Project No 518294 SES6
CASES
Cost Assessment of Sustainable Energy Systems

Instrument: Co-ordination Action

Thematic Priority: Sustainable Energy Systems

DELIVERABLE No. D.13.7
[Book on project activites/results]

This is a draft version the final version will be published at beginning 2009

Due date of deliverable: 30/09/2008
Actual submission date: 14/11/2008

Start date of project: 1st April 2006 Duration: 30 Months

Organisation name of lead contractor for this deliverable: **Fondazione Eni Enrico Mattei**

Revision: Anil Markandya

Project co-funded by the European Commission within the Sixth Framework Programme (2002-2006)		
Dissemination level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

The Social Cost of Electricity: Scenarios and Policy Implications

The Social Cost of Electricity: Scenarios and Policy Implications

Private and external costs assessment, policy implication and scenarios for the EU and selected non-EU Countries

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Foreword

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Introduction

This volume combines methodology and results on private and Full Costs estimation with the assessment and the evaluation of different instruments of energy policy, and the projection of electricity scenarios.

The book provides the results of the research performed by the CASES project, which is a Coordination Action on "Cost Assessment of Sustainable Energy Systems" funded by the European Commission under the Sixth Framework Programme, Sustainable Energy Systems.

Description and objectives of the CASES project

The CASES Coordination Action (CA for short) carried out its activities from April 2006 to September 2008. In this period it evaluated policy options for improving the efficiency of energy use, underpinning this evaluation with a consistent and comprehensive picture of the social cost of energy, and made this crucial knowledge available to all stakeholders.

In particular CASES compiled a complete and coherent assessment of the social cost (external plus private cost) of different electricity generation technologies, in EU countries and in selected non-EU countries, under well-defined energy scenarios to 2030.

The cost database provides an unique quantitative support to the assessment of alternative policy options in the perspective of improving the efficiency of energy use. CASES, in providing a set of recommendations on the use of different policy instruments for the internalisation of the external costs of energy production, contributes directly to policy and provides an information base on the effectiveness and on the consequences of the use of different instruments. In addition, the assessment of the Full Cost estimates of electricity generation allows policy-makers to become more aware of the consequences that different fuels and technologies have on human health, the environment and society. Finally the project disseminates research findings to energy sector producers and users, and to the policy-making community.

In detail the objectives of the CASES CA were the following:

- To compile coherent and detailed estimates of both external and internal costs of electricity generation for different energy sources at the national level for the EU-25 Countries and for some non-EU Countries under energy scenarios to 2030;
- To evaluate policy options for improving the efficiency of energy use, taking account of the Full Cost data;

- To disseminate research findings to energy sector producers and users and to the policy making community.

A complete and consistent assessment of the Full Cost of energy sources, which includes the external cost plus the private cost, is of paramount importance for energy and environmental policymaking. Energy policy making is concerned with both the supply side and the demand side of energy provision. On the supply side, deciding on alternative investment options requires the knowledge of the Full Cost of each energy option under scrutiny. On the demand side, social welfare maximisation should lead to the formulation of energy policies that steer consumers' behaviour in a way that will result in the minimisation of costs imposed to society as a whole. Demand side policies can benefit significantly from the incorporation of full energy costs in the corresponding policy formulation process.

These issues are of particular relevance when framed within the current European context of progressive enlargement and integration. In particular two recent developments are of relevance here: the liberalisation of the European markets for gas and electricity, and the recent addition of new Member States. These processes are intrinsically dynamic. New policy instruments are being developed and applied in order to cope with the changes in the policy arena, including emissions trading and the understanding of different options is continually enriching the policy framework.

In this perspective, the first objective of this Coordinated Action was to compile a consistent and detailed set of estimates of the external and internal costs of electricity generation for different technologies at the national level for the EU-25 Countries and for Turkey, Brazil, India and China, under energy scenarios to 2030. The project builds on state-of-the art methodologies to arrive at a dynamic assessment of Full Costs, by updating all the information from previous projects, such as ExternE, according to the evolution of technologies and to the expansion of knowledge on external costs. The integration of private and external costs is built within one dynamic framework, to arrive at agreed ranges of estimates, for different countries, of the Full Cost of each energy source. Following this objective, CASES provides state-of the-art projections of the evolution of energy prices and of the private and external costs of major technologies, likely to be employed to generate energy from different sources over the next 25 years.

The second objective of the CA is applying the comparative cost data of different types of electricity generation technologies, to the assessment of alternative policy options for improving the efficiency of energy use and reducing its impact on environment over the next decades. Important in this context are not only the cost estimates, but also the range of their uncertainty; a better understanding of the social and private costs also strengthens the

credibility of policy making decisions by reducing the uncertainty ranges. In this part of the project, the social and fiscal implications of a given policy measure are analysed, with an eye for the distributional consequences for poor and vulnerable groups. This assessment is dynamic and underlines the implications of different levels of internalisation on the investment decisions and on key social indicators. The analysis in addition covers the impact of the use of different methods of decision-making (the project focuses in particular on Cost-Benefit and Multi-Criteria Decision Analysis), on the selection of projects and the implications of different policies to reduce energy insecurity, now and over time. Different instruments to promote renewable energy sources are then compared in terms of the degree to which they internalise the positive externalities associated with renewable energy use.

The third objective of the project was the dissemination of the knowledge on electricity generation costs. Once evaluated and brought into a coherent framework, the results of the different components of the project are of great interest for the energy sector producers and users, as well as for the policy-making community. Dissemination consists of a set of activities to validate and disseminate the projects outputs. These activities range from publication of articles in the peer-reviewed literature, to presentations and lectures at project workshops and conferences involving key stakeholders and policy makers, and at external seminars, workshops and conferences, to open discussions with energy producers' and end-users' organisations, and of course, this book.

Institutions and research centres involved

The Consortium of the CASES's Co-ordination Action consisted of twenty-six partners established in twenty States, it covers the whole European area and also involves three institutions in two developing continents (Asia and South America).

Most of the institutions are established for research activities (11) and for higher education (9). The other participants are not specialised in one particular activity but they provide a scientific expertise and carry out complementary activities necessary to achieve the objectives of this Co-ordination Action.

Table 0.1List of institutions and research centres involved in the CASES project

Institutions involved into the CASES project
Fondazione Eni Enrico Mattei - FEEM (IT)
University of Bath - UBATH (UK)
National Technical University of Athens - NTUA (GR)
University of Stuttgart – Institute of Energy Economics and the Rational Use of Energy - USTUTT/IER (DE)
Flemish Institute for Technological Research - VITO (BE)
Danish technical University, Risoe National Laboratory - RISOE/DTU (DK)
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Energy Research Centre of the Netherlands - ECN (NL)
Vrije Universiteit Amsterdam-Institute for Environmental Studies - VU/IVM (NL)
POYRY/ECON Analysis AS - ECON (NO)
Fundação COPPETEC - COPPETEC (BR)
SWECO Grøner as - SWECO (NO)
Lithuanian Energy Institute - LEI (LT)
Indian Institute of Management Ahmedabad - IIMA (IN)
Energy Research Institute - ERI (CHN)
Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas - CIEMAT (ES)
Univerzita Karlova v Praze - Charles University Enviroment Center - CUEC (CZ)
Stockholm Environment Institute - SEI (SE)
Centre for European Policy Studies - CEPS (BE)
University of Warsaw - Warsaw Ecological Economics Center - UWARS (PL)
Energy Agency of Plovdiv - EAP (BG)
Turkiye Bilimsel ve Teknik Arastirma Kurumu - Marmara Research Center, Institute of Energy - TUBITAK (TR)
Wageningen Universiteit - WU (NL)
Istituto di Studi per l'Integrazione dei Sistemi - ISIS (IT)
Paul Scherrer Institut - PSI (CH)

Structure of the book

This work combines methodology and data on social costs with the evaluation of different instruments of energy policy, and the projection of electricity scenarios. In the book the contributions of the partners of the project are collected and harmonised. The research activities this book reports range from databases and technical reports on emissions, to private, external and social costs of electricity generation in Europe and in selected non-EU countries, to studies on electricity insecurity, on uncertainties in external costs estimation, to studies on policy assessment and on policy instruments to internalize external costs in the electricity sector and and finally, to electricity scenarios by country and primary fuel for 2010, 2020 and 2030.

This volume is divided in three parts: the first part concerns cost assessments, the second part concerns policy evaluation and the third part provides electricity scenarios up to 2030.

The first part reports on the methodologies and the results about private and external costs of electricity generation. The analysis of exernal costs includes the damage estimation on human health, environment, crops, materials and climate change (Chapter 1). Moreover, the uncertainty on external costs estimation is assessed. In the analysis performed, external (Chapter 1) costs and private costs (Chapter 3) are assessed for the whole life cycle of the power plant, from construction to dismantling, including cost of extraction and transportation of fuel and waste disposal. Following that Chapter 2 is focused on the assessment of the insecurity of supply externalities and the policy instruments to reduce electricity supply insecurity.

Costs are calculated and assessed for a wide set of technologies, which includes nuclear and fossil fired power plants, renewables and combined heat and power plants. Then social costs of electricity are calculated by summing private and external costs and are assessed as average values of all EU-27 countries (Chapter 4). In addition, a country-specific analysis is presented for selected technologies for selcted non EU countries: Brasil, India, China and Turkey (Chapter 5). The time horizon considered includes present, 2020 and 2030.

The second part of the book focuses on policy evaluation. Chapter 6 reports on a comparative analysis of instruments to internalise externalities in the electricity sector in Europe. A detailed evaluation of alternative policy options for improving the efficiency of energy use and reducing its impact on environment over the next decades is developed. This assessment is dynamic and underlines the implications of different levels of internalisation of externalities on the investment decisions and on key social indicators in Europe and in some non European countries. Policy instruments to promote renewables energy sources in Brasil, China, India and Turkey are analysed. Then Chapter 7 illustrates an analysis of the methodologies used to policy evaluation, in particular cost benefit analysis, cost effectiveness analysis and multi criteria decision analysis.

The third part of the book presents innovative electricity scenarios, which take into account social costs, by country and primary fuel for 2010, 2020 and 2030. This part shows the evolution of energy prices and of the private and external costs of major technologies, likely to be employed to generate energy from different sources over the next 25 years. In addition it analyses how the technological mix for electricity production will change from present to future if external costs were internalized. Chapter 8 describes such scenarios for the EU, while Chapter 9 extend the scenario analysis to Brazil,

China, India and Turkey.

The annex provides, in a CD-Rom, all databases on emissions, external, private and social costs and the tools used for policy evaluation. The homogeneous data templates are designed for Europe and show the values of emissions and costs by each technology at present, in 2020 and in 2030. The database of external costs includes the damage estimation on human health, environment, crops, materials and climate change. External, private and social costs are assessed for the whole life cycle of the power plant, from construction to dismantling, including cost of extraction and transportation of fuel and waste disposal.

The editors and the authors would like to thank the many people who attended the various workshops at which the outputs of this research were presented. Their comments have helped to make for a better final product. All erros and omissions, however, remain those of the editors and contributors.

Part I *Cost assessment*

1 External costs

Philipp Preiss, Rainer Friedrich, Onno Kuik, Luke Brander, Kristin Magnussen, Ståle Navrud, El Hadji Fall, Ari Rabl, Bob van der Zwaan

1.1 EXTERNALITIES AND EXTERNAL COSTS

Externalities exist in the form of external costs and external benefits. External costs occur when an economic subject causes a loss of welfare to another one and does not compensate this change of welfare. A compensation for this change of welfare due to external costs would eliminate the market imperfection caused by externalities. This procedure is called internalisation of externalities because external costs are considered in market mechanisms. In a situation where all externalities are internalised there is no relevant externality anymore although there are of course still emissions and damages.

For example, a cost-benefit analysis requires the estimation of the MDC (marginal damage costs) and MAC (marginal avoidance costs). These values should be equal in order to determine the optimum instruments and therefore, the optimum total emissions. A reasonable and practicable dimension which enables to compare costs and benefits are monetary values. Therefore, the impact pathway approach is used in order to estimate the costs of emissions and benefits of emission reduction.

The costs reveal the preferences of the society, i.e. the willingness to pay to avoid the damages.

With this assessment method, a general path from emissions to the costs and benefits is followed to estimate them as transparently, consistently and comprehensively as possible.

External Costs per kWh

External cost per kWh electricity can be calculated multiplying LCI data per kWh with generalised damage factors “Euro per unit of emission” for the corresponding region or country where these emissions take place. These generalised factors have been derived with the software tool EcoSenseWeb. The procedure to generate these averaged and aggregated external costs per

tonne of emission will be explained in more detail in the next chapters.

It has to be emphasised that the LCI data as well as the private costs per kWh are provided for average European conditions.

It has to be recognised that in reality these will vary for the technologies depending on the actual location due to several factors. These factors are for example, different fuel supply chains but also the different efficiency of thermal power plants due to different ambient temperatures.

Moreover, it has to be noted that especially the efficiency of wind and photovoltaic technologies significantly depend on the location where they operate because the availability of solar radiation or advantageous average wind speeds influence directly the life time electricity output and therefore the emissions and also the private costs per kWh.

For example, the solar radiation [kWh/m2] in Southern Italy may be up to factor 2 larger than at a middle European conditions like in Germany. Consequently the kWhs produced per year in Italy would be two times higher, and therefore, emissions per kWh in Southern Italy would be 50% of the emissions per kWh in Germany. Hence, the external costs per kWh (but also the private costs per kWh) will be only ca. 50%.

Furthermore, the location of the life cycle emissions per kWh electricity produced by renewable like onshore-wind or PV are not allocated to certain countries because the main parts like production of converters and PV modules for different countries are provided by the same producers. Moreover, the emissions include many processes and are not attributed to certain countries. Therefore, in order to calculate country specific social costs per kWh LCI data per kWh and private costs per kWh for European average conditions would need to be adjusted to the country-specific conditions. If emissions can then be attributed to different countries, country-specific damage factors can be applied.

For example, in case of solar thermal the “Solar through” is assumed to be located in Spain, because it makes no sense that such a plant would be located in countries like Germany as the direct solar radiation would not be intense enough.

Finally, for emissions due to operation of fossil and bio fuelled power plants damage factors for a certain country should be applied because this emission can be allocated to the corresponding country. For all other life cycle stages average European (EU27) damage factors should be applied because this is the best estimate regarding the location of the emissions.

Emissions due to operation of thermal power plants often have very high stacks . Therefore, for large power plants the corresponding damage factors (high stack) should be applied.

Some externalities could not be quantified and thus could not be included in the social costs. For example, with regard to nuclear, these are risk

aversion (a risk with a lower probability but higher damage is seen as worse than the same risk with higher probability, but lower damage) and the risk of terrorist attacks. For onshore or offshore wind energy converters the visual intrusion has not been quantified.

1.2 THE IMPACT PATHWAY APPROACH TO GENERATE EXTERNAL COSTS

For the calculation of site-specific marginal damages the Impact Pathway Approach should be applied for each source of emission, e.g. a coal-fired power station and the corresponding emissions from the stack.

Marginal damages have to be calculated because the creation of secondary pollutants like sulfates, nitrates and ozone depends also on the background concentration of NOx, SO_2, NH_3, NMVOC, etc.[1] Therefore, two scenarios have to be calculated, one background and one with additional, or reduced emissions.

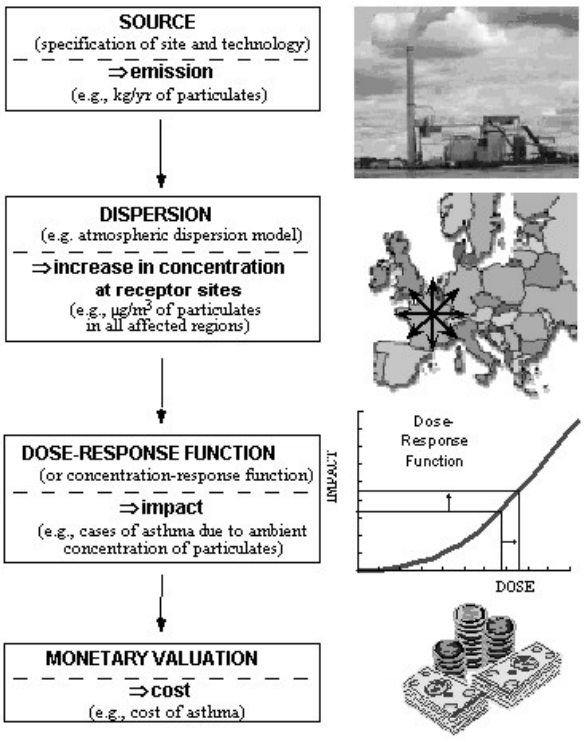


Figure 1.1 Impact Pathway Approach

The IPA (Figure 1.1) starts with the emission of a pollutant at the location of the source into the environment. It models the dispersion and chemical transformation in the different environmental media. By introducing receptor and population data, it identifies the exposure of the receptors and calculates the impacts. These impacts are then weighted and aggregated into external costs.

For many questions in research and policy we are not interested in the damages caused by one single process at a certain location but we are interested in the damages per functional unit (e.g. kWh) of a certain technology or even per economic sector in different regions, countries or sub-regions. Secondly, the high quality dispersion modelling at regional, i.e. a European scale makes it too expensive, and since the data is not available, often impossible, to perform calculations for each single source of emission.

With regard to the classical pollutants, parameterised results from an Eulerian dispersion and chemical transformation model from The Norwegian Meteorological Institute (Tarrasón, 2008) have been derived based on source receptor matrices (SRM). These SRM allow us to attribute to each unit of emission in one region a concentration or deposition increment in each of the 50 x 50 km^2 EMEP grid cells all over Europe. According to the IPA, with the aid of CRF (concentration response functions) and the number of exposed population physical impacts are then calculated for each grid cell. Finally, the impacts are weighted and aggregated by means of monetary valuation of each physical impact in order to derive external costs per unit of emission.

The following describes the approach how the country average external costs per unit of emission were derived. These values are provided in the corresponding Excel file and for specific years in the annex.

Average values for classical air pollutants, greenhouse gases, heavy metals, formaldehyde and dioxins and several radionuclides for countries within Europe and North Africa are included. Different heights of release and different time of release are taken into account, as far as methodologically feasible at the moment.

Emission weighted European averages which can be used for evaluation of emissions located in the EU27 are also provided. These values can be used for up- and downstream process for which the location can not be identified. Since they are emission-weighted, this is an approximation if the location within Europe is not known.

The values for classical air pollutants in Europe correspond to different heights of release and different time of release. The time of release has to be specified in the spreadsheet “Assumption”. The values are based on

parameterised results of an Eulerian dispersion model developed and applied by MET.NO (Tarrasón, 2008).

Results are available for emission of so called classical pollutants: NH_3, NMVOC, NO_x, PPM_{coarse}, $PPM_{2.5}$, SO_2.

Results are available for emissions in 39 European and non-European countries and 5 sea regions. The receptor domain covers the whole of Europe. Impacts included are impacts to human health, crops, damage to materials and loss of biodiversity. Population data is taken from SEDAC (2006).

With a Northern Hemispheric model (Tarrasón, 2006) external costs due to impacts to human health outside Europe caused by emissions of classical pollutants in Europe have been estimated and included. A simplifying assumption is that the impacts to human health outside of Europe are evaluated with the same monetary values as impact within Europe.

Moreover, with the same model, for emissions in five North African countries, external costs within these countries as well as in Europe and in the Northern Hemisphere have been calculated.

For heavy metals, formaldehyde, dioxins and several radionuclide species values for impact assessment and external costs are taken from other studies; regarding heavy metals values for the pathway inhalation are taken from ESPREME, whereas for As, Cd, Pb due to ingestion, they are newly calculated with the WATSON mode. For Hg value is taken from Spadaro and Rabl (2007b).

The evaluation of greenhouses gases is a very contentious issue because the assessment of the impacts is highly uncertain. Moreover, since the impacts are spread all over the whole world and into the future, the monetary evaluation is dependent on value choices, like discounting and equity weighting. Nonetheless, with regard to impact assessment and external costs evaluation of energy technologies the recommendations have a decisive and crucial influence on the results and corresponding decisions. Therefore, different approaches based on impact assessment as well as on the standard price approach have been used to provide a reasonable range of estimates of the external costs.

1.3 DISPERSION & CHEMICAL TRANSFORMATION OF CLASSICAL AIR POLLUTANTS IN EUROPE

Model runs were performed with the EMEP/MSC-West Eulerian dispersion and chemical transformation model by MET.NO. These model runs are based on emission scenarios, i.e. including spatial distribution of different sources

on a 50 x 50 km^2 EMEP grid. Model runs have been performed which take into account all source and total emission data. Secondly, model runs have been performed reflecting the emissions and corresponding impacts of only SNAP sector S1, i.e. "Combustion in energy and transformation industry", i.e. very high stacks. Since meteorological data differ from one year to another not only one but a set of representative meteorological years have been chosen by MET.NO. To derive the SRM for each pollutant in a certain region a reduction of each pollutant by 15% for each source of emission within a corresponding sub-region is modelled separately. Europe is divided into 66 regions, i.e. some larger countries are subdivided into sub-regions.

The countries and sea areas covered are listed in Table 1.1.

Table 1.1 countries and sea areas

EU27 countries				Non-EU27		SEA areas(5)	
AT	Austria	IE	Ireland	AL	Albania	ATL	Remaining N.E. Atlantic
BE	Belgium	IT	Italy	BA	Bosnia and Hercegovina	BAS	Baltic Sea
BG	Bulgaria	LT	Lithuania	BY	Belarus	BLS	Black Sea
CY	Cyprus	LU	Luxembourg	CH	Switzerland	MED	Mediterranean Sea
CZ	Czech Republic	LV	Latvia	CS	Serbia and Montenegro	NOS	North Sea
DE	Germany	MT	Malta	HR	Croatia		
DK	Denmark	NL	Netherlands	MD	Republic of Moldova		
EE	Estonia	PL	Poland	MK	The FYR of Macedonia		
ES	Spain	PT	Portugal	NO	Norway		
FI	Finland	RO	Romania	RU	Russian Federation		
FR	France	SE	Sweden	TR	Turkey		
GB	United Kingdom	SI	Slovenia	UA	Ukraine		
GR	Greece	SK	Slovakia				
HU	Hungary						

Subdivision of countries in sub areas: Germany in four areas, France: in seven areas, United Kingdom in three areas, Spain in five areas, Poland in three areas, , Italy, Norway, Sweden, Finland and Ucraine in two areas each.

Methodology

For a 15% reduction of an airborne pollutant (e.g. NO_x) within a country/sub-region of Europe (e.g. Belgium = BE) based on meteorological conditions (e.g. in the year 2000) and background emissions of e.g., assumed for the year 2010 a model run was performed by MET.NO. The result is a matrix covering the resulting concentration of different pollutants in each of the 50 x 50 km^2 grid cell of the EMEP grid. This matrix contains the results in terms of concentrations of a primary (NO_x) or secondary (nitrates and ozone, increased sulphates, etc.) air pollutants on the grid. The chemical reactions and interactions are quite complex. For example, a reduction of NO_x emissions in regions where also NH_3 is emitted say, by agricultural processes, leaves more background NH_3 for reaction with background SO_2 than without reduction of NO_x . The reaction of additional free NH_3 and SO_2, increases the concentration of sulphates at certain locations, downwind.
Table 1.2 shows some of the primary and secondary pollutants and depositions provided by the regional and Northern Hemispheric dispersion model.

Table 1.2 Primary and secondary airborne pollutants

Shortcut	Comment	Unit
aNH_4	ammonium particles (ammonium nitrate and sulphate)	$\mu gN/m^3$
aNO_3	nitrate particles with diameter below 2.5µm	$\mu gN/m^3$
DDEP_OXN	total dry deposition of oxidized nitrogen	mg/m^2
DDEP_RDN	total dry deposition of reduced nitrogen	mg/m^2
DDEP_SOX	total dry deposition of sulphur	mg/m^2
NO_x	$NO_x = NO_2 + NO$	$\mu gN/m^3$
pNO_3	nitrate particles with diameter above 2.5 a. below 10 µm	$\mu gN/m^3$
SIA	secondary inorganic aerosols	$\mu g/m^3$
SO_4	sulphate, includes also ammonium sulphate	$\mu gS/m^3$
$SOMO_{35}$	sum Over Means Over 35 ppb	ppb day
tNO_3	total coarse and fine nitrate aerosols	$\mu gN/m^3$
WDEP_OXN	wet deposition of oxidized nitrogen	mg/m^2
WDEP_RDN	wet deposition of reduced nitrogen	mg/m^2
$WDEP_SO_x$	wet deposition of sulphur	mg/m^2
PPM_{25}	primary particles with diameter below 2.5 µm	$\mu g/m^3$
PPM_{co}	primary particles with diameter between 2.5 and 10 µm	$\mu g/m^3$

SIA includes all secondary inorganic particles with an aerodynamic diameter < 10µm. It consists mainly of ammonium nitrate and sulphates. However, sulfates are mainly smaller than 2.5 µm. Therefore, $SIA_{2.5}$ and SIA_{coarse} are derived to be able to apply the concentration response functions

(CRF) regarding impacts to human health.

Different Meteorological Years

Based on meteorological years 1996, 1997, 1998 and 2000, average results have been derived representing typical conditions of the present. This exercise has been performed in order to reflect not only one, more or less arbitrary year, but more typical and average conditions like wind speed, wind direction, precipitation, temperature, stability, etc.

The year 2003 was an exceptional warm one in Europe. Therefore, the results based on meteorological year 2003 can be used to estimate future conditions, reflecting the influence of climate change.

Different Background Emission Scenarios in 2010 and 2020

Sine the background concentration of NH_3, NMVOC, NO_X and SO_2 influences the creation of secondary pollutants (sulphates, nitrates, ozone) two set of SRM are available. One corresponds to a emission scenario in 2010 and second corresponds to emission scenario in 2020. For most countries the emissions in 2020 are lower than in 2010. Because of non-linearity of the chemistry the creation of secondary pollutants and hence the marginal damage per unit of emission differs between the two scenarios as can be observed in the Excel file.

It has to be emphasised that because of non-linear atmospheric chemistry and because of different background concentrations of e.g. NO_x and NMVOC, especially with regard to ozone there can occur large differences in [Euro per tonne] values. Negative external costs can occur for NO_x emission in 2010 but also for a few locations / cells in Europe in 2020.

It is recommendable, especially with regard to cost-benefit analysis for future measures, to use the set corresponding to the conditions in 2020.

If in the "Assumption" years between 2000 and 2014 are defined, the dispersion results reflecting background emissions in 2010 are used. All other future years are based on 2020 background emissions.

Different Height of Release

The SRM have been derived by simulation of 15% emission reduction in each sub-region. This has been done in two ways, providing two sets of SRM, i.e.

- for pollutants from all sources, i.e. all SNAP sectors (i.e., including transport, industry, domestic firing systems, but also combustion plants),

and

- for pollutants (primary particles, SO_2 and NO_x) from for SNAP sector 1 (combustion in power plants) only.

Since the first SRM set provide an average value for all emissions, these values can be used if the height of release is unknown. The second SRM corresponds to releases above 100m. Further processing of the results allowed to derive values (in Euro per tonne of pollutant), corresponding to low release height for primary particulate matter, i.e. below 100m. If the height of release is unknown, as it often the case in LCI data which includes all life cycle stages of a product, the corresponding values called "Unkno_Height of Release_20xx_xx" should be used. For emissions from power plants the results according to "High Height of Release" should be used.

Dispersion and Chemical Transformation in North African Countries

SRM for emissions in five North African Countries have been provided, too. For each of these countries, namely, Algeria, Morocco, Tunisia, Egypt and Libya, the model runs with the corresponding EMEP/MSC-West Eulerian dispersion model have been performed.

The results of the model runs have been used to estimate the concentration increments, and further, the accumulated exposure within the source countries, within Europe and within the Northern Hemisphere.

However, there was no distinction in terms of different heights of release. The results are based on meteorological year 2001 and an emission scenario for 2000.

Dispersion and Chemical Transformation in the Northern Hemisphere

The external costs are displayed in the spreadsheet separately and correspond to impacts to human health, outside the regional area of Europe, caused by emissions within Europe. The values are derived by applying the same monetary values per impact to all countries of the Northern Hemisphere as within Europe, disregard whether the impacts take place in America or Asia, etc.

The introduction of the North Hemispheric range, within EcoSenseWeb has expanded the range of analysis. The concept of hemispheric range analysis results from the need of performing an estimation of the intercontinental influence on concentrations of primary and secondary airborne pollutants. Analysis is based on corresponding EMEP/MSC-West Eulerian dispersion model runs which produced source-receptor relationships at the hemispheric scales for four regions of the Northern Hemisphere.

The emissions data are based on /Edgar 2000/ data, and within the EMEP area EMEP emissions are used. Meteorological input data correspond to the year 2001. The methodology is described in more detail in the Technical Paper by Tarrasón (2006). The Northern Hemisphere has been divided into four areas: Far East (FE), Middle East (ME), North America (NA), Europe (EU). For the purpose of NEEDS a fifth region (WEU) has been included, where Russia has been excluded from Europe.

The effect of reductions of six different pollutants (NO_x, SO_2, NMVOC, NH_3, $PPM_{2.5}$ and PPM_{co}) has been computed. Each scenario reduces, similar to the regional SRM, one pollutant from one area by 15%. SR-matrices are provided in a way, that the standard impact assessment is based on a 100 x 100 km^2 grid which is derived from the EMEP 50 x 50 km^2 grid. Further explanation can be found in the EMEP Status Report (1/06) at page 2 and 3.

1.4 PHYSICAL IMPACTS TO HUMAN HEALTH, CROPS AND MATERIALS AND DAMAGE EXPRESSES AS EXTERNAL COSTS

According to the IPA, the physical impact to the receptors can be calculated by multiplying the concentration or deposition in each grid cell with the number of receptors, e.g. population or surface area, and by a factor per unit of concentration or deposition. The impact over the whole area of Europe is than summed up. The methods are further described below.

Concentration Response Functions (CRF) and monetary values for Human Health impacts - Classical air pollutants

Table 1.3 gives an overview of the concentration response functions for PM and ozone and corresponding monetary values.. These are the most important and reliable concentration response functions (core). The corresponding monetary values demonstrate the different severity of the endpoints. Since the probability of the less severe endpoints is much higher they also contribute considerably to the total external costs. Nonetheless, the reduced life time expectancy (YOLL, Years of life lost) is the most important endpoint.

The research regarding toxicity of secondary particles and direct effects of NO_2 is still progressing. A set of so called core CRF is available in Torfs et al, (2007). Since the secondary particles (nitrates and sulfates, Secondary Inorganic Aerosols) are assumed to be equally toxic as the Primary Particulate Matter this set of CRF is called “SIA_E_PPM”. However, the

research and the assumptions of the toxicity of nitrates and sulphates, and the relation to N_2O is still controversially discussed and sensitivity assessments are also possible.

Table 1.3 Overview of the concentration response functions for PM and ozone and corresponding monetary values

Core Endpoints										
	Pollutant	**Risk group (RG)**	**RGF value**	**Age Groupe (AG)**	**AGF value**	**CRF** [1/(µg/m3)]	**phys. Impact** per person per µg per m3 [1/(µg/m3)]	**unit**	**Monet Val** per case or per YOLL [Euro]	**External costs** per person per µg per m3 [1/(µg/m3)]
primary and SIA < 2.5, i.e. Particle < 2.5µm										
Life expectancy reduction - YOLLchronic	PM2.5	all	1.000	Total	1	6.51E-04	6.51E-04	YOLL	40,000	2.60E+01
netto Restricted activity days (netRADs)	PM2.5	all	1.000	MIX	1	9.59E-03	9.59E-03	days	130	1.25E+00
Work loss days (WLD)	PM2.5	all	1.000	Adults_15_to_64_years	0.672	2.07E-02	1.39E-02	days	295	4.10E+00
Minor restricted activity days (MRAD)	PM2.5	all	1.000	Adults_18_to_64_years	0.64	5.77E-02	3.69E-02	days	38	1.40E+00
primary and SIA < 10, i.e. Particle < 10µm										
Increased mortality risk (infants)	PM10	infants	0.002	Total	0.009	4.00E-03	6.84E-08	cases	3,000,000	2.05E-01
New cases of chronic bronchitis	PM10	all	1.000	Adults_27andAbove	0.7	2.65E-05	1.86E-05	cases	200,000	3.71E+00
Respiratory hospital admissions	PM10	all	1.000	Total	1	7.03E-06	7.03E-06	cases	2,000	1.41E-02
Cardiac hospital admissions	PM10	all	1.000	Total	1	4.34E-06	4.34E-06	cases	2,000	8.68E-03
Medication use / bronchodilator use	PM10	Children meeting PEACE criteria - EU average	0.200	Children_5_to_14	0.112	1.80E-02	4.03E-04	cases	1	4.03E-04
Medication use / bronchodilator use	PM10	asthmatics	0.045	Adults_20andAbove	0.798	9.12E-02	3.27E-03	cases	1	3.27E-03
Lower respiratory symptoms (adult)	PM10	symptomatic_adults	0.300	Adults	0.83	1.30E-01	3.24E-02	days	38	1.23E+00
Lower respiratory symptoms (child)	PM10	all	1.000	Children_5_to_14_years	0.112	1.86E-01	2.08E-02	days	38	7.92E-01
Ozone [µg/m3] - from SOMO35										
Increased mortality risk	SOMO35	Baseline_mortality	0.0099	Total (YOLL = 0.75a/case	1	3.00E-04	2.23E-06	YOLL	60,000	1.34E-01
Respiratory hospital admissions	SOMO35	all	1.000	Elderly_65andAbove	0.158	1.25E-05	1.98E-06	cases	2,000	3.95E-03
MRAD	SOMO35	all	1.000	Adults_18_to_64_years	0.64	1.15E-02	7.36E-03	days	38	2.80E-01
Medication use / bronchodilator use	SOMO35	asthmatics	0.045	Adults_20andAbove	0.798	7.30E-02	2.62E-03	cases	1	2.62E-03
LRS excluding cough	SOMO35	all	1.000	Children_5_to_14_years	0.112	1.60E-02	1.79E-03	days	38	6.81E-02
Cough days	SOMO35	all	1.000	Children_5_to_14_years	0.112	9.30E-02	1.04E-02	days	38	3.96E-01

Where:
Risk Group RG: group within the general population with handicap
RGF value: Share of RG within the general population
Age group AG: groups distinguished by different age cohorts
AG value: Share of different age cohorts
CRF: concentration-response function
YOLL: years of life lost
RAD: Restricted activity days
WLD: Work loss days
MRAD: Minor restricted activity days
LRS: lower respiratory symptoms

Impact and Damage Assessment on Building Materials and Crops

The following section summarises material that is described in detail in ExternE, Methodology (2005 Update). Therefore, only the basic principles of the approach are described here.

Air pollutants emitted by burning of fossil fuels have a serious impact on buildings. The effects include loss of mechanical strength, leakage and failure

of protective coatings due to degradation of materials. For several materials that are frequently used in buildings, dose-response functions have been obtained. A dose-response function links the dose of pollution, measured in ambient concentration and/or deposition, to the rate of material corrosion. In order to be able to calculate costs, a damage function needs to be obtained.

The state of the art of impacts of atmospheric pollutants on building materials is summarized in /ExternE, Methodology 2005 Update/, page 109 – 122.

The exposure-response functions used for impact assessment and recommended for ExternE are listed for the different building materials.

In a two-step approach, the exposure-response functions link the ambient concentration or deposition of pollutants to the rate of material corrosion, and the rate of corrosion to the time of replacement or maintenance of the material. Performance requirements determine the point at which replacement or maintenance is considered to become necessary. This point is given in terms of critical degradation.

CRF for the following materials are implemented in EcoSenseWeb:

- Limestone
- Sandstone
- Natural stone, mortar, rendering
- Zinc and galvanised steel
- Paint on steel
- Paint on galvanised steel
- Carbonate paint

As an example the CRF for Limestone is displayed (CRF for other materials are similar and can be reviewed in /ExternE, Methodology 2005 Update/.

$R = (2.7[SO_2]^{0.48}e^{-0.018T} + 0.019 Rain[H+]) \cdot t^{0.96}$

R is the surface recession in µm, [SO2] is the SO_2 concentration in $\mu g/m^3$, T is the temperature in °C, t is the time in years, Rain is the amount of precipitation in mm/year and [H+] is the hydrogen ion concentration in precipitation in mg per litre. When performing cost calculations the maintenance frequency (1/t) is sought for a specified value of the surface recession, corresponding to a critical damage where maintenance action is required or desirable.

Transforming this equation gives the function:

$1/t = [(2.7[SO2]^{0.48}e^{-0.018T} + 0.019 Rain[H+])/Rcrit]^{1/0.96}$

Monetary values used for the evaluation of impacts to building materials are shown in Table 1.4.

Table 1.4 Monetary values used for the evaluation of impacts to building materials /Droste-Franke, 2004/

Materials – maintenance costs per m2	Monetary value [$Euro_{2000}$]
Galvanised steel	country specific (17 – 55)
Limestone	299
Mortar	33
Natural stone	299
Paint	13
Rendering	33
Sandstone	299
Zinc	27

Impact and Damage Assessment on Crops

This section is taken from /ExternE, 1999, Vol. 7/ and /ExternE, Methodology 2005 Update/. It draws on the latest methodological developments within the ExternE-Pol project and on earlier reports of the ExternE methodology.

Concentration Response Functions - Effects from SO_2
The function assumes that yield will increase with SO_2 from 0 to 6.8 ppb, and decline thereafter. The function is used to quantify changes in crop yield for: wheat, barley, potato, sugar beet and oats and is defined as

$y = 0.74 \cdot [SO_2] - 0.055 \cdot [SO2]2$ for $0 < [SO_2] < 13.6$ ppb

$y = -0.69 \cdot [SO_2] + 9.35$ for $[SO_2] > 13.6$ ppb

with y = relative yield change and
$[SO_2]$ = SO_2 concentration in ppb

Concentration Response Functions - Effects from Ozone
For the assessment of ozone impacts, a linear relation between yield loss and the AOT 40 value (Accumulated Ozone concentration above a Threshold of 40 ppbV) calculated for the growth period of crops (May to June) is assumed. The relative yield change is calculated using the following equation together with the sensitivity factors given in Table 1.5:

$y = 99.7 - Alpha \cdot AOT40crops$

with y = relative yield change
Alpha = sensitivity factors

Table 1.5 Sensitivity factors for different crop species

Crop species	Sensitivity factor
Rice	0.4
Tobacco	0.5
Sugar Beet, potato	0.6
Sunflower	1.2
Wheat	1.7

Concentration Response Functions - Acidification of Agricultural Soils

An upper-bound estimate of the amount of lime required to balance atmospheric acid inputs on agricultural soils across Europe is estimated. Ideally, the analysis of liming would be restricted to non-calcareous soils, but this refinement has not been introduced given that even the upper-bound estimate of additional liming needs is small compared to other externalities. The additional lime required is calculated as:

$dL = 50\ kg/meq \cdot A \cdot dDA$

with dL = additional lime requirement in kg/year
A = agricultural area in ha
dDA = annual acid deposition in meq/m2/year

Concentration Response Functions - Fertilisation Effects from Nitrogen Deposition

Nitrogen is an essential plant nutrient, applied by farmers in large quantity to their crops. The deposition of oxidised nitrogen to agricultural soils is thus beneficial (assuming that the dosage of any fertiliser applied by the farmer is not excessive). The reduction in fertiliser requirement is calculated as:

$dF = 14.0067\ g/mol \cdot A \cdot dDN$

with dF = reduction in fertiliser requirement in kg/year
A = agricultural area in km2
dDN = annual nitrogen deposition in meq/m2/year

Monetary Valuation of Crop Losses

Updated prices of the crops damaged by air pollution. Prices have changed significantly in recent years, those for important crops such as wheat and potato have gone up.

Table 1.6 Updated prices of major crops /ExternE, Methodology 2005 Update/

	Updated Prices per tonne	Source
Sunflower	273	FAOSTAT € (2001)
Wheat	137	IFS € (2003)
Potato	113	FAOSTAT € (2001)
Rice	200	IFS € (2003)
Rye	99	FAOSTAT € (2001)
Oats	132	FAOSTAT € (2001)
Tobacco	2895	IFS € (2003)
Barley	93	IFS € (2003)
Sugar beet	64	FAO € (2002)

1.5 NON-CLASSICAL POLLUTANTS AND RADIONUCLIDES

Country-specific results regarding the inhalation pathway have been calculated for the heavy metals (As, Cd, Cr, Ni, Pb) in ESPREME. Country specific values regarding ingestion have been calculated for As, Cd and Pb by /Fantke 2008/ within NEEDS. No distinction of height of release is possible. The values for Mercury /Spadaro and Rabl, 2007b/, Formaldehyde /NewExt_Final, 2003/ and dioxins /MethodEx, 2006/ are also included. These are so called generic values, directly expressed as "Euro per tonne". Since these are European averages they are applicable to all countries in Europe and any height of release.

As a first approximation the average values can also be applied in North African countries, but more specific research will be necessary for these countries to have specific values.

The value for Cr-VI is derived from the value for Cr. It is assumed that only Cr-VI is the toxic part of Cr. Furthermore, it is assumed that ca. 20% of Cr is Cr-VI. Hence, the monetary value for Cr-VI is ca. 5 times the value for Cr. Therefore, the damage costs for Cr or Cr-VI have to be used alternatively and not both.

Concentration Response Functions (CRF) and monetary values for Human Health impacts due to heavy metals, formaldehyde and dioxins

CRF for inhalation of HM can be found at /ESPREME, 2007/, /Spadaro and

Rabl, 2007b/, /MethodEx, 2006/. Here also new country specific external costs due to inhalation of heavy metals are available which are now included in EcoSenseWeb.

For As, Cd and Pb there has been a parameterisation of new WATSON model runs including ingestion of food and drinking water due to emissions into air. This is described in /Fantke 2008/.

The monetary valuation of morbidity and mortality is based on multiplication of the YOLL (Years of life lost) and the YLD (years lost due to disability) are by the corresponding monetary value of a life year lost, i.e. 40,000 Euro per VOLY. The monetary valuation of IQ loss is based on /Spadaro and Rabl, 2007b/, i.e. 8,600 Euro per IQ point.

Table 1.7 Physical end-points of human health effects due to ingestion of food used within the parameterisation procedure /Fantke 2008/

Pollu-tant	End-Point		Risk Group	Expos. Time	Unit Risk	Severits Measure			Costs per Case
-	Name	Fatality	-	[years]	[risk/kg$_{intake}$]	YOLL	YLD	IQ Points	[€/case]
As	skin cancer	85%	all	70	7.83E-01	5.18	0.16	0	213,520
As	bladder cancer	85%	all	70	3.91E+00	3.94	0.31	0	169,660
As	cardiovascular mortality	100%	all	35	2.35E+02	12.80	0.00	0	512,000
As	still birth (babies)	100%	all	1	2.86E+02	0.00	1.28	0	51,200
Cd	osteoporosis	100%	all	35	6.26E+02	0.00	0.28	0	11,200
Cd	renal dysfunction	100%	all	35	3.13E+01	0.00	0.64	0	25,600
Pb	anaemia	100%	all	1	1.32E+02	0.00	0.64	0	25,600
Pb	IQ points loss (children)	100%	0-1 years	1	1.15E+03	0.00	0.00	1	8,600

Table 1.8 Physical end-points of human health effects due to ingestion of drinking water used within the parameterisation procedure /Fantke 2008/

Pollu-tant	End-Point		Risk Group	Expos. Time	Unit Risk	Severits Measure			Costs per Case
-	Name	Fatality	-	[years]	[risk/kg$_{intake}$]	YOLL	YLD	IQ Points	[€/case]
As	skin cancer	85%	all	70	7.83E-01	5.18	0.16	0	213,520
As	bladder cancer	85%	all	70	3.91E+00	3.94	0.31	0	169,660
As	cardiovascular mortality	100%	all	35	2.35E+02	12.80	0.00	0	512,000
As	still birth (babies)	100%	all	1	2.86E+02	0.00	1.28	0	51,200
Cd	osteoporosis	100%	all	35	6.26E+02	0.00	0.28	0	11,200
Cd	renal dysfunction	100%	all	35	3.13E+01	0.00	0.64	0	25,600
Pb	anaemia	100%	all	1	2.74E+02	0.00	0.64	0	25,600
Pb	IQ points loss (children)	100%	0-1 years	1	1.15E+03	0.00	0.00	1	8,600

Radionuclides

A simplified approach for assessment of impacts related to radioactivity has been used. This is applied to the normal operation of nuclear fuel cycles regarding emissions of radionuclides because quantified impacts per kWh are quite low and the share of radionuclides to these impacts is again very small. As far as possible, updated data (especially relation between Bq and manSv) has been used according to UNSCEAR 2000. This approach is not site specific but in /UNSCEAR 2000/ typical population densities for the release of certain radionuclides have been assumed.

No accident scenario has been reassessed. The applied approach is depicted in Figure 1.2.

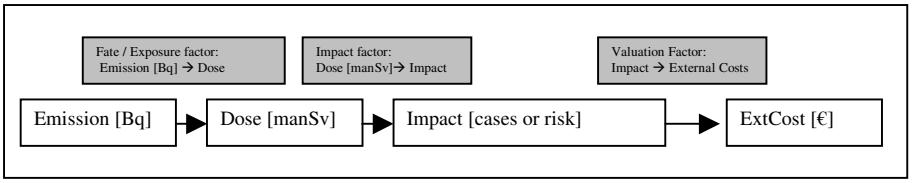


Figure 1.2 Scheme of assessment of exposure, physical impact and external costs due to release of radionuclides

The evaluation of release of radionuclides due to normal operation (i.e. electricity generation but also mining / milling and reprocessing is based on generic factors taken from UNSCEAR reports. The dispersion and exposure modelling, i.e. the relation between emission [Bq] and dose [manSv], is included in the calculation of these fate and exposure factors, for a variety of radionuclides and for representative locations. Finally, discounting with declining discount rate according to Weitzman (1999) is applied to the most

important nuclei Rn-222, H-3 and C-14, as explained at the end of this chapter.

Fate / Exposure factors

The factors relating emissions of different radionuclides expressed as radioactivity [Bq] to collective dose, i.e. population dose [manSv] are taken from UNSCEAR (1993) and UNSCEAR (2000). Dispersion and exposure modelling for a variety of radio nuclides and for representative locations were used by UNSCEAR to derive these factors. For I-131 to water, U-234 and U-238 to water the ratio between DALYs for release in water to release in air reported in Impact (2002) have been used.

Table 1.9 Fate / Exposure factors for radionuclides

Radionuclide	Emission into:	[manSv/PBq]
Aerosols, radioactive, unspecified	air	2000
Carbon-14	air	92270
Carbon-14	water	1000
Cesium-137	air	7400
Cesium-137	water	98
Hydrogen-3, Tritium	air	4.1
Hydrogen-3, Tritium	water	0.85
Iodine-129	air	64000
Iodine-131	air	20300
Iodine-131	water	63400
Krypton-85	air	0.214
Noble gases, radioactive, unspecified	air	0.43
Radon-222	air	2.5
Thorium-230	air	30000
Uranium-234	air	8000
Uranium-234	water	198
Uranium-238	air	7000
Uranium-238	water	1960
Strontium-90	water	4.7
Ruthenium-106	water	3.3
Lead-210	air	1000
Polonium-210	air	1000
Radium-226	air	600

Impact factors

The factors relating collective dose to human health impact, so called risk factors, are recommended in Torfs et al (2007). A linear dose-effect relationship is assumed.
The recommendation for ExternE / NEEDS is to use the ICRP60

recommendations for core analysis, i.e.
0.05 cases per manSv for fatal cancers
0.12 cases per manSv for non-fatal cancers and
0.01 cases per manSv for hereditary defects.

Valuation factors

The impact, i.e. cases of fatal cancers, non-fatal cancers and hereditary defects can be aggregated to external cost by multiplication with the corresponding monetary values listed below:

- 1.12 million Euro per fatal cancer (EcoSenseWeb V1.3x, User's Manual),
- 481 thousand Euro per non-fatal cancer (Friedrich and Bickel, 2001) and
- 1.5 million Euro per hereditary defect (equal to on value of prevented fatality (VPF) (UNITE_D5_Annex3, 2001).

This evaluation is based on DALYs per cancer. Due to the multiplication of the number of DALYs per case of cancer with the monetary Value Of a chronic Year of Lifetime lost (VOLYchronic) the delay between exposure and actual appearance of case of cancer and the corresponding years of life lost is discounted implicitly because the VOLYchronic is derived by contingent valuation questionnaire which elicits the WTP to reduce the risk of reduced life expectancy (at the end of the life). Respondents implicitly discount this benefit because it is only in the future. It is still under discussion if it would also be appropriate to include a so called "cancer premium" since the incident of a case of cancer is somehow much more "catastrophic" for the corresponding individual and his social environment and the WTP per YOLL maybe higher then. Further explanations of the implemented factors can be found in EcoSenseWeb, User's Manual (2008).

1.6 TREATMENT OF EMISSIONS AND DAMAGES IN THE PRESENT AND FUTURE – REAL PRICES & DISCOUNTING

It is important to ensure that all monetary inputs and outputs in an appraisal process are expressed in consistent ways in order to be comparable with each other.

There are several issues that have to be taken into account when electricity generation is compared not only at the present but also in the

future:

- new technologies in the future will have higher efficiency and different upstream process chains and therefore, different total emissions
- background emissions will be different – therefore, the marginal damage per unit of emission will be different
- monetary values, i.e. willingness to pay will, corrected by an elasticity factor, increase with economic growth (so called "uplift")
- in order to calculate the net present value (NPV) of a future damages the time preference has to be taken into account; this is done by pure rate of time preference (PRTP)
- real prices have to be taken constant
- up- and downstream process have to be covered.

Generalised values, i.e. [Euro per tonne] are provided in the Excel file "ExternalCosts_per_unit_emission_080821" including damages to human health, biodiversity, crops & materials and global warming. The adjustment to different years of emission is done automatically after defining the year of assessment in the spreadsheet "Assumption". The basic values are then adjusted by uplift and discounting in order to have damage factors for a certain point in time. Increasing WTP (uplift) is assumed with regard to impacts to human health and biodiversity.

All values are expressed in $Euro_{2000}$ prices. The issue of "real prices" is stressed in detail in HEATCO (2006).

In order to calculate external costs for certain future years the unit costs are recalculated by the uplift. Results are discounted according to whether the results shall be expressed in net present value (NPV) year 2000 or NPV of the year of emission.

Different background emission scenarios for present and future

These should be seen as values corresponding to present and to future background emissions because this has an influence on the marginal damage of precursor emissions. Therefore, in the Excel file for years of assessment including 2000 till 2014 the 2010 background emission scenario is taken; for years after 2014 the 2020 background emission scenario is taken.

Results in spreadsheets "…20xx_00" correspond to emissions in year 20xx and costs are discounted to the year 2000; results in the spreadsheet "…20xx_xx" correspond to emissions in year 20xx but costs are discounted to the year of release, i.e. 20xx.

Real prices

The monetary values per health impact in ExternE, Methodology (2005

Update, Table 7.6 Summary of morbidity values) are based on Euro2000 , i.e. price in the year 2000.

For example, for the external costs calculation the increased mortality years of life lost YOLLchronic is used with a value of 40,000 [Euro2000] i.e. price in year 2000.

These are the costs in the year 2000 expressed in Euro2000. In future years these costs increase, as explained below.

Future damages and sum of present and future damages

What is the sum of a damage caused by an emission of PPM2.5 in 2000 and an emission in 2020 expressed as the NPV in the year 2000, if the physical impacts are one YOLL in 2000 and one in 2020?
a) Damage of one YOLL in 2000
1 YOLL * 40,000 Euro / YOLL = 40,000 Euro
b) Damage of one YOLL in 2020 – expressed as NPV in 2000

Increasing willingness to pay (WTP)

The value of health impacts is expected to change in real terms. The assumption is that the WTP, e.g., per year of lifetime lost (YOLL) will increase with per capita income growth rate – or the average rate of growth in GDP.

Based on the /IEA 2006/, Annex B, "GDP and Population growth Assumptions" for OECD Europe we assume till 2030 an average annual growth rate of 2% and 1% after 2030.

The income elasticity tends to differ between resources and between countries. In HEATCO (2006) it is recommend that – where evidence exists – the income elasticity used should be specific to the cost or benefit being considered. Specific recommendations are made for travel time, accidents, air pollution, noise and climate change impacts respectively. These are between a factor of 0.7 and 1. Often a factor of 1 is recommended as base and 0.7 is suggested for sensitivity analysis. In this report a factor of 0.85 is used.

We assume a growth rate of 2 %, assuming an "Elasticity of Marginal Utility of Consumption" equal to 0.85. Therefore, the damage in 2020 (NPV 2020) will be
40,000 Euro * (1+0.02*0.85)^20 =
40,000 Euro * 1.4009 = 56,038 Euro

Discounting to net present values (NPV)

To calculate the NPV in 2000 for the damage in 2020 we need to discount

(discount rate = i) by growth rate (g) times elasticity (n) plus 1% pure rate of time preference (z).
i = z + g*n
To calculate the NPV in 2000 for the damage caused in 2020 we would account for PRTP, i.e. ca. 1 % (cf. page 30 in /ExternE 2005 update/), and growth rate i.e. together 3%. Therefore, the NPV in 2000 for one YOLL in 2020 would be
56,038 Euro / 1.03^20 = 31,027 Euro.
Therefore, the NPV in 2000 for one YOLL in 2020 is 31,027 Euro
To discount a YOLL in 2040, i.e. 72,185 Euro we have to discount to 2030 with 2% and then down to 2000 by 3%, i.e.
72,185 Euro / 1.02^10 / 1.03^30 = 24,397 Euro.
Answer to the example:
The NPV in 2000 for one YOLL in 2000 plus one YOLL in 2020 would be 40,000 Euro plus 31,027 Euro = 71,027 Euro.

Summary of the Important Assumptions

Increasing WTP in the future is assumed for impacts to human health and biodiversity i.e., assuming costs for crops and materials remain constant.
Use growth rate of 2%/a till 2030, 1% after, with income elasticity of 0.85.
For example, this leads to the following increased WTP per YOLL:

Table 1.10 WTP per YOLL

Year	Number of YOLL	VOLY [Euro2000] – NPV in year of occurrence
2000	1	40,000
2010	1	47,344
2020	1	56,038
2030	1	66,327
2040	1	72,185
2050	1	78,561
2060	1	85,500
2070	1	93,052
2080	1	101,271
2090	1	110,216
2100	1	119,950

Discounting to NPV
→ se growth rate (i.e. 2%/a till 2030, 1% after) plus PRTP of 1%/a.

For example, this leads to the following NPV per YOLL:

Table 1.11 NPV per YOLL

Year	Number of YOLL	VOLY [Euro2000] – NPV in year of occurrence
2000	1	40,000
2010	1	35,228
2020	1	31,027
2030	1	27,326
2040	1	24,397
2050	1	21,781
2060	1	19,447
2070	1	17,362
2080	1	15,501
2090	1	13,839
2100	1	12,356

How to combine different external costs (e.g., classical pollutants and external costs of greenhouse gases) and private costs

According to HEATCO (2006) the conversion from one price year to another price base year is undertaken using a price index. Ideally, this price index should be sectoral specific. In practice this is not always available. The consumer price index is used for user benefits and externalities. In the European Union this latter index is known as the Harmonised Index of Consumer Prices (HICP).

Moreover, international comparison of unit values may necessitate conversion from one currency to another if all values are to be expressed in comparable terms.

When comparing values between countries, it is not sufficient to use official (nominal) exchange rates only since these do not reflect differences in purchasing power. Instead it is useful to use the purchasing power parity (PPP) exchange rate since it provides a more accurate guide to real differences in resource costs and WTP values in different countries.

How to recalculate from US$2005 prices to Euro2000 prices? According to Methodex (2007): → 1.373 US$ per 1 Euro

1.7 VALUING THE "MISSING" EXTERNALITIES OF ENERGY PRODUCTION

The external costs of energy production include a number of items that have hitherto proved hard to value in monetary terms. These cost items include the external value of land use change, acidification of the aquatic environment, eutrophication, visual intrusion, and the cost of damage resulting from climate change.

The following paragraphs review the general progress of valuation research in these areas and presents results of some of the most interesting recent studies. The crucial question with regard to the literature on land use change and ecosystem damage is whether the results from individual studies in the respective areas can be 'scaled-up' or 'transferred' with enough confidence in order to be used in cost assessments at the European level. There are several key questions with regard to damage costs of climate change. One set relates to the assessment of the economic impacts *per se*; another set of questions regards the rules of aggregation for these impacts, both over time and over space.

1.8 LAND USE CHANGE AND BIODIVERSITY

The monetary valuation of ecosystems and biodiversity is controversial. One can argue that it is either not possible to "reduce" nature to a commodity that can be exchanged for commodities that can be bought and sold in markets, or at least, that it is not morally right to do so. Even if one assumes that people can have well-defined preferences for ecosystem services, at least at the margin (valuing only incremental changes in provision), it can be argued that a purely anthropocentric approach to valuation discriminates against the inalienable rights of future generations or of other, non-human living species.

There is now a formidable literature on the concepts of ecosystems and biodiversity, their functions and economic services, and ways and means to assess and measure these functions and services (e.g., MEA 2005; Albers and Ferraro 2006). Ecosystems are dynamic complexes of plants, animals and microorganism communities and the nonliving environment interacting as a functional unit. Biodiversity is the variability among living organisms from all sources, including terrestrial, marine and other aquatic ecosystems and the ecological complexes of which they are a part. Biodiversity can refer to variety in genes, species, and ecosystems; it can refer to various spatial and temporal scales; and it can include several attributes such as compositional,

structural, and functional biodiversity. Furthermore, for each level (genes, species, ecosystems) biodiversity can be measured in various ways, for example by counting, by determining relative abundance or the degree of similarity. There is some controversy among experts whether biodiversity should be considered an environmental service itself or that it contributes to the creation of environmental services (Albers and Ferraro 2006). However, the latter view (biodiversity contributes to environmental services) is gaining more support (MEA 2005; Albers and Ferraro 2006).

Linking physical and economic indicators in land use change

Koellner (2001) and Koellner and Scholz (2007; 2008) developed practical characterisation factors for ecosystem quality for use in life cycle assessments. The approach takes a relative measure of species' abundance as its starting point. This measure, called the "Ecosystem Damage Potential" (EDP) is defined as the inverse of the relative species' abundance that is associated with a particular land use. Koellner and Scholz use the CORINE land cover classification to assign EDP measures to land use types in Europe.

The valuation of a change in land use can now proceed in two steps. In the first step, the change in land use is translated in a change in EDP (a physical indicator of ecosystem quality). In the second step, the change in EDP is valued in monetary terms. One possibility is to base the valuation on the estimated costs of the engineering measures that are necessary to effectuate the change in land use. This method is called the restoration cost approach. An alternative approach to valuing land use change would be to base it on explicit willingness-to-pay estimates from original studies on the costs and benefits of land use changes in different settings. This is the approach we will briefly describe in the next paragraph.

Willingness to pay for land use change (meta-analysis)

The economic valuation literature addresses a broad range of changes to land use and biodiversity. We collected over 160 valuation studies that deal in some way with land use change and biodiversity. The changes in land use described and valued cover a broad spectrum of land use types and degrees of change. Valuation studies have addressed changes from one land use type to another, changes in area of a particular land use type, and changes in ecosystem quality. In order to compare the estimated values of these various changes, we have described each change in a generic metric of land occupation and land use change, namely the Ecosystem Damage Potential (EDP) described above.

Having described land use changes in terms of EDP to reflect impacts on

biodiversity and standardised monetary value estimates to a common metric (Euro in 2004 prices), we can examine the value of biodiversity and the factors that influence this value. For our data set the average value per EDP per hectare per year is € 4,706. The median value is € 604, which indicates that the distribution of values is skewed with a long tail of high values.

We might expect that the estimated values will vary with a number of important variables, such as income, population density, the size of the area under consideration, and the magnitude of the change in EDP being considered. We observe a clear positive relationship between population density and biodiversity value. As population increases, so does the value of biodiversity. This makes sense in that more people living in the vicinity of an area with high biodiversity means more people that hold values for that biodiversity. There appears to be no discernable relationship between GDP per capita and the value of biodiversity. Although we might expect that people's willingness to pay to protect biodiversity would increase as they become richer, it appears that the value of biodiversity is constant across income levels.

There are diminishing returns to scale for areas supporting biodiversity. As the size of area increases the value of biodiversity per hectare declines. In other words, adding an additional hectare to a large ecosystem area is worth less in terms of biodiversity than adding an additional hectare to a small ecosystem area. We also observe that values per EDP decline as the magnitude of change in EDP increases. This suggests that the amount that people are willing to pay per unit of biodiversity diminishes as the change in biodiversity increases. The value of a change in biodiversity is therefore not a simple linear function of change in biodiversity, but depends on the scale of change.

In order to provide values for changes in biodiversity that can be adjusted to reflect important local characteristics, we estimate a value function. Using a statistical regression analysis we can relate the variation in estimated biodiversity values to a number of key explanatory variables. The natural log of Euros per EDP per hectare per year was used as the dependent variable. The explanatory variables include population density, size of affected area, change in biodiversity, and type of ecosystem. The best-fit model is presented in Table 1.12. The results confirm the sign of the relationships between biodiversity value and population density, size of affected area, and change in biodiversity as described above. The results also indicate that biodiversity values vary depending on the type of ecosystem, with forests and coastal ecosystems having higher biodiversity values than rivers.

Table 1.12 Estimated biodiversity value transfer function

Variable	Coefficient
Constant	8.740
Population density (ln)	0.441
Forest (dummy variable)	1.070
River (dummy variable)	– 0.023
Coast (dummy variable)	0.485
Change in EDP	– 2.010
Area (ha)	– 0.312

We have compared the results of our willingness-to-pay approach to the restoration cost approach. With the restoration cost approach the unit value of ecosystem damage due to SO_x deposition in Germany is € 0.26 per kg. In the willingness-to-pay approach, the unit value damage increases to € 0.48 per kg deposition. The value transfer function can be used for all countries (or even the sub-country level), provided information is available on population density, the shares of different ecosystems, and the average size of ecosystem areas in these countries or at the sub-country level.

Conclusion

We reviewed a new approach to the assessment and valuation of land use change and biodiversity. Key to this approach is a relative measure of species' abundance – the "Ecosystem Damage Potential") – that is associated with land use. We carried out a meta-analysis of economic studies related to the valuation of land use change and biodiversity loss with the purpose of estimating a value transfer function. A first application of the value transfer function to real data suggested that this function provides reasonable estimates of the value of land use changes in a European context. More research is needed, however, to validate the approach and to apply it routinely.

1.9 ACIDIFICATION

There are a limited number of European valuation studies and estimates for acidification. The studies seem to be concentrated to Norway and Scotland – areas where acidification of lakes have been considered a major environmental problem. The studies on acidification focus on biodiversity –

plant and animal life – in lakes, and fish populations used for angling in particular.

A methodological challenge in the studies is the way to link the actual physical changes in the lake (environmental good) and the valuation, and to convey this good to the respondents. Knowing exactly which "good" or "change in good" which has been valued is vital for good benefit transfer exercises.

One study where the economists worked together with natural scientists in order to get the physical links correct, is Navrud (2001a). We discuss this study below. The CV scenario in this study was later developed further and applied in Scotland (Bateman et al., 2005), but with no link to the actual acidification situation there.

Linking physical and economic indicators in acidification

Methodologically, Navrud (2001a) uses the damage function approach as the valuation framework. The damage function approach applied to the impact of air pollution on ecosystems has four main steps:

1. use air dispersion models to estimate how changes in emissions of a pollutant affect atmospheric concentrations;
2. calculate how changes in atmospheric concentration will affect deposition and concentration of the pollutant in the recipient (soil, water);
3. use dose-response functions to calculate the impacts on affected ecosystems (e.g. fish stocks) from changed depositions, and
4. estimate damages (or benefits) by calculating the economic values of the impact. In the case of reduced emissions damage function approach should rather be termed the benefit function approach.

The concepts of critical levels and critical loads were developed in the framework of the 1979 Convention on Long Range Trans-boundary Air Pollution (LTRAP) of the United Nations Economic Commission for Europe, and widely accepted as a basis for designing control strategies in the Second Sulphur Protocol signed in Oslo in June 1994 (UN-ECE 1996). Critical levels refer to the direct effect of pollutant concentrations while critical loads are derived for pollutant depositions, also taking into account accumulation effects in soil and water. For sulphur and nitrogen acidity the critical load is defined as "the highest deposition of acidifying compounds that will not cause chemical changes leading to harmful effects on ecosystem structure and function" (UN-ECE 1996). Thus, step ii) and iii) in the damage function approach would consist of calculating changes in critical load exceedance and its impact on fish stocks.

Linking changes in emissions and exceedance of critical loads

Critical loads for surface water are derived from the concept that the annual acid deposition to a watershed should not exceed the amount of alkalinity (i.e. buffer capacity) that is produced annually in the watershed and the lake. The buffering capacity is determined by the geology and soil characteristics of the water shed. The acid deposition should be less than the buffering capacity in order to leave a minimum level of buffering capacity that is necessary to avoid damages to aquatic organisms, including fish. Thus, this critical biological value varies with the natural buffering capacity of surface water, measured as acid neutralising capacity.

Dose-response functions for exceedance of critical loads and fish damage

A "1000 lake survey" collected data on water chemistry and status of the fish populations from 1005 lakes throughout Norway in 1986. Fish damage was then presented in the same grid system as the critical loads; i.e. a system of grids of 0.5 ° latitude by 1° longitude divided into 16 sub-grids. Additional data for areas poorly covered was collected in 1989 and 1990. Water samples were collected from each lake and analysed. Status for all fish species (brown trout, arctic char, perch and pike) was recorded for each lake, based on interviews with representatives of the environmental authorities at the county level. The status of the fish society in each lake was classified using a fish damage index with three categories. Class 1 (unaffected) indicates no reduction in the fish populations, class 2 (reduced) indicates a reduction in the densities of one or more populations, and class 3 (extinct) indicates that all populations are extinct. Naturally thin populations were classified as unaffected. After excluding limed lakes, 697 lakes with acceptable fish information remained

Dose-response functions between exceedance of critical loads and fish status were then estimated for each class. Using a logistic regression model Henriksen et al. (1995, 1999) calculated how exceedance of critical loads affects the probability for a fish population to be classified in each of the three damage classes. When the critical load is exceeded the probability of fish damage increases with increasing exceedance.

It is difficult to predict damage class 2, since the curves for damage class 1 and 3 are so close. The reason is that damage class 2 fails to represent a stable state, since the fish population will disappear (i.e., class 3) without a large reduction in deposition. Predicting if a lake has damages to its fish population or not (i.e. damage class 3 or 1) at a given level of critical level exceedance is relatively easy. These three damage classes formed the basis for the Contingent Valuation survey performed in April 1996. However, in a re-analysis of the data with only two damage classes (damaged and undamaged), Henriksen et al. (1999) were able to identify dose-response

functions which could correctly predict 83% and 85% of the undamaged and damaged fish populations respectively.

Economic valuation of fish damages

Since acid rain is one of the largest environmental problems in Norway, the entire Norwegian population was considered to be affected by this change in fish stocks, even though the largest impacts occur in Southern Norway. Thus, a nation-wide survey with in-person interviews of 1,009 Norwegian households was carried out in April 1996.

The stated preference method of contingent valuation was used to estimate the economic value of the increased number of lakes with undamaged fish stocks. Although the objective of the study was to assess the benefit of a reduction acid deposition (through the Second Sulphur Protocol), the respondents were asked for their willingness to pay (WTP) for technical measures (liming) that would have an equivalent impact on fish stocks as the reduction in deposition.

