The impact of carbon sequestration on the cost of electricity and hydrogen in Europe in the medium term

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Abstract

Carbon sequestration is a distinct technological option to control carbon emissions, complementing other measures such as improvements in energy efficiency and utilization of renewable energy sources. The deployment of carbon sequestration technologies in electricity generation and hydrogen production will increase the costs of these energy carriers. Our economic assessment has shown that the introduction of carbon sequestration technologies in Europe in 2020, will result in an increase in the cost of electricity by 35-57% depending on the electricity generation technology; gas turbines will remain the most competitive option for generating electricity; and the competitiveness of the IGCC technology will emerge. When carbon sequestration is coupled with natural gas steam reforming or coal gasification for hydrogen production, the cost of hydrogen will increase by 14-16%. Furthermore, natural gas steam reforming with carbon sequestration is far more economically competitive than coal gasification. Finally, our analysis demonstrates that even with the deployment of carbon sequestration technologies, coal will not become an attractive fuel for the generation of electricity and the production of hydrogen; on the contrary, natural gas will remain the fuel of choice as it offers significant economic advantages.

Introduction

Affordable and plentiful energy is an absolute prerequisite for the high quality of life Europeans enjoy and an essential ingredient to economic prosperity. Yet, with the turn of the century, the European Union (EU), as the rest of the world, is confronted with a major challenge: how to meet the continuously increasing energy demand, a result of the economic growth in EU member states, while minimising the adverse effects of energy production and use to the environment, the ecosystem and the human welfare. Driven by concerns about emissions of greenhouse gases (GHG), mainly of carbon dioxide (CO_2), the EU has ratified the Kyoto Protocol and has intensified a European energy-strategy debate launching a number of policy initiatives aiming to reduce CO_2 emissions, along with securing the energy supply [1].

Despite measures taken to promote the penetration of renewable energy sources (RES) in Europe, it is expected that fossil fuels will remain the main source for energy, at least for the next 20 years. Even when hydrogen is considered as the universal energy carrier of the future, creating the so-called *hydrogen economy*, it is strongly argued that at the onset, hydrogen will be produced by fossil fuels via processes that also emit CO_2. One of the options considered controlling the level of CO_2 emissions, complementing improvements in energy efficiency, combined heat and power and the evolution towards zero and low-carbon fuels (including RES and fuel switching from coal to natural gas) is carbon sequestration, an integrated process that includes (i) the capture of CO_2 from emission sources and the atmosphere, (ii) the transportation of CO_2, and, (iii) its permanent storage or reuse. Carbon sequestration is most applicable to large combustion plants and specifically to thermal power stations, where it could contribute stopping the release of about 90% of generated CO_2 in the atmosphere. Furthermore, carbon sequestration technologies may play a catalytic role in the deployment of a hydrogen economy complementing the production of hydrogen from fossil fuels in a sustainable manner.

The deployment of carbon sequestration technologies poses a technological and scientific challenge, as well as a financial burden. Existing CO_2 capture technologies need to be modified, and new ones

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need to be developed; a CO_2 transport network needs to be deployed; and environmentally acceptable, safe, verifiable, approved by the public and economically viable storage options need to be provided. Ultimately, a major factor that may dictate whether or not, carbon sequestration will be deployed in Europe is the associated economics, provided that the optimism in geological storage capacity materialises. The resulting additional charge to the cost of electricity and hydrogen should be justifiable, in the frame of sustainable growth. This work aims to estimate the effects of deployment of carbon sequestration on the cost of electricity and hydrogen in Europe in the medium term. The time horizon set in this study is 2020.

Carbon sequestration: An Overview

There are different approaches to carbon sequestration, which can be broadly grouped into two main categories: the enhancement of natural carbon sequestration processes (terrestrial sequestration and ocean fertilization) and the capture of CO_2 directly from the emission sources and its permanent storage. While it is generally accepted that terrestrial sequestration and ocean fertilization are not expected to play a significant role in controlling CO_2 emissions in Europe [2], the capture of CO_2 directly from the emission sources and its permanent storage has the potential to remove larger quantities of CO_2 and in a shorter time period. Since emission sources in transport, industry and manufacturing are small and disperse, while power generation plants (for electricity and potentially for hydrogen) are comparatively few and large but currently responsible for one third of the total CO_2 emissions, it is evident that significant steps towards reducing CO_2 emissions can be made faster and more cost effectively by applying the carbon sequestration technology to power plants.

Several commercial technologies are available today that are able to separate CO_2 from a stream of gases. However, none of these technologies has been developed for large-scale carbon sequestration operations. Rather, they have been developed to produce a stream of high purity CO_2 for commercial markets, such as chemical manufacturing and food processing, to remove CO_2 from natural gas or to produce hydrogen for the petrochemical industry. The applicability of each capture technology depends on the conditions of the gas that contains the CO_2, namely its composition, temperature and pressure, the concentration of CO_2 and the degree of required CO_2 removal. Among these technologies, chemical absorption is considered as the state-of-the-art for the separation of CO_2 when present at low partial pressures, having demonstrated at least 90% removal efficiency, hence making this process ideal for removing CO_2 from the flue gases of gas turbine combined cycle (GTCC) plants and supercritical pulverised coal (SC) plants. Physical absorption combined with pressure swing adsorption is suitable for removing CO_2 from integrated gasification combined cycle (IGCC) and hydrogen production plants. The main disadvantages of these capture technologies are the high energy requirements (with concomitant penalty on power plant efficiency and thus in fuel consumption) and the increased capital costs. In the future, membranes, and specifically gas absorption membranes, may offer a significant potential for CO_2 capture.

