EET/2003/01

IEA/EET Working Paper

Uncertainties in relation to CO_2 capture and sequestration. Preliminary results.

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March 2003

INTERNATIONAL ENERGY AGENCY

Report Number EET/2003/01
Paris, 25 March 2003

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Abstract

This paper has been presented at an expert meeting on CO_2 capture technology learning at the IEA headquarters, January 24th 2003. The electricity sector is a key source of CO_2 emissions and a strong increase of emissions is forecast in a business-as-usual scenario. A range of strategies have been proposed to reduce these emissions. This paper focuses on one of the promising strategies, CO_2 capture and storage. The future role of CO_2 capture in the electricity sector has been assessed, using the Energy Technology Perspectives model. Technology data have been collected and reviewed in co-operation with the IEA Greenhouse Gas R&D implementing agreement and other expert groups. CO_2 capture and sequestration is based on relatively new technology. Therefore its characteristics and its future role in the energy system is subject to uncertainties, as for any new technology. The analysis suggests that the choice of a reference electricity production technology and the characteristics of the CO_2 storage option constitute the two main uncertainties, apart from a large number of other factors of lesser importance. Based on the choices made cost estimates can range from less than zero USD for coal fired power plants to more than 150 USD per ton of CO_2 for gas fired power plants. The results suggest that learning effects are important, but they do not affect the CO_2 capture costs significantly, other uncertainties dominate the cost estimates. The ETP model analysis, where choices are based on the ideal market hypothesis and rational price based decision making, suggest up to 18% of total global electricity production will be equipped with CO_2 capture by 2040, in case of a penalty of 50 US$ per ton of CO_2. However this high penetration is only achieved in case coal fired IGCC-SOFC power plants are developed successfully. Without such technology only a limited amount of CO_2 is captured from gas fired power plants. Higher penalties may result in a higher share of CO_2 capture and sequestration. While CO_2 capture technology will be important for the future role of coal, the model results suggest that the future role of natural gas is not affected significantly. Model results indicate only limited competition between CO_2 capture and renewables. Both CO_2 mitigation strategies show a significant growth in case of the 50 USD/t CO_2 penalty. In conclusion it is recommended to develop CO_2 capture and sequestration technology, to reduce remaining uncertainties regarding the permanence of CO_2 storage, and to reduce the costs of this strategy through advanced power plant designs.

In a next step, this model will be further developed with CO_2 capture in industry and in other parts of the energy sector. A report on CO_2 capture and sequestration, building on the work that is described in this paper, is planned for the fall of 2003.

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1. Introduction

Various studies suggest that CO_2 capture and sequestration could become a key technology for achieving a significant emissions reduction. However the results differ with regard to the costs of such a strategy. A number of recent papers have addressed this issue, e.g. (Rubin and Rao, 2002). This uncertainty is important for policy makers because it affects the conclusion whether CO_2 capture and sequestration is a good strategy or not. Also the competition between gas and coal is affected significantly by the data used. The competition between coal and gas is a key energy policy issue, therefore the model input data require close assessment. The Energy Technology Perspective (ETP) model structure for CO_2 capture is shown in figure 1. The storage options have been described in quite some detail in order to allow sensitivity analysis (e.g. to consider only offshore storage because of public concerns).

Figure 1

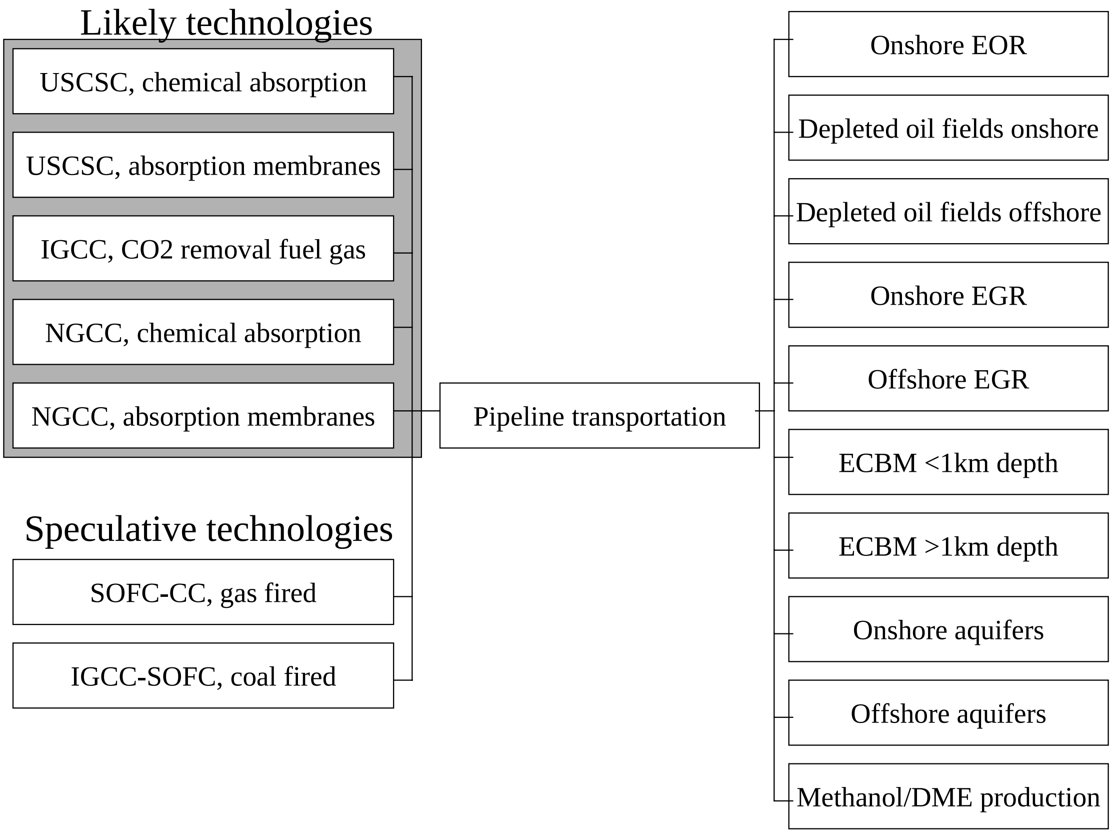

Figure 1: ETP model structure for carbon capture and sequestration.

The goal of this paper is to quantify the uncertainties, and to develop policy strategies how to deal with these uncertainties. "Uncertainties" includes methodological issues and technology characteristics that will affect the cost-effectiveness of CO_2 capture ad storage. The discussion is based on the data that have been gathered for the MARKAL systems engineering model that is being developed in the ETP project (Gielen and Unander, in preparation). Note that CO_2 capture is not a particularly uncertain technology. In fact, it should be considered much more of a "proven" technology than many renewables supply options or advanced nuclear reactors. CO_2 capture has been applied successfully for decades in the production of ammonia, hydrogen, and direct reduced iron (DRI). The difference in uncertainty between CO_2 capture and other new technologies is a relevant issue for policy makers. This paper deals only with the uncertainty for CO_2 capture, a first step in this assessment.

In recent years a significant number of papers focusing on CO_2 capture have been published. The basis and the approach differ considerably. Basically there are three types of studies:

- Engineering assessments – focusing on one specific proven technology, high confidence (cost accuracy +/- 25%);
- Comparative studies – combining data from different engineering studies;
- Modeling assessment studies based on software packages such as ASPEN. This is the only way to assess new technologies. However the data are more uncertain. In fact the feasibility of the technology is in some cases uncertain.

A model with a broad time horizon (2050 in the ETP case) needs data from different sources with a different level of accuracy. Generally speaking new technologies will look more attractive, but the data are more uncertain. The model does not account for data uncertainty, so without proper guidance more cost-effective speculative technologies are selected instead of less attractive proven technologies. Therefore the model should contain a balanced dataset, and care is required regarding the conclusions that are drawn from any model run including speculative technologies. On one hand, considering only proven technologies increases the credibility of the study. On the other hand, technological change may be very important and may lead to radically different policy conclusions.

The focus of this paper is on gas and coal fired power plants with CO_2 capture. Basically CO_2 could also be recovered from industrial plants such as refineries (coking units, hydrogen production), blast furnaces and cement kilns, see e.g. Gielen (2003). However the potential in the electricity sector is dominant. This neglects the future potential for hydrogen energy systems with CO_2 capture and sequestration, which could become of similar importance on the long term.

Note that some experts suggest that public acceptance and legal obstacles may pose serious issues for the introduction of CO_2 capture and sequestration. Such issues are beyond the scope of this paper.

2. Technology data and uncertainties

The costs for CO_2 capture and sequestration depend on
- Methodological choices;
- Technology performance forecasts;
- Costing/pricing approaches.

These three categories will be discussed separately.

