instrument, alongside regulation, may lead to additional CCS deployment, or introduction of CCS. However, the basic composition of the electricity park of NRP-NL will not be altered, except for two cases with fast deployment of CCS and earlier decommissioning of older plants. In these cases, all of the old, existing coal power plants will be decommissioned in 2030, leaving room for new and additional capacity in the period 2020 to 2030, compared to the NRP-NL-SVV reference case.

5.2 Starting point NRP-NL: the new reference projections for the Netherlands

ECN and PBL made new reference projections for the Dutch government (ECN/PBL, 2010). The projections take into account the impact of the recent and current economic crisis. This has a decreasing effect on the future electricity demand compared to reference projections and other long term energy outlooks made in previous years (e.g. ECN, MNP, 2005; WLO, 2006; ECN/PBL, 2009). The new reference projections will be the basis for policy assessments of current or new policy measures by the Dutch government. It is therefore also used as starting point and basis for the analyses reported in this chapter, to support the ECF study on additional CCS policy instruments. It should be noted that the analysis of individual policy measures like an EPS of 350 gram/kWh, an additional coal tax, and obligation on CCS, all aimed as elements in achieving the year 2020 targets, is separately conducted for the two Dutch ministries. Previously PBL, with the supported of ECN, has conducted two policy assessments on similar proposals by two political parties, Groenlinks and D66 (PBL, 2009, 2009b).

5.2.1 Overview of assumptions

Two policy variants: only one is used as basis

The new Dutch reference projections denoted as NRP-NL in the remainder of this chapter, has two policy variants:

1) SV, based on existing NL and EU policies and instruments (‘*NRP-NL-SV*’).
2) SVV, equal to assumptions as in SV but supplemented with additional and planned national policy measures, notably for energy saving and renewables. The result is a somewhat lower electricity demand and a substantial higher share of renewable electricity production (‘*NRP-NL-SVV*’).

In the remainder of this chapter, the new reference projection variant SVV is used as a starting point. It is denoted as NRP-NL-SVV in the remainder of this chapter. The additional CCS policy packages are surmounted on top of this NRP-NL-SVV projection.

To understand the results of the analyses, the scenario assumptions of NRP-NL are relevant and need to be understood well.

Economic growth and electricity demand

The GDP growth is less than in the previous Global Economy and Strong Europe long term scenarios for the Netherlands (WLO, 2006). The Green4Sure scenario (CE, 2007) is a normative scenario based on the economic growth figures of the Strong Europe scenario. The results for this scenario were calculated by ECN, based on assumptions provided and determined by CE (ECN, 2007). The Green4Sure scenario exhibits additional policies on energy saving, renewables and CCS.

Effect of economic crisis

The electricity demand was 119.2 TWh in 2008, somewhat higher than in 2007 (118.5 TWh). During the second half of 2008, the impact of the financial and economic crisis became apparent and had its impact on the growth in demand. During 2009, the economic decline led to a decrease in the electricity demand with more than 5% (CBS/Statline, 2010). A preliminary estimate for the final electricity demand in 2009 is about 113 TWh. The net import decreased from 16 TWh in 2008 to 5 TWh in 2009, the lowest figure in the last 10 years. The average net import in the years 2000-2008 was 18 TWh.

Table 5.1 *GDP and electricity demand, scenarios and projections since 2006*

	GDP growth	Electricity demand [TWh]		
	[%/yr] (2011-2030)	2020	2030	2040
Global Economy (High Oil Price variant)	2.7	156	181	212
Strong Europe (WLO, 2006)	2	137	148	161
Green4Sure (CE, 2007; ECN, 2007)	2	127	124	n/a
CE (2009)	unknown	140		
Update reference projections 2009				
UR-GE (fuel prices as in EC, 2008)	2.7	156	181	n/a
UR-GE (h) (higher fuel prices WEO2008)	2.7	156	180	n/a
New Reference Projections 2010				
NRP-NL-SV	1.7	130	136	n/a
NRP-NL-SVV	1.7	128	131	n/a

CO_2 prices and fuel prices

NRP-NL assumes the following CO_2 price path:

- 20 €/ton in the third ETS period 2013-2020. The impact of the economic crisis is taken into account which will result in relatively low CO_2 price. The previous reference projection (ECN/PBL, 2009) used 35 €/ton as a default value.
- Increasing to 50 €/ton CO_2 in 2040.

The natural gas and (imported) hard coal prices have been assumed equal to the prices used in the EU baseline 'Trends to 2030 - update 2007' (EC, 2008)[8], see also Figure 5.1 below. The NRP-NL fuel prices are equal to the previous UR-GE scenario (ECN/PBL, 2009). For hard coal an additional handling cost of about 0.2 €//GJ is used.

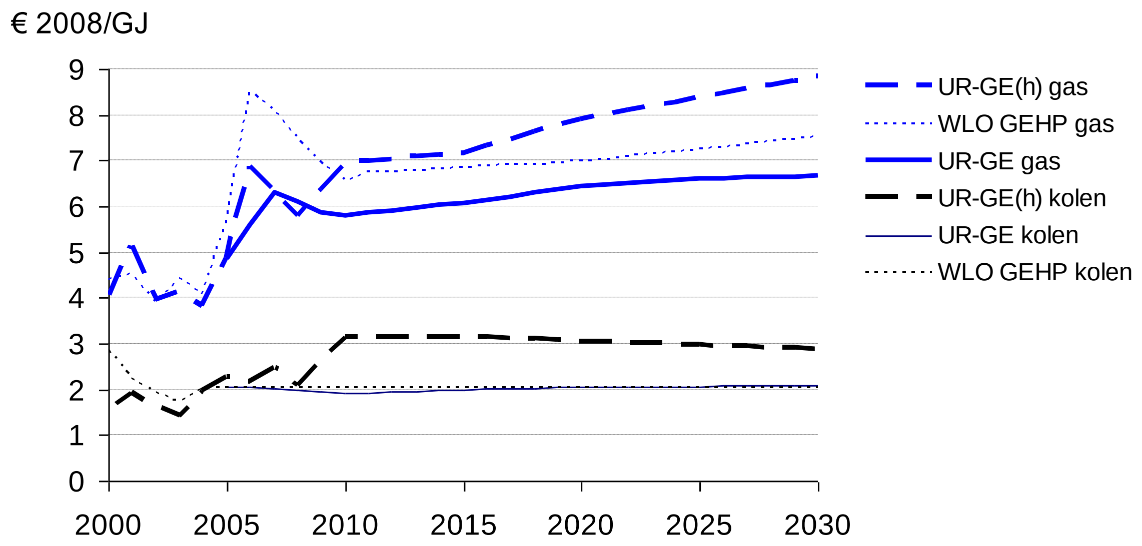

Figure 5.1 *Natural gas and (imported) coal prices assumed for NRP-NL (equal to UR-GE), Sources: (ECN/PBL, 2009; Seebregts et al, 2009).UR-GE equal to (EC, 2008) fuel prices. UR-GE(h) equal IEA WEO 2008 prices. WLO-GEHP equals the high oil price variant of the WLO Global Economy scenario*

Source: WLO, 2006.

[8] In September 2010, the EC published an update 'EU Energy Trends to 2030 - Update 2009'.

CCS policies and CCS deployment
On CCS policies, no specific variant has been defined or analysed as part of the NRP-NL study. Both SV and SVV contain only one large demonstration CCS power plant: the joint Electrabel and E.ON demo for their two new coal-fired power plants in the Rotterdam area. Based on a 250 MW_e equivalent, the plan is to capture 1.1 Mton CO_2 by the end of 2015 (Electrabel Newsletter, 2009). This demo will receive the required subsidies within the EU EERP and additional subsidies from the Dutch government.

Results of NRP-NL-SVV
The results for the power generation sector and the domestic electricity demand for the Netherlands are summarised here. More details are given in the Annex to this report.

5.2.2 Power generation sector: assumptions and results

Assuming additional policies aiming to reach the EU and the Dutch national 2020 targets on renewable energy, energy saving and GHG emission reduction, ECN developed a scenario for the electricity production in the Netherlands. The electricity generation capacity and the production mix are displayed in the next two figures. Interfaces (i.e. cross-border interconnections) and the electricity production system of the neighbouring countries Belgium, France, Germany, Norway and the United Kingdom are also modelled as part of the ECN scenarios. So, the Dutch power generation sector and its electricity market are modelled and analysed as part of the integrated Northwest Europe electricity market.

New build fossil-fired power plants: 10000 MW in period 2009-2015
The power generation sector accounts for a substantial amount of CO_2 emissions. In addition, the (new) large power plants constitute the main potential for large scale CCS. The current new build fossil-fired power plants (about 10 GW up to 2015) and electricity generation by wind energy contribute mainly to the overall increase from about 25 GW end of 2008, to a projected generation capacity of almost 42 GW in 2020 (NRP-NL-NL), see Figure 5.2. The domestic electricity production is displayed in Figure 5.3. After 2010, the net import changes into a net export situation.

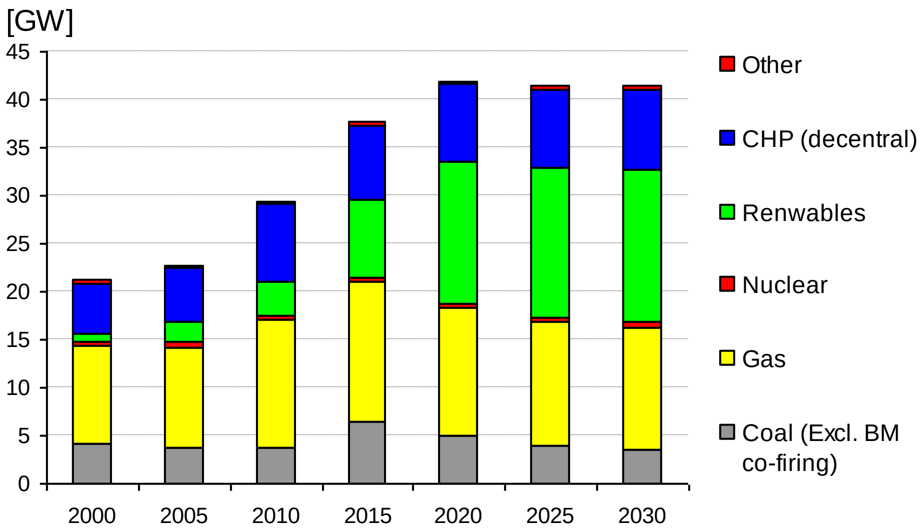

Figure 5.2 *Installed total generating capacity 2000-2030, NRP-NL-SVV, new reference projection*

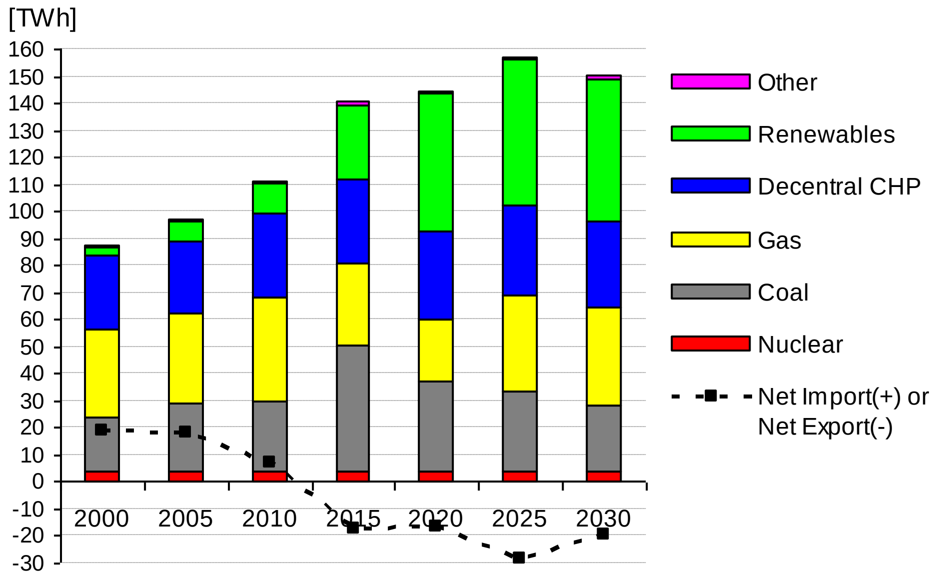

Figure 5.3 *Electricity production and development net import/export, 2000-2030, NRP-NL-SVV, new reference projection*

One of the main drivers of the growth in electricity production is the amount of new build power plants in the Netherlands in the period 2009-2015. The details of these new build plants, either under construction or planned, are given in Table 5.2. The total amount new build of large scale fossil fired power plants amounts to almost 10 GW, consisting of 5 GW new coal and about 6 GW of new gas. This is exclusive of new build in decentral CHP and renewables.
ECN considers the amount of assumed new built power plants in NRP-NL realistic and plausible with the scenario assumptions of NRP-NL. A vast majority is of this 10 GW is already under construction or, for part of the new gas, has recently started production (Sloecentrale).

