Coal in Europe: what future? Prospects of the coal industry and impacts study of the Kyoto protocol

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T H E S E

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Le 19 décembre 2006

Charbon en Europe : quel avenir ?
Perspectives de l'industrie du charbon
et étude des impacts du Protocole de Kyoto

devant le jury composé de :

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THESIS

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Ekawan RUDIANTO

In partial fulfillment of the requirement for the degree of

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Specialisation : Techniques et Economie de l'Exploitation du Sous-Sol

COAL IN EUROPE: WHAT FUTURE?

Prospects of the coal industry and impacts study of the Kyoto Protocol

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Prediction is very difficult, especially about the future
Niels Bohr
Danish physicist (1885 - 1962)

Pour Wieke, Dimas et Dinand

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Abstract

From the industrial revolution to the 1960s, coal was massively consumed in Europe and its utilization was constantly raised. In the aftermath of World War II, coal had also an important part in reconstruction of Western Europe's economy. However, since the late 1960s, its demand has been declining. There is a (mis)conception from a number of policy makers that saying coal mining and utilizations in Europe is unnecessary. Therefore in the European Union (EU) Green Paper 2000, coal is described as an "undesirable" fuel and the production of coal on the basis of economic criteria has no prospect. Furthermore, the commitment to the Kyoto Protocol in reducing greenhouse gases emission has aggravated this view. Faced with this situation, the quest for the future of coal industry (mining and utilization) in the lines of an energy policy is unavoidable.

This dissertation did a profound enquiry trying to seek answers for several questions: Does the European Union still need coal? If coal is going to play a part in the EU, where should the EU get the coal from? What should be done to diminish negative environmental impacts of coal mining and utilization? and finally in regard to the CO2 emission concerns, what will the state of the coal industry in the future in the EU?

To enhance the analysis, a system dynamic model, called the Dynamics Coal for Europe (the DCE) was developed. The DCE is an Energy-Economy-Environment model. It synthesizes the perspectives of several disciplines, including geology, technology, economy and environment. It integrates several modules including exploration, production, pricing, demand, import and emission. Finally, the model emphasizes the impact of delays and feed-back in both the physical processes and the information and decision-making processes of the system. The calibration process for the DCE shows that the model reproduces past numbers on the scale well for several variables. Based on the results of this calibration process, it can be argued that the DCE model can be used to do a forecasting for examining long-term behavior of coal industry in the EU-15. Finally, the algorithm and modules construction for the DCE model can be used to construct a model for other non-renewable energy sources for Europe.

Keywords: Coal, Kyoto Protocol, System Dynamics model

Résumé

Au cours de la période allant de la révolution industrielle aux années 60, le charbon a été massivement consommé en Europe et son utilisation s'est constamment accrue. Après la deuxième guerre mondiale, le charbon a joué également un rôle important dans la reconstruction de l'économie de l'Europe de l'ouest. Il faut noter cependant que la demande de charbon a commencé à décliner depuis le début des années 1960. Il en résulte de la part de certains décideurs une tendance à dire que l'extraction du charbon et son utilisation en Europe sont inutiles. Par conséquent, dans le livre vert de l'union européen 2000 (UE), le charbon est décrit comme un carburant «indésirable», et en se basant sur des critères économiques, sa production n'a aucune perspective. En outre, l'engagement du protocole de Kyoto dans la réduction de l'émission des gaz à effet de serre a aggravé cette perception. Face à cette situation, un nouveau débat sur l'avenir de l'industrie du charbon (extraction et utilisation) dans la perspective d'une politique énergétique communautaire est inévitable.

Cette dissertation a fait une enquête profonde en vue d'apporter des réponses à plusieurs questions. L'union européenne a-t-elle toujours besoin du charbon ? Si le charbon est appelé à jouer un rôle au sein de l'UE, d'où proviendrait-il? Que devrait-on faire pour diminuer les incidences négatives sur l'environnement consécutives à l'extraction du charbon et de son utilisation ? Finalement, au regard des soucis d'émission de CO2, quelle sera la situation de l'industrie du charbon dans l'avenir au sein de l'UE ?