2.1. The impact of methodological choices

The following issues will be discussed:
- The selection of a reference technology (Freund, 2002);
- Electricity or CO_2 valuation;
- Energy system boundaries (full fuel cycle emissions or power plant emissions, only capture or capture, transportation and storage);
- Economic life cycle system boundaries (including R&D and learning investments or not);
- Crediting of supply security benefits;
- Regional system boundaries: costs for the national economy vs. costs for the global economy.

2.1.1. The selection of a reference technology

The choice of a reference system based on costing or marginal costing is crucial for estimating CO_2 emission mitigation costs. In a costing approach, identical power plants with and without CO_2 capture equipment are compared (the two IGCC options in figure 2). In this case the CO_2 capture costs amount to 15 USD per ton of CO_2. In a marginal costing approach, the system boundaries are chosen much broader. The reference plant is the plant with the highest marginal supply costs in the base case without CO_2 policies, i.e. the plant that sets the product price in an ideal market (as simulated by MARKAL-ETP). By definition the electricity costs will be lower than for the alternative with CO_2 capture.

In fact the IGCC power plant with CO_2 capture can be compared to all types of competing power plants, with different electricity prices and different CO_2 emissions. The example in figure 2 shows that the CO_2 capture costs can vary from 25 USD per ton CO_2 up to 95 USD per ton CO_2, depending on the reference chosen. Some of the references suggest even no emission reduction at all for the IGCC with CO_2 capture. Of course the latter case is hypothetical because e.g. the supply of hydro is limited in most developed countries, while the cost for Photovoltaic electricity (PV) are very high. Therefore these “random” reference choices have no policy relevance.

Which reference is relevant for the policy maker depends on the energy system characteristics (supply and demand characteristics). A comparison of an identical plant with and without CO_2 capture (a costing approach) does not reflect the real costs to society in case of a greenfield investment decision. In the MARKAL approach, the reference plant is the highest cost supplier. This represents the marginal producer. Generally speaking this will result in higher cost estimates for CO_2 capture than a costing approach, e.g. in case the NGCC is the marginal producer. Competing emission reduction options (in other sectors) are considered explicitly. The model is run with an exogenous CO_2 price, so this approach does not affect the CO_2 value in the electricity sector directly. However the electricity price and electricity demand may change in this energy systems approach in a CO_2 policy case, compared to a base case. This may affect the choice of the reference electricity plant.

2.1.2. Electricity or CO_2 valuation

There are two variables in the analysis: the electricity price and the CO_2 price. If one of them is fixed, the other one can be calculated. In case only the electricity sector is analysed, policy makers are mostly interested in the CO_2 emissions reduction costs at a fixed electricity price. However a comparison across sectors is only possible if the value of CO_2 emissions (or emission reductions) is fixed and the costs for electricity supply are calculated, including the CO_2 emissions costs.

This allows for comparison of measures outside the electricity sector. For example policy makers and electricity producers have the option to buy emission reduction credits on the market. Especially in the case of moderate emission reduction targets (e.g. the Kyoto targets), the price of these credits may be well below the costs of CO_2 capture. In case this marginal costing reference is a PFBC in combination with landfill gas credits and the credit price is 5 USD per ton of CO_2, the cost for CO_2-free electricity is 34 mills per kWh, compared to 55 mills per kWh for the IGCC with CO_2 capture (figure 2). Again, there is no reduction of CO_2 emissions for the IGCC with CO_2 capture if such a reference is chosen. In conclusion CO_2 capture data from literature are meaningless if the reference is not well defined. Usually data from different studies will be incomparable. This is a strong argument to use one integrated model (such as the ETP model) for proper comparison.

Figure 2

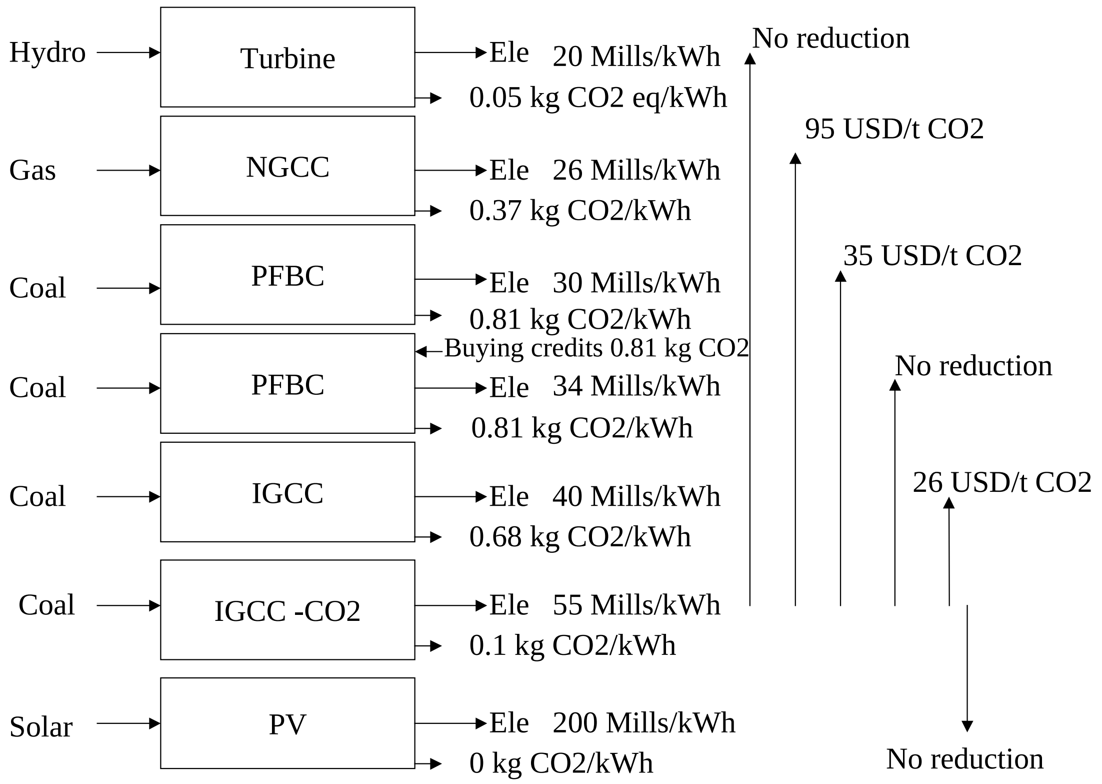

Figure 2: Electricity production costs, CO_2 emissions and CO_2 capture costs for IGCC (IGCC-CO_2), in comparison to different reference electricity supply systems. Figures are indicative (see table 1). Covers only direct emissions. NGCC Natural Gas fired Combined Cycle. PFBC Pressurized Fluid Bed Combustion. IGCC Integrated Gasification Combined Cycle. PV PhotoVoltaics.

2.1.3. Emissions consequences of life cycle systems boundaries

Life cycle emissions and power plant emissions can differ to a considerable extent. This is not relevant in case a costing reference is chosen (where upstream emissions are almost identical for the reference power plant and the power plant with CO_2 capture), but it may be very relevant in the case of marginal pricing (where different fuels may have very different upstream emissions). Spadaro et al. (2000) suggest 21-28% upstream emissions for coal, and 20-12% upstream emissions for gas. They decline to 14% and 18%, respectively, in the 2005-2020 period. For renewables and nuclear, upstream emissions are generally considerably lower than for fossil fuels[1]. Goal of the following assessment is to show the regional diversity in life cycle emissions factors that must be accounted for.

One reason why life cycle emissions are considerably higher than direct emissions during fuel combustion is the energy use for fossil fuel production, transportation and processing. The CO_2, methane (CH_4) and nitrous oxide (N_2O) emissions during production and processing constitute another reason.

In the case of coal, methane emissions are most relevant. CH_4 emissions depend on the deposit type (high for deep mines, negligible for open pit mines), the geological history of the coal deposit and the application of methane recovery technologies. The methane content can range from 0 to 25 m^3 per tonne of coal (0 to 14 kg CO_2 equivalents per GJ) (IEA, 1994). This increases the emissions per ton of coal by 0 to 15%. Generally speaking the methane content increases with the depth of the coal deposit. Proper recovery technologies can reduce these emissions significantly.

Apart from CH_4, the CO_2 emissions during mining and transportation matter. While coal mining represents about 1% of the direct emissions during coal use, the emissions for coal transportation from Australia to Europe amount to 4% of the direct emissions during use (IEA Coal Research 1997). In conclusion upstream emissions can amount up to 20% of the emissions during coal use.

In the case of gas fired power plants, both energy use during transportation and CH_4 leakages during production and transportation can be relevant.

