Carbon Capture and Storage Technologies in the European Power Market

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Abstract:

We examine the potential of Carbon Capture and Storage (CCS) technologies in the European electricity markets, assessing whether CCS technologies will reduce carbon emissions substantially in the absence of investment subsidies, and how the availability of CCS technologies may affect electricity prices and the amount of renewable electricity. To this end we augment a multi-market equilibrium model of the European energy markets with CCS electricity technologies. The CCS technologies are characterized by costs and technical efficiencies synthesized from a number of recent CCS reviews. Our simulations indicate that with realistic values for carbon prices, new CCS coal power plants become profitable, totally replacing non-CCS coal power investments and to a large extent replacing new wind power. New CCS gas power also becomes profitable, but does not replace non-CCS gas power investment fully. Substantially lower costs, through subsidies on technological development or deployment, would be necessary to make CCS modification of existing coal and gas power plants profitable for private investors.

Keywords: Carbon capture and storage, fossil fuels, energy, carbon emissions, abatement.

JEL classification: H23, Q40, Q54

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1. Introduction

CCS technologies may play a major role in reaching the ambitious emission targets discussed in the last IPCC report (IPCC, 2007). Presupposing that the remaining technical challenges on CCS are successfully solved and that future costs will fall in line with current projections, we examine to what extent technology-neutral abatement policies (e.g., carbon taxes or tradable quotas) will be sufficient to cause a wide deployment of CCS in Europe. Based on a broad review of CCS cost projections and using LIBEMOD, a detailed, multi-market model of the European energy market, we find that a \$30 tax per ton CO_2 would be sufficient to make CCS the profit-maximizing choice for all *new* coal plants. Installing CCS in already *existing* coal power plants would remain unprofitable. For natural gas power, similar results hold for a CO_2 tax at \$65.

CCS technology has been the focus of much international political interest: The G8 has committed to launch 20 large scale CCS pilots by 2010, and to aim for a broad deployment of CCS by 2020 (G8, 2009). CCS technology receives significant funding in the US, and the aim is to have five to ten commercial demonstration plants by 2016 (Global CCS Institute, 2010). Likewise the EU is pushing forward to meet their goal of having 12 demonstration plants by 2015 (Zero Emission Platform, 2010). CCS is of particular interest in the EU because as much as 50 percent of EU's current electricity supply is based on coal, lignite and natural gas, making these fuels pivotal in the EU energy security policy. Moreover, CCS could play an important role in the EU plan to reduce emissions of greenhouse gases (GHGs) by 20 percent relative to 1990. This is part of EU's 20-20-20 targets, which also involve other targets for the energy sector, such as increasing renewable energy production as a share of energy consumption to 20 percent.

There are still significant uncertainties about CCS: which capture technologies will be offered, when will they be available, at what cost, and what will the capture efficiencies be? There is an important distinction between i) technologies that can be "retrofitted" (modified) to existing plants, and ii) technologies that are applicable to new (greenfield) plants. The main technology applicable to retrofitting is "post-combustion", which removes the carbon after combustion. Greenfields have additional options, such as pre-combustion (separating carbon from the hydrogen in the fuel, and then burning the clean hydrogen) and oxy-fuel (burning the fuel with pure oxygen to obtain a higher concentration of CO_2 in the resulting gas stream, thereby lowering costs of removing CO_2). According to IEA (2006, 2008) pre-combustion and oxy-fuel are expected to be more cost effective than post-combustion techniques.

At present, neither the cost level nor the time of market entry for CCS technologies is known. The CCS technology is still untested at full-scale in power plants, and current CCS pilot-projects seem to be characterized by delays and large cost overruns. For example, the projected cost of the Norwegian Mongstad and Kårstø CCS projects ballooned by more than 500 percent before construction had even begun, and the goal to have full scale CCS in place by 2012 has been postponed (Ramn, 2009).

One contribution of this paper is a review of various sources for CCS technical efficiency and cost estimates, and a detailed breakdown of the cost structure. Here we distinguish between four types of CCS technologies; new (greenfield) coal and gas power plants with CCS, and existing coal and gas power plants modified (retrofitted) by CCS.

The main contribution of this paper is in analyzing the economic issues. To this end we use our "best-guess" estimates of CCS costs and technical efficiencies to augment the numerical multi-market equilibrium model LIBEMOD of the Western European energy markets (see, for example, Aune et al. 2008) with the four kinds of CCS electricity technologies. The model is used to answer such questions as: suppose the CCS technologies become available in the market, and that current cost projections and expected technical efficiencies are correct – to what extent will we see profit-maximizing agents in the European energy market install CCS in power plants under plausible values of a carbon tax? Will existing power plants be retrofitted with CCS, or will CCS primarily be used in new plants? How will the availability of CCS affect the market share of renewable energy?

These questions can not be answered solely on the basis of current cost estimates. First, since a CCS installation uses a significant share of the electricity produced by the plant, CCS abatement costs will depend on the equilibrium energy prices. We therefore need a model in which coal, natural gas and electricity prices are endogenous and determined simultaneously with the investment decisions of the energy suppliers. Second, CCS competes with other carbon abatement options, such as switching to renewable energy or reducing energy consumption. Thus, in order to assess the likely potential of the different kinds of CCS technologies, such competing options must be included in the numerical model.

The LIBEMOD model offers a detailed description of the energy industry in Western Europe. It determines investment, production, trade, consumption and energy prices in each of 16 Western European countries, distinguishing between five energy goods (coal, gas, oil, biomass and electricity), four user groups of energy, and a number of electricity technologies including standard coal power and gas power, coal power and gas power with CCS, nuclear and several types of renewables. The detailed modelling provides a solid foundation to assess whether CCS investment is profitable. In addition, the model reflects national differences in the energy industry, which may have impact on the distribution of CCS investment over countries.

Using LIBEMOD we can identify the 2030 market equilibrium, assuming rational, well-informed agents and competitive markets. In our reference scenario, where a uniform \$90 CO_2 tax is imposed, we find that greenfield CCS coal power becomes profitable. This technology totally replaces non-CCS coal power investments and to a large extent new wind power. Greenfield CCS gas power also becomes profitable, and nearly replaces all non-CCS gas power investments. Due to the public resistance to nuclear power in most Western European countries, we decided to put an exogenous constraint on new investments in nuclear capacity. When varying the constraint, we find that new nuclear mainly replaces CCS coal power and that it has little effect on investments in the other electricity technologies.

In our 2030 reference scenario, greenfield CCS lowers emissions in the electricity sector in Western Europe by more than 90 percent compared to a situation without CCS and no CO_2 tax. Hence, the first of EU’s three 20 percent targets is likely reached. On the other hand, in the reference scenario the total market share of wind, hydro and biomass power is less than 20 percent, and therefore EU’s second 20 percent goal is not met. Yet, the rationality of a target for the share of renewable electricity (energy) production is definitely questionable: because it is emissions of GHGs that create global warming, a target on GHGs emissions should be sufficient.

A key result in the present study is that regulations mandating retrofitting of CCS, or subsidies that substantially lower CCS retrofit costs, would be necessary to retrofit CCS in existing coal and gas power plants. However, such policies do not seem desirable from a social welfare point of view.

Previous work on the market potential of CCS has left a mixed picture. Results for the European electricity market from the (global) MIT EPPA model suggest there will be no deployment of CCS technologies in 2040, even with carbon prices at 200 USD/TCO_2 (McFarland, Reilly and Herzog, 2003). According to the authors, this is due to high base year electricity prices in Europe, and consequently a high cost penalty for CCS as this technology consumes a lot of electricity to run the carbon capture facilities. We obtain the opposite result, but it should be noted that the MIT model is a global model, and naturally the European electricity market is not modeled as detailed as in LIBEMOD. The MIT study contrasts sharply with OECD/IEA (2004), which, like our study, finds a large market potential for CCS in European electricity production in 2030 - primarily CCS greenfield coal power plants using pre-combustion technology. Interestingly, Odenberger and Johnsson (2009), which analyzes the role of CCS in Europe, and Schumacher and Sands (2009), which examines market diffusion of CCS in Germany, both conclude – like we do - that there is no potential for retrofitted CCS.

Other recent studies are Riahi et al. (2004), Edmonds et al. (2004), IEA (2006) and Aune et al. (2010). With some exceptions, these studies examine global CCS investments. In Riahi et al. (2004) and Edmonds et al. (2004), CCS plays – like in our study - an important role in reducing carbon emissions, however, there is diffusion of CCS mainly after 2050. These two studies do not separate between retrofitted CCS and greenfield CCS. Both IEA (2006) and Aune et al. (2010) distinguish – like we do - between retrofitted and greenfield installations, and both conclude – in contrast to our study - that a significant share of the CCS installations might be retrofitted. This result reflects low cost estimates of CCS retrofitting. The IEA (2006) study also suggests – in contrast to our study - that there will be no CCS greenfield gas power, reflecting the low CO_2 tax ($25) in the simulations.

