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Carbon capture and storage technologies in the European power market

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 cost estimates and CCS technology 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 fully. Substantially lower CCS costs, through subsidies on technological development or deployment, would be necessary to make CCS modification of old coal and gas power plants profitable.

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, 2007C). Presupposing that the remaining technical challenges on CCS are successfully solved and that future costs will fall in line with current projections, it remains an open question 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 the detailed multi-market LIBEMOD 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, though 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 installing 20 large scale CCS pilots by 2010. CCS technology receives significant funding in the US as part of the Recovery Act (including \$1 billion from the Department of Energy), and the European Union (EU) wants to see 10-12 full scale demonstration plants by 2015. CCS technology is seen as an important element in the EU plan to reduce emissions of greenhouse gases (GHGs) by 20 percent, increase the share of renewable energy to 20 percent, and reduce energy consumption by 20 percent (EU, 2009). CCS is of particular interest because as much as 50 percent of EU's current electricity supply is based on coal, lignite and natural gas, making these fuels key factors in the energy security policy of the EU.

In order to assess the likely role of CCS in European abatement policies we will consider two questions separately: technical uncertainties and economic uncertainties. There are still significant uncertainties on which capture technologies that will be offered, when they will be available, at what cost, and what the capture efficiencies will 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 (oxidizing the fuel to create CO_2 and H2 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). 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. 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 project ballooned by more than 200 percent before construction had even begun, and the goal to have CCS in place by 2012 has been pushed to 2015. On these technical and cost issues, our contribution in this paper is a review of various sources for 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.

Our main contribution is in analyzing the economic issues, which can be seen as a follow-up to the technical issues: Suppose the CCS technology becomes available in the market and that current cost projections and expected 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? In order to answer these questions we use our “best-guess” estimates of costs and technical efficiencies to augment the multi-market equilibrium model LIBEMOD of the Western European energy markets (see, for example, Aune et al. 2008) with CCS electricity technologies.

Using LIBEMOD we can identify the 2030 market equilibrium, assuming rational, well-informed agents and competitive markets. In our reference scenario, where a uniform CO_2 tax of \$90 is imposed, greenfield CCS coal power is profitable. This technology totally replaces non-CCS coal power investments and to a large extent it also replaces new wind power. Greenfield CCS gas power also becomes profitable, and totally replaces non-CCS gas power investments.

A key result 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 are hardly desirable from a social welfare point of view.

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 zero CO_2 tax. With CCS and a \$90 CO_2 tax, emissions in the power sector are reduced by much more than 20 percent from the

1990 level, and the first of EU's three 20 percent targets will likely be reached for the electricity sector. On the other hand, we also find that in the reference scenario, the total market share of wind, hydro and biomass power falls below 20 percent. Moreover, the target of a 20 percent drop in electricity consumption is far from realized even though the end user price of electricity increases substantially. In fact, the electricity consumption in the 2030 equilibrium exceeds the 1990 level. On the other hand, the rationality of a consumption target, and also the rationality of a market share target for renewable electricity production, is definitely questionable: because it is emissions of GHGs that create global warming, a target on GHGs emissions should be sufficient. Moreover, as long as there are more options for reducing GHG emissions, no particular solution should receive extra support as is the case of renewables.

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 finds no deployment of CCS technologies in 2040, even with carbon prices at 200 USD/TCO_2 in 2040 (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 finds a large market potential for CCS in European electricity production in 2030 - primarily CCS greenfield coal power plants with pre-combustion technology at CO_2 prices as low as $50. Interestingly, Odenberger and Johnsson (2008), 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. (2009). With some exceptions, these studies examine CCS investments from a global perspective. In both Riahi et al. (2004) and Edmonds et al. (2004) CCS plays an important role in reducing carbon emissions, however, the market diffusion of CCS happens mainly beyond the year 2050. Moreover, these studies do not separate between retrofitted CCS and greenfield CCS. Both Aune et al. and IEA (2006) differ between retrofit and greenfield installations, and both conclude that a significant share of the CCS installations might be retrofitted. This result reflects low CCS retrofitting cost estimates. The IEA (2006) study also suggests that there will be no CCS greenfield gas power, which likely is due to the low CO_2 prices in their model simulations ($25). These results are more or less the opposite of the ones we obtain; our study suggests a substantial role of greenfield CCS already in 2030, but no investment in retrofitted CCS.

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 plants and coal power plants, and, we also distinguish between CCS used on new "greenfield" power plants and CCS "retrofitted" to, that is, installed on 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 a broader set of technological capture options, and for a tighter integration of the capture facility with the rest of the 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; post-combustion, pre-combustion and oxyfuel. 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 capture facilities in both coal and gas power plants. Studies of greenfield gas plants also seem to assume this technology, as do studies of greenfield coal plants using pulverized coal (PC). Note that there are several varities 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. This technology is often assumed for greenfield coal power plants, assuming the plant will install integrated gasification combined cycle (IGCC). 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, was rarely assumed in the studies reviewed below.