The bulk of natural gas is transported via pipelines. In 1998, there were 857,000 kilometres of natural gas pipelines worldwide, supplying about 20% of global energy (about 85 EJ). However gas is still mainly a regional energy source, constrained by high transportation costs. Only 16% of total world gas production moves internationally by pipeline. Transportation energy requirements depend on the transportation distance. The energy consumption for trunk pipelines amounts to 2.5% per 1000 kilometres. Therefore especially long-range (international) transport of natural gas results in a significant transportation energy use.

A 15-20% reduction of the energy consumption for pipeline transportation can be achieved through pipeline and compressor optimization (Wu et al. 2000). Also increased pressure can reduce losses. Ercolani and Donati (2000) indicate for a 5,000 km pipeline 12-13% losses in a low pressure operating mode (current practice), while future high pressure pipelines would result in a 3.7% loss for the same transportation distance. This represents a saving of 70%.

In some regions natural gas losses from pipelines are substantial. Globally, most emissions arise within Russia, which is responsible for an estimated 50-55% of the total (around 25 Mt CH_4). Long transportation distances, permafrost conditions and insufficient maintenance cause these high losses. (PNNL, 2001). The Russian losses can be split into losses from the transmission and production

[1] This excludes solar PV and low head hydro in the tropics, because of methane emissions from forest flooding.

segments (around 1.5%) and losses from the distribution segment (around 1.2%) (PNNL, 2001, pp. 29). A 1.5% loss equals a CO_2 emission of 6.3 kg CO_2/GJ. On top of that there is gas consumption for transportation, which amounts to 10% of the gas throughput (about 5.6 kg CO_2/GJ) (PNNL, 2001, p. 13). Adding transmission losses and energy use for transmission suggests an indirect emission of 11.9 kg CO_2 equivalents per GJ. A significant share of the Russian gas is transported to Western Europe. For proper comparison of gas vs. coal for Western European power plants, these emissions should be accounted for. In the US, production, processing and transmission losses are lower due to better maintenance and shorter transportation distances. Transportation losses amount to 1.2%, and distribution losses amount to 0.4% (PNNL, 2001, p.p. 29). This equals 7 kg of CO_2 per GJ. In conclusion upstream gas emissions can range from negligible for well-maintained supply systems close to the consumer up to 20% for Russian Gas supplied to Europe. Currently available technology is capable of reducing methane emissions by a factor four by the year 2010 (IEA GHG, 2002). On the long term transportation energy requirements may be reduced by a factor three.

Apart from international pipeline transportation, liquefied natural gas (LNG) shipping plays an increasingly important role for long distance transportation. About 90 Mt of LNG (about 4.5 EJ) were transported by sea in 1999, mainly to Japan, Korea and France. LNG production and transportation constitute a source of CO_2 and CH_4 emissions. Emissions during transportation amount to 1.5 kg CO_2/GJ. Total emissions amount to more than 10 kg CO_2 per GJ (almost 20% of the emissions during combustion) (Tamura et al., 2001).

This brief analysis suggests that upstream emissions are not negligible in the coal vs. gas comparison for power plants. The characteristics of the specific supply chain must be accounted for, global averages make no sense. Depending on the supply chain the upstream emissions can amount to 0-20% of the emissions for the power plant. Upstream emissions are bound to decline because of technological progress. At the same time they may increase because of increasing transportation distances and a shift from pipelines to LNG, driven by resource exhaustion. The net impact is probably a slight decline of emissions.

Downstream of the power plants, the consideration of CO_2 compression for transportation and storage is an important issue. For a coal fired power plants it makes a 2% efficiency difference (in absolute terms, 4% in relative terms) if the CO_2 compression to 100 bar is accounted for or not (Dijkstra and Jansen, 2002). 100 bar is sufficient pressure for transportation and storage at depths up to 800 metres. For deeper reservoirs (especially gas fields), higher pressures of up to 200 bar may be required. The energy consumption for pressurization increases accordingly[2].

Leakage from underground CO_2 reservoirs to the atmosphere may become an issue. So far the experience with storage is very limited. The only reference are natural oil, gas and CO_2 reservoirs, where resources have been stored for millions of years. However these examples can not prove that all reservoirs are suitable for CO_2 storage. There are plenty of formations that do not contain oil or gas, but that may have contained some in the past. Also cap rocks can be damaged by exploitation, e.g. the land usually sinks because of gas production, a clear indication of changes in the underlying sediment structure. Leakage may be delayed, and it may occur some distance from the reservoir, or there may be a time lag between storage and leakage. Therefore any estimate is speculative. However given the time horizon of the CO_2 problem of hundreds or even thousands of years[3], even small leakage rates may be of importance for the net capture efficiency and the costs per ton of CO_2. For example in the case of oceanic storage, 0-50% of the original amount of CO_2 stored may be released after 200 years, depending on the depth of injection (Caldeira, 2002). Because of the lack of data for underground reservoirs, any estimate is speculative. The costs increase by 5 to 100% for a 5 to 50% leakage, which

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[2] But not proportionally. There is far less energy required to increase the pressure from 100 to 200 bar than from 1 to 100 bar.

[3] Eventually all CO_2 may be absorbed in the ocean. However this is a very slow process, taking thousands of years. Also fossil fuel resources are abundant (especially coal), and therefore the “age of fossil fuels” may last for several centuries more.

should be considered high leakage rate estimates in case the reservoirs are chosen carefully. It is likely that leakage can be minimised through proper design and operating procedures.

2.1.4. R&D and learning investments

The US Coal Utilization and Research Council estimates that the development of CO_2 capture systems for coal fired power plants will cost 0.94 billion USD up till 2020. Demonstration systems will cost another 1.35 billion USD (CURC, 2002). The next step would be to bring costs down through deployment (so-called learning investments) (IEA, 2000). Note that the R&D costs are rather limited, compared to the quantities of CO_2 involved. If a cumulative quantity of 2 Gt CO_2 is stored (a low estimate, it may be a factor 100 more), the R&D costs amount to 1 USD/t CO_2, which is negligible.

2.1.5. Supply security benefits

The introduction of CO_2 capture technology can affect the use of gas and coal in the electricity sector. The supply of natural gas could be considered less secure than the coal supply, because key supply regions such as the Former Soviet Union and the Middle East are widely considered to be politically less stable. Also gas supply is based on large volume pipelines and LNG terminals that are vulnerable to disruption, while coal supply is more diverse. Also a surging gas demand could result in higher gas prices and a higher dependency on the Middle East and the FSU. However the ETP modeling results that are discussed below suggest that the impact on gas demand is very limited, therefore there are no significant supply security benefits.

2.1.6. Costing consequences of regional systems boundaries

Most oil and gas are imported in the IEA member countries, while coal is often an indigenous resource (e.g. in the US). Therefore using coal instead of oil and gas will have beneficial effects on the trade balance[4]. Also coal mining is a labour intensive activity, often in regions with few other economic activities. Therefore coal mining can enhance the regional distribution of economic activity, depending on the location of resources. This is an important consideration in many countries. The marginal cost of coal depends on alternative use of the labour pool and capital. In an economic environment with unemployment and low interest rates, one could argue that coal is virtually “for free” from a national perspective. This valuation would enhance the benefits of coal with CO_2 capture in comparison to other CO_2-free fuels. Instead a global perspective does not reveal such benefits[5].

2.2. *Technology performance forecasts*

The following key issues that influence the technology performance will be discussed in this section:

- The power plant type where sequestration is applied;
- Economies of scale;
- The reference year and the assumptions for technology learning;
- The benefits from CO_2 sequestration (in case of EOR, EGR and ECBM);
- Transportation distances.

[4] Autonomy in itself is not important. However in a situation with a significant trade deficit, such as the current case for the USA, impacts on the trade balance may constitute a policy relevant issue.
[5] Note that some studies suggest that the oil revenues of the oil-exporting countries have been misallocated over the past 25 years (Askari and Jaber, 1999). This misallocation could be considered a type of costs.

2.2.1. The impact of the power plant type

At this moment CO_2 capture technology is mainly based on chemical absorption from flue gases. The chemical absorption process (current technology) is inherently inefficient. Steam consumption for the latest systems is on average about 1.5 ton low pressure steam per ton of CO_2 recovered (3.2 GJ/t) for a system with 90% recovery (slightly higher for higher recovery rates) (Mimura et al. 2002). The recovery energy declines from 3.4 to 2.9 GJ/t for CO_2 concentrations increasing from 3 to 14% (18 to 26% of the fuel input, respectively). The extremes represent the conditions for NGCC exhaust gas and coal fired power plants. Costs amount to 20-30 USD/t CO_2 for coal and gas fired systems, respectively[6] (Iijima and Kamijo, 2002).

Four strategies are proposed to enhance the recovery energy efficiency and reduce capture costs (Dijkstra and Jansen 2002, NPD 2002).