Pour approfondir l'analyse, un modèle dynamique de système appelé « The Dynamics Coal for Europe" (DCE) a été développé. Le DCE est un modèle qui prend en compte trois dimensions : l'énergie, l'économie, et l'environnement. Il s'appuie sur plusieurs disciplines telles que : la géologie, la technologie, l'économie et l'environnement. Il intègre plusieurs modules comprenant l'exploration, la production, l'évaluation, la demande, l'importation et l'émission du CO2. En conclusion, le modèle met l'accent sur l'impact du temps de réaction (retard et recto-action) sur deux processus : physique (par exemple le temps pour faire l'exploration du charbon) et de l'information.

Le procédé de calibrage pour le DCE prouve que le modèle reproduit le même résultat que les données réelles. Basé sur les résultats de ce procédé de calibrage, il se peut que le modèle de DCE puisse être employé pour faire des prévisions pour examiner le comportement à long terme de l'industrie du charbon dans l'EU-15. Finalement, l'algorithme et la construction de modules pour le modèle de DCE peuvent être employés pour construire un modèle pour d'autres sources d'énergie non-renouvelables pour l'Europe.
Mots-clés : Le charbon, protocole de Kyoto, modèle dynamique du système

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Glossary and Acronym

ASTM : American Society for Testing Materials
Bcf : Billion cubic feet
BOF : Basic Oxygen Furnace
CBM : Coal Bed Methane
CCS : Carbon Capture & Storage
CCT : Clean Coal Technology
CIF : Cost, Insurance and Freight
CMM : Coal Mine Methane
DCE : Dynamic Coal for Europe : a modelof system dynamics
EC : European Commission
ECBM : Enhanced coal bed methane recovery
ECSC : European Coal and Steel Community
EEA : European Environment Agency
EIA : Energy Information Administration
EOR : Enhanced oil recovery
EU : European Union
GHG : Green House Gases
GJ/t : Giga Joule per tons
Gtce : billion metric-ton of coal equivalent (1 Gtce=29.31 exajoules or EJ).
GtC : billion metric ton of carbon.
GtCO2 : billion metric ton of carbon dioxide.
GTL : Gas To liquid
GW : Gigawatt [=1 million kilowatt (kW)=1000 megawatt (MW)]
HC : Hard Coal
IEA : International Energy Agency
IGCC : Integrated Gasification Combined Cycle
IPCC : Intergovernmental Panel on Climate Change
JORC : Joint Ore Reserves Committee
MCIS : McCloskey Coal Information Service
MJ/kg : Mega Joule per kilogram
Mtce : Million tons coal equivalent
Mtoe : Million tons oil equivalent
Mt : Million tons
MWh : Megawatt-hour. 1 MWh is the amount of electricity generated by an 1 MW-unit in 1 hour.
OECD : Organization for Economic Co-operation and Development
PCI : Pulverized Coal Injection
PFBC : Pressure Fluidized bed combustion
TWh : Terrawatt-hour
TonC : Tons Carbon
Tce : Ton Oil Equivalent
UNECE : United Nation Economic Commission for Europe
UNFCC: United Nations Framework Convention on Climate Change
USGS : United States Geological SUrvey
WCI : World Coal Institute
WEC : World Energy Council
WETO : World Energy, Technology and Climate Policy Outlook

Introduction

Background to the problem

Every type of energy has its legend. Although the role of coal in energy supply has now been taken by oil and gas, coal once had a glorious role as one of the factors that shaped Europe's economic and political development in the nineteenth and twentieth centuries. From the beginning of the industrial revolution to the 1960s, this fossil fuel was massively consumed and its utilization was constantly raised. In the aftermath of World War II, coal had also an important part in the reconstruction of Western Europe's economy.

Challenged by a great decline in demanding coal and steel in the post-war period which could have plunged Western Europe into an economic recession, some European countries (France, West Germany, Italy, Belgium, Luxembourg and the Netherlands) created the European Coal and Steel Community (ECSC)[1] on April 18th, 1951. The ECSC introduced a common free steel and coal market, with freely set market prices, and without import/export duties. The ECSC functioned by striking a balance between production and distribution. Subsequently, when the coal and steel industry crashed into crisis in the 1970s and 1980s, the ECSC was able to lead a response which made it possible to carry out the industrial restructuring. The ECSC ceased to exist on July 23th, 2002, and its responsibilities and assets were then assumed by the European Committee (Council Decision (2002/596/EC).