Pre-tests of the survey instrument showed that respondents protested against a scenario where they were asked to pay for increments in fish stocks which were the result of reduced sulphur emissions mainly from other European countries (Norway receives about 90% of its sulphur depositions from other countries). This clearly illustrates the problem of valuing transboundary pollution impacts. Even though the national liming program scenario avoided much of this protest behavior, it is impossible to avoid protesters completely since some people also find it unfair that they should pay for the liming even if their utility from the program is positive. However, this type of protest behavior is found in most CV studies. In general, a new tax earmarked for liming was accepted as a fair and realistic payment vehicle both in the pre-test and the final survey.

Contingent Valuation of reduced fish damage

The study suggested that the annual WTP per household was in the range of 367-705 NOK. The annual aggregate benefits for all 1.98 million Norwegian households at that time were calculated at 727 - 1,396 million NOK, which is equivalent to 80.0-153.6 million Euros. These benefits can be compared to the saved costs of liming these water courses from fulfillment of the Second Sulphur Protocol of 211 millions NOK/year (Henriksen and Hindar 1997; table 4). Thus, the benefit-cost ratio of such a liming project would be 3.45 - 6.62.

The potential for benefit transfers

There are at least two options in selecting a *unit of transfer* of this valuation estimate:

i) per tonne of reduced sulphur deposition, measured as critical load exceedance sulphur, and

ii) per square kilometer reduced land area of critical load exceedance.

Looking at the weight-based unit first, we find that in 1990 145,000 tons of sulphur were deposited in Norway, which is 30,000 tonnes above the critical load. In 2010, with the fulfillment of the Second Sulphur Protocol, the annual deposition in Norway would be reduced to 69,000 tons, of which 10,000 tons exceeds the critical load. Thus, there is a reduction of 20,000 tonnes (66.7 %) in terms of "critical load exceedance" by sulphur. If we assume a linear relationship between the reduced deposition and the economic value, we can calculate the annual economic value per tonne of "critical load exceedance" of sulphur at 4,000-7,680 Euros. The corresponding numbers on a per household basis is 2.0-3.9 mEuro/tonne/year (1 mEuro = 10^{-3} (0.001) Euros). Since the impact caused by 1 tonne of sulphur varies from location to location due to differences in buffering capacity of the soils, and thus the critical loads, the economic value as Euro per reduced tonne of critical load exceedance of sulphur is a better measure than reduction in total sulphur deposition for transfer of these estimates to other locations in Europe.

The second area-based unit can be calculated in a similar way. Henriksen and Hindar (1997) found that the area where the critical load for sulphur was exceeded was 80,040 km^2 in 1990, i.e. 25 % of the total area. They predict that this area will be 34,550 km^2 (10.8 % of total land area) with the Second Sulphur Protocol in 2010. This is a reduction in area with exceeded critical loads of 45,490 km^2 (56.8 %). Again assuming a linear relationship (i.e. constant economic value per unit of reduced area with exceeded critical loads), we find an economic value of 15,982 - 30,688 Euro/km^2/year. This is equivalent to 8.1 -15.4 mEuro/ tonne/year.

However none of these approaches account for the difference in population density, and thus the number of users and non-users affected by the policy. This will greatly affect the aggregated damages or benefits of a policy.

Europe had 729 million inhabitants in 1997 (UN, 1998), 374 million lived within the European Union, and 4 million lived in Norway. The land area of Europe is 23 million km^2, out of which the Union covers 3 million km^2, and Norway 0.3 million km^2. The population density of Europe, the Union and Norway is 31.65, 115.38 and 13.5 inhabitants per km^2, respectively. Norway is much more sparsely populated than the average for Europe. Thus, the number of people affected by a change in fish stocks and environmental quality in general, is higher within the Union and Europe as a whole.

Therefore, a direct transfer of the Norwegian damage estimate per ton of sulphur would *ceteris paribus* underestimate the damage costs to Europe. However, differences in income level, other socio-economic variables, cultural preferences, and institutions in different countries should also be taken into account.

Conclusion

There is large uncertainty inherent in the estimates of the damage value due to acidification of the aquatic environment. The uncertainty stems both from the calculation of impacts (i.e. uncertain dose-response functions) and the economic valuation procedure (i.e. uncertainty of the contingent valuation surveys). To be able to use these estimates to calculate parts of the social benefits of second generation international agreements on emission reductions of SO_2 and NO_x based on critical load, we must assume that the marginal WTP is constant, i.e. independent of the current level of acid deposition, and that Norwegians are representative of all Europeans when it comes to WTP for reducing fish damages. However, the Navrud (2001a) study shows that it is possible to link the critical loads concept with economic valuation. Similar studies in other European countries should be performed to test the validity of these estimates. The possibility of applying this methodological framework to other potential impacts from sulphur and nitrogen depositions, e.g. impacts on forest ecosystems, should be considered.

1.10 EUTROPHICATION

Eutrophication of fresh and salt water is a big problem in most European countries. Still, most of the European surveys on eutrophification seem to be concentrated to Northern and Central Europe. Many of the studies value the eutrophication of coastal (salt water) location, but there are also several valuation studies of eutrophication of fresh water, for instance in Norway where water quality was valued in fresh and salt water according to the scheme in Magnussen and Navrud (1992). Then a similar approach was used to value two more Norwegian lakes in 1994-95 (Bergland et al 1995/2000) and even two more Norwegian lakes following the same scheme in 1997 (Magnussen et al. 1997). These studies were recently used as the basis for benefit transfer and new original valuation studies of lakes in Germany (Muthke and Holm-Mueller, 2004), Poland and the Czech Republic (Scasny et al. 2007).

The valuation studies on eutrophication focus on use and non-use values. Often water quality improvement is valued as one "bundle" of environmental services, but a few studies distinguish between separate services such as drinking water and recreation. Most studies use the Contingent Valuation method, while some use the Travel Cost method. The environmental stressors causing the environmental problems are mainly a mixture of man-made pollutions from sewage, agriculture and industry.

Linking physical and economic indicators in eutrophication

The linking of physical indicators and economic valuation is a major challenge for valuation studies in this area. In different studies, different indicators have been used. In some studies the indicator is a percentage reduction of nutrient inflow in a specific water body, in other studies it is a measure of clarity of the water (mean sight depth), and, finally, in some studies it is the provision level of certain services such as swimming or angling. As a result, the estimates of different studies are not very easily comparable, as the values will relate to different "goods" or different aspects of eutrophication. There are, however, some interesting examples where the approach used in Norway in 1992, 1995 and 1997 is used again in Germany, Poland and the Czech Republic.

In order to link the physical indicators to economic valuation in the original Norwegian studies, natural research scientists were involved in linking the percentage reduction of nitrogen and phosphorus leaching to effects on water quality measured as sight depth, oxygen percentage, algae growth etc. (dose-response-functions), and then to describe what these water quality levels imply for the water users, for angling, swimming, drinking water etc. These effects on water quality and usage were illustrated with the aid of maps, cards and pictures.

The potential for benefit transfers

There are several examples of benefit transfer studies and meta-analyses. A major challenge for benefit transfer in this area is finding the appropriate unit of transfer. In a number of studies the "good" to be valued was a "50% reduction of nutrient input into the Baltic Sea ". While benefits of this "good" may be transferred between Baltic States, it is difficult to imagine how these benefits could be transferred to other countries. Hokby and Soderqvist (2003) used data from studies on the willingness to pay for eutrophication reduction in the Baltic Sea to derive income and price elasticities for eutrophication reduction. They found that 1% increase in income would result in a 0.6% to 1.3% increase in demand for eutrophication reduction, and a 1% increase in the price of eutrophication reduction would result in a 1.6% to 2.1% decrease

in demand for nitrogen reduction. It would be interesting to examine whether these elasticities could also be applied elsewhere.

Scasny et al. (2007) report research in benefit transfer validity between Norway and two new member states of EU – Poland and the Czech Republic. Based on the original eutrophication contingent valuation study conducted in Norway in 1994 (Bergland et al. 1995), repeated later in Norway in 1997 (Magnussen et al. 1997) and Germany 2000 (Muthke and Mueller-Holm 2004), two studies were conducted in Poland and the Czech Republic in 2005 where they ask residents for their willingness-to-pay for a hypothetical improvement of water quality in a lake which is strongly eutrophicated and therefore not usable for all recreational activities. The studies were designed in a way that would match the Norwegian original as close as possible, with regard to site selection, scenario, payment vehicle and even the questionnaire design.

The results show that naïve single benefit transfer yields the largest error rates. Transfers adjusted by purchasing power decreases the errors; however, they remain still very large. Benefit function transfer yielded significantly reduced error rates but they are still considerable.

Scasny et al. (2007) have some interesting reflections regarding which factors may influence value estimates of water quality improvements due to reduced eutrophication which may be of importance for further attempts at benefit transfer in this area. They note that both the lakes and the economic situation of the households surrounding the lakes in the different countries seem to be different, therefore choice of a transfer unit may play an important role in explaining the differences in the reported WTP. Even though the "good valued" is a one- or two class improvement in water quality the sites are not identical. Many characteristics of the lakes – which may be of importance for peoples' valuation – and therefore for benefit transfer exercises - differ; like the lakes' surface, their perimeter and length of perimeter easily accessible by potential users, the character of the surrounding area, flora and fauna at and around the lake, etc. Further, the use and alternative options at different sites can be different and should be considered in benefit transfer exercises. Scasny et al. (2007) note for instance that there are considerable differences in the types of activities that take place in and by the Norwegian and Polish /Czech lakes as well as in the frequencies in which they occur.

Scasny et al. (2007) also note that the payment vehicle may be viewed differently by the citizens of the various countries. In particular, in contrast to the Norwegian respondents, many Czech and Polish respondents did not consider an increase in sewage taxes an appropriate payment vehicle for the improvements. Finally, there are also significant natural and socio-economic differences that make benefits transfer difficult.

Conclusion

There are several studies available on this topic, especially from the northern and central part of Europe. There are also several examples of benefit transfer studies and meta-analyses. However, the linking of physical indicators and economic valuation is a major challenge for benefit transfer for this topic. Many of the eutrophication studies were carried out quite early in the 1990s, and the methodology and values reflect this fact. With the EU "Water Framework Directive", the interest for water quality, eutrophication and valuation has risen again lately and new valuation studies in several European countries will be carried out under EC´s 6th Framework Program for Research in the project "Aquamoney"(http://www.aquamoney.ecologic-events.de/).

More original studies as well as more studies testing for the validity of benefit transfer within countries, between "similar" countries and between countries presumably "less similar" are needed to bring more light to this very policy-relevant exercise.

1.11 VISUAL IMPACTS OF WIND, HYDRO AND OVERHEAD TRANSMISSION LINES

The European studies that value aesthetic effects of wind parks are from the Nordic countries (Norway, Denmark and Sweden) and from southern Europe (France and Spain). The number of European surveys valuing aesthetic effects of hydropower is limited. The largest number of surveys is from Norway, but there are also valuation studies from Sweden, Iceland and Austria. It is not surprising that a large number of studies are from Norway, because this country has a much higher percentage of hydropower (99 %) in their electricity production than any other country. Further, large proportion of the country's rivers and water courses are already used for power production, implying that the interest in the remaining (not-developed) water courses increase. However, also Iceland and Sweden do have proportions of their electricity production stemming from hydropower.

A variety of methodological approaches have been used in this area: Contingent Valuation, Hedonic Price method and Conjoint Analysis/Choice Experiments.

Linking physical and economic indicators in visual intrusion

The surveys on aesthetic effects of wind focus either on visual effects only, or visual effects and noise and environmental effects of windmills in general. The surveys on aesthetic effects of hydropower often include other factors

than aesthetic effects as well, because development of hydropower implies visual effects as well as changes in biodiversity etc, and the aesthetic effects may be difficult to distinguish. For some of the studies, it is difficult to see whether aesthetic effects are actually included (as part of other effects) at all.

One special feature of the valuation studies on visual effects of windmills, is that the alternative (or the reference scenario) seems to be of some or even great importance, at least the Norwegian studies point in that direction. That may imply that not only visual effects have been included in the WTP, but also tells that this may be difficult to keep apart for respondents. If the alternative is perceived as "worse" in an environmental sense, windmills seem to be preferred. However, if the electricity alternatively can come from other environmental friendly options, the choice is more uncertain. These same problems do not occur when windmills are moved "further away" ashore – where the difference is only that (hardly) nobody can see them – and the electricity production is the same.

Navrud et al. (2008) assessed the value of visual intrusion by overhead transmission lines in the Oslo area in Norway in 1998/1999. The CV scenario was constructed to value visual intrusion only (and eliminating impacts from electromagnetic fields by explicitly stating that there would be the same health risk from these fields whether the lines were overhead or as cables underground). 608 households in the eastern part of the municipality of Oslo, Norway were interviewed. 11% of the respondents were classified as protest bidders. 77% of the non-protest respondents stated that they would pay something to have some or all of the power line buried as a cable, with a mean willingness to pay of 156 to 680 NOK per household per year, depending on the location of the lines (conservation area vs. developed infrastructure area) and the distance of the respondent from the line. The highest willingness to pay was from households living close to transmission lines through urban areas.

The potential for benefit transfers

A problem for the transfer of damage values of windmills is that most studies in this area have difficulties in separating visual or aesthetic effects from other effects. Some studies do not aim at this, but even studies that do encounter problems in this area, as is for instance clear from the dependence of willingness to pay on the reference scenario.

With respect to hydropower, the situation is comparable. The results from two Norwegian CV studies have been used to estimate the damage costs of a portfolio of projects assumed to be representative of Norwegian hydropower projects (Vågnes et al. 2001). This benefit transfer exercise was based on a unit value (WTP/kWh of electricity production) transfer, both with and without adjustments based on expert assessment according to a list of criteria,

including characteristics of the rivers/lakes, the development plan and its potential impacts, as stated in EIAs of the project.

Average annual environmental costs of Norwegian hydropower projects were found to be 0.28-0.30 eurocents per kWh, using unit value transfer with and without adjustments, respectively. Two hydropower EIA experts compared the River Øvre Otta Development Plan and seven development projects within the Sauda Project (Navrud 2001b) with the projects in the national portfolio of hydropower projects, to determine which projects were similar enough to justify unit value transfer. Run-of-river projects in the national portfolio could not be valued, since there are no original valuation studies of such projects in Norway.

The relatively few studies available, and the "bundle" of environmental goods valued (purposely or not) in the existing studies, makes it difficult to foresee good benefit transfer of these values for *aesthetic effects* of hydropower. More original studies of good quality, and with clear understanding of which (bundle of) environmental effects valued, are needed first.

There are very few studies on the valuation of visual intrusion of overhead transmission lines. The very few existing valuation studies, and varying natural conditions and individual preferences between sites make benefit transfer difficult and the transfer errors potentially big. Thus, more valuation studies are needed in order to improve transfer of landscape aesthetic values for policy use in cost-benefit analysis and externality costing.

Conclusion

The damage cost of visual intrusion is highly project- and site-dependent and is also very sensitive to the alternative or reference scenario ("how would electricity be generated without the windmill or dam?"). Aesthetic effects of wind parks, dams and transmission lines can in principle be monetised with a sufficient degree of certainty to be used in cost-benefit analyses. But we need more studies that carefully "unbundle" the external impacts of wind, hydro, and transmission. Choice Experiments, which produce values for individual attributes of the energy source, could be a potentially powerful tool in this regard. However, such new valuation studies need to identify and describe the attributes that people value, and test whether they are actually able to allocate their total willingness-to-pay (WTP) to these individual attributes. Contingent Valuation studies that are able to isolate the individual attributes are another option.

1.12 GREENHOUSE GAS EMISSIONS

The impact pathway of the emissions of greenhouse gases is extensive as compared to the impact pathways of conventional air pollutants, both in time and in space. Greenhouse gases are stock pollutants that through their build-up in the atmosphere cause an increase in temperatures and changes in related climate variables at a global scale and over a long time period. The time period over which the impacts of current emissions occur extends the lifetime of the gases in the atmosphere because of extensive time lags in the climate system. Apart from the geographical and temporal extend of the impacts, the impacts are also manifold as climate change can potentially affect many sectors of society, including health and safety, economic production and consumption, recreation, and environmental and natural assets. Because of the unprecedented rate of warming and climate change that is predicted by scientific assessments, we are unsure or even in deep ignorance about the extent and the probabilities of some of the more extreme impacts.

Because of the extensive and complex impact pathways of greenhouses gas emissions, their damage is commonly assessed with the help of more or less complex Integrated Assessment Models (IAM). An IAM is essentially a computer model of economic growth with a controllable externality of endogenous greenhouse warming. It combines [some] dynamics of global economic growth, with [reduced-form] dynamics of geophysical climate dynamics. Worldwide, there are only a handful of IAMs that have passed some test of professional quality and that have been consequently updated with the most recent scientific information on climate dynamics. These IAMs include DICE (and various variants thereof), FUND and PAGE. For a description of the PAGE model, see Hope (2006). FUND has been used extensively in recent EU projects such as GreenSense, NEEDS and Methodex.

Discounting

The recent publication of the Stern Review on the economics of climate change has attracted a lot of attention, not only in the popular press, but also in academic journals (Stern, 2007). The Stern Review assessed the economics of moving to a low carbon economy, focusing on a medium to long term, plus the potential of different approaches to adaptation and lessons for the UK, in the context of climate change goals. Using the results from an integrated assessment model (the PAGE model), the review estimated that the total damage costs of climate change could be at least 5% of global GDP. If a wider range of risks and impacts is taken into account, the estimates of damage could rise to 20% of GDP or more. The review suggested a marginal cost of emissions of € 85 per ton of CO_2. In contrast to these high costs of

inaction, the costs of action – reducing greenhouse gas emissions to avoid the worst impacts of climate change – can, according to Stern, be limited to around 1% of global GDP each year.

Discussions on the Stern Review in the academic literature note that Stern takes an extreme position by applying a pure rate of time preference of only 0.1 percent in combination with a relatively flat marginal utility function and an infinite time horizon (Nordhaus 2007; Weitzman 2007). Nordhaus (2007) in particular argues that these particularities of the Stern review drive its results and could lead to bizarre policy recommendations. Weitzman (2007) agrees on the discounting issue, but delves deeper into the 'deep' uncertainties of climate change that to a large extent motivated the use of the 'near-zero' social discount rate by Stern. His analysis reaches the somewhat 'unnerving' conclusion that because of 'deep' or 'structural' uncertainty about the scale and probabilities of rare catastrophes that could be associated with 'extreme' manifestations of climate change, expected utility theory (on which cost-benefit analysis is based) may not really give the right answers. Weitzman (2008) therefore calls upon a radically different refocus of IAM's on extremes rather than on, what he calls, "middle-of-the-distribution" kinds of assessments.

Equity weighting

The impacts of climate change may affect people in very different economic circumstances. The aggregation of monetised impacts of climate change over people with (very) different income levels is problematic. The prime reason for this is that the correct metric of social cost-benefit analysis is utility (or its money-equivalent) and not money itself. A standard assumption in economics is that utility is a declining function of income, that is, an equal amount of money income to a poor man is worth more (in terms of increments in his utility) than to a rich man (in terms of increments in the utility of the rich man). It is common practice in climate change damage cost assessments to use some form of equity weighting to reflect these differences in marginal utilities of income between the rich and the poor. Through equity weighting more weight is given to monetised damages that accrue to poor people, or –in practice– to people that live in poor regions, than to rich people. Equity weighting matters in a quantitative sense: equity-weighted estimates of the marginal damage costs of CO_2 are substantially higher than estimated without equity-weights (Anthoff et al., 2006).

Equity weighting introduces an additional source of variance in global damage estimates. Anthoff et al. (2006) show that, apart from the parameter value of the elasticity of utility, equity weights are sensitive to the regional aggregation of an IAM, the baseline economic scenario against which the climate change damages are evaluated, and also to the income level that is used to normalise the equity weights. Anthoff et al. (2006) find that estimates

of marginal damage costs can differ by two orders of magnitude depending on the region of normalisation.

Why is this important? In most equity-weighted estimates of marginal damage costs, the reference level of income that serves to normalise regional equity weights is "average world income". In aggregating regional damages into global damages, damages in richer regions receive lower weights and damages in poorer regions receive higher weights. While this would make sense for a "global planner", Anthoff and Tol (2007) argue that this procedure would make no sense for an assessment by a regional planner, such as, for example, the European Commission. The reason for this is that by using average world income in normalising equity weights, domestic (EU) impacts are not valued at domestic (EU) values (because these EU values receive a lower weight in the aggregation). This can easily lead to inconsistencies in policy assessments. Take for example a cost-benefit assessment of measures relating to externalities from energy generation. Physical health impacts from conventional air pollutants (valued at EU 'utility-prices') would be valued higher than equal health impacts from climate change (valued at equity-weighted 'utility-prices'). Anthoff and Tol (2007) calculate the consequences of some policy-consistent variants of equity-weighting (where EU impacts are valued at EU 'utility-prices'; the variants ranging from not caring for what happens outside the EU to valuing all foreign damages at EU 'utility-prices') and conclude that marginal damage cost estimates can differ by two orders of magnitude depending on the variant chosen.

Concluding then, equity weighting is appropriate in the aggregation of climate change damages over regions (people) with disparately different income levels, not only for ethical reasons but also for strictly economic reasons. However, the standard way of equity-weighting that was used in IAMs to estimate marginal damage cost from a global perspective may be less appropriate for use in regional cost-benefit frameworks as for the EU (which is most relevant for the CASES project). Apart from this 'normalisation' issue, the impact of equity weighting on marginal damage costs is also very sensitive to the elasticity of utility with respect to income, regional aggregation in IAMs, and the baseline economic scenario.

Estimates of marginal damage cost

The science of the integrated assessment of climate change damages is steadily progressing. As is common in fast-developing areas of research, cutting-edge theoretical and conceptual contributions, such as those of Weitzman (2008) and Anthoff & Tol (2007), have not yet made it into standard assessments. A radical refocus of research strategy along Weitzman's recommendations has not yet occurred, although stochastic elements are increasingly being built into IAM's. For the CASES project, we

propose, for the time being, to rely on conventional cost-benefit analysis, keeping in mind the potential caveats.

Choosing between the various estimates of marginal damage costs that have been produced by IAM's in recent years is not easy because of a number of reasons:

The estimates of the IAM's are based on specific sets of parameter values of, for example, the social rate of discount and the elasticity of utility. Much (if not most) of the IAM output has been produced to test the sensitivity of these estimates to parameter assumptions. Before using such estimates some reflection on the choice of parameter values is necessary.

There are a number of IAM's with their own specific strengths, weaknesses, and (possibly) subjective biases. Rather than relying on one specific IAM we would prefer to take as much IAM information as possible into account by as many different researchers as possible.

The quality of IAM's and their underlying data and assumptions are continuously improving. On the one hand, we would therefore prefer the more recent assessments. On the other hand, the most recent assessments have not yet had the opportunity to be reviewed and judged by a larger community. They are still very fresh and (possibly) immature.

The Social Cost of Carbon project by DEFRA (2005) shares a number of the qualities we seek. It is reflexive, it is very much aware of the policy context in which the values are used, and it combines the results of a number of IAM's in a transparent manner. The drawback is that it is two years old, therefore missing the most recent developments. We are of the opinion, however, that the most recent developments have primarily been at the conceptual and theoretical level, viz. the work of Weizman and Stern, and less at a more precise assessment of the social cost of carbon per se. Therefore, we think that the social cost of carbon, as reported in the DEFRA study of 2005, could very well be used in the CASES project.

The DEFRA study distinguishes between a central guidance value and upper and lower estimates. The values are based on full Monte Carlo runs of the FUND and PAGE models, in which all parameters varied to reflect the uncertainty surrounding the central parameter values in both models. The lower and upper bounds are the 5% and 95% probability values of the PAGE model, while the central guidance value is based on the average of the mean values of the FUND and PAGE models.

Common assumptions that were applied in both models were a declining discount rate according to the UK Government 'Green Book' and equity weighting of damages in different regions. The underlying emissions scenarios are the IPCC SRES A2 scenario for PAGE and an emissions scenario for FUND that is in-between the IPCC IS92a and IS92f scenarios. Both models predict rising marginal damages of emissions over time, that is, the present value (discounted back to the year of emission) of the damage of one tonne of CO_2 emitted in 2020 is larger than the present value (also

discounted back to the year of emission) of one tonne emitted in 2005. This is a common finding of all IAM's and basically reflects that underlying assumption that the world economy is continuously growing over the models' time horizons. Therefore, even if physical damage due to one tonne of CO_2 would be similar across time (for example causing a similar rise in sea level), the economic value of damage would increase (because the stock of coastal assets would have increased in value).

The lower estimates of marginal damage costs (PAGE5%) evolve from € 4/tCO_2 in 2000 to € 8/tCO_2 in 2030. The upper estimates (PAGE95%) evolve from € 53/tCO_2 in 2000 to € 110/tCO_2 in 2030. The central estimate evolves from € 23/tCO_2 in 2000 to € 41/tCO_2 in 2030. The central estimate is the average of the means of FUND and PAGE.

1.13 UNCERTAINTIES OF EXTERNAL COSTS: HOW LARGE ARE THEY AND TO WHAT EXTENT DO THEY MATTER?

The uncertainties of environmental damages are far too large for the usual error analysis of physics and engineering (using only the first term in a Taylor expansion). Rigorous systematic assessment of the uncertainties is difficult and few studies have attempted it. Among the studies that have tried to give at least some indication of the uncertainties, most report only very a limited sensitivity analysis, for instance indicating an upper and a lower value based on the range of just one input parameter, without examining the combined effect of several uncertain inputs (e.g. of atmospheric dispersion, dose-response function and monetary valuation). Many damage assessments involve so many different inputs that an analytical solution was usually not considered, and of the uncertainty analyses that have been done, almost all use Monte Carlo techniques and numerical calculations (see e.g. Morgan & Henrion 1990). The Monte Carlo approach is powerful, capable of treating any problem, but it is computationally intensive and the result is "black box": it is difficult to see how important each of the component uncertainties is or how the result would change if a component uncertainty changes – especially for a reader who does not have access to the details of the calculations.

As a simple and transparent alternative Rabl and Spadaro [1999] have developed an analytic approach based on lognormal distributions. The justification lies in the observation that the calculation involves essentially a product of factors, and that the resulting uncertainty of the product is approximately lognormal for most damage costs of pollution. Thus it suffices to specify geometric standard deviations. They can be interpreted in terms of multiplicative confidence intervals of the lognormal distribution: if a cost has

been estimated to be μ with geometric standard deviation σ_g, the probability is approximately 68% that the true value is in the interval $[\mu/\sigma_g, \mu.\sigma_g]$ and 95% that it is in $[\mu/\sigma_g^2, \mu.\sigma_g^2]$. Following the practice of the physical sciences we show error bars corresponding to 1 standard deviation, unlike epidemiology and the social sciences where 95% confidence intervals ($\approx$ 2 standard deviations) are usually reported.

Compared to a Monte Carlo analysis, this analytic approach yields typical answers that are easy to apply and communicate; the calculation is simple enough to allow the reader to modify the assumptions and see the consequences. Furthermore, the analytic approach can be coupled with Monte Carlo results for certain steps of the impact pathway analysis, thus combining the best features of each method; that has been demonstrated by Spadaro and Rabl [2008] for the dispersion of the classical air pollutants.

Whatever the method, an assessment of the uncertainties of damage costs must begin with a detailed examination of the uncertainties of each of the inputs to the impact pathway analysis, to estimate standard deviation and shape of the probability distribution of their uncertainties. This involves expert judgment with its unavoidably subjective aspects. These component uncertainties are then combined to obtain the total uncertainty of the damage cost. In Section 2 we update the original estimates of Rabl & Spadaro [1999] and show the results for mortality, the most important impact of the classical air pollutants (NO_x, PM, and SO_2). Of course the total damage cost of these pollutants is the sum over all impacts, for instance health and agricultural losses. Spadaro and Rabl [2008] have shown that for typical cases the distribution of a sum of lognormally distributed damage costs is also approximately lognormal; they have also developed a simple approximate method for estimating the geometric mean and geometric standard deviation of the distribution of the sum.

This method can readily be used for most pollutants, not only NO_x, PM, and SO_2 but also toxic metals and dioxins. For greenhouse gases, by contrast, we have not been able to carry out an analogous analysis because we find the problem too complex, with too many different impact types and too many possible damage mechanisms. A thorough analysis, with detailed examination of the uncertainties of each of the inputs, would require mastery of models such as FUND (Tol 1995) or PAGE (Plambeck and Hope 1996), clearly beyond the scope of the present project. For that reason we use a simpler global approach for greenhouse gases, and the presentation is different from the classical air pollutants.

However, it is not the uncertainty of the damage cost by itself that matters; rather it is the cost penalty (i.e. the extra cost beyond the social optimum) that society has to bear if a policy choice has been based on an erroneous estimate. Previously we had evaluated this cost penalty for the important example of national emission ceilings for NO_x and SO_2 (Rabl et al 2005), and

here we present a detailed analysis of a global ceiling for CO_2 emissions. We also estimate the value of reducing the uncertainties by further research.

1.14 UNCERTAINTIES FOR PM, NO_X AND SO_2

Methodology

The damage cost C for a single impact or health end point due to a pollutant is essentially a product of uncorrelated variables, as explained in the paper of Spadaro and Rabl (2008). That is obviously the case if one does an approximate calculation using the "uniform world model" (UWM) (Curtiss and Rabl 1996, Spadaro 1999)

$$C = p \rho s_{CR} / v_{dep} \quad (1.1)$$

where p = cost per case ("price") [€/case],

s_{CR} = CRF slope [(cases/yr)/(pers·(μg/m^3))],

ρ = average population density [pers/km^2] within 1000 km of source, and

v_{dep} = depletion velocity of pollutant (dry + wet) [m/s].

The depletion velocity is the sum of dry and wet deposition velocities and, in the case of reactive pollutants, an equivalent velocity for chemical transformation. The UWM is exact (because of the conservation of matter) in the limit where the distribution of either the sources or the receptors is uniform and the key atmospheric parameters are the same everywhere. In practice the agreement with detailed models is usually within a factor of two for primary pollutants and stack heights above 50 m. For secondary pollutants such as nitrates and sulfates the variation with stack height is negligible, and the agreement between UWM and detailed models is better than a factor of two. It yields typical, rather than site-specific results and is therefore relevant for policy applications where the sites are not known in advance.

Looking at a product z of uncorrelated variables x_i

$$z = x_1 x_2 x_3 \ldots x_n \quad (1.2)$$

and taking the logarithm, one sees that the familiar rules for the mean and standard deviation of a sum can be applied to the logarithms. The mean of the logarithm of a random variable is the logarithm of the geometric mean □g; specifically, if p(z) is the probability distribution of z, the geometric mean is given by

$$\ln(\mu_{g,z}) = \int_0^\infty p(z) \ln(z)\, dz \quad (1.3)$$

Since the mean of $\ln(\mu_{gz})$ is the sum of the logarithms of the geometric means $\mu_{g,xi}$ of the x_i, $\mu_{g,z}$ is given by the product

$$\mu_{g,z} = \mu_{g,x1}\, \mu_{g,x2} \cdots \mu_{g,xn} \quad . \tag{1.4}$$

Let us now define the geometric standard deviation $\sigma_{g,z}$ as

$$[\ln(\sigma_{g,z})]^2 = \int_0^\infty p(z)\, [\ln(z) - \ln(\mu_{g,z})]^2\, dz \tag{1.5}$$

and analogously for the x_i. Assuming independence of the distributions one finds that the geometric standard deviation $\sigma_{g,z}$ of the product z is given by

$$[\ln(\sigma_{g,z})]^2 = [\ln(\sigma_{g,x1})]^2 + [\ln(\sigma_{g,x2})]^2 + \ldots + [\ln(\sigma_{g,xn})]^2 \tag{1.6}$$

This is the key formula for our estimation of the uncertainties. One needs to estimate the geometric standard deviations $\sigma_{g,xi}$ for each of the factors x_i in the calculation and combine them according to this equation. The relative importance of each uncertainty source is immediately obvious: because of the quadratic combination of terms, terms with small $\sigma_{g,xi}$ make a negligible contribution to the total uncertainty.

Total σ_g of Damage Costs

Based on a review of the literature and on expert judgment, we have estimated the geometric standard deviations σ_{gxi} for each of the key parameters that enter the calculation of mortality, which is by far the dominant impact; the results for other health endpoints are essentially the same. Since the other impacts of the classical air pollutants, namely crop losses and damage to buildings, are very small compared to the health impacts, their uncertainty makes a negligible contribution (again because of the usual quadratic combination of terms).

Table 1 shows our assumptions for the component uncertainties and the result for the damage cost for mortality. Of course such choices involve expert judgment with their inevitable subjective aspects. However, it is easy for the reader to make different choices and calculate the corresponding σ_g. For sulfates and nitrates, ExternE assumes the same CRFs as for PM (apart from an overall scale factor), therefore the contributions to the uncertainty are the same for each of these pollutants, with relatively minor differences due to

i) atmospheric dispersion and chemistry (we assume different geometric standard deviations for PM, NO_x and SO_2).

ii) the toxicities of primary PM, sulfates and nitrates relative to ambient PM_{10}, as discussed at the end of Section 3.2 of Spadaro and Rabl [2008].

The resulting geometric standard deviations are 2.78 for primary PM, 3.26 for SO_2 and 3.39 for NO_x. The distribution of a product is exactly lognormal if each of the factors is lognormal. In practice it is sufficient for the factors with the largest widths to be approximately lognormal, a condition satisfied in the present case. Thus lognormality for the distribution of the result is very plausible for the damage costs.

Table 1.13 Uncertainty of damage cost estimates per kg of pollutant for mortality. Sample calculations of geometric standard deviation σ_g, inserting the component uncertainties σ_{gi} into Eq.6. The relative contributions of the σ_{gi} to total can be seen under $ln(\sigma_{gi})^2$.

	Log normal ?	σ_{gi} **PM**	$ln(\sigma_{gi})^2$	σ_{gi} SO_2 via sulfates	$ln(\sigma_{gi})^2$	σ_{gi} NO_x via nitrates	$ln(\sigma_{gi})^2$
Exposure calculation							
Dispersion	*yes*	1.5	*0.164*	1.7	*0.282*	*1.7*	*0.282*
Chemical transformation	*yes*	1	*0.000*	1.2	*0.033*	*1.4*	*0.113*
Background emissions	*no*	1	*0.000*	*1.05*	*0.002*	*1.15*	*0.020*
Total σ_g for exposure		1.50	*0.16*	1.76			
Relative risk	*no*	*1.5*	*0.164*	*1.5*	*0.164*	*1.5*	*0.164*
Toxicity of PM components	*?*	*1.5*	*0.164*	*2*	*0.480*	*2*	*0.480*
YOLL, given relative risk	*no?*	*1.3*	*0.069*	*1.3*	*0.069*	*1.3*	*0.069*
Total σ_g for ERF		*1.88*	*0.40*	*2.33*			
Monetary valuation							
Value of YOLL (VOLY)	*yes*	2	*0.480*	2	*0.480*	2	*0.480*
Total (Eq.6)		**2.78**	***1.04***	**3.42**	***1.51***	**3.55**	***1.61***

We show three significant figures merely to bring out the differences between these pollutants and the larger uncertainties of the secondary pollutants. But since the estimation of uncertainties is extremely uncertain, we believe that it would be appropriate to cite just a single set of results for air pollutants such as PM, SO_2 and NO_x that act via inhalation. For policy applications, typical uncertainties are more instructive than detailed values of geometric standard deviation for each source and each impact. For inhalation of most air pollutants we suggest a typical geometric standard deviation of 3. For toxic metals Rabl (2008) estimates a σ_g around 4 (the corresponding ratios are median/mean ≈ 0.38, low/mean ≈ 0.1 and high/mean ≈ 1.5), and for dioxins a σ_g of about 5.

Sum over Endpoints, Impact Categories or Pollutants

We have also developed a simple method for estimating the uncertainty of the sum of damage costs for a set of different impact types or pollutants, and we have verified its usefulness by means of detailed Monte Carlo calculations. We have verified with Monte Carlo calculations for a large number of realistic cases that the sum of lognormally distributed damage costs is, to an excellent approximation, also lognormal. Then we have derived two analytical estimates for the geometric standard deviation of the sum, one an over- the other an underestimation. Finally we have found that the average of these two estimates turns out to be remarkably close to the correct answer. The details can be found in Spadaro and Rabl (2008).

As a general observation we note that whereas the absolute error of a sum is larger than the absolute errors of the summands, the relative error is smaller than the largest relative error of the summands: in the cases we have examined for air pollution, the relative error of the sum can even be significantly smaller. For the cost per kWh, for most energy systems, there are contributions from PM_{10}, NO_x and SO_2, as well as the greenhouse gases. For the latter the uncertainty is much larger than for the former; it is difficult to estimate but might correspond to a geometric standard deviation of 5. Thus the geometric standard deviation of the cost per kWh is intermediate between 3 and the one of the greenhouse gases, and in most cases it is closer to the former than the latter.

1.15 UNCERTAINTIES FOR GREENHOUSE GASES

Review of the literature

It was not possible to implement for climate change the detailed approach shown above. As an alternative we have looked at the range of damage cost estimates in the literature, in particular the recent reviews by DEFRA (2004, 2005) and by Tol (2005). Tol reviews over 100 estimates for the marginal damage cost of CO_2 to determine an overall probability density function. The uncertainty proves to be strongly right-skewed, with a median of \$3.8/t_{CO2}, a mean of \$25.4/t_{CO2}, and a 95% confidence limit of \$95/t_{CO2}. According to Tol (2005), under standard assumptions of time discounting, equity weighting, and risk aversion, the marginal damage cost is unlikely to exceed \$14/t_{CO2}, and is probably even smaller.

The highly skewed distribution of these damage cost estimates in the literature is fairly consistent with a lognormal function, even though a few studies claim negative damages. Indeed, global climate change produces both

winners and losers, at least at moderate temperature increases, but it is not plausible that the net world-wide damage cost could be negative. As representation of the distribution found by Tol we therefore take a lognormal distribution, with median μ_g = \$3.8/t_{CO} and upper limit $\mu_g \sigma_g^2$ = \$95/t_{CO22} (the median and upper limit of the 95% confidence interval of Tol's review); thus σ_g = 5. That is also reasonably consistent with DEFRA and with the simple model we present in Section 3.2.

A model for the damage cost as function of emissions

Most of the integrated assessment models use a damage cost function with the shape:

$$C_{dam} = \rho(\Delta T_{stab})^{\theta}, \tag{1.7}$$

in which C_{dam} is the damage cost expressed as fractional loss of GWP (global world product), ΔT_{stab} the global average temperature change with respect to the pre-industrial atmospheric temperature in stabilized conditions, i.e. when equilibrium is reached of the climate system, and ρ and θ coefficients characterizing the shape of the damage function. GWP is a commonly employed measure for the size of the global economy; it is incomplete because it only covers tangible markets but no better alternative is available. Usually θ is taken as 2. Central to our analysis is the definition of ΔT_{stab} as the stabilized global average temperature change obtained after a specified emission profile leads to new equilibrium values of the atmospheric CO_2 concentration and the corresponding increase in atmospheric temperature. Time lags exist both between the CO_2 emissions level and the stabilized CO_2 concentration, and between this new atmospheric CO_2 concentration and ΔT_{stab}, typically in each case of at least several decades up to a century.

Since we need to express C_{dam} as function of E, we first relate ΔT_{stab} to the atmospheric CO_2 concentration P by recalling that a roughly logarithmic relation exists between this concentration and global temperature increase (Houghton *et al.*, 1996). More precisely, the stabilization level of atmospheric CO_2 concentration, P_{stab}, can be related to ΔT_{stab} by (see Caldeira *et al.*, 2003):

$$\frac{P_{stab}}{P_{280}} = 2^{\left(\frac{\Delta T_{stab}}{\Delta T_{2X}}\right)}, \tag{1.8}$$

in which P_{280} is the pre-industrial CO_2 concentration of about 280 ppmv, and ΔT_{2X} the climate sensitivity, defined as the temperature change ΔT_{stab} resulting from a doubling of the atmospheric CO_2 concentration. Hence, a stabilization concentration target for atmospheric CO_2 increases exponentially with the ratio of the stabilization temperature change and the climate sensitivity. As before, neither ΔT_{stab} nor ΔT_{2X} are instantaneous

temperature changes, but global mean surface temperature changes attained if CO_2 concentrations are held constant long enough to reach stable average climate conditions. ΔT_{2X} is thought to lie in a range of about 1.5 to 4.5 ˚C although it could well be larger.

In order to derive a simple time-independent relationship between P_{stab} and E, we employ the curves of Fig.1 in Wigley *et al*. (1996) representing a set of time-dependent emission profiles for the period 1990 – 2300 calculated for different values of P_{stab}. We take for each value of P_{stab} the corresponding annual emission level E averaged over this time frame. A linear fit to these data can be written in the form

$$\frac{P_{stab}}{P_{280}} = \varepsilon + \delta \frac{E}{E_s} \qquad \text{with } \delta = 1.45 \text{ and } \varepsilon = 0.94. \tag{1.9}$$

where E_s is the current emissions level of about 25.7 Gt_{CO2}/yr.

Combining Eqs.7 to 9, and assuming $\theta = 2$, we obtain this model of the damage cost

$$C_{dam}(E) = \rho \left[\Delta T_{2X} \ln(\varepsilon + \delta \frac{E}{E_s}) / \ln 2 \right]^2 . \tag{1.10}$$

The marginal damage cost is of course the derivative with respect to the emissions E

$$\frac{dC_{dam}}{dE} = \frac{2}{\ln 2^2} \rho \Delta T_{2X}^2 \frac{\ln(\varepsilon + \delta E / E_s)}{\varepsilon + \delta E / E_s} \frac{\delta}{E_s} \quad . \tag{1.11}$$

We have carried out a Monte Carlo analysis of this expression, assuming normal distributions with the following means and standard deviations:

δ: *Normal (1.45, 0.10)*

ε: *Normal (0.94, 0.05)*

ρ: *Normal (0.0020, 0.0005)*

ΔT_{2X}: *Normal (3, 1.2)*

The resulting distribution of marginal damage costs is highly skewed, although fairly different from lognormal; it has a geometric standard deviation of about 3.5. It is easy to get higher or lower values for the geometric standard deviation by making different assumptions on the distributions of the parameters. On balance we feel that a geometric standard deviation around 5 seems reasonable for current estimates of the marginal damage cost of climate change.

A model for the Abatement cost as function of emissions

Like in Rabl et al (2005), we assume that the marginal CO_2 abatement cost takes the functional form:

$$\frac{dC_{ab}}{d(-E)} = \frac{1}{G}\alpha\left(\frac{E-\beta}{E_s}\right)^{\gamma}, \qquad (1.12)$$

in which C_{ab} is the globally aggregated abatement cost as fraction of GWP (abridged to G in this formula), E and E_s (both in Gt_{CO2}/yr) are as before, and α (in €/tCO_2), β (in Gt_{CO2}/yr) and γ are coefficients characterizing the non-linear convex form of the abatement cost function. The factor G is added to the relation used in Rabl et al (2005) in order to stay consistent with the way damage costs are expressed in Eq.1.7 and because in the present analysis we find it convenient to express all costs as fraction of GWP. For GWP we adopt today's value of approximately 50 trillion €/yr. We choose the signs in Eq.1.12 so that with a positive α the marginal cost dC_{ab} is positive for a reduction of E. The parameters α, β, and γ may be determined by least squares regression if cost data are available as a function of the abatement level. Alternatively, they may be estimated on the basis of energy technology assessments or energy systems modeling. Here we choose the marginal abatement cost curves depicted in Figure 1.3, based on an evaluation of published integrated assessment modeling results (see notably Goulder and Mathai 2000; Goulder and Schneider 1999; van der Zwaan *et al* 2002; Yohe 1996). Figure 1.3 is for the long term, by contrast to near-term abatement cost curves obtained through detailed engineering energy technology analyses, such as the GAINS model of Klaassen *et al*. (2005) for the 2020 time horizon. Over such a short time the potential for deep reductions is limited or exceedingly costly, because many of the technological options require long lead times or have costs that are still unacceptably high. In the long run, however, major cost reductions are to be expected as a result of technological progress and learning-by-doing. Thus, our abatement cost assumptions concern the long run and should not be interpreted as realistic short-term policy goals.

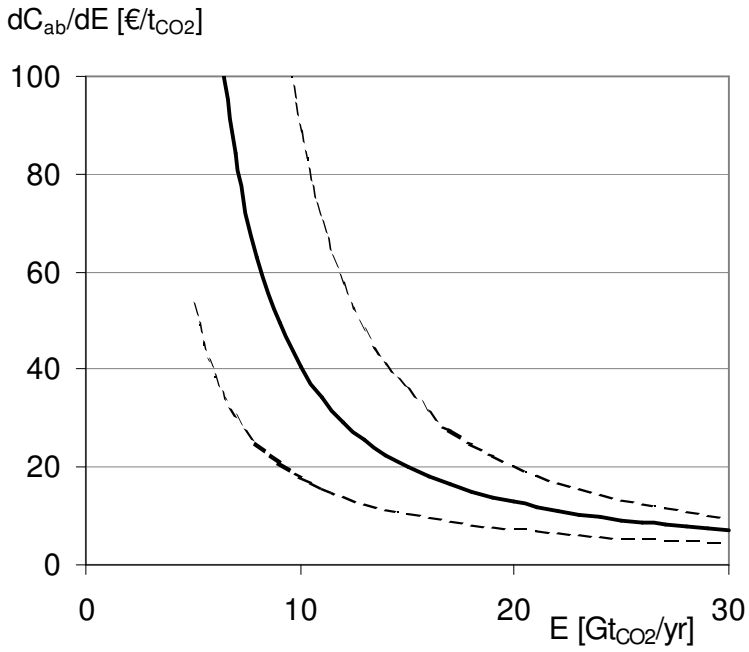


Figure 1.3 Our choice for the marginal abatement cost curve (solid line) and lower and upper bounds (dashed lines). The coefficients are α=7.5, β=3, and γ=–1.3 for the central curve, α=5, β=2, and γ=–1.1 for the lower limit, and α=10, β=4, and γ=–1.5 for the upper limit.

The cost of reducing CO_2 emissions from starting point E_s to level E is the integral of the marginal abatement cost equation of Eq.1.12:

$$C_{ab}(E)=\frac{1}{G}\frac{\alpha E_s}{\gamma+1}\left[\left(\frac{E_s-\beta}{E_s}\right)^{\gamma+1}-\left(\frac{E-\beta}{E_s}\right)^{\gamma+1}\right] \qquad \text{for } \gamma\neq\text{-}1. \qquad (1.13)$$

For a Monte Carlo analysis of the abatement cost we assume normal distributions with the following means and standard deviations:

α: *Normal (7.5, 1.0)*

β: *Normal (3, 0.5)*

γ: *Normal (-1.3, 0.1)*

The resulting distribution of marginal abatement costs is approximately normal, except when the emission level drops below about 8 Gt_{CO2}/yr. The

ratio of standard deviation and damage cost is about 0.15 at E = 25 Gt_{CO2}/yr, increasing to about 0.25 at E = 10 Gt_{CO2}/yr.

1.16 EFFECT OF THE UNCERTAINTIES

Some people question the usefulness of damage cost estimates because of their large uncertainties. Here we address that objection by asking "how large is the social cost penalty if one makes the wrong choice because of uncertainties in the cost or benefit estimates?" We examine one the most important and general policy choices, namely the choice of national or global emission ceilings. For NO_x and SO_2 we have already published the results before this project (Rabl et al 2005).

The methodology in that paper was to use curve fits to data of abatement cost C_{ab} as function of emission level E. For the marginal damage cost D = dC_{dam}/dE we assumed a constant value (but for NO_x and SO_2 different in different countries). The analysis was done at the country level for NO_x and SO_2, at the global level for CO_2. We determined the optimal emission level $E_{o,est}$ (i.e. the optimal emission ceiling) by minimizing the total cost C_{tot} = C_{dam} + C_{ab}. This is the estimated optimum, based on the available estimate of the marginal damage cost, D_{est}. Since the true optimum $E_{o,true}$, corresponding to the true damage cost D_{true}, is different from the estimated one, the realized total cost will be higher than the true minimum. The cost penalty ΔC is the difference between the realized total cost $C_{tot}(E_{o,est})$ and the true minimum $C_{tot}(E_{o,true})$

$$\Delta C = C_{tot}(E_{o,est}) - C_{tot}(E_{o,true}) \quad . \tag{1.14}$$

We also consider the cost penalty ratio

$$R = C_{tot}(E_{o,est})/C_{tot}(E_{o,true}) \tag{1.15}$$

as function of $x = D_{true}/D_{est}$, both numerator and denominator being evaluated with the true damage cost D_{true}.

We found a remarkable insensitivity to uncertainties. For NO_x and SO_2 an error by a factor of three increases the total social cost by at most 20%, and in most cases much less, i.e. R is less than 1.2. That paper also looked at dioxins and CO_2, pollutants for which the uncertainties of the damage cost are even larger than in the case of NO_x and SO_2. Nonetheless we found similar insensitivity to uncertainties even for these pollutants.

For the present paper we have redone the analysis for CO_2, using the more realistic and detailed models of the paragraph above. The optimal emission level E_o is found by minimizing $C_{tot}(E)$, hence by setting the sum of the marginal abatement cost and the marginal damage cost equal to zero, so that:

$$-\frac{\alpha}{G}\left(\frac{E-\beta}{E_s}\right)^{\gamma}+\frac{2}{\ln 2^2}\rho\Delta T_{2X}^2\frac{\ln(\varepsilon+\delta E/E_s)}{\varepsilon+\delta E/E_s}\frac{\delta}{E_s}=0 \qquad (1.16)$$

at $E = E_o$.

Unlike the case with linear damage costs, there is no analytical solution, and so we use the FindRoot function of Mathematica® to obtain a numerical solution. As central values we take the ones used above for the Monte Carlo analysis of abatement and damage costs in Sections 3.2 and 3.3; they are also listed in the caption of Figure 1.4. For these central values the optimal emission level is found to be E_o = 8.7 Gt_{CO2}/yr, about one third of the current emission level E_s. The marginal damage and abatement costs at E_s are about 77 €/t_{CO2} and 9 €/t_{CO2}, respectively, while at the optimum they are equal to approximately 54 €/t_{CO2}.

Figure 1.4 shows the sensitivity of E_o to changes in the parameters p. As a compact format we represent each p in non-dimensional form as $x = (2p - p_{max} - p_{min})/(p_{max} - p_{min})$. The central value $p_{central}$ equals $(p_{max} + p_{min})/2$, corresponding to x=0. For the large uncertainty range chosen for the parameters α, β, γ, δ, and ε, we find that E_o varies by less than 20% in most cases.

The largest variations derive from changes in the climate sensitivity, ΔT_{2X}, and the main parameter used to express climate change damage costs, ρ. Especially for values of x close to -1, for these two parameters, E_o could be much larger. For ΔT_{2X}, however, we find it reasonable not to consider values below 2 °C, given the low likelihood that the climate sensitivity could be so low. For ρ, we consider 0.0010 a generous lower bound (although Figure 1.4 extends down to ρ = 0.0005). Since we abstract from the time-dimension of the cost-benefit problem, we cannot explicitly consider the effect of variations in the discount rate. However, it is implicitly included in changes of ρ. Thus, limiting ourselves for ΔT_{2X} and ρ down to values of x = -0.5 but up to x = 1, corresponding to a broad uncertainty range, we find that the optimal emission level E_o = 8.7 Gt_{CO2}/yr varies by no more than 2.3 Gt_{CO2}/yr or less than 30%.

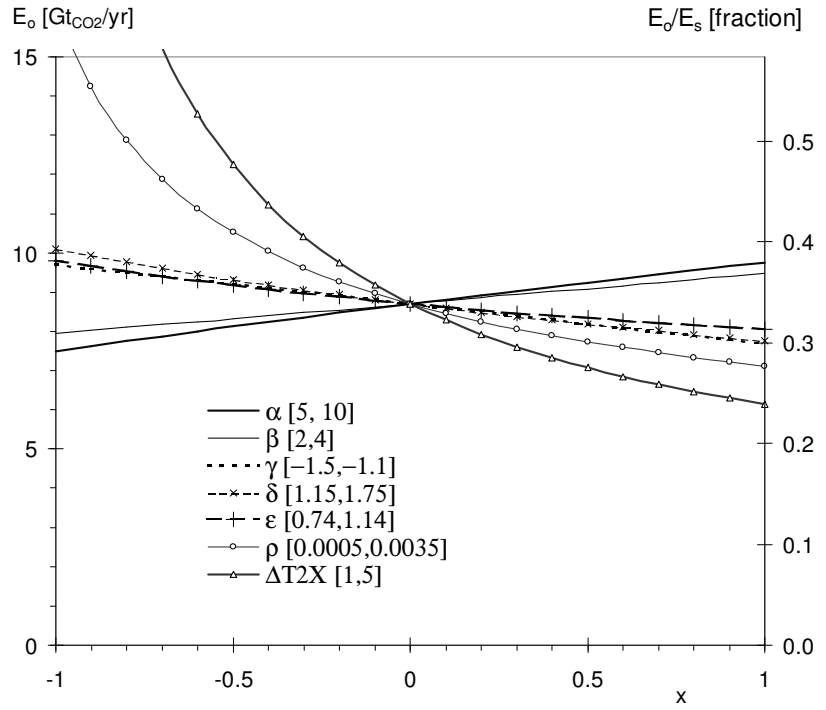


Figure 1.4. Dependence of the optimal emissions level E_o (in Gt_{CO2}/yr and as fraction of current emissions E_s) on parameters $\alpha, \beta, \gamma, \delta, \varepsilon, \rho$, and ΔT_{2X} of the optimization problem.

In Figure 1.4 each curve shows the effect of varying the parameter under consideration while keeping the others fixed at their central value. The x-axis shows the variation of each parameter p in non-dimensional form as $x = (2p - p_{max} - p_{min})/(p_{max} - p_{min})$. The central values are $\delta = 1.45$, $\varepsilon = 0.94$, $\rho = 0.0020$, $\Delta T_{2X} = 3$ºC, $\alpha = 7.5$ €/t_{CO2}, $\beta = 3$ Gt_{CO2}/yr, and $\gamma = -1.3$; the ranges are indicated as $[p_{min}, p_{max}]$ in the labels.

1.17 COST PENALTY AND VALUE OF RESEARCH

Due to uncertainties in damage and abatement costs the optimal emission level may well be determined incorrectly. Consequently, the real cost borne by society when establishing a desirable CO_2 emission level is larger than at the social optimum. Of course, various political processes may also preclude

the choice of the optimal emission level, but here we are interested in what we call the "cost penalty", i.e. the extra social cost due to damage and abatement cost estimation errors. Rather than looking at the uncertainty in each of the parameters, as we did in paragraph 1.16, we here take a simplified approach by considering overall errors in the damage and abatement cost, respectively.

Suppose that damage costs have been estimated as $C_{dam,est}(E)$, while the true damage cost is $C_{dam,true}(E)$. Likewise, we assume that the abatement cost has been estimated as $C_{ab,est}(E)$, whereas it is really $C_{ab,true}(E)$. The optimal emission level corresponding to the estimated costs is $E_{o,est}$, instead of the true optimum $E_{o,true}$. We represent damage and abatement cost uncertainties by random variables, x_{dam} and x_{ab}:

$$x_{dam} = C_{dam,\,true}(E)/C_{dam,\,est}(E), \tag{1.17}$$

and

$$x_{ab} = C_{ab,\,true}(E)/C_{ab,\,est}(E). \tag{1.18}$$

We look at variations of x_{dam} and x_{ab} separately because their magnitudes and probability distributions are very different. Uncertainties in the abatement cost are much smaller than those in the damage cost. Also, for the former a normal distribution seems most plausible. We characterize the distribution of x_{ab} by considering a Gaussian with mean 1 and standard deviation σ_{ab}. Since for large σ_{ab} a significant portion of the Gaussian corresponds to negative values of x_{ab}, i.e. negative abatement costs, we truncate this Gaussian at zero and replace it by a normalized distribution that is proportional to the Gaussian at positive x_{ab}. For uncertainties in the damage cost function we assume a lognormal distribution with $\sigma_{g,dam} = 5$.

Since we focus in this section on variations in x_{dam} and x_{ab}, we use these variables as arguments of the true optimal emission level $E_{o,true}(x_{dam},x_{ab})$ as well as of the difference $\Delta C(x_{dam},x_{ab})$ between the total cost at $E_{o,est}$ and that at $E_{o,true}$:

$$\Delta C(x_{dam}, x_{ab}) = [C_{dam,true}(E_{o,est}) + C_{ab,true}(E_{o,est})] - [C_{dam,true}(E_{o,true}) + C_{ab,true}(E_{o,true})]. \tag{1.19}$$

The cost penalty $\Delta C(x_{dam},x_{ab}=1)$ resulting from damage cost errors is shown in Fig.3 as function of x_{dam}, keeping $x_{ab} = 1$. To get a sense for the magnitude of the cost penalty with respect to the total costs incurred at the optimum, it is instructive to complement the cost penalty in absolute terms (solid line and left hand scale) with that in relative terms as ratio $\Delta C/C$ (dashed line and right hand scale), with in this case $\Delta C=\Delta C(x_{dam},x_{ab}=1)$ and $C=C(x_{dam},x_{ab}=1)$. Analogously, the cost penalty $\Delta C(x_{dam}=1,x_{ab})$ due to abatement cost errors is shown in Figure 1.6, again both in absolute and in relative terms (left and right hand scales, respectively). Given that the uncertainty range for abatement costs is probably smaller than for damage costs, we think it justified to depict a smaller x-axis span for x_{ab} than for x_{dam}.

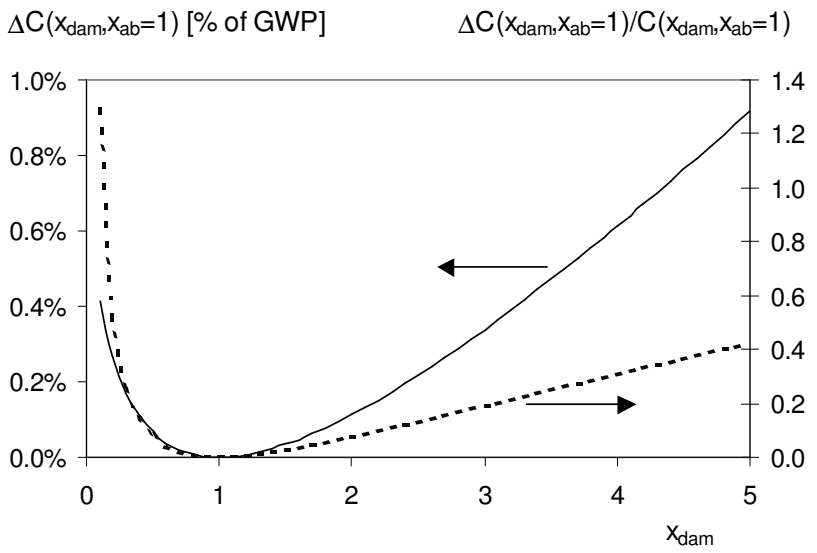


Figure 1.5 The cost penalty $\Delta C(x_{dam},x_{ab}=1)$ if the true damage cost is a factor x_{dam} times the damage cost estimate, in absolute terms (solid line, left scale) and in relative terms as fraction of the total cost $C(x_{dam},x_{ab}=1)$ at the optimum (dashed line, right scale)

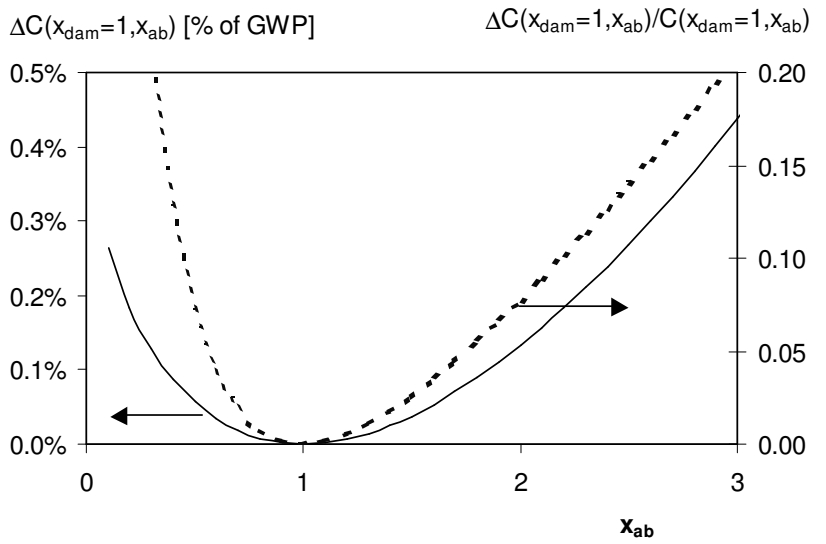


Figure 1.6 The cost penalty $\Delta C(x_{dam}=1,x_{ab})$ if the true abatement cost is a factor x_{ab} times the abatement cost estimate, in absolute terms (solid line, left scale) and in relative terms as fraction of the total cost $C(x_{dam}=1,x_{ab}=1)$ at the optimum (dashed line, right scale)

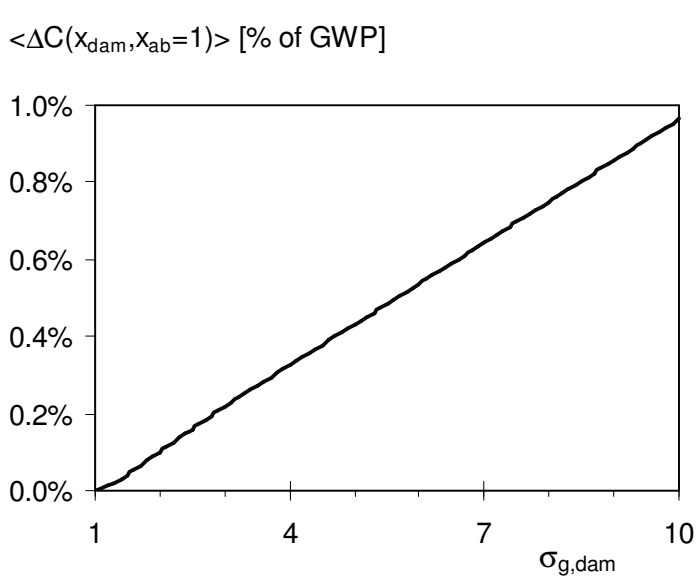
Like in Rabl *et al* [2005], we find that the cost penalty is relatively small near the optimum, in other words, the optimum is fairly broad. Only when the damage and abatement cost errors get large, does the cost penalty become substantial. Figure 1.5 and Figure 1.6 show that when the true damage cost is five times the estimated one, the relative cost penalty amounts to about 40%, and that when the true abatement cost is three times the estimated one, the relative cost penalty amounts to about 20%. These relative changes may still be considered modest, but in absolute terms the cost penalty can become really enormous. The reason is that the stakes involved in global climate change, i.e. the costs both at the damage and abatement side of the problem, are simply very high. For example, for x_{dam}=5 and x_{ab} = 2, the cost penalty reaches values nearing 1% and 0.2% of GWP, respectively, close to the total costs of 1.2% of GWP involved in the climate change problem at the optimum.

Uncertainties in damage and abatement costs can be reduced by further research. To assess the value of such research we calculate the expectation value $<\Delta C(x_{dam},x_{ab}=1>$ as function of the geometric standard deviation $\sigma_{g,dam}$

of the damage cost, with x_{dam} characterized by a distribution *Lognormal(1,*$\sigma_{g,dam}$*)*. Likewise, we determine the expectation value $<\Delta C(x_{dam}=1,x_{ab})>$ as function of the standard deviation σ_{ab} of the abatement cost, with x_{ab} characterized by a distribution *Normal(1,*σ_{ab}*)*. Even though some abatement options exist with negative costs, we do not believe that on a global scale total abatement costs could be negative in the long term. We therefore truncate the normal distribution at $x_{ab} = 0$. The results are shown in Figure 1.7.

Figure 1.7 provides an indication of the value of improved information on the damage and abatement costs. For example, if research reduces the geometric standard deviation $\sigma_{g,dam}$ of the damage cost from 5 to 4, the expectation value of the cost penalty decreases from around 0.4% to around 0.32% of GWP. Hence the value of such research is almost 0.1% of GWP. In relative terms less than a tenth of a percent benefit may seem negligible, but in absolute terms this reduction of the cost penalty corresponds to an amount of about 40 billion €. In a similar way, if further research reduces the standard deviation of relative abatement cost estimates from 1 to 0.5, the benefit is about 0.06% of GWP, that is, about 30 billion €. We thus conclude that research to reduce the uncertainty of damage and abatement cost estimates can be extremely cost-effective. We also observe that the possible gains from continued climate change damage cost analyses (i.e. climatic externality studies) may be significantly higher than those obtainable by increasing our understanding of the nature of abatement technologies and their prospected costs. The reason is the small likelihood for extreme climate events with high impacts, that is, the lognormal distribution of the damage cost function. Note that the change of slopes in Fig.5b) around $\sigma_{ab} = 0.2$ is a reflection of the truncation at $x_{ab} = 0$. Such details should not be taken too literally, since the probability distributions are not known sufficiently well.

a)



b)

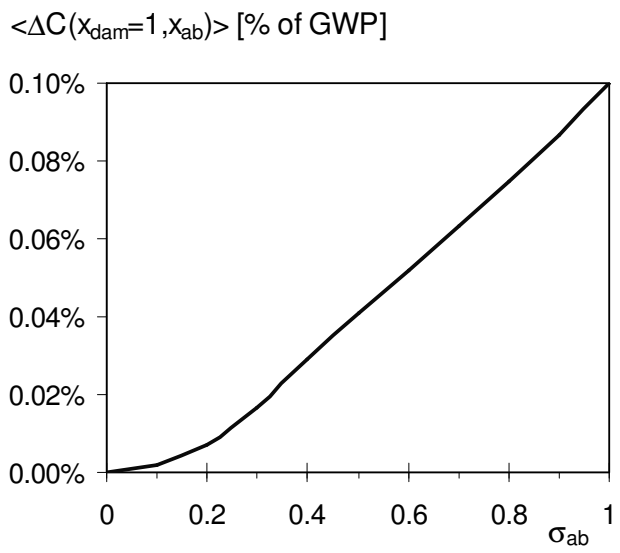


Figure 1.7 Expectation value of the cost penalty: a) $<\Delta C(x_{dam}, x_{ab}=1>$ as function of the geometric standard deviation $\sigma_{g,dam}$ of the damage cost; b) $<\Delta C(x_{dam}=1, x_{ab})>$ as function of the standard deviation σ_{ab} of the abatement cost.

Conclusions

We have presented a simple and transparent method for analyzing the uncertainty of the damage costs of pollution, based on geometric standard deviations. If a damage cost has been estimated to be μ with geometric standard deviation σ_g, the probability is approximately 68% that the true value is in the interval $[\mu/\sigma_g, \mu.\sigma_g]$ and 95% that it is in $[\mu/\sigma_g^2, \mu.\sigma_g^2]$. We find that for NO_x, SO_2 and PM_{10} σ_g is about 3, and for toxic metals it is about 4. For greenhouse gases we estimate a σ_g of about 5 on the basis of a literature review.