TenneT: more than 30 GW of new fossil and nuclear power plants
The about 10 GW new build up to 2015 is far less compared to the reported plans by TenneT (TenneT, 2009). The TenneT figure is about 30 GW of new build fossil and nuclear power up to 2020. Up to and including 2016, TenneT reports a value of 25 GW. About 9 GW of the new power plants has signed a contract with TenneT to be connected to the grid.

CE: only 7 GW new build (including decentralised CHP)
CE (2009) assumes only new build of 7 GW fossil capacity in the period up to 2020, including large scale power plants and decentralised CHP. As can be seen from Table 5.2, this 7 GW is too low in view of what is currently already under construction or contracted to being build.

A license does not necessarily mean a power plant will be build
At this moment, licences for five new coal-fired plants have been granted. It should be noted that granting of licences and permits are no guarantee the power plant will be build. Only three plants are currently under construction. One of the plans (Essent) is being dismissed. Another plan (Vattenfall/Nuon’s Magnum plant) is waiting for a final investment decision to make it a coal/biomass gasification plant rather than the CCGT plant currently under construction.

New Coal and CCS
Three new ‘capture-ready’ coal-fired power plants are currently under construction, in total about 3500 MW_e. The first units will produce electricity in 2012 and 2013. On the longer term, old coal-fired power plants are assumed to be closed down, starting after 2015. The existing coal-fired fleet amounts to almost 4200 MW_e and consists of 8 units on six locations.

After 2020, no new coal-fired power plants will be built in the Netherlands according the NRP-NL-SVV reference projection. The currently being built 3500 MW of new coal-fired capacity will be available for CCS in the period 2015-2050, assuming a 40 years lifetime. Large scale biomass fired power plants which could also qualify for CCS are not forecasted as plausible within the context of the NRP-NL scenario assumptions.

In the period 2010-2015 three new ‘capture ready’ coal-fired power plants will be built in the Rotterdam and Eemshaven areas. First demo’s will be applied to two of these projects prior to 2020: one at each location. In NRP-NL-SVV only one demo has been assumed, lacking certainty on additional subsidies for a second demo in the Eemshaven area. The Electrabel/E.ON joint project in Rotterdam will receive the necessary funds with the EERP and additional national subsidy. A total of 1.1 Mton/year will be captured from 2015 onwards. This demo has been modelled as part of NRP-NL. The Vattenfall/Nuon Magnum plant in the Eemshaven is intended to be a multi-fuel IGCC, but the final decision to build the gasification unit still has to be made by Vattenfall/Nuon. Therefore it is modelled as a natural gas CCGT plant in the ECN/PBL reference projection NRP-NL.

Natural Gas and CHP
The share of natural gas fired power plants will remain substantial. Part of those plants will be flexible enough to cope with large shares of intermittent wind energy. Decentralised CHP will remain an important option within the NL electricity system.

Nuclear
Current Dutch policy will keep the only nuclear power plant at Borssele open until 2034. The next Dutch government (elections in June 2010) is to decide on new nuclear power plants. One Dutch electricity producer, Delta, has launched a plan to have a second nuclear power plant in operation by the year 2018 (Delta, 2009). It is not included in NRP-NL-SVV, lacking a government decision on new nuclear power plants in the Netherlands. The outcome is highly uncertain due to the political and societal controversy of new nuclear power in the Netherlands.

Renewables: mainly wind energy and biomass
The prime focus of NRP-NL is on the year 2020 because of the 2020 NL and EU targets and the existing and planned policy measures to achieve these targets. However, the NRP-NL projections have been consistently extrapolated up to the year 2040 for electricity demand and electricity generation but without additional policies after 2020. For this study for ECF, the time period is restricted to the years 2010 up to and including 2030.

Table 5.2 *New build large scale power plants in the Netherlands, in the period 2009-2020 (updated from table in Seebregts et al, 2009)*

Company	Location	Capacity [MW_e]	In operation (planned)	Type	Net efficiency [%]	Status
Assumed as part of NRP-NL reference projections						
Gas						
Delta	Sloe area (Sloecentrale)	870	2009	CCGT	58	In operation since October 2009
Electrabel	Flevocentrale	870	2009/2010	CCGT	59	In operation?
Enecogen	Rijnmond	840	2010	CCGT	58	Under construction
Essent/RWE	Moerdijk	400	End 2011	CCGT (CHP)	58 [4)]	License 28-5-2008
Essent/RWE	Maasbracht (Maasbracht-C)	+635	2011	Upgrade Maasbracht-B tot CCGT	58[5)]	Contracts signed May 2008
Intergen [3)]	Rijnmond	419	2010	CCGT	58	Under construction
Vattenfall/Nuon [1)]	Eemshaven (Magnum)	1200	2012	CCGT	56	Under construction
Corus	Ijmuiden	525	2012	Blast furnace gas, CHP	unknown	Start Note (In Dutch: 'Startnotitie') 16-10-2008
Total new large scale gas		**5759**				
Coal						
E.ON	Maasvlakte (MPP-3)	1070	2012	pulverised coal	46[2)]	Under construction
Electrabel	Maasvlakte	800	2012	pulverised coal	46	Under construction
RWE	Eemshaven	1600	2013	pulverised coal	46	Under construction
Total new coal		**3470**				
Other plans but not assumed to proceed in NRP-NL reference projections						
Gas fired						
Advanced Power	Eemshaven	1200	2013	CCGT	58-60	Start Note 8-7-2008 MER available
Electrabel	Bergum	454	2014	Unknown	Unknown	Via TenneT (2009)
NAM	Schoonebeek	130	2011	gas, CCGT		Via TenneT (2009)
Vattenfall/Nuon [11)]	Amsterdam, Hemweg ('Hemweg-9')	435	2012	CCGT, possibly CHP	min. 57	Start Note (In Dutch: 'Startnotitie') 11-4-2008 Final decision April 2010
Vattenfall/Nuon [11)]	Diemen	max. 435 MW_e, max. 250 MW_{th}	Unknown	CCGT, CHP	min. 59, electrical up to 80 total efficiency	Start Note (In Dutch: 'Startnotitie') 11-4-2008 Final decision August 2010

Company	Location	Capacity [MW_e]	In operation (planned)	Type	Net efficiency [%]	Status
Unknown	Maasvlakte	600	2011	gas	Unknown	Via TenneT (2009)
Coal fired						
Essent/RWE	Geertruidenberg	800		pulverised coal	46	Plan dismissed
Essent/RWE/ Shell	Zuid-West Nederland	1000 MW		IGCC	46	Plan dismissed
C.GEN	Europoort	400-450	2012	IGCC	46	Start Note (In Dutch: 'Startnotitie') 25-9-2008 Dismissed (October 2010)
C.GEN	Sloe area	400-450	Unknown	IGCC	46	Press release
Nuclear						
Delta	Sloe area	Max. 2500	2018	Nuclear		Start Note (In Dutch: 'Startnotitie') 25-6-2009
ERH	Sloe area	Additional 2500	2019	Nuclear		ERH (2010) Start Note Sep 2010

Notes for Table 5.2:

1) The conversion efficiency is strongly dependent of the fuel mix. The priority alternative (Dutch: voorkeursalternatief) includes a 60% coal/biomass (720 MW, efficiency 45%) and a 40% natural gas (480 MW, efficiency 54%). Using 100% natural gas gives an efficiency of 54% (less than about 58% for other CCGT's; the reason being the gasturbines are designed to cope with syngas instead of natural gas). Vattenfall/Nuon has postponed the decision to build a multi-fuel gasification unit. Building the gas-fired CCGT's (1400 MW, 3 units) has started. A gasification unit may follow later.
2) With 30% biomass as fuel, the efficiency is 1%-point lower (45%).
3) Building has started in January 2008 (Press releases, Intergen en Oxxio, 2007).
4) Environmental Impact Statemen (Dutch: MER). Operating hours 7000 (expectation, as start/stop unit) and 8200 hours (worst case with respect to total emissions, the base load operation unit). The permit (dated 29 May 2008) reports that the CCCT will be used primarily as flexible peak load unit. It will be switched off often during nighttime.
5) Press release Essent/RWE 29 May 2008; previously in MER: 56% using natural gas, possibly 42% for bio-oil using boiler; in that case an average of about 52% (740 MW gas 160 MW bio-oil). Old unit B was 37% (and 640 MW capacity). PrEssent/RWE, number 4, November 2008 reported a value of 58.8%.
6) If unit is built, it will replace the conventional boiler unit Hemweg-7. District heating is being considered. Vattenfall/Nuon is planning to decommision older units within 7-9 years. This involves older units in the region Utrecht and Amsterdam.
7) Intended as additional CHP unit for district heating purposes.
8) Start Note (In Dutch: 'Startnotitie') mentions coal, petcokes (maximum about 25%, natural gas and clean biomass (maximum about 25%). The design will be capture ready such that on the longer term about 85% of the CO_2 produced from coal, petcokes or biomass, can be captured.
9) In the old reference projection RR-GE from 2005 (ECN/MNP, 2005), 2400 MW (4000 MW in WLO-GEHP, WLO, 2006) new build coal was assumed. And no existing coal power plants had been decommissioned. Only the new Sloecentrale was assumed to operate. The remainder of the increase in the gas-fired power comes from decentral CHP.
10) All net efficiencies are based on a.o. (Seebregts & Daniëls, 2008).
11) Final decisions to construct these two plants was made by Nuon in April 2010 (Hemweg-9) and August 2010 (Diemen 34). [9]

[9] See http://www.nuon.com/company/core-business/energy-generation/power-stations/hemweg9.jsp http://www.nuon.com/company/core-business/energy-generation/power-stations/diemen34.jsp (both visited 6 Dececember 2010).

Operating hours of new and old fossil power plants
The operating hours of both old and new power plants have been calculated by ECN's electricity market model. The NRP-NL-SVV reference projection features high shares of renewable electricity production in the period 2020-2030. Despite of this large share of renewable capacity with low and limited marginal costs of production, the operating hours of new coal fired power plants remain at high levels. Existing and older coal power plants will be operating less, and will be decommissioned beginning with the oldest ones first.

With respect to the business cases of the three new coal fired power plants assumed to be built, it can be concluded that their business cases are not largely affected negatively by the high share of renewable electricity production. Based on the CO_2 prices assumed up to 2030, these new coal fired power plants will produce for more than 7200 hours on an annual basis in the period 2015-2030.

During off-peak hours, the very old coal fired plants (built before 1990) and (old) gas-fired will be out of the dispatching order. Consequently, for these old coal power plants substantially less than 4000 operating hours result, which may also adversely impact start up and shutdown costs, and overall net efficiencies. This frequent start/stop behaviour will further worsen the variable cost of production as it reduces the net efficiency of operation (e.g. see (TU Delft, 2009)). New gas fired plants will operate mainly during peak hours, when the market price is high enough to cover the marginal cost of production.

Wholesale electricity prices from NRP-NL and sensitivity analyses
The average wholesale markets prices calculated for NRP-NL show approximately the same values for NRP-NL-SV and NRP-NL-SVV. The latter show somewhat lower prices due to the additional production capacity caused by the higher penetration of wind energy, an option with very low marginal production costs. E.g. the electricity price in 2020 is 62 €/MWh for NRP-NL-SV, while for NRP-NL-SVV it is slightly lower 60 €/MWh. This is mainly caused by the additional production capacity (42 GW versus 37 GW in the year 2020).

Figure 5.4 below show an indication of how electricity prices evolve in time, with NRP-NL-SV as basis, and also as a long term outlook up to 2040. For that case, sensitivity analyses have been conducted for lower and higher fuel and CO_2 prices.

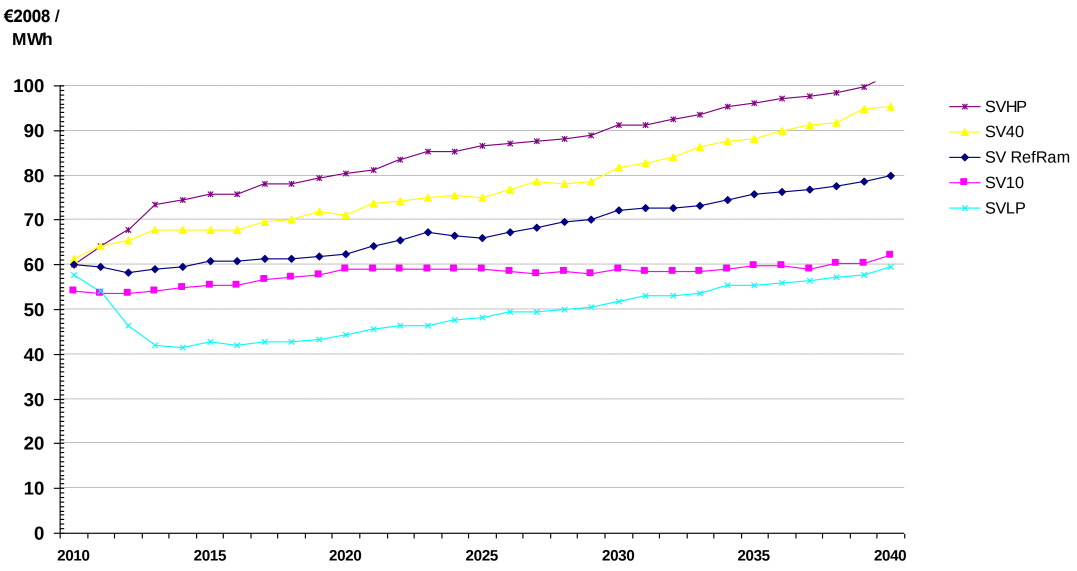

Figure 5.4 *Wholesale market electricity prices project in NRP-NL-SV (SV RefRam) and four sensitivity analyses for lower/higher fuel prices and lower/higher CO_2 prices*[10].

5.3 Feasibility of low EPS values for new power plants

The feasibility of low EPS values for new power plants can be viewed from a technical and a market perspective.

5.3.1 Technical

In theory, but only if technical developments and research are successful in the next 10 years, attaining low EPS values for new fossil power plants will be possible. An illustration of CCS deployment, possibly in combination with biomass co-firing, that can reach EPS values of 150, 350 or 500 gram/kWh is given in the next table. A 55% biomass co-firing percentage would result in about 350 gram/kWh. To attain a similar value with CCS, the necessary CO_2 capture rate should be 62% assuming a net efficiency of 37% (in comparison to 46% without CCS). Values of 150 gram/kWh or even lower can be achieved by assuming a 34-35% net efficiency and CO_2 capture percentages of 85 to 90%.

A combination of CCS and biomass co-firing can even result in net negative CO_2 emissions.
Attaining EPS values of 500 gram/kWh or even lower with only biomass co-firing is a technical challenge in the next 10 years. The new currently being built coal power plants are designed to co-fire at most about 35% biomass, on an energy basis. This would result in somewhat more than 500 gram/kWh. However, such high values of biomass percentages need to be demonstrated to be technically viable and reliable, without adverse effects. In addition, the price of solid biomass is expected to be substantially higher than the hard coal price. The current biomass price is about three times higher than the coal price (ECN/KEMA, 2009). The biomass price is even higher than the natural gas price (in terms of €/GJ). Therefore, the variable cost of production becomes higher. Based on NRP-NL default fuel prices, the variable cost would be about 5 €/MWh higher than based on 100% coal (see also Section 5.5).

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10 SVHP = higher fuel prices, +40% for gas, +20% for coal; SVLP = lower fuel prices, -40% for gas, -20% for coal; SV40 = Higher CO_2 price: in 2020 already 40 €/ton; SV10 = lower CO_2 prices, 10 €/ton CO_2 from 2013 onwards.

Table 5.3 *Combinations of coal with different percentages of CCS and/or bio-mass co-firing and resulting CO_2 emissions per kWh*

Net efficiency [%]	CO_2 capture rate [%]	Biomass co-firing (on energy basis)	CO_2 emission [gram/kWh]
46	-	0	741
With biomass co-firing			
45	-	20	606
44	-	55	350 (EPS 350)
With CCS			
37	45	-	507 (ca. EPS 500)
37	62	-	350 (EPS 350)
37	75	-	230 [11]
35	90	-	97 [12]
37	75	-	230
34	85	-	150 (EPS 150)
35	90		97
With CCS and BM co-firing			
35	90	20	-111

EPS of 150 gram/kWh for new gas power plants

Current new gas power plants (CCGT type) have an emission of about 350 gram/kWh. Without CCS, it will not be possible to achieve values of 150 gram/kWh. As all demos for CCS will be applied on coal or lignite power plants, it is not realistic to expect CCS on new gas power plants in the EU before it has been demonstrated fully on coal/lignite plants. Moreover, in terms of CO_2 reduction CCS for (new) gas is not as effective as CCS on coal plants. Irrespective of these arguments, two of the four policy packages have assumed some CCS on new gas but not earlier than the year 2025 (see Section 5.4).

5.3.2 Market perspectives and extreme case 'EPS only in NL'

From a market perspective, it is obvious that - without any financial instrument - these low EPS values will not be achievable. Without any additional financial instrument, imposing an EPS of 500 gram/kWh or less on *new coal-fired power plants* will effectively result in a de facto closure of new and of existing coal-fired plants in the Netherlands. We also assume closure of existing coal power plants in this case as it is not logical to impose only a stringent EPS on new plants without policies on more polluting older power plants. Without additional subsidies, either the necessary investment in CCS technology will be a barrier or - in case of large shares of biomass - the variable cost of production will be the prime barrier. Power plants will only produce electricity if the variable cost of production is less than the price of electricity they receive.

The rationale for the results in this case is consistent with previous (qualitative) assessments ECN has made (reported in PBL, 2009, 2009b). For this ECF study, the 'EPS only' case has been analysed more quantitatively as well. It has been consistently analysed for the Dutch power generation sector, as part of the Northwest European electricity market. For neighbouring countries, e.g. for Germany, no EPS has been assumed in this extreme case. ECN used its electricity market model POWERS which is able to analyse the Dutch electricity generation in detail as part of the Northwest European electricity market. It is also able to include the supply and demand curves of the neighbouring countries as well, in order to analyse the impacts on the Dutch competitive position compared to e.g. Germany.

[11] Based upon (Seebregts & Scheepers, 2007),'Vragen over nieuwe kolencentrales', ECN-O-08-002.

[12] This value is indicative if e.g. on a full scale CCS would be applied on new coal-fired power plants currently being built. However, if the CCS demonstration projects are successful, the net efficiency is expected to be higher than 35% in case of further upscaling after 2020. Moreover, for new coal-fired power plants that start operating from 2020 on, values between 37-41% are considered attainable (Seebregts & Groenenberg, 2009).

From the ‘EPS only’ case, it follows that:

The wholesale electricity price in the Netherlands will increase by 10% (from 60 to 66 €/MWh in the year 2020) if an EPS of 500 or less will be imposed on coal-fired power plants in the Netherlands.

*Reaching the Dutch **renewable energy target** for 2020 is more difficult*, as biomass co-firing in coal-fired power plants will not be applied anymore. Biomass co-firing in NRP-NL-SVV accounts for more than 8 TWh of renewable electricity production, 16% of the 50 TWh renewable electricity production in total in the year 2020. The Dutch electricity demand in 2020 is about 128 TWh. So, in 2020 and the NRP-NL-SVV reference case, renewable energy sources account for almost 40% relative to domestic electricity demand.

The net export to Germany will drop by 6 to 17 TWh (12 TWh on average in period 2019-2030). The effect of a de facto closure of coal fired plants in the Netherlands will cause less efficient and more polluting coal and lignite power plants in Germany to operate more. This is a sort of ‘CO_2 leakage’ effect, but due to the EU ETS, it will not impact overall EU-27 CO_2 emissions (‘waterbed effect’). However, for other pollutants and for air quality emissions (NO_x SO_2 and particulate matter), it may have an adverse effect. On average, the Dutch coal-fired power plants are more efficient and less polluting than the German ones.

Table 5.4 *NRP-NL-SVV in 2020, and extreme case ‘Only EPS’ with coal power plants not operating anymore*

Aspect		NRP-NL-SVV (reference case)	Without coal (Only EPS)	Difference
Electricity demand	[TWh]	128	128	0
Production in the Nederlands	[TWh]	145	136	-9
Net export	[TWh]	16	7	-9
CO_2 emission, central power plants	[Mton/year]	45	31	-14
Fuel use	[PJ]			
Natural Gas		160	354	+ 194
Hard coal		278	0	- 278
Biomass (co-fired)		69	0	-69
Average wholesale electricity price	[€/MWh]	60	66	+6

In case of additional financial instruments for new and currently built coal-fired power plants, CCS deployment may lead to lower variable cost than for these plants without CCS, and consequently potentially to a lower wholesale market price (merit order effect). In particular, after 2020 and with rising CO_2 prices, coal-fired plants with CCS are more attractive in the merit and dispatching order, than coal without CCS or gas power plants.

5.4 Assumptions four policy packages

The four policy packages have been analysed and quantified with NRP-NL-SVV as starting point (‘reference case’). In each of the four policy package cases, assumptions have been made on the extent of CCS deployment on new coal or new gas. For all cases, it has been assumed that:
- No CCS on old coal (built and operated before 2010) will occur.
- No CCS retrofit on old and new gas operated before 2020 will occur.

5.4.1 CCS deployment

The amount of CCS deployed in terms of MW_e (net) is given in Table 5.4 (below). As can be seen, for the two fast cases, additional new capacity (compared to NRP-NL-SVV) directly deployed with CCS has been assumed. That new capacity will replace older coal fired power plants that have been built in 1994 and 1995. So, the lifetime of the most recent old coal fired power plants is limited to 30 to 35 years. With the assumed financial instruments it is more beneficial to invest in new coal fired power plants with very low CO_2 emissions. The total share of coal-fired capacity can thus remain roughly the same as in NRP-NL-SVV, without the need to use rather expensive natural gas instead. The use of this 'clean' coal may also serve the security of supply with respect to the need to import natural gas from outside the EU.

In all policy cases, it is assumed that additional financial instruments compensate for the higher cost of production (see Section 3.4) as long as the CO_2 price does not suffice to make CCS deployment cost-efficient. As introduced earlier, the CO_2 price assumed in NRP-NL is 20 €/ton CO_2 in the period 2013-2020. In the period 2020 to 2030 it increases to 40 €/ton CO_2. Such CO_2 prices will not be sufficient to make CCS an economically viable option.

Table 5.5 *CCS deployed in MW_e (net)*

	2015	2020	2025	2030	Remarks
Reference case					
NRP-NL-SVV	200	200	200	200	Only 1 demo in 2015-2020
Extreme case, only EPS, so without any additional financial instruments					
0 Only EPS	200	0	0	0	
Policy package cases, assuming additional financial instruments					
1 Slow Coal (SC)	200	980	1680	3080	Only 1 demo in 2015, All retrofit on new coal built in 2012-2015, in phases.
2 Fast Coal (FC)	400	1680	4080	5080	2 demos in 2015, retrofit on new coal built in 2012-2015, and on additional new coal 2025-2030
3 Slow Coal Gas (SCG)	200	980	1680	4080	Only 1 demo in 2015 All retrofit on new coal built in 2012-2015, in phases. CCS on 1000 MW new gas in 2030
4 Fast Coal Gas (FCG)	400	1680	5080	7080	2 demos in 2015, retrofit on new coal built in 2012-2015, and on additional new coal 2025-2030 CCS on 1000 MW new gas in 2025, and on new 2000 MW gas in 2030

In all four policy package cases, the three new coal-fired power plants currently under construction will be retrofitted for CCS deployment. For the Fast Coal and Fast Coal Gas cases, it is assumed that additional new coal-fired capacity directly equipped with CCS will be built between 2020 and 2030. In these two cases, it has been assumed that the three coal power plants built in 1994 and 1995 will be decommissioned prior to 2030. Hence, in 2030 only new coal is operational in the Fast Coal variants.

It is assumed that the additional use of a financial instrument, alongside regulation, may lead to additional CCS deployment, or introduction of CCS. However, the basic composition of the electricity park of NRP-NL-SVV will not be altered, except for the two cases with fast deployment of CCS and earlier decommissioning of older coal-fired plants. In these cases, all of the old, existing coal power plants will be decommissioned in 2030, leaving room for new and additional capacity in the period 2020 to 2030, compared to the NRP-NL-SVV reference case.

5.4.2 No CCS retrofit on old coal and decommissioning

It is assumed that no retrofit on the old existing 4173 MW_e coal plants will take place. Decommissioning of existing coal-fired plants follows the schedule as in Table 5.6 below. The reference case decommissions two old coal power plants prior to 2020. Three old coal power plants will be decommissioned in the period between 2020 and 2025. They have reached a lifetime of more than 40 years by then. The three newest coal power plants built in 1994 and 1995 remain operating up to 2030.

Table 5.6 *Existing ('Old') coal power plants decommissioned, or not operating anymore in MW_e (cumulative, net). Existing coal in 2010 = 4173 MW_e (8 units, 7 pulverised coal, 1 gasification i.e. IGCC, the Buggenum plant)*

	2015	2020	2025	2030
NRP-NL-SVV	0	1247	2693	2693
0 Only EPS	0	4173	4173	4173 (= all old)
1 SC	0	1247	2693	2693
2 FC	0	1247	2693	4173 (= all old)
3 SCG	0	1247	2693	2693
4 FCG	0	1247	2693	4173 (= all old)

5.4.3 Biomass co-firing in coal power plants: about 20% on energy basis

To keep the analysis comparable to NRP-NL-SVV, it has been assumed that the remaining and new coal fired power plants will co-fire biomass on an about 20% energy basis in the period 2020-2030. Use of biomass in combination with CCS reduces the CO_2 emissions below an EPS of 150 gram/kWh, viz. a negative CO_2 emission of -111 gram CO_2/kWh (see also Table 5.1 in Section 5.3). It should be noted that in the current EU ETS the 'negative' CO_2 emissions of biomass combustion in combination with CCS cannot yet be credited. In the indicative calculations performed as part of this study, the assumption is that these negative CO_2 emissions can be credited.

