THE FUTURE ROLE OF CO_2 CAPTURE IN THE ELECTRICITY SECTOR

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Abstract

This paper analyses the role of CO_2 capture and storage (CCS) for 15 world regions, using the IEA Secretariat's Energy Technology Perspectives (ETP) model. This bottom-up model describes global energy supply and demand for the period 2000-2050. The results suggest that if CCS technologies meet development targets and CO_2 abatement policies are introduced at a level of 50$/t CO_2, fossil fuelled power plants with CO_2 capture will represent up to 17% of global electricity production by 2030 and 31% by 2050.

Deployment of CCS technologies in the electricity sector will result in increased fossil fuel use for two reasons: availability of CCS allows for wider utilisation of fossil fuels for power generation and more fuel is needed to cover CCS energy requirements. By 2050, coal use will increase by up to 175% in comparison to scenarios without CCS technologies but with similar policy incentives. Renewables grow at a high rate, but less than in the scenario without CCS.

Slightly slower growth of renewables in the scenario with CCS available does not mean higher CO_2 emissions. On the contrary, in 2050, the energy system with CCS available emits 7.9 Gt CO_2 per year less than the same system without CCS available (both systems operate with US$50/t CO_2 policy incentives). Moreover, if reduced externalities are included in calculations, the total system costs with CCS available are lower than for the system without CCS. If cumulative emissions are fixed in the calculations, the undiscounted cumulative system costs for a scenario with CCS are 39% lower than for a scenario without CCS. This means that the introduction of CCS brings both environmental and economic benefits if CO_2 is given a price. Various sensitivity analyses show the robustness of CCS in the policy mix. Thus, this study recommends that policies be further developed so CCS technology can be applied in practice.

Introduction

The future role of CO_2 capture and storage (CCS) depends on a large number of factors that are not known in advance. In spite of this, governments and investors need to make certain decisions concerning future energy systems now, based on the information available. Energy models can be used to assist the decision making process. This paper represents an analysis of the IEA Secretariat regarding the future role of CCS. It is based on a bottom-up model of the world energy supply and demand and has a number of unique features that are lacking in other energy models, such as a detailed representation of global energy supply and demand, and a technology database based on information from the IEA network.

The input dataset used by the model is based on the information obtained from over forty international research frameworks (Implementing Agreements) working under the auspices of the IEA. The main contributor was the IEA GHG R&D Programme, and the authors would like to acknowledge here the support provided by the Programme.

In the ETP model, the world is divided into 15 regions. Each region is characterized in detail. For example, the regional potential of renewable energy is based on Geographical Information Systems (GIS) analysis. Not only the energy demand, but also the energy supply is endogenous in this model. As a consequence, demand side measures influence energy supply. This can be important if, for example, CO_2 Enhanced Oil Recovery is widely introduced and more oil is extracted due to availability of cheap CO_2.

An extensive IEA Secretariat publication on CCS is planned for October 2004. This paper discusses the preliminary model runs where key technologies have been identified and uncertainties assessed.

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Characteristics of CO_2 capture technologies

Table 1 provides an overview of the main CO_2 capture technologies considered in the model and their costs expressed per kWh electricity and per tonne of CO_2 captured. The cost calculated per tonne of CO_2 avoided would be 15-30% higher than data given in the Table 1 due to the cost of CO_2 transport and storage and because of additional CO_2 emissions due to energy needed for capture and CO_2 pressurization. All costs in Table 1 are calculated for a specific fuel price, 1.5 US$/GJ for coal and 3.0 US$/GJ for gas (in the model, fuel prices are endogenous and may vary). Each technology has a starting year when it becomes available in OECD countries (table 1). Availability of new technologies in developing countries and transition economies is delayed by 10-15 years. There are no constraints on the growth of CCS technologies.

The figures in Table 1 imply a significant cost reduction potential of CCS technologies, both for coal and for gas-fired power plants. In the long term, the additional cost per kWh electricity for power plants with CCS declines to 1-2 US$ cents from today's level of 3-6 US$ cents. These declined additional costs still result in a total production cost increase of 20-40 percent, but compared to consumer electricity prices this increase is much less dramatic. The cost reduction is crucial to make CCS competitive with other mitigation options, and to keep their costs well below CO_2's damage cost. Cost reduction will be achieved through new, more energy efficient capture technologies, higher efficiency power plants with lower quantities of CO_2 to be captured per kWh (learning by R&D), and to a lesser extent learning-by-doing in the manufacturing process (de-bottlenecking, series production, etc.).