Nevertheless, coal still has an important role in Europe's economy today. The power supply system of the European Union (EU) is currently based on a mix of nuclear energy, coal, gas and hydroelectric power. Coal has been an essential part of the European energy primer consumption and electricity production. Indigenous coal production and import together supply almost 15% of the European primary energy consumption. About 26% of the EU's electricity is coal based, while large quantities of coal are also required by the steel making industry and raw-materials industries, such as cement works, paper mills and briquetting.

Coal, as any other energy sources, has intrinsic disadvantages as well as advantages. Being a solid and heavy mineral, coal is bulky and requires large storage areas. With a lower calorific value than oil and gas coal does not have the ease of use of a liquid or gaseous fuel. Coal also generates pollution at stage of the production and utilisation cycle. The physical disadvantages of coal have considerably reduced its markets for expansion. However, the world coal reserve is plenty, so that it can be exploited more than 200 years. It is safe to be transported and the fluctuation of its price is less than that of oil as well gas.

Today, difficult decisions will have to be taken regarding the future of the European coal industry on account of its lack of competitiveness. Coal is described by the Green Paper as an "undesirable" fuel and its production on the basis of economic criteria has no prospect either in the former European Union or in the applicant countries (Green Paper, the European Commission, (EU), 2001). Furthermore, the commitment to the Kyoto Protocol in reducing greenhouse gases emission might aggravate the coal prospect.

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[1] *It was the fulfillment of a plan developed by a French economist Jean Monnet, publicized by the French foreign minister Robert Schuman*

In the late 1960s, the role of coal as source of energy was overtaken by oil. Since years the demand has been declining, not only in the EU-15 but also in new member (accession) countries. The demand of hard coal in Western Europe declined from about 600 Mt in the early 1960s to less than 60 Mt in 2004, whilst lignite declined from 396 Mt in 1973 to 262 Mt in 2002. Following the closure of last remaining coal mines in Netherlands in 1975, Belgium in 1992, Portugal in 1994 and France in 2004, only three member states of the EU-15 (the United Kingdom, Germany, and Spain) continue to produce hard coal, while Greece produces mainly lignite.

Three reasons can explain this declining production. First is competition with other fuel sources. Coal has to compete with other fuels, particularly natural gas. Market deregulation of energy and electricity has brought many benefits but it has also had undesirable consequences for coal industry. Energy security is not adequately valued in energy markets and deregulation has lowered its economic returns to and increased the risk aversion of the major utilities, making the financing of new technology in coal-fired power plant more difficult – especially when that technology requires large investments of capital and relatively long capital-recovery periods.

Second is high operating cost. As the most easily accessible seams are exhausted, hard coal has to be mined under current mining methods in increasingly difficult geological conditions and at greater depths. The result is high mining cost. The operating cost of most hard coal exploitations in Western Europe is higher than those in other countries and than the imported coal price[2]. This has called the member countries to import coals to satisfied domestic need rather than to produce internally. Today, almost 45% of EU coal needs is covered by imported production. Concerning hard coal in EU-15, 70-75% of its demand is covered by imported coal.

There is a general (mis)-conception that coal mining (and utilization) in Europe is unnecessary because of growing world coal trade and untapped possibilities for importing cheap coal from outside the European Community. Added to those beliefs is the view that, albeit some deposits are still economically exploitable, most Europe's coal deposits are nearly depleted to the point where the exploitation is relatively inefficient and high operating costs. Such viewpoints have spilled over into the formation of policies towards the industry that are not always beneficial.

Last reason is the growing environmental concerns, and particularly emission reduction. Environmental concerns have highlighted the weaknesses of solid fuels. Under the Kyoto Protocol, the European Community committed itself to reduce its emissions of six greenhouse gases (GHGs) by 8% during the period 2008 to 2012 in comparison with their levels in 1990. This target is shared between the member states under a legally binding burden-sharing agreement, which sets individual emissions targets for each member state.

Combustion of coal, like other fossil fuels - gas and oil – produces carbon dioxