7

Wind power development and the function of law

This chapter relates to the function of the law in relation to the implementation of renewable energy policy objectives. Four different legal regimes are analysed in respect of their functions (or malfunctions) with regard to the development of wind power. The targeted countries are Sweden, Denmark, Norway and England. The comparative studies of the legal systems aim to present ideas about how ineffective systems can be improved. In a wider context, this relates to the implementation of renewable energy policy objectives as a means towards sustainable development.

Together with the decisive factors of economic and technological prerequisites, the implementation of renewable energy policies, such as planning goals for wind power, is also dependent upon the requirements of the law. In the face of supposedly strong economic incentives to promote the development of wind power, barriers to implementation exist in the design of the legal and administrative systems.

This chapter describes and analyses legal systems in the development of renewable energy in general and wind power in particular. Among the key questions are: what roles do the legal regimes surrounding the planning, installation, and operation of windmills play in the implementation process? The legal regimes are evaluated in terms of their abilities to facilitate and impede the development of wind power. Therefore, the starting point is that the law does in fact have a bearing on the possibilities to implement effectively wind power, as well as other renewable energy policies. Consequently, it is presumed that the institutional settings in countries with a significant installed capacity for wind power have adjusted in a manner that allows the execution of such developments. With a careful analysis of these legal preconditions the study thus aspires to disclose some of the reasons to the unsuccessful story of Swedish wind power development.

In addition to the analysis of the relevant laws and legal rules, this chapter also includes a comparative analysis of the legal functions in the different countries with starting point in the Swedish legal system. The purpose of the comparison is in brief to produce some ideas regarding the choice between different legal solutions that would meet the Swedish planning goal for wind power. The selection of Denmark and Norway is motivated by their overall similarities in social and legal system designs and their considerable differences in terms of installed wind power capacity. The decision to include England in the comparison is driven by that country's strong and sudden development during the first decade of the 21st Century.

APPLICABLE LEGAL FUNCTIONS

A key issue regarding the function of law vis-à-vis the development of wind power is what legal rules that should be studied; obviously not all rules are relevant in this respect. The initial task was therefore to identify the laws and legal rules that have impact on the development of wind power. From the starting point of the characteristics of wind power as such the core legal functions are:

a) The laws and legal rules related to the use of natural resources that are essential for wind energy production, most notably wind along with land and water areas;

b) the legal framework for physical planning, including relevant policy guidelines;

c) environmental consideration rules;

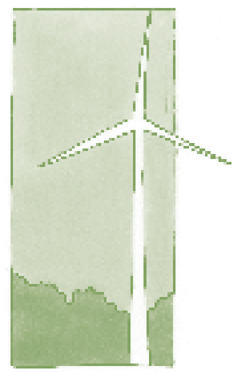
d) rules relating to authorisations for windmill installations, for instance, permits and environmental impact assessment regulations; and

e) legal rules regarding the possibilities for public participation

ACQUIRED EXPERIENCES FROM THE COUNTRY STUDY

The examination of the legal functions has brought several similar and dissimilar features to light. With regard to the use of wind, land, and water areas the law generally provides some guidance as to how, by whom, and for what purpose resources may or may not be used. The right to harness wind energy for energy purposes is something that typically lacks specific regulation. In Sweden it is generally considered that the right of disposition of "land-based" wind belongs to the land owner, and the right to expropriate areas for this purpose is open to question (Michanek, 1990). The corresponding regulation in Norway however clearly allows for expropriation with the intention to harness wind, something that clearly increases the possibilities for implementing plans for wind power development.

On the subject of land use and the balancing of opposing interests, the country-based examination shows some differences regarding the regulation of land use and the mechanisms for dealing with potential conflicts of interests in connection with wind power development. Denmark has chosen to regulate explicitly wind power development through the use of a specific planning instrument, while Norway and England have adopted rather detailed guidelines for the planning and location of windmill installations, which aim to prevent conflicts by presenting assessment criteria for the balancing of interests. In Sweden, the use of land is legally controlled through non-wind-power-specific regulations. There are several problems associated with the Swedish rules, as compared with the more precise and directed regulations applied in the other examined countries, most notably that the design and wording of the rules imply a high degree of uncertainty in connection with their application.



In Sweden, the majority of the environmentally related rules are laid down in the Environmental Code, as are the environmental requirements for windmill installations. The rules for environmental consideration are expressed in the form of assessment rules, which basically implies that every activity (e.g., a windmill installation) is assessed individually for compliance with the requirements. The system has in-built flexibility with regard to local conditions, and the end result is essentially the same as that achieved through the use of legal standards. However, for activities such as wind power production, with foreseeable and specific environmental impacts, the use of legal standards might be a better choice; the Danish legal standards for windmill installations concerning, for example, noise pollution, construction, visual impacts etc., seem to entail shorter trials, less uncertainty, and fewer appeals, without compromising protection of the environment.

In all four examined countries, the main components of the systems for physical planning are the same, involving decentralisation, different planning levels, and several types of plans. However, there are considerable differences between the countries with regard to how the planning is controlled and by which bodies. Therefore, the possibilities to achieve energy policy objectives vary significantly. The major factors to consider in this respect are: 1) the control of the content of the plans; 2) the responsibility for planning; and 3) the enforcement of planning and the legal effects of plans. In brief, the examination of the planning systems in the different countries revealed the following interesting supportive legal functions.

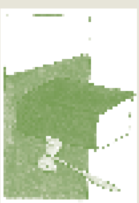
- The Danish (and to some extent the Norwegian) vertically integrated system for planning means that the overarching planning goals must be reflected and addressed in the legally binding plans. Implementation deficits are thereby significantly reduced.

- The Danish wind power-specific legislation, particularly the wind power planning directive, is probably very important for the potential to implement legally the wind power policies.

- The possibilities for developers to produce proposals for zone-plans for windmill installations under Norwegian law to some extent offset the problem associated with passive planning authorities.

- The Norwegian and English guidelines for the planning and location of windmills complement the planning law with wind power-specific regulations that produce substantial guidance for the assessment of different sites and conflicts of interest.

Finally, depending on the size and location of the installation, the development of wind power often requires some sort of authorization, such as a permit, license or plan. The rationale behind permit requirements is the necessity to control the activity beforehand, for example, to prevent environmental damage. The Swedish legal system involves multiple trials for windmill installations and appears to be more complicated than what can be justified considering the relatively uncomplicated environmental impacts of windmill installations.



Comparative analyses of wind law in different countries

After determining the relevant legal functions, the valid law applicable to the planning, installation, and operation of windmills has been determined for all four countries in keeping with the method of constructive jurisprudence (see Chapter 5 in the *Methods and Models* book). A somewhat more comprehensive analysis is made with regard to Swedish law. Valid law in the four countries was subsequently used as the basis for the comparative analysis in which the relevant legal regimes were compared in relation to the specific research questions. Finally, the legal functions are revisited from the starting point of the analysis of the legal material and the comparative samples, with the goal of outlining the main characteristics of a legal and administrative system that meet the requirements for efficient and environmentally considerate production of wind power.

LEGAL SYSTEM CREATES BARRRIERS

The results of the analysis of Swedish law indicate that the legal system creates barriers to the development of wind power. The main obstacles are found in the system for physical planning and the concession system, although quite a few individual hindering provisions are also identified. The lack of sufficient control and extensive municipal power structures together create an unpredictable and ineffective planning system, which basically lacks the confidence to implement effectively the planning goals. The installation of windmills may require several different permits, which may seriously hamper development owing to lengthy processes and appeals. Among the individual rules, the location requirement in the Environmental Code is a noteworthy obstacle to the development of wind power generation; the requirement that alternative sites be assessed objectively has in several cases obstructed the installation of windmills. Overall, the implementation deficits detected in the Swedish system are considerable.

The examination of the corresponding legal functions in Denmark, Norway, and England reveals some very important differences with respect to planning control and permit requirements, as well as regarding substantial provisions. Generally, it appears that there is a correlation between the level of overarching control over the physical planning on the one hand, and the potential to implement successfully national energy policy objectives on the other. Time limits for permit procedures, legal standards for emissions, and explicit rules for the balancing of opposing interests are among the valuable procedures that could be employed in Sweden. Realisation of the Swedish wind power planning goals will presumably require changes in the law. The most important issue is perhaps to reduce the implementation deficits by improving the legal framework governing the planning and installation processes. The factors that emerge as crucial in this respect are: 1) removal of the general permit requirement, which would transfer the entire trial to the planning system; and 2) breaking up of the municipal planning monopoly.

The present study presents some ideas for the design of a planning system that would implement key environmental and energy policy objectives. Such a system would have to include national planning instruments for setting targets and directing lower-level planning. Moreover, it is necessary to establish control functions for the contents, adoption, and implementation of the overview plans, since these are to serve as the link between the national level and the legally binding detailed plans. Substantial rules for the planning and location of windmills, including an environmental impact assessment, should be implemented at this stage in the planning process. The final stage in the process would be the detailed plan; if well designed, this plan would represent the optimal instrument for controlling local development.

The law should state that the use of renewable energy promotes and enhances security of supply and mitigates the adverse effects of climate change, and that the potential for using and developing such energy sources must always be considered in the context of physical planning. The law should furthermore specify that it is the responsibility of the planning authorities to develop and integrate new renewable energy sources through physical planning. It must be made clear that the purpose of planning, particularly at the local level, is to develop the community as well as to implement national planning objectives.

In summary, the achievement of wind power planning goals, renewable energy policies, and ultimately, sustainable development necessitates changes in the existing legal system. The current institutional framework, especially in Sweden, contains substantial implementation deficits that seriously jeopardise the possibilities to reach the targets.

For more information:

Maria Pettersson,
Social Science, Luleå University of Technology
Gabriel Michanek,
Faculty of Law, Uppsala University

Further reading

Pettersson, M., 2008, Renewable Energy Development and the Function of Law. A Comparative Study of Legal Rules Related to the Planning, Installation and Operation of Windmills. Doctoral Dissertation, Luleå University of Technology, Luleå, Sweden.

Söderholm, P., Ek, K., and Pettersson, M., 2007. ”Wind Power Development in Sweden: Global Policies and Local Obstacles”. Renewable & Sustainable Energy Reviews, Vol. 11 (3): 365-400.

Söderholm, P., Pettersson, M., Ek, K., and Michanek, G., 2007, “Policy Effectiveness and the Diffusion of Carbon-free Energy Technology. The Case of Wind Power”. In Making International and National Climate Policy Work at the Local Level. Lundqvist, L. and Biel, A. (Eds.). From Kyoto to the Town Hall. , Earthscan: 93-117.

8

Geographical allocation of wind power investments

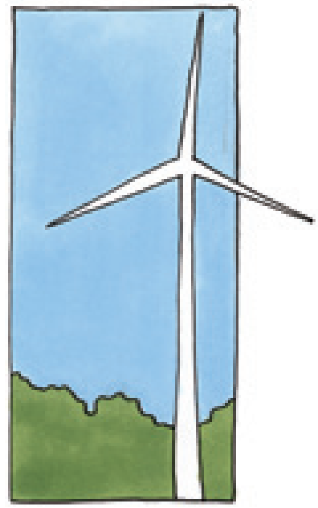
This chapter investigates the influence of geographical allocation of wind power on wind power investments in Northern Europe (Germany and the Nordic countries). To minimise investments in wind power capacity, the investments obviously have to be made at sites with the most favourable wind conditions. However, investments in power transmission can motivate wind investments close to either the load centres or the power plants to be replaced by wind power. The trade-off between investments in wind power capacity and investments in transmission capacity has been investigated. The aim is to illustrate how several properties of the power generation and transmission system influence the allocation of new wind power capacity associated with the lowest system costs.

Wind power is considered to be a key technology in efforts to decrease carbon dioxide emissions from the electricity generation sector, and large investments in wind power are expected in the European electricity generation systems to facilitate compliance with the EU renewable energy sources (RES) directive (DIRECTIVE2009/28/EC 2009). This directive is extrapolated to national targets by the EU using a methodology that is based on an equal increase in the share of renewables weighted for the GDP of each member state (DIRECTIVE2009/28/EC 2009) with adjustments for gross final energy consumption and past efforts to integrate renewable energy. However, there is obviously no correlation between the GDP per capita and the basic capabilities of the member states to generate renewable energy, and it has been suggested that the cost to reach the target for renewable sources could be significantly reduced if the member states collaborated to reach the common EU RES target rather than each country investing domestically to comply with national targets (Eurelectric, 2004). With respect to wind power, its production obviously depends strongly on wind conditions, which vary greatly between countries. Thus, it is of interest to investigate the geographical allocations of wind power from a cost-minimising perspective. The results of this comparison could serve as the basis for a discussion on the importance of collaboration to meet the RES targets and the possible consequences if mechanisms for collaboration are successfully established.

BALANCING INVESTMENTS IN WIND POWER AND TRANSMISSION CAPACITY

The geographical regions considered here encompass the Nordic countries and Germany. It is assumed that investments in wind power generation correspond to 20% of the total electricity demand (182 TWh). This is arbitrarily chosen, simply to correspond to large wind power investments in the Nordic-German system. Cost-efficient wind power allocation is a trade-off between minimising investments in wind power capacity, thereby allocating investments to sites with the most favourable wind conditions, and minimising investments in transmission capacity, with the result that wind power investments are made in proximity to load centres, despite the fact that these sites do not correspond to the sites with optimal wind conditions. For simplicity, it is assumed that the total demand for electricity remains unchanged as new wind power is integrated into the power generation system. In such a case, there is also the possibility to allocate wind power capacity close to power plants in which electricity generation is reduced (as they are entirely or partially replaced by wind power), thereby minimising investments in transmission capacity by making use of existing lines. In the Nordic-German system, the most favourable wind conditions are found in Norway, and the majority of the fossil-fuelled electricity generation (i.e., electricity generation with the highest running costs and thus the generation that will be replaced as the electricity demand remains unchanged) is located in Germany. Therefore, there is a need to balance investments in wind power capacity and transmission capacity in the Nordic-German system. The present analysis compares the free allocation of wind power over the region with allocation that fulfils national restrictions on the levels of wind power grid penetration. These restrictions are based on national planning frameworks for wind power in the Nordic countries.

The analysis was carried out using a linear cost-optimisation model of the heat and power sector with a 1-hour time resolution. This model minimises the sum of the running costs to meet the heat and power demand and the wind power and transmission investment costs necessary to reach a wind power production level that corresponds to 20% of the total electricity demand for the region investigated. The BALMOREL model was used as a starting point for the modelling in this project (Ravn, 2001). In the BALMOREL model, each country is subdivided into regions that are delimited by bottlenecks in the transmission system. Within each region, the electricity demand has to be satisfied on an hourly basis, either through electricity generation in units located within the region or through imports from other regions. For the purpose of investigating wind power allocation, an add-on called WALL (Wind power ALLocation) has been developed and included in the BALMOREL model. Within this add-on, each region was complemented with three wind power investment areas, which correspond to the lowland, upland, and offshore wind power generation for each region. Wind speed data were used as an input, recalculated to the wind power production data. The wind speed data were retrieved from the NECP/NCAR Reanalysis database (Kalnay et al., 1996). This database contains wind speed data measured every sixth hour over a 2.5°×2.5° grid around the globe. To derive hourly wind power generation from the NECP/NCAR wind speed data a method developed within the EU Trade Wind project (Van Hulle, 2009) was applied. For further details regarding the model and input data, see Göransson and Johnsson (2010).



GREAT POSSIBILITIES FOR EXPORTING NORWEIGIAN AND SWEDISH WIND POWER

Figure 8.1 illustrates the geographical allocations of wind power capacity and transmission capacity investments provided by the model. Since the difference in wind power generation costs between the regions with good and poor wind conditions in the Nordic-German system (90 €/MWh) is greater than the cost of transmission from one end of the system to the other (25 €/MWh), new wind farms are concentrated in windy regions (i.e., central and southern Norway, central Sweden, and western Denmark). However, the difference in wind power generation costs between different regions with good wind conditions is in the same range as the difference in transmission costs between these regions, and the results from the model show that the distribution of wind farms between such windy regions depends on: 1) the extent to which existing lines can be used to transmit new wind power; 2) the availability of alternative low-cost generation; and 3) the correlation of wind power generation between exporting regions. When there is a substantial level of wind power already present in the importing region, as in the case of south-central Germany, the correlation between the exporting and importing regions also have an impact on the distribution. Thus, factors 1-3 determine the distribution of wind power capacity investments between western Denmark, central Sweden, and central and southern Norway in the case of free allocation (Figure 8.1a). As shown in Figure 8.1a, additional wind power investments in Denmark are limited, despite good wind conditions and proximity to fossil fuel-supplied demand due to the lack of flexible low-cost generation capacity (factor 2). South Norway and central Sweden have the most favourable conditions for wind power generation (Figure 8.1a). A combined investment in Sweden and Norway decreases the wind power correlations (factor 3) and maximises the use of the hydroelectric power capacity in Sweden and Norway as a complement to wind power generation (factor 2). In the case of co-ordinated wind power investments, national limitations on wind power are more likely than the export market to set upper limits. In the case of national limitations on wind power grid penetration, wind power investments are made up to given limitations in Denmark, Norway, and Sweden (Figure 8.1b). For a more detailed analysis of the results, see Göransson and Johnsson (2010).

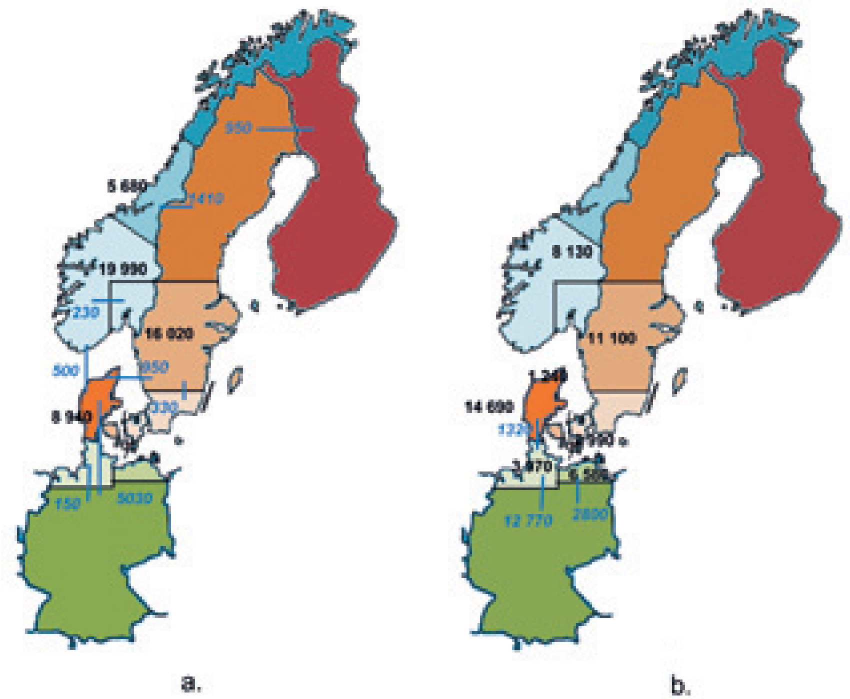


Figure 8.1. Allocation of wind power investments (black) and transmission investments (blue) in MW, as obtained using the model. a) Twenty percent of the total electricity demand is to be met by wind power. There is free allocation of wind power investments. b) Twenty percent of the total electricity demand is to be met by wind power. The following national upper limits apply to wind generation: 20% (of the electricity demand) for Sweden, Norway, and Finland; 50% for Denmark; and no limit for Germany. Source: Göransson and Johnsson, 2010.

Figure 8.2 presents the total system costs relative to those of the present system. As illustrated in Figure 8.2, large-scale wind power integration in the Nordic-German electricity generation system would be less costly if wind power investments were co-ordinated and allocated to regions with the most favourable conditions. The cost of installing wind power that corresponds to 20% wind power grid penetration in the system as a whole would correspond to an increase of around 25% compared to the present system if wind power could be allocated freely, compared to an increase in costs of around 30% if investments in the respective countries are limited to current upper national targets. Note that the cost of CO_2 would increase the total cost of the present system much more than the total costs of the systems with 20% wind power and could compensate for the increase in total system costs attributed to wind power investments. The value of free allocation is in the range of 900-1600 M€/year for the Nordic-German system. In a system of free allocation, Sweden and Norway would accommodate up to 60% wind power (share of national electricity demand), which would create massive challenges for the siting and permit-issuing processes, factors that are not considered in the present work. Yet, it can be concluded that Sweden and Norway have great possibilities for exporting renewable energy in the form of wind power.

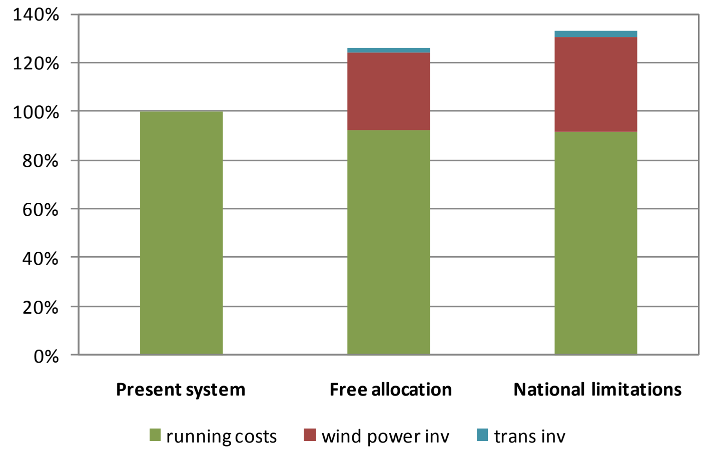


Figure 8.2. Total system costs relative to the present system subdivided into running costs, wind power capacity investments, and transmission capacity investments. Free allocation: 20% of the total electricity demand is to be met by wind power. There is free allocation of wind power investments. National limitations: 20% of the total electricity demand is to be met by wind power. The following national upper limits apply to wind generation: 20% (of the electricity demand) for Sweden, Norway, and Finland; 50% for Denmark; and no limit for Germany. Source: Göransson and Johnsson, 2010.

For more information:

Lisa Göransson and **Filip Johnsson**
Energy Technology, Chalmers

Further reading:

Göransson, L., Johnsson, F., 2010. Geographical Allocation of wind power investments - a Nordic-German perspective. Submitted for publication.

9

Seasonal impact of large shares of wind power:

an example

Large annual shares of wind power, as foreseen for several EU Member States, especially Germany, will cause significant seasonal variations in the electricity markets. Electricity prices may vary substantially, not only due to variations in load, but also due to variations in intermittent electricity production. These variations will affect both other electricity-supply technologies and international electricity trade. This chapter presents a simple and basic example of such features for Germany and its trade balance with the Nordic countries.

Model-based analyses indicate that wind power will supply a considerable share of the electricity generation in certain Member States beyond 2020. In the case of Germany this may exceed 100 TWh per year by 2025, as indicated by the Market scenario (in Chapter 1), which corresponds to around 15 percent of the total supply in 2025. Between 2002 and 2009, wind-power production increased by 20 TWh in Germany. This means that the expansion pace in terms of production, on an average yearly basis, will need to be around 30 percent higher between 2025 and 2009 than it was between 2002 and 2007 if a production of 100 TWh is to be reached by 2025 (in 2009, the wind power production in Germany was around 40 TWh). A supply of 100 TWh of wind power by 2025 is in line with a recent scenario analysis ordered by the German Bundesministerium für Wirtschaft und Umwelt (Prognos AG, EWI and GWS, 2010).

SEASONAL VARIATIONS

Relatively high annual levels of wind power imply significantly higher (and lower) seasonal contributions in relative terms, due to fluctuations. The wind power generation profile of Germany used in the EPOD model (see Chapter 12 in the *Methods and Models* book) is shown in Figure 9.1 (normalised to an annual production of 100 TWh). This is a calculated curve, based on estimates from the TRADEWIND project (2009) and the Pathways project, aggregated over the three different wind power classes available in EPOD (and the ELIN/ELOD model), i.e., offshore, lowland onshore, and highland onshore.

The view presented in Figure 9.1 is simplified, since domestic grid limitations may affect the total available production, especially if wind power capacity achieves a significant size. Nevertheless, it is clear that the challenge of intermittent production lies ahead for a region that invests heavily in wind power. Furthermore, the assumed production profile implies that variations in wind power production are substantial, even though they are distributed over a country of Germany's size (this is an assumption that has been confirmed by actual production data collected by Vattenfall). More on the impact of intermittent power production may be found elsewhere in this book, e.g. Chapter 6.