As mentioned in the introduction, current cost numbers for CCS are hypothetical as there are no full scale power plants in operation with CCS technology. Our modelling setup 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, according to our experience, differ significantly in their cost estimates, we rely solely on written, published cost estimates. We identified our 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). The parameters have been “normalizing” to correct for differences in capital charge rates, fuel costs etc.

The IPCC lists a variety of reasons why retrofit CCS is likely to be more expensive than greenfield CCS; less efficient heat integration, land availability on site, access to plant areas, need for special ducts, etc. The IPCC study does not, however, contain any specific information on gas retrofit – nor were we able to find any information in other CCS studies. Below we have assumed that the relative cost difference between greenfield gas and retrofitted gas is the same as the one between greenfield powdered coal and retrofitted powdered coal. These four cases all involve post-combustion technologies, making this the most intuitive comparison.

To check our normalized estimates, the parameters for coal plants were compared to the normalized cost parameters identified by Deutch et al. (2007). The aggregate implications of our cost parameters (“Cost per ton co2 avoided”) were compared to the reported estimates in McKinsey (2008) and IEA/OECD (2008). These tests indicate that our estimates are plausible and in the low-to-mid range. 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 of net power output	10 %	15 %	40 %	30 %
Reduction of 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 ($/$TCO_2$ avoided)***	27.4	58.8	60.9	105.8
Abatement cost ($/$TCO_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)

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. First, CCS for gas is more expensive “per ton co2 avoided” than for coal because natural gas has a lower CO2 emission per generated MWH. Second, retrofit is substantially more expensive than greenfield, reflecting the large reduction in net power output in CCS retrofit, see discussion above.

3. The LIBEMOD model

We use the multi-market equilibrium model LIBEMOD to find the potential of differenct 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.

In each model country there is investment in energy infrastructure, and production, trade and consumption of energy. LIBEMOD has 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 a few exogenous countries such as Russia. Coking coal, steam coal and oil are traded in global markets.

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. Trade in natural gas/electricity 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 they can be expanded through investment. Fossil fuels are traded in annual markets, whereas for electricity the model distinguishes between summer and winter (seasons) and day and night.

Energy in each model country is transported and distributed to the users at costs that differ according to user group and energy good. There are four groups of users of energy: 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 represent end-user demand, here derived from a nested CES utility function with five levels. Whereas demand from transport is restricted to oil, the other end-users typically demand several of the seven energy goods.

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) 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 can not 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.
- 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.

An electricity producer maximizes profits, subject to the technical constraints. This gives rules for operations, as well as a decision rule for optimal investment, see Aune et al. (2008).

LIBEMOD determines all energy quantities – investment, production, trade and consumption – and all energy prices, both producer prices and end-user prices. In addition, the model calculates emissions of carbon by sectors and countries. For a more detailed description of LIBEMOD, including data sources, see Aune et al. (2008). The version of LIBEMOD used in the present paper – LIBEMOD 2000 CCS – differs somewhat from the one documented in Aune et al. (2008), the main differences being i) electricity is traded in two (not six) periods over the 24-hour cycle, ii) more electricity technologies are available (greenfield CCS and retrofit CCS), and iii) we use a more aggregated representation of coal markets.

4. Simulation results

4.1. Business as usual scenario

In this section we use LIBEMOD to examine the impact of CCS investments on energy markets in Western Europe, focusing on alternative long-run equilibriums in 2030. In the first scenario, there is no CCS and no carbon tax in any of the model countries. This gives a 2030 equilibrium in which both production of electricity and carbon emissions have almost doubled relative to the observed 2000 outcome (the base year of the model.) The driving forces of these huge increases are i) economic growth over 30 years, and ii) shift in the market structure to competitive markets. The latter point reflects that the observed 2000 outcome is characterized by a number of market imperfections;

whereas these have been removed in 2030 assuming achievement of the EU goal of establishing competitive energy markets; see European Parliament (2003a, 2003b).

Imposing competitive markets typically increases total production of electricity. In addition, the composition of technologies changes and low cost electricity technologies increase their market shares. In the LIBEMOD simulations coal power is the big winner, and hence investment in coal power and production of coal power soar. Economic growth, confer i) above, strengthen these effects through outwards shifts in the demand curve, which tend to push up the price of electricity, thereby giving incentive to more investment in, and production of, electricity. For a more detailed discussion of the impact of liberalization of the Western European energy markets, as well as the role of economic growth, see Aune et. al. (2008).

Table 2 shows the equilibrium composition of electricity technologies in 2030. With no CCS investment and no carbon tax, conventional coal power, that is, old and new steam coal power 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, whereas conventional oil power has been phased out, reflecting the high cost of this technology.[1] Nuclear, where we have imposed no investment, has a market share of 16 percent, 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.