5.5 Impacts of costs of production on investment, merit order and operating hours

In order to understand the electricity market behaviour both with respect to investments in new capacity and with respect to the operational behaviour (merit order considerations) of electricity producers, it is necessary to look at the cost of production by old and new power plants.

The development of variable cost of production over time, and the value of the wholesale market prices is determined by the combination of:

1) the level and increase of the electricity demand,
2) the seize (Gigawatts) and the type (fuel/technology) of generating capacity as present in the NRP-NL-SVV reference case, and
3) the NRP-NL-SVV scenario assumptions on fuel and CO_2 prices.

The wholesale electricity market price development in the NRP-NL-SVV case has already been shown in Section 5.2 (Figure 5.4). It shows that the 'long run marginal costs' of the Dutch electricity system tend to more than 60 €/MWh in 2020, to 70 in 2030 and 80 €/MWh in 2040. With both increasing CO_2 and natural gas prices, this upward trend of electricity prices is robust as long a low marginal cost technologies like nuclear or intermittent renewable sources will have minority shares in the total electricity production. In such cases, fossil fuelled electricity generation will remain to often constitute the marginal and price setting option.

The cost of new power plants with CCS [13]

Previous cost estimates for new power plants that will start operating in the period 2015-2020 are given as indication in Figure 5.5. It should be noted that the default point estimates have been computed with relatively high values discounting (WACC values of 9 to 9.5%). This makes capital intensive options like coal with and without CCS relatively expensive. Moreover, financing cost during construction is discounted with a higher factor (about 13%).

Based on previous ECN analyses (Seebregts & Groenenberg, 2009; Wetzels et al., 2009), the cost of coal with CCS ranges from about 60 to 100 €/MWh, very dependent on the technical and financial parameters (see also Figure 5.5). With optimistic estimates for financial parameters like the construction time period, the (average weighted) cost of capital, and net efficiencies, the cost can be on the low side. With more a pessimistic view it could be up to 100 €/MWh. A default value based on 2020 year fuel prices is about 78 €/MWh.[14] This is well above the average wholesale market prices projected for the NRP-NL-SVV case, which leads to the conclusion that CCS is not a cost-effective option for 2020.

Table 5.7 *Financial and techno-economic parameters new fossil technology in operation around 2020*

Parameter	Bandwidth values (midpoints are 'default point estimate values')
WACC (nominal, pre-tax)	Ca. 9-9.5% (dependent on technology)
Construction period	3-5 years (coal)1-2 years (natural gas)
Technical lifetime	30-40 years (coal) en 25-35 years (natural gas CCGT)
Net efficiency	46-50% Coal 37-41% Coal w/ CCS 57-61% CCGT 48-52% CCGT w/ CCS
CO_2 capture rate	80-90%
Cost of CO_2 transport and storage	6 €/ton CO_2 transport and stored
Capacity factor	80-90%
Investment costs	+/-25% relative to point estimate (dependent of technology)
O&M costs	+/- 20% relative to point estimate (dependent of technology)

13 ECN has used its own assumptions on the cost of CCS for the time frame 2015-2030, based on previous studies in 2008 en 2009 (These may differ from the assumptions of the ECF Roadmap 2050.

14 The cost of new gas with CCS is lower than coal with CCS, which is in contrast with most other known studies. The reason here is the relatively low gas price in the NL-NRP-SVV scenario. If a higher gas price would be used e.g. as used in the two most recent IEA World Energy Outlooks (IEA, 2008; 2009), gas with CCS would be more costly than coal with CCS.

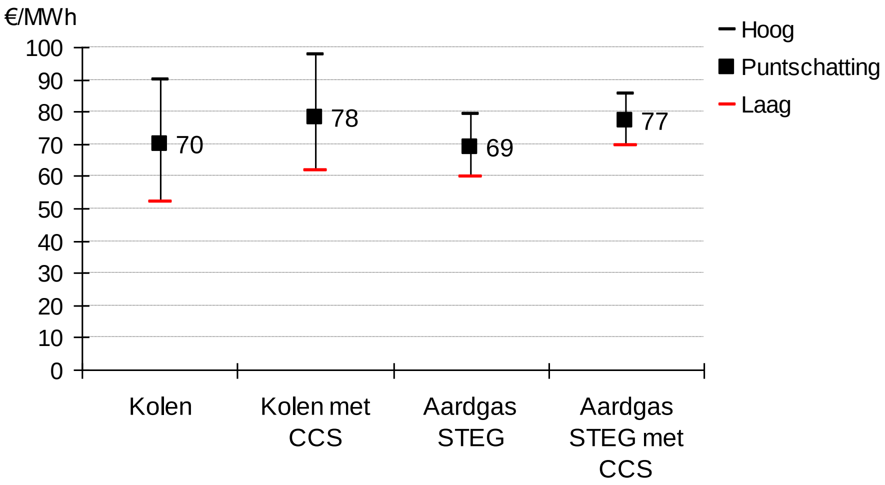

Figure 5.5 *Costs of electricity production for new coal or new gas power plants without and with CCS, with scenario prices (from Wetzels et al, 2009)*

Effects of additional financial instruments on costs and merit order

In case of additional financial instruments for new and currently built coal-fired power plants, CCS deployment may lead to lower variable cost than for these plants without CCS, and consequently to a lower wholesale market price (merit order effect). In particular, after 2020 and with rising CO_2 prices, coal-fired plants with CCS are more attractive in the merit and dispatching order, than coal without CCS or gas power plants. However, the high investment costs represent a major hurdle. The four cases assume these investment hurdles are somehow overcome by additional financial incentives or other policies, enabling the CCS deployment as indicated in Table 5.5.

Variable cost of production determines position in the merit order and operating hours

The next Figure 5.6 and Table 5.7 show indications of the variable cost of production which is determining for the position in the merit order of operating plants. Once the CO_2 price exceeds a certain level, the variable cost of production of coal with CCS becomes lower than coal without CCS. With the coal prices assumed, this level is somewhere in the range of 50 to 60 €/ton CO_2.

The variable cost (fuel plus CO_2) of new coal fired power plants is about 33 €/MWh (100% coal) to 38 €/MWh (20% biomass) in 2020, see Table 5.8**.** In 2030 this increases to 48 and 50 €/MWh**,** respectively. In 2020 and 2030, the variable cost of new CCGT's is higher, about 46€/MWh. Variable other O&M costs need to be added to these fuel and CO_2 costs. These other variable O&M costs range from 3 to 5 €/MWh, depending on the type of technology. It should be noted that variable costs are very dependent of fuel and CO_2 prices, which are uncertain factors and driving forces in future energy scenarios.

During off-peak hours, the very old coal fired plants and (old) gas-fired will be out of the dispatching order (see Figure 5.6). Consequently, for these old coal power plants substantially less than 4000 operating hours results, which may also adversely impact start up and shutdown costs, and overall net efficiencies. This frequent start/stop behaviour will further worsen the variable cost of production as it reduces the net efficiency of operation (e.g. see (TU Delft, 2009)). New gas fired plants will operate mainly during peak hours, when the market price is high enough to cover the marginal cost of production.

Table 5.8 *Variable cost of production, years 2020 and 2030, and 60 euro/ton CO_2) Values rounded off, fuel prices in accordance with NRP-NL*

	2020, 20 €/ton CO_2			2030, 40 €/ton CO_2				60 €/ton CO_2	
	Fuel	CO_2	Total	Fuel	CO_2	Total		CO_2	total
New coal, 46% (Pulv. Coal)	18	15	33	18	30	48		44	63
With BM 20%	26	12	38	26	24	50		36	62
New gas, 58% (CCGT)	39	7	46	40.5	13.8	54			
Newest old coal, 43%	19.2	15.8	35	19.5	31.7	51	less than new gas	47	67
Very old coal, 38%	21.8	17.9	40	22.0	35.8	58	more than new gas	54	76

Note: Only fuel and CO_2 costs have been included in this table. Other variable O&M costs may results in relatively small additional contributions.

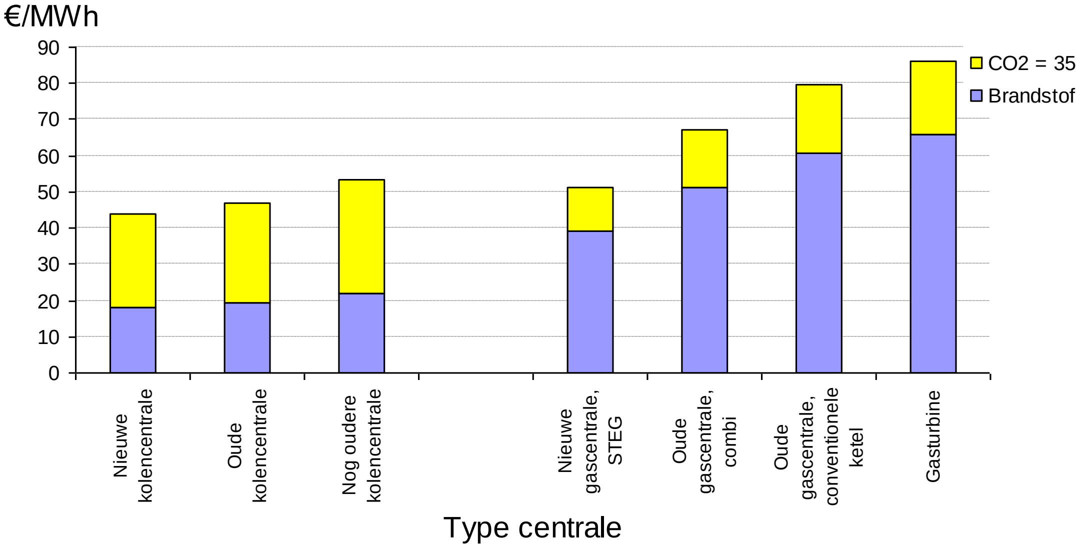

Figure 5.6 *Variable cost of production old and new coal and gas, based on (Seebregts et al, 2009), with CO_2 price of 35 €/ton*

In case of additional financial instruments for new and currently built coal-fired power plants, CCS deployment may lead to lower variable cost than for these plants without CCS, and consequently potentially to a lower wholesale market price (merit order effect). In particular, after 2020 and with rising CO_2 prices, coal-fired plants with CCS are more attractive in the merit and dispatching order, than coal without CCS or gas power plants. This phenomenon is illustrated in Figure 5.7 below (From Seebregts et al., 2010). As can be seen, in case of very high CO_2 prices (100 €/ton), coal without CCS has variable costs higher than the wholesale market electricity price. Moreover, gas without CCS will then have a better position in the merit order than coal without CCS.

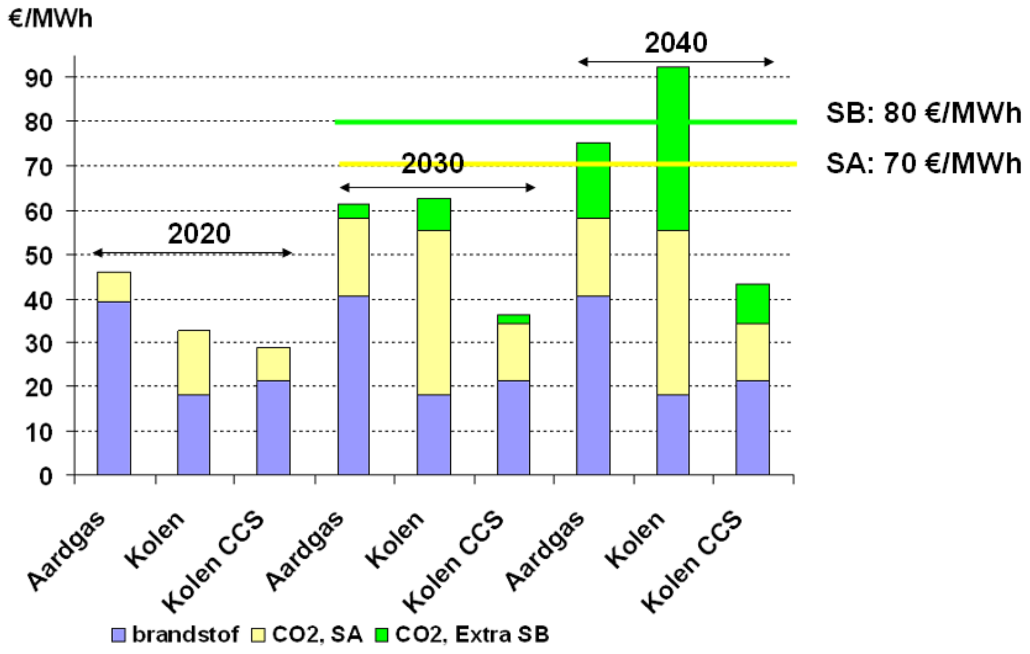

Figure 5.7 *Variable costs of production for new fossil power plants, with CO_2 prices of 20 €/ton (2020), 40 €/ton (NRP-NL-SVV, 2030); 50 €/ton (2030, SB) or 100 €/ton (2040, SB). Only fuel and CO_2 costs included. CCS has somewhat higher other variable O&M costs than without CCS (about 3 €/MWh). Because of less net efficiencies, CCS options have higher fuel cost components*

Based on (Seebregts et al, 2010).