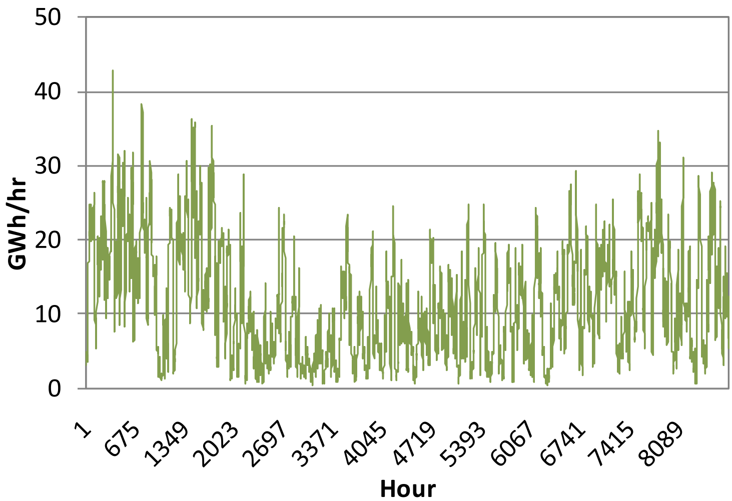


Figure 9.1. Assumed total wind production profile (in GWh/hr), assuming an annual production of 100 TWh in Germany. The profile includes all three subclasses in EPOD, weighted as 50% offshore, 30% onshore lowland, and 20% onshore highland. (Source: own data adaptation based on TRADEWIND wind data, www.trade-wind.eu).

ELECTRICITY PRODUCTION IN GERMANY IN 2025 ACCORDING TO THE MARKET SCENARIO

In Figure 9.2, the weekly electricity production in Germany is shown for the model year 2025 and for the Market scenario. The results shown are EPOD modelling results based on ELOD model outputs taken from the overall European model calculations, which are more thoroughly described in Chapter 1. The weekly fluctuations in wind power output are clearly indicated in Figure 9.2 (for onshore and offshore wind power). Wind power production is generally higher during the winter, i.e., at the beginning and at the end of the year. Due to massive investments in wind power (around 100 TWh, as mentioned earlier) and additional nuclear capacity (around 30 TWh more than today – new investments are optional in the Market scenario), Germany has in the Market scenario for 2025 an excess capacity, which is exported. The net export of electricity amounts to almost 50 TWh.

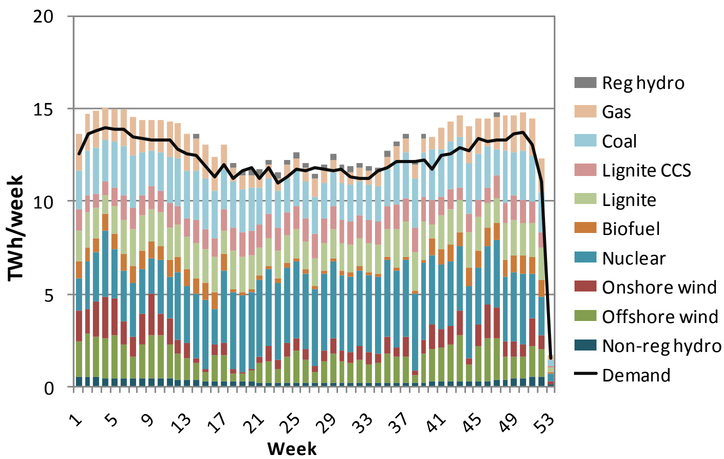


Figure 9.2. Weekly electricity production and load in Germany in model year 2025, for the Market scenario (Week 53 contains only one day).

HIGH-LOAD CONDITIONS COMBINED WITH VARIATIONS IN WIND POWER

A closer look at a specific 48-hour load block during the winter (Figure 9.3) reveals the hourly electricity dispatch for the German supply system (EPOD model runs). The chosen load-block includes the annual top-load hour, as a whole, for the modelled system, i.e., Northern and Western Europe. Once again, the fluctuations in wind power production in Germany are significant and affect the rest of the supply system. This specific load-block happens to coincide with a period of high wind power production (offshore and onshore combined). Therefore, marginal electricity costs are at certain times, especially during night-time, very low (close to 30 €/MWh). In the peak periods, marginal costs approach 50 €/MWh.

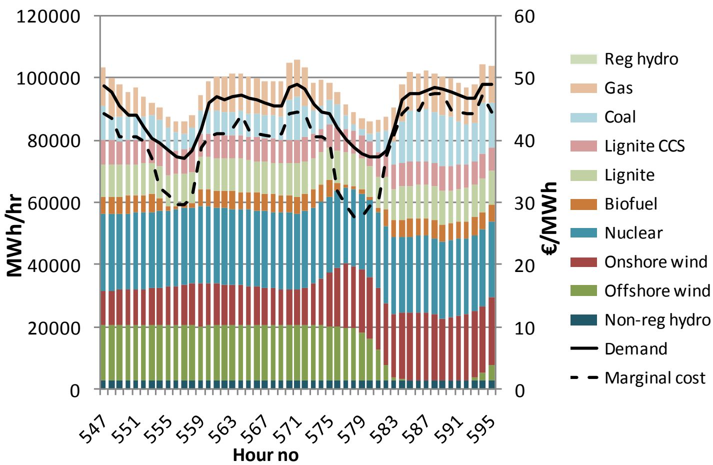


Figure 9.3. Electricity supply and marginal electricity costs in a 48-hour high-load block in Germany in 2025 (Market scenario).

To what extent are these fluctuations in marginal costs explained by fluctuations in wind power? Figure 9.4 presents a sensitivity run under identical conditions, apart from a 50 percent reduction in the output from German wind power. This mimics a situation that has exactly the same power system, electricity load, and time of year but in which wind power production is halved (due to, e.g., other wind conditions) on a national level during the specified period. The German supply system compensates for the reduction in wind power by increasing other production means (gas and hard coal) and decreasing the level of net exports. These two options account for equal shares in this specific case. Furthermore, marginal electricity costs are significantly higher, typically 30 percent during the studied period, and show significantly less prominent fluctuations than in the former case.

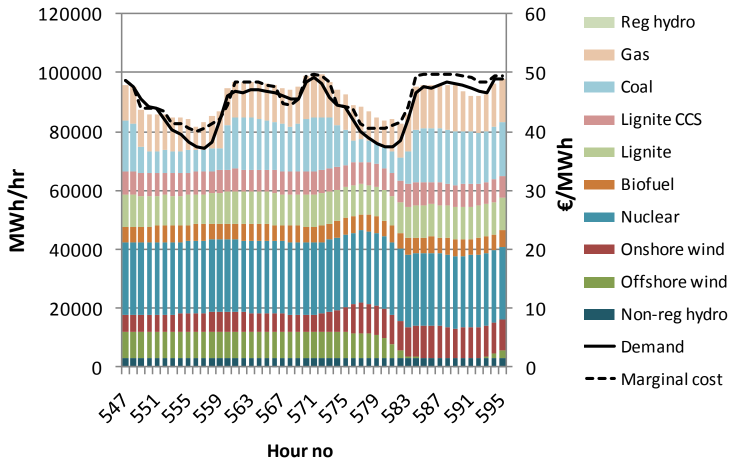


Figure 9.4. Electricity supply and marginal electricity costs during a 48-hour, high-load block in Germany in 2025 (Market scenario), using a 50% reduction in wind power production compared to the situation shown in Figure 9.3.

IMPACT ON ELECTRICITY TRADE BETWEEN GERMANY AND NORDIC COUNTRIES

In Figure 9.5, the Nordic electricity supply is shown, during the same 48-hour segment as above, and for the sensitivity case with less wind power in Germany. The Nordic countries, including Sweden, Norway, Finland and Denmark, are an important part of the German electricity trade balance. In contrast to Germany, the Nordic countries have access to abundant regulatable hydro power, which enables a relatively horizontal marginal-cost curve during the specific period (cf. Figure 9.5).

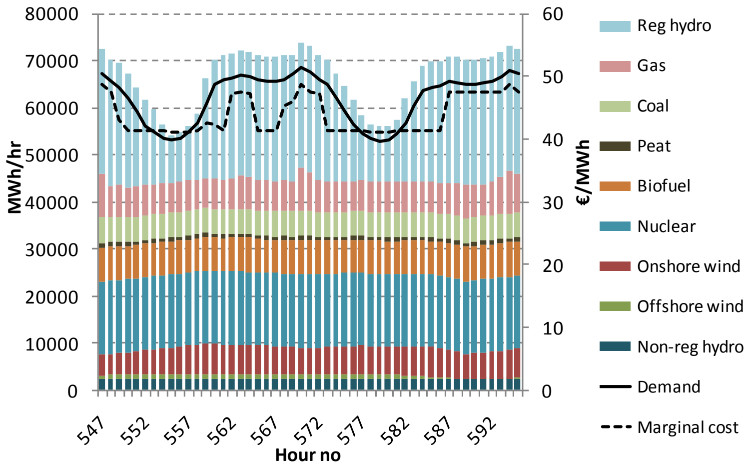


Figure 9.5. Electricity supply and marginal electricity costs during a 48-hour, high-load block in the Nordic countries in 2025 (Market scenario, sensitivity case with less wind power in Germany).

Nordic electricity exports to Germany are increased in the case of lowered wind power in Germany. Consequently, the marginal electricity costs are affected also in the Nordic countries. This becomes obvious in Figure 9.6, in which marginal electricity costs in Germany and the Nordic countries are shown for both of the investigated cases. In the reference case, the large share of wind power (and other supply capacity) leads to relatively low (and fluctuating) marginal electricity costs in Germany during the investigated load-block.

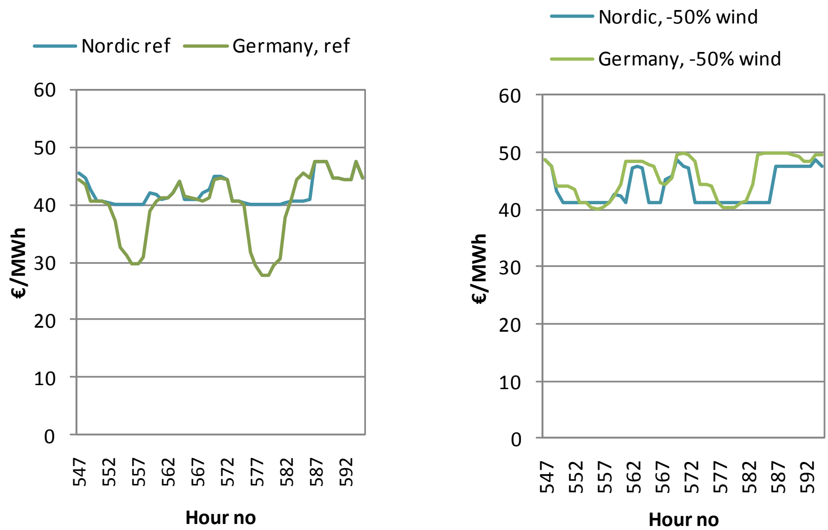


Figure 9.6. Marginal electricity costs during a 48-hour, high-load block in Germany and in the Nordic electricity market in the reference case (left panel), and in a case in which only 50% of the wind power is available in Germany (right panel).

CONCLUDING REMARKS

This chapter presents a rather basic example in which fluctuations in wind power have significant impacts on the rest of the power system, trade balances between regions, and marginal electricity costs. This is especially true once wind power attains a considerable share of a region's electricity supply. It is highly likely that other combinations of load and wind power output (than the one analysed here), e.g., low demand and high wind power output, would reveal even more significant system effects. In that respect, the international (and domestic) electricity trade may moderate some of the fluctuations associated with an intermittent electricity supply.

Also shown, is a case in which Germany has excess power in the modelled year 2025. This outcome is based on assumptions made regarding the comparative advantages for new CCS schemes (lignite) and targeted investments in wind power, while at the same time nuclear power use is allowed to increase (Market scenario assumptions). German nuclear power policy has, hitherto, involved a phasing out of the existing nuclear power stations and a ban on investments in new nuclear power stations. However, recent political statements point towards a postponement of the phasing out process (see, e.g., information available on the website of Bundesministerium für Wirtschaft und Technologie, http://www.

bmwi.de). In a case corresponding to that outlined here, but in which a German nuclear phase-out has been initiated, it is likely that the same high volume of wind power would have even greater domestic impacts than those indicated here. In such a case, international electricity trade would play an important role in moderating wind power variations.

For more information:

Thomas Unger, Profu
Mikael Odenberger, Energy Technology, Chalmers

Further reading:

Göransson, L., 2008, "Wind power in Thermal Power Systems – Large-scale Integration", Thesis for the degree of licentiate of engineering, Chalmers University of Technology.

Odenberger, M., 2009, "Pathways for the European electricity supply system to 2050 – implications of stringent CO_2 reductions". Thesis for the degree of doctor of philosophy, Chalmers University of Technology. ISBN 978-91-7385-297-5.

10

The impact on climate of European electricity

A basic assumption of European electricity generation modelling in the Pathways project is that CO_2 emissions will be reduced substantially (by 85 percent) by 2050. As a consequence, the average CO_2 emissions specific from electricity generation in all the EU Member States are reduced constantly over time. According to the results from the model, specific CO_2 emissions are below 600 kg/MWh electricity in all Member States by 2020. In 2005, the corresponding upper limit was 900 kg/MWh. However, even though the average level of specific emissions is reduced over time, marginal specific emissions may remain at a relatively high level, even in a long-term perspective. This is also an important indicator when estimating the environmental performance of electricity.

AVERAGE SPECIFIC CO_2 EMISSIONS

In the European electricity generation modelling of the Pathways project, it is assumed in both the Policy and the Market scenarios that CO_2 emissions from total electricity generation will have to be reduced by 85 percent by 2050. This implies that the specific CO_2 emissions from electricity generation will have to be significantly reduced in almost all European countries (Figure 10.1). There are very few exceptions to this rule. However, in some countries, particularly those in which specific emissions are

Defining the pathways from sector specific scenarios

Two different European Energy Pathways are defined in this project: the Policy Pathway and the Market Pathway. The Policy Pathway relies more on targeted policies that promote energy efficiency and renewable energy; the measures in this pathway are primarily demand-side-oriented. In contrast, in the Market Pathway, the measures are more supply-side-oriented and the cost to emit CO_2 is the predominant policy measure. These two Pathways are based on the results from the sector-specific scenarios and analyses described in Chapters 1-46 of this book.

currently very low, e.g., Sweden and Norway, specific emissions may increase to some extent. In these countries, even single gas-fired power plants significantly affect the levels of specific emissions. However, the specific emissions remain at very low levels throughout the entire modelling period. For countries in which specific emissions are currently very high, e.g., Poland, the UK, and the Czech Republic, the decrease in specific emissions will be quite dramatic. By 2020, the average specific emissions in all Member States will be less than 600 kg CO_2/MWh. In 2005, the corresponding number was 900 kg/MWh. Figure 10.1 illustrates the general trend that all Member States will gradually decrease their specific emissions in response to climate change policies and technological developments. The behaviours of individual countries, and certain deviations from the general rule, should be regarded as the result of common European climate and renewable policies rather than actual national policies.

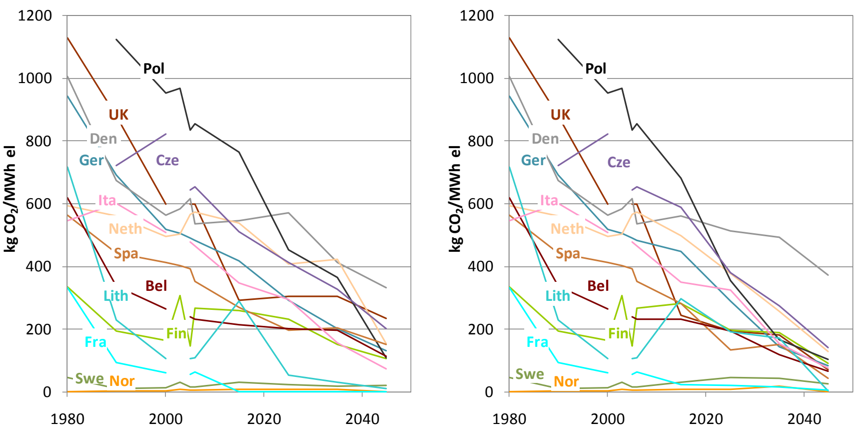


Figure 10.1. Average specific CO_2 emissions from electricity production in selected European countries in the Policy scenario (left) and the Market scenario (right), based on EPOD model runs (Statistics from EURELECTRIC, 2007).

THE CONCEPT OF MARGINAL EFFECTS

Another complementary indicator to average specific CO_2 emissions is marginal specific CO_2 emissions. This is defined here as the additional CO_2 emission that arises from a marginal increase in electricity use (or alternatively, the reduction in CO_2 emissions that arises from a marginal decrease in electricity use). Such a marginal increase (or decrease) in electricity use may be defined over many years, a single year or over a shorter time period. The definition related to single years (or shorter time) is commonly referred to as the short-term (or "operational") marginal effect, i.e., the change in electricity use does not affect investments in electricity generation. It only involves operation in, at that time, existing power plants, generally the most expensive (alternatively, the least efficient) ones. The analysis of a more long-term change in electricity, typically several years, requires estimates of the long-term marginal effect (sometimes referred to as the 'build margin'). The long-term marginal effect also considers investments in new power plants. Such marginal specific CO_2 emissions (short-term and long-term) are important indicators for evaluating the environmental impact of a change in electricity use (or supply for that matter). This view takes its starting point from the fact that every change in a system (in the demand or supply side) should be valued against the effects it has on the system. Such effects are, therefore, regarded as "marginal" (if sufficiently small) deviations from a reference outcome. A more thorough discussion on the concept of marginal electricity and other means to evaluate the climate impact of electricity can be found in Elforsk (2008) and Elforsk (2006).

THE SHORT-TERM PERSPECTIVE

Figure 10.2 shows that the short-term marginal effect may be substantially different from the average specific CO_2 emission, also in a relatively long-term perspective. Sweden, with very low average emissions, is linked to a wider and common electricity market with neighbouring countries, such as Germany and Poland, where average specific emissions are significantly higher. In a common market, a marginal change in electricity use is likely to affect, to some extent, the same power plants on the margin, regardless of whether the increased use of electricity occurs in Sweden or in Germany (limited only by interconnector bottlenecks). This is evident in Figure 10.2, especially for the Policy scenario

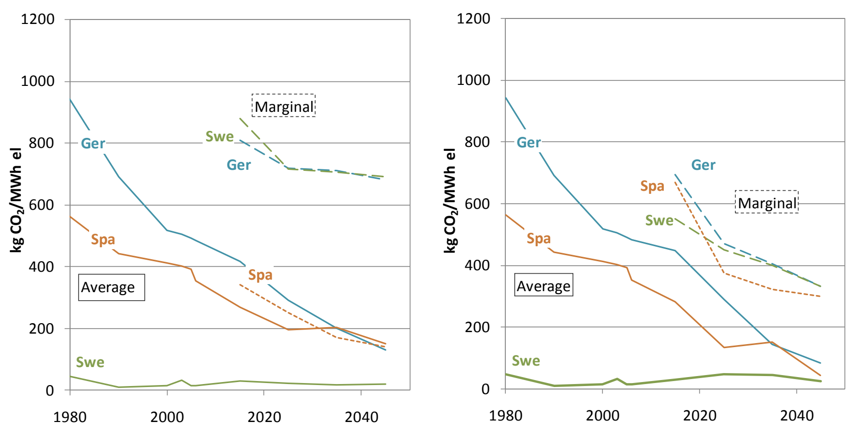


Figure 10.2. Marginal specific CO_2 emissions from electricity production in selected European countries in the Policy scenario (left) and Market scenario (right), based on EPOD and ELOD model runs (Statistics from EURELECTRIC, 2007).

(left panel). It also means that a country with lower average specific emissions may experience significantly higher marginal emissions than a country with higher average emissions (compare Sweden and Spain in the Policy scenario). Furthermore, a very ambitious climate target for electricity generation as a whole does not necessarily result in very low marginal emissions in the future. On the margin, there may exist power plants with substantial CO_2 emissions, even though the bulk of the generation capacity is CO_2-lean. However, such a CO_2-intensive generation margin is significantly "thinner" in a CO_2-lean future than is currently the case, i.e., the share of CO_2-emitting electricity generation will be substantially smaller in the future than it is today. Comparing the Market and Policy scenarios, it is clear that marginal emissions are generally lower in the Market scenario (cf. Sweden and Germany). This is explained by higher marginal costs for reducing CO_2 in the Market scenario, owing to higher electricity demand, given the same CO_2-reduction target. However, exceptions (cf. Spain in Figure 10.2) exist for this specific example.

If the marginal specific CO_2 emissions are low, as they are seemingly in e.g. Spain beyond 2030 in the Policy scenario, this means that CO_2-lean technologies have a greater impact on the marginal electricity production and thus, on price formation. Such technologies may include conventional gas power, biomass-coal cofiring schemes, CCS power plants, and even biomass-only condensing power plants.

THE LONG-TERM PERSPECTIVE

An example of the long-term marginal effect is shown in Figure 10.3. This effect was estimated with the MARKAL-NORDIC model, including, among other sectors, the North European electricity market. The effect was estimated by increasing electricity demand in a North European country by 5 TWh over the period 2010-2050, and comparing it to a reference case (the input assumptions were somewhat different from what is assumed in the default Market and Policy scenario assumptions). Even though the results may fluctuate over the years, the trends are similar to what has been reported above. The long-term CO_2 effect gradually decreases over time (Figure 10.3, right panel). This is due to the fact that the increase in electricity use is met, in the short-term, by existing coal-fired power and in the long-term, by a mix of investments in new technologies, including high-efficiency fossil power (such as CHP schemes), CO_2-lean fossil power, such as gas and/or CCS schemes and renewables, together with the increased utilisation of existing (at that time) capacity (Figure 10.3, left panel).

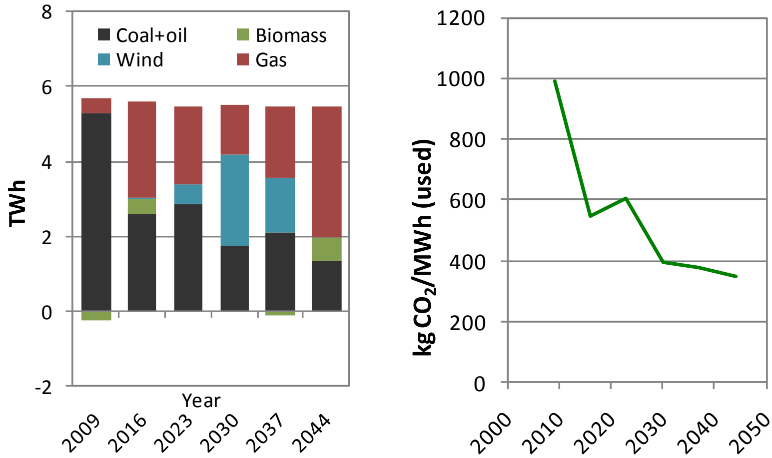


Figure 10.3. The long-term marginal effect for electricity use in the Nordic countries, estimated using the MARKAL-NORDIC model. The left panel shows the change in North European electricity production caused by an increase in annual electricity demand of 5 TWh in Sweden, as compared to a reference case. Production is generally >5 TWh due to transmission losses. The right panel shows the resulting change in CO_2 emissions normalised to the use of 1 MWh of electricity.

AN ILLUSTRATIVE EXAMPLE - IMPACT ON CLIMATE OF ELECTRIC CARS

As mentioned earlier, the long-term marginal effect is an outcome if the changes (the effects of which are in focus) in the electricity system are of significant magnitude and duration. A typical example of such a change would be significant penetration of electric cars in the future (this would be a change compared to a case in which such cars would not have been introduced). However, estimates of such long-term effects on the European perspective have not been undertaken directly in the Pathways project. Instead, the electricity system models of the project have been used to estimate short-term effects, as reported above.

Figure 10.3 shows the long-term effects of a change in electricity demand in Sweden that were estimated using different boundary conditions. It is clear that the long-term effect (valid for Sweden) reported in Figure 10.3 is very similar to the short-term effect reported for Sweden in the Market scenario (Figure 10.2, right panel). There are reasons to believe that these effects, when displayed over a longer time period, have features in common.

Electric vehicles have significantly better efficiency than vehicles with conventional combustion engines. Taken together with prospects for a considerably CO_2-leaner electricity production in the future, this implies that a shift from conventional combustion engines to electric cars is beneficial for the climate. Needless to say, a shift to electric cars would also be beneficial in terms of other pollutants. When emissions associated with electricity are sufficiently low, electric vehicles have lower emissions per useful service than conventional vehicles. To elucidate this “point of break-even”, the specific CO_2 emissions over time from a new average car in a reference case and those from an electric car were estimated (Figure 10.4). Based on EU targets for car efficiencies and the share of biofuel-powered cars, the specific CO_2 emissions over time from an average new car in a reference case were established (Figure 10.4, red line).

To establish the corresponding emissions from electric vehicles, the short-term marginal CO_2 effect was used in line with the previous discussion. For different developments in the Market and Policy scenario (Figure 10.2), the specific emissions from electrical vehicles are presented as an interval (Figure 10.4, beige area). The interval represents the uncertainties of the concept of marginal effects per se, as well as the geographical and scenario-related spread reported in Figure 10.2. As can be seen in Figure 10.4, the emissions from electric vehicles are higher than those from the reference car in the present day (2010). However, the CO_2 emissions from electric vehicles decrease rapidly as CO_2 emissions associated with electricity production decrease. Already by 2020, electric vehicles could be more CO_2-efficient than the average car in the reference case. However, if marginal electricity production is associated with comparatively high CO_2 emissions also in the future (as indicated for Sweden and Germany in the Policy scenario), the point of break-even may lie further ahead or may even

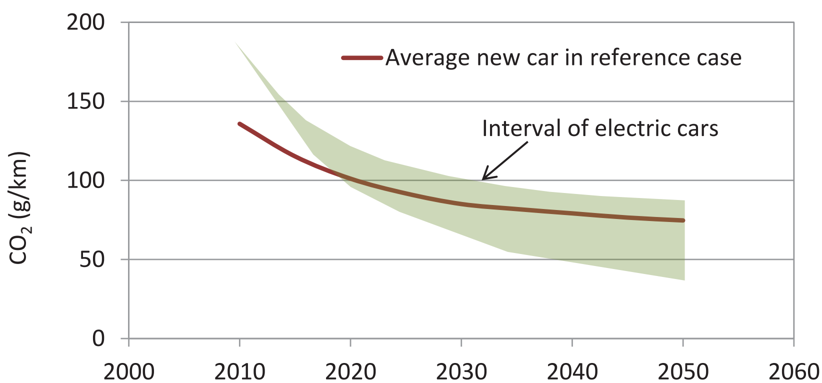


Figure 10.4. Schematic development of specific CO_2 emissions from new “average cars” and new electric cars.

be unattainable. In that case, electric cars might not become more CO_2-efficient than the reference car, which of course also undergoes technological development, efficiency improvements, and fuel shifting (e.g., to biofuels). Nevertheless, based on the collective analyses and modelling experiences of the Pathways project, it seems likely that electric cars will represent, in a decade or two, a significant improvement in terms of climate mitigation over the average new car.

CONCLUDING REMARKS

In contrast to average (specific) emissions, it is difficult to estimate marginal CO_2 emissions, especially concerning future emissions. This applies to short-term as well as long-term marginal effects. The uncertainties are large and the results may vary substantially due to alternative input assumptions, geography, and time. Therefore, the quantifications made in this chapter should not be over-interpreted, but rather should be used as qualitative information. Nevertheless, understanding the concept of marginal effects and the principles of using them are important due to their relevance to environmental assessments of the use of electricity. The important insights may be summarised as follows:

- All countries will reduce their specific emissions and their marginal emissions given that ambitious climate policy instruments are put in place. Thus, the climate impact from using electricity will gradually (and constantly) be reduced over time.

- There may, also in the future, exist significant differences between countries. Countries with low average emissions do not necessarily have lower marginal emissions than countries with higher average emissions.

- Integrated electricity markets are an important factor when evaluating the CO_2 effect linked to a specific country, and they tend to harmonise marginal CO_2 emissions from using electricity among countries, despite the fact that the overall production mix may vary substantially.

For more information:

Thomas Unger, Profu,
Mikael Odenberger, Energy Technology, Chalmers
Erik Axelsson, Profu

Further reading

Axelsson, E., Rydén, B., and Colpier U., 2010, "EMER model results: Two Pathways to Sustainable European Energy System". Pathways Internal report 1/2010. See also www.energy-pathways.org.

Elforsk, 2006, "Marginal electricity and environmental assessment of electricity". Report written by Sköldberg H., Unger T. and Olofsson M. (in Swedish), Elforsk report 06:52.

Elforsk, 2008, "Effects of changing electricity use/electricity production – Model calculations", report written by Sköldberg H. and Unger T. (in Swedish). Elforsk report 08:30.

Odenberger M., Johnsson F., 2009, "Pathways for the European electricity supply system to 2050 – the role of CCS to meet stringent CO_2 reduction targets", paper submitted for publication (available as appended paper in Odenberger M. 2009, "Pathways for the European electricity supply system to 2050 – implications of stringent CO_2 reductions", Thesis for the degree of doctor of philosophy, Chalmers University of Technology, ISBN 978-91-7385-297-5).

11

Conflicts in policy within the electricity supply system:

a brief example

Presently, a variety of policy measures exists within the European power sector, national means of control, and common EU policy. It is not obvious that all the present policies are complementary, and rather there is a risk of disturbances and that some policies are superfluous. A brief analysis of the synergies from the EU policy package (EU-20-20-2020 targets) show that enforcement of RES targets and the efficiency targets can lead to a situation in which the EU ETS becomes redundant, i.e., very low or zero prices for CO_2. Furthermore, the analysis investigates the implications of implementing the so-called Emission Performance Standards (EPS) in addition to the EU ETS, which would increase the risk of price decreases in the CO_2 emission market.

THE CONCEPT OF EMISSION PERFORMANCE STANDARDS

The method used in this analysis is primarily based on ELIN model runs. The objective is to investigate scenarios, including an interpretation of the EU-20-20-2020 targets for the power sector, with and without the implementation of different Emission Performance Standard (EPS) levels. EPS simply sets an emission standard for power plants, which is expressed as a limitation in emitted emissions per produced unit of electricity. The EPS levels studied build on the suggested levels from ECOFYS (Wartman et al., 2009), with variations regarding the year of introduction and whether the EPS is introduced only for new investments or also for existing power plants. It should also be pointed out that the implementation of EPS in this study is limited to condensing power plants, i.e., power plants that only generate electricity, in contrast to combined heat and power (CHP) and industrial back-pressure power plants, which are not subject to any EPS limitations.

The EPS levels taken from ECOFYS and applied in the scenarios, i.e., 350 g CO_2/kWh and 150 g CO_2/kWh, entail the following limitations for investments in new thermal power plants:

- The 350 g CO_2/kWh level requires the state-of-the-art gas-fired power plants, biomass power plants or coal plants with CCS.
- The 150 g CO_2/kWh level requires biomass power or CCS and prohibits coal or gas from being used in conventional power plant configurations.

RISK FOR ZERO CO_2 PRICE

Introduction of EPI has been compared to a reference case. The reference case without EPS includes all parts from the EU's policy package (RES target, CO_2 limitation, and efficiency measures) and meets the target for CO_2 emission reductions within the power sector (30% below the levels of emissions in 1990) by 2020 (corresponding to a total European reduction of 20%) and the target of 85% reduction by 2050. RES-based electricity has a 30% share of the power sector by 2020 (corresponding to a total EU share of 20%) and a 45% share by 2050. Efficiency measures are assumed to reduce electricity demand by 13% (relative to the EU baseline) by 2020 and by 23% by 2050. Thus, the reference case relates to development within the Policy scenario. The results indicate that the combining of these three targets runs a risk of low prices for CO_2 around 2020 (Figure 11.1).

The introduction of any EPS at the above levels would limit the use of conventional coal power plants, thereby increasing the "risk" of periods of "zero" pricing of CO_2 emission allowances. Obviously, the impact depends on the EPS level implemented and whether or not existing power plants are affected by the EPS (Figure 11.2). The inclusion of existing power plants in the EPS scheme would likely mean earlier retirement. The more power plants that are included in an EPS scheme, the more dramatic the effects will be on the EU ETS.

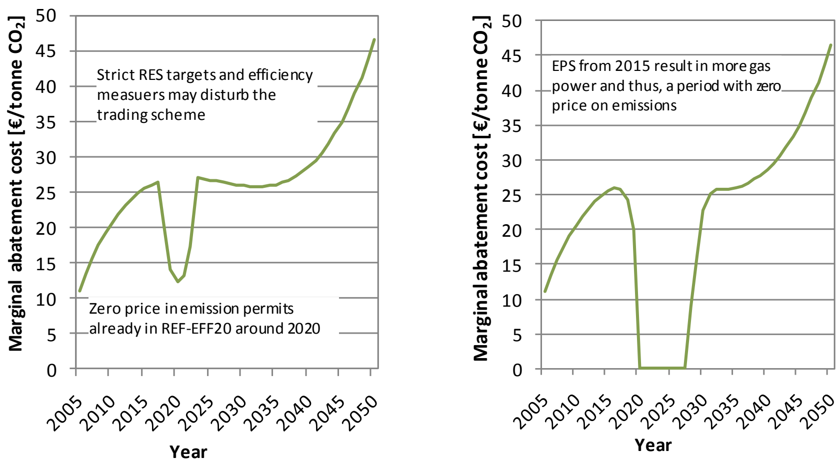


Figure 11.1. Schematic view of marginal costs of CO_2 emissions, including the EU policy package with or without EPS

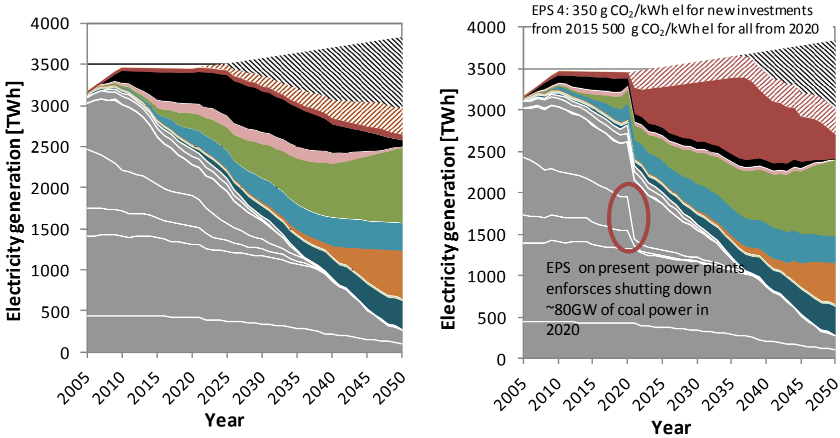


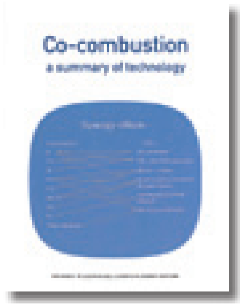
Figure 11.2. European electricity supply in the reference case (without EPS; left panel) and in a case with the EPS scheme (right panel).

The preliminary work presented in this chapter shows that introducing different policy instruments, with overlapping goals, may affect each other in a significant way. When it comes to the introduction of EPS the modelling analyses reported here show that:

- EPS is a means of control that is currently unrefined and difficult to balance with other policies.
- Strict EPS level reduce significantly the technology options, which can lead to problems with capacity ramp-up for low-carbon technologies (e.g., RES, CCS, and possibly nuclear).
- EPS may lead to increased dependency on gas, which raises questions in terms of the security of supply.
- EPS may have a significant impact on the EU ETS scheme by depressing EUA prices. Model calculations indicate, depending on the design of the EPS, that the prices for CO_2-emission allowances could approach zero.

For more information:

Mikael Odenberger and
Filip Johnsson,
Energy Technology, Chalmers



Overview of the Pathways booklet:

Co-combustion
- a summary of technology

Co-combustion of biomass or waste together with a base fuel in a boiler is a simple and economically suitable way to replace fossil fuels by biomass and to utilise waste. Co-combustion in a high-efficiency power station means utilisation of biomass and waste with a higher thermal efficiency than what otherwise had been possible. Due to transport limitations, the additional fuel will only supply a minor part (less than a few hundreds MWfuel) of the energy in a plant. There are several options: Co-combustion with coal in pulverised or fluidised bed boilers, combustion on added grates inserted in pulverised coal boilers, combustors for added fuel coupled in parallel to the steam circuit of a power plant, external gas producers delivering its gas to replace an oil, gas or pulverised fuel burner. Furthermore biomass can be used for reburning in order to reduce NO emissions or for afterburning to reduce N_2O emissions in fluidised bed boilers. Combination of fuels can give rise to positive or negative synergy effects, of which the best known are the interactions between S, Cl, K, Al and Si that may give rise to or prevent deposits on tubes or on catalyst surfaces, or that may have an influence on the formation of dioxins. With better knowledge of these effects the positive ones can be utilised and the negative ones can be avoided.

The AGS Pathways report (2007:EU3) is available at: www.energy-pathways.org.

12

Co-firing of biomass with coal:

a cost-effective option for Europe

Co-firing of biomass with coal represents a near-term option for power generation from renewable energy sources (RES-E). The near-term technical potential for biomass co-firing in existing coal-fired power plants in the EU27 is estimated to approximately 50-90 TWh/yr, which requires a biomass supply of 140-250 TWh/yr. The 2010 RES-E target for the EU27 countries is 21% (of gross electrical consumption). The estimated co-firing potential in the EU27 amounts to 20-33% of the estimated gap between the current RES-E production and the RES-E target. However, for some member states, the national co-firing potential is sufficiently large to fill the national gap. Co-firing of biomass could also offer an opportunity to stimulate the development of lignocellulosic supply systems by representing a near term market for such biomass.

In this chapter, biomass co-firing is described as an example of *bioenergy stepping stones,* i.e., options for promoting desirable bioenergy development based on targeting near-term and cost-effective bioenergy options that can act as bridges to more long-term options. A more technical presentation of biomass co-firing is given in the AGS Pathways report "Co-combustion – a summary of technology", see page 132.

Co-firing is the simultaneous combustion of two or more fuels in the same plant, so as to produce one or more energy carriers. Co-firing biomass with coal in existing boilers costs about 2-5 times less to implement than other bio-electricity generating options and is also in the low-cost range compared to other renewable electricity (RES-E) options (Hansson et al., 2009). Biomass co-firing with coal is more efficient than other available bioelectricity options; since the impact on conversion efficiency of low levels of biomass co-firing is small, the conversion efficiency is equivalent to that of coal-fired power plants. The typical conversion efficiency for a dedicated biomass-fired power plant is 25%, while the average conversion efficiency for conventional coal-fired power plants in OECD countries is about 35%, while the new state-of-the-art plants reach at least 43%.

Biomass co-firing has the advantage that it makes use of the infrastructure associated with coal power plants and therefore represents a bioenergy expansion option that is not constrained by the rate at which new bioenergy conversion facilities can be put in place. Moreover, uncertain biomass supplies do not jeopardise the fuel supply for power plant owners, who can manage a temporary loss on the biomass supply side (or short-term biomass price volatility) by increasing the share of coal in the fuel mix. This fuel flexibility also works in the opposite direction, in that plant owners can increase the share of biomass in the fuel mix (up to technically defined limits) in response to low biomass prices and/or high RES-E prices.

Experience has shown that a 10% biomass fuel share can be co-fired without any major problems of alkali-related high-temperature corrosion, slagging or fouling. The high number of coal-fired power plants also makes biomass-co-firing an interesting option for many European countries (Figure 12.1). Approximately two-thirds of the roughly 150 coal-fired power plants around the world that presently co-fire biomass, either as in the pilot or commercial setting, are located in Europe. A wide variety of biomass materials, including herbaceous and woody materials, wet and dry agricultural residues, and energy crops, are used in these plants.

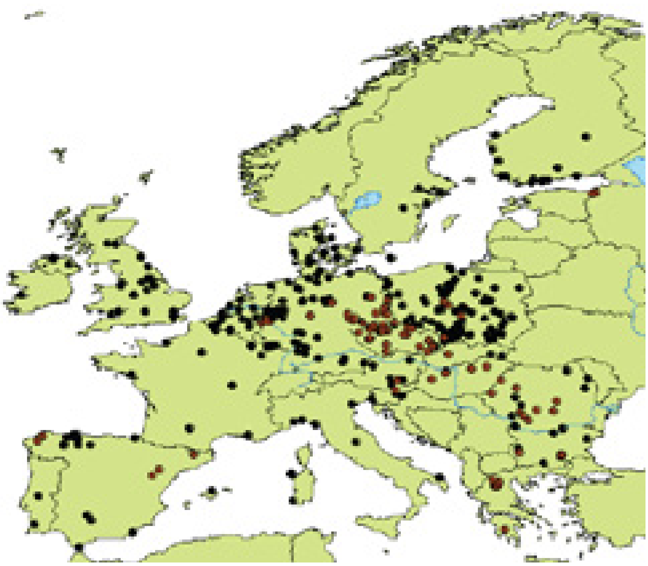


Figure 12.1. Location of the European (EU27) coal-fired-power plants included in the Chalmers Power Plant Database, with about 1100 coal-fired power blocks in total. The black dots represent hard coal plants and the brown dots represent lignite plants. Cyprus, Latvia, Lithuania, Luxembourg, and Malta lack coal-fired power facilities.

THE NEAR-TERM POTENTIAL FOR BIOMASS CO-FIRING WITH COAL IN EUROPE

The Chalmers Power Plant Database was used to assess the potential for RES-E from biomass co-firing in existing coal-fired power plants in the EU (see next page). Two cases were considered. In Case 1, boilers commissioned in 1967 or later were assumed to be available for co-firing, and in Case 2, boilers commissioned in 1977 or later were assumed to be available. The technical potential for RES-E was calculated to be 50 and 90 TWh per year in the EU27 for Cases 2 and 1, respectively. In all the countries, the technical potential for RES-E from co-firing corresponded to less than 10% of the total national gross electricity production in 2005 and it was less than 5% in most countries (Figure 12.2).

Despite this apparently limited potential in the context of total electricity generation, biomass co-firing could become an important option in relation to future RES-E targets in several EU countries. It should be noted that if biomass preparation technologies allow for substantially higher biomass shares in the fuel mix, the role of biomass co-firing could take on greater importance. For instance, a combination of torrefaction (a drying method) with washing out of the mineral salts might produce solid biofuels that can be co-fired at high concentrations with coal without causing the problems associated with burning biofuels of high alkali content.

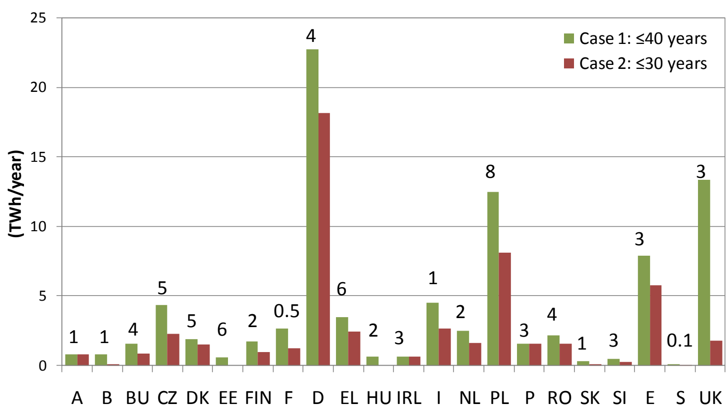


Figure 12.2. Technical potential for RES-E production from biomass co-firing with coal in existing plants in the EU27 MS for Cases 1 and 2. The numbers listed above the bars for Case 1 correspond to the percentages of the national gross electricity production in 2005 (Eurostat, 2007). The EU27 MS not included in the figure lack potential for biomass co-firing. Source: Hansson et al., 2009.

Using the Chalmers Power Plant Database to assess the potential for biomass co-firing in Europe

The Chalmers Power Plant database (PP db) contains information on all the plants in the EU plus Iceland, Norway and Switzerland with a capacity that generally exceeds 10 MWe. Besides locations, the PP db includes the name, position, fuel type, net power capacity, and age of the power plants. It also contains information about plants that are under construction or planned (for a more detailed description, see Chapter 2 in the *Methods and Models* book).

The near-term technical potential of biomass co-firing and the corresponding biomass demand were calculated based on*:

- the available boiler capacity for co-firing in the different MS, as obtained from the PP db. The capacity was quantified for three separate boiler types: fluidised bed boilers, pulverised coal-fired boilers, and grate-fired boilers;
- the load factor, which was estimated on a nation-by-nation basis and for plants that use lignite and hard coal separately. This estimation was based on the 2004 data for annual national power generation by fuel and the national total capacities for the two types of coal, as listed in the PP db;
- the assumed maximum biomass share in the fuel mix for the different boiler types included in the PP db, which was set at 15% for fluidised bed boilers and 10% for pulverised coal-fired and grate-fired boilers (energy basis);
- the conversion efficiencies of the power plants, which were set at 30% for plants that were 31-40 years old, 35% for plants that were 21-30 years old, 37% for plants that were 11-20 years old, 40% for plants that were 0-10 years old, and 45% for plants that were under construction or being planned. It was assumed that the inclusion of biomass in the fuel mix did not affect the conversion efficiencies.

** The maximum amount of bio-electricity that can be produced from biomass co-firing in the existing coal-fired power plant infrastructure. The corresponding biomass demand for co-firing should not be interpreted as the projected demand for biomass for co-firing in any future year, but rather as an indication of the prospective extent of this specific biomass use.*

BIOMASS CO-FIRING AS A STEPPING STONE TOWARDS ATTRACTIVE FUTURE BIOENERGY OPTIONS

Biomass co-firing offers the opportunity to stimulate the development of lignocellulosic supply systems, while offering several additional benefits in terms of providing low-cost RES-E and substantial CO_2 reductions as the biomass replaces the most-carbon-intensive electricity generation. Will the prospective demand for biomass for co-firing link to future efficient and cost-competitive bioenergy options by stimulating a substantial development of lignocellulosic supply systems?

Considering first the absolute sizes, the potential biomass demands for co-firing in the EU27 are estimated at 500 PJ and 950 PJ for the above-described Case 2 and Case 1, respectively. There is substantial variation among the countries, which reflects the varying levels of importance attached to coal-based power in the different countries. However, for many countries, the potential demand for biomass for co-firing is substantial in relation to the present production levels of biomass. This is shown in Figure 12.3, which also shows that the potential biomass demand for co-firing is clearly significant in many countries when compared with the prospective biomass demand associated with policy targets (in this case, biofuel targets).

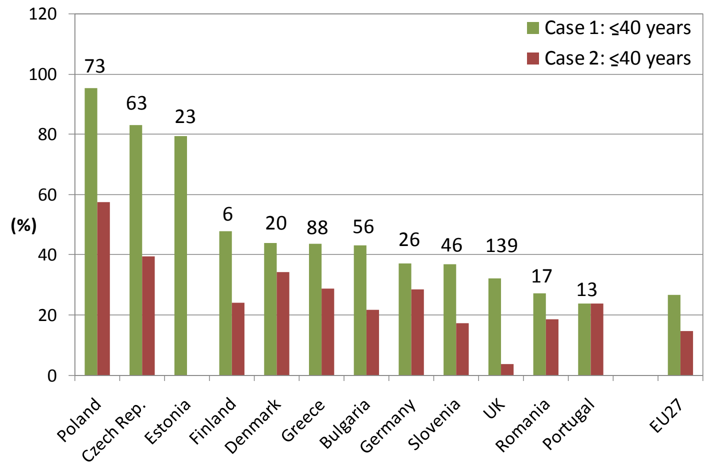


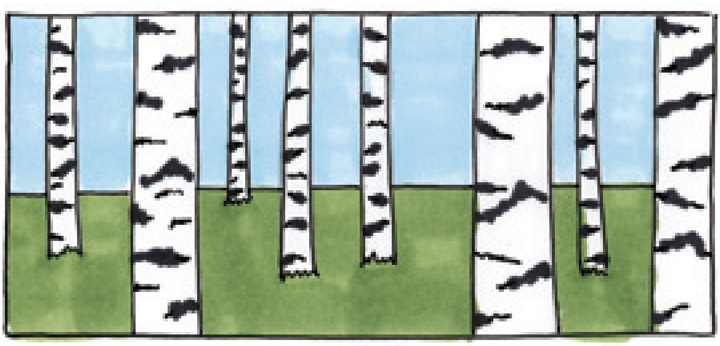
Figure 12.3. Potential demand for biomass for co-firing in existing coal-fired power plants, as a percentage of the amount of biomass needed to meet a 10% biofuels target in 2010. Above the bars, the assessed biomass demands for co-firing in Case 1 are expressed as percentages of the primary production of biomass for energy in the different Member States in 2005. Source: Hansson et al., 2009.

Compared with the production of lignocellulosic crops, the potential demand for biomass for co-firing is high in all countries that have possibilities for co-firing, since the current production levels of lignocellulosic crops are limited. Thus, from the perspective of absolute size biomass, co-firing with coal clearly qualifies as a potentially important near-term source of biomass demand in many countries. If biomass co-firing expands strongly in response to policy targets and other stimulatory mechanisms, biomass output for energy would have to increase substantially in many countries.

