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How may CCS technology affect the electricity market in North-Western Europe?

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Abstract

The EU electricity market is changing. Electricity demand in Europe is on the rise, the power plant fleet is aging, and a large share of the capacity will need to be replaced in the coming decades. An ambitious target has been formulated for the share of renewable energy, and CO₂ prices are anticipated to increase. On top of this, CO₂ Capture and Storage (CCS) has appeared as an important technology in the transition to a long term sustainable energy supply. This paper discusses the implications all of the above developments for the EU electricity market, with an emphasis on the market North Western Europe. On the whole electricity prices in North Western Europe until 2020 are anticipated to increase, but this may only partly be ascribed to the pending introduction of CCS.

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1. Introduction

The electricity market in the European Union is subject to many changes. Electricity demand in Europe is increasing as a consequence of demographical and economic growth. The EU power plant fleet is aging, and a large share of the capacity may need to be replaced in the coming decades. Furthermore, an ambitious target has been formulated for the reduction of greenhouse gas emissions (GHG) and the share of renewable source in primary energy supply. CO₂ prices are anticipated to increase, as the amount of EUAs will be further restricted in the second phase of the EU-ETS, and most likely in the phases beyond 2012. On top of these developments CO₂ capture and storage (CCS) has emerged as a chief technology to reduce CO₂ emissions on the medium term. The whole of these developments may have important implications for the EU electricity market, e.g. with respect to the type of fossil fuel fired power plant technologies that will be deployed, the potential role of CCS and technology development therein, and electricity prices.

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This paper explores a number of major developments that have a bearing on the electricity market, and the effect that these may have on trends in electricity prices and the power generation portfolio. While emphasis will be on the role that CCS might play in the coming decades, the implications of fleet replacement, the EU renewables target, and a revised EU ETS will be considered as well. We will emphasize developments in five countries in North Western Europe, where CCS is likely to take off first: the United Kingdom, the Netherlands, Germany, France, and Belgium.

In the following we will firstly outline a number of contextual developments related to EU energy policies, and outlooks for CO₂ and fossil fuel prices (section 2). Next, we will look into the current and future composition of the EU power fleet (section 3), and the costs of CO₂ capture and storage (section 4). We will discuss possible implications of these trends for the place of fossil-fuel based power generation in the merit order dispatch (section 5), and draw a number of preliminary conclusions (section 6).

2. Policy context

2.1. EU energy policies

Objectives for an EU energy policy were laid down in the 2007 Energy Policy Package². Targets for supply security in this package are mostly qualitative and emphasise the importance of the internal energy market, external energy relationships, and mechanisms to ensure Member States solidarity. Fears for lack of supply security in the EU mainly relate to the increasing dependence on gas imports, which are expected to rise from a current 50% to 80% in 2020 (IEA [1]).

Climate objectives are quantitative. They require greenhouse gas emissions reduction by 20% in 2020, or by 30% if other countries commit themselves to reduction targets as well, while renewable sources must supply 20% of primary energy.

A cornerstone of EU climate policy still is the EU Emissions Trading Scheme (ETS). It has been reviewed and a number of major modifications to the Emissions Trading Directive³ were proposed in January 2008 that most likely will have important implications for the electricity sector. Chief objective of the EU ETS review was to establish a reformed ETS for the years between 2013 and 2020 and beyond. A single EU cap has been proposed, declining annually by 1.74% up to 2028. According to the proposed revision, 100% emission allowance units (EAUs) for the power generation sector will be auctioned starting from 2013, the reason being that in the first phase of the EU ETS free allocation of allowances to this sector led to sizeable windfall profits for the sector. Empirical analyses showed general increases in electricity prices and in profits across the EU electricity market over the year 2005–2006 (Sijm *et al.* [2]). This was caused not only by a general increase in oil and gas prices or scarcity of peakload capacity, but also and foremost following a pass through of the opportunity costs of the CO₂. Eventually these windfall profits would undermine the legitimacy of the EU ETS. Full auctioning was considered an appropriate solution to avoid this in the third phase of the EU ETS, and will have a severe impact on the electricity generation sector.