The most drastic change in the market shares from the base year is the conversion from gas to coal. While gas power had a market share of 18 percent in the base year, its share is now just 4 percent. The other major shift is the reduced importance of Nuclear, which had a market share of 29 percent in the base year. The latter change may follow from our imposed restriction on new nuclear. Renewables are not much affected; they had a market share of approximately 4 percent in the base year. [2]

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[1] In 2000, the market shares were as follows: coal power 25 percent, gas power 18 percent, oil power 6 percent, nuclear 29 percent, hydro 19 percent and other technologies 4 percent.

[2] See Aune et al. (2008), page 106, for the base year market shares.

Table 2 Market share of electricity technologies in 2030 (Percent)

	No CCS no CO_2 tax	No CCS CO_2 tax	CCS 90 USD CO_2 tax	CCS 45 USD CO_2 tax	CCS 180 USD CO_2 tax
Conventional gas	4	22	4	12	0
Conventional coal	66	13	0	11	0
Conventional oil	0	1	0	0	0
Greenfield CCS gas	0	0	8	0	15
Greenfield CCS coal	0	0	44	36	39
Hydro	9	12	10	10	10
Renewable	5	31	15	14	18
Nuclear	16	21	18	18	18

4.2. Reference scenario

In the reference scenario we allow for CCS investments and impose a \$90 CO_2 tax (This tax, as well as all other values reported below, is measured in 2007 USD). The change from the first scenario – no CCS and CO_2 tax – to the reference scenario can be decomposed in two ways. One way is to allow for CCS investment, but keep the assumption of no carbon tax. Existing plants will then not invest in CCS (retrofitted CCS) and no new plants with integrated CCS facilities (greenfield CCS) are put up. These results reflect that CCS implies costs and there are no benefits from CCS without carbon taxes.

Alternatively, starting in the first scenario (no CCS and CO_2 tax) we can impose a \$90 CO_2 tax but keep the assumption of no CCS investments. The market share of conventional (non-CCS) fossil fuel based electricity production then decreases from 70 percent to 35 percent, reflecting a much lower market share of conventional coal power (decreased from 66 to 13 percent), and, in fact, a higher share of conventional gas power (increased from 4 to 22 percent). The higher market share of gas power 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. The market share of nuclear also increases, reflecting that (i) nuclear production is unchanged (we do not allow investment in nuclear), and (ii) total electricity supply has decreased by 25 percent, see Table 3, because the CO_2 tax increases costs of production.

We now turn to our reference scenario, that is, CCS investments and a \$90 CO_2 tax. Compared with the case of no CCS investment and a \$90 CO_2 tax, 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 (0 market share), whereas greenfield CCS is profitable; greenfield coal CCS obtains a market share of 44 percent, which is much higher than the market share of greenfield gas CCS - 8 percent. The large market share of greenfield CCS coal reflects the low cost of coal fire power plants (before taking into account the CO_2 tax) as well as the large fraction of CO_2 emissions that is removed by CCS (90% 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.

The effect of allowing CCS investment (for a given CO2 tax) is as if the aggregate marginal cost curve of electricity production shifts downwards. Such a shift increases total production of electricity, whereas the producer price of electricity decreases from 112 to 80 USD/MWh, that is, by almost 30 percent, see Table 3 (next page).

Table 3. Average producer price of electricity, electricity production and CO2 emissions (percentage change relative to the Kyoto target) in 2030

	No CCS no CO_2 tax	No CCS CO_2 tax	CCS 90 USD CO_2 tax	CCS 45 USD CO_2 tax	CCS 180 USD CO_2 tax
Producer price*	53	112	80	76	86
Production**	5258	3942	4606	4624	4605
CO_2 emissions	96	20	5	27	-8

*** USD/MWh, ** TWh**

For renewable electricity production, costs are unchanged whereas the producer price has decreased. Therefore, the market share of renewable decreases by as much as 16 percentage points (from 31 to 15 percent) compared to the no CCS scenario. All the same, renewables are still success increasing their market share from 4 percent in the base year to 15 percent in our reference scenario. Finally, there is a small decrease in the market share of hydro production, primarily reflecting the increase in total electricity supply.

The significant shifts in the composition of electricity technologies, particularly that conventional coal is phased out and almost replaced by CCS plants, and also the huge decrease in renewable electricity production, lead to significant changes in investments and emissions. As seen from Table 4, in the reference scenario 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. The introduction of CCS (when the CO_2 tax is $90) leads to a drop in total CO_2 emissions in the model countries of almost 15 percent, whereas the drop in emissions in the electricity sector is more than 90 percent. In order to set the emission levels in perspective, they are compared with the Kyoto target for the model countries.[3] In the reference scenario, emissions are 5 percent above the Kyoto target, whereas in the first scenario (no CCS, no CO_2 tax) emissions are almost twice as high as the Kyoto target, see Table 3.