- CO_2 capture from pressurized gas flows at the front-end or at the back-end (resulting in lower gas volumes to be treated and the possibility to use physical adsorption systems);
- The use of absorption membranes for CO_2 separation at the back-end;
- The use of oxygen for combustion, either for front-end or for back-end separation;
- Solid oxide fuel cell systems with CO_2 capture at the back-end that combine the first three elements with a very high electric efficiency.

Coal gasification, shift reactors, hydrogen separation and hydrogen turbines play a crucial role in case of front-end CO_2 removal (Dijkstra and Jansen, 2002). Already existing GE F-class turbines can accept gas containing 45% H_2. The efficiency of pre-combustion natural gas reforming incl. membranes is forecast to be slightly higher than for current post-combustion absorption systems (around 2010 60% electric efficiency for CC, 51% for post-combustion amine absorption systems and 47% for pre-combustion natural gas reforming)(NPD, 2002). However in comparison to post-combustion absorption membrane systems, efficiency gains are marginal. Also the efficiency of gas fired oxy-fuel systems is forecast to be lower than for post-combustion absorption (mainly due to the oxygen requirements three times higher than for IGCC (Williams, 2000)). However for IGCCs pre-combustion CO_2 removal in combination with hydrogen turbines will be essential.

Note that the efficiency of systems using oxygen depends critically on the energy requirements for oxygen production. New inorganic membrane based separation systems may reduce the energy requirements from 235 kWh/t O_2 for cryogenic separation to 147 kWh/t (Stein and Foster, 2001). For an IGCC this implies an increase by 3.2% in absolute terms (7% in relative terms). At the same time the costs of the oxygen production are reduced by 35%, which reduces the investment costs for IGCC by 75 USD/kWh. Similar figures apply to gas based systems. These figures suggest that new oxygen separation systems are a key for reaching IGCC efficiency targets of 50-52%.

It has been mentioned before that the assessment of the coal/gas competition requires a consistent dataset. It makes no sense to consider technology improvements for one fuel and not for the other. Because of the similar conversion technologies it is possible to compare long-term efficiencies for gas and coal based electricity generation. An IGCC with CO_2 capture can be considered as a gas based combined cycle with coal gasification, oxygen production, steam reforming and CO_2 separation as additional elements. The oxygen requirements amount to 0.093 kWh/kWh, CO_2 capture requires 0.082 kWh/kWh, the gasification efficiency is 90%[7], future combined cycles achieve 60% efficiency. Energy requirements for steam reforming are negligible. Therefore the net efficiency of the IGCC without CO_2 capture is 48.9% efficiency, while the efficiency of IGCC with CO_2 capture is 0.9*60*(1-0.093-0.082)=44.6%. This back-of-envelope assessment does not account for the higher efficiency of IGCC combined cycles, compared to gas fired combined cycles. Even higher efficiencies

[6] Based on (optimistic) assumptions of 10% discount rate, fuel gas 1 USD/GJ, electricity price 20 mills/kWh, 135 bar CO_2 pressure.

[7] This is a crucial assumption. Some studies suggest gasification efficiencies as low as 75%, which seems rather low for large scale gasification units.

can be achieved in case the gasification energy efficiency can be increased, which depends on the gas cleaning technology (low temperature or high temperature gas cleaning). This explains the higher efficiency figures in table 1 for the 2020 coal IGCC option (50% vs. 48.6%).

This leaves in the long run three competing systems:

- gas fired combined cycles with post-combustion chemical absorption or membrane systems;
- ultrasupercritical coal fired power plants with post-combustion amine absorption, from 2015 onward; equipped with membrane absorption systems (or precombustion decarbonisation systems (IEA 1998c);
- gas or coal fired SOFC integrated with combined cycles.

The efficiency of the new capture technologies is significantly higher than for existing technologies (table 1). Note the resulting cost reduction per ton CO_2: 45% for coal fired power plants, but almost constant costs for gas fired power plants. Note that this excludes any economies of scale.

Table 1: Current ETP model efficiency and cost assumptions for gas and coal fired power plants with and without CO_2 capture and sequestration. CA = Chemical Absorption. CC = Combined Cycle. SOFC = Solid Oxide Fuel Cell. Comparison based on 10% discount rate, 30 year process life span. Coal price 1.5 USD/GJ; gas price 3 USD/GJ. CO_2 product in a supercritical stage at 100 bar. CO_2 transportation and storage is not included. Based on (IEA GHG 2000, David and Herzog 2000, Dijkstra and Jansen 2002, Freund 2002, internal IEA data). CO_2 capture costs are expressed relative to the same power plant without capture.

Technology type	Fuel + type	Starting year	INV [$/kW]	FIX [$/kW.yr]	Eff [%]	Loss [%]	Capture Eff. [%]	Ele costs [Mills/kWh]	Capture costs [$/t CO_2]
Likely	*No CO_2 capture*								
	Coal steam cycle	2010	1075	23	43			29.1	
	Coal steam cycle	2020	1025	31	44			29.2	
	Coal IGCC	2010	1455	57	46			37.4	
	Coal IGCC	2020	1315	50	50			33.8	
	Gas CC	2005	400	14	56			26.1	
	Gas CC	2015	400	14	59			25.2	
	CO_2 capture								
	Coal steam cycle – CA	2010	1850	80	31	-12	85	51.0	24
	Coal steam cycle – membranes +CA	2020	1720	75	36	-8	85	46.3	21
	Coal IGCC – Selexol	2010	2100	90	38	-8	85	52.3	20
	Coal IGCC – Selexol	2020	1900	75	45	-5	85	45.6	18
	Gas CC – be CA	2010	800	29	47	-9	85	36.8	29
	Gas CC – fe Selexol	2020	900	33	51	-8	85	36.8	35
Speculative	*No CO_2 capture*								
	Coal IGCC-SOFC	2030	1800	75	60			41.3	
	Gas CC + SOFC	2025	800	40	70			30.6	
	CO_2 capture								
	Coal IGCC – SOFC	2035	2100	100	56	-4	100	49.0	13
	Gas CC + SOFC	2030	1200	60	66	-4	100	39.2	28

2.2.2. Economies of scale

Unit production costs decline as the production capacity of equipment increases. Engineering literature usually suggests a 20% cost reduction for a power plant twice as large. The same scaling factor may apply to CO_2 capture, transportation and storage. Off course the size of power plants is limited by the regional electricity market size, as distribution losses increase with the electricity transportation distance. However a doubling from 400 MW to 800-1000 MW seems feasible. This would allow a cost reduction of 20%. These savings can be combined with the substitution of the power plant as discussed in the previous section.

2.2.3. The reference year and the assumptions for technology learning

Riahi, Rubin and Schrattenholzer (2002) have used the IIASA MESSAGE model to assess the impact of learning effects. They assume a progress ratio of 87% (a conservative estimate compared to other emerging technologies, based on learning for desulphurization technologies). The cumulative capacity is 1 GW[8] for the starting year, and initial costs amount to 45 USD/t CO_2 for capture from coal fired power plants and 30 USD per ton CO_2 for capture from gas fired power plants. This excludes transportation and sequestration, note the difference with the figures in table 1. Costs are reduced by a factor four by the end of the century, when 90% of all power plants are equipped with carbon capture. While the progress ratio constitutes an assumption that may be disputed, these calculations indicate the potential importance of learning effects. These learning effects may include some technology substitution, (e.g. introduction of SOFCs with CO_2 capture as an add-on to hydrogen fuelled combined cycles) and economies of scale. Note that this 75% cost reduction exceeds the combined cost reduction for technology substitution and economies of scale to a considerable extent. However the starting value for coal is much higher than in the ETP model (45 vs. 24 USD/t CO_2). The starting value for gas is close to the ETP assumption. Therefore the cost reduction for coal corresponds to the bottom-up analysis, while the cost savings for gas seem rather optimistic.

2.2.4. Potential benefits from CO_2 sequestration

In recent years Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) and Enhanced Coalbed Methane (ECBM) production have received a lot of attention. These are CO_2 storage options that could create benefits because of enhanced fossil fuels production. The main characteristics are listed in Table 2. The benefits amount to 0-35 USD per ton of CO_2 (excluding the costs for the wells and CO_2 recycling). Compared to the capture costs of 19-51 USD per ton CO_2, there is a potential to offset part or even total capture costs. EOR creates the highest benefits, followed by ECBM and EGR. However in most cases the costs will exceed the benefits. Also the potential for enhanced fossil fuel production is limited by the reservoirs available.