The rest of the paper is laid out as follows: In Section 2 we synthesize recent estimates of CCS costs. Section 3 offers a description of LIBEMOD. In Section 4 we present our simulation results, and Section 5 concludes.

2. CCS technology and costs

We distinguish between CCS used for gas power and CCS used for coal power. We also distinguish between CCS used in new "greenfield" power plants and CCS "retrofitted" to, that is, installed in, existing power plants. We interpret retrofit strictly, that is, adding a capture facility without significantly changing the rest of the power plant. A greenfield plant with carbon capture allows for (relative to a retrofitted CCS plant) a broader set of technological options, and for a tighter integration of the capture facilities with the electricity plant. A third possibility, namely installing a capture technology in an existing power plant while also investing significantly in redesigning the power production process, is disregarded in the present study.

At present, there are three "types" of capture technologies under development; post-combustion, pre-combustion and oxyfuel (Zero Emission Platform, 2010). With post-combustion the fossil fuel is burnt, and the carbon dioxide is then separated from the flue gasses. In the studies we have seen, this seems to be the preferred solution for retrofitted coal power, retrofitted gas power, greenfield gas power and also for greenfield coal plants using pulverized coal (However, see discussion below). Note that there are several varieties of the post-combustion CCS technology; the one that is most suitable to, for example, retrofitted gas may not be the most suitable to, for example, retrofitted coal.

The second capture technology, pre-combustion, removes the carbon from the fuel and burns clean hydrogen. Steam-reforming, see, for example, OECD/IEA (2004), is a pre-combustion technology. The pre-combustion technology is often assumed for greenfield coal power plants, provided the plant installs integrated gasification combined cycle (IGCC). In the present study we assume that greenfield coal power plants install integrated gasification combined cycle, that is, use a pre-combustion technology. Finally, with oxyfuel the fuel is burnt in pure oxygen, creating a stream of highly concentrated carbon dioxide that is easier to capture. This technology, while seen as promising, is rarely assumed in technical studies, and was therefore disregarded in the present study.

As mentioned in the introduction, current CCS cost figures are hypothetical as there are no full scale power plants in operation with the CCS technology. Our numerical model LIBEMOD requires fine-grained cost parameters (fixed operating and maintenance cost, variable operating and maintenance cost, fuel cost, investment cost). Rather than depending on direct input from engineers and industry experts, who, in our experience, differ significantly in their cost estimates, we rely solely on publicly available cost estimates: we identify cost parameters from a variety of studies collected and tabulated in the IPCC special report on “Carbon Dioxide Capture and Storage” (Metz et al. 2005). We have adjusted the published parameters in order to correct for differences in the original studies, for example wrt. fuel costs, rate of return to capital and the base year, see the Appendix for details.

Table 1 shows the CCS technologies assumed in the present study, along with the corresponding efficiencies and costs. According to the table, there are large cost differences between the four cases (greenfield vs. retrofit, coal power vs. gas power), but for all cases transport and storage costs are small relative to capture costs. The table documents that CCS is more expensive “per ton CO_2 avoided” for gas than for coal, which reflects the lower CO_2 emission of natural gas (relative to coal) per generated MWH. Note that the costs in Table 1 reflect the energy prices in the calibration equilibrium.

As seen from Table 1, the reduction in CO_2 emissions per MWH delivered to the grid is in the range of 83 to 89 percent. Typically, engineering numbers for CCS emission reductions are around 90 percent, but this is before taking into account that a share of the produced electricity is used to run the CCS facilities. In fact, the large power requirements of retrofitted CCS makes this technology substantially more expensive than greenfield CCS; for coal power plants the reduction in net power output in retrofitted CCS is as high as 40 percent, whereas the corresponding reduction for greenfield CCS is 10 percent. More generally, the IPCC lists a variety of reasons why retrofitted CCS is likely to be more expensive than greenfield CCS: land availability on site, access to plant areas, need for special ducts, and, as mention above, less efficient heat integration.

To check our estimated parameters for CCS coal power, we compared these with cost parameters identified in Deutch et al. (2007). In addition, the aggregate implications of our cost parameters ("Cost per ton CO_2 avoided") were compared with the estimates in McKinsey (2008) and IEA/OECD (2008). These comparisons indicate that our estimates are plausible and in the low-to-mid range relative to other studies. Published reports on cost estimates of planned Norwegian post-combustion projects suggest that our cost estimates are low as-of-today (Kjerschow et. al (2009), Røkke et. al (2008)). However, our estimates aim to identify the costs of a well-developed, commercialized CCS technology rather than the first-of-a-kind plant. Further details regarding methodology and results are found in the Appendix.

Table 1. Overview of CCS costs

	Coal greenfield IGCC Pre-combustion	Gas Greenfield Post-combustion	Coal retrofit Post-combustion	Gas retrofit Post-combustion
Reduction in net power output	10 %	15 %	40 %	30 %
Reduction in CO_2 emissions per MWH	89 %	88 %	83 %	86 %
COE* without CCS	49.4**	44.8	25.8	33.0
Incremental COE* increase due to CCS	18.3	18.7	48.2	32.6
COE* with CCS	67.7	63.5	73.9	65.6
Abatement cost ($/T$CO_2$ avoided)***	27.4	58.8	60.9	105.8
Abatement cost ($/T$CO_2$ avoided – with transport/storage)***	35.6	67.4	73.9	116.6

*COE – average cost of energy.

**All values are measured as $/MWH (2007 USD) unless otherwise noted.

***Engineering figures (no equilibrium effects). Fuel prices taken from the LIBEMOD calibration equilibrium.

3. The LIBEMOD model

We use the multi-market equilibrium model LIBEMOD to find the market potential of different CCS technologies in the Western European electricity markets. LIBEMODs main focus is on the electricity and natural gas markets of Western Europe, but it also covers global markets for coal and oil.

The model distinguishes between model countries – each of 16 Western European countries – and exogenous countries/regions, the latter group containing all countries in the world outside Western Europe.

Producers in LIBEMOD maximize profits and end-users maximize utility, subject to being atomistic agents and subject to a number of agent-specific constraints (The model is solved as a mixed complementarity problem). In each model country there is production, trade and consumption of energy, as well as investment in energy infrastructure. There are seven energy goods - coking coal, steam coal, lignite, natural gas, oil, biomass and electricity – which are all traded in competitive markets. Natural gas and electricity are traded between model countries as well as with a few exogenous countries such as Russia. Coking coal, steam coal and oil are traded in global markets, whereas biomass and lignite are traded in domestic markets only.

Production of energy takes place in all countries. Typically, in a model country, there is extraction of (some) fossil fuels, production of biomass, and production of electricity (see detailed description below). Non-model countries/regions typically extract coking coal, steam coal and oil, and trade these in the global markets.

Natural gas and electricity trade is constrained by networks of gas pipes/electricity lines running between countries. At each point in time the capacities of pipes/lines are given, but private agents extend the capacity if such investments are profitable.

In each model country, energy is transported and distributed to the users at costs that differ according to user group and energy good. There are four groups of energy users: Power producers, households (including services), industry and transport. The first group represents intermediate demand; power plants demand a fuel as an input in production of electricity. This fuel could be steam coal, lignite, natural gas, oil or biomass. The three latter groups of energy users represent end-user demand. Whereas demand from the end-user sector "transport" is restricted to oil, other end-users typically demand several of the seven energy goods.

For end users, demand is derived from a nested CES utility function with five levels. At the top-nest level, there are substitution possibilities between energy-related goods and other forms of consumption. At the second level, consumers face a trade-off between consumption based on the different energy sources. Each of these is a nest describing complementarity between the actual energy source and consumption goods that use this energy source (for example, electricity and light bulbs). Finally, the fourth and fifth levels are specific to electricity in defining the substitution possibilities between summer and winter (season) and between day and night. Thus, except for electricity, energy goods are traded in annual markets. Note that the calibrated parameters of the utility functions differ between end users and countries.

LIBEMOD offers a detailed description of production of electricity. In general, there are a number of technologies available for production of electricity in existing plants or in new plants: steam coal power, lignite power, gas power, oil power, reservoir hydro power, pumped storage power, nuclear, waste power, biomass power and wind power. For steam coal power and gas power, a producer can install carbon capture and storage in an existing plant (retrofitted CCS), or build a new power plant with CCS (greenfield CCS).