Table 4. Investment by electricity technology in 2030

	No CCS no CO_2 tax	No CCS 90 USD CO_2 tax	CCS 90 USD CO_2 tax	CCS 45 USD CO_2 tax	CCS 180 USD CO_2 tax
Conventional gas	3*	77	0	44	0
Conventional coal	374	2	0	0	0
Retrofit CCS gas	0	0	0	0	<1
Retrofit CCS coal	0	0	0	0	0
Greenfield gas	0	0	47	0	87
Greenfield coal	0	0	260	209	226
Hydro	9	17	13	12	14
Renewable	34	335	167	141	206
Nuclear	0	0	0	0	0
Sum	421	430	488	407	533

All figures in GW.

Changes in quantities and prices lead to changes in welfare. In LIBEMOD, traditional welfare is the sum of consumer surplus, producer surplus and the tax income of the governments. However, one should also take into account that CO_2 emissions differ between the scenarios. Here we valuate emissions at the CO_2 tax rate ($90 ton/ CO_2). Comparing the first scenario (no CCS, no tax) with the reference scenario, we find that in the reference scenario annual traditional welfare has decreased by 150 million USD, whereas the annual value of lower CO_2 emissions in the reference scenario is 300 million USD. Hence, the change from the first scenario to the reference scenario increases annual total welfare - traditional welfare corrected by the value of lower CO_2 emissions - by 150 million USD. Similarly, the change from the case of no CCS investment and a CO_2 tax of $90 to the reference

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

scenario, that is, the impact of allowing CCS investment, increases annual traditional welfare by 13 million USD, whereas the annual value of lower CO_2 emissions is 50 million USD. Hence, the change in annual total welfare is 62 million USD.

4.3. Alternative CO_2 tax scenarios

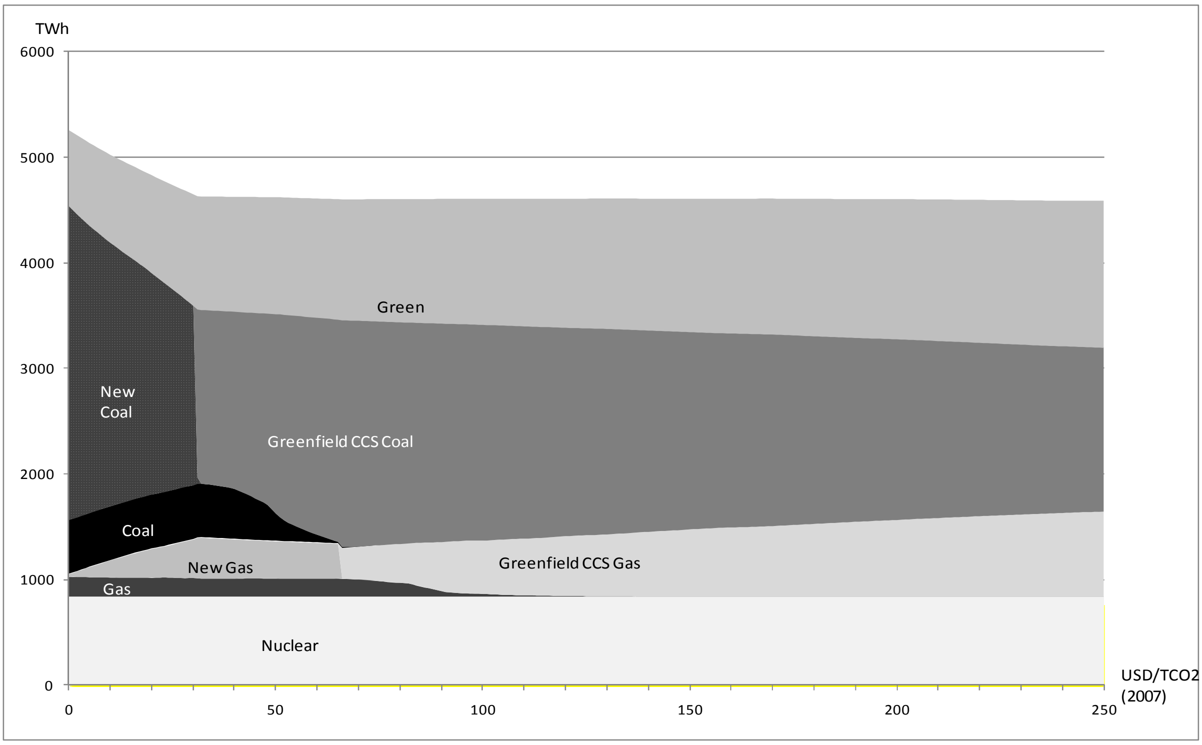
In our reference scenario, the CO_2 tax is \$90. We now examine the impacts of different CO_2 taxes. Following IEA (2000), we consider a tax of \$45 and a tax of \$180. Like in the reference scenario, we allow for CCS investments. From Table 2 we see that there is production of retrofitted CCS gas power only in the case of a \$180 CO_2 tax, although the level of production is tiny – 2 TWh in the country which has the most efficient retrofitted CCS gas. There is no production of retrofitted CCS coal power even with a \$180 CO_2 tax. This is important since it speaks strongly against the belief that a policy of allowing new coal plants without CCS is acceptable because conventional coal plants will be retrofitted with CCS later.