Back-end chemical and physical absorption processes use proven technologies; however, they have not yet been applied to power plants on the scale of several hundred MW. The feasibility of new technologies and their integration into the various electricity production processes needs to be proven on a commercial scale. Retrofit of existing power plants is not covered by the data of Table 1, while it may be commercially attractive in certain cases.

The ETP model

The model that has been used for this analysis is called the Energy Technology Perspectives (ETP) model. It belongs to the MARKAL family of bottom-up systems engineering models [1]. MARKAL has been developed during the past 30 years by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA's Implementing Agreements.

The ETP model is a micro-economic representation of part of the world economy, divided into 15 regions. The fifteen regions in this study are: Africa, Australia/New Zealand, Canada, China, Central and South America, Eastern Europe, the Former Soviet Union, India, Japan, Mexico, Middle East, Other Developing Asia, South Korea, USA, and Western Europe. Only that part of the economy, which has energy relevance, is modelled. The energy system is modelled as a set of interdependent technical product flows and processes. Various technologies can be used to generate certain product flows. These technologies are characterised by their physical and economic properties. The process technology and process activity levels determine the physical and monetary flows within the energy system. Capital scarcity is reflected by region and sector specific discount rates.

ETP is a linear programming model that minimises an objective function calculated as a sum of annualised costs of an energy system that satisfies a certain energy demand under constraints (e.g., the attainment of certain production levels, the availability of certain technologies, etc.). The model solution represents the equilibrium that would be achieved in an ideal market and (according to neoclassical welfare economics) would maximise welfare.

The strength of this type of models is that they are very well suited to assess long-term investment decisions for complex systems where future technology characteristics will be very different from current technology. The model consists of a technology database with thousands of technologies that cover the whole energy system. The ETP model matrix contains 700,000 rows, 750,000 columns and 5 million non-zeros.

The energy demand and energy prices are calibrated with and documented in the IEA World Energy Outlook [2]. Each region contains about 1500 technologies that describe the energy system "from cradle to grave". Demand is characterized by 105 vectors, ranging from residential lighting to megatons of energy intensive materials such as steel [3]. The technology database contains existing technologies and new ones that may become available in the future. For CCS technologies, only learning by R&D resulting in introduction of improved technologies in later years has been considered. For renewables, learning-by-doing with continuous cost decrease for existing technologies has been considered as well. The reason is that such effects can be of higher importance for renewables. The cost assumptions for CCS and renewables are discussed below. A more detailed discussion of the model data is beyond the scope of this paper. Further documentation is available from the authors upon request.

CCS is split into three parts: CO_2 capture, transport and storage. CO_2 capture has been modelled for the electricity sector (including various industrial CHP plants), manufacturing processes in the energy intensive industries, and the production of transportation fuels (existing refineries and production of various synfuels). In the electricity sector, fossil fuelled power plants with CO_2 capture compete with the same plants without CO_2 capture and various other low-CO_2 energy supply options such as renewables. Electricity savings on the demand side are modelled explicitly and compete directly with CO_2 capture from power plants as an emission reduction strategy. Retrofit of CO_2 capture to existing power plants has not been considered. Storage options include, among others, onshore and offshore aquifers, CO_2 use for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) and Enhanced Coalbed Methane Recovery (ECBM).

Economic incentives to decrease CO_2 emissions have been introduced in the model. It is assumed that in industrialized countries these incentives are introduced gradually during the next 10 years, and stabilize afterwards. The same introduction pattern is followed in developing countries, but with a delay of 20 years. The following analysis focuses on the GLO50 scenario, where the penalty for emission stabilizes at 50 US$/t CO_2. The energy demand in this scenario is calibrated with the IEA World Energy Outlook 2002, and it results in a stabilization of global CO_2 emissions at a level of about 28 Gt CO_2 per year by 2050 compared to 24 Gt/year today.

