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The GAINS Model for Greenhouse Gases – Version 1.0: Carbon Dioxide (CO_2)

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Abstract

Many of the traditional air pollutants and greenhouse gases have common sources, offering a cost-effective potential for simultaneous improvements of traditional air pollution problems and climate change. A methodology has been developed to extend the RAINS integrated assessment model to explore synergies and trade-offs between the control of greenhouse gases and air pollution. With this extension, the GAINS (**G**HG-**A**ir pollution **IN**teraction and **S**ynergies) model will allow the assessment of emission control costs for the six greenhouse gases covered under the Kyoto Protocol (CO_2, CH_4, N_2O and the three F-gases) together with the emissions of air pollutants SO_2, NO_x, VOC, NH_3 and PM. This report describes the first implementation (Version 1.0) of the model extension model to incorporate CO_2 emissions.

GAINS Version 1.0 assesses 230 options for reducing CO_2 emissions from the various source categories, both through structural changes in the energy system (fuel substitution, energy efficiency improvements) and through end-of-pipe measures (e.g., carbon capture). GAINS quantifies for 43 countries/regions in Europe country-specific application potentials of the various options in the different sectors of the economy, and estimates the societal resource costs of these measures. Mitigation potentials are estimated in relation to an exogenous baseline projection that is considered to reflect current planning, and are derived from a comparison of scenario results for a range of carbon prices obtained from energy models.

A critical element of the GAINS assessment refers to the assumptions on CO_2 mitigation measures for which negative life cycle costs are calculated. There are a number of options for which the accumulated (and discounted over time) cost savings from reduced energy consumption outweigh their investments, even if private interest rates are used. If the construction of the baseline projection assumes a cost-effectiveness rationale, such measures would be autonomously adopted by the economic actors, even in the absence of any CO_2 mitigation interest. In practice, however, it can be observed that various market imperfections impede the autonomous penetration. Due to the substantial CO_2 mitigation potential that is associated with such negative cost options, projections of future CO_2 emissions and even more of the available CO_2 mitigation potentials are highly sensitive towards assumptions on their autonomous penetration rates occurring in the baseline projection.

Assuming that all negative cost measures would form an integral part of the Energy Outlook developed in 2003 by the Directorate General for Energy and Transport of the European Commission that has been developed with a cost-minimizing energy model, CO_2 emissions in Europe would approach 1990 levels in 2020, even in absence of any specific climate policy. Beyond that, GAINS estimates for 2020 an additional reduction potential of 20 percent. With full application of all mitigation measures contained in the GAINS database, the power sector could reduce its CO_2 emissions by 550 Mt, the transport sector by 400 Mt, industry by 190 Mt, and the residential and commercial sector by 50 Mt below the baseline projection. Total costs of all these measures would amount to approximately 90 billion €/year.

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About the authors

At time of writing this report, Ger Klaassen, Christer Berglund, and Fabian Wagner worked together in the Transboundary Air Pollution program of the International Institute for Applied Systems Analysis (IIASA).

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1 Introduction

1.1 Interactions between air pollution control and greenhouse gas mitigation

Recent scientific insights open new opportunities for an integrated assessment that could potentially lead to a more systematic and cost-effective approach for managing traditional air pollutants simultaneously with greenhouse gases. These include:

- Many of the traditional air pollutants and greenhouse gases (GHG) have common sources, offering a cost-effective potential for simultaneous improvements for both air pollution problems and climate change. For instance, climate change measures that aim at reduced fossil fuel combustion will have ancillary benefits for regional air pollutants (Syri *et al.*, 2001). In contrast, some ammonia abatement measures can lead to increased nitrous oxide (N_2O) emissions, while structural measures in agriculture could reduce both regional air pollution and climate change. Methane (CH_4) is both an ozone (O_3) precursor and a greenhouse gas. Hence, CH_4 abatement will have synergistic effects and some cheap abatement measures may be highly cost effective.

- Some air pollutants (e.g., tropospheric ozone and aerosols) are also important greenhouse gases and exert radiative forcing. As summarized by the Intergovernmental Panel on Climate Change (IPCC), changes in tropospheric ozone were found to have the third-largest positive radiative forcing after carbon dioxide (CO_2) and CH_4 (Houghton *et al.*, 2001), while sulphate aerosols exert negative forcing. Furthermore, understanding is growing on the role of carbonaceous aerosols, suggesting warming effects for black carbon and cooling effects for organic carbon.

- Other air pollutants such as ozone, nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC) act as indirect greenhouse gases influencing (e.g., via their impact on OH radicals) the lifetime of direct greenhouse gases (e.g., CH_4 and hydrofluorocarbons). Global circulation models have only begun to incorporate atmospheric chemistry and account fully for the important roles of conventional air pollutants.

It is clear that interactions between air pollutants and radiative forcing can be multiple and can act in opposite directions. For instance, increases in NO_x emissions decrease (via OH radicals) the lifetime of CH_4 in the atmosphere and thereby cause reduced radiative forcing. At the same time, NO_x emissions produce tropospheric ozone and increase radiative forcing. A further pathway leads to increased nitrogen deposition that may cause, via the fertilisation effect, enhanced growth of vegetation. This in turn offers an increased sink for carbon – although the net effect cannot yet be fully quantified.

Time is an important factor in the context of mitigation. While the climate change benefits (i.e., temperature decreases) take effect on the long-term, reduced air pollution will also yield benefits for human health and vegetation in the short and medium terms.

1.2 GAINS: The RAINS extension to include greenhouse gases

The Regional Air Pollution INformation and Simulation (RAINS) model has been developed at the International Institute for Applied Systems Analysis (IIASA) as a tool for the integrated assessment of emission control strategies for reducing the impacts of air pollution. The present version of RAINS addresses health impacts of fine particulate matter and ozone, vegetation damage from ground-level ozone, as well as acidification and eutrophication. To explore synergies between these environmental effects, RAINS includes emission controls for sulphur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOC), ammonia (NH_3) and fine particulate matter (PM).

Considering the new insights into the linkages between air pollution and greenhouse gases, work has begun to extend the multi-pollutant/multi-effect approach that RAINS presently uses for the analysis of air pollution to include emissions of greenhouse gases (GHG). This could potentially offer a practical tool for designing national and regional strategies that respond to global and long-term climate objectives (expressed in terms of greenhouse gas emissions) while maximizing the local and short- to medium-term environmental benefits of air pollution. The emphasis of the envisaged tool is on identifying synergistic effects between the control of air pollution and the emissions of greenhouse gases.

The new tool is termed 'GAINS': **G**HG-**A**ir pollution **IN**teractions and **S**ynergies. It is not proposed at this stage to extend the GAINS model towards modelling of the climate system.

1.3 Objective of this report

The objective of this report is to describe a first version of the GAINS model (Version 1.0) related to emission control options for CO_2 and associated costs. Other reports have been prepared for the other five Kyoto greenhouse gases (CH_4, N_2O, HFCs PFCs, SF_6) and are available on the Internet (http://www.iiasa.ac.at/rains/gains/index.html).

1.4 Structure of the report

This report has the following structure: Section 2 describes the methodology to extend the RAINS air pollution model to include emissions of greenhouse gases. Section 3 reviews sources of CO_2 emissions and options for controlling them. Section 4 describes options and costs for reducing CO_2 emissions in the various sectors. Section 5 discusses interactions between the control of CO_2 emissions and of other air pollutants. Section 6 presents initial results from the first version of the GAINS model. Conclusions are drawn in Section 7.

2 Methodology

2.1 Introduction

A methodology has been developed to assess, for any exogenously supplied projection of future economic activities, the resulting emissions of greenhouse gases and conventional air pollutants, the technical potential for emission controls and the costs of such measures, as well as the interactions between the emission controls of various pollutants. This new methodology revises the existing mathematical formulation of the RAINS optimisation problem to take account of the interactions between emission control options of multiple pollutants and their effects on multiple environmental endpoints (see Klaassen *et al.*, 2004).

This report addresses the implementation of carbon dioxide (CO_2) and its interactions into GAINS. Accompanying reports have been prepared for methane (Höglund-Isaksson and Mechler, 2005), for the F-gases (Tohka, 2005), and for nitrous oxide (Winiwarter, 2005). This section of the CO_2 report first describes the basic model concept of the RAINS model for air pollution. Subsequently, the method to calculate emissions of CO_2 is described, followed by the costing methodology and the new formulation of the optimisation method.

2.2 The RAINS methodology for air pollution

The Regional Air Pollution Information and Simulation (RAINS) model developed at the International Institute for Applied Systems Analysis (IIASA) combines information on economic and energy development, emission control potentials and costs, atmospheric dispersion characteristics and environmental sensitivities towards air pollution (Schöpp *et al.*, 1999). The model addresses threats to human health posed by fine particulates and ground-level ozone as well as risk of ecosystems damage from acidification, excess nitrogen deposition (eutrophication) and exposure to elevated ambient levels of ozone.

These air pollution related problems are considered in a multi-pollutant context (see Figure 2.1) that quantify the contributions of sulphur dioxide (SO_2), nitrogen oxides (NO_x), ammonia (NH_3), non-methane volatile organic compounds (VOC), and primary emissions of fine (PM2.5) and coarse (PM10-PM2.5) particles. A detailed description of the RAINS model, on-line access to certain model parts, as well as all input data to the model, can be found on the Internet (http://www.iiasa.ac.at/rains).

The RAINS model framework makes it possible to estimate, for a given energy- and agricultural scenario, the costs and environmental effects of user-specified emission control policies. Furthermore, a non-linear optimisation mode has been developed to identify the cost-minimal combination of emission controls meeting user-supplied air quality targets. This optimisation mode takes into account regional differences in emission control costs and atmospheric dispersion characteristics. The optimisation capability of RAINS enables the development of multi-pollutant, multi-effect pollution control strategies.

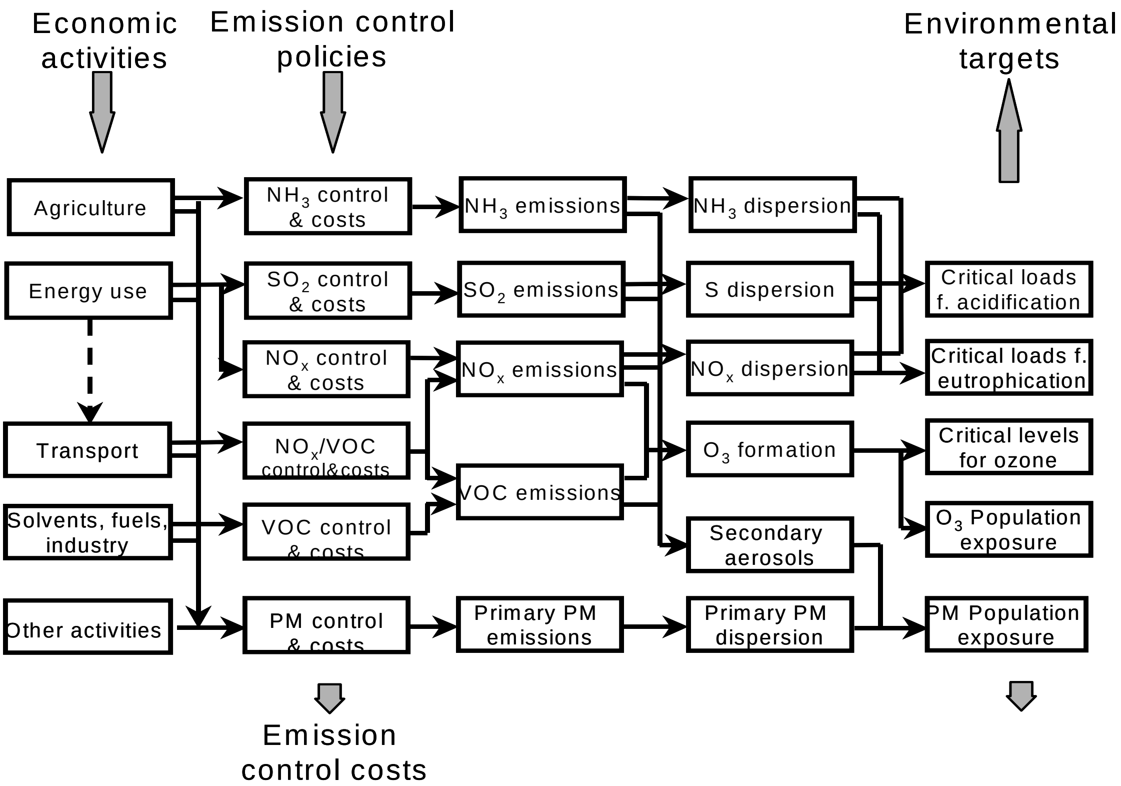

Figure 2.1: Information flow in the RAINS model.

In particular, the optimisation can be used to search for cost-minimal balances of controls of the six pollutants (SO_2, NO_x, VOC, NH_3, primary $PM_{2,5}$, primary $PM_{10\text{-}2.5}$ (= PM coarse)) over the various economic sectors in all European countries that simultaneously achieve:

- user-specified targets for human health impacts (e.g., expressed in terms of reduced life expectancy),
- ecosystems protection (e.g., expressed in terms of excess acid and nitrogen deposition), and
- maximum allowed violations of World Health Organisation (WHO) guideline values for ground-level ozone.

The RAINS model covers the time horizon from 1990 to 2030, with time steps of five years. Geographically, the model covers 47 countries and regions in Europe. Five of them represent sea regions, the European part of Russia is divided into four regions, and 38 are individual countries. Overall, the model extends over Europe from Ireland to the European part of Russia (West of the Ural) and Turkey. In a north to south perspective, the model covers all countries from Norway down to Malta and Cyprus.

2.3 Emission calculation

The methodology adopted for the estimation of current and future greenhouse gas emissions and the available potential for emission controls follows the standard RAINS methodology. Emissions of each pollutant *p* are calculated as the product of the activity levels, the "uncontrolled" emission factor in absence of any emission control measures, the efficiency of emission control measures and the application rate of such measures:

$$E_{i,p} = \sum E_{i,s,f,t,p} = \sum A_{i,s,f} * ef_{i,s,f,p} * (1-\eta_{t,p}) * X_{i,s,f,t} \qquad \text{Equation 2.1}$$

where

i,s,f,t	Country, sector, fuel, abatement technology,
$E_{i,p}$	Emissions of the specific pollutant *p* in country *i*,
$A_{i,s,f}$	Activity (fuel use *f*) in a given sector in country *i*,
$ef_{i,s,f,p}$	"Uncontrolled" emission factor,
$\eta_{t,p}$	Reduction efficiency for pollutant *p* of the abatement option *t*, and
X	Actual implementation rate of the considered abatement option.

If no emission controls are applied, the abatement efficiency equals zero ($\eta_{t,p}= 0$) and the application rate is one ($X = 1$). In that case, the emission calculation is reduced to simple multiplication of activity rate by the "uncontrolled" emission factor.

For the calculation of baseline emission estimates, the "uncontrolled" emission factor is assumed to be constant over time with potential changes in activity levels as a result of exogenous and autonomous developments.

In GAINS, the business as usual scenario, the so-called "Current Legislation" (CLE) scenario, starts from the "controlled" emission factors of the base year, and modifies them following the implementation of abatement measures that are expected to result from legislation in place.

2.4 Cost calculation

2.4.1 General approach

In principle, GAINS applies the same concepts of cost calculation as the RAINS model to allow consistent evaluation of emission control costs for greenhouse gases and air pollutants. The cost evaluation in the RAINS/GAINS model attempts to quantify the values to society of the resources diverted to reduce emissions in Europe (Klimont *et al.*, 2002). In practice, these values are approximated by estimating costs at the production level rather than at the level of consumer prices. Therefore, any mark-ups charged over production costs by manufacturers or dealers do not represent actual resource use and are ignored. Any taxes added to production costs are similarly ignored as subsidies since they are transfers and not resource costs.

A central assumption in the RAINS/GAINS cost calculation is the existence of a free market for (abatement) equipment throughout Europe that is accessible to all countries at the same conditions. Thus, the capital investments for a certain technology can be specified as being independent of the country. Simultaneously, the calculation routine takes into account several country-specific parameters that characterise the situation in a given region. For instance, these parameters include average boiler sizes, capacity/vehicles utilization rates and emission factors. The expenditures for emission controls are differentiated into:

- investments,
- fixed operating costs, and
- variable operating costs.

From these elements RAINS/GAINS calculates annual costs per unit of activity level. Subsequently, these costs are expressed per metric ton of pollutant abated. Some of the parameters are considered common to all countries. These include technology-specific data, such as removal efficiencies, unit investments costs, fixed operating and maintenance costs. Parameters used for calculating variable cost components such as the extra demand for labour, energy, and materials are also considered common to all countries.

Country-specific parameters characterise the type of capacity operated in a given country and its operation regime. They include the average size of installations in a given sector, operating hours, annual fuel consumption and mileage for vehicles. In addition, the prices for labour, electricity, fuel and other materials as well as cost of waste disposal also belong to that category. All costs in RAINS/GAINS are expressed in constant € (in prices of the year 2000).

Although based on the same principles, the methodologies for calculating costs for individual sectors need to reflect the relevant differences (e.g., in terms of capital investments). Thus, separate formulas are developed for stationary combustion sources, stationary industrial processes and mobile sources (vehicles).

2.4.2 Stationary combustion sources

2.4.2.1 Investments

Investments cover the expenditure accumulated until the start-up of an abatement technology. These costs include, e.g., delivery of the installation, construction, civil works, ducting, engineering and consulting, license fees, land requirement and capital.

The RAINS/GAINS model uses investment functions where these cost components are aggregated into one function. For stationary combustion sources the investments for individual control installations may depend on the boiler size *bs*. The form of the function is described by its coefficients ci^f and ci^v. Coefficients *ci* are valid for hard coal fired boilers. Thus, the coefficient *v* is used to account for the differences in flue gas volumes of the various fuels. For retrofitting pollution control devices to existing boilers, additional investments are taken into account through a retrofitting cost factor *r*. Specific investments are described as a function of the size of the installation, the flue gas volume and the retrofit factor:

$$I = (ci^f + \frac{ci^v}{bs}) * v * (1 + r) \qquad \text{Equation 2.2}$$

For all pollutants, investments are annualised over the technical lifetime of the plant *lt* by using the real interest rate *q* (as %/100):

$$I^{an} = I * \frac{(1+q)^{lt} * q}{(1+q)^{lt} - 1} \qquad \text{Equation 2.3}$$

2.4.2.2 Operating costs

Annual **fixed expenditures** OM^{fix} cover the costs of repairs, maintenance and administrative overhead. These cost items are not related to the actual use of the plant. As a rough estimate for annual fixed expenditures, a standard percentage *k* of the total investments is used:

$$OM^{fix} = I * k \qquad \text{Equation 2.4}$$

Variable operating costs OM^{var} are related to the actual operation of the plant and may take into account elements such as:

- additional demand for labour,
- increased or decreased energy demand for operating the device (e.g., for fans and pumps), and
- waste disposal.

These cost items are calculated with the specific demand λ^x of a certain control technology and its (country-specific) price c^x:

$$OM^{var} = \lambda^l c^l + \lambda^e c^e + ef * \eta * \lambda^d c^d \qquad \text{Equation 2.5}$$

where

η	emission removal efficiency,
λ^l	labour demand,
λ^e	additional energy demand
λ^d	demand for waste disposal (per unit of emission reduced),
c^l	labour cost,
c^e	energy price,
c^d	waste disposal cost, and
ef	unabated emission factor.

2.4.2.3 Unit reduction costs

Unit costs per unit of activity

Based on the above-mentioned cost items, the unit costs for the removal of emissions can be calculated where all expenditures of a control technology are related to one activity unit. For example, in the case of stationary combustion to one unit of fuel input (in PJ). In the case of stationary combustion, the investment-related costs are converted to fuel input by applying the capacity utilization factor *pf* (operating hours/year):

$$c_{PJ} = \frac{I^{an} + OM^{fix}}{pf} + OM^{\mathrm{var}}$$ Equation 2.6

The cost effectiveness of different control options is evaluated by relating the abatement costs to the amount of reduced emissions:

$$c_{per\,emission\,reduction} = c_{PJ} / (ef * \eta)$$ Equation 2.7

2.4.3 Industrial process emission sources

2.4.3.1 Investments

GAINS calculates for industrial process sources investments in relation to the activity unit of a given process. For the majority of processes these activity units are annual tons produced, e.g., for the cement industry the investment function is related to one million ton cement produced.

The investment function and annualised investments are given by the following two equations:

$$I = ci^{f} * (1 + r)$$ Equation 2.8

$$I^{an} = I * \frac{(1+q)^{lt} * q}{(1+q)^{lt} - 1}$$ Equation 2.9

2.4.3.2 Operating costs

The operating costs are calculated with formulas similar to those used for stationary combustion. Since the activity unit is different, the formulas have a slightly different form:

$$OM^{fix} = I * k$$ Equation 2.10

$$OM^{\mathrm{var}} = \lambda^{l} c^{l} + \lambda^{e} c^{e} + ef * \eta * \lambda^{d} c^{d}$$ Equation 2.11

The coefficients λ^l, λ^e, and λ^d relate to one ton of product; *ef* is the emission factor for the specific pollutant.

2.4.3.3 Unit reduction costs

Unit costs per ton of product

This cost is calculated from the following formula:

$$c = I^{an} + OM^{fix} + OM^{\mathrm{var}}$$ Equation 2.12

Unit costs per ton of pollutant removed

As for combustion sources, one can calculate costs per unit of emission removed:

$$c_{per\,emission\,reduction} = c_{PJ} / (ef * \eta)$$ Equation 2.13

2.4.4 Mobile sources

2.4.4.1 Investments

The cost evaluation for mobile sources follows the same basic approach as for stationary sources. The most important difference is that the investments are given per vehicle, not per unit of production capacity. The following description uses the indices *i*, *s*, *f* and *t* to indicate the nature of the parameters:

i	denotes the country,
s	the transport (sub)sector/vehicle category,
f	the fuel type,
t	the control technology.

The costs of applying control devices to mobile sources include:

- additional investments,
- increase in maintenance costs expressed as a percentage of total investments, and
- change in fuel cost resulting from the inclusion of emission control.

The investments $I_{i,s,f,t}$ are expressed in €/vehicle and are available separately for each technology and vehicle category. They are **annualised** according to:

$$I^{an}_{i,s,f,t} = I_{i,s,f,t} * \frac{(1+q)^{lt_{i,s,f,t}} * q}{(1+q)^{lt_{i,s,f,t}} - 1} \qquad \text{Equation 2.14}$$

where

$lt_{i,s,f,t}$ lifetime of control equipment.

2.4.4.2 Operating costs

The increase in maintenance costs (**fixed costs**) is expressed as a percentage *k* of the total investments:

$$OM^{fix}_{i,s,f,t} = I_{i,s,f,t} * k_t \qquad \text{Equation 2.15}$$

A change in fuel cost is caused by:

- a change in fuel quality required by a given stage of control, or
- a change in fuel consumption after inclusion of controls.

It can be calculated as follows:

$$OM^{var}_{i,s,f,t} = \Delta c^e_{s,f} + \lambda^e_{s,f,t} * (c^e_{i,s,f} + \Delta c^e_{s,f}) \qquad \text{Equation 2.16}$$

where

$l^e_{s,f,t}$	percentage change in fuel consumption by vehicle type *s* caused by implementation of control measure *t*,
$c^e_{i,s,f}$	price for fuel type *f* (net of taxes) in country *i* and sector *s* in the base year,
$\Delta c^e_{s,f}$	change in fuel cost caused by the change in fuel quality.

This change in fuel cost is related to one unit of fuel used by a given vehicle category.

2.4.4.3 Unit reduction costs

The unit costs of abatement ce_{PJ} (related to one unit of fuel input) are time dependent and add up to:

$$c_{PJ} = \frac{I^{an} + OM^{fix}}{fuel\,use} + OM^{e} \qquad \text{Equation 2.17}$$

These costs can be related to the emission reductions achieved. The costs per unit of abated are then:

$$c_{per\,emission\,reduction} = c_{PJ} / (ef * \eta) \qquad \text{Equation 2.18}$$

The most important factors leading to differences among countries in unit abatement costs are differences in annual energy consumption per vehicle and country-specific differences in unabated emission factors due to different vehicle stocks and driving patterns.

2.5 The optimisation for greenhouse gases and air pollutants

2.5.1 Objective

Traditionally, the RAINS model employs ‘national cost curves’ for emission controls for each pollutant and country, which rank the available emission control measures according to their cost-effectiveness. While such cost curves are computationally efficient and facilitate understanding and review by national experts, they cannot directly capture interactions between the emission control options of different pollutants. In the earlier analyses of air pollution strategies, only few of such interactions were of practical relevance (e.g., three way catalysts simultaneously controlling NO_x and VOC emissions), and tailored solutions were developed to handle these aspects. In the GAINS model, with the new focus on greenhouse gases, such interactions become more relevant, and a new concept needed to be developed.

Instead of national (pollutant-specific) emission reduction levels curtailed by the national cost curves, the new methodology uses the application of individual emission control options as decision variables. All economic and emission-relevant features are directly connected to these variables. This allows to fully capturing all interactions between pollutants for each individual emission control measure. In such a way, the traditional ‘cost curve’ approach of the RAINS model is replaced by a ‘technology-driven’ problem formulation. The major disadvantage of this approach is that it puts significantly higher demands on computing power. The larger dimensions of the optimisation problem will also limit the practical possibility for analysing non-linear relationships (e.g., in the formation of ground-level ozone). It needs to be examined to what extent such constraints will limit the accuracy of results, or alternatively whether a tailored mathematical algorithm can be developed that enables treatment of the most important non-linearities.

The new formulation of the RAINS model allows simulation of a variety of flexible mechanisms for controlling GHG and air pollution emissions. This includes, *inter alia*, the possibility of simulating carbon taxes for all greenhouse gases, emission taxes for conventional air pollutants, trading of carbon and other greenhouse gases within selected countries in Europe (e.g., the EU), and the clean development mechanism of the Kyoto protocol, where emission permits could be acquired from Non-Annex I countries. In doing so the analysis of European medium-term emission control strategies can be embedded in the context of global long-term development, which might determine, *inter alia*, carbon prices for the world market under alternative regimes of flexible mechanisms.

2.5.2 General specification

A new formulation of a mathematical programming problem describing the interactions of emission control options for different pollutants has been developed.

The following variables are defined:

- Index i corresponds to a region or country. The number of elements is about 50.
- Index j corresponds to a receptor or grid cell. The number of elements is around 5000.
- Index p corresponds to a directly emitted pollutant. In the current GAINS implementation 11 pollutants are considered (SO_2, NO_X, VOC, NH_3, PM, CO_2, CH_4, N_20, HFC, PFC, SF_6).
- Index d corresponds to sub-categories of pollutants (or pollutant species). This is currently only the case for PM, for which RAINS distinguishes the PM fine, PM coarse and PM rest fractions.
- Index s corresponds to a sector (the number of sectors is about 30).
- Index f corresponds to a specific fuel-type activity (e.g., brown coal or industrial production type).
- Index a corresponds to an "economic" activity (a combination of a sector and fuel type activity for example gasoline use in transport). The number of elements is around 300 for each region.
- Index t corresponds to a technology. Such technologies may consist of two types:
    - No control (e.g., brown coal use in power generation)
    - Control options (e.g., combustion modification of brown coal fired power plant)

The **decision variables**, i.e., the variables to be changed in order to satisfy the objective function, are the activity rates x_{iat}, reflecting the levels at which a technology t is used for activity a in region i. For example, such a decision variable would describe the extent to which combustion modification is used for new hard coal fired plants in Poland.