The transport of CO_2 does not pose any technological obstacles. Nowadays, CO_2 is transported via high-pressure steel pipelines (100-200 bar). As an alternative, the use of tankers has been proposed as a future solution to transport CO_2 to offshore storage sites or to locations far away from the CO_2 generation sources.

An option to improve the economics of carbon sequestration is CO_2 utilisation. However, it should be born in mind that the amount of CO_2 that can be utilised is extremely small when compared to the amount being generated. The largest potential for CO_2 utilisation is offered by the petrochemical industry for enhanced oil recovery (EOR). The injection of CO_2 into oil wells may increase oil production and store simultaneously CO_2 underground. However, this process is marginally competitive under today's oil prices. As such, EOR is used nowadays only in few locations, mainly in USA. The potential for EOR in North Sea appears to be small, given that EOR is far more difficult to be deployed in offshore oil fields than inland. It is noted that once North Sea oil platforms are decommissioned and removed, it is unlikely that an EOR project could justify the costs of new platforms and wells. As such, any CO_2-based EOR projects in North Sea should be initiated within the next 10 years [3]. An alternative use of CO_2 is enhanced coalbed methane (ECBM) recovery that can be achieved by injecting CO_2 into coal strata that cannot be mined. There is only one demonstration plant and one pilot plant worldwide, both situated in N. America. The EU is currently funding the first project of its kind in Europe, located in Poland (RECOPOL). The European potential for ECBM recovery is modest, in the areas of the upper Silesian basin in Poland and the Czech Republic, and the Saar/Lorraine basin in Germany and France [4].

The amount of CO_2 that cannot be utilised after capture needs to be stored safely and permanently, at a low cost and in a way that is environmentally compatible and in accordance with international treaties and national legislation. The main options for storing CO_2 are: (i) underground in suitable geological formations, such as active and depleted oil and gas reservoirs and deep saline aquifers (geological storage) and (ii) in the ocean (ocean storage). However, the latter option is hindered by the lack of fundamental understanding of the potential impact to the marine ecosystem and environment, given that, the injection of CO_2 increases the acidity of water with potentially catastrophic effects to marine life. On the other hand, disposal of chemicals and periodic storage of natural gas in geological formations is a widely accepted industrial practice with a long accumulated experience. Furthermore, potential geological storage sites are widely dispersed and plentiful in number, characteristics that make geological storage the most favourable CO_2 storage option today. The major issue associated with geologic storage is the assessment of storage capacity and the estimation of retention times. Although CO_2 is not toxic, it may cause asphyxiation, contaminate drinking water supplies and, on a global scale, may make carbon sequestration an ineffective strategy to control CO_2 emissions if leaks are large enough. Currently, there is only one commercial application of geologic CO_2 storage, in a saline aquifer in North Sea, the Sleipner Project, where one million tonnes of CO_2 are injected and stored annually (equivalent to the emissions of a 140 MW power plant). A monitoring project funded by the EU (SACS) studies the behaviour of injected CO_2 in the Sleipner field; and a demonstration programme in Canada, the Weyburn Project, co-funded by the EU, studies the storage of CO_2 in geological formations associated with EOR.

A review of carbon sequestration economics

The deployment of carbon sequestration technologies in power plants will require additional investments for the development of infrastructure (e.g. CO_2 capture facilities, pipelines, injection wells, etc.) and will increase operating and maintenance (O&M) costs (e.g. due to increased maintenance requirements, consumables, labour). Furthermore, energy will be required for the capture of CO_2 (e.g. for the regeneration of a loaded amine in chemical absorption), and the compression of the captured CO_2 at pressures of about 100 bar to facilitate its transport. This demand for energy will be met by the power plant itself, thus decreasing its net power output. This additional energy consumption, compared with a plant without CO_2 capture, is estimated to result in the drop of the power plant efficiency by 13% to 25% (see below), depending on the power plant type and the capture method. Maintaining the net power output of a plant will require the expansion of the plant or the construction of another plant. In turn, both options will require additional capital and will result in an increase in fuel consumption so that the same amount of power (as electricity or hydrogen) can be generated. In addition, energy will be needed for the storage of the captured CO_2, which, although may not be provided directly from the same power plant that will generate the CO_2 emissions, it will have an impact on the total efficiency of the power system. Overall, the introduction of carbon sequestration technologies will result in increases in the cost of electricity (COE) and the cost of hydrogen (COH).

The cost of carbon sequestration is highly variable and depends on a range of technological, financial, legal and even political factors. Since CO_2 capture technology has not yet been deployed commercially in power plants, the costs can be estimated based on basic engineering principles. Table 1 lists the average capital costs as presented in the open literature [5-10] for a number of power generation technologies. The sharp increases in capital cost of GTCC reflect the high cost of the scrubber and its peripheral equipment, and also the reduction of the power output due to energy losses in capture and compression of CO_2 [11]. It has been reported that in coal plants, about half of the increase in capital costs is due to the cost of CO_2 capture equipment and half is a result of reductions in the power output. Furthermore, the higher increase in capital costs in GTCC compared with coal plants is due to the lower concentration of CO_2 in the flue gas of GTCC plants, that makes CO_2 capture more demanding in terms of equipment and energy consumption. About a third of the efficiency penalty for CO_2 capture in a coal plant is due to auxiliary power consumption, such as the flue gas fan and the CO_2 compressor, while the rest is due to steam consumed for the regeneration of the amine. In contrast to the relatively high availability of information on capital costs, operating and maintenance costs are not typically reported. The operating cost is usually dominated by fuel costs, highlighting the importance of plant efficiency. Other major contributors to operating costs are labour, maintenance, chemical and other consumables, etc. These costs are thoroughly presented in [11].