At the same time, since the bioenergy supply potentials, as presented in Chapter 25, are much greater than the potential demand for biomass for co-firing, there is a low risk that biomass demand for co-firing will deplete biomass markets, unless strong (institutional or other) supply-side barriers prevent a supply-side response to the increased demand for biomass. In fact, the estimates indicate that the potential biomass demand for co-firing could be met using only the residues from agriculture and forestry, which implies that stimulation of the production of lignocellulosic crops might require specific policies that link co-firing with such biomass sources (e.g., by requiring that a certain percentage of the co-fired biomass is from lignocellulosic crops). This is also true for biomass imports. The availability of cheap biomass from third countries might prevent the development of a domestic biomass supply infrastructure that is stimulated by biomass demand for co-firing. For instance, more than half of the biomass used for co-firing with coal in the UK in 2005 consisted of vegetable oil residual products (e.g., palm, olive, and sunflower oils).

Therefore, if the objective is to stimulate specifically the development of European production systems for lignocellulosic plants, to achieve learning and cost reduction in the production, it may be necessary to differentiate between biomass sources in terms of policy. This could be achieved by linking credits for the green electricity generated by co-firing to the requirement that a certain share of the biomass fuel is derived from the production of lignocellulosic plants within the EU.

The proposed stepping-stone function of biomass co-firing with coal presumes that it represents a near-term market for lignocellulosic biomass that gradually decreases over time, making way for other bioenergy options, which will benefit from the already established biomass supply infrastructure. Obviously, the analyses presented here, which primarily focused on the existing coal-fired power plant infrastructure, propose a near-term option that will not compete for biomass in the longer term, since the power plants will eventually be shut down due to advanced age.



However, to the extent that new coal-fired power plants will be built (possibly prepared for co-firing from the start), this option might persist as a competing use of biomass, even in the longer term. New technological developments may make biomass co-firing with coal competitive in a future climate regime with high CO_2 prices. For instance, if carbon capture and storage becomes widely available, biomass co-firing with coal may become a long-term option for low-CO_2 power (possibly even providing power associated with "negative" CO_2 emissions). As noted above, this could also be the case if biomass preparation technologies allow for substantially higher biomass shares in the fuel mix.

For more information:

Göran Berndes,
Physical Resource Theory, Chalmers
Filip Johnsson and **Jan Kjärstad**,
Energy Technology, Chalmers

Further reading:

Hansson, J., Berndes, G., Johnsson, F., Kjärstad, J., 2009, Co-firing biomass with coal for electricity generation – An assessment of the potential in EU27. Energy Policy, 37(4): 1444-1466.

Hansson, J., 2009, Perspectives on Future Bioenergy Use and Trade in a European Policy Context. Thesis for the degree of doctor of philosophy, Chalmers University of Technology. ISBN 978-7385-270-8.

Johnsson, F., Berndes, G., Berggren, M., 2006. Cost competitive bioenergy: linking lignocellulosic biomass supply with co-firing for electricity in Poland. In: World Bioenergy 2006, 30 May – 1 June 2006, Jönköping, Sweden.

”Co-combustion – a summary of technology”, AGS Pathways report 2007:E3

13

Biomass integrated with natural gas plants:

an example of a bridging technology

Increased efficiency and a lower cost for biomass power are feasible by applying the right technologies under the appropriate conditions. A comparison of different options for the integration of biomass with existing gas turbine plants reveals possibilities for raising biomass electric efficiencies by up to 10-15% and lowering costs by 10-20 €/MWh, as compared to non-integrated biomass plants. This chapter presents options for pathways for the enhanced development and diffusion of biomass-based power.

In view of the slow turnover of the existing power plant stock and the high relative fraction of gas power in new power infrastructure investments (see Chapter 2 in the *Methods and Models* book), gas power plants are anticipated to be important in the European energy system for decades to come. Therefore, it is of interest to examine ways for the introduction of renewable or low-carbon technologies connected to these plants. This chapter evaluates the integration of biomass into existing combined cycle gas turbine (CCGT) plants for natural gas for (heat and) power generation. CCGT plants are the most common plants for natural gas-based electricity generation in Europe. The goal has been to find options for retrofit/integration that give higher (electric) efficiency and lower levelised costs (LCoE) than stand-alone biomass plants. Integration of biomass in CCGT plants could be

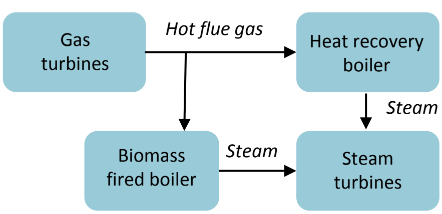


Figure 13.1. Simplified scheme for a fully-fired hybrid combined cycle, HCC (Case 1).

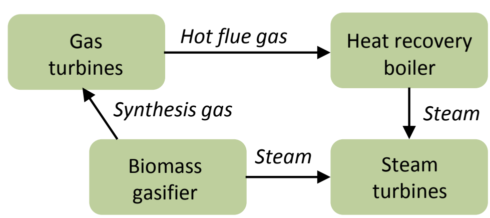


Figure 13.2. Simplified scheme for a biomass gasification plus CCGT layout (Case 1).

especially interesting when there is a strong growth in electricity demand (cf. the Pathways Market scenario), which typically will yield a continued increase in natural gas-fired electricity generation. Electrification of the transportation sector may further increase the need for electricity.

TWO CASES REPRESENTING DIFFERENT EUROPEAN PLANTS AND CONDITIONS

Here, the focus is on three types of CCGT plants in two regions: two condensing power plants in Spain (Case 1); and a 600 MWth CHP plant in Gothenburg, Sweden (Case 2). The existing power plants are used as reference plants. In Case 1, the CCGTs have been optimised for high efficiency, with no supplementary firing and triple pressure steam cycles. In contrast, the reference CCGT in Case 2 is optimised for load flexibility and district heating, with a high level of supplementary firing and a single pressure steam cycle. Biomass options were based on fluidised bed combustion/gasification of solid fuels. Combustion options were integrated with the CCGTs using hybrid combined cycle (HCC) configurations (Figure 13.1; Table 13.1), a concept that has been described previously (Brückner et al., 1992; Egard et al., 1999; Kassem and Harvey, 2001; Montenegro et al., 1987; Petrov, 2003; Takizawa et al., 1993; Westermark, 1991; Wingård and Leckner, 1991). The HCC uses existing gas turbines as the topping cycle and biomass fluidised beds as the bottoming (steam) cycle, in fully-fired or parallel-powered modes. The gasification options (Figure 13.2; Table 13.2) produce medium-value syngas or high-value synthetic natural gas (SNG) as the final product, the latter being based on previous studies (Ahlgren et al., 2007; Ingman et al., 2006). In Case 2, the heat output could be increased by adding condensing heat exchangers in the lowest flue gas temperature levels (Table 13.2).

Table 13.1. Efficiencies of the simulations for Case 1 (Spain), involving biomass integration with a triple-pressure CCGT. The values shown are for specific biomass efficiency, except for the reference plants. The gasification options have the same thermal capacity but vary with respect to the sizes of gasifier and combustion section, respectively (the figure shows gasifier size). GT, gas turbine(s).

Options	Reference gas power plant		Stand-alone steam plant		Hybrid combined cycle concept				Gasification concept		
Configu-rations	01 - double GT	02-single inter-cooling & reheat GT	Full stand-alone (steam drying)	Light integration (flue gas drying)	01 Fully Fired	01 Parallel-powered	02 Fully Fired	02 Parallel-powered	01 Hybrid 25 MW_{th}	01 Hybrid 45 MW_{th}	01 Air blown 45 MW_{th}
LHV eff (%)	57.1	57.0	35.5	37.9	41.0	37.9	40.0	38.0	46.0	49.6	48.7

Table 13.2. Efficiencies of simulations for Case 2 (Gothenburg), involving biomass integration with a single-pressure CCGT. All the efficiency values relate to specific biomass efficiency, except for the reference plant.

	Reference CCGT	Stand-alone steam plant	Hybrid with limited flue gas condenser	Hybrid with adv. flue gas condenser	Stand-alone with flue gas condenser	Gasification
Level of substitution (%)	0	≤ 100	39	39	≤ 100	≤ 100
Total (%)	93.0	98.6	97.9	115.3	115.3	91.9
Electric (%)	**44.4**	**32.4**	**41.7**	**38.3**	**28.1**	**26.0**
DH (%)	48.6	66.2	56.2	76.9	87.2	66.0

Reference and retrofit options were simulated using the Ebsilon Professional software (Evonik, 2009) and Aspen Plus software (Aspentech, 2009). Assessments of component investment costs were performed to derive expressions for estimating the levelised costs of the options. A qualitative assessment of the technical risks for the different options was performed, generating a rough estimate on how developed the respective technologies are and the expected performance regarding system availability. A description of the methodology can be found in Chapter 7 in the *Methods and Models* book.

EFFICIENCY AND COST BENEFITS

There are possibilities for significant improvements in efficiency for biomass energy integrated with CCGT plants, as compared to stand-alone options, as shown in Tables 13.1 and 13.2. The performance of the biomass options is designated as biomass efficiency for the integrated options, i.e., specific (net) efficiency of biomass use, with changes in output compared to the gas-only reference cases attributed to the solid fuel. The large difference in gasification scheme performance observed between the two cases is due to the energy-consuming upgrade of syngas to SNG, and the less-efficient CCGT in Case 2. In contrast, hybrid schemes were shown to be more effective when applied to a CCGT, which is less-optimised for high electric efficiency and has lower steam temperatures (as in Case 2).

The cost assessments (Figures 13.3 and 13.4) show potentials for decreasing the lower levelised costs, LCoE, when biomass is integrated with natural gas, in the 10-20 €/MWh range, as compared to the stand-alone options. However, as shown in Figures 13.3 and 13.4, the magnitude of the benefit and the optimal technology vary with fuel costs and discount rates. In addition, for CHP plants, the price for sold heat will have a strong impact on the LCoE.

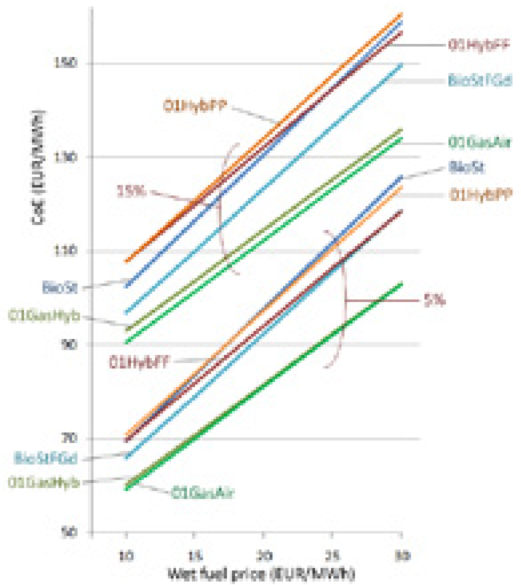


Figure 13.3. LCoE for biomass options as a function of biomass fuel cost, for Case 1, for various discount rates (percentages shown). Hyb, Hybrid; BioST, stand-alone option; Gas, gasification; FF, fully fired; PP, parallel-powered; Air, air-blown combustor: FGd, flue gas drying. Source: Pihl et. al., 2010.

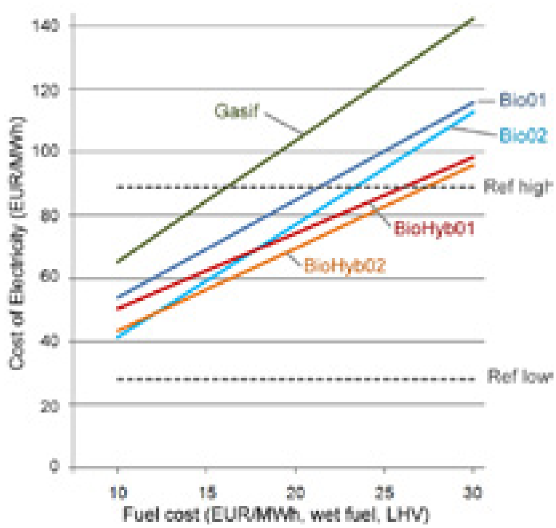


Figure 13.4. LCoE for biomass options as a function of biomass fuel cost, for Case 1, for a district heating price of 25 €/MWh. Dotted lines show the LCoE for the reference CCGT. 'Ref low' refers to gas/CO_2 prices of 20/20 €/MWh or ton, and 'Ref high' gives the corresponding values for gas/CO_2 prices of 40/50€/MWh or ton. BioHyb, Hybrid; Bio, stand-alone option; Gasif, gasification; 01, simple flue gas condensation; 02, advanced flue gas condensation.

RISK ASSESSMENT

The assessment of the technical risks (Figure 13.5) shows significant differences between the options, mainly due to large differences in the levels of technical maturity. Simple steam/boiler-based conversion is regarded as a commercial technology with very low risk, while hybrid plants have some uncertainties and gasification-based conversion can be perceived as largely undeveloped, with success depending on several critical components, all of which must show high reliability. Figure 13.5 and Table 13.2 show that factors other than efficiency and cost, such as the risk and level of substitution, should be considered when comparing retrofit options.

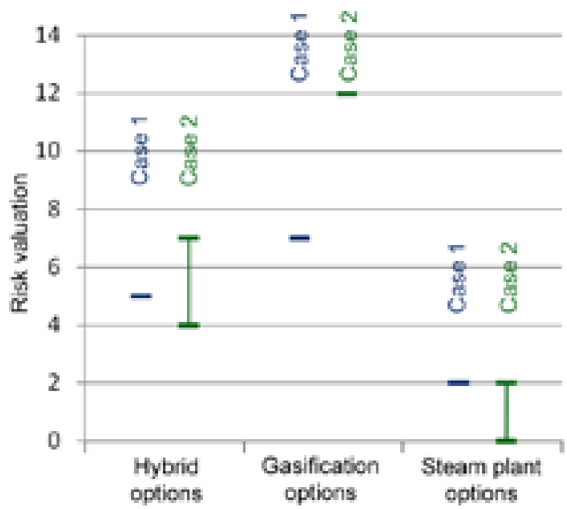


Figure 13.5. Risk valuation of the compared options.

CONCLUSIONS

Efficiency and cost benefits can be realised by integrating biomass thermal conversion with existing gas power plants. The choice of best technology is both site- and case-specific and depends on various factors, such as fuel costs and availability, interest rates, and the type of gas power plant. The main conclusions are as follows:

- Hybrids for solid combustion with highly efficient gas power plants must be applied using the most efficient hybrid (HCC) schemes so as to maximise benefits.
- Hybrid technology is most efficient when applied to less-optimised (less-efficient) CCGT plants, while gasification gives the highest efficiency when applied to highly optimised and efficient CCGT plants.

- Integration options are generally more cost-efficient than stand-alone options at high fuel prices, low discount rates, and low district heating costs.
- Natural gas and CO_2 prices need to be high (both at 40-50 €/MWh or tonne, or at least one has to be significantly higher) for biomass substitution of natural gas in existing CCGTs to be profitable.
- Options based on integration are less-developed than stand-alone technologies and have higher risks, which should be considered when evaluating investments. Technology-specific policy support measures could be needed to develop and phase in these new technologies.
- A 5% level of integration of biomass in all CCGTs in the EU27 that are under construction or that are up to 20 years old would correspond to 8 GW, which represents a 90% increase in biomass/waste capacity.

For more information:

Erik Pihl and **Henrik Thunman**
Energy Technology, Chalmers

Further reading:

Pihl, E., 2010, ”Integrating biomass in existing natural gas-fired power plants”. Thesis for the degree of licentiate, Department of Energy and Environment, Chalmers University of Technology.

Pihl, E., Heyne, S., Thunman, H., Johnsson, F., 2010, ”Highly efficient electricity generation from biomass by integration and hybridization with combined cycle gas turbine (CCGT) plants for natural gas”. Energy 35, Pages 4042-4052.

Pihl, E., Johnsson, F., Thunman, H., 2009, ”Biomass Retrofitting a Natural-Gas Fired Plant to a Hybrid Combined Cycle (HCC)”. 22nd International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems (ECOS), August 31 - September 3, 2009, Foz do Iguaçu, Paraná, Brazil.

14

Linking mobile and stationary energy systems:

potential for plug-in hybrid vehicles

Increasing demands for energy efficiency in transportation, as well as recent advances in electric conversion, control, and storage have facilitated the electrification of the automobile and increased the attractiveness of grid electricity for transportation energy. The viability of using electric vehicles for personal transportation, with a focus on plug-in hybrid vehicles (PHEVs), is investigated. Important factors determining the viability are identified and various implications of possible linking of the stationary and mobile system are assessed. It is found that the design of PHEVs has to be individually adopted to increase their competitiveness. Moreover, synergies can be reached in the integration of PHEV with the electric system, even though participation in regulatory markets is unlikely to push the introduction of PHEV.

Energy systems for modes of transport, which are heavily dependent upon fossil oil, have in the 20th century developed in a manner that is decoupled from stationary energy systems. Although major changes have yet to take place, the prospect of dwindling oil reserves and the resolve to decrease CO_2 emissions and to enhance efficiency, suggest that increased integration of these two energy systems will occur. Some processes for non-oil transport fuel production (e.g., the generation of liquid fuels via biomass gasification) are likely to be less efficient than refinery processing and will produce higher levels of waste heat (the issue is also discussed in Chapter 36). An alternative, fermentation, is likely to consume large quantities of low-temperature heat during processing. The increased reliance on large-scale utilization of intermittent resources, such as solar energy, will necessitate the derivation of efficient methods for adjusting electricity supply and demand, which may be feasible through the development of hydrogen or electricity storage and utilization systems, including transportation.

Assessing the competitiveness and potential of plug-in hybrids

Four specific research questions have been addressed regarding the competitiveness of PHEV linking the stationary and mobile sectors. For each of these questions, different methods or models have been applied and these are briefly summarised below.

Question	Applied method
What technical/ economic conditions are required for the economic viability and competitiveness of PHEVs?	A techno-economical analysis of different vehicle options, given European conditions for, e.g., energy prices and driving patterns, has been performed. Crucial factors governing the economic viability from a consumer perspective is the size of the battery, the charging options and the driving pattern. To determine the individual movement pattern of the car, GPS tracking has been used.
What are the effects on operational costs and CO_2 emissions of different strategies for the integration of PHEVs into the electricity system?	The impact for different charging strategies of PHEVs on the electricity systems operational cost and CO_2 emissions in a wind/thermal system has been assessed using the Balwind model (see Chapter 15 in the *Methods and Models book)*. The current electricity production system of Western Denmark was used as an example. Four different PHEV charging strategies were investigated: immediate charging when coming home, delay to night-time charging, optimal charging for minimisation of electricity production cost with or without bidirectional charging option.
What are the opportunities, and what is the value of PHEV participation in different regulating power markets?	A model was developed for simulating the participation of PHEVs in today's German and Swedish regulating power markets. The simulation was based on observed market price data from a long time period. The charging time of the individual cars was based on simulated driving patterns, as well as optimisation of the economic benefit of participation in the different markets. In addition, strengths, weaknesses, opportunities, and threats (SWOT) of PHEVs as regulating power providers were identified.
What influence will the composition of the long-term CO_2-neutral energy supply have on the competitiveness of electric vehicles?	To analyse future developments in the energy system, the GET model was applied. The model is a perfect foresight model with "mature" technologies and costs. The system costs are minimised for the entire global energy supply system for various CO_2-stabilisation scenarios, given the demands of heat, electricity and transportation. The competitiveness of different car powertrain options was investigated for three different assumptions on the long-term CO_2-neutral energy supply, namely: a system dominated by solar energy, a system dominated by nuclear energy, and a system dominated by coal with CCS.

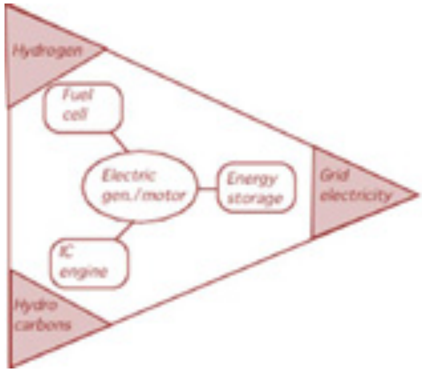


Figure 14.1. Potential routes for the evolution of electrified vehicle powertrains. Source: Karlsson and Holmberg, 2007.

Increasing demands for energy efficiency in transportation, as well as recent advances in electric conversion, control, and storage have facilitated the electrification of the automobile (Hybrid Electric Vehicles [HEV]), which in turn has promoted the provision of transportation energy from grid electricity (Plug-in Hybrid Electric Vehicles [PHEVs] and Battery Electric Vehicles [BEVs]). Figure 14.1 proposes the central role of electric drives in different future powertrain options, although the sources and carriers of the supplied energy may vary.

In this chapter, the viability from a European context of using electric vehicles for personal transportation, with a focus on PHEVs, is investigated. Four questions regarding the competitiveness of PHEV linking the stationary and mobile sectors are addressed:

1. What technical/economic conditions are required for the economic viability and competitiveness of PHEVs from a consumer perspective?
2. What are the effects on operational costs and CO_2 emissions of different strategies for the integration of PHEVs with electrical systems?
3. What are the opportunities and what is the value of PHEV participation in different regulating power markets?
4. What influence will the composition of the long-term CO_2-neutral energy supply have on the competitiveness of electric vehicles?

1. What technical/economic conditions are required for the economic viability and competitiveness of PHEVs from a consumer perspective?

The battery technology that is currently being considered for electric vehicles mainly involves Li-ion chemistries. These batteries are required to supply sufficient energy and power density to propel the vehicle. However, further technical development is needed, for example, concerning the increased lifetime and safety of these battery systems. By comparing two US studies on the future competitiveness of different conceptual vehicle under Swedish (i.e., roughly European) conditions in terms of energy costs and average driving conditions, factors that are of importance for the viability of BEVs and PHEVs were identified (Karlsson and Ramirez, 2007). It was showed that the detailed conditions concerning performance requirements, technical specifications, possible share of driving using electricity, and cost mark-ups, were crucial for the competitiveness of PHEVs in comparison to HEVs and conventional internal combustion engine (ICE) cars. A central factor was found to be the cost of the battery. As it is likely that batteries continue to be relatively expensive in the future, the BEV does not appear to be competitive when used under the assumed driving pattern.

Also shown, using simple examples that crucial factors in utilising batteries for powering cars are the individual car movement pattern and the charging options. Driving the same distance every day provides good opportunities for effective utilisation of an optimized battery, as compared to a car movement pattern that consists of irregular and/or infrequent trips. Unfortunately, there are very few data on the appearances and distributions of movement patterns for individual

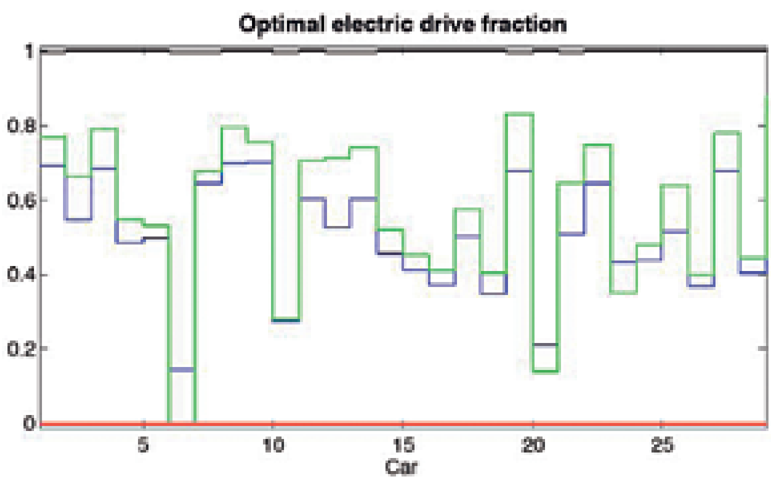


Figure 14.2. Optimal electric drive fractions (EDF), i.e., share of total distance on electricity, for the 29 cars, respectively. The expected EDF for the Monte Carlo distribution (blue), the optimal EDF for parameter values corresponding to the base case (light-green), the minimum profitability (red), and the maximum profitability (black) are shown. Source: Karlsson, 2009.

cars. Regularly performed travel surveys do track persons rather than individual cars, and for instance, in Sweden, this type of survey is typically conducted for one day only. As part of this project, we investigated a small dataset of vehicle movements. The dataset consists of the GPS-tracked movements of 29 cars over a period of about 2 weeks. For the individual cars a Monte Carlo analysis of varying technical and economic parameters was conducted. Also, the following assumptions were used: 1) electrical charging once daily; 2) optimal size of the battery; and 3) the corresponding potential electric drive fraction (EDF, which reflects the share of the total driving distance that is propelled by electricity) (Karlsson, 2009). As shown in Figure 14.2, the optimal battery size and the EDF value are strongly dependent upon the individual movement pattern of the car. (Partially as a consequence of this result, a project has been initiated, in which a larger sample of randomly chosen private cars is being logged using GPS to obtain individual car movement patterns (www.chalmers.se/brd).)