The **objective function** consists then of the minimisation of total pollution control costs for all relevant pollutants over all relevant regions subject to constraints on regional emissions. The objective function is to minimise total costs over all countries:

$$Total\,costs = \sum_{i \in I} cost_i \qquad i \in I \qquad \text{Equation 2.19}$$

The costs for each country consist of the sum of the costs for all technologies over all relevant activities:

$$cost_i = \sum_{a \in A} \sum_{t \in T_a} C_{i,a,t} * X_{i,a,t} \qquad i \in I,\; a \in A, t \in T_a \qquad \text{Equation 2.20}$$

where C_{iat} are the unit costs of emission control measure t applied to activity a. X_{iat} are the activity rates related to these control measures t and T_a is the set of all emission control measures of activity a. Ai is the set of activities.

The emissions of pollutant p of activity a is the sum of the emissions related to activity rates x_{at} is defined as

$$Em_{i,p,a} = \sum_{t} E_{i,p,a,t} * X_{i,a,t} \qquad i \in I,\; p \in P,\; a \in A \qquad \text{Equation 2.21}$$

with E_{ipat} as the unit emissions of pollutant p per activity after application of technology t (the emission factor). For instance, emissions of NO_x from brown coal fired power plants are calculated as the sum of the emissions from the amounts of brown coal fired without NO_x control, with combustion modification and with selective catalytic reductions, respectively. Total emissions of pollutant p in a region are calculated as the sum of the emissions from all activities and are defined by

$$TotEm_{i,p} = \sum_{t} Em_{i,p,a,t} \qquad i \in I,\; p \in P \qquad \text{Equation 2.22}$$

Finally, **constraints** can be formulated for the problem. The activity rates themselves can be bounded, e.g., because certain technologies can only be applied to new installations:

$$X_{iat\,\min} \le X_{iat} \le X_{iat\,\max} \qquad i \in I,\; t \in T, a \in A \qquad \text{Equation 2.23}$$

In addition, emissions for each activity can be bounded, e.g., to reflect caps on total emissions imposed by existing legislation. Total emissions levels of a region can be specified for each pollutant:

$$TotEm_{ip} \le TotEM_{ip\,\max} \qquad i \in I,\; p \in P \qquad \text{Equation 2.24}$$

When specifying maximum emission levels, the corresponding total and marginal costs can be calculated. Alternative emission levels can then be specified to generate individual points of the cost function for a pollutant. The minimum value that total emissions can take then reflects the full application of best available technologies.

More complex constraints can also be added. First, the total (exogenous) demand for an activity can be specified to be at least as high as that in the baseline. For instance, when reducing carbon dioxide emissions in the power sector, the amount of electricity produced has to be at least as high as in the baseline. Second, constraints might reflect emission control legislation requiring technologies that are not worse (in terms of emissions per unit) than a certain reference technology. For instance, new coal-fired plants could be required to meet emission factors not higher than those resulting from combustion modification. Third, it is straightforward to extend the optimisation by adding constraints on deposition or concentrations of certain pollutants for one or several receptor points. This feature already exists in the present RAINS module. Finally, in particular for the control of greenhouse gas emissions, a constraint can be specified for the sum of the emissions of the basket of greenhouse gas (using, e.g., their global warming potential as weights), either for each region separately or jointly for several regions.

The simulation of joint implementation (JI) or carbon trading (ET) is another extension. One can distinguish two cases. If JI or ET is only considered between the regions distinguished in the model, the constraint on total emissions (Equation 2.23) is modified to include emissions of all regions:

$$TotEm_p = \sum_i \sum_a Em_{i,p,a} \qquad i \in I\ , \quad p \in P \qquad \text{Equation 2.25}$$

while the objective function (Equation 2.18) remains unchanged. If not all regions participate in the trades, the number of trading regions can be limited to a subset of regions.

Trading or JI with regions outside the model domain is modelled through a modification of the objective function. This will still minimise pollution control costs subject to the usual constraints (in particular Equations 2.19 to 2.25) but consider, in addition to the costs of controlling emissions within the model domain (i.e., of all countries part of the set *I*), also the (net) costs of buying emissions from elsewhere. These net costs of buying emissions elsewhere equal the (permit) price per unit of pollutant (T_p) times the (net) quantity bought (Qi_p) by each region/country. The price can be set exogenously, e.g., using the results of other global models. Thereby, the objective function now is to minimise:

$$\textit{Total costs} = \sum_{i \in I} \cos t_i + \sum_{i \in I} Tp \times Qip \qquad \text{Equation 2.26}$$

The volume of emission reductions that can be bought for a given price can be restricted by adding a constraint on the quantity than can be bought for that particular price.

2.6 Aggregation of emission sources

Greenhouse gas emissions are released from a large variety of sources with significant technical and economic differences. Conventional emission inventory systems, such as the inventory of the United Nations Framework Convention on Climate Change (UNFCCC), distinguish several hundreds of different processes causing various types of emissions.

In the ideal case, the assessment of the potential and costs for reducing emissions should be carried out at the very detailed process level. In reality, however, the objective to assess abatement costs for a large number of countries, as well as the focus on emission levels in 10 to 20 years from now restricts the level of detail that can be meaningfully maintained. While technical details can be best reflected for individual (reference) processes, the accuracy of estimates on an aggregated national level for future years will be seriously hampered by a general lack of reliable projections of many of the process-related parameters, such as future activity rates or autonomous technological progress. For an integrated assessment model focusing on the continental or global scale it is therefore imperative to aim at a reasonable balance between the level of technical detail and the availability of meaningful data describing future development, and to restrict the system to a manageable number of source categories and abatement options.

For the GAINS greenhouse gas module, an attempt was made to aggregate the emission producing processes into a reasonable number of groups with similar technical and economic properties. Considering the intended purposes of integrated assessment, the major criteria for aggregation were:

- The importance of the emission source. It was decided to target source categories with a contribution of at least 0.5 percent to the total anthropogenic emissions in a particular country.
- The possibility of defining uniform activity rates and emission factors.
- The possibility of constructing plausible forecasts of future activity levels. Since the emphasis of the cost estimates in the GAINS model is on future years, it is crucial that reasonable projections of the activity rates can be constructed or derived.
- The availability and applicability of “similar” control technologies.
- The availability of relevant data. Successful implementation of the module will only be possible if the required data are available.

It is important to carefully define appropriate activity units. They must be detailed enough to provide meaningful surrogate indicators for the actual operation of a variety of different technical processes, and aggregated enough to allow a meaningful projection of their future development with a reasonable set of general assumptions.

3 Carbon dioxide

3.1 Introduction

Carbon dioxide (CO_2), with a current abundance near 400 parts per million is the compound that exerts the strongest climate forcing of all trace gases in the atmosphere. Among the trace gases, the contribution of CO_2 to the greenhouse effect is estimated at 60 percent, which is about 70 percent of the gases covered by the Kyoto protocol. Not considered in the Kyoto basket are ozone (a secondary compound) and chlorofluorocarbons (CFC), which are being phased out already according to the Montreal protocol. Overall, atmospheric concentrations of CO_2 have increased by about a third over the last 200 years (Houghton *et al.*, 2001).

The atmosphere itself acts as just one reservoir in the global carbon cycle. Other compartments include dissolved CO_2 in seawater (especially in the deep ocean), biomass of terrestrial or marine organisms and in soils, fossilised biomass as peat, fossil gas, oil, and coal, and carbonated minerals (e.g., lime). While vegetation is both emitting and absorbing CO_2, the unbalanced concentration increase is primarily related to the combustion of fossil fuels. The oxidation of carbon stored in the fuels to CO_2 is the process that releases energy, so energy production and CO_2 emissions are intrinsically linked processes.

There are significant differences in CO_2 emissions per unit of energy released, especially between natural gas and coal. Natural gas has a considerable content of chemically bound hydrogen to oxidise into water. Coal contains only little hydrogen and thus has the highest CO_2 emissions. Any change in the natural equilibrium of carbon between the atmosphere and the biosphere (e.g., land use change, deforestation) also impacts atmospheric CO_2 concentrations, as do processes that tackle carbonated minerals (e.g., cement production, but also volcanoes).

This section first describes the emission source categories for CO_2 considered in GAINS. Second, it explains the emission factors and the methods to calculate emissions. Subsequently, the options and costs for the main fuel combustion sectors (power plants and district heating, transport, domestic sector) are discussed before some initial results are presented in Section 4.

3.2 Emission source categories

The United Nations Framework Convention on Climate Change (UNFCCC) distinguishes between the following sources of anthropogenic CO_2 emissions: biomass burning, international bunkers, fugitive emissions from fuels, fuel combustion (sector approach), industrial processes, solvent and other product use, agriculture, land-use change, forestry and waste (UNFCCC, 2004; http://ghg.unfccc.int).

In the UNFCCC inventory, the category "national total" does not include emissions from fuel sold to ships or aircrafts engaged in international transport (international bunker fuel emissions). Furthermore, in the case of CO_2, the "national total" does not include emissions from biomass burning or emissions or carbon removal from land-use changes and the forestry sector. Instead, emissions of CO_2 from biomass, burning, land-use change and forestry as well as international bunkers are reported separately.

Almost 95 percent of the national total CO_2 emissions reported by Annex I countries for 1990 (14,615 Mt CO_2) originated from fuel combustion. Industrial processes contributed less than five percent, fugitive emissions one percent and solvents, other product use and agricultural waste contributed around 0.15 percent. In the non-Annex I countries that have reported to the UNFCCC, total national emissions added to 1,560 Mt CO_2. In these countries, fossil fuel combustion was responsible for around 94 percent and industrial processes for the remaining six percent. Other source categories were negligible in 1990.

In 1990, an additional two percent of CO_2 emissions were related to international bunkers, and another three percent to biomass burning. Land-use and forestry changes resulted in a net decrease of emissions by roughly 13 percent in the Annex I countries. In the reporting non-Annex I countries, international bunkers add six percent and biomass burning another 16 percent to the total national emissions reported. Land-use change and forestry were five percent of the national total emissions of the Annex I countries for 1990.

3.3 Activity data

The GAINS model database includes activity data for historical years, i.e., 1990, 1995 and 2000, and five-year projections up to 2030. In fact, the model allows for several projections (activity pathways) that can be stored and used to assess alternative scenarios.

Historical data and projections of future activities like population, fuel consumption, number of animals, etc., were taken from the existing RAINS database, which has been compiled from United Nations, EUROSTAT and International Energy Agency (IEA) statistics. Projections of future activities have been extracted from the baseline scenario developed for the Clean Air For Europe (CAFE) program of the European Commission (Amann *et al*., 2004).

3.4 Emission factors

In the interest of a comprehensive economic assessment of the full range of options for the control of greenhouse gases, GAINS attempts to capture all anthropogenic sources of CO_2 emissions. In view of the relevance of the sources, the current version of GAINS (Version 1.0) focuses on fuel combustion, industrial processes and fugitive emissions.

As a result, the current GAINS assessment does not include CO_2 emissions from solvent use, other products, agricultural waste and fugitive emissions. While bunkers for national and international air transport are included in GAINS, international bunkers for shipping are not included at this stage. Additionally, the current analysis does not include emissions from biomass burning for non-energy purposes, land-use changes and forestry. Including these sources would provide an interesting extension of the approach in the future.

3.4.1 Energy use

Carbon dioxide emissions from fuel consumption depend primarily on the carbon content of the fuel. Data on the supply of commercial fuels, combined with typical carbon content figures, provide a sound starting point for the estimation of CO_2 inventories (Houghton *et al*., 1997b; p. 1.1).

The RAINS model uses energy balances on energy content basis (PJ) that can be combined with the reference values for carbon emission factors that have been compiled by the Intergovernmental Panel on Climate Change (IPCC). Since fuel qualities and emission factors may differ substantially between countries, IPCC recommends the use of local energy factors and emission factors when preparing national inventories. The GAINS model already includes information on country- and sector-specific heat values, but currently does not include information on country-specific carbon emission factors. For the time being, the reference approach is used to calculate the national CO_2 emissions from the energy use of fossil fuels.

Fossil fuels are also used for non-energy purposes (non-energy use of fuels) and some of these applications result in the storage of carbon, such as the production of ammonia from natural gas or asphalt from oil. Part of the carbon stored might oxidise quickly, for instance the carbon from fertiliser production, lubricants, detergents and volatile organic solvents (Houghton *et al*., 1997b; p. 1.25 to 1.28).

Table 3.1 provides the CO_2 emission factors that are presently used by GAINS.

3.4.2 Industrial processes

A range of (non-energy related) industrial activities leads to CO_2 emissions. These include production and handling of mineral products (cement production, limestone production, limestone use and soda-ash production), chemical industry (ammonia, carbides), metal production (iron, steel and ferroalloys, aluminium, magnesium and other metals) as well as other sources (Houghton *et al.*, 1997b; p. 2.3).

The IPCC emission inventory guidelines specify methodologies based on reference emission factors for cement production, lime production, limestone use, soda-ash production, ammonia production, calcium carbide production, iron and steel, ferroalloy and primary aluminium production. Table 3.1 summarises the emission factors from IPCC for energy and the most important non-energy sources by type of fuel as used in GAINS (Houghton *et al.*, 1997b).

3.4.3 Fugitive emissions from energy

Fugitive emissions from energy are releases of gases from human activities. In particular, these emissions may arise from the production, processing, transportation, storage and use of fuels. Although the most significant greenhouse gas here is methane, CO_2 emissions may result from burning of coal in coal deposits and waste piles (Houghton *et al*., 1997b; p. 1.112) and from sulphur dioxide scrubbing. National inventories sometimes include estimates of these fugitive emissions (www.unfccc.int). Reported total fugitive emissions in Europe amount to about

0.5 percent of the total CO_2 emissions. For the time being RAINS excludes this category, but future extension could include them in a simplified way by relying on the national estimates.

Table 3.1: Reference emission factors for carbon dioxide (CO_2) in GAINS.

RAINS fuel category	*Energy [kg CO_2/GJ]*	*Non-energy use of fuel [kg CO_2/GJ]*	*Industrial processes [kg CO_2/ton]*
Brown coal	99.5	25.8	
Hard coal	94.3	23.9	
Derived coal	100.0	25.5	
Other solids 1 (Biomass)	0.0	0.0	
Other solids 2 (Other waste)	55.0	0.0	
Heavy fuel oil	76.7	19.5	
Middle distillates	73.4	36.9	
Gasoline	68.6	18.0	
LPG	68.6	18.0	
Methanol	68.6	18.0	
Natural gas	55.8	37.8	
Cement production (ton cement)			500
Lime production (ton lime)			850

Source: Houghton *et al.*, 1997b

4 Emission control options and costs

4.1 Modelling structural changes in multiple sectors

While there are a limited number of options under development to capture carbon dioxide (CO_2) at its source, the most important potential for reducing CO_2 emissions results from lower consumption of carbon intensive fuels. Such reductions can be achieved through lower final demand for energy, through increased fuel conversion efficiency to satisfy a given final demand with less primary energy input, and through fuel substitution where carbon intensive fuels are replaced by fuels with less carbon content.

Compared to the 'add-on' emission control options that are typically included in the air pollution related parts of RAINS, modelling of structural changes requires a fundamentally different concept. Structural composition of energy consumption and the consumption volumes of individual fuels cannot any longer be considered as fixed exogenous inputs for the modelling exercise, but evolve as the central means for controlling the level of CO_2 emissions. Thus, the most important relationships that safeguard internal consistency (e.g., between demand and supply) and constraints that limit the application potentials to realistic rates need to be reflected in the modelling approach.

Traditionally, the options and potentials for modifications in energy systems are studied with specialised energy models. These type of models attempt to outline potential changes in energy systems based on empirically observed behavioural and economic principles while maintaining physical consistency in the energy and material flows. Although there are a wide variety of concepts, it is common to such specialised energy models that realism in their analysis evolves through the level of detail. Consequently, specialized energy models that assess concrete options for changes (e.g., in national energy systems) exhibit a good deal of complexity with significant technical and structural detail.

It is difficult to maintain the level of detail that is obviously required for any realistic quantitative assessment of the options for structural changes in national energy systems in one continental scale modelling exercise, as envisaged for the GAINS model. However, this challenge is not new in integrated assessment modelling. Similar situations apply to the modelling of atmospheric transport or to the simulation of environmental impacts, which are traditionally described with complex models that incorporate a great deal of detailed and site-specific data. In these cases, 'reduced-form' representations of the complex disciplinary models have been successfully developed for RAINS that describe, in terms of selected output indicators, the relevant response of the full system towards well-defined changes in input variables in a mathematically efficient form.

To model the potential of structural changes that can lead to reductions in CO_2 emissions, GAINS implements the most important relationships that safeguard physical consistency (e.g., to balance demand and supply for the individual fuels) and applies constraints to the substitution potentials that are derived from specialised energy models that capture the full detail of national energy systems. In such a way, the GAINS greenhouse gas model needs to be operated in conjunction with national energy models that provide for each country the substitution potentials under a range of assumptions. While national energy models will provide the baseline projection and the potentials for and costs of deviations from this baseline, the GAINS model will then balance such measures against controls of other air pollutants and greenhouse gases so that the environmental targets will be achieved in a (cost-) optimal way.

To ensure that the model system remains manageable, the options for structural changes that are considered should be restricted to the most relevant alternatives. Obviously, the choice of options to be considered depends on the sector. The following sections describe the measures in the power, transport, industry, and domestic (residential and commercial) sectors.

4.2 Power sector

4.2.1 Fuel substitution

Options for fuel substitution

As one of the major practical options for reducing CO_2 emissions from power generation, GAINS considers the substitution of carbon-intensive fuels by carbon-free fuels or fuels with less carbon content. Thus, in the present implementation (Version 1.0), GAINS provides for the possibility to replace hard coal, brown coal, fuel oil, and natural gas with:

- natural gas,
- nuclear energy,
- hydropower,
- biomass combustion,
- on-shore wind turbines,
- off-shore wind turbines,
- solar photovoltaic, and
- other forms of renewable energy such as geothermal, wave and solar thermal.

In GAINS each potential replacement option (i.e., from each original power generation mode to each low carbon mode) is modelled as an individual measure, with country-specific costs and country-specific application potentials. Furthermore, GAINS distinguishes between new-built capacities and existing plants, in order to reflect limitations in replacement potentials of existing infrastructure imposed by practical considerations, increased costs of retrofit measures and the shorter remaining lifetime of investments for already existing plants.

In principle, the same options as shown in Table 4.1 apply for existing and newly built power plants. The main difference is that for shifting from brown coal, hard coal or heavy fuel oil to natural gas, only the difference in fuel costs matters since it is assumed that (part of the) boilers can be fired with natural gas without additional investments in the boiler. For shifting from existing fossil fuel plants (e.g., brown coal, hard coal, heavy fuel oil) to (new) nuclear or renewable plants, sunk costs are considered.

Table 4.1: Options for fuel substitution considered in GAINS 1.0

->New fuel *Original fuel*	*Gas*	*Nuclear*	*Hydro-power*	*Biomass*	*Wind*	*Solar photo-voltaic*	*Other renewables*
Brown coal	x	x	x	x	x	x	x
Hard coal	x	x	x	x	x	x	x
Heavy fuel oil	x	x	x	x	x	x	x
Natural gas		x	x	x	x	x	x

Table 4.2: Average net electricity production efficiencies assumed for fuel substitution.

	Average net electricity production efficiency [%] (for existing plants ranges across countries are given in parentheses)
Brown coal	33 (29-35)
Hard coal	35 (29-35)
Heavy fuel oil	35
Gas	50 (39-50)
Nuclear	100
Hydropower	100
Biomass (wood)	33
Wind	100
Solar photovoltaic	100
Other renewables (wave, geothermal energy)	15

GAINS considers the differences in power generation efficiencies between these options listed in Table 4.1 and calculates the resulting implications on primary energy input to maintain the original volume of electricity output. For example, 1 PJ of hard coal can be burned in an existing hard coal fired power plant with a (net) efficiency of 35 percent, thus generating 1PJ*0.35 = 0.35 PJ of electricity. To generate the same amount of electricity using natural gas (assuming an efficiency of 50 percent) 0.35PJ/0.5 = 0.7 PJ of gas input is needed. Technology-specific average fuel efficiencies for the various technologies are derived from the literature (Table 4.2). For existing plants (numbers in brackets), country-specific data have been extracted from national energy statistics, so that they vary from country to country.

Potential for fuel substitution

With respect to fuel substitution, the GAINS analysis distinguishes cases where existing plants continue to operate with lower carbon fuels (natural gas, biomass) without major retrofit investments and fuel substitution options that require complete construction of new generating capacity (wind, solar, hydropower, etc.).

As discussed above, the GAINS model starts from an exogenously supplied baseline scenario of energy consumption. Such projections of energy use are supposedly internally consistent in terms of physical energy and material flow balances, and consistent with a wide range of assumptions. These include sectoral rates of economic growth, the evolution of the economic wealth of consumers, consumer preferences, the development of global energy prices, technological progress, import and export flows of energy, energy policy and carbon prices. However, any such projection is only one possible picture of the future development and alternative assumptions on relevant driving factors might lead to other developments.

Nevertheless, it is important to determine the physical, technical and economic limitations within which fuel substitution can take place, as they will serve as constraints to the calculations of the GAINS model. There are important physical limitations, in particular to the availability of fuels. While the availability of globally traded fuels (such as coal, oil and to some extent for natural gas) is usually not of prime relevance for possible deviations from medium-term national energy projections, the availability of renewable energy sources is a crucial aspect in national fuel substitution strategies. For this report, country-specific data on the potential supply of electricity in Europe from the major renewable energy sources in the power sector were compiled from several studies (see Table 4.3).

These estimates are based on a variety of studies and include results of the PRIMES model for the "with climate policies" scenario developed for the CAFE program (http://europa.eu.int/com/environment/air/cafe/activities/basescenario.htm). It is important to note that these estimates have been derived from scenario studies, where the resulting volumes of renewable energy have been considered as economically attractive under certain (climate) objectives, e.g., for a given carbon price and with assumptions on the prices of other energy forms and the pace of diffusion of the renewable technologies. The full technical potential for renewable energy might be larger, though only available at higher costs.

It is also important to mention that the estimates in Table 4.3 relate to different years (2010 and 2020), and were conducted at different points in time. The more recent estimates (e.g., for the PRIMES projections; Pettersson, 2004) generally find higher potentials than earlier studies such as CEC (1994), ESD (1997), and Hendriks *et al.* (2001). Further work with specialised energy models will be necessary to refine these estimates to clarify potential time-dependencies in the potentials of renewable energy and to determine their economic aspects. Subsequently, such features could then be included in future GAINS calculations.

Country-specific estimates are also available for the potential contribution of other renewables, in particular for solar photovoltaic, geothermal energy and solar thermal energy (ESD, 1997; Hendriks *et al.*, 2001; Petterson, 2004) as well as for tidal energy (especially tidal barriers). However, further analysis is needed to arrive at more robust estimates. From Table 4.3, it can be seen that the potential of these other renewable energy forms in Europe is relatively small compared to hydropower, biomass and wind, at least up to 2020. For comparison, Hendriks *et al.* (2001) estimate EU-15 potentials in 2010 of 7.3 PJ_{el} for solar photo-voltaic, 34 PJ_{el} for geothermal, 2 PJ_{el} for wave energy and 378 PJ_{el} for tidal energy.

Table 4.3: Estimates of the potential availability of hydropower, biomass, other renewables (i.e., geothermal), solar photovoltaic and wind energy for electricity production in Europe in 2020 [in $PJ_{electric}$, except biomass in PJ fuel input].

	Hydropower (Total)	*Hydropower small*	*Biomass*	*Other renewables*	*Solar photo-voltaic*	*Wind*
Albania	15		2			
Austria	171	24	30	5	0	19
Belarus			16			
Belgium	2	0	22	0	0	13
Bosnia-H.	13		1			
Bulgaria	15	2	27			4
Croatia	18		5	5		2
Cyprus			3			1
Czech Republic	15	3	18			10
Denmark	0	0	77	0	0	47
Estonia	0	0	6			1
Finland	48	3	33		0	11
France	261	10	52	7	0	89
Germany	95	28	184	0	1	315
Greece	20	2	10	1	0	16
Hungary	1	0	1	0		9
Ireland	3	0	9		0	11
Italy	161	15	128	172	1	71
Latvia	13	0	9			4
Lithuania	2		8			5
Luxembourg	0		1		0	1
Macedonia	2		2			
Malta			1			0
Moldavia	1		5			
Netherlands	0		60		0	27
Norway	518	10	2		0	27
Poland	19	5	27	10		47
Portugal	51	15	42	2	0	11
Romania	82	31	39			15
Russia_Kaliningrad			0			
Russia_Kola-Karelia	28		5			36
Russia_Remaining	117		262			869
Russia_StPetersburg	14		10			
Serbia-Montenegro	32					
Slovak Republic	20	4	11			7
Slovenia	20	2	7			1
Spain	162	51	254	19	0	124
Sweden	244	11	33		0	30
Switzerland	144	12	11	3		6
Turkey	271	27	31	6		20
Ukraine	44		86			12
United Kingdom	18	0	167	4	0	145
Total	1114	107	877	32	0	1250

Sources: CEC, 1994; ESD, 1994; Hendriks *et al.*, 2001; PRIMES, EUROSTAT, 2003; IEA, 2003b, Pettersson, 2004. For hydropower, 100 percent efficiency is assumed.

Additional assumptions need to be made on the potential for the expansion of natural gas and nuclear energy in the electricity sector. Since these potentials depend largely on national peculiarities (political preferences, structural features of the gas infrastructure, etc.), GAINS derives constraints for increased use of natural gas and nuclear energy from the specific scenarios developed with national energy models that address these questions on a solid basis. Thus, substitution potentials for these fuels have to be seen as a scenario-dependent input to GAINS, and no absolute limits are considered in the GAINS databases.

Costs of fuel substitution

For fuel substitution, costs are calculated in GAINS as the difference in electricity generation costs between baseline (with the original fuel) and the substitution case. For this purpose, electricity generation costs are first computed for both modes following the standard approach of the RAINS model. In a second step, substitution costs from fuel *a* to fuel *b* are computed as the difference between the costs of the two generation modes.

For each power generation option, the cost calculation includes investments, fixed and variable operating costs, as well as fuel costs. It is important to mention that air pollution control costs (e.g., flue gas desulphurisation, $DeNO_x$ equipment and dust filters) are not included in these costs since they are calculated separately in the GAINS/RAINS framework.

Investments (*I*) are annualised over the technical lifetime of the plant *t* by using the real interest rate *q* (as %/100) and expressed per kW electric capacity:

$$I^{an} = I * \frac{(1+q)^{lt} * q}{(1+q)^{lt} - 1} \qquad \text{Equation 4.1}$$

Investments include all costs accrued until the start-up of an installation (construction, engineering, land use, licensing fees, etc.). Fixed operating costs include costs that are related to the existing capacity but independent of its actual operation, such as routine maintenance, insurance, etc. Variable operating costs cover labour costs, fuel costs, and costs for other production means such as cooling water or waste disposal. For new generation capacities the technical lifetimes assumed are technology-specific and vary between 15 and 30 years.