Table 1: Average values of specific capital costs (SCI), efficiency and specific CO_2 emissions for different power plant types as reported by various sources [5-10] (prices are reported in euros, based on the assumption that the euro is in parity with the US dollar).

Plant Type	SCI (€/kW)	SCI with capture (€/kW)	Change (%)	Efficiency (%)	Efficiency With capture (%)	Change (%)	Specific CO_2 Emissions (kg/MWh)	Specific Emissions w/capture (kg/MWh)	Reduction (%)
SC	1151	1976	71.7	41.8	31.4	24.8	776	121	84.5
GTCC	536	998	86.1	55.4	48.2	13.0	369	50	86.3
IGCC	1395	1881	34.8	42.7	35.6	16.6	753	91.8	87.8

Besides the ‘traditional’ pathways to produce electricity (pulverised coal and natural gas), IGCC plants have recently been designed to produce electricity with high efficiencies and a reduced impact to the environment. Electricity can be produced by combusting syngas, a mixture of carbon monoxide and hydrogen, or pure hydrogen in a gas turbine. However, the second option (combustion of hydrogen) is best suited for carbon sequestration, based on the cost of electricity [12]. These plants only now are becoming commercial, and as such there is variability in design and performance, thus the reported costs are not consistent. The increase in capital cost with the deployment of carbon sequestration is significantly lower than the corresponding increases in coal and natural gas plants. This is attributed to the higher concentration of CO_2 in the syngas and the high pressure of the syngas that facilitate the easier removal and compression of CO_2. Also, the efficiency penalty for IGCC plants is smaller compared with coal and natural gas plants; one reason for this is that physical solvents used in IGCC decarbonisation are less energy intensive than chemical solvents used in coal and natural gas plants.

The cost of CO_2 transport depends on the distance between the CO_2 source and the utilisation/storage site, the volume of CO_2 transferred, the terrain, the existing regulations, the inlet pressure and the presence of existing infrastructure. The economics of CO_2 transport have been discussed in detail in [13]. The cost of CO_2 transport is significantly lower than that of capture, being about €1.1 per tonne CO_2 when the throughput is 5 million tonnes annually[1] and the pipeline length is 100 km. The cost increases to €4.4/tonne CO_2 for a pipeline of 400 km. The cost of storage depends on the type of reservoir (aquifer, oil or gas reservoir, coal bed, ocean), the amount of work necessary to access the reservoir and the injection method. Roughly, the costs are within the range of €1-3/tonne CO_2 stored [14].

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[1] As an indication, a 500 MW coal power plant emits 3.5 million tonnes CO_2 annually.

Economic assessment methodology

The most common method to estimate the cost of carbon sequestration in power plants is the so-called *plant-level approach*, where the cost of electricity for a plant without carbon sequestration (called *reference plant*) is compared with the cost of electricity for a plant with carbon capture, referred to as the *capture plant*. Although this approach has several shortcomings, see for example Ref. [15], it is widely used as it can provide with an indication of the increase in costs expected with the deployment of carbon sequestration technologies.

A range of values for the COE has been reported in the literature. The observed variability results from the use of different values for variables such as reference plant performance (e.g. efficiency and load factor), reference plant capital and operating costs and more importantly cost and performance of capture technologies, fuel cost, discount rates, etc. In an effort to clarify the outcome of all these studies, investigators have re-calculated original results into a comparable set so that they can be more easily evaluated, e.g. in [5]. However, the assumptions of these analyses, and more specifically the cost of natural gas, are considered unrealistic, under the current European situation. Finally, other investigators have performed simple and probabilistic parametric analyses, e.g. [16], to overcome the issue of uncertainty.

Another way of presenting the economics of carbon sequestration is to calculate the cost per tonne of CO_2 avoided. This is also referred to as the mitigation cost, MC. The mitigation cost, in €/tonne CO_2 avoided, is calculated by diving the difference of the cost of product (electricity or hydrogen) between a reference and a capture plant to the specific CO_2 emissions avoided.

The uncertainty of the current costs associated with carbon sequestration technologies impedes our efforts to calculate accurately the today's cost of introducing carbon sequestration technologies in the power system. Unquestionably it is of greater value to know the cost of carbon sequestration in the future, in a time horizon when (and if) carbon sequestration technologies will be deployed. To be able to perform such calculations, not only the anticipated changes in costs and technology performance for power plants should be known but also for the sequestration technologies, information that is not available even for the present time. However, some predictions can be made by taking advantage experience in similar technologies. Without doubt, the cost of technologies is expected to decrease in the future because of technological improvements and innovation and the creation of larger markets. It is likely that improved solvents, membranes and adsorbers, equipment and processes can reduce both the operating cost and the capital investment required for more economic carbon sequestration technologies. Efficiencies of plants with CO_2 capture will improve as a result of technology innovation and overall improvements in power plant efficiency. Yet, projections of costs will always be speculative and cost reductions will depend on the extent to which these technologies will be utilised. Last but not least, future cost assessment requires knowledge of the development of fuel costs with time.

Estimation of the cost of deployment of carbon sequestration in electricity generation and hydrogen production in Europe in 2020

In our study, an attempt was made to calculate the costs of electricity and hydrogen produced by fossil fuels in the future taking into account the impact of introduction of carbon sequestration technologies using a plant-level approach. The time horizon for the analysis was set to 2020.