For hydro, renewable, nuclear, conventional coal and greenfield gas, there is a clear tendency that the outcome of a \$45 tax is somewhere between the no tax case and a \$90 tax, and also that the outcome of a \$180 tax mainly reinforces the change from no tax to a \$90 tax. However, for conventional gas and greenfield CCS coal the effects are more involved. First, the market share of conventional gas is 4 percent both without a tax and with a \$90 tax, but under a \$45 tax this technology has a market share as high as 12 per cent, reflecting a substantial investment in non-CCS gas-fired plants. Yet, a tax at \$180 chokes all types of conventional fossil fuel based electricity production. Second, for greenfield CCS coal the market share increases from 36 percent under a \$45 tax to 44 percent under a \$90 tax, but drops to 39 percent when a tax at \$180 is imposed. The latter two cases call for a closer look at the relationship between production of electricity by technology and the tax rate.

4.4. Sensitivity results

Figure 1 shows production of electricity (TWh) by group of technologies for CO_2 tax rates between 0 and \$200 when CCS technologies are available. For nuclear, production is independent of the tax rate (see discussion above), whereas for the group green technologies (hydro, wind, bio, waste) production is increasing in the tax rate.

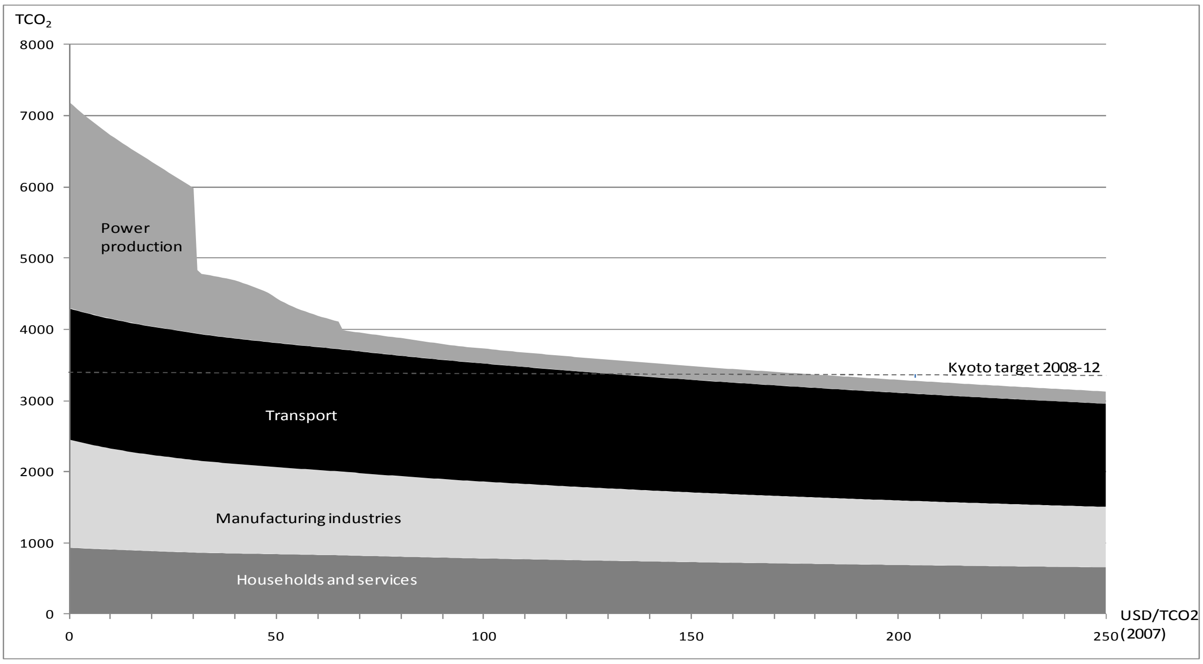
Figure 1. Production by group of technologies (TWh) relative to the CO_2 tax ($/t$CO_2$)



A closer look reveals that it is mainly wind power that is increasing in the tax rate, but there is also a significant contribution from new bio power. For existing steam coal (lignite) plants, production 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, 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 existing gas plants, production is first slightly decreasing up to around $65, and then decreasing at a much higher rate until it reaches zero production around $140. Electricity production in new gas power stations 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.

Figure 2 shows the relationship between emissions of CO_2 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 above $40 leads to higher production in greenfield CCS gas, lower production in 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. On the other hand, we have not included new abatement technologies like biofuels or CCS in any of the other energy user groups.