2.2. Outlook CO₂ prices

Following the proposed amendments to the EU ETS discussed above, in particular the proposed cap for emissions from ETS installations up to 2020, CO₂ prices are projected to increase. This is crucial for the introduction of CCS, although views on the minimum CO₂ price required to incentivize CCS have changed over the past few years. Initial model results suggested that CCS would come in at price on the order of 25–30US\$₂₀₀₂/tCO₂ (IPCC [3]), but recent estimates are higher. While levels in the 30–40 €/tCO₂ range may be sufficient to provide confidence to candidate investors in CCS in the long term, in the short run higher levels may be necessary to make

² SEC(2007)12

³ 2003(87)EC

up for the perceived uncertainty related to possibly volatile CO₂, as well as the fossil fuel prices and the technological risks to this novel technology.

Arguably, operators from fossil-fuel based power plants under the EU ETS would seek alternative ways to reduce emissions before deploying CCS on a large scale. Fuel switching from lignite to hard coal and from coal to natural gas has a considerable potential still, notably in Germany, the UK and Spain. This includes both modification in current load factors in existing plants, with CO₂ reduction potentials in Germany, the UK and Spain up to 23, 39 and 42 Mt CO₂, and the construction of new capacity. A recent study from the Deutsche Bank estimated that at a gas and coal prices at €8.9/GJ and €2.32/GJ, and a CO₂ price of 40 €/t, natural gas would be preferred over coal. CCS at this price level would still be too expensive. Only at a nominal CO₂ price of 52–62 €/t CCS could compete with natural gas, assuming CCS efficiency would be between 40 and 35% respectively. If the introduction of CCS would be effectuated by 2020, this would correspond to a nominal price between 70 and 83 €/t in 2020 (Lewis and Curien [4]).

2.3. Outlook fossil fuel prices

Price trends for coal and natural gas will affect preferences for new fossil-fuel based capacity. Coal prices in 2020 may be similar in most countries in North Western Europe, an exception being coal prices in Germany. Hard coal may well be on the order of 0.2€/GJ higher in Germany, because coal will mostly need to be transported onshore from international harbours on the coast. Prices for natural gas will be high, in line with projected oil prices, especially in Belgium and the United Kingdom. The electricity grids and markets in these countries are closely connected. The UK's isolated geographical position limits opportunities to obtain electricity elsewhere, which drives up the price of electricity in this segment of the EU power market.

Table 1 Projected fuel prices 2020 (€/GJ; based on Özdemir *et al.* [6])

	Netherlands	Belgium	Germany	France	United Kingdom
Natural gas	4.8 – 6.8	5.4 – 7.7	4.8 – 6.8	4.8 – 6.8	5.5 – 7.9
Coal	2.0 – 2.5	2.0 – 2.5	2.2 – 2.7	2.0 – 2.5	2.0 – 2.5

3. Electricity market and fleet capacity in the EU

Following the adoption of common rules for the internal electricity market⁴ the EU electricity market has been liberalized. Still, electricity networks are mostly national, and electricity prices diverge. Germany and France have medium price levels, whereas levels in the Benelux and the UK are higher. Price levels are likely to converge however, provided that sufficient transmission capacity is available. Future price levels will depend on the expansion of fossil fuel based capacity, renewable energy, expansion and improvement of interconnection. Newly planned interconnections include NorNed, between the Netherlands and Norway (0.7 GW), BritNed, between the Netherlands and the UK (1 GW), while transmission capacity between the Netherlands and Germany is planned to be increased by 2 GW. The improvement of interconnection is likely to promote convergence of power prices under a range of scenarios, including policies for energy efficiency and nuclear energy (Özdemir *et al.* [6]).

The liberalization of the EU internal markets for electricity and gas since 2003 is supported by the European Regulator's Group for Electricity and Gas (ERGEG), which is a body of independent national energy regulatory authorities, which was set up by the European Commission as an Advisory Group to the Commission on energy issues. One of its accomplishments has been the establishment of an Electricity Regional Initiatives Task Force early 2006. This Task force initiated 7 regional energy market projects (REMs). The Central-West electricity REM aims to integrate power markets Belgium, France, Germany, Luxembourg and the Netherlands, which constitute 42% of the EU 25 Electricity market. Priorities in this region include *inter alia* the improvement of interconnections,

⁴ 2003/54/EC

improvement of data exchange, balancing and congestion management. The UK is part of a REM with France and Ireland.