A. Electricity generation

Three types of plants were considered in this analysis: supercritical coal plants (SC), natural gas combined cycle plants (GTCC) and integrated gasification combined cycle plants (IGCC). It has been assumed that both the reference and the capture plant have the same net power output. As such, additional capital, operating and maintenance and fuel costs are incorporated in the results so that the power output is maintained. The values for the parameters that were used in this analysis are presented in Table 2. The assumptions for the costs and performance of the reference power plants (see Table 3) are based on the results of the Shared Analysis Project [17]. The corresponding parameters for the capture plants were estimated by using engineering judgement based on the following rationale: Due to technological learning, the capital cost of both reference and capture plants will decrease with time. The scenario that this analysis is based on, assumes that the capital cost decrease rate for reference plants is lower for GTCC plants (since they are a mature technology) and higher for the IGCC plants (which is a technology at its infancy). It is herein assumed that the difference in capital costs between reference and capture plants (See Table 1) will become narrower with time due to faster improvements in the capture plants, despite the fact that no significant deployment of capture technologies is expected to happen before 2020 to trigger a major learning effect. This assumed cost reduction would come from R&D improvements. Furthermore, it is assumed that the narrowing of such a cost gap will be minimal for IGCC plants, since both reference and capture plants are new technologies so improvements will happen at a similar pace. The difference of specific capital investment (SCI) between captured and reference plants in 2020 is ultimately assumed to be 10% narrower than the values reported in Table 1 for SC and GTCC plants (calculated as 65% and 77% respectively) and 5% narrower for IGCC plants (33%). The efficiencies of the capture plants were determined in an analogous approach.

Table 2: Economic basis for the plant-level economic analysis for the calculation of the cost of electricity

Parameter	***Value***
Plant size	500 MW_e
Load factor	90% for GTCC – 85% for SC and IGCC
Discount rate	10%
O&M costs	6% of capital investment for GTCC reference plants 9% of capital investment for SC and IGCC reference plants 6% of additional capital investment required for all capture plants
CO_2 transport and storage costs	Transport cost: €1/tonne CO_2 transported Storage cost: €2/ tonne CO_2 stored

Table 3 Techno-economic characteristics of power plants

Plant type	***SCI (€/kW)***	***Efficiency (%)***	***Specific CO_2 Emissions (kg/MWh)***
Reference GTCC	528	62.0	350
Capture GTCC	951	53.9	Calculated, see Table 4
Reference IGCC	1333	50.0	750
Capture IGCC	1856	41.7	Calculated, see Table 4
Reference SC	1114	51.0	750
Capture SC	1894	39.6	Calculated, see Table 4

The contribution of CO_2 transport and storage costs to the total cost of electricity was calculated based on the scenario that CO_2 is transported 100 km and injected to an aquifer. Based on the assumption that the CO_2 removal efficiency in the capture plant is 90%, the typical amount of CO_2 that is transported from a 500 MW_e coal plant is about 3.5 million tonnes annually. Based on the previous section, the transport and storage costs were set as €1/tonne and €2/tonne CO_2

respectively. Finally, fuel prices were set at €1.55/GJ for coal and €3.35/GJ for natural gas, according to Ref. [17].

The cost of electricity was partitioned into 4 components: COE due to capital investment (COE_{ci}), COE due to fuel costs (COE_{fc}), COE due to O&M costs (COE_{OM}), and COE due to CO_2 transport and storage (COE_{seq}). The latter cost component is applicable only to capture plants. The results of the analysis are summarised in Table 4 and in Figure 1.

Table 4: Calculated cost of electricity and CO_2 mitigation costs in 2020

	$GTCC_{ref}$	***$GTCC_{cap}$***	***$IGCC_{ref}$***	***$IGCC_{cap}$***	***SC_{ref}***	***SC_{cap}***
COE_{ci} (c/kWh)	0.67	1.21	1.79	2.49	1.50	2.54
COE_{fc} (c/kWh)	1.95	2.24	1.12	1.34	1.09	1.41
COE_{OM} (c/kWh)	0.40	0.72	1.61	2.03	1.35	1.98
COE_{seq} (c/kWh)	-	0.11	-	0.24	-	0.26
COE (c/kWh)	3.02	4.28	4.52	6.11	3.94	6.19
ΔCOE (%)	41.75		35.17		57.20	
MC (€/t)	40.66		24.07		34.46	
Increased fuel consumption (%)	15.0		19.9		28.8	
CO_2 Emissions (kg/MWh)	350	40.3	750	89.9	750	96.6

The results show that:

- The deployment of carbon sequestration technologies will increase the cost of electricity by 35-57% depending on the power plant technology
- GTCC technology will continue to be the most economic pathway to produce electricity, even with the deployment of carbon sequestration technologies.
- IGCC technology cannot be competitive with other electricity generation technologies when carbon sequestration is not considered. However, the deployment of carbon sequestration makes IGCC an attractive pathway, bringing the technology at the same level of competitiveness with supercritical pulverised coal plants.
- The cost of CO_2 transport and storage is unlikely to have a significant contribution to the total cost of electricity
- The main component in the cost of electricity in SC and IGCC plants is the capital cost, and in GTCC plants the cost of fuel. As such, technological developments that can reduce capital costs offer a higher potential to lower the COE in coal plants than in natural gas-fuelled plants.