Annual ***fixed expenditures*** OM^{fix} (per kW_{el}) cover the costs of repairs, maintenance and administrative overhead. These cost items are not related to the actual use of the plant. As a rough estimate for annual fixed expenditures, a (technology-specific) standard percentage *k* of the total investments is used:

$$OM^{fix} = I * k \qquad \text{Equation 4.2}$$

In turn, ***variable operating costs*** OM^{var} per kW_{el} are related to the actual operation of the plant and take into account fuel use (fuel input), efficiency and operating hours.

$$OM^{var} = c^{f} * (3.6/1000) * pf * 100/\eta^{e} \qquad \text{Equation 4.3}$$

where

c^f fuel price (cost per unit; €/GJ),

pf plant factor (annual operating hours at full load),

η^e electricity generation efficiency (%).

Total costs per kWh electricity produced can then be expressed as:

$$Ce = \frac{(I^{an} + OM^{fix})}{pf} + OM^{\mathrm{var}} \quad \text{Equation 4.4}$$

Alternatively, these costs can be expressed per PJ electricity produced by converting kWh into PJ_{el}. In this case, the additional costs of substituting a fossil-fuel fired (reference *r*) plant by an alternative fuel *a* related to one PJ of electricity produced are:

$$\Delta Ce_{ra} = Ce_a - Ce_r \quad \text{Equation 4.5}$$

The additional cost can then be expressed in PJ of input of the reference fuel (e.g., per PJ of hard coal) by multiplying the additional costs (per PJ_{el}) by the generation efficiency of the reference fuel:

$$\Delta Cf_{ra} = \Delta Ce_{ra} \; * \eta_r^{\;e} / 100 \quad \text{Equation 4.6}$$

Costs per ton CO_2 mitigated can be calculated by subtracting the emissions of the alternative fuel (per unit of reference fuel replaced) from the emissions (per PJ of the reference fuel) of the reference fuel:

$$\Delta E_{r \longrightarrow a} = \frac{\Delta Cf_{ra}}{(ef_r - ef_a * \eta_r^e / \eta_a^e)} \quad \text{Equation 4.7}$$

Country-specific costs of electricity generation are calculated based on technology-specific and fuel-specific combustion efficiencies, as well as country-specific capacity utilisation rates and fuel prices for each individual country. Relevant data are already contained in the RAINS databases (see http://www.iiasa.ac.at/web-apps/tap/RAINSWeb/MainPageEmco.htm). Default data for alternative means of electricity production are provided in Table 4.4, where fuel prices (net of VAT and fuel taxes) vary between countries. Statistics are reported on a regular basis by the International Energy Agency for its Member States (IEA, 2003a), and given by Kulik (2004) and Kononov (2002) for the Ukraine and Russia.

The values presented in Table 4.4 refer to data used by GAINS for calculations for the year 2020. They have been derived from reported national statistics for the year 2000 and adjusted by the temporal change of fuel prices given in the energy baseline between 2000 and 2020 (Mantzos *et al.*, 2003; Chapter 7). The price for brown coal (on an energy content basis) is assumed equal to the hard coal price in a country. Region- and country-specific fuel costs for biomass are taken from EUBIONET (2003) and Lindmark (2003). While prices have been relatively stable in the past, for scenario calculations changes in capacity utilisation rates and other fuel prices are used as an integral part of the energy projection.

Table 4.4: Default values for operating hours and fuel prices for electricity generation, used for GAINS calculations for the year 2020 if no national data are available. Country-specific ranges are given in brackets. Note that low values for fuel prices usually apply to non-EU countries (former FSU countries). Country-specific operating hours are given on the RAINS website.

	Capacity utilisation [hours/year]		*Fuel prices in 2020*
	Existing power plants	*New power plants*	*[€/GJ]*
Brown coal	4425	4990	1.3
Hard coal	4000	4500	1.3-2.0
Biomass	4300	4700	3.2-5.3
Heavy fuel oil	3460	3850	1.9-6.7
Natural gas	2500	4700	2.1-6.4
Nuclear	5500	5500	2.0[a]
Wind turbines	2500	2500	-
Hydropower	3500	3500	-
Solar photovoltaic	1080	1080	-

[a] Includes the costs of uranium, enrichment as well as fabrication costs (recalculated per GJ fuel input assuming 100% efficiency (IEA/NEA, 1998).

Technology-related cost data were collected for all options considered in the GAINS model. Data were taken from the databases of IIASA's MESSAGE model (Nakicenovic *et al.*, 2000; Riahi and Roehrl, 2000; Riahi *et al.*, 2003; Strubegger and Reitgruber, 1995) and from a variety of other sources (Coenen, 1985; Hendriks *et al.*, 2001; IEA/NEA, 1998, Jankowski, 1997; IER, 2001; Marsh *et al.*, 2002; European Commission, 2003). Table 4.5 lists the major cost items for new power generating capacities and provides average unit costs for electricity production as calculated with the default values for capacity utilisation contained in the RAINS model database and the energy prices listed in Table 4.4.

In the GAINS calculations, costs differ between countries due to differences in operating hours and fuel prices. Costs of fuel substitution are calculated as the differences between the production costs of the new reference unit and the alternative with lower carbon emissions. For wind energy, the most significant intermittent source of electricity, back-up costs are added to the production costs, assuming that back-up is provided by gas-fired power plants and that the unit back-up costs amount to one third of the unit cost in a gas-fired plant.

Table 4.5: Costs of new electricity generation options used for calculating costs of fuel substitution in GAINS.

	Investments [€/kW$_{el}$]	*Fixed operating and maintenance costs [€/kW$_{el}$] [%]*	*Typical unit costs [€cts/kWh]*
Brown coal	1010	34.3 (4.3)	4.2
Hard coal	970	26.2 (2.7)	3.8
Heavy fuel oil	708	47.5 (6.7)	6.8
Natural gas	673	45.7 (6.7)	4.4
Nuclear energy	2010	90.0 (4.5)	4.4
Hydropower	3000	48.5 (1.6)	6.3
Biomass (wood)	1455	75.6 (5.2)	7.6
Wind turbines, onshore	1000	25.0 (2.5)	4.2
Wind turbines, offshore	1750	30.0 (1.7)	6.2
Solar photovoltaic	4000	92.2 (2.3)	29.9
Other renewables (i.e. geothermal, wave)	1420-3500	86-140.0 (6.1-4.0)	3.8-7.3

4.2.2 Fuel efficiency improvements

Options for fuel efficiency improvements

Another important option for reducing CO_2 emissions is the improvement of fuel efficiency, which allows the production of the same amount of electricity with less fuel and hence less emissions.

In most cases, energy models assume fuel efficiencies (for new electricity generation technologies) to improve autonomously over time. For instance, a gas turbine built in 2030 would be more efficient than a gas turbine built in 2000 due to autonomous technological progress. Additionally, costs are often considered to decrease over time due to technical progress. Given the time horizon of GAINS up to 2030, GAINS considers beyond these autonomous technological improvements, combined heat and power generation (CHP) and (coal-based) integrated gasification combined cycle (IGCC) as two explicit options for efficiency improvements. However, GAINS does not embark on additional assumptions for further autonomous efficiency improvements of conventional plants, but follows the assumptions underlying the baseline energy projection.

Cogeneration (or CHP) is a highly efficient technique to jointly produce thermal energy (heat) and electricity. In 1999, approximately 11 percent of total electricity generation in the EU-15 was generated by means of co-generation (CEC, 2002). The potential for CHP depends critically on sufficient demand for heat close to the plant. Large combined cycle plants (100 to 250 MW_{el}) tend to be used in industries such as the chemical industry and the iron and steel industry. In the non-ferrous metals, pulp & paper and food industry, smaller combined cycles are commonly used (Hendriks *et al.*, 2001). The food industry also uses gas turbines. The commercial sector chiefly uses gas engines, and large combined cycles are common for district heating purposes for the residential sector.

Integrated Gasification Combined Cycle (IGCC) plants consist of a gasifier, gas clean-up system and sulphur recovery plant, gas turbine/generator, heat recovery steam generator, and steam turbine generator. IGCC plants can be fired with different coals or oil-derived feedstock such as heavy oil and tar, as well as with biomass and waste. IGCC power plants combine two mature technologies: gasifiers and combined cycles. Energy efficiencies of IGCC plants are higher than for conventional hard coal fired plants. In addition, SO_2 removal ranges from 90 to 99 percent. Nitrogen oxide emissions are generally 70 to 80 percent lower than those from traditional coal-fired power plants (Schönhart, 1999). Particle emissions are usually below the relevant emission limits for large combustion plants. However, as of today there is only limited experience in the commercial operation of integrated power plants (Rabitsch, 2000).

Potential for fuel efficiency improvements

Significant uncertainty surrounds the potential fuel savings and penetration of renewable energy. Therefore, the proposed Directive of the EU (CEC, 2002) contains an obligation for EU member states to analyse the potential for (highly efficient) co-generation facilities. Bearing this in mind, Hendriks *et al.* (2001) propose as a conservative estimate that CHP units might supply the future growth in industrial heat demand. In addition, existing steam boilers and steam turbines could be retrofitted by adding a separate gas turbine up-front. Existing steam boilers/steam turbines are assumed to produce 50 percent of industrial heat demand, of which around 80 percent might be suitable for CHP. However, an increased penetration of energy conservation measures might reduce the potential for CHP (Hendriks *et al.,* 2001). Thus, potential reductions in emissions depend on the type of CHP and its efficiency. The type of CHP is mainly industry- and not necessarily country-specific.

According to Hendriks *et al*. (2001), only new dwellings and commercial sites within the residential and commercial sector are realistic markets for CHP. On this basis, GAINS Version 1.0 assumes as rough estimates that in Northern Europe 50 percent of the heat demand for new dwellings might be supplied by CHP, in Central Europe 25 percent, and in Southern Europe 10 percent. Given these estimates on the total potential, the question arises to what extent a further penetration of CHP is assumed in the baseline energy projection. There is only little country-specific information available on this assumption for the baseline scenario. Previous analysis indicated that, depending on the marginal carbon costs, up to 10 percent of the CO_2 emission reductions achieved in the EU might originate from an increased use of CHP. To arrive at country-specific details further analysis with energy models is needed.

In principle, IGCC plants can be used to replace conventional new hard coal fired plants, although at extra costs. Estimates of the International Energy Agency suggest that in 2010 up six to eight percent of the total global coal-fired capacity could consist of IGCC plants.

Costs of fuel efficiency improvements

The literature provides a range of estimates for the costs of fuel efficiency improvements and different co-generation technologies (Coenen, 1985; Jankowski, 1997; Hendriks *et al*., 2001). Estimates of investments for (coal-fired) IGCC plants range around 1550 €/kW_{el} (Rabitsch, 2000). Annual operating and maintenance costs are estimated at 78 €/kW_{el}. The electric efficiency is assumed to be 46 percent. Given the fuel costs for a coal-fired plant, electricity generation costs are computed at approximately 5.5 €cts/kWh compared to around 4 €cts/kWh for a traditional single steam cycle coal-fired power plant. The SO_2 removal efficiency is typically 99 percent, and 80 percent of the NO_X emissions are removed.

Table 4.6: Costs and efficiencies of combined heat and power generation (CHP)

		Coal *CHP*	*Gas* *Combined cycle, large plants*	*Gas* *Combined cycle, district heating*	*Gas* *Combined cycle, small plants*	*Gas* *Gas turbine*	*Biomass*
Size	MW_{el}	41	100-250	100-250	25-100	10-50	
Investment	€/kW_{el}	1400	500	680	750	800	1400
O&M fixed	€/kW_{el}	22	9	7	14	14	50
O&M variable	€/kWh	0.001	0.004	0.004	0.004	0.004	0
Efficiency: - Electricity	(%)	30	44	48	42	40	40
- Heat	(%)	34	34	36	32	39	39
Lifetime	Years	15	15	15	15	15	15

4.2.3 Carbon capture

Options for carbon capture

Various possibilities have been identified to capture CO_2 from energy conversion processes. In principle, two basic options can be distinguished (Rabitsch, 2000; Hendriks *et al.*, 2002):

- Pre-combustion: fossil fuel is converted to a carbon rich stream;
- Post-combustion: carbon is removed from the flue gas.

Pre-combustion removal is applied within IGCC plants. In the post-combustion process, carbon is removed through absorption, adsorption or separation (membrane or cryogenic). While many methods are technically feasible, chemical or physical absorption seems to be most promising for natural gas and coal combustion.

Potential for carbon capture

Carbon dioxide can be stored in underground layers such as empty oil fields, empty natural gas fields and aquifers. Remaining oil fields can be exploited with enhanced oil recovery, and for unminable coal enhanced coal bed methane recovery can be applied (Hendriks *et al.*, 2002). Studies suggest a best estimate of the global cumulative storage potential of 1,660 Gt CO_2 (i.e., 80 times the current net annual CO_2 emissions). The uncertainty ranges from 500 to 6,000 Gt CO_2 (see Hendriks *et al.*, 2002). Riahi *et al*. (2004) propose that, with present assumptions on costs and on economic growth, between 90 and 243 Gt C might be sequestered over the period 1990-2100. This would represent 10 to 25 percent of global carbon emissions.

Since technologies for carbon capture and storage are still under development, time is a critical factor in estimating the practical application potential. The majority of the recent literature on carbon capture and storage concludes that the vast majority of the potential will occur only in the second half of the century (Riahi *et al.*, 2005). For the next 20 years, the potential is mainly seen for demonstration purposes and in some niche markets. Furthermore, because current power plants are not yet ready for the gasification technology, limited potential is seen for carbon prices below 25 \$/t CO_2.

Even less solid information is available on national or regional potentials for carbon storage. Hendriks *et al*. (2002) quote a storage potential of around 75 Gt CO_2 for Western Europe, 12 Gt CO_2 for Eastern Europe, and 350 Gt CO_2 for the former Soviet Union. Assuming storage for 100 years, these estimates imply an annual potential for Western and Eastern Europe of 770 Mt CO_2 (i.e., between 15 and 20 percent of the European emissions in 1990). More recent estimates suggest country-specific potentials for niche markets (e.g., refineries), but provide only rough estimates for carbon storage from power plants (Wildenborg *et al*., 2005).

Pending results of more detailed national studies and given the necessary lead time for establishing the infrastructure, it is assumed in GAINS Version 1.0 that by 2020 carbon capture will not be applied to a significant extent for power plants in Europe. It is, however, implicitly assumed in the cost and emission calculations for hydrogen vehicles that carbon capture will be applied in refineries for hydrogen production for transport purposes.

Table 4.7: Calculation of carbon dioxide (CO_2) emissions from hard coal and natural gas in new power plants in GAINS before carbon capture.

GAINS sectors	PP_new_HC	Power plants new, hard coal	
	PP_new_Gas	Power plants new, gas	
Activity rate	Fuel use		
Unit	PJ		
Data sources	RAINS databases		
Emission factors		Unit	Default
	Hard coal	kt CO_2/PJ	94.3
	Natural gas	kt CO_2/PJ	55.8
Data sources	Fuel use: country-specific, based on the RAINS database. Emission factors: default values from IPCC (Houghton *et al.*, 1997a).		

Costs of carbon capture

Costs of carbon capture consist of the costs of carbon separation, compression, transport and storage. In post-combustion processes, CO_2 is separated from the flue gases using amine-based solvents (the best-known process). The heat required for this process causes a loss of electric efficiency between 10 and 25 percent.

To efficiently transport CO_2 by pipeline, it needs to be compressed, so that transportation costs depend on the transport distance and the flow size. Storage costs are a function of the depth of storage and the type of storage. Compression costs range typically from 5 to 10 €/t CO_2 (Hendriks *et al.*, 2002; p. 14). The literature estimates of transportation and storage costs range from 6 to around 8.5 €/t CO_2 for Western Europe and from 2.5 to 15 €/t CO_2 depending on the volume stored (Hendriks *et al*., 2002; p 59; Riahi *et al*., 2004). For GAINS, costs for compression, transportation and storage are assumed at 14 €/t CO_2 (Table 4.8).

Table 4.8. Cost of power generation with carbon dioxide (CO_2) removal for new plants in GAINS 1.0.

	Investments *[€/kW$_{el}$]*	*Fixed O&M* *[€/kW$_{el}$/yr]*	*Variable O&M costs: C transport and storage* *[€/t CO_2 captured]*	*Net electricity generation efficiency* *[%]*	*Carbon removal efficiency* *[%]*	*Unit costs* *[€cts/kWh]*
Hard coal plants with carbon capture	1788	130	14	26	85	9.8
Natural gas plants with carbon capture	1000	63	14	44	85	6.2

Data sources: Hendriks *et al.* (2002), Riahi *et al.* (2003, 2004).

The calculation of the annual costs of carbon capture (per kW_{el}) follows the standard methodology, with the exception that costs of carbon transport and storage are included in the variable O&M costs:

$$OM^{\mathrm{var}} = \left(c^t \times \left(ef_{\mathrm{CO_2}} \times \eta^r / 100\right) + c^f\right) \times \left(3.6/1000\right) \times pf \times 100 / \eta^e \qquad \text{Equation 4.8}$$

where

- c^f fuel price (cost per unit; €/GJ),
- c^t costs of carbon dioxide transport and storage fuel price (costs per unit; €/tCO_2 captured),
- ef_{CO2} unabated CO_2 emission factor (kt CO_2/PJ),
- pf plant factor (annual operating hours at full load),
- η^e electricity generation efficiency (%), and
- η^r CO_2 removal efficiency (%).

4.3 Transport

A variety of options exist to control the rapidly growing CO_2 emissions from the transport sector. This can be achieved through non-technical measures such as lowering transport demand, structural changes including a shift to other transport modes, and various technical measures. These include improvements in fuel efficiency and the use of alternative fuels that lead to lower CO_2 emissions (i.e., diesel, compressed natural gas, ethanol or hydrogen). GAINS distinguishes between fuel efficiency improvements and alternative fuels.

4.3.1 Fuel efficiency improvements

Options for fuel efficiency improvements

A variety of technical means are available to improve fuel efficiency, and it is beyond the scope of the GAINS integrated assessment to model all the available options in detail. Instead, GAINS groups available measures into a limited number of technology packages and compares their cost-effectiveness and environmental efficiency with those of potential measures in other sectors.

For ***passenger cars and light duty vehicles using gasoline***, GAINS distinguishes two technology packages that lead to more fuel-efficient cars.

The *improved gasoline car* combines a number of different measures described by Bates *et al.* (2001; p. 56) that reduce fuel consumption by approximately 25 percent compared to the year 2000 vehicles with conventional, gasoline based internal combustion engines. Such improvements can be achieved through basic engineering measures (e.g., reducing engine friction, reducing aerodynamic drag plus brake drag, and application of high strength steel bodies with lightweight interior), as well as through modified engine designs using variable valve lifting or advanced gasoline direct injection engines.

A second, more efficient option, the *advanced gasoline car*, would combine the same engineering measures with a hybrid internal combustion engine instead of a gasoline direct injection engine. This would increase fuel efficiency improvements to a range between 35 percent (Marsh *et al.*, 2002) and 44 percent (Bates *et al.*, 2001; p. 56). In GAINS Version 1.0, a 40 percent improvement is assumed compared to the average year 2000 vehicle.

Similar packages have been assumed for ***passenger cars and light duty vehicles using diesel***.

An *improved diesel car* would incorporate a variety of basic engineering measures, lightweight interior and lightweight body structure. These are estimated to reduce fuel consumption by about 15 percent compared to the reference 2000 models (Bates *et al.*, 2001; Marsh *et al.*, 2002). Fuel efficiency improvements of approximately 40 percent are considered feasible for *advanced diesel cars*, essentially hybrid electric vehicles with compression ignition direct injection engines (Bates *et al.*, 2001; Ogden *et al.*, 2004).

For ***heavy-duty vehicles*** (trucks, buses), which are currently using diesel engines, the following two options for fuel efficiency improvements are included in GAINS.

The literature discusses a variety of measures that could lead to *improved diesel heavy-duty vehicles.* Reduction of rolling resistance, aerodynamics cab roofs and aerodynamic cab deflectors, as well as various engine improvements are estimated to reduce fuel consumption by around 15 percent compared to vehicles of conventional design (Bates *et al.*, 2001). Since approximately half of the trucks had already implemented deflectors or cab roof fairing in 2000 (Bates *et al.*, 2001; p. 65), the improvements relative to the actual year 2000 model year would be somewhat lower. Marsh *et al.* (2002) list a set of technical measures that yield reductions of seven percent for trucks and around 14 percent for buses. Using typical European ratios between the number of trucks and buses, the average improvement for the entire category emerges at eight percent. This number is taken as a conservative estimate for the calculations in GAINS Version 1.0.

For *advanced heavy-duty vehicles*, fuel efficiency improvements of 35 percent have been suggested by Marsh *et al.* (2002) based on hybrid electric traction.

Potential for fuel efficiency improvements

The introduction of more fuel-efficient vehicles is essentially limited by the availability of appropriate technology and the turnover rate of the existing fleets. It is assumed that the options outlined in the previous section will be on the market by the year 2010 and can then be applied to all new vehicles as they gradually replace the existing vehicle stock. No premature scrapping of existing vehicles is assumed in the present analysis.

Costs of fuel efficiency improvements

GAINS calculates the costs of all emission control options considering investments, operating costs and fuel costs. Thus, costs of fuel efficiency improvements consider increased investments of such options, modified O&M costs and savings from reduced fuel consumption. The following paragraphs review the information on investments and operating costs for the various packages of fuel efficiency improvements.

For ***passenger cars*** and ***light duty vehicles using gasoline***, Bates *et al.* (2001) mention additional investments of 1,250 €/car for applying the measures assumed for the *improved gasoline car*. Cost estimates for hybrid cars (the *advanced gasoline car*) are provided by Bates *et al.* (2001), Concawe/EUcars/JRC (2003a), Marsh *et al.* (2002) and SAIC (2002), ranging from an additional 5,500 €/car to nearly 7,700 €/car (all prices given in 2000 prices). Marsh *et al.* (2002; p. E-10) expect these costs to come down to around 2,700 €/car in the year 2020 if volume production starts. Following these arguments, GAINS assumes the lower estimate of 2,711 €/car to be more representative for the time horizon of this study (2015-2020).

Cost data for ***passenger cars*** and ***light duty vehicles using diesel*** are provided by Bates *et al.* (2001), mentioning 1,086 €/car for the measures listed under the *improved diesel car* option that reduce fuel consumption by 16.4 percent. Marsh *et al.* (2002) expect year 2020 costs that drop to 362 €/car. GAINS Version 1.0 assumes the average of these estimates for its calculations. For the *advanced diesel car,* which essentially involves hybrid engines, estimates range from 7,228 €/car (Bates *et al.*, 2001) for the present situation to 2,800 €/car for mass production in 2020 (Ogden, 2004). For the GAINS Version 1.0 calculations addressing 2015 to 2020, the latter estimate is used.

There are a number of cost estimates for ***heavy-duty vehicles*** available. Typical measures that would achieve the fuel savings of the *improved heavy-duty vehicle* amount to 1,341 €/vehicle (Bates *et al.*, 2001), which leads with current fuel prices (even excluding fuel taxes) to net cost savings. The existence of such cost savings would suggest these measures to be included already in a cost-minimized baseline projection. Since available information on the baseline scenario does not indicate such a development, GAINS 1.0 takes a more conservative assumption of 2,700 €/vehicle as proposed by Marsh *et al.* (2002) for the year 2020. For hybrid vehicles, which form part of the *advanced heavy-duty vehicle* category in GAINS, Marsh *et al.* (2002) suggest additional investments to decline from 25,620 €/vehicle in 2000 down to 6,000 €/vehicle for trucks and to 8,300 €/vehicle for buses in the year 2020. In order to not be overly optimistic, GAINS 1.0 assumes for heavy-duty trucks in 2020 additional investments of 20,400 €/vehicle.

The available evidence does not indicate significant differences in fixed annual operating and maintenance costs between the reference and the more fuel-efficient cars (Marsh *et al.*, 2002; Bates *et al.*, 2001; Concawe/EUcars/JRC, 2003b).

4.3.2 Fuel substitution

Options for fuel substitution

Carbon dioxide emissions from transport can also be reduced by substituting gasoline and diesel with fuels that cause lower carbon emissions. For the time frame (up to 2030) of this study, the most relevant options include the use of bio-diesel, the replacement of gasoline engines with diesel engines, and the use of compressed natural gas, ethanol and hydrogen fuel cells. For a comprehensive assessment it is crucial to consider such fuel substitutions from a systems perspective, i.e., to consider emissions from well to wheel of each option and not only emissions released from the vehicle. It is also important to consider side impacts on the emissions of other pollutants, such as nitrogen oxides (NO_x), volatile organic compounds (VOC) and fine particles (PM), which are of major concern for regional and local air quality.

Conventional diesel

Due to the higher energy efficiency of conventional diesel engines compared to gasoline engines, the replacement of gasoline driven cars with diesel cars will result in lower CO_2 emissions for the same mileage and comparable engine sizes. Nonetheless, the share of diesel engines at this stage is expected to increase rapidly in the baseline and further increases are not expected to be possible based on potential constraints of diesel availability at the European scale.

Bio-diesel

Diesel can be replaced by bio-diesel at no additional investments at the vehicle. Taking into account the carbon emissions that occur during feedstock production and transportation of diesel and bio-diesel, the net reduction in CO_2 emissions is estimated at around 65 percent (CEC, 2001; IEA, 1999). This gives an emission factor of 25.7 kg CO_2/GJ if 100 percent of the diesel used by a car would be replaced by bio-diesel. In general, the literature assumes no differences in O&M costs for the different fuels.

Ethanol

For a consistent evaluation, emissions from ethanol production need to be included at some stage in the calculation. This can be done by either explicitly modelling ethanol production or by applying a modified emission factor to all consumed ethanol (the tank-to-wheel factor). The type of feedstock is crucial for the overall efficiency of ethanol.

Hendriks *et al*. (2001; p. B20) conclude that, in comparison to gasoline vehicles, avoided life cycle emissions are between 42 and 70 kg CO_2/GJ ethanol (or 61 to 100 percent of the tail-pipe emission) depending on the feedstock used (sugar beet or wheat). IEA (1999) quotes reductions in well-to-wheel emissions between 45 and 90 percent depending on the feedstock (cellulose or sugar starch). Concawe/EUcars/JRC (2003b) finds well-to-wheel carbon emissions of ethanol similar to those of gasoline if ethanol is used as blended fuel. If used as neat fuel, well-to-wheel emission could be 30 to 80 percent lower, depending on the feedstock and technology used to produce ethanol. Although tank-to-wheel emissions are comparable to gasoline, well-to-tank emissions are significantly lower for pure ethanol.

Including emissions from ethanol production in the emission factor and assuming for ethanol the average well-to-wheel emission factor 55 percent below that of gasoline, the adjusted life cycle emission factor of ethanol used by GAINS is 50 percent lower than the emission factor for the gasoline reference car.