As to the size of future CCS based capacity, this will depend not only on the demand for electricity, but also on the age of existing capacity, and the rate of capacity replacement. These will affect company decisions to invest in new plants that will be equipped with CO₂ capture installations. Electricity generation capacity in the EU is aging, and a large number of power plants will need to be replaced. It is estimated that almost half of the fossil-fuelled power generation capacity is older than 25 years, while around 10% is over 40 years old. In particular many coal based plants will need to be retired before long. Remaining fossil capacity in 2030 and 2050 has been projected 258 and 29 GW (Georgakaki [7]). Still, a large number of proposals for new fossil-fired power plants has been tabled recently, which would result in large capacity increases. Proposals for new plants have been put forward for the Netherlands (11-15 GW), Germany (16-45 GW), and the United Kingdom (14-33 GW). Important factors in investment decisions are also fossil fuel prices and CO₂ prices depending *inter alia* on the emission ceiling and allocation method(s) under the EU-ETS (see above).

4. Cost of CCS technology and the role of policy

4.1. Costs, learning and cost escalations

Numerous studies have addressed the costs of CO₂ capture and storage. A number of recent studies that are representative for North Western Europe (Ploumen *et al.* [8]; Tzimas and Petevis [9]; Eurelectric[10], as well as recent press notifications from industry were used to extract some typical values for today's capital requirements and costs for operation and maintenance, both for power plants and without CCS. They are listed in Table 2.

Table 2 Representative cost estimates and operational efficiencies for newly built power plants with and without CCS, into operation in 2020

		PC	PC CCS	IGCC	IGCC CCS	GTCC	GTCC-CCS
Specific capital investment, (typical)	€/kW	1400	2400	1800	2500	700	1050
Variable O&M	€/MWh	2	4	2.5	3	0.5	1.5
Fixed O&M	€/kW/yr	53	65	60	70	30	45
Operational efficiency		48%	39%	48%	40%	59%	50%
Availability/Load factor		90%	90%	90%	90%	90%	90%
CO ₂ captured			85%		85%		85%

While the studies cited report on the cost of CO₂ capture and storage today, projections for cost reductions need to be taken into account in any policy analysis or recommendation. Rubin *et al.* [11] estimate future cost trends based on historical experience curves for other energy and environmental process technologies for various types of electricity plants, including PC and NGCC with post-combustion capture and IGCC with pre-combustion capture. Learning rates in these plants for each doubling of capacity are estimated on the order of 1-8% both for capital cost and the cost of electricity, with corresponding reductions of the cost of electricity between 3 and 26%. Projected cost reductions and learning rates for the cost of electricity were largest for IGCC, followed by PC and NGCC plants respectively. Changes in the cost of transport and storage have not been accounted for in these projections, but these are considered relatively small.

An effect counteracting any cost reductions though learning is the recent cost increase in industrial and infrastructural construction works. These must be attributed to two major causes. Firstly, world prices of commodities commonly used in construction, such as steel have risen substantially. Secondly, a scarcity in engineering capacity for building new installations, including power plants, has become apparent following the worldwide increase in the demand for new process installations. Table 3 illustrates this trend with examples of increasing costs estimates for newly built PC plants made public by RWE. While it is still unclear whether cost

escalations are structural or just temporary, it is clear that these developments may render many cost estimates in studies undertaken prior to 2005 outdated to a certain extent.