The last conclusion highlights the strong dependence of electricity costs on natural gas price, given the volatility of the natural gas market. In order to identify the threshold price of natural gas, above which GTCC technology becomes equally competitive with coal-based technologies (IGCC and SC) after the deployment of carbon sequestration, an alternative scenario was considered: It was assumed that the cost of coal is 15% below the set coal price of €1.55/GJ, i.e. €1.32/GJ (low coal price scenario). The COE for IGCC becomes 5.91 c/kWh and 5.98c/kWh for SC. Therefore, overall, the COE produced from coal varies between 5.90-6.00c/kWh. The calculated threshold price of natural gas is €5.78 (low coal price). This threshold price of natural gas, in the case where carbon sequestration is not considered, i.e. based on reference plants calculations, is significantly lower, calculated as €4.64/GJ. Therefore, it is unlikely that coal-based power plants can be competitive to GTCC plants after the deployment of carbon sequestration as long as natural gas price does not exceed €5.7/GJ. Ultimately, carbon sequestration makes coal even more unattractive as a fuel for electricity generation.

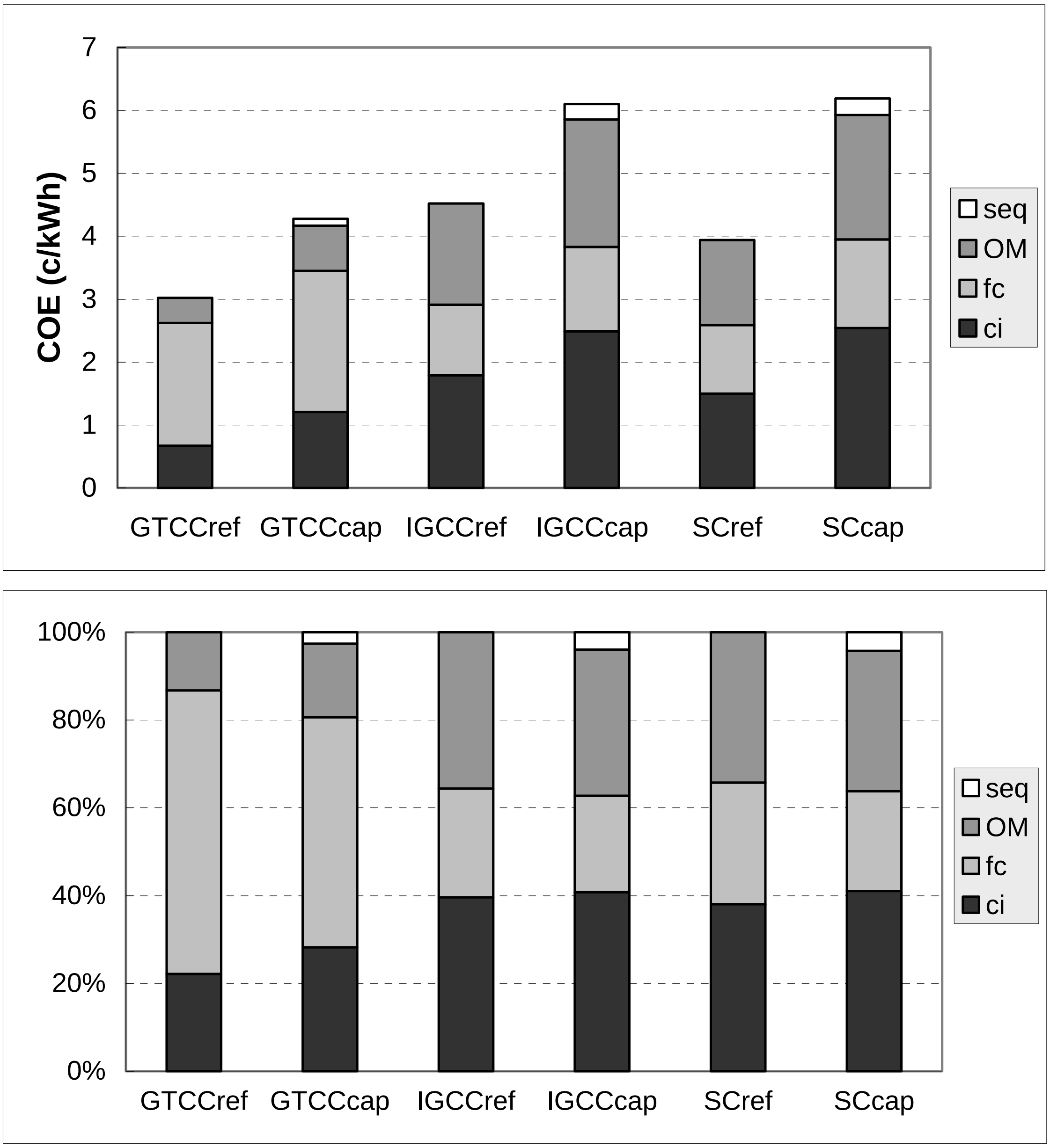

Figure 1: Calculated cost of electricity with and without carbon sequestration in 2020: absolute values (top); contribution in percentage (bottom) of capital investment costs (ci), fuel costs (fc), operation and maintenance costs (OM) and CO_2 transport and storage costs (seq) to the cost of electricity.

Obviously, the accuracy of these results depends strongly on the assumptions of the economics and performance of both the reference and the capture plants used in the baseline scenario (Table 2 and Table 3). Furthermore, our confidence in the assumptions regarding the reference plants is higher than that of the capture plants given that the former are matured technologies. To estimate the sensitivity of the results of our calculations, two alternative scenarios were considered: In a 'high technological development' scenario both SCI and efficiency of the capture plant were improved compared with the reference scenario: the difference of SCI and plant efficiency between the reference plant and the capture plant were narrowed by 10%, compared with the reference scenario. In a 'low technological development' scenario the difference of SCI and plant efficiency between the reference plant and the capture plant were increased by 10%. All assumptions are summarised in

Table 5. The results for the cost of electricity and mitigation cost are shown in Table 6. The COE changes only slightly by 2.8% for GTCC, 2.6% for IGCC and 3.4% for SC. It is interesting to note that if the slow technological development is assumed for GTCC, while a fast technological development is assumed for coal technologies, GTCC still remains the most competitive source for electricity as long as natural gas prices remain below €5.38-5.98/GJ depending on the coal price.