The future role of CCS

Figure 1 shows CO_2 capture at increasing policy incentive levels starting from 10 US$/ton CO_2 (GLO10 scenario) up to 100 US$/ton CO_2 (GLO100 scenario). The ETP model analysis suggests that CCS can play an important role in 15-20 years. This result is much more optimistic than other analyses that show little CCS before 2050, or that neglect this option, such as most of the IPCC SRES scenarios [4]. The use of CCS increases gradually in the period 2015-2050 due to the increasing energy demand, limited life span of existing equipment, CCS cost reduction due to technology learning, and introduction of CO_2 policies in industrialized and later in developing countries.

Figure 1

Figure 2 shows the CCS technology mix in the GLO50 scenario. Deployment of CCS technologies starts around 2015, and in 2050 18.4 Gt of CO_2 is captured and stored. In 2020 capture from power plants (including industrial CHP, and including all capture from IGCCs for cogeneration of electricity and transportation fuels) represents 50% of all CO_2 capture and reaches 79% in 2050, the rest being captured in the fuel processing and manufacturing industries (such as ammonia, iron and cement clinker production and Fischer-Tropsch synthesis of transportation fuels). The modelling results suggest that the IGCC technology will play a key role in a CCS development. In 2030, IGCC represents about half of total CO_2 capture. By 2050, its share has increased to 70% of total CO_2 capture. The IGCC is used not only for hardcoal and lignite but also for black liquor (by product of a pulp industry). It can be noted that IGCC using black liquor with CCS results in electricity and heat cogeneration with negative CO_2 emissions. The future role of CCS for IGCC depends on the introduction of electricity-transportation fuel cogeneration plants of a Future-Gen type. Without such plants, CO_2 capture from IGCC halves and total CCS declines by 25%. Steam cycles with flue gas CO_2 capture are not selected by the model but a sensitivity analysis with Ultra Supercritical Steam Cycle (USCSC) investment cost reduced only by 16% from 1675 to 1400 US$/kW showed a significant use of this technology. It is, therefore, important to keep both IGCC and USCSC options open for future deployment of CCS.

Figure 2

Results indicate that, beyond 2025, capture in developing countries will grow at a high rate. By 2050, 38% of total capture activity will be located in developing countries.

The electricity production capacity triples in fifty years (Figure 3) and the electricity production increases in line with it. Renewables grow the fastest, from 19% to 43% of electricity production capacity in 2050. Initially hydro dominates, but in later periods wind, biomass and geothermal power plants play a important role as well.

The electricity output from fossil fueled power plants with CCS increases to 17% of total electricity production by 2030, and 31% by 2050 (about 48 EJ electricity production, see Table 2). Note that this excludes biomass co-combustion in coal fired power plants with CCS. If this biomass is included, the share of electricity production with CCS increases to 33%.

Figure 3

Results of modeling indicate that while the capacity of fossil fueled power plants without CCS remains nearly constant over the years, their output declines. Electricity production from coal fired power plants without CCS virtually ceases by 2030 and no new coal fired power plants without CCS are being built. This suggests there may be a retrofit potential, which is not considered in this analysis. Gas fired plants without CCS remain in operation and new ones are also built, but their output declines to 16% of total electricity production by 2050.

Two model runs have been compared, one with CCS and one without CCS in technology portfolio (incentive level US$50/t CO_2 for both). The difference in global CO_2 emissions amounts to 4.9 Gt in 2030 and 7.9 Gt in 2050 in favor of a scenario with CCS. This implies a 30% higher emission reduction if CCS is considered. In case CCS is considered, coal use will increase by up to 175% by 2050, in comparison to scenarios without CCS technologies, which is equivalent to a doubling of current consumption. In the range of ambitious policy targets (US$25+), consideration of CCS cuts the penalty needed to reach a certain cumulative emission reduction by half (Figure 4). In case CCS is not considered, other emission reduction strategies can be applied to reach the same targets, but the cost will increase. For example the additional cumulative undiscounted systems cost without CCS to reach the GLO50 scenario cumulative emission reduction are 11 trillion US$ higher, an increase of 63%. However this result depends critically on the technology learning assumptions for renewables, and should be considered a high estimate.