5.6 Numerical results policy package cases

The results as calculated for the four policy package cases focus on the changed impacts to:

- wholesale market electricity prices in the Netherlands,
- net export of electricity,
- competitiveness of the Dutch power generation sector,
- CO_2 emitted and other emissions (notably NO_x, SO_2 and particulate matter), and
- renewable electricity by biomass co-firing.

The amount needed for financial support to compensate for the higher total cost of production is addressed in Section 5.7. The impact for each of the cases has been indicatively quantified and compared to the NRP-NL-SVV reference case. The results are summarised in the various sub-sections and tables below.

5.6.1 Wholesale electricity prices

For electricity prices and export effects, the 5-year averages around the indicated 'midpoint' year have been given in Table 5.8 below. In the ‘Only EPS’ case, i.e. without any additional national financial support, the wholesale market electricity prices increase by about 10% compared to the reference case. This will also have an increasing effect on end user prices in the Netherlands. This has been already explained in Section 5.3.

There is hardly any noticeable effect for the four policy package cases with the financial support to compensate for the higher costs. The changes in the merit order appear to be negligible as to the impact on the wholesale electricity prices. The main reason is that new coal with CCS will have variable costs of production substantially lower than the average wholesale electricity market prices. The three new coal power plants without CCS were also positioned left in the merit order. As CCS will have a small decreasing impact on the net MW_e available for electricity production, the overall effect is negligible.

Table 5.9 *Average wholesale market electricity price, the Netherlands*

[€/MWh]	2015	2020	2025
NRP-NL-SVV	58.8	60.5	63.3
0 Only EPS	58.8	64.5*	70.0
1 SC	58.8	60.4	63.6
2 FC	58.8	60.7	63.4
3 SCG	58.8	60.4	64.0
4 FCG	58.8	60.7	63.4

* For electricity prices effects, the 5-year averages around the indicated 'midpoint' year have been given. They may differ therefore (slightly) from the average price in the actual midpoint year. E.g. the average price in the year 2020 is 66 €/MWh in the case ‘Only EPS’. The 5-year average is 65 €/MWh.

5.6.2 Net export volume

In the ‘Only EPS’ case, i.e. without any additional national financial support, the net export volume decreases. This extreme case worsens the competitive position of the Dutch power production. There is hardly any noticeable effect for the four policy package cases with financial support to compensate for either the necessary investments or the increased variable cost of production. In the period 2015 to 2030, small increases of no more than 1.5 TWh are observed. The largest effects are in 2020. In 2030 the differences are less than 0.5 TWh. The reason for the small differences is the assumption that producers are compensated for the higher cost in the case of CCS deployment. With relative higher CO_2 prices, the variable cost of CCS is smaller than for the same power plant without CCS. Therefore, for remaining attractive in the merit order in situations with high CO_2 prices, deployment of CCS is necessary.

Table 5.10 *Net export from NL to neighbouring countries*

[TWh]	2015	2020	2025
NRP-NL-SVV	15.6	15.2	24.7
0 Only EPS	15.6	9.3	12.6
1 SC	16.2	16.7	25.1
2 FC	16.4	16.4	24.8
3 SCG	16.2	16.7	25.1
4 FCG	16.4	16.4	24.9

Note: For export effects, the 5-year averages around the indicated 'midpoint' year have been given. During the years 2000-2008, the Netherlands was a net importer of electricity (between 15-20 TWh on a yearly basis).

5.6.3 CO_2 captured and emitted on Dutch territory

The amount of CO_2 captured increases with the amount of capacity for which CCS is deployed:

Table 5.11 *CO_2 Captured, Dutch large scale power plants*

[Mton/year]	2015	2020	2025	2030
NRP-NL-SVV	1.4	1.4	1.4	1.4
0 Only EPS	1.4	0.0	0.0	0.0
1 SC	1.4	6.5	10.2	18.5
2 FC	2.8	10.8	24.4	28.4
3 SCG	1.4	6.5	9.8	19.0
4 FCG	2.8	10.8	24.1	29.6

Inclusion of new gas with CCS makes gas with CCS with respect to variable costs sometimes more attractive than new coal with CCS. Note that NRP-NL-SVV exhibits relatively low gas prices as compared to e.g. recent IEA World Energy Outlook projections (IEA WEO, 2008; 2009). As a consequence the operating hours of coal with CCS reduce somewhat in the variants with gas CCS included. As a result, the amount of CO_2 captured is less than one perhaps would expect without taken notice of that effect. With higher gas prices, this effect would not occur to that extent.

The amount of CO_2 emitted on Dutch territory ('chimney emissions') from Dutch power plants decreases with the amount of capacity for which CCS is deployed. The reduction effect will be correspondingly larger compared to the NRP-NL-SVV reference case. Deployment of CCS leads to more use of fossil fuels due to smaller net efficiencies. As a consequence, the net CO_2 reduced is less than the amount of CO_2 captured.

Table 5.12 *CO_2, Dutch large scale power plants*

[Mton/year]	2015	2020	2025	2030
NRP-NL-SVV	54.8	45.0	45.4	43.2
0 Only EPS	54.9	31.0	32.1	32.0
1 SC	54.8	42.1	36.4	27.3
2 FC	53.8	37.7	24.7	21.4
3 SCG	54.8	42.1	36.7	25.3
4 FCG	53.8	37.7	24.3	18.8

5.6.4 Other emissions on Dutch territory

Deployment of CCS on either new coal or new gas power plants may also affect the air quality emissions of SO_2 and particulate matter (both for coal) and of NO_x (for gas and coal). Based on the use of a Performance Standard Rate (PSR) as part of the Dutch NO_x Emission Trading System, the deployment of CCS will lead to the use of more fossil fuel, and hence to more NO_x emissions.

For CCS on coal fired power plants, there is some synergy. In that case, both SO_2 emissions and PM_{10} emissions will be lower than for the same plants without CCS (e.g., see Daniels et al, 2008, 'Trendanalyse luchtverontreinigende emissies', Trend analysis air quality emissions).

5.7 Financial gap analysis

This section provides an indication of the financial gap i.e. how many subsidies would be needed to compensate for the higher cost of CCS as long as the CO_2 price is not sufficient to make CCS cost-efficient. As an indication for the amount of subsidies, a simple financial gap analysis has been performed in two ways:

1) What is the difference between the cost of electricity production by coal with CCS and the average wholesale market price? A similar rationale is used in the Dutch SDE subsidy scheme for renewable electricity generation.
2) Which CO_2 price is needed to make coal with CCS a cost-efficient option? This is indicative for a policy instrument using a contract for differences.

The representative power plant is coal-fired with CCS with the characteristics as in Table 5.13.

1. Cost in €/MWh versus electricity market price

If we use the default values from the previous section, the cost of electricity production by coal with CCS is 78 €/MWh, see also Section 5.5. The average wholesale market electricity price is about 65 €/MWh (about 60 in 2020 and 70 in 2030). So, this leads to a financial gap of 13

€/MWh. Multiplication of this financial gap with the net electricity produced results in a total financial gap (yearly) for each power plant equipped with CCS.

Table 5.13 *Characteristics coal with CCS*

Parameter		Default value	Low	High
Cost of production coal with CCS	[€/MWh]	78		
Wholesale electricity market price	[€/MWh]	65 (year 2025)		
'Financial gap'	[€/MWh]	13		
CO_2 price	[€/ton]	20	10	40
Coal price	[€/GJ]	2.5	2	3

Note: The fuel and electricity prices in 2020 have been used as default values for these calculations.

2. CO_2 price needed

Another way of calculating the financial gap is to calculate the CO_2 price needed to make CCS costefficient. This has been done by increasing the CO_2 price up to the level that the electricity production cost is equal to or less than the average wholesale market price. The Slow Coal variant has been used for that purpose. CO_2 prices have been varied between 50 up to 100 €/ton CO_2.

For simplicity, it has initially been assumed that no biomass cofiring takes place, and coal with CCS occurs with a net efficiency of 35% and a capture rate of 90%. In that case the net CO_2 emission is 97 gram/kWh.[15] So, an additional 10 €/ton CO_2 emitted will result in a (variable) cost increase of less than 1 €/MWh (0.97 €/MWh). For the wholesale market electricity price, an increase by 10 €/ton CO_2 in the period 2020-2030 results in an average increase of about 4 to 5 €/MWh. This is based on performing sensitivity analyses on NRP-NL-SVV with CO_2 prices of 30 to 100 €/ton CO_2.

The overall result is that CCS becomes economically viable for CO_2 prices of 70 to 80 €/ton CO_2 (in the context of the NRP-NL-SVV scenario). See also next Table 5.14. The results are consistent with previous ECN analyses based on a higher economic growth scenario (the URGE scenario, see (ECN/PBL, 2009, 2009a) and (Seebregts and Groenenberg, 2009). The financial gap is somewhat larger in the case with 20% co-firing of biomass. ECN/KEMA calculations show that 20% of co-firing would lead to a financial gap of about 6 €/MWh (based on use of the relatively cheap agricultural residues, wood pellets are more costly), see (ECN/KEMA, 2009).

Table 5.14 *Financial gap, for coal CCS, with different CO_2 prices, SC case as indicative and for illustration*

Cost of electricity coal with CCS (100% coal) [€/MWh]	With 20% biomass cofiring	Wholesale market price (average) [€/MWh]	Gap in [€/MWh] 100% coal	Gap in [€/MWh] 80% coal 20% biomass	CO_2 price [€/ton]
78 (default)	84	61	17	23	20
79	83	63	16	20	30
81	82	71	10	21	50
82	81	76	8	5	60
83	80	81	2	-1	70
84	79	86	-2	-7	80
85	78	92	- 7	- 14	90
86	77	99	- 13	- 22	100

[15] Assuming 20% biomass co-firing the net CO_2 emission would be negative, -111 gram/kWh (See Section 5.3, Table 5.2). In that case, an increase of 10 €/ton CO_2 results in a variable cost decrease of 1 €/MWh. 20% biomass results in about 6 €/MWh additional fuel costs compared to 100% coal.

Table 5.15 *Cumulative financial gap, for coal CCS, SCG case as indicative and illustration*

	2020	2025	2030	2020	2025	2030	2020	2025	2030
CO_2 price	TWh CCS Coal (3 SCG case)			Cumulative gap in [M€/year]			% of total ' electricity bill'		
20	6.0	9.2	18.0	103	157	305	1.3	1.9	3.5
30	Assumed that CCS deployment and production will not change with increasing CO_2 prices (for simplicity)			96	147	287	1.2	1.8	3.3
50				60	92	180	0.8	1.1	2.0
60				48	74	144	0.6	0.9	1.6
70				12	18	36	0.2	0.2	0.4
80				-12	-18	-36	-0.2	-0.2	-0.4
90				-42	-64	-126	-0.5	-0.8	-1.4
100				-78	-120	-234	-1.0	-1.5	-2.6

The cumulative financial gap can be compared to the overall ‘electricity bill’ based on domestic electricity demand and the average wholesale electricity price. This total electricity bill ranges from almost 8 billion € in 2020 to 9 billion € in 2030 (NRP-NL-SVV reference). The cumulative financial gap is only a few percent of this total amount as long as the CO_2 price is not high enough.

Table 5.16 *Total ‘Electricity bill’ based on wholesale market prices*

	2020	2025	2030
TWh, demand	128.3	128.7	131.0
average price, €/MWh	61	63	67
Total, M€	7763	8140	8838

Uncertainties

The value of the CO_2 price needed to make CCS economically viable is dependent of a number of uncertain factors. This applies not only to the more technical parameters of a power plant with CCS, but also to the financial and economic parameters, and the scenario assumptions of the NRP-NL-SVV reference case. *The financial gap calculations shown above therefore should be interpreted with these uncertainties in mind.*

5.8 Which package?

At the beginning of this chapter it has been suggested to consider two packages: EPS only and EPS with financial incentives. A closer inspection reveals, however, that actually the second package consists of financial incentives only. The EPS had no effect on the modelling, as it has been assumed that the coverage of the financial gap by a financial incentive is sufficient to deploy carbon capture. Or, to put it differently, if the demonstration activities have proven CCS to be reliable (technically and the energy penalty has decreased), if other crucial aspects have been solved (safety and other aspects of transport and storage) and if CCS has proved to be socially acceptable - if all these conditions have been met, the introduction of CCS is mainly a financial issue. If this is true, no package of finance and regulation would be needed.
However, other aspects could be relevant.