In conclusion, GTCC technology, even with the additional costs incurred by the deployment of carbon sequestration technologies, remains the most competitive technology for electricity generation, as long as the price of natural gas remains below approximately €5.5/GJ, depending on the coal price and the developments in power plant costs and performance.

Table 5: Assumptions on power plant economics and performance for alternative scenarios

Plant		***Reference Scenario***	***High development***	***Low development***
GTCC	***SCI (€/kW)***	951	909	993
	Efficiency (%)	53.9	54.7	53.1
IGCC	***SCI (€/kW)***	1856	1804	1908
	Efficiency (%)	41.7	42.5	40.9
SC	***SCI (€/kW)***	1894	1816	1972
	Efficiency (%)	39.6	40.7	38.5

Table 6: Results of the analysis based on the alternative scenarios

Scenario	***GTCC***		***IGCC***		***SC***	
	COE (c/kWh)	***MC (€/t CO_2)***	***COE (c/kWh)***	***MC (€/t CO_2)***	***COE (c/kWh)***	***MC (€/t CO_2)***
Reference	4.28	40.66	6.11	24.07	6.19	34.46
High	4.16	36.73	5.96	21.87	5.98	31.08
Low	4.40	44.64	6.25	26.30	6.40	37.92

B. Hydrogen production

The cost of hydrogen produced from fossil fuels in the mid-term (2020) was calculated using a plant-level approach, similar to the methodology described in the previous section. The following analysis attempts to calculate the cost of hydrogen focusing on two main pathways, namely natural gas steam reforming and coal gasification.

In contrast with electricity generation technologies, steam reforming and coal gasification, although mature technologies, they have not been widely deployed due to the limited demand for hydrogen. Reformers and gasifiers are utilised mainly in the petrochemical and chemical industry. Due to their limited deployment, cost and performance information about gasification and reforming plants is scarce in the open literature, hindering any attempt to calculate precisely the cost of hydrogen. Although the following analysis is based on the latest available information, it is understood that the degree of confidence in the results cannot be determined.

Effort was made to keep the methodology for calculating the cost the hydrogen, similar to the previously described methodology for the calculation of the cost of electricity. It was assumed that the hydrogen production plant has a capacity of 5 million Nm^3/d, which is more than 2 times larger than the largest single stream steam reformer built to date [18]. Reference plant characteristics were obtained from [19]. The characteristics of the capture plants were estimated based on the following assumptions:

- Given that CO_2 is already separated during the production of hydrogen in the reference plant, carbon sequestration requires only minor changes in the capture system and the compression of the separated CO_2. The cost for such a compressor may vary between €10-30 million [20-21]. The higher value was considered in this analysis. The SCI for the capture plant used herein were €12/GJ and €32/GJ for steam reforming and coal gasification respectively.
- The energy penalty associated with CO_2 sequestration in hydrogen production plants is 6% in line with the literature [18, 22].

As with the previous analysis, the contribution of CO_2 transport and storage costs to the total cost of hydrogen was calculated based on the scenario that CO_2 is transported 100 km and injected to an aquifer. All assumptions are listed in Table 7 and Table 8.

Table 7: Assumptions of economic parameters used in the plant-analysis for the production of hydrogen

Parameter	***Value***
Plant size	5 million Nm^3/d
Load factor	90%
Discount rate	10%
O&M costs	6% of capital investment
Fuel costs	€3.35/GJ for natural gas €1.55/GJ for coal
CO_2 transport and storage costs	Transport cost: €1/tonne CO_2 transported Storage cost: €2/ tonne CO_2 stored

Table 8: Hydrogen plant characteristics

Plant type	***SCI (€/GJ)***[2]	***Efficiency (%)***
Reference steam reformer	10	75.0
Capture steam reformer	12	70.5
Reference coal gasifier	30	50.0
Capture coal gasifier	32	47.0

As in the previous analysis, COH was partitioned into 4 components: COH due to capital investment (COH_{ci}), COH due to fuel costs (COH_{fc}), COH due to O&M costs (COE_{OM}), and COH due to CO_2 transport and storage (COH_{seq}).

Emissions have been estimated based on mass balance calculations: It was assumed that the following reactions take place:

$CH_4 + 2H_2O \leftrightarrow CO_2 + 4H_2$ (steam reforming)

$C + 2H_2O \leftrightarrow CO_2 + 2H_2$ (coal gasification)

Furthermore, it was assumed that natural gas consists of pure methane and coal contains 86% carbon. Energy content (for natural gas and coal) was converted into mass using the low heat values of the fuels (43.2 MJ/kg and 25.5 MJ/kg respectively). The results of the analysis are shown in Table 9 and in Figure 2.

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[2] For hydrogen production technologies, SCI is the total capital investment divided by the annual hydrogen production.