Figure 4

Faster learning due to higher investments and the resulting decrease in costs for renewables have been analyzed further. In the basic GLO50 scenario (with CCS) investment costs per kWh for wind decline by 23% and for PV by 58% over the next 50 years. These assumptions have been based on the Reference Scenario of the World Energy Outlook [2]. In the additional model runs, it was assumed that costs decline by 33% for wind and 86 % for PV (scenario GLO50a) and 44% for wind and 88% for PV (scenario GLO50b). The resulting electricity production mix is shown in table 2. Note that the use of biomass declines with more optimistic assumptions for wind and PV. The reason is that in the basic GLO50 scenario, there is a significant co-combustion of biomass in coal fired power plants with CCS. As there are fewer such power plants in the other two scenarios, the opportunities to co-combust biomass decline. Besides significant differences in technology mix, the scenarios with more optimistic cost developments for renewables are characterized by lower undiscounted system costs. This suggests that a strategy aiming for maximized use of renewables could be cost-effective. It will be the case, however, only if renewables lower their costs significantly. The share of fossil fueled power plants with CCS declines from 31% in the basic GLO50 scenario to 21% in the GLO50b scenario. This is a significant decline, but given the optimistic learning assumptions for renewables one can conclude that fossil fuels with CCS pose a robust strategy in comparison to renewables with 21% representing a lower bound of the possible share of power plants with CO_2 capture.

Table 2

Conclusions and policy recommendations

- CCS can become a key technology for CO_2 emission reduction in the first half of the 21^{st} century;
- CCS results in a need for an additional equipment and in additional energy use, compared to the same plants without CCS. As a consequence it increases electricity cost. From a CO_2 policy perspective, incentives in the range of 10-50 US$/t CO_2 are needed for the period 2015-2050 to ensure deployment of CCS. This incentive translates into an electricity production cost increase by 1-2 US cents/kWh and price incentives of the same range will be needed (alternatively, a target for an increasing share of CO_2-free electricity may be set; such a strategy would pass the cost and part of the risk on to the consumer; anyway, credible long-term incentives are essential in order to induce CCS investments);
- The additional CO_2 reductions increase to 7.9 Gt CO_2 per year in 2050, compared to a scenario with the same policy incentives but without CO_2 capture available. Without CCS the cumulative cost of emission stabilization increase by 63%;
- The electricity sector represents by far the most important sector where CCS can be applied. According to the ETP model analysis, up to 78% of all CO_2 capture takes place in the electricity sector by 2050;
- In a scenario aiming for CO_2 emission stabilization at 28 Gt per year, the share of renewables in electricity production increases to 43%. This result depends on the learning assumptions for renewables. With more optimistic assumptions for wind and PV, their share may increase to 60%. The share of fossil fuelled power plants with CCS would decline from 31% to 21%. The learning potential for renewables is an important uncertainty for the future role of CCS;
- The ETP model suggests a large-scale introduction of CCS from 2015 onward. The introduction is a gradual process over a period of decades. This gradual change is caused by the long life span of existing equipment, the learning effects for CCS technologies that result in cost reduction, regional differences in capital availability and regionally different CO_2 policy scenarios;
- Various other factors have been analysed that affect the use of CCS, but that have not been discussed in detail. The future acceptance of nuclear energy, the electricity market structure and economic growth are key factors that can affect the use of CCS. However in all analyses CCS plays a key role. Given the robustness of the results for CCS it is recommended to include them into the energy/CO_2 portfolio. At this moment it is not yet possible to identify particular technology “winners”. Various technology pathways should be further investigated. It is likely that different technologies can coexist.

The ETP model is based on perfect foresight and it does not account for risk that technology development may fail or government policies may change. While the CCS technologies have significant potential, their practical introduction will be limited by investor uncertainty and the political willingness to use scarce funds for an environmental problem of an uncertain magnitude. Moreover, local public acceptance of CO_2 storage is a concern.

Development of CCS technologies requires several commercial scale demonstration projects of a 250-500 MW scale. The total cost of such pilot plants is in the order of several billions of dollars. The burden of further development of CCS could be shared between fuel suppliers, the electricity production sector and governments. Technology development and deployment is an industry issue, government should provide the right incentives and the legal and planning framework. A CCS project for a single power plant can reduce CO_2 emissions by several Megatons. Therefore a limited number of projects can result in a significant reduction of countries emissions.

Uncertainties regarding the feasibility and permanence of storage need to be reduced via additional RD&D. Permanence validation and monitoring systems need further development. The technology should be disseminated to developing countries. Systems similar to the Clean Development Mechanism could be developed that would allow for credits in case of CCS.

Table 1: Characteristics of power plants with and without CO_2 capture.