However, it is not the uncertainty of the damage cost by itself that matters; rather it is the cost penalty (i.e. the extra cost beyond the social optimum) that society has to bear if a policy choice has been based on an erroneous estimate. Previously we had evaluated this cost penalty for the important example of national emission ceilings for NO_x and SO_2 [Rabl et al 2005] and we found that the cost penalty is remarkably small despite the very large uncertainties. In the present chapter we have presented a detailed cost-benefit analysis global warming to determine the optimal global ceiling for CO_2 emissions. This ceiling is about a third of the current emission level. We have examined the effect of uncertainties, both of damage costs and of abatement costs, and we find, just like in the case of NO_x and SO_2 emissions, that the cost penalty is small in relative terms. But in absolute terms it is quite large because of the very large global costs involved in climate change. We also quantify the value of reducing the uncertainties by further research: it is very large.

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2 Electricity supply externalities, energy security

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2.1 INTRODUCTION

Energy security is defined by the IEA as being the "availability of regular supply of energy at a reasonable price" (IEA: 2001)

For European policy makers, energy security is an important issue because private decisions about energy use may not fully take into account the costs of energy insecurity. Disruptions in supply and dramatic price increases have macroeconomic impacts that individuals/firms do not take into account. Furthermore, agents tend to underestimate the risks of disruption and subsequent price adjustments, and there are other less tangible effects such as the psychological costs of people feeling insecure about their energy supplies. Therefore, it is important from a policy perspective to estimate the size of the external costs of energy arising from energy insecurity.

There is some debate however about the magnitude and importance of the costs of energy security and insecurity. This chapter therefore takes a critical look at the various aspects of energy security costs as related to electricity supply and distribution in the EU. Where relevant, predictions have been made to 2030.

The chapter is organised as follows. The first section of this chapter looks at the Value of Lost Loads (VOLL), the costs incurred by interruptions in the electricity supply. Based on published research from across the world, the section presents how these costs vary across regions and sectors, and predict how these values will change in 2030.

The second and third sections of this chapter develop two models looking at how energy security costs can have impacts at a national level. The first model in section 2 takes a critical look at macroeconomic or pecuniary externalities

associated with energy security, and in section 3 a model is presented which estimates the historical costs of energy security policies.
The final section undertakes an initial assessment of the policy options to reduce and insure against energy insecurity in Europe. After reviewing the relevant EU green papers, it presents alternative market based and non-market policy options.

2.2 AN OVERVIEW OF SELECTED STUDIES ON THE VALUE OF LOST LOAD (VOLL)[2]

The tripping of high voltage lines in Germany in 2006 had large consequences for electricity users throughout a significant part of Europe (UCTE, 2007).
Energy interruptions cause significant impacts on consumers and the economy. Recent interruptions include those in Germany in 2006 (UCTE, 2007), Australia (2004) and the USA, Scandinavia and Italy (2003) (IEA, 2005; Bialek, 2004).

These events have focused the attention of energy planners on the importance of the reliability of electricity supply. More broadly, these instances of power supply interruptions have contributed to a wider discussion on the pertinence of energy supply security at large.

Security of energy supply has at least four important features: reliability, capacity, diversity, and dependency. All, or at least a subset of these facets of energy supply security are usually distinguished in the literature (DTI, 2006). This section is only dedicated to security of *electricity* supply, as one of the essential topics in the more general theme of *energy* supply security, so we here focus mainly on the aspect of reliability. Reliability is interpreted as relating to both the production and the distribution network parts of the total electricity supply chain. Measuring whether or not, and the extent to which, energy supply is secure, is not trivial. Quantifying security of energy supply is particularly difficult because there is no such thing as a market for the quality of energy supply, or, inversely, there is no market for insuring against interruptions of that supply. One way of dealing with the quantification of security of energy supply is determining the reverse. It proves often easier to estimate the costs of the effects of supply interruptions for energy consumers than the value of situations in which no such interruptions occur. The cost of the impacts of supply interruptions, or value of security of energy supply, proves to be very different from the willingness-to-pay to avoid these interruptions. Still, a strong relationship exists between these two notions. The value of security of energy supply relates, naturally, to the level of the actual demand for the corresponding energy services.

Since this section focuses on the electricity sector, we express the costs or

'value' of interruptions in the supply of energy (electricity) as the Value Of Lost Load (VOLL), which is the total damage caused by a failure of supply divided by the loss of supply. The aggregate value of (in)security of electricity supply can thus be expressed by multiplying the probability of the intensity, frequency and duration of supply disruptions, i.e. the expected quantity of electricity un-served, by this VOLL variable. While other variables are found in the literature as well, VOLL is our expression of reference throughout this section, the main purpose of which is to provide an overview of some of the most relevant recent VOLL-related references. In this section, we examine what the factors are that determine VOLL, how it can be measured, and what the relative (dis)advantages are of each of the different methods of measurement. We then provide an overview of recent VOLL studies, link the information available from these studies to data on Gross Domestic Product (GDP), and stipulate VOLL ranges for developed and developing countries applicable in 2030. Finally, we briefly speculate on how measures for the security of electricity supply, and hence levels of VOLL, may evolve in the future.

Value Of Lost Loads

Production and network failures both imply costs associated with the interruption in power supply. The cost can be expressed by the probability of an interruption multiplied by VOLL. VOLL is usually expressed, as in this report, in terms of the estimated total damage caused by not delivered electricity divided by the amount of electricity not delivered in kWh. Calculating VOLL as variable for quantifying supply interruption costs constitutes one of the important approaches towards evaluating security of electricity supply and provides insight in the value of security of energy supply at large. As many investment decisions in the energy sector are dominated by arguments regarding demand for security of supply, estimating the level of VOLL may be informative and even essential for justifying these decisions. The higher is the product of VOLL and the probability of supply disturbances, the more valuable are investments in generation and/or network capacity extension or improvement.

Since VOLL is determined by the costs of interruptions in power supply, we ask ourselves what the factors are that determine these costs. Interruption costs prove to be highly variable, as a result of several facts or circumstances (see notably SEO, 2003; Ajodhia, 2006; DTI, 2006):

- *Differences between distinct types of customers*. Different sectors face different electricity costs and differ in their dependency on electricity. For

example, interruption costs for the service sector generally tend to be higher than those for the industrial sector.

- *Differences in perceived reliability level*. The perceived reliability level influences the extent to which customers prepare themselves for potential interruptions. This is itself determined by the frequency of recent interruptions and also the local dependency on electricity.
- *Differences in time of occurrence*. Interruption costs may vary significantly with the season of the year, the day of the week, and even time of the day at which the disturbance occurs.
- *Differences in duration*. The duration of the interruption is also a key determinant for the costs incurred. At least for the industrial sector, the longer the duration, the higher are the total costs experienced.
- *Differences in notification*. Advance notice about the occurrence and duration of an interruption lowers its consequences, since consumers may take preventive action or reschedule activities accordingly.

As a result of these different facts and circumstances, VOLL does not adopt a single value, but rather can imply a large range of values dependent on the relative importance of these factors.

Ways of measuring VOLL

VOLL cannot be determined or observed directly from market behaviour, simply because no market exists in which supply interruptions are traded. Still, VOLL may be determined indirectly. In the present literature on this subject matter, one can distinguish several distinct ways available to measure interruption costs and VOLL. We here distinguish four methods to estimate the effects of supply interruptions, thereby roughly (but not completely) following Billinton *et al.* (1993), CPB (2004), and de Nooij *et al*. (2007). These four methods each have their strengths and weaknesses. In order to compare them, evaluate them, and, if needed, to make a choice between them, it is necessary to inspect their respective advantages and disadvantages. In the literature, the criteria used for assessing these different methods are: (1) their costs, (2) the accuracy of their results, and (3) the amount of information that can be acquired through them (Ajodhia, 2006).
A **revealed preference** method may be used to examine the financial means dedicated by a firm to the prevention of supply interruptions: these are indicative for the expected costs of these interruptions. At least two possibilities exist for reducing the effects of a power supply interruption: the installation of back-up power and the creation of interruptible contracts. Another revealed preference method uses power load data, for instance as determined by the load forecasting

departments of utilities, to construct electricity demand curves. These demand curves can be used to calculate the consumer surplus loss, which in turn can be employed to estimate interruption costs[3]. The demand curve reflects the customers' willingness-to-payfor electricity services. Although not using electricity is not an option in many cases, it is sometimes possible to defer the use of electricity to another point in time, by which less can be paid for it. At points in time when the customer's willingness-to- pay is high, that is, when the price elasticity of demand is low, only a minor part of customer demand is shifted to another moment when a power supply disruption or interruption occurs, and the corresponding consumer surplus loss is relatively large. The revealed consumer surplus loss minus the bill savings is equal to the cost of the power supply interruption (Sanghvi, 1982). However, in countries with a high reliability of supply back-up generators and interruptible contracts are rarely used. The consumer surplus method requires a lot more data and assumes that marginal interruption costs rise and that a demand curve for electricity is up-to-date and accurate, which is not always easy to derive.

Two **stated preferences** methods can be distinguished: the contingent valuation method (CVM) and conjoint analysis (SEO, 2004)[4]. When applying CVM, consumers have to indicate in a *direct* way how much money they are ready to pay for more reliability, i.e. their explicit willingness-to-pay, or how much money they want to receive in order to accept lower reliability of supply, i.e. their explicit willingness-to-accept (WTA). When conjoint analysis is performed, consumers have to show their preferences with regard to both reliability and electricity prices, by ranking and giving marks to a number of different situations or scenarios with varying assumptions on the prevailing characteristics and conditions of power supply and the distribution network. Customers can hereby provide in an *indirect* way a ranking between varying combinations of electricity prices and availability. A main disadvantage of using stated preferences is that the setting up carefully formulated questionnaires can be a difficult, time-consuming, and expensive task. The hypothetical character of stated preference studies often involves disadvantages additional to those of consumer surplus based analyses..

Proxy methods estimate interruption costs indirectly, through an inspection of variables that are closely related to the direct costs induced by power supply interruptions. In this context, the costs of lost production may be quantified explicitly, but also the costs resulting from e.g. overtime work, the costs associated with the restarting of machinery or the generation of materials waste (typically for firms), or the costs as a result of lost leisure time, spoiled goods, and stress (notably for households). Proxy methods have as main advantage that

they require few and easily obtainable data. Still, they possess several significant disadvantages, including the difficulties in determining the relationship between proxy and interruption costs and the relationship between wage rates and the value of free time. This means proxy methods often yield an over-estimate of the interruption costs (Sanghvi, 1982; Billinton *et al*. 1993). Also, customers do not always use their leisure time when faced with a power outage, since other work-related activities can often be carried out during the interruption time instead.

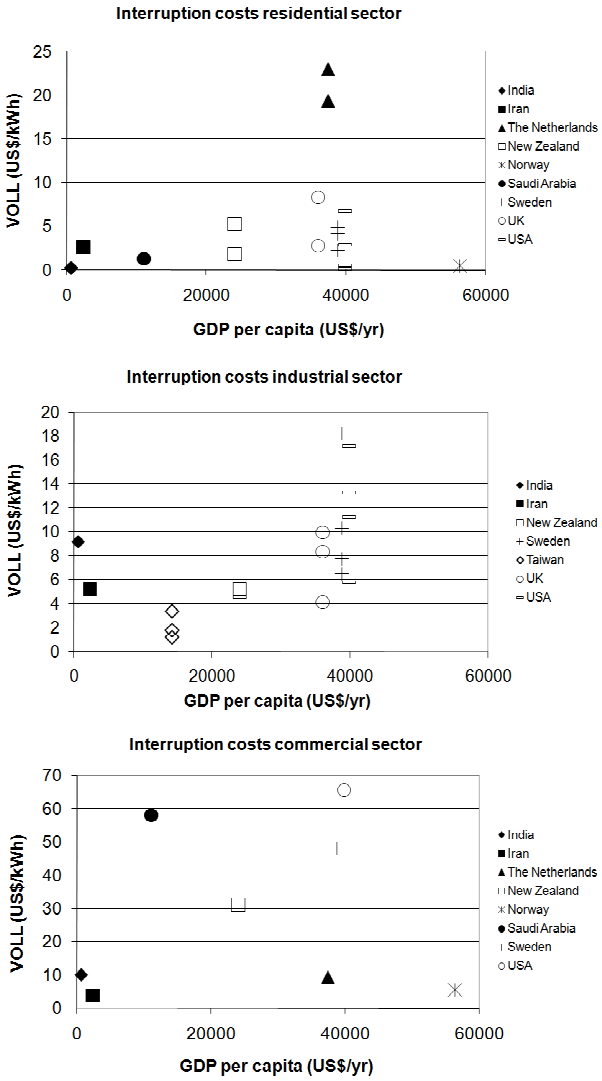
Interruption cost **case studies** involve the gathering of a wide variety of data and facts immediately after a large-scale power disturbance occurs. With these data, the costs of both production and network interruptions can be quantified, directly or indirectly. Simultaneously, other issues can be dealt with, quantitatively or qualitatively. Related questions that can be addressed in specific case studies, for example, are to what extent a nation is prepared to undergo large power disturbances from a societal point of view. Data from case studies can be very accurate and detailed, but can be more costly to obtain than proxy and revealed preference methods. Also, Of course, by definition a single case study can never be fully representative for interruptions and their consequences in general (Billinton *et al*., 1993; Ajodhia, 2006; Nooij *et al.,* 2007).

VOLL results by country

First of all, we observe from Figure 2.1 that levels of VOLL depend significantly on the sector under consideration. We see that the commercial sector is specially highly sensitive to power outages, with VOLL reaching levels up to around 70 $/kWh. The residential and industrial sectors may also be seriously affected by electricity interruptions, but less so than the commercial sector, typically up to values of some 25 $/kWh. Since VOLL applicable to an entire national economy averages interruption costs over all consumers involved – that is, including those whose activities are only moderately influenced by a short interruption or enduring blackout – economy-wide VOLL levels are generally significantly lower than those for each of the reported economic sectors.

Secondly, and preliminarily, given the caveats listed above, we may conclude from Figure 2.1 that for each of the three presented sectors, as for the economy as a whole, VOLL typically tends to be higher for countries with a relatively high GDP per capita than for those with a low per capita GDP. The main reason is that developed countries usually have a higher share of electricity to energy consumption, and are therefore generally more dependent on power supply, than

developing countries.


Interruption costs residential sector
VOLL (US$/kWh)
25
20
15
10
5
0
0
20000
40000
60000
GDP per capita (US$/yr)
India
Iran
The Netherlands
New Zealand
Norway
Saudi Arabia
Sweden
UK
USA
Interruption costs industrial sector
VOLL (US$/kWh)
20
18
16
14
12
10
8
6
4
2
0
0
20000
40000
60000
GDP per capita (US$/yr)
India
Iran
New Zealand
Sweden
Taiwan
UK
USA
Interruption costs commercial sector
VOLL (US$/kWh)
70
60
50
40
30
20
10
0
0
20000
40000
60000
GDP per capita (US$/yr)
India
Iran
The Netherlands
New Zealand
Norway
Saudi Arabia
Sweden
USA

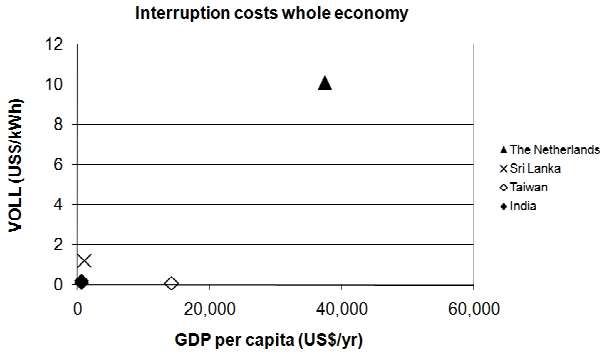


Figure 2.1: VOLL comparison for different countries, for the residential, commercial and industrial sectors, as well as for the economy as a whole. Costs are normalized per kWh non-delivered electricity and are expressed in (2004) US$. Sources: Ajodhia (2006), p. 90-91, for VOLL data; IMF (2007) for GDP per capita data.

Other studies have looked at the cost of disruption to electricity supply in a number of ways. Estimates peg the overall economic loss from all US outages over the past years at $70-120 billion/yr (Amin and Schewe, 2007). Assuming that on average consumers in the US, using a total amount of electricity of about 4000 billion kWh/yr, are affected by an aggregate power outage of 1-2 days/yr, one concludes that the corresponding VOLL as applicable to the entire US economy lays in the range of 2-9 €/kWh. A study by ICF (2003) confirmed this range. Interestingly, these figures are all typically two orders of magnitude higher than the average customer retail electricity price, and figures for VOLL are therefore not to be confused with the willingness-to-pay for secure power supply. Unlike VOLL figures, however, willingness-to-pay numbers are typically of the same order of magnitude as, or less than, the customer retail electricity price. Kariuki and Allan (1996) developed a method for calculating VOLL on the basis of data that reflect the perceptions of customers regarding the reliability of power services as well as their concerns regarding electricity supply interruptions. Subject to an extensive sensitivity analysis, and with different weighting methods (w.r.t. energy consumption vs. number of consumers), they find values for VOLL

in the range of 2-20 £/kWh, that is, 3-33 €/kWh. In CIGRE (2001) other hand, a value of VOLL for Australia is reported of about 12 €/kWh, and for Canada of some 4-9 €/kWh. The same report suggests that similar figures for Great Britain are lower, ranging from 2-3 £/kWh, that is, 4-5 €/kWh, while in Norway energy-not-supplied is valued at approximately 3 €/kWh[5].

Here, we report our personal estimates, based on the literature review described above, of the levels of VOLL in the year 2030. We do so by stipulating both a maximum range and an approximate 90% confidence level (CL) range, and emphasize that these are our personal guesses based on what we learned from our inspection of the references we found in the literature (see reference list hereafter). The depicted ranges reflect the envelope of all possible and different kind of uncertainties as summarized in the topology in the beginning of this section. Since our aim was to quote figures for 2030 we have slightly increased the present estimates for VOLL, in order to obtain numbers that are applicable in about two decades from now. We think such is necessary to reflect an increasing electrification worldwide, especially in the developing world, but also elsewhere, over the coming couple of decades. On this basis we believe it is safe to conclude that VOLL figures lay in a range of 4-40 $/kWh for developed countries and 1-10 $/kWh for developing countries. With about 90% confidence we can probably narrow these ranges down to, respectively, 5-25 $/kWh and 2-5 $/kWh. In principle we believe that the available data do not allow assigning probabilities to the specific values within these ranges. The data do seem to suggest, however, that they are left-skewed, that is, are skewed towards the lower values within each range, and thus have a median value that is closer to the lower bound than to the upper bound of the range in each of the cases. Certainly not enough data seem to be available to consistently distinguish between different levels of VOLL for different countries within the two broad categories listed.

2.3 NATIONAL AND EU LEVEL ESTIMATES OF ENERGY SUPPLY EXTERNALITIES[6]

This section presents an overview of how energy security is related to the external costs of electricity production. For European policy makers, energy security is an important issue because private decisions about energy use may not fully take into account the costs of energy insecurity. Disruptions in supply and dramatic price increases have macroeconomic impacts that individuals/firms do not take into account. Furthermore, agents tend to underestimate the risks of disruption and subsequent price adjustments, and there are other less tangible

effects such as the psychological costs of people feeling insecure about their energy supplies. Therefore, it is important from a policy perspective to estimate the size of the external costs of energy arising from energy insecurity.

Macroeconomic External Costs

As noted in Hunt and Markandya (2004), three potential kinds of externality associated with energy security exist: These are:
Monopsony wedge externality. E.g. when the additional demand for imported oil from a country results in the world price of oil rising and so exerts an additional cost on other oil importing countries. The importing country will – from an economically rational standpoint – ignore the additional cost to other countries and so that constitutes an external cost. Note that there is no market failure in terms of global inefficiency, but resulting financial transfers out of a country/region may be of concern.

- *Incomplete rent capture***.** The consumer surplus – here understood as economic rent – is the difference between the market price and the price the consumer would be willing to pay for a given fuel mix quantity. It exists because of the inability of the supplier to capture the full rent from consumers using differentiated pricing strategies. Thus, an energy mix change within a country, e.g. as a consequence of a greater proportion of imported gas, will lead to a change in the level of this rent and so result in an externality.
- *Macroeconomic Externalities*. These result from changes in the international energy markets, e.g. increases in the price of oil, that impact on an importing or exporting country differentially, and in markets other than the energy market. Such changes generate externalities only to the extent that they constitute impacts not accounted for in individual decisions.

There are major limitations in techniques available for measuring in quantitative terms the first two types of externalities described above. Consequently, we focus our efforts on exploring the third type – the macroeconomic externalities.

Macroeconomic externalities are examples of pecuniary externalities where the actions of one economic agent affects another through changes in price(s). This means the measurement of any externalities has to be done through economic means, either modelling the economy or through empirical estimation. Modelling allows specific changes to be assessed, but requires an accurately developed and calibrated model – this can be expensive and the information required can be hard to obtain. Empirical estimation, by contrast, benefits from being derived directly from real-world data but suffers from having to find a

specific outcome (i.e. size of the externalities) from a general dataset (i.e. the economic data). In the subsequent analysis, we use evidence from both methods – modelled and empirical - and estimate the gross cost of fuel price uncertainty to find the upper bound of the energy security externalities.

Below, we report on a literature review of the impacts of energy insecurity relating to oil, gas and coal as it relates to electricity supply, with the focus on the EU region. On the basis of the findings of this review we make first estimates of the 'externality unit values' for energy insecurities. The majority of empirical work has been in relation to oil, and our work reflects this, focusing primarily on macroeconomic costs of oil market uncertainties, though also briefly discussing evidence relating to coal and gas.

The mechanisms through which pecuniary externalities arise are described in the paragraphs below. However, the classification of all macroeconomic costs as externalities is not universally accepted and the identification of an externality effect is important in determining appropriate policy responses.

Macro-economic consequences of energy market changes have to date largely been the consequences of activities in the world oil market though, in principle, were there to be similar dependence on other imported fuels in the energy mix the mechanisms would apply to these other fuel sources. Thus, whilst the following section identifies empirically observed mechanisms by which oil price increases bring about macro-economic changes, these may be seen to be based on generic macro-economic principles.

Following the majority of economic modelling of energy prices and their macro-economic linkages, there is a clear line of causation from oil price increase to macro-economic impact that exists:

1. Payment for oil imports results in a worsening trade balance for an importing country (since higher fuel prices result in an increase in total payments - assuming fuel price inelasticity);
2. The consequent current account and balance of payments deficits, and associated depreciation of the exchange rate, results in other more costly imports from outside the EU.
3. Higher import costs – of oil and other commodities - may lead to higher price levels and inflation. Higher unemployment may result from the transfer of resources needed to pay for the oil imports and lower GDP may result.

This is a simplification of the central mechanism. There is considerable discussion about a number of complicating factors in the operation of such a mechanism (Bohi and Toman, 1996). For example, the terms of trade effects may

be positive or negative. Additionally, whilst it is acknowledged that higher oil prices raise prices, unless these prices continue to rise there will not be on-going inflation. Thus, whilst energy price increases may aggravate existing inflationary processes, they should not necessarily be seen to be the cause of continuing inflation.

There also appears to be the threat of government – rather than market – failure that contributes to the macroeconomic impacts of energy price increases (Bohi and Toman, 1996). For example, because of regulation, an increase in oil prices will not lead to efficient adjustments in gas and electricity prices. These price rigidities may cause adjustment problems throughout economy where regulation cannot simultaneously constrain market power and allow regulated prices to adjust to market conditions.

The externality estimates are based on the total macroeconomic costs associated with given changes in energy markets. The estimates are derived directly from a review of the historically observed macroeconomic effects of these changes, as well as changes that are simulated in macroeconomic models.

In the following analysis we look principally at the impact of sudden, but sustained, increases in price on the macro-economy.

Modelling the Macro-economic Impacts of Oil Price increases

A number of general equilibrium macro-economic models have been developed to simulate the impact of energy price increases and/or supply disruptions on the macro-economy and these have largely focused on the impacts of oil supply shocks that last for a year or more. Note that whilst price volatility in itself has potential macro-economic consequences they are not regarded as being as significant as the sustained price rises resulting from medium term oil price shocks and are not studied separately here.

The outputs of such models are helpful in isolating these impacts from other macro-economic trends – something that a reliance on untreated observational data is unable to do. This section therefore briefly reviews the outputs of a number of these models in terms of their EU-wide macroeconomic costs of energy price rises. Hunt and Markandya (2004) reviewed the published results produced by these models up to 2004, shown in Table 2.1. Results reviewed subsequently to 2004 that are most pertinent are reported in Table 2.2. In general, the differences between the two sets of results are small; we therefore conclude that the same input values used to produce the Hunt and Markandya (2004) external cost estimates are valid to apply in our up-dated calculations, below.

Roeger (2005) used the DSGE model to estimate the effects of a 50% oil price rise on the euro area macro-economy. The paper does not give the baseline price. After 4 quarters, GDP is 0.5% lower than the baseline case, and falls further to 0.6% after 2 years and 0.9% after 5 years. Other studies that have presented results of this kind include World Bank (2005).

The summary results do not reflect the complexity of the models and the variety of their outputs for world regions. Nevertheless, despite the model differences there is some consistency in the pattern and extent of GDP changes. The models show that even when the oil price increase is assumed to be permanent, GDP impacts are likely to be greatest in the first four years of the price increase, and decline subsequently, suggesting that economic agents adapt their expectations to the new price level so that factor and product markets move to new equilibria over this time period. Surprisingly, there is also a degree of consistency in the scale of annual GDP losses associated with specific oil price increases. Thus for the industrialised countries a $10 price increase per barrel gives rise to a 0.5% loss of GDP (EC, 2002) or a proportionate linear scaling of that, on average (IMF, 2000). For the Euro zone countries, there is a similar consistency in the results though here it appears that GDP is more sensitive to oil price increases than for the industrialised countries as a whole. For Euro zone countries, as presented in Table 2.2, a 50% increase in oil prices results in a 0.4% decline in annual GDP for the first year, simply taking the arithmetic mean of these results, with a range of 0.1% to 0.8%.

A number of strong assumptions are adopted in order to derive these values and these are explained in detail below. In addition, the macroeconomic cost estimates only allow us to include the effect of a sustained price increase. No separate estimates based on price volatility are made since there are - as yet - no good studies of sectoral or macro-economic costs resulting from price volatility (Sauter and Awerbuch, 2003). We therefore assume that the unit value estimates derived below are minima. We assume for simplicity that the time period considered is only one year. The greater uncertainty for impacts in subsequent periods suggests that in the limit this gives rise to a plausible minimum estimate.

Table 2.1: Macroeconomic cost estimates of Oil Price increases presented in Hunt & Markandya (2004)

Source	Driver	Estimate	Units	Country / Region
EC 2002	Sustained $10 increase in price of crude oil (per barrel)	- 0.5%	GDP growth rate	Industrialised countries
IEA 2004	Sustained increase $25-$35 i.e. $10 per barrel crude oil	- 0.5%	GDP growth rate	Euro Zone
		0.5%	Inflation	Euro Zone
IMF 2000	Sustained increase of $5 per barrel of crude oil (20% increase)	- 0.25% (over first four years, then fades to negligible)	GDP growth rate	World
		- 0.4% (percentage deviation from baseline after one year)	GDP growth rate	Euro Area
		0.5% (percentage deviation from baseline after one year)	Inflation	Euro Area
		- 7.8 ($ billion)	Trade balance	Euro Area
IMF 2004	Sustained increase of $5 per barrel of crude oil (20% increase)	- 0.4% (after one year)	GDP growth rate	Euro Zone
Jones et al 2002	Price change exceeding a three year high	- 0.05 to – 0.06	Elasticity GDP to oil price shocks	USA
Sauter and	Sustained 10% rise in oil price	- 1.5% (for 3-6 months)	GDP growth rate	Euro Zone
Awerbuch 2003		- EURO 35 to 70 billion	GDP	Euro Zone
World Bank 2000	50% increase in price in first year, then decline back to	- 0.25% (over first two years)	GDP growth rate	Industrial countries
in IMF 2000	original level by the third year.	0.2%	Inflation	Industrial countries
Huntington 2004	Doubling of oil price	-3.7%	GDP	USA and Euro Zone
IEA 2001	Price level: 1% increase	0.44%	% change in Investment	IEA member countries
	Price volatility: 1% increase	- 0.11%	% change in Investment	IEA member countries

Table 2.2. Impacts on Eurozone GDP of 50% increase in oil prices (deviation from baseline GDP after 1 year)

Source	Year	Driver	Estimate (%)	Country / Region
Barell and Pomerantz	2004	50% increase in oil prices	-0.8	Eurozone
EU Commission	2004	50% increase in oil prices	-0.5	Eurozone
Dalsgaard et al	2001	50% increase in oil prices	-0.4	Eurozone
World Bank	2000	50% increase in oil prices	-0.3	World
Hunt et al	2001	50% increase of oil prices	-0.1	Eurozone
Dieppe and Henry	2004	50% increase of oil prices	-0.1	Eurozone

In order to estimate the external effects of energy insecurity in terms of cost per kilowatt hour, we follow the same methodology as Hunt and Markandya (2004). As with the earlier work, we assume that the main externality is the macroeconomic effects and that these can be classified as externalities.

We make the conversion from gross macro-economic costs to costs per kilowatt hour by making a series of steps. The first step is to identify a benchmark for the world oil price against which deviations in price – and therefore GDP - can be measured as a reference value in the event of an oil price change, for instance. However, the predictive models reviewed do not make this assumption explicit. We are therefore obliged to simply adopt the outputs from these models in our analysis. Similarly, whilst we would like to make explicit a second step to apportion a price increase that can be seen as typical to a given oil supply reduction – and thus to allow us to relate a GDP change resulting from a price change to the energy production from a given volume of oil – we have to assume that a 50% price increase (most frequently used in the models) is appropriate. Total GDP for the EU27 in 2005 equated to €10.9 trillion. Therefore, a 0.4% fall in GDP – identified from Table 2.2 - equates to €43.8 billion p.a. or €175.2 billion over a four year period. For the world as a whole the equivalent figures are €142.7 billion p.a. and €570 billion over the four year period.

In order to express the estimated welfare cost of the oil price change in the same terms as the rest of the externalities considered by CASES, it must be decided whether the loss is expressed per barrel of oil consumed or per barrel of oil foregone. We consider that it is correct to assign the cost across the barrels consumed as this can be taken to be the cost per kilowatt hour of electricity generated. This will give the average cost.

Given that we have now derived a macroeconomic cost per barrel of oil not supplied to the market, i.e. its opportunity cost, we need to make the final conversion to the energy provided by one barrel of oil. The conversion factor for changing barrels per day into kilowatt hours is shown in Table 2.3. A conversion factor of 40% to estimate total electricity production per possible kWh output was used to reflect the energy generating capabilities of oil-fired power plants in the EU[7].

Since the project is focussed on the external costs of electricity generation, the costs from the model so far need to be apportioned to the level of oil being used in electricity. Thus, we estimate the proportion of oil which is used for electricity generation and the proportion of electricity generation which arises from oil-fired power plants. At this stage, aggregated figures for the whole EU will suffice, but disaggregated data could highlight interesting facets of the scenario.

In 2004, 4% of EU25 electricity production came from oil[8] and the proportion of oil used in the EU for electricity generation was 5%[9]. Thus, the proportion of oil price variation that can be apportioned to electricity generation is 0.04*0.05 = 0.00002.

Table 2.3: Summary of Cost Estimation Process: Oil security externality

	EU27
GDP loss over 1 year (€bn)	43.8
GDP loss over 4 years (€bn)	175.1
Original oil consumption (mb/day)	82.5
Fall in oil consumption (mb/day)	3
New oil consumption (mb/day)	79.5
Change in GDP per barrel consumed (1 year loss) (€)	1.5
Change in GDP per barrel consumed (4 year loss) (€)	6.0
Electricity generation per barrel (kWh)	1648.8
Thermal Efficiency	40%
Likelihood of shock	0.2
Cost estimate per kWh - 1year loss (€)	0.002289
Cost estimate per kWh - 4 year loss (€)	0.009154
cost (€/kWh) 1 year loss	0.000458
Cost (€/kWh) 4 year loss	0.001831
Cost proportional to electricity generation (€/kWh)	0.000004

Since we want an annual equivalent these figures need to be multiplied by the probability of the event occurring in any given year to give us expected values. As an indication the current probability of a price increase of this magnitude occurring can be approximated on the basis of historical data. Harks (2003) estimates that a 3 million barrel shortfall event may be expected to occur at present on a 1 in 5 year frequency, based on historical events. Adopting this probability, the resulting expected value for the EU27 – assuming a 0.4% annual loss in GDP - is €0.000004 per kWh within a range of €0.000001 - €0.000008 for a 0.1% and 0.8% annual GDP loss. The breakdown of this model is shown in Table 2.3.

The model presented above is a simplified model of the economy that asks ‘what is the cost of this event happening, and what is the likelihood of the event?’

It estimates an upper bound to the external pecuniary effects of a fall in supply of oil to the EU's electricity generating sector.

Gas and Coal

The above section has looked at the energy security externalities related to the macroeconomic effects of oil price rises. It found that the small levels of electricity generation from use of oil in the EU imply that these externalities are very small. Gas, coal and nuclear power have much larger shares of the electricity generation so that price volatility of these may have significant effects.

Russia, Algeria and Norway are the biggest three source countries for natural gas imports to the EU27 from 1999-2006, with Nigeria significantly smaller, whilst Russia, Australia and South Africa are the largest source countries for coal imports to the EU. However, whilst energy security risks from these fuels are well known, see Stern (2004) for example on possible causes of gas insecurity, to our knowledge, no quantitative analysis has been undertaken on the macro-economic – or other – sources of possible external costs from such risks. We highlight this as a research gap.

Overall Conclusions

Measurement of energy security externalities remains a complex and difficult exercise. Problems of definition as to what constitutes these externalities make agreement on what the policy issue is hazardous. Additionally, the range of assumptions that need to be made in order to calculate quantitative estimates of the size of these externalities means that these estimates should be viewed as indicative only. There are also a range of gaps in the coverage of the analysis, notably the exclusion of oil price volatility impacts, and the potential macroeconomic costs of gas and coal supply disruption, that suggest that the negligible values (around 0.000004 €/kWh) currently estimated are much lower than the true costs, whether categorised as external or not.

2.4 ESTIMATING HISTORICAL ENERGY SECURITY COSTS[10]

Since the oil shocks of the 1970s, energy security has been a concern for governments and policy makers. At the time, different countries responded to these concerns in different ways. It may be therefore the case that the cost of these responses gives an indication of the value the policy makers have placed upon energy security, and so investigating this cost may yield important information. Energy security is currently high on the agenda of the European Union's energy policy, and so it is a pertinent time to examine the costs of previous energy security policies.

Methodology

In order to assess the cost of the electricity generation policies of governments, we need to compare the actual costs to the economy of electricity generation with the cost of the policy they would have otherwise undertaken if they had no concerns for energy security. Therefore, we create a electricity generation counterfactual scenario based upon the lowest cost, and measure the ES premium as the difference between the actual cost and the estimated lowest cost.
The counterfactual ('lowest cost') model makes a set of assumptions which are outlined below:

1. *All the extra cost is due to energy security issues*. We recognise that a number of factors may have led to the least-cost option not being chosen, including uncertainty, politics, or contractual restrictions. Any disaggregation will be attempted in the discussion section.
2. *We use average data over the whole of the time period***.** This is due to data limitations. This assumption makes it possible to avoid highly complex modelling of demand and supply over the time period, including delays of data availability and construction delays.
3. *The capacity available at the beginning of the period is maintained throughout, thereby negating the need for additional capacity, and therefore construction costs*. This is a necessary simplification for the model. This assumption places extra emphasis upon the fuel and operating costs of power stations as there will be less construction modelled. However, in practice, it is not unusual to extend the life of power stations with refits or refurbishment. We take the 1980 generation levels to be the levels available without extra construction for the whole period**.**

4. *There are no additional costs to stopping generation from one fuel.* This includes any social costs of a halt in electricity generation from one fuel, for example coal miner protests. Foreseeable decommissioning costs are included in the operating costs of plants.
5. *There are no limitations to capacity in each country for each fuel*, that is, if it was cheapest to do so, 100% of each country's electricity could be provided for by just one method.
6. *There are no requirements for diversity in energy supply*. That is, there are no contractual or political requirements for a minimum or maximum level of electricity from one source
7. *Each country is a price taker in the fuel markets and that the prices would be the same regardless of the quantities used.* However, it is noted that the prices do show a difference between countries even in internationally traded goods.
8. *There is no trade in electricity between countries* but the target generation for the model is the average generation of each country between 1980-2000. That is, we do not model any specific policies to engage in electricity trading even if it is the lowest cost option to do so.

The counterfactual scenario uses the following algorithm:

1. Generate at the 1980 generation levels using the cheapest technology at F+O (Fuel plus Operation) cost. This is allowable since it is a good indicator of the usable capacity at the start of the scenario, so construction costs need not be considered (they are sunk costs). We refer to the cheapest technology as Technology A
2. Consider the F+O costs for each fuel and the F+O+C (Fuel + Operation + Construction) cost of Technology A. If Technology A is the cheapest based on F+O+Cthen build up to the target output (1980-2000 average generation) using A, OR use up to the 1980 capacity of the cheapest unused technology.
3. If the target capacity has not been reached, repeat step 2.

Given the lack of data availability, and for consistency, the real life costs were estimated using a similar technique. Instead of using the 1980-2000 average total generation as the target, the target was the 1980-2000 average generation by fuel. So, for each country and each technology, we took the F+O costs of generating at the 1980 level and the F+O+C costs of generating the difference between the 1980 and the 1980-2000 average level. Where the 1980-2000 average was lower than the 1980 level (i.e. capacity declined) we took the average level of generation at the F+O costs.

Data

The model examines four large European nations: France, Germany, Italy and Spain, over the period 1980 to 2000. The reason for looking at the 1980-2000 period is that it occurs after the oil price shocks of the 1970s which prompted many governments to examine their energy policies. By 1980 these policies would have just started to be implemented. France was chosen as it had a clear shift in energy policy in the period leading up to 1980, when the policy to concentrate on nuclear generation was implemented. The first hypothesis of the model was that this policy increased the cost to the French economy in order to increase energy security. The other countries appeared not to have such a distinct shift in policy and provide the basis of comparison with France. The UK and the Netherlands were not examined since their energy security policies were based around the development of North Sea gas.

The IEA's energy database[11] provided data for the energy balances of the countries over the relevant period. The fuels used to generate electricity were coal, oil, gas, nuclear and renewables, which includes hydroelectricity, geothermal, combustible renewables and waste, and 'solar, wind and other'. The energy balances show the total energy from that source going to the four types of electricity generation plants – the figures are negative because the fuels are an input into that process.

The next data needed was the costs of the electricity generation processes. The costs of electricity generation fall into three main categories: construction and investment costs, operation and maintenance costs, and fuel costs. Nuclear energy also incurs decommissioning costs, but these are included in the construction costs (see Carle and Moynet, 1993).

Data availability for the total costs for each generation method for each country over the time period is extremely limited in the public domain and, due to the politicized nature of the generation industry, some industry based sources for costs may be less than ideally transparent. Where possible, we used representative cost breakdowns available in the literature to find the proportion of the total cost of generation that arises from fuel, operating costs and construction costs. We then used the fuel prices to estimate the operating costs, construction costs and total costs. This is because the most detailed data by country was for fuel, so each country's cost differences could be estimated best using this method.

The fuel costs for coal, oil and gas were obtained from the IEA's database, which contains quantities and prices for fuel inputs to electricity generation and for industry. The prices used were for steam coal, high sulphur fuel oil and

natural gas. Where possible we used the prices for electricity generation, but for French coal and gas we used the prices to industry as the prices to electricity generation were unavailable. A comparison between the industry and generation prices for other countries showed that this is a reasonable substitution to make. The operation and construction costs for coal and gas were estimated from these fuel costs using cost breakdowns from Küffer (1993) for Swiss electricity generation in the early 1990s. This data was chosen as it was the most complete dataset. Cost breakdowns for oil-fired generators for the period were harder to obtain, but Yoda et al (1993) provide detail for Japanese generators from 1982-1992. They also provides cost breakdowns for the other fuels which are comparable to the other sources.

Fuel costs for nuclear and renewables are more complex. Uranium costs are usually withheld as confidential for security reasons, and only represent a small part of the total fuel costs to generation since processing costs have to be considered. These are often linked to long-term agreements with preferential rates and are rarely made public. For renewables, the fuel costs are effectively zero (or there may be transport and processing costs for waste generation). The costs for nuclear and renewables are therefore more linked in with construction, maintenance and decommissioning costs. These vary widely among the technologies used and often contain site-specific costs. Construction and investment costs are also paid over a long time-span, and so the accounting/discounting method used can affect the cost considerably. The following paragraphs outline our estimations for nuclear and renewable costs.

The primary source for nuclear power in France is Carle and Moynet (1993). They present costs for the construction and running of nuclear, coal and gas power stations and the date of publication suggests that these would be representative figures for the central period we are modelling. As a comparison, their costs for coal and gas generation correspond with those derived from the IEA statistics above. Since there was greater investment in the French nuclear industry (including the upstream industries) in the 1970s, we assume that the French nuclear costs are lower than the other countries. The cost includes dismantling, fuel waste treatment and R&D costs.

To estimate the price of nuclear power for Germany, Italy and Spain figures from Küffer (1993) were used. This source presents Swiss data, but it is reasonable to assume that given the investments mentioned above, the Swiss costs are similar to the costs in these countries. This includes the “back-end of the fuel cycle, decommissioning and final storage” of the nuclear waste (p.269).

The majority of renewable electricity in each of the countries throughout the

period was from hydroelectricity. The costs for this were taken from SWEB/ETSU (1993) and Küffur (1993).

Table 2.4 shows the costs used in the construction of the model. Due to the limitations of the data, the cost for renewable electricity is assumed to be the same in each country, and the cost for nuclear is the same for Germany, Italy and Spain. However, because the cost of coal, oil and gas-fired electricity varies, it still allows the model to have different outcomes for each country. It shows that costs in Germany are generally higher than the other countries, due in part to higher fuel costs, and in part to less efficient generation (as calculated by our model). This lack of efficiency may in part be due to problems caused by reunification, as two different generation policies merged to become one.

		Average Consumption (KTOE/yr)	Cost per TOE of fuel (€/KTOE)	Annual Fuel Cost (€/yr)	Average Output (GWh/yr)	Average Fuel Cost per GWh (€/GWh)	With Operating Costs (Fuel + Operating) (€/GWh)	With Construction Costs (F+O+C) (€/GWh)
France	Coal	9,700	98,000	980,000,000	40,000	25,000	36,000	79,000
	Oil	2,500	200,000	570,000,000	12,000	46,000	52,000	69,000
	Gas	770	250,000	190,000,000	4,500	42,000	51,000	98,000
	Nuclear	75,000	34,000	2,600,000,000	290,000	9,000	19,000	42,000
	Renewables	6,400	-	-	68,000	-	9,900	130,000
Germany	Coal	80,000	200,000	16,000,000,000	310,000	52,000	77,000	170,000
	Oil	3,500	210,000	790,000,000	12,000	68,000	77,000	100,000
	Gas	11,000	220,000	2,400,000,000	42,000	57,000	69,000	130,000
	Nuclear	35,000	320,000	11,000,000,000	140,000	21,000	35,000	83,000
	Renewables	4,200	-	-	26,000	-	9,900	130,000
Italy	Coal	6,200	120,000	740,000,000	27,000	27,000	40,000	87,000
	Oil	21,000	210,000	4,100,000,000	100,000	42,000	47,000	63,000
	Gas	7,800	200,000	1,400,000,000	39,000	35,000	42,000	81,000
	Nuclear	500	320,000	160,000,000	1,900	21,000	35,000	83,000
	Renewables	6,600	-	-	46,000	-	9,900	130,000
Spain	Coal	13,000	110,000	1,300,000,000	57,000	23,000	34,000	75,000
	Oil	3,700	230,000	910,000,000	16,000	57,000	64,000	85,000
	Gas	910	260,000	210,000,000	5,600	38,000	46,000	88,000
	Nuclear	11,000	320,000	3,500,000,000	43,000	21,000	35,000	83,000
	Renewables	2,700	-	-	29,000	-	9,900	130,000

Table 2.4: Average cost per GWh 1980-2000. Rounded to 2 sf[12]

Results

Table 2.5 shows the results of the model run. It shows the actual case versus the lowest cost case costs in total and per Gigawatt hour. The overall cost estimated is the difference between the two cases. Although it has the lowest costs for electricity, France has the lowest overall energy security cost at just 3% of the total electricity cost. Italy and Spain have the largest ES costs, at 11% and 10% respectively.

This suggests that the French policy of investing in a secure fuel also led to lower electricity costs. The largest Energy Security Premiums were for the Italian and Spanish policies, which in part were aimed at making oil and gas supplies more secure, whereas our model estimated the cheapest scenario would have been to use less gas.[13]. The difference in renewables is due to changes from the 1980 level (which we modeled as cheapest in all countries) and the 1980-2000 average level.

Table 2.5: Results from the Energy Security Cost Model. Rounded to 2 sf

	Generation (GWh/yr)	Actual Case (2000 €/GWh)	Lowest Cost Case (2000€/ GWh)	Modelled ES cost (€/GWh)
France	410,000	33,000	32,000	1,000
Germany	530,000	73,000	69,000	4,200
Italy	210,000	50,000	46,000	4,300
Spain	150,000	53,000	51,000	2,100

Discussion and further research

The model shows that there is a difference between the estimated lowest cost and estimated actual costs of generation for all the countries. The estimated cost premium was lowest for France in both absolute and relative terms and highest for Italy. Inasmuch as this model can yield firm conclusions, it suggests that policies such as France's, where a secure fuel is set as the cornerstone of electricity generation, are lower cost than policies such as Italy's, in which attempts were made to make existing fuels such as oil and gas more secure.

However, the results from this model are sensitive to the data used for costs. This is limited in three main ways.

1. The methodology for investment and operating costs is very simple, and is based on energy generation costs presented in the literature. A more transparent methodology, which would tie in better with the CASES project would be to use the overnight investment cost methodology with the Average Annualised Generation Cost model, but this requires annual cost data which is unavailable.

2. Where cost data has been unavailable, data from similar countries has been transferred. Ideally, more accurate data for each country would be used.

3. The costs and quantities used for the modelling were based on the 1980-2000 average. This leads to a static model which cannot account for changes in the price/costs of generation over the time. A dynamic model, which allowed for changes in price over time, would be more realistic. This would require construction and operating cost data for the whole time period. It would also allow for the modelling of obsolescence/planned closure of plants over the time which would place a greater emphasis on the construction costs and ensure that the model would be less reliant upon the capacity available in 1980. In this respect the model could be developed further based on the data given in Chapter 3.

However, despite these limitations, these results provide a valuable first indication of the importance of energy security in determining energy supply costs. Energy security is still an important policy concept this model suggests that different energy security policies do have costs that impact on the price of electricity. With greater information about historical costs, these impacts could be understood more fully, enabling a more informed analysis of current energy security decisions.

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2.5 AN INITIAL ASSESSMENT OF ENERGY SECURITY POLICY OPTIONS [14]

Energy and climate change remain on top of the agenda of the EU. Rising oil prices, regional concentration of conventional oil and natural gas, increasing demand for energy of emerging economies together with decreasing stocks within the EU, the alleged use of energy as a "political weapon" by politically unstable regions, as well as rising emissions of greenhouse gases (GHG) and their adverse effect on the global climate are just some of the issues associated with current patterns of energy use. Policy makers in the EU are aware of the pressing nature of these issues. The recent initiative to develop a sustainable integrated European climate and energy policy is a

clear indication of this. While EU energy policy for the last 40 years has in principle been confined to the narrow fields of nuclear energy and coal, the EU and its Member States are starting to develop a coherent internal and external energy strategy or "vision" to ensure the competitiveness of European industries while at the same time combating climate change and ensuring security of energy supply.

This section outlines policy options to reduce insecurities associated with the EU's energy supply. After classifying and analyzing the security of supply risks in the EU, the measures adopted by the EU in the European Council Action Plan[15] and the related Energy Policy for Europe (EPE) are described. It will then give a comprehensive overview about the most important market-compatible, economic risk-management strategies, in which responsibility is shared among Member States, the EU, energy companies and consumers. An effective energy policy, however, cannot solely rely on markets. Government action will be especially needed to meet the long-term policy objectives.

Risk assessment

In its 2000 Green Paper on the security of supply, the European Commission (EC) notes that "energy security must be geared to ensuring … the proper functioning of the economy, the uninterrupted physical availability … at a price which is affordable … while respecting environmental concerns. […] Security of supply does not seek to maximize energy self-sufficiency or to minimize dependence, but aims to reduce the risks linked to such dependence" (EC, 2000). However, the EC also highlighted the risk of supply failure associated with increasing dependency on imported hydrocarbons is growing (EC, 2007). The EC thus shares the view expressed in other definitions (see, for example, Egenhofer et. al., 2004), that security of supply is essentially a strategy to reduce or hedge risks that derive from energy use, production and imports. These security-of-supply concepts consist of a variety of approaches aimed at 'insuring' against supply risks with an emphasis on cost-effectiveness and the shared responsibility of governments, firms and consumers.

There are nuances regarding cost-effectiveness, which are mainly driven by different appreciations of risks. Either directly or indirectly, the approaches include price as a concern. While price volatility can be seen as proof that markets work, nevertheless, security of supply is, albeit more loosely, tied to a concept of price. Energy must be available at a 'reasonable' price – not at any price. By definition, if the price were allowed to increase without a limit, there would always be a sufficiently high price at which demand would equate to available supplies – but it would be naïve to say in this case that the security of supply was guaranteed. Yet just how far it is

acceptable to allow prices to move in order to restrict demand and allocate scarce supplies is a question that can only be decided politically (by the government or regulator) or contractually (by the parties accepting limits to price increases). On the other hand, price fluctuations may themselves be considered as a threat to security – in particular with respect to crude oil. Indeed, in the case of oil, the logistics are such that the risk of physical shortages is minimal and any tightness of supplies would immediately be reflected in prices. Natural gas markets, however, are characterized by different logistics, different pricing mechanisms, etc.

In line with the European Commission's 2000 Green Paper on the security of energy supply, the following types of risks can be identified:

- *Technical risks* include systems failure owing to weather, lack of capital investment or generally poor conditions of the energy system.
- *Economic risks* mainly cover imbalances between demand and supply, stemming from a lack of investment or insufficient contracting.
- *Political risks* concern potential government decisions to suspend deliveries because of deliberate policies, war or civil strife, or as a result of failed regulation, which is referred to as 'regulatory risk'.
- *Environmental risks* describe the potential damage from accidents (oil spills or nuclear accidents), including pollution, the effects of which are less tangible or predictable (e.g. greenhouse gas emissions).

It is also interesting to note that most supply disruptions experienced in the EU in recent decades have had domestic causes. In the UK, for example, the worst disruptions to energy supplies in recent history were those caused by the strikes of British coal miners in 1973-74, and the blockade of access to oil refineries by protesting truckers and farmers in autumn 2000 (Mitchell, 2007). Similarly, the power interruptions of November 2006, which affected 15 million European households, were caused by the tripping of several high-voltage lines, which started in Northern Germany (UCTE, 2007). Other reasons for disruptions included grid failure, lack of reserve capacities, etc. As the above list and the following risk assessment show, there are many different risks to the security of supply, of which import dependence on politically unstable or unpredictable countries is but one. In any case, independence from imports is no option and would be no guarantee for security, as shown by the above examples of supply disruptions. Therefore, in order to identify a suitable response, it is necessary to first clarify the exact nature of the risks including its likelihood and potential consequences (i.e. a risk assessment). The second step in this respect is then to identify the possible responses and the responsible actor/s (more specifically, those involved with risk management).

Turning to gas and notably to the European dependence on Russia, the risks associated with import dependency can be mitigated by a number of

general, well-known (horizontal) measures. These not only include diversification by region or by fuel to the extent possible, but also storage requirements, mutual solidarity and the development of liquefied natural gas (LNG). In addition, measures for network development and for improving the functioning of the internal gas and electricity markets will provide for further flexibility within the gas markets with positive impacts on security. Moreover, previous work by CEPS (Luciani, 2004) has shown that in the case of Russian gas, import dependence does not necessarily entail greater insecurity, provided adequate EU policies are in place.

Security of supply as an externality

The concern about security of supply in liberalised markets is connected to viewing security as a public good or externality. In liberalised markets, new competitors will be tempted to 'free-ride' on the security provided by the incumbent suppliers and competition may have a negative effect by downplaying security or prioritising cost-cutting. Similar fears have been expressed with regard to other network industries such as airlines, railways and electrical grids.

Normally, security is viewed as a matter for governments to look after. This perception holds true for small commercial or household customers, who will not be in a position to judge their security requirements exactly and will need standard contract formulae that set the level of protection to be decided by the regulator. The level of protection does not need to be 100 per cent. Gas in households and small commercial establishments is primarily used for cooking and for ambient- and water-heating. In situations of emergency, all such uses can be reasonably curbed to some degree. It is therefore also reasonable to set the guaranteed level of supplies at an appropriate percentage of 'standard' consumption.

Not all customers need to be protected against supply disruptions. In liberal markets, customers have a choice of whether to assume responsibility for security of supply themselves or to allow the supply company to bear the responsibility and subsequently to pay a risk premium through higher energy prices. The former is typically done by large industrial users, for which (short-term) security might not be an issue, given they can switch fuels. A large industrial user may choose to buy gas from a risky but cheap source, accepting the risk of higher short-term prices from a spot market or mitigating the risk by installing a dual-firing capability or a back-up from another supplier.

Indeed, the Commission has frequently argued that a unified EU gas market would be intrinsically more secure than the individual member countries' markets. The reasoning here appears to be based primarily on

scale: a larger market, served by a wider and well-interconnected network that receives supplies from a larger number of exporters, may be expected to be more stable. This conjecture may well be the case; however, numerous conditions need to be fulfilled, notably functioning markets, established interconnections and more generally that the necessary regulatory or contractual arrangements are in place.

A European response: The Energy Policy for Europe

The EU's current energy policy package was instigated in 2007, and titled "An Energy Policy for Europe". In the centre of this new energy policy is the EU's commitment to reduce its greenhouse gas (GHG) emissions by at least 20% by 2020 compared with 1990 levels, not least because CO_2 emissions from energy make up 80% of EU GHG emissions. By using less energy and using cleaner, locally produced energy, the EU aims to increase energy security by limiting its growing exposure to increasingly volatile prices for oil and gas, while stimulating competitiveness in the European energy market.

In general terms, the EPE is based on five pillars. First, the EU aims at increasing its energy efficiency by saving 20% of its energy by 2020. This will save about 780 million tones of CO_2 from being emitted into the atmosphere. Second, the share of renewable energy sources in the total energy mix is intended to triple to 20% by 2020, while aiming for a 10% biofuel component in vehicle fuel by 2020.The third pillar focuses on reducing the carbon emissions from hydrocarbons. Of particular importance in this context is the role of coal, which is relatively cheap and available in Europe, but "dirty" in environmental terms as compared to other energy sources. The development of carbon capture and storage (CCS) technologies is thus a crucial factor in securing future energy supplies. The fourth and fifth pillars of the EPE are the EU's carbon market and an open and competitive internal energy market. A competitive market is expected to increase security of supply by improving the conditions for investment in power plants and transmission networks, which in turn will help avoid interruptions in power or gas supplies. To facilitate its creation, the European Commission has recently published its third legislative package[16] including proposals for a number of measures to increase competition in the EU electricity and gas markets. These include, amongst others, the separation of production and supply from transmission networks ("unbundling"), the facilitation of cross-border energy trade, as well as greater transparency of the markets. These proposals are currently being discussed by the Member States within the Council. While a pan-European energy market is under development, Member States will likely continue to implement national policies suited for the specific market-situation. It is vitally important that Member State

measures do not delay or hinder cross-border markets from emerging, in order not to undermine the potential efficiency gains from a functioning pan-European market, and avoiding a further renationalisation of energy policy.

The EPE also contains a chapter dedicated explicitly to increasing security of supply, which calls on a "spirit of solidarity" between Member States, especially in case of an energy supply crisis. A similar notion has been included in the Draft Reform Treaty ("Lisbon Treaty"). Other proposed measures include:

- Diversification of energy sources and transport routes (e.g. the Nabucco pipeline project has been selected as a "priority project of European interest"),
- Developing an effective crisis response mechanism (including warning capacity),
- Improving oil data transparency and reviewing oil supply infrastructures and oil stocks mechanisms,
- Analysis of availability and costs of gas storage facilities in the EU,
- Assessment of impact of current and potential energy imports and the conditions of related networks on each Member State's security of supply,
- Establishment of an Energy Observatory within the European Commission.

In addition the Council called for deepening dialogues and partnerships with a large number of producer, transit and consumer countries. By mainstreaming energy issues into its external policy dimension, the EU intends to maintain/create a long term framework as a basis for stable relations with its international partners in the energy field. This will be crucial in strengthening the power of the EU's foreign and security policy. However, as pointed out by Larsson (2007), Europe's first priority should be to take care of its domestic problems by making sure that internal challenges, such as market liberalization and ownership unbundling, are not exploited by foreign actors. Similarly, the EU should focus more on decreasing demand for energy, increasing efficiency and developing alternative energy sources, rather than on giving priority to plentiful, secure and reliable energy supplies to support economic growth (Larsson, 2007). Such a strategy will effectively reduce risks associated with current energy supplies.

Market compatible strategies to increase the security of energy supply

The European Economic Area will become increasingly dependent from gas pipe supplies coming from very few countries. Whereas over 80% of the global natural gas reserves of 181.5 trillion m^3 (BP, 2007) are located at a distance from Europe which allows for pipeline transport (Mueller, 2007), Europe lacks the infrastructure to tap resources in the Middle East, the region with the largest proved reserves (over 40% of global reserves). Over 80% of

Europe's natural gas imports come from three countries (EC, 2006), where the gas market is tightly controlled by governments. In this respect, fears of "gas cartels" or of energy being used as a political weapon do not seem unfounded. Similarly, there is a risk of a lack of investment in exploration, production and transportation, despite reserves being abundantly available in areas surrounding Europe. If gas is unable to take a larger share in power generation, it will not be able to live up to its expectation to be a "bridge" to a low-carbon economy and may even become a sunset industry. In addition, the future carbon price will have an impact on the future of the gas markets.

Current energy scenarios show that a reduction of dependency on gas through an increase of domestic production or through energy savings is not credible. The situation is different with regard to diversification of exporting countries. Europe's position in the world market could be more favourable depending on whether African/Middle Eastern exports grow substantially, backed by significant volumes of LNG. The latter's growth (especially in a spot market) seems to be a key factor for improving Europe's position in the gas market, as it increases market flexibility.

Another critical factor is transportation capacity towards Europe, as it seems very likely projected infrastructure will not be able to meet expected demand. This implies the need to gain access to gas reserves, to open up producing areas to international investments and to give due attention to the stability of 'transit countries'.

Finally, regarding the risk of depleting gas reserves, there is no problem of scarcity even in the long term and conventional reserves should be sufficient at least until 2035–40, so that the risk of price increases (owing to the need for unconventional reserves) is also small.

Non-market strategies

A key strategy to secure supplies is based on diplomacy and stable international relations. In this respect, the EU needs not only to focus on its Eastern neighbours, but also on major energy players in Africa and the Middle East. Nevertheless, good diplomatic relations and stable external affairs cannot reduce risks to zero. There is always a risk associated with import dependency.

Importers should be encouraged to diversify their sources and promote demand flexibility. Policymakers should put forward measures (e.g. exemptions from competition law, financial instruments) that welcome the introduction of geographical diversification of gas imports, while increasing imports from an established source should be avoided. Although such policy measures are best formulated at the member-state level, they should be based on a systematic and formal market-surveillance mechanism, coordinated by the European Commission together with national regulators – possibly within

the Council of European Energy Regulators or another agency.

The case for the EU to develop a set of policies to promote diversification and redundancy of import capacity is strengthened by the fact that it would not only improve security but also, and indeed primarily, because it would support competition in gas markets.

A proposal to deal with import-dependency risks

Identifying relevant risks is a political responsibility that should be addressed at the EU level, in close consultation with Member States and stakeholders. This effort is greatly helped by a European solidarity mechanism, taking into account the technical, economic and infrastructural situation. At present, the only significant threat could arise from Europe's single most important supply country, Russia. The already dominant role that Russia plays as a supplier is exacerbated by the importance that it has in new Member States. Such a threat means that if gas of such a significant proportion is not delivered, it can cause physical interruptions over a period of time but not indefinitely.

Not all consumers have the same needs. A differentiation among priority (firm or non-interruptible) and interruptible customers should be made. Suppliers should be required to protect their priority customers. As long as their exposure to the possible negative event (percentage shortfall in supplies) is lower than the share of priority over total customers, they may not need to worry about security of supplies. This idea suggests that the security of supply standard could be defined as the guarantee that all the gas volumes demanded by non-interruptible (firm or protected) customers, are available at a reasonable price. Such a standard is best established at the EU level.

As a result, an increase of natural gas in power generation will improve the non-interruptible and interruptible consumer ratio and therefore increase security of supply for gas. Nevertheless, to some extent this increases the risks for power generators, who would eventually need to invest in dual-fired generation, which is likely to increase their costs.

Interruptible customers need to be offered lower prices since they do not require protection in the event of a crisis (they may opt to withdraw from the market or maintain their own alternative fuel capacity).

The distinction among various kinds of customers can be contractual, in which case the law or regulatory system should guarantee the meaning of contractual obligations. Thus suppliers' claims of force majeure as an impeding factor to the delivery of gas are limited. Details would need to be agreed at the member-state level. In an interconnected, competitive market, well-diversified companies enjoying a small protected-customer base could be permitted to sell emergency supply rights to other companies that possess less diversified supplies or customer bases (or both), or that are more oriented

towards priority customers. An agency should be in charge of general oversight of the security of the system, including the surveillance of interconnection capacity and ensuring a supplier of last resort. The agency could be organised as either an EU or Member State body, such as an EU agency or a system of national agencies, possibly placed within the national regulators. The agency could be funded partly by taxpayers and partly by a levy on emergency supply rights for importers to meet their minimum security obligations. A company's gas procurement portfolio and the composition of its customer base should determine storage obligations.

Cost implications for the power sector should be included in estimations. Costs could be socialised to some extent, because diversification of sources and redundancy of import infrastructure or a provider of last resort are also tools to encourage competition. As such, they may be assumed to be a systemic priority. Who will be called upon to finance this activity is an open question that will need to be decided by policy makers.

Liquefied Natural Gas (LNG)

The development of LNG markets is expected to ease some concerns about security of supply, especially in terms of pipeline diplomacy, because of its advantages of flexibility and diversification. Currently, about 11% of Europe's gas imports are in the form of LNG. However, some drawbacks remain. Besides the fact that LNG technology is sensitive to physical threats, exporters have not kept up with increasing facilities in importing countries, leading to some regasification terminals standing idle. In addition, the EU is expected to face fierce competition from other importing countries, such as the US (Larsson, 2007).

Overall, the enlarged EU faces the challenge of major investment in natural gas and LNG capacity to secure a possible demand of 629 billion cubic metres (bcm) by 2015 (up from 532 bcm in 2006). LNG imports are expected to cover a large share of this increase, with LNG regasification capacity likely to double to 198 bcm in 2015 (up from 93.2 bcm in 2007). However, global regasification capacity will continue to exceed liquefaction capacity due to the requirement for spare capacity resulting from arbitrage and seasonal demand variations (Toenjes and de Jong, 2007).

In reality, demand for natural gas and LNG may be even higher, depending on the degree to which the current and future commitments from the Kyoto Protocol are fulfilled. Investment in expanding current gas pipeline links and LNG receiving facilities along with new infrastructure over the next 20 years translates into a total cost estimate of between $150 and 200 billion (approximately €100 – 135 billion).

Sustained uncertainty about future gas prices may have an adverse impact on raising appropriate financing. Gas prices will be influenced by new

infrastructure investment, production in more difficult conditions and longer transportation routes. The EU emissions trading scheme – itself another gas 'driver' – creates additional uncertainty about prices, although it is generally expected that it will push prices up. For example, McKinsey (in Lekander, 2003) assumes that CO_2 regulation increases demand growth from 2.7% to 3.8% p.a., translating into an increase of gas border price by 15% in 2014.

The good news is that technological progress is expected to reduce both capital investment and unit transport costs, thereby opening up new supply opportunities for pipelines and LNG.

There is, therefore, the need for well-calibrated policy regarding the regulations of construction and access to infrastructure facilities (LNG tankers, terminals and pipelines), to avoid hampering their development. The establishment of a systematic and formalised market-surveillance mechanism will be crucial in this respect, coordinated by the EC together with national regulators, possibly within the CEER or another EU agency.

Oil security

The supply of oil in the European Economic Area and OECD countries has largely been secured by existing infrastructures, topped up by security measures such as the IEA strategic stocks and demand restraint measures. However, Europe and all other major consumer regions are faced with declining domestic oil extraction rates, leading to increasing import dependency and stronger competition between oil importers. At current production rates, the EU-25 will have exploited all its proved reserves by the end of 2014 (BP, 2007). On the other hand, global estimates of how much recoverable oil remains have consistently increased over time. BP (2007) estimates proved oil reserves to amount to 1.2 trillion barrels at the end of 2006. At the current rate of global production, these remaining reserves would last for another 40.5 years. This reserves-to-production (R/P) ratio has remained rather constant when compared with 1996 and 1986 levels of 41 and 39.8 years, respectively. However, appropriate investment is key for future production to match demand. Additionally, undiscovered conventional resources are estimated to amount to 880 billion barrels (IEA, 2006). In the long-run, non-conventional oil resources (e.g. oil sands, gas-to-liquids, coal-to-liquids, oil-shale, etc.) will play an increasing role in global oil supply. With estimated reserves of at least 1 trillion barrels, they are expected to contribute almost 8% to global oil supplies by 2030 (IEA, 2006). Moreover, these resources are mostly located outside the current oil-producing countries. Whether non-conventional alternatives will be commercially available will depend on world oil prices and technology/infrastructure development.

A primary mission of the IEA was the creation of a mechanism to

mitigate the negative effects of oil disruptions. The mechanism of emergency response was set up under the 1974 agreement on an International Energy Programme (IEP). The IEP Agreement requires IEA countries to hold oil stocks equivalent of at least 90 days of net imports of the previous calendar year and to increase supply (by releasing oil stocks and increasing domestic production) and reduce demand (by means of demand restraints and fuel switching) in the event of an oil supply disruption of 7 per cent or more to the IEA or individual countries (IEA, 2007a). The IEA emergency measures are kept in constant readiness through periodic tests involving administrations and the oil industry. They have been mobilised on several occasions over the years making a significant contribution to restoring market stability in terms of uncertainty.

There are two different categories of stocks, depending on the holder: *public stocks*, held exclusively for emergency purposes, are oil reserves held by agencies or owned directly by governments; *industry stocks* include stocks held to meet government stockholding obligations and stocks held for commercial purposes. In June 2007, total oil stocks in IEA member countries totalled some 4.1 bn barrels (about 150 days of net imports), of which 1.5 bn barrels were public stocks and 2.6 bn barrels were industry stocks (IEA, 2007b). IEA stocks seem adequate for a medium-scale disruption of short- to medium-term duration, while for larger disruptions the instrument is sufficient only for short periods of time.

Stockdraw and demand restraint policies are the most feasible and effective measures in the IEA context, because of high oil stock capacity, great dependence on oil (high demand), the reduced spare capacity and the reduced fuel-switching capacity. A recent example of their effectiveness has been the 2005 IEA Collective Action in response to the hurricanes in the Gulf of Mexico, which resulted in 57.5 m barrels made available by the IEA's 26 Member States from all forms of stock release and increased indigenous production, in addition to 1.7 m barrels made available from demand restraint (IEA, 2007b).