Table 9: Calculated cost of hydrogen and mitigation cost

	Steam reforming		***Gasification***	
	Reference	***Capture***	***Reference***	***Capture***
COH_{ci} (€/GJ)	1.00	1.20	3.00	3.20
COH_{fc} (€/GJ)	4.47	4.75	3.10	3.30
COH_{OM} (€/GJ)	0.60	0.72	1.80	1.92
COH_{seq} (€/GJ)	-	0.24	-	0.71
COH (€/GJ)	**6.07**	**6.92**	**7.90**	**9.13**
ΔCOH (%)	13.99		15.56	
MC (€/t)	**11.19**		**5.55**	
Increased fuel consumption (%)	6.4		6.4	
CO_2 Emissions (kg/GJ)	84.9	9.0	247.8	26.4

The results show that:

- The deployment of carbon sequestration on natural gas steam reforming and coal gasification will increase the cost of hydrogen by 14-16% respectively.
- Hydrogen production via steam reforming is significantly more economical than production using coal gasification.
- The cost of CO_2 transport and storage is unlikely to have a significant contribution to the cost of hydrogen.
- The cost of hydrogen as produced by steam reforming is dominated by the cost of fuel. In coal gasification, capital costs play a role equally important to the cost of fuel.

With a natural gas price of €3.35/GJ, coal gasification can be a competitive option only when coal is available at a price of €0.51/GJ. Vice versa, with a coal price of €1.55/GJ, coal gasification is competitive to steam reforming when the price of natural gas exceeds €4.90/GJ. Even, if coal price drops by 35% to €1/GJ, then hydrogen production by steam reforming is more economical as long as the price of natural gas remains below €4.01/GJ. Therefore, under the current trends of the energy market, hydrogen production via steam reforming is more competitive than hydrogen produced by coal gasification (Figure 3). Coal gasification may offer an advantage over steam reforming only under specific local conditions, i.e. abundant local coal reserves and lack of natural gas delivery infrastructure.

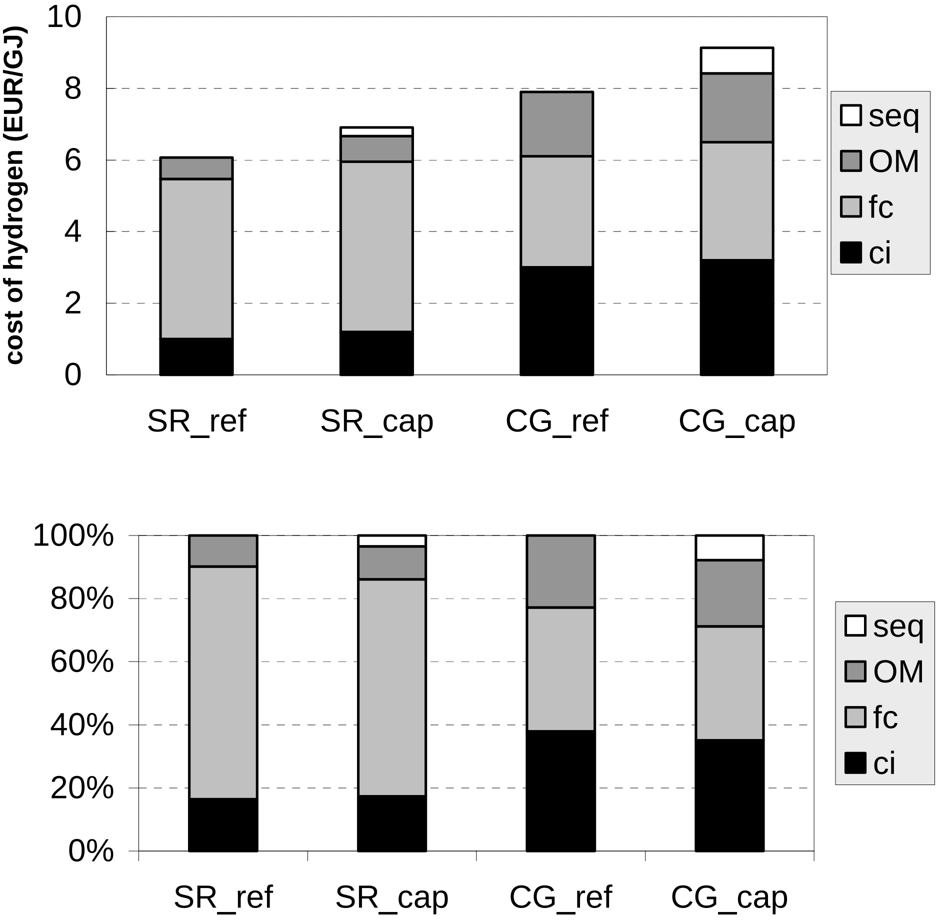

Figure 2: Calculated cost of hydrogen as produced by steam reforming (SR) and coal gasification (CG): absolute values (top); percentage contribution (bottom) of capital investment costs (ci), fuel costs (fc), operation and maintenance costs (OM) and CO_2 transport and storage costs (seq) to the cost of hydrogen.

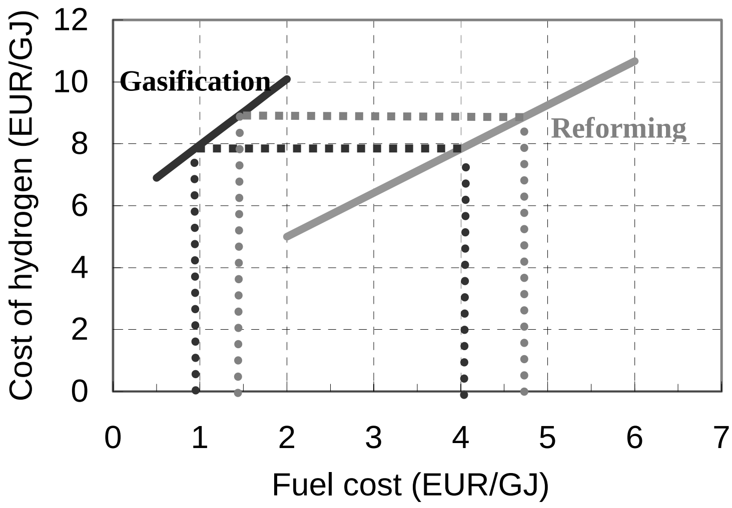

Figure 3 Cost of hydrogen as a function of fuel cost, produced by coal gasification and by steam reforming.