Compressed natural gas

Compressed Natural Gas (CNG) vehicles have been used in Europe and other parts of the world for many years. Their further expansion is constrained by the additional costs for the vehicle and the limited refuelling infrastructure (Concawe/EUcars/JRC, 2003a). Hence, so far CNG vehicles could only penetrate niche markets. However, the capacity of the current infrastructure for distribution and refuelling is believed to be sufficient to allow market penetrations of up to 10 percent. An increased use of natural gas in the transport sector would necessitate further imports of natural gas from Siberia, south-west Asia or the Middles East (as LNG – Liquified Natural Gas), which would cause additional energy demand and GHG emissions for the transport of the gas.

It is unclear to what extent vehicles fuelled by CNG consume more or less fuel than their gasoline counterparts. Some sources suggest reductions of 18 percent (Marsh *et al.*, 2002), whereas others indicate increases of up to 20 percent (PRIMES). The Concawe/EUCars/JRC study (2003a; p. 30) suggests no major differences in fuel consumption (three percent more for CNG cars). GAINS assumes no difference in fuel consumption. Due to the lower carbon content of natural gas, the shift to CNG results in lower CO_2 emissions per vehicle kilometre.

Hydrogen

While hydrogen powered cars have no tailpipe emissions of carbon, the source of hydrogen has crucial influence on the overall life cycle emissions of fuel cells. If hydrogen is produced from solar or hydropower, life cycle carbon emissions are close to zero. If natural gas is used as feedstock to produce hydrogen (and if carbon is captured and sequestered during the hydrogen production) carbon emissions are around 10 kg CO_2/GJ hydrogen produced (Ogden *et al.*, 2004). These emissions are comparable to the emissions from gasoline production (6.1-12 kg CO_2/GJ, IEA, 1999; p. 42), which are accounted for in the GAINS model in the refinery sector.

For consistency, emissions from hydrogen production need to be included at some stage in the calculation, either explicitly through modelling hydrogen production or by applying a modified emission factor to all consumed hydrogen. As a conservative assumption that remains valid even for large-scale hydrogen production, GAINS 1.0 assumes that all hydrogen will be produced from natural gas and that the carbon from the production process will be captured and sequestered. Thus, GAINS 1.0 uses an emission factor of 10 kg CO_2/GJ hydrogen produced based on Ogden *et al.* (2004) and includes the carbon sequestration costs in the fuel costs of hydrogen (Table 4.8). However, for the distance-related emission factor, GAINS takes into account the lower fuel consumption of fuel cells.

Table 4.9: Carbon dioxide (CO_2) emission factors for fuel substitution options in GAINS [in grams CO_2/km].

	Passenger cars and light duty trucks, gasoline	*Passenger cars and light duty trucks, diesel*	*Heavy duty vehicles, diesel*
Reference 2000 car	196	240	655
Diesel	199	240	-
Bio-diesel		84	233
Ethanol	96		
Compressed natural gas	159		555
Hydrogen fuel cell	15		

Potentials for fuel substitution

Conventional diesel

The replacement of gasoline driven cars by cars with diesel engines is limited by the natural turnover rate of gasoline cars. Since no premature scrapping is currently assumed in GAINS, vehicle turnover will eventually be constrained by the availability of diesel fuel in Europe. Consultations with the European oil industry in the course of the Clean Air for Europe (CAFE) programme of the European Commission indicated that a continued trend in the shift from gasoline to diesel demand for passenger cars in Europe could meet supply limits. There is a physical limit to the fraction of diesel that can be produced from a crude oil barrel during the refinery process without major new investments. Furthermore, the projected growth in diesel demand from heavy-duty vehicles would leave little space for a major increase in the number of diesel light duty vehicles.

Bio-diesel and ethanol

The potentials for bio-diesel and ethanol are mainly determined by supply constraints. An earlier estimate of the potential production of bio-diesel and methanol for the European countries was provided in Klaassen *et al.* (2004). These estimates were based on productivity data of agricultural land for bio-diesel and methanol production as presented in the TERES-II study for the five largest EU countries (Hendriks *et al.*, 2001; p. B19) and combined with country-specific data on arable land as contained in the RAINS database.

These estimates assume that all countries set aside the same share of arable land for bio-diesel and methanol production as the five largest EU countries, and that the productivity (in terms of tons bio-fuel/hectare) would be the same. According to these estimates, which do not incorporate regional differences in climatic factors, ethanol from European production could substitute up to six percent of the gasoline consumption of the year 2000. The bio-diesel supply would amount to four percent of total diesel consumption in 2000. For comparison, the European Commission proposed a share of bio-fuels in total gasoline and diesel consumption of 5.75 percent in 2010 (CEC, 2001). The same document contains an optimistic scenario where the share of bio-fuels in total transport energy demand increases to seven percent in 2015 and eight percent in 2020.

Alternatively, a common market for bio-diesel and ethanol with free imports and exports across Europe could be assumed. In that case, around eight percent of diesel consumption in 2020 could be covered by bio-diesel and nine percent of the gasoline could be replaced by ethanol. On top of this, ethanol could be imported from outside Europe (e.g., from Brazil).

Compressed natural gas

While, in principle, the resource availability of natural gas as a transport fuel should not be a limiting factor, the extension of the necessary distribution infrastructure might restrict a rapid conversion to CNG as a fuel for automotive vehicles. The European Commission and recent studies (CEC, 2001; Concawe/EUcars/JRC, 2003a) indicated the feasibility of CNG reaching a market share of 10 percent of total transport fuel consumption. This estimate is taken for the present version of the GAINS model as an upper limit.

Hydrogen

Constraints for the availability of hydrogen used are based on the report of the EU High-level Group for Hydrogen and Fuel Cells (EC, 2003a). This report suggests a market share for the EU-15 at two percent of the passenger car fleet that could be fuelled by zero-carbon hydrogen in 2020. This number could increase to 15 percent in 2030 and 32 percent in 2040. The market shares of the other alternative fuels as they are presently used for the GAINS calculations are listed in Table 4.10.

Table 4.10: Maximum market penetration of alternative fuels assumed for the GAINS calculations (for Europe as a whole).

	2010	*2015*	*2020*
Bio-diesel (% of total diesel demand in transport)	6 %	8 %	8 %
Ethanol (% of gasoline in light duty vehicles)	6 %	8 %	10 %
Natural gas (% of fuel demand for light duty vehicles)	2 %	5 %	10 %
Hydrogen (% of passenger car fleet)	0 %	1 %	2 %

Costs of fuel substitution

Costs of fuel substitution in the transport sector consist of additional investments and operating costs. These apply to engine modifications and differences in fuel costs between the conventional and alternative fuels, which are determined by the differences in fuel prices and fuel efficiencies.

Investments

Diesel

Diesel engines are more expensive than gasoline engines. For GAINS, the costs of shifting from gasoline to diesel are derived as the average of literature estimates provided in Bates *et al.* (2001), De Klerk *et al.* (1998) Concawe/EUcars/JRC (2003a) and Marsh *et al.* (2002).

Bio-diesel

Diesel can be replaced by bio-diesel without additional investments for the vehicle. There is no indication for increased operating and maintenance costs provided by the literature.

Ethanol

Gasoline vehicles can operate with an ethanol/gasoline mixture of up to 20 percent ethanol without additional investments (Bates *et al.*, 2001; Greene and Schaefer, 2003; Van Thuyl *et al.*, 2003). Operating costs are taken from De Klerk *et al.* (1998), which are lower than the estimates of Marsh *et al.* (2002), but higher than the values given in Bates *et al.* (2001). No additional O&M costs have been reported in the literature compared to the gasoline car.

Compressed natural gas

Investments for a passenger car fuelled by compressed natural gas are reported to be around 15 percent higher than for the reference gasoline car (Bates *et al.*, 2001; de Klerk *et al.*, 1998). Cost estimates for heavy duty vehicles reveal a wide span, ranging from a 30 percent increase (Bates *et al.*, 2001) to a one percent decrease estimated for 2020 (Marsh *et al.*, 2002). GAINS relies on the estimate provided by Bates *et al.* (2001).

Hydrogen

A large range of cost estimates is provided in the literature for hydrogen fuelled cars. Costs depend on the technology and fuel chosen (i.e., methanol with on-board reforming to hydrogen, hydrogen produced from natural gas or gasoline with on-board production of hydrogen). Estimates of additional investments in comparison to a conventional gasoline car range from around 2,200 €/car to around 10,000 €/car (Jung, 1999; Padro and Putsche, 1999; Bates *et al.*, 2001; Marsh *et al.*, 2002; Concawe/EUcars/JRC, 2003a; Ogden *et al.*, 2004), depending on the technology (current, advanced, improved) and when it will be employed.

For mass production, average investments are estimated at around 2,600 €/car (Jung, 1999; Marsh *et al.*, 2002; Ogden *et al.*, 2004). Concawe/EUcars/JRC (2003a; p. 36) estimates investments (retail price) for the hydrogen fuel cell in 2010 to be 9,583 € higher than for a conventional gasoline car. GAINS uses 4,500 €/car as the costs for 2015/2020, assuming some progress in reducing costs while mass production will not yet have fully started by that date. Obviously, these cost estimates bear large uncertainties, especially in relation to the speed at which the technology will gain a sufficiently high market share.

For heavy duty vehicles, the literature also provides a wide range of cost estimates. Marsh *et al.* (2002) list for the year 2000 a 70 percent difference in investments, which is not expected to disappear until 2020. Bates *et al.* (2001) suggest investments to be 37 percent higher than for conventional heavy-duty trucks. In absence of more specific information, GAINS Version 1.0 adopts the average of these estimates for its calculations.

Fuel prices

Gasoline, diesel

The GAINS model contains databases with scenario- and country-specific prices (free of taxes) for gasoline, gas and diesel (Table 4.11). These data are used to determine price differences whenever appropriate. For the year 2020, these prices were adjusted by the price index of the baseline energy scenario suggesting an increase of around five percent in real terms (Mantzos *et al.*, 2003; Chapter 7). For the calculations in GAINS 1.0 the median prices for all countries of 10.6 €/GJ for gasoline and 8.7 €/GJ for diesel are used.

Bio-diesel

Production costs of bio-diesel are estimated at around 15 €/GJ (Hendriks *et al.*, 2001; Van Thuijl *et al.*, 2003).

Ethanol

Cost estimates for the production of ethanol range from 5 €/GJ to 21 €/GJ (Hendriks *et al.*, 2001; Van Thuyl *et al.*, 2003). These estimates depend on the feedstock used (sugar starch, wheat or lignocellulose), the volume of production and the year of implementation. For modest production increases, an average price of 13.7 €/GJ seems plausible.

Compressed natural gas

No estimates of the costs of compressed natural gas were found in the literature, so that the gas prices for the transport sector as contained in the RAINS database have been used.

Hydrogen

Ybema *et al.* (1995) estimated the costs of producing hydrogen at around 10 €/GJ. Adding 65 percent transportation costs (IEA, 1999), the price at the pump (excluding taxes) should be around 16 €/GJ. Padro and Putsche (1999) provide a range of estimates for hydrogen prices at the pump. Depending on the number of cars per day and the technology (liquid hydrogen or compressed natural gas), costs range from 11.3 to 28.7 $/GJ. For large stations with a sufficiently large number of cars per day, average costs are around 15 €/GJ. Ogden *et al.* (2004) estimate a pump price of 15.3 $/GJ for steam reforming using natural gas and of 17 $/GJ if CO_2 is captured and sequestered. GAINS adopts a price of 17 €/GJ (including carbon capture costs) that is consistent with the assumption made for the emission coefficient for CO_2.

Table 4.11: Fuel prices excluding taxes for the year 2020 (future prices are scenario specific).

Fuel	*FUEL Price [€/GJ]*
Gasoline	10.6 (Country-specific 7.5-19.7)
Diesel	8.7 (Country-specific (6.5-17.9)
Bio-diesel	14.9
Compressed natural gas	6.5 (Country-specific 6.1-13.7)
Ethanol	13.7
Hydrogen	17

Cost calculation for efficiency improvements and fuel substitution

Investments

The cost evaluation for mobile sources follows the same basic approach as for stationary sources. The most important difference is that investments are given per vehicle, not per unit of production capacity. The number of vehicles is computed in GAINS Version 1.0 from the total annual fuel consumption for a given vehicle category and average fuel consumption per vehicle per year.

The following description uses the indices *i, j,* and *t* to indicate the nature of the parameters:

i	denotes the country,
s	the transport (sub)sector/vehicle category,
f	the fuel type,
t	the control technology

The costs of applying control devices to the transport sources include:

- additional investments,
- increase in maintenance costs expressed as a percentage of total investments, and
- change in fuel cost resulting from the inclusion of emission control.

Additional investments $I_{i,s,f,t}$ are given in €/vehicle and are available separately for each technology and vehicle category. They are annualised using the equation:

$$I_{i,s,f,t}^{an} = I_{i,s,f,t} \times \frac{(1+q)^{lt_{i,s,f,t}} \times q}{(1+q)^{lt_{i,s,f,t}} - 1} \qquad \text{Equation 4.9}$$

where:

$lt_{i,s,f,t}$	lifetime of control equipment.

Operating costs

The increase in maintenance costs (fixed costs) is expressed as a percentage *k* of total investments:

$$OM_{i,s,f,t}^{fix} = I_{i,s,f,t} * k_t \qquad \text{Equation 4.10}$$

The change in fuel cost can be caused by change in fuel type (in case of fuel substitution) or through changes in fuel consumption (when moving to a more fuel efficient car) or both combined. It is calculated as follows:

$$OM_{i,s,f(a)}^{\mathrm{var},e} = fuel_{i,s,f(a)} \times c_{i,s,f(a)} - fuel_{i,s,f(r)} \times c_{i,s,f(r)} \qquad \text{Equation 4.11}$$

where:

$fuel_{i,j,r}(t)$	fuel consumption of the reference car at time *t*,
$fuel_{i,j,a}(t)$	fuel consumption of the alternative car at time *t*,
$c^f_{i,j,r}(t)$	fuel price of the reference fuel used by the reference car (net of taxes) in country *i* and sector *j* in year *t*,
$c^f_{i,j,a}(t)$	fuel price of the alternative fuel used by the alternative car (net of taxes) in country *i* and sector *j* in year *t*.

The annual fuel consumption per vehicle is a function of the consumption in the base year

(t_0=1990), of the (autonomous) fuel efficiency improvement, and the change in activity per vehicle (i.e., change in annual kilometres driven) relative to the base year:

$$fuel_{i,s,f}(y) = fuel_{i,s,f}(y_0) * fe_{i,s,f}(y) * \Delta ac_{i,s,f}(y) \qquad \text{Equation 4.12}$$

where

$fe_{i.s.f}(y)$	fuel efficiency improvement in time step y relative to the base year,
$\Delta ac_{i,s,f}(y)$	change in activity per vehicle in time step y relative to the base year.

Unit reduction costs

The unit costs of abatement ce_{PJ} (per car) add up to:

$$ce_{PJ,i,s,f,t}(y) = I^{an}_{i,s,f,t} + OM^{fix}_{i,s,f,t} + OM^{var,e}_{i,s,f}(y) \qquad \text{Equation 4.13}$$

These costs can be related to the emission reductions achieved (i.e., the difference in CO_2 emissions of the reference car and the alternative vehicle). The costs per unit of CO_2 abated are:

$$cn_{i,s,f(a),t}(y) = \frac{ce_{PJ,i,s,f(a),t}(y)}{ef_{i,s,f(r)} \times fuel_{i,s,f(r)} - ef_{i,s,f(a)} \times fuel_{i,s,f(a)}} \qquad \text{Equation 4.14}$$

The most important factors leading to differences among countries in unit abatement costs are the annual energy consumption per vehicle and fuel prices.

4.3.3 Summary of control options

Table 4.12 to Table 4.14 summarise the CO_2 control options in GAINS Version 1.0 for gasoline passenger cars, diesel passenger cars and diesel heavy-duty vehicles, respectively.

Table 4.12: Carbon dioxide (CO_2) emission control options in GAINS for passenger and light-duty vehicles using gasoline.

	Additional investment [€/car]	*Fuel consumption[1)]*		*CO_2 emission factor*	
		[l/100km]	*Change (%)*	*[kg CO_2/GJ]*	*[g/km]*
Reference gasoline car 2000	0	8.0	0	68.6	192
Efficiency improvements:					
Improved gasoline car	1250	6.0	-25	68.6	144
Advanced gasoline/hybrid car	2711	4.8	-40	68.6	115
Fuel substitution:					
Conventional diesel	1340	6.8	-15	73.4	188
Bio-diesel[2)]	-	-	-	-	-
Ethanol (100%)	0	8.0	0	34.3	96
Compressed natural gas	1800	8.0	0	56.1	159
Hydrogen fuel cell	4500	4.4	-55	10.0	15

Notes:

1) Fuel consumption is given in gasoline equivalents and refers to the year 2000.

2) Because of limited supply potential of bio-diesel, GAINS models only its replacement for conventional diesel and not for gasoline cars. In the same vein, the current version of GAINS does not incorporate a further shift from gasoline to diesel engines beyond that what is envisaged in the baseline.

Table 4.13: Carbon dioxide (CO_2) emission control options in GAINS for passenger and light-duty vehicles (passenger cars) using diesel.

	Additional investment [€/car]	*Fuel consumption[1)]*		*CO_2 emission factor*	
		[l/100km]	*Change*	*[kg CO_2/GJ]*	*[g/km]*
Reference diesel car 2000	0	8.7	0	73.4	240
Efficiency improvements:					
Improved diesel car	725	7.5	-15%	73.4	207
Advanced diesel/hybrid car	2800	5.3	-40%	73.4	146
Fuel substitution:					
Bio-diesel (100%)	0	8.7	0	25.7	84

Note: 1) Fuel consumption refers to the year 2000

Table 4.14: Carbon dioxide (CO_2) emission control options in GAINS for heavy-duty vehicles (HDV) using diesel.

	Additional investments [€/car]	*Fuel consumption[1)] [l/100km]*	*Change[3)]*	*CO_2 emission factor [kg CO_2/GJ]*	*[g/km]*
Reference HDV 2000	0	24.1	0	73.4	665
Efficiency improvements:					
Improved HDV	2717	22.2	-8 %	73.4	610
Advanced HDV	20400	15.6	-35 %	73.4	430
Fuel substitution:					
Bio-diesel (100%)	0	24.1	0	25.7	233
Compressed natural gas	11630	27.0	+12 %	54.7	555
Hydrogen fuel cell	37877	17.5	-28 %	10.0	66

Note: 1) Fuel consumption refers to the year 2000.

4.4 Industry

A variety of options exist to control the CO_2 emissions in the industrial sector. GAINS distinguishes fuel efficiency improvements and electricity efficiency improvements on the end-use side. In addition, a number of fuels shift options are considered, while Version 1.0 of the model has not yet implemented co-generation.

4.4.1 Fuel efficiency improvements

Options for fuel efficiency improvements

A large number of energy saving options in industry have been identified by de Beer *et al.* (2001). In principle, GAINS applies the methodology developed by de Beer *et al.* (2001) and consists of the following six steps:

1. Determine the fuel savings per unit of production of the fuel saving option (in GJ/ton product or as percent of the fuel consumed), assuming that the option would not have been implemented at all otherwise.
2. Determine the maximum technical potential application of the technology (%).
3. Determine the current (1990/2000) level of application of the fuel saving option (%).
4. Combine Step 2 and 3 to determine the additional technical application in any future year (%).
5. Determine the levels of production (e.g., steel production) in the future to which the option applies. Alternatively, determine the level of fuel consumption in 2020 (e.g., for the category miscellaneous fuel savings in other chemical industry) to which the option applies (percent reduction in fuel consumption).
6. Determine the CO_2 reduction for the average fuel mix and the associated emission coefficients for that sector and country.

In summary, the potential annual fuel savings per option equal the (maximum potential 2020 minus current implementation) * fuel savings/unit production * production levels in 2020.

Costs per unit of fuel saved (e.g., PJ) consist of annualized investments plus annual operating and maintenance (O&M) costs. Investments are annualized using a lifetime of 15 years and an interest rate of four percent. Costs savings depend on the (average) fuel type saved and the country- specific fuel prices. For industry, these (tax-free) fuel prices are based on data reported by the IEA for 2000 and have been adjusted by the expected price increase assumed in the baseline scenario for the year 2020 (Mantzos *et al*., 2003). If, with a private discount rate of 12 percent, net costs of the option are negative, GAINS Version 1.0 assumes that the option is already implemented in the baseline projection and that no further potential is available.

Iron & steel industry

GAINS distinguishes five options for fuel savings in the iron & steel production (Table 4.15).

Table 4.15: Fuel savings options in the iron and steel industry in GAINS.

		Investments [€/GJ]	*O&M costs [€/GJ]*
1	Inject coal & waste in blast furnace	11	0
5	Recovery of low temperature heat	93	0
9	Thin slab casting	48	-0.1
10A	Miscellaneous I (low costs)	15	0
10	Miscellaneous II (high costs)	50	0

The first option is the *injection of pulverized coal and plastics waste* in blast furnaces replacing pulverized coal. The maximum injection rate is 30 percent. Current (1990) injection rates vary between zero (Ireland) and 30 percent (the Netherlands) (De Beer *et al.*, 2001; p. 9). Where no data is available, GAINS assumes a current injection rate of five percent. The maximum technical penetration is 75 percent. For an increase of the injection rate from zero to 30 percent, fuel savings are 0.5 GJ/ton of crude steel produced. This implies that countries with an injection rate of 10 percent have savings at 2/3 of the 0.5 GJ (((30%-10%)/30%)*0.5 GJ/ton). As an initial estimate, crude steel production (i.e., pig iron production) levels for 2020 are based on data from the RAINS model for the year 2000, and possible increases in steel production between 1990 and 2020 are ignored. Investments are estimated at 11 €/GJ saved, with fuel cost savings of 1 €/GJ saved (because coal injected is cheaper than coking coal).

The second option (*low temperature heat recovery*) represents various efficient recovery measures of low-temperature heat (coke dry quenching, heat recovery from stove waste gas and blast furnace gas). Total fuel savings are estimated at 0.75 GJ/ton crude steel (De Beer *et al.*, 2001; p. 11). For calculating the fuel costs savings, the current EU-average fuel mix in the iron & steel industry (i.e., 57 percent solid fuels, four percent liquid and 39 percent gaseous fuels) and the country-specific industrial fuel prices for 2020 are used. The maximum potential is assumed at 50 percent, at which investments are set at 93 €/GJ saved.

As a the third option, GAINS considers the *application of thin slab casting*, which requires less energy to reheat the slabs before rolling than continuous casting (De Beer *et al.*, 2001, p. 15). Per ton of steel, 1.5 GJ of fuel and 0.15 GJ electricity is saved[1]. This gives total fuel savings of 1.95 GJ/ton steel. Fuel costs savings are based on the average fuel mix in the sector. The maximum penetration is assumed at seven percent in 2020. Investments are estimated at 48 €/GJ saved, and savings of O&M costs of 0.1 €/GJ saved.

Finally, two groups of measures for fuel conservation are considered in GAINS, one with investments of 15 €/GJ saved per 1 GJ/ton crude steel (*Miscellaneous I*), and a more expensive one (*Miscellaneous II*) with investments of 50 €/GJ saved (De Beer *et al.*, 2001; p. 15/16). With the assumptions on fuel costs, cost savings of the cheap miscellaneous options are higher (for all countries) than the additional investments, even for on a private discount rate of 12 percent. Therefore, it is assumed in GAINS Version 1.0 that the option "Miscellaneous I" is already incorporated in the baseline.

Chemical industry

For the chemical industry, many different fuel saving options are distinguished in GAINS (see Table 4.17). The calculation of costs savings applies the country-specific industrial fuel mix and country- specific industrial fuel prices for 2020 (see Table 4.16). These prices (tax-free) are based on IEA data for the year 2000 and adjusted by the price index of the baseline scenario for the year 2020 (Mantzos *et al.*, 2003; Chapter 7). Biomass prices are based on EUBIONET (2003), and cost data and fuel efficiency improvements are based on De Beer *et al.*, 2001 (pages 20-28) unless otherwise mentioned.

Table 4.16: Fuel prices in industry (excluding taxes) in the year 2020 assumed for the baseline scenario in GAINS 1.0.

Fuel	*Price [€/GJ]*
Heavy fuel oil	Country-specific (3.4-5.1)
Natural gas	Country-specific (4.1-6.6)
Hard coal	Country-specific (1.3-2.0)
Brown coal	1.3
Derived coal	1.7
Other solids (biomass)	Country-specific (3.2-5.3)

The first option (*process integration*) includes improved integration of heat exchangers, cogeneration of heat and power, and other process adaptations. Fuel savings are estimated at 3.5 GJ/ton ammonia produced and the potential application is 100 percent. National data on ammonia production (for the year 2000) are derived from the United Nations (UN) statistics (UN, 2003). Since fertilizer production in Europe is generally not expected to increase, constant production levels are assumed for 2020. Investments are set at 10 €/GJ saved.

[1] Recalculated into a fuel saving, assuming an electric efficiency of 33 percent (i.e., 0.15*3=0.45 GJ fuel).

Table 4.17: Options for fuel saving in the chemical industry in GAINS 1.0

		Investments [€/GJ]	*O&M costs [€/GJ]*
16	Process integration fertilizer industry	10	0
17	Advanced reformer fertilizer industry	65	0
18	Efficient CO_2 removal fertilizer industry	15	0
19	Low pressure NH_3 synthesis (fertilizer industry)	25	1
20	Miscellaneous petrochemical industry	10	0
21	Process integration petrochemical industry	20	0
22	Gas turbine integration petrochemical industry	16	0
23	Debottlenecking petrochemical industry	10	0
24	Cracking furnace petrochemical industry	40	0
25	Fractionation in petrochemical industry	25	0
27A	Miscellaneous I other chemical industry	25	0.1
27B	Miscellaneous II other chemical industry	50	0.2

The second option is the *advanced steam reforming* of the primary reformer in the ammonia plant. The potential application is 100 percent, and fuel savings are estimated at 4 GJ/ton ammonia produced; investments are 65 €/GJ saved. The third option is the removal of CO_2 from the synthesis gas stream using *scrubbing with solvents*. The potential application is 100 percent, fuel savings are estimated at 1 GJ/ton ammonia produced and investments are estimated at 15 €/GJ saved. A fourth option is *low pressure ammonia synthesis* that reduces the requirement for compression power, but decreases the production. The overall reduction in energy demand is estimated at an average 0.25 GJ/ton ammonia produced (with a range from 0 to 5 GJ/ton). The potential application is 100 percent, investments are 25 €/GJ saved and O&M cost increase by 1 €/GJ saved.

In the petrochemical industry, a number of fuel-saving measures are conceivable. Computer controls, reduced flaring, energy accounting and the use of chemical to limit coking can reduce energy by seven to 10 percent per ton of ethylene produced, although other sources suggest a saving of only one percent (see comments from experts in De Beer *et al.*, 2001; p. 24). GAINS Version 1.0 assumes that five percent of the average fuel consumption (SEC: specific energy consumption) of 17 GJ/ton ethylene produced can be saved with such “Miscellaneous I” measures. National ethylene production is derived on UN statistics (UN, 2003; UN, 2000). The potential application is 100 percent and investments are set at 10 €/GJ saved.