2. What are the effects on operational costs and CO2 emissions of different strategies for the integration of PHEVs into the electricity system?

The integration of electric and mobile systems may lower electricity operational costs and emissions, as a result of possible load shifting and increased flexibility, especially for a system that involves intermittent renewable sources of electricity, such as wind power. Using detailed modelling of the operational cost for electricity production in a wind/thermal system (see Chapter 15 in the *Methods and Models* book), the effects on production costs of different strategies to integrate PHEVs into the grid were investigated (Göransson et al., 2009, 2010).

The simulated production system was the current electricity production system in Western Denmark (Jutland). Up to 20% of the load was converted into an electric vehicle-charging load profile. This study showed that PHEVs can reduce the CO_2-emissions from the power system if they are actively integrated. The emission reductions were attributed to a reduction in emissions related to thermal plant start-ups and part-load operation (Figure 14.3). See Chapter 6 for an elaborate description of the PHEV impact on a wind-thermal system.

According to the simulations, emissions of the power sector were reduced by up to 4.7% compared to a system without PHEVs. This reduction can be translated into a halving of the total emissions from PHEVs when running in electric mode, as compared to the emissions of a standard car. In addition, the costs were reduced in the case of active integration.

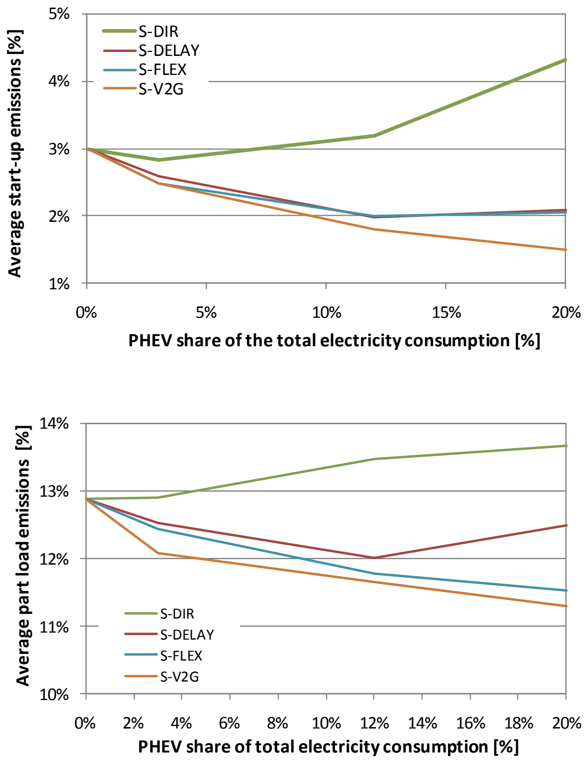


Figure 14.3. Impacts on electric system CO_2 emissions of different PHEV integration strategies . The S-DIR strategy is no action taken, while the other three represent increasing degrees of active integration. (a) Impact on start-up CO_2-emissions, and (b) impact on part-load CO_2-emissions with PHEV share of electricity consumption. The value of 100% represents the average system emissions in the system without PHEVs (i.e., 649 kg CO_2/MWh). Source: Göransson et al., 2010.

3. What are the opportunities and what is the value of PHEV participation in different regulating power markets?

Another option for lowering the costs of the electricity system is the utilisation of batteries or the flexibility of charging to provide regulating power. The participation of PHEVs on the different regulating power markets in Germany and Sweden was simulated, using real prices from these markets and simulation of the vehicle-charging behaviours and associated options (Andersson et al., 2010). The results of this modelling indicated that the maximum average profits in the German market were in the range of €30–80 per vehicle and month, whereas the regulating power market in Sweden produced no profit (Figure 14.4). The observed differences in profitability can be explained by the fact that in Sweden, the market only pays for the regulating power that is actually utilised , i.e., for the transfer of energy, while on the German market, there is an additional payment for having the power available. Thus, the specific structure of the individual market is of profound importance for viability. The regulating power markets are quite small. In Sweden it accounts for approximately 400 MW, which means that not all electric vehicles in a large fleet could participate. Furthermore, the vehicles would need to be pooled for larger power providers due to the minimum power requirements for participation. This would require an institutional infrastructure, an "aggregator", which would organize the pooling as well as the technical infrastructure. None of these requirements are expected to be in place in the near future, which implies that regulating power markets are unlikely to be the driving force for transport electrification.

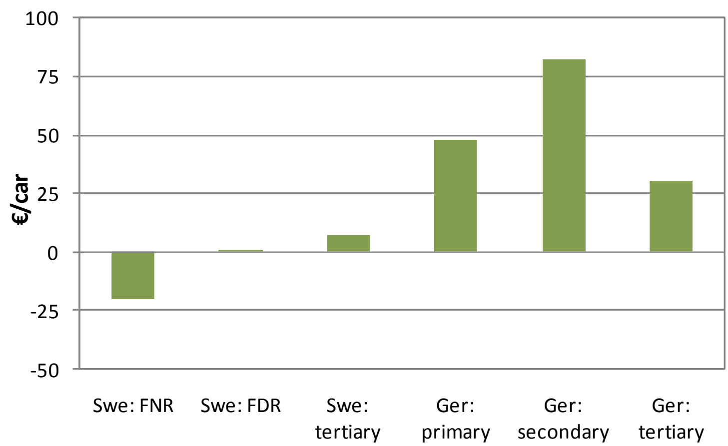


Figure 14.4. Average profit generated by one PHEV during one month in the regulating power markets in Sweden and Germany. Source: Andersson et al., 2010.

4. What influence will the composition of the long-term CO_2-neutral energy supply have on the competitiveness of electric vehicles?

The effects of integration may also affect the competitiveness of electric vehicles. There are three major options for the large-scale, long-term CO_2-neutral supply of energy on a global scale: 1) solar energy (and energy from other renewable sources, such as wind); 2) nuclear energy; and 3) energy from coal with carbon capture and storage (CCS). Table 14.1 summarises how the options for producing electricity, fuels, and heat in a carbon-constrained world affect the cost-effectiveness of a range of fuels and propulsion technologies in the transportation sector (Hedenus et al., 2009, 2010). The long-term CO_2-neutral energy supply affects the absolute and relative prices of different energy carriers and thus has an impact on the economic conditions for the choice of solutions in the transportation sector. The analysis shows that a system dominated by coal with CCS for cars favours solutions that involve hydrogen, which in this system is produced at about half the cost per unit of energy as electricity, or synfuels if the CCS option is extended to bio-energy supplies (BECCS). Energy supply that is dominated by nuclear or solar technologies favours electricity for transportation. The main analyses were performed without any consideration of energy taxes. It is noteworthy that, as was carried out in the sensitivity analysis, the addition of energy taxes at the current European level for transportation would represent a boost for electric cars, owing to the higher energy conversion efficiencies of these cars.

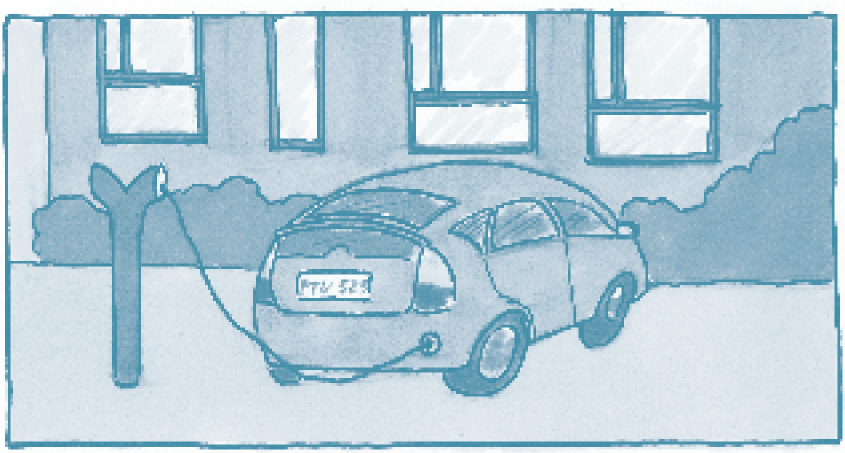


Table 14.1. Stylized main results for energy carriers and private car technology. Adapted from Hedenus et al., 2010.

Scenario (major CO_2-neutral energy supply)	Energy price average of H_2 and electricity	Relative price ratio H_2:electricity	Private cars: long-term fuel and technology choices
Base case (Solar)	100%	≈ 1	PHEV with biofuels
Nuclear	44%	≈ 1	PHEV with biofuels
Coal with CCS	52%	≈ 0.6	HEV with H_2
CCS including BECCS	50%	≈ 0.6	HEV with synfuel from biomass and coal

For more information:

Sten Karlsson
Physical Resource Theory, Chalmers

Further reading

Andersson, S-L., A. K. Elofsson, M. D. Galus, L. Göransson, S. Karlsson, F. Johnsson, G. Andersson, 2010. Plug-in Hybrid Electric Vehicles as Regulating Power Providers - Case Studies of Sweden and Germany. Energy Policy 38, 2751–2762.

Hedenus, F, S. Karlsson, C. Azar, F. Sprei, 2010. Cost-effective energy carriers for transport – The role of the energy supply system in a carbon-constrained world. Int J Hydrogen Energy 35: 4638-4651.

Göransson, L., S. Karlsson, F. Johnsson, 2010. Integration of plug-in hybrid electric vehicles in a regional wind-thermal power system. Energy Policy 38: 5482–5492.

Karlsson S., 2009, Optimal size of PHEV batteries from a consumer perspective – estimation using car movement data and implications for data harvesting. In WEVA 3, 2009.

15

CO_2 emission abatement under the European Union Emission Trading Scheme

The European Union Emissions Trading Scheme (EU ETS), established in 2005, is the world's largest emissions trading scheme for CO_2 and other greenhouse gases (GHG). The scheme encompasses a wide variety of industrial activities with varying capabilities for dealing with the challenges associated with CO_2 emission abatement. The environmental effectiveness of the trading scheme has to date been relatively limited. Excessive allocation of allowances in the first trading period and an economic recession in the second period have combined to undermine the efficiency of the scheme.

The EU ETS, which is the first large-scale attempt to price CO_2 emissions, has attracted significant attention. The trading scheme was introduced as a means to assist the EU member states in achieving compliance with their commitments under the Kyoto Protocol in as cost-effective a manner as possible. Thirty countries (EU27, Norway, Iceland, and Liechtenstein) and nine industrial sectors are involved in the EU ETS. All with varying starting points and varying capabilities to deal with the challenges associated with emission reduction. The scheme includes key actors on both the supply side and the demand side of the European energy systems. The scheme covers CO_2 emissions from large stationary sources in the European energy and industrial sectors, including power plants, oil refineries, coke ovens, iron and steel plants, and industries for the manufacture of cement, lime, glass, ceramics, and pulp and paper (European Union, 2009). More than 10000 installations participate in the trading scheme, collectively responsible for approximately 40% of the EU's total greenhouse gas emissions (EEA, 2009). Four branches dominate the overall emission of the trading scheme: power and heat producers; mineral oil refineries; iron and steel producers; and cement manufacturers. A relatively low number (~800) of the large emission sources (>0.5 $MtCO_2$/year) are collectively responsible for more than 80% of all EU ETS emissions (~30% of total GHG emissions in the EU). This implies that changes in individual plants could have significant effects on the overall GHG emissions of the EU.

Near-term emissions targets can probably be met through measures that are already available, such as increased energy efficiency, optimisation of production processes, and shifts in the usage of fuel and feedstock mixes. However, to realize the goals of future, stricter, emission targets, more radical shifts in production processes are required. A characteristic shared by all the industry sectors assessed here is an ageing capital stock that is heavily dependent upon the use of fossil fuels. Retrofitting or replacing the existing plant stock will involve significant investments, and the deployment of alternative production processes will take time. Therefore, to motivate investment, price signals need to be sufficiently high and the investor needs some level of certainty regarding future price development.

This chapter presents and discusses the experiences of and outlook for CO_2 emission abatement within the EU ETS (for a description of the methodological approach see Chapter 3 in the *Methods and Models* book).

EXPERIENCES OF EU EMISSION TRADING SCHEME

The performance of the CO_2 emissions trading scheme over 5 years has been mixed. With the exception a few upswings and downswings the price of carbon has remained in the range of 10-25 €/tCO_2 (Figure 15.1). In the first trading period (Phase I, 2005-2007), the sum of the emission allowances distributed exceeded the actual emissions, which resulted in weak price development. For the second trading period (Phase II, 2008-2012), a stricter cap was enforced, and in 2008, verified emissions exceeded allocated allowances by 10%. The economic downturn has lead to significant drops in industrial production and power demand, with the result that verified emissions where again below the emission cap in 2009. The levels of emissions fell by 10.6% in 2009 compared with the previous year, and verified emissions were below the total number of allowances in all branches, except for the power and heat industry, resulting in an overall surplus of allowances. In relative terms, the iron and steel industry and the cement industry experienced the largest emission reductions, with emission decreasing by almost 29% and 20%, respectively. The combined surplus for these two sectors corresponded to 152 million EU allowances (almost 8% of the total number of emission allowances distributed in 2009). Figure 15.2 illustrates the CO_2 emission trends in the four most emission-intensive branches.

This book is accompanied by the **Methods and Models book**, which describes the methodologies used in the Pathways project.

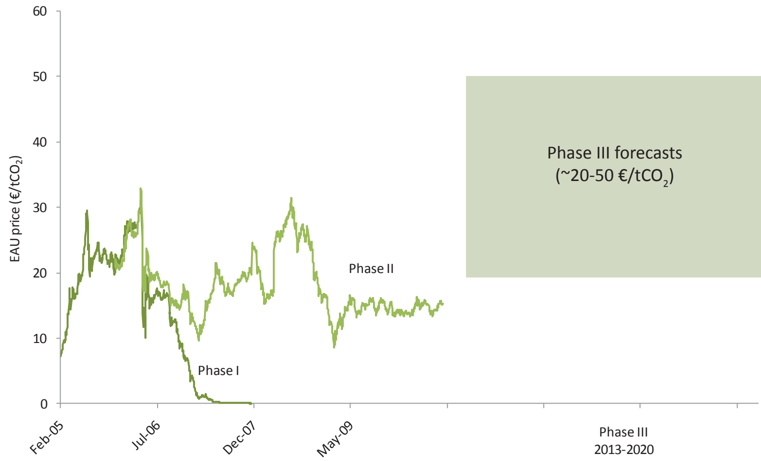


Figure 15.1. Price development of EU allowances (EUA) in Phase I (2005-2007) and Phase II (2008-2012) (ECX, 2010), and forecasted price range for Phase III (2013-2020) (Ecofys, 2009).

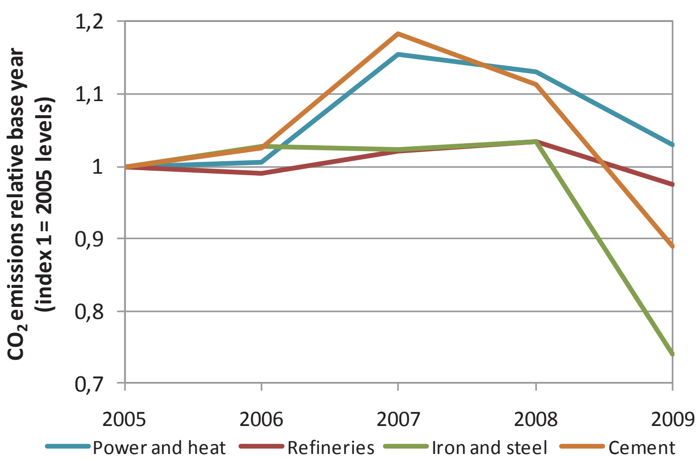


Figure 15.2. CO_2 emission trends in period 2005-2009, for the four branches with the largest shares of total EU ETS emissions. Data source: CITL, 2010.

FUTURE OUTLOOK

Despite the turbulence that it has experienced, the EU ETS has succeeded in imposing a price on CO_2 emissions, albeit a low price, and the details of the third trading period (Phase III, 2013-2020) are currently being negotiated. The stated goal is to reduce GHG emissions within the scheme to a level 21% below the 2005 level by 2020 (EU, 2009). Auctioning will be the main for allocation of emission allowances from 2013, although industries that are deemed to be at significant risk of carbon leakage will continue to receive a share of their emission allowances free of charge (~25% of the total emissions covered by the EU ETS). For the power sector, full auctioning will be used. In addition, the scope of the scheme will be widened. Aviation will be included in the scheme from 2012, and new industrial branches (e.g., aluminium and ammonia production) and two new greenhouse gases (nitrous oxide and perfluorocarbons) are to be included in the scheme from the beginning of the third trading period. In addition, in an attempt to simplify the administration of the scheme, member states will be allowed to exclude smaller installations (<25 $ktCO_2$/year) from the EU ETS.

Several challenges remain unresolved with respect to the design of the future trading scheme. Three issues in particular have been the focus of much debate:

Carbon leakage. European industries have raised the concern that the EU ETS may jeopardise the competiveness of European industry. The European Commission has initiated a process to address the potential risk for carbon leakage. In the absence of a global agreement with binding GHG emission targets, EU businesses risks losing market share to unconstrained competitors. In addition, in the longer term, new investments may be relocated to regions that have not yet restricted CO_2 emissions. No formal decision has yet been taken but sectors in which a significant share of the products are traded on a global market and/or where CO_2 costs constitute a large share of the production costs will most likely continue to receive a share of their emission allowances free of charge.

Offsets. The EU ETS allows operators to compensate some of their emissions by acquiring credits from emission reduction projects undertaken in economies in transition (emission reduction units, ERUs) or in developing countries (certified emission reductions, CERs). The upper limit for offsets differs between member states; in total up to 279.4 million CERs or ERUs may be used annually (EEA, 2009). This corresponds to more than 13% of the cap for Phase II of the trading scheme.

Banking between periods. Operators are allowed to carry over any surplus allowances from Phase I to Phase II. The combined effect of continued low demand for allowances in Phase II due to the prolonged recession, an abundant supply of relatively cheap offsets, and the provision of banking to Phase III may undermine the effectiveness of the trading scheme.

It is likely that the European economy has not yet reached the end of the current economic crisis. However, effective policies need to be in place as the economy starts to recover. Despite sometimes conflicting interests, the EU and its member states had up until the current economic crisis managed to enforce a reasonably potent mix of policies aimed at facilitating the transition towards a low-carbon economy. However, to reach the emission reduction targets required to stabilise the climate, extensive additional efforts need to be made, on both the supply side and the demand side of the European energy systems. Ensuring that the trading scheme delivers sufficiently strong price signals in the forthcoming trading periods is therefore of great importance. Obviously, any new policy initiatives, including the future design of the EU ETS, need to balance environmental effectiveness with other objectives. Nevertheless, now more than ever the situation calls for decisiveness. The economic recession must not used as a scapegoat for lack of action.

For more information:

Johan Rootzén and **Filip Johnsson**
Energy Technology, Chalmers

Further reading

Rootzén, J. and Johnsson, F., 2011, "CO_2 emission abatement under the European Union Emission Trading Scheme". Working paper to be submitted for publication.

16

Escalation of a European CO_2 transport and storage infrastructure

To study the potential role of Carbon Capture and Storage (CCS) in the European electricity system, two types of analyses of CCS were made. First, the development of the power generation system, including CCS, was modelled using the techno-economic model ELIN for a variety of scenarios. Second, the results of the modelling were analysed in terms of the required ramping up of the CCS infrastructure, taking into account power plants, transportation networks, and storage sites. Thus, this constitutes a CCS infrastructure analysis. The role of CCS has been addressed using several model versions, since the model methodology was developed throughout the course of the project. Model calculations and results are described in Chapter 17.

This chapter presents an analysis of the conditions needed for rapid establishment of a large-scale CO_2 transport and storage (CCS) infrastructure within the power and heat sectors of EU member states (MS). This analysis reveals that most of the EU MS have identified structures that may be suitable for subsurface storage of CO_2. Several MS have clusters of large power plants along with considerable national or regional concentrations of plant ownership, both of which factors may facilitate the ramping up of a bulk carbon capture and storage (CCS) infrastructure. The gradual phasing in of CCS plants will obviously play a key role in building up a large-scale transport infrastructure. CCS plants are likely to be located at existing sites, and owners of coal plants currently under construction may choose to retrofit the plant for CCS rather than building new plants. CO_2 pipeline trajectories are likely to follow existing trajectories for natural gas pipelines, minimising interference with the surroundings, thereby facilitating and speeding up the processes of obtaining permits. The timing, conflicts of interest, and public acceptance, especially for onshore facilities, are additional factors that must be taken into account when considering the transport and storage of CO_2. Case studies from Germany and the UK are evaluated. According to the results, 5.2 $GtCO_2$ will be transported and stored in Germany between 2020 and 2050, while the corresponding figure for the UK is 3.7 $GtCO_2$. The specific costs for this transport and storage would range from €3.4 to €4.4 per tCO_2 in Germany and from €5.4 to €8.1 per tCO_2 in the UK.

Methodology

The aim of the present study was to investigate the potential for CCS for EU MS and to identify obstacles and possibilities related to the establishment of a large-scale CO_2 infrastructure (Kjärstad and Johnsson, 2009). Initially, each MS was investigated for the relevance of CCS to the power and heat sector. Then, the potential cost of CO_2 transport and storage was evaluated and categorised into three levels for each MS, with particular emphasis being placed on power plant clusters, ownership concentration, source-sink distance, and onshore storage potential. The chosen cost category for each MS was then used as the input in a techno-economic modelling system to evaluate the future electricity supply system in Europe, as described in Chapter 17 (cf. also Odenberger and Johnsson, 2008). Finally, based on the modelling results, case studies from Germany and the UK were examined; detailed CO_2 transportation and storage infrastructures are developed and issues related to the ramp-up of such infrastructures are discussed.

CCS IS A RELEVANT CO_2 MITIGATION OPTION FOR EU MEMBER STATES

Apart from the smallest MS, i.e., Cyprus, Luxembourg, and Malta, most MS currently have identified structures that could be used for subsurface storage of CO_2. Of the remaining 24 member states, Estonia and Finland are the only MS that are completely without suitable reservoirs, while Lithuania appears to have very limited storage potential, apart from trapping through the dissolution of CO_2 in aquifer brine (formation water). All other MS have, as of October 2008, identified potentially suitable reservoirs. In particular, Denmark, Germany, The Netherlands, Spain, and the UK are believed to have large storage capacities. However, the estimated storage potentials in Germany and Spain are rough regional estimates and the storage potential in The Netherlands is dominated by the Groningen field, which will not be available for CO_2 storage purposes until after 2040. Public acceptance may represent a barrier to onshore storage of CO_2, and only nine MS have to date identified offshore storage sites. Clusters of large plants (≥500 MW) are found in most MS and perhaps more surprisingly, most countries also have a considerable concentration of plant ownership, either locally/regionally or nationally. In fact, only Slovenia and Sweden have no particular plant clusters and a weak concentration of plant ownership. Plant clusters and ownership concentration are two factors that are likely to facilitate the cost-efficient build-up of a CO_2 transport and storage system. Six countries have transport distances of less than 100 km between large sources and potential sinks, although in general, transport distances are likely to lie in the range of 100 km to 300 km. In summary, from the analysis it can be concluded that CCS is a relevant CO_2 mitigation option for 21 of the EU MS; the results are compiled and shown in Table 16.1.

BUILD-UP OF THE CCS INFRASTRUCTURE

According to modelling results (cf ”Early model results” in Chapter 17), CCS will be initiated in Germany in 2020 at a rate of 98 Mtpa, and will grow to 190-205 Mtpa between 2040 and 2050, with a total cumulative level of captured and stored CO_2 of 5.2 Gt up to 2051. In the UK, CCS will first be applied in 2023 at 8 Mtpa, and increase rapidly to between 150 and 160 Mtpa from 2035 onwards, to achieve a total cumulative level of 3.7 Gt by 2051. There should be sufficient storage capacities both in Germany and the UK to accommodate these volumes (Table 16.1). Most of the German storage capacity is located in aquifers in the North German Basin (NGB), while most of the UK's storage capacity is located in aquifers, and in gas and oil fields in the North Sea. Figure 16.1 shows the prjected development of CO_2 infrastructure in Germany and the UK. Power plants with CO_2 capture are shown as black circles. Storage sites are shown in green (aquifers), blue (oil fields), and red (gas fields), with booster stations (pump station along the CO_2 pipeline) in purple. In Germany, very few aquifers have actually been identified, so each red rectangle is assumed to contain nine aquifers with a storage capacity of at least 400 Mt, corresponding to the number of similar aquifers actually identified in the rectangle farthest to the east (Chadwick et al., 2007). However, subsequent analyses have reduced the German storage potential, implying that it would have been more appropriate to apply 100 Mt as the average storage capacity per aquifer (Knopf et al., 2010).