There are four types of costs in electricity production: fuel costs, maintenance costs (related to maintained power capacity, see below), start-up costs (related to additional capacity started in a time period, see below) and investment costs. A power producer obtains revenues from using (part of) the maintained power capacity to produce and sell electricity. In addition, the power producer may sell the remaining part of the maintained power capacity to a national system operator who buys reserve power capacity in order to ensure (if necessary) that the national electricity system does not break down. For each type of technology and each country, efficiency typically varies across power plants.

Several of the cost elements are linked to technical constraints faced by power producers. For fossil-fuel based plants, these are:

- A producer chooses the level of (installed) power capacity that is maintained. Maintained power capacity cannot exceed installed power capacity.
- A producer can sell a share of the maintained power capacity to the system operator (see above). Production of electricity per unit of time can not exceed the remaining capacity.

- All power plants need some downtime for technical maintenance. Because this is an annual constraint, the producer may choose in which period(s) technical maintenance will take place.[1]
- Start-up and ramping-up costs are incurred if electricity production varies between periods in the same season. These costs depend on the additional capacity started at the beginning of each period.

For reservoir hydro power, there are two technology-specific constraints. First, total availability of water, that is, the sum of reservoir filling at the end of the previous season plus the seasonal inflow, should not be lower than total use of water, that is, the sum of water used for production in the present season plus reservoir filling at the end of the present season. In addition, reservoir filling at the end of a season cannot exceed the reservoir capacity.

For wind power, supply in a country reflects the pattern of wind, that is, number of hours with wind at different speeds at different sites. We assume that, in each country, the best sites are used first. This means that the marginal cost of producing wind power (per KWh) will be increasing. For a given investment in wind power in a given country, a specific amount of KWh is produced per unit of time. This amount differs between the four time periods that electricity is traded (summer day, summer night, winter day and winter night) because wind conditions change over season and over the day.

Finally, producers of biomass power demand biomass, which is offered from competitive domestic producers. On the national level, marginal cost of biomass is increasing and convex. As mentioned above, due to the public resistance to nuclear power in most Western European countries, we decided to put an exogenous constraint on new investments in nuclear capacity.

All electricity producers maximize profits under the assumption of knowing all market prices (perfect foresight), subject to technical constraints. This gives rules for operations, as well as a decision rule for optimal investment (see Aune et al. (2008)). With respect to investment, there is a unit cost of

[1] For most technologies, necessary maintenance downtime is roughly ten percent. Hence, for sufficiently high electricity prices the operating time for most technologies are 90 percent of the hours over a year. The main exception is wind power with an operating time significantly below 50 percent (according to our data the operating time varies across Western European countries from 19 percent to 42 percent), since wind turbines can only operate when the wind is sufficient and not excessive. Roughly, wind power production is 50 percent higher at night than during the day.

investment (USD/MWh) that differs by technology. The benefit of investment is a higher installed capacity that allows for higher production of electricity. At the margin, cost of investment is equal to the shadow value of installed capacity.

In LIBEMOD we distinguish between old and new power plants. An old plant had pre-existing capacities in our data year 2000. We do not allow for investment in old plants. A new plant is a unit that did not exist in our data year 2000. In other words, only operation decisions are taken for old plants, whereas both investment and operation decisions are taken for new plants. We assume that there is investment in almost all electricity technologies, the exceptions are nuclear (due to political reasons, see Section 4), lignite power (excessive costs under a reasonable CO_2 tax) and waste power (marginal production capacity and lack of reliable data).

LIBEMOD is a static model. In the equilibrium of a future year, exogenous variables are country-specific income levels, capacities in old power plants in the data year, capacities in international electricity (gas) transmission lines (pipes) that existed in the data year, and the CO_2 tax.[2] In addition, there is a large set of calibrated parameters, such as demand elasticities and depreciation rates for all types of capital with pre-existing capacities in the data year. The model determines all energy quantities – investment, production, trade and consumption – and all energy prices (both producer prices and end-user prices) in all domestic, regional and global markets. In addition, the model calculates emissions of carbon by sectors and countries.

LIBEMOD has been calibrated to the data year 2000, imposing that the parameters should reproduce observed demand, costs and efficiency distributions in 2000. For markets that we assume were competitive in 2000, that is, the coal and crude oil markets, calibrated prices will be identical to observed market prices. For other good, for example, natural gas and electricity, observed prices differ from calibrated prices, reflecting the market imperfections in the actual 2000 markets.

For the CES utility functions (one for each type of end-user in each model country), the share and distribution parameters are calibrated to minimize the deviation from exogenous own-price and cross-price demand elasticities. For households, these are in the range of -0.4 to -0.6, whereas for industry the range

[2] Strictly speaking, there is one "dynamic" element in LIBEMOD, namely that start-up cost in a time period depends on the capacity used in the previous period in the same season, see discussion above.

runs from -0.6 to -0.8. For each model country there is a load curve with four segments – one for each time period. According to our data, demand is typically higher in winter than in summer (heating requires more energy than cooling), and higher during the day than at night. For a more detailed description of LIBEMOD, including data sources, see Aune et al. (2008).[3]

4. Simulation results

4.1. Main scenarios

In this section we use LIBEMOD to examine the effects on energy markets in Western Europe of allowing CCS investments, focusing on alternative long-run equilibria in 2030. In all equilibria we assume that the EU goal of establishing competitive energy markets (European Parliament (2003a, 2003b)) has been achieved.[4] In order to identify the impact of CCS investment on the energy industry and emission targets, we first compare three scenarios (see Table 1). In the first scenario we do not allow CCS investment and impose no carbon policy. In the second scenario we keep the assumption of no CCS investment, but introduce a climate policy in the form of a uniform CO_2 tax imposed on all emission sources in all model countries. Following IEA (2008), our main focus is on a $90 tax (this tax, as well as all other values reported below, is measured in 2007 USD)[5]. In the third scenario, we allow investment in CCS under the assumption of a common CO_2 tax at $90. Next, we examine robustness. First, in section 4.2 we examine the impact of alternative values of the CO_2 tax. Then, assuming a CO2 tax at $90, we study in section 4.3 the

[3] The version of LIBEMOD used in the present paper differs somewhat from the one documented in Aune et al. (2008), the main differences being i) electricity is traded in two periods over the 24-hour cycle (six periods in Aune et al. (2008)), ii) more electricity technologies are available (CCS) and iii) we use a more aggregated representation of coal markets.

[4] The energy industry in Western Europe is still characterized by a number of market imperfections. A liberalization will typically benefit low-cost power technologies, which, according to Aune et al. (2008), will be coal power. For a more detailed discussion of the impact of liberalizing the Western European energy markets, see Aune et. al. (2008).

[5] According to IEA (2008), a tax of $90 per ton CO2 in 2030 will be sufficient to stabilize global GHG concentrations in the atmosphere at 550 ppm. This is by many, among others the IEA (2008), regarded as the most likely scenario.

impact of changing some of our basic assumptions. The main cases in section 4.3 are referred to as scenarios 4-7.

Table 2 Scenarios

Scenario 1	*No CCS investment, no CO_2 tax*
Scenario 2	*No CCS investment, \$90 CO_2 tax*
Scenario 3	*CCS investment, \$90 CO_2 tax (Reference scenario)*
Scenario 4	*CCS investment, \$90 CO_2 tax, increased nuclear capacity*
Scenario 5	*CCS investment, \$90 CO_2 tax, lower CCS costs*
Scenario 6	*CCS investment, \$90 CO_2 tax, higher thermal efficiency*
Scenario 7	*CCS investment, \$90 CO_2 tax, lower wind power costs*

Impact on supply of electricity

Table 3 shows the equilibrium composition of electricity technologies in 2030. With no CCS investment and no carbon tax (scenario 1), conventional coal power, that is, old and new steam coal power without CCS and lignite power without CCS, captures 66 percent of the market. Conventional gas, that is, old and new gas power stations without CCS, has a small market share (4 percent), whereas conventional oil power has been phased out (due to the change in market structure, see discussion above), reflecting the high cost of this technology. Nuclear, where we do not allow investment, has a market share of 16 percent (from plants already in existence in 2000), whereas the market share of hydro (reservoir hydro and pumped hydro power) and renewable (wind, bio and waste power) is 9 and 5 percent, respectively.

Moving from scenario 1 to 2, that is, keeping the assumption of no CCS investment opportunities but introducing a \$90 CO_2 tax, we find that the resulting tax-caused cost increase reduces the equilibrium total electricity supply in 2030 by 25% (from 5258 TWh to 3942 TWh see Table 3). The market share of conventional (non-CCS) fossil fuel based electricity production decreases from 70 percent to 35 percent, reflecting a much lower market share of conventional coal power (decreased from 66 to 13 percent), partly counteracted by an increased share of conventional gas power (increased from 4 to 22 percent). The relative shift from coal to gas reflects that the CO_2 emission coefficient is lower for gas than for coal. As expected, renewables is the big winner of a CO_2 tax – its market share increases from 5 to 31 percent. Note that the increase in investment in renewables (ten times relative to scenario 1) is much larger than the increase in production (five times relative to scenario 1), reflecting that wind power only operates when the wind is sufficient. The market share of the (unchanged) nuclear power production also increases (by six percentage points), reflecting the decrease in total electricity supply.. The increase in the market share of hydro (by three percentage points) also mainly reflects lower total production of electricity: production of old reservoir hydro – the dominating hydro technology – fully reflects total inflow of water, which does not change between our scenarios. Moreover, costs of reservoir hydro investment are high, so production from new hydro is tiny.