Demand restraint as a policy approach refers to the short-term oil savings that can be achieved during a period of crisis. The measures to achieve demand restraint fall into three main categories: persuasion and public information, administrative and compulsory measures, and allocation and rationing schemes. Demand-restraint programmes reflect local demand patterns and economic structures, legislation and emergency-response policies.

In general, IEA countries must have a ready programme of demand restraint measures equal to 7% of oil consumption if supplies are cut by 7% (approximately equivalent to 3.4 mb/d, see BP, 2007), and 10% of oil consumption (approximately equivalent to 4.9 mb/d, see BP, 2007) if

supplies are cut by more than 12%. Restraint measures are designed mainly for the road transport sector, which is the biggest oil-consuming sector in OECD countries (>50%), but price elasticity of the sector remains very low in the short term and is decreasing.

Ensuring security in liberalised electricity markets

Issues for the electricity sector are continuity and reliability of supply. Risks include electricity blackouts due to ageing infrastructure and a lack of investment in networks, especially cross-border capacity, erosion of reserve capacity, unwarranted public opposition to new investment projects in generation and transportation, bad regulation and increasing domestic generation market share of incumbent companies. A particular aspect is the slow progress in liberalisation and integration of the electricity market. Markets in "transition" create their own risks such as erosion of reserve capacity. Such issues are likely to disappear, once the market functions properly.

In general, liberalisation increases security of supply by increasing the number of market participants and improving the flexibility of the energy systems. Liberalisation may, however, also pose new risks. Reserve capacity is one such risk. In the monopolised market structure, capacity shortages have never been a problem. The system inherently produced excess capacity in the knowledge that costs could easily be passed on to consumers. In competitive markets the situation has reversed. Investment decisions for generation capacity are based on calculations of profitability. Particularly if peak demand only rarely occurs, which by definition is the case for the marginal kWh, incentives to build reserve capacity are low. Theoretically, shortages of generation capacity could be offset by trade but interconnection capacity is not sufficient.

Sufficient investment in electricity capacity in unregulated markets does not take place continuously but in a cyclical manner. At present, there is no scientific consensus on whether markets are expected to produce adequate capacity levels continuously. Practical experience is too limited and available cases involve complex and disputed data.

Most European electricity systems do not have any specific provisions to ensure adequacy of capacity. They rely on the electricity market to provide the incentive for investment. Price (expected) is the only driver of investment incentives. While in theory spot pricing can deliver optimal results with regard to securing supply in the long and the short term, real markets seem not to be able to verify theory and therefore raise questions over their ability to secure supply. The specificities of electricity (non-storability) make wholesale prices highly volatile, making it vulnerable to supply interruptions.

There are a number of factors that instigate market failure in the setting of

optimal investment signs (based on price) to invest in generation adequacy. These include price restrictions, imperfect information (about consumer willingness to pay or future supply and demand), regulatory uncertainty and/or restrictions relating to investment regulation and risk-averse behaviour by investors.

Regulatory intervention towards the maintenance of reserve capacity is desirable because of its public good character. The more reserve capacity exists, the higher the reliability of the supply system and the service. At the same time, consumers having the certainty of existence of reserve capacity will opt for understating their willingness to pay, and attempt to free-ride on the demonstrated willingness of others (as demonstrated by the premiums they would be willing to pay) and thus distort the market to their benefit.

Long-term contracts are not optimal investments where they concern peaking units, as they allow for free-riding by consumers (prices are received from competing retail companies that buy from generators at probably higher prices and then have to compete); furthermore, such contracts do not have a sufficient duration to dampen the business cycle.

The provision of electricity is characterised by a strongly asymmetric loss-of-welfare curve. The loss of welfare because of under-investment by a certain amount is many times higher than the loss of welfare as a result of over-investment by the same amount.

Two strategies are proposed to reduce the risk of under-investment. The first is to continuously over-invest in the electricity system. This strategy, however, is flawed by a welfare loss with regard to the social optimum, but at the same time it insures against the much greater risk of under-investment. The second strategy is to 'flatten' the investment optimum by changing the dynamics of the system. By making demand more responsive to price, random rationing and extreme prices could be avoided. The least valuable loads would reduce their demand and thereby the overall social cost of a disruption would be reduced from the average value of lost load to the value of lost load of the least valuable customers.

There are a number of suitable cost-effective mechanisms that could address the issue: mothball reserves, capacity payments, capacity requirements, reliability contracts and capacity subscriptions. These all have different merits and shortcomings. The baseline should be that the demand for reserve capacity should be made explicit, i.e. that the solutions should be market-based. Capacity markets, reliability contracts and capacity subscriptions satisfy this condition. Reliability contracts and capacity markets are the most market-based and they also pose the fewest legal issues at the EU level in terms of state-aid rules, public service obligations and cross-border problems.

The analysis has shown that in order to be effective in a cost-efficient

way, the instrument finally chosen should be applied to the entirety of the market, which could be the EU as a whole or 'regional markets', should this concept be implemented as the European Commission has suggested. The existing reality in the European Union is that it is the national governments or their regulators that are responsible for ensuring adequacy.

Beyond the market

The above focus on market oriented policy options does not imply that markets can achieve everything. For long-term policy objectives government action will be needed. Examples include R&D or the development of new and breakthrough technologies to cope with climate change. Moreover, the EU is dependent on imports from areas where market rules do not apply and economic decisions on whether to explore, produce or sell energy is largely linked to political considerations.

There may thus be a need for the EU to act on the following fronts.

On the demand side, the promotion of a strong and ambitious energy saving and energy efficiency policy in the EU and ideally across the OECD or even globally could reduce dependence on politically unstable or unreliable countries. Another area is investment in energy efficiency programmes by utilities with a focus on networks upgrade and smart metering systems to give the customers awareness of their consumption through a real time measure. A particular objective should be to limit the use of oil to essential areas such as transport and petrochemical, or a reflection on how to make best use of natural gas.

On the supply side, focus should be laid on supporting near zero carbon technologies such as renewables and carbon capture and storage (CCS). This would include especially temporary support mechanisms for renewables electricity or second-generation biofuels to help bring down costs, creating the regulatory framework for carbon capture and storage as well as facilitating pilot and demonstration projects in the area. Ultimately, it should be up to the markets to choose the appropriate technologies (be they renewables, CCS or nuclear) based on the political objectives of the EU and/or its member states. Choices will most likely be different across member states depending on political preferences, political acceptability and resource endowment.

Regarding R&D, the EU should focus on all energy technologies including both demand and supply with the objective of maintaining or increasing diversification and flexibility of EU and global energy markets but also to reduce GHG emissions from fossil fuels. Attention will be needed to ensure the deployment of technologies to bring down costs – once these have come close to being competitive – while minimising the environmental

impact.

For oil, the objective should be to maintain or increase market flexibility both in the EU and globally (e.g. by increasing spare oil production capacity), liquidity (e.g. by preventing the exclusion of oil resources from the global market) and diversity (e.g. develop unconventional oil), essentially to reduce transaction costs by improving the functioning of markets.

For natural gas, the objective should be to improve the functioning of the internal gas market, notably by increasing liquidity both for piped gas and LNG. Liquidity of the market presupposes that it remains attractive for producers to deliver sufficient volumes to the EU and the right incentives for infrastructure investment are in place. In addition, existing bodies such as the Gas Coordination Group could be used to identify possible measures to cope with possible supply disruptions, including better co-ordination or harmonisation of national regulations on gas supply and on gas stocks.

For the electricity sector, continuity and reliability will be enhanced by a more harmonised or even unified management of the European grid, more investment in generation and grids and improved cooperation between Transmission System Operators (TSOs). These measures, in particular, are a key to foster the regional markets and ultimately European energy markets integration.

The above measures constitute the existing "EU consensus" of no-regret options to address EU energy policy objectives. Too often, however, such no-regret options fail due to policy inertia, expediency or simply lack of interest. To avoid such failure in the future, the European Commission in its role as Guardian of Treaty could be given special responsibility for tracking member states and EU progress towards the implementation of these measures.

Röller et al (2007) show that member states' energy policies remain largely determined by exogenous factors such as availability to domestic resources and geography. Member states have very different starting points, facing different energy challenges. Against such a background of heterogeneity, identifying the "European added-value" beyond the above consensus will be difficult (Behrens and Egenhofer, 2008). On the other hand, if an energy policy for Europe attempts to go beyond the "lowest common denominator", i.e. the policies and measures that all member states agree with, such a policy will need to submit member states to the test on whether domestic energy policies meet "agreed EU policy objectives". This will include energy security measures.

2.6 CONCLUSION

This chapter has looked at a number of aspects of energy security and insecurity issues, and at policies that can be used to control them. In general, there are significant costs incurred by power blackouts as measured by VOLLs, and these are likely to increase in both developed and developing countries in future years as dependence on electricity grows. However, the macroeconomic external costs of electricity insecurity appear to be less important.

Energy policy in the EU has to take these issues into account, using both market and non-market policies to ensure a regular supply of electricity at a predictable price. Key policies are needed to integrate both electricity markets and transmission grids, since these will both help spread the risks of sudden shortages and blackouts.

Historically, much more attention has been paid to energy security as it relates to oil, in particular securing oil supplies. However, it is increasingly becoming clear that gas and coal are also subject to insecurities and indeed as far as oil is concerned the externalities with respect to electricity production are very small.. This chapter highlights a gap in the research relating to the costs of gas and coal security. Although some qualitative- and policy-based research has been carried out already, more needs to be done to investigate the macro-economic and external costs of these fuels.

The chapter also developed a new estimates of what countries have been willing to pay to have a more ‘secure`electricity supply system by comparing the actual costs of generation from 1980 to 2000 with the lowest costs (which could have involved more reliance on cheapr but imported fuels). The results for France, Germany, Italy and Spain show that France had the lowest difference between the two costs, suggesting that perhaps it paid the smallest premium to have a more secure supply system. The highest costs on the other hand were for Italy and Spain. Again this is only indicative and further work is needed here.

Finally the chapter has examined a number of policy options for energy security being implemented or considered in the EU member states and at the EU level itself. While a great deal of attention is being paid to the issue of energy security and a number of measures have been taken it is fair to say that a full assessment of their effectiveness has not been carried out, comparing the costs of the measures against indicators of possible gains.

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3 Private costs

Markus Blesl, Steffen Wissel

3.1 INTRODUCTION

This chapter analyses the long-term development of heat and electricity generating costs based on present best predictions about the evolution of the considered technologies. The calculated costs follow a technology development and energy price assumption up to 2030. Calculations are based on renewable energy sources, fossil fuel technologies with and without carbon capture and storage and nuclear-based electricity technologies. After careful consideration of all the options the chapter concludes that fossil and nuclear-based electricity generation are still projected to be the most competitive technology options for heat and electricity supply from a private cost point of view.

The technologies and plant types covered by the present study include units for today as well as for the years 2020 and 2030. Various technological options (fossil, nuclear, renewable) are available to contribute to a secure, cost effective and environmentally friendly energy and electricity supply system. The complex financial structure of commercial plants means that it is often impossible to compare the capital costs of of the electricity generation technologies by the various options. This study has taken what we know to be the actual and future costs of building, maintaining and running different types of heat and electricity generating sytems.

To quantify the generating costs of future technologies the levelised generating costs are calculated for each considered technology. These are explained in detail below.

3.2 METHODOLOGY

The costs reported here are calculated according the Average Levelised Lifetime Generating Costs (ALLGC`s). The methodology calculates the generation costs on the basis of net power supplied to the station busbar, where electricity is fed to the grid. The cost estimation methodology discounts the time series of expenditures to their present values in a specified base year by applying a discount rate. A discount rate takes into account that

the future value of any amount of money does not have the same value as the same sum earned or spent today. The levelised lifetime cost per MWh of electricity generated is the ratio of total lifetime expenses versus total expected outputs, expressed in terms of present value equivalent. This cost is equivalent to the average price that would have to be paid by consumers to repay exactly the investor/operator for the capital, fuel expenses and Operation and Maintenance (O&M) expenses, including a rate of return equal to discount rate. The base year for the following calculations is 2005, and values are expressed in real terms (Euro 2005). Hence, the normal inflation is excluded from the calculations. However escalation of fuel prices and increased O&M costs, e.g. due to higher staff and materials costs, are considered.

The formula to calculate for each power plant, the Average Lifetime Levelised Generating Costs is:

$$\sum_{t=0}^{T} \frac{\overline{p} \cdot E}{(1+r)^t} - \sum_{t=0}^{T} \frac{I_t + M_t + F_t}{(1+r)^t} = 0 \qquad (3.1)$$

Solving 3.1) for $\overline{p}$, one gets ALLGC as:

$$ALLGC = \frac{\sum_{t=0}^{T} \frac{[I_t + M_t + F_t]}{(1+r)^t}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+d)^t}} \qquad (3.2)$$

I_t	Investment expenditures in year t
M_t	Operation and Maintenance expenditure in year t
F_t	Fuel expenditures in year t
E_t	Electricity generation in year t
r	Discount rate
ALLGC	Average Lifetime Levelised Generating Costs ($\overline{p}$)

The capital (investment) expenditures in each year include construction, refurbishment and decommissioning expenses. A widely adopted methodology to evaluate capital costs, (e.g. by OECD), defines the specific overnight construction cost (OIC) in €/kW and the expense schedule from the construction period. The overnight construction cost is defined as the total of all costs incurred for building the plant immediately ("overnight"). Interest rates during construction can deviate from the general adopted discount rate, and the costs are expressed in terms of percentage of OIC. The capital costs are part of the levelised generation cost, which is the basis for cost

comparisons and assessments.

The fuel price assumptions of fossil and nuclear plants are based on projections up to 2030. For nuclear power plants any cost figures include all costs of the front (uranium, conversion, enrichment) and back end (intermediate storage, final disposal) of the fuel cycle.

O&M costs contribute a small but not negligible fraction to the total cost. Fixed O&M costs [€/kWa] include cost of the operational staff, insurances, taxes etc. Variable O&M costs [€/MWh] include cost for maintenance, contracted personnel, consumed material (i.e. operating materials, operating fluids) and cost for disposal of normal operational waste (excluding radioactive waste).

The discount rate that is considered appropriate for the energy sector may differ from plant to plant. In this chapter, two interest rates were used: 5% and 10%.

Private costs of generating electricity may also include, in addition to the ALLGC, other cost items that may vary from plant to plant. Possible items may be environmental taxes on fuels, carbon emission charges, system integration costs, etc.. For the purpose of comparison only the ALLGC costs are reported here as private costs.

3.3 ASSUMPTIONS

Fuel prices

For the projection of future heat and electricity production costs fuel price assumptions of the used energy carriers are necessary. Fuel price assumptions are generally to be burdened with the restricted projection methodology, due to the high uncertainties by a given market and the law of demand and supply. Lignite and biomass (straw, wood chips, biogas) are local energy carriers, which are not included in an international price mechanism. Taking inflation into account the fuel prices of these two types of energy carriers will be constant. Of particular noteworthiness for nuclear power is that the total fuel cycle costs are considered (natural uranium, conversion, enrichment, intermediate and final disposal). In the projections in Table 3.1, the oil price is gradually increasing from 2010. Naturally gas is following a similar pattern. After 2030 constant prices for all energy carriers are assumed.

Table 3.1 Fuel price assumptions on plant level, according to EUSUSTEL (2006), IEA (2008)

Energy Carrier	Unit	2005	2010	2015	2020	2025	2030
Coal	[€$_{2005}$/GJ]	1.96	1.86	1.97	2.07	2.14	2.19
Lignite	[€$_{2005}$/GJ]	0.97	0.98	0.98	0.98	0.98	0.98
Natural gas	[€$_{2005}$/GJ]	6.11	6.32	6.03	5.95	6.62	6.63
Oil	[€$_{2005}$/GJ]	6.65	5.35	5.39	5.82	6.70	7.14
Light Oil	[€$_{2005}$/GJ]	9.83	8.53	8.57	9.01	9.89	10.32
Nuclear	[€$_{2005}$/GJ]	0.62	0.62	0.62	0.62	0.62	0.62
Biomass [1)]	[€$_{2005}$/GJ]	4.00	4.00	4.00	4.00	4.00	4.00

[1)] wood forest residual

Heat credits for Combined Heat and Power (CHP)

An important distinction needs to be made in comparing electricity power plants with combined heat and power plants (CHP`s), which use rejected heat with typical simple processes. The value of heat recovery can be measured by the cost avoided in using recovered thermal energy for a specific purpose, as opposed to using another source of energy. Most commonly, recovered heat replaces thermal energy output from some type of fuel-burning-equipment, usually a boiler. In this case, the value of recovered thermal energy is equivalent to the cost of fuel energy that would have otherwise been consumed. The displayed energy is commonly refered to as an energy credit or fuel credit. The amount of energy displaced by recovered heat is a function of the efficiency of the displaced boiler (or other heating equipment). The alternative heat generation technology in this report is given by a gas boiler with an efficiency of 88%.

Back-up costs

The introduction of the intermittent renewable energies, like wind or solar power, affects the electricity generating system. The inflexibility, variability, and relative unpredictability of intermittent energy sources are the most obvious barriers to an easy integration and widespread application of wind and solar power. Due to the fluctuation by producing energy with wind and solar plants a back-up technology is necessary for compensating this. The back-up cost of not assured generating power of solar and wind plants can be calculated with equation (3).

$$C_{BU} = \frac{A_k}{h_v} - \frac{A_k \cdot P}{h_w} = A_k \cdot \left(\frac{1}{h_v} - \frac{P}{h_w} \right) \quad (3.3)$$

C_{BU}	Cost Back-Up
h_v	Full loading hours, supply
h_w	Full loading hours of the renewable power station
P	Power credit (capacity factor) of the renewable energy plant
A_k	Annuity, incl. the annual fix costs of the Back-Up technology

In this equation, the provision of the back-up power is reduced by a capacity factor (P) for the renewable technologies. Back-up technologies here are a hard coal condensing power plant for minimum back-up costs and a gas-fired CCGT plant for maximum back-up costs.

3.4 TECHNOLOGIES

The data about the technology characterization reflects the current and the future stage of the currently commercial heat and electricity generating technologies.

Nuclear power plants

Nowadays, the most commonly used reactor is the Pressurized Water Reactor (PWR). The electrical efficiency of nuclear power plants is restricted due to the low operating temperatures, so that efficiency is about 33%. The availability of modern reactors varies from 80 to 95%. A typical lifetime for current reactors is 40 to 60 years.

The industry of nuclear power has been developing and improving reactor technology for almost five decades and is preparing for the next generations. The evolutions can be divided into two categories. The first one is the further development of current standard reactors, which are called “generation III” reactors. Third-generation reactors are still thermal reactors, but with higher availability and longer operating lifetime (60 years), improved safety (reduced possibility of core melt accidents), higher burn-up and reduced investment costs. “Generation IV” reactors are not taken into account for the private cost calculations because the commercial deployment will be after 2030.

Hard Coal and Lignite fired power plants

One of the oldest technologies still dominating electricity production is the pulverized coal combustion (PCC). The PCC technology can be applied for lignite as well; however this will result in a somewhat lower efficiency due to the lower heat content of lignite. Recent development includes the application of supercritical pulverised coal combustion with supercritical steam conditions. This results in an overall efficiency of 44.5% for lignite and 46% for hard coal. The integrated gasification combined cycle (IGCC) is the combination of a coal gasification unit and a gas fired combined cycle unit. The combined cycle technology is similar to the technology used in modern natural gas fired power plants (CCGT). Lignite fuelled IGCC power plants have an efficiency of 44%, while that of hard coal based IGCC plants is about 45%.

In the future, for the mature PCC-technology no major technical innovation or milestone can be expected. However, by elevated steam parameters, installation of superheating steps and application of lower condenser pressures further increases in power plant efficiency up to 52% for the supercritical case can be achieved. In 2030, an efficiency of the IGCC power plants up to 55% can be expected. In the long term prospect, the IGCC technology has the potential to increase the efficiency considerably above 52%.

The power plant with CO_2-separation (pre-combustion, post combustion and oxyfuel combustion) requires additional individual components. These components have an impact on the cost (about 1370 €/kW in 2020) and efficiency. In this paper, IGCC technology with CO_2 capture is considered to be available after 2010. Additional energy is required for the compression and liquefaction of the captured CO_2. The efficiency penalty due to CO_2 capture was assumed to be 6%, which is in accordance to Hendriks (2008). The specific total cost for transport and storage depends on many factors (e.g. accessibility to the storage area, topography and technical feasibility). The cost are assumed by 3 €/t CO_2 and 15 €/t CO_2 in lower case and upper case.

Natural gas- and oil-fired power plants

Combined Cycle Gas Turbines (CCGT`s) are based on the structure of the single gas turbine, but a second turbine (steam turbine) is added. The residual heat from the flue gasses from the simple gas turbine unit is recuperated in a heat recovery steam generator for making steam. The efficiency of the gas cycle is approximately two-thirds of the net efficiency. This is less than a simple single gas turbine plant, due to the combination of the rankine and the gas turbine cycle the overall efficiency of a CCGT plant reaches 57.5%. In comparison to the simple gas turbine unit is the CCGT less flexible. The low construction costs (440 €/kW) and the short construction time of 2 years are

the major advantages of the CCGT power plant. For the CCGT plants with separation of CO_2, there is a net efficiency loss of about 6%.

In future, for gas turbines and CCGT`s no real technical breakthroughs can be expected. Also, costs are not expected to decrease a lot, because the capital costs are at a relative low level already. New materials allow higher turbine inlet temperatures of the gas turbine and the option of supercritical steam parameters. By 2030, in view of the expected deployment of new materials and of better cooling options for the gas turbine, an overall efficiency of 63% and investment costs of 385 €/kW are assumed.

The technology of oil-fired plants can be condensing power plants (43 % efficiency) or common gas turbines with 36% efficiency.

Combined Heat and Power (CHP)

Two types of production technologies (back pressure and extraction condensing) are considered. In this present paper, natural gas CCGT and hard coal fuelled systems have been included for fossil energy carriers as well as straw and wood for biomass as extraction condensing processes. Data estimates for 6000 hours per annum (h/a) full load hours in the reference case and in the sensitivity analysis range from 3500 to 6000 h/a. The technical lifetime for fossil plants is 35 years and 30 years for the biomass plants. Investment costs for biomass CHP plants are in the range of 1750 to 2600 €/kW.

The technologies for CHP are mature, but increased efficiency can be expected. CCS will play also an important role in future CHP´s.

Renewable plants – Hydro

The existing technology is mature and well advanced (efficiency about 85%), whereas the mechanical design is relatively simple. Although the investment costs of hydro power stations reach up to 5850 €/kW, the generation costs are very low. Due to the high efficiency of currently operating hydro plants, only small ameliorations could be made on some technical items.

Renewable plants – Wind

Sites for onshore and offshore plants are considered. Despite the higher investment costs (onshore: 2628 €/kW and offshore: 4044 €/kW), the interest in offshore is increasing. By using the kinetic energy in the wind offshore, there is less turbulence and there are higher wind speeds, which result in expected utilisation times or more than 3000 h/a and up to 4000 full load hours per year. Inland wind power plants have an average availability of approximately 2000 to 2600 h/a. From an economic point of view, two parameters dominate the cost of generating electricity by wind: the investment cost of the plant and the electricity production rate of the turbine.

In future the main expected trend of the wind technology is the further up-scaling of the turbines, in order to minimize the higher costs of foundation and cabling.

Renewable plants – Photovoltaic (PV)

PV systems are generally distinguished into building-integrated systems (facade or roof installations) and centralized systems (ground mounted power plants). In this chapter multi-cristalline PV cells have been investigated, which currently are the most applied material for PV cells and feature an efficiency of around 15%.

The cost of electricity generation in PV systems is clearly higher than the cost of other technologies. New materials and manufacturing processes are under development aiming at a reduction of resource use, higher efficiency (up to 20%) and costs (open space investment costs 2008: 4275 €/kW and 2030: 2000 €/kW).

Renewable plants – Solar thermal (Solar through)

Starting from operational experiences of more than 20 years, parabolic trough technology is considered an approved and mature technology. The efficiency of solar thermal plants is in the same range as PV (about 15%).

Considered Technologies

Table 3.2 summaries the economical characterisations of the considered technologies for 2008.

Table 3.2 Technical characterization

Energy carrier	Technology	net, el. power,net	net, el. efficiency	Investment costs	Technical lifetime
		[MW]	[%]	[€/kWel]	[a]
Nuclear	PWR	1300	33	1850	40
Heavy oil	Condensing	350	43	720	35
Hard coal	Condensing	600	46	1000	35
	IGCC	450	45	1350	35
Lignite	Condensing	965	44.5	1300	35
	IGCC	450	44	1200	35
Natural gas	CCGT	800	57.5	500	35
	Gas turbine	50	38	280	35
Hydro	Run of river	0.2	85	5850	70
	Run of river	1	85	5500	70
	Run of river	50	85	3500	70
	Dam	1000	83	3500	120
Wind	On-shore	2	100	1000	20
	Off-shore	2	100	1650	20
Photovoltaic	Roof	0.00312	15	5200	25
	Open space	0.00312	15	4275	25
Solar thermal	Solar through	80	13.2	3360	30
Natural gas	CHP, extraction	200	54	620	35
Hard coal	CHP, extraction	500	42.5	1170	35
Natural gas	CHP, back pres.	200	45[1)]	620	35
Hard coal	CHP, back pres.	200	35[1)]	1300	35
Biomass straw	CHP, extraction	6,1	19[1)]	2600	30
Biomass wood	CHP, extraction	6,1	19[1)]	1750	30

[1)] el. efficiency at thermal peak load

Technology development

Looking towards the future 20 to 25 years, it can be estimated that the investment costs of condensing power plants will decrease In particular, the investment cost of nuclear plants can be reduced, under the right conditions, by 25% by 2030. The net electrical efficiency of future power plants will increase of up to maximum 63% for natural gas CCGT plants. Two power plant types with CCS have been considered in the reviewed technology characterizations: the Combined Cycle Gas Turbine power plant and the Integrated Gasification Combined Cycle power plant, fuelled with both hard coal and lignite. Taking 2030 as reference year, there is a net efficiency loss of 5.5% for natural gas and of 3.5% of coal plants in comparison to PCC plants.

Figure 3.1 and Figure 3.2 illustrate the assumed data for investment costs and for the efficiency of the power plants.

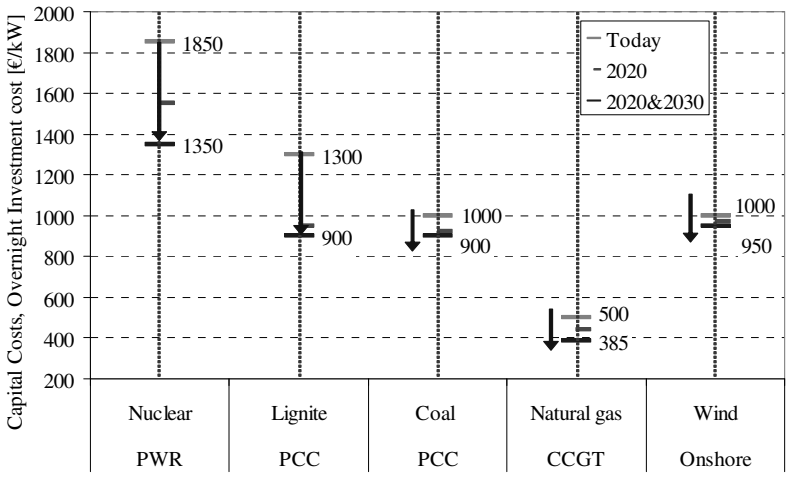


Figure 3.1 Range of specific overnight investment costs

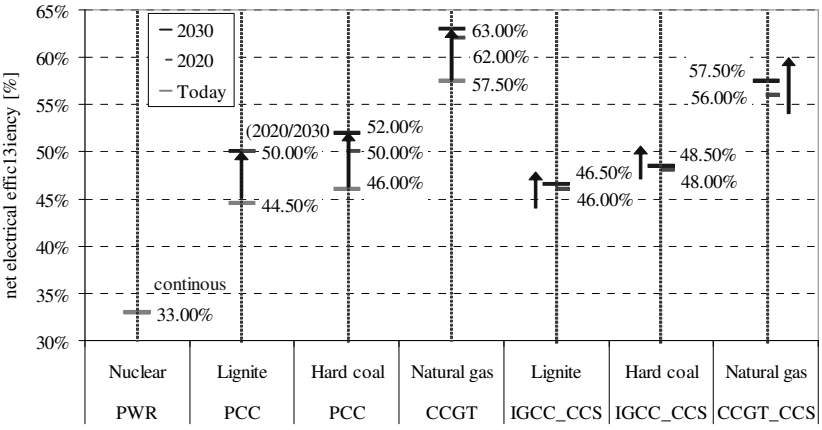


Figure 3.2 Net electricity efficiency (today – 2030)

3.5 PRIVATE COSTS

Private costs of fossil and nuclear power plants, 2008

Capital cost repayments and fuel costs tend to be the two largest components of the cost of electricity. In this case, the nuclear PWR and the lignite condensing power plant have the lowest specific private costs per MWhel. The higher capital costs make the nuclear power more expensive than the lignite condensing plant. An advantage of the gas power plant is its low investment costs. On the other hand, fuel costs amount to more than 80% of the total electricity production costs. This makes the gas technology very dependent on the gas prices, which are as volatile as the prices of oil and of which is following the trend of long term price increasing. Gas power plants can serve in base, cycling a peak load with acceptable production costs. Whether the oil power plants are completely uncompetitive due to the fuel price.

For current fossil and nuclear technologies, lignite condensing plants have the lowest production costs at a discount rate of 5 and 10% (see Figure 3.3).

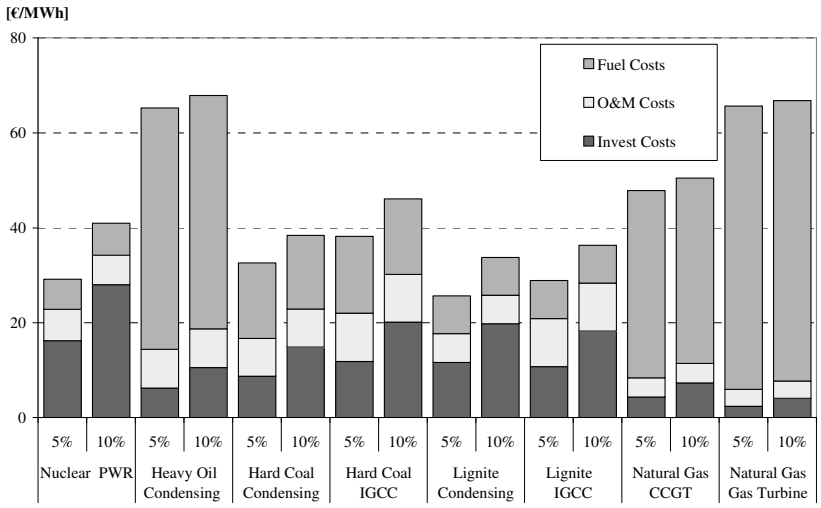


Figure 3.3 Private costs with a discount rate of 5 and 10%, 7500 h/a

Private costs of fossil and nuclear power plants, 2020

Lignite and nuclear keep a dominant position in 2020 as well. The costs of

known fossil and nuclear fuel based technologies decrease mainly because of higher efficiency and lower investment costs (see Figure 4). At a 5% discount rate the electricity production costs of lignite-based power plants decrease by approximately 5 €/MWhel between 2008 and 2020 and the costs of nuclear-based technologies by approximately 4 €/MWhel. Another interesting result is the strong increase of the production costs of oil power plants, which increase to more than 40% due to the higher fuel price of oil. Despite the oil-gas price coupling mechanism the production costs of IGCC gas plants remain of a constant level. This development can be explained firstly, by the increasing efficiency factor (57.5 to 62%) and secondly by the lower overnight capital costs (Figure 3.1). The natural gas and coal CCS enter the market in 2020 with costs of 35 €/MWhel for lignite, 43 €/MWhel for coal and 60 €/MWhel for natural gas (at a discount rate of 5%). In line with the differences in average availability (see Figure 3.5) full load hours, the electricity production costs of the nuclear power and the lignite power plants are nearly constant below 40 €/MWhel. This result is mainly driven by the low fuel costs. The use of CCS-technology increases the production costs by more than 20%.

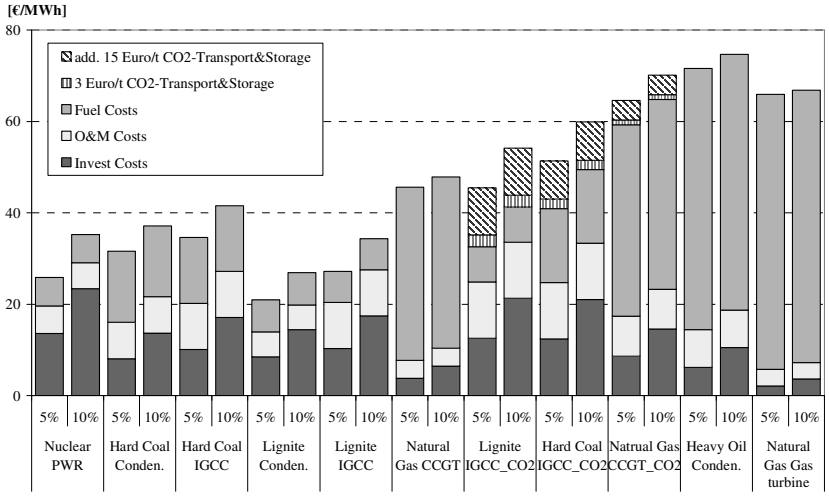


Figure 3.4 Fossil/Nuclear private costs with a discount rate of 5 and 10%, 7500 h/a (2020)

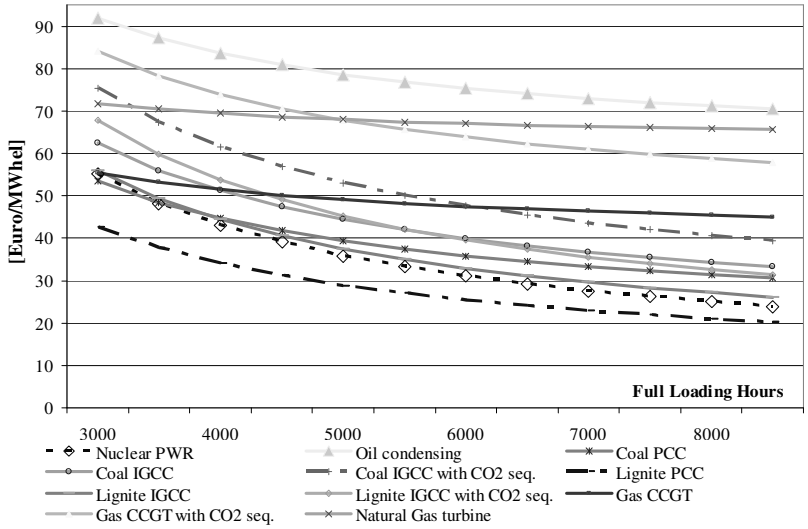


Figure 3.5 Fossil/Nuclear effect of availability by 5% discount rate, without costs for CO_2 transport and storage (2020)

Private costs of Combined Heat and Power, 2020

In 2020, Combined Heat and Power is a mature technology with high potential for the heat and electricity markets. The production costs of the several technologies will be nearly at the same range as the production costs of current CHPs. In comparison with the conventional fossil-fuel based CCS CHPs the costs of CHPs with CO_2 sequestration are approximately 20% higher. At a discount rate of 5%, the costs of common fossil CHPs ranges between 10 and 64 €/MWhel (at maximum level, with heat credit). For a coal CCS condensing CHP the production costs are 31 €/MWhel and for a gas-fired CCS CHP 64 €/MWhel. The biomass-fired cogeneration plants are uncompetitive due to the high share of fuel costs (see Figure 3.6). Over two-thirds of the biomass production costs are related to the high fuel prices.

The additional costs for CO_2 transport and storage of the plants with CO_2-sequestration range from 1 to 5 €/MWhel for the gas CHP and from 2 to 10 €/MWhel for the coal CHP.

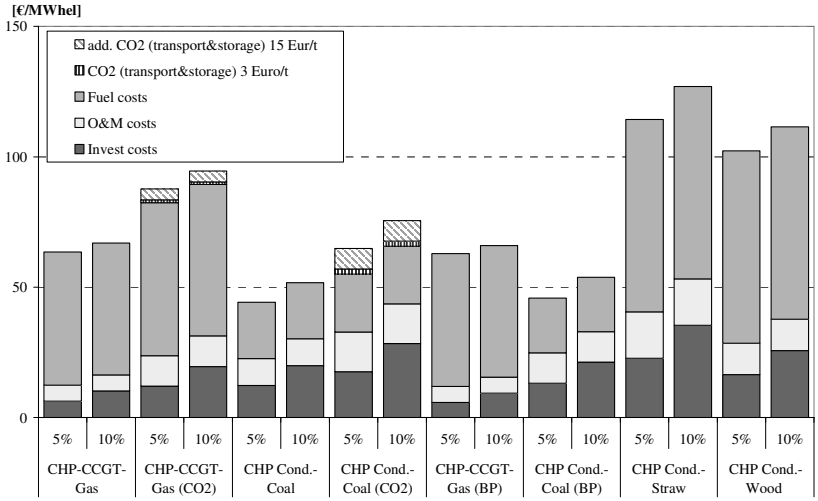


Figure 3.6 CHP private costs with a discount rate of 5 and 10%, 6000 h/a (2020)

The influence of the annual full load operating hours of the CHPs on the specific electricity generating costs is shown in Figure 7. It can be seen that the decrease of the specific electricity generating costs of biomass CHPs is substantial. A reduction of the annual full load operating hours of the CHPs by 500 h/a increases the specific electricity generating costs between 2.5 and 3.7% for natural gas and 5.0 to 10.1% for biomass.

Figure 3.7 illustrates the effect of availability of the generating costs. The full load hours varies between 3500 and 6000 hours per year.

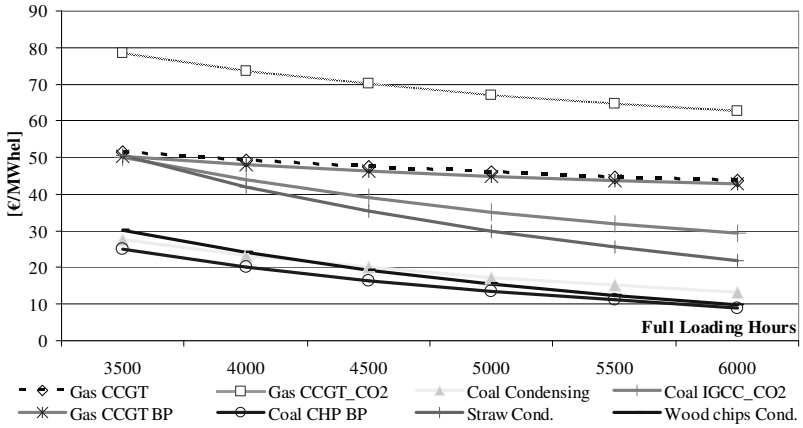


Figure 3.7 CHP effect of availability (full loading hours) by 5% discount rate (2020, with heat credit but without costs for CO_2 transport and storage)

Private costs Renewable Sources

For the renewable sources the generic framework and assumptions adopted to calculate private costs for those plants have been adapted to reflect their specific characteristics. The lifetimes of renewable technologies, with the exception of hydro power, are maximum 30 years (solar thermal). The average full loading hours of volatile generating technologies (wind and solar) are significantly lower than the generic assumption of 7.500 h/a for nuclear, coal and gas plants.

Three types of run of river hydro plants (small, medium and large), a hydro dam and hydro pump storage are considered in the category hydro power generation. The production costs of hydroelectricity are depicted in Figure 3.8. At a discount rate of 5% the electricity production costs of hydropower range between 68 and 110 €/MWhel. All typologies of hydro power plants are mature technologies with little potential for cost reduction.

For wind power plants only a marginal production cost has been evaluated, although the investment cost for offshore turbines is considerably higher. Thanks the more stable wind conditions and higher availability (4044 h/a) of the offshore plant have nearly the same costs. Considering the private costs of wind power plants in 2030, there are nearly no cost differences in comparison to 2008. The current private costs of wind energy will decrease by onshore plants from 55 to 53 €/MWhel and for offshore plants from 57 to 51 €/MWhel (incl. back-up, min). In 2008, solar generated electricity

production costs are absolutely uncompetitive with other renewable technologies or fossil and nuclear generated technologies. At a discount rate of 5%, the cost of PV decreases of about a factor two from 2030 to 2008. But for solar plants the installation site will remain the crucial factor of the private costs, and thus the costs will stay at a high level, also after 2030. In general, solar power roof systems are more expensive than open space systems. For roof systems of solar energy the private costs will remain at over 200 €/MWhel.

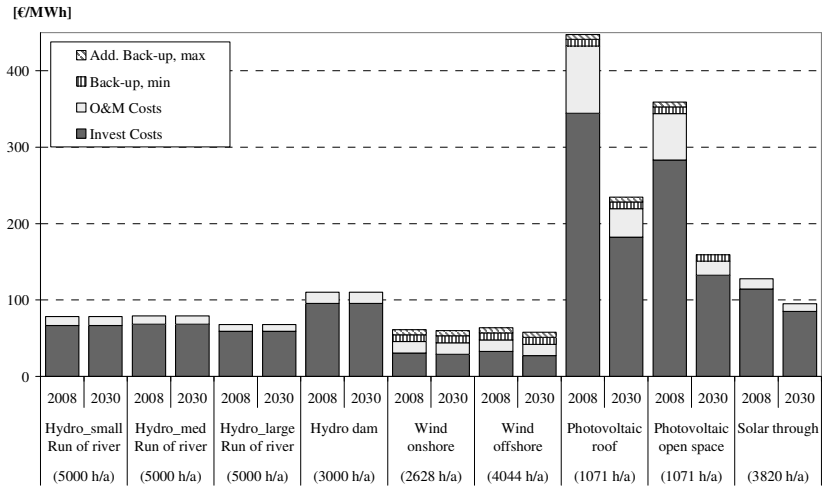


Figure 3.8 Development of the private cost development of renewable energy sources by 5% discount rate

3.6 CONCLUSIONS

Summarising the calculation results for the various electricity generation technologies, regarding the capital, fuel, operating and maintenance cost as well as the CO_2 cost for transport and storage, we observe that the conventional power plants are projected to have economic advantages compared to technologies using renewable energy sources. The assumed input data for capital cost, O&M costs, efficiencies, technical availability and lifetime of the power generation systems are based on actual estimations of power plant manufactures, power plant operators and scientists. Comparisons of average levelised lifetime costs of electricity are drawn for

the years 2008, 2020 and 2030. For CO_2 transport and storage two different costs were assumed (3 €/t CO_2 and 15 €/t CO_2) and for all technologies detailed and characteristic sensitivity analysis were performed.

The lowest private costs of generating electricity from the traditional main generating technologies (nuclear, hard coal, lignite and hydro) are within the range of 25 to 45 €/MWhel. The private costs for renewable energy sources stays on a high level up to 2030. At a discount rate of 5% the costs for generating electricity with renewable energies are about 52 €/MWhel for wind turbines and between 230 - 330 €/MWhel for PV systems. Combined Heat and Power plants are already today very competitive with private costs from 40 to 60 €/MWhel. In comparison to the conventional fossil power plants the generation costs of CCS-power plants, which are currently in the development status, will be significant higher due the greater capital and operating costs and the lower efficiency. In 2030 the levelised lifetime costs of CCS-plants are about 25 % higher, but with an increasing CO_2-value the CCS plants could be more competitive than the traditional plants.

The choice of the discount rates of 5 and 10% reflects an assessment of power generation investment strategies.

Within this framework and limitations, this chapter suggests that none of the traditional electricity technologies can be expected to be the cheapest in all situations. Also, the chosen generating technology will depend on the specific circumstances of each project.

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4 Social costs of electricity in EU

Roberto Porchia

4.1 METHODOLOGY AND DATA DESCRIPTION

This chapter provides new estimates on social costs of electricity generation in Europe. Results are obtained by summing external costs due to impacts on human health, environment, crops, materials and to climate change impacts, to private generation costs. This exercise results in levelised and homogenous values for all EU27 countries. Data are levelised since European average values for private costs, emissions inventory and external cost of greenhouse gases and heavy metals are considered. Data are homogeneous since the same set of technologies, which includes nuclear and fossil fired power plants, renewables and combined heat and power plants, is considered for the whole analysis. Results are provided for present (period 2005-2010), 2020 and 2030.[17]

Private costs included in social costs

To calculate social costs private costs calculated with the *Average Levelised Generating Costs* (ALLGC) methodology described in Chapter 3 are used. The methodology calculates the generation costs (in EuroCents/kWh) on the basis of net power supplied to the station busbar, where electricity is fed to the grid. This cost estimation methodology discounts the time series of expenditures to their present values in 2005, which is the specified base year, by applying a discount rate. According to the methodology used in the IEA study in 2005[18], the levelised lifetime cost per kWh of electricity generated is the ratio of total lifetime expenses versus total expected outputs, expressed in terms of present value equivalent. The total lifetime expenses include the value of the capital, fuel expenses and operation and maintenance expenses, inclusive the rate of return equal to discount rate.

To make private costs comparable across technologies some adjustments at the average lifetime levelised generating cost (ALLGC) are introduced for Combined Heat and Power plants and for wind and solar technologies. The ALLGC for combined heat and power plants (CHP) does not take into account the fact that the plant is used also to produce heat, in addition to

electricity. The value of heat recovery can be measured by the cost avoided in using recovered thermal energy for a specific purpose, as opposed to using another source of energy. The value of recovered thermal energy is equivalent to the cost of fuel energy that would have otherwise been consumed, which is referred to as an energy credit or fuel credit. A gas boiler, with an efficiency of 90 percent, gives the alternative heat generation technology in this report. Then in the computation of Full Cost the fuel credit is subtracted from the ALLGC.

An adjustment of the ALLGC should be made also for wind and solar technologies. A back-up technology is necessary for compensating the fluctuations in despachable electricity caused by producing electric power with wind and solar plants, which are intermittent energy sources,. The back-up cost of uncertain generating power of solar and wind plants is calculated with the equation estimated by Friedrich in 1989[19]. In this equation, the provision of the back-up power is reduced by a capacity factor (P) for the renewable technologies. In the calculation of Full Costs the ALLGC is summed to the back up cost of a gas-fired CCGT plant for maximum back-up costs.

The methodology proposed above determines for each technology a private cost of electricity production levelised for all Europe. To reach the objective of comparability, country-specific cost components are not considered. In particular the estimation is not influenced by the capital market's differences across Europe since overnight investments costs are considered. In addition, all costs are considered net of taxes, which change from country to country. This assumption is consistent with the objective to assess Full Costs from the policymaker point of view, to provide a full production cost scenario. Moreover, for the purpose of comparison, additional plant specific costs – environmental taxes on fuels, carbon emission charges, system integration costs, etc. – are not included in the private cost of generating electricity.

The costs are determined for new plants built respectively in 2007, 2020 and 2030. The values estimated for 2007 are used for the period 2005-2010; this approximation is acceptable by considering the homogeneity of the European electricity scenario in these five years. To assess Full Costs of electricity production, a discount rate of 5 percent is considered. The basis year for the analysis is 2005.

External costs included in social costs

External cost of electricity generation (in EuroCents/kWh) are calculated by multiplying the average height of release values of unit of emission for classical air pollutants (2000 Eurocent/kg) times the quantity of emission for unit of electricity generated (kg/kWh).

Marginal external costs of emissions

Marginal external costs for classical air pollutants are calculated with the methodology described in Chapter 1. The impact categories which are addressed using the ExternE methodology and that are analyzed in the Full Costs assessment are the environmental impacts, the damage to materials and the global warming impact.

The costs of emission are calculated with respect to the impact of pollutants on human health, crops, damage to materials, and loss of biodiversity caused by acidification and eutrophication. For all these categories of impact the principal air pollutants, formaldehyde and a set of heavy metals are considered. [20]

The values estimated for conventional air pollutants correspond to an average (stack) height of release for all sectors. However for technologies characterised by a large combustion plant with a high stack, a more sophisticated attribution of emissions would be desirable. As a first step, at least the emissions due to operation (mainly burning fuel) have to be attributed to high stack values, instead of average height of release.

The impact on health and environment is assessed also for a set of radionuclides[21].

An important component of the total external cost of electricity production is the cost of green house gases. To calculate the Full Cost of electricity generation the marginal abatement costs to reach the Kyoto objectives are used. The results are obtained by interpooling 26 models "observations" of MACs (marginal abatement cost) for different future years, 61 observations for the years 2000, 2025 and 2050. The abatement cost for unit of emission is calculated for CO_2, CH_4 and N_2O. Since data are not site specific, the same value for all EU-27 countries is used.

EcoSense calculates all types of external costs in Euro 2000. Then these values are actualised to 2005 by using the average EU Harmonised Indices of Consumer Prices (HICPs)[22]. Hence the external costs used to calculate Full Costs are homogeneous with the private costs, which are calculated in Euro 2005. All results reflect the Willingness To Pay in the year of release, (respectively 2010, 2020 and 2030).[23]

Life cycle inventory – emissions for electricity generation

To calculate the external cost of each kWh of electricity produced, the marginal value for unit of emission is multiplied by the quantity of pollutants emitted at each production stage per unit of electricity. The methodology adopted to estimate the emissions of pollutants for energy generation subdivides the process of electricity generation into four sub-processes representing the life cycle stages:

1. power plant construction,
2. fuel supply,
3. power plant operation,
4. power plant dismantling.

Starting from a detailed process chain analysis, which for most technologies was specified down to the individual power plant components and their performance, the material and energy demand as well as the waste and the release of emissions were identified and quantified. These results for the individual processes refer to the functional unit of one kilowatt hour (1 kWh) of generated net electricity (i.e. electricity, which is supplied to the grid) and summed up along the process chain.

The LCI data analysis covers transport and construction services and the supply of materials. All direct and indirect emissions of the manufacturing and transportation of materials for the power plant construction are relevant. In addition, since during construction phase there is heat demand for several construction processes and before commissioning of fossil power plants, there are test runs of turbines, which go without generation of electricity, the also the heat and the energy demand for construction are taken in to account. Along the life cycle all wastes of the power plant operation as well as the material-specific final end-of-life treatment at the power plant dismantling are balanced. Emissions caused by disposal of operational wastes are included in the process of power plant operation. While disposal of wastes at the end of the technical life time of the power plant are assigned to the process of power plant dismantling.

To ensure homogeneity of cost components the assumption on technology technical life time, installed capacity, power efficiency etc., which are used for estimate the emissions database, are the same used for estimate private costs of electricity and power generation.

External costs not included in the analysis

The methodology adopted to calculate the Full Cost of electricity production includes the damage costs of emissions of pollutants into air, soil and water. This methodology allows to include a wide set of external costs in the analysis and ensure the use of homogeneous and widely approved estimates, however some relevant components of the total external cost are excluded.

These ”other costs” are particularly relevant for nuclear. In the assessment of the nuclear fuel cycle one of the most contentious issues has been the valuation of serious nuclear accidents and the assessment of the risk of nuclear weapons proliferation. The “ExternE Methodology report”[24] indicates that in monetary terms the damage cost of a nuclear accident could amount to billions of Euro. However, even if there is a high level of public concern about the possibility of such an accident, the experts assign very low probability of the kind of failure that would produce a severe accident for the type of reactors used in Western Europe. Then the very low probability that the accident occurs will translate billions of Euro of possible damage costs into thousands of Euro of *expected* damage costs. Despite their theoretical relevance these types of external costs are not included in the Full Costs calculation because the statistically small number of accidents made it

difficult to elaborate models to calculate a homogeneous set of estimate for Europe to 2030.

Additional external costs not assessed in this book but analysed by the CASES project are the cost of acidification of the aquatic environment and the cost visual intrusion[25]. With respect to the monetary estimates of acidification, the costs of the impact of pollution on freshwater fish populations are not included because there is large uncertainty in the estimated values. The uncertainty is derived from the calculation of impacts and from the economic valuation procedure. Also the costs of visual intrusion are excluded from the set of external costs analysed in the Full Costs assessment. These costs are assessed by evaluating the aesthetic effects of wind parks, hydroelectric dams and power transmission lines; however only few studies are available on this topic and a consistent set of estimates is not available for all Europe.

As a separate set of external costs, not included in the social costs assessment, there are the energy supply externalities as are described in Chapter 2.

4.2 RESULTS ON EUROPEAN SOCIAL COSTS OF ELECTRICITY GENERATION

Table 4.1lists the technologies for electricity production which are assessed in this report. The set of technologies includes nuclear, fossil fired

	2005-2010				2020				2030			
	#	costs			#	costs			#	costs		
		priv	ext	full		priv	ext	full		priv	ext	full
biomass (woodchips) CHP with an extraction condensing turbine	1	1,13	0,65	1,79	1	0,98	0,82	1,80	1	0,98	0,99	1,97
nuclear power plant	2	3,10	0,21	3,32	2	2,62	0,14	2,76	2	2,28	0,11	2,40
hard coal CHP with backpressure turbine	3	0,89	2,99	3,88	4	0,91	3,28	4,19	7	1,04	4,21	5,25
hard coal CHP with extraction condensing turbine without CO2 capture	4	1,31	2,76	4,07	6	1,34	2,98	4,31	6	1,39	3,82	5,21
hard coal CHP with extraction condensing turbine with CO2 capture	5	1,31	2,76	4,07	5	3,12	1,13	4,26	4	3,09	1,40	4,48
biomass (straw) CHP with an extraction condensing turbine	6	2,02	2,02	4,61	7	2,18	2,19	4,37	5	2,18	2,62	4,80
lignite IGCC with CO2 capture	7	3,00	2,38	5,38	3	3,39	0,76	4,15	3	3,34	0,94	4,28
lignite IGCC without CO2 capture	8	3,00	2,38	5,38	8	2,83	2,13	4,96	8	2,77	2,91	5,68
natural gas CHP with extraction condensing turbine with CO2 capture	9	4,12	1,28	5,39	20	6,37	0,85	7,22	20	6,32	1,04	7,36
natural gas CHP with extraction condensing turbine without CO2 capture	10	4,12	1,28	5,39	11	4,37	1,35	5,72	13	4,40	1,77	6,17
lignite condensing power plant	11	2,68	2,97	5,65	9	2,18	2,97	5,15	12	2,14	3,94	6,07
natural gas combined cycle CHP with backpressure turbine	12	4,31	1,39	5,71	12	4,27	1,57	5,83	14	4,24	2,06	6,31
natural gas combined cycle with CO2 capture	13	4,81	1,39	6,20	19	5,98	0,92	6,90	18	5,91	1,12	7,03
natural gas combined cycle without CO2 capture	14	4,81	1,39	6,20	14	4,58	1,45	6,04	15	4,54	1,90	6,43
wind, on-shore	15	6,11	0,10	6,21	15	6,02	0,07	6,09	11	5,96	0,07	6,03
wind, off-shore	16	6,36	0,09	6,46	16	6,14	0,07	6,21	9	5,81	0,07	5,88
hard coal condensing power plant	17	3,33	3,14	6,47	17	3,23	3,30	6,52	19	3,16	4,14	7,30
hard coal IGCC with CO2 capture	18	3,91	2,70	6,61	10	4,20	1,47	5,66	10	4,16	1,79	5,95
hard coal IGCC without CO2 capture	19	3,91	2,70	6,61	13	3,54	2,48	6,03	16	3,50	3,27	6,77
hydropower, run of river >100MW	20	6,81	0,04	6,85	18	6,80	0,05	6,85	17	6,80	0,06	6,86
hydropower, run of river 10MW	21	7,83	0,06	7,90	21	7,83	0,07	7,91	21	7,83	0,09	7,92
hydropower, run of river <100MW	22	7,93	0,04	7,98	22	7,93	0,05	7,99	22	7,93	0,06	8,00
natural gas, gas turbine	23	6,58	2,08	8,66	23	6,60	2,29	8,89	24	6,53	2,95	9,48
heavy oil condensing power plant	24	6,57	2,40	8,96	24	7,19	3,00	10,2	28	7,46	3,64	11,1
hydropower, pump storage	25	11,0	0,06	11,1	26	11,0	0,07	11,1	29	11,0	0,09	11,1
hydropower, dam (reservoir)	26	11,0	0,08	11,1	27	11,0	0,09	11,1	30	11,0	0,11	11,1
light oil gas turbine	27	9,87	2,47	12,3	29	10,1	2,93	13,0	31	10,3	3,68	14,0
solar thermal, parabolic trough	28	12,8	0,12	12,9	25	10,3	0,11	10,4	25	9,5	0,11	9,61
MCFC (biogas)	29	31,9	3,33	35,3	31	13,2	4,03	17,3	27	6,4	4,39	10,7
MCFC (natural gas)	30	33,5	2,00	35,5	30	13,3	2,43	15,8	26	7,3	2,65	9,91
solar PV, open space	31	35,9	0,89	36,8	32	20,8	0,82	21,6	32	16,6	0,93	17,5
solar PV, roof	32	44,8	0,87	45,6	33	25,1	0,80	25,9	33	23,5	0,91	24,4
SOFC (natural gas)	33	46,8	0,94	47,7	28	11,6	0,99	12,5	23	7,02	1,23	8,25

technologies, renewables and combined heat and power plants. For fossil fired and for some CHP technologies the same technology is assessed with and without CO_2 capture and storage; this distinction is available only projections to 2020 and 2030. For the period 2005-2010 the same levelised values are reported for technologies with and without CO_2 storage.

In

Table 4.1, technologies are ordered from the cheapest to the most expensive with in terms of social cost of electricity generation and expressed

	2005-2010				2020				2030			
	#	costs			#	costs			#	costs		
		priv	ext	full		priv	ext	full		priv	ext	full
biomass (woodchips) CHP with an extraction condensing turbine	1	1,13	0,65	1,79	1	0,98	0,82	1,80	1	0,98	0,99	1,97
nuclear power plant	2	3,10	0,21	3,32	2	2,62	0,14	2,76	2	2,28	0,11	2,40
hard coal CHP with backpressure turbine	3	0,89	2,99	3,88	4	0,91	3,28	4,19	7	1,04	4,21	5,25
hard coal CHP with extraction condensing turbine without CO2 capture	4	1,31	2,76	4,07	6	1,34	2,98	4,31	6	1,39	3,82	5,21
hard coal CHP with extraction condensing turbine with CO2 capture	5	1,31	2,76	4,07	5	3,12	1,13	4,26	4	3,09	1,40	4,48
biomass (straw) CHP with an extraction condensing turbine	6	2,02	2,02	4,61	7	2,18	2,19	4,37	5	2,18	2,62	4,80
lignite IGCC with CO2 capture	7	3,00	2,38	5,38	3	3,39	0,76	4,15	3	3,34	0,94	4,28
lignite IGCC without CO2 capture	8	3,00	2,38	5,38	8	2,83	2,13	4,96	8	2,77	2,91	5,68
natural gas CHP with extraction condensing turbine with CO2 capture	9	4,12	1,28	5,39	20	6,37	0,85	7,22	20	6,32	1,04	7,36
natural gas CHP with extraction condensing turbine without CO2 capture	10	4,12	1,28	5,39	11	4,37	1,35	5,72	13	4,40	1,77	6,17
lignite condensing power plant	11	2,68	2,97	5,65	9	2,18	2,97	5,15	12	2,14	3,94	6,07
natural gas combined cycle CHP with backpressure turbine	12	4,31	1,39	5,71	12	4,27	1,57	5,83	14	4,24	2,06	6,31
natural gas combined cycle with CO2 capture	13	4,81	1,39	6,20	19	5,98	0,92	6,90	18	5,91	1,12	7,03
natural gas combined cycle without CO2 capture	14	4,81	1,39	6,20	14	4,58	1,45	6,04	15	4,54	1,90	6,43
wind, on-shore	15	6,11	0,10	6,21	15	6,02	0,07	6,09	11	5,96	0,07	6,03
wind, off-shore	16	6,36	0,09	6,46	16	6,14	0,07	6,21	9	5,81	0,07	5,88
hard coal condensing power plant	17	3,33	3,14	6,47	17	3,23	3,30	6,52	19	3,16	4,14	7,30
hard coal IGCC with CO2 capture	18	3,91	2,70	6,61	10	4,20	1,47	5,66	10	4,16	1,79	5,95
hard coal IGCC without CO2 capture	19	3,91	2,70	6,61	13	3,54	2,48	6,03	16	3,50	3,27	6,77
hydropower, run of river >100MW	20	6,81	0,04	6,85	18	6,80	0,05	6,85	17	6,80	0,06	6,86
hydropower, run of river 10MW	21	7,83	0,06	7,90	21	7,83	0,07	7,91	21	7,83	0,09	7,92
hydropower, run of river <100MW	22	7,93	0,04	7,98	22	7,93	0,05	7,99	22	7,93	0,06	8,00
natural gas, gas turbine	23	6,58	2,08	8,66	23	6,60	2,29	8,89	24	6,53	2,95	9,48
heavy oil condensing power plant	24	6,57	2,40	8,96	24	7,19	3,00	10,2	28	7,46	3,64	11,1
hydropower, pump storage	25	11,0	0,06	11,1	26	11,0	0,07	11,1	29	11,0	0,09	11,1
hydropower, dam (reservoir)	26	11,0	0,08	11,1	27	11,0	0,09	11,1	30	11,0	0,11	11,1
light oil gas turbine	27	9,87	2,47	12,3	29	10,1	2,93	13,0	31	10,3	3,68	14,0
solar thermal, parabolic trough	28	12,8	0,12	12,9	25	10,3	0,11	10,4	25	9,5	0,11	9,61
MCFC (biogas)	29	31,9	3,33	35,3	31	13,2	4,03	17,3	27	6,4	4,39	10,7
MCFC (natural gas)	30	33,5	2,00	35,5	30	13,3	2,43	15,8	26	7,3	2,65	9,91
solar PV, open space	31	35,9	0,89	36,8	32	20,8	0,82	21,6	32	16,6	0,93	17,5
solar PV, roof	32	44,8	0,87	45,6	33	25,1	0,80	25,9	33	23,5	0,91	24,4
SOFC (natural gas)	33	46,8	0,94	47,7	28	11,6	0,99	12,5	23	7,02	1,23	8,25

in Euro cents per units of electricity production (kWh). Social costs are calculated by adding all external costs to the private cost of production. In the columns the values and the ranks for current values and projections to 2020 and 2030 are reported.

At present, the cheapest technology, after the internalization of external costs, is biomass (woodchips) CHP with an extraction condensing turbine. Other currently "cheap" technologies are nuclear (European pressurized reactor) [26] and hard coal CHP with backpressure turbine. But with respect to the low value of nuclear Full Cost should be stressed that some nuclear specific external costs (eg the cost of a nuclear accident or the risk of nuclear proliferation) are not considered in this analysis. Photovoltaic technologies are the most expensive technologies even if the share of external cost is very small, however a strong decreasing in private cost is foreseen for the next 20 years. For the next 20 years a good performance of Full Cost reduction is foreseen also for fuel cells technologies and for hydroelectric (run of river hydropower, less than 100MW).

The high value of Full Costs for solar technologies is partly explained by the assumption of European average values for the Life Cycle Analysis. However the country-specific cost per kWh should be much lower than the average in the Mediterranean area, because it is higher the quantity of electricity which is produced.

In addition Table 4.1 shows that, if Full Costs instead of private costs are considered, then the most viable renewables technologies (hydropower and wind) will be cheaper than almost all classical fossil fired technologies. These sets of technologies are fully comparable since back-up costs, calculated for a fired CCGT plant as back-up technology, are added to generation costs for wind and solar, which are intermittent renewables energies.

In Figure 4.1, Figure 4.2 and Figure 4.3 the average European values are reported for the period 2005-2010, for 2020 and for 2030. External costs, private cost and Full Costs are reported for each technology. External costs are composed by human-health-related external costs (excluding those caused by radionuclides), environmental (i.e., not related to human health) external costs, radionuclides damage costs and marginal abatement cost of greenhouse gas emissions. The figures show the incidence, in percentage terms, of each cost component on the total value, and the increasing or decreasing of each value from present to 2030.

Table 4.1 Technologies ranked for full cost (EuroCents2005/kWh) in 2005-2010, in 2020 and in 2030.