Process integration in the petrochemical industry can reduce energy consumption by approximately five percent (1.5 GJ/ton ethylene). The potential application is 100 percent and investments are set at 10 €/GJ saved. Similarly, *integration of the gas turbine* in the conventional cracker can replace combustion air from the furnace burners by the off-gases of the gas turbine. Fuel savings are estimated at 1.8 to 3.3 GJ/ton ethylene. GAINS assumes 2.5 GJ/ton ethylene in view of comments from experts cited by De Beer *et al.* (2001; p. 24). The maximum penetration is assumed at five percent. Additional investments are 40 €/ton ethylene or 16 €/GJ saved (given that 2.5 GJ is saved per ton ethylene).

Debottlenecking is expected to reduce fuel consumption by 0 to 1.5 GJ/ton ethylene (De Beer *et al.* and comments cited therein). GAINS assumes 0.75 GJ/ton ethylene, with a 100 percent application potential. Investments are set at 10 €/GJ. The *cracking furnace’ yield* can be improved by using radiant coils, ceramics and high-pressure combustion. This is expected to save 1.3 GJ/ton ethylene. The potential application is assumed at 100 percent and investments are set at 40 €/GJ. Finally, fuel consumption in the petrochemical industry can be reduced by *improved fractionation*, e.g., better distillation controls, replacement of ethylene refrigerant by a multi-component refrigerant, optimization of the distillation sequence, use of advanced recovery systems and the use of heat pumps. The potential applicability is set at 100 percent and total savings are estimated at 1.5 GJ/ton ethylene requiring investments of 25 €/GJ saved.

Finally, a range of other measures can be applied to reduce energy use in other sectors of the chemical industry. "*Miscellaneous I*" reflect cheap measures, which save on average five percent of fuel use in the other chemical industry (not petrochemicals and not ammonia production). "*Miscellaneous II*" measures save 10 percent of the fuel use. Investments are assumed at 25 €/GJ saved for Miscellaneous I and 50 €/GJ saved for Miscellaneous II measures. O&M costs increase with 0.1 €/GJ saved for Miscellaneous I and 0.2 €/GJ saved for Miscellaneous II. Fuel use statistics of the chemical industry is extracted from the baseline energy projection for 2020. For the other European countries, data are estimated from IEA statistics assuming a (constant) country-specific share of the fuel consumption of the chemical industry in total final energy consumption. Fuel use for the other chemical sector is calculated by subtracting the fuel use for ammonia and ethylene production from the total fuel use in the chemical industry.

Even with a private discount rate of 12 percent, fuel cost savings would exceed the annualized investments for all options except for "Advanced reformers in fertilizer industry" (option 17), "Cracking furnaces in the petrochemical industry" (option 24) and "Miscellaneous II in other chemical industry" (option 27B). Thus, there is some uncertainty about the extent at which the other measures (with negative costs) are already assumed to be implemented in the baseline scenario.

Glass, pottery and buildings sector

GAINS distinguishes several options for fuels in the glass, pottery and buildings sector (see Table 4.18). In addition, GAINS distinguishes four other options for the cement industry.

For cement industry, the first option is the *use of waste* (such as car tyres, municipal waste and plastic, paper, textiles and meat and bone meal) to replace fossil fuels (Damtoft, 2003). In 2000, the average use of waste material in the cement industry in the EU was 12.5 percent (De Beer *et al.*, 2001) and 25 percent in Germany (Damtoft, 2003). GAINS assumes that all countries could increase the percentage up to 30 percent. Data on fuel consumption per unit of cement (2.95 MJ/kg cement) and cement production per country are taken from the RAINS databases. Furthermore, it is assumed that solid waste (GAINS category OS2) can substitute fossil fuels for average investments of 1 €/GJ fossil fuel replaced (De Beer *et al.*, 2001; p. 32.).

Table 4.18: Options for fuel savings in the glass, pottery and buildings sector in GAINS

		Investments [€/GJ]	*O&M costs [€/GJ]*
28	Use of waste instead of fossil fuel in cement industry	1	0
29	Reduce clinker content of cement in cement industry	0	0
32	Apply multi-stage preheaters & pre-calciners in cement industry	46	-2.5
33	Optimize heat recovery clinker cooling in cement industry	2	0
36	Improved melting & furnace design in glass industry (non-metallic minerals)	25	0
37	Raise cullet percentage in raw materials in glass industry	0	2.6
38	Batch & cullet preheating in glass industry (non-metallic minerals)	18	0
40	Miscellaneous measures in other glass, pottery & buildings industry	15	0
41	Miscellaneous measures in other glass, pottery & buildings industry	15	0

As a second option, GAINS considers the *reduction of the clinker content* in cement since clinker production is the most energy-intensive process in cement production. Lowering the clinker to cement ratio reduces energy and process related CO_2 emissions. Present country-specific clinker to cement ratios (ranging from 66 to 94 percent) are derived from De Beer *et al.* (2001; p. 32) for the EU-15 countries. A ratio of 80 percent is assumed for all other countries. The clinker to cement ratio can be reduced to 75 percent. Per percentage point decrease in the clinker to cement ratio, 0.96 kg CO_2 is saved per ton cement produced[2]. Depending on the present ratio, the reduction potential is therefore country-specific.

For example, in Belgium the clinker-cement ratio is currently already 66 percent so that no further reduction is foreseen in GAINS Version 1.0, while Spain has a clinker cement ratio of 78, for which it is assumed that it can be reduced to 75 percent. Note that the emissions reduced are both fossil fuel- and process-related and it is not possible to separate them. Additional costs for shipping are expected to be compensated by the avoided costs for clinker production, so that no net additional costs occur.

A third option is the *application of multi-stage pre-heaters and pre-calciners* for existing pre-heater kilns. This consists of adding a pre-calciner and, to the extent possible, an extra cyclone. Average energy use can be reduced by 1.4 GJ/ton clinker produced. Investments are 46 €/GJ saved, while operation and maintenance costs decrease by 2.5 €/GJ saved. Application is limited to new plants, for which the ECOFYS consultancy group assumes a potential of five percent in 2010. GAINS Version 1.0 assumes 10 percent for 2020.

A further option in the cement industry is the *optimisation of heat recovery* and efficiency improvements in clinker cooling. Average potential savings are estimated at 0.1 GJ/ton clinker produced (with a range from 0.04 to 0.15). The maximum application potential is 50 percent since the current application is 50 percent, where investments are 2 €/GJ saved.

[2] This number is derived by dividing the CO_2 emission reduction (1 million ton CO_2 in 2010) in ECOFYS by the cement production in 2010 (RAINS) taking the average decrease in the EU clinker/cement ratio of five percentage points between 2010 and 2020.

Of the four options, only the optimisation of heat recovery (option 32) has clearly positive costs with a private discount rate of 12 percent. Hence, only this option is not assumed to be part of the baseline. For the decrease in the clinker to cement ratio (option 29), this is not clear since the net costs are zero. Although the clinker to cement to ratio is being reduced in practice (Madridejos, 2003), the calculation in GAINS Version 1.0 assumes that this option will be still available for implementation beyond the baseline.

For the glass industry, three options are considered in GAINS. *Improved melting and furnace design* in regenerative furnaces can be achieved through multi-pass regenerators, fusion cast corrugated cruciforms, insulation of regenerator structure, and waste heat boilers. For regenerative furnaces energy savings of eight percent of fuel input is possible, if fuel demand is 8 GJ/ton glass produced. Glass production data for 2020 are taken from the RAINS database. The potential application is limited to regenerative furnaces, which represent 75 percent of the fuel use in the glass industry. Investments are estimated at 25 €/GJ saved.

A second option in the glass industry is to *raise the percentage of cullet (recycled glass) in the raw materials* used. For each 10 percent cullet substitution, a 2.5 percent reduction in fuel consumption is assumed. The percentage of cullet used is country-specific (for EU countries based on data from the PRIMES model) ranging from 32 to 80 percent in 2020, while currently 32 percent is assumed for countries with no data (this percentage can be increased to 80 percent). Thus, the percentage of the fuel use that can be saved is country-specific and ranges from 0 to 12 percent depending on the baseline cullet percentage. The UK competition commission (UKCC) estimates costs of glass recycling at maximally 8.3 £/ton glass recycled, where the minimum price received per ton glass would be 5 £/ton. This gives (in the worst case) net glass recycling costs of 3.3 £/ton or 5.4 €/ton glass recycled[3], or additional costs of 2.6 €/GJ saved. GAINS uses this conservative estimate, given what with this assumption on fuel prices fuel cost savings exceed these costs[4].

A third option in the glass industry is *batch and cullet preheating* using waste heat. Energy savings are estimated at 0.8 GJ/ton glass, although electricity demand increases by 0.02 GJ/ton (or 0.04 GJ fuel equivalents assuming 50 percent efficiency of electricity generation on the spot). Net fuel savings are estimated at 0.76 GJ/ton. Preheating can be done if the percentage of cullet is at least 50 to 60 percent. Using country-specific information on the cullet percentage in the baseline scenario, one can estimate the fraction of furnaces using at least 50 percent cullet (which ranges from 54 to 100 percent). Investments are 18 €/GJ saved.

With these assumptions on costs, all these measures in the glass industry have private costs lower than the expected fuel savings. Therefore, all these options are assumed to be part of the baseline in GAINS Version 1.0.

For the remaining glass, pottery and buildings sector, two options are conceivable. In the ceramic goods sector, *miscellaneous measures* can save 30 percent of the fuel used at investments of 15 €/GJ saved. Fuel use of the ceramics sector is estimated at 35 percent of the

[3] In the best case net revenues are 19 €/ton recycled.

[4] Only if recycling costs (UKCEC, 2001) consist of investments, net recycling costs are higher using a private discount rate. In this case gross costs per GJ saved might amount to 6.6 €/GJ saved.

total fuel use of the construction, building and materials sector (CBM). PRIMES fuel consumption data have been used on the for the CBM sector for the EU-30 countries, while for the other countries the share of the CBM sector in total fuel consumption of industry for the year 2000 (IEA, 2002; IEA, 2002b) is assumed constant over time.

Finally, a range of measures can be applied to the other products in the CBM sector (other than cement, glass, and ceramics productions). Fuel savings add up to 30 percent and the associated investments are 15 €/GJ. Also these measures result in negative costs with the assumptions made on investments and fuel prices, even if a private discount rate of 12 percent is applied.

In summary, positive net costs are only calculated for multi-stage pre-heaters and the reduction in the clinker to cement ratio, so that for GAINS 1.0 only these measures are considered to be available for application beyond the baseline projection.

Pulp and paper industry

Five major measures for fuel savings can be identified for the paper and pulp industry (see Table 4.19). The first measure consists of *heat recovery during thermo-mechanical pulp production*. Heat can be recouped as steam in an evaporator boiler system. This is expected to save 4.4 GJ/ton pulp (with a range from 3.2 to 5.5). Electricity demand increases by 0.5 GJ/ton or 1.0 GJ fuel per ton pulp produced under the assumption of a 50 percent efficiency in electricity generation. Net fuel savings are 3.4 GJ/ton pulp. Production levels of pulp for 2020 are available in the RAINS database. The share of mechanical pulp production is based on FAO data for the year 2000 (FAO, 2004). The maximum potential application is 80 percent. In 1990, already 50 percent of pulp production in the EU has applied this measure, except in Finland, where all pulp is produced on this basis. Investments are estimated at 4.4 €/GJ saved and O&M costs will increase by 4.1 €/GJ saved (all data based on De Beer *et al*., 2001; p. 42).

Table 4.19: Options for fuel savings in the pulp & paper industry

		Investments [€/GJ]	*O&M costs [€/GJ]*
43	Heat recovery thermo-mechanical pulping	4.4	4.1
45	Pressing to higher consistency paper	25	0
48	Reduced air requirements	35	1
49A	Miscellaneous I fuel savings in paper & pulp	25	0
49B	Miscellaneous II fuel savings in paper & pulp	50	0

A second option is the *pressing of paper to a higher consistency* by using an extended nip press. This can reduce heat demand by approximately 0.5 GJ/ton paper produced. Electricity demand increases by 0.05 GJ/ton, so that net savings with an assumed 50 percent efficiency of electricity generation amount to 0.4 GJ/ton paper produced. Paper and board production levels are based on FAO (2004) and assumed to increase at the same rate as pulp production in the RAINS database. The maximum penetration is assumed at 95 percent, with investments savings of 25 €/GJ.

As a third option, energy can be saved through *reduced air requirements*. For example, by controlling the humidity in paper machine drying so that the amount of ventilation air is reduced. This may reduce heat demand by 0.3 GJ/ton paper. The potential application is 100 percent. Investments are 35 €/GJ saved and O&M costs increase by 1 €/GJ saved.

Finally, two sets of miscellaneous measures are considered for paper and pulp mills. Low costs (“*Miscellaneous I*”) measures, such as more efficient steam distribution, and energy management can save in the paper mills 0.5 GJ of heat per ton paper produced. Associated investments are 25 €/GJ saved. High costs (“*Miscellaneous II*”) measures such as waste heat recovery are expected to save 0.2 GJ/heat per ton paper produced. Investments of the latter group are assumed at 50 €/GJ saved.

With the assumptions on costs and fuel prices as described above, only heat recovery in thermo-mechanical pulping (option 43), reduced air requirements (option 48) and “Miscellaneous II fuel savings in paper & pulp” (option 49B) emerge with positive life cycle costs. Since it is assumed in GAINS Version 1.0 that all options with negative costs will already be implemented in the baseline projection, only these three measures emerge as additional potential for reducing CO_2 emissions.

Food, tobacco, beverages and other industries

Five energy conservation options are distinguished for the food, beverages, tobacco and other industries (see Table 4.20). The first option relates to more *efficient evaporation of dairy products*. This is relevant for products that involve significant amounts of energy for production, such as milk powder, whey powder and concentrated products. The share of total fuel consumption of the food, beverages and tobacco (FBT) industry used for concentration and drying of dairy products is estimated for 1990 at 10 percent for the EU as a whole (De Beer *et al*., 2001; p. 46). Fuel consumption of the total FBT sector was 623.5 PJ. Hence fuel consumption for concentration and drying is estimated at 62.35 PJ.

Since production of dry products in the EU-15 was 3.65 million ton (FAO, 2004), fuel use per ton can be estimated at around 17 MJ/ton product. A six-stage evaporator with thermo-compressors instead of a two-stage evaporator can reduce the steam demand from 0.3-0.5 kg per kg water evaporated to 0.2-0.4 kg. This equals 0.6 MJ steam per kg water evaporated. Electricity consumption increases by 0.006 MJ/kg water. The net effect on fuel use (assuming electricity is generated in-house with 50 percent efficiency) is a decrease of 0.59 MJ per kg water evaporated. Mechanical vapour recompression can bring steam demand down to 0.03 kg/kg water evaporated. Electricity demand increases by 50 MJ/ton water evaporated. Similarly, the net effect is 0.64 MJ fuel/kg water evaporated.

The complete cycle from evaporating and drying in drying towers uses 5.5 MJ/kg water evaporated, so that efficiency improvements amount to approximately 11 percent. Production statistics of dry products and concentrates (dry whey, dry whole cow milk and dry whole skim milk) are extracted from FAO (2004). The potential application of this option is estimated at 100 percent, where investments are 55 €/GJ saved.

Table 4.20: Energy conservation options in food, beverage and tobacco industries and other industries in GAINS

		Investments [€/GJ]	*O&M costs [€/GJ]*
50	Efficient evaporation dairy products	55	0
53	Miscellaneous sugar industry	40	0
53A	Miscellaneous I Fuel savings (non-dairy food sector)	20	0
53B	Miscellaneous II Fuel savings (non-dairy food sector)	50	0
54A	Miscellaneous I Fuel savings (textile and others)	10	0
54B	Miscellaneous II Fuel savings (textile and others)	30	0

Measures can be taken in the sugar industry to improve the energy efficiency of evaporation and pulp drying. Overall, potential savings are estimated at 4 GJ/ton sugar produced (De Beer *et al*., 2001; p. 48). Sugar production data are taken from FAO (2004) and are assumed constant over time. The potential application of this option is 100 percent, where investments are 55 €/GJ saved.

Third, cheap ("*Miscellaneous I*") and more expensive ("*Miscellaneous II*") measures can be implemented in other industries belonging to the food, beverages and tobacco sector. It is assumed that with cheap measures, 10 percent fuel can be saved at investments of 10 €/GJ saved. More expensive measures can reduce energy consumption by 15 percent at investments of 50 €/GJ saved. Fuel use data of this sector (FBT) are derived from the energy baseline projections for 30 countries and from the IEA database (IEA, 2004) for the other countries (assuming a constant share for the non EU-30 countries for this sector in total industrial fuel consumption over time). Fuel use of the other FBT sectors has been calculated as the residual of total FBT fuel use minus fuel use for sugar and dairy products.

Finally, two sets of measures are distinguished for other industries (engineering & other metals, as well as textile, leather and clothing). Low cost measures ("*Miscellaneous I*") are assumed to reduce energy demand by 15 percent at investments of 10 €/GJ saved, and a high cost group ("*Miscellaneous II*") by another 15 percent at costs of 30 €/GJ saved. Fuel use data for this sector have been derived from the baseline energy scenario. For the other countries, data are based on the shares given in IEA (2004) for these industries (textile, wood products, construction, industry other not specified) in total industrial fuel consumption in 2000 and the RAINS fuel use forecasts for other countries.

GAINS Version 1.0 assumes that options 50, 53, 53B will not be included in the baseline since private costs exceed private fuel saving revenues. Option 54 B is still applicable in 11 out of the 42 RAINS regions.

Refineries

Hendriks *et al.* (2001; p. 26) discuss several options for energy efficiency improvements in petroleum refineries bearing in mind the complexity and the usually unique character of each refinery (see Table 4.21). *Reflux overhead vapour recompression* can increase energy efficiency of the crude distillation process. As a result, a higher fraction of the heat energy is recovered. Savings are 0.15 GJ/ton crude oil or approximately five percent of the specific fuel consumption (SEC) for the EU-average crude oil intake. The GAINS calculations apply country-specific

SEC, based on Hendriks *et al*. (2001). Crude oil production levels for 2020 are taken from the RAINS database. The potential application is assumed at 100 percent.

Power recovery can be achieved with power recovery turbines that recuperate the energy of pressurized gas that would otherwise get lost if the pressure needs to be reduced after the cracking operation. Fuel savings are estimated at 0.01- 0.05 GJ/ton crude oil (or 0.9 percent of the SEC) depending on the type of cracker (hydro- or fluid catalytic), where investments are estimated at 12 €/GJ saved. *Improved catalysts* can increase the efficiency of catalytic conversion, e.g., of crackers and catalytic reformers. Savings are estimated at 0.1-0.5 GJ/ton, where the lower value is used as a conservative estimate in GAINS. O&M costs are 5 €/GJ. Finally, a range of *miscellaneous other measures* are possible, resulting in energy savings from 0.15 and 0.175 GJ per ton crude oil with investments between 15 and 50 €/GJ.

Table 4.21: Fuel efficiency options for refineries

		Investments [€/GJ]	*O&M costs [€/GJ]*
55	Reflux overhead vapour recompression	1	0
56	Power recovery	12	0
57	Improved catalyst	0	5
58	Miscellaneous I (low cost measures)	15	0
59	Miscellaneous II (high cost measures)	50	0

Summary

With the assumed fuel prices and with a private discount rate of 12 percent per year, costs for 18 out of the 42 options exceed the associated fuel cost savings. Thus, it is assumed that only these 18 options are not yet included in the baseline projection (options 1, 5, 9, 10A, 17, 24, 27B, 29, 32, 43, 48, 49B, 50, 53, 53B, 54B, 57 and 59). Table 4.22 summarizes the carbon emissions avoided per sector and country of the above range of measures.

Table 4.22: Potential for further reductions of carbon dioxide (CO_2) emissions through fuel savings in industry beyond measures assumed to be taken in the GAINS Version 1.0 baseline in 2020 [Mt CO_2].

	Iron & steel	*Chemical*	*Cement, glass & other*	*Paper & Pulp*	*Food & Other*	*Refineries*	*Total*
Albania	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Austria	0.7	0.0	0.0	0.2	0.2	0.2	1.4
Belarus	0.0	0.5	0.0	0.0	0.7	0.4	1.6
Belgium	0.9	0.2	0.0	0.1	1.7	0.4	3.3
Bosnia-H.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bulgaria	0.1	0.3	0.0	0.0	0.1	0.1	0.6
Croatia	0.0	0.0	0.0	0.0	0.1	0.1	0.2
Cyprus	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Czech Republic	0.5	0.2	0.0	0.1	0.4	0.1	1.3
Denmark	0.0	0.0	0.0	0.0	0.3	0.1	0.4
Estonia	0.0	0.1	0.0	0.0	0.1	0.0	0.2
Finland	0.4	0.0	0.0	0.5	0.2	0.1	1.2
France	2.2	1.1	0.2	0.5	2.4	1.2	7.6
Germany	4.4	1.9	0.4	0.9	2.3	1.5	11.3
Greece	0.0	0.1	0.2	0.0	0.5	0.3	1.0
Hungary	0.2	0.2	0.0	0.0	0.2	0.1	0.7
Ireland	0.0	0.2	0.1	0.0	0.2	0.0	0.5
Italy	1.6	0.4	0.2	0.3	1.5	0.8	4.6
Latvia	0.0	0.0	0.0	0.0	0.1	0.0	0.1
Lithuania	0.0	0.2	0.0	0.0	0.1	0.1	0.4
Luxembourg	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Macedonia	0.0	0.0	0.0	0.0	0.1	0.0	0.1
Malta	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moldavia	0.0	0.0	0.0	0.0	0.7	0.0	0.7
Netherlands	0.6	1.4	0.0	0.0	0.9	1.0	4.0
Norway	0.0	0.1	0.0	0.2	0.0	0.2	0.5
Poland	0.7	0.7	0.1	0.2	2.8	0.4	5.1
Portugal	0.1	0.2	0.2	0.3	0.2	0.2	1.1
Romania	0.2	0.4	0.1	0.0	0.2	0.5	1.5
Russia_Kaliningrad	0.0	0.0	0.0	0.0	0.1	0.0	0.1
Russia_Kola-Karelia	0.0	0.0	0.0	0.0	0.3	0.0	0.3
Russia_Remaining	6.2	4.9	0.4	0.3	6.6	2.3	20.6
Russia_StPetersburg	0.0	0.0	0.0	0.0	0.5	0.0	0.5
Serbia-Montenegro	0.0	0.0	0.0	0.0	0.1	0.1	0.3
Slovak Republic	0.4	0.1	0.0	0.0	0.1	0.0	0.7
Slovenia	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Spain	0.7	0.4	0.2	0.4	1.1	1.2	4.1
Sweden	0.4	0.0	0.0	1.3	1.3	0.1	3.2
Switzerland	0.0	0.0	0.0	0.1	0.2	0.0	0.3
Turkey	0.7	0.2	0.5	0.1	8.5	0.8	10.8
Ukraine	2.6	2.5	0.1	0.0	15.3	0.0	20.5
United Kingdom	1.1	0.6	0.1	0.2	1.7	1.4	5.1
Total	24.6	17.0	3.0	6.0	52.0	14.0	116.0

4.4.2 *Electricity efficiency improvements*

Options for efficiency improvements

A large number of options exist to save electricity in the various industrial sectors (De Beer *et al*., 2001). The remainder of this section discusses for the various sectors the most relevant options.

Iron & steel

Several options are available to in the iron & steel industry (Table 4.23). *Energy in the process gas from blast furnace and basic oxygen furnaces can be recovered* (De Beer *et al*., 2001; p. 11), suggesting an average recovery potential of 1.15 GJ/ton of liquid steel produced. GAINS data on future production levels for liquid steel in 2020 are based on RAINS data on the production of crude steel in electric arc furnaces (see www.iiasa.ac.at/web-apps/tap/RainsWeb/ and Klimont *et al*., 2002). For the EU countries these projections have been derived from the baseline energy projection. A maximum penetration of 20 percent is assumed following De Beer *et al*. (2001). In countries where the specific electricity consumption in 1990 was already below 25 GJ/ton steel (e.g., in Austria), only 10 percent have been assumed as the additional recovery potential. De Beer quotes investments of 9 €/GJ electricity saved per year, and annual operating and maintenance costs (O&M) at 10 percent of these investments.

Table 4.23: Options for electricity savings in the iron & steel industry

		Investments [€/GJ saved]	*O&M [€/GJ saved]*
3	Recovery energy in process gas of blast and basic oxygen furnace	9	0.9
6	Scrap preheating electric arc furnaces	50	-9.5
7	Inject oxygen and fuel in electric arc furnaces	70	-5
8	Improved process control thin slab casting	9	0
10A	Miscellaneous I (low cost)	15	0
10	Miscellaneous II (high cost)	50	0

A second option for reducing electricity consumption is the *scrapping of preheating in electric arc furnaces*. Scrapping the preheating of the scrap saves electricity since it uses the off-gases of the furnace. According to De Beer (2001; p. 13), savings amount to approximately 80 kWh per ton liquid steel or 0.29 GJ/ton steel. In addition, there are fuel savings of 0.2 GJ/ton steel. Assuming that additional fuel would otherwise be used to generate electricity with an efficiency of 50 percent (in gas combined cycle turbines), net electricity savings of 0.19 GJ/ton steel emerge. To reflect possible space limitations for the installation of the equipment, the maximum potential for this option is set at 10 percent. For investments, 50 €/GJ electricity saved are assumed, where annual O&M costs are reduced on average by 9.5 €/GJ saved.

Injecting oxygen and fuel in the electric arc can reduce electricity consumption by 80 kWh/ton steel (or 0.29 GJ/ton steel), although fuel demand will increase by 0.24 GJ/ton steel. Net savings are therefore 0.168 GJ of electricity/ton steel, assuming that fuel would otherwise be used to generate electricity on the spot with an efficiency of 50 percent. For 1990, the implementation rate is reported at 60 percent (De Beer *et al*., 2001; p. 14), and the maximum penetration is limited to 80 percent. Investments are 70 €/GJ electricity saved, where annual operating and maintenance costs (O&M) are reduced by 5 €/GJ saved.

Improved process control in mini mills could save around 30 kWh/ton steel. However, the expected savings compared with other systems are believed too small. For 2020, the maximum penetration is set to 100 percent (De Beer *et al*., 2001; p. 15) with investments of 9 €/GJ saved. Finally, there exists a variety of other "*miscellaneous*" measures (De Beer *et al*., 2001) including low costs measures such as bottom stirring, hot metal charging in the electric arc furnace, and preventive maintenance. Electricity savings are estimated at 0.1 GJ/ton crude steel for investments of 15 €/GJ saved. More expensive measures such as variable speed drives and ultra high power transformers could save 0.05 GJ/ton steel at an investment of 50 €/GJ saved.

Non-ferrous metals (aluminium)

In the aluminium industry (Table 4.24), a portfolio of options exists to *retrofit existing cells* (Hall-Heroult processes) such as alumina point feeding, process computer control and conversion from wet to dry anodes (De Beer *et al*., 2001; p. 18). Retrofitting saves 1 MWh/ton aluminium produced for investments of 192.5 €/GJ electricity saved (De Beer *et al*., 2001; p. 18). Electricity saving retrofitting measures are only assumed for non-point feed prebake (non-PFPB) units. Country-specific data on non-PFPB units are taken from Tohka (2004), indicating that in the EU countries most smelters already use PFPB technology. Aluminium production data (primary production) are taken from the RAINS databases (Klimont *et al*., 2002).