Table 3 Examples of cost escalations for pulverised coal plants, plans RWE

Unit	Construction/announcement	€/kW investment
BoA 2/3 twin unit Neurath 2 x 1,050 MW	January 2006 start of construction	1048
Hard coal-fired power plant Eemshaven/ the Netherlands 1,560 MW	Announced April 2006	940
Hard coal-fired power plant Ensford, 1,530 MW	Announced November 2006	1307
Lingen, Germany (same type as in Eemshaven), 1600 MW	Announced Nov 2006	1250
New estimate Eemshaven	October 2007	1410
RWE, Poland 800 MW	Announced Dec 2007	1500 ¹

¹ Source: Ensoc Weekly, 7 December 2007

4.2. The role of policy

An important amendment of the Emissions Trading Directive would also regard the inclusion of CCS operations in the third phase of the scheme. In its review proposal, the European Commission considered that from 2013 onwards installations capturing, transporting or storing CO₂ should be covered by the trading scheme ‘in a harmonized manner’, in order to encourage and incentivize large scale deployment of the option. Pending the adoption of a reviewed EU ETS in which CO₂ capture, transport and storage operations could be included separately, a CCS chains may in its entirety be opted in in the trading scheme through Article 24 of the ETD. Installations that include a full CCS chain would not need to hand in allowances for any CO₂ stored.

The European Commission considered that stimulation of CCS demonstrations should be the responsibility of Member States and their co-operations with industry. To this end an amendment to the Directive on environmental State Aid has been tabled, which would allow Member States to financially support CCS operations. In addition, Member States would be allowed to use revenues from auctioning to stimulate emission reduction technologies, which could include CCS. Note though that the idea of a passive role of the EU in stimulating CCS has been challenged in the European Parliament.

5. CCS in the electricity market in North Western Europe

5.1. CCS and competing CO₂ mitigation technology

In the EU Electricity market, generation capacity with CCS will need to compete with other GHG reducing technologies. Table 4 provides an overview of the investment costs and cost efficiency of fossil fuel based power generation options with and without CCS, nuclear energy, wind energy and biomass co-firing.

Table 4 Projected costs of CO₂ emission reducing technologies in the power generating sector in 2020. Values reflect cost in new installations operating as of 2020, and exclude external costs. Discount rate: 9-10.5%. (based on Daniëls and Farla [12] for cost effectiveness (2005 estimates and therefore outdated), other costs are recent ECN experts’ judgements partly based on Scheepers *et al* [13], IPCC [3], Ploumen *et al* [8], Jacobs [18]).

	Specific capital requirement (range) euro/kW _e		Cost effectivity euro/ton CO ₂	
	Low	High	Low	high
NGCC	560	840	0	70

NGCC with CCS	840	1260	20	60
PC	1050	1750	Reference technology	
PC with CCS	1920	2880	20	40
IGCC	1490	2230	0	150
IGCC with CCS	1730	2590	20	40
Nuclear power	2000	3000	0	20
Wind onshore	880	1320	20	70
Wind offshore	1250	2100	20	80
Biomass cofiring	1050	1750	40	90

An important comment is that the figures concern new power generation in base load operation, implying that fluctuating load factors have not been accounted for. Only for wind a correction for the costs related to the intermittency of wind supply has been made. Lower load factors will drive these capital costs upward, and costs for retrofitted plants are higher as well. This complicates an accurate assessment of the implications of CCS in the EU electricity market.

Nevertheless, the higher cost of fossil-fuel based conventional electricity generation with CCS will most likely effect the position of these plants in the merit order dispatch. The merit order is determined on the basis of short run marginal costs, which determine the marginal power price on a day-to-day basis. They are based on the cost of fuel and any EUAs that an operator would need to surrender to cover his emissions. Base load plants usually have low short run costs, while peak load capacity has high short run costs. The marginal power plant dispatched (and that may vary over time) will largely set the electricity market price. If the variable cost of electricity is under this marginal price, the operator may keep the difference, so base load plants tend to have higher margins than peak load plants. In addition, investment in new capacity will only be economically viable if the integral cost of electricity (COE) is (sufficiently) less than the (projected) wholesale electricity market price. Figure 1 shows COEs for new capacity including also an uncertainty bandwidth (derived from Seebregts & Jansen, 2009 [15]). The default estimates for the CCS options are based on a CO₂ price of 35 €/ton CO₂ and gas and coal prices of 7 and 3 €/GJ.

The impact of CCS technology on the position of a power plant in the merit order could work out in two ways.