	2005-2010				2020				2030			
	#	costs			#	costs			#	costs		
		priv	ext	full		priv	ext	full		priv	ext	full
biomass (woodchips) CHP with an extraction condensing turbine	1	1,13	0,65	1,79	1	0,98	0,82	1,80	1	0,98	0,99	1,97
nuclear power plant	2	3,10	0,21	3,32	2	2,62	0,14	2,76	2	2,28	0,11	2,40
hard coal CHP with backpressure turbine	3	0,89	2,99	3,88	4	0,91	3,28	4,19	7	1,04	4,21	5,25
hard coal CHP with extraction condensing turbine without CO2 capture	4	1,31	2,76	4,07	6	1,34	2,98	4,31	6	1,39	3,82	5,21
hard coal CHP with extraction condensing turbine with CO2 capture	5	1,31	2,76	4,07	5	3,12	1,13	4,26	4	3,09	1,40	4,48
biomass (straw) CHP with an extraction condensing turbine	6	2,02	2,02	4,61	7	2,18	2,19	4,37	5	2,18	2,62	4,80
lignite IGCC with CO2 capture	7	3,00	2,38	5,38	3	3,39	0,76	4,15	3	3,34	0,94	4,28
lignite IGCC without CO2 capture	8	3,00	2,38	5,38	8	2,83	2,13	4,96	8	2,77	2,91	5,68
natural gas CHP with extraction condensing turbine with CO2 capture	9	4,12	1,28	5,39	20	6,37	0,85	7,22	20	6,32	1,04	7,36
natural gas CHP with extraction condensing turbine without CO2 capture	10	4,12	1,28	5,39	11	4,37	1,35	5,72	13	4,40	1,77	6,17
lignite condensing power plant	11	2,68	2,97	5,65	9	2,18	2,97	5,15	12	2,14	3,94	6,07
natural gas combined cycle CHP with backpressure turbine	12	4,31	1,39	5,71	12	4,27	1,57	5,83	14	4,24	2,06	6,31
natural gas combined cycle with CO2 capture	13	4,81	1,39	6,20	19	5,98	0,92	6,90	18	5,91	1,12	7,03
natural gas combined cycle without CO2 capture	14	4,81	1,39	6,20	14	4,58	1,45	6,04	15	4,54	1,90	6,43
wind, on-shore	15	6,11	0,10	6,21	15	6,02	0,07	6,09	11	5,96	0,07	6,03
wind, off-shore	16	6,36	0,09	6,46	16	6,14	0,07	6,21	9	5,81	0,07	5,88
hard coal condensing power plant	17	3,33	3,14	6,47	17	3,23	3,30	6,52	19	3,16	4,14	7,30
hard coal IGCC with CO2 capture	18	3,91	2,70	6,61	10	4,20	1,47	5,66	10	4,16	1,79	5,95
hard coal IGCC without CO2 capture	19	3,91	2,70	6,61	13	3,54	2,48	6,03	16	3,50	3,27	6,77
hydropower, run of river >100MW	20	6,81	0,04	6,85	18	6,80	0,05	6,85	17	6,80	0,06	6,86
hydropower, run of river 10MW	21	7,83	0,06	7,90	21	7,83	0,07	7,91	21	7,83	0,09	7,92
hydropower, run of river <100MW	22	7,93	0,04	7,98	22	7,93	0,05	7,99	22	7,93	0,06	8,00
natural gas, gas turbine	23	6,58	2,08	8,66	23	6,60	2,29	8,89	24	6,53	2,95	9,48
heavy oil condensing power plant	24	6,57	2,40	8,96	24	7,19	3,00	10,2	28	7,46	3,64	11,1
hydropower, pump storage	25	11,0	0,06	11,1	26	11,0	0,07	11,1	29	11,0	0,09	11,1
hydropower, dam (reservoir)	26	11,0	0,08	11,1	27	11,0	0,09	11,1	30	11,0	0,11	11,1
light oil gas turbine	27	9,87	2,47	12,3	29	10,1	2,93	13,0	31	10,3	3,68	14,0
solar thermal, parabolic trough	28	12,8	0,12	12,9	25	10,3	0,11	10,4	25	9,5	0,11	9,61
MCFC (biogas)	29	31,9	3,33	35,3	31	13,2	4,03	17,3	27	6,4	4,39	10,7
MCFC (natural gas)	30	33,5	2,00	35,5	30	13,3	2,43	15,8	26	7,3	2,65	9,91
solar PV, open space	31	35,9	0,89	36,8	32	20,8	0,82	21,6	32	16,6	0,93	17,5
solar PV, roof	32	44,8	0,87	45,6	33	25,1	0,80	25,9	33	23,5	0,91	24,4
SOFC (natural gas)	33	46,8	0,94	47,7	28	11,6	0,99	12,5	23	7,02	1,23	8,25

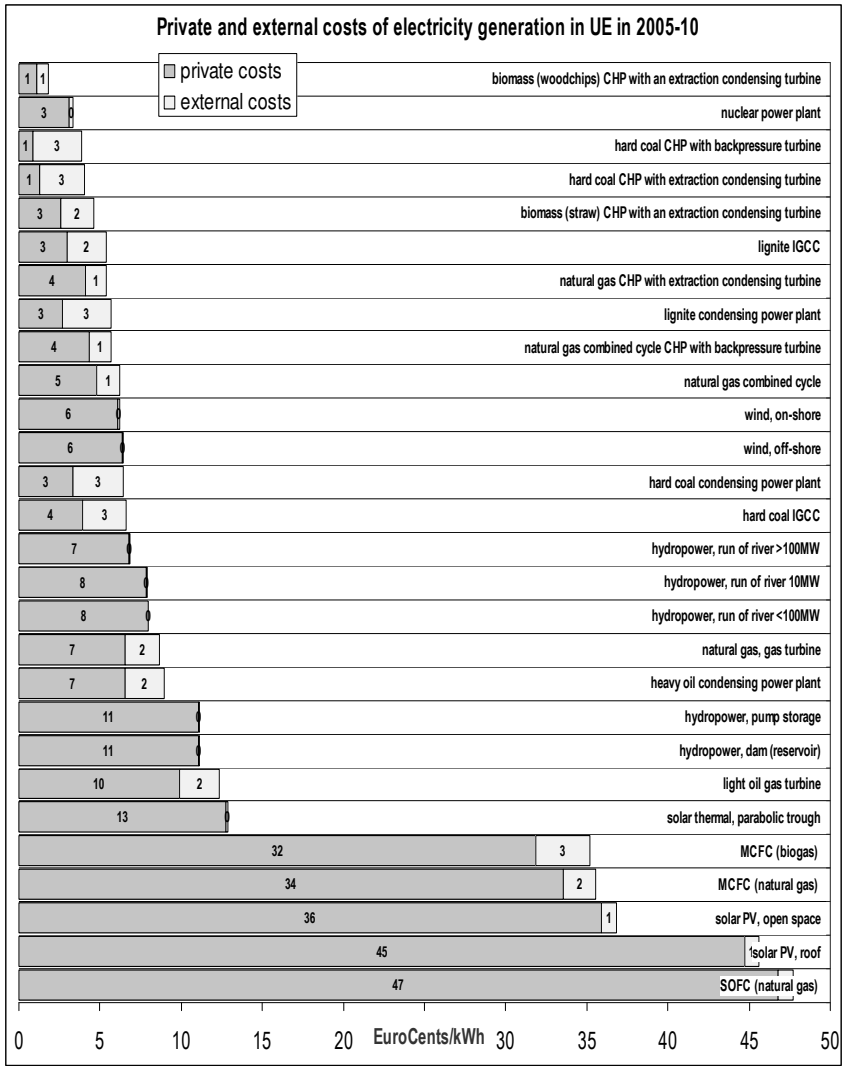


Figure 4.1 Rank of technologies depending on social cost composition for electricity production in 2005-2010

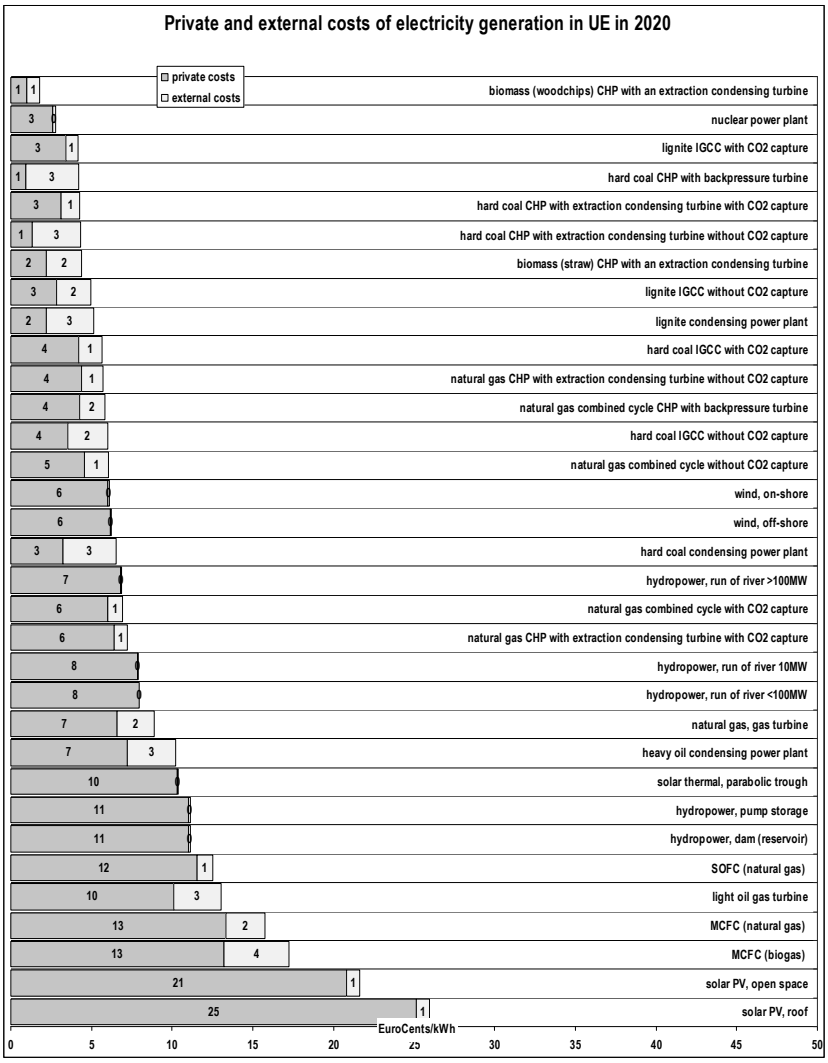


Figure 4.2 Rank of technologies depending on social cost composition for electricity production in 2020

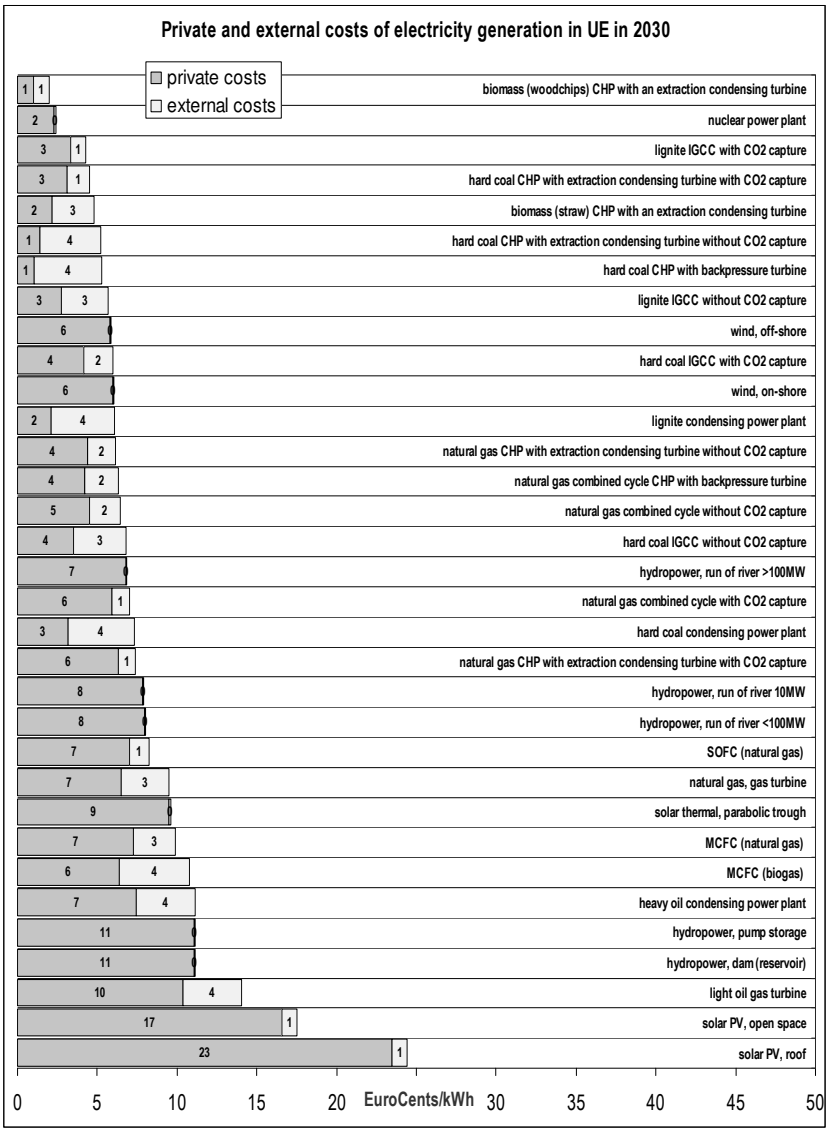


Figure 4.3 Rank of technologies depending on social cost composition for electricity production in 2030

4.3 TECHNOLOGICAL COMPARISON AND TRENDS

Full Costs assessment for the period 2005-2010

The results obtained for social costs confirm the general opinion that external costs have a strong impact on Full Costs for fossil fuel thermal power plants. At present the share of external costs for hard coal and lignite is around 50 percent, and this is caused principally by an important negative impact on climate change, since abatement costs of green house gases are between the 60 and the 80 percent of total external cost. This means that if external cost had to be internalized, then the market price of electricity generated by classical fossil technologies should be doubled.

The share of external costs on total is between 20 and 25 percent for oil and gas thermal plants and for gas combined heath and power plants. For these technologies the high price of fuel has an high incidence on private costs. The main components of external cost are related to human health for oil power plants, while they are related to climate change for gas power plants and CHPs.

Data also confirms that renewables are "clean" technologies, since the share of external costs is around 1 or 2 percent of Full Cost. For renewables external costs are related for 2/3 to human health and for 1/3 to climate change. For hydro and wind, external costs are mainly caused by emissions generated during dismantling of the plants; for solar technologies, external costs are generated mainly during the construction of the plant.

The share of external costs is very high for coal combined heat and power technologies; it reaches the 70 percent of Full Costs. If only private costs were considered, the cheapest technologies would be hard coal combined heat and power technologies with backpressure turbine.

In the set of CHP technologies, the lowest share of external cost, less than 10 percent of Full Cost, is reported for fuel cells. The external costs for fuel cells are low not only as percentage, compared to the high values of private costs for these technologies, but also in absolute terms. The amount of external costs for Solid Oxide Fuel Cell at natural gas is lower than the external costs of other CHP technologies.

Full Costs assessment from 2010 to 2030

For the majority of the technologies, the share of external cost on full generation cost is foreseen to increase in the next 20 years.

The trend of Full Costs is given by an increasing of the willingness to pay from present to 2030, raising the damage cost of each unit of emission, and by the emissions per kWh, which are foreseen to shrink due to technological

improvements.

The current low level of external cost reported for renewables will remain almost constant for the next 20 years. A different trend is reported for solar thermal technology, for which a constant high reduction of costs is registered for the whole period for all private and external costs components.

A different evolution is foreseen for private costs, which are strongly conditioned by the trend of the international fuel prices, and by the introduction of new, cheaper technologies. Fuel costs increases for gas and oil and causes private costs to increase for the technologies using these fuels, although this is partially compensated by a decrease in investment costs. The investment costs are generally constant or deceasing from present to 2030. Solar technologies display the most substantial decrease in private costs. According to the available forecasts, higher R&D activities will reduce significantly the production costs, generating 1 kWh of electricity with solar PV will cost in 2030 only 30 percent of the present cost.

Data show a strong increasing of private price for thermal technologies coupled with CO_2 sequestration. Since for 2005 no distinction is made between plants without and with CO_2 capture, while distinction is made for 2020 and 2030, hence the greater cost is given by the investment cost for the CO_2 capture technology. Analogously, results show a consistent reduction in external costs, in particular for the marginal abatement cost of GHGs. On average the investments costs observed in 2005 are lower than the real cost which should be observed if carbon sequestration would be assessed. However for these technologies, the increase of investment cost is widely compensated by a reduction in external costs. Data show that from 2005 (without considering CO_2 sequestration) to 2020 (with CO_2 sequestration assessment), the Full Cost of electricity generation will decrease for almost all types of power plants.

Moving the time horizon from present to 2030 yields no differences in the ranking of traditional technologies; however the table shows that the price of production will decrease for renewables technologies and a strong price reduction is observable for fuel cells technologies.

4.4 CONCLUSIONS

This chapter provided estimates, updated to 2007, of the Full Costs of electricity generation in Europe. The results are obtained for present, for 2020 and for 2030 by summing external costs on human health, environment, materials and climate change to private generation costs. Full Costs were calculated and assessed for a wide set of technologies, which includes nuclear

and fossil fired power plants, renewables and combined heat and power plants. Full Costs are assessed as average values of all EU-27 countries.

Results indicate that, in 2005-2010, the least expensive technology is biomass (woodchips) CHP with an extraction condensing turbine with a European average Full Cost of 1.79 Eurocents per kWh. This technology is followed by nuclear (European pressurized reactor) and hard coal CHP with a Full Cost of 3.32 and 4.07 Eurocents per kWh. This rank will not change significantly in the next years. Also for 2020 and 2030 it is foreseen that the least expensive technology will be woodchips CHP with a price of 1.80 and 1.97 Eurocents per kWh.

The most expensive technologies are natural gas fuel cells and solar photovoltaic, which have a full generation costs from 35 up to 48 Ec/kWh in 2005-2010. However a strong reduction of generation costs is foreseen in the next 20 years for these technologies thanks to investments in technological improvement.

Results show that hard coal combined heath and power generation has the highest share of external costs on Full Costs, presenting for 2005-2010 85 percent of Full Cost. High incidence of external costs on Full Costs, around 50 percent, is obtained also for coal and lignite thermal power plants.

Solar photovoltaic and solar thermal technologies display the lowest incidence of external costs on total costs (in the order of 1 percent only).

In the analysis performed, private and external costs are assessed for the whole life cycle of the power plant, from construction to dismantling, including cost of extraction and transportation of fuel and waste disposal. Private costs and quantity of pollutants emitted, which are plant specific, are calculated for new power plants build in 2005-2010, in 2020 and 2030, hence old power plants, still existing are excluded from the analysis. All costs are expressed in Euro 2005.

Some limits to the analysis are due to the exclusion from the assessment of probabilistic external costs, e.g. external cost of nuclear accident. These external costs may have a very high cost but are usually associated to a very low probability of occurrence. Moreover, for combined heat and power (CHP) heath credits have been subtracted to the private costs, to analyse the share of cost relative to power generation, excluding the share relative to heat generation, while all external cost are attributed to power generation; thus external costs for CHP are overestimated.

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5 Methodology and Results in non-EU Countries

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5.1 SOCIAL COSTS ASSESSMENT IN NON-EU COUNTRIES

Background

This chapter is aimed at understanding the social costs of various fuel cycles for electricity generation in four non-EU countries. It has two main objectives, namely: (1) to develop a methodological framework that can be used to calculate the external costs of energy fuel cycles in Brazil, China, India and Turkey; and (2) to undertake studies of at least two national fuel cycles in each of these countries. The results should generate new insights into the external costs of fuel cycles in EU compared with cost levels in non-EU countries.

For application in non-EU countries, we developed a simplified methodological framework that can be used to transform scenario- and model-based cost data into the database system that have been developed in the ExterneE project. This framework allows cost data generated by the participating non-EU countries to be compared with the cost of fuels cycles in the EU.

This chapter is based on the seven research reports written on this subject within the CASES project, including:

- a methodology report;
- five national reports on external costs of fuels cycles in the participating non-EU countries; and
- a report on the comparative assessment of fuel cycle costs and methodological challenges across the participating countries.

The national case studies are mainly based on results of existing research in the four participating countries. In the EU, there has been long-term government support to such kinds of studies and the ExternE project lasted 15 years and involved more than 20 European research institutes. Hence, the research is much better established and the methodologies are better coordinated. In non-EU countries, the studies are much less systematic and

the existing case studies are often based on different models and approaches. It was therefore decided to simplify the ExternE methodologies for easier application by the country teams and the methodology report has been prepared for linking the ExternE framework and the different energy and environment impact models applied in the four countries.

The four countries included in this Chapter, Brazil, China, India, and Turkey have very different size and energy sector characteristics. In Brazil 83 percent of its electricity comes from hydro (EIA, 2007). India and China mainly rely on coal for electricity generation and are witnessing a rapid increase in their electricity demand and associated GHG emissions and local pollution. Turkey is a big country whose electricity mainly comes from natural gas and hydro.

Measures taken to improve consistency of the country case study results

In the country reports, the external costs are expressed in different currencies. The Turkish country report only gives the physical amount of various emissions and no cost data. The other three country reports express external costs of different fuel cycles in their domestic currencies, e.g. Chinese Yuan in the Chinese country report, Rupee in the Indian Country Report and USD in the Brazil report. To improve consistency all costs have been converted to Euro using the exchange rates shown below.

1 € = 10.75 Chinese Yuan
1 € = 58.03 Indian Rupees
1 € = 1.47 US$

In the country reports, the price or unit cost of each type of emissions is set based on different criteria or reference. The CASES Project provided two options for estimating the external damage costs of GHG emissions from energy cycles: domestic estimates based on country studies and estimates obtained from the EU studies. In general we have used the domestic estimates but for some external effects, notably those arising from GHGs, we took estimates based on EU study of the external costs. This was done to increase the comparability of the different country case study results, since GHGs have global impacts and the external value should be the same independent of where the emissions take place. The values taken are from the new NEEDS study (NEEDS, 2007) and are applied for comparing all country study results. The values are shown in Table 5.1 below.

Table 5.1 The marginal costs in for greenhouse gases in the base year

GHG	CO_2	CH_4	N_2O	SF_6
Marginal Damage Cost (2005 Euro/ton)	20.66	747.29	27202.90	1290.64

Source: NEEDS, 2007.

5.2 COAL FUEL CYCLES IN CHINA, INDIA AND TURKEY

This section examines and compares the coal fuel cycle case studies performed by the country teams and compares and explains the reasons behind their differences and similarities. In this study, the coal fuel cycle is assumed to include both coal and lignite power plants. The Chinese and Indian studies focus on coal while the Turkish one focuses on lignite.

Methodology

The impacts from the coal fuel cycle considered to be most relevant are those caused by atmospheric emissions from the power generation stage on human health, materials, crops and ecosystems and global warming. In addition, impacts on occupational health should be analyzed, which are most important for underground coal mining. Discharges of effluents from mining activities might have significant impacts on groundwater systems, but these effects are very difficult to quantify. Table 5.2 below lists the methodology for assessing the external costs of the different fuel cycle stages.

Table 5.2 Methodology for Assessing the External Cost of Coal-fired Fuel Cycle

Fuel cycle stage	Impacts	Guidance on Data and Calculation
Mining	CH_4 emission Waste water Solid waste Land damage Health hazards and mortality	- Base year: 2005 - Amount of coal use for power generation in base year - Data on amount of domestically mined coal used - Coal mined * CH4 emission factor = CH4 emissions (if domestic CH4 emission factor unavailable, use IPCC 2006 default data) - Country-specific data about waste water, solid waste and land degradation generated, to produce each ton of coal. If data are not available, use EU per ton average data - Occupational health hazards and mortality during coal mining
Coal transport	Fuel consumption during transport and the related CO_2, SO_2, NO_x, and PM emissions	- Fuel consumption for coal transport: estimate total coal transport, split it into various transport modes as railway, waterway and road, based on national statistics. - Emission factors for CO_2, SO_2, NO_x, and particulates, preferably use national specific data. If unavailable, use IPCC default data or expert judgment. - Other externalities, such as solid waste generation at terminals and spillage during transport considered minor and ignored.
Coal beneficiation	Air pollution GHG emissions Wastes	- Waste water and soil pollution from country-specific values for the amount of coal benefited. - The waste water discharged into public systems without treatment. - Total power consumption for the coal beneficiation process. Use national average emission factor of electricity or other fossil fuel used to estimate total air pollutants emitted due to power or fossil fuel consumption.
Power generation/ transmission	Air pollution GHG Emissions Fly ash	- Estimate pollutant loads from power generation based on total coal consumed or directly as model output. - Fly ash released from stack should be included.
Ash disposal	Fuel consumption and the associated emissions	- Estimate total fly ash generated - Ash disposal options: slurry in large ash-ponds, use in cement production, road construction, brick making, and agriculture. Particulates dispersed during the disposal and generally ≤1%. - Fossil fuel used for ash disposal
Calculate the external costs		- Monetary value of each externality. Based on country-specific studies or data from the ExternE project or any other secondary sources. - Unit costs are deflated based on per capita GDP comparison of countries (PPP) to get a likely per unit costs of various externalities for the target country.

It can be seen that although the construction and de-commissioning of a coal-power plant consumes materials, involve transportation of concrete, steel, sand and other heavy building materials, which lead to energy consumption and various emissions, this step is not included in the methodology guidance above for the external cost assessment for these countries. Since collecting, estimating, and modelling external costs often takes time and involves labour-intensive processes, and data could not be collected in the time available it was decided to neglect some impacts and processes and focus on the priority impacts. Generally five main types of impact have been evaluated

1. The effects on recreation, cultural objects, and ecosystems.
2. The occupational health impacts.
3. Employment benefits and local economic impacts.
4. Local income effects.
5. The impacts of transmission lines on bird populations.

Since the coal fuel cycle brings about a large number of impacts, it is necessary to identify a range of priority impacts for further analysis. This is possible since some burdens/impacts are several magnitudes larger than others and the minor ones are therefore insignificant. The priority impacts are accordingly believed to make up the main externalities (Risoe DTU, 2007; EC, 2005).

The country studies have selected different fuel cycle stages and priority impacts for in-depth analysis and Table 5.3 gives an overview. The level of analysis in the country studies has been categorized into two levels, namely Quantitative (labelled "Q") and Non-Quantitative (labelled "NQ"). The impacts are considered to be analyzed quantitatively if specific damage costs have been estimated or if the data provided by the country teams is sufficiently detailed to enable the coordinating team to calculate specific damage costs. The impacts are considered to be analyzed non-quantitatively if no specific damage costs have been estimated or the data are insufficient for calculation of damage costs. Impacts that have not been considered in the country studies are marked with "-" in Table 5.3.

Table 5.3 Overview of stages and impacts analyzed for the coal fuel cycle

Fuel cycle stage	Impacts	China	India	Turkey
Facilities	Air pollution	-	-	NQ
construction/	GHG emissions	-	-	NQ
decommissioning	Occupational health	-	-	NQ
Mining	Air pollution	NQ	Q	NQ
	GHG emissions	NQ	Q	-
	Land damage	NQ	NQ	-
	Occupational health	NQ	-	NQ
	Wastes	NQ	-	-
Coal/lignite transport	Air pollution	NQ	Q	Q
	GHG emissions	NQ	Q	Q
Coal/lignite	Air pollution	-	Q	-
beneficiation	GHG emissions	-	Q	-
	Wastes	-	-	-
Power generation/	Air pollution	Q	Q	Q
transmission	GHG Emissions	Q	Q	Q
	Occupational health	-	-	NQ
	Wastes	Q	Q	NQ

The China Coal Fuel Cycle Case Study

The Chinese country team estimates the externalities of the coal fuel cycle in a cost per kWh basis. In this analysis, a power plant with a capacity of 100MW, annual plant load of 6000 hours and annual power generation of 6 billion kWh is considered. The heat value of the crude coal is 16.74 J/kg, the ash content is 15%, the efficiency of the electrostatic dust removal is 99% and the power plant efficiency is 35%. On-site electricity use amounts to 5% of the total generation.

The calculated external costs from the power generation stage are shown in the Table 5.4. The costs are calculated based on the emission rates from the power plant mentioned above. The prices used for valuating the externalities from the priority impacts are based on Chinese Pollutants Charge Standards (PCS) and US Environmental Value Standard numbers (US EVS)[27].

Table 5.4 The External Costs of Coal Combustion for Electricity, based on the Level of National Emission Charges

Pollutant	National Emission charge (RMB/kg)	Pollutants emission from coal combustion (g/kWh)	Environmental Costs (0.01 RMB/kWh)
SO_2	6.000	8.461	5.050
NO_x	8.000	3.792	3.326
CO	0.023	0.122	0.012
CO_2	1.000	816.640	1.878
Suspended particles	2.200	0.189	0.041
Powdered Coal ash	0.120	51.947	0.623
Furnace Dust	0.100	14.210	0.142
Total			11.072

Source: Jiang et al, 2007, the Chinese Coal Fuel Cycle Report under WP7.

To facilitate comparison between the country studies, the results from the Chinese cost/kWh analysis are adjusted to the CASES standard format. The damage cost of CO_2 is changed using the agreed CASES value of 20.66 €/ton. This cost can be applied to all country studies since climate change is global in nature and therefore so is the corresponding damage costs. The costs of the other priority pollutants are based on the specific Chinese values. The calculated damage costs are converted from Chinese Yuan to Euro using the conversion factor from December 2007 of 0.0930 €/Yuan. The results are shown in Table 5.5 below.

Table 5.5 Emissions and external costs of electricity for the Chinese coal fuel cycle

Unit	CO_2	SPM	SO_2	NO_x	CO	Ash	Dust	Total cost
g/kwh	816.64	0.189	8.416	3.792	0.122	51.947	14.21	
€ cent /kWh	1.69	0.004	0.47	0.309	0.001	0.058	0.013	2.54

From Table 5.5 it can be seen that the major external costs from the Chinese coal fuel cycle are caused by CO_2 emissions followed by emissions of SO_2 and NO_x. The total damage costs are calculated to be 2.54 € cent/kWh.

The Indian Coal Fuel Cycle Case Study

The Indian country study includes most major fuel cycle stages, namely, mining, coal transport, coal beneficiation and power generation/transmission. The external costs are calculated based on a case study using Indian power sector conditions and the main assumptions are given in Table 5.6 below.

Table 5.6 Assumptions in the Indian Coal Fuel Cycle Case Study

Indicator	Assumption
Coal used per kWh power generation	0.7 kg/kWh (average)
Diesel use for coal transport by railway	49.37 ml/ton coal per km
CO_2 emitted per ton of coal transported	0.131 gms CO_2/kg coal per km
SO_2 emitted per ton of coal transported	0.00082gms SO_2/kg coal per km
NO_x emitted per ton of coal transported	0.00147gms NO_x/kg coal per km
Average coal transport distance	617 km
Coal Mining CO2 emissions	Around 2g CO_2/kwh
Coal transport CO2 emissions	57g CO_2 / kWh
Ash disposal emissions	14g CO_2 / kWh
Average % of ash content in Indian coal	40%
Average ash disposal km	75 km
Average load taken by truck	7.5 ton
Fuel efficiency of truck	5 km per litre
Cost of water	0.0005 Rs./ml

Based on the assumptions in Table 5.6, the Indian team modelled the external costs for six out of the seven major steps in the coal fuel cycle. The facilities construction/decommissioning stage has not been quantified, but since a coal power plant generally has a lifetime of several decades, the external costs of this step are small and negligible. Table 5.6 shows the calculated priority impacts for the different fuel cycle stages.

The Indian country study monetises the various priority impacts. The valuation of the damage from SO_2 and NO_x emissions has been done using prices from the US market while valuation of damage from SPM has been based on an Indian study of human health impacts. The damage costs of GHG emissions are based on prices from the European carbon market and the cost of water is based on the water price for industrial consumers in India. The study uses a conversion factor of 1 USD = 40 Indian Rupees when converting US damage costs to Indian Rupees.

The priority pollutants included in the Indian country study are CO_2, CH_4, RPM (Respiratory Particulate Matter) SPM (Suspended Particulate Matter),

SO_2, NO_x and water pollution. The damage costs of CO_2 and CH_4 have been adjusted using the CASES standard values of 20.66 €/ton CO_2 and 747.29 €/ton CH_4 to facilitate cross-country comparison. The damage costs for SO_2 and NO_x based on US market prices continue to be used. The Indian cost numbers have been converted to Euros using a conversion factor from December 2007 of 0.017 €/Rs. The results are shown in Table 5.7 below. We note that while the figures for SO2 and NOx are somewhat lower than those in the EU externality study, those for SPM and CO2 are comparable.

Table 5.7 External costs of electricity for the Indian coal fuel cycle

Stage	Unit	CO_2	CH_4	RPM	SPM	SO_2	NO_x	Water*	Total
Mining	g/kwh	2	0.511	0.079	0.200	0.013	0.007	0.038	
	€cent/kWh	0.004	0.038	0	0.003	0	0	0	0.045
Beneficiation	g/kwh	0.5	-	-	-	0.003	0.002	2113	
	€cent/kWh	0.001		-	0	0	0	0.18	0.181
Transport	g/kwh	57	-	-	-	0.353	0.634	-	
	€cent/kWh	0.118		-	0.045	0.016	0.074	-	0.253
Power generation	g/kwh	1307.67	-	-	0.280	7.48	4.09	0.725	
	€cent/kWh	2.70		-	1.98	0.33	0.48	0	5.49
Ash disposal	g/kwh	1.49	0.001	-	0.0045	0.01	0.02	-	
	€cent/kWh	0.003	0	-	0.002	0	0.002	-	0.007
All stages	g/kwh	1368.66	0.512	0.079	0.4845	7.859	4.753	2113.8	
	€cent/kWh	2.826	0.038	0	2.03	0.346	0.556	0.18	5.976

Note: *Water is given in ml/kWh. The CO2 values are those from the Indian study and not based on the common ones reported in Table 5.1.

It can be seen from Table 5.7, that the major external costs from the Indian coal fuel cycle are caused by the power generation stage. Here CO_2 emissions account for the largest damage costs followed by SPM and NO_x. The damage costs from SO_2 emissions are relatively low and this might be explained by the lower sulphur content of Indian coal. The transport stage is the second largest contributor with the main damage from CO_2 emissions and after that comes the coal beneficiation stage. Here water use accounts for the main externality. The impacts from coal mining and ash disposal are relatively small compared to the other fuel cycle externalities. The total external cost of the Indian coal fuel cycle is calculated to 5.976 € cent/kWh.

The Turkish Lignite Fuel Cycle Case Study

The lignite fuel cycle as defined in the Turkish case study consists of five stages: (1) lignite extraction; (2) transportation of the lignite to the power plant; (3) operation of the power plant; (4) construction and dismantling of

the power plant and (5) waste disposal. The Turkish country study is based on a lignite power plant fuelled with domestic lignite. The lignite is, after extraction, transported 8 km to the power plant by conveyor belts. Overburdens from the lignite extraction are transported about 4 km to a dumpsite largely by truck. Unlike the Chinese team, that totally neglects the external costs from power plant construction/decommissioning and the India Team that analyzes it non-quantitatively, the Turkish team gives detailed data on the various external costs during the construction and dismantling of the power plant.

In the Turkish case study, special importance is attached to external impacts due to steel and concrete transportation during the construction and dismantling of the power plant. The Turkish country study does not, however, give emission data for the parameters mentioned above and generally it does not monetise any of the externalities analyzed. Although the report gives a description of the local climate, geography, population, and land use circumstances, the external costs associated with water pollution, land damage, public health impact, as well as eco-system impacts are not quantified.

The Turkish country study places its main focus on quantifying the externalities from the transport and power generation stages. The priority pollutants included are CO_2, SPM, SO_2 and NO_x and in addition different kinds of waste have been quantified. However, as mentioned above, the impacts have not been monetized. Therefore it has been decided to value the main impacts based on results from the UK part of the ExternE project. Since the damage cost of a specific impact varies for different countries, the costs can be adjusted to Turkish conditions using the relationship between the UK and Turkish PPP GNI per capita. The UK GNP PPP for 2003 is $ 31430 while the Turkish is $ 7720 and the conversion factor applied to the UK external costs can therefore be calculated to 0.246. The calculated external costs are shown in Table 5.8 below. The NO_x emissions from transport have not been included in the final number since they seem to be too high compared with other studies.

Table 5.8 Adjusted Results of the Turkey Coal Cycle Case Study

Stage	Unit	CO_2	SPM	SO_2	NO_x	Total cost
Transport	g/kwh	32.23	-	0.02	(66.42)	
	€ cent/kWh	0.067	-	0.003	(5.39)	0.07
Power	g/kwh	999.3	0.22	6.08	2.25	
generation	€ cent/kWh	2.065	0.079	0.953	0.182	3.279
All stages						3.35

It can be seen from Table 5.8, that the power generation stage is responsible for a significant fraction of the external costs and that the main damage is caused by emission of CO_2 and SO_2. Emissions of NO_x and SPM have a smaller impact. If the NO_x emissions from the transport stage are excluded, the damage from transport seems to be small. However, since the NO_x emissions data appear questionable, the damage costs from the transport stage are surrounded with some uncertainty. The total external cost from the coal fuel cycle stages assessed is 3.35 € cent/kWh.

Comparison and Analysis

From the results above it can be seen that the external costs of the coal fuel cycle for the different countries considered are of similar magnitude but reflect different national conditions. The Indian coal fuel cycle has an external cost of 5.076 € cent/kWh. The external cost of the Turkish lignite fuel cycle is somewhat lower, namely 3.35 € cent/kWh, while the external cost of the Chinese coal fuel cycle is as low as 2.54 € cent/kWh. As mentioned earlier in the chapter, some studies have only quantified one or two fuel cycle stages while others have included almost all stages. The relatively high external costs for the Indian coal fuel cycle might therefore be partly explained by the inclusion of most stages, while the lower cost for the Turkish fuel cycle can be somewhat explained by the inclusion of only two stages. Since the power generation stage is responsible for the main externalities of the coal fuel cycle, however, the inclusion of different upstream stages should only result in smaller differences between the studies.

Since the same value for CO_2 has been applied for China, India, and Turkey, the external costs for CO_2 should be readily comparable. For the other priority pollutants, different approaches for valuation have been applied and the cost estimates for the different studies are therefore associated with some inconsistency. One should therefore be careful when comparing the different cost results.

5.3 NATURAL GAS FUEL CYCLES IN BRAZIL AND CHINA

This section focuses on the analysis of the natural gas fuel cycle in Brazil and China. The Chinese case study includes most impacts of air emissions while the Brazilian study focuses on the health impacts. Both include impacts of GHGs.

Methodology

Volume 4 of the ExternE report focuses on oil and gas fuel cycles. It defines the stages of a natural gas fuel cycle as including gas exploration, construction and decommissioning of plant and pipelines, extraction, operation of pipelines, gas treatment, power generation, disposal of wastes, transmission of electricity and transport of materials and personnel. It also points out that for the natural gas to electricity fuel cycle, the most significant externalities are likely to be associated with extraction and power generation (EC, 1995a). Page 235 to 246 of the ExternE oil and gas report give a full list of the burdens, receptors and impacts of all stages of the natural gas fuel cycle. The valuation applied here is based on the ExternE methodology, but conducted in a similar simplified way as for the coal fuel cycle**.**

Table 5.9 shows an overview, similar to the one for the coal fuel cycle, of the major fuel cycle stages and priority impacts analyzed.

Table 5.9 Overview of stages and impacts analyzed for the gas fuel cycle

Fuel cycle stage	Impacts	Brazil	China
Facilities construction/ (decommissioning)	Air pollution	NQ	-
	GHG emissions	NQ	-
	Occupational health	NQ	-
Gas exploitation	GHG emissions	NQ	NQ
	Land damage	-	NQ
	Occupational health	NQ	-
	Wastes	-	NQ
Gas transport and treatment	Air pollution	NQ	NQ
	GHG emissions	NQ	NQ
Power generation/ transmission	Air pollution	Q	Q
	GHG Emissions	Q	Q
	Occupational health	NQ	-

The Brazilian Natural Gas Fuel Cycle Case Study

The Brazilian country study identifies the following main sets of impacts on human health as being of greatest relevance for the Brazilian natural gas fuel cycle:

1. impacts of plant construction and operation phases of occupational health;
2. impacts of GHG emissions (CO_2, CH_4 and N_2O) from gas platforms (extraction and operation) and energy generation; and

3. impacts of atmospheric emissions from the energy generation phase on human health.

The external costs from the Brazilian natural gas fuel cycle have been calculated based on a generation complex consisting of both single and combined cycle power plants. The total capacity of the complex is 1355 MW. The impacts valued are from the power generation stage and priority burdens include CO_2, N_2O and NO_x emissions. The external cost of NO_x has been calculated as the damage costs to human heath from wet deposition in an area around the power generation complex. The total cost of nitrate deposition has been calculated to US $61 890 084 in 2005 values, which is equivalent to (also at the value for same year) an additional cost of around US $5.23/ MWh generated.

The external costs for the Brazilian natural gas fuel cycle have been estimated for the power generation stage of a combined cycle power plant. The priority impacts included are CO_2, N_2O and NOx. The CO_2 and N_2O damages have been monetized using the standard CASES values of 20.66 €/ton for CO_2 and 27202.9 €/ton for N_2O. The damage cost of nitrates has been converted from US$ to Euros using a conversion factor from December 2007 of 0.68 €/$. The results are shown in Table 5.10below.

Table 5.10 Brazilian natural gas fuel cycle

Area	Stage	Unit	CO_2	N_2O	Nitrates	Total cost
Brazil	Power	g/kwh	393.0	0.013	0.71	
	generation	€ cents/kWh	0.81	0.035	0.35	1.20
Average	Power	g/kwh	354.8	0,009	0,27	
EU	generation	€ cents/kWh	0,75	0,006	0,19	0,95

As shown in Table 5.10, the main external costs are caused by CO_2 emissions followed by wet deposition of nitrates. The total external cost is calculated to 1.20 € cent/kWh. These figures are not so different from those arrived at in the EU study; the table compare Brazilian values with the values of the operation stage ottained for EU for a natural gas combined cycle power plant for the period 2005-2010.

Chinese Natural Gas Fuel Cycle Case Study

The Chinese natural gas study both includes an analysis of the size of the impacts from the different fuel cycle stages and an examination of the external costs for a power generation case study. Table 5.11 below shows the size of the priority impacts of a natural gas fuel cycle for a natural gas flow of 1000 m^3. The study does not make explicit the detailed technical parameter

assumptions. Instead, it directly uses the emission estimates of a detailed case study by Dong et al. of 10 gas wells with a capacity of 550,000m^3/day each.

Table 5.11 Analysis list of natural gas lifecycle emissions

		Exploitation	Transport	Utilization	Total
Waste gas	CO_2 (kg)	232.6		1440	1672.6
	SO_2 (kg)	0.415		0	0.415
	H_2S (kg)			0	0
	NO_X (kg)	0.159	0.087	2.734	2.98
	CH_4 (kg)	0.295	0.006	0.144	0.445
	CO (kg)	0.015	0.003	1.312	1.33
Waste water		0.15	0.006	2.607	2.763
Solid waste	Waste residuals (kg)	6.4		—	6.4
	Rock debris (kg)	6.814		—	6.814
	Sewage (kg)	0.007		—	0.007

The analysis of the external costs of the natural gas fuel cycle focuses on the priority impacts from the power generation stage. The calculations are based on a 100 MW natural gas power plant with an annual power generation of 6 billion kWh. The heat value of natural gas is set to 36 MJ/m^3. The results of the case study are given in Table 5.12 below. The valuation of the priority impacts are based on Chinese and US government charges on emissions, obtained from China Pollutants Charge Standard (PCS) and the U.S. Environmental Value Standard (US EVS). Note, however, that these estimates are derived from a methodology that we could not review.

Table 5.12 The External Costs of the Natural Gas Fuel Cycle in RMB/kWh

Pollutant	Standard of National Emission charge (RMB/kg)	Emission (g/kWh)	Environmental Costs (0.01RMB/kg)
SO_2	6.000	0.023	0.001
CO_2	0.023	402.000	0.925
NOx	8.000	1.240	0.992
Suspended particles	2.200	0.047	0.010
Total			1.928

The externalities of the Chinese natural gas fuel cycle are given, as in the case of the coal fuel cycle, for the power generation stage for the priority pollutants. The priority pollutants included are CO_2, SPM, SO_2, NO_x and CO. The damage costs for CO_2 has been adjusted using the CASES standard value

of 20.66 €/ton. The costs of the other pollutants are based on Chinese and US standard pollution charges. The costs are converted from Chinese Yuan to Euros using the conversion factor from December 2007 of 0.0930 €/Yuan. The results are shown in Table 5.13 below.

Table 5.13 Chinese natural gas power generation fuel cycle

Unit	CO_2	SPM	SO_2	NO_x	CO	Total cost
g/kwh	402.0	0.047	0.023	1.240	-	
€ cent/kWh	0.83	-	0	0.092	0.001	0.92

As can be seen in Table 5.13, the major external cost arises from CO_2 emissions while a smaller contribution is due to emissions of NO_x. The external costs of the other priority pollutants remain marginal.

Comparison and Analysis

In the studies of the natural gas fuel cycle, only the power generation stage has been quantified in monetary values. This means that in terms of fuel cycle stages covered, the results of the studies are comparable. In the Brazilian and Chinese studies, CO_2 emissions have been adjusted using standard CASES damage values. This means that the damage costs from CO_2 emissions are comparable for the Brazilian and Chinese country studies. The size of the total external costs, however, are also quite similar for the Brazilian and Chinese country studies.

5.4 BIO-DIESEL FUEL CYCLE IN TURKEY

Methodology

The differences between bio-diesel and fossil fuels are: (1) CO_2 emissions from the combustion stage are not included in the external cost calculation because it is usually assumed that emissions cancel out (at least partly) due to previous fixation of CO_2 by the growing plants. (2) SO_2 emissions from biomass are generally much lower than for fossil fuel cycles, because of the almost negligible sulphur content in biomass. The most important emissions in all cases are those of ozone precursors, such as NO_x and VOCs. The magnitude of these emissions depends again on the fuel and technology used. (3) Among the burdens and impacts of the upstream stages, the major ones may be the road damages caused by the biomass transport and ecological problems of biomass removal. Biomass transport is a significant fuel cycle

stage because of the low density of biomass as fuel. Biomass collection, if not carried out properly, may also imply significant environmental impacts, such as loss of nutrients from the soil or increased erosion.

Table 5.14 Methodology for Assessing the External Cost of Bio-diesel Fuel Cycle

Cycle Steps	Main Activity		Emissions
Biomass cultivation	Fertilizer use for biomass cultivation	Synthetic fertiliser use Animal manure use	NO_x emissions
	Fossil fuel consumption for farming machines	Fossil fuel consumption by trucks, tractors etc Fossil fuel consumption for water pumping Electricity consumption for water pumping	Air Pollution GHG emissions
	Land use change	Damage to vegetation and trees, changes in bio carbon inventory	
Crude oil production	Crude biomass transport to oil factory	Fossil fuel consumption for transportation	Air Pollution GHG emissions
	Processing at the oil factory	Electricity and fossil fuel consumption Water consumption Wastewater handling	GHG emissions Air pollution Water consumption and pollution
Blending with diesel Combustion	Transport of biodiesel from factory to blending site	Fossil fuel consumption during transport	Air Pollution GHG emissions
	Processing at the biodiesel blending site	Electricity and/or fossil fuel consumption in biodiesel blend production	Air Pollution GHG emissions
Combustion	Transport/power generation		Air Pollution GHG emissions

The methodology on bio-diesel also includes very detailed tables on cost components to be collected and how private and external costs of the bio-diesel fuel cycle should be calculated. Table 5.15 below shows an overview of the impacts considered by the Turkish bio-diesel fuel cycle.

Table 5.15 Overview of stages and impacts analyzed for the Turkish bio-diesel fuel cycle

Fuel cycle stage	Impacts	Turkey
Biomass cultivation	Air Pollution	-
	GHG emissions	NQ
	Ecological effects	-
	Land use changes	-
Biomass/oil transportation	Air Pollution	-
	GHG emissions	NQ
	Accidents	-
Conversion processes and blending	Air Pollution	-
	GHG emissions	NQ
	Wastes	-
Combustion/power generation	Air Pollution	-
	GHG emissions	NQ
	Occupational health	-

The Turkish Bio-diesel Fuel Cycle Case Study

The bio-diesel fuel cycle assessment has the following stages: (1) Production of rapeseed; (2) Transport of rapeseed to a crushing facility; (3) Recovery of rapeseed oil at the crusher; (4) Transport of rapeseed oil to a bio-diesel manufacturing facility; (5) Conversion of rapeseed oil to bio-diesel; (6) Transport of bio-diesel to the point of use; and (7) Use the fuel in a diesel engine.

The results of the Turkish study of bio-diesel production from Canola Oil are given in the mass flow diagram shown in Figure 5.1. The study does not proceed to estimate the various emissions from the fuel cycle stages and it does not monetise any external costs. Since no complete impact data have been given in the study, it has not been possible to calculate any external cost.

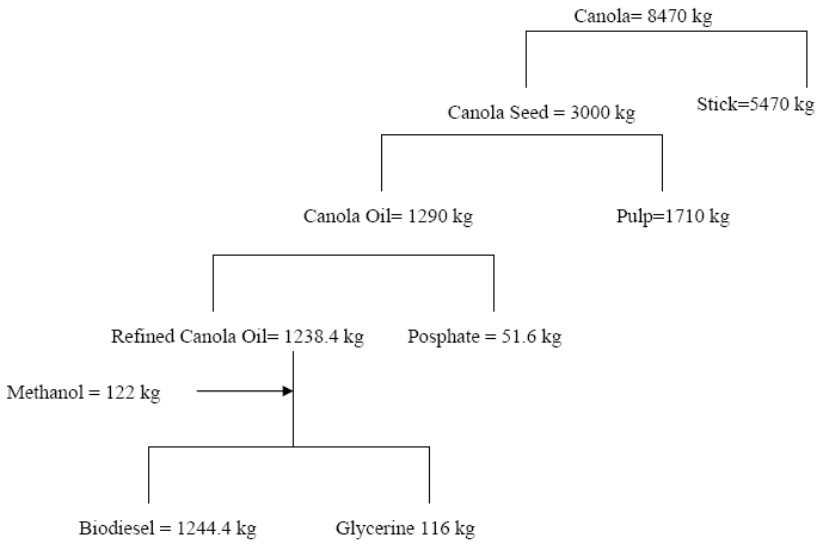


Figure 5.1 Mass flow diagram of Biodiesel production from Canola oil. Source: CASES Project – WP7 report on social costs of electricity in Turkey

5.5 HYDRO FUEL CYCLE IN BRAZIL

Methodology

Hydropower projects do not involve major CO_2 and air pollutant emissions in the process of electricity generation, but have a large variety of environmental and social impacts due to the construction of large dams and alterations to river flows. They can also change the local climate, cause inundation of land and buildings, as well as involve resettlements of local residents.

Based on a specific hydropower project in Norway, the ExternE project identifies the following 10 priority impacts to be analyzed for the hydro fuel cycle (EC, 1995b):

1. Impacts of flow alteration, impoundment and rock waste disposal sites on agriculture;
2. Impacts of construction of roads, transmission lines, impoundment and rock waste disposal sites on forestry;
3. Impacts of alteration of river on water supply;

4. Impacts on waterway transport;
5. Impact of the construction and operation phase on recreational activities;
6. Impacts of the construction and operation phases on cultural objects (and objects of archaeological interest);
7. Impacts of the construction and operation phases on terrestrial and aquatic ecosystems (birds, plants, fish, and wild-life loss of habitats, noise in the process of construction and operation).
8. Impacts of construction and operation on occupational health;
9. Impacts of construction and operation on local and national employment and local income;
10. Impacts of transmission lines on bird populations.

The Brazilian Hydropower Fuel Cycle Case Study

The Brazilian hydropower case study only assesses impacts from selected impacts as shown in Table 5.16 below.

Table 5.16 Overview of major fuel cycle stages and impacts analyzed for the Brazilian hydro fuel cycle

Fuel cycle stage	Impacts	Brazil
Facilities construction/ (decommissioning)	GHG emissions	-
	Occupational health	NQ
	Public health	Q
Power generation/ transmission	GHG emissions	-
	Occupational health	NQ
	Public health	Q

The Brazilian hydropower fuel cycle study focuses on the health impacts. It quantifies the health impacts including the following two components:

1. Impact of the construction phases resulting from the significant increase in the population;
2. Impacts of the operation phase as a result of the increase in water-borne diseases and the increase in infectious disease and parasite vectors due to the changes in the water regime and the synergy with the increase in the population.

The construction of a hydro power plant leads to an increase in the local population and a subsequent increase in the state public health expenditures and public expenditures on sanitation. The public expenditures on sanitation include investments for expanding water supply, sanitary sewage and solid waste facilities.

The morbidity value resulting from diseases is estimated using the Disease Cost Method (DC), which takes into account, as shown below, medical expenditures from the treatment of diseases and the value of work days lost as the result of the disease.

DC Total = expenditure on treatment + value of work days lost

The statistical value of life is calculated based on the European statistical value of life for 1998 ($3,250,000 in 1992 $), per capita GDP, the parity of purchasing power, life expectancy, as well as health expenditures. The value is calculated to US$ 929,744.

The Brazilian case study takes into account the morbidity values for VTDs (vector transmissible diseases) which are *schistosomiasis mansoni* (gastropods), yellow fever, malaria, leishmaniasis, dengue fever, filariasis, chagas disease and onchocerciasis (insects). These are caused by the increase in vectors due to the construction of dams. Also included are water-borne diseases (WBD) resulting from alterations in flows (reservoir) in the construction of a hydro-electric plant, which are: cholera, typhoid fever, dysenteries and internal parasites and infectious diarrhoea (low levels of hygiene). The impacts of vector-borne diseases are valued based on the number of patients, the length of hospitalisation and the cost of treatment.

Due to some recent legislation, such as the Epidemiological Control Program and the Intensification of Endemic Controls Program, hydropower plant constructors are required to implement some measures and programs to mitigate increases in diseases from the construction of hydro projects. The legislation recommends that implementation of these programs should begin a year before construction is started. This part of the cost is included in the hydropower construction costs (private cost) and does not therefore constitute an external cost.

The avoided costs related to the increase in water borne diseases is calculated as the avoided increase in incidences of some epidemic diseases due to the construction of the hydro power plant. This part of the external costs is calculated based on three kinds of diseases with highest incidences in the region: leishmaniasis, dengue fever, and malaria.

For hydroelectric generation a case study was prepared related to the implementation of the Rio Madeira Complex in Rondônia in the Amazon region. The complex is composed of two hydroelectric plants, with a total capacity of 6500 MW and is planned to enter into operation in 2012. In addition to the Rio Madeira case study, two studies carried out by Reis (2001) are also presented: One for the Tucuruí plant (4000 MW), constructed between 1975 and 1984 in the Amazon region and expanded to 4375 MW in 2005 and one for the Serra da Mesa plant (1275 MW), which commenced operations in 1998 and is located in the Cerrado region. These plants are all located in regions of low population density, but with a propensity to

endemics if these are not controlled. The Tucuruí plant was constructed at a time with lack of stringent environmental legislation and hence few external costs were internalized in the private costs. The Serra da Mesa plant was constructed in compliance with more restrictive environmental legislation and Rio Madeira, has to fulfil modern environmental standards. Therefore the results of the three case studies represent different stages of internalization of external costs. The results for the three power plants are shown below.

For the Rio Madeira Complex an additional cost of US$ 1.03/MWh was estimated for the increase in costs for the local health system. On the other hand, the programs put in place by the entrepreneurs to control endemic diseases have prevented externalities related to the endemic diseases. For this complex, the estimated control costs are about US$ 0.87/MWh, which have already been incorporated in the private cost. For the Tucurui plant, the endemic diseases not considered in the private costs have been calculated in an additional cost of US$ 0.64/MWh.

Using an exchange rate of 1 € = 1.47 US$, the results of the Brazilian hydro fuel cycle are converted into Euro cents per kWh. The adjusted external costs of the three dams analyzed are shown in Table 5.17below.

Table 5.17 Brazilian hydro fuel cycle

Construction & power generation	Unit	Local health system	Vector born diseases	Total cost
Rio Madeira	€ cent/kWh	0.070	0.059	0.129
Tucurui	€ cent/kWh	-	0.043	0.043
Serra da Mesa	€ cent/kWh	0	0	0

Comparison and Analysis

The Brazilian study is different from the other fuel cycle studies for several reasons, but mainly because it focuses on the health impacts during the construction and operation of hydropower projects and because it provides one of the few estimates of the external costs of high dams in the tropics. Some significant externalities have also not been considered in the study. The emission of CH_4 from tropical hydro power reservoirs can be quite substantial and this impact has not been considered for the Brazilian case.

5.6 CONCLUSIONS

Overall cost results

Under this part of the CASES project, the four countries conducted external cost assessments on a range of different fuel cycles. Table 5.18 offers an overview of the external cost results of all case studies after exchange rate and GHG cost adjustments.

Table 5.18 Summary table of the adjusted results of all fuel cycle case studies under WP7

Fuel cycle	Brazil € cent/kWh	China € cent/kWh	India € cent/kWh	Turkey € cent/kWh
Coal		2.54	5.98	
Lignite				3.35
Natural gas	1.20	0.92		
Hydro dam	0 / 0.043 / 0.129			

From Table 5.18 it can be seen, that after the same GHG damage costs have been applied to the different cost numbers and the costs have been converted to € cent/kWh, the results have a similar magnitude. The coal/lignite fuel cycle generally has the highest external costs, followed by natural gas and the renewable technologies.

Impacts covered in the fossil fuel cycle assessment

The external cost of the Chinese coal fuel cycle is lower than in the Indian one, but as shown in Table 5.3 this could be explained by the fact that the Chinese study is based on a different methodology and because the coal fuel cycle assessment only covers the emissions during the power generation stage, while the Indian coal fuel cycle also covers coal mining, transportation, beneficiation and waste disposal.

The similarities of the results can be partly explained by the fact that for the coal and natural gas fuel cycles, CO_2 emissions constitute a major component of the total external costs. Table 5.19 shows the cost of CO_2 emissions from the coal fuel cycles in China, India and Turkey and it can be seen that the CO_2 emissions tend to constitute half or more of the total external cost of the fuel cycles.

Table 5.19 CO_2 emissions, adjusted costs and the total adjusted external costs of coal fuel cycles

	CO_2 emissions (g/kWh)	Adjusted CO_2 emission costs (€ cent/kWh)	Total Adjusted external cost (€ cent/kWh)	Source
China	816.64	1.69	2.54	Table 5.5
India	1368.66	2.826	5.976	Table 5.7
Turkey	1031.53	2.132	3.35	Table 5.8

Methodological challenges and data limitations

Table 5.20 gives an overview of the external costs given in physical units in the fossil fuel based fuel cycles covered in the case studies. It can be seen, that for all five countries, the external impacts quantified for coal and natural gas are often air pollution and GHG emissions, as well as solid waste (ash etc.) and liquid waste (mainly water). This shows that for external cost studies, these cost results are most readily available.

Table 5.20 Contents and Bases of Impact Valuation in the Case Studies

		Stage	Impacts quantified	Unit Price
China	Coal	Coal combustion at power plant	SO_2, NO_x, CO, CO_2, SP, Powdered Coal ash, Furnace Dust	China national standards on emission charges and US Environmental Value Standard numbers
India	Coal	Mining:	CO_2, CH_4, RPM, SPM, SO_2, NO_x, Water*	SO_2 and NO_x: prices from the US market
		Beneficiation:	CO_2, SO_2, NO_x, Water*	RPM and SPM: based on an Indian study of human health impacts
		Transport:	CO_2, SO_2, NO_x	GHG emissions: prices on the European carbon market
		Power generation:	CO_2, SPM, SO_2, NO_x, Water*	Water: the water price for industrial consumers in India.
		Ash disposal:	CO_2, CH_4, SPM, SO_2, NO_x,	
Turkey	Lignite	Coal transportation and Power generation	CO_2, SO_2, TPS, liquid waste, solid waste	Results given in physical terms
China	Natural gas	Power generation	SO_2, CO_2, NOx, Suspended particles	China national standards on emission charges C and US Environmental Value Standard numbers
Brazil	Natural gas	Gas extraction and power generation	CO_2, CH_4 and N_2O	Increase in the incidence of respiratory diseases

Except for Brazil, which focuses on a health impacts assessment, the other four countries do not follow the damage function approach of ExternE. This shows that the subsequent steps of the ExternE damage function approach, (namely: dispersion and definition of dose-response functions), are more difficult to implement in the fuel cycle studies in the four countries. For China the last valuation step is mainly based on levels of emission charges set by the governments or charges used in the US. Consequently, the results do not consider the local population, climate, vegetation and geographic situation. When external costs are estimated on the basis of local government emission charges, the results are actually the shadow costs or opportunity costs taken into account by economic agents when deciding whether to take emission reduction measures or not.

The Brazilian case study followed more strictly the ExternE damage function approach.

The results of the studies presented in this chapter reveal, that in order to expand the application of the ExternE approach and methodology in non-EU countries, much more needs to be done. This includes allocation of more resources for local research teams to allow more in-depth analysis of the different fuel cycles and initiation of larger research projects so that sufficient quantities of data and on-site observations, interviews, questionnaires, expert estimates etc. can be carried out.

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Part II *Policy Evaluation*

6 Policy instruments

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6.1 POLICY INSTRUMENTS TO PROMOTE RENEWABLE ENERGY SOURCES IN EU MEMBER STATES

Introduction

This chapter presents policy instrument for the internalization of external costs via the promotion of renewables. This introduction will give recall the definition of external costs and show their connection to renewable energies.

External costs are defined as non-market disadvantages (or advantages) experienced by third parties, e.g. households, the public or coming generations. (Bartmann, 1996, p. 36) Those advantages or disadvantages are not taken into account in private costs calculations. The sum of private costs and external costs is called social costs or Full Costs. In the following, the discussion is restricted to negative external effects of energy production. By not taking those effects into account the price of the production causing the effects is too low and consequently the quantity produced is too high. Consideration of the external costs could be achieved by internalizing those costs in the market and price mechanisms. (Krewitt and Schlomann, 2006, p. 5) If the producer was forced to consider the external costs, the supply curve would shift. The produced quantity would be reduced and the price increased. Because different energy production technologies cause diverse external effects the relative prices of the technologies and hence the merit order would also change.

Several policy instruments have been proposed to achieve internalization of external costs. The optimal instrument for internalization creates no distortions on the market. Furthermore it should be efficient and fair, minimize costs and uncertainty and have low administrative costs. (Longo and Markandya, 2005, p. 17) The first best option is a tax on the amount of the external costs or an equivalent quantity regime with certificate trading. Instruments that support or subsidise environmentally friendly technologies

like instruments for the promotion of renewable energies or combined heat and power production are the second best options as they can establish indirect internalization. (Krewitt and Schlomann, 2006, p. 6) Other possible instruments are the standard-price approach, charges, and negotiations. (Bartmann, 1996, p. 43)

Promotion instruments for renewable energies can be justified by the differences in external costs between renewable and conventional energy production technologies. The external costs of renewable energy production are generally lower than those of conventional energy production. Thus renewable energies are highly disadvantaged by the present prices which do not include external costs. According to the Community Guidelines on State Aid for Environmental Protection financial support up to 0.05 €/kWh can be seen as compensation for external costs. (Hohmeyer, 2001, p. 4) Different analyses have shown that the differences in external costs outweigh the extra costs of renewable energy sources, except for technologies which so far have very high production costs like photovoltaic. (Krewitt and Nitsch, 2003, p. 540; Krewitt und Schlomann, 2006; Hohmeyer, 2001) However the promotion of renewable energies can only remunerate the reduced external costs. Promotion of renewables can adjust the relative prices between renewable and conventional technologies but it does not bring prices to their Full Cost level. Thus full internalization cannot be achieved.

On the other hand one has to keep in mind that the promotion of renewables is not solely based on the objective of internalization. Even if internalization is attained better by other instruments like emission taxes there are good reasons for the promotion of renewable energies. In the proposal for a new directive on the promotion of the use of energy from renewable sources (European Commission, 2008) the need to further promote the use of renewable energies is justified by their contribution to "climate change mitigation through the reduction of greenhouse gas emissions, sustainable development, security of supply and the development of a knowledge based industry creating jobs, economic growth, competitiveness and regional and rural development". (p. 2)

Having substantial shares of renewable energy sources in the energy mix will enhance the diversity of production and reduce the import dependency of energy production as usually domestic renewable resources are used. The security of supply is thereby greatly increased. Furthermore decentralised renewable energy plants are often situated in regions with lower economic activity and can provide additional sources of income and employment both for highly qualified and less qualified employees.

There is also a rationale for promoting renewable energies from the perspective of resource economics. Resource economics deals with the optimal allocation of resources over time. In traditional resource economics

present generations are favoured over future generations due to the discounting of future utilities. From an efficiency perspective there are two rules for the depletion of exhaustible resources. The resource has to be completely depleted over the time horizon. And the growth rate of the marginal productivity of the resource has to be equal to the marginal productivity of capital (interest). That means that at every point in time with one unit of the resource the same present value is gained. The second rule is called the Hotelling rule. (Bartmann, 1996, p. 60; Hensing et al, 1998, p. 29) The level of the present value is determined by several parameters, one of them being the possibility for perfectly substituting the resource in the long-term. Bartmann, 1996 describes the substitution of the resource with an inexhaustible backstop technology. For its development high capital assets are necessary. The substitution takes place in three phases. In the first phase only the exhaustible natural resource is used. The Hotelling rule demands a substitution of the resource with capital. During a transitional period the resource stock tends to zero and the backstop technology steps in. Finally the resource is completely depleted and only the backstop technology used. (p. 62) The resource must be depleted at the exact point in time when the shadow price of the resource reaches the costs of the backstop technology. (Hensing et al, 1998, p. 32) In reality the future costs of the backstop technology are not known and can furthermore be influenced by current research and development activities. By lowering the costs for backstop technologies also the equilibrium price development of the resource is lowered. That means that the industry which is exploiting the conventional resource has no incentive to develop backstop technologies as this devaluates their resource stock and benefits only the consumers. For that reason there is from an economic perspective too little private commitment for backstop technologies and their development has to be ensured by public support. (Hensing et al, 1998, p. 38)

Generally environmental policy instruments can be classified in command and control measures, economic instruments and voluntary initiatives. Command and control measures prescribe a certain technology or a certain standard. The obliged actors have no room for flexibility. Those instruments will not be covered in the following.

Economic instruments provide economic incentives to reach the desired level of renewable energy. They can be distinguished in two different approaches. Price based instruments regulate the price producers of renewable energy receive. The quantity which is supplied depends on the production cost curve of renewable energies. Fixed feed-in tariffs and fixed premium systems are price based instruments. The other approach is to set the quantity of renewable energy and let the price be determined by the market. A green quota with tradable green certificates and the tender system

are examples of quantity based instruments. In theory price and quantity based instrument can reach the same results. In practice the choice of instrument in a specific situation depends on what information is given and what exactly is intended by the instrument.

In the following the different promotion instruments for renewable electricity will be described. For all instruments there are several different design choices.

Feed-in tariff

All renewable electricity fed into the grid is remunerated with a fixed tariff which is paid instead of the electricity price. Grid access for renewable electricity is guaranteed. Usually the feed-in tariff is paid by the grid operators and collected from the electricity consumers. If there are several regional grid operators the sums paid to renewable operators are balanced between them. In the customary configuration renewable energy operators receive the tariff from the grid operators. The costs are passed on proportionally to the electricity suppliers and onward to all electricity customers. In some cases energy-intensive industries are partly or completely exempt from paying a mark-up for the promotion of renewable energy. Tariffs could be regularly adjusted according to specific criteria. For example, the tariffs could be indexed to a specific parameter like the inflation rate or the production costs of renewable energy plants. Alternatively they could be reduced by a fixed amount or percentage in a certain time frame, e.g. 2% every year. Tariffs can be uniform or technology-specific.

Fixed premium

All renewable electricity fed into the grid is paid a premium that comes additionally to the electricity price, which the renewable energy operators realise on the electricity market. Also the feed-in premium is usually paid by the grid operators and collected from the electricity consumers. For the design of the feed-in premium basically the same options as for the feed-in tariff exist.

Tendering System

For the installation of new renewable electricity capacity an auction is held. Deadlines for project implementation and meaningful penalties for non-compliance should be put in place. The winners of the auction can either receive a tariff for all renewable electricity which they produce, a premium or a fixed investment subsidy. The financial support for renewable energy

operators is financed by a mark-up paid by all electricity customers. Auctions can be either held separately for each renewable energy technology (or for groups of technologies) or unspecific for all renewable energy technology together.

Tradable Green Certificates

A group of agents in the energy supply chain – electricity producers, retailer or consumers – is obliged to have a certain quota of renewable electricity in their portfolio. Compliance is demonstrated by presenting renewable energy certificates. Those certificates are tradable. They can be traded together with the physical electricity or as a separate commodity. Certificates are either valid only in the current commitment period of the quota, usually a year, or they can be banked for or borrowed from the following period. The price for renewable certificates can be restricted by a price floor or a price cap. The renewable quota can be technology specific or comprising all renewable technologies.

Investment subsidies

Investment subsidies are a very simple form of promotion instrument. Renewable energy operators are granted a fixed amount of financial support for the installation of the plant.

Favourable changes in the existing tax system – Taxation Incentives

There are several possibilities of changing the tax system in order to improve the situation for renewable energy production. For renewable energy plants special favorable depreciation regulations could be introduced. Furthermore renewable energy could be subject to a lower VAT rate and be exempt from energy or environmental taxes which are put on conventional energy sources.

6.2 ANALYSIS OF LINKAGES TO EMISSION TRADING

Low consumer prices, emission reduction and increased production of renewable energy are among the goals pursued by energy policy. These objectives are not independent from each other as renewable energy sources produce much less emissions than conventional energy sources while still having higher production costs. Regulatory instruments affect each other and hence the realization of the different objectives. (see also Jensen and Skytte,

2003, p. 63f) On the one hand policies for emission reduction will favour the use of renewable energies. On the other hand instruments to promote renewable energies will reduce emissions and both policies are expected to increase consumer prices in the short-term.

Besides understanding the impact of single isolated policies more and more attention has recently been paid to the interaction of different instruments that are applied in parallel in the energy sector. The European emissions trading scheme and national instruments for the promotion of renewable energies act upon overlapping groups of actors. Sijm and van Dril (2003) indicate that the indirect interactions between the target groups of emission trading and renewable support schemes are "manifold, significant and complex" (p. 13).

Several analyses have been carried out to study the effects of the interaction of diverse policy instruments.