Wettable cathodes can increase the efficiency of aluminium production. This could save between 0.2 and 0.3 MWh/ton, with 2.5 MWh/ton being used in GAINS. The potential application is set at 100 percent, where costs are estimated at 550 €/GJ saved following De Beer *et al*. (2001; p. 19).

Table 4.24: Options for electricity savings in the non-ferrous metal industry

		Investments [€/GJ saved]	*O&M [€/GJ saved]*
13	Retrofit existing Hall-Heroult aluminium production	193	0
14	Wettable cathodes in aluminium industry	550	0

Chemical industry

Three options for electricity savings in the chemical industry were identified (see Table 4.25). The first option is the *replacement of mercury by membrane cells* to reduce electricity demand during the production of chlorine. This option reduces electricity demand by 0.8-1.3 GJ/ton chlorine produced (1.05 on average), while fuel demand increases by 0.75 GJ/ton chlorine (De Beer *et al*., 2001). The fuel demand increase corresponds to an increase in electricity consumption of 0.375 GJ/ton, assuming a 50 percent efficiency of electricity generation. With this assumption, net savings in electricity of 0.675 GJ/ton chlorine emerge. Chlorine production data are taken from UN industry statistics (UN, 2002) and assumed constant over time. This technology can only be applied to the chlorine processes using mercury.

Country-specific information on the type of processes are based for the EU-15 on De Beer *et al.* (2001; p. 27). They range from 28 to 100 percent of total chlorine production. For all other countries with chlorine production, the EU-average for mercury based chlorine production is used. Investments are 650 €/GJ for existing installations and zero for new installations (de Beer *et al*., 2001). Assuming a lifetime of 50 years for an installation and homogenous vintage structures, in the period 2000 to 2020 it is assumed that 40 percent of the currently existing installations will be replaced resulting in average investments of 390 €/GJ.

Table 4.25: Options for electricity savings in the chemical industry

		Investments [€/GJ saved]	*O&M [€/GJ saved]*
26	Replace mercury by membrane cells other chemical industry.	390	0
27A	Miscellaneous I other chemical industry	25	0.1
27B	Miscellaneous II other chemical industry	50	0.2

Other electricity saving measures in the other chemical industry include adjustable speed drives and more efficient motors and appliances. GAINS distinguishes two groups of such measures with low and high costs. Measures summarized in *Miscellaneous I* are assumed to save 15 percent of electricity at investments of 25 €/GJ electricity saved and O&M costs of 0.1 €/GJ saved. *Miscellaneous II* measures could save additional 10 percent at an investments of 50 €/GJ electricity saved and O&M costs of 0.2 €/GJ saved (De Beer *et al*., 2001; p. 28). The application potential is limited to the other non-chlorine producing chemical industry.

Electricity consumption for the chemical industry is derived from the energy baseline forecasts (http://www.iiasa.ac.at/web-apps/tap/ RAINSWeb/RAINSServlet1, BL-CLE of April 2004). For the remaining countries it has been assumed that the share of electricity demand of the chemical industry in total industrial electricity demand of the year 2000 as reported by IEA (2002b) will remain constant over time. Data on electricity consumption for chlorine production are estimated from chlorine production statistics using a generic specific electricity consumption of 11 GJ/ton chlorine for mercury-based production and 9.75 GJ/ton for other chlorine production methods.

Glass, pottery and buildings sector

Various measures to save electricity can be taken in the *cement industry* (option 34; Table 4.26), including the use of roller mills instead of ball mills, efficient grinding technologies, high efficiency classifies, and high-efficiency motors and drives (De Beer *et al*., 2001; p. 34). Potential savings are estimated at 10 kWh/ton cement for a specific electricity consumption of 110 kWh/ton cement in 1990. A specific energy consumption of 70 kWh/ton cement is reported for new plants. National cement production statistics and projections are extracted from the RAINS databases and investments are 35 €/GJ electricity saved.

Table 4.26: Options for electricity savings in the glass, pottery and buildings industries

		Investments [€/GJ saved]	*O&M costs [€/GJ saved]*
34	Electricity savings cement industry	35	0
39	Electricity savings glass industry	20	0
40A	Miscellaneous measures ceramics	15	0
41A	Miscellaneous measures other glass, pottery & buildings industry	15	0

Several measures are available to save electricity in the *glass industry* (option 39; Table 4.26), with typical saving rates of 0.35 GJ/ton glass produced at investments of 20 €/GJ electricity saved (De Beer *et al*., 2001; p. 37). National statistics and projections of glass production levels are taken from the RAINS databases. It is assumed that such measures are applicable to all plants.

In the production of *ceramic products* electricity can also be saved through a variety of measures (option 40A; Table 4.26). Electricity savings are typically estimated between 15 and 25 percent (De Beer *et al*., 2001; p. 38), where 20 percent efficiency is assumed in GAINS. New plants are assumed 30 percent more efficient than existing ones (De Beer, 2001; p. 38). In line with De Beer (2001), it is assumed that the ceramics industry uses 18 percent of the electricity of the "buildings, construction and materials" sector. Electricity consumption data for this sector are taken from the baseline energy projection. For the remaining countries, it is assumed that the share of electricity consumption from the building sector in total electricity consumption reported for the year 2000 (IEA, 2002b) will remain constant over time. The potential application is 100 percent with investments at 15 €/GJ saved.

Various measures can be applied to save electricity for other activities (lime stone, gypsum, etc.) in the construction, building and materials (CBM) sector (option 41; Table 4.26). De Beer (2001; p. 39) suggests possible electricity savings of up to 20 percent, in principle applicable to all plants for typical investments of 15 €/GJ saved. National data on electricity use for this sector have been compiled from the reported electricity consumption in the CBM sector minus the electricity consumed for the production of cement, glass and ceramics.

Paper and pulp industry

Several options are available to save electricity in the pulp & paper industry (see Table 4.27). Electricity can be saved through the use of *super pressured ground wood* (using elevated pressure) in the production of mechanical pulp. This reduces electricity consumption by 600 kWh/ton (or 50 percent) compared to traditional mechanical pulp production (De Beer *et al.*, 2001; p. 41). Since industry representatives suggest lower savings, GAINS uses an average reduction of 27.5 percent or 350 kWh/ton pulp (or 1.25 GJ/ton pulp). Pulp production data are taken from the RAINS databases. The share of mechanical pulping is based on FAO data for the year 2000 (FAO, 2004). The maximum potential application is assumed at 10 percent with investments at 220 €/ton pulp. With savings of 1.25 GJ/ton pulp, investments amount to 176 €/GJ saved. O&M costs are reduced by 2.6 €/ton or 2.1 €/GJ (De Beer *et al.*, 2001).

Electricity consumption of mechanical pulping can be reduced by *refiner improvements* (De Beer *et al*., 2001; p. 42). Savings are estimated at 0.35 GJ/ton pulp. Estimates for the additional potential vary between zero and 25 percent, since the actual penetration is already 75 to 100 percent in most European countries. GAINS assumes an average additional potential of 12.5 percent. Investments are 23 €/GJ saved and O&M costs increase by 7.4 €/GJ saved.

Further measures in this sector (De Beer *et al*., 2001; p. 44) are grouped into a low-cost class ("*Miscellaneous I*") with a typical saving of 0.2 GJ electricity per ton of paper produced and 10 percent of electricity in the pulp mill at investments of 25 €/GJ electricity saved. The high cost class ("*Miscellaneous II*") represents measures that could save 0.3 GJ/ton paper and additional 10 percent of electricity demand in the pulp mills at investments of 50 €/GJ electricity saved. Specific electricity demand for pulp mills is (on average) 1700 kWh for mechanical pulping and 575 kWh for chemical pulping (De Beer *et al.*, p 70). Country-specific shares of mechanical and chemical pulping are derived from FAO (2004). The application potentials for both groups are assumed at 100 percent. Paper and board production statistics come from FAO (2004), and production levels are assumed to follow trends in pulp production.

Table 4.27: Options to save electricity in the pulp & paper industry

		Investments [€/GJ saved]	*O&M costs [€/GJ saved]*
42	Super pressured ground wood (mechanical pulp)	176	2.1
44	Refiner improvements paper & pulp industry	23	7.4
49C	Miscellaneous I electricity savings paper & pulp	25	0
49D	Miscellaneous II electricity savings paper & pulp	50	0

Food, beverages and tobacco and other industries

In the food beverages and tobacco (FBT) sector, various options for electricity savings exist in the non-dairy and sugar industries (see Table 4.28). These measures are grouped into low cost ("*Miscellaneous I*") and high cost ("*Miscellaneous II*"). "Miscellaneous I" measures save 15 percent on electricity consumption and "Miscellaneous II" measures additional 20 percent. Electricity consumption of the FBT sector is taken from the energy baseline projection. For other countries data are taken from IEA (2002b) for the year 2000, and it is assumed that the share of the food sector in total industrial electricity consumption will remain constant from 2000 onwards. Electricity consumption is corrected for the electricity use in the sugar industry (De Beer *et al*., 2001). The potential applicability is 100 percent for both sets of measures. Investments are 20 €/GJ saved for the low cost option and 50 €/GJ for the high cost group.

In the same vein, two groups of measures are considered for the other industries. Both the "Miscellaneous I" (low cost) and the "Miscellaneous II" (high costs) measures are assumed to save 15 percent of electricity consumption (De Beer *et al*., 2001; p. 49). For the potential application, 100 percent is assumed in both cases. For the EU countries, the share of these sectors in total industrial electricity consumption is taken from the energy baseline projection (other industries, engineering & other, metal and textile, leather clothing.). For other countries, the shares of these sectors (textile, wood prod, construction, industry other not specified) as reported by IEA (2002b) for 2000 is applied to the expected industrial electricity use in 2020. Investments are 10 €/GJ saved for the low cost option and 30 €/GJ for the high cost group.

Table 4.28: Options for electricity savings in the food, beverages and tobacco and other industries

		Investments [€/GJ saved]	*O&M costs [€/GJ saved]*
53C	Miscellaneous I electricity savings, non-dairy food sector	20	0
53D	Miscellaneous II electricity savings, non-dairy food sector	50	0
54C	Miscellaneous I electricity savings, textile and others	10	0
54D	Miscellaneous II electricity savings, textile and others	30	0

Summary

With the assumptions described above, full application of all measures would yield in 2020 a reduction in electricity demand of 940 PJ for the entire model domain. This corresponds to approximately 13 percent of total electricity consumption in industry in that year. Taking into account that for these calculations all options that have private costs lower than the industrial electricity price in 2020 (with a discount rate of 12 percent) are already included in the baseline projection, only four additional options remain to be implemented (option 13, 14, 26 and 42). Together, these four measures would reduce industrial electricity demand in Europe by only 15.1 PJ in 2020, i.e., by approximately 0.2 percent.

Obviously, it needs to be stressed that this result is extremely sensitive towards the assumptions on the measures that are already included in the baseline projection. For GAINS Version 1.0, the assumption has been made that all measures which yield cost savings – calculated over their whole technical life time and using a private interest rate of 12 percent – will be applied in the base case even in absence of any constraint on CO_2 emissions. Alternatively, with the assumption that none of the measures above were included in the base case, the reduction potential would amount to 13 percent of total electricity use in industry.

4.4.3 Fuel shifts

In addition to energy conservation measures, lower CO_2 emissions can also be achieved through shifts to fuels with lower carbon contents. Table 4.29 shows all investments and operating costs, plus efficiencies and lifetimes assumed in the calculations. Data are based on Alsema and Nieuwlaar (2001), Coenen (1985), Hendriks *et al*. (2001) and Jankowski (1997).

In practice, the potentials for such shifts are determined by a number of physical factors such as the availability of alternative fuels, limited transition rates in the energy infrastructures (e.g., of gas distribution networks), etc. Economic aspects include the economic viability of such fuel shifts, influenced by the difference in fuel prices, the availability of capital for necessary upfront investments, and other market forces.

Analysis of the differences between the baseline scenario calculated with the PRIMES model and the PRIMES climate policy scenario (which assumes a flat rate carbon tax of 20 €/t CO_2) reveals for the EU countries a limited potential for such fuel changes in the industrial sector with costs below the assumed carbon tax. This result is explained by the fact that already the baseline projection suggests a relatively high share of natural gas use in industry, so that there is little potential for further shifts at costs below 20 €/t $CO_{2.}$ The PRIMES energy baseline scenario does not suggest for 2020 coal use in industrial boilers, and only very little use of heavy and medium oil. However, for completeness the details of the calculations are added.

Table 4.29: Costs and mitigation efficiencies of industrial boilers

	Investments [€/kWth]	*Fixed O&M per year [€/kWth]*	*Efficiency heat [%]*	*Lifetime [years]*
Brown coal	246	17.0	88	20
Hard coal	246	17.0	88	20
Heavy fuel oil	116	6.8	90	20
Natural gas	90	2.1	90	20
Biomass, waste, wood (OS1)	100	5.0	80	20

Source: Alsema and Nieuwlaar (2001), Coenen (1985), Hendriks *et al*. (2001), Jankowski (1997).

In principle, GAINS distinguishes for the industrial sector fuel shifts from coal and oil to natural gas and biomass. Table 4.30 shows the fuel shifts occurring between the baseline energy case and the PRIMES scenario with a 20 €/t CO_2 carbon price. In the industrial sector, fuel shifts occur only in eight countries in the EU, and even there only to a limited extent. Note that no data were available quantifying potential fuel shifts in non EU-30 countries. In some countries (Finland and the UK) there is very little shift from heavy fuel oil to natural gas because only very little heavy fuel oil is used even in the baseline. Further analysis will be necessary to quantify the country-specific fuel substitution potentials at higher costs.

Table 4.30: Potentials for fuel shifts in industrial boilers for the year 2020 for the GAINS Version 1.0 baseline energy projection with costs lower than 20 €/ton CO_2 [PJ fuel input]. These potentials are derived from a comparison of two energy projections with different carbon prices.

	Heavy fuel oil to natural gas	*Heavy fuel oil to other solids*
Belgium	0.4	0.0
Denmark	0.3	0.0
Finland	0.1	0.0
Greece	0.1	0.0
Poland	0.3	0.0
Portugal	0.2	0.0
Sweden	0.1	1.9
UK	0.8	0.0

The costs for fuel substitution are calculated from the price differences of the different options. National fuel prices are derived from IEA (2000) and have been modified by the baseline projection price index for industrial fuels for 2020. As a result, the analysis suggests for the year 2020 a potential reduction of 0.2 Mt CO_2 at costs of 1 million €/year.

4.4.4 Concluding remarks

The analysis of the industrial sector indicates the existence of a large number of measures for mitigating CO_2 emissions. In total, full implementation of all measures included in the GAINS databases could lower industrial emissions by around 116 Mt CO_2 in 2020. For estimating realistic mitigation potentials, the assumption of which measures will autonomously be implemented in the baseline development due to negative life cycle costs is absolutely critical.

With the assumption that all measures with negative life cycle costs are already included in the baseline projection, an additional potential for electricity savings in industry of 15 PJ, i.e., one percent, is estimated for 2020. Finally, preliminary analysis indicates that a limited potential (0.2 Mt CO_2 at costs of around 1 million €) might exist for fuel shifts beyond the baseline trends in the industrial boilers. However, this estimate is restricted to the EU countries, so that further analysis is required to assess the Europe-wide potential, and does not include potential fuel shifts with costs higher than 20 €/ton CO_2.

4.5 Residential and commercial sector

In GAINS, the domestic residential and commercial (domestic) sector distinguishes three sub-sectors: household, services and agriculture. Herein, options to reduce CO_2 emissions can be grouped into two major classes:

- Energy end use savings (insulation of private houses and office buildings, more efficient electric appliances and lighting as well as office equipment and cooling devices).
- Fuel substitution from oil and coal to gas and from fossil fuels to renewables (biomass and solar energy).

There is substantial information on the costs and efficiencies of these options (Hendriks *et al.*, 2001), but data on the extent to which these options have already been implemented in the past, or will be implemented in the future, is scarce. GAINS distinguishes two categories of options (electricity efficiency improvements and fuel shifts, insulation of buildings).

4.5.1 Electricity efficiency improvements

A variety of options exist to reduce electricity consumption of domestic appliances (Joosen and Blok, 2001). These range from compact fluorescent lamps to efficient cold (e.g., fridges), wet (e.g., washing machines) and brown (e.g., television sets) appliances. For the scope of the GAINS analysis, a limited number of packages of measures has been formulated that show distinct differences in emission reductions and costs. For the time being, on the basis of the average share of the electricity consumption of these appliances, five packages are distinguished (see Table 4.31).

For each of these options, potential energy savings are calculated as the electricity demand for lighting (or appliances) in the domestic sector * the electricity saved (%) by this option * the potential applicability of the option. Since electricity demand for lighting and other appliances in the domestic sector is not directly available from energy statistics, it is estimated in GAINS based on country-specific total domestic electricity demands as given in the baseline energy scenario for 2020 for the domestic sector, and an average share for lighting purposes as in Joosen and Blok (2001). Shares of compact fluorescent lamps, cold, wet, brown, and misc. appliances are 22, 39, 21, 9, and 10 percent, respectively. The maximum application potential is assumed to be a function of time, starting from the present country-specific application rates and converging to the maximum rate of application in 2020 (see Joosen and Blok, 2001).

Table 4.31: Five packages of electricity saving measures in households in GAINS.

Options	*Investments [€/GJ electricity saved]*	*Investments [€cts/kWh electricity saved]*	*Lifetime [years]*	*Gross cost [€cts/kWh electricity saved]*	*Electricity saved*
Compact fluorescent lamps	5.8	2.1	8	0.3	60%
Efficient cold appliances	240.1	85.8	15	7.7	70%
Efficient wet appliances	625.5	223.4	15	20.1	50%
Efficient brown appliances	0.0	0.0	15	0.0	81%
Miscellaneous efficient appliances	23.4	8.4	8	1.2	30%

Source: Joosen and Blok (2001). Interest rate used 4 %.

With the energy baseline electricity prices for the household sector of around 10 €cts/kWh (excluding excise duties) (Mantzos *et al*., 2003; Chapter 7), negative life cycle costs are calculated for compact fluorescent lamps, even if a private interest rate of 17.5 percent is assumed. This suggests that they would be fully applied in any cost-optimized baseline energy projection. The same applies for brown appliances, where additional costs of best-practice TV sets are expected to be negligible in 2010 (Joosen and Blok, 2001). Similar arguments hold for miscellaneous appliances such as, e.g., electric appliances for hot water production.

Summary

Full application of the measures for electricity efficiency improvements outlined above, assuming that all measures with negative costs are already part of the baseline projection, would reduce energy consumption in households by approximately 700 PJ in 2020, or eight percent of total domestic electricity consumption, over the entire model domain.

4.5.2 Options for fuel substitution and insulation

There are essentially three different main decisions that actors in the residential and commercial sector can take in order to reduce emissions of CO_2: (i) insulate the buildings; (ii) replace carbon-intensive fuels by carbon-free fuels or fuels with lower carbon content (i.e., fuel substitution); and (iii) combine these two options.

GAINS distinguishes in total 22 variants and combinations of these options for reducing CO_2 emissions (Table 4.32). These include use of fuels with lower carbon content (light heating oil (MD), natural gas (GAS), biomass (OS1), solar thermal (SLT) and improved insulation of buildings (INS). GAINS considers the differences in energy efficiencies between these options and calculates the required changes in primary energy input in order to maintain the original volume of heat output.

Table 4.32: Carbon dioxide (CO_2) reduction options from space heating in the residential and commercial sector in GAINS.

				TO			
FROM	*Heating oil + insulation (MD_INS)*	*Heating oil + insulation (GAS)*	*Natural gas + insulation (GAS_INS)*	*Solar thermal (SLT)*	*Solar thermal + insulation (SLT_INS)*	*Biomass (OS1)*	*Biomass + insulation (OS1_INS)*
Heating oil	x	x	x	x	x	x	x
Heating oil + insulation			x		x		x
Heating oil + insulation			x	x	x	x	x
Natural gas + insulation					x		x
Solar thermal					x		
Biomass							x

Potentials for fuel substitution and insulation

Potential application of CO_2 control measures may be limited for at least four reasons: (1) an option is already assumed in the baseline projection, especially if such a baseline projection has been developed with cost-minimizing rationales; (2) the autonomous turnover of the existing stocks of buildings or heating systems is limited, and no premature scrapping or retrofitting is assumed; (3) an options is too costly (economic constraint); or (4) institutional factors. The most important institutional factors that may hamper the penetration of, e.g., extra insulation are uncertainty, information costs, or high transaction costs.

To reflect such limitations, GAINS specifies lower and upper bounds for the activity rates of existing equipment and for the penetration of new measures. Such bounds limit undue replacement of existing capital stock and reflect measures that are already included in the baseline projection. Limitations imposed by institutional factors are formalized through upper bounds on the replacement rate. The values of these bounds are country-specific and are derived for the potential supply of heat from the major energy sources in the domestic sector. The following sub-sections explain the way how these bounds for applicability and penetration rates have been derived for GAINS Version 1.0.

Oil

The current GAINS implementation excludes premature scrapping of existing oil heated boilers in the domestic sector. The potential for replacement of small and medium oil heated boilers with other fuel input is derived from an assumption of a technical life time of 40 years and uniform age distribution of the currently existing boilers. Thus, the actual potential for substitution in future years is determined by the resulting annual phase-out of 2.5 percent of the currently existing capacity and the overall development of oil heating capacity in the energy baseline scenario.

Natural gas

In addition to the lower bound reflecting the natural replacement rate of existing boilers, GAINS Version 1.0 assumes an upper limit on the penetration of new gas boilers to reflect potential constraints in the extension of gas distribution infrastructures (e.g., into areas with low demand densities) and overall resource constraints. Currently, values for these bounds have been derived from an analysis of alternative PRIMES energy scenarios and fixed at an additional 20 percent in comparison to the gas-intensive baseline projection.

Solar thermal

The *technical* potential for solar thermal space heating in the EU-15 has been estimated at nearly 60 Mtoe per year (about 250 PJ, equivalent to, e.g., the total space heating demand of Belgium). At the same time, the *economic* potential is much smaller. At present 40 percent of the technical potential (100 PJ) is actually utilized (ESTIF, 2003). Studies show that diffusion rates are low, which is caused by several reasons, inter alia high capital costs and aesthetic problems (see, e.g., Duffie and Beckman, 1991). In addition, according to ESTIF (2003), solar thermal use has up to now entered the market to significant extents in only four countries (Austria, Greece, Germany, and Turkey). These studies suggest the maximum potential for solar thermal energy 40 percent higher than projected in the baseline energy projections.

Biomass

Studies on the possible contribution of biomass to the future global energy supply arrived at very different conclusions. Berndes *et al*. (2003) concluded that it is difficult to establish to what extent bio-energy is an attractive option for climate change mitigation in the energy sector. Furthermore, large-scale energy cropping could be resisted because of its impacts on water quality, wildlife, recreation, etc.. Canell (2003) also stresses the notion that “there is no objective basis upon which to set a realistic ‘potential’ land area for energy crops” (p.110).

Given the above reasoning, it is difficult to establish a maximum potential for biomass use in the domestic sector in Europe on a robust basis, especially for individual countries. As a preliminary assumption, GAINS Version 1.0 caps the potential increase in biomass use at 40 percent above the energy baseline projection.

Insulation

EUROSTAT (1999) provides for the EU-15 and Norway country-specific estimates of the present level of insulation of residential and commercial buildings. However, there is a lack of data for Southern and Eastern Europe, including Russia. Northern countries such as Sweden and Finland have 100 percent of the dwellings fully insulated according to the EUROSTAT criteria, while, e.g., Austria only has only 33 percent (Table 4.33). In the absence of specific information, GAINS assumes that the percentage given for Austria also applies for other countries for which no specific information is available.

Based on Joosen and Blok (2001), GAINS Version 1.0 applies for insulation an average 32 percent reduction of energy demand for space heating, relative to the country-specific heat demand in the base year corrected for the installed penetration of insulation measures. Thus, climatic factors are implicitly incorporated in the estimates. For the future, for each country the current level of insulation as reported by EUROSTAT (1999) is taken as lower bound, so that any new-built houses need to comply at least with the current standards. As an upper limit, it is assumed based on historic observations (Joosen and Blok, 2001) that not more than three percent of the existing buildings can be insulated per year. For countries with low insulation rates a 50 percent increase in 2020 is assumed as an upper bound.

Table 4.33: Insulation rates for buildings for selected countries [percent of total space area]

	No insulation	*Roof insulation*	*Wall insulation*	*Floor insulation*	*Double glazing*	*Average*
Austria	39 %	37 %	26 %	11 %	53 %	32 %
Belgium	21 %	43 %	42 %	12 %	62 %	40 %
Denmark	1 %	76 %	65 %	63 %	91 %	73 %
Germany	-	42 %	24 %	15 %	88 %	42 %
France	21 %	71 %	68 %	24 %	52 %	54 %
Netherlands	14 %	53 %	47 %	27 %	78 %	51 %
Norway	3 %	77 %	85 %	88 %	98 %	87 %
Sweden, Finland	-	100 %	100 %	100 %	100 %	100 %
UK	15 %	90 %	25 %	4 %	61 %	45 %

Source: EUROSTAT (1999)

Costs of fuel substitution and insulation

Costs of fuel substitution are calculated as the difference between the heat production costs with the existing oil or gas boiler (as in the baseline projection) and the replacement option (see Section 2.4). GAINS considers for a reference building in the domestic sector the substitution of existing oil heating systems by either gas, solar thermal or biomass heating using pellets. In addition, GAINS includes substitution of new gas boilers by solar thermal or biomass systems.

For each space heating option, costs are calculated following the standard approach in GAINS, i.e., considering investments as well as fixed and variable operating costs including the costs of fuel. Investments for all space heating systems are derived from BGW (2003) (Table 4.34). For the GAINS calculations, these costs have be related to living space (m^2) for a number of different house types, starting from a single family house up to a 12 flat construction representing buildings in the service sector. In absence on detailed quantitative information on the country-specific size distributions for residential and commercial buildings, GAINS uses a single category with the mean costs as provided in Table 4.34.

Table 4.34: Investments for heating systems in the domestic and commercial sector

House type		*Natural gas*		*Heating oil*		*Biomass*		*Solar thermal + Natural gas*	
	[m^2]	*[€]*	*[€/m^2]*	*[€]*	*[€/m^2]*	*[€]*	*[€/m^2]*	*[€]*	*[€/m^2]*
12 flats	968	38000	39	48300	50				
6 flats centralized	523	27100	52	33900	65				
House (terrace)	183	12500	68	15300	84	24100	132	16200	89
Single family house	193	12900	67	15900	82	25400	132	16600	86
Mean			57		70		132		87
Median			59		74		132		87
Standard deviation			14		16		0		2

Source: BGW, 2003; p 12.

For insulation, data of the GAINS cost calculation are based on information provided in Joosen and Blok (2001). GAINS considers a package of insulation measures including wall, roof and window insulation, with costs of 57, 28, and 128 €/m^2 insulated, respectively. This results in average costs of 71 €/m^2 insulated. For a reference building it adds up to a total of 8,520 €.

Following the methodology presented in Section 2.4, GAINS calculates the resulting costs for all CO_2 reduction options from space heating related to a ton of CO_2 reduction. Prices of the replaced fuel, i.e., of light fuel oil or natural gas, are calculated from the national average prices for households excluding VAT and other fuel taxes as provided in IEA (2003) for the year 2000, adjusted by the price index of the energy baseline scenario (Mantzos *et al*., 2003; Chapter 7). Costs per ton CO_2 avoided vary across countries due to differences, e.g., in fuel inputs reflecting climatic conditions, fuel prices and already installed insulation. As an example, Table 4.35 summarizes calculation results for Germany.

Table 4.35: Costs calculations for space heating options in the residential and commercial sector in Germany

		Heating oil	*Heating oil + insulation*	*Natural gas*	*Natural gas + insulation*	*Solar thermal*	*Solar thermal+ insulation*	*Biomass*	*Biomass+ insulation*
Fuel input	GJ/yr	65	44	65	44	52	35	65	44
Efficiency	%	80	80	80	80	100	147	80	80
Investments	€/boiler	8400	8400	6840	6840	10440	10440	15840	15840
Investments for insulation	€/120m^2	-	8520	-	8520	-	8520	-	8520
O&M (per yr)	€/boiler	200	200	62	62	76	76	377	377
Fuel price w/o tax (2020)	€/GJ	17.57	17.57	15.47	15.47	15.47	15.47	10.66	10.66
Energy saving from insulation	%	-	32%	-	32%	-	32%	-	32%
Lifetime	Years	20	20	20	20	20	20	20	20
Interest rate	%	4	4	4	4	4	4	4	4
Costs									
Annuities	€/year	618.1	1245.0	503.3	1130.2	768.2	1395.1	1165.5	1792.5
Fuel costs	€/year	1138.3	774.0	1002.5	681.7	802.0	545.4	691.0	469.9
O&M	€/year	200.0	200.0	62.0	62.0	76.0	76.0	377.0	377.0
SUM	€/year	1956.4	2219.1	1567.8	1873.9	1646.2	2016.5	2233.5	2639.3
Cost/GJ	€/year	30.2	50.4	24.2	42.5	31.8	57.2	34.5	59.9
Cost/GJ useful heat	€/year	37.7	42.8	30.2	36.1	31.8	38.9	43.1	50.9
CO_2/year	kg/year	4756.3	3234.3	3615.8	2458.8	2892.7	1967.0	0.0	0.0
CO_2	kg/GJ	73.4	73.4	55.8	55.8	55.8	55.8	0.0	0.0
Cost per ton CO_2 avoided	€/tCO_2	Switch from oil	173	-341	-36	-166	22	58	144
		Switch from gas			265	108	272	184	296

This approach used for GAINS Version 1.0 involves a number of simplifying assumptions, which could be revised to reflect critical differences in the potentials and costs of space heating options across countries and between residential and commercial buildings. In practice, options for energy savings are quite different between these two sectors, as are basic motives held by households and the commercial service sector (i.e., their utility versus profit maximising behaviours).

5 Interactions with other emissions

A number of cases have been identified where emissions of carbon dioxide (CO_2) and related emission control options influence emissions of other greenhouse gases and air pollutants, and vice versa (Table 5.1). Emissions of methane (CH_4) result from the combustion of coal and gas, during the production of coal and gas, and during transportation of natural gas. Shifting away from coal will also reduce methane emissions. Increasing use of natural gas will have the opposite effect. Burning biomass might increase particulate matter (PM), nitrogen dioxide (NO_2) and volatile organic compounds (VOC) emissions depending on the control measures.

In the transport sector, shifting to natural gas increases CH_4 emissions. Shifting to diesel could increase PM emissions depending on the control technology. Fuel substitution towards bio-fuels (ethanol and biomass) might increase nitrous oxide (N_2O) and ammonia (NH_3) emissions due to the increased use of fertiliser for biomass production. However, fuel efficiency improvements will reduce all air pollutants. In the domestic sector, shifting to biomass might increase the emissions of various pollutants.

Table 5.1: Carbon dioxide (CO_2) emitting sectors and interactions with emissions of other air pollutants.

Sector		*Important interactions with other gases*
Power plants/Industry/ Domestic sector	Coal combustion/production	CH_4
	Gas combustion/production	CH_4
	Biomass burning	PM, NO_x, VOC, CH_4
	Fuel efficiency/ renewables (except biomass)	All
Transport	Shift to natural gas	CH_4
	Shift to diesel	PM
	Shift to bio diesel/ethanol	N_2O
	Fuel efficiency changes	All
Industrial processes	Lime production/limestone use	$SO_{2,}$

The RAINS methodology considers for each CO_2 emitting activity the associated emissions of other greenhouse gases and air pollutants. Thus, in any scenario calculation of GAINS, the model internally accounts for any change in these emissions that occurs as a by-product of changing CO_2 emissions.

6 Initial results

This section presents initial results from the GAINS Version 1.0 analysis. As previously mentioned, the assumption on the fate of CO_2 mitigation measures for which negative life cycle costs are calculated has critical influence on the baseline emission projection and on the estimate of further mitigation potentials. If the construction of the baseline projection assumes a cost-effectiveness rationale, such measures would be autonomously adopted by the economic actors, even in the absence of any CO_2 mitigation interest. However, in practice it can be observed that various market imperfections impede the autonomous penetration.

The initial results from the GAINS Version 1.0 are based on the assumption that all negative cost measures would form integral part of the baseline projection, i.e., of the Energy Outlook developed in 2003 by the Directorate General for Energy and Transport of the European Commission (Mantzos *et al*., 2003). Since this projection has been developed with a cost-minimizing energy model, it is logical to assume that the large number of mitigation measures for which in this report negative costs are computed are already included. Thus, there remains only limited mitigation potential from the remaining measures.

Furthermore, the GAINS Version 1.0 analysis reported in this paper derived the potential for fuel shifts from a comparison of fuel consumption patterns between the base case projection (without specific climate policy) and a case with a carbon price of 20 €/t CO_2. Thus, this initial analysis does not include the potential for fuel substitutions at higher costs. In addition, this initial analysis makes conservative assumptions on the potential market penetration of carbon capture and sequestration for 2020 and on reversals of public opinions in Europe towards a further expansion of nuclear power beyond what is assumed in the baseline projection.

In summary, the GAINS Version 1.0 analysis employs optimistic assumptions on the baseline development of CO_2 emissions, but adopts very conservative estimates about additional mitigation potentials. Future refinements of the GAINS model will address these issues in a more realistic way. Section 6.1 compares the GAINS CO_2 emission estimates with inventories from other sources. Section 6.2 presents the baseline projection of CO_2 emissions up to the year 2020. Summary estimates of mitigation potentials and are provided in Sections 6.3 to 6.4, and Sections 6.5 to 6.8 discuss sectoral mitigation potentials.

6.1 Emission inventories

Table 6.1 compares the preliminary GAINS CO_2 emission estimates for 1990 and 2000 with the official national submissions to the United Nations Framework Convention on Climate Change (UNFCCC) as available on the web site in October 2004 and other studies. For the entire European domain, the GAINS model estimates total CO_2 emissions at 6,675 Mt in 1990. For the countries for which emissions are reported in the UNFCCC database, GAINS estimates are in total two percent lower than the officially reported numbers, both for 1990 and 2000. While for most countries the GAINS estimates correspond reasonably well to the national submissions to the UNFCCC, larger discrepancies for a few countries need further exploration.

Table 6.1: Comparison of carbon dioxide (CO_2) emission estimates from different sources [Mt CO_2].

	1990				2000	
	GAINS	*UNFCCC*	*EDGAR*	*ECOFYS*	*GAINS*	*UNFCCC*
Albania	6		7		4	
Austria	58	62	65	68	62	66
Belarus	114	126	209		74	73
Belgium	110	118	125	115	124	127
Bosnia-H.	21		15		21	
Bulgaria	81	84	73		47	
Croatia	22	23	36		23	
Cyprus	5				8	
Czech Republic	159	164	160		123	128
Denmark	53	53	55	54	55	53
Estonia	33	38	56		15	17
Finland	58	62	61	53	68	62
France	382	394	408	379	412	402
Germany	992	1015	1067	979	859	858
Greece	76	84	81	79	97	104
Hungary	68	67	76		59	59
Ireland	31	32	33	32	43	44
Italy	433	440	446	418	463	463
Latvia	21	24	33		7	7
Lithuania	36	40	118		12	
Luxembourg	10	11	13		10	
Macedonia	12		11		11	
Malta	2		3		3	
Moldavia	29		47		23	
Netherlands	159	160	184	156	179	174
Norway	28	35	48		35	
Poland	362	381	367		313	315
Portugal	44	44	47	43	67	63
Romania	174	173	191		93	
Russia_Kaliningrad	9				7	
Russia_Kola-Karelia	30				20	
Russia_Remaining	946				706	
Russia_StPetersburg	68				48	
Serbia-Montenegro	61		91		49	
Slovak Republic	63	60	58		36	42
Slovenia	14	14	13		15	
Spain	222	227	238	220	317	307
Sweden	53	56	59	55	70	56
Switzerland	43	44	48		49	44
Turkey	148		156		225	
Ukraine	676	704	837		399	
United Kingdom	570	584	615	582	574	543
Total	6482				5897	4005

Sources: UNFCCC estimates for 1990 and 2000 based on UNFCCC database of emissions (UNFCCC, 2004) and the latest national communications from Bulgaria, Hungary, Poland and Romania for the 1990 data (http://www.unfccc.int/) as well as EDGAR (2004).

6.2 Baseline emission projections

The GAINS Version 1.0 baseline estimate of future CO_2 emissions relies on the projected activity levels of the baseline scenario for the 25 EU Member States from the "Energy Outlook" developed in 2003 by the Directorate General for Energy and Transport of the European Commission (Mantzos *et al*., 2003). As one basic assumption, this energy projection does not include any climate policy measures beyond those which were already in force in 2003. Since this forecast has been developed with a cost-minimizing energy model, it is assumed for the GAINS Version 1.0 analysis that all mitigation measures with negative life-cycle cost measures form integral part of the baseline energy projection. For the non-EU countries, national reports of activity projections have been used. Details on projected fuel consumption and production levels are available from the RAINS website (http://www.iiasa.ac.at/web-apps/tap/RainsWeb/MainPageEmco.htm).

The resulting baseline projection of CO_2 emissions are presented in Table 6.2. Total European CO_2 emissions decline in the case without additional climate policies from around 6,500 Mt CO_2 in 1990 to around 5,950 Mt CO_2 in 2010. Afterwards, emissions are calculated to increase to 6,400 Mt in 2020 and to 6,950 Mt CO_2 in 2030. For the EU-25, CO_2 emissions decline in these projections by three percent in 2010 compared to 1990, and increase then in 2020 to a level four percent higher than in 1990 and 11 percent higher in 2030. The Kyoto Protocol commitments for the EU-25 would require a reduction of approximately eight percent in 2012 (i.e., a reduction of roughly 205 Mt CO_2).

Table 6.2: GAINS 1.0 estimates of carbon dioxide (CO_2) emissions between 1990 and 2030 under the baseline projection without additional climate policies [Mt CO_2].

	1990	*2000*	*2010*	*2020*	*2030*
Albania	6	4	5	7	9
Austria	58	60	63	69	73
Belarus	114	72	86	87	104
Belgium	110	120	119	131	156
Bosnia-H.	21	18	20	21	25
Bulgaria	81	46	45	48	50
Croatia	22	22	24	26	29
Cyprus	5	7	8	9	10
Czech Republic	159	125	103	102	106
Denmark	53	52	46	44	46
Estonia	33	15	14	13	13
Finland	58	63	57	61	65
France	382	391	423	464	471
Germany	992	839	847	896	908
Greece	76	93	110	116	121
Hungary	68	59	63	65	76
Ireland	31	42	47	49	51
Italy	433	457	454	469	493
Latvia	21	7	8	11	11
Lithuania	36	12	17	22	25
Luxembourg	10	9	12	13	14
Macedonia	12	10	11	12	14
Malta	2	2	3	3	3
Moldavia	29	23	24	22	22
Netherlands	159	169	176	185	210
Norway	28	34	41	43	41
Poland	362	312	312	341	358
Portugal	44	65	75	87	101
Romania	174	92	102	112	125
Russia-Kaliningrad	9	7	7	7	8
Russia-Kola-Karelia	30	20	24	24	26
Russia-Remaining European area	946	683	828	837	864
Russia-St. Petersburg	68	48	56	54	58
Serbia-Montenegro	61	46	54	61	77
Slovak Republic	63	36	40	48	52
Slovenia	14	15	17	18	18
Spain	222	289	310	344	373
Sweden	53	60	66	81	116
Switzerland	43	43	46	48	54
Turkey	148	222	265	371	530
Ukraine	676	400	417	419	462
United Kingdom	570	534	509	549	590
Total Europe	6482	5618	5952	6390	6960
EU-25	4016	3830	3899	4189	4462

6.3 Estimates of the maximum CO_2 mitigation potential in 2020

A hypothetical scenario has been constructed to explore the scope for CO_2 mitigation resulting from a full implementation of all measures contained in the GAINS Version 1.0 database. This estimate explores the lowest level of CO_2 emissions that could be achieved with the analysed measures for the baseline projection of activity levels for the year 2020. This analysis considers implementation of all measures irrespective of costs, but follows the assumptions on the maximum penetration rates of individual measures.

Table 6.3 presents the development of CO_2 emissions. Compared to the baseline in 2020, emissions in the model domain are 1,185 Mt CO_2 or 19 percent lower (or 18 percent lower than in 1990). However, these are cautious estimates and need to be interpreted with care. Additional emission reductions seem possible since this particular scenario does not include several mitigation options, such as additional co-generation in the industrial sector, fuel shifts with costs higher than 20 €/ton CO_2, and the expansion of nuclear power. Additionally, carbon capture and sequestration of CO_2 from fossil-fuel fired power plants (but not from hydrogen production in refineries) is excluded from this particular calculation for the year 2020. Given the fact that in this maximum reduction case around 400 Mt CO_2 are still emitted from brown and hard coal fired power plants, carbon capturing and sequestration could theoretically reduce additional 340 Mt CO_2 or five percentage points, if fully applied.

Table 6.3: Preliminary estimates of CO_2 emissions for the maximum reduction case [Mt CO_2]

	1990	*Baseline emission 2020*	*Emission reduced MFR 2020*	*Remaining emission MFR 2020*	*Reduction % of 2020 baseline*
Albania	6	7	0.9	6	13%
Austria	58	69	17.5	52	25%
Belarus	114	87	13	74	15%
Belgium	110	131	21.4	110	16%
Bosnia-H.	21	21	2.2	19	10%
Bulgaria	81	48	11.2	37	23%
Croatia	22	26	3.7	22	14%
Cyprus	5	9	1.3	8	14%
Czech Republic	159	102	18	84	18%
Denmark	53	44	6.6	37	15%
Estonia	33	13	2.9	10	22%
Finland	58	61	15.8	45	26%
France	382	464	126.3	338	27%
Germany	992	896	186.8	709	21%
Greece	76	116	17.8	98	15%
Hungary	68	65	13.9	51	21%
Ireland	31	49	7.6	41	16%
Italy	433	469	76.8	392	16%
Latvia	21	11	3.6	7	33%
Lithuania	36	22	6.3	16	29%
Luxembourg	10	13	2.5	11	19%
Macedonia	12	12	1.2	11	10%
Malta	2	3	0.4	3	13%
Moldavia	29	22	3.2	19	15%
Netherlands	159	185	23.6	161	13%
Norway	28	43	4.4	39	10%
Poland	362	341	58.8	282	17%
Portugal	44	87	17.8	69	20%
Romania	174	112	25.9	86	23%
Russia-Kaliningrad	9	7	0.8	6	11%
Russia-Kola-Karelia	30	24	9.6	14	40%
Russia-Remaining European area	946	837	112.2	725	13%
Russia-St. Petersburg	68	54	5.8	48	11%
Serbia-Montenegro	61	61	4.4	57	7%
Slovak Republic	63	48	10.7	37	22%
Slovenia	14	18	4.1	14	23%
Spain	222	344	74.5	270	22%
Sweden	53	81	27.4	54	34%
Switzerland	43	48	5.6	42	12%
Turkey	148	371	68.7	302	19%
Ukraine	676	419	76.8	342	18%
United Kingdom	570	549	93.8	455	17%
Total Europe	6482	6390	1186	5205	19%
EU-25	4016	4189	836	3353	20%

6.4 Cost function for reducing CO_2 emissions

The relation between emission control costs and the associated emission control potentials can be displayed in form of cost functions. Figure 6.1 illustrates such a cost function for CO_2 for the entire European model domain ranking the emission control options from all sectors according to their marginal costs. Reduction potentials and costs have been derived for the activity levels of the baseline projection of the year 2020. This particular figure displays the marginal costs as a function of emission reductions in 2020 across all sectors where the graph has been truncated above 800 €/t CO_2.

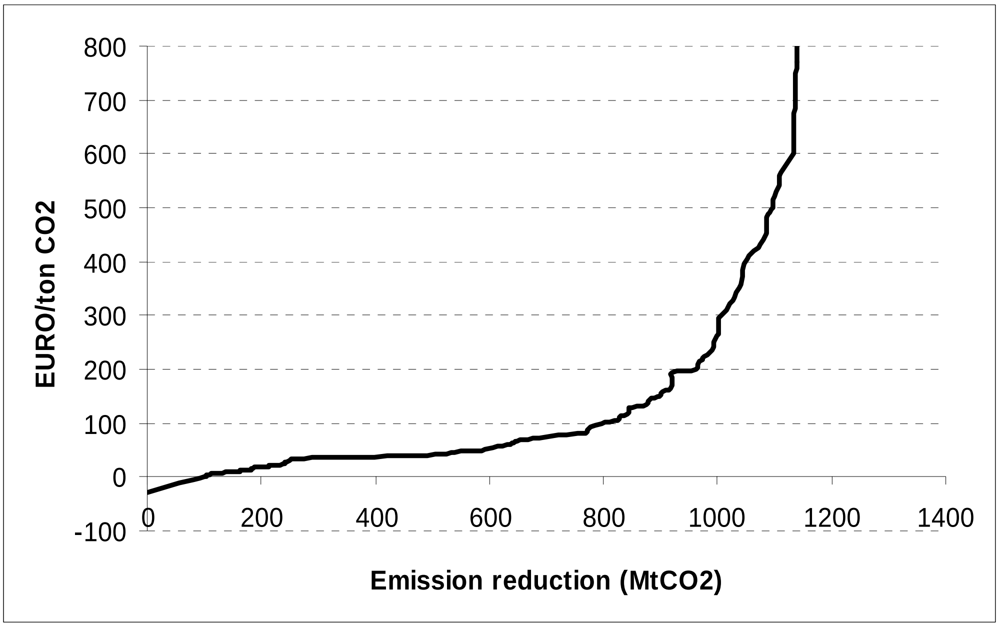

Figure 6.1: Cost function for the entire GAINS model domain for 2020

Given the assumptions on efficiencies, penetration rates, control costs and interest rates as described in the preceding sections, approximately 100 Mt CO_2 can be avoided at negative costs in the year 2020. In these circumstances, fuel savings outweigh investment and operating costs, especially in the industry and the power sector. Overall, 210 Mt CO_2 can be avoided at costs below 20 €/t CO_2. 500 Mt CO_2 can be reduced at marginal costs of 40 t/CO_2, and close to 800 Mt CO_2 for marginal costs below 100 €/ton CO_2.

While the above curve (Figure 6.1) displays costs for the entire GAINS model domain, GAINS provides such information for each country and each year contained in the databases. This information will be made available on the Internet. For the maximum application of the available mitigation measures, the GAINS model estimates costs of 126 billion € per year for Europe as a whole, with average costs of 105 €/t CO_2 (Table 6.4).

Table 6.4: Costs of the maximum application scenario in 2020

	Emission reduced MFR 2020 [Mt CO_2]	*Annual costs [million €/year]*	*Average costs [€/tCO_2 abated]*
Albania	0.9	209	232
Austria	17.5	1,474	84
Belarus	13	1,210	93
Belgium	21.4	2,317	108
Bosnia-H.	2.2	266	121
Bulgaria	11.2	1,078	96
Croatia	3.7	525	142
Cyprus	1.3	123	95
Czech Republic	18	1,905	106
Denmark	6.6	878	133
Estonia	2.9	341	118
Finland	15.8	1,132	72
France	126.3	8,658	69
Germany	186.8	19,103	102
Greece	17.8	2,677	150
Hungary	13.9	1,753	126
Ireland	7.7	1,323	172
Italy	76.8	8,979	117
Latvia	3.6	410	114
Lithuania	6.3	774	123
Luxembourg	2.5	316	126
Macedonia	1.2	202	168
Malta	0.4	39	98
Moldavia	3.2	273	85
Netherlands	23.6	3,849	163
Norway	4.4	1,019	232
Poland	58.8	6,875	117
Portugal	17.8	2,733	154
Romania	25.9	3,131	121
Russia-Kaliningrad	0.8	90	113
Russia-Kola-Karelia	9.6	502	52
Russia-Remaining European area	112.2	11,968	107
Russia-St. Petersburg	5.8	719	124
Serbia-Montenegro	4.4	619	141
Slovak Republic	10.7	1,151	108
Slovenia	4.1	543	132
Spain	74.5	8,620	116
Sweden	27.4	2,251	82
Switzerland	5.5	1,305	237
Turkey	68.7	8,266	120
Ukraine	76.8	5,656	74
United Kingdom	93.8	11,443	122
Europe	1,186	126,705	107
EU-25	836	89,667	107

6.5 Mitigation potential in the power sector

Under baseline assumptions without any climate policies, CO_2 emissions from the European power sector would drop from 2,423 Mt CO_2 in 1990 to 2,261 Mt CO_2 in 2020 (Table 6.5). Note that this calculation only includes the European part of the Russian Federation. In the EU-25, emissions would only marginally change in 2020 compared to 1990. Given the limitations on penetration rates, maximum implementation of the mitigation measures that are currently assumed in GAINS, emissions from the power sector in the model domain would drop by 24 percent compared to the baseline in 2020. Power plant emissions would be 27 percent lower in the EU-25; for individual countries reductions would vary between 5 and 74 percent.

For the power sector, total costs of such a maximum reduction would amount to 22 billion €/year, of which 15.6 billion €/year would occur in the EU-25. On average, costs of this CO_2 reduction case are around 40 €/ton CO_2, owing to the fact that this scenario does not include potential fuel substations with costs higher than 20 €/ton CO_2. It is interesting to note that costs in some countries are very low or even negative. This is caused by the low operating hours of power plants burning heavy fuel oil and the high price of this fuel compared to electricity generation from renewables, especially wind turbines. To confirm this, it will be necessary to further review the assumptions of operating hours for wind turbines and fossil-fuel fired plants.

Table 6.5: Carbon dioxide emissions and mitigation costs for the power sector for the maximum application of GAINS measures

POWER PLANTS	*1990* *Mt CO_2*	*Baseline* *Mt CO_2* *2020*	*MFR avoided emissions* *Mt CO_2* *2020*	*MFR Remaining emissions* *Mt CO_2* *2020*	*MFR emission reduction* *Relative to CLE* *2020*	*Annual costs* *Million €* *2020*	*Average costs* *€/tCO_2* *2020*
Albania	1	2	0.1	2	7%	2	20
Austria	14	18	6.8	11	38%	149	22
Belarus	59	50	7.5	43	15%	47	6
Belgium	21	33	5.4	27	17%	136	25
Bosnia-H.	14	13	1.4	12	11%	59	42
Bulgaria	45	27	6.9	20	25%	367	53
Croatia	5	7	2.0	5	27%	58	29
Cyprus	2	3	0.5	3	15%	17	34
Czech Rep.	83	47	10.3	36	22%	516	50
Denmark	24	18	1.9	16	11%	48	25
Estonia	25	8	1.7	7	20%	85	50
Finland	16	21	9.3	12	45%	461	50
France	39	78	47.7	30	61%	1841	39
Germany	374	346	98.9	247	29%	4326	44
Greece	33	52	9.1	43	17%	532	58
Hungary	27	22	8.1	14	36%	323	40
Ireland	10	16	2.1	14	13%	79	38
Italy	118	131	28.9	102	22%	648	22
Latvia	10	4	2.1	2	54%	110	52
Lithuania	17	10	3.5	7	34%	182	52
Luxembourg	0	2	0.3	1	20%	18	60
Macedonia	7	5	0.7	5	13%	31	44
Malta	1	2	0.2	2	8%	4	20
Moldova	17	12	2.0	10	17%	104	52
Netherlands	42	53	2.5	51	5%	22	9
Norway	0	6	0.5	6	8%	15	30
Poland	211	178	35.9	142	20%	1718	48
Portugal	15	27	6.2	21	23%	258	42
Romania	73	42	15.4	26	37%	526	34
Russia-Kalin.	5	4	0.4	4	10%	7	18
Russia-Kola	15	11	8.5	3	74%	299	35
Russia-other	371	344	53.5	291	16%	2139	40
Russia-St.Peters	43	30	2.8	27	9%	68	24
Serbia-M.	40	39	2.5	37	6%	116	46
Slovakia	24	21	7.1	14	34%	325	46
Slovenia	6	7	2.6	4	38%	102	39
Spain	61	93	31.7	61	35%	1451	46
Sweden	5	27	17.0	10	63%	829	49
Switzerland	1	7	0.5	7	7%	-22	-44
Turkey	32	111	29.1	82	26%	1443	48
Ukraine	303	154	34.4	120	22%	959	27
UK	214	178	39.3	138	22%	1388	35
EUROPE	2423	2261	547	1715	24%	21786	40
EU-25	1393	1395	379	1015	27%	15568	41

Figure 6.2 provides a summary of the fuel shifts in the power sector that occur in Europe for this scenario. The shares of hard coal (HC), brown coal (BC) and heavy fuel oil (HFO) decline drastically. On the other hand, gas consumption hardly increases because it is rather high already in the baseline projection. Hydropower (HYD+HYS), biomass (OS1), other renewables (e.g., wind energy (WND) and others such as geothermal energy and solar PV) increase significantly. In addition, there are significant reductions in electricity production resulting from electricity savings in the domestic sector.

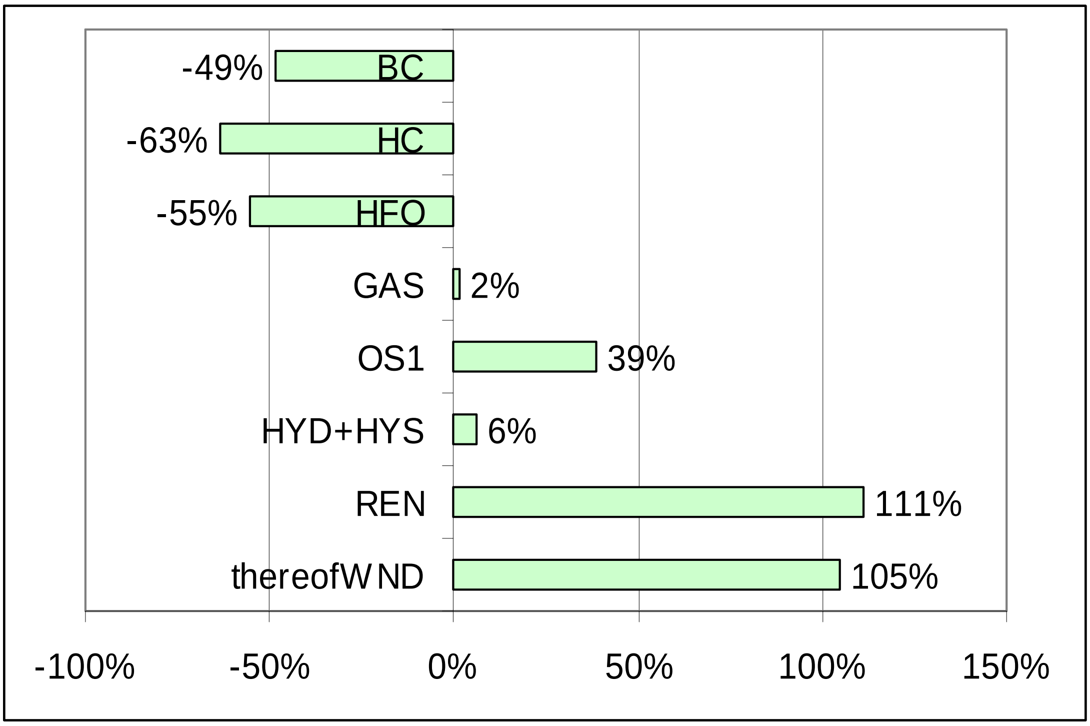

Figure 6.3: Fuel shifts in the power sector for the maximum application scenario relative to the baseline projection in 2020.