We now turn to scenario 3 (the reference scenario), that is, we allow for CCS investments and keep the assumption of a \$90 CO_2 tax imposed on all emission sources in all model countries. Compared with the case of no CCS investment and a \$90 CO_2 tax (scenario 2), conventional fossil fuel based power production decreases its market share from 35 percent to 4 percent because coal power production is completely phased out. Retrofitted CCS is unprofitable (zero market share), whereas greenfield CCS is profitable; greenfield CCS coal obtains a market share of 44 percent, whereas the market share of greenfield CCS gas is 8 percent, that is, the market share of CCS is as high as 52 percent.

Table 3 Supply of electricity (TWh) and market share (percent) by technologies. 2030

	Scenario 1 *No CCS* *No CO_2 tax*		*Scenario 2* *No CCS* *\$90 CO_2 tax*		*Scenario 3* *CCS* *\$90 CO_2 tax*	
	Production	Market share	Production	Market share	Production	Market share
Conventional gas	228	4	874	22	170	4
Conventional coal	3478	66	511	13	0	0
Conventional oil	0	0	33	1	0	0
Greenfield CCS gas	0	0	0	0	373	8
Greenfield CCS coal	0	0	0	0	2047	44
Hydro	460	9	485	12	473	10
Renewable	262	5	1203	31	705	15
Nuclear	836	16	836	21	836	18
Total supply	5263		3942		4606	

The large market share of greenfield CCS coal reflects the low cost of coal-fire power (before taking into account the CO_2 tax) as well as the large fraction of CO_2 emissions that is removed by CCS (90 percent per ton fuel). For CCS gas, the punishment from the tax is smaller because gas has a lower CO_2 emission coefficient than coal, but this is not enough to outweigh the high costs of gas power relative to coal power.[6]

Allowing CCS investment (for a given CO2 tax) in effect shifts the aggregate marginal cost curve of electricity production downwards. Such a shift increases total production of electricity, see Table 3, and hence the producer price of electricity decreases. With lower producer price of electricity, but

[6] Above, the change from scenario 1 to scenario 3 goes through scenario 2. Alternatively, the change could go through scenario 2*, defined as the case of allowing CCS investments but not imposing a CO_2 tax. Note that the change from scenario 1 to scenario 2* will not have any effect: Existing plants will not invest in CCS (retrofitted CCS) and no new plants with integrated CCS facilities (greenfield CCS) will be put up: Costs with CCS are higher, and there would be no benefits to a private electricity producer from CCS without a carbon tax being imposed.

unchanged costs of renewable production, the market share of renewable decreases. In fact, the drop is as high as 16 percentage points.

Impact on prices, emissions and welfare

The change from scenario 1 to 2, that is, the partial effect of imposing a \$90 CO_2 tax (when there are no investment opportunities in CCS) shifts the marginal cost schedule of electricity supply upwards. Therefore, total supply of electricity decreases and the consumer price of electricity, which is equal to the producer price of electricity, increases: as seen from Table 4, the producer price increases from 53 USD/MWh to 112 USD/MWh, that is, more than doubles.[7] Note, however, that total profits of electricity producers decline because of the CO_2 tax on emissions.

Lower supply of electricity in itself decreases emissions of CO_2, an effect which is strengthened by a relative shift towards less-emitting electricity technologies.. In order to set the emission levels in perspective they are compared with the Kyoto target for the model countries.[8] Whereas in scenario 1 emission are almost 100 percent above the Kyoto target for the model counties (see Table 4), in scenario 2 emissions are "only" 20 percent above the Kyoto target.

[7] We find that electricity prices do not vary that much between the four time periods, even though we have included start-up and ramp-up costs, see the discussion in Section 3. In Aune et al. (2008) we have 12 time periods, but we still do not obtain electricity prices that differ much over the year. It may be necessary with a much more refined time structure in order to obtain substantial price volatility. We therefore expect that our results underestimate the potential for some technologies to be operational mainly in peak periods.

[8] For details on how the Kyoto target is transformed to a CO_2 target for the model countries, see Aune et al. (2008).

Table 4. Average producer price of electricity (USD/MWh), CO_2 emissions (percent relative to the Kyoto emission level) and change in annual total welfare relative to scenario 1 (MUSD). 2030

	Scenario 1 *No CCS* *no CO_2 tax*	*Scenario 2* *No CCS* *\$90 CO_2 tax*	*Scenario 3* *CCS* *\$90 CO_2 tax*
Producer price	53	112	80
CO_2 emissions		20	5
Total welfare	96	88	150

The introduction of CCS (when the CO_2 tax is $90), that is, the change from scenario 2 to 3, shifts the marginal cost schedule of electricity supply downwards because more electricity technologies have become available. The shift in the supply of electricity leads to a higher production of electricity, and hence a lower producer price of electricity – the producer price decreases from 112 to 80 USD/MWh, that is, by almost 30 percent. Whereas increased total production of electricity suggests that emissions have increased, the change in the composition of electricity technologies – conventional fossil fuel based electricity production is almost fully replaced by CCS (see Table 3) – has the opposite effect. It turns out that the latter effect dominates. In fact, emissions in scenario 2 are 20 percent above the Kyoto target whereas in scenario 3 they are only 5 percent above. The decline in emissions is mainly found in the electricity sector: moving from scenario 1 to scenario 3 lowers emissions in this sector by more than 90 per cent.

The significant shifts in the composition of electricity technologies, particularly the phasing out of conventional coal, the phasing in of CCS plants, and also the huge impact on renewable electricity production, lead to significant changes in investments. As seen from Table 5, in scenario 3 investment in greenfield coal with CCS amounts to about 50 per cent of total investment, whereas the corresponding number for greenfield gas with CCS is 10 percent.

Table 5. Investment by electricity technology in 2030 (GW)

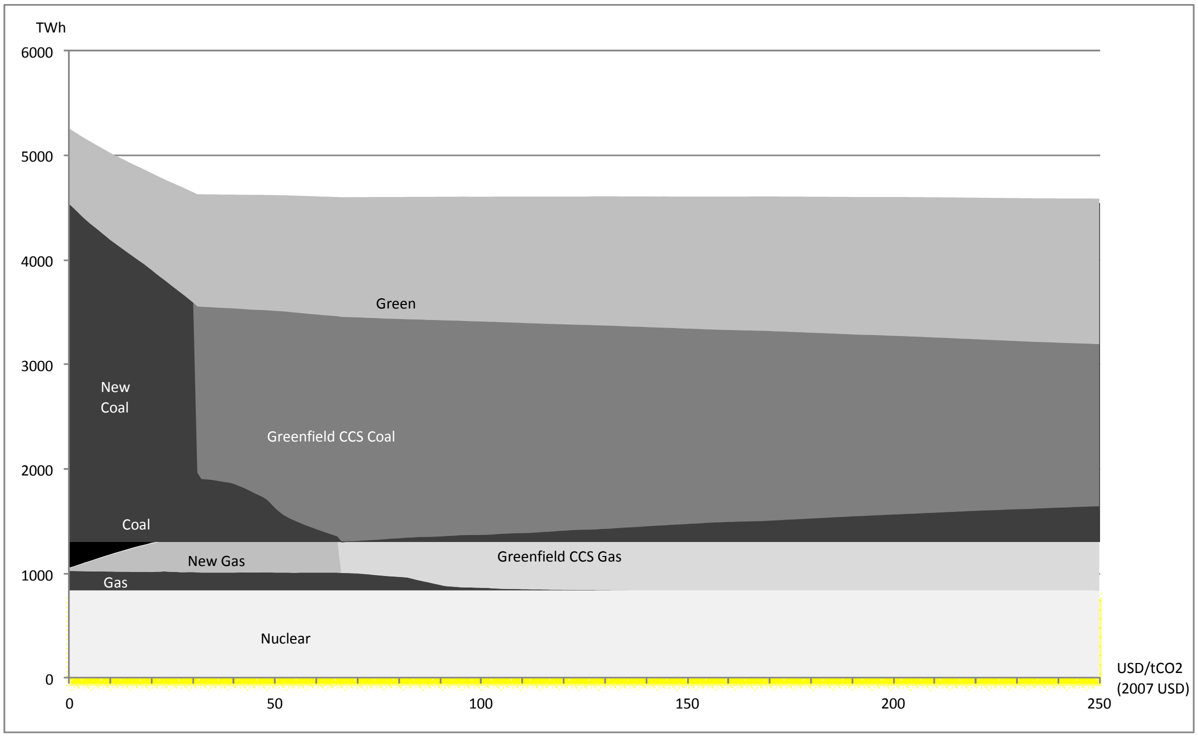
	Scenario 1 No CCS no CO_2 tax	Scenario 2 No CCS \$90 CO_2 tax	Scenario 3 CCS \$90 CO_2 tax
Conventional gas	3	77	0
Conventional coal	374	2	0
Conventional oil	0	0	0
Greenfield gas	0	0	47
Greenfield coal	0	0	260
Hydro	9	17	13
Renewable	34	335	167
Nuclear	0	0	0
Sum	421	430	488