Comparison based on 10% discount rate, 30 year process life span. Coal price 1.5 US$/GJ; gas price 3 US$/GJ; biomass price 4 US$/GJ; black liquor 0 US$/GJ. CO_2 product in a supercritical state at 100 bar. CO_2 transportation and storage not included. Capture costs compared to the same power plant without capture [5,6,7,8,9,10,11,12].

Fuel, technology	Starting	INV [$/kW]	FIX [$/kW.yr]	Eff [%]	Eff. loss [%]	Add. fuel [%]	Capt. eff. [%]	Capt. costs [$/t CO_2]	El. costs [Mils/kWh]	Add. el. costs [Mils/kWh]
Likely technologies										
No CO_2 capture										
Coal, steam cycle	2010	1075	23	43					**29.1**	
Coal, steam cycle	2020	1025	31	44					**29.2**	
Coal, USC steam cycle	2020	1260	30	50					**31.5**	
Coal, IGCC	2010	1455	57	46					**37.4**	
Coal, IGCC[1]	2020	1260	35	46					**33.0**	
Gas, CC	2005	400	14	56					**26.1**	
Gas, CC	2015	400	14	59					**25.2**	
Black liquor, IGCC	2020	1300	50	28					**23.5**	
Biomass, IGCC	2020	2400	50	40					**74.6**	
With CO_2 capture										
Coal, steam cycle, CA	2010	1850	80	31	-12	39	85	24	**51.0**	21.9
Coal, steam cycle, Membranes +CA	2020	1720	75	36	-8	22	85	21	**46.3**	17.1
Coal, USC steam cycle, membranes +CA	2030	1675	45	42	-8	19	95	17	**49.0**	17.5
Coal, IGCC, Selexol	2010	2100	90	38	-8	21	85	20	**52.3**	14.9
Coal, IGCC, Selexol	2020	1635	50	40	-6	15	85	11	**41.0**	8.0
Gas, CC, Back-end CA	2010	800	29	47	-9	19	85	29	**36.8**	10.7
Gas, CC, Front-end Selexol	2020	800	33	51	-8	16	85	25	**34.8**	9.6
Black liquor, IGCC	2020	1620	50	25	-3	12	85	4	**27.9**	4.4
Biomass, IGCC	2025	3000	100	33	-7	21	85	23	**96.1**	21.5
Speculative technologies										
No CO_2 capture										
Coal, IGCC & SOFC	2030	1800	75	60					**41.3**	
Gas, CC & SOFC	2025	800	40	70					**30.6**	
With CO_2 capture										
Coal, CFB, Chemical looping	2020	1400	45	39	-5	13	85	14	**38.2**	14.7
Gas, CC, Chemical looping	2025	900	25	56	-4	7	85	33	**34.5**	9.3
Coal, IGCC & SOFC	2035	2100	100	56	-4	7	100	13	**49.0**	7.7
Gas, CC & SOFC	2030	1200	60	66	-4	6	100	28	**39.2**	8.6

CA = Chemical Absorption. CC = Combined Cycle. CFB – Circulating Fluidized Bed. IGCC Integrated Gasification Combined Cycle. SOFC = Solid Oxide Fuel Cell. USC – Ultra Supercritical

[1] The IGCC data for 2010 refer to a European highly integrated plant based on a Shell gasifier, while the 2020 data refer to a less integrated US design based on an E-gas gasifier. The efficiency remains at the same level because new gas turbines will become available in the 2010-2020 period (the so-called "H-class"), which result in an increase of the efficiency. The gasifier substitution reduces capture efficiency losses and reduces investment cost penalties.

Table 2: The impact of renewables learning assumptions on electricity production mix in 2050; in GLO50 wind and PV decrease their cost by 23 and 58 % over 50 years, in GLO50a by 33% and 86% respectively and in GLO50b by 44 and 88%.