CO_2-EOR costs have dropped dramatically since the 1980s, from more than 1 million USD per pattern, to less than half of that. CO_2 prices have also fallen by 40%. Of course, flood costs vary depending on field size, pattern spacing, location and existing facilities, but in general, total operating expenses (exclusive of CO_2 cost) range from 2 to USD3 per barrel (bbl), or about 10% more than waterflood operating expenses. Costs can be split into capital costs (about 0.8 USD per bbl), operating cost (2.7 USD per bbl), royalties taxes and insurance 3.6 USD per bbl and CO_2 costs (3.25 USD per bbl) (Kinder Morgan, 2002). Typically, to CO_2 flood a field, the field should have original oil in place of more than 5 million barrels, and have more than 10 producing wells (Kinder Morgan, 2002). In the case or EOR, total production costs (excluding CO_2 costs) are approximately 7 USD per bbl oil (about 50 USD per t oil). At a wellhead oil price of 15 USD per bbl and assuming an injection rate of 2.5 t CO_2/t oil, the profit amounts to 25 USD per ton CO_2. Note that this is an extreme case due to the unusual geology of these oil fields, the benefits will be lower for most other fields.

CO_2 can be transported via pipelines, by tank wagons and with ships. Because of the huge volumes involved, in practice only pipelines and ships are cost-effective options. Costs depend on the distance and the volumes, ranging from 1 to 10 USD/t CO_2. While pipeline transportation is an established technology, CO_2 transportation by ship is not. This may become an important issue because the prime locations for underground CO_2 storage do not coincide with the CO_2 source locations. For example

[8] About 100 Mt ammonia is produced annually, 150 –200 Mt CO_2 is captured in the process. The cumulative ammonia capacity is 300-400 Mt CO_2. A similar cumulative capacity of hydrogen production with CO_2 capture exists in other industries. Total cumulative capacity equals 80 to 110 GW (coal fired) power plants. In case the MESSAGE model would be run with this higher initial capacity, the results might look quite different.

the bulk of the conventional oil reserves is located in the Middle East, the main gas reserves occur in the Middle East and Russia. The main emission sources can be found in the population centres of OECD countries, future emission growth will be concentrated in developing regions such as Eastern China. Therefore the mismatch of sources and sinks locations constitutes a limitation for underground CO_2 storage, unless cost-effective inter-regional transportation systems are developed. With regard to ECBM the coal reserves are more evenly spread around the globe, some reserves are close to the main population centres.

Table 2: Characteristics of carbon sequestration options that enhance fossil fuels production.

	EOR	EGR	ECBM
Benefits[9]	0.33-0.42 t oil/t CO_2	0.03-0.05 t methane/t CO_2	0.08-0.2 t methane/t CO_2
	\$25-\$35/ t CO_2	\$1-\$10/t CO_2	\$3-\$20/t CO_2
Limitations	Oil gravity at least 25º API Primary and secondary recovery methods have been applied Limited gas cap Oil reservoir at least 600 metres deep Local CO_2 availability	Depleted gas field Local CO_2 availability	Coal that cannot be mined Sufficient permeability Maximum depth 2 km Local CO_2 availability
Global potential (cumulative)			
2010-2020	35 Gt CO_2	80 Gt CO_2	20 Gt CO_2
2030-2050	100 Gt CO_2	700 Gt CO_2	20 Gt CO_2

EOR is an established technology. The additional recovery amounts to 8-15% of the total quantity of original oil in place, which increases total oil recovery by one third for an average field. About 45 Mt CO_2 per year is used for EOR. Most existing EOR projects are located in the United States. EOR is limited to oil fields at a depth of more than 600 metres. The oil should have a gravity of at least 25º API (at most 904 kg/m^3). At least 20-30% of the original oil should be still in place. EOR is limited to oil fields where primary production (natural oil flood driven by the reservoir pressure) and secondary production methods (water flooding and pumping) have been applied. Many oil fields have not yet reached that stage. Also the occurrence of a large gas cap limits the effectiveness of CO_2 flooding. Because of these limitations a detailed field-by-field assessment is required. The net storage is between 2.4 and 3 tons of CO_2 per ton of oil produced. Estimates for storage potentials vary widely from a few Gigatons (Gt) of CO_2 to several hundred Gigatons of CO_2, depending how many of these constraints are considered. The cumulative storage capacity (the total quantity that can be stored over the whole period up to that year) increases in time as EOR can be applied to more depleted oil fields. Note that the credits from EOR can be disputed. Similar to the CO_2 costing issue, either benefits or marginal benefits can the accounted for. A large number of competing options exist for EOR (see table 3). It depends on the reservoir and local supply conditions if CO_2 flooding is really the best option.

[9] Excludes cost for CO_2 injection wells and recovery wells, CO_2 recycling and gas preparation. Fuels valued at current wellhead price.

Table 3: Screening criteria for enhanced oil recovery methods. Second figure indicates current average conditions (Green and Willhite, 1999, p. 9, DOE 2002). PV = Pore Volume.

Method	°API	Viscosity [cp]	Composition	Oil saturation [% PV]	Formation type	Net thickness [m]	Per-meability [md]	Depth [m]	T [ºC]	Cost [$/bbl]
N2 (&flue gas)	>35/ 48	<0.4/ 0.2	High % C1-C7	>40/75	Sandstone/ Carbonate	Thin unless dipping	-	>2000	-	
Hydrocarbon	>23/ 41	<3/ 0.5	High % C2-C7	>30/80	Sandstone/ Carbonate	Thin unless dipping	-	>1350	-	
CO_2	>22/ 36	<10/ 1.5	High % C5-C12	>20/55	Sandstone/ Carbonate	-	-	>600	-	2-8
Micellar/ polymer, Alkaline/ polymer Alkaline flooding	>20/ 35	<35/ 13	Light, intermediate	>35/53	Sandstone	-	>10/450	<3000/ 1100	<95/ 25	8-12
Polymer flooding	>15/ <40	<150/ >10	-	>70/80	Sandstone	-	>10/800	<3000	<95/ 60	5-10
Combustion	>10/ 16	<5000/ 1200	-	>50/72	High porosity sand/sandstone	>3	>50	<4000/ 1200	>40/ 55	3-6
Steam	>8/ 13.5	<200,000/ 4,700	-	>40/66	High porosity sand/sandstone	>6	>200	<1500/ 500	-	3-6

EGR is a method for re-pressurisation of depleted gas fields that can be applied when the 80-90% of the gas has been produced. Because of the repressurization more gas can be extracted from the field. Although target reservoirs for carbon sequestration are depleted in methane with pressures as low as 20-50 bars, they are not devoid of methane. Additional methane can be recovered from depleted natural gas reservoirs by CO_2 injection. This process is called Enhanced Gas Recovery (EGR) (Oldenburg and Benson, 2001). The injected CO_2 will flow in the reservoir due to pressure effects and gravitational effects. Liquid CO_2 will flow down because of the high density compared to gaseous methane. Gaseous CO_2 is also notably denser than CH_4 at all relevant pressures and will tend to flow downwards, displacing the native CH_4 gas and repressurizing the reservoir (Oldenburg and Benson, 2001). Modeling studies suggest that after 10 years the gas produced still contains only 10% CO_2 by mass (Oldenburg and Benson, 2001). Given an initial pressure of 120 bar, another 10-15% of the initial gas in place could be recovered, using EOR. A 10 % additional recovery means that 1.8 GJ of gas is recovered per ton of CO_2 stored, if the whole reservoir is filled with CO_2 up to its original pressure (16/44*50*0.1). Modelling studies for the Netherlands suggest that a coal fired IGCC in combination with CO_2 removal and injection in a depleted gas field would be an economic option (Over et al., 1999). So far this option is not yet applied. Because gas production started later than oil production, the potential increases more in time. The potential for CO_2 use for EGR is larger than for EOR because it can be applied to all types of gas fields (see table 1). However the benefits are substantially lower. EGR encompasses in the ETP model also the CO_2 storage in depleted oil fields with substantial gas caps.

ECBM is an established method for methane (coal gas) recovery from coal seams. While conventional coalbed methane recovery may achieve 40-50% recovery (close to the wells), the recovery increases to 90-100% in case of ECBM. ECBM is limited to coal seams that will not be mined. This constitutes a major source of uncertainty, because what should be considered future coal reserves depend in future mining technology and energy demand trends. ECBM can only be applied to coal seams of sufficient permeability. Because of the increasing pressure the CO_2 absorption increases from 2 mole per mole methane at 700 metres, up to 5 mole/mole at 1500 metres. The coal should not be deeper than 2000 metres because the increasing temperature limits the methane content of the coal and the increasing pressure reduces the coal seam permeability. The methane content of deep coal seams can vary from 5-25 m^3/t coal and the thickness of the coal seams varies, so the ECBM potential per well and the CO_2 storage costs will vary by a factor 5 or more. Note that the most attractive option from a methane recovery perspective (shallow coal reserves with thick coal layers) is the least attractive one from a CO_2 storage perspective and from a future coal mining perspective. Note that the ECBM potential is limited by the coal seam permeability. Based in IEA GHG R&D program data, the potential for CO_2 sequestration via ECBM is estimated to amount to 100 –150 Gt , while 20 Gt CO_2 could be stored at zero costs or could even create a profit (IEA GHG 1998b). Note that these data depend critically on the assumptions regarding the coal permeability, the costs for enhancing the coal seam permeability and the costs for injection wells (which rises exponentially with the depth of the coal seam). Obviously storage at high costs makes little sense, given the abundant availability of low-cost aquifer storage options.