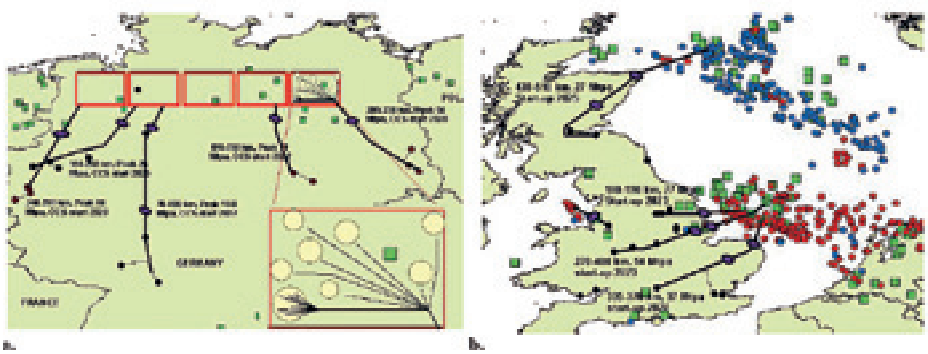


Figure 16.1. CCS infrastructures derived from the analysis in the present chapter (Kjärstad and Johnsson, 2009). a, Germany; b, UK. Source: Kjärstad and Johnsson, 2009.

Table 16.1: CCS Relevance and Cost Classification EU MS. Source: Kjärstad and Johnsson, 2009.

	GHG emissions Base Year Mt CO2 eqv	GHG emissions 2006 Mt CO2 eqv	CO_2 Power & Heat[1] Share 2006, %	Storage Capacity[2] Mt CO2	Identified Sites Onshore/Offshore	Plant Clusters	Ownership Concentration	Approx distance[3] Source-sink, km	Storage Cost Classification	CCS Relevance
Austria	79.0	91.1	13.2	500	Onshore	Yes	Fair	0-280	2	Moderate
Belgium	145.7	137.0	16.5	199	Onshore	Yes	Considerable	40-100	1	Moderate
Bulgaria	132.6	71.3	38.4	2120	Onshore[4]	Yes	Considerable	0-170	1	Good
Cyprus	6.0	10.0	36.5	0	na	Yes	Considerable	na	3	Poor
Czech Rep	194.2	148.2	36.8	853	Onshore	Yes	Fair	10-60	1	Good
Denmark	69.3	70.5	38.1	2756	Onshore & Offshore	Copenhagen	Considerable	0-120	1	Good
Estonia	42.6	18.9	60.6	0	na	Yes	Considerable	250-400 plus	3	Poor
Finland	71.0	80.3	36.6	0	na	Helsinki	Fair	370-1000	3	Poor
France	563.9	541.3	8.7	8692	Onshore	Yes	Fair	0-240	2	Moderate
Germany	1232.4	1004.8	32.8	6300-12800	Onshore & Offshore[4]	Yes	Considerable	20-450	1	Good
Greece	107.0	133.1	38.3	254	Onshore & Offshore	Yes	Considerable	30-240	1	Good
Hungary	115.4	78.6	22.2	616	Onshore	No	Poor	60-130	1	Good
Ireland	55.6	69.8	20.7	455	Offshore	Yes	Considerable	30-150	1	Good
Italy	516.9	567.9	21.4	6550	Onshore & Offshore	Yes	Considerable	0-150	1	Good
Latvia	25.9	11.6	17.4	404	Onshore	No	Considerable	70-170	1	Good
Lithuania	49.4	23.2	16.1	37	Onshore	No	Considerable	250-530	3	Poor
Luxemb	13.2	13.3	11.0	0	na	No	Considerable	80 plus	2	Good
Malta	2.2	3.2	62.1	0	na	Yes	Considerable	na	3	Poor
Netherlands	213.0	207.5	23.8	2340	Onshore & Offshore	Yes	Considerable	0-200	1	Good
Poland	563.4	400.5	44.0	2940	Onshore	Yes	Fair	0-220	1	Good
Portugal	60.1	83.2	23.5	0	Onshore & Offshore	Lissabon	Considerable	0-100	2	Moderate
Romania	278.2	156.7	31.1	9000	onshore	Yes	Considerable	0-100	1	Good
Slovakia	72.1	48.9	16.8	1716	onshore	No	Considerable	0-80	1	Good
Slovenia	20.4	20.6	30.8	94	onshore	No	Poor	0-50	1	Moderate
Spain	289.8	433.3	23.4	14179	onshore	Yes	Poor	0-300	2	Good
Sweden	72.2	65.7	12.4	1610	Offshore	No	Poor	25-310	3	Poor
UK	776.3	652.3	28.3	14400	Offshore	Yes	Poor	60-480	2	Good
SUM EU	**5768**	**5143**	**26.8**	**76015-82515**	Offshore					

1: Power and Heat refers to Public Power and Heat generation corresponding to source category 1A1a as defimed by UNFCCC

2: Storage potential refers to those figures that have been publicly announced as of November 2010 involving various degrees of accuracy. Also, investigations are ongoing within several MS to raise the accuracy and/or to identify new potential structures

3: Distance source-sink refers to straight line distance, a "real life" pipeline will necessarily be considerably longer

4: Storage potential includes 3 Mt offshore potential in Bulgaria and 2901 Mt offshore potential in Germany

CCS INFRASTRUCTURE IN GERMANY

According to the results (cf. ”Early model results” Chapter 17), 22 GW of lignite-based CCS capacity should come on line in Germany between 2020 and 2024, provided that suppliers are able to supply plant equipment and construct the plants in time. The rapid build-up of lignite-based CCS capacity, together with the obvious concentration of ownership of existing lignite plants, (with RWE owning all the lignite plants in North-Rhine Westphalia (NRW) in the west and Vattenfall owning most of the lignite plants in the east), support the build-up of three large-scale centralised transport and storage systems (although ownership concentration may of course be different post-2020). Nine GW of coal plants with CCS will also come on line in Germany albeit considerably later, between 2035 and 2044. Therefore, it has been assumed that these plants will need to build their own separate CO_2 transport and storage systems. Based on the ages of the existing plants, coal-based CCS plants will be located in NRW and Niedersachsen in the northwest and in Hessen and Baden-Württemberg in the southwest, indicating the establishment of two additional transport systems. In addition, two coal plants are expected to construct and operate their own transport system due to their proximity to storage sites in the NGB. The system for transporting CO_2 from Hessen and Baden-Württemberg will be expensive relative to the other systems, as relatively low volumes of CO_2 (16.5 Mtpa) will have to be transported for more than 400 km. This may lead to coal-CCS plants being constructed further north, closer to known storage sites. Apart from public acceptance, German storage will require changes in existing laws, and the integrity of the hundreds of old gas and oil wells in the NGB may also pose a challenge. In Germany, between 3300 km and 3700 km of pipelines must be laid to accommodate the amount of CCS projected. Total investment costs for the German transport and storage system range from €6.1 billion to €7.8 billion, corresponding to injectivities of 1.0 Mtpa and 0.5 Mtpa per well, respectively. Transport-related costs will account for between 76% and 84% of the total investments. System costs between 2020 and 2050 are calculated as being between €17.9 billion and €22.9 billion, while specific costs (for transport and storage) are calculated at between €3.4 and €4.4 per tCO_2.

CCS INFRASTRUCTURE IN THE UK

Some forty-seven 600 MW coal-based CCS blocks will be installed at existing sites in the UK between 2023 and 2044. Since, the replacement of ordinary coal-fired plants with plants that have CCS units is based on the age of the existing plant, it is assumed that the 3.6 GW Drax plant in North Yorkshire, the 1.5 GW Aberthaw plant, and the 400 MW Uskmouth plant in south Wales will be decommissioned. Specific aquifers with sufficient storage potential for at least 40 years of storage have been chosen from among the CCS systems in the Midlands and Yorkshire and the southern parts of the UK. Based on plant age, one single 600 MW CCS block should have been installed in Aberthaw in southern

Wales, although this would have required 200 km of pipeline to connect to the southern system starting up at the Didcot plant in Oxfordshire. Instead, a fourth CCS unit was installed on the Kingsnorth site in Kent. The northern system, comprising the Cockenzie and Longannet sites, may be able to supply CO_2 for EOR (Enhanced Oil Recovery) in the oil fields of the northern parts of the North Sea, while the western system, which comprises four coal blocks on the Fiddlers Ferry site in Warrington, may choose to store CO_2 in the gas and oil fields of the Irish Sea. The CO_2 will be transported to existing natural gas terminals in St. Fergus, Easington, Theddlethorpe, and Bacton, where the CO_2 will be pressurised to around 200-250 bars before entering the offshore pipelines. In total, between 2200 km and 2600 km of pipelines will be laid in the UK, of which 1220 km will be located onshore. Total investment costs for the transport and storage system range from €6.7 to €10.1 billion, and the specific cost is calculated to lie between €5.4 and €8.1 per tCO_2. One difference in the UK compared to the German case is that there is at present little ownership concentration of power plants (apart from in Scotland), which means that the large-scale, centralised CCS infrastructure envisaged in the present work may be more difficult to achieve in reality.

In summary, this chapter gives an overall assessment of the prospects for CCS in the European power sector and provides a detailed analysis of the CCS infrastructures in Germany and the UK. CCS in the power sector will probably be prioritised to different extents in the EU MS, given that CO_2 emissions from this sector account for between 8% and 60% of total national GHG emissions. However, the prospects for CCS appear to be good in several MS, and the costs for transport and storage of CO_2 should not be prohibitive in the context of large-scale deployment of CCS. Expanded utilisation of lignite for power generation together with CCS could improve considerably the energy security of the EU.

For more information:

Jan Kjärstad
Energy Technology, Chalmers

Further reading:

Kjärstad, J. and Johnsson, F., 2009. “Ramp-up of large-scale CCS infrastructure in Europe”. Proceedings for the 9th Conference on Greenhouse Gas Technologies. Energy Procedia, 1(1): 4201-4208.

17

The role of carbon capture and storage

Carbon capture and storage (CCS) technologies are amongst the most important bridging technologies for the electricity sector to advance to a stage of zero emissions. CCS equipped power plants fired by coal fuels (lignite and hard-coal) makes it possible to continue using coal, thereby decreasing the dependency on natural gas imports to Europe, and to influence the price in the EU ETS. Coal CCS in the commercial setting is expected to become competitive at CO_2 prices of 25-40 €/tCO_2.

In the present analyses, it is assumed that CCS will become commercially viable from 2020 onwards. This is an important assumption which, as will be shown in this chapter, will have far-reaching impacts on the development of the European electricity supply system over the coming decades. Capture costs are expected to be 20-30 €/tCO_2 for coal CCS, while the costs for CO_2 transportation and storage are estimated to be between 5 and 10 €/tCO_2 depending on specific conditions in EU Member States. The CCS cost estimates are based on findings from the ENCAP project (2008) and from the work of Kjärstad and Johnsson (2009).

The role of CCS has been addressed using several model versions, since the model methodology was developed throughout the course of this project. In this chapter, both the early model results and the outcome of the final version of the model is dicussed.

EARLY MODEL RESULTS INDICATED MASSIVE INVESTMENTS IN CCS

Earlier work on this issue applied an aggregated version of the ELIN model (EU25 countries aggregated into a single region) to analyse the development of the European electricity system until 2050, with CCS being included as an option from 2020 (Odenberger and Johnsson, 2008). The analysed scenario can be considered as being similar to the "Market" scenario in terms of development of demand for electricity. This earlier version of ELIN did not include load distribution within each model year, which combined with the simplification of treating the EU25 countries as a single region (for example, assuming no limitations on power transfer between Member States and no country-specific fuel markets or CO_2 transportation and storage costs) tends to overestimate the demand for CCS as a technology (base-load power plants may be somewhat favoured in a model with a simplified description of the electricity load). Thus, neither the relationship between base-load and peak-load nor the individual Member States' prospects of facilitating a CCS transportation and storage system are fully taken into account. Nevertheless, the results indicated about 2000 TWh of electricity generation from CCS, corresponding to roughly 48 Gt of CO_2 captured between 2020 and 2050. At the same time, the marginal price for CO_2 would have to increase from 20 to 60 €/tCO_2. In addition, the results imply that Europe would have to triple coal imports and build up a CCS infrastructure (power plants, pipeline transportation system, and storage facilities) at a pace that is triple the historical peak level in terms of annual capacity additions.

REFINEMENT OF THE MODELLING GIVES A MORE BALANCED VIEW

Subsequent work, in which the ELOD model (a refined version of the ELIN model) was applied to the EU27 plus Norway, revealed a lower demand for CCS. The ELOD model describes the European electricity system on the Member State level (country-by-country) and includes a time-step division of the model years (each year is divided into 16 time steps with differentiated load levels), nation-specific biomass markets, nation-specific CO_2 transportation and storage costs, and physical limitations of the interconnectors between Member States. Results based on the Pathways project's main scenario "Policy Pathway" reveal an electricity output from CCS schemes of about 1000 TWh (~25% of total generation) by 2050 (Figure 17.1, left panel). The capacity ramp-up is much less pronounced than in the previous modelling, as is the impact on the coal fuel market, which shows an almost flat demand. In this scenario, capture amounts to roughly 15 Gt CO_2 between 2020 and 2050. These new results confirm CCS as a price-setter within the EU ETS after 2020, with marginal prices on CO_2 ranging from about 30 €/tCO_2 (during almost the entire period but with an increase during the last 5 years) to 55 €/tCO_2.

The "Market" scenario presented in Figure 17.1 (right panel) indicates electricity output from CCS schemes of around 2000 TWh by 2050 (~40% of total generation) , albeit with less strain on the capacity ramp-up as compared to the early model results. Lignite CCS comes into play from 2020 (where available), while hard coal CCS is required somewhat later. The Market scenario considers higher investment costs for CCS as well as for nuclear energy, as compared to the Policy scenario (CCS costs increased by 30% and nuclear costs increased by 50%). This explains the gas "bubble" between 2015 and 2045, which is more competitive in the Market scenario than in the Policy scenario with lower electricity demand. The cumulative CO_2 capture between 2020 and 2050 in this scenario amounts to around 24 Gt CO_2. In addition, the higher investment costs for nuclear energy and CCS result in increased dependency on gas, which acts as a price-setter for electricity and prior to 2020, also sets the price for CO_2. Between 2020 and 2030, lignite CCS sets the marginal CO_2 emission cost, and after 2030 hard coal is on the CO_2 margin, leading to higher CO_2 prices after 2030, as compared to the Policy scenario cost of about 40 €/tCO_2, rising rapidly to as much as 100 €/tCO_2 by 2050.

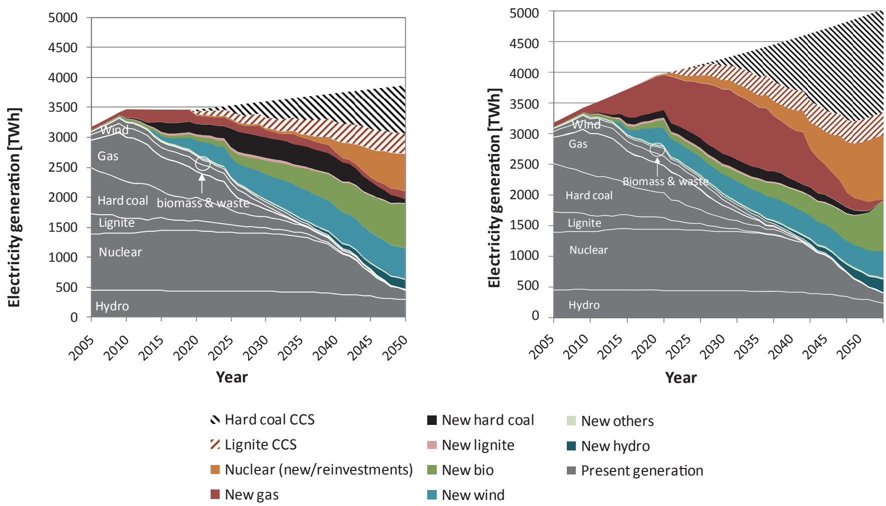


Figure 17.1. Electricity generation in the Policy scenario (left panel) and electricity generation in the Market scenario (right panel). The contribution from the present system is given in the grey field, with the generation mix indicated by white lines.

REGIONAL DISTRIBUTION OF CCS

The ELOD model includes different country-specific transportation and storage costs (Figure 17.2). Since capture costs are associated only with technologies (and not countries), transportation and disposal costs determine where the overall CCS costs are lowest for any given CCS technology. Countries in Central Europe and Norway have certain comparative advantages in this respect (more on this may be found in Kjärstad and Johnsson, 2009). Furthermore, there are costs related to technology and fuel. Lignite CCS is generally assumed to be cheaper than hard coal (or gas) CCS.

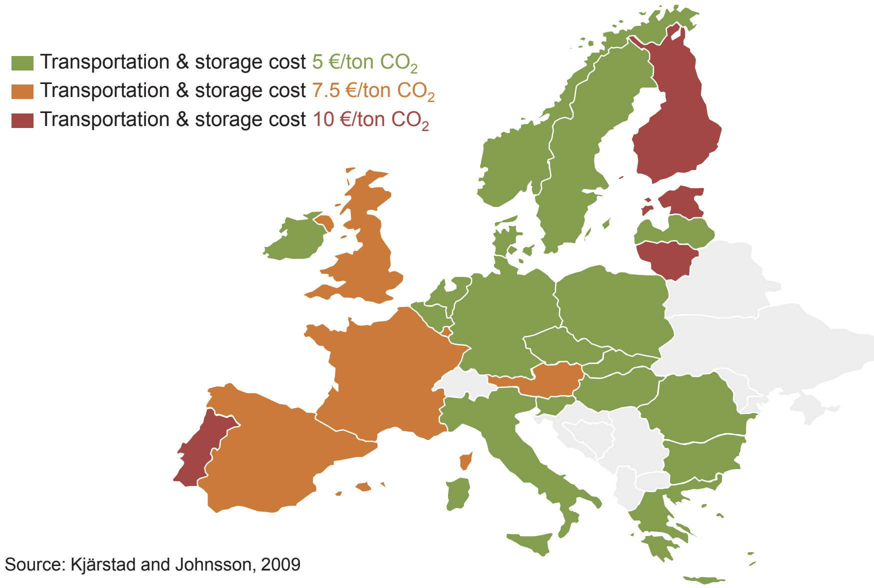
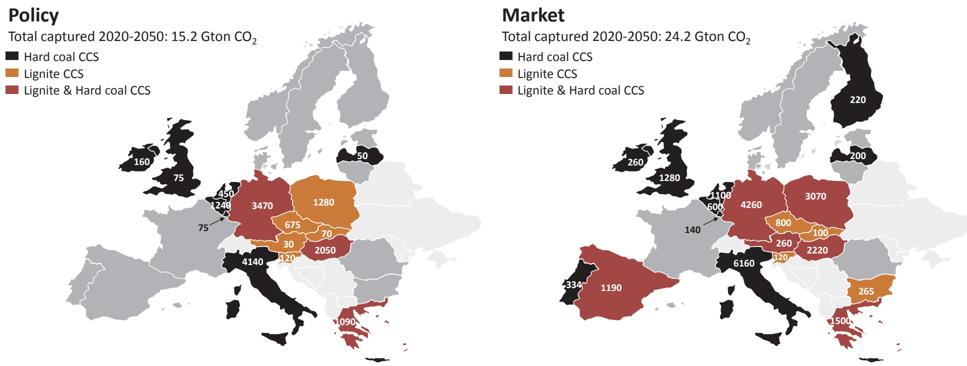


Figure 17.2. Costs for transportation and storage implemented in ELIN.

Defining the pathways from sector specific scenarios

Two different European Energy Pathways are defined in this project: the Policy Pathway and the Market Pathway. The Policy Pathway relies more on targeted policies that promote energy efficiency and renewable energy; the measures in this pathway are primarily demand-side-oriented. In contrast, in the Market Pathway, the measures are more supply-side-oriented and the cost to emit CO_2 is the predominant policy measure. These two Pathways are based on the results from the sector-specific scenarios and analyses described in Chapters 1-46 of this book.

Figure 17.3 presents the regional distributions of CCS for the Policy and Market scenarios. The figure shows not only the amounts of CO_2 captured between 2020 and 2050, but also whether hard coal and (or) lignite power plants are involved. Countries such as Italy, Germany, and Poland account for the largest amounts of stored CO_2. This is partly due to assumed low transportation and storage costs, as discussed in relation to Figure 17.2.



Numbers: captured 2020-2050 in Mtonne

Figure 17.3. Distribution of CCS shown as amounts of CO_2 captured in EU Member States in the Policy scenario (left) and the Market scenario (right).

WHAT IF CCS FAILS TO DELIVER?

Throughout the analysis of the European electricity system in the Pathway project, CCS has generally been regarded as a technology that is commercially available from 2020 and onwards. Furthermore, the assumed CO_2-mitigation goals of more than 80 percent reductions by 2050, generates marginal CO_2-abatement costs of at least 30 €/tCO_2. This generally exceeds the assumed capture costs of CCS schemes in many Member States, which means that CCS is not only available but also competitive from 2020. This is a very important assumption and it explains why CCS tends to play a very important role in the modelling results obtained throughout the Pathways project. But what if CCS fails to deliver? To make a comparison with the results obtained under the assumption that CCS is available, model runs without the option for investments in CCS schemes have also been carried out. The results presented in the following section were generated using a somewhat older version of the ELIN model and based on other general assumptions. Therefore, the results are not directly comparable to the previous results relating to the Market and Policy scenarios.

In Figure 17.4, two cases are shown for Northern Europe (Germany, the UK, and the Nordic countries): 1) a reference case in which it is assumed that CCS becomes commercially available in 2020 (left panel); and 2) a case that excludes the option of investing in CCS (right panel). Under the assumption that the possibility to invest in nuclear power is equal for both cases, it is clear that renewable sources, and also conventional fossil power, especially gas, replace the share taken by CCS in the reference case. Thus, it is fair to say that there exists a competition between renewables and CCS.

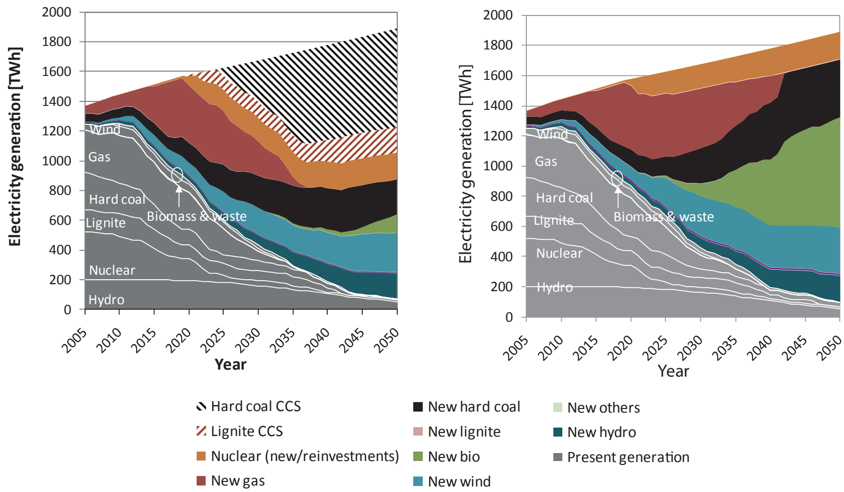


Figure 17.4. Electricity generation in Northern Europe (the Nordic countries, Germany, and the UK) for a case in which CCS becomes commercially available from 2020 (left) and a case in which CCS is not available at all (right). The results were obtained using an older version of the ELIN model and with somewhat different assumptions than presented hitherto in this chapter. Source: Odenberger et. al., 2009.