Green quota and emission trading

Many have focused on the interaction of tradable green certificates and emissions trading. When those two instruments are in place three different markets exist. Renewable electricity producers are active on the green certificates market and the electricity market. Conventional producers are active on the electricity market and the emission permits market. (see also Jensen and Skytte, 2003, p. 65)

Jensen and Skytte (2003) have analyzed the interaction of green certificates and emission permits in different case studies in an analytical paper. They see the two instruments to some extent as substitutes for each other and investigate the separate attainment of each of the goals by either one of the instruments or both instruments and the simultaneous attainment of both goals with both instruments. (p. 66) Hindsberger et al. (2003) have analysed the effect of co-existing instruments in an international context with a quantitative model. They argue that some consequences cannot be assessed only on theoretical grounds. (see p. 86) BALMOREL, a numerical model covering the Baltic Sea region, is used for the analysis. BALMOREL is a one period static model with possibilities of investment in new production technologies. It maximises the sum of consumers' surplus and producers' surplus and incorporates environmental and energy constraints. The reproduced markets, the electricity market, the emission permits market and the green certificate market, have different geographical extensions within the model. (p. 87)

For their calculations Hindsberger et al. (2003) defined 30 different combinations of emission goals and renewable energy goals. They discovered that the electricity spot price decreases with higher renewable targets. (p. 90)

The promotion of renewables leads to replacement of the marginal production unit and hence to a reduction of the wholesale price of electricity. (Rathmann, 2007, p. 342f) Also Unger and Ahlgren, 2005 came to similar conclusions when analyzing the effects of a Nordic TGC market on the electricity and CO_2 market with MARKAL. They affirm that the introduction of a green quota reduces the wholesale electricity price. (p. 2157) When a green quota is introduced consumer costs and consumer price can increase or decrease. On the one hand the wholesale power price is lowered but on the other hand there are additional costs from the use of renewable energy. The overall effect is ambiguous. (Jensen and Skytte, 2003, p. 67) Likewise Unger and Ahlgren (2005) discovered the effect of a green quota on the retail electricity price to be ambiguous depending on the level of the quota. When the reduction in wholesale price outweighs the costs of the green certificates the retail price will be lower than without the quota. (p. 2157)

Hindsberger et al. (2003) show that a rising green quota increases the price of green certificates but decreases the price of emission allowances. (p. 90f) The latter effect is found also by Unger and Ahlgren (2005). (p. 2157)

Amundsen and Nese (2005) have analyzed an integrated tradable green certificate market with an analytical model. They argue that a percentage requirement for green electricity has an indeterminate effect on the quantity produced as the overall consumption may change at the same time. (p. 8)

The emission trading causes an unambiguous increase of consumer prices because the costs of the marginal production unit are increased. (Jensen and Skytte, 2003, p. 67) The European Emission Trading increases the electricity price by the costs of purchasing allowances where the emissions exceed the allocation and the opportunity costs of the allocated permits (Rathmann, 2007, p. 342f). Also Hindsberger et al. discovered that the electricity spot price increases with lower emission limits. If ambitious targets are adopted for both emissions and renewable energies the price is the same as without goals. Stronger emission limits increase the price of emission allowances but have virtually no influence on the price of green certificates. The aggregate costs tend to increase with an increasing green quota and a decreasing emission constraint. (p. 88ff) Contrary to those findings NERA, 2005 expects the emission-trading scheme to lower the green certificate price. By increasing the wholesale price for electricity the emission constraint lowers the cost gap and thus the green certificate price for a given quota. (p. 27)

Reinaud (2003) points out that emission trading by itself will not lead to increased renewable energy production but other policies are needed for this purpose. (p. 9) Amundsen and Nese (2005) claim furthermore that if the green quota is combined with emission trading harsher emission constraints will lead to a decline in green electricity generation because the green certificate price is reduced more than the wholesale price is increased. This

would lead to outcomes contrary to the purpose of both policy instruments. (p. 10f) Also NERA (2005) point out that when a green quota is set relative to total production by reducing overall electricity consumption emission trading will reduce also the renewable generation compared to a situation without emission trading. (p. 28)

The interaction of the two instruments makes it possible to use both instruments for the emissions goal or the renewable goal. A certain share of renewable energy can be reached by setting a green quota but also by setting the emission cap below a certain level. However Jensen and Skytte (2003) establish that in order to reach the renewable goal and minimise consumer prices it is always optimal to apply only the green quota compared to the emissions cap or a combination of both instruments. (p. 68f) The solution is not as clear-cut for the emissions goal. It depends on the effect of the green quota. When the green quota is negatively correlated to the consumer price it is optimal to use the green quota to achieve the emissions goal. However when the green quota is positively correlated to the consumer price it is optimal to use the emission quota. A combination of both instruments will not lead to any advantage. (p. 69)

When attempting to reach both goals simultaneously it can happen that one goal envelops the other. In that case the argument is the same as before with only one goal. Otherwise neither goal alone is sufficient to fulfill both. Here again the solution depends on the effect of the green quota. When the green quota is negatively correlated to the consumer price it is optimal to set the green quota high enough to reach both goals. In case of positive correlation it is optimal to set both quotas to their respective goals. Regulating only through the emission quota is never the favourable choice. (Jensen and Skytte, 2003 p. 69f)

Bräuer et al. (2000) have carried out a theoretical analysis of the co-existence of certificate markets. They assume a situation where renewable energy producers can operate on the green certificate market as well as on the emission permit market and distinguish closed and open co-existence. Closed co-existence means that renewable energy producers do not participate in the electricity trade while in open co-existence they operate also on the electricity market. (p. 3)

Although in closed co-existence renewable energy producers do not operate on the electricity market there are still interactions between the certificate markets. Due to the green quota additional renewable electricity is being produced and other low priced emission reduction measures are not needed any more. Emission reductions are provided “for free” by renewable energy production as their additional costs are covered by the green certificate price. The price of CO_2 permits drops. For renewable energy producers there is no change compared to isolated examination of the two

markets. (p. 8f)

In open co-existence the price for green certificates is reduced by the price of emissions permits. The price of emission permits is already included in the electricity price which renewable energy producers can realize on the market. The buyers of green certificates benefit from reduced prices. The price of emission permits is the same as in the case of closed co-existence. (p. 10f) With regard to the CO_2 target there is a twofold support for renewable energies which goes to the expense of reductions through rational energy use. (p. 12)

Morthorst. (2001) analyzed the interaction between the separate markets by focusing on the green certificate market. When only the green certificate market exists in addition to the electricity spot market the long-run marginal costs of renewables can be broken down into the spot market electricity price, the value of achieved CO_2 reductions and the costs for achieving the renewable energy target. The price of the green certificates is equal to the value of emission reductions plus the costs for the renewable target. When those certificates are traded internationally the buying country pays a price which is higher than the costs of the renewable energy target while the value of the CO_2 reduction remains in the selling country. This results in a bias for domestic renewable capacity expansion. (p. 349f)

When the green quota is combined with an emission permit scheme based on grandfathering, the costs of CO_2 reduction will be partly included in the electricity spot market price. In this analysis it is assumed that only the costs actually paid are included in the electricity price and the value of the grandfathered permits is not. In this case the price for green certificates will fall to some extent but the national value of the CO_2 reduction is still considerably higher than the increase of the electricity spot price. Countries importing green certificates still have to pay a higher price for achieving renewable energy targets than the home country. (Morthorst, 2001, p. 351) However the European Emissions Trading Scheme has shown that the value of emission permits has been completely included in the electricity price even though they were granted for free to the electricity producers.

Hence there would be no difference to the combination of a green quota with an emission permit scheme based on auctioning. In this case the electricity price increase is equal to the price of the permits and hence to the national value of CO_2 reductions. (Morthorst, 2001, p. 351f) The price of green certificates will fall to level of additional costs to achieve the renewable energy target and importing countries will now pay the same for achieving the renewable energy target than the home country. Trade in certificates will hence be equal to domestic implementation. (p. 352f)

The calculations of Unger and Ahlgren (2005) show that a green quota obligation would change the Nordic-Continental trade patterns. Biomass

combustion would dominate the certificate scheme in the short run but also investment in non-renewable energy plants would be affected. Also Hindsberger et al. (2003) found out that strong renewable goals with, as well as without, strong emission constraints will motivate investments in wind power, biomass and waste-fuelled technologies in Denmark, Finland, Germany and Sweden. Furthermore the results indicate that under strong emission and renewable energy goals Denmark and Finland will produce an electricity surplus while Germany and Sweden will be importers. (p. 92)

Morthorst (2003) analyzed the interactions between an international green certificate market and an international emission trading scheme with a small three-country model. According to his results an increasing renewable quota eases the situation for the conventional power industry. For that reason the emission cap has to take into account the required renewable energy production and both quotas should be adjusted in a coordinated manner. (p. 79f)

Feed-in tariff and emission trading

The interaction of feed-in tariffs and emissions trading has received less attention that that of green certificates and emissions trading. However a detailed analysis has been carried out by Rathmann (2007). He shows that by reducing CO_2 emissions the promotion of renewable energy reduces the CO_2 price and consequently also the wholesale price for electricity. The wholesale price is further reduced because the additional renewable electricity will replace the marginal production unit. For the retail price there is on the one hand an increase through the fee for the support of renewables and on the other hand a reduction through reduced wholesale prices. For Germany the results show that the retail price is lower than it would be without support of renewables. Consumers gain from the reduction and the benefit for those consumers exempt from the renewable support fee is even higher. (p. 347) A rough estimation for the EU indicates that electricity prices would be almost 30 €/MWh higher without additional renewable electricity production in line with directive 2001/77/EG. The net electricity price reducing effect persists as long as the CO_2 abatement cost curve has a slope higher than 0.04 (€/t)/(Mt/a). (p. 348) This interaction between additional renewable energy production and the CO_2 price would not exist if emission reductions caused by renewables were taken into account ex ante in the national allocation plans. This would maintain the climate protection effect of the renewable support scheme in addition to that of the emission trading thus keeping both instruments independent of each other. (p. 343) In order to reduce the effect of the emission trading on the electricity price ex post allocation of emission rights based on benchmarks would be more favourable because it reduces the

opportunity costs for electricity producers. (p. 348)

Conclusions

When discussing different instruments for the promotion of renewable energy one has to keep in mind that those instruments can only be successful in a favourable political and legal environment. Creating encouraging framework conditions is at least as important as the choice of instruments.

Morthorst et al. (2005) (p. 31) and Dinica. (2006) (p. 464ff) point out that stable conditions and the risk/profitability characteristics of the scheme rather than the support system itself determine the investment behaviour and hence the success of diffusion. Long-term and sufficiently ambitious targets should be set and only new capacities considered for any change of the instrument. (Ragwitz et al, 2006)

In the proposal for a directive on the promotion of the use of energy from renewable sources (COM 2008/19 final) the European Commission encourages the introduction of a system of guarantees of origin which can be issued, transferred and cancelled electronically. Guarantees of origin shall be issued not only for electricity produced from renewable energy sources but also for heating and cooling from renewable energies. Member states shall mutually recognise their guarantees of origin. Designated bodies shall maintain national registers of guarantees of origin. Member states can transfer guarantees of origin to other member states and also persons in different member states may trade. Furthermore the proposed directive addresses administrative procedures, planning, construction and information and training to support the development of renewable energy.

From the experiences that have been gained with practical implementations of promotion instruments in the members of the European Union it can be seen that in many cases the situation for renewable energies can be enhanced simply by improving the framework conditions without a fundamental change of instrument. Munoz et al. (2007) even assume that more than two-thirds of the cost reduction potential of harmonization can be attributed to the optimization of national support schemes. (p. 3105f) It would hence be important to set clear guidelines for creating simple and transparent procedures for planning, permission acquirement, and grid connection. Positive experiences of some member states should be conferred to other member states by however not ignoring national situations and traditions.

Some concepts have been proposed for harmonized European promotion schemes. Mostly European harmonization is connected with tradable green certificates as it is widely doubted that a system of feed-in tariffs can be made compatible with a single liberalised European electricity market. A

harmonized European green quota system would require harmonized quotas constructed on a single European aim. Green certificates would be recognised mutually and ideally traded European wide. However national aims of diversifying energy sources would not be considered with a European quota. (See Ringel, 2006, p. 12ff)

Munoz et al. (2007) on the other hand propose a harmonized European feed-in premium system which is based on a modular premium paid on top of the electricity price. (p. 3108ff) They suggest that the premium is not constant but set separately for each technology and country. However the composition of the premium is harmonized. It consists of investment costs, some grid services, a political incentive and an additional non-harmonized component to account for national priorities. The grid services element compensates renewable energy plants when they provide grid services. This could be extended to other decentralised production units as well. The political incentive element would be linked to the EU targets and signal the degree of political willingness. It is the same across all member states for generation of the same kind. Guaranteed grid access and priority transmission are assumed for this scheme.

To date, bearing in mind the possibilities for improvement within chosen promotion schemes there seems to be no compelling argument for prescribing the same promotion instrument for all member states. Countries with different traditions regarding renewable energy production, public involvement and political intervention are bound to choose different approaches. This is not per se a drawback but can offer the chance for every country to find the promotion scheme which can best promote renewable energies under local conditions. Combining national policy instruments with a harmonized, favourable and transparent framework is the best way forward at the moment.

6.3 ADDITIONAL POLICY INSTRUMENTS

Introduction

This section analyses the extent to which policy instruments internalize externalities in EU member states. More specifically, the goal is to examine the internalization degree of subsidies in general, trading of emission allowances and their specific allocation mechanisms, taxes, command and control and voluntary agreements. Policy instruments focusing on direct promotion of renewable electricity production are not discussed here (see 6.1 and 6.2). Nevertheless, renewable technologies may be targeted indirectly by

the other instruments and thus are not excluded as such. After all, if all externalities would be internalized, technologies with a low social cost will be promoted and investments will be triggered in both renewable and non-renewable technologies.

What is the extent to which different policy instruments succeed to internalize external costs? When producing electricity, a power plant may emit pollutants that are transported in the atmosphere and then when inhaled can create a health risk and/or after deposition can disturb ecosystems. The power plant operator has no incentive to account for this damage, when making decisions. His duty is to respect the emission thresholds imposed by environmental regulation, but not the avoidance of further small risks and damages. The damages occurring thus are external effects, i.e. not taken into account by the person or institution causing the effects. These external costs are not accounted for by the decision maker; thus they should be internalised by using appropriate instruments, e.g. a tax (Bickel P.; Friedrich R., 2005).

Environmental economics theory (Proost S.; Rousseau S., 2007) states that if there is a large number of polluters (causing external costs) and victims (exposed to pollution), full internalization of external costs is not evident. In the ideal solution, there exists an optimal level of pollution when the marginal cost of reducing the pollution equals marginal environmental damage. This theorem is fundamental because accepting the existence of an optimal pollution level means accepting that some pollution remains, depending on the external costs and the costs for reducing the emissions. The reason is that reducing (overall) social costs is not the same as minimizing the external costs. The second theorem says that pollution is reduced in a cost minimal way when the marginal cost of pollution reduction is equal between the source of emissions. A policy is said to be cost efficient when this theorem is fulfilled.

It is argued that there would not be any need for subsidies in the presence of a fully functioning market system in which all externalities are internalized (EEA, 2005). However, subsidies can help create markets, and speed up the intial development of markets and technologies, but they can also slow market development in the long term and encourage 'lock-in' to existing systems. From a broad economic perspective, it could be argued that subsidies are inefficient and would not be needed if the external costs of all activities were internalized. In some respects, therefore, one can see the application of some subsidies, for example those introduced for environmental purposes, as attempting to rectify market failures. If environmental externalities are better internalized, there will be more of a level playing field for technologies and there should be less need for pro-environmental subsidies. We are, however, far from the point where externalities are fully internalized, and the ideal objective, of prices reflecting

all costs including external ones, still seems an unachievable ideal, despite rhetorical support.

In the context of long term goals for climate mitigation, EU-models show the importance of renewable energy technologies. One may however not forget that the targets imposed to those calculation models (for emissions for example) can only be met when technology transitions also occur in the mix of non-renewable technologies, along with a reduction of the demand, mostly induced by price signals. The importance of policy instruments, other than promoting renewable energy sources, is for this reason of great importance. The most convincing example is the existence of a price in those models for CO_2 induced by the Emission Trading Scheme (ETS) and a shadow price for CO_2 when limiting the emission of the other sectors. The emission reductions are mainly accelerated through price signals in the models. If, however, in the real world there is lack of policy instruments that have a comparable effect and if only renewable technologies are promoted, targets will not or not fully be met. In EEA (2005), it is argued that those price increases for non-renewable energy are important. "If the prices of non-renewable energy are not increased where applicable by internalizing its external costs and abolishing subsidies, the price of renewable energy must be reduced. In theoretical terms, inefficiency is countered with inefficient measures." In the following the different instruments are described.

Abolishing distorting subsidies

Subsidies to energy in general (as opposed to targeted subsidies for renewables) can be a serious obstacle to an efficient energy system. Subsidies are large mainly in developing countries, but are also substantial in Europe and they keep energy prices artificially low. Worldwide, the energy use would decrease by 13% and the CO_2 emissions by 16% if subsidies for energy use would be abolished (The World Bank/Oxford University Press, 2003).

In the EU, energy use is strongly subsidized, according to EEA (2004). Because there is no consensus on a clear definition of energy subsidies, the EEA looked to both direct (on budget) and indirect (off budget) support mechanisms. The so called "On-budget" subsidies are sums that are categorized as government expenses. "Off-budget" support are fiscal exemption, preferential market entry etc. The minimum estimates of the EEA for the total subsidies for energy use in the EU in 2001 amount to 29,2 billion Euro. The largest share (82%) goes to non-renewable energy, mainly fixed fuels (coal) and to natural gas and oil. The support for renewable energy gets a 18% share. The smallest share of energy subsidies is provided to nuclear

power. However, the EEA report states that these figures "exclude the potential cost of not having to pay full-liability insurance cover for a critical nuclear accident or fuel incident since commercial and State liabilities are limited by international treaty" EEA, (2004).

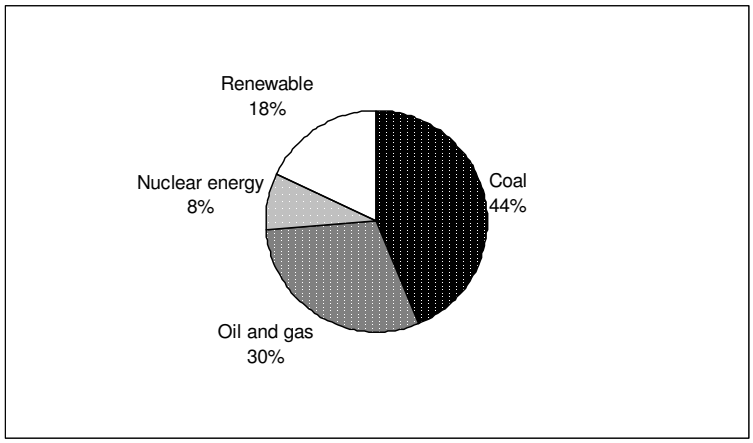


Figure 6.1 Subsidies for energy use (EU-15, 2001).

Source EEA (2004).

Subsidies become inefficient because their existence leads to overproduction of the subsidized product, or if it creates 'economic rents', in other words undue profits for individuals or parts of the sector. The latter occurs when the subsidy is no longer needed or larger than the incremental support needed — in other words, above the needed threshold. Even green subsidies should be temporary, otherwise they can effectively slow the development of innovative technologies (EEA 2005).

EU Emissions Trading

Tradable permits have been designed to achieve reductions in pollution (such as emissions of CO_2) or use of resources (such as fish quotas) in the most effective way through the provision of market incentives to trade (EEA, 2005). Certificates or marketable (tradable) permits/quotas are, among others, emissions trading schemes, White, Green and Combined Heat and Power (CHP) Certificates. For emissions trading schemes, the basic principle is that any increase in emission from a given source must be offset by a decrease in

emissions of an equivalent quantity. For example, when a statutory ceiling on pollution levels is fixed for a given area, a polluting firm can set up a new facility or expand its activities only if it does not increase the total pollution load. The firm must therefore buy ‘‘rights’’ or allowances to pollute from other firms located in the same control area, which are then required to abate their emissions by an amount equal to additional pollution emitted by the new activity (V. Oikonomou; C. J. Jepma 2007).

EU Emissions trading, Allowance allocation

Three basic approaches have been used in past programs to allocate allowances to sectors/facilities (1) “Grandfathering”—allocating on the basis of historical emissions. (2) “Benchmarking”—allocating on the basis of some emission rate (per unit of input or output) and (3) “Auctioning”—requiring the purchase of allowances.

Grandfathering and benchmarking are both systems with free allocation. The primary difference between auctioning and free allocation of allowances is in terms of their impacts on income distribution. Under auctioning the allowance revenues go to the public authorities, whereas with free allocation the value of the allowances goes to the installations covered under the ETS (European Commission 2008).

The opportunity cost is the cost incurred by choosing one option over the alternative. The opportunity cost of an allowance is identical in both cases. In theory, the energy efficiency policy and the fuel choice of companies is independent of the allocation system of emission rights. With auctioning, buying emission rights is a way for a company to make it possible to emit CO_2. The company pays for the remaining emissions, thus a real price has to be paid for the emissions. With free allocation, using emission rights is also a way for the company to make it possible to emit CO_2. An alternative is to make the plant more efficient, to reduce emissions and sell rights on the market. The opportunity cost of using emission rights is then the price of emission rights on the market.

When an asset can be freely traded, its opportunity cost is equal to the market price. In this case, the assets are emission rights. The opportunity cost of emission rights is the price of the emission rights. It cannot be lower than the market price because the company would sell emission rights on the market. The opportunity cost cannot be higher than the market price because it can not exceed the cost of buying emission rights on the market. No matter what allocation system is used, companies include in their investment calculations a (shadow) price for emitting greenhouse gases. This economic theorem is used in optimization models to simulate the effect of EU-ETS by introducing a shadow price on emitting greenhouse gases.

The adverse macroeconomic impacts of introducing a greenhouse gas emissions constraint through auctioning in the EU ETS sectors can be partly offset by returning the allowance revenues to the economy. Obviously, the method chosen by Member States to recycle these revenues in the economy is important to determine the scale of this offsetting effect (European Commission 2008). NERA(2007) comes to this conclusion that under "idealized" conditions, the decision to adopt one of the three major alternatives would affect neither the cost savings from emissions trading nor the ability of the program to cap emissions from program participants.

The allocation of permits among industries has been the subject of a debate (Longo A.; Markandya A., 2005). The usual argument to support grandfathering is that while inefficient, it provides greater political control over the distributional effects of regulation (Stavins 1997). On the other hand, Cramton and Kerr (2002) argue that an auction is preferred to grandfathering because it reduces tax distortions and the need for politically contentious arguments over the allocation of rents, provides more flexibility in distribution of costs and greater incentives for technological innovation.

An important difference between permits that are auctioned by the government and permits that are issued for free is that with free permits the polluter pays only the abatement cost, but with auctioned permits the polluter must also pay the remaining damage at the new emission level, as pointed out by Desaigues and Rabl (2001). The difference in cost to the polluter is very large: a factor of three or more as can be seen from the results of Rabl et al. (2004). It is clear that external costs are not fully internalized when having an allocation with free auctioning, because no price has to be paid for the remaining damage (Torfs R; De Nocker L. 2005).

Ecofys(2008) investigated the impact of using output based benchmarks as a rule for allocation in the so called IFIEC method. Ecofys writes that the IFIEC method limits the CO_2 costs of electricity production to the actual costs of achieving a clean production level, as determined by a benchmark.

They believe that the application of the IFIEC method reduces electricity costs for end-users in the order of, on average, 10-30% of industry's electricity bills and 5-20% of household bills. Within EU-ETS, the IFIEC method provides the same environmental incentives as auctioning and better incentives than the current system of grandfathering, provided that a single (not fuel-specific) benchmark is used for all electricity producers under EU-ETS.

Not everybody is convinced of the advantages of a benchmark based system. There are indeed advantages as some may perceive benchmarked allocation as fairer (NERA 2007) and it may address competitiveness impacts and emissions leakage if updated. But it is also argued that the system is too complicated and may reduce scheme cost-effectiveness.

Taxes

OECD gives a definition (Torfs R.; De Nocker L. 2005) of environmentally related taxes "…as any compulsory, unrequited payment to general government levied on tax-bases deemed to be of particular environmental relevance. Taxes are unrequited in the sense that benefits provided by government to taxpayers are not normally in proportion to their payments. …. The name, or the expressed purpose, of a given tax is not a criterion….The focus is instead on the potential environmental effects of a given tax, which is determined by the tax impacts on the producer and consumer prices in question, in conjunction with the relevant price elasticities."

Full Cost pricing requires that external (environmental or other) costs are accounted for in market prices of economic goods to ensure a proper allocation of resources and to achieve maximum social welfare. Emission charges/taxes stand for direct payments based on measurements or estimates of quantity and quality of pollutants discharged.

There are two recognized approaches to internalizing environmental costs through the application of a tax (EEA 2005).

1. Pigouvian tax. The tax is set at the level that internalizes all the environmental costs, i.e. the costs of environmental damage (also called externalities or external costs), into the price. To guarantee this, the tax rate must be equal to the marginal social costs and the marginal social benefit that result from the activity that emits an additional unit of pollution (see OECD, 2001). This approach is referred to in the literature as a Pigouvian tax after Pigou who developed the rationale for environmental taxation.

2. Baumol-Oates tax. The tax is set at a level which is estimated to be sufficient to achieve a given environmental objective.

The preferred approach — based on theoretical economic considerations — is the first (the Pigouvian) approach: this way of taxing (in a perfect market) results in the most efficient use of resources. However, full internalization of external costs is difficult to achieve in practice because the value of environmental damage is generally not known. The more pragmatic Baumol–Oates approach is therefore generally used, meaning that, if the environmental target is given, environmental taxes can be used to achieve this target effectively, again resulting in the most efficient use of resources. They also provide incentives for technological improvements and increased efficiency in the long run (dynamic efficiency).

Sometimes, it is argued that VAT already internalizes a part of the externalities. VAT is the most important tax on electricity in many MS. In (Torfs R.; De Nocker L. 2005) it is argued that because VAT is a general tax

for all products and services, VAT does not give price signals and does not internalize at all. When comparing taxes with environmental impacts, one should not take into account VAT. Only when there is a (partial) exemption for VAT, it can be included, and regarded as a subsidy.

Electricity tax based on technology mix

Product charges/taxes are applied to products that create pollution either when they are manufactured, consumed or disposed of (V. Oikonomou; C. J. Jepma 2007). Product charges/taxes are intended to modify relative prices of products and/or finance collection and treatment systems. One practical form of product charges/taxes is tax differentiation leading to more favourable prices for ''environmentally friendly'' products and vice versa, so that prices reflect the true costs and tell the ecological truth. However, as it is often not feasible to fix a different tax for each individual case, averaged external costs for classes of goods, sites or activities are used to determine the tax to be imposed (Bickel P.; Friedrich R., 2005).

The problem with averaged external costs for classes of goods is that there is no possibility to switch to the technology of choice and benefit from this. Having a consumer price equal to the social cost because for example there is an electricity tax equal to the external cost of electricity production, does not necessarily mean that external costs are fully internalised. It is a product tax based on the average electricity production and thus averaging the effects in the retail market does not give proper price signals to the consumer. Few tax systems are coupled to environmental performances knowing that they are general taxes. A consumer price equal to social cost is not as good as full internalization.

Emissions trading with safety valves

A safety valve is a hybrid of the price and quantity instruments (taxes and emissions trading). The system is essentially an emission cap and tradable permit system but the maximum (or minimum) permit price is capped. Emitters have the choice of either obtaining permits in the marketplace or purchasing them from the government at a specified trigger price (which could be adjusted over time). The system is sometimes recommended as a way of overcoming the fundamental disadvantages of both systems by giving governments the flexibility to adjust the system as new information comes to light. It can be shown that by setting the trigger price high enough, or the number of permits low enough, the safety valve can be used to mimic either a pure quantity or pure price mechanism. China uses the CO_2 market price for funding of its Clean Development Mechanism projects, but imposes a safety

valve of a minimum price per tonne of CO_2.

Performance-based command and control

Command and control measures prescribe a certain technology or a certain standard. In general, legal or regulatory instruments are being used when governments can set legal requirements on power companies, industry and households with financial penalties for non-compliance. They are traditional main pillars of environmental policy. Examples include standards on energy use, emissions and standards for technology. The debate on making Carbon Capture and Storage mandatory for certain new coal power plants is vivid and shows that the influence of such instruments can be large. Their ability to internalize depends on the knowledge of externalities and the choice of standards. An often unrealistic condition for full internalization is the continuous adaptation of the standards to changing conditions.

Negotiated and voluntary agreements

Organizational measures include negotiated and voluntary agreements. They are commitments undertaken by power producers or industries in consultation or negotiation with a public authority and are usually recognized by that agency; they are expected to have a high degree of effectiveness if they are combined with other policies. These agreements can take many forms concerning the degree of bindingness (e.g., legally non-binding press statements to legally binding covenants). They include a wide range of issues, such as a decrease in energy consumption or phasing in of low sulphur petrol. Internalization is often not met because of lack of information on costs and reduction volumes and because agreements often don't have a legally binding character.

Implementation of policy instruments in Europe

The following documents are of interest for a better understanding of future implementation of policy instruments: the EU Green Paper on European Strategy for Sustainable, Competitive and Secure Energy SEC(2006)317; the Green Paper on energy supply security COM(2000)769; the Commission's new Green Paper on energy efficiency COM (2005) 265; Directive2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market (RES-E Directive); 2004/8/EC Directive on the promotion of cogeneration, European Commission. (2008); Proposal for a Directive of the European Parliament and of the Council on the promotion of the use of energy from renewable

sources. Brussels, 23.1.2008, COM 2008

The impact assessment of the EU ETS review (European Commission 2008) concludes that the preferred long term option is full auctioning with free allocation taking place during a transitional period based on harmonised EU-wide rules, and taking into account progress in reaching an international agreement to avoid net carbon leakage and for those installations in energy intensive sectors exposed to international competition.

Do policy instruments internalize external costs?

When the objective is to fully internalise external costs, the only condition to be fulfilled is that consumer prices have to reflect full social cost. Internalizing as such can be the objective, although it does not tackle a specific environmental problem and although it is not common to have such a "vague" objective. Many people wonder whether it is sufficient that prices go up and consumption has somewhat lowered thinking that this is the only effect of a price increase. The theory behind Full Cost pricing, however, cannot easily be applied, as it relies on strict assumptions that are not easily met in reality. Assumptions made include the existence of clear preferences and the existence of competitive markets, which in reality are only partially or not met. The difficulty to apply the Full Cost pricing in practice has led to the adoption of a less ambitious objective than that of welfare maximization.

A policy objective does not necessarily have to match with the principles of full internalisation. Some policy objectives can not be realized following the principles of full internalization, because the assumptions behind the objective are simply in contrast with the theory of social cost minimisation.

Lower social cost versus full internalization

Within the context of policy instruments evaluation, it is important to be able to distinguish real internalizing effects and effects caused by decreasing total or average external costs. When investment decisions are made, e.g. about which power plant technology to use or where to site a power plant, it is evident that it would be of interest for society to take environmental and health impacts into account and include the external effects into the decision process, i.e. to internalise external costs. To support the decision process, the social costs of the investment alternatives, i.e. the sum of internal and external costs, can then be compared (Bickel P.; Friedrich R., 2005).

Policy instruments that fully internalise external costs differ from policy instruments that aim at lowering the social costs: (1) it is possible that the level of the remaining emissions is too low or too high than (in economical terms) the social optimum and (2) no price has to be paid for the external

costs from the remaining emissions in contrast to the principle of the polluter pays principle. An overview of advantages and disadvantages is given in (Proost S.; Rousseau S. 2007):

Table 6.1 Advantages and disadvantages of policy instruments

Policy instruments	Advantages/disadvantages
Emission tax = marginal damage	Correct choice of emission reduction technologies. Consumption pays the marginal social cost.
Subsidy equal to marginal damage	Correct choice of emission reduction technologies. Too large consumption because the product is sold much below marginal social cost.
Product tax	No incentive to switch to cleaner technology Too small consumption.
Technological standard	Correct choice of emission reduction technologies. Difficult to determine the correct standard appropriate for all producers. Too large consumption because the product is sold below marginal social cost.

Source: Proost S.; Rousseau S. (2007)

Low external cost versus low social cost technologies

Often, it is argued that renewable technologies are in favour of non-renewable technologies because the external costs are lower (EEA 2005). The provisions in the guidelines for support for renewable energy are based on calculations of external costs and follow a practical approach. “Member States may grant operating aid to new plants producing renewable energy that will be calculated on the basis of the external costs avoided. These are the environmental costs that society would have to bear if the same quantity of energy were produced by a production plant operating with conventional forms of energy. They will be calculated on the basis of the difference between, on the one hand, the external costs produced and not paid by renewable energy producers and, on the other hand, the external costs produced and not paid by non-renewable energy producers. At any event, the amount of the aid thus granted to the renewable energy producer must not exceed EUR 0.05 per kWh .” One could wonder why operating aid is based on the difference of the external costs and not on the difference of the social costs. After all, the sum of both private and external costs is a better indicator.

Policy linkages with emission trading

It was found very important to make good estimates of overlaps between ETS and other EU or local policies. Overlapping effects occur when the effects of two or more policy measures can not be simply aggregated (Duerinck J. et al. 2008). The combined effect of two or more measures is not always the sum of the individual effects. Various policies have been defined at national or EU level that affect GHG emissions from the electricity sector. It can theoretically be shown that other policy instruments from sectors covered by EU-ETS might have significant effects on the emission trading price, distribution of emissions reduction or distribution of efforts. *However, other policy instruments have no effect on total GHG emissions with the cap and trade emission trading is enforced at EU-level after 2012.* This is more than an overlap, the emission reductions of all those extra policies vanish in the overall CO_2 cap. Of course there are more externalities than CO_2.

Concerning the link of ETS with taxes, one can read in (European Parliament 2008): "The EU…recalls that the energy tax directive foresees that, under certain conditions, taxation can be fully or partially replaced by alternative market-based instruments, including, in particular, the EU-ETS" (p. 18) When combining taxes with EU-ETS there is consensus that the effects are additive and that sector should only be subject to one system (Sijm J 2003). "Of the different Community market-based instruments existing in the field of energy, transport and environment, energy taxation is, perhaps, the most cross-cutting with impacts in all three areas and directly interacting with all other instruments" (European Parliament 2008). Excluding the environmental impacts addressed by EU ETS from the scope of the Energy Taxation Directive might be a viable solution that could also resolve the problem of potential overlap between the two instruments while ensuring that the remaining objectives of energy taxation are observed. Such a solution could also avoid difficulties stemming from the differing features of EU ETS (uniform price across the EU that however varies over time) and energy taxation (different prices reflecting the freedom of Member States to set tax rates above the minima as they see fit, that tend, however, to be rather stable over time). However, any move towards such a solution merits further in-depth analysis, especially if the EU ETS is significantly broadened in scope.

Concerning the link of ETS with policies promoting renewables one can read in (Sijm 2003) that "the operational linkages and interactions between emissions trading and renewable energy policies in general, and between the markets for power, green certificates and emission allowances in particular, are quite intricate and sometimes complicated. Overall, however, there seem to be no major problems or conflicts between the operation of the EU ETS and the Dutch support policies for renewable electricity. On the contrary, the

operation of the instruments seems to be mutually reinforcing in the sense that obtaining the operational target of one instrument enforces the achievement of the target of the other. The only problem might be the double or over-stimulation of existing producers of renewable energy." Little literature is found on the modeling of the impact of combining the EU-ETS and MS renewable energy objectives. Nijs W. and Van Regemorter D. (2008) examine the impact of the renewable objectives of Belgium, given a climate policy, both in terms of cost and change in the energy system in 2020. In the context of overlapping effects it is interesting to analyze the difference between a "full policy" scenario with a carbon price and a renewable target and a scenario with only a renewable target. The targets in the proposed EU-directive for Belgium are for the non-ETS sectors a reduction of 15% CO_{2eq} in 2020 compared to 2005 and a renewable target share of 13% in 2020. The cost of reaching this target and its implications for the energy system are evaluated with the Belgian partial equilibrium MARKAL/TIMES model. It has benefited from the development of TIMES and the associated software VEDA within the EU FP6 research project NEEDS. The macroeconomic background for Belgium is derived with GEM-E3 and only CO_2 emissions have been modeled. The model assumes a discount rate of 4% and has 12 time slices (day, night and peak for the four seasons) in the time horizon up to 2050 so fluctuating electricity demand is modeled accurately.

The addition of a renewable energy and biofuel target above the climate policy does not impose an excessive cost for Belgium as shown in Table 6.2. The total additional cost increases over the entire horizon by 8% going from 1.04 to 1.12 % of GDP_{2000}.

Table 6.2 Total discounted welfare cost compared to a Belgian reference scenario without policy.

	Policy assumptions in 2020.	Annualised additional cost [M€$_{2000}$]	Annualised additional cost, % GDP_{2000}	CO_2 emissions in 2020 (Mton)
Reference scenario	No climate policy	/	/	149
Only carbon policy	Carbon price 35 €/t	2289	1.04%	107
Only renewable policy	Biofuel 10% RES 13%	775	0.35%	124
Carbon and renewable policy	Carbon price 35 €/t Biofuel 10% RES 13%	2472	1.12%	101

Source: Nijs W. and Van Regemorter D., 2008

The addition of both targets on top of a climate only policy accelerates the reduction of CO_2-emissions, but after 2030 the difference in terms of CO_2 emissions and technology choices is small. On the longer term, the price on carbon stimulates renewable technologies and the marginal cost of renewable decreases from 51€/MWh in 2020 to zero after 2030. When imposing a CO_2 *target* and not a CO_2 price in the model, the marginal cost of the 13% renewables target lowers from 51 €/MWh to 28 €/MWh in 2020. Making the CO_2 price endogenous lowers the marginal cost of a renewable target although the CO_2 emissions and system cost stay unchanged. Because of this large difference, it is important to stress that the cost of a renewable target on top of a climate target has to be examined in a European model where the CO_2 price is endogenous. The most important conclusion in the context of policy instruments is that a policy targeted only on renewable energy alone is not enough for the climate target. The CO_2 emissions in 2020 decrease from 119 Mton to 101 Mton in the "full policy" scenario, but they increase to 124 Mton in the scenario with only promotion of renewable energy.

Policy recommendations and conclusions

Following recommendations and conclusions can be made:

- Up to now, external costs are decreasing, but are not internalized.
- Few tax systems are coupled to environmental performances and this is why making the consumer price equal to the social cost is not at all full internalization.
- Full internalization is more than stimulating technologies with a lower total social cost and certainly more than stimulating technologies with a lower external cost.
- Relative prices matter (stimulating green electricity production by lowering the price is effective), but green promotion is not enough for reducing CO_2 emissions;
- The interaction of tax systems with EU ETS is additive but for each target group, only a single instrument should be used. Further research is needed for analyzing the overlapping effects and the meaning of combining policy instruments.
- The interaction of promoting renewables with EU ETS is strong in the medium long term, but after 2030, an assumed strict climate policy induces increased use of renewables due to the high carbon price.
- A European model is needed to bridge the gap between policy instruments and the resulting technology combination with their social cost, taking into account all interactions between technologies and taking into account the interaction with non-electricity energy vectors.

6.4 POLICY INSTRUMENTS TO PROMOTE RENEWABLE ENERGY SOURCES IN BRASIL, CHINA, INDIA AND TURKEY

In the developing countries selected for this analysis, the governments have been implementing policy instruments to promote renewable energy in power generation, with an aim to: 1) mitigate GHG emissions, 2) foster economic development of rural areas, and 3) enhance the energy security by diversifying the energy matrix and by reducing the dependence on imported energy sources. In recent years, rapid economic growth has been widely observed in these developing countries. In 2006, Turkey achieved GDP growth rate by 6.1%, China 10.7% and India 9.2% (World Bank Statistics). Under this momentum of economic growth, these countries have been undergoing increasing electricity consumption. Given that the power sector is characterised by its high greenhouse gas (GHG) emissions, a cleaner energy matrix is necessary to support sustainable economic development. Lack of access to electricity has been a crucial contribution to economic and social inequality amongst areas within a country, as has happened in Brazil, China, and India. Whilst grid extension to these off-grid remote areas is not always economically plausible, electrifying these areas by means of local renewable resources can be an alternative. Energy security or security of supply of a country is its ability to supply energy to meet demand at a price that protects economic growth. Long-term measures to increase national energy security may be aimed to decrease the dependence on one energy source or imported sources and to exploit local fossil fuels or renewable resources.

Governments have a number of options that they can use to promote renewable energy. The first is to support the voluntary measures, particularly through education and dissemination. The second type refers to environmental standards or energy taxes. The third option is to promote renewable energies through direct support. Generally, a mix of policy instrument is essential to success. (Sawin, 2004) This report will focus on the investigation of policy instruments that offer direct support to renewable energy projects, in the developing countries of Brazil, China, India, and Turkey. The following paragraps briefly review the policy instruments that are currently active in the four countries.

Brazil

As of 2005, Brazil had installed power generation capacity of around 100GW. Hydroelectricity accounted for over 70% of the capacity, mainly from large-scale hydro power, and gas fired power plant ranked the second, with 10.07%. By contrast, the share of installed capacity of coal-fired power is around 1.4%. In terms of electricity production, hydropower, both large- and small-scale, contributed more than 80% of the domestic power production in that year. See Table 6.3 below for more information. In 2005, the installed capacity of renewables-based power plants other than hydro was only 5% of the total capacity; given its abundant renewable resources, Brazil has a great potential in further fostering renewables energy technologies.

Table 6.3: Installed capacity and electricity generation by technologies as of year 2005 in Brazil

	Installed capacity (MW)	% of capacity	Electricity production (GWh)	% of production
Coal	1,415	1.41	9,971	2.47
Oil	5,251	5.24	11,737	2.91
Gas	10,085	10.07	18,813	4.67
Nuclear	2,007	2.00	9,855	2.45
Large hydro	68,400	68.29	337,457	83.73
Small hydro	1,740	1.74		
Wind	28.6	0.03	93	0.02
Biomass	3,068	3.06	14,361	3.56
Other sources	8,170	8.16	745	0.18
Total	100,164.6	100	403,032	100

Source: Brazilian Ministry of Mines and Energy (MME) and IEA statistics

The earliest renewable energy projects date back to mid 1970s. Since the 1990s, government programmes commenced to electrify off-grid rural areas through renewable energy technologies. A federal programme, the Programme for Energy Development in State and Municipalities (PRODEEM), during the years 1994-2001, was launched, in order to electrify remote villages through locally available renewable sources and thereby to promote self-sustainable social and economic development of these areas. In general, flaws in the execution were revealed. Firstly, the programme only installed 18% of the systems planned, 46% of systems installed were mislaid, and 36% were installed correctly but soon stopped working. Secondly, the target of diversifying energy resources was not met as photovoltaic technology prevailed, whereas wind systems and small hydroelectric stations

were excluded. (Ruiz, Rodríguez, and Bermann, 2007)

During 2001-2004, two programmes were launched to promote electricity generation by using wind power and small hydroelectric power. These are the Emergency Energy Programme (PROEÓLICA) for the wind power and the Programme for the Commercialisation and Development of Small Hydroelectric station (PCH-COM) for the latter source. PROEÓLICA aimed to install wind turbines for 1050MW and to connect them to the electrical network;a purchase of the generated electricity (up to 1050 MW). It was guaranteed over a period of 15 years, at a price fixed by the regulatory authority. Upon enactment of the programme, this price lay at R$ 112/MWh. In May 2002 a new reference price of R$ 72.35/MWh was determined by ANEEL (Resolution No. 248), which, however, was reckoned unable to cover the emerging cost[28] of power generation from wind energy. This programme later on was transferred to the Alternative Energy Source Incentive Programme (PROINFA). The PCH-COM programme aimed to commercialise small hydroelectric stations. A total capacity of 1200 MW was planned to be installed during the years 2001-2003. Loans were provided to the enterprise; also, generated electricity by private sectors was guaranteed a purchase from the utility at a fixed price. However, four months after it was launched, this programme became inactive as the prices did not provide enough incentives to the private investors.

Regulated by Law 10438/02 and later revised by the Law No. 10762/03 and Decree 5025 in March 2004, the Alternative Energy Source Incentive Programme (PROINFA) was enacted in 2002 and became the main programme operating to promote electricity generation from renewable energy sources. In the first phase (year 2002-2006[29]), this programme required installation of 3300 MW of electricity capacity from wind turbines, small hydropower stations, and biomass plants, with 1100 MW for each source. A tendering system was introduced to contract this capacity. Long-term purchase guarantee was offered to independent power generators: produced electricity will be purchased by Eletrobrás[30] at fixed feed-in prices for 20 years. The fixed purchase prices vary amongst renewable sources and are determined by the economic value of the benchmark competing energy source[31], as shown in Table 6.4. The PROINFA-tariffs are adjusted annually according to the IGP-M, the General Market Price Index[32]. The unadjusted economic values (feed-in tariffs) and adjusted purchase prices of electricity contracted in the first phase of PROINFA are shown in Table 6.4.

Table 6.4: Feed-in tariffs by different renewable energy technology in Brazil

Renewable Energy Technology	Feed-in tariffs R$/MWh (March 2004)	Feed-in tariffs €cents/kWh (March 2004)	Adjusted tariffs €cents/kWh (July 2005, adjusted by IGP-M index)
Small-scale hydro	117.02	4.50	5.1
Wind power	180.18 – 204.35	6.93-7.86	7.8-8.9
Biomass			
Sugarcane	93.77	3.61	4.1
Wood residues	103.20	3.97	4.5
Rice husks	101.35	3.90	4.4
Landfill biogas	169.08	6.50	7.3

Note: 1€ = R$ 2.60. Source: do Valle Costa, La Rovere, and Assmann (2008)

In the first phase, the programme established a *minimum equipment nationalisation index*[33] at 60% of the equipment value, which will increase to 90% in the second phase of the programme due to expected larger scale of long-term projects (Dutra and Szklo, 2008). This index aimed at developing the manufacturing industry of renewable energy technologies that produce durable goods and create employment opportunities.

Pursuant to Law 10438/2002, the second phase of PROINFA aims to achieve the target that the gross electricity consumption from wind energy, biomass, and small hydro power to achieve 10% of the total electricity consumption by 2022. In 2004, a new regulatory framework for the power sector was introduced by the Law 10848, and as understood, the second phase of PROINFA will have to operate in compliance with this new model. The new model introduces a bidding system to replace the previous wholesale energy market to contract new electricity generation capacity from both conventional and non-conventional fuels. This aims to control excess rise of the electricity tariffs as contracts will be given to the projects which generate electricity at lower prices. In order to keep promoting the use of renewable energy, a share of electricity amount to be contracted in the bidding processes will be reserved to these sources. The share will be defined by the Ministry of Mines and Energy (MME), under the condition that the bidding prices from renewable sources shall not exceed 0.5% of the final tariff in any year, when compared to a power generation expansion based on conventional sources. Moreover, the accumulated tariff impact due to renewables shall not exceed 5% of the tariff if it was formed only by conventional sources. The capacity of new renewables projects will be capped to limit their impact on the final electricity tariffs. Despite the broad guidelines mentioned above, the implementation date of the second phase is still unknown.

China

China has roughly 9.4% of the world's installed electricity generation capacity and is predicted to be responsible for up to 25% of the increase in global electricity generation over the next three decades. For the purpose of power production, coal has been a dominant source. In 2005, it was used to generate almost 79% of China's electricity, whereas renewable resources – hydro power (mainly large scaled) and biomass - accounted for 16%, of which hydro power has a dominant share. See Table 6.5 for more information.

Table 6.5 Power generation by sources in 2005 in China

	Electricity production (GWh)	% of total production
Coal	1,972,267	78.97
Oil	60,634	2.43
Gas	11,931	0.48
Biomass	2,504	0.1
Nuclear	53,088	2.13
Hydro power	397,017	15.9
Total	2,497,441	100

Source: IEA energy statistics

In 1970s and 1980s, demand of electricity grew in rural areas. In order to meet this trend, China provided financial incentives to promote using renewable sources, such as biogas, fuel wood, and small hydropower, to generate electricity. These incentives included low interest loans, financial grants, and subsidies. China emitted 10.6% of global carbon emission from fossil fuels in 1990 and 14.2% in 2003, and this share is projected to rise to 22.2% by 2020 (IEA, 2006). In correspondence with this, since 1990s, environmental protection and sustainable development have also become targets for government policies to promote electricity generation from renewable sources, in particular solar energy, wind power, and biomass.

Several executive programmes have commenced since 1990s to promote electricity generation from renewable resources. The Brightness Programme, implemented in 1996, is an umbrella programme that includes the Township Electrification Programme (TEP) (implemented 2001-2003), and the Village Electrification Programme (2005-2010). The TEP contracted 20 MW of solar PV and 840 kW of wind, and 200 MW of small hydro through public biddings, to provide electricity for more than 1000 townships. The Wind

Power Concession Programme, implemented in 2002, has been the main programme to develop large-scale on-shore wind projects to connect to the grid. As of 2005/2006, the installed capacity of each RET nationwide is reported in the second column of Table 6.6.The Renewable Energy Law, a latest regulatory framework for renewable energy projects, took effect on January 1, 2006. By encouraging investment in wind, solar, water, biomass, and other renewable resources, the Law notifies that installed capacity of renewables-based generation shall reach 15% of total generation capacity by 2020 and the projected capacity by different renewable energy technologies (RETs, hereafter), as shown in Table 6.6, shall be achieved. Moreover, the Chinese government's Eleventh Five-year Plan, dating from 2006 to 2011, specifies measures in detail to increase the shares of renewable energy: 1) the construction of 30 large-scale wind farms with a 100MW capacity; 2) the provision for grid-connected wind and biomass to reach 5 GW and 5.5 GW respectively; 3) to achieve biomass and waste fuelled generation of more than 5.5 GW by 2010.

Table 6.6: Realised and projected installed capacity of different RETs in China

RET	Current installed capacity (2005/2006) (MW)	Projected installed capacity in 2020 (MW)
Small hydro power	2850	300,000 [34]
Biomass	1880	30,000
Wind power	1260	30,000
Solar PV	65	1,800

Source: Fang and Zeng (2007)

Supported by various programmes, the major policy instruments that are currently active for renewables-based power generation include renewable portfolio standards (see below), market regulating mechanisms, fiscal incentives, and grants for research and development. In late 2007, the Renewable Portfolio Standard (RPS) mandates were announced (REN21, 2008). Firstly, the share of non-hydro renewable energy should be 1% of total power generation by 2010 and 3% by 2020. Secondly, any power producer in China with capacity greater than 5GW must increase its actual ownership of power capacity from non-hydro renewables to 3% by 2010 and 8% by 2020. Market regulatory mechanisms are employed for biomass and wind power technologies connected to the grid. Favourable tax rates and custom duties reductions are provided to the renewable technologies. Other financial incentives are also available: 1) renewable energy development fund is

provided to encourage studies in renewable energy in rural areas, to cover early-stage research and development costs for projects in all areas, and to help fund construction of renewable projects on islands; 2) low interest loans are provided for renewable energy project[35].

In 2006, the National Development and Reform Commission (NDRC) announced the feed-in tariffs policy for different renewables technologies. As shown in Table 6.7below, the tariffs vary with different technologies. A fixed premium of 0.25 Yuan, around 2.33 €cent/kWh, is provided per unit of electricity generated by biomass technology. Since 2002 (when the Wind Power Concession Programme was implemented) a government tendering system has been introduced to contract generation capacity from large-scale on-shore potential projects (100-200MW), and a power purchase agreement at winning bidders' prices was guaranteed by state-owned utilities for 25 years. In 2006, it was modified as that the winning bidder's price is the feed-in tariff for the first 10-15 years, and after that, the purchase price will be the average local feed-in price on the market. For other renewables-based technologies, tariffs will be determined case by case.

Table 6.7: Feed-in tariffs for different RETs in China, announced in 2006

Renewable energy technology (RET)	Feed-in Tariffs (Yuan/kWh)
Biomass	0.25 Yuan + coal fired power price
Wind power	Following the Wind Concession Programme, the lowest bidder's price as the fixed power purchase price for the first 30,000 full load hours. The duration of the purchase depends on individual plant's load factor, ranging between 10-15 years. After 30,000 full load hours, the project generator will receive the average local feed-in-tariff on the power market at that time.
Solar and other RETs	Project-based approval price

Source: REN21(2008)

As shown in Table 6.7the technologies of small hydro power, biogas, wind power, and municipal wastes have favourable VAT rate at 6%, 13%, 8.5%, and 0% respectively (the standard rate is 17%). Biogas, including biogas production and related equipment production costs and purchases, has a favourable VAT rate. Since 2001, the VAT for municipal waste-generated

electricity had been completely refunded, and in 2004, the regulation further clarified that this VAT refund is only applicable for electricity generated using more than 80% fuels stemming from municipal waste, which gives a strong incentive for municipal power generation. These VAT exemptions are considered a significant reduction in power generation costs of these technologies and help to level the playing field so that renewable energy is better able to compete at the cost basis (Sawin, 2004).In the case of wind power, for instance, the reduction is about 0.05-0.07 Yuan/kWh (around 0.47-0.65 €cent/kWh) according to the difference in cost in the various wind farms (Li, Shi, and Ma, year unknown; NREL, 2004). Moreover, further income tax reduction by 15% are applicable for the biogas and wind power technologies, and this should encourage power generators to invest further on technology improvement, which, in turn, will lower generation cost.

Table 6.8: Favourable tax rates for renewable technologies (issued in 2001) in China

Technologies	VAT	VAAT (Value-Added Annex Tax)	Income Tax
General	17%	8% of VAT	33%
Small hydro power	6%	8% of VAT	33%
Biogas	13%	8% of VAT	15%
Municipal waste	0	0	33%
Wind	8.5%	8% of VAT	15%

Source: Li, Shi, and Ma[36](year unknown)

India

Conventional fuel cycles, especially coal-fired power, have been traditionally the main technologies applied in electricity generation in India. As of April 30, 2008, official statistics show that 64.6% (92,156.84) of the total installed capacity is from thermal power, 24.7% (35,908.76 MW) from large hydroelectric power, 7.7% (11,125.41 MW) from other renewable sources, and 2.9% (4,120 MW) from others. As of December 31, 2007, total renewable-based electricity generation capacity in India is 11,478 MW, including 11,272 MW (98.2%) of grid connected and 205 MW from captive/distributed generators[37]. As shown in Table 6.9, nearly 70% of the total renewable grid-connected capacity,, is accounted by wind energy, 18.15% by small-hydro power, 6.39% by cogeneration-bagasse, and 5.37% by biomass power. Comparing the installed capacity with the estimated potential shown in the same table shows that India still has considerable renewable resources unexploited.

Table 6.9: Estimated potential and cumulative achievement of electricity capacity of renewables in India (as of December 31, 2007)

RET	Estimated potential (MW)	Cumulative installed capacity (MW)	% of total installed capacity
Wind power	45,195 (53.31)	7,844.52	69.59
Biomass	16,881 (19.91)	605.80	5.37
Small Hydro power (Up to 25MW)	15,000 (17.69)	2,045.61	18.15
Bagasee cogeneration	5,000 (5.9)	719.83	6.39
Waste	2,700 (3.18)	55.25	0.49
Solar power		2.12	0.02
Total	84,776	11,272.13	100

Source: Annual report (2007-08), Ministry of New and Renewable Energy

The Indian renewable energy programme was launched primarily as a response to the perceived rural energy crisis in the 1970s. Cash subsidies were provided for promoting renewable energy technologies. In the early 1990s, the focus of programmes shifted from purely subsidy-driven dissemination to technology promotion, through a commercial route. Aiming to promote investment in renewable technologies, this technology-push approach embodied fiscal and financial incentives such as subsidised interest rates (low interest loans), capital subsidies, long repayment schedule, tax concessions, low import tariffs, duty waivers and accelerated depreciation. (Ghosh, et al, 2002)

The India Alternate Energy Project was launched in 1991, aiming to achieve commercialisation of wind power and solar PV technologies. Feed-in tariffs and purchase guarantee were applied at the state level. The effectiveness in the dissemination of wind power technology turned out to be more significant than that for solar PV technology, due to massive investment cost of solar PV technology[38]. In the 10th Five-Year Plan starting from April 2002, solar technology was targeted as the main means to electrify 5000 villages[39]. Even though low cost financing was provided, the massive investment cost of solar technology and low possibility of return made this project unattractive for private sector[40] (Thakur et al, 2005).

In 2003, the Electricity Act[41] took effect, which has been serving as a regulatory framework for Indian power sector reform as well as for efficient and environmentally benign policies. In accordance with the Electricity Act 2003, the Indian government released the National Electricity Policy in

February 2005 in which the need for the promotion of non-conventional energy sources was emphasised. Specifically, the Policy notes the need to reduce the capital cost of projects based on renewable energy and stresses the importance of promoting competition amongst renewables projects. Based on this broad policy mandate, State Electricity Regulatory Commissions (SERCs) ought to increase the share of electricity from non-conventional resources and guarantee a purchase of such electricity at prices resulting from competitive bidding procedures. In practice, it is completely left to the individual SERC to enact detailed policy measures to promote the development of renewable technologies. More recently, the Integrated Energy Policy, released in August 2006, further requires power regulators to mandate feed-in laws for renewable energy, where appropriate, as provided under the Electricity Act 2003, as well as to provide alternative incentive structure for utilities to integrate renewables into their systems.

Currently, a combination of policy instruments - Renewable Portfolio Standard and feed-in tariffs, at the state level, is the main market mechanism. The RPS ratios and feed-in tariffs are state-specific (See Table 6.10 for the details). Renewable electricity as a proportion of total procurement power by the distribution licensees is determined by respective SERC. These ratios range from 0.5% to 10% (Singh, 2007) and are guided by the potential for renewable energy resources, existing utilisation and expected investment in each state. The tariffs at which distribution companies guarantee to purchase also vary amongst areas, as well as technologies. These buy-back prices under the RPS are measured mainly in a cost-based nature and determined by investment cost and rate of return[42] (Singh, 2007). More recently, in January 2008, with a view to harness the vast solar energy potential in the country for power generation, a new initiative on developing grid interactive solar power generation has been announced. A maximum capacity of 10 MW from each Indian state will be eligible under the scheme and 5 MW per developer. A fixed premium of 12 Rs/kWh, around 20.68 €cents/kWh, for solar photovoltaic power and 10 Rs./kWh, around 17.23 €cens/kWh, for solar thermal power are provided for electricity fed to the grid. Developers will sell electricity to state-run utilities and the premium will be paid to them on top of the tariff the utilities offer. The subsidy is valid for a period of 10 years (MNRS Annual report, 2007/08).

In addition, fiscal and financial incentives are also available in each state to encourage investment in technology development.

Table 6.10: RPS and feed-in tariff in large states of India as of 31/07/2007

State	RPS (%)	Feed-in Tariffs (Rupee/kWh)			
		Wind	Small hydro	Biomass	Bagasee cogeneration
Andhra Pradesh	5 (2005/06, 2007/08) 0.5 fro wind energy	3.37 with 5% annual increment (base price as on 01/04/2004)		2.63 (2005-06) with 1% annual increment for 5 yrs	2.63 (2005-06) with 1% annual increment for 5 yrs
Chattishgarh	Available			2.67 (2004-05)	2.67 (2004-05)
Gujarat	1 (2006/07) 1 (2007/08) 2 (2008/09)	3.37 for new wind mills for up to 20 years		3	3
Haryana	3 (2007/08)	4.08 with 1.5% annual increment (base year 2007-08)		4	3.74 with 2% annual increment (base year 2007-08)
Karnataka	Min 5 Max 10	3.4 fixed for 10 yrs	2.8 for 10 yrs	2.88 (2004-05) with 1% annual increment on base year for 10 yrs	2.8 with an annual increment by 2%
Kerala	Available	3.14 fixed for 20 yrs		Incentives only up to 2005-06	Incentives only up to 2005-06
Madhya Pradesh	0.5	1st year: 3.97 2nd year: 3.80 3rd year: 3.63 4th year: 3.46 5th – 20th yr: 3.3		3.33 – 5.14 for 20 yrs, with increment of 3 - 8 praise.	3.33 – 5.14 for 20 yrs, with increment of 3 - 8 praise.
Maharashtra	3 (2006/07) 4 (2007/08) 5 (2008/09)	New project: 3.5 in the first year, with an annual increment by Rs. 0.15, for 13 years		3.04 – 3.43 with 1% annual increment for 13 yrs	3.05 (commission year)

	6 (2009/10)				
Orissa	3 (2007/08) 3.5 (2008/09) 4 (2009/10) 4.5 (2010/11) 5 (2011/12)	N A			
Punjab	1 (2007/08)	3.66 with 5% annual increment till 2012		3.59 (2007-08) with five annual increment of 3% till 2012.	3.59 (2007-08) with five annual increment of 3% till 2012.
Rajasthan	*Wind*: 2 (2006/07), with an annual increment by 0.3, till max 4. *Biomass*: 0.37 (2006/07), and 0.83 (2007/08), with annual increment by 0.3, till max 2. *Solar*: up to 50MW *Others*: 25 MW	Projects commissioned after 3/02/06: 3.31 for the first 10 yrs; 3.79 from 11 to 20 yrs. Updated tariffs: 3.59/3.67, depending on areas (base year 2008-09)	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14.	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14. 3.60–3.96 (2007/08)	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14. 3.60–3.96 (2007/08)
Tamil Nadu	10	2.90		2.73 (2000-01) with 5% annual increment for 9 yrs	2.73 (2000-01) with 5% annual increment for 9 yrs
Uttar Pradesh	7.5		3.39 – 1.90 for the 1st to 20th year of operation.	2.86 for existing and 2.98 for new with 4 praise increment per year.	2.86 for existing and 2.98 for new with 4 praise increment per year.

Source: Singh (2007); MNRE Annual report 2007/08

Turkey

Currently, electricity is mainly generated from thermal power plants, geothermal energy and hydro power plants. As shown in Table 6.11, electricity generated from conventional thermal sources comprises the largest share of Turkey's electricity supply, contributing 75% in 2005. Hydroelectricity generation takes up almost all of the remainder, 24.43%. Turkey has abundant hydraulic resources and currently identified gross potential and energy production capacity are nearly 50GW and 112 TWh/year (Bilgen et al, 2008), and the government hopes to expand the hydroelectric power plant capacity to 35GW by year 2020 (Kaya, 2006). Currently, Turkey is heavily dependent on imported energy sources, such as natural gas and oil, and hydropower capacity will be fully exploited. Therefore, to increase the dependency on domestic energy source and to expand the use of other renewable resources to diversity energy sources become main driving forces for the development of renewable energy.

Table 6.11: Electricity generation by fuel sources in 2005

	Generation (GWh)	% of total generation
Coal	43192	26.67
Oil	5483	3.39
Gas	73445	45.35
Biomass	34	0.02
Waste	88	0.05
Hydro	39561	24.43
Geothermal	94	0.06
Wind	59	0.04
Total	161956	100.00

Source: IEA statistics

Turkey has favourable natural conditions to develop biomass, geothermal power, wind power, and solar power generation technologies. Biomass used to be an important source of energy consumption in Turkey, mainly for heating and cooking. However, since 1980s, its contribution to total energy consumption has dropped from 20% to 8% in 1995. Despite this, Turkey still has rich agricultural potential. The total agricultural residues amount calculated in dry base has been measured approximately between 40 and 53 million tons, and this is considered having a high potential to replace lignite (40 million tons) and hard coal (1.3 million tons) used in electricity

production. Also, Turkey has significant potential in geothermal energy. In 2005, geothermal ranked the second main renewable resource after hydropower in electricity generation, and its installed capacity is 20.4 MW as of 2006 (Bilgen et al, 2008). Provided with Turkey's natural condition (owning coast), Turkey's technical wind energy potential is around 88,000 MW. By 2006, the installed capacity of wind power was 50 MW (Ben Jannet Allal and Vigotti, 2007) and 40 new wind farm projects (totalling approximately 1400 MW) already obtained licences. (Guner Law Office, 2008). In spite of that Turkey has high solar potential, the development of solar technology, particularly electricity generation, is still in an early stage.

Market deployment policies for renewables started in 1984[43] with third-party financing and excise and sales tax exemptions. In 2001, the Electricity Market Licensing Regulation of the Electricity Market Law took effect and contained two regulations to promote the use of renewable energy. Firstly, the legal entities applying for licences for construction of renewable energy facilities are required to pay only 1% of the total licence fee. Secondly, renewable-based generation facilities are exempted from paying the annual licence fees for the first eight years following the facility completion date as specified in the licence. Meanwhile, priority of connection to the transmission and/or distribution systems is given to the renewable-based generating facilities. The real beginning for a national renewable energy policy took place in the decree of Modification of the License Regulation in the Electricity Market in 2003; however the Regulation was not considered sufficient to overcome high investment cost, risk and lack of security associated with the entry of renewable power generators into the electricity market. (Bilgen et al, 2008)

The Law on Utilisation of Renewable Energy Resources for the Purposes of Generating Electricity Energy took effect on May 18, 2005. Providing the primary regulatory platform, the Law focuses on expanding the use of renewable energy sources for generating electrical energy by establishing the necessary legal and regulatory framework. Meanwhile, the Law also ensures that the increase in the use of renewable energy sources shall not disturb free market conditions.

In accordance with the Law, several policies related to fostering renewable-based electricity generation are specified. To begin with, certificates are issued by the authority as a mean of regulating and monitoring. Private legal entities that generate electricity from renewable resources are granted a certificate that specifies the type of resource utilized to generate electrical energy, as well as the incentives to which each entity is entitled. A mandatory purchase scheme is provided to these generators under which the electricity generated from renewables will be purchased by means oflegal retail sale licensees, on the basis of bilateral agreements. Each retail

licensee is obliged to purchase the certified electricity[44] from renewables at the ratio of its total energy sales within the previous calendar year to total electrical energy amount offered by all legal retail licensees. In case that the total certified electricity amount is sufficient, the ratio for each retail entity shall not be lower than 8% of its sales in the previous year. The guarantee to buy the electricity energy generated from renewable energy resources was for 7 years but in 2006 it was extended to 10 years. The feed-in price of a specific year shall be the Turkish average wholesale electricity price in the previous year as determined by EMRA (Energy Market Regulatory Authority), but it should lie within the range of Turkish Lira equivalent to 5 to 5.5 €cents/kWh[45]. For example, the buy-back price for renewables based electricity was 9.13 YKr/kWh, around 5.2 €cent/kWh in 2007. Moreover, the Council of Ministers is entitled to raise this price up to 20 %, i.e. approximately 1 €cent/kWh, at the beginning of each year. This feed-in incentive is applicable for plants put into operation by December 31st, 2011, which may be extended for two years.

Financial incentives are offered to energy projects during their investment period. Firstly, low-interest loans can be taken up to 45% of the capital cost. Secondly, tax credit is offered for up to 20% of R&D expenses for three years. Thirdly, the sale price, rent, rights of access and usage permissions of state owned land are subject to an 85% reduction, provided that the property is used for the purpose of generating electrical energy from RER (Guner Law Office, 2008). Finally, national funds are available to promote R&D.

Conclusions

The review above suggests that legal and political frameworks exist to promote RETs in all four countries. Most of policy instruments consist of a mixture of command-and-control and economic instruments. A feed-in pricing system is commonly employed in all four countries. Table 6.12provides a summary of feed-in prices by countries and technologies. Mandate of renewable portfolio standard is employed in China, India, and Turkey. In China, the policy instruments vary by technologies, such as a tendering system for wind power and a fixed feed-in premium for biomass. In compliance with RPS and feed-in tariffs as broadly stipulated by law, each state in India defines the ratio of RPS and the prices to be employed to different types of technologies. Brazil employs respective feed-in incentive for different RETs, but on the contrary, Turkey only specifies one universal feed-in price. Financial incentives in various forms, such as favourable tax rates, duty exemption, and subsidies to encourage investment and R&D are available in China, India, and Turkey.