1) First, the Dutch government could appreciate some kind of certainty. In theory, a package of regulation effectively obliging CCS (by mandate or implicitly by an EPS) and financial incentives to bridge the additional costs offers more certainty that no unabated fossil fuel will be burned anymore than a financial compensation only - in the latter case the generator is not *obliged* to accept the incentive, but it is offered only A financial instrument is needed to effectively stimulate CCS. There is no alternative: regulation only will lead to the closure of coal-fired power plants, but no CCS. A financial instrument will have budgetary implications, even when they are relatively modest. If the government wants to try to minimize the financial burden of the incentive, a package including regulation might be

preferred. This, however, could diminish the flexibility of future approaches to some extent as the regulatory part of the package has to be announced in a timely way. Due to the effect of a strengthened EU ETS system, the position of coal-fired power plants without CCS will change in the dispatch order. However, at moments of low CO_2 prices, they still might continue to produce, even when it might be expected this will not often be the case. This risk will be eliminated by an implicit (EPS) or explicit (CCS mandate) prohibition to generate without CCS. This certainty is only the case if the regulatory part of the package is uncontested. It will be argued in the next chapter that, due to conflicting types of EU regulation, this is not fully certain. The certainty argument is a valid one, but only after the compatibility with EU regulation has been fully clarified.

2) Secondly, it could be argued the government has already announced that 'some kind of legal obligation will be drafted'. In that case it is advised to combine this with a financial incentive system, but ECN's opinion on the package with regulation has become irrelevant.

In Chapter 7, other aspects of the package will be discussed.

5.9 Limitations and uncertainties

The analysis reported here has limitations to be aware of. The total societal cost and benefits expressed in purely monetary terms in each of the four policy packages is beyond the scope of this study. This study only addresses partial impacts: on variable cost of production, on the wholesale electricity market prices, on net exports, and on CO_2 emissions ('chimney emissions'). E.g. co-benefits for air quality emissions (NO_x, SO_2 and particulate matter) are not covered. On the other hand, external costs are not included e.g. reported in (CASES, 2008). Inclusion of such costs and co-benefits and performance of a more complete societal cost-benefit analysis of the various policy packages could lead to additional insights and could show the robustness of the proposed packages in reducing CO_2 emissions, or its synergy with or adverse effects in other areas.

Finally, the assumptions made for the background scenario used i.e. the NRP-NL-SVV reference case, and the assumptions on technology cost are uncertain factors. Other studies like (ECN/PBL, 2010) and (Seebregts & Groenenberg, 2009) address these uncertain factors in more detail. These uncertain factors are also reasons to interpret the results of this study with due care, in particular the use of absolute figures.

5.10 Summary of findings

- The budgets needed for financial support in the period 2020 to 2030 have been assessed. ECN has made calculations in the context of the recent Dutch Reference Projection.
    - The support needed is about 300 million € per year, corresponding with a net electricity production of 18 TWh by three coal power plants, in the period 2020 to 2030, at a CO_2 price of 20 €/ton. [16] This indicative amount depends on the used assumptions. However, the order of magnitude will be in the order of hundreds of million Euros. The support needed decreases with increasing CO_2 prices for instance as a result from strengthening the EU ETS.
    - Without financial compensation for the additional costs of CCS, the cost of electricity production by these plants is between 78 €/MWh (100% coal) and 84 €/MWh (with the additional assumption of 20% co-firing of biomass). The average whole-

[16] Other assumptions: Coal price of about 2.3 €/GJ; Gas price: about 6 €/GJ. Wholesale market electricity price under these conditions: 61 €/MWh. 100% coal. With 20% co-firing of biomass, the support needed for the additional cost of co-firing would be about 100 million. ECN/KEMA calculations show that 20% of co-firing would lead to a financial gap of about 6 €/MWh (based on use of agricultural residues), see (ECN/KEMA, 2009).
Net efficiencies of coal power plants with CCS: 35 to 39% depending on when retrofit CCS will be applied. First demos: 35%. For CCS on new coal power plants after 2025, 39%. Loss in net MW_e capacity: 20% for first demos.

sale market price is 61 €/MWh. Consequently, the financial gap is between 17 and 23 €/MWh.
  - CCS can be deployed cost-effectively, from a producers' perspective, at a CO_2 price of about 75 €/ton CO_2. The cost of production by the coal power plant with CCS then would approximately equal to the (higher) market price of electricity (break even point). The financial gap will then be zero. CCS at gas fired power plants needs an even higher CO_2 price, under the assumptions made.
- The competitive position of Dutch electricity producers and large Dutch consumers of electricity is not significantly affected by the policy package:[17]
  - The wholesale market electricity price will only change slightly. The changes will be equal or less than 1%, i.e. on an average wholesale market electricity price of about 60 €/MWh, the change is between -0.1 to +0.6 €/MWh (-0.01 to 0.06 ct/kWh).
  - The consequences for the net exporting position are modest, between 6 and 10%. The net export changes are less than 1.5 TWh compared to net export electricity figures ranging from 15 to 25 TWh in the period 2020-2030.

[17] Findings 6 a) and b) are based on electricity market model calculations. These include among others, merit order effects in dispatching the power plants. The model treats the Netherlands in detail with interconnections to neighbouring countries in Northwest Europe.

6. EU legal requirements relevant to member state incentives

6.1 The EC Treaty

Some have questioned whether progressive national CCS policies are acceptable from a legal point of view. National measures to stimulate CCS beyond a deployment level that would be achieved by EU policies alone might be restricted by relevant EU legislation. In this respect it is informative to read the EC Treaty.

Article 114 of the EC Treaty[18] deals with the approximation of laws. Paragraph 5 stipulates: *"[…] if, after the adoption of a harmonisation measure by the European Parliament and the Council, by the Council or by the Commission, a Member State deems it necessary to introduce national provisions based on new scientific evidence relating to the protection of the environment or the working environment on grounds of a problem specific to that Member State arising after the adoption of the harmonisation measure, it shall notify the Commission of the envisaged provisions as well as the grounds for introducing them."*

Paragraph 6 continues and directs that the Commissions shall approve or reject within 6 months the relevant national provisions. It shall do so after having verified whether or not they are a means of arbitrary discrimination or a disguised restriction on trade between Member States, and whether or not they shall constitute an obstacle to the functioning of the internal market. In the absence of a decision by the Commission within this period the national provisions shall be considered to have been approved. When justified by the complexity of the matter and in the absence of danger for human health, the Commission may notify the Member State concerned that the period may be extended for a further period of up to six months.

Thus, the EC Treaty leaves room for national measures on top of EU policies that would be required to protect the environment. It therefore probably does not constitute an obstacle for national CCS policies. Most likely, the UK government will want to refer to this article in the Treaty should UK regulatory policies (Section 2.2.2) be challenged from a legal perspective.

6.2 The IPPC Directive

The 1996 Directive on Integrated Pollution Prevention and Control (IPPC) introduced a permit system to prevent and limit pollution from large-scale industrial installations. Permits are issued by the competent authorities in member states and require industrial operators to apply Best Available Techniques (BATs), considering the most cost-effective means of achieving a high level of environmental protection. Based on the BATs, which are set at EU level, the permits include precise limit values for atmospheric pollutants that cause acid rain and smog, such as sulphur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs) and dust. CO_2 is not considered. In order to ease compliance, the directive allows authorities to take into account the technical characteristics and location of the installation concerned, as well as local environmental conditions, when drawing up emission limits. The IPPC Directive has recently been codified (Directive 2008/1/EC of the European Parliament and of the Council of 15 January 2008 concerning integrated pollution prevention and control).

Article 9.3, paragraphs 3, of the codified IPPC Directive states: *"Where emissions of a greenhouse gas from an installation are specified in Annex I to Directive 2003/87/EC […] the permit*

[18] Consolidated versions of the Treaty on European Union and the Treaty on the Functioning of the European Union, Official Journal C 115 of 9 May 2008.

shall not include an emission limit value for direct emissions of that gas unless it is necessary to ensure that no significant local pollution is caused."

Article 9.4, continues in paragraph 4: *"[...] the emission limit values and the equivalent parameters and technical measures [...] shall be based on the best available techniques, without prescribing the use of any technique or specific technology."*

The IPPC Directive has been in place for over ten years and the Commission has undertaken a two year review with stakeholders to examine how it, and the related legislation on industrial emissions, can be improved to offer the highest level of protection for the environment and human health while simplifying the existing legislation and cutting unnecessary administrative costs. The results of this review have provided clear evidence of the need for action to be taken at a Community level. On 21 December 2007 the Commission adopted a Proposal for a Directive on industrial emissions[19]. The Proposal recasts seven existing Directives related to industrial emissions into a single clear and coherent legislative instrument. The recast includes in particular the IPPC Directive. Regarding emission limitation values for greenhouse gases the proposal contains similar language to the codified IPPC Directive from 2008 referred to above.

Article 10 reads in its first paragraph: *"Where emissions of a greenhouse gas from an installation are specified in Annex I to Directive 2003/87/EC in relation to an activity carried out in that installation, the permit shall not include an emission limit value for direct emissions of that gas, unless necessary to ensure that no significant local pollution is caused."*

Paragraph 2 of the same article states: *"For activities listed in Annex I to Directive 2003/87/EC [...], Member States may choose not to impose requirements relating to energy efficiency in respect of combustion units or other units emitting carbon dioxide on the site."*

Article 2, paragraph 2 stipulates that "General binding rules shall be based on the best available techniques, without prescribing the use of any technique or specific technology".

6.3 Outlook

The Spanish EU presidency hopes to conclude the IPPC review by the summer of 2010. The forbid of emission limit values for greenhouse gases covered by the EU ETS turned out a controversial issue in the European Parliament over the course of 2009. This is especially striking, since the Directive for the Geological Storage of CO_2 in Article 38.3 explicitly opens a perspective on an EU wide emissions performance standard. This article states that if, after the review of the Storage Directive in 2015 permanence of long term CO_2 storage, safety for man and environment, and economic feasibility of CCS are sufficiently demonstrated, then the review shall examine whether it is needed and practicable to establish a mandatory requirement for emission performance standards for new electricity generating large combustion installations[20].

In its correspondence with the UK administration on its policy proposals the European Commission has indicated that it considers the stipulations from the IPPC Directive and proposed Industrial Emissions Directive an obstacle for the introduction of an EPS in the UK (Johnston, 2010, personal communication). The UK government's legal advice argues that this is not and cannot be the legal effect of art 9(3) of the IPPC Directive. In its argumentation the EC did not consider Article 114 in the EC Treaty (Section 6.1), which leaves room for more stringent national measures if these are required to protect the environment. Legal advice to the Irish government is of the opinion that the IPPC limits Member States options for introducing emissions performance standards for existing power stations (and those having gained permits), but that legal frame-

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[19] Brussels, 21.12.2007 COM(2007) 844 final. Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on industrial emissions (integrated pollution prevention and control) (Recast).

[20] Directive 2009/31/EC of the European parliament and of the Council on the geological storage of carbon dioxide.

works could be developed to avoid potential illegality for new power stations. The advice states that "regardless of the outcome of this legal debate, member States definitely retain a number of options for introduction of domestic CO_2 EPS for their power sector" (ClientEarth, 2010). Additionally, it argues that the scope of the relevant article of the IPPC Directive is confined to permits.

The UK administration may choose to use the precise wording in the IPPC directive and the Industrial Emissions Directive to defend its proposed CCS policies. The languages in these directives forbid including emission limit values in greenhouse gas permits, but do not include any reference to a technology mandate.

7. Discussion

Some considerations emerged from the preceding chapters. The discussion will start with some general observations and follow with more specific ones which will take the outcome of the impact assessment of Chapter 5 into account.