	GLO50 [EJel/yr]	GLO50a [EJel/yr]	GLO50b [EJel/yr]
FF – CCS	28.6	25.6	21.5
FF + CCS	47.7	38.4	32.1
Nuclear	9.6	9.4	9.3
Hydro	24.1	23.5	21.7
Bio/waste	14.5	9.4	9.6
Geothermal	8.5	7.5	6.4
Wind	18.7	26.7	33.6
Solar	0.0	12.8	21.5
Total	151.8	153.3	155.7

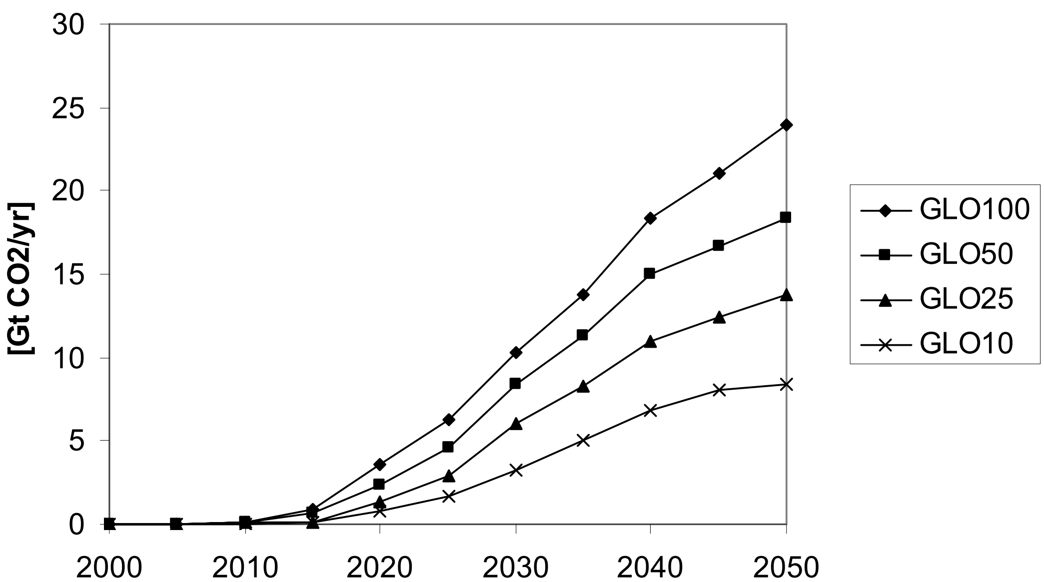

Figure 1: CO_2 capture at various policy incentive levels