Table 6.12: Summary of feed-in tariffs in the four developing countries (€cent/kWh)

RET	Brazil (March 2004)	China	India	Turkey
Wind power	6.93-7.86	3.4 (Varies with bidding results)	5-7.03	5-5.5
Small hydro	4.5	No fixed price	4.83-5.84	-
Biomass	3.61-6.5	4.37 (fixed premium of 2.33)	4.53-8.86	-
Solar PV	--	No fixed price	25.42 (fixed premium of 20.68)	-
Solar thermal	--	No fixed price	21.97 (fixed premium of 17.23)	-

Note: 1€=10.75 Yuan; 1€=58.03 Indian Rupees; 1€=1.47 US$

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7 Assessment of Policy Instruments and Electricity Generation Technologies

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7.1 INTRODUCTION

All policy instruments presented in Chapter 6 aim at the direct or indirect internalisation of environmental externalities associated with the production of electricity. If environmental externalities are better internalised, there will be more of a level playing field for cleaner or renewable energy technologies and relevant investments will be triggered. However, according to the basic principles of environmental economics theory, full internalisation is in many cases not evident, certainly when having a large numbers of polluters and victims (Proost S. and Rousseau S., 2007). It relies on strict assumptions, such as the existence of clear preferences and the existence of competitive markets, which in reality are only partially or not met. To this purpose, instead of full internalisation two less ambitious and more realistic policy objectives have been adopted in order to serve as the basis on which policy instruments are assessed and their overall attractiveness is gauged:

1. How to produce low carbon electricity in a sustainable way?
2. How to increase the penetration of renewable electricity production?

Policy instruments mainly targeting technologies using non-renewable fuels have been assessed with respect to policy objective (1), while policy objective (2) is used to assess instruments aiming to support technologies exploiting renewable energy sources. Although the distinction between the two groups is by no means exclusive, meaning that most policy instruments can significantly help to achieve both policy objectives, the adopted classification facilitates a comparative view on their strong and weak points with respect to the corresponding major objectives.

Figure 7.1 presents the flow chart describing the assessment procedure and specifying the discrete roles of researchers and stakeholders. The set of criteria used for the comparative evaluation of the identified policy instruments have been selected as to represent all major concerns of policy

makers. The scores of instruments in each criterion have also been determined by the research team following a literature review and taking account of the experiences so far gained from their practical implementation. The multicriteria methodology used to support the assessment procedure consists in helping stakeholders articulating their preferences about the relative importance of each criterion and in aggregating the so derived global scores in order to produce a global ranking of policy instruments encompassing all evaluation aspects. This final stage of stakeholders' involvement took place during a workshop held in Bruges on April 23rd 2008. During this workshop the stakeholders were presented with the definitions of instruments and criteria and the multicriteria assessment methodology. They were then asked to weigh the different criteria by using the Multi-Cases tool, developed in the framework of the CASES project and suitably adapted to handle the specific policy problems. The tool automatically calculates a ranking of instruments from their scores and the weights of the criteria. Each stakeholder observes a different ranking based on his or her weights. From the data of all stakeholders an overall ranking of policy instruments can be generated.

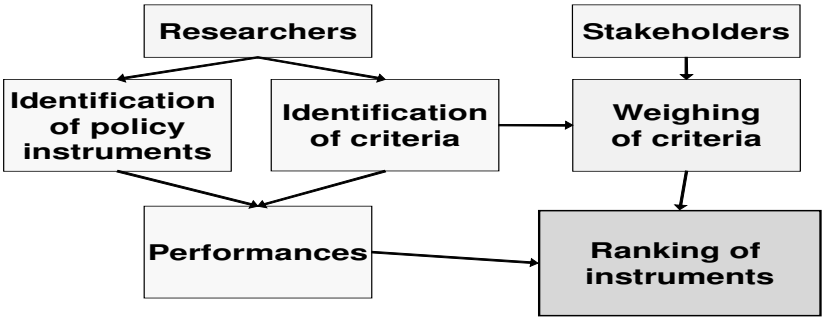


Figure 7.1: Procedure for policy assessment

The ranking of policy instruments provides valuable information to policy makers by indicating the most attractive among different generic policies and the most appealing among their alternative design options to achieve the defined policy objective. However, in reality there is a mix of policies that are implemented for pursuing different policy objectives and leading to a mix of electricity generation technologies, depending also on country or local conditions. Having this in mind, we have constructed a third policy exercise for ranking all commercially available technologies by taking account of the degree they satisfy the most important policy objectives and respective social

concerns. The assessment procedure follows the same multicriteria methodology and is implemented also in the stakeholders' workshop by using the Multi-Cases tool. Besides the obtained multicriteria ranking, the analysis aims to reveal the hidden costs besides the weights assigned by stakeholders to the evaluation criteria and provides an alternative way of indirect monetization of non-monetized goods. Therefore, the obtained technology rankings are directly comparable to those obtained on the basis of the social costs estimated in this project (Chapter 5) and provides useful insights in the ambiguities characterizing social attitude in front of non-market goods.

Section 7.2 gives a short description of the Multiple Criteria Decision Analysis (MCDA) framework and presents the structure of the developed Multi-CASES Tool. The next three sections are devoted to the three policy exercises and include an overview of the evaluation criteria and the discussion of the obtained results. Finally, some concluding remarks are included in the closing section of this chapter.

7.2 THE MULTICRITERIA METHOD AND TOOL

Overview

Multiple Criteria Decision Analysis (MCDA) has been increasingly applied during the last 30 years for aiding decisions involving several actions compared along multiple competing criteria. MCDA is particularly suited to help resolving conflicts between criteria, especially if there is significant ambiguity in measuring performances and/or in articulating preferences. The underlying assumption is that values do not a-priori exist in human mind - especially for unfamiliar environmental goods - and that there is a need to apply a systematic value elicitation procedure to facilitate decision makers or other stakeholders construct and articulate their preferences. A diversity of multicriteria methods and weighting techniques are in use today for translating the performances of the examined actions, measured in physical or qualitative scales, into a global value or preference index for each alternative reflecting human judgment about the underlying scores.

The strength of MCDA is better reflected in problems of a strategic nature encountered in many different fields of economic activity. These problems refer to non-repeated decision situations with a medium to long-term planning horizon and usually have more serious and often non-reversible consequences. Similar types of problems are the design of policies and the formulation of action plans, technological choices, siting decisions, project evaluation and approval etc.

The energy sector has been a fertile ground for the emergence of several problems which are intrinsically of multiple criteria nature. Moreover, MCDA methods and models have revealed an effective contribution to the successful resolution of several real world problems and provided the foundations for sound decision support. Among the first historical applications of MCDA in energy planning in early '80s, is the multicriteria comparison of alternative power generation technologies by Siskos and Hubert (1983). Later on, the rapid developments in the field of multicriteria modelling resulted in an exponential increase in the number of applications in the complex and highly uncertain conditions of the energy sector, while the exigency for sustainable development introduces a global, intergenerational and interdisciplinary perspective in energy planning. In the particular case of discrete alternatives, relevant publications deal with the assessment of alternative technological solutions, scenarios, locations, investment projects and energy policies (Diakoulaki et al., 2005).

MCDA is usually implemented in a participative framework involving experts and stakeholders interacting with each other and facilitating a deeper understanding of the policy issue at hand. Participation and interaction constitute two essential elements of the policy making process which is transformed into a learning procedure that motivates stakeholders to think harder about the conflicts addressed and eventually to arrive at a better and commonly accepted solution (Martinez-Alier et al., 1998; Lahdelma et al. 2000). Moreover, the involved actors might influence the structure of the problem in the sense that they can suggest inclusion of additional alternatives or criteria or rejection of some of the proposed ones, provide novel insights about performances and relevant uncertainties etc.

It is important to stress, that MCDA is not a methodology providing the right solution in a decision problem, simply because such a universally accepted right solution does not exist. Instead, it is a formal approach that helps decision makers organize the available information, think on the consequences, explore their own wishes and tolerances and minimize the possibility for a post-decision disappointment (Belton and Stewart, 2002).

MCDA methods are classified in two broad categories, each following a different approach to preference elicitation and in the aggregation of criteria information. The first category (MAVT methods) use a compensatory approach assuming that it is possible to completely offset a disadvantage in one evaluation criterion by an advantage in another criterion, while the second one (outranking methods) follow a non-compensatory approach denying such possibility. Between these two categories, MAVT methods present the advantage of greater simplicity and transparency and can be more easily understood by stakeholders in the constrained time frame of a

workshop. In addition, they are more compatible with the valuation framework of environmental economics, because they use a similar utilitarian background where decisions result from explicit or implicit trade-offs between conflicting interests or points of view. Therefore, they can act in a compatible or complementary way to the external and internal cost values assessed in the CASES project, by including evaluation aspects that can not be expressed in monetary terms.

Description of the MCDA method

Multi-Attribute Value Theory (MAVT) methods associate with each alternative option a unique number ('value') providing an overall evaluation of this option if all criteria are taken into account according to the decision maker's preferences.

The starting point in all MAVT models is the definition of partial value functions in each criterion for reducing performances in the [0-100] interval. This means that partial value functions are defined with a strict reference to the worst and best performance, which are usually graded 0 and 100, respectively. Intermediate performances receive a value between 0 and 100, depending on the attitude of the decision maker against risk. Risk adverse individuals have the tendency to assign a higher value to a performance that is slightly better than the worst, while risk prone individuals do not very much appreciate small improvements from the worst case and assign high values only to performances close to the best. Their attitude is respectively depicted by a convex and concave value function reducing performances to the [0-100] interval. Worst and best performances refer to either the considered set of alternatives (local scale) or to potentially achievable scores (global scale). In the present applications we have considered local scales and linear value functions for all criteria denoting a neutral attitude against risk.

The basic property of these partial value functions is that alternative a is strictly preferred to alternative b if $v_i(a) > v_i(b)$, while indifference between the two alternatives holds only if $v_i(a) = v_i(b)$.

Partial values are then aggregated to derive total values and construct a complete preorder of the examined alternatives. The transition from partial to global value functions (taking into account the whole set of criteria) implies the use of an aggregation formula together with the weights provided by the decision maker. The simplest and most commonly used aggregation model is the additive one:

$$V(a) = \sum_i w_i \cdot v_i(a) \qquad (7.1)$$

where, $V(a)$ is the total value associated with alternative a, and w_i is the weight attached to criterion i by the decision maker. Policy options are then ranked according to $V(a)$ from the highest to the lowest value.

Description of the weighting technique

Several weighting methods have been developed in the framework of MCDA. The choice is restricted among methods facilitating stakeholders to realize their own preferences without being too complicated and leading to inconsistencies that would be difficult to resolve within the short duration of a one-day workshop. For this reason more complicated methods like the trade-off method which is the most appropriate method for use in combination with a MAVT method have been excluded.

It has been decided to use in parallel two weighting methods. This gives stakeholders the opportunity to proceed in an iterative way in the articulation of her/his preferences and confirm or revise the initially defined weights. Among the available simple and meaningful weighting methods we have selected the RATIO method and the LEVEL method to be integrated in the MCDA procedure.

In the RATIO weighting method the stakeholder is firstly asked to rank the criteria from the most the least important and then he is asked to rate them according to the assumed difference in their relative importance. More specifically, the most important criterion is assigned a value of $a = 100$ and the stakeholder defines a value $b \leq 100$ to denote the relative importance of the second ranked criterion. The closer is the value b to 100, the less is the difference between the relative importance of the two criteria. Then the stakeholder assigns a value $c \leq b$ to the third ranked criterion and so on, until the bottom ranked criterion. The defined values are translated into relative weights by normalizing them to sum to one.

In the LEVEL weighting method a hierarchical scale is utilised in which the stakeholder is asked to place each criterion according to its relative importance. In this way, she/he is not obliged to specify her/his preferences in a numerical scale. The most important criterion is simply placed at the highest level and the least important at the lowest. One or more blank lines can be used for denoting a greater difference in importance between two consecutive (in terms of importance) criteria. The numerical weights are derived by assigning a number to each level (line) starting with number 1 for the bottom line, 2 for the next line and so on, until the top of the scale which is assigned the total number of lines used in placing the examined criteria

(including all blank lines). The so defined values are translated into relative weights by normalizing them to sum to one.

Description of the Multi-CASES Tool

The Multi-Cases Tool has integrated the selected MCDA and weighting methods in the Excel computational framework and can be directly used by any user or stakeholder wishing to rank a number of alternatives by taking into consideration their performances in multiple criteria. The tool is developed in a dynamic and interactive way giving the user the flexibility to define the elements of the decision problem to express and eventually revise preferences, to add or reject alternatives or criteria and finally to perform sensitivity analyses.

The Multi-Cases Tools consists of 11 sheets, as follows:

1. *Home*: The introductory sheet to the tool.
2. *Steps*: Provides an overview of all methodological steps.
3. *Criteria*: Asks the user to define and orderly rank the examined criteria from the most to the least important.
4. *Alternatives*: Asks the user to define the examined alternatives
5. *Performances*: Asks the user to specify the performances of alternatives in each criterion in the automatically constructed evaluation matrix.
6. *RATIO Weights*: Asks the user to implement the RATIO weighting method and provides the calculated relative weights.
7. *LEVEL Weights*: Asks the user to implement the LEVEL weighting method and provides the calculated relative weights.
8. *RATIO Results*: displays the global score of the examined alternatives calculated on the basis of the performances defined in the sheet "performances" and the specified RATIO weights. Alternatives can be sorted in a descending order of global preference.
9. *LEVEL Results*: displays the analogous results derived on the basis of the specified LEVEL weights.
10. *Sensitivity Analysis*: displays the final ranking of the examined alternatives for a maximum of 4 scenarios as derived from the sheets "RATIO Results" and "LEVEL Results". In each scenario alternatives are classified in three ordered groups.
11. *Stakeholder Data*: Stores all necessary input and output data for use in the elaboration of results.

7.3 ASSESSMENT OF POLICY INSTRUMENTS TO PRODUCE LOW CARBON ELECTRICITY IN A SUSTAINABLE WAY

Scoring of instruments on criteria

As explained in Chapter 6, the alternative policy options for the production of low carbon electricity have been conceived as scenarios assuming the implementation of one major policy instrument (Emissions Trading, CO_2 tax, Electricity tax, voluntary agreements and command and control policies) under specific design characteristics. For each base case scenario, additional policy variants have been defined, differing from the base case only in one specification which is also indicated in their name. The policy scenarios thus established are evaluated on their ability to decrease GHG emissions from electricity production, by taking also into account a number of other criteria reflecting different aspects of sustainability. In total ten criteria have been examined, the four being measured in relative quantitative terms and the other six using a qualitative scale ranging from 1, denoting the worst performance, to 5 denoting the best performance. Table 7.1 presents the evaluation matrix established for this policy problem, with the scores determined on the basis of expert judgement and data from (European Commission, 2008).

The conflict behind this policy problem is that all policy scenarios have their strong and weak points. The following paragraphs give the definition of criteria and explain shortly the differences in the scores.

Quantitative criteria

1. **Effective to decrease GHG (GHG):** The extent to which the policy scenario achieves the stated objective of decreasing greenhouse gases by the electricity sector within a specified time period. The numbers correspond to estimated CO_2-equivalent emissions, relative to the emissions of 1990, assumed to have a score of 100.

The -30% GHG reduction scenario of EU-ETS and the CO_2 tax > 50 €/ton scenario present the maximum decrease of GHG emissions, with all their variants presenting a lower emission reduction ability. As expected all variants of the Null scenario (the one without any specific climate policy), will lead to more or less increasing levels of GHG emissions, with the option of prohibiting nuclear electricity receiving the worst score. Electricity taxes are also considered to be less effective, especially if the tax is based on the lower value of 43 €/ton CO_2.

Alternatives	Acr	GHG	GHG EU	PR COST	OTHER EXT	FLEX	PRED	DYN-EFF	EQU	CONS INT	PROD INT
No specific CO2 policy -Base Case	**NULL**	130	130	100	35	5	5	2	3	2	2
No specific CO2 policy -No policy for NOx, SOx or PM	**NULL noNEC**	130	130	95	100	5	5	1	3	2	2
No specific CO2 policy -No promotion of Renewables	**NULL noREN**	145	145	80	35	5	5	1	3	2	2
No specific CO2 policy -EU Green Certificate System	**NULL greenEU**	130	130	90	35	5	5	2	3	2	2
No specific CO2 policy -No Nuclear	**NULL noNUC**	170	170	130	35	5	5	2	3	2	2
No specific CO2 policy -No CCS	**NULL noCCS**	130	130	100	35	5	5	2	3	2	2
No specific CO2 policy -Social tariffs	**NULL soc**	130	130	100	35	4	5	2	4	2	2
EU-ETS -Base Case Full Auctioning and -20% GHG reduction	**ETS**	80	87	130	30	5	4	4	3	3	5
EU-ETS -30% GHG reduction	**ETS strong**	70	80	145	25	5	3	5	3	3	5
EU-ETS -no CDM restriction	**ETS CDM**	80	95	120	30	5	4	5	3	3	5
EU-ETS -Free Emission Rights Grandfathered	**ETS grand**	80	87	130	30	5	4	5	2	3	5
EU-ETS -Free Emission Rights Benchmark (Output based)	**ETS bench**	80	87	130	30	3	4	5	4	3	5
EU-ETS -No policy for NOx, SOx or PM	**ETS noNEC**	80	87	123	85	5	4	4	3	2	4
EU-ETS -No promotion of Renewables	**ETS noREN**	80	87	120	30	5	4	4	3	3	5
EU-ETS -EU Green Certificate System	**ETS greenEU**	80	87	115	30	5	5	5	3	3	5
EU-ETS -No Nuclear	**ETS noNUC**	80	87	150	30	5	4	5	3	3	5
EU-ETS -No CCS	**ETS noCCS**	80	87	160	30	5	4	5	3	3	5
EU-ETS -Social tariffs	**ETS soc**	80	87	130	30	4	4	5	4	3	5
CO2 tax -Base Case 43 €/ton	**C-TAX**	80	80	130	30	4	5	5	3	3	5
CO2 tax > 50 €/ton	**C-TAX high**	70	70	150	25	4	5	5	3	3	5
CO2 tax -No policy for NOx, SOx or PM	**C-TAX noNEC**	80	80	125	85	4	5	4	3	2	4
CO2 tax -No promotion of Renewables	**C-TAX noREN**	80	80	120	30	4	5	4	3	3	5
CO2 tax -EU Green Certificate System	**C-TAX greenEU**	80	80	115	30	4	5	5	3	3	5
CO2 tax -No Nuclear	**C-TAX noNUC**	80	80	150	30	4	5	5	3	3	5
CO2 tax -No CCS	**C-TAX noCCS**	80	80	160	30	4	5	5	3	3	5
CO2 tax -Social tariffs	**C-TAX soc**	80	80	130	30	3	5	5	4	3	5
Electricity Tax based on technology mix and a carbon price of 43 €/ton	**E-TAX L**	110	110	95	30	2	4	3	3	3	2
Electricity Tax based on technology mix and a carbon price > 50 €/ton	**E-TAX H**	90	90	95	30	2	4	3	3	3	2
Performance based command and control	**C&C**	80	80	130	30	2	5	2	3	3	2
Voluntary agreement to reduce GHG	**VOL**	80	80	130	30	1	5	3	3	3	2

Table 7.1 Evaluation matrix for the assessment of low carbon policy scenarios

2. **Effective to decrease GHG in EU (GHG EU):** The extent to which the policy instrument achieves the objective of decreasing EU-greenhouse gases within a specified time period. The numbers correspond to estimated CO_2-equivalent emissions, relative to the emissions of 1990, assumed to have a score of 100.

This criterion shows the emissions reduction that will be realised within EU, therefore excludes reductions realised in other places of the world and accounted for through the exploitation of trading mechanisms. Thus, the scores differ only in the case of the EU-ETS scenarios, in which 30% of total emission reduction is assumed to be realised outside EU. Obviously, in the scenario with no CDM restriction the score is even lower since domestic efforts are expected to be further reduced.

3. **Private Cost (PR COST):** The percentage increase in the costs needed to decrease GHG emissions, e.g. the use of low carbon technologies, compliance costs and regulatory costs relative to the cost of the Null scenario which assumes no extra specific CO_2 policy and has a score of 100.

As expected, the least stringent policy scenarios (different variants of the Null scenario) present the best performance in the cost criterion. In particular the option with no promotion of renewables receives the highest score. The EU-ETS and CO_2 tax scenarios present higher costs by 15% up to 60%, with the worst score assigned to the variant not allowing for carbon capture and storage. An average increase of the electricity generation cost of 30% in the EU-ETS scenarios is in line with European Commission (2008). Performance-based command-and-control policies as well as voluntary agreements present also increased costs, whereas E-taxes are considered to reduce total costs in comparison with the base case Null scenario.

4. **Non-CO_2 externalities (OTHER EXT):** this criterion measures the degree to which other externalities are reduced by decreasing GHG emissions. All major non-CO_2 externalities are grouped together, including: the damage of local pollutants (NO_x, SO_x and PM) on human health and ecosystems, security of supply, effects on employment, depletion of non renewable resources and other more difficult to assess.

Since the largest part of non-CO_2 externalities are owed to conventional pollutants NO_x, SO_x and PM, the Null scenario variant assuming no policy for these pollutants is assigned the worst score of 100. All other scenarios including other variants of the Null scenario are considered to significantly improve the performance in this criterion, provided they include measures for conventional pollution abatement. The variant of prohibiting nuclear electricity is also considered to present a bad score. Obviously, the most effective GHG emission reduction scenarios, like the EU-ETS and the CO_2

tax > 50 €/ton scenarios are considered to be the most effective instruments achieving the best score.

Qualitative criteria

1. **Flexibility (FLEX):** The extent to which the policy instrument will retain its effectiveness under a range of changing environmental, economic, technological and social conditions. That is, will the instrument automatically adjust or, if not, how easily will the policy instrument, once implemented, be modified to accommodate changes.

The Null scenarios and the EU-ETS scenarios are considered to be the most flexible policy options, with a few exception for some variants presenting a more rigid structure. The CO_2 tax options present a slightly lower score because they do not automatically adjust to changing economic parameters. Electricity taxes are generally less flexible than carbon taxes, as do the command and control policies, while the least flexibility of all instruments is expected from voluntary agreements to reduce GHG.

2. **Predictability (PRED):** The extent to which the policy instrument provides power generators with a stable incentive ('carrot' or 'stick'), of known duration. An instrument with a high degree of predictability should reduce 'market risk', so that generators feel confident enough to modify their investment plans and to innovate and reduce costs in response to the policy instrument.

Besides the Null scenarios, the CO_2 tax scenarios, voluntary agreements and command-and-control policies are considered to provide a relatively stable environment with known and reduced market risks. EU-ETS scenarios and Electricity taxes are characterised as less predictable policies, with the EU-ETS -30% GHG reduction scenario receiving the lowest score among all policy scenarios.

3. **Dynamic Efficiency (DYN-EFF):** The extent to which the policy instrument provides continuing incentives for innovation and diffusion that will lead to improved performance - in environmental quality or cost – through the development and adoption of new environmentally cleaner and economically more efficient practices or technologies.

All the design options of CO_2 Tax and EU-ETS scenarios, except from those assuming no policies for NO_x, SO_x and PM and no measures for the promotion of renewables, are considered to present the highest dynamic efficiency. Electricity taxes and voluntary agreements receive medium scores, while command-and-control policies together with the Null scenarios do not succeed to promote innovation and continuously improve

environmental quality, especially if the variant does not include policies for NO_x, SO_x and PM reduction and for the promotion of renewables.

4. **Equity (EQU):** The extent to which the policy instrument does not yield disproportionate burdens or benefits – financial or environmental - to particular groups, or unduly limit the options of future generations.

The social tariff design of the Null scenario, EU-ETS and CO_2 tax receive the highest score in this criterion (although still not achieving the maximum) as providing measures to alleviate the burden of the most vulnerable groups in society. An equally high score is assigned to the Free Emission Rights Benchmark design of EU-ETS. All other policy scenarios receive a medium score of 3, with the worst score assigned to the grandfathering design with free emission rights of EU-ETS.

5. **Effective to make consumer price reflect full social cost (CONS INT): T**he extent to which the consumer price mechanism achieves to internalise environmental externalities and accordingly differentiate the electricity price.

All the examined policy options are not sufficiently effective to make consumer price reflect full social cost receiving a score equal to 3. This is mainly because the consumer pricing mechanism is mostly based on averaging the more or less internalised external costs. As expected the Null scenarios and the design options of CO_2 Tax and EU-ETS scenarios assuming no policies for NO_x, SO_x and PM present a lower score because of the lower degree of internalisation.

6. **Effective to make production cost equal to full social cost (PROD INT):** The extent to which the policy option is effective to make the cost of producing electricity equal to its full social cost. Full internalisation can be reached more easily at the production side since tariffs are more diverse in time and in relation to the way of production. Those diverse costs will be passed to the consumer (mostly on an average basis). The assumption of full internalisation implicates in most cases a "dynamic efficient" policy. Nevertheless, the opposite is not always true, for example in the case where prices are not as high as the total social cost.

All the design options of CO_2 Tax and EU-ETS scenarios (except from no policy for NO_x, SO_x and PM) are considered as being sufficiently effective in internalizing external costs in the cost of electricity production and receive the highest score. Electricity taxes, command-and-control policies and voluntary agreements are very ineffective in this criterion, and receive the lowest score.

Multicriteria ranking of instruments

The policy problem of "how to produce low carbon electricity in a sustainable way", defined by means of the evaluation matrix shown in Table 7.1, was solved during the stakeholders' workshop by using the Multi-CASES Tool. The average weights derived by the individual sets of weights produced from the 28 participating stakeholders are shown in Table 7.2.

The deviation of individual weights from these average values does not exceed 2-3% and only 10% of stakeholders have provided completely different weights. The average weights derived by the two methods are remarkably close, especially for the middle-ranked criteria. It can be seen that the weights derived from RATIO method present a greater dispersion in comparison with the weights derived from the LEVEL method, due to the relatively constrained framework of placing criteria in the LEVEL method.

The ability to reduce GHG emissions is placed at the top of the list as the most important criterion. Three criteria follow with weights varying around 12%, namely costs, ability to reduce other externalities and GHG emission reduction within EU. All other criteria present almost equal weights varying around 7-8%.

Table 7.2 Average weights of criteria for the assessement of low carbon policy scenarios

RATIO Method		LEVEL Method	
Effective to decrease GHG	16%	Effective to decrease GHG	14%
Private Cost	13%	Private Cost	12%
Non-CO_2 externalities	12%	Effective to decrease GHG in EU	12%
Effective to decrease GHG in EU	11%	Non-CO_2 externalities	11%
Dynamic Efficiency	9%	Dynamic Efficiency	9%
Equity	8%	Equity	9%
Production Cost - Internalisation	8%	Production Cost - Internalisation	9%
Predictability	7%	Predictability	9%
Consumer Price - Internalisation	7%	Flexibility	8%
Flexibility	7%	Consumer Price - Internalisation	8%

The average global scores calculated by using average weights are shown in Figure 7.2. It can be seen that the impact of the weighting method on the global score and consequently on the final ranking of policy instruments is low. This means that the ranking of the examined policy options is not sensible to mean deviations of weights of 1-2.

One can distinguish at least three groups of policy options, one group of best performing policies (0.75-0.85), one medium group (0.5-0.65) and the bottom ranked options with an average global score lower than 0.5. The

group of "best performing policy scenarios" includes exclusively different design options of the EU-ETS and of the CO_2 Tax. On the other side, the group of "worst performing policy scenarios" includes the Null scenario and in particular the variant assuming no policy for the reduction of NO_x, SO_x and PM and the variant prohibiting nuclear electricity. All other scenarios are placed in the medium group with the voluntary agreements and the command-and-control policies being ranked first in this group.

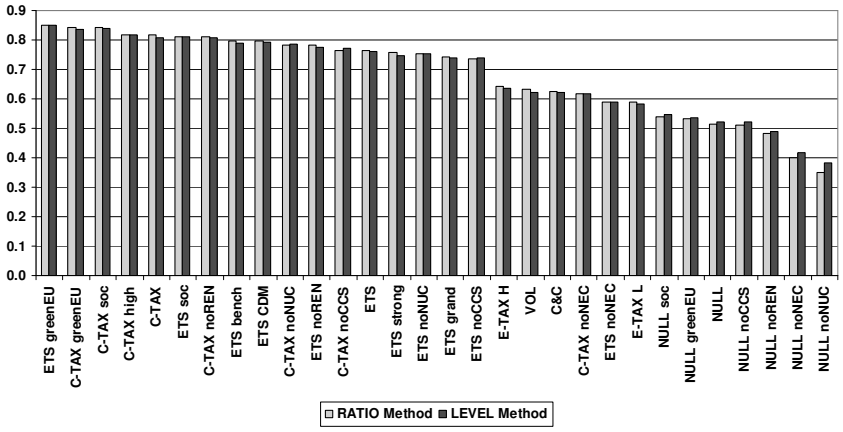


Figure 7.2: Average global scores of low carbon policy scenarios

Table 7.3 shows for each instrument the average ranking position across all stakeholders, calculated by adding the rank orders of all stakeholders and dividing by the number of stakeholders. This explains why often instruments have the same average ranking positions.

Figure 7.3 shows the average rankings of all instruments, which are representative for the whole group of stakeholders. It is namely shown for how many stakeholders an instrument appeared among the top 10 and the top 5 instruments (by using the RATIO method). It results that there is an impressive consensus on the superiority of the EU-ETS and of CO_2 tax to help producing electricity in a sustainable way.

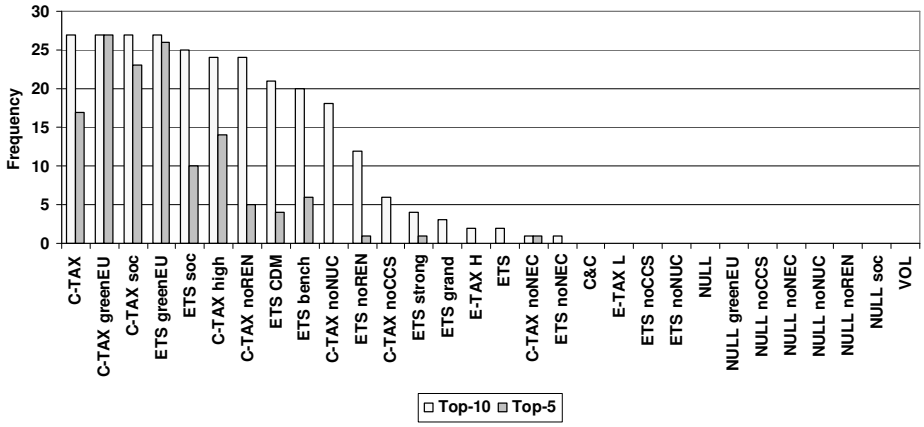


Figure 7.3 Number of appearances of low carbon policy scenarios in the top 10 and top 5 places

Table 7.3 Average ranking of low carbon policy scenarios

Policy Type	Policy Variant	RATIO Method	LEVEL Method
ETS	ETS - EU Green Certificate System	2	2
C-TAX	CO_2 - EU Green Certificate System	3	3
C-TAX	CO_2 - Social tariffs	3	3
C-TAX	CO_2 - Base Case 43 €/ton	6	6
C-TAX	CO_2 - tax > 50 €/ton	6	5
ETS	ETS - Social tariffs	6	6
C-TAX	CO_2 - No Renewables	7	7
ETS	ETS - no CDM restriction	8	9
ETS	ETS - Free Emission Rights Benchmark	9	9
C-TAX	CO_2 - No Nuclear	10	10
ETS	ETS - No Renewables	10	11
C-TAX	CO_2 - No CCS	13	12
ETS	ETS - Base Case	13	13
ETS	ETS - 30% GHG reduction	14	15
ETS	ETS - No Nuclear	14	14
ETS	ETS - Free Emission Rights Grandfathered	15	16
ETS	ETS - No CCS	17	16
E-TAX	Electricity Tax > 50 €/ton	18	19
VOL	Voluntary agreement to reduce GHG	20	20
C-TAX	CO_2 tax - No policy for NOx, SOx or PM	20	20
C&C	Performance based command and control	20	20
ETS	ETS - No policy for NOx, SOx or PM	22	22
E-TAX	Electricity Tax = 43 €/ton	22	23
NULL	No CO_2 policy - Social tariffs	24	23
NULL	No specific CO_2 policy - EU Green Certificate	24	24
NULL	No specific CO_2 policy -Base Case	26	25
NULL	No specific CO_2 policy - No CCS	26	25
NULL	No specific CO_2 policy - No Renewables	27	27
NULL	No specific CO_2 policy - No policy for NO_x, SO_x or PM	29	28
NULL	No specific CO_2 policy - No Nuclear	30	29

By looking to the rank order of the policy scenarios per type of instrument, one can see that for the EU-ETS and the CO_2 Tax the best performing options are the scenarios assuming combination with Green Certificate systems and those providing for social tariffs for alleviating the burden of the most vulnerable groups. A high CO_2 Tax, and the option of no CDM restrictions in the EI-ETS are also among the top ranked scenarios, while the "grandfathered", "noCCS" "no NEC" and "no NUC" are clearly not the favourites.

7.4 ASSESSMENT OF POLICY INSTRUMENTS TO PROMOTE RENEWABLE ENERGY SOURCES

Scoring of instruments on criteria

The policy instruments for the promotion of renewable energies have been evaluated against a number of criteria evolving around the concept of sustainable development as shown in Figure.7.4.

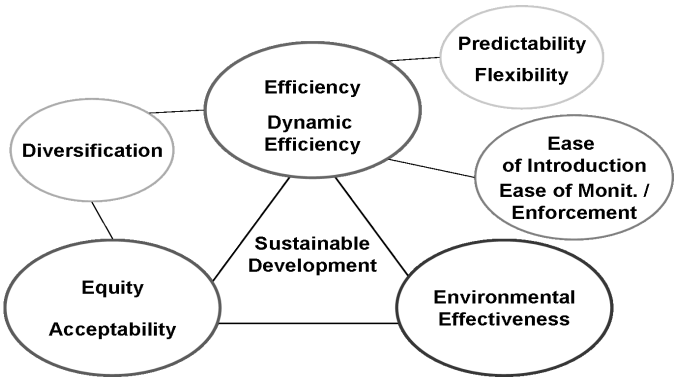


Figure.7.4: Criteria for the evaluation of policy instruments

Performances on these criteria are difficult to measure on a quantitative scale, not only because they reflect mostly qualitative aspects, but also because the assessment procedure does not refer to specific socioeconomic, technological and physical conditions. The qualitative scale used is here again ranging from 1, denoting the lowest performance, to 5, denoting the highest performance. As shown in Table 7.4, it may happen that in some criteria all instruments present a more or less satisfactory performance, resulting in a concentration of scores around the highest values. This means that the discriminating capacity of that criterion is reduced, although small differences in performances could be of interest for policy makers. The scoring procedure starts by assessing the performance of the identified base case instruments on the established 5-level scale. Differences in the performance of policy variants were assessed by taking into account the impact of the specific design characteristics.

It is clear that there is no instrument presenting the highest performance in all evaluation criteria. Each instrument has its strong and weak points that have to be taken into consideration in the selection of the most effective policy or mix of policies. The following paragraphs give the definition of criteria and explain shortly the differences in the scores of policy instruments.

Alternatives	Acr	RES_EFF	COST	DYN_EFF	EQUIT	PRED	FLEX	INTRO	ACCT	DIV	MNT_ENF
FIT - Base case	**FIT-BC**	5	3.7	4	5	5	3	3.5	4.8	5	4
FIT - Tax financed	**FIT-1**	4.7	3.7	3.8	4.7	5	2.5	2.5	4.3	5	4
FIT - Constant over time	**FIT-2**	4.5	3	3.3	5	5	2	3.5	4.5	5	4.5
FIT - Decreasing over time	**FIT-3**	4.5	3.3	4	5	5	2.5	3.5	4.5	5	4
FIT - Same for all technologies	**FIT-4**	4	4	3.8	4.7	5	3	4	4.3	3	4.5
FIT - Hardship clause	**FIT-5**	5	3.3	3.8	4.3	5	3	3.5	5	5	4
FPS - Base case	**FPS-BC**	5	3.7	5	5	3	4	3.5	4.8	5	4
FPS - Tax financed	**FPS-1**	4.7	3.7	4.8	4.7	3	3.5	2.5	4.3	5	4
FPS - Constant over time	**FPS-2**	4.5	3	4.3	5	3	3	3.5	4.5	5	4.5
FPS - Decreasing over time	**FPS-3**	4.5	3.3	5	5	3	3.5	3.5	4.5	5	4
FPS - Same for all technologies	**FPS-4**	4	4	4.8	4.7	3	4	4	4.3	3	4.5
FPS - Hardship clause	**FPS-5**	5	3.3	4.8	4.3	3	4	3.5	5	5	4
TS - Base case	**TS-BC**	3.5	3.5	4	4	4	3	3.5	4	4	4
TS - Tax financed	**TS-1**	3.5	3.5	3.7	3.5	4	2.5	3	3.5	4	4
TS - Auction over lowest premium	**TS-2**	3.5	3.5	4	4	3	3.5	3.5	4	4	4
TS - Auction over lowest investment subsidy	**TS-3**	3	3	3.7	4	4	2.5	3.5	4	4	4
TS - No technology banding	**TS-4**	3.5	4.5	3.7	3	4	3	4	3	2	4
TGC - Base case	**TGC-BC**	5	3.3	4.8	3.5	1.7	4.7	3	3.3	3	2.7
TGC - Constant quota	**TGC-1**	4.7	3.3	4.5	3.5	1.7	4.7	3	3.3	3	2.7
TGC - Obligation on consumer	**TGC-2**	5	3.3	4.8	3.5	1.7	4.7	2.5	3	3	2.3
TGC - Obligation on retailers	**TGC-3**	5	3.3	4.8	3.3	1.7	4.7	3	3.3	3	2.7
TGC - Technology specific quotas	**TGC-4**	5	3	5	3.8	1.7	4.3	2.5	3.5	4	2.3
TGC - Banking and borrowing	**TGC-5**	4.7	3.7	4.5	3.5	1.3	5	3	3.5	3	2.7
TGC - Neither - nor	**TGC-6**	5	3.3	4.8	3.8	1.3	4.7	3	3.3	3	3
TGC - Price cap and floor fixed	**TGC-7**	4.3	3.3	4.5	3.3	2	4.3	3	3.5	3.5	2.7
TGC - Only cap in form of penalty	**TGC-8**	4.3	3.7	4.5	3.3	1.7	4.3	3	3.3	3	2.7
IS - Subsidy on investment cost	**IS-1**	3	2	3	4	5	2	5	4.5	4	5
IS - Subsidy on investment cost - efficiency & production	**IS-2**	4	3	4	5	5	3	4	4.5	4	4
TI - Taxation - Lower VAT rates	**TI-1**	3	3.5	4	5	3	4	4	4	3	4
TI - Taxation - Favourable depreciation possibilities	**TI-2**	2	3	3	4	3	4	4	4	3	3
TI - Taxation - Exemption from taxes	**TI-3**	4	3.5	4	5	3	4	4	4	3	4

Table 7.4 Evaluation matrix for the assessement of policy instruments to promote renewable energy sources

1. Effectiveness to increase RES (RES_EFF): The extent to which the policy instrument achieves the stated objective of increasing the share of renewable energies in the electricity production within a specified time period.

The base case design of fixed Feed-In-Tariffs and Fixed Premium Systems receive the highest score. Environmental effectiveness is considered to decrease if the support is not regularly adjusted over time, is the same for all technologies or has a limited -tax financed- budget. Tradable Green Certificates are also considered as ecologically effective, assuming appropriate quota and high penalties. The least environmental effectiveness of all instruments can be expected from taxation incentives, especially from depreciation regulations, which can hardly motivate additional investment in renewable energies. (Morthorst et al, 2005; Resch et al, 2005; Ringel, 2006)

2. Cost-efficiency (COST): The extent to which the policy instrument achieves the stated objective at the lowest possible cost for economic actors (businesses, households and government), within a specified time period and with a high degree of certainty. The relevant cost components are: costs needed to bring about the stated objective of the action, e.g. costs of abatement technologies, and the compliance costs (resources needed to comply with the monitoring and general administrative requirements) incurred by economic agents and regulatory costs incurred by the regulator.

All instruments present medium scores, meaning that the promotion of renewables generally requires significant financial resources. Fixed Feed-In-Tariffs and Fixed Premium Systems are considered to be the most cost efficient instruments, although not achieving the maximum score. Cost efficiency is assumed to increase if there is no differentiation of support for different technologies, meaning that only the most competitive technologies are used and the overall costs are minimized. The lowest score is assigned to investment subsidies based only on cost since these schemes give no incentive to maximise the output and this impairs also the cost-efficiency (Butler and Neuhoff, 2004; Elliot, 2005; Grotz and Fouquet, 2005; Morthorst et al, 2005; Ringel, 2006; Toke, 2004).

3. Flexibility (FLEX): The extent to which the policy instrument will retain its effectiveness under a range of changing environmental, economic, technological and social conditions. That is, will the instrument automatically adjust or, if not, how easily will the policy instrument, once implemented, be modified to accommodate changes?

Tradable Green Certificates is the most flexible instrument since their price is automatically adjusted to changes in the electricity price level, costs of renewable electricity and other economic effects, especially if banking and

borrowing of certificates is allowed. The flexibility of taxation incentives is quite high, since the support provided adjusts automatically to changes in economic parameters. Feed-In Tariffs and Tendering schemes are rather inflexible, while Fixed Premium schemes have a higher flexibility than feed-in tariffs because only the premium part of the revenues for renewable operators is fixed. The lowest score is assigned to investment subsidies the constant over time design of Feed-In-Tariffs. (Morthorst et al, 2005; Resch et al, 2005)

4. Predictability (PRED): The extent to which the policy instrument provides power generators with a stable incentive ('carrot' or 'stick'), of known duration. An instrument with a high degree of predictability should reduce 'market risk', so that generators feel confident enough to modify their investment plans and to innovate and reduce costs in response to the policy instrument.

Feed-In-Tariffs and investment subsidies receive the highest score. Feed-In-Tariffs because they are guaranteed for existing plants and only change for new plants, while issues of financing do not influence the predictability of the system. Investment subsidies are also considered to present low risks because renewable energy producers receive the support upfront so they do not have any financial uncertainty. The least predictability of all instruments can be expected from Tradable Green Certificates. In this system renewable operators have to operate on two different markets, the electricity market and the certificate market. On both markets they face fluctuating prices with unknown future development. Investors, facing decreasing production costs for renewable energy, have no security that they will be able to compete with new plants in the future. (Morthorst et al, 2005; Mitchell et al, 2006; Rio, 2005)

5. Dynamic Efficiency (DYN_EFF): The extent to which the policy instrument provides continuing incentives for innovation and diffusion that will lead to improved performance - in environmental quality or cost – through the development and adoption of new environmentally cleaner and economically more efficient practices or technologies.

Fixed Premium schemes, especially the base case and decreasing over time design and Tradable Green Certificates with technology-specific quotas are considered to be the most dynamic efficient instruments because competition in the market gives the incentive to reduce costs and adjust their production to the demand level. When premiums are decreased according to a fixed pattern, cost reductions are already anticipated in the scheme. Similarly, technology-specific quotas will promote not only the cheapest renewable electricity technology but also other currently more expensive technologies. Most other instruments do no give sufficient incentives for innovations and

cost reductions, with the lowest score assigned to investment subsidies based on investment costs. (Morthorst et al, 2005; Resch et al, 2005)

6. Equity (EQUIT): The extent to which the policy instrument does not yield disproportionate burdens or benefits –financial or environmental– to particular groups, or unduly limit the options of future generations.

Most policy instruments achieve high scores on the equity criterion as encouraging broad public participation thus giving many people the chance of benefiting from the scheme, while securing a fair distribution of burdens. The same scores are assigned to subsidies on investment cost - efficiency and& production, and to the lower VAT rates and to tax exemptions within taxation incentives. The least performing in terms of equity is assigned to Tendering Systems and Tradable Green Certificates since benefits are mostly confined to large companies. Tendering without technology banding has the lowest performance since benefits are concentrated in a few competitive branches. Accordingly, technology-specific quotas achieve a higher equity because the benefits of the promotion scheme are more evenly spread. (Rio, 2005)

7. Ease of introduction (INTRO): The extent to which the policy instrument is relatively easy to implement, and does not require significant changes –by either government or generators– to existing legal, managerial, and technological (e.g. IT) systems. If new legislation is necessary, how feasible is it? Are the informational requirements for setting the policy instrument manageable?

Investment subsidies based on investment costs receives the highest score because no extra institutions have to be set-up, not even a legislative process is required. The least ease of introduction of all instruments is expected from tax financed design of Feed-In-Tariffs and Fixed Premium Systems whose implementation has to compete with other public projects for scarce public resources, while generally requiring a lengthy political process to agree on the level of support. Uniform tariffs or premiums are easier to implement because there is no need to capture all the differences between technologies. Tradable Green Certificates are also very complex to set-up, especially in case the obligation is on consumers, or for technology-specific quotas. (Morthorst et al, 2005)

8. Ease of monitoring and enforcement (MNT_ENF): The extent to which reliable compliance monitoring and enforcement can be implemented at an acceptable cost. Monitoring and enforcement costs will depend on the informational requirements and the institutional and human resource requirements.

Also according to this criterion investment subsidies based on investment costs receive the highest score: their lowest monitoring and enforcement

costs are due to the fact that when the subsidy is disbursed there are no further requirements. Generally speaking, for all other instruments, once introduced, there are no significant difficulties in monitoring and enforcement. Tradable Green Certificates with obligation on consumers and technology specific quotas have the most complex requirements for monitoring and enforcement. Under the first option, because of the large number of heterogeneous consumers, monitoring of compliance gets extremely complicated. Under the second option, of the low ranking is due to the different certificates that have to be treated separately. (Resch et al, 2005)

9. Diversification (DIV): The extent to which the policy instrument will lead to a diversified electricity generation system, by encouraging investment in a range of technologies, at different scales and at geographically dispersed sites.

Feed-In-Tariffs and Fixed Premium Systems have the potential of achieving a very high diversification of the electricity system by encouraging the deployment of different technologies by both small private investors and large companies. The only exception is for uniform tariffs or premiums which will only promote the cheapest technologies. Investment subsidies and tendering systems can also enhance diversification, with the exception of the no technology banding variant which receives the lowest score, since uniform auctions are expected to promote larger projects of the cheapest technologies in only the most favourable sites leading to increased regional concentration. The same reasoning applies to Tradable Green Certificates, while taxation incentives have also a limited diversification potential because they do not specifically support a variety of technologies.

10. Acceptability (ACCT): The extent to which the policy instrument is understood by the public, acceptable to generators, and sellable to decision-makers in government. If an instrument has been used with any success in the past, political resistance may be low. The acceptability of an instrument will also depend on whether it avoids negative and creates positive impacts in other important policy areas (e.g. employment).

Feed-In-Tariffs and Fixed Premium Systems are considered as the most acceptable instruments because of the broader public participation including private persons and small companies. The hardship clause variant receives the highest score because it increases the acceptability of the scheme to the industry sector. Investment subsidies and taxation incentives present also a quite high acceptability, the former because they are easy to understand and benefits are dispersed to a large number of investors, the latter because they are not expected to draw a lot of public attention. Tendering systems are less acceptable by small companies because of the uncertainty of getting the

project, especially for the no technology banding variant. Acceptability of Tradable Green Certificates receive also a low score because the scheme is mainly addressing large companies, while its acceptability is further reduced if the obligation is on consumers which are expected to feel unfairly burdened. (Resch et al, 2005)

Multicriteria ranking of instruments

The policy problem of "how to increase the penetration of renewable electricity production" defined by means of the evaluation matrix shown in Table 7.4 was tackled during the stakeholders' workshop by using the Multi-CASES Tool. The average weights derived by the individual sets of weights produced from the 28 participating stakeholders are shown in Table 7.5. The deviation of individual weights from these average values does not exceed 2-3% and only 10% of stakeholders have prescribed completely different weights.

Table 7.5 Average weights of criteria for the assessement of policy instruments to promote renewable energy sources

RATIO Method		LEVEL Method	
Environmental Effectiveness	18%	Environmental Effectiveness	14%
Cost-Efficiency	16%	Cost-Efficiency	14%
Dynamic Efficiency	11%	Dynamic Efficiency	11%
Predictability	10%	Equity	10%
Equity	9%	Predictability	10%
Flexibility	9%	Flexibility	10%
Ease of Monitoring & Enforcement	8%	Ease of Introduction	9%
Ease of Introduction	8%	Ease of Monitoring & Enforcement	9%
Acceptability	6%	Acceptability	8%
Diversification	5%	Diversification	6%

The ranking of criteria is almost the same regardless of the weighting method used. Environmental effectiveness and costs are at the top of the list. Dynamic efficiency as the next criterion also has a very high position. Predictability, equity and flexibility are in the middle of the list. Predictability and flexibility act in different directions. Policy instruments which are very predictable tend to be less flexible and vice versa. Some stakeholders have put an emphasis on one or the other but many have attached a similar weight to flexibility and predictability. The administrative criteria ease of monitoring and enforcement and ease of introduction are in

the lower middle range, both with the same weight. Contrary to equity, which is in the upper middle range, acceptability receives a low average weight. The least important criterion according to stakeholders' weighting is the diversification of policy instruments. Having different renewable energy technologies in the market seems to be no objective by itself if not contributing to the environmental effectiveness.

Table 7.6 shows for each instrument the average ranking position across all stakeholders, calculated by adding the rank orders of all stakeholders and dividing by the number of stakeholders. This is the reason why often instruments have the same average ranking positions. With both weighing methods the base case of the fixed premium system and the base case of the feed-in tariff are at the top of the instrument ranking, with the LEVEL method giving to the premium system a slightly better position. Generally, there is a clear favour for the price based instruments over quantity regimes.

Table 7.6 Average ranking of policy instruments to promote renewable energy sources

Instrument Type	Instrument Variant	RATIO Method	LEVEL Method
FPS	Premium System - Base Case	2	1
FIT	Feed-in tariff - Base Case	2	2
FPS	Premium System - Hardship	4	4
FIT	Feed-in tariff - Hardship	5	4
FPS	Premium System - Decreasing	7	6
FIT	Feed-in tariff - Uniform	7	7
FPS	Premium System - Uniform	7	7
FIT	Feed-in tariff - Decreasing	8	6
FPS	Premium System - Tax financed	8	10
FIT	Feed-in tariff - Tax financed	9	10
IS	Investment Subsidy - Eff	12	10
FPS	Premium System - Constant	12	12
FIT	Feed-in tariff - Constant	13	12
TI	Energy & Environmental Taxes	13	14
TGC	Quota - Neither banking nor	17	19
TGC	Quota - Base Case	18	20
TI	VAT	19	16
TS	Tender - Base Case	19	17
TGC	Quota - Banking and borrowing	19	21
TGC	Quota - Retailers	19	22
TS	Tender - Premium	21	18
TS	Tender - No technology banding	22	22
TGC	Quota - Specific	22	23
TGC	Quota - Constant	24	25
TGC	Quota - Consumers	24	26
IS	Investment Subsidy - Inv Costs	25	23
TS	Tender - Tax financed	26	26
TGC	Quota - Price cap	26	28
TS	Tender - Subsidy	27	26
TGC	Quota - Cap and floor	27	27
TI	Depreciation	31	31

This becomes obvious when looking at the first column of the table where the instrument type is shown. The first choices all belong to premium system or feed-in tariff system. Supporting renewable energy with favourable depreciation regulations is the least favourable option. This support element should be used rather in addition to other promotion instruments. The variants of the quota system and the tendering system are mainly found in the

lower part of the list. The investment subsidy, which is based on the efficiency of renewable energy plants, is the 11th instrument of the list. It ranks higher than the quantity-based instruments. The best instrument from the category taxation incentives is the exemption of renewable energies from energy and environmental taxes.

These results are rather surprising in their clarity. They do not fully reflect the predetermined choices of the stakeholders but are based on their weighing of criteria. The first two criteria (environmental effectiveness and cost-efficiency) do not lead to a clear favour for the price-based instruments. in terms of dynamic efficiency, scores are highest for the quota system but also good for the premium system. The fourth and fifth criteria (predictability and equity) are clearly in favour of price-based instruments while the next, flexibility, favours the quantity based schemes. Overall this weighing results in the price-based instruments reaching much higher rankings than the quantity based instruments.

Figure 7.5 shows the average rankings of all instruments, which are representative for the whole group of stakeholders. It is shown for how many stakeholders an instrument appeared between the top 10 and the top 5 instruments (by using the RATIO method).

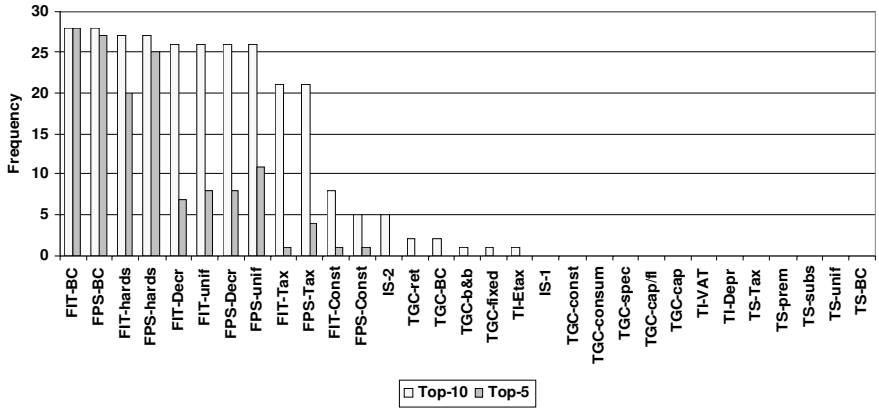


Figure 7.5 Number of appearances of policy instruments to promote renewable energy sources in the top 10 and top 5 places

Here we can see that individual results can differ significantly from the average even though the overall consensus is quite high. But for example the

TGC variant with obligation on retailers appeared twice in the top 10 list while its average ranking position was only 19.

The rankings thus obtained reveal also the relative attractiveness of alternative design variants of the examined generic policies. It can be seen that for Feed-In-Tariffs and Fixed Premiums, the base case variant is always the most preferred, followed by the hardship clause variant. Constant tariffs or premiums and tax financed schemes are ranked at much lower places. Tendering systems are all placed at the bottom of the list, with the base case variant ranked first in the 19th place. Among the Tradable Green Certificates variants, the base case is not the best option but the quota system without banking and borrowing, the two being quite close together. Price restrictions with a price cap or price cap and price floor are the worst options and are also placed at the bottom of the whole instrument list.

7.5 ASSESSMENT OF ELECTRICITY GENERATION TECHNOLOGIES

Introduction

Chapter 5 presents new estimates on Full Costs of electricity generation in Europe for a wide set of technologies for the present period (2005-2010) and for 2020 and 2030. Full Costs are obtained by summing external costs due to global warming impacts and impacts on human health, environment, crops and materials, to private generation costs. External costs have been calculated on the basis of the ExternE methodology by multiplying the marginal external cost values per unit of emission (2000 c€/kg), provided by the updated EcosenseWebV1.2 tool for classical air pollutants and averaged for EU-27, times the average quantity of emissions released from the respective technologies. The results are used to rank technologies from the cheapest to the most expensive with respect to their full social costs.

The analysis presented in this section aims to provide an alternative ranking of technologies, using the MCDA assessment procedure and exploiting the judgement of stakeholders for the relative importance of each particular social cost component, as expressed during the CASES workshop held on April 2008. Moreover, an attempt is made to exploit the stakeholders' individual preferences in order to express the value attached to various environmental impacts in monetary terms.

Recently, there has been a growing interest into exploiting the multicriteria assessment procedure as a valuation framework by intimating the monetary equivalents hidden behind preference statements. Gregory and Slovic (1997)

explicitly propose a constructive valuation approach using a multicriteria method and giving emphasis on the implied participatory discursive procedure in which *'the depth of respondents' understanding replaces breath of population sampling'*. Most applications in this field aim at the valuation of specific ecological resources, although there are already attempts to use relevant approaches in the assessment of technological solutions in the energy sector (e.g. Keeney et al., 1995; Hobbs and Horn, 1997; Diakoulaki et al, 2007). Moreover, a systematic attempt to derive monetary equivalents for environmental externalities associated with alternative emission abatement scenarios for Europe was made in the framework of the ExternE-Pol project (2005).

The results obtained from this assessment exercise are far from being considered as reliably reflecting social preferences, and in particular the Full Costs of the examined technologies. This is mainly because of the small number of stakeholders participating to the workshop and the short time given to them to fully grasp the range of values of each particular impact category and realise the necessary trade-offs between the evaluation criteria. Moreover, inherent features of the multicriteria assessment framework, in particular the lack of any practical limitation in the expression of human preferences, might lead to idealistic rankings and unrealistic monetary values that do not comply with the economic constraints faced in the real world. However, the proposed MCDA procedure provides useful insights in the spontaneous preferences of stakeholders regarding environmental externalities, while representing an alternative approach for determining the implied monetary equivalents of non-monetised impacts.

Scoring of technologies on criteria

The criteria used in the comparative assessment of electricity generation technologies are drawn from the social cost estimates presented in Chapter 5 for the year 2020. External cost components are measured either in physical units (CO_2 emissions) or in monetary terms. Some additional quantitative or qualitative criteria have been added to the list in order to take account of other important decision variables not reflected in the social cost estimates. Table 7.10 shows the scores assigned to the examined technologies in each of the following criteria.

Table 7.7 Evaluation matrix for the assessement of electricity generation technologies

Alternatives	Acr	PR COST	CO2eq	HEALTH	RADIO	ACC PAST	ACC FUT	ENV	FOOD	GRID COST
nuclear power plant	NUC	2.653	13	0.190	0.1452	0.001	4	0.015	1	3
heavy oil condensing power plant	OIL CL	7.194	208	2.390	0.0017	0.132	4	0.213	1	3
light oil gas turbine	OIL GT	9.681	435	1.853	0.0019	0.132	4	0.174	1	3
hard coal condensing power plant	COA CL	3.203	751	1.548	0.0012	0.157	4	0.186	1	3
hard coal IGCC without CO2 capture	COA IGCC	3.495	694	0.930	0.0011	0.157	4	0.105	1	3
hard coal IGCC with CO2 capture	COA IGCC CCS	4.150	154	1.042	0.0013	0.157	4	0.118	1	3
lignite condensing power plant	LIG CL	2.135	817	1.134	0.0005	0.157	4	0.130	1	3
lignite IGCC without CO2 capture	LIG IGCC	2.778	786	0.934	0.0005	0.157	4	0.094	1	3
lignite IGCC with CO2 capture	LIG IGCC CCS	3.351	106	1.051	0.0005	0.157	4	0.106	1	3
natural gas combined cycle without CO2 capture	GAS STAG	4.519	395	0.563	0.0002	0.085	2	0.077	1	3
natural gas combined cycle with CO2 capture	GAS STAG CCS	5.875	110	0.620	0.0002	0.085	2	0.086	1	3
natural gas, gas turbine	GAS GT	6.563	620	0.864	0.0002	0.085	2	0.124	1	3
hydropower, run of river 10MW	HYD S	7.229	13	0.198	0.0002	0.001	1	0.016	1	3
hydropower, run of river <100MW	HYD M	4.519	9	0.142	0.0001	0.001	1	0.011	1	3
hydropower, run of river >100MW	HYD L	4.519	8	0.127	0.0001	0.001	1	0.010	1	3
hydropower, dam (reservoir)	HYD DAM	7.350	15	0.245	0.0002	0.001	2	0.020	1	3
hydropower, pump storage	HYD PMP	7.350	14	0.251	0.0002	0.001	2	0.020	1	3
wind, on-shore	WIND ON	6.019	10	0.142	0.0005	0.001	1	0.007	1	4
wind, off-shore	WIND OFF	6.143	7	0.173	0.0004	0.001	1	0.006	1	5
solar PV, roof	PV ROOF	25.140	56	0.479	0.0022	0.001	1	0.032	1	3
solar PV, open space	PV OPEN	20.829	108	1.082	0.0028	0.001	1	0.064	1	3
solar thermal, parabolic trough	SOL TH	11.969	8	0.105	0.0002	0.001	1	0.007	1	3
natural gas CHP with extraction condensing turbine without CO2 capture	CHP GAS	4.225	366	0.527	0.0002	0.085	2	0.072	1	4
natural gas CHP with extraction condensing turbine with CO2 capture	CHP GAS CCS	5.450	101	0.574	0.0002	0.085	2	0.079	1	4
hard coal CHP with extraction condensing turbine without CO2 capture	CHP COAL	0.945	674	1.406	0.0011	0.157	4	0.167	1	4
hard coal CHP with extraction condensing turbine with CO2 capture	CHP COAL CCS	1.468	119	0.805	0.0010	0.157	4	0.092	1	4
natural gas combined cycle CHP with backpressure turbine	CHP GAS STAG	4.134	424	0.612	0.0002	0.085	2	0.083	1	4
hard coal CHP with backpressure turbine	CHP COAL BP	0.503	741	1.555	0.0012	0.157	4	0.183	1	4
biomass (straw) CHP with an extraction condensing turbine	CHP STRAW	4.751	69	1.691	0.0029	0.085	2	0.360	2	4
biomass (woodchips) CHP with an extraction condensing turbine	CHP WOOD	3.791	57	0.639	0.0028	0.085	2	0.078	2	4
MCFC (natural gas)	MCFC NG	7.300	184	1.958	0.0018	0.085	2	0.167	1	3
SOFC (natural gas)	SOFC	7.080	127	0.664	0.0005	0.085	2	0.069	1	3
MCFC (biogas)	MCFC BIO	7.824	326	3.196	0.0269	0.085	2	0.241	1	3

1. Private cost (PR COST): The private costs comprise investment, operation and maintenance and fuel costs and are expressed in c€/kWh.

The range of values is about 25 c€/kWh, with CHP turbines being the cheapest technologies and PV panels the most expensive. The nuclear and coal/lignite technologies are generally less expensive compared to other fossil fuel technologies and most of the renewable technologies.

2. GHG emissions (CO_2 eq): The life-cycle emissions of greenhouse gases from each technology and expressed in g/kWh of CO_2 equivalents.

The range of values is about 800 g/kWh, with the wind energy presenting the lowest emission levels and lignite power plants the highest. The nuclear and other renewable technologies generally perform better, with the exception of PVs which produce considerable emissions in other life cycle stages.

3. External health costs (HEALTH): They include damages to health due to emissions in the atmosphere of particles, gases like NO_2, SO_2, metals and the formation of ozone. They are expressed in c€/kWh.

The range of values is about 3 c€/kWh, with biogas fuel cells presenting the worst performance followed by oil condensing units and other coal condensing or CHP turbines. Wind and solar technologies have the lowest health impact, while hydro and nuclear are also very close to the minimum impact.

4. Environmental external costs (ENV): They include damages to ecosystems due to emissions to air, soil and water of particles, gases like NO_2, SO_2, the formation of ozone, and the emissions of metals and are expressed in c€/kWh.

The range of values is here much lower (about 0.35 c€/kWh), with renewable technologies causing the least damages and biomass CHP the highest.

5. Radionuclides external costs (RADIO): They include damages to health due to radionuclides emissions in the life cycle of the examined technologies and are expressed in c€/kWh.

Obviously, nuclear electricity has the highest cost, which is 2-3 orders of magnitude higher compared to the damage caused by most other technologies.

6. Fatal accidents from past experience (ACC PAST): The risk of a fatal accident using the frequency of occurrence of a severe accident in the past and the number of fatalities involved in previous accidents are depicted on this criterion. The data are derived from the ExternE project and the work done by PSI (Hirschberg et al., 1998) and the corresponding values are expressed in fatalities/GWyear.

The range of values is about 0.15 c€/kWh), with renewable technologies and nuclear energy causing the least accidents and technologies using coal the highest.

7. Severe accidents perceived in future (ACC FUT): The risk of severe accidents in the future is measured on a 5-level qualitative scale, where "1" denotes the poorest performance, and "5" the best performance.

The distinction of technologies is the same with the previous criterion, with the only difference being the classification of nuclear and oil power plants together with coal units to the most risky technologies.

8. Food safety risk (FOOD): The risk that using biomass fuels will put a stress on food supply safety and food prices is taken into consideration in this criterion. A 5 level qualitative scale is utilized with "1" denoting the lowest risk and "5" the highest risk.

It can be seen that all technologies receive the lowest score with the exception of the two biomass CHP units.

9. Costs for grid connection (GRID COST): The risk that a certain technology will induce high cost for grid connection is considered under this criterion, which is measured on a 5 level qualitative scale where "1" denotes the lowest and "5" the highest cost.

The worst score (5) is assigned only to the wind off-shore technology, while all technologies suitable for decentralised electricity production such as CHP and wind on-shore receive 4 and the remaining technologies 3.

Table 7.7presents the evaluation matrix constructed on the basis of the above described scores. It can be seen that the main dilemma posed to energy planners and other stakeholders in the energy sector is between private costs and different external cost components. Their decision is explicitly or implicitly based on a compromise between these two major costing aspects.

Multicriteria ranking of technologies

The policy problem of "how to define sustainable electricity technologies" defined by means of the evaluation matrix shown in Table 7.7 was tackled during the stakeholders' workshop by using the Multi-CASES Tool. The average weights derived by the individual sets of weights produced from the 30 participating stakeholders are shown in Table 7.8. The deviation of individual weights from these average values does not exceed 3%, although 20% of stakeholders present a mean deviation from average weights larger than 5%.

Table 7.8 Average weights of criteria for the assessement of electricity generation technologies

RATIO Method		LEVEL Method	
External health costs	19%	External health costs	16%
Private cost	17%	GHG emissions	14%
GHG emissions	16%	Private cost	14%
Environmental external costs	12%	Environmental external costs	12%
Radionuclides external costs	9%	Radionuclides external costs	10%
Costs for grid connection	9%	Food safety risk	10%
Food safety risk	8%	Severe accidents perceived in future	9%
Severe accidents perceived in future	7%	Costs for grid connection	8%
Fatal accidents from past experience	4%	Fatal accidents from past experience	7%

As already observed in previous exercises, the LEVEL method produces less dispersed weights due to the different preference elicitation approach followed. However, in both weighting methods health impacts are at the top of the list with about 18%, followed by the private cost and CO_2 emissions receiving both around 15%. All other criteria receive lower weights of around 10%, with past accidents presenting the lowest weight of approximately 5%.

The average global scores calculated by using average weights are shown in Figure 7.6. It can be seen that the impact of the weighting method on the global score and consequently on the final ranking of the technologies is very low, leading to no significant changes in their rank order, especially for the top and bottom ranked technologies.

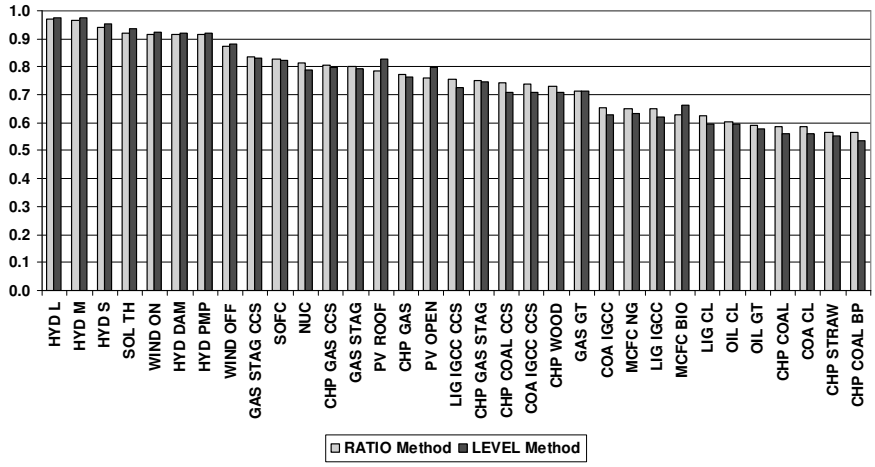


Figure 7.6 Average global scores of electricity generation technologies

One can distinguish at least three groups of technologies. The group of the best performing technologies, achieving a score higher than 0.9, includes practically all hydro units and wind on-shore. In the second best group are placed technologies with average global score between 0.8 and 0.9, among which wind off-shore, gas and nuclear units and PVs. The third group includes mostly innovative technologies using fossil fuels, and fuel cells, while the worst performing group includes conventional oil and lignite power plants, and CHP using straw or coal, all presenting a global score lower than 0.6.