1) Policy packages are often used in energy policy. This is either the case when they try to combine cost-effectiveness and the interests of different stakeholders (political feasibility) or introduce mutual enforcing elements of a step-by-step approach (e.g. gradually stricter application of regulation, combined with financial incentives for front runners). This could be a useful starting point of our considerations of how to stimulate CCS.
2) One has to sketch a clear picture of what the actual policy aims are. In particular, in the debate on 'clean coal', two different policy aims may be distinguished. One aim is to get rid of 'dirty coal'. The other aim is to promote CCS. The optimal policy instruments or packages are not the same. In case the abolishment of dirty coal is the aim, regulatory instruments are useful: if coal is the problem, the emission of coal has to decrease. It would be useful to start with the most polluting plants. This approach, however, does not lead to investments in CCS in all cases, but may for instance trigger a shift to natural gas or a higher share of biomass co-firing instead. If an incentive for CCS is the policy purpose, investments in CCS have to be feasible from both a technological and economic perspective. The modelling of the Dutch electricity market showed that an EPS might be successful in attaining the first goal (the end of dirty coal), but not of the second one (attainment of CCS).
3) One has to realize that CCS is a complex and many-sided issue. It is complex, as actual introduction of CCS cannot be decided by one single party. After the capture of CO_2, transport and storage is needed. If a coal-fired plant is obliged to capture CO_2, it cannot be obliged to transport and store the abated emissions. The generator can be obliged to take these issues into account - e.g. when selecting the site of the plant - but not to solve it. Transport finally will be a regulated business in which other parties play a role. Storage is an issue with large public attention in which the government itself is an important player. It would be senseless to oblige coal-fired plants to capture CO_2 when transport and storage issues have not been organized and regulated. In many cases transport and storage will be organized in a public-private partnership.
4) Legal prohibitions of introducing specific regulation in the Netherlands exist, but do not seem fully insurmountable. Both the EC Treaty - leaving room for national measures on top of EU policies - and the Geological storage Directive - mentioning a review by the Commission in 2015 in which emission performance standards could be proposed - offer arguments for an eventual regulatory approach in the Netherlands. The legal wording is important, however. Close cooperation with countries like the United Kingdom or Ireland facing comparable challenges makes sense.
5) A possible policy package could consist of (improvements of) emissions trading, financial incentives and regulation.
6) From an environmental perspective, CO_2 emissions are already capped by the EU ETS. Theoretically, strong arguments can be made against a combination of the existing ETS cap on the one hand and regulation on the other. In summary, they include (Boot &, van Bree, 2010):
   - If the ETS cap is not adjusted, an EPS next to the EU ETS will not further reduce greenhouse gas emissions covered by the trading scheme, since emissions are set by the cap;
   - If the ETS cap is not adjusted downwards, an EPS may reduce the demand for emission allowances and, hence, lowers the price for these allowances. The incentive for *all other installations* not covered by the regulation may be reduced. To counter this effect, the cap has to be decreased in combination with the regulation.

7) Some analysts argue that the ETS will not, whatsoever, be able to stimulate CCS in the coming decades, as it does not incentivize long-term clean energy investments and influences mainly short-term operational decisions (Skillings 2009, PBL 2009). It is a fact that the revised ETS Directive of 2009 has specified a cap of EU emission allowances by a linear annual reduction of 1.74%. This linear reduction probably will not contribute sufficiently to the EU ambition of reducing greenhouse gas emissions by 85-90% in 2050 and at least does not guarantee a nearly fully decarbonised power system. Therefore, the ambition of the EU ETS has to be increased to make it really effective in the long-term. This could start with strengthening the 2020 target.
8) To some extent a specific incentive for CCS is comparable with that of renewable energy. Both CCS and renewable energy technologies need cost reductions and learning experiences to make them competitive in an electricity market with CO_2 prices. This is the reason why temporary specific stimulation of those technologies that have a learning curve could be defended. In the end, of course, CCS is not fully comparable with renewable energy as it does not deliver 100% carbon reduction, increases the use of primary fossil energy and therewith of all other negative external effects of coal-fired (and to a lesser extent gas-fired) power generation. As CCS is a 'bridging technology' towards a more sustainable energy system, this is an additional argument to use only temporary financial incentives in an eventual package. CCS also will have a different position in the merit order and therewith ultimately effective incentives of renewable energy and CCS will be different.

Section 3.3 discussed seven requisites for effective and efficient CCS policies. These policies have been analysed in Chapter 5. Table 7.1 attempts to summarise the results.

Table 7.1 *Estimated effects of different instruments in promoting CCS*

	Rapid diffusion	CO_2 reduction	Consistent, predictable	Budget	Avoid perverse effects	Acceptability	Flexibility
Regulation	-	0	0/+	0	-	0	-
Financial incentive	++	0	0/+	-	0	0	0
Package regulation and finance	++	0	0/+	0/-	0	0	-
Package finance and regulation	++	0	0/+	0/-	0	0	0

Four policy approaches have been looked at. Regulation and financial incentives do not need further explanation. The package 'regulation plus finance' implies that a regulatory framework has been defined by the government but the additional costs of the obligation to apply CO_2 capture will be paid collectively. In the package 'finance plus regulation' it is the other way around: a subsidy is offered but at some moment the financial support will be replaced by regulation.

Regulation only does not lead to rapid diffusion of CCS, as has been illustrated in Chapter 5. The other packages will contribute to the diffusion of CCS, as in all of them the cost difference between the electricity price and CCS are assumed to be covered. If an effective EU ETS cap has been defined, no instrument will contribute to CO_2 reduction as the European cap has been fixed: reduction in the Netherlands enables emitters elsewhere to emit more ('the waterbed effect'). One could argue that in the long run a proof of cost-effective CCS could be an argument in the eventual discussions to strengthen the cap. In theory, regulation could be suggested in a timely way which will enable a consistent and predictable policy framework. This is only the case, however, if the suggested regulation is acceptable from a European legal point of view. As this is not fully certain for generators that already received a permit, regulation has not been rated with a '+'. The package finance followed by regulation could be ranked somewhat higher in that respect, as the first effects will be delivered by the financial contracts to be concluded by the generator and the government. A policy framework has to be designed carefully how these contracts will be followed by regulation. A financial instrument only could be quite predictable, if designed carefully. An EPS only does not lie heavy on the public budget, whereas the other instruments do. The purpose of a package including regulation is to announce in a timely way against which conditions the financial support will finish. Therefore, the budgetary effect might be somewhat less than in the case with a financial support only. Regulation only might lead to perverse reactions: the closure of Dutch coal-fired power plants could lead to additional generation by less efficient German plants, or less opportunities to co-fire biomass and to attain the Dutch 2020 target for renewable energy. The suggested ranking of acceptability is for consideration only. Regulation only will not be acceptable for most stakeholders in industry but will be appreciated by environmental NGOs. Financial instruments will not be appreciated by those stakeholders who are afraid that this will imply less financial support for renewable energy. Packages might be more acceptable for different stakeholders, depending on the specific conditions. Regulation offers more certainty, but less flexibility. Taylor-made financial support probably could offer some flexibility.

In all, regulation only does not contribute to the aim which is supposed to be most relevant. Chapter 5 suggested that the budgetary impact of a financial instrument could be relatively small. If flexibility is an important consideration, either the financial instrument or a financial instrument including regulation could be a useful option.

To summarize, the following general considerations apply:
1) if the EU ETS could be improved to attain the 100% emission reduction, the short-term environmental (CO_2) arguments for structural additional instruments are not strong, but the argument for stimulating technological innovation required for medium and long-term emissions reductions still applies,
2) some legal possibilities for introducing an emissions performance standard seem to exist,
3) temporary specific instruments are needed to decrease costs of those technologies that are not cost-effective by now and are needed later in the power fuel mix with low or zero carbon emissions. This is to some extent valid as much for CCS as it is for renewable energy,
4) an EPS alone will lead to less coal-fired generation but not necessarily to more CCS,
5) it is assumed that the Dutch government has a strong interest in promoting CCS,
6) in that case an adequate financial support is suggested,
7) whether only a financial incentive or a package including regulation is preferred depends on the political objectives of the government.

In all, a package with a temporary financial stimulus of CCS is not only defendable but will be needed in case further progress with CCS is preferred by the Dutch government. Ideally, this would be complemented with a reduction of the EU ETS cap. To give guidance to investors, the Netherlands could consider a package of financial instruments and regulation for the period after 2020. Without a more stringent cap, the package will decrease costs of CCS but does not lead to more CO_2 reduction. In case the arguments of sound theory against regulation are weighed more heavily, a financial incentive next to a plea for strengthening of ETS would suffice.

Taking the outcome of the computations of Chapter 5 into account, we consider the following approach feasible:
1) A ban on unabated coal-fired power could be introduced for all new investments not having started a permit procedure.
2) At least financial support for the difference of full costs of capture (between CCS and new unabated coal-fired power plants including the CO_2 price) is defendable: it will de facto stimulate CCS, it does not lead to an increase of the wholesale electricity price, it has no effect on the Dutch export position and - compared with the subsidy costs of renewable en-

ergy - can be implemented against reasonable costs. It depends on the political preference whether this will be combined with regulation.

3) In case regulation would be part of the package, an EPS of 350 g/CO_2 has been modelled. This EPS would apply to all coal-fired power plants that are already capture-ready - those that are being built by now and will be built in the future. ECN did not consider all features of CCS of gas-fired power stations sufficiently thoroughly to propose an EPS for gas-fired power stations by now. And as an EPS for gas-fired power stations cannot be proposed by now, it is difficult to defend an EPS of 150 for coal-fired power stations, as in that case coal would be even cleaner with respect to CO_2 than gas. Theoretically, a CCS mandate offers some advantages compared with an EPS, but it is difficult to imagine a CCS mandate when this technology is still in the demonstration phase. Furthermore, the EPS was explicitly mentioned in the opinion of Dutch Parliament on 3 November 2009.
4) The costs of financial support could be financed by either a part of the auction revenue of allowances paid by electricity generators and/or a small levy on the electricity price.
5) Although in principle a tender system seems to be the preferred option to finance the cost differential between CCS and unabated coal, in practice other approaches could be considered as well, as the analyses of different systems did not show one option showing better results in all aspects than the other ones. Technically the three coal-fired power plants being built now are comparable and therefore the costs will not differ much. An approach equivalent with the SDE for renewable energy (feed-in premium) could be considered as well. A contract for differences would be a complicated new instrument. The government is advised to look at a simple financial approach for these three coal-fired power plants. More sophisticated approaches could be considered for next steps, also taking into account the learning experiences of other countries.
6) Any policy package influences the overall CO_2 emission only if it is combined with a reduction of the ETS cap. The revised ETS Directive includes an option to increase the overall EU mitigation target from 20 to 30% in 2020, compared to 1990 GHG levels, as part of the outcome of the Copenhagen process towards a new global climate treaty. The Commission should review the situation by 30 June 2010 and could include recent developments in CCS in its review. This will not be an easy debate. A more conservative expectation is that a reduced cap will be valid by 2020.
7) A plea by the Netherlands alone to decrease the CO_2 cap of the Emission Trading Scheme does not weigh heavily. Other countries in North Western Europe - especially the United Kingdom - are in a comparable position in which they are searching for ways to stimulate CCS in a cost-effective way. France easily could join this group and maybe eventually Germany as well. The Netherlands is advised to look for like-minded countries that are prepared to ignite the debate on how to further decrease the European ETS cap.
8) The government itself has to take the final responsibility for the organisation of transport and storage. This cannot be done by private partners only. Power generators have to be able to contract transport and storage options. Private parties can play an active role in the implementation of transport and storage activities, but the government has to organize and regulate this. In the first point to point transport lines this is less urgent, but in a more complex transport system an overall approach is needed. Therefore, the government has already commissioned the elaboration of transport and storage strategies. The financial support of the CCS activities has to include at least a large part of transport and storage costs. Electricity generators could be made responsible for a - relatively small- remaining part of the costs to stimulate them to keep this as low as possible. Public consultation and communication have to be an important aspect of the approach.
9) The Netherlands government could announce that it is considering this approach and start to prepare activities and legislation. In order to further increase the speed of activities it could suggest a covenant with all relevant partners (e.g. electricity generators, transport and storage companies, NGOs, local governments) to work jointly towards a common goal and dovetail the different pieces of the overall approach. The Steering Committee CCS could play an active role in contributing to and implementation of the covenant.

10) One has to realise, however, that CCS is a promising but at large scale unproven technology. We advise the Netherlands government to evaluate by 2018 - taking experience with the demonstration plants into account and after the review by the European Commission - whether the package is still feasible. At that moment the prospects of CCS in gas-fired power stations and an eventual stricter EPS for coal-fired power stations at a later moment could be considered as well.