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



4.5. Robustness

We now examine how our main results depend on key cost and efficiency assumptions when the CO_2 tax is $90. First, assume that both retrofitted and greenfield CCS technologies become cheaper. To be more specific, in this scenario costs of investment, operation and maintenance are 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 10 percent. The market share of greenfield CCS coal increases by 12 percentage points to 56 percent, whereas greenfield CCS gas increases its market share from 8 to 9 percent, see Table 5. On the other hand, it is still optimal with no retrofitted CCS production.

A higher total production of electricity lowers the price of electricity, making it not profitable neither to operate existing conventional gas power stations, nor to invest in new conventional gas power stations (There is no conventional coal power production even before CCS costs are reduced, see discussion above). Moreover, a lower price of electricity reduces investment in green technologies, in particular the market share of renewable drops by 6 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 of less than one percent.

Table 5. CO_2 tax at $90. Market share of electricity technologies in 2030. Percent

	Reference case	Lower costs in all CCS plants	Lower wind power costs	Higher thermal efficiency
Conventional gas	4	0	4	2
Conventional coal	0	0	0	0
Conventional oil	0	0	0	0
CCS gas	8	9	8	9
CCS coal	44	56	35	45
Hydro	10	9	10	10
Renewable	15	9	25	15
Nuclear	18	17	18	18

An alternative assumption is that only retrofitted CCS, which uses different types of post-combustion technologies, becomes cheaper.[4] 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 gas with CCS requires a cost reduction (or government support) of the three cost 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 will never be a dominant technology in the 2030 equilibrium. In the extreme case of no costs of investment, operation and maintenance for retrofitted CCS, both retrofitted CCS gas and retrofitted CCS coal has a share of total investment of around five percent, reflecting (i) depreciation, 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

[4] Lower costs for the electricity producers may reflect lower social costs or subsidies provided by the government.

maintenance are reduced by one third – the market share of greenfield CCS increases by 13 percentage points to 65 per cent.

We have also 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.

If we change the efficiency plant assumptions by increasing thermal efficiency in all new fossil fuel and biomass power plants by five percent, 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 and biomass fuel plants can, cet. par., sustain their production of electricity through less use of fuels. Lower demand for fuels tend to decrease fuel prices, thereby giving an incentive to use more fuels and thus to produce more electricity. 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 partly that coal is traded in a global market (not in a Western European market like natural gas), and partly 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 wind power decreases. However, the latter effect is so small that the market share of renewable (15 per cent) does not change.

5. Discussion and conclusion

CCS is likely to become an important carbon abatement option for Europe. With a CO_2 tax of $90, our results indicate that greenfield CCS coal power plants become profitable, totally replacing non-CCS coal power investments and to a large extent replacing new wind and bio power. All the same, production of wind and bio power increases considerably compared to the base year. Greenfield CCS gas power also becomes profitable, but does not replace non-CCS gas power plants fully. Substantially lowered CCS costs, through subsidies on technological development or deployment, would be necessary to make retrofitted CCS profitable.

The effect of CCS investment in our reference scenario with a CO_2 tax of $90 is as if the aggregate marginal cost curve of electricity production shifts downwards. Such a shift increases total production of electricity, whereas the producer price of electricity decreases by almost 30 percent. Therefore, the market share of renewable energy decreases significantly. In fact, in the reference scenario the share of renewables in the energy mix is below 20%, which may indicate that the renewable target of the EU may be non-optimal from a social welfare point of view.

Some may find the absence of CCS retrofit investments surprising. However, politicians should not be tempted to subsidize retrofit installations as such installations likely would substitute for 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. (2009), who find that subsidies to retrofitted CCS only replaces greenfield CCS, and the subsidies have minor effects on electricity production and CO_2 emissions.

At present, there is research on several carbon capture technologies, and governments may have a hard time deciding on what 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 cheap. According to our study, governments should rather go for integrated solutions when allocating their development and demonstration subsidies.

In the reference scenario, we implicitly assumed that private investors know that the CO_2 price would be $90 in 2030, and also that CCS technologies would be operable by 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 CCS if carbon emissions are punished sufficiently.

We have also assumed that CCS technologies are available to cost based prices, while more likely suppliers of CCS technologies have market power and hence will charge a mark-up. Higher prices on CCS mainly affect the point at which these technologies enter the market. Because this happens well below our reference CO_2 tax rate of $90, a (somewhat) higher cost of CCS technologies may not change the equilibrium market shares significantly.

Finally, there clearly is a role for coordinating transport of captured CO_2 - such transport is likely a natural monopoly. Uncertainty about the availability of transport services could be a barrier for investment in capture facilities at the plant site. In that case the EU may commit to offer a transport solution to the investors, for instance, the EU could commit to transport removed CO_2 at a price equal to the estimated average transport and storage cost.