Whether or not CCS manages to deliver will not only affect other means of electricity supply, but is also likely to affect market prices for electricity and CO_2 allowances. This is shown in Figure 17.5, wherein the marginal electricity costs (left panel) and marginal CO_2-abatement costs (right panel) are presented for both investigated cases. Marginal electricity costs are taken as the average of the domestic marginal costs for all six countries. Even though the marginal costs for the case in which CSS is not available are clearly higher than those in the reference case, the difference is not overwhelming in any sense. Marginal electricity costs are typically 5-10 €/MWh higher, while marginal CO_2-abatement costs are around 10-15 €/tCO_2 higher in the long-term perspective. However, the effect of the CO_2 abatement cost on the total system cost becomes less significant towards the end of the period when the level of total emissions allowed for is cut by approximately half (assuming here 60 percent emission reduction relative to the levels in 1990 emissions). A comparison of the total system cost for each case reveals that it is more costly to follow the pathway that excludes CCS, i.e., by typical increase in costs of 2-3 percent (corresponding to roughly €100 billion in present-day value). Both cases are characterised by heavy dependency on one specific fuel, namely, hard coal in the CCS case and biomass (combined heat and power, cofiring schemes and, to a certain extent, condensing power plants) in the case that excludes CCS, i.e., about 40–50 percent of the electricity generation in 2050 stems from these fuels in the two cases. The large share of biomass power in the latter case is partly explained by the fact that wind power is reaching its assumed upper limits in the model configuration at the same time as biomass fuel costs are assumed to be relatively constant. The assumptions of further potentials (with higher costs) for wind power and more expensive biomass fuel resources would create a different balance between wind and biomass power. Marginal electricity costs in such a case would, accordingly, be higher and give increased incentives for other renewables. Finally, higher marginal electricity costs stimulate energy efficiency and conservation measures for a given economic and technological development. Electricity demand has, however, been kept at the same level in both cases of this analysis.

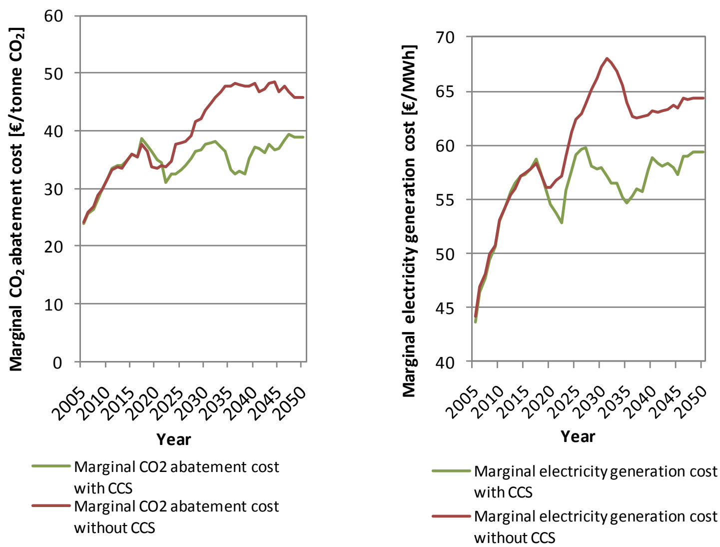


Figure 17.5. Marginal electricity costs (left panel) and marginal CO_2-abatement costs (right panel) in both investigated cases. Source: Odenberger et. al., 2009.

More information on the impact of excluding CCS as a future option may be found in Odenberger et al. (2009). Technology costs and efficiencies are also presented in that paper.

CONCLUDING REMARKS

Some of the main findings from the modelling work concerning the role of CCS may be summarised as follows:

- If commercially viable, CCS may play a very important role in the future European electricity supply. Model results indicate that as much as 40 percent of total European electricity supply may be based on CCS post 2040.
- Countries that are currently high in carbon intensity have a large demand for CCS.
- The CCS "potential" will be limited by market dynamics within coal markets, power plants industries' abilities to supply power plants, and the cost of technology in relation to the costs of other options.
- The main assumption that CCS will be commercially available from 2020 and onwards is decisive for the modelling work carried out within the Pathways project. If CCS does not prove to be commercially viable, the challenges presented to the electricity supply system are likely to be much more serious. For a given climate target, this would further increase the demand for renewables, energy efficiency, and conservation measures and also probably nuclear power.

For more information:

Mikael Odenberger, Energy Technology, Chalmers
Thomas Unger, Profu
Filip Johnsson, Energy Technology, Chalmers

Further reading

Kjärstad J., Johnsson F., 2009, "Ramp-up of large-scale CCS infrastructure in Europe", Energy Procedia, Vol 1, issue 1, pp. 4201-4208

Odenberger, M., Johnsson, F., 2009. "The role of CCS in the European electricity supply system". Energy Procedia 1 (1): 4273-4280.

Odenberger M., Johnsson F., Unger T., 2009,"Pathways for the North European electricity supply", Energy Policy 37, pp. 1660-1667.

18

From source to sink: prospects for CO_2 capture in European industry

A first estimate of the potential for CO_2 capture and storage (CCS) in European industry shows that considerable reductions in CO_2 emissions could be achieved by targeting large point sources in the most emission-intensive industry sectors (i.e., mineral oil refineries, integrated steel plants, and cement plants). In addtion, this analysis reveals that the total costs of CCS in several regions could be lowered if efforts to develop CO_2 transportation infrastructures were co-ordinted across sectors and between member states.

Total EU greenhouse gas (GHG) emissions amount to approximately 5000 $MtCO_2$-eq/year (EEA, 2009). A relatively low number (approximately 800) of large CO_2 emission sources (>0.5 Mt CO_2/year) in the power, heat, and industry sectors are collectively responsible for more than 30% of the total GHG emissions in the EU. Consequently, reductions in the emissions from individual plants could have significant effects on the overall GHG emissions. Therefore, it is important to consider how the current industry structure influences the potential to reduce CO_2 emissions in the short-, medium-, and long-term. Efforts to reduce industrial CO_2 emissions through measures that are already available, such as increased energy efficiency, optimisation of production processes, and alterations in fuel and feedstock mixes, are essential. However, to realise deep cuts in emissions, more radical shifts in the production processes are required. CCS is recognised as one of several key abatement options in EU efforts to reduce GHG emissions. To date, most attention has been focused on the application of CCS technologies in fossil-fuelled power plants. The aim of this chapter assessment is to provide a first estimate of the potential for CO_2 capture in European industry and to identify regions with good prospects for the deployment of integrated CO_2 transportation networks. Emphasis is placed on three industrial sectors with good prospects for CCS implementation: mineral oil refineries, iron and steel plants, and cement factories. Potential capture sources are identified and the potential for CO_2 capture is estimated based on branch- and plant-specific conditions. The geographical distribution of point sources, as well as the occurrence of potential capture clusters and their locations in relation to suitable storage sites are assessed through geospatial analysis (for a more thorough description of the general methodological approach see Chapter 3 in the *Methods and Models* book).

PROSPECTS FOR CO_2 CAPTURE IN EUROPEAN INDUSTRY

Several methods can be used to separate and capture CO_2 in industrial processes. Post-combustion capture through chemical absorption can be applied to almost all industrial processes. However, process-specific capture technologies could provide more cost-effective solutions. A summary of the assumptions made regarding possible capture options and the annual capture potential is presented in Table 18.1.

If the full potential of the CO_2 capture technologies considered in this study could be realized, 60-75% (270-330 $MtCO_2$/year) of the emissions from large industry point sources would be avoided. These estimations should be seen as illustrative of the potential role of CO_2 capture in large industry point sources, i.e., a first estimate. Extensive development work remains to be completed in all parts of the CCS value chain, and deployment on a commercial scale is at least a decade away. The assumptions made herein regarding CO_2 capture costs and potential capture rates should be considered as first assumptions. The industry CO_2 capture projects currently being set up will provide valuable insights into both the technical and economic aspects of industry capture.

Table 18.1. Characteristics and potential for CO_2 capture at large industrial emission sources in the EU.

Source type	Cost per tonne of CO_2 captured (€/t)	Average capture rate (% of total CO_2 emitted)	Capture technology	Annual capture potential (Mt CO_2/year)[a]
Mineral oil refineries[b]	~30	65	Oxyfuel combustion	94
	~45	80	Post-combustion Capture	116
Integrated steel plants[c]	~20	70	Top Gas Recycling Blast Furnace	106
Cement plants[d]	~34	50	Oxy combustion	67
	~60	80	Post-combustion capture	107

[a] These estimates does not include additional emissions associated with the capture process (the capture process will require supplementary energy, which will result in additional CO_2 flows).
[b] Cost estimates based on data from various sources (IPCC, 2005; Allam et al., 2005; Statoil Hydro, 2009).
[c] Cost estimates based on data from IPCC (2005).
[d] Cost estimates based on data from IEA GHG (2008).

FROM SOURCE TO SINK

The costs of CO_2 transport and storage are generally assumed to be low in comparison to the CO_2 capture costs, although this makes the assumption that a large-scale infrastructure is in place that serves several emission sources. Thus, to limit the costs of transport and storage, the CCS infrastructure needs to be carefully planned. One way to limit cost would be to create capture clusters in regions with several emission sources that are located close to each other.

Figure 18.1. Geographical distribution of large point sources (>0.5 Mt CO_2/year) in the European industry sector. Triangles, refineries; circles, integrated steel plants; stars, cement plants. Regions with high densities of large stationary CO_2 emissions (including power plants and pulp and paper industries) are highlighted in grey. The cumulative emissions in each 150×150 km grid cell exceed 20 MtCO_2/year. Source: Rootzén et. al., 2010.

As illustrated in Figure 18.1, industrial emission sources are unevenly distributed across the EU. The industrial branches assessed here would likely benefit from an integrated transport and storage infrastructure involving numerous plants, and in particular power plants. To identify regions with favourable conditions for the clustering of CO_2 sources, the emission levels of 871 large stationary point sources, including power plants (the locations of EU power plants were retrieved from the Chalmers Power Plant database; see Chapter 2 in the *Methods and Models* book), refineries, integrated steel plants, cement plants, and pulp and paper industries (information on the locations and emissions of the EU pulp and paper industries were retrieved from the results presented in Chapter 19, have been summarised with respect to geographical location (in 150×150km grid cells). The areas highlighted in grey on the map constitute clusters of CO_2 emission sources (>20 MtCO_2/year). High flows of CO_2 and the geographical proximity of emission sources make these regions good candidates for the deployment of integrated CO_2 transportation networks.

In the same way as the CO_2 sources are heterogeneously distributed across Europe, so are the potential CO_2 storage sites. The potential for geological storage of CO_2 in the EU has been assessed in the GESTCO and GeoCapacity projects (Vangkilde-Pedersen, 2008; GeoCapacity, 2009). Saline aquifers (both onshore and offshore) are considered to have the largest storage potential, although more detailed analysis is needed to determine site-specific capacities. Even though they have a lower storage potential, depleted hydrocarbon fields have the advantage of being relatively well explored, as the geology has often been carefully examined and the fields are proven capable of retaining fluids and gases for very long time periods. Assuming that offshore storage of CO_2 will be the preferred option, the best matches between emission clusters and potential storage sites are found in regions bordering the North Sea, in the south-eastern part of the UK, northern France, Belgium, The Netherlands, and in north-western Germany. Figure 18.2 shows the aggregated CO_2 emissions from large stationary point sources within specified distances from the North Sea.

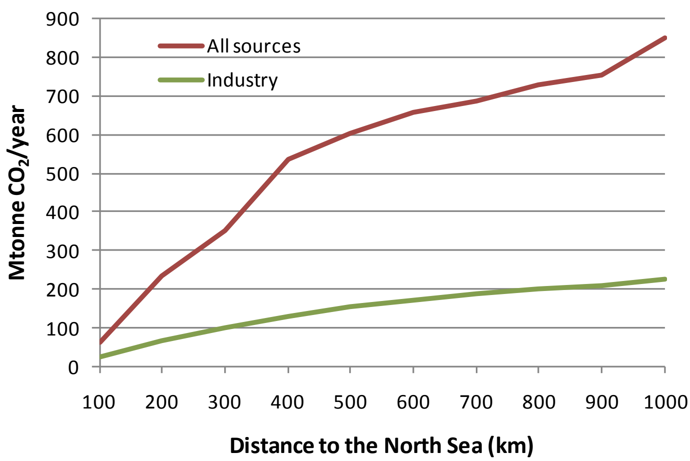


Figure 18.2. Distribution of emissions from large stationary emission sources in relation to the distance to the North Sea. Aggregated emissions from power plants, refineries, integrated steel plants, cement plants, and pulp and paper industries are labelled "All Sources". The category "Industry" refers to emissions from refineries, integrated steel plants, and cement plants. Source: Rootzén et. al., 2010.

INCENTIVISING INDUSTRY CCS

Although forecasts for the prices of CO_2 emission allowances in Phase III (2013–2020) of the EU Emission Trading Scheme vary, recent analysis suggest that the price will end up in the lower part of the range of 20-40 €/tCO_2. The industrial sectors assessed here belong to the sectors that may be exposed to a significant risk of carbon leakage, and will most likely continue to receive a share of their emission allowances free of charge also during the third trading period. Therefore, the trading scheme alone will not incentivise investments in industry CCS in Phase III. However, given that there will be a more stringent cap on emissions beyond 2020, resulting in higher CO_2 prices, industry CCS could contribute to significant emission reductions. The total capture rate could be up to 50% of total industrial emissions if the carbon price is high enough. In this context, it is noteworthy that higher CO_2 prices are likely if there is a significant growth in demand for electricity and other types of energy together with stringent emission reduction targets (as in the Market Pathway scenario), as compared to a weak growth in demand (as in the pathway Policy scenario).

Replacement/retrofitting of the existing stock of industrial plants with CCS will involve substantial investments, which mean that the deployment of CCS will take some time. In a policy environment characterised by significant levels of uncertainty, additional support for the research and development of CCS in industry will be required. As for power plants, demonstration projects urgently need to be implemented for several of the most important industrial processes.

For more information:

Johan Rootzén and **Jan Kjärstad**
Energy Technology, Chalmers

Further reading:

Rootzén, J., Kjärstad, J., Johnsson F., 2010, "Prospects for CO_2 capture in European Industry", accepted for publication in Management of Environmental Quality, Vol. 22 No. 1.

19

Potential for CCS within the European pulp and paper industry

Assessment of the potential for Carbon Capture and Storage (CCS) in the European Pulp and Paper industry suggests that if CCS is to be introduced on a large scale in this industry, biomass-based emissions must be included when planning the CCS infrastructure. The total capture potential is about 60 Mt/year. If only fossil emissions are considered for the CCS infrastructure, this potential is dcreased to about 15 Mt/year.

For the European Pulp and Paper industry (PPI), various technology pathways that are both profitable and in line with development towards sustainability have been identified to date (see Chapter 39). However, owing to geographical and infrastructural limitations, some technology pathways cannot be implemented in all the paper mills. One example of a technology with these limitations is Carbon Capture and Storage (CCS).

Nevertheless, CCS is of interest to the European PPI for the following reasons:

- The PPI has large point sources of CO_2 emissions;
- The CO_2 concentrations in stack gases from the PPI are relatively high;
- There are opportunities for heat-integrating the CCS unit, thereby decreasing the energy demand for CCS;
- CCS for biomass-based activity has the potential to reduce the CO_2 concentration in the atmosphere.

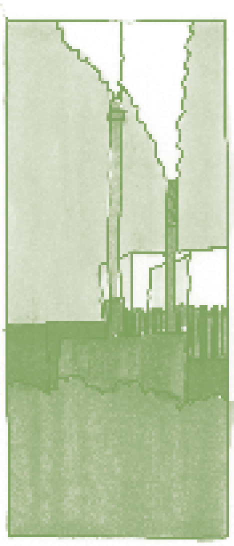
DETAILED RESULTS COMBINED WITH DATA FOR THE EUROPEAN MILLS

To estimate the potential for CCS on a European level, the results from detailed studies were linked with the actual European PPI stock. Thus, the techno-economic potential for CCS on a mill level (Hektor and Berntsson, 2007) was combined with mill-specific data for the European PPI stock (e.g., CEPI, 2007 and CEPI, 2008), to provide an estimate of the techno-economic potential of CCS on a European level. Moreover, the geographical locations of the mills were combined with information on the infrastructures surrounding the mills, to determine whether the potential is affected by mill location. The geographical positions and potential industrial CCS-clusters are based on work presented in Chapter 18.

The approach combined the advantages of detailed and aggregated approaches and assessed the overall potential for Europe, while considering the important characteristics of each mill. A more thorough description of the method can be found in Chapter 10 in the *Methods and Models* book.

INCLUSION OF MORE THAN 170 PULP AND PAPER MILLS AND ALMOST 80% OF ALL CO_2 EMISSIONS

The European PPI has been defined as mills located in the countries that are included in the Confederation of European Paper Industries, CEPI (CEPI, 2009). In all, 171 mills were selected based on competitive strength and size. Thus, the assessment includes 50 kraft pulp and/or paper mills, 45 mechanical pulp and paper mills, and 76 paper mills without any virgin pulp production (having only bought pulp and/or RCF/DIP).



The levels of on-site CO_2 emissions from the pulp and paper mills included are presented in Table 19.1. For the purpose of comparison, the total on-site emissions of CO_2 for all CEPI mills (CEPI, 2008) are also included. The fossil CO_2 emissions were derived from the Chalmers Industry Database (see Chapter 3 in the *Methods and Models* book), while the biomass-based CO_2 emissions were based inter alia on annual reports or calculated from the energy data of the mills. As shown in Table 19.1, 95% of the CO_2 emissions that originated from biomass and 47% of the fossil CO_2 emissions are covered. This means that in total, 77% of the CEPI CO_2 emissions are included. The geographical distribution of the total CO_2 emissions for the PPI is shown in Figure 19.1. The regions with the highest emission levels are located around the Baltic Sea (in Sweden and Finland), in the south of Spain, and in the middle of Portugal.

Table 19.1. CO_2 emissions for the mills included in the assessment, and comparisons with CEPI total emissions.

Type of mill	Kraft		Mechanical	Paper
	Market pulp	Pulp and Paper	Pulp and Paper	
Mills [no.]	21	29	43	70
Fossil CO_2 [kt/yr]	1 391	3 164	4 759	9 420
Biomass CO_2 [kt/yr]	24 308	30 775	5 524	2 217
Total CO_2 [kt/yr]	25 699	33 940	10 283	11 637
CEPI total fossil				*39 605*
CEPI total biomass				*66 113*

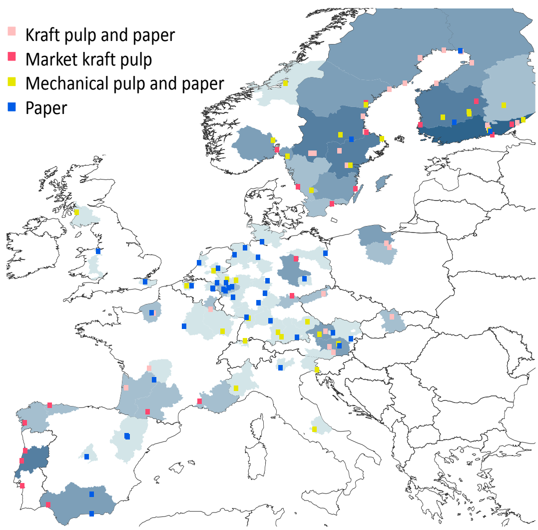


Figure 19.1. Geographical distribution of on-site CO_2 emissions from the European PPI. The coloured squares represent individual mills (emitting >0.1 $MtCO_2$/yr). The regions coloured in blue have a high density of emissions; the darker the colour, the higher the emission level. Source: Jönsson and Berntsson, 2008.

CARBON CAPTURE POTENTIAL OF 10-60 Mt/YEAR

At present, CCS is not a commercial technology, and the necessary infrastructure for both the transport and storage of CO_2 is neither in place nor definitely planned. However, it is reasonable to assume that the infrastructure will be developed initially in proximity to sites with many large point sources, i.e., capture clusters. It can also be assumed that the infrastructure will initially be built around large point sources. Furthermore, it is reasonable to assume that mills with high levels of emissions will have greater potential for the profitable introduction of CCS than sites with low levels of emissions. Based on these assumptions, a matrix was constructed that contains six different future scenarios for the implementation of CCS in the European PPI (Table 19.2).

Table 19.2. Potential scenarios for the future implementation of CCS

Case description	Capture done by all included mills	Capture done only by mills within capture clusters	Capture done only by mills within fossil capture clusters
Mills with emissions >0.1 $MtCO_2$/yr	A1	A2	A3
Mills with emissions >0.5 $MtCO_2$/yr	B1	B2	B3

The geographical positions of the pulp and paper mills included in relation to the geographical positions of other energy-intensive industries, capture clusters, and potential storage sites are displayed in Figure 19.2. Most of the kraft pulp and paper mills with high levels of emissions are located on the eastern coast of Sweden and in Finland, far away from most of the fossil capture clusters created by other energy-intensive industries. The paper mills of central Europe have the most beneficial geographical positions, as they are located in or near fossil capture clusters created by other energy-intensive industries and near the potential storage sites in the North Sea. However, if both fossil-based and biomass-based emissions are included, a much larger proportion of the European PPI would be positioned in capture clusters.

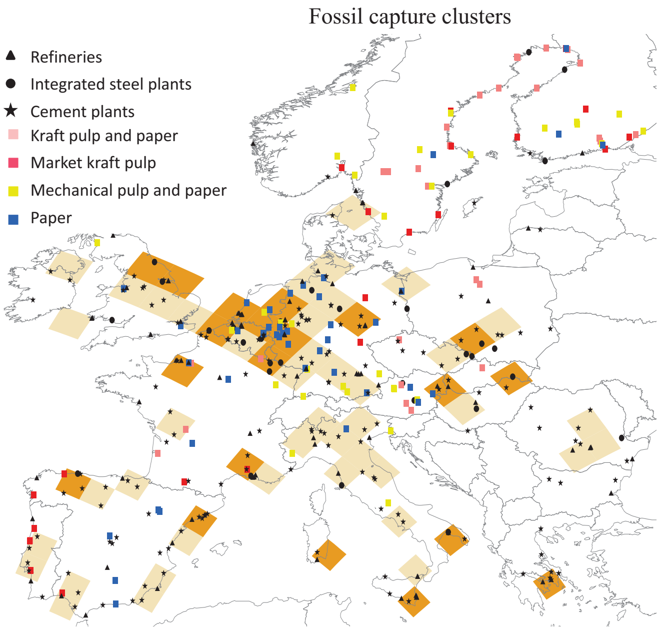
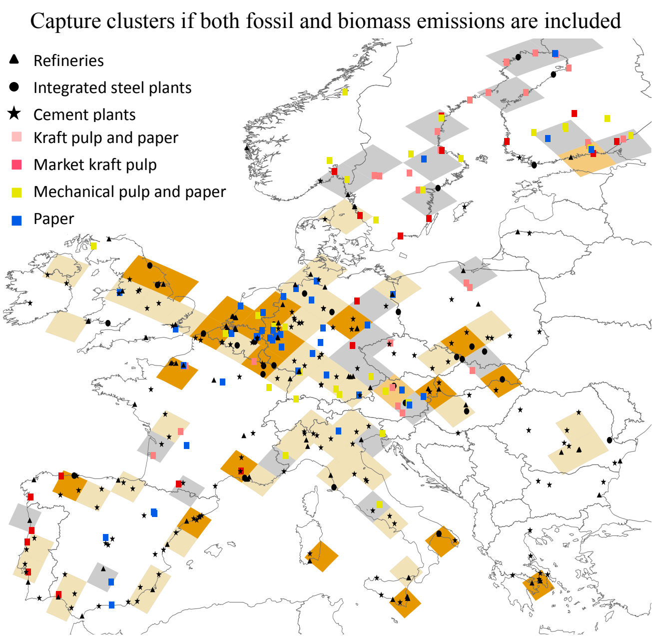


Figure 19.2. Geographical distribution of pulp and paper mills that emit more than 0.1 Mt CO_2/yr in relation to other large industrial point sources with emissions of >0.5 Mt CO_2/yr. Possible capture cluster areas are represented by coloured squares (150 × 150 km); the orange squares represent clusters with more than two industries that together emit more than 5 MtCO_2/yr; and the yellow and grey clusters represent clusters that emit more than 1 MtCO_2/yr. Source: Jönsson and Berntsson, 2008.



Regarding the distributions of the high-level emitters and low-level emitters included here, it is clear from Figure 19.3 that one-third of the mills (i.e., those with emissions >0.5 Mt/yr) account for 75% of the total emissions. It is also noteworthy that about 80% of the total potential for CCS in the A1 and B1 scenarios can be captured if capture clusters that include biomass emissions are considered (A2 and B2). To achieve significant reductions in CO_2 emissions within the European PPI, the emission-intensive Scandinavian kraft PPI must be included in the capture scheme. If only the emissions from the mills located in fossil-based capture clusters are included (A3 and B3), the capture potential is reduced by about 45 $MtCO_2$/yr, as compared to the potential calculated for the mills in both the fossil-based and biomass-based capture clusters (A2 and B2).