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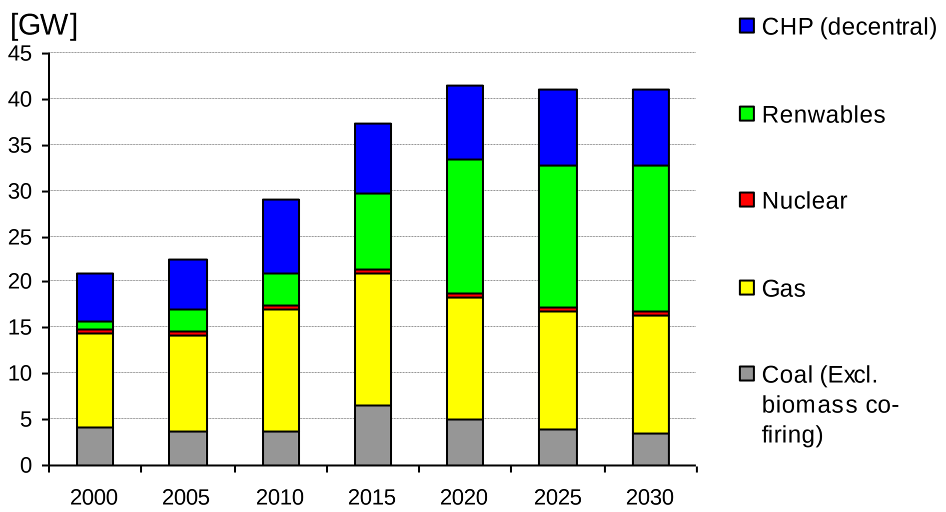
Appendix A Annex to Chapter 5: Results NRP-NL-SVV reference case

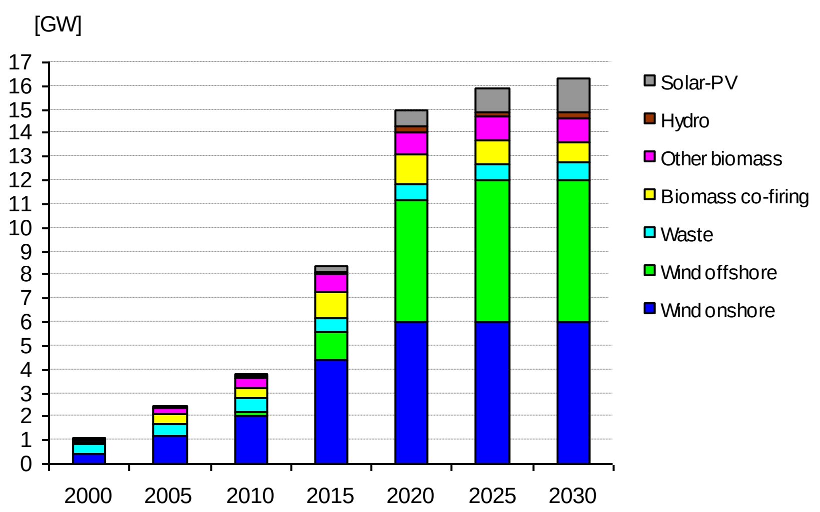
This Annex contains more detailed quantitative results of the NRP-NL-SVV reference projection that forms the starting point for the ECF analyses. These results are additional to the tables and figures given as part of Chapter 5. The results of the NRP-NL-SVV reference projection are summarised in the figures below.

A.1 NRP-NL-SVV

A.1.1 Installed generating capacity and production fuel mix

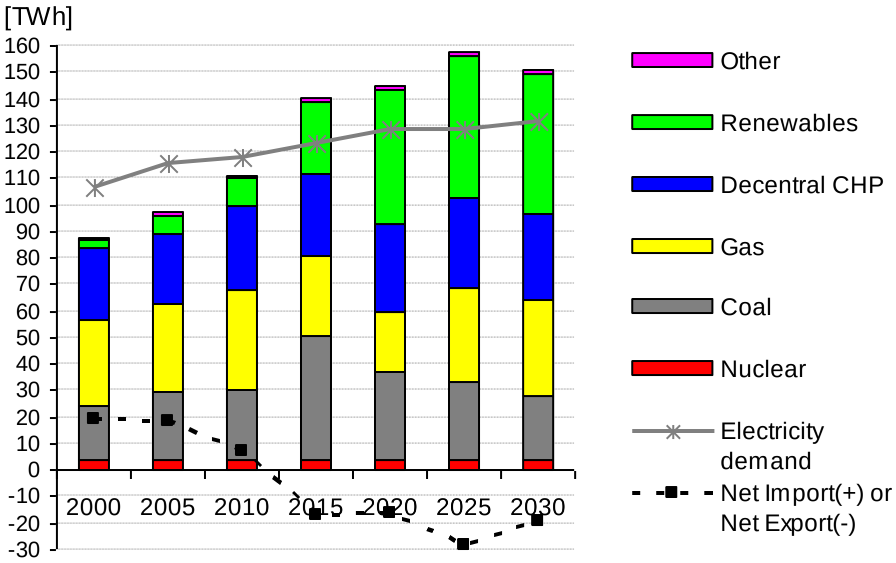


Figuur A.1 *Installed electricity generation capacity, in GW_e , The Netherlands, 2000-2030, NRP-NL-SVV*



Figuur A.2 *Renewable electricity generation capacity, in GW_e , The Netherlands, 2000-2030, NRP-NL-SVV*

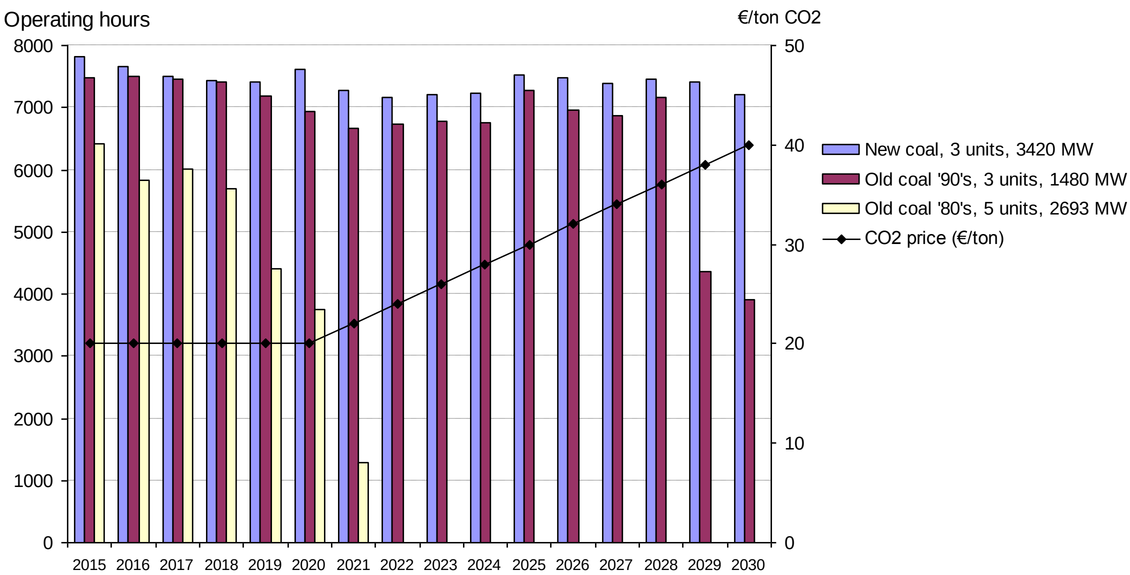
The production fuel mix and development of net import or export is given in Section 5.3. For convenience it is repeated here. In addition, the Dutch domestic electricity demand is displayed as well.



Figuur A.3 *Electricity generation fuel mix, electricity demand and net import/export, all in TWh, 2000-2030, the Netherlands, NRP-NL-SVV*

A.1.2 Operating hours, coal-fired power plants

The NRP-NL-SVV reference projection features high shares of renewable electricity production in the period 2020-2030. Despite of this large share of renewable capacity with low and limited marginal costs of production, the operating hours of new coal fired power plants remain at high levels. Existing and older coal power plants will be operating less, and will be decommissioned beginning with the oldest ones first.



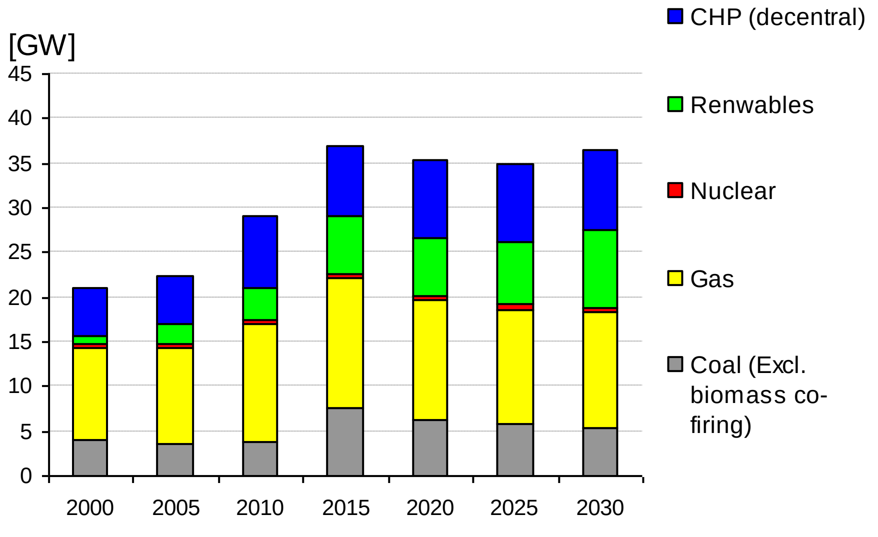
Figuur A.4 *Operating hours coal-fired power, 2015-2030, the Netherlands, NRP-NL-SVV*

- **Full load hours of the *3 new coal-fired power power plants (3500 MW$_e$ in total) currently under construction* will remain above 7200 hours throughout the period 2015-2030.** Large shares of wind energy will not affect the business cases of new coal.
- **Full load hours of *3 existing coal-fired power power plants (about 1500 MW$_e$ in total) built in 1994 and 1995* will remain above 7200 hours throughout the period 2015-2025. In 2030, the full load hours will drop to less than 4000 hours.**
- **Five *older existing coal-fired power power plants (about 2700 MW$_e$ in total) will be decommissioned between 2015 and 2025.* Full load hours will drop fast after 2018 as these units are relatively inefficient compared to the other plants.**
- Due to the large increase of new power plants in the Netherlands, about 10000 MW in the period 2009-2016, and the electricity demand projection, **new natural gas CCGT's will have full load hours of less than 4000 hours**. As CCGT's are less capital intensive than coal-fired power plants, this may not really affect their business cases.

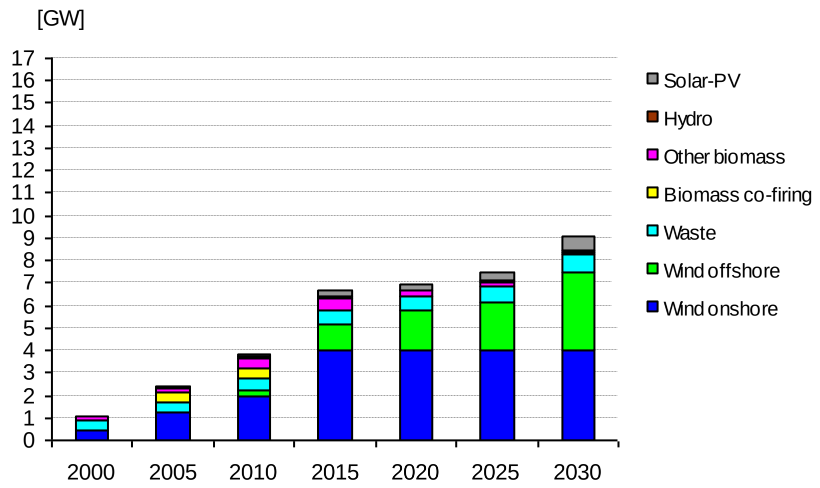
With respect to the business cases of the three new coal fired power plants assumed to be built (4 units, 3420 MW$_e$ net including one 200 MW$_e$ net CCS demo), it can be concluded that their business cases are not largely effected negatively by the high share of renewable electricity production.

A.2 NRP-NL-SV, only existing policies (less renewables)

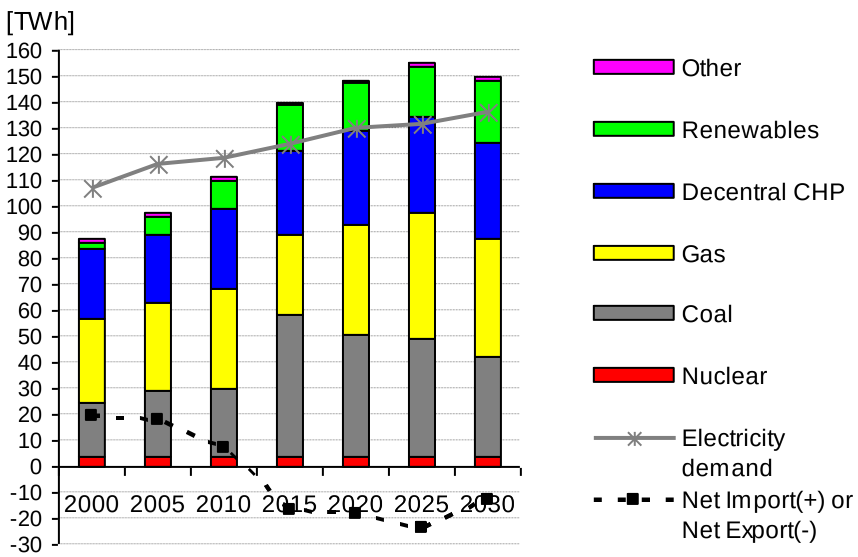
A.2.1 Installed generating capacity and production fuel mix



Figuur A.5 *Installed electricity generation capacity, in GW$_e$, The Netherlands, 2000-2030, NRP-NL-SV, variant based on 'Existing policy instruments' (less renewables)*



Figuur A.6 *Renewable electricity generation capacity, in GW_e , The Netherlands, 2000-2030, NRP-NL-SV, variant based on 'Existing policy instruments' (less renewables)*



Figuur A.7 *Electricity generation fuel mix, electricity demand and net import/export, all in TWh, 2000-2030, the Netherlands, NRP-NL-SV, variant based on 'Existing policy instruments' (less renewables, only 2 old coal decommisioned prior to 2020)*