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Estimated costs of Carbon Capture and Storage (CCS)

Using the tabulated studies in the IPCC report, we broke down total capture costs using total costs with and without capture technology, subtracting fuel and capital costs from each of these, leaving a residual that we split between fixed and variable operating & maintenance (O&M) costs. Total costs were 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). The split between fixed and variable O&M costs was done by using a prior estimate of variable O&M costs in the "without capture technology" case, and splitting the "incremental" O&M costs in the capture case 50-50 between the fixed and variable categories. The 50-50 split was chosen because these two categories were roughly equal in size for the non-CCS case. After breaking down the cost numbers in the studies in the IPCC report in this manner, 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%). In this way, the studies were in a sense "normalized," allowing us to compare the cost components across studies and choose "reasonable" values for our model. Values for the reduction in CO2 emissions and reduced power output were selected by considering the distribution of estimates and selecting typical values.

Table A1 Capture costs.

		Coal IGCC greenfield	Coal PC greenfield	Gas greenfield	Coal retrofit	Gas retrofit
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	88.90 %	87.50 %	88.20 %	83.30 %	85.70 %
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
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 coal retrofit CCS (i.e., modifying an existing coal power plant with CCS technology so as to capture CO_2) and greenfield CCS (i.e., new coal or gas power plants with CCS). In our model, Greenfield CCS coal plants were assumed to be of the integrated gasification combined cycle (IGCC) type. As seen in table A1, IGCC (which use pre-combustion technology) strictly dominate pulverized coal (PC) greenfield plants with CSS. Greenfield CCS gas power plants were assumed in the IPCC studies to use post-combustion technologies. We were unable to find reports or studies with estimates for gas CCS retrofit costs, so we assumed that these differed from gas CCS greenfield costs with the same relative magnitudes as the difference between PC greenfield CCS and PC retrofit CCS. As all four of these cases involve post-combustion technologies, this seemed the most relevant comparison.

The "normalized" cost components displayed significant variation across the studies tabulated in the IPCC report. For the case of coal, we were able to compare our chosen cost parameters with cost parameters from five recent studies collected and made comparable in a 2007 MIT report (Deutch et al. 2007). These studies were made comparable to our cost figures by converting numbers to \$/MWH, using 2000 as the base year, and imposing our capital charge rate (13% rather than 15.1%). 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. Whereas Figure A1 shows costs for PC plants, 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 estimates. As can also be seen by comparing the two figures, IGCC dominates PC when CCS is added. For this reason, our study assumes that new coal power plants with CCS will not use powdered coal, but rather use the IGCC option.

Figure A1 LIBEMOD PC estimates compared to "normalized" studies in MIT report (first four clusters of columns are without CCS, last four with CCS)

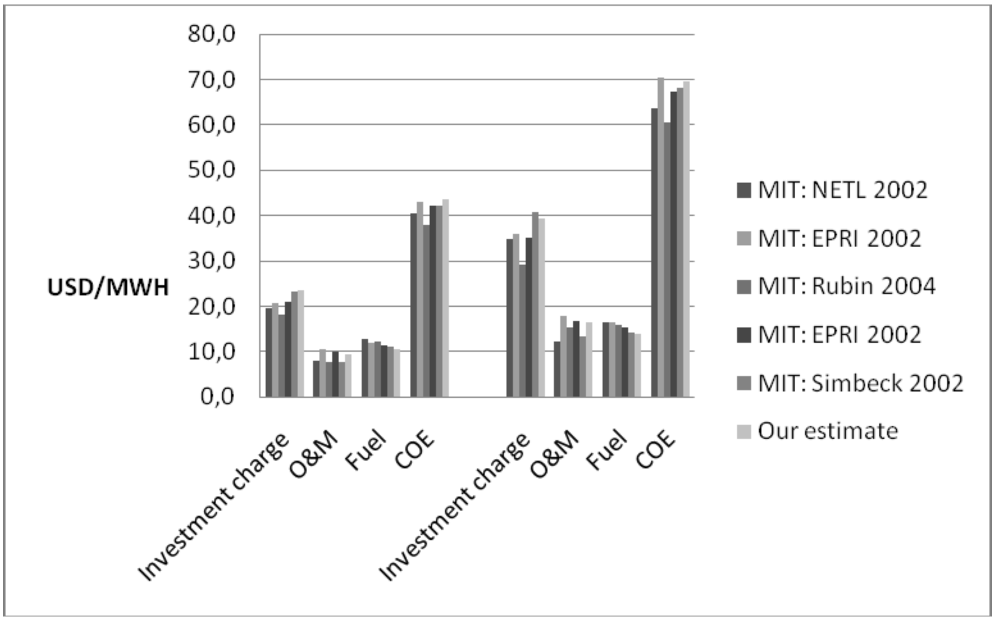
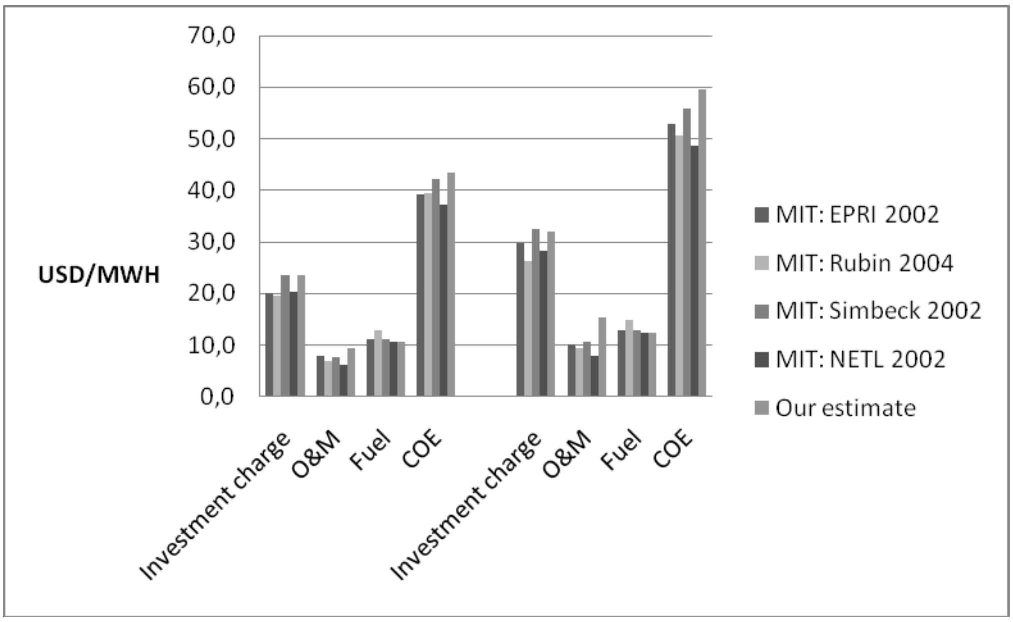