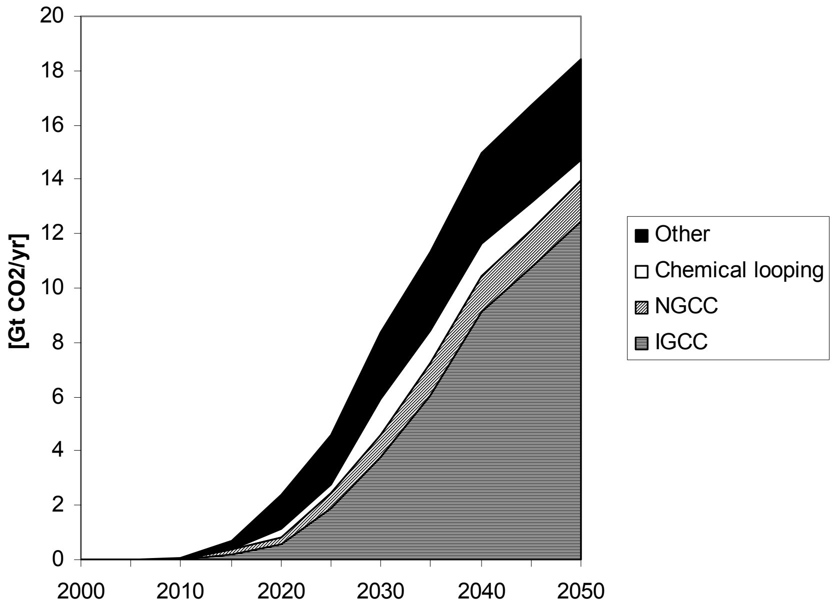

Figure 2: CO_2 capture by technology, GLO50 scenario

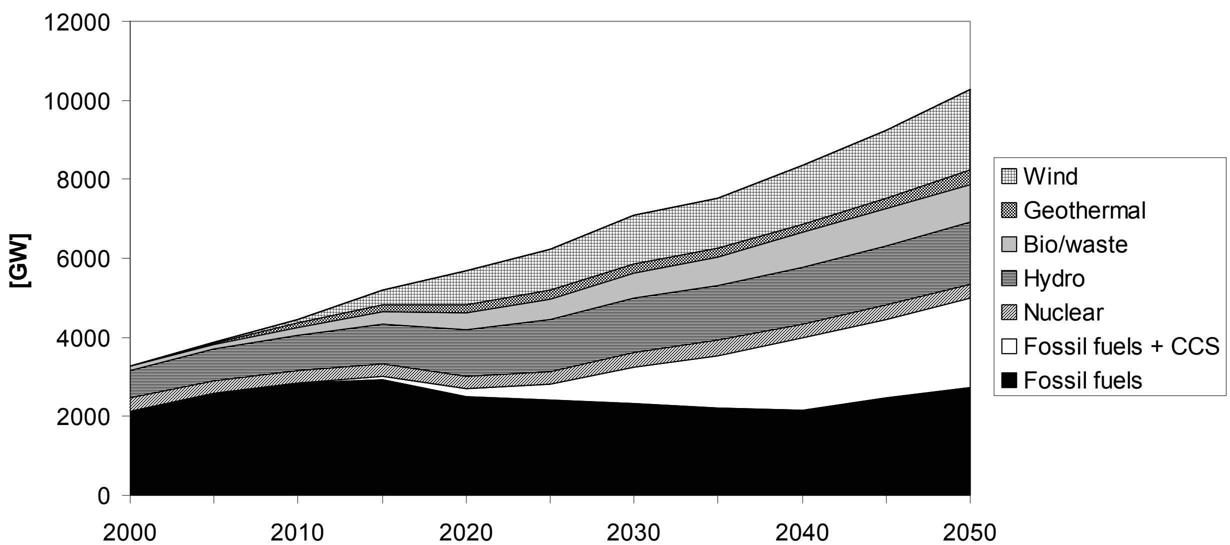

Figure 3: The electricity production capacity, GLO50 scenario.

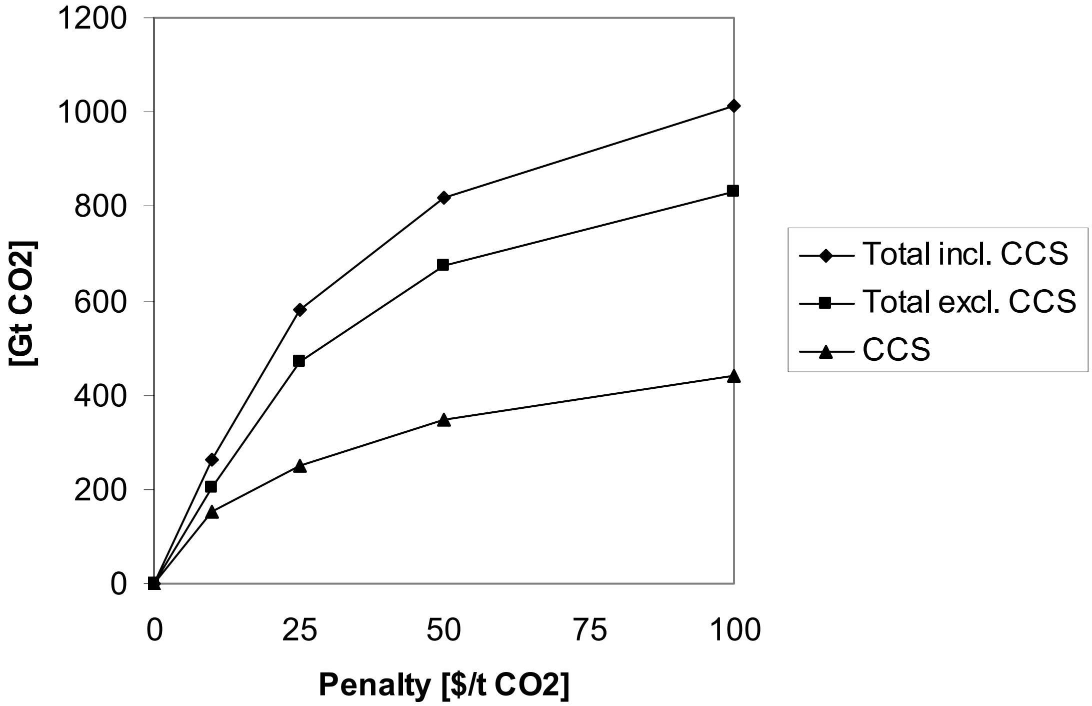

Figure 4: Cumulative emission abatement 2000-2050 as a function of the penalty level.

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