Changes in quantities and prices lead to changes in welfare. In LIBEMOD, traditional welfare is the sum of consumer surplus, producer surplus and tax income of the governments. However, one should also take into account that CO_2 emissions differ between the scenarios. Here we value emissions "negatively" at the CO_2 tax rate (\$90 ton/ CO_2), i.e., each extra ton of CO_2 emitted lowers welfare by \$90. Comparing the scenario 3 (CCS, CO_2 tax) with scenario 1 (no CCS, no CO_2 tax), we find that annual traditional welfare has decreased by 150 million USD in scenario 3, whereas the annual value of lower CO_2 emissions in scenario 3 (relative to scenario 1) is 300 million USD. Hence, the change from scenario 1 to scenario 3 increases annual total welfare - traditional welfare corrected by the value of lower CO_2 emissions - by 150 million USD, see Table 4. Similarly, the change from scenario 2 to scenario 3, that is, the impact of allowing CCS investment (under a \$90 CO_2 tax rate) increases annual traditional welfare by 13 million USD, whereas the annual value of lower CO_2 emissions (in scenario 3) is 50 million USD. Hence, the change in annual total welfare is 62 million USD.

4.2 CO2 tax rates

In scenario 3, the CO_2 tax is \$90. We now examine the impacts of different CO_2 taxes. Figure 1 shows production of electricity (TWh) in 2030 by group of technologies for CO_2 tax rates between 0 and \$250 when CCS technologies are available. For nuclear, production is independent of the tax rate (see discussion above), whereas for the group referred to as green technologies (hydro, wind, bio, waste) production is increasing in the tax rate. A closer look reveals that it is mainly wind power that is increasing in the tax rate, but there is also increased production from new bio power.

Figure 1. Production by group of technologies (TWh) relative to the CO_2 tax ($/tCO_2$). 2030



For old steam coal (lignite) plants (included in "coal" in Figure 1), production in 2030 is roughly independent of the tax rate up to around $30 ($45), and from there continuously decreasing until it reaches zero production around $85 ($70). For new steam coal power ("new coal" in Figure 1), production is first decreasing in the tax rate, but around $30 there is a significant jump to zero production because the entire production is taken over by greenfield CCS coal.

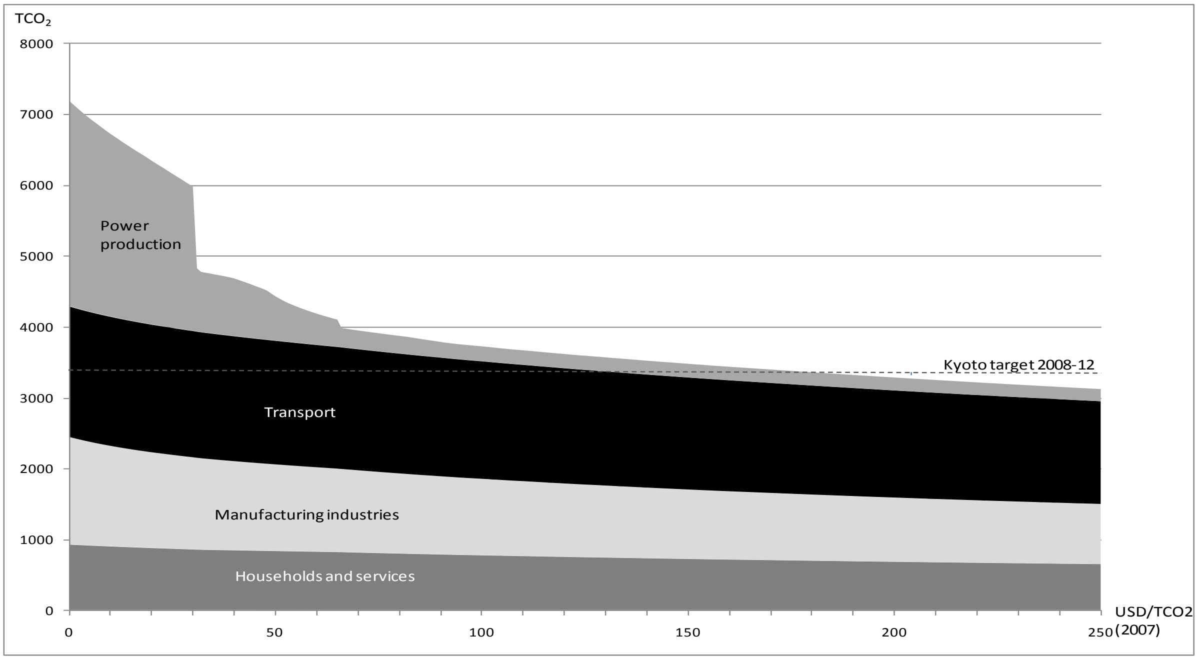
For old gas-power plants ("gas" in Figure 1), production in 2030 is first slightly decreasing up to around $65, and then decreasing at a much higher rate until it reaches zero production around $140. Production in new gas power stations ("new gas" in Figure 1) is increasing in the tax rate up to $30 and then slightly decreasing. Around $65 the entire production of new gas power is taken over by greenfield CCS gas, which is always increasing in the tax rate. Finally, for tax rates exceeding $178 there is a tiny production of retrofitted CCS gas (0-4 TWh), whereas there is never any production of retrofitted CCS coal.

The technology switching points in Figure 1, where new coal power is replaced by CCS greenfield coal and new gas power is replaced by CCS greenfield gas, reflect carbon taxes relative to abatement costs. A sufficiently high carbon tax makes investment in conventional fossil fuel based electricity production unprofitable, whereas investment in greenfield CCS is profitable provided the costs of CCS technology are not too high. In such a case, agents will invest in CCS greenfield plants until profit is driven down to zero. To identify this equilibrium level, taking into account factors like competing abatement alternatives and effects of changed fuel demands on prices, requires a model like LIBEMOD.

For tax rates exceeding \$85, production in old coal stations is not profitable (see discussion above). One may therefore expect that old coal plants are retrofitted under high tax rates. This is wrong: costs of retrofitting CCS are so high that investment in this technology is unprofitable. Hence, under high carbon taxes owners of old coal power plants prefer to close their stations.

Figure 2 shows the relationship between emissions of CO_2 in 2030 and the CO_2 tax. For tax rates up to around \$40, the relationship is steeply declining and it has two vertical line segments; one around \$30 (where new coal power without CCS is replaced by greenfield CCS coal) and another around \$65 (where new gas power without CCS is replaced by greenfield CCS gas). A tax at \$40 gives emissions roughly 1/3 above the Kyoto target for the model countries. Increasing the tax further leads to higher production of greenfield CCS gas, lower production of greenfield CCS coal, and lower emissions. As seen from Figure 2, in order to reach an emission level corresponding to the Kyoto target the tax has to be as high as \$180. Note that we have not introduced new abatement technologies like biofuels or CCS for any of the end-user groups (Only for power generation). Such investment opportunities may have a significant effect on total emissions.

Figure 2. CO_2 emissions (Mt CO_2) relative to the CO_2 tax (\$/t CO_2). 2030



4.3 Robustness

We now examine how our main results depend on some of our key assumptions, that is, i) no nuclear investments, ii) costs and efficiency of thermal power stations, both with and without CCS, and iii) costs of wind power. In the discussion below, we allow investment in CCS and the CO_2 tax is assumed to be $90, like in scenario 3.

Above we assumed there was no expansion of the nuclear production capacity, reflecting the political resistance to nuclear in most of the model countries – nuclear accidents may be devastating to humans. On the other hand, some regard increased nuclear production as a tempting alternative to a costly carbon policy. Therefore, we now examine the impact of investments in nuclear.