6.6 Mitigation potential in the transport sector

In the baseline scenario, transport emissions in the model domain increase by nearly 50 percent between 1990 and 2020 (Table 6.6). This increase occurs despite the fuel-efficiency improvements expected from the voluntary agreement with the European car industry to reduce CO_2 emissions from passenger cars. Given the assumptions on the penetration of technologies and the availability of alternative fuels, maximum implementation of the options included in GAINS would lower the increase in emissions to 12 percent compared to 1990. This is equivalent to a reduction of 25 percent compared to the baseline emissions in 2020.

The average costs of these measures amount to 215 €/ton CO_2 avoided. These costs do not include fuel taxation, which are ignored in the calculation since they represent transfer payments and not resource costs. Costs vary from country-to-country due to differences in the composition of the vehicle fleet and differences in the annual mileage driven. Total costs of the maximum reductions of about 400 Mt CO_2 amount to 86 billion €/year.

Technology- and fuel changes in this maximum scenario are presented in **Error! Reference source not found.**. Light duty vehicles (LDV), improved diesel (MD) and gasoline (GSL) engines of the baseline projection are replaced by advanced (ADV, hybrid) versions that partially use bio-diesel, ethanol and natural gas. Hydrogen (H2) also gains a small share in the market. Heavy-duty vehicles shift from the standard and the improved vehicle to the advanced heavy-duty vehicles, which, to the extent possible, use biodiesel and hydrogen.

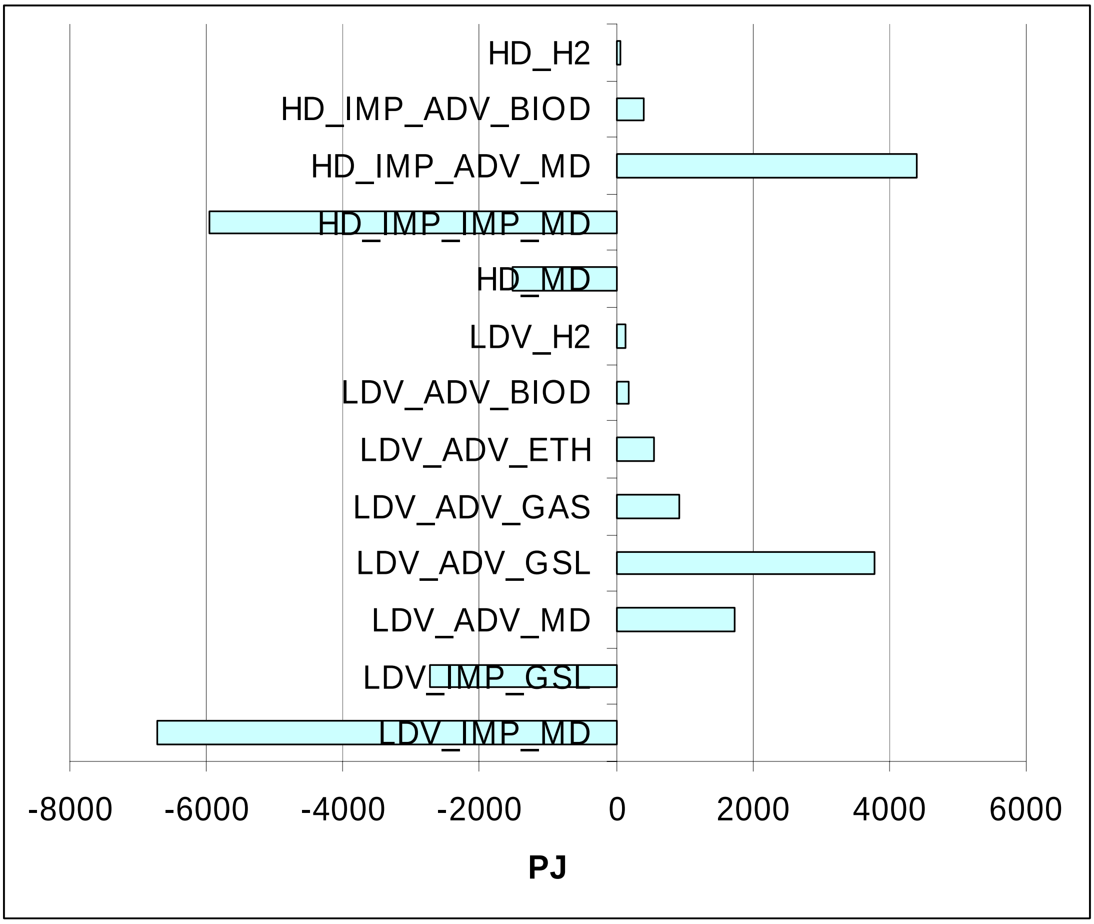

Figure 6.4: Fuel and technology shifts in the transport sector (MFR relative to baseline).

Table 6.6: Carbon dioxide emissions and mitigation costs for the transport sector for the maximum application of GAINS measures

TRANSPORT	*1990* *Mt CO_2*	*Baseline* *Mt CO_2* *2020*	*MFR avoided emissions* *Mt CO_2* *2020*	*MFR Remaining emissions* *Mt CO_2* *2020*	*MFR emission reduction* *cf. 2020* *2020*	*Annual costs* *Million €* *2020*	*Average costs* *€/t CO_2* *2020*
Albania	1	2	0.6	1	30%	170	283
Austria	14	24	6.3	18	26%	1058	168
Belarus	13	17	3.6	14	21%	1032	287
Belgium	21	30	8.6	21	29%	1818	211
Bosnia-H.	2	3	0.7	2	23%	208	297
Bulgaria	10	9	2.0	7	22%	610	305
Croatia	4	6	1.3	5	22%	410	315
Cyprus	1	3	0.7	2	23%	105	150
Czech Rep.	11	16	4.0	12	25%	1245	311
Denmark	13	15	3.5	12	23%	792	226
Estonia	2	3	0.7	2	23%	218	311
Finland	13	14	3.6	10	26%	501	139
France	120	171	47.7	123	28%	5134	108
Germany	163	225	61.4	164	27%	13277	216
Greece	18	28	6.0	22	21%	1707	285
Hungary	9	15	4.2	11	28%	1224	291
Ireland	5	15	4.4	10	29%	1180	268
Italy	114	146	36.1	110	25%	7504	208
Latvia	3	4	1.0	3	25%	279	279
Lithuania	4	6	1.6	4	27%	465	291
Luxembourg	3	7	2.1	5	30%	303	144
Macedonia	1	2	0.5	1	25%	168	336
Malta	0	1	0.2	1	20%	38	190
Moldova	2	3	0.5	2	17%	138	276
Netherlands	28	47	11.6	35	25%	3192	275
Norway	12	16	3.1	13	19%	950	306
Poland	28	51	12.5	38	25%	4080	326
Portugal	12	30	8.3	22	28%	1777	214
Romania	16	26	6.6	19	25%	1981	300
Russia-Kalin.	1	1	0.3	1	30%	80	267
Russia-Kola	4	4	0.7	3	18%	171	244
Russia-other	123	153	26.3	127	17%	7202	274
Russia-St.Peters	6	8	1.7	6	21%	494	291
Serbia-M.	7	8	1.5	7	19%	494	329
Slovakia	5	9	2.6	6	29%	730	281
Slovenia	2	5	1.2	4	24%	423	353
Spain	62	120	32.5	88	27%	5677	175
Sweden	22	24	6.0	18	25%	1265	211
Switzerland	14	17	4.4	13	26%	1265	288
Turkey	32	105	20.5	85	20%	3912	191
Ukraine	34	60	12.0	48	20%	3339	278
UK	122	151	41.1	110	27%	9246	225
EUROPE	1077	1598	394	1205	25%	85862	218
EU-25	808	1177	312	865	27%	64270	206

6.7 Mitigation potential in industry

Although GAINS model distinguishes a number of individual industrial sectors (combustion processes in refineries, coke oven plants), industrial boilers and other combustion processes (i.e., furnaces), as well as process emissions (i.e., cement and lime production), this analysis presents aggregated results. Emissions from this sector decline in the baseline projection from around 1,800 Mt CO_2 down to nearly 1,400 Mt CO_2, inter alia due to the assumed autonomous implementation of CO_2 mitigating measures for which negative costs are calculated (Table 6.7). Beyond these measures, the maximum application case leads to a further reduction of industrial emissions of around 13 percent in 2020 compared to the baseline (Figure 6.5).

Costs of these further reductions are moderate, with significantly lower average costs than in other sectors. Significant potentials for further reductions exist in the iron & steel and in the food & other industry sectors, which make up more than half of the reductions computed for the maximum case. While costs for additional measures in the iron & steel industry and in refineries are high, cost-effective reductions are estimated for the food & other industry sectors. However, there are a number of uncertainties associated with these estimates.

Firstly, for some countries there is insufficient information on the sectoral split of fuel consumptions available in the International Energy Agency (IEA) statistics, which might lead to an overestimate of the emissions especially in the food & other industries sector for some countries (e.g., for the Ukraine). A systematic underestimate of the estimates is caused by the fact that the present GAINS approach does not account for an additional potential for co-generation in the industrial sector beyond what is assumed in the baseline projection.

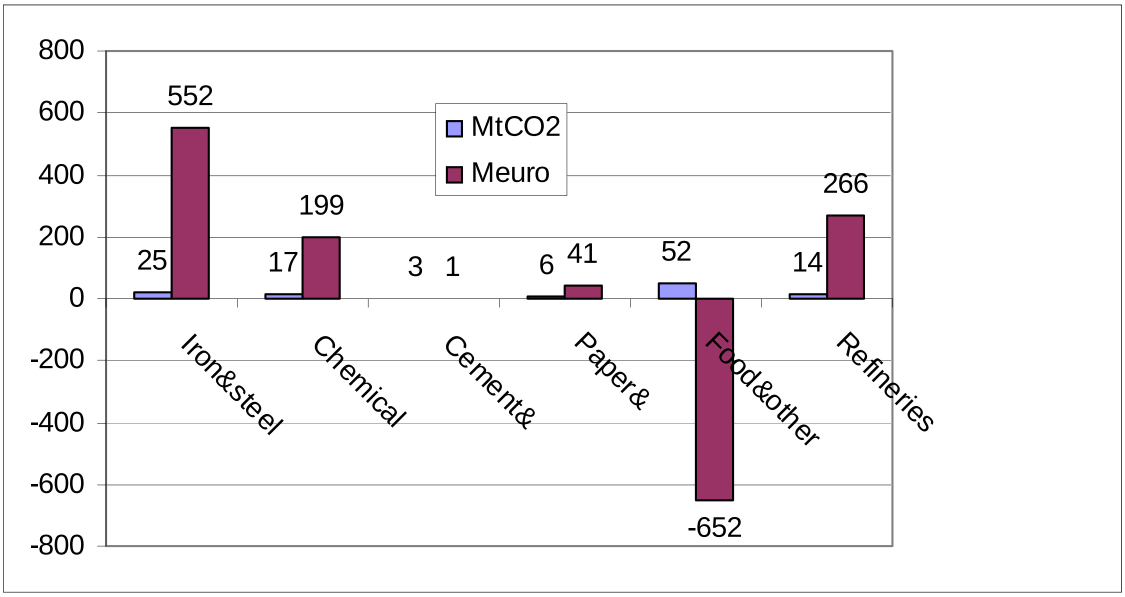

Figure 6.5: Maximum potential for CO_2 reductions and associated costs in the industrial sector relative to the baseline energy projection.

Table 6.7: Carbon dioxide emissions and mitigation costs for the industrial sector for the maximum application of GAINS measures

INDUSTRY	*1990* *Mt CO_2*	*Baseline* *Mt CO_2* *2020*	*MFR avoided emissions* *Mt CO_2* *2020*	*MFR Remaining emissions* *Mt CO_2* *2020*	*MFR emission reduction* *cf. 2020* *2020*	*Annual costs* *Million €* *2020*	*Average costs* *€/t CO_2* *2020*
Albania	3	2	0.0	2	2	2	49
Austria	16	14	2.7	11	26	63	23
Belarus	24	10	1.7	8	22	96	57
Belgium	42	35	6.5	28	25	177	27
Bosnia-H.	4	3	0.0	3	2	3	63
Bulgaria	19	9	2.0	7	38	8	4
Croatia	8	7	0.1	7	2	7	70
Cyprus	1	2	0.0	2	2	1	59
Czech Rep.	37	26	3.5	22	18	43	12
Denmark	10	7	0.7	6	13	17	24
Estonia	3	1	0.4	1	52	9	23
Finland	21	21	2.0	19	11	43	22
France	128	104	23.7	81	29	184	8
Germany	223	138	17.7	120	18	552	31
Greece	19	24	1.5	23	14	31	21
Hungary	13	11	1.2	10	17	35	29
Ireland	5	7	0.7	6	14	16	23
Italy	121	100	8.8	91	14	202	23
Latvia	3	2	0.5	2	35	-9	-18
Lithuania	8	3	0.9	2	45	26	29
Luxembourg	6	3	0.0	3	1	0	52
Macedonia	4	3	0.0	3	1	1	36
Malta	0	0	0.0	0	0	0	0
Moldova	3	3	0.7	2	24	21	30
Netherlands	41	35	8.4	27	28	258	31
Norway	13	18	0.6	18	3	27	45
Poland	63	64	7.8	56	18	208	27
Portugal	14	21	2.2	19	19	23	10
Romania	70	27	2.6	25	15	64	25
Russia-Kalin.	1	1	0.1	1	6	2	20
Russia-Kola	9	6	0.2	5	5	7	35
Russia-other	324	247	25.4	222	15	1115	44
Russia-St.Peters	12	8	0.5	8	6	16	32
Serbia-M.	12	12	0.3	12	3	14	47
Slovakia	21	11	0.8	10	12	39	49
Slovenia	4	3	0.1	3	4	4	40
Spain	73	85	8.4	77	17	58	7
Sweden	18	22	4.0	18	21	158	40
Switzerland	8	9	0.2	9	3	7	35
Turkey	57	112	14.2	98	27	433	30
Ukraine	224	124	29.1	95	28	931	32
UK	119	96	10.7	85	13	110	10
EUROPE	1805	1438	191	1247	13	5003	26
EU-25	1007	835	113	722	14	2248	20

6.8 Mitigation potential in the residential and commercial sector

Carbon dioxide emissions from the domestic sector decrease in the baseline scenario by approximately 11 percent compared to 1990. Given the assumptions on the potential penetration of natural gas, alternative fuels and insulation, measures that are included in the GAINS databases could reduce emissions further by an additional six percent in 2020, compared to the baseline (see Table 6.8). Annual costs of these measures are calculated at 14 billion €/year or approximately 260 €/t CO_2 avoided.

The maximum reduction case would entail increases in the use of solar thermal heating with (SOLAR_INS) and without insulation of the buildings (SOLAR). In addition, the use of biomass (with and without insulation) would increase by around 27 percent compared to the baseline. Finally, insulation at gas-heated homes (GAS_INS) would increase by around 12 percent. These increases would go at the expense of the use of oil (with and without insulation: MD and MD_INS) and natural gas without insulation (GAS) (Figure 6.6).

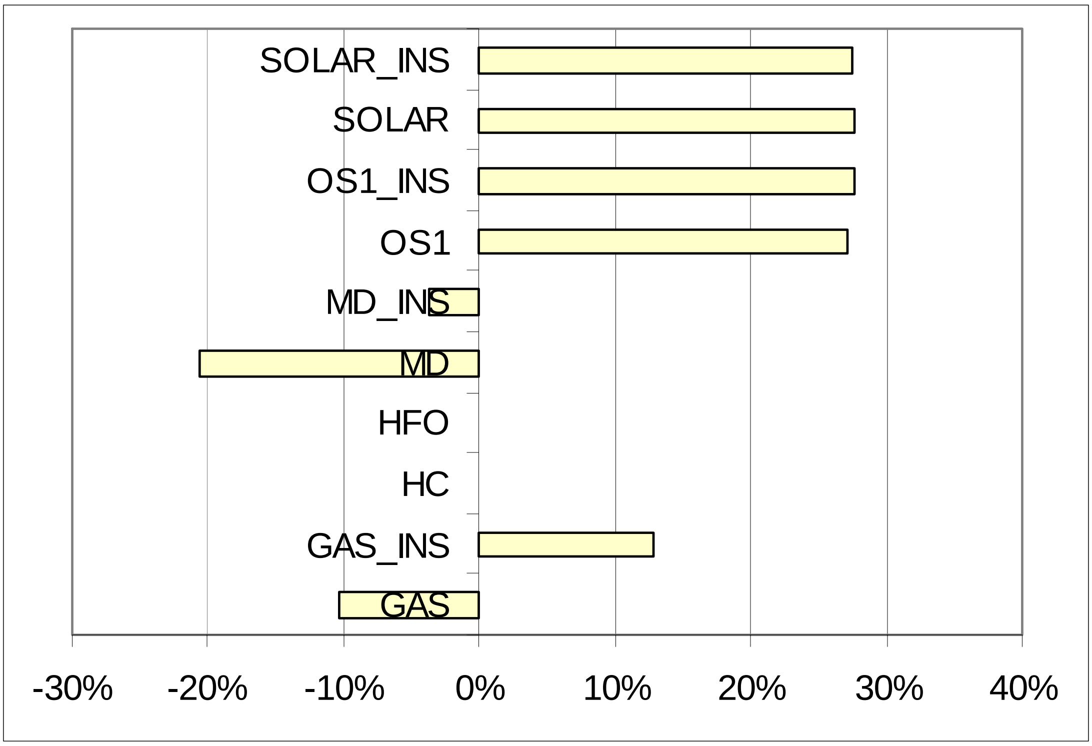

Figure 6.6: Fuel shifts in the domestic sector for the maximum carbon dioxide (CO_2) reduction case, in comparison to the baseline levels projected for 2020.

Table 6.8: Emissions of carbon dioxide (CO_2) and costs of the maximum application of GAINS measures in the domestic sector.

DOMESTIC	*1990* *Mt CO_2*	*Baseline* *Mt CO_2* *2020*	*MFR avoided emissions* *Mt CO_2* *2020*	*MFR Remaining emissions* *Mt CO_2* *2020*	*MFR emission reduction* *cf. 2020* *2020*	*Annual costs* *Million €* *2020*	*Average costs* *€/t CO_2* *2020*
Albania	1	1	0.1	1	15%	34	340
Austria	12	11	1.7	9	16%	205	122
Belarus	18	10	0.2	10	2%	35	211
Belgium	24	26	0.8	26	3%	187	234
Bosnia-H.	1	2	0.0	2	2%	-4	114
Bulgaria	7	2	0.3	2	13%	94	299
Croatia	4	5	0.3	5	6%	52	175
Cyprus	0	0	0.0	0	12%	0	0
Czech Rep.	27	11	0.3	10	2%	100	389
Denmark	6	5	0.6	4	12%	22	40
Estonia	2	1	0.1	0	18%	30	313
Finland	7	4	0.8	4	18%	128	162
France	83	95	7.3	87	8%	1498	205
Germany	213	159	8.8	150	6%	948	108
Greece	6	11	1.2	9	12%	407	333
Hungary	18	15	0.4	15	3%	170	435
Ireland	10	9	0.4	9	5%	48	108
Italy	70	81	2.9	78	4%	625	213
Latvia	5	1	0.1	1	9%	30	349
Lithuania	5	2	0.3	2	14%	101	346
Luxembourg	1	2	0.0	2	3%	-5	-109
Macedonia	0	0	0.0	0	1%	2	400
Malta	0	0	0.0	0	5%	-1	-111
Moldova	7	4	0.1	4	1%	12	218
Netherlands	38	40	1.0	39	3%	378	361
Norway	2	2	0.3	1	18%	28	99
Poland	55	43	2.6	41	6%	868	332
Portugal	2	7	1.0	6	15%	676	647
Romania	14	17	1.4	16	8%	560	407
Russia-Kalin.	2	1	0.0	1	1%	1	83
Russia-Kola	2	2	0.1	2	6%	25	195
Russia-other European area	128	93	7.0	86	8%	1512	216
Russia-St.Petersburg	7	8	0.7	7	10%	141	194
Serbia-M.	3	2	0.1	2	3%	-5	-98
Slovakia	11	5	0.1	5	2%	57	487
Slovenia	2	3	0.2	2	7%	13	84
Spain	21	34	1.9	32	6%	1436	766
Sweden	6	5	0.4	5	8%	0	0
Switzerland	20	14	0.5	13	3%	55	117
Turkey	23	40	4.9	35	12%	2477	503
Ukraine	115	80	1.2	79	1%	428	353
UK	107	111	2.7	108	3%	699	261
EUROPE	1088	964	52.9	911	6%	14067	266
EU-25	734	681	35.7	645	5%	8620	241

7 Conclusions

Many of the traditional air pollutants and greenhouse gases have common sources, offering a cost-effective potential for simultaneous improvements for both air pollution problems and climate change. A methodology has been developed to extend the RAINS integrated assessment model to explore synergies and trade-offs between the control of greenhouse gases and air pollution. With this extension, the GAINS model (**G**HG-**A**ir pollution **IN**teraction and **S**ynergies) allows for the assessment of emission control costs for the six greenhouse gases covered under the Kyoto Protocol (CO_2, CH_4, N_2O and the F-gases) together with the emissions of air pollutants SO_2, NO_x, VOC, NH_3 and PM.

On the whole, the GAINS methodology enables a consistent evaluation of emission control costs for greenhouse gases and air pollutants, so that costs can be readily compared across the pollutants. For the first time, this methodology allows an analysis of the potential and costs of fuel substitution measures for the reduction of pollution, so that these structural changes can be compared with add-on emission control measures on a consistent basis.

This report describes the GAINS methodology for estimating emissions, costs and control potentials for carbon dioxide (CO_2) emissions in Europe and discusses the initial results from a first implementation for 42 European countries. To the maximum meaningful and feasible extent, GAINS emission estimates are based on methodologies and emission factors proposed by the Intergovernmental Panel on Climate Change (IPCC) reporting guidelines. Even the provisional emission estimates of GAINS match reasonably well with other emission inventories, such as the national submissions to United Nations Framework Convention on Climate Change (UNFCCC), although certain discrepancies need further analysis.

The RAINS extension allows projections of future greenhouse gas emissions for a range of exogenous driving forces (e.g., economic development), consistent with projections of air pollution emissions. GAINS Version 1.0 assesses 230 options for reducing emissions from the various source categories, both through structural changes in the energy system (fuel substitution, energy efficiency improvements) and through end-of-pipe measures (e.g., carbon capture). GAINS quantifies for 42 countries/regions in Europe country-specific application potentials of the various options in the different sectors of the economy and estimates the societal resource costs of these measures. Mitigation potentials are estimated in relation to an exogenous baseline projection that reflects current planning and are derived from a comparison of scenario results for a range of carbon prices obtained from detailed energy models.

A critical element of the GAINS assessment refers to the assumptions on CO_2 mitigation measures for which negative life cycle costs are calculated. There are a number of options for which the accumulated (and discounted over time) cost savings from reduced energy consumption outweigh their investments, even if private interest rates are used. If the construction of the baseline projection assumes a cost-effectiveness rationale, such measures would be autonomously adopted by the economic actors, even in the absence of any CO_2 mitigation interest. However, in practice it can be observed that various market imperfections impede the autonomous penetration. Due to the substantial CO_2 mitigation potential that is associated with such negative cost options, projections of future CO_2 emissions and even more of the available CO_2 mitigation potentials are highly sensitive towards assumptions on their autonomous penetration rates occurring in the baseline projection.

For GAINS Version 1.0 the Energy Outlook developed by the Directorate General for Energy and Transport of the European Commission (Mantzos *et al.*, 2003) has been adopted as the baseline energy projection.

Assuming that all negative cost measures would form integral part of that baseline projection, CO_2 emissions in Europe would approach 1990 levels in 2020, even in absence of any specific climate policy. Beyond that, GAINS estimates for 2020 an additional reduction potential of 20 percent. Total costs of all these measures would amount to approximately 90 billion €/year. The initial analysis suggests for 2020 a mitigation potential of 550 Mt CO_2 from the power sector in the EU-25. This can be materialized through fuel shifts towards biomass, wind energy and other renewables (hydropower, solar PV and others), combined with electricity savings (e.g., in the domestic sector). This potential is equivalent to 24 percent of the baseline emissions in 2020, additional costs amount at 16 billion €/year.

In the transport sector, maximum introduction of advanced diesel and gasoline passenger and heavy duty vehicles using alternative fuels (biodiesel, ethanol, hydrogen and CNG) could reduce the expected baseline increase in emissions by approximately 400 Mt $CO_{2,}$ which constitutes some 25 percent of the baseline emissions in 2020, at costs of 64 billion €/year in the EU-25. In the industry sector, efficiency improvements and to a smaller extent fuel shifts could reduce emissions by approximately 200 Mt CO_2 at costs of 2 billion € per year in the EU-25. Major contributions would come from the iron & steel sector and the chemical industries as well as from food processing & other sectors. Finally, in the domestic sector, some 50 Mt CO_2 could be avoided in 2020 by introducing solar thermal heating and systems and improving insulation at annual costs of approximately nine billion €/year in the EU-25.

There are large differences in costs across countries and sectors. A ranking of mitigation measures across sectors and countries suggests that for a marginal cost of 100 €/t CO_2, 800 Mt CO_2 could be avoided in 2020. This would reduce Europe's emissions nearly 13 percent below their 1990 levels. For marginal costs of 50 €/t CO_2, 590 Mt CO_2 could be avoided in 2020, which would reduce Europe's emissions more than nine percent below their 1990 levels. These are cautious estimates and need to be interpreted with care. Additional emission reductions seem possible since this particular scenario does not include several mitigation options, such as additional co-generation in the industrial sector, fuel shifts with costs higher than 20 €/ton CO_2, and the expansion of nuclear power. Carbon capture and sequestration of CO_2 from fossil-fuel fired power plants is also excluded from this calculation for the year 2020.

Further work will be necessary to refine this assessment, especially with respect to treatment of measures for which negative life cycle costs are computed, and to include the additional mitigation potentials listed above.

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