The above classification of technologies is quite representative for the whole group of stakeholders. Fig. 7.7 shows for how many stakeholders a technology appeared among the top 10 and the top 5 technologies (by using the RATIO method). It can be seen that consensus is very high for most types of hydro power plants and wind on shore. On the other side, individual results can differ significantly from the average, since for example, Lignite IGCC or CHP Coal, both with CCS, are placed twice in the top 10 list, though their average ranking position was only 17 and 19, respectively.

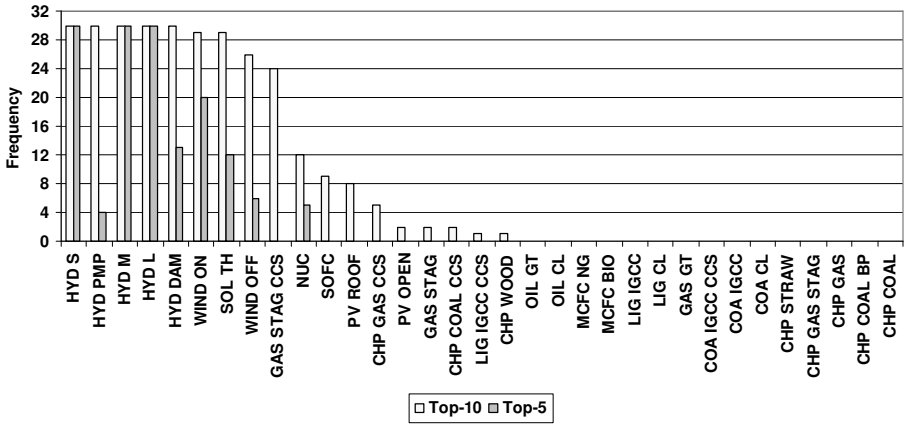


Figure 7.7 Number of appearances of electricity generation technologies in the top 10 and top 5 places

Indirect monetization of impacts

Indirect monetization is based on the assumed equivalence of the stakeholder's relative preferences, relating the weight w_i calculated for each criterion measuring an environmental impact or other impact on non traded goods to the weight w_c of a monetary criterion (e.g. cost or profit) adequately reflecting market prices. The defined weights are considered to reflect the importance attached to the maximum improvement that can be achieved in each criterion when moving from the worst to the best score. Thus, the following identity can be assumed:

$$\frac{w_i}{IR_i} = \frac{w_c}{IR_c} \tag{7.2}$$

where, IR_i and IR_c denote the impact range (i.e. the maximum potential gain) of the physical impact *i* and of the cost criterion, respectively. The underlying assumption is that the value functions for all impact categories are linear, e.g. improvements in the impact level are valued the same, independent of the absolute impact level. The linearity assumption reflects neutral behaviour against risk. This is a simplifying, although a reasonable hypothesis given the limited range of impact levels under consideration. Hence, the per unit monetary equivalent of the physical impact *i,* m_i is calculated as:

$$m_i = \frac{IR_c \cdot w_i}{IR_i \cdot w_c} \tag{7.3}$$

It can deduced that for any pair of criteria *i/c,* the higher the ratio of weights and/or the lower the ratio of impact ranges, the higher is the per unit monetary value implicitly assigned to the physical impact *i*.

Based on the above hypothesis, the weights assigned by stakeholders during the multicriteria assessment of technologies have been further elaborated in order to reveal the hidden monetary equivalents. The analysis is restricted only to the environmental impacts taken into consideration in the Full Cost estimates of Chapter 5. These criteria are measured in quantitative terms and allow for a direct comparison of the two valuation approaches.

The impact range of the examined criteria has been defined by excluding the most expensive technologies of PVs and Solar thermal units. It is considered that the impact range of 25 c€/kWh does not represent a cost difference of a realistic decision situation because of the much smaller scale of these technologies. In addition, such a cost difference could lead to extremely high monetary values for the examined environmental impacts.

Table 7.9 shows the average monetary equivalents for each impact category, calculated by excluding the 20% of the extreme top and bottom values.

Table 7.9 Average monetary equivalents

Impact	RATIO Method	LEVEL Method
HEALTH	3.88	3.33
CO2eq (€/t)	120.27	119.71
ENV	23.77	24.56
RADIO	45.07	45.34

The monetary equivalent for GHG emissions is provided directly in monetary terms (€/t CO_2eq) since this criterion is measured on a physical impact scale. For the other three criteria, the calculated monetary equivalents represent a coefficient to be multiplied with the already defined monetary values. This means that for example health impacts calculated through the MCDA equivalents are 3.33-3.88 times higher than the respective CASES values, depending on the weighting method used.

A general observation is that all environmental impacts have been overestimated in comparison with the value estimates shown in Table 7.7. This explains the obtained multicriteria rankings and the position of all renewable energy technologies on the top of the list. The calculated monetary equivalents can be used to translate the qualitative ranking shown in Table 7.7, in a quantitative ranking based on Full Costs. Specifically, for each technology the external cost estimates are multiplied by the corresponding monetary equivalents (or by the respective unit value in case of GHG emissions) and added to private costs. Table 7.10 shows the so calculated Full Costs in comparison with the respective CASES estimates. As expected, the higher the contribution of environmental externalities to total social costs, the larger the deviation between the two valuation approaches. Thus, in most renewable energy technologies the difference in Full Costs is about 1 c€/kWh and reaches 3-5 c€/kWh only for the PV technologies. On the contrary, the difference becomes much higher in the technologies using fossil fuels. The deviation for the most polluting ones (conventional coal and lignite units, CHP coal) varies around 18 to 20 c€/kWh, with the MCDA costs being 4 times higher than the CASES estimates. A similarly high cost difference of 8 c€/kWh is observed in the nuclear power plant, with the MCDA estimate

appearing 4 times higher than the CASES estimate, mainly because of the high monetary equivalent calculated for Radionuclides.

Table 7.10 gives a graphical representation of the recorded deviation.

Table 7.10 Comparison of social costs (c€/kWh)

Technology type		CASES	RATIO Method	LEVEL Method
HYD L	hydropower, run of river >100MW	4.7	5.5	5.3
HYD M	hydropower, run of river <100MW	4.7	5.6	5.4
WIND ON	wind, on-shore	6.2	7.0	6.8
WIND OFF	wind, off-shore	6.3	7.2	7.0
HYD S	hydropower, run of river 10MW	7.5	8.8	8.5
HYD DAM	hydropower, dam (reservoir)	7.6	9.3	8.9
HYD PMP	hydropower, pump storage	7.7	9.3	8.9
CHP COAL CCS	hard coal CHP with extraction condensing turbine with CO2 capture	2.6	9.6	8.1
CHP WOOD	biomass (woodchips) CHP with an extraction condensing turbine	4.6	9.9	8.8
CHP GAS CCS	natural gas CHP with extraction condensing turbine with CO2 capture	6.3	11.9	10.7
NUC	nuclear power plant	3.0	12.0	11.1
SOL TH	solar thermal, parabolic trough	12.1	12.8	12.6
LIG IGCC CCS	lignite IGCC with CO2 capture	4.7	12.8	11.0
GAS STAG CCS	natural gas combined cycle with CO2 capture	6.8	12.8	11.5
SOFC	SOFC (natural gas)	8.1	14.0	12.7
CHP GAS	natural gas CHP with extraction condensing turbine without CO2 capture	5.6	14.3	12.4
COA IGCC CCS	hard coal IGCC with CO2 capture	5.6	14.7	12.7
GAS STAG	natural gas combined cycle without CO2 capture	6.0	15.4	13.3
CHP GAS STAG	natural gas combined cycle CHP with backpressure turbine	5.7	15.8	13.6
COA IGCC	hard coal IGCC without CO2 capture	6.0	21.5	18.0
LIG IGCC	lignite IGCC without CO2 capture	5.5	21.8	18.1
CHP COAL	hard coal CHP with extraction condensing turbine without CO2 capture	3.9	22.5	18.4
GAS GT	natural gas, gas turbine	8.9	23.5	20.3
LIG CL	lignite condensing power plant	5.1	23.6	19.4
CHP STRAW	biomass (straw) CHP with an extraction condensing turbine	7.0	23.9	20.5
MCFC NG	MCFC (natural gas)	9.8	23.9	20.6

CHP COAL BP	hard coal CHP with backpressure turbine	3.8	24.2	19.7
COA CL	hard coal condensing power plant	6.5	27.1	22.5
OIL CL	heavy oil condensing power plant	10.2	27.5	23.5
PV ROOF	solar PV, roof	25.8	29.2	28.4
PV OPEN	solar PV, open space	22.2	29.4	27.7
OIL GT	light oil gas turbine	12.6	29.9	25.9
MCFC BIO	MCFC (biogas)	12.0	35.8	30.3

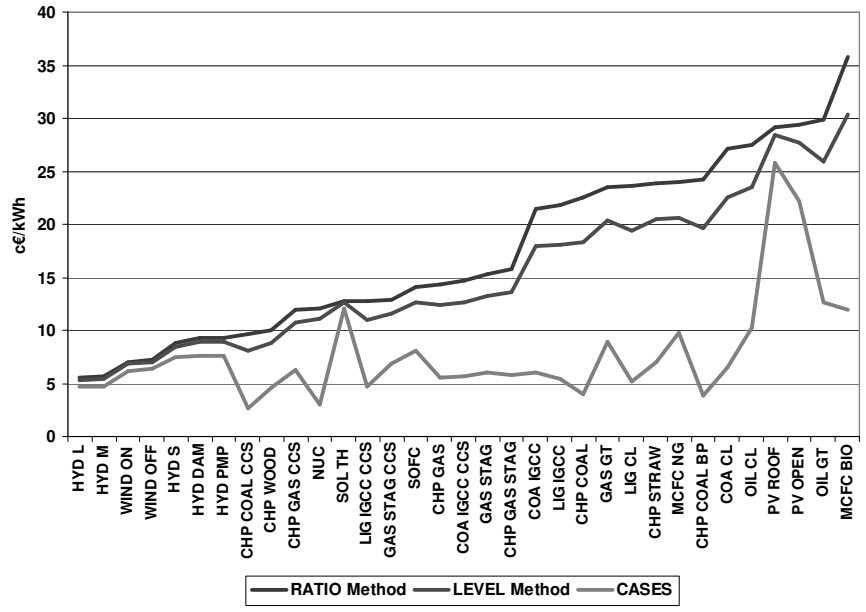


Figure 7.8 Range of social cost estimates of electricity generation technologies

Certainly, the degree to which the so calculated MCDA Full Costs reflect the values attached by society to the environmental goods affected by electricity generation is rather questionable. The defined weights are not expressing the Willingness To Pay of the respondents, mainly because they were not asked to articulate their concerns in such a scale and they have not been informed during the workshop of the translation of their preferences in a monetary scale.

It can therefore be deduced that MCDA has the capacity to act as a valuation approach, provided that it is implemented in an interactive, learning

procedure giving the stakeholder the opportunity to go deeper into the decision problem and better understand the real trade-offs behind the available choices. If such a condition is satisfied, MCDA can be proved as a valuable tool for handling complex decision situations, especially at the local level, where monetary estimates for specific environmental impacts are not available or not convincing for the wider public. Moreover, in such a decision situation the active participation of stakeholders in the decision procedure is generally considered as very important for achieving a common understanding of the problem faced and a wide acceptance of the proposed solution. In these cases, MCDA and monetary valuation can be exploited in a complementary way. MCDA facilitates participation and articulation of preferences, whereas monetization can be exploited for translating preferences in a tangible and more familiar value scale that can guide the process of preference elicitation towards more realistic judgments.

7.6 CONCLUSIONS

The assessment of policy instruments and of electricity generation technologies has led to valuable insights both on the multicriteria methodology used and on the respective policy problems. The experience from the workshop has shown that stakeholders are very interested in participating in such a participative procedure. However, the time available has proved to be too short to really make everybody understand the formulation and assumptions of the problems, and to get familiar with the MCDA tool.

When confronted with the ranking of instruments or technologies some stakeholders felt that this result did not represent their opinion. There can be different reasons for this. The ranking of the instruments is based on the weighing of criteria and on the performance of the examined alternatives with regard to the criteria. The weighing was controlled by stakeholders. The performances on the other hand were supplied by the CASES partners involved in the workshop. This approach was supposed to make the procedure more transparent and to prevent stakeholders from picking the obvious choice of instrument without reflecting. However if stakeholders fundamentally disagree with the performances they will likely also disagree with the final ranking that results from their weights. During the workshop stakeholders had the possibility to review and change the performances but due to lack of time and the large number of variants and criteria, stakeholders had little chance to use this option.

Another reason that the final ranking did in some cases not reflect the real opinions of stakeholders could be that stakeholders base their choice of instrument, at least partly, on criteria which were not included in the exercise. Nonetheless, no other criteria appeared in the discussion and the list was already quite extended. Stakeholders may base their spontaneous choice on some fixations or false impressions without having realised the reasons explaining their viewpoints. In this case the outcome should differ from the predetermined judgment of the stakeholders and this should be an incentive for everyone to reflect and reconsider their whole attitude. It may also be the case that the weights which the stakeholders assigned to the criteria during the exercise do not truly reflect their predetermined opinion. Here, either stakeholders try to appear for example more environmentally friendly than they really are, or the weighting method itself did not help them to articulate their true preferences. The last exercise of technologies assessment and the implied monetary equivalents shows that such biases are very likely to occur in a MCDA procedure. To this purpose, a combined MCDA-monetisation approach seems very appropriate as a constructive learning procedure.

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Part III Electricity scenarios

8 Electricity scenarios in EU countries

Name Surname

This chapter is divided in two parts. First the common used models for EU are described and compared. Then the ECON model assumptions and results are explained in details.

8.1 EXISTING MODELS FOR EU COUNTRIES

Energy models produce forecasts for the future global energy situation, especially in terms of energy demand, energy mix and security of supply. A range of organisations issue regular projections that serve a variety of political and economic purposes and with different emphases and methodologies. This variety means that the forecasts are often difficult to compare. On the basis of selected parameters, the first part of this chapter compares the points of view of three well-established models regarding electricity sector scenarios for the EU-25.

Models descriptions

PRIMES is a modelling system for energy supply and demand in the EU member states up to 2030. PRIMES results are published in the 'European Energy and Transport Trends to 2030' (EC DG-Tren, May 2006). Updated scenarios are expected to be released shortly.

The EC DG-Research published the 'World energy, technology and climate policy outlook' (WETO-H_2) in 2006. The WETO presents results from the POLES model which is a world partial equilibrium simulation model for the energy sector, with endogenous international energy prices.

The International Energy Agency (IEA) model uses its 'World Energy Outlook' to carry out long-term energy projections up to 2030. There is a strong focus on concerns about the security of energy supplies, investment in infrastructure, the environmental damage caused by energy production and use and the unequal access of the world's population to modern energy. In this model (2006), a Reference scenario is compared to an Alternative policy scenario.

Comparison of main assumptions

While the models reference scenarios have similar population and GDP growth rate assumptions, their main differences lie in the prices of the different fuels and the value attached to carbon which are all presented in the next table. Whereas the IEA scenarios are characterized by a constant energy price environment over the forecasting period, the PRIMES reference scenario is based on a slight progression. The other two PRIMES as well as the WETO scenarios assume a stronger increase in energy prices. Concerning the future power generation fuel mix, the most important element is the price differential between natural gas and coal. This differential remains more or less constant in the IEA scenarios and is slightly higher in the PRIMES reference scenario, followed by the medium gas and soaring oil price scenario and the two WETO scenarios. The differential grows most rapidly in the soaring oil and gas scenario.

		Primes reference	Primes medium gas & soaring oil prices	Primes Soaring oil & gas prices	WETO reference	WETO Carbon Constraint	IEA reference & alternative
OIL							
($ per bbl)	**2010**	44.6	61.9	61.9	38.7	38.5	51.5
	2020	48.1	75	75	53.5	50.4	
	2030	57.6	98.5	98.5	66.7	61.1	55
GAS							
($ per Mbtu)	**2010**	5.8	5.8	6.5	4.7	4.7	5.9
	2020	6.4	7.2	8.9	8.3	8.2	
	2030	7.7	9.5	12.9	11.0	10.3	6.5
COAL							
($ per ton)	**2010**	59.5	59.5	64.8	57.5	57.5	55
	2020	67.1	67.1	76.2	69.0	65.2	
	2030	71.0	71.0	94.3	80.5	75.9	60
CO2							
(€ per tCO2)	**2010**	5	5	5	10	10	
	2020	5	5	5	15	58	
	2030	5	5	5	20	105	

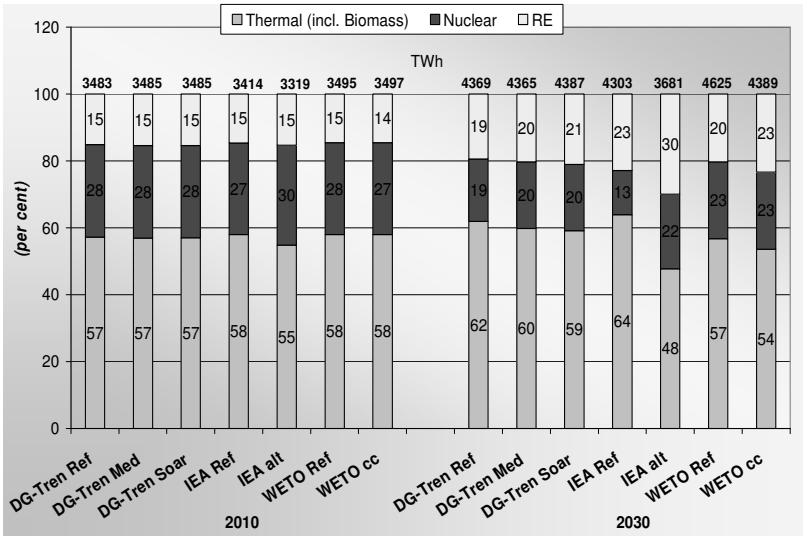
Table 8.1 : Main assumptions for the scenarios

As far as carbon is concerned, PRIMES considers a relatively low carbon value environment while WETO's is higher, in particular for the carbon constraint scenario which sets stricter limits on CO_2 emissions[49] such that carbon values increase linearly to 105 € per tCO_2 in 2030. The IEA's trends in CO_2 emissions are based on improved efficiency of energy use and increased use of nuclear power and renewables[50]. It is important to note how increasingly "carbon" has become an essential part of energy forecasting.

8.2 MAIN RESULTS OF EXISTING MODELS

All scenarios show a sustained growth in electricity generation based, among others, on the assumption of the shift development of electricity intensive information and communication technologies ("third industrial revolution"). This development is even more pronounced in the case of the WETO reference scenario. The WETO carbon-constrained electricity demand is slightly lower as a result of a higher carbon value and higher electricity prices which improves end-use efficiency. The IEA alternative scenario falls well below all others due to major efficiency and energy intensity improvements in energy use.

Concerning the fuel-mix in power generation, RES gain a greater share over the forecasting period (2010 to 2030). RES-based power generation doubles in most cases. Nuclear decreases slightly in volume in most scenarios, except for WETO's modest increase. The share of nuclear, however, falls in all scenarios. Thermal power production, in general, shows a sustained growth, with its share increasing (even if marginally in some scenarios), except in the case of the IEA's WEO.

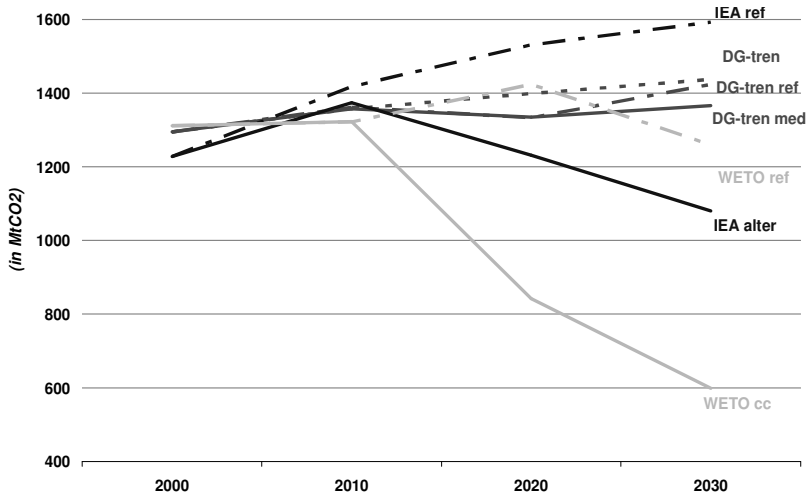


Source: OME based on all the different scenarios

Figure 8.1 Total power generation, by source

CO2 emissions from power generation

It should be noted that both the WETO carbon constraint scenario and the IEA alternative policy scenario show a sharp decrease in CO_2 emissions since they were designed to exactly achieve this important cut - albeit less so for the IEA scenario. In the case of WETO's carbon constraint, the model is designed to achieve a 50 per cent reduction of the 1990 TPES emissions by 2050 (factor 2 reduction). It is interesting to note that in the electricity sector, this reduction would already be achieved before 2030.



Source: OME based on all the different scenarios

Figure 8.2 CO2 emissions 2000 to 2030

8.3 DESCRIPTION OF THE ECON CLASSIC MODEL

On the demand side Econ's base case and other scenarios are based on DG Tren's Baseline 2005 report, which is an update to the Trends to 2030 report published in 2003, where 2030 projections are derived from the PRIMES model. In this report, demand projections from the DG Tren study are used. On the supply side, cost assessments are based on the NEEDS study.

The Econ Classic model is an optimization model for the electricity market that maximizes welfare (and minimizes costs) subject to a set of

conditions, the most important one being supply equals demand. The Classic model is solved for a set of chosen years. Classic covers all EU27 regions as well as Norway and Switzerland.

In Econ Classic certain variables such as fuel prices, costs of production, income growth and transmission capacities are exogenous. Regarding capacity, known capacity developments including decided or ongoing investments, refurbishments, mothballing and retirements are entered exogenously into the model. In addition, investment in new capacity and in refurbishments is endogenous. Endogenous investment decisions are based on long-term marginal costs and projected demand. Demand is endogenously determined based on GDP growth projections and (endogenous) electricity price development. Hence, investment levels are determined by demand growth while types of investment in terms of technology are determined by the relative competitiveness of different technologies (long term marginal costs), subject to potentials and transmission capacities.

The Econ Classic model regularly undergoes improvements and updates. For the CASES project, the version of the Classic model used is based on the most recent update from Q-3 2007. This model version contains the latest available macro and growth estimates from October 2007, while fuel prices are based on forward prices for 2008. Generating capacities for non-renewable technologies are derived from the March 2007 Platts database, while transmission capacities are derived from the Union for the Coordination of Transmission of Electricity (UCTE).

Inputs and assumptions

The fuel prices are the same as the fuel prices used in NEEDS project:

Table 8.2: Fuel prices assumption

Constant 2005 prices	2010	2020	2030
Oil (€/GJ)	5.425	5.786	7.233
Gas (€/J)	4.535	4.605	5.581
Coal (€/GJ)	1.57	1.753	1.858

These energy prices are also in line with the reference scenarios of DG Tren Primes, and of the IEA and WETO.

Carbon values, or CO2 prices, have been set to 20€/tCO2 consistently for years 2010, 2020 and 2030. Free allocation shares for CO2 emissions have been set to zero for all scenarios.

The scenarios contain a fixed minimum level of power generation based on renewable energy sources (RES-E) in order to take account of a voluntary EU policy of RES-E promotion. This 'floor' input is calibrated so that the

share of RES-E generation is approximately 28% in 2030 in the base scenario.

Investment costs are obtained from the assessment of private and external costs of power generation undertaken by the New Energy Externalities Development for Sustainability (NEEDS) project.

The CASES project does not provide assessments of the potentials for different technologies in different countries. It is however necessary to restrict investments in wind power capacity particularly. If potentials and system costs are not taken into account, wind investment could grow to implausible levels. The restrictions used in the model have been derived from the Green-X database, and adjusted for the exogenous wind capacity from DG Tren. As wind investment potentials in Green-X are defined as technical potentials, this potential has been adjusted downwards somewhat to increase the realism of the potentials.

In terms of nuclear, only five countries are assumed to make new investments; Finland, France, Sweden, UK and Bulgaria. This restriction is based on the national policy attitudes towards nuclear in different countries. For Sweden the nuclear investment is restricted to upgrades in existing capacity.

8.4 RESULTS OF THE ECON CLASSIC MODEL

In addition to the simulation of the base year, 2007, two different scenarios, consisting of six model runs, were carried out for this project. The next table lists the different runs.

Table 8.3: List of scenarios

Scenario	Name of runs	Description
1	Base Case	Econ Classic base model from Nordic Power Quarterly Q3 - base year 2007
2	2010	2010 with private costs of generation
	2020	2020 with private costs of generation
	2030	2030 with private costs of generation
3	2010_ExtCosts	2010 with full costs of generation
	2020_ExtCosts	2020 with full costs of generation
	2030_ExtCosts	2030 with full costs of generation

The external costs included in the Full Cost scenario are:

- Human health costs, except those relating from radio nuclides.
- Environmental costs, such as loss of biodiversity, crops and material.
- Radio nuclides, causing radioactive contamination.
- Marginal costs of greenhouse gases.

Including these external costs in the costs of generation makes conventional technologies more costly. Hence, this could lead to a shift in the composition of supply side technologies, encouraging more investment in renewables. Next figures show a cost comparison for different generation technologies for average EU cost estimates. Based on private costs alone, hard coal would be preferable to onshore wind power, while this is reversed when external costs are included (external costs are the sum of all four costs listed above). Nuclear is the cheapest option regardless of cost composition. It should be observed, though, that the capital costs are fairly low as the discount rate has been set to only 5%. This would favour investment in capital intensive capacity like nuclear.

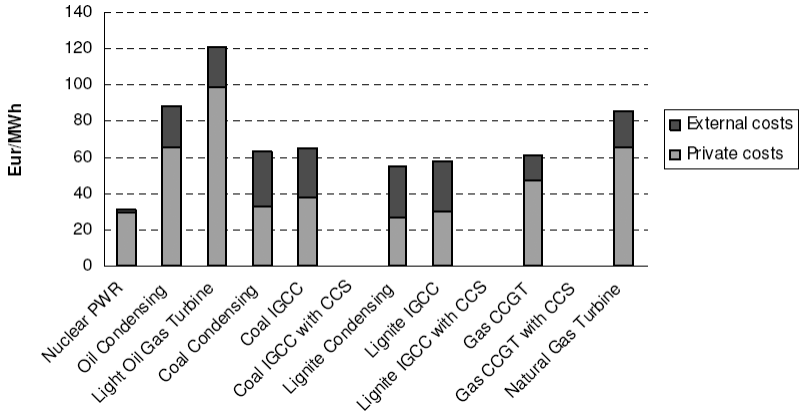


Figure 8.3 Composition of marginal costs for nuclear and thermal technologies 2005-2010 (€/MWh)

Table 8.4

Technology	Private Costs	External Costs
Nuclear PWR		
Oil Condensing		
Light Oil Gas Turbine		
…		
…		
…		
…		

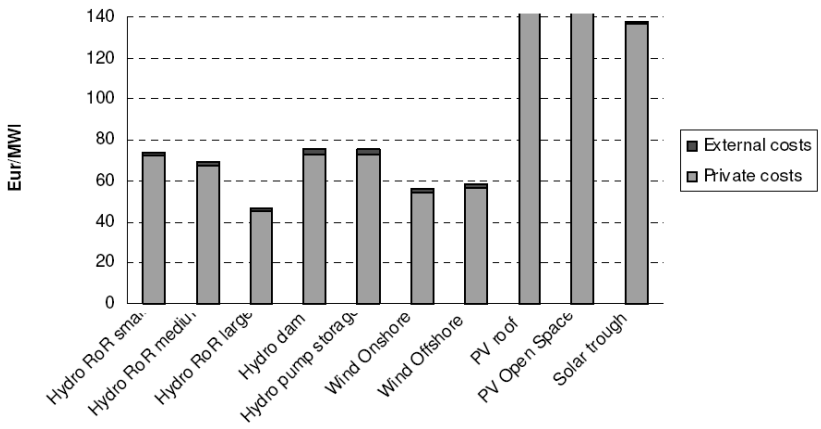


Figure 8.4 Composition of marginal costs for renewable technologies 2005-2010 (€/MWh)

Please insert a table below the figure giving the data.

Table 8.5

Technology	Private Costs	External Costs
…		
…		
…		
…		
…		
…		
…		

Investments

The current aggregate capacity in the EU27 is distributed on different technologies, though coal-fired, gas-fired and nuclear generation account for most of the generation.

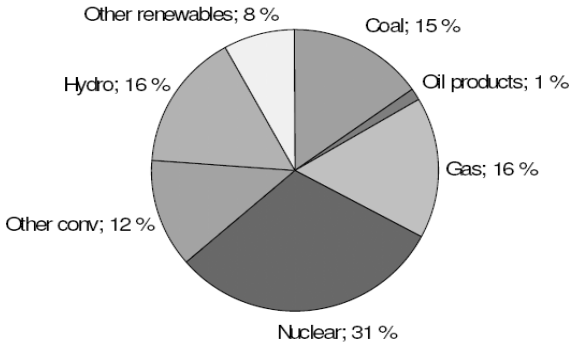


Figure 8.5 Shares of electricity generation by fuel for EU27 in 2007 (%)

The shares of fuel types used for electricity generation change as investment in capacity are carried out. The results show that investments, and hence fuel shares depend strongly on whether external costs are included or not. As expected, including external costs makes renewable technologies relatively cheaper, which in turn leads to phase-out of conventional technologies such as coal and gas-fired generation. This hypothesis is

confirmed as shown in Figure 8.6, where it emerges that investments in coal capacity are replaced by wind and natural gas when external costs are included. It should be noted that the figure only shows endogenous investments.

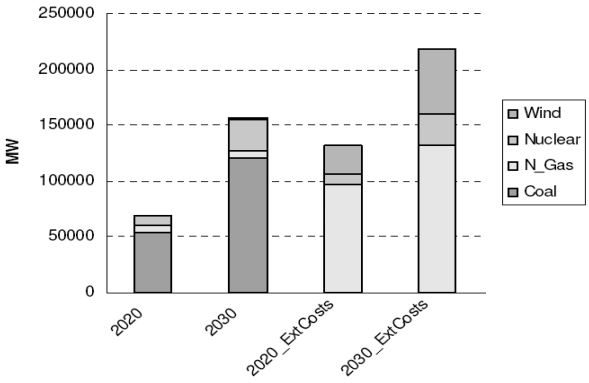


Figure 8.6 Total endogenous investments in generation capacity in the EU

Table 8.6 Total endogenous investments in generation capacity in the EU

	2020	2020 with Ext Costs	2030	2030 with Ext Costs
Wind				
Nuclear				
Natural Gas				
Coal				

For the scenarios with private costs investment decisions are dominated by coal, which due to relatively low fuel prices has the lowest marginal costs. Coal accounts for 90% and 80% of the investments in 2020 and 2030 respectively. When external costs are included investment decisions shift in favour of natural gas and wind. Investment in nuclear are relatively similar between the two sets of scenarios as nuclear consistently has the lowest marginal costs, and investments are restricted by the applied capacity ceilings.

It is also evident that total capacity investments increase between the two scenario sets. It does so for two reasons. The first reason is that wind power generally has a lower load factor than coal generation, and hence more capacity is needed to meet energy demand. The second reason is that higher

operating costs for thermal technologies means that less fossil generation is refurbished, while coal plants are retired earlier. So in effect, higher operating costs displaces coal power in favour of wind and marginally less expensive natural gas generation.

Demand

From the base year (2007) the demand levels in the model years 2010, 2020 and 2030 increase according to the specification of the demand curves, the GDP growth rates from Primes, and the development in prices. GDP growth and price parameters differ between demand sectors, of which there are five in Classic; Households, Services, Other (non-energy-intensive) industry, Energy-Intensive Industry and Electrical Boilers[51].

Figure 8.7 shows the total demand for EU27 (and Norway and Switzerland). For the scenarios without external costs, demand is consistently higher than in the scenarios with Full Costs. This is because the higher electricity prices resulting from higher costs of production in the Full Cost scenarios curb demand by 7.5% in 2030. Including external costs curbs demand by 10% in 2010 as the price difference for this year is higher. This is due to the generation park being similar in the two 2010-runs, and that higher operational costs of capacity have not yet been mitigated by investments in relatively cheaper technologies. The model probably overestimates the demand response in 2010 since long-term price elasticities are assumed.

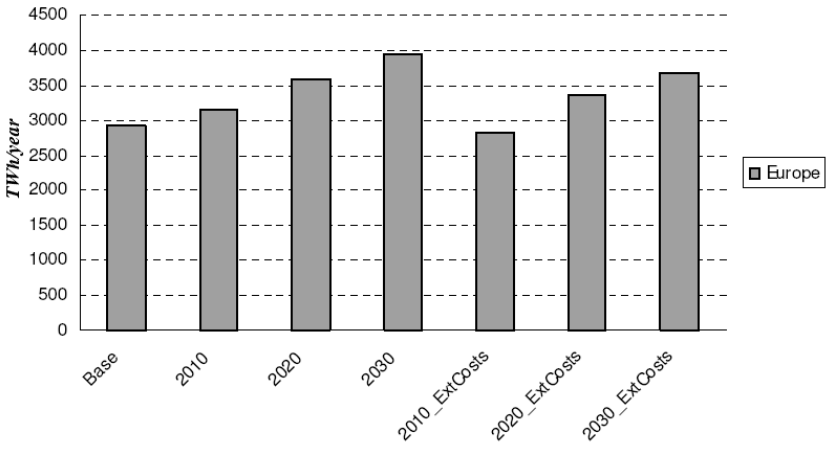


Figure 8.7: Total demand in the EU area

Generation

Developments in generation are closely linked with investments and demand. Total generation distributed by fuels in the EU area is displayed in Figure 8.8 and Figure 8.9. These figures indicate that higher operating costs through the introduction of external costs have significant implications for the generation mix.

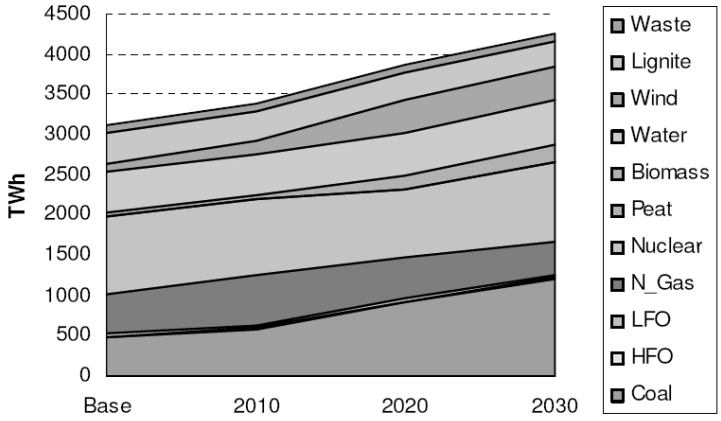


Figure 8.8: Total generation by fuel in the EU area – Private cost scenario

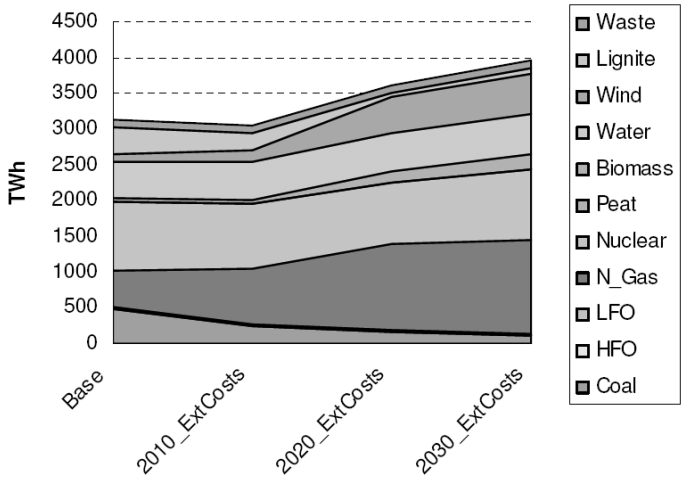


Figure 8.9: Total generation by fuel in the EU area – Full Cost scenario

With costs of generation reflecting private costs alone coal generation is, given the fuel price assumptions, the cheapest technology, and will thus cover base load demand for many EU countries. By the same reasoning, wind investments are relatively restricted. Hence, wind generation, with an assumed fixed load factor accounts for roughly 10% of overall generation in 2030. This share can be attributed to exogenous wind investment according to the DG Tren study, meaning that investments in wind are driven purely by policy. In the Full Cost scenario, wind generation accounts for 15% of total generation. Adding external costs to investment and operating costs thus yields an extra 5% of wind generation generated by private sector investments. Coal and lignite generation, which have high external costs conversely become more expensive and are replaced by natural gas and wind subject to the applied restrictions. Nuclear generation remains relatively similar between scenarios as explained above. It is also worth noting that total generation levels are lower in the Full Cost scenarios due to lower demand, since higher overall marginal costs yields higher prices and hence demand cuts.

Fuel use in the electricity sector

Inputs of various fuel types follow analogously from the generation mix. Fuel use intensity naturally depends on the efficiency assumptions of the various plants, and these are outlined in
Table 8.7 below.

Table 8.7: Plant type efficiencies (%)

Plant type	Fuel type		Efficiency	
	Operating	Start-stop	Full load	50% load
New GT (CO)	Light Fuel Oil	Light Fuel Oil	33 %	16 %
New CCGT (CO)	Natural Gas	Natural Gas	54 %	27 %
New Scrubbed Coal (CO)	Coal	Heavy Fuel Oil	43 %	22 %
New IGCC Coal (CO)	Coal	Heavy Fuel Oil	47 %	24 %
New Lignite (CO)	Lignite	Heavy Fuel Oil	40 %	20 %
New IGCC Lignite (CO)	Lignite	Heavy Fuel Oil	40 %	20 %
New nuclear	Nuclear	Nuclear	100 %	100 %

The efficiency of these plant types determines the economics of investment decisions. In the Private cost scenario, the assumed coal plant efficiency makes coal the least expensive option given the investment costs,

operating costs and the fuel prices. Including external costs increases the operating costs of coal plants relative to gas-fired plants, and this is verified through the fuel use of the various fuel types in Figure 8.10 below.

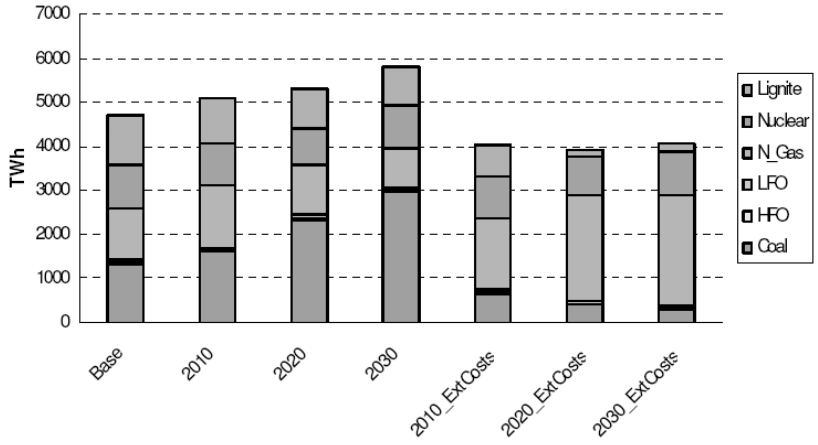


Figure 8.10 : Fuel use in electricity generation by fuel type

The gap in total fuel use between the Private and the Full Cost scenario is largely explained by differences in renewables, bearing in mind, however, that overall generation is lower in the Full Cost scenario.

CO_2 emissions

One of the main purposes of CASES is to assess the relationship between external costs of electricity production and the environment. In this analysis, we have derived the CO2 emissions from electricity generation under the various scenarios. The results are summarized hereafter:

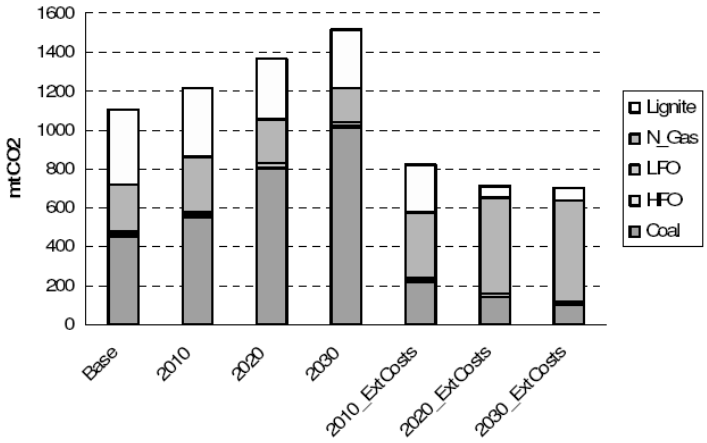


Figure 8.11 : Total CO2 emissions in the EU area (Mton CO2)

The CO2 output corresponds to the generation output. In the Private Cost scenario, capacity investments are dominated by coal and lignite, and CO_2 emissions increase by about 50% from the base year to 2030. In the Full Cost scenario coal and lignite are replaced by natural gas and wind, and as a result CO2 emissions in 2030 are almost 900 $mtCO_2$ lower than in the Private cost scenario. Moreover, the CO2 mix is different, with CO_2 emissions in the Full Cost scenario mainly stemming from natural gas. For the Full Cost scenario, emissions fall in 2010 relative to 2007 by around 300 $mtCO_2$. The main reason for this reduction is that natural gas replace existing coal and lignite generation, as well as a reduction in overall electricity demand. This relatively strong effect is due to Classic being a fundamental model assuming perfect competition and hence swift market adaptation as a result of changes to the merit order. The increase in demand and restrictions on wind investment yields a lower reduction between 2020 and 2010. Between 2020 and 2030 there is no reduction in emissions. It is however clear that adding Full Costs to the marginal production costs curb emissions from power generation by over 50% compared to 1990 levels. This result is achieved with a CO2 price of 20€/tCO_2.

8.5 CONCLUSIONS

Including external costs in the cost of electricity production has significant implications for the cost-efficient development of the electricity sector in Europe. The first impact external costs have is on the merit order of generation technology marginal costs which thus leads to changes generation mix. External costs raise the costs of generating electricity from fossil fuels compared to renewable generation. This again alters investment costs, which in many cases shifts investment from coal to wind. Wind investment is however restricted due to limited natural endowments, land-use and system costs, so the thermal investments will still be carried out. Due to external costs, the thermal technology with the lowest marginal cost is CCGT, which is both a more efficient and "cleaner" technology than coal. With regards to the generation mix, there is also a second effect. Higher operating costs shorten the lives of existing (old) coal and lignite technologies, making new investment cheaper than coal and lignite refurbishment. The result is a distinct difference in the generation mix with and without external costs. Even nuclear plays a role in some countries, but is generally restricted due to political and public opinion objections. These objections are related to security issues surrounding waste transport and management and the risk of nuclear accidents, effects which are not included in the CASES external cost evaluations. The second profound effect of including external costs is the increase in the price of electricity, due to higher costs of production. This curbs electricity demand, necessitating less investment and refurbishments compared to the situation with private costs. The third and arguably most important effect is the mitigation of CO_2. The shift in the generation mix displaces coal and lignite in favour of natural gas and wind, leading to huge gains in CO_2 emission reductions, even with a moderate carbon tax of €20/ton CO_2. In fact, using external costs as provided by CASES will reduce CO_2 emissions in the power generating sector by more 50% both in 2020 and 2030 compared to 1990 levels.

9 Electricity scenarios in Brazil, China, India and Turkey

Name Surname

9.1 ELECTRICITY SCENARIOS IN BRAZIL

With respect to CO_2 emissions, Brazil has a favorable scenario thanks to its energy structure, with a predominance of renewable sources. As a result, Brazil has one of the lowest rates of emissions from the energy sector, with respect to GDP, in the world. Nevertheless, in the last few years there has been a strong increase of fossil energy in the energy supply mix. This is mostly due to the recent restructuring of the power industry, which seeks to attract private capital for building new plants. Thus, technologies that do not require very high initial investments and that have a shorter payback period are preferred, as is the case of natural gas thermal power plants. Therefore, renewable energy sources, such as hydro, are losing ground, leading to an increase in energy based CO_2 emissions.

Two scenarios are presented: the *baseline scenario* for the Brazilian energy sector which has been simulated using the MESSAGE model, and the *alternative scenario* for the expansion of the generating capacity of the power industry which has been built taking into account penalties for greenhouse gas emissions.

The new results show a reduction in emissions in 2030 from 112 $MMtCO_2$ to 84 $MMtCO_2$ that means a reduction of 25%. An increase in the cost of expansion can also be seen in the alternative scenario, as shown by the table below that compares the results of both scenarios.

Table 9.1: Comparison of the baseline and alternative scenario for Brazil

		Cost (million US$)		Variation	Emissions (MMtCO2)		Variation	Abatement Curve
Year	Generation	Baseline	Alternative	Cost	Baseline	Alternative	Emissions	Thousand US$/ tCO2
2010	490.66	7,622	7,948	326	54.19	54.73	0.54	0.61
2015	636.80	16,060	17,990	1,930	73.26	67.72	-5.53	-0.35
2020	853.75	22,515	26,260	3,745	86.10	78.70	-7.40	-0.51
2025	974.50	11,954	14,868	2,914	87.25	79.58	-7.67	-0.38
2030	1,074.58	11,364	12,449	1,086	112.25	83.71	-28.54	-0.04
Total	4,458.17	77,712	88,864	11,152	444.07	395.50	-48.57	-0.23

9.2 ELECTRICITY SCENARIOS IN CHINA

In order to analyze future energy demand and emissions in China, three scenarios have been presented. The three scenarios are defined as follows:

- *Baseline scenario*: This scenario gives a basic trend to describe future economic activities. There will be better international trading and China's economy will be part of global economy. Therefore China could rely on international markets and energy resource imports to meet part of its energy supply needs.
- *High demand scenario*: This scenario presents a high demand for energy in the future. The major driving force is China's assumed role as a centre for manufacturing following WTO accession, which will bring more energy-intensive product production to China, such as steel, non-ferrous products and building materials. At the same time, more technology transfer and R&D on high efficiency energy use technologies is also assumed.
- *Policy scenario*: Various energy and emission control policies are assumed for this low demand scenario, which reflects energy supply and environmental constraints.

The basic assumptions for the three scenarios, such as population and GDP growth, are the same.

Energy demand scenarios

Primary energy demand in the baseline scenario could go to 2.1 billion toe in 2020 and 2.7 billion toe in 2030. The annual growth rate from 2000 to 2030 is 3.6%, while energy elasticity of GDP is 0.58. Coal will be the major component energy in China (1.5 billion toe in 2030), with a 58% share in

total energy demand. There is a rapid increase for natural gas demand in China, with its share in total primary energy use increasing from 4% in 2000 to 17.3% in 2030 (average annual growth rate: 10%). With respect to final energy use, electricity and oil increase rapidly. Electricity demand increases from 112 million toe in 2000 to 451 million toe in 2030. Coal use in the residential sector will generally decrease and be replaced by gas and electricity; coal will be mainly used in large equipment such as boilers, steel industry and cement industry.

For the *high demand scenario*, primary energy demand in 2030 is 2.9 billion toe, which is 250 million tons higher than the baseline scenario. Of the total primary energy demand, coal provides 59.1%, oil 16.1%, natural gas 17.8%, and nuclear 1.2%. Because this scenario assumes better integration in international markets, there is greater reliance on imported energy such as natural gas and oil.

With the calculation of energy demand, several pollutant emissions were also calculated. SO_2 emission will keep increasing before 2010 with the rapid increase of coal use in China. After 2010, more and more desulphurization technologies will be used and therefore SO_2 emission will be reduced from fossil fuel use. Compared with *high demand scenario*, SO_2 emission for *baseline scenario* in 2010 is 4.5 million tons lower, but still increase 9.45 million ton from 2000. This will be big challenge for government target. Because of lack of policy to control NOx, its emission keeps going up. Same trend is seen for TSP emission.

Concerning the effects for policy options used in the *policy scenario*, by comparing with *baseline scenario* and *high demand scenario*, it has been noticed that there is a package of policy options which could be adopted now to reduce the growth rate of energy demand. For example policy to promote penetration rate of high energy efficiency technologies, fiscal energy and environment policies including vehicle fuel taxes, subsidies for renewable energy, emission taxes, resource taxes etc., and policy to promote public involvement, are important for China to go to a low energy demand scenario.

Energy supply scenarios

In the baseline and high demand scenarios, coal production could reach 1.31 billion toe by 2020 and 1.48 billion toe by 2030. Chinese coal industry experts estimate an upper bound of coal production of 1.2 billion toe by 2020. Coal demand, therefore, could exceed domestic coal production in China. Oil production is projected to be 190 million tons in 2020 and 175 million tons in 2030. This is within the forecast of experts from the oil industry, which range from 180 to 200 million tons in 2020. Natural gas production will be 133 billion m3 in 2020 and 312 billion m3 in 2030. The production of natural gas is within the range of natural gas production

forecast by energy experts, which ranges from 130 to 150 billion m3 in 2020. Nuclear power generation will increase quickly in future, but still represents a small share, because of its high cost. The model results shows that nuclear power generation could reach 256 TWh in 2020 and 344 TWh in 2030, compared with 16.7 TWh in 2000. The installed capacity will be 39,400 MW in 2020 and 53,030 MW in 2030. Hydropower output will increase from 224 TWh in 2000 to 555 TWh in 2020 and 722 TWh in 2030, with capacity reaching 154 GW in 2020 and 201 GW in 2030.

Only a few of countries in the world are using coal in large scale new plants, therefore development of clean coal technologies depends on them. China is the hugest country to use coal, and in future the coal use will increase quickly, which could take more than 40% of world total coal use in 2020. Therefore, clean coal technology is crucial for China. China should have clear development plan to promote clean coal technology. It is better to work in close coordination with other countries to develop new generation of clean coal technologies.

9.3 ELECTRICITY SCENARIOS IN INDIA

The *baseline scenario* for India has been articulated by capturing the average GDP growth rate in the 10th Plan period (2002-07) and the future expectations. Though the achieved GDP growth rate of 7.2% during the period was below the target of 8%, it has been the highest growth rate achieved in any previous plan periods. The services sector has been the major driver of economic activity while the agricultural growth has become irrelevant to the economic growth – at 2.5% trend growth rate and a share of 16% in GDP it added 0.4 percentage points to the GDP.

The *baseline scenario* results for India shows that the total primary energy supply has increased by almost 5.65 times during the period 2005 and 2050, mainly driven by increasing share of coal, oil, nuclear and biomass.

Nuclear and gas are making an impact in the energy supply not just because they are clean but also by the impending nuclear deal and recent gas discoveries respectively. As regards to coal, it is going to be the mainstay in India's primary energy supply contribution almost 30 per cent of the primary energy supply.

Coming to the power generation, the results show that the total primary energy supply to power sector has increased by 7.5 times with 1835 Mtoe being supplied in the terminal year 2050. The installed capacity increased from 137 GW in year 2005 to 1448 GW in the terminal year 2050. Similarly, the generation output increased from 872 TWh in 2005 to 10076 TWh in year

2050.

Coal continues to be dominating in the final energy mix with a share of 63% in the installed capacity and 76% in the generation output. In the reference scenario, the GHG emissions in terms of CO2 show an increasing trend: from 1291 MT of CO2 in 2005 to 6636 MT in 2050.

External costs are implemented in the model by multiplying the amount of electric power generated (i.e., kWh) from each power plant during each time period each region with corresponding external cost. This ensures that the matching external costs are directly charged to every unit of output from each power plant. With the aim of the model to minimize the total energy system cost, this extra cost thus invokes different response options in the energy system. The model thus answers various questions such as whether to pay or not an extra charge on power production from a technology; whether to install or not a system with NOx removal, SOx removal, or CO2-capture & sequestration; whether to reduce or not electricity consumption in different demand sectors and to substitute the electricity by other fuels etc.

Results

The power generation in the *baseline scenario* is primarily coal driven with different types of coal power plants contributing by 61% to the total power generation at the end of 2050. Super critical technology slowly makes its way from year 2010 onwards and finally captures a share of 22% in the terminal year 2050. From the year 2030, the conventional coal plants are replaced by advanced coal like integrated coal gasification combined cycle (IGCC) taking a share of 12.4% in the year 2050. The other competitive system in 2050 is the CCGT, which contributes more than 24% of total power production. Approximately 15% of the electric power is supplied by the nuclear and renewable energy sources in the year 2050 as shown in figure below.

After the internalization of external costs into baseline cost, the structure of the power generation mix has altered considerably. In this scenario, the overall power generation gets reduced by 13% (in absolute terms 780 TWh) in the year 2050 as compared to the baseline scenario. In the externality scenario, although coal remains the major contributor to total power production, however, its share is reduced from 61 per cent in baseline scenario to 44 per cent in externality scenario in the year 2050.

Some of the advanced coal technologies like IGCC plus CCS also make its way along with only IGCC power plant technologies. Combined together these two contributes 15 per cent of generation in the externality scenario as compared to nil in the baseline scenario. Share of renewable energies including hydro and biomass also gets increased in the externality scenario.

With the introduction of external cost into the total production cost of electricity, emission gets reduced quite considerably. Within the period, the

emission reduction of CO2, SO2, and NOx happens because of the premature retirement of coal plants without SO2/NOx control. Although the dominance of technologies based on fossil fuels continues, however, different developments can be observed in CO2 emissions and local pollutants. With the penetration of CO2 removal technologies, total CO2 emissions are reduced by 12% in the externality scenario, 5/5 as compared to the Baseline. Substantial reduction in SO2 and NOx emissions relative to the Baseline scenario is also observed during the period. This suggests that ancillary benefits are also derived from policies that directly address other environmental issues than CO2 mitigation. Emissions of local air pollutants (SO2/ NOx) are substantial with replacement of conventional coal plants with the desulphurization systems together with advanced coal and IGCC plus CCS.

9.4 ELECTRICITY SCENARIOS IN TURKEY

In the study, a Reference Case was developed to compare alternative scenarios. Greenhouse Gas (GHG) Reduction scenarios analyze options in form of technologies and policies that are primarily oriented toward the reduction of CO2, CH4, and N2O. This analyze has a projection up to 2020.

Reference Case Results

The future price of coal index does not vary too much, after peaking in 2001 it gradually declines to 101. The future price of gas also declines continuously after peaking in 2005 (139). The oil price index has its peak in 2006 (150) and continually drops until 2015 (119) and after that steadily increases to 125 by 2020. A total capacity of 4500-5000 MW nuclear units would be added to the power system until the year 2015. Limitations on natural gas and import coal used to produce electricity would affect the system adversely, however, they would make import dependency increase.

Final energy demand increases from 68 Mtoe to 177 Mtoe in the study period. Industry has the highest share, then residential and transportation. Oil products, electricity, and coal are the most important players. Demand of electricity and hard coal more than triple while that for oil products more than double.

As for the final demand, primary energy supplies also about triple and reach 223 Mtoe (from 84 Mtoe in 2003) at the end of the study period. Overall energy imports are estimated to increase from 61 Mtoe to 157 Mtoe between 2003 and 2020. The total economic cost of the Reference Case is

$350.4 billion of which $167.9 billion is going to meet import requirements.

GHG Scenarios Results

Based on results from the GHG scenarios, the following conclusions can be drawn in relation to formulating a national policy on climate change. As the next figure shows, Low Growth and DSM (Demand-Side Management Scenario) are clearly essential ingredients of future climate change policies. The DSM scenario is a "win-win" option compared to the Reference Case. Under the Low Growth and DSM scenarios, the economic cost of energy supply and the cost of energy imports will be lower, as well as the emissions of CO2/GHG. In addition, there are substantial ancillary benefits involved in terms of PM, SO2, NOX.

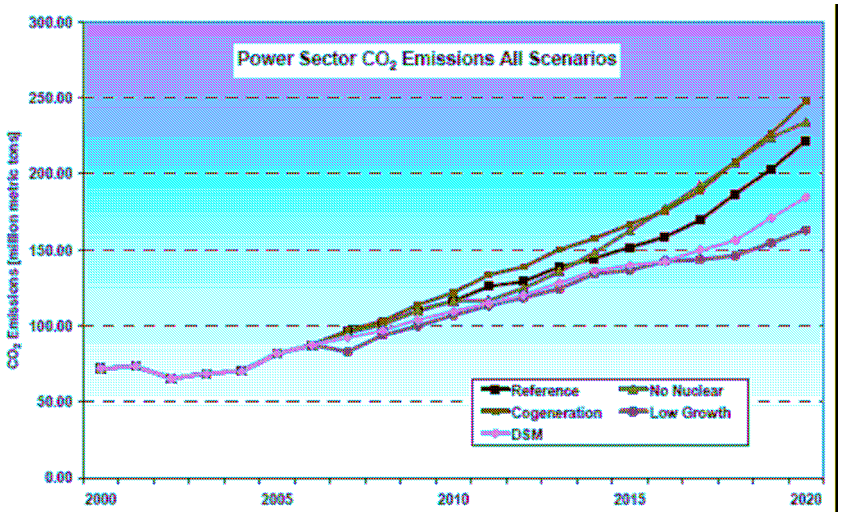


Figure 9.1: CO2 projections to 2020 all scenarios

The DSM seems to be the best scenario in order to decrease CO2/GHG emissions. Just by implementing conservation in industrial and residential sectors, both CO2/GHG emissions could be decreased by 7% and cost effectiveness could be $-113/ton. Low Growth Scenario can't be accepted as effective because it downsizes the economy, although it decreases the emissions by 8.8.

Table of acronyms

Acronims	Full text
NOx	Mono-nitrogen oxides
SO_2	Sulfur dioxide
NH_3	Ammonia
NMVOC	Non-methane volatile organic compounds
As	Arsenic
Cd	Cadmium
Pb	Lead
Hg	Mercury
$PPM_{2.5}$	Particles less than 2.5 micrometers in aerodynamic diameter
PPM_{coarse}	Particles between 10 and 2.5 micrometers in aerodynamic diameter
aNH_4	ammonium particles (ammonium nitrate and sulphate)
aNO_3	nitrate particles with diameter below 2.5µm
DDEP_OXN	total dry deposition of oxidized nitrogen
DDEP_RDN	total dry deposition of reduced nitrogen
DDEP_SOX	total dry deposition of sulphur
NO_x	$NO_x = NO_2 + NO$
pNO_3	nitrate particles with diameter above 2.5 a. below 10 µm
SIA	secondary inorganic aerosols
SO_4	sulphate, includes also ammonium sulphate
SOMO35	sum Over Means Over 35 ppb
tNO_3	total coarse and fine nitrate aerosols
WDEP_OXN	wet deposition of oxidized nitrogen
WDEP_RDN	wet deposition of reduced nitrogen
WDEP_SO_x	wet deposition of sulphur
PPM_{25}	primary particles with diameter below 2.5 µm
PPM_{co}	primary particles with diameter between 2.5 and 10 µm
PPM_{co}	primary particles with diameter between 2.5 and 10 µm
SIA_{10}	inorganic particles with an aerodynamic diameter < 10µm
CRF	concentration response functions
YOLL	years of life lost
WTP	Willingness to pay

Annexes

EMISSIONS DATABASE – LYFE CYCLE INVENTORY

2008_05_15 LCI Daten_CASES.xls

EXTERNAL COSTS DATABASE

ExternalCosts_per_unit_emission_080821.xls
ExternalCosts_per_unit_emission_080821.doc

SOCIAL COSTS DATABASE

D_06_01 private ext and Full Costs 08_08_21 values.xls

TOOL FOR POLICY ASSESSMENT

D_11_2 NTUA_MCDA_Tool-V3.xls

[1] The table of acronyms is provided at the end of the document.
[2] This section is based on Welle and Zwaan (2007)
[3] See Sanghvi (1982), p. 184.
[4] Both methods are based on evaluating the consumer surplus. Cf. Billinton *et al*. (1993), p. 97.
[5] Longo et al (2007) estimated the willingness-to-pay to reduce blackouts amongst consumers in England, and found that it is £0.36 (€0.53) to reduce the duration of blackouts by one minute of blackout per year. This is
[6] This section is based on Arnold et al (2007)
[7] http://www.e8.org/index.jsp?numPage=138
[8] Source: http://www.iea.org/Textbase/stats/electricitydata.asp?COUNTRY_CODE=37 "Electricity/Heat in European Union - 27 in 2005"
[9] Source: Eurostat website, "Supply, transformation, consumption - oil - annual data"
[10] This section is based on Arnold et al (2008)
[11] http://www.iea.org/Textbase/stats/index.asp
[12] Notes: Nuclear and Renewables prices are derived from published total costs, and operating and fuel costs are worked from these. For other fuels, fuel costs were derived from IEA prices and quantities, and operating and construction costs worked from these.
[13] This of course is based on the 1980-2000 average and the fall in the price of gas generation in the late 1990s is not significant in our non-dynamic model.
[14] This section is based on Behrens and Egenhofer (2007)
[15] Council document 77224/1/07 REV 1
[16] Electricity proposals: COM(2007) 0528, COM(2007) 0531; Gas proposals: COM(2007) 0529, COM(2007) 0532
[17] Full Costs of electricity production are assessed by Work Package 6 in the CASES Project. Additional information on Full Costs estimation and results are available in the CASES Deliverable D.6.1.
[18] IEA, OECD, NEA "Projected Costs of Generating Electricity", Paris, 2005.
[19] Friedrich, R.; Kallenbach, U.; Thöne E.; Voß A.; Rogner, H.; Karl, H.; Externe Kosten der Stromerzeugung. Schlussbetrachtung zum Projekt im Auftrag vom VDEW, VWEW Energieverlag, Frankfurt (Main) 1989.
[20] The impact of the following air pollutants and heavy metals is assessed: Ammonia (NH3), Non-methane volatile organic compounds unspecified (NMVOC), Nitrogen oxides (NOx), Particulates (PPMco – between 2.5 and 10 10um, and PPM25 – less then 2.5 um), Sulfur dioxide (SO2), Cadmium (Cd), Arsenic (As), Nickel (Ni), Lead (Pb), Mercury (Hg), Chromium (Cr), Chromium IV (Cr-IV).
[21] The following radionuclides are assessed: Aerosols, Carbon-14, Hydrogen-3, Tritium, Iodine-129, Iodine-131, Krypton-85, Noble gases, Radon-222, Thorium-230, Uranium-234.
[22] Data are actualised from 2000 to 2005 by using a coefficient of 1,1095. The coefficient is calculated by using the Harmonised Indices of Consumer Prices (HICPs) from 2001 to 2005, available at the following website:
http://epp.eurostat.ec.europa.eu/portal/page?_pageid=1996,39140985&_dad=portal&_schema=PORTAL&screen=detailref&
language=en&product=STRIND_ECOBAC&root=STRIND_ECOBAC/ecobac/eb040
[23] These external costs are expressed in Euro per tonne in the year of release, 2010-2020-2030, based on aggregation scheme "SIA_E_PPMc" for Human Health Impacts, based on average meteorology - corresponding to emissions from All SNAP-Sectors.
[24] "ExternE Methodology report", EC, 1995.
[25] These type of external costs are assessed in the CASES deliverable D.3.2 "Report on the monetary valuation of energy related impacts on land use changes, acidification, eutrophication, visual intrusion and climate change".
[26] With respect to the "low" Full Cost of nuclear it should be remarked that private costs calculated with the average lifetime levelised generating technology seem to underestimate the real industrial production cost, as pointed out by electricity sector stakeholders invited to the

"First CASES Stakeholders Workshop – Social costs of electricity production" February 2008, Brussels.

[27] We note that these values are not based on the externality methodology and justification for them is not provided. Nevertheless they are included because they are considered the relevant ones by the Chinese authorities.

[28] The emerging cost was estimated to be between R$ $_{2001}$ 101.40/MWh and R$ $_{2001}$ 218/MWh. (Wachsmann and Tolmasquim, 2003)

[29] Later, the deadline of the first phase was postponed from December 2006 to December 2008 (Decree MME 452/2005). This is the deadline for start-up of operation of contracted power generators.

[30] Eletrobrás is currently a holding company that links directly the Ministry of Mine and Energy. Several utility companies that generate and transit companies in the country are under its holding.

[31] The Law 10436 initially defined the economic values of three types of RETs at 80% at least of the average national rate of supply to the end users, but the temporary measure 127/03 amended this value of 50%, 70%, and 90% of the average national rate for electricity generated from biomass, small hydro, and wind power, respectively. Average national rate of supply is measured as the ratio of income from electricity supply to end users in the past 12 months to respective electricity consumed, shown in R$/MWh.

[32] The General Market Price Index is composed of three elements: (1) Wholesale Trade Market Price Index (IPA-M) (60%), (2) Consumer Market Price Index (IPC-M) (30%) and (3) National Construction Cost Index (INCC-M) (10%). (Kissel and Krauter, 2006)

[33] This index refers to a mandate that a minimum percentage of total equipment in value must be manufactured domestically.

[34] This also includes large hydro power.

[35] Interest rate subsidy is provided to the banks that provide low-interest loans.

[36] The published year of this reference is not available.

[37] This figure comprises 95 MW from biomass cogeneration, 86.53 MW from biomass gasifier, and 23.70 from waste.

[38] This was due to the initial incentives based on capital subsidies and tax benefits due to 100% depreciation. However, because these incentives did not relate to generation, it ended up with the situation that many unviable wind machines were installed in a hurry to avail tax benefits without considering wind sitting issues. (Banerjee, 2006)

[39] It was planned that 18000 villages would be covered by the year 2012.

[40] Through Electricity Act 1991, Indian power sector was open for Independent Power Producers (IPPs).

[41] The Act has deepened the power sector reform in India and enabled competition in this sector.

[42] Despite being notified in the National Electricity Policy, the measure of price bidding exercises has not been adopted to contract renewables-based projects.

[43] The build-own-transfer (BOT) and the build-own-operate (BOO) schemes were put in place in 1984 and financed major power projects (not limited to renewables) with the main objective of attracting private investors. The BOT and BOO financing schemes ended in 2000 and were replaced in 2001 by financial incentives within the framework of the Electricity Market Law. (Bilgen et al, 2008)

[44] The relevant information on the amount of certified electrical energy from RE will be issued by EMRA (Energy Market Regulatory Authority).

[45] However, legal entities that hold licenses based on renewable energy resources and which have the opportunity to sell above the limit of 5.5 eurocent/kWh in the market shall benefit from this opportunity.

[46]. National Technical University of Athens

[47]. VITO

[48]. University of Flensburg

[49] Factor 2 reductions in 2050 compared to 1990 (650 ppmv CO_2 eq.).

[50] According to the alternative scenario, just a dozen specific policies in key countries account for 40% of the reduction in global CO2 emissions.
[51] Electrical boilers can switch between oil and electricity and are only significant in Norway and Sweden