Apart from the options that would create benefits, there are options without offsetting revenues: aquifer storage and oceanic CO_2 storage. Storage in aquifers is currently studied in the Statoil CO_2 storage project in the North Sea Sleipner field. So far results suggest that storage is technologically feasible. Globally deep saline aquifers can hold hundreds of years of CO_2 emissions. Calculations from the beginning of the 90's suggested that 2% of the aquifer volume can be filled with CO_2, other estimates suggest 13-68%. The higher the storage efficiency, the fewer wells are required and the lower the storage costs.

The oceanic storage of CO_2 is the most controversial option. Two types of storage can be discerned: dissolution in seawater and storage of CO_2 hydrates or liquid CO_2 at depths of more than 4000 metres. Most technologies for deepwater storage are established technologies. However little is known regarding the impact of increased CO_2 concentrations on the oceanic ecosystem. Pilot projects in Hawaii and in Norway were cancelled because of protests from environmentalists. While oceanic storage is not critical for Western countries, the suitable underground storage potential in Japan is limited. Therefore oceanic storage may pose a key alternative in the case of Japan. At the same time this is a country where the sustainable use of oceanic resources is a sensitive issue. Wide acceptance of environmentally acceptable oceanic storage systems is a key requirement for large-scale application of this option. For the time being oceanic storage is not considered in the ETP model. This is a variable for sensitivity analysis.

2.2.5. Transportation distances

Because of the aggregate scale of the ETP model with 15 world regions, a fixed transportation distance is assumed for each capture and storage combination. In practice the transportation distance may vary substantially within a region. Therefore the costs may vary by about 10 USD per ton CO_2, compared to the cost assumptions in the model. The uncertainties regarding the storage options have been discussed previously. Because of these uncertainties the costs may vary by an additional 10 USD per ton CO_2. Note that this is a modelling shortcoming, not a practical uncertainty.

2.3. Costing versus pricing approaches

Three issues are discussed in this section in relation to the financial evaluation:
- Fossil fuel prices;
- Regional investment costs;
- Discount rates.

2.3.1. Fossil fuel prices

The fuel prices constitute a second important variable for the fuel choice in the electricity sector. The assumptions in the ETP model are listed in table 4. The figures indicate a coal and gas price gap in 2030 ranging from 0.47 USD per GJ in regions with ample gas resources up to 3.02 USD per GJ in regions with LNG imports. The latter figure seems significant and may explain why coal is preferred instead of gas. But according to Davison (2002) even this price gap is insufficient to achieve a switch from gas to coal.

Table 4: Coal and gas price assumptions, 2000-2050. 2000-2030 figures are based on the World Energy Outlook (WEO 2002).

			2000	2010	2020	2030	2040	2050
Gas	USA/CAN/MEX/CSA	[$/GJ]	3.70	2.56	3.22	3.79	4.17	4.59
	WEUR/EEUR/AUS	[$/GJ]	2.84	2.65	3.13	3.60	3.96	4.36
	FSU/MEAST/AFR/OASIA	[$/GJ]	1.34	1.15	1.63	2.10	2.31	2.54
	JAP/SKO/CHI/IND	[$/GJ]	4.45	3.70	3.89	4.17	4.59	5.05
Coal	AUS/CHI/USA	[$/GJ]	1.00	1.05	1.10	1.15	1.20	1.25
	Others	[$/GJ]	1.30	1.44	1.52	1.63	1.79	1.97

2.3.2. Regional investment costs

The region specific cost multipliers are listed in table 5. These multipliers are applied to all processes. The ETP model covers 15 regions. The database is set up as one “reference database” for the US, and corrections are made to this database, based on the relative costs of other regions in comparison to the US.

This analysis is complicated by a number of problems:

- Products and processes are often not completely identical across regions;
- The currency exchange rates tend to fluctuate. Changing exchange rates affect the relative investment costs. Especially exchange rates for developing countries can easily fluctuate by a factor 2;
- The project system boundaries may differ by region. For example in developing countries it may be necessary to build a road, new power lines or other infrastructure for new power plants;
- The regions in the model are very large. Any cost factor is an average that may differ considerably for locations (and countries) within regions;
- Especially in developing countries, some technologies may rely on imported equipment, others on locally produced equipment. Such a difference can have a significant impact on prices;
- In developing countries the availability of skilled labour may be a limiting factor. In case workers have to be hired from abroad, this will often result in significantly higher cost (though foreign workers may in some cases work at lower wage rates than locals, e.g. in the Middle East OPEC countries).

Table 5: Region specific cost multipliers (USA = 100).

	INVCOST	FIXOM	VAROM
AFR	125	90	85
AUS	125	90	90
CAN	100	100	100
CHI	90	80	80
CSA	125	90	85
EEU	100	90	85
FSU	125	90	85
IND	90	80	80
JPN	140	100	100
MEA	125	90	85
MEX	100	90	90
ODA	125	80	80
SKO	100	90	90
USA	100	100	100
WEU	110	100	95

It should be stressed that the model is based on a number of important simplifications:

- The labour productivity remains constant over the period 2000-2050;
- It is assumed that the average relative labour costs converge to some extent. Therefore the relative labour cost differences are assumed to be smaller than the average value reported for historical years. Except for this convergence it is assumed that the relative regional labour costs remain constant over the period 2000-2050;
- FIXOM and VAROM consist of 50% labour costs (that are region specific) and 50% materials and auxiliaries costs (that are assumed to be the same in all regions);
- The exchange rate is fixed.

2.3.3. Discount rates

The discount rates in the model differ by region and by sector. An overview of model discount rates is shown in table 6. The model simulates the real-world energy system, therefore the discount rates should reflect the real world discount rates (a so-called descriptive approach). These are usually significantly higher than the long-term social discount rate, despite comments from certain economists that lower discount rates would be more appropriate (Portney and Weyant, 1999).

ETP model discount rates are real discount rates, excluding inflation. The discount rate will differ among world regions, depending on capital availability and perceived risk. Investments in developing countries carry additional political instability risk. Sometimes governments are not able to pay their debts, see the recent cases of Russia and Argentina. In the event of a default, investors do not know what a workout will look like in an emerging country market (Budyak, 1998). Such causes can explain the gap in real government bond rates. For example the bond rate gap between the USA and Latin American developing countries amounts to 4 percent.

Compared to governments, lending money to industries or to individuals constitutes a much higher risk. Some will not pay back. Also the transaction costs are relatively higher. Therefore the interest rate is higher. Equity is another type of money supply for companies. The long-term return on investment for equity is several percent higher than for loans, because the owner of the equity is exposed to an increased risk (that the company goes bankrupt, in which case loans are paid back first, and usually the equity owner gets nothing). In a situation where electricity supply is governed by government, the lending rate may apply. In a liberalised market, the equity rate is more plausible. The ETP figures are based on the 30-year government bond rate (for the main country in the region, if applicable), corrected for inflation. For developing countries Moody's country ranking has been used as a measure for creditworthiness (Stern, 2002). Industry has been split into lending and equity (stocks etc.). One percentage point has been added in the case of industrial lending, in order to reflect the average incremental risk associated with lending to industry. 5.5% has been added for industrial equity risk (Stern, 2002).

Table 6: Region and sector specific discount rates in the ETP model.

	Real bond yield 2000-2001 [%]	Industry/Electricity Lending [%]	Industry/Electricity Equity [%]
Africa	8.2	9.2	13.7
Australia	2.6	3.6	8.1
Canada	3.7	4.7	9.3
China	5.2	6.2	10.7
FSU	8.7	9.7	14.3
IEA Europe	3.7	4.7	9.3
India	8.0	9.0	13.5
Japan	2.0	3.0	7.5
Korea	5.6	6.6	11.1
Latin America	7.2	8.2	12.7
Mexico	7.2	8.2	12.7
Middle East	5.6	6.6	11.1
Other Asia	8.2	9.2	13.7
Other Europe	5.7	6.7	11.3
United States	4.2	5.2	9.7

Note that a related problem is the discounting for carbon leakage back to the atmosphere. In case these leakages are valued at commercial discount rates, they are irrelevant. However in case a social discount rate is applied, the situation may be very different (a 5-100% cost increase has been estimated above). This problem is similar to the discounting problem for afforestation projects, where carbon is released once mature trees are harvested.