Costs of nuclear are uncertain, varying significantly between both open sources and between different industry experts. We use IEA (1998) as the source for nuclear data, which is also our main source for data on other non-CCS electricity technologies. Opening for a “laissez-faire” investment in nuclear gives nuclear a market share of around 50 percent when there is no carbon tax, and a market share of almost 90 percent under a \$90 CO_2 tax. Such market shares seem very unrealistic, and in the following we therefore assume that there is a limit on nuclear investment, but a less stringent one than the one included in the main scenarios: new nuclear capacity (in each model country) can amount to as much as 50 percent of the pre-existing capacity.

Table 6 Supply of electricity (TWh) and market share (percent) by technologies. CCS and \$90 CO_2 tax in all scenarios. 2030

	Scenario 3		*Scenario 4 Increased nuclear capacity*		*Scenario 5 Lower CCS costs*	
	Production	Market share	Production	Market share	Production	Market share
Conventional gas	170	4	46	1	0	0
Conventional coal	0	0	0	0	0	0
Conventional oil	0	0	0	0	0	0
Greenfield CCS gas	373	8	457	10	460	9
Greenfield CCS coal	2047	44	1669	36	2835	56
Hydro	473	10	473	10	466	9
Renewable	705	15	683	15	468	9
Nuclear	836	18	1311	28	836	17
Total supply	4606		4638		5064	

Table 6 shows the outcome of this relaxed rule under a \$90 CO_2 tax. Although nuclear production increases by slightly more than 50 percent, reflecting higher nuclear capacity and somewhat lower downtime for new nuclear than for old nuclear, total production of electricity is almost unchanged – it increases by less than 1 percent. Increased nuclear production mainly replaces CCS greenfield coal – the market share of the latter decreases by eight percentage points to 36 percent. Green electricity production is almost unchanged; costs of green production have not changed, whereas the price of electricity has only changed marginally. Because investments in nuclear mainly replaces CCS greenfield coal, emissions of CO_2 decrease but not by very much:

they are reduced from 5 percent above the Kyoto target to 3 percent above the Kyoto target.

Next, we consider the case of lower costs of retrofitted and greenfield CCS technologies; costs of investment, operation and maintenance are all reduced by one third for all CCS technologies, that is, only fuel costs are not reduced. Lower CCS costs increase total production of electricity by almost ten percent. The market share of greenfield CCS coal increases by 12 percentage points (relative to scenario 3) to 56 percent, whereas greenfield CCS gas increases its market share from eight to nine percent, see Table 6. On the other hand, it is still optimal with no retrofitted CCS production.

A higher total production of electricity lowers the price of electricity in the market, making both operation of old conventional gas power stations and investment in new conventional gas power stations unprofitable (There is no conventional coal power production even before CCS costs are reduced, see discussion above). Further, a lower price of electricity reduces investment in green technologies; the market share of renewable, for example, drops by six percentage points, mainly reflecting less investment in wind power. With respect to CO_2 emissions, there are different effects. On the one hand, emissions decrease because conventional gas power is phased out, but on the other hand increased greenfield CCS coal, which partly replaces wind power production, tends to increase emissions. It turns out that the net effect is a change in emissions by less than one percent.[9]

An alternative assumption is that *only retrofitted* CCS becomes cheaper.[10] If costs of investment, operation and maintenance of retrofitted CCS are reduced by one third, it is still not optimal to retrofit existing gas-power plants with CCS, whereas there is a tiny production in retrofitted CCS coal-power plants (market share of 0.3 percent). In fact, production of retrofitted CCS gas requires a cost reduction (or government support) of the three cost

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[9] Because of the great uncertainty related to CCS technologies, it is also interesting to examine the impact of higher CCS costs. If costs of investment, operation and maintenance are increased by 50 percent for all CCS technologies, the market share of greenfield CCS coal (gas) drops from 44 (8) percent in scenario 3 to 24 (0) percent.

[10] Because of depreciation a substantial share of the plants existing in the data year 2030 have been removed in the 2030 equilibrium. In LIBEMOD we assume that the plants with the lowest efficiency are the oldest. This means that “removing the oldest plants” is equivalent to “removing the most inefficient plants.” Hence, in 2030 the (old) plants that may still operate are few, but these have the best efficiencies amongst the plants existing in 2000. Even for these (efficient) plants we find in scenario 3 (the reference scenario) that it is not profitable to invest in CCS retrofit.

components of at least 40 percent, whereas retrofitted CCS coal becomes profitable if costs are reduced by at least 20 percent.

Note that retrofitted CCS may never become a dominant technology in the 2030 equilibrium. In the corner case of no costs of investment, operation and maintenance for retrofitted CCS (the government cover these costs), this technology has a share of total investment of around eight percent reflecting (i) depreciation of old capacity, that is, the small capacity in 2030 of plants existing in 2000, and (ii) that around 1/3 of the electricity produced in CCS plants is used to operate the carbon capture facilities, see discussion in Section 2. Finally, if *only greenfield* CCS becomes cheaper – costs of investment, operation and maintenance are reduced by one third – the market share of greenfield CCS increases by 13 percentage points (relative to scenario 3) to 65 percent.

Table 7 Supply of electricity (TWh) and market share (percent) by technologies. CCS and \$90 CO_2 tax in all scenarios. 2030

	Scenario 3		*Scenario 6* *Higher thermal efficiency*		*Scenario 7* *Lower wind power costs*	
	Producti on	Market share	Producti on	Market share	Producti on	Market share
Conventional gas	170	4	111	2	171	4
Conventional coal	0	0	0	0	0	0
Conventional oil	0	0	0	0	0	0
Greenfield CCS gas	373	8	431	9	361	8
Greenfield CCS coal	2047	44	2062	45	1635	35
Hydro	473	10	473	10	473	10
Renewable	705	15	703	15	1168	25
Nuclear	836	18	836	18	836	18
Total supply	4606		4615		4643	

Table 7 examines the case of five percent higher thermal efficiency in all new fossil-fuel plants (both with and without CCS) and in new biomass-power plants. Notice first that the impact on total production of electricity – after all general equilibrium effects are taken into account - is marginal. With higher thermal efficiency, new fossil fuel plants and biomass fuel plants can, cet. par., sustain their production of electricity through less use of fuels. If so, demand for fuels decreases, and hence fuel prices tend to decrease, thereby giving an incentive to use more fuels and thus to produce more electricity.

Compared with Scenario 3, production of greenfield CCS gas increases by as much as 15 per cent (58 TWh) because the price of gas drops significantly, reflecting that the supply curve of natural gas is almost vertical at the initial equilibrium. The drop in the price of coal is much lower, reflecting that the supply curve of coal is rather flat. According to LIBEMOD, production of greenfield CCS coal increases by only one percent (15 TWh) when all general equilibrium effects are taken into account. As noted above, there is a tiny increase in *total* production of electricity – production increases by less than one percent. Therefore, the price of electricity falls marginally and hence production of green electricity decreases, but not by very much.

Finally, we have examined the impact of lower costs of capital, operating and maintenance for new wind power by one third. This increases total production of electricity by only one percent, mainly reflecting that around 20 percent of greenfield CCS coal production is replaced by new wind power. Hence, total emissions of CO_2 is reduced, but not by more than one percent.

5. Discussion and conclusion

CCS is likely to become an important carbon abatement option for Europe. With a \$90 CO_2 tax, our results indicate that greenfield CCS coal power plants become profitable, totally replacing non-CCS coal power investments and partly replacing new wind and bio power. Yet, with CCS and a \$90 CO_2 tax, production of wind and bio power is much higher than in the base year 2000. Greenfield CCS gas power also becomes profitable, but does not replace non-CCS gas power plants fully. Substantially lower CCS costs, for example, through subsidies, would be necessary to make retrofitted CCS profitable. If the CO_2 tax in 2030 is much lower than \$90, for example, if a tax at \$15 is imposed, which roughly corresponds to the recent quota prices in EUs Emission Trading System, then there will – according to the present paper - be no CCS greenfield investments.

Interestingly, we also find that the tax level ”trigger points” that cause investors to move to CCS for gas and coal (and which are influenced by input price responses and general equilibrium effects) are quite close to the “engineering” estimates frequently used in policy discussions. This suggests that at least in this specific case, using these rough figures provides reasonable guidance for policy discussions.

The partial effect of introducing CCS investment is to shift the aggregate marginal cost curve of electricity production downwards. Such a shift increases total production of electricity, whereas the producer price of electricity decreases, and hence the market share of renewable electricity decreases. In fact, in scenario 3 the share of renewables in the electricity mix is below 20 percent, which may indicate that the 20 percent renewable target of the EU may be non-optimal from a welfare point of view.