Figure A2 LIBEMOD IGCC cost assumptions compared with normalized estimates in the MIT report (first four groups of columns are without CCS, last four with CCS)



The second stage of the CCS process concerns the transport of gas from the capture site to the storage site. The two main options are transport by pipeline and by ship. In general, the case for a pipeline compared to ship increases with the volume of gas and decreases with the distance involved. For pipelines there is also the question of interdependence: Considered in isolation, a pipeline from a single power plant may be economically unprofitable – but if we consider what the IPCC calls a "backbone" transport structure, then pipelines may form an infrastructure where powerful economies of scale is combined with the need for coordination of decisions. Given the complexity of detailed cost estimates (which depend on terrain, barriers, existing pipeline structures and plans for future networks etc.) and the transport route uncertainty (the location of storage sites is not yet known), we used a figure from the IPCC report relating transport costs per ton to distance, and based our analysis on an average transport distance of 300 km. This distance is based on the only assessment identified by the IPCC regarding the match between large single-point emission sources and potential carbon storage sites in Europe (Bradshaw and Dance 2004). Though Bradshaw and Dance are careful to not oversell their first-pass attempt to identify storage sites–their judgment is that significant amounts of CO_2 emitted from European power plants will require less than 300 km of transport: Roughly 57% 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.

Based on an IPCC figure relating distance to transport cost (estimate based on transporting 6 Mt per year) and the Bradshaw and Dance estimate of typical transport distances, we arrive at an estimate of \$3 per ton CO_2 transported. Because the major cost of CCS is within capture, the uncertainty surrounding this estimate is not critical.

Storage costs are assumed to vary widely between sites – depending on specific site characteristics. As reported by the IPCC, the onshore storage costs for saline formations in Europe have been estimated at 2.2-7.1 US\$/tCO_2, with a most likely value of 3.2 (in 2007 dollars) – which we take as our cost parameter for storage in the LIBEMOD model.[5] Again, the costs are small relative to the capture costs, making the uncertainty surrounding them of less importance. These 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 US\$/tCO_2 in one study reported in the IPCC report and 0.07-0.09 in another reported study.

[5] Another study noted in the IPCC report estimates that 90% of European storage facilities have a cost less than 2 US\$/tCO_2.

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 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. Finally, 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 (see Figure A3) the more aggregated cost measure of "cost per ton CO_2 avoided" with the estimates from the McKinsey, IEA/OECD and MIT studies (see Metz et al. 2005, McKinsey (2008), IEA/OECD (2008)). In this figure, the years written in quotation marks refers to the "scenario years" the studies consider. 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 "engineer numbers" – they are derived entirely from the cost parameters of a plant, and do not take into account the economic concept of cost 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, as the IEA/OECD report in particular 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%). For coal, they report 30-40 dollars per MWH today, dropping to 30 dollars/MWH over time, compared to roughly 10 dollars 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.**