On the one hand, the costs of CO₂ capture will drive up the short run costs of fossil-fuel based electricity, which could render CCS the price setting technology. Consequently, the overall price of electricity based on the entire portfolio of production routes is likely to increase. Note that this argument on short run costs requires further validation because earlier work has shown that the cost of electricity from a capacity mix based on coal-based CCS plants will be lower than that from a capacity mix based on NGCC plants without capture, under certain fuel and carbon price conditions (Tzimas and Peteves, 2005). Still, if a plant operator manages to cover (part of) the increase in short run costs following CCS deployment with revenues from the sales of EUAs, the total (capital plus variable) cost of electricity does not need to increase as much.

On the other hand, CCS may render fossil fuel capacity less flexible. Low load factors for such plants imply frequent discontinuations of CO₂ transport and injections as well, which will come at a cost. This implies that during off peak periods (night, weekends) their production cannot be lowered easily, and that operators would prefer to deploy their CCS plants day round.

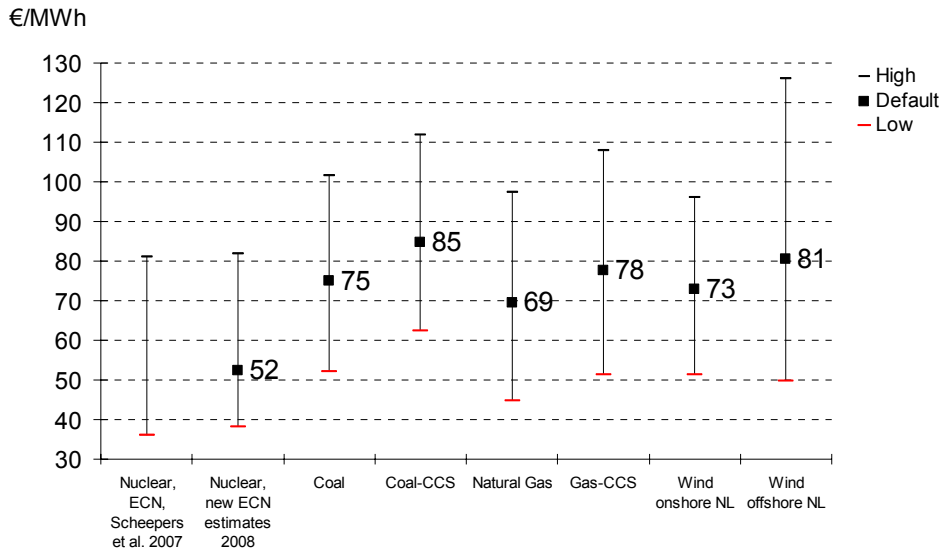


Figure 1 Cost of electricity for new generating technology in 2020 (Source: Seebregts & Jansen, 2008 [15]).

5.2. Impact of CCS deployment on the electricity market

Results from runs with the ECN POWERS model suggest that large scale development of CCS could have a substantial impact on the wholesale market electricity prices after 2020.

For the indicative analyses, use is made of energy prices assumptions for an upcoming updated reference projection for the Netherlands. These assumptions are:

- a CO₂ price of 50 €/ton CO₂ in the period 2013-2030
- a natural gas price ranging from 8 to 10 €/GJ (in period from 2015 to 2030), and
- a hard coal price of 2,3 €/GJ.

Existing and new policies and instruments have been taken into account if considered certain and concrete enough. E.g. no credit is given for national covenants aiming at substantial CO₂ reduction in 2020 compared to 1990 levels.

The base case assumes no large scale CCS deployment, although now small scale pilots and demos for new power plants are considered to be applied in the Netherlands within the next decade.

The what-if analyses involve:

1. Large scale deployment of CCS at three newly planned 'capture-ready' coal-fired power plants (3,5 GW in total, two in Rotterdam area, one in Eemshaven), starting in the period 2015-2020
2. Large scale deployment of all new coal-fired power plants coming into operation after 2020.

The first three have rather low net efficiencies after retrofitting (from 46 to 33%), the second exhibit a net efficiency of about 39% (in accordance with Table 2). These what-if's have been defined rather extreme and optimistic with regard to the CO₂ capture efficiency (90%) and the time of deployment (already from 2015 onwards). Reason for these choices is to find out if CCS deployment has either significant or negligible impact on the electricity market.