Some readers may find the result of no CCS retrofit investment surprising. As pointed out above, it reflects huge costs of installing and operating CCS in existing plants, for example, the large drop in net-power output due to own use of electricity. Although the maximum possible production in CCS retrofitted plants is moderate because a substantial share of the initial 2000 capacity has been depreciated, in LIBEMOD we assume that depreciation removes the less efficient units. Hence, in 2030 we are left with the most efficient plants that were in operation in 2000, and even with these efficient units we do not obtain any CCS retrofit investment.

To some extent our result of no CCS retrofit investment may reflect that we jump directly from the 2000 calibration to the 2030 long-run equilibrium. An alternative assumption would have been to study the equilibrium in a year (or several years) between 2000 and 2030. Assume that in the future, say 2020, new fossil fuel plants may be built so-called capture ready, and thus their incremental CCS costs may be much lower than assumed in the present study. If we then examine the equilibrium both in 2020 and 2030, capture-ready fossil fuel plants may be built in the 2020 equilibrium if investors are uncertain about future carbon taxes. If the 2030 carbon tax turns out to be “high”, the 2020 fossil fuel vintage plants may be augmented with CCS facilities in the 2030 equilibrium.

We find it too speculative to include such a technology option in the analysis. In any case, politicians should not be tempted to subsidize retrofit installations, as such installations likely would replace more efficient greenfield installations. Politicians should rather stick to high carbon prices, and let the market sort out the correct technology diffusion pattern. A similar conclusion is drawn by Aune et al. (2010), who find that subsidies to retrofitted CCS “crowd out” investments in greenfield CCS and have minor effects on electricity production and CO_2 emissions.

At present, there is research and development on several carbon capture technologies and governments may have a hard time deciding which projects to support with R&D funds. Our results suggest that capture technologies that are intended as end-of-pipe technologies have a small market potential unless such solutions become much cheaper than suggested by the current cost estimates. According to our study, governments should rather go for integrated solutions when allocating their development and demonstration subsidies.

Above we have assumed that CCS technologies will be feasible for electricity production by 2030 and that private investors know that the CO_2 price will be \$90 in 2030. Although the Kyoto protocol was negotiated in 1997, and capture and storage technologies have been in use for several decades at smaller facilities like ammonia plants, our modelling assumptions may overestimate the speed of market penetration of CCS technologies. Yet, we believe in the logic of our model, and hence we think there is a substantial potential for greenfield CCS if governments can commit today to punish carbon emissions sufficiently in the future.

We have also assumed that CCS technologies are available at cost based prices. If suppliers of CCS technologies have market power, they may charge a mark-up which would show up as higher CCS investment costs. Higher CCS investment costs affect the point at which these technologies enter the market, and also their equilibrium market penetration. As one of our robustness tests showed: if costs of investment, operation and maintenance are increased by 50 percent for all CCS technologies, the market share of greenfield CCS coal (gas) drops from 44 (8) percent to 24 (0) percent in Scenario 3.

Our data suggest that costs of transport and storage are low relative to capture costs. Yet, uncertainty about the availability of transport and storage services could be a barrier for investment in capture facilities at the plant site. Transport of captured CO_2 is a natural monopoly, and hence there is a role for coordination. For example, the EU could commit to transport and store removed CO_2 at a price equal to the estimated average transport and storage cost.

LIBEMOD is a static model. It is well known that within a static framework, the impact of imposing a carbon tax is equivalent to that of imposing quotas auctioned by the government: if the government sets the number of quotas so that it equals total emissions under the carbon tax, the competitive price of quotas will equal the carbon tax. However, in a dynamic framework the impact of a carbon tax and a cap-and-trade system may differ. With a constant carbon tax over time, emissions will typically change over time: as more environmentally friendly technologies are phased in, emissions decline. In contrast, under a cap-and-trade system where the number of auctioned quotas is constant over time, the price of quotas will decline as more environmentally friendly technologies are phased in. This difference suggests that there will be more R&D in environmentally friendly technologies under the constant tax regime than under the constant emission regime. The impact of a carbon tax versus tradable quotas within a dynamic version of LIBEMOD may therefore be a challenging topic for future research.

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Appendix: Estimated costs of Carbon Capture and Storage (CCS)

In this Appendix we explain the derivation of the costs and efficiency figures in Table 1. Our starting point is the set of tabulated studies in the IPCC report (Metz et al, 2005). These studies report total costs both with and without capture technology. Total costs are based on the reported levelized cost of electricity (COE), which is defined as the “constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors” (Deutch et al. 2007).

From these total costs, we then subtract the reported fuel and capital costs (which differed between the reported studies), leaving a residual that we split between fixed and variable operating & maintenance (O&M) costs. For O&M costs not related to capture of carbon, the split follows the corresponding one in the LIBEMOD data, which is close to a 50-50 split. For O&M costs related to capture of carbon, we impose a 50-50 split.

Having decomposed the cost numbers reported in the IPCC report, we “rebuilt” the costs using the same base year (2000), the same fuel price (coal and gas prices from 2000), and the same capital charge rate (13 percent) for each reported study. In this way, the studies were “normalized,” allowing us to compare the cost components across studies, and by considering the distribution of estimates we selected typical (median) values.

Table A1 Capture costs.

		Coal IGCC green-field	Coal PC green-field	Gas green-field	Coal retrofit	Gas retrofit
Plants without CCS	**Investment cost**	26.6	26.6	14.2	0.0	0.0
	Operating and maintenance cost	10.7	10.7	4.9	13.7	7.3
	- Variable O&M	5.5	5.5	2.6	7.1	3.9
	- Fixed O&M	5.2	5.2	2.3	6.6	3.5
	Fuel cost	12.0	12.0	25.6	12.0	25.6
	COE*	49.4	49.4	44.8	25.8	33.0
CCS technical effects	**Reduction of net power output**	10 %	20 %	15 %	40 %	30 %
	Reduction of CO2 emissions per MWH	88.9 0 %	87.5 0 %	88.2 0 %	83.3 0 %	85.7 0 %
Incremental cost change due to CCS	**Investment cost**	9.6	18.1	9.6	20.5	10.9
	Operating and maintenance cost	6.6	7.8	4.8	19.3	11.9
	- Variable O&M	1.8	4.2	2.4	10.2	5.9
	- Fixed O&M	4.8	3.6	2.4	9.0	6.0
	Fuel cost	2.0	3.6	4.2	8.4	9.8
	Incremental COE* increase due to CCS	18.3	29.5	18.7	48.2	32.6
Plants with CCS	**Investment cost**	36.2	44.7	23.8	20.5	11.0
	Operating and maintenance cost	17.3	18.5	9.8	33.0	19.3
	- Variable O&M	7.3	9.8	5.1	17.3	9.8
	- Fixed O&M	10.0	8.8	4.7	15.7	9.5
	Fuel cost	14.1	15.7	29.9	20.5	35.5
	COE*	67.7	78.9	63.5	73.9	65.6
	Abatement cost ($/TCO2 avoided)	27.4	44.4	58.8	60.9	105. 8
	Abatement cost ($/TCO2 avoided – including transport/storage)	35.6	53.6	67.4	73.9	116. 6

* COE – average cost of energy

** All values are measured as $/MWH (2007 USD) unless otherwise noted

The above methodology was used for retrofitted CCS coal (i.e., modifying an existing coal power plant with CCS technology so as to capture CO_2) and greenfield CCS (i.e., new coal power or new gas power plants with CCS). In our study, greenfield CCS coal plants are assumed to be of the integrated gasification combined cycle (IGCC) type. As seen in Table A1, this (pre-combustion) technology strictly dominates greenfield CSS with pulverized coal (PC). Like the IPCC study, we assume that greenfield CCS gas power plants use post-combustion technologies.

The methodology of identifying retrofitted gas power costs differed from the other CCS cases. Whereas estimates for retrofitted CCS with PC were available, we were unable to find studies with estimates for retrofitted CCS gas power. We have therefore assumed that costs of retrofitted CCS gas differ from costs of greenfield CCS gas with the same relative magnitude as the difference between retrofitted CCS with PC and greenfield CCS with PC. Note that all of these four cases involve post-combustion technologies, making the comparison relevant.

Needless to say, the estimates of our "rebuilt" parameters are clearly uncertain. For CCS coal we were able to compare our cost parameters with cost parameters from five recent studies collected and made comparable in a 2007 MIT report (Deutch et al. 2007). We made these studies comparable to our cost figures by converting numbers to $/MWH, using 2000 as the base year, and imposing our capital charge rate (13 percent rather than 15.1 percent).