2.4. Overview of uncertainties

The analysis above has revealed a large number of uncertainties of a very different nature. This uncertainty can be expressed in terms of its consequences for electricity costs, or it can be expressed in terms of costs per ton of CO_2. In figures 3 and 4, the uncertainty has been expressed in CO_2 terms. The figures suggest that uncertainties dominate technology learning effects. Especially the choice of a reference is a key issue. While capture benefits and leakage also seem important, their probability is not very high. Discount rates matter both for coal and for gas systems, and fossil fuel prices are especially important for gas systems. Other uncertainties are not shown in these figures because they are considered to be of secondary importance.

Figure 3

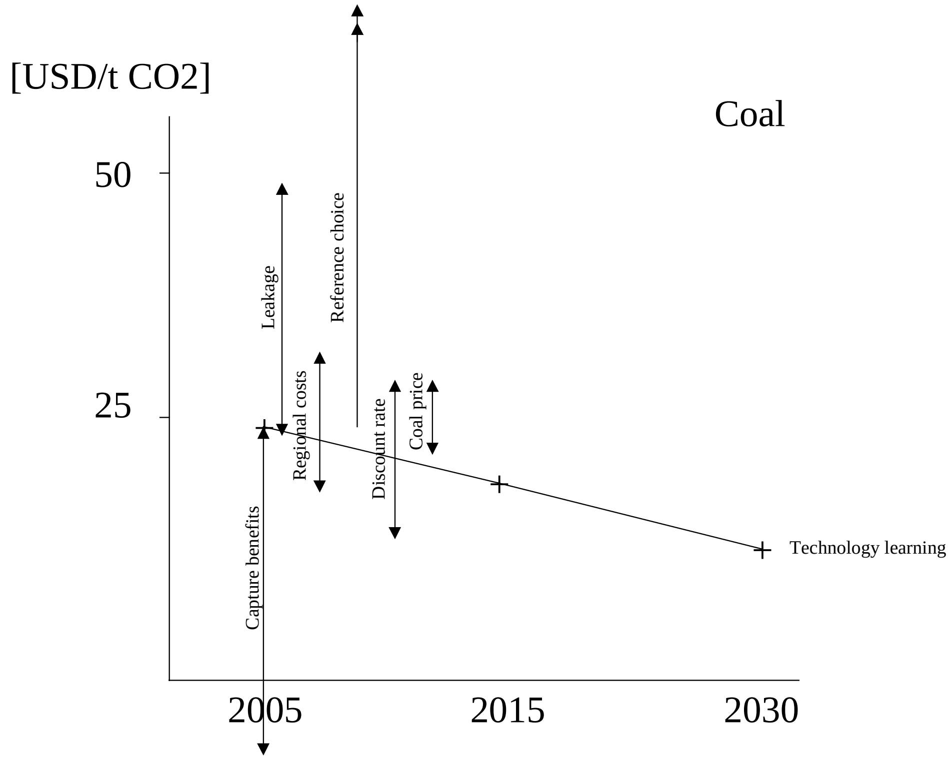

Figure 3: Range of CO_2 capture costs uncertainties for coal fired power plants.

Figure 4

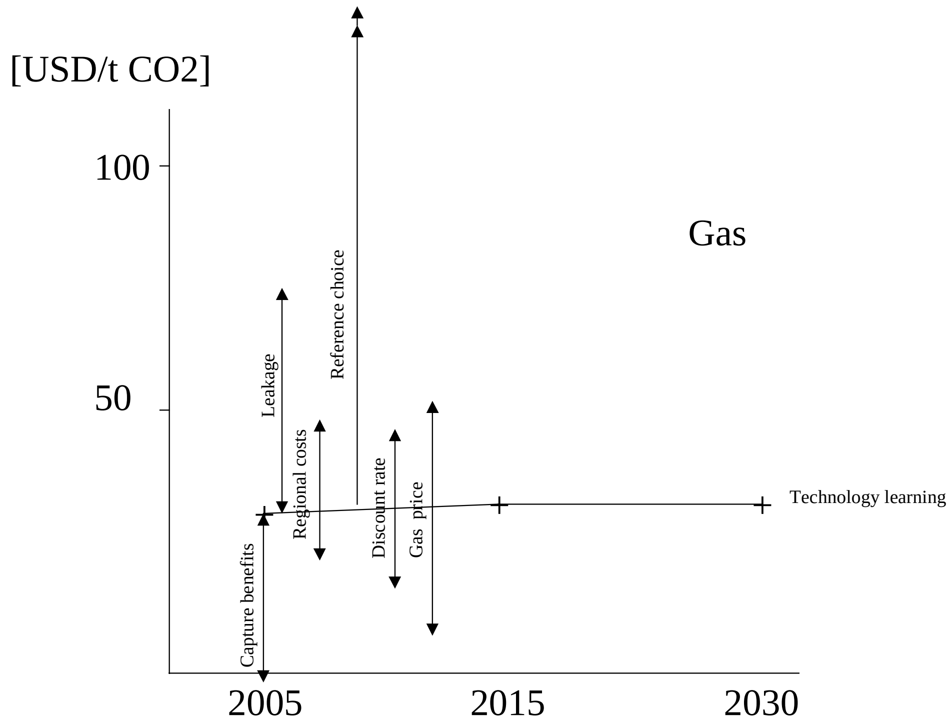

Figure 4: Range of CO_2 capture costs uncertainties for gas fired power plants.

3. ETP modelling results

Four model runs are compared:

- A Reference Scenario (RS), no CO_2 policies;
- A case with a penalty of 50USD/t CO_2 from 2010 onward (TAX50);
- A case with a penalty of 50USD/t CO2 from 2010 onward, no CO2 capture (TAX50 no capture);
- A Sensitivity Analysis (SA) with a penalty of 50USD/t CO_2 from 2010 onward, excluding SOFC technology.

Note that the coal and gas prices are exogenous in this model run (see table 3). In the ultimate ETP2 model, the fuel supply is endogenised. This will mitigate any fuel switch between gas and coal, because of increasing supply costs as demand increases (or, vice versa, declining supply costs as demand decreases). Therefore the current model runs overestimate the fuel substitution effects.

Figure 5 shows the fuel mix, figure 6 shows the electricity supply and figure 7 shows the CO_2 capture modelling results.

Figure 5

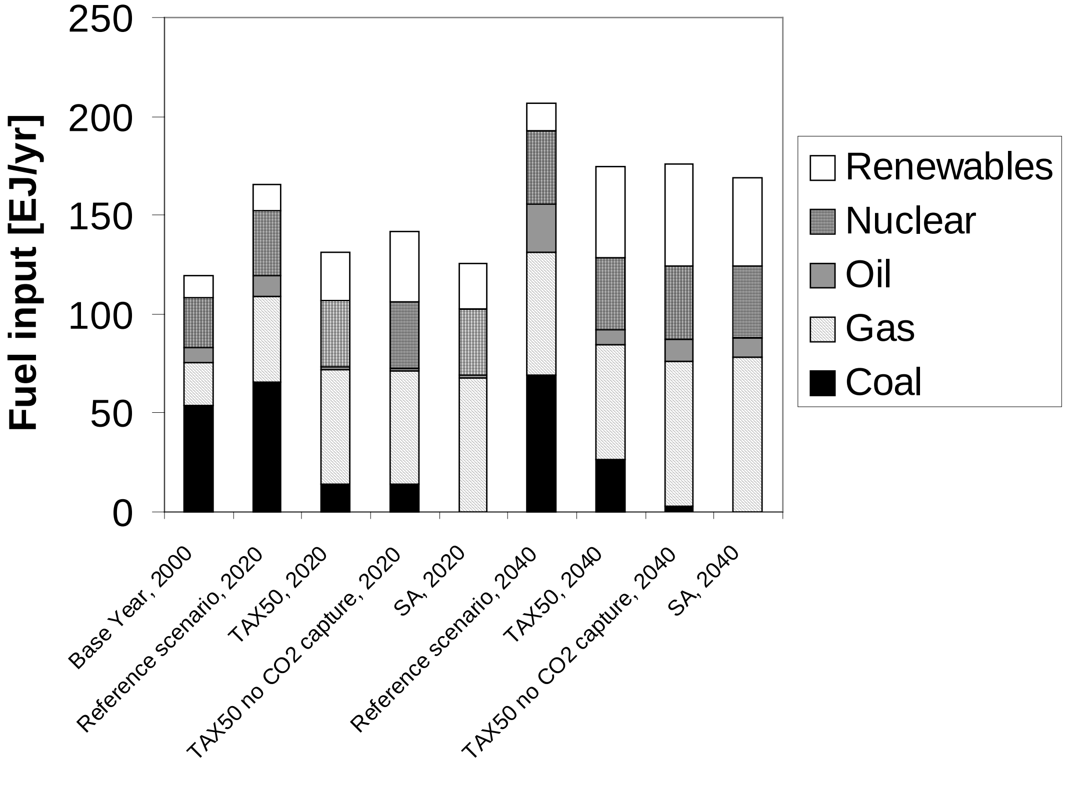

Figure 5: Fuel mix for electricity production.