Figure 2 shows some indicative and illustrative numerical results under these assumptions. The impact of CCS deployments is displayed with respect to: (a) the wholesale electricity market price; (b) the net import balance (for the Netherlands); and (c) the CO₂ emissions of the centralized production park in the Netherlands.

The electricity market prices are likely to increase due to increasing fossil fuel and CO₂ prices. The deployment of CCS does not affect these market prices significantly. The same holds for the export balance. However, the domestic CO₂ emissions will decrease a lot. In 2030, CO₂ emissions for the power generation sector could be reduced by about 45% compared to the baseline case without CCS.

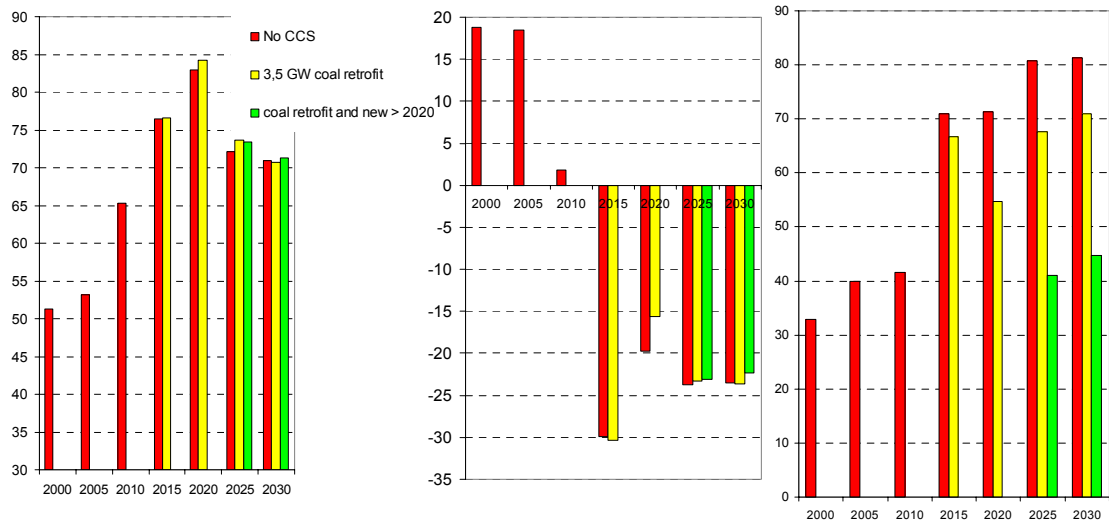


Figure 2. Impact of CCS on (a). wholesale electricity market price; (b) net import balance (the Netherlands); (c) CO₂ emissions, centralized production park in the Netherlands

From the results, it also follows that at a CO₂ price of 50 €/ton and with the fuel prices postulated, the market price is not high enough when compared to the integral cost of electricity (COE) of coal with CCS. The market price is in the range of 70 to 85 €/MWh, while the COE for a new coal plant with CCS is about 87 €/MWh (see also Figure 1). The latter estimate is without inclusion of other parameter uncertainties (e.g. lower load factors, lower CO₂ capture efficiency, higher discount rate) which could further increase the COE. Therefore, it can be concluded that CCS would need a much higher CO₂ price or other types of support to become viable. It seems unlikely that operators would retrofit their base load plants, or embark on new fossil-fuel based power plants with CCS, if they cannot use them at high load factors. Thus, the sales of EUAs will need to make up for any increases in short run costs required for capturing and storing the CO₂. Such continuous or nearly continuous deployment and additional supporting schemes have to justify the large investments made upfront.

Details and additional analyses on the impact of CCS on electricity market prices and emissions are reported in Seebregts & Groenenberg, 2008 [14]. This includes CCS for gas-fired power plants and the co-firing of biomass in coal power plants. CCS deployment for gas-fired power plants may have a more significant impact on the wholesale market price. Use of substantial amounts of biomass may result in even 'negative' CO₂ emissions.