The results are depicted in Figures A1 and A2 where, for each cost category, the first four bars refer to studies reported in the MIT study and the last bar is the cost assumption used in the present study. Figure A1 shows costs for PC plants, whereas Figure A2 shows costs for IGCC plants. In both figures the bars to the left (right) show power plants without (with) CCS. As seen from the figures, the cost assumptions in the MIT study are in line with the assumptions used in the present study – with somewhat higher costs for IGCC in our study. In addition, by comparing Figure A1 and Figure A2 we see that also for the normalized estimates in the MIT study IGCC dominates PC when CCS is added. This supports our assumption that new coal power plants with CCS will not use powdered coal, but rather the IGCC option.

Figure A1 LIBEMOD PC estimates compared with estimates in the MIT report (First four clusters of columns are without CCS, last four with CCS)

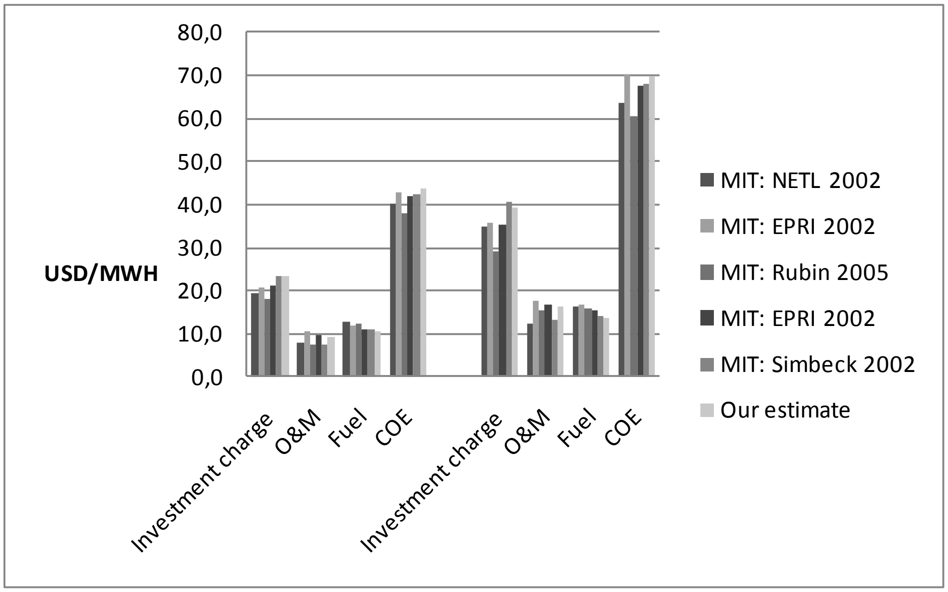
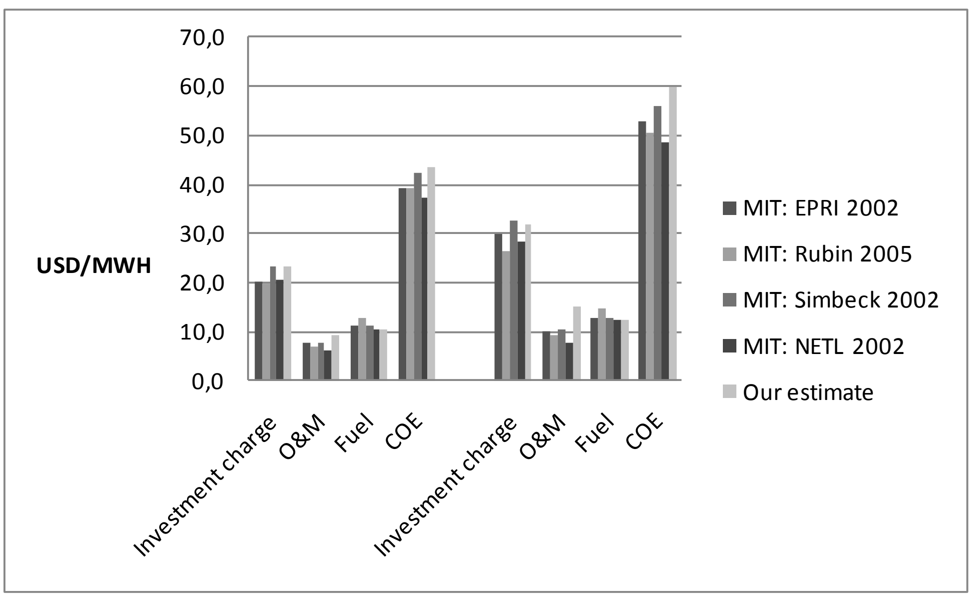


Figure A2 LIBEMOD IGCC cost estimates compared with esti-mates in the MIT report (First four groups of columns are without CCS, last four with CCS)



The second stage of the CCS process concerns transport of gas from the capture site to the storage site. The two main transport options are pipeline and ship. The cost advantage of pipeline relative to ship increases with the volume of gas and decreases with the transport distance. For pipelines there is also the question of interdependence: Considered in isolation, a pipeline from a single power plant may be economically unprofitable. If, however, we consider what the IPCC study calls a "backbone" transport structure, then pipelines may form an infrastructure where powerful economies of scale are combined with the need for coordination of decisions. Because cost estimates depend on a number of complex factors like terrain, barriers, existing pipeline structures, plans for future networks, and the location of storage sites, we have to simplify.

First, we assume – as does the IPCC report - an average transport distance of 300 km from the point of emission to the carbon storage sites, see Bradshaw and Dance (2005). It should be noted that Bradshaw and Dance are careful to not oversell the estimate of 300 km – their judgment is that 57 percent of European large single-point emission sources are within a 300 km regional buffer of potential storage sites, making 300 km close to the median. Second, using an IPCC estimate of the unit transport cost (estimate based on transporting six Mt per year), we arrive at an estimate of $3 per ton CO_2 transported. Because the major cost of CCS is within capture, the uncertainty of this estimate is not critical.

Storage costs are assumed to vary widely between sites – depending on specific site characteristics. As reported by the IPCC report (Metz et al, 2005), the onshore storage costs for saline formations in Europe have been estimated at 2.2-7.1 $/tCO_2$, with a most likely value of $3.2, which we take as our cost parameter for storage in the LIBEMOD model.[11] Hence, also storage costs are small relative to capture costs, making the uncertainty of storage costs of less importance.

The above estimates do not include monitoring costs, which will depend strongly on regulatory requirements and the duration of monitoring. The IPCC report also provides estimates of monitoring costs, and these are relative low compared with the other CCS cost elements – around 0.05 $/tCO_2$ in one study reported in the IPCC report and 0.07-0.09 in another reported study.

Our transport and storage cost of around $6 per ton CO_2 is low compared with IEA/OECD (2008) and McKinsey (2008), but quite close to the

[11] Another study noted in the IPCC report estimates that 90 percent of European storage facilities have a cost less than 2 US$/$tCO_2$. Experts seem to agree that there is plenty of storage capacity in Europe, see for example, Bradshaw and Dance (2005), but there is disagreement on the risk of leakages, see Ehlig-Economides and Economides (2010) .

MIT study. IEA/OECD (2008) reports \$20/ton CO_2 in 2010, dropping to \$15 in 2030. McKinsey (2008) reports \$12 to \$26 per ton CO_2. The latter study expects transport distances to increase over time and offshore storage to come in use, thereby raising costs to a range of \$17 to \$32 per ton CO_2. The MIT study assumes a transport cost for each ton transported 100 km at \$3.5, which is assumed to fall rapidly (with mass flow rate) towards \$0.50. Their assumed injection/storage cost is \$0.5 to \$8 per ton CO_2. With our assumed average European transport distance of 300 km, and a transport cost of roughly \$1 per 100 km per ton, this gives a range of \$3.5 to \$11 per ton CO_2 (comparable with our \$6 per ton CO_2).

We also compared the more aggregated cost measure "cost per ton CO_2 avoided" with the estimates from the IEA/OECD, McKinsey and MIT studies, see Figure A3. In Figure A3 the years written in quotation marks refer to the "scenario years" considered. For instance, IEA/OECD "2010" is the estimate in IEA/OECD (2008) for the year 2010. Several of these studies present ranges – which we represent with a light shading of the "min to max" range. Note also that these are engineering numbers – they are derived entirely from the cost parameters of a plant, and therefore differ from the economic concept of costs of reducing CO_2 where general equilibrium effects are taken into account and social values are used in the assessments.

The comparison in Figure A3 could also be taken to show the danger of relying on one source. For example, the IEA/OECD report seems to have significantly higher abatement costs than other sources for coal plants. Their "incremental" COE due to capture costs are also higher, despite using a lower capital charge rate (12 percent). For coal, the IEA/OECD study reports \$30-40 per MWH today, dropping to \$30 per MWH over time, compared with roughly \$10 for the studies normalized in Metz et. al. (2005).

Figure A3 Cost of CO_2 avoided ($/$TCO_2$). First group of columns refers to CCS in greenfield coal power plants, the second group to CCS in greenfield gas power plants