The additional cost introduced by the deployment of carbon sequestration to the production of hydrogen for alternative transport fuel in 2020

Driven by concerns about the security of energy supply and emissions of GHGs, the European Commission took the initiative to propose the introduction of alternative fuels in the transportation sector and set an indicative target of substituting 20% of traditional fuel by alternative fuel by 2020 [23]. Among the alternative fuels considered in the Communication of the Commission is hydrogen. The vision of the Commission is that hydrogen substitutes 5% of the energy demand of the road transport sector by 2020.

According to the European Union Energy Outlook to 2020, the total transportation energy demand in 2020 will be 358.8 Mtoe [17]. As such, the demand for hydrogen will be 17.9 Mtoe or 751 million GJ. Based on the previous section, it is herein assumed that the required amount of hydrogen will be produced by natural gas steam reforming. Based on an average plant load factor of 90%, the daily production of hydrogen should be 2.29 million GJ or 212 million Nm^3. Assuming that the daily production rate of a steam reforming plant will be 5 million Nm^3, then the number of natural gas steam reforming plants required is 43, in order to meet the demand for hydrogen.

In a scenario where there are no constraints in CO_2 emissions, the total capital cost for these plants is estimated at €7.63 billion (at a SCI of €10/GJ). Assuming an overall process efficiency of 75%, the amount of natural gas consumed annually will be 1.0 billion GJ. The total annual cost of hydrogen production will be €4.56 billion. In the process of hydrogen production, 63.7 million tonnes of CO_2 will be emitted in the atmosphere, which is equal to 8.6% of the CO_2 emissions from the road transport sector in EU15 in 1999[3] or 6.1% of the total CO_2 emissions of the transport sector in 2020 [17].

In a 'carbon sequestration' scenario where 90% of the generated CO_2 during hydrogen production will be captured and stored, the capital cost of the required hydrogen production plants will rise to €9.15 billion (at a SCI of €12/GJ). Due to the reduction of the process efficiency (to 70.5%), 6.4% additional fuel will required, i.e. 1.07 billion GJ that will cost €3.57 billion. The total annual cost of hydrogen production will be €5.20 billion. During production, 68 million tonnes of CO_2 will be generated, however, only 6.8 million tonnes will be emitted in the atmosphere (or 0.9% of the CO_2 emissions from the road transport sector in EU15 in 1999 or 0.7% of the total CO_2 emissions of the transport sector in 2020), while 61.2 million tonnes will be stored annually. Assuming that each hydrogen production plant is associated with a single storage site, then 1.4 million tonnes of CO_2 will be stored annually in each of the 43 geological storage sites. It is noted that the annual storage rate at Sleipner is 1 million tonnes, while the annual use of CO_2 for EOR worldwide is 40 million tonnes.

Overall, under a 'carbon sequestration' scenario annual costs are increased by €640 million compared with an 'unrestricted emissions' scenario for the production of 751 million GJ of hydrogen annually, while 56.9 million tonnes of CO_2 are avoided, at a cost of €10.95/tonne CO_2. The results are summarised in Table 10.

Table 10: Economics of hydrogen production (with and without carbon sequestration) to meet the demand for hydrogen by the transport sector in 2020.

	No CO_2 constraints	*Carbon sequestration*	*Difference*
Capital cost	€7.63 billion	€9.15 billion	€1.52 billion
Natural Gas consumption	1.00 billion GJ	1.07 billion GJ	~ 70 million GJ
Annual cost of hydrogen production	€4.56 billion	€5.20 billion	~ €640 million
CO_2 emissions	63.7 million tonnes	6.8 million tonnes	56.9 million tonnes

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[3] The CO_2 emissions from road transport in EU15 in 1999 were 743.3 million tonnes [24].

Conclusions

Our economic assessment of the effects of deployment of carbon sequestration on electricity generation in Europe in 2020, has shown that:

- the cost of electricity will be increased by 35% to 57% depending on the electricity generation option
- GTCC will remain the most competitive option for electricity generation
- IGCC will become equally competitive to PC technology, and,
- Unless coal prices drop dramatically (or natural gas prices increase significantly) natural gas will remain the fuel of choice for electricity production.

Our analysis of the effects of deployment of carbon sequestration on hydrogen production in Europe in 2020, has indicated that:

- the cost of produced hydrogen using natural gas steam reforming or coal gasification will increase by 14-16% respectively
- hydrogen production via steam reforming is significantly more cost effective than production by coal gasification,
- the cost of hydrogen produced by steam reforming is dominated by the cost of fuel; and,
- unless coal prices drop dramatically (or natural gas prices increase significantly) natural gas will be the most cost effective fuel to produce hydrogen.

Finally, our assessment on the introduction of hydrogen as an alternative transport fuel in Europe in 2020, indicates that the CO_2 mitigation cost will be relatively small (€11/tonne CO_2 avoided), based on the assumption that all required hydrogen will be produced by natural gas steam reforming, equipped with carbon sequestration with 90% capture efficiency.

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