Note that increasing intermittent production from renewable sources eventually may complicate (nearly) fully time deployment of fossil fuel capacity in general. It is true that a larger share of power from renewable sources may well lead to a reduced consumption of fossil fuels in electricity generation. Yet, intermittency of wind and solar energy will hamper the closure of fossil fuel capacity. While it may prove difficult to close fossil fuel capacity, deployment of intermittent resources will reduce fossil fuel based electricity production, which is likely to lead to a

higher price of conventional electricity. This is because the intermittent character of renewable energy sources impedes closure of fossil fuel based capacity, so that long run costs will remain constant, while fossil fuel based electricity production drops.

In addition, long run costs of electricity may increase because excess generation from particularly wind energy during off peak periods with a lot of wind, an excess of electricity production may occur. This problem most likely will occur only in certain areas, such as regions surrounding the North Sea, which happens to be a zone where CCS may readily be applied. A number of solutions for this problem are conceivable, including a decrease of wind production, an increase of the demand for electricity (e.g. by recharging electrical vehicle during off peak periods), transportation of excess electricity to neighbouring regions, or temporary storage of electricity. All these options will increase long run costs of electricity supply in the region.

6. Conclusions

While EU electricity demand is increasing, a substantial share of the EU coal-based capacity will need to be replaced. Fossil fuel prices and CO₂ prices are likely to increase, just as the costs for engineering. At the same time, ambitious objectives have been formulated for GHG emission reductions and the share of renewables in primary energy supply and 2020, and ways to realize large scale demonstration and eventually widespread deployment of CCS are being considered by industry and governments in North Western Europe.

Against this background, we explored the role of CCS in the electricity market by 2020. While the precise position of CCS in the merit order will depend on the costs of fossil fuels and CO₂, it seems unlikely that the load factor of fossil-fuel based capacity would be lowered. Not only would this require discontinuing operations in the remainder of the CCS chain, indications exist that the cost of electricity from coal with CCS will come down faster than the cost of electricity from gas-based capacity.

Still, on the whole electricity prices in North Western Europe until 2020 are anticipated to increase, but this may only partly be ascribed to the pending introduction of CCS. Rising fossil fuel and CO₂ prices by themselves exert an upward pressure on the cost of electricity, also in absence of CCS. Increasing supplies of energy from renewable sources will reduce load factors in fossil-fuel based capacity, and lead to higher costs of conventional power generation. We conclude therefore that higher electricity prices cannot provide an overriding argument against CCS in the EU mitigation portfolio.

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Appendix: The POWERS Model

The POWERS model (Seebregts et al., 2005 [16]) simulates the Dutch electricity market within a North Western European context. POWERS is coupled to the detailed Industry/CHP model Save-Production (Daniëls & van Dril, 2007 [17]). Apart from providing electricity prices to the latter model, POWERS also uses results from Save-Production, namely on industrial electricity demand and generation with CHP. To achieve equilibrium on the electricity market, the two models have to perform several iterations, until electricity prices, electricity demand and CHP production remain nearly constant.

The POWERS model was originally developed in 2001 to analyze the liberalized Dutch electricity market, incorporating the new structure of the electricity market and the increasing competition between energy companies. The model is based on the system dynamics. This means that the decisions regarding production volume, plant capacity allocation, and price setting made by each market player is based on information from the previous period.

The model was extended in 2004 to support the new Reference Projections for the Netherlands (up to 2020) and a long-term scenario study (up to 2040). Currently the model contains:

- A detailed description of the production capacity of the current market players in the Netherlands,
 - Current and future interconnections with Belgium, France, Germany, Norway and the United Kingdom,
- and
- Linkages to detailed electricity demand models for the Netherlands.

Among other purposes the model is suitable for determining:

- Outlooks for forward prices on the Dutch wholesale electricity market,
- The electricity production mix of the Dutch power sector based on the production capacity,
- Import and export flows of electricity,
- A consistent coupling with decentralized CHP plants, and
- CO₂ emissions.

The model takes into account investments in new capacity, fuel prices, and CO₂ emission permit prices, which can be scenario specific. The model has been validated against historic operating experience with respect to the electricity production and fuel mix, CO₂ emissions and spot market prices (Amsterdam Power eXchange, APX) for the period 2000-2004.