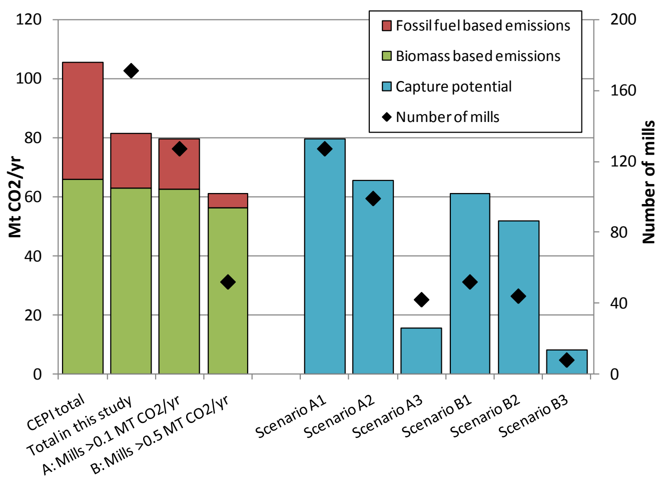


Figure 19.3. Distributions of included emissions according size and origin, together with the potential for captured CO_2 emissions for the six capture scenarios presented in Table 19.2. Source: Jönsson and Berntsson, 2008.

BIOMASS EMISSION SHOULD BE CONSIDERED IN THE DESIGN OF CCS INFRASTRUCTURE

The amount of CO_2 that can be captured is strongly dependent upon the expansion of infrastructure. The results show that 10-64 $MtCO_2$/yr can be captured, depending on the assumptions made for the transport and storage infrastructure. Furthermore, the results show that when adding the PPI capture potential to the potential for CCS within other energy-intensive industries, the majority of the PPI emissions originate from kraft pulp and paper mills that are distant from other energy-intensive industries and potential fossil capture clusters. Therefore, to achieve significant reductions in emissions, large biomass-based point sources of CO_2 emissions need to be included in the plans for CCS infrastructure. The best matches between CO_2 sources and potential storage places are located in the regions bordering the Baltic Sea. Thus, while the paper mills of central Europe are most suitable for CCS, these mills generally have much lower on-site emission levels than the Scandinavian kraft pulp and paper mills. For the mills (and other emissions sources) that border the Baltic Sea, storage in closed aquifers, such as those located close to Gotland, might be possible, although this needs to be investigated further. The emissions from the power sector were not included. If these emissions were included, central Europe would have an even larger density of fossil CO_2 emissions. Therefore, it should be further investigated whether the biomass-based capture clusters in Scandinavia are sufficiently large to justify construction of the needed infrastructure.

For more information:

Johanna Jönsson and **Thore Berntsson**
Heat and Power Technology, Chalmers

Further reading:

Jönsson, J. and Berntsson, T., 2008, Analysing the Potential for CCS within the European Pulp and Paper Industry, Congress Proceedings of ECOS 2008, Krakow, Poland, June 24-27.

20

Public attitudes towards climate change mitigation options

No matter how promising an option appears to be to mitigate emissions of greenhouse gases from a technological and economic perspective, for it to be implemented successfully it has to be socially acceptable to the general public. Therefore, when it comes to climate change mitigation options, it is necessary to investigate not only the technical and economic barriers, but also the social and political barriers that need to be overcome.

To investigate public attitudes, opinions, and understanding of issues regarding energy, environment, climate change, and climate change mitigation options, several joint studies, based on surveys of the general public, have been performed in Sweden, the US, the UK, and Japan as part of the Pathways project. The first surveys were conducted in 2003-2005. In both Sweden and the US, the surveys have been repeated at 3-5-year intervals using similar questions. The Swedish surveys were carried out in 2005 and 2010, whereas the US surveys were performed in 2003, 2006, and 2009.

Overall, the results reveal remarkable similarities in the public attitudes among the polled countries, although there are some significant discrepancies between the countries, as well as over time. Among the most striking similarities are those in: 1) support of renewables; 2) research priorities; 3) basic understanding of which technologies produce or reduce carbon dioxide; and 4) willingness to pay for solving global warming. Regarding the most appropriate political level for controlling greenhouse gas emissions, a majority of the respondents in both the UK and Sweden put the international level first. Even among the US respondents, close to a majority now (2009) believe that the US should join international treaties on climate change mitigation. This represents a substantial change of opinion compared to the situation in 2003, when only one-third of the American respondents were in favour of the US joining international treaties.

The survey results also show that Carbon Capture and Storage (CCS) is a largely unknown technology. There also seem to be a polarisation (similar to that which *is seen towards nuclear power) among those respondents that are supportive and those that are non-supportive of the technology.*

The most striking difference between the countries surveyed is the larger proportion of hard-core sceptics in the US, who do not believe in the science of climate change and the need for action, as compared to a much lower percentage of sceptics in the other countries. Nevertheless, the similarities between the different countries are consistent and appear to be stable over time.

ATTITUDES TOWARDS THE ENVIRONMENT AND GLOBAL WARMING

The survey questions aimed at investigating attitudes towards the environment and global warming can be divided into three categories:

1. **Environmental versus other societal issues**. To place the public attitudes to the environment and global warming in a wider perspective, the respondents were asked to rank the importance of the environment in relation to other issues facing society, such as unemployment, education, and crime.

2. **Climate change versus other environmental issues**. To investigate further people's attitudes towards climate change, the respondents were asked to rank the importance of different environmental issues, including climate change.

3. **Perceived urgency in mitigating climate change**. To assess concerns about global warming and climate change, the respondents were asked to identify statements that best corresponded to their opinion regarding climate change caused by humans.

The survey results reveal rather large differences between countries in terms of how respondents rank the importance of the environment versus other societal issues, reflecting differences of opinion in the prevailing public debate in the surveyed countries. In the US, the ranking of the importance of the environment as a societal issue seems to be stable over time. In 2009, the American respondents ranked the environment as number 12 in importance, up from number 13 in 2003 but down from number 10 in 2006. In contrast, in the UK, the environment was ranked as number 7 in importance in 2003. As shown in Figure 20.1, the Swedish public, in general, seem to rank environmental issues even higher, ranking the environment as number 5 in importance in 2005, moving it up to 4th place in 2010. In the Japanese survey, no such question was included.

In 2003, the respondents in the US and the UK placed terrorism as the top issue facing the countries. However, in 2006 and 2009, the economy and healthcare had replaced terrorism as the most important issues facing the US, followed by unemployment. This change might be seen as a reflection of the recent economic downturn and the healthcare debate in the US over the last couple of years.

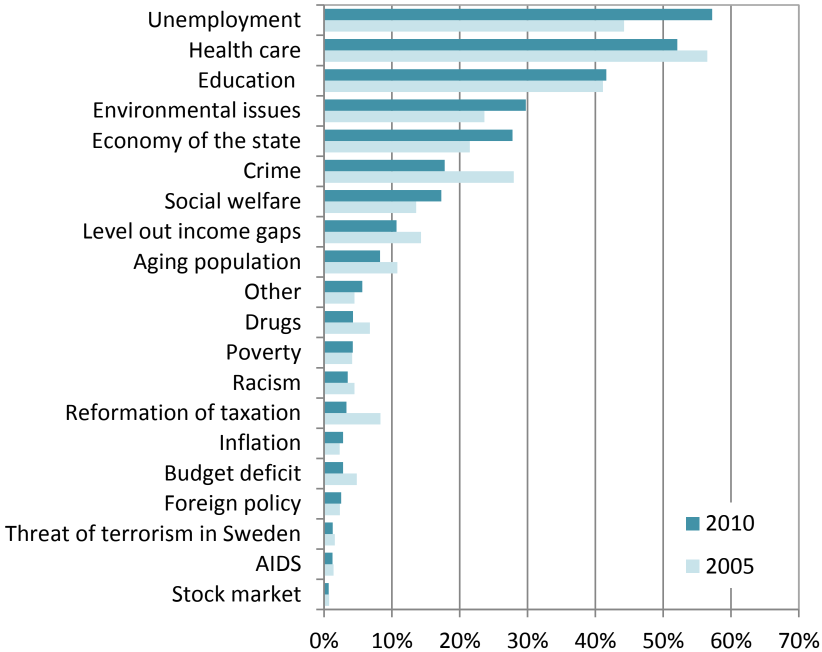


Figure 20.1. Swedish respondents' ranking of the most important societal issues facing Sweden in 2005 and 2010. The ranking of the different issues reflect, for the most part, the prevailing public debate. An example of this is the intensive debate in the autumn of 2004 concerning the correctional system in Sweden following a series of breakouts and riots at Swedish prisons. This might explain the significant difference between 2005 and 2010 concerning crime as a societal issue. Environmental issues are ranked number 4, whereas unemployment is the respondents' biggest concern in 2010. Sources: AGS Pathways, 2007 ; Löfblad and Haraldsson (forthcoming).

In the first surveys (2003-2005), global warming was considered the most important environmental issue in both the UK and in Sweden, while the US respondents ranked it only as number 6, after water pollution, ecosystem destruction, overpopulation, and toxic waste (Figure 20.2). These outcomes were comparable to those obtained in Gallup surveys conducted in the US for the same time period, in which various forms of water pollution were ranked as the leading environmental concern. However, since 2003 there has been a significant shift in US public opinion regarding the importance of global warming. In the 2006 survey, global warming was suddenly ranked as number one, followed by the destruction of ecosystems in second place and water pollution in third place. This change in the public opinion indicates that a higher percentage of the US population today recognises that global warming is a real problem, although the 2009 survey in the US has seen a reversal in public opinion regarding the urgency of solving global warming.

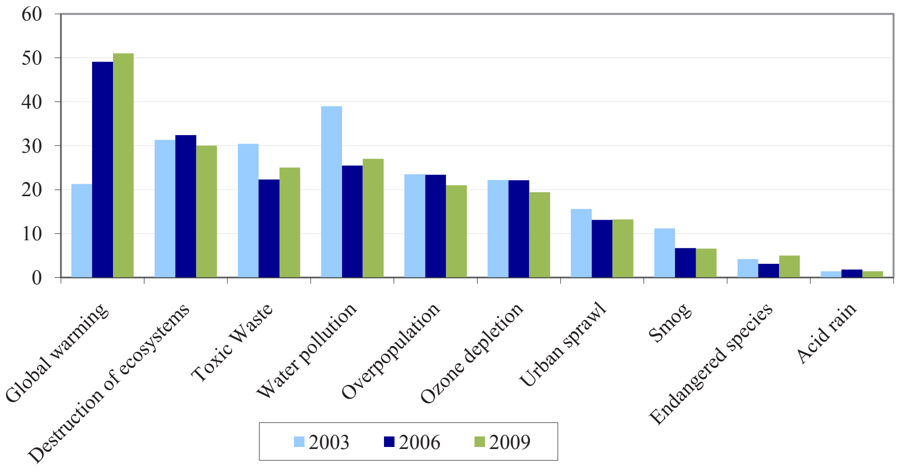


Figure 20.2. US respondents' ranking of the most important environmental issues in 2003, 2006, and 2009. There has been a dramatic change since 2003 regarding the extent to which people in the US view global warming as a problem of importance. Source: O'Keefe and Herzog, 2009a.

To assess the perceived urgency among the public to mitigate global warming and climate change, the respondents were asked to state which of four statements corresponded most accurately with their opinion regarding climate change caused by humans. The survey results indicate strong support for action against global warming in the UK, Japan, and Sweden. In the US, this support was weaker, and a comparatively high percentage (16%) of the respondents in 2003 had no opinion on this question. Compared to the other surveyed countries, more respondents in the US believe that concern about global warming is unwarranted (Figure 20.3); since 2003, this subgroup of respondents has increased from 7% to 11%. According to the results of the surveys, the American respondents appear to be consistent in their belief that some action should be taken, although in 2009 somewhat fewer of these respondents believed that immediate action should be taken, as compared to 2006.

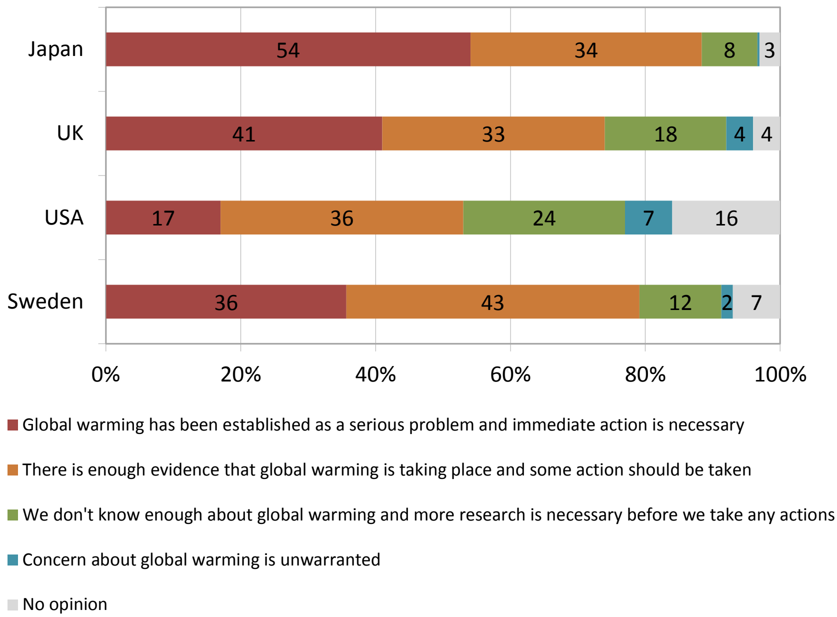


Figure 20.3. Comparison of the surveyed countries (2003-2005) regarding the respondents' perceived urgency to mitigate climate change. The highest percentage of respondents who think that concern about global warming is unwarranted is found in the US. Source: AGS Pathways, 2007.

ATTITUDES TOWARDS AND RECOGNITION OF CLIMATE CHANGE MITIGATION OPTIONS

Both the American and the European surveys asked the respondents to rank their priorities for the national energy agency, and they revealed remarkable similarities regarding the areas for which the public wanted to see their government provide research funding. Out of a list of 13 alternatives, new renewable energy technologies, such as wind and solar energy, were the clear leader, with a majority (around 50%), of the respondents in the US, UK, and Sweden listing it as one of their top two national research priorities (Figure 20.4). Energy conservation was also ranked rather high in all surveyed countries, with the highest ranking in Sweden compared to the US and the UK (ranked as number 2, number 6 and number 4, respectively). Anti-terrorism options, on the other hand, received a much higher priority in both the US (ranked as number 2 in 2003, and number 4 in 2009) and the UK (ranked as number 3 in 2003), as compared to Sweden (ranked as number 11 in 2005, and number 12 in 2010). Processes to remove carbon from the atmosphere were of lower importance to the public in the US and the UK, as compared to the Swedish public. In the US, new oil and gas reserves were ranked high in priority (as compared to the UK, where only 6% of the respondents considered this a priority; the Swedish survey did not include this alternative), and it moved up to 2nd place in the ranking, after new energy sources, in 2009. In Sweden, the most significant changes in priorities over time (2010 compared to 2005) concern public transport and energy-efficient buildings, which are now ranked as number 4 and number 6, respectively.

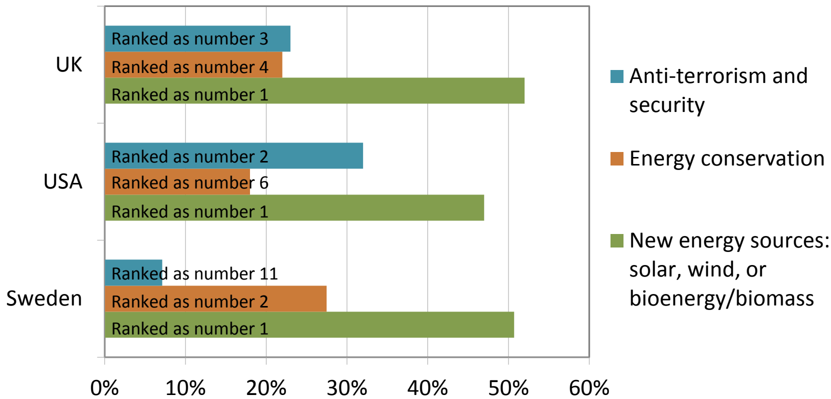


Figure 20.4. Comparison of the surveyed countries (2003-2005) concerning the ranked priority of three research areas for the national energy agency. Source: AGS Pathways, 2007.

Another question that was posed in the surveys aimed at assessing the respondents' opinions regarding how they believe their country will handle the climate change issue, and whether lifestyle changes or new technologies will solve the problem (Figure 20.5). In comparison to the respondents in the US, UK, and Japan, the Swedish respondents (in 2005) expressed the strongest confidence in new technologies, with around one-third (34%) of the respondents believing that new technologies will be developed to mitigate global warming. In Japan (2003), 66% of the respondents instead believed that changes in lifestyle were required to reduce energy consumption, as compared to one-third of the Americans (2003), one-quarter of the Britons (2003), and only one-fifth of the Swedes (2005). Subsequently, there has been an increase in the number of US respondents who believe lifestyle changes will be necessary. However, the most significant shift in opinion (2010, compared to the situation in 2005) is shown by the Swedish respondents, who now seem to follow the US respondents' position, with a clear majority (53%) of the respondents believing that lifestyle changes will be necessary, while fewer respondents believe new technologies will be developed to solve the problem of climate change.

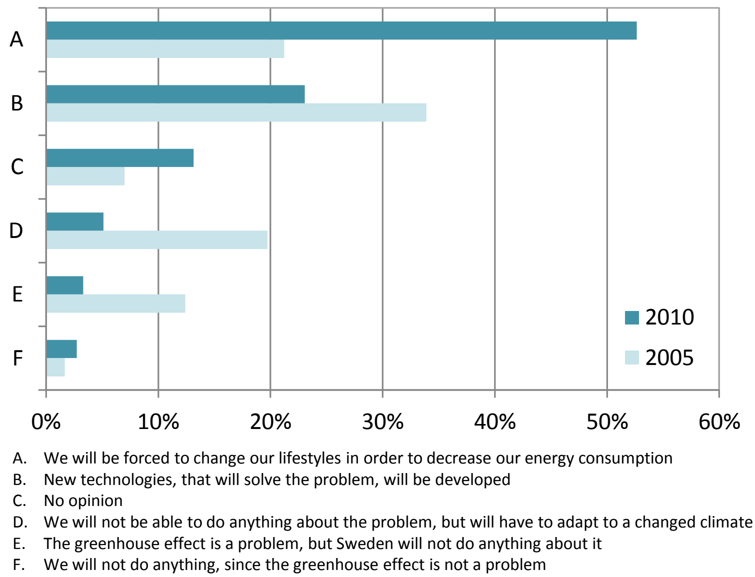


Figure 20.5. Swedish respondents' opinions regarding how they believe Sweden will handle the climate change issue, and whether lifestyle changes or new technologies will solve the problem. Sources: AGS Pathways, 2007 ; Löfblad and Haraldsson (forthcoming).

When asked which technologies they would choose if they were responsible for designing a plan to mitigate global warming, the respondents in all four countries expressed strong preferences for using energy-efficient cars, wind energy, energy-efficient household appliances, and solar energy (Figure 20.6). These technologies are generally well-appreciated, and have received coverage in the media for the last two to three decades. Consequently, the public is well-informed on these technologies. Around 70-90% of the respondents said that they would definitely or probably use energy-efficient cars, wind energy, energy-efficient household appliances or solar energy to address global warming. Carbon sequestration (e.g., through increasing wooded areas) is clearly a more popular option in Japan than in Sweden (90% versus 56%, respectively, would definitely or probably use this method), with the US and UK having support levels intermediate to those in Japan and Sweden. The support for iron fertilisation of the oceans is weak in all the countries surveyed, with only 15-25% of the respondents in favour of this technology.

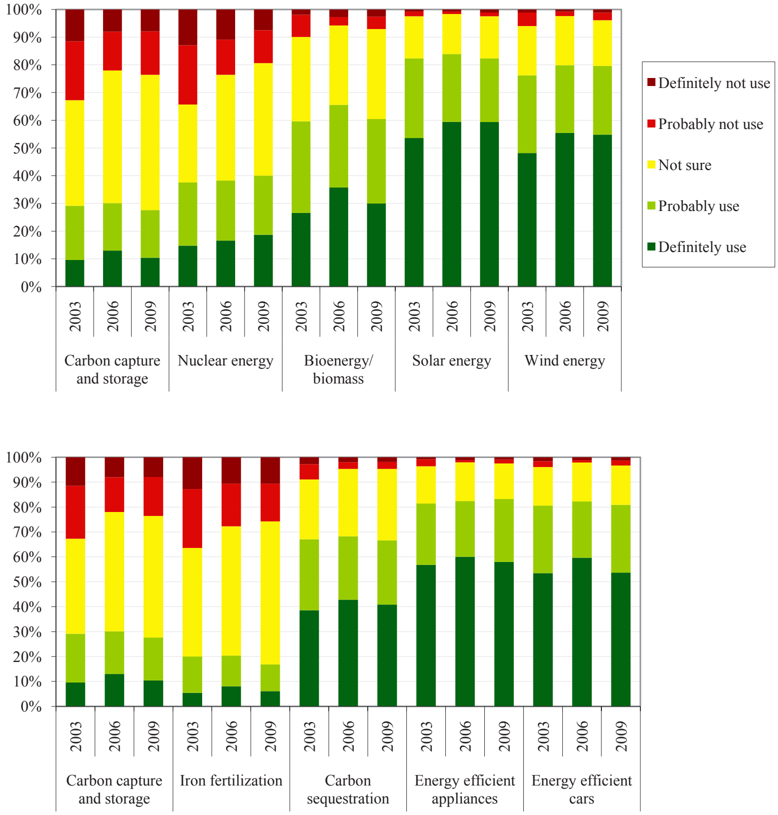


Figure 20.6. US respondents' choices with respect to climate change mitigation options, i.e. which technologies they were to use if they were responsible for designing a plan to address global warming. Source: O'Keefe and Herzog, 2009a.

The survey results also show that name recognition for a specific technology does not translate into support for that technology. As is the case for public support for or opposition to nuclear power, there is a polarisation of public opinion in all the surveyed countries as to whether or not they would choose to use CCS as a means to mitigate global warming. Across all four surveys, the largest proportion of the respondents was unsure whether or not to support CCS, while the remainder was roughly divided between being supportive or non-supportive (Figure 20.7). This might be explained by a general lack of knowledge regarding the technology.

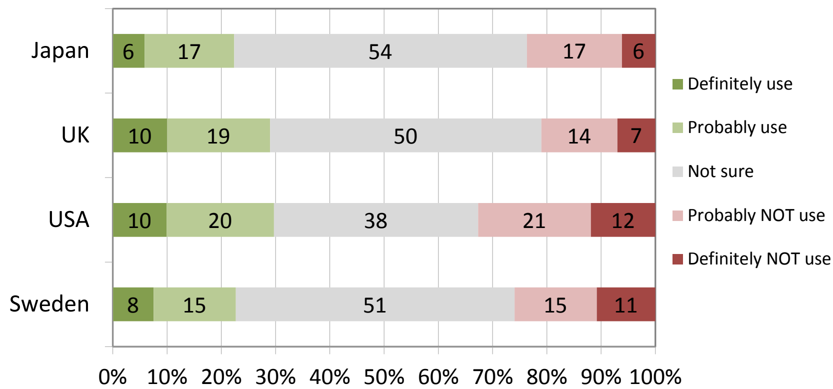


Figure 20.7. Comparison of the respondents' opinions in the surveyed countries regarding support for or opposition to CCS; the respondents were asked if they would use CCS if they were to design a climate change mitigation plan (results from 2003-2005). Source: AGS Pathways, 2007.

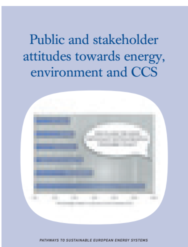
As part of the Pathways project, a survey was also conducted of the attitudes towards CCS of Swedish stakeholders (energy companies and associations, industrial companies and associations, as well as public authorities and ministries). The result of that survey, which was carried out in 2005-2006, showed that even among stakeholders, knowledge of CCS was rather limited, and only a few of the polled companies/organisations had a clear position on CCS. However, in general, the respondents seemed optimistic about the future for CCS, and they believed that more information about the technology would be likely to help ease the public's concern over CCS.

CONCLUDING REMARKS

As shown in this chapter, the survey results reveal remarkable similarities in the public opinion among the polled countries. Especially regarding the support for renewables, research priorities and basic understanding of climate change mitigation options.

For more information:

Ebba Löfblad and **Mårten Haraldsson**
Profu
Filip Johnsson, Energy Technology, Chalmers



Further reading

AGS Pathways, 2007, Public and Stakeholder Attitudes towards Energy, Environment and CCS. Report 2007:EU2.

Löfblad, E., Haraldsson, M., (forthcoming), Public attitudes towards climate change mitigation options. AGS Pathways Internal report.