Figure 6

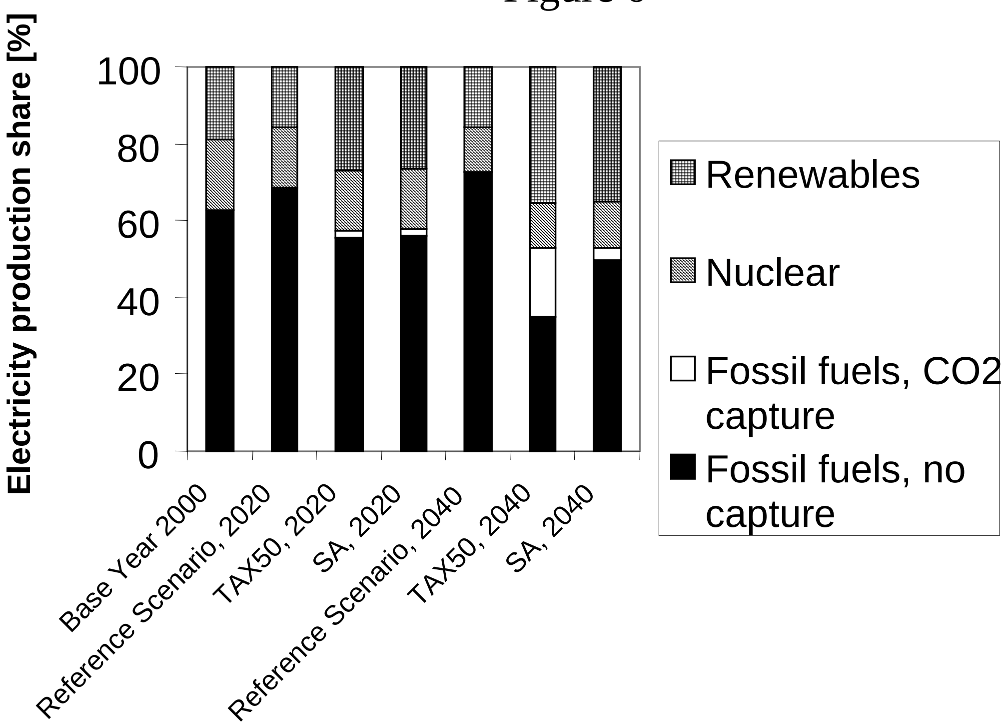

Figure 6: Electricity production shares in various policy scenarios, 2020 and 2040.

Figure 7

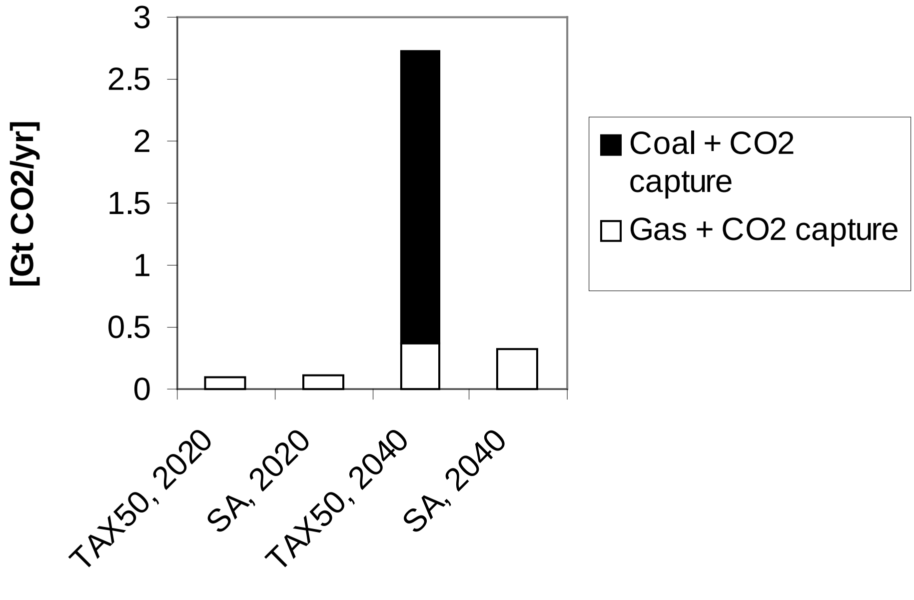

Figure 7: CO_2 capture in the TAX50 and SA scenarios, 2020 and 2040.

Figure 5 shows in the Reference Scenario a strong growth of total fuel consumption. The highest growth occurs for gas. In the TAX50 scenario, coal consumption declines sharply in 2020 and is replaced by gas, renewables and energy savings. This result should be analysed in more detail, such a strong substitution effect is unlikely. It may be explained by the model assumptions regarding technology life span. Note that in 2040, coal demand recovers to some extent. Still it is significantly lower than in the Reference Scenario. Comparison of the TAX50 and TAX50 no capture results indicates that the gas consumption is not very sensitive with regard to the availability of capture technology. However coal disappears without capture.

Figure 6 shows the electricity production shares. In the TAX scenario, fossil fueled power plants with CO_2 capture gain a significant position. They represent 18% of total electricity production in 2040 in the TAX50 scenario. Note however that this result is very sensitive with regard to the feasibility of the IGCC-SOFC combination (for coal), which is speculative. In case this technology option is not available (the SA scenario), CO_2 capture represents only 3% of the electricity supply. This is also illustrated by the analysis of the quantities CO_2 captured (figure 7). In the TAX50 scenario, the capture amounts to 2.7 Gt CO_2 per year. However without the IGCC-SOFC combination it declines to 0.3 Gt CO_2 per year. In all policy scenarios, the share of renewables increases significantly compared to the reference scenario. Figure 5 indicates that the share of renewables in the fuel mix is higher than in the scenario with capture. However the results suggest that the renewables and CO_2 capture strategies are largely complementary.

4. Conclusions and next steps

Technology learning is one of the factors that will effect the future role of CO_2 capture. However these learning effects should not be overestimated. The analysis suggests that in comparison to other uncertainties, learning is not a key parameter. In terms of costs per ton of CO_2 captured, the introduction of new CO_2 capture technologies for coal can reduce capture costs by 45%, in case the same power plant without capture is chosen as a reference. However in terms of costs per kWh electricity, learning effects are not very important. However even with modest learning effects, the potential contribution of CO_2 capture to emissions reduction is significant. Fossil fuel fired power plants with CO_2 capture represent up to 18% of total global electricity production by 2040, according to the latest set of ETP model calculations. The bulk of this is coal-based IGCC-SOFC, a speculative technology.

Learning includes in this analysis a switch from proven power plant concepts to speculative concepts. Developing these concepts into full-scale power plants implies an upscaling by a factor 100,000 (from 1 kW to the 100s MW scale). Obviously the success of such upscaling is a major source of uncertainty, especially with regard to membrane systems and SOFCs. Apart from these R&D and engineering issues, deployment can help to reduce the investment costs.

Regarding the fossil fuel competition, gas seems not very much affected by the availability of CO_2 capture technology. Both in the scenarios with and without CO_2 capture, gas gains market share at the expense of coal in case CO_2 policies are introduced. Note that this result means that the supply security benefits of CO_2 capture technologies are limited. However the picture may look differently in case of higher CO_2 penalties than the 50 USD/t CO_2 assumed in this analysis. Coal benefits from CO_2 capture technology, however this result depends on the availability of the IGCC-SOFC option.

A number of caveats must be added regarding the input data assumptions that may affect the results:

- The timing when certain CO_2 capture technologies may become available deserves more attention;
- This is a global analysis. In case, for example, coal is a national resource vs. imported gas, the cost gap between both fuels may look different from a national policy makers perspective (e.g., in the USA or China). This may result in more coal use in a CO_2 policy case;
- There is no fuel supply curve in these model runs, so the fuel switches are exaggerated;
- The characteristics of competing CO_2-free electricity supply options have not been discussed in this paper. Obviously they affect the assessment of CO_2 capture technologies as well;
- The impact of discount rates should be analysed in more detail.

These issues will be dealt with in an upcoming analysis. This model will be further developed with CO_2 capture in industry and in other parts of the energy sector. A report on CO_2 capture and sequestration, building on the work that is described in this paper, is planned for the fall of 2003.

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Acknowledgements

I would like to thank Paul Freund (IEA GHG R&D Program), Carmen Difiglio and Fridtjof Unander (IEA-EET) for their comments on draft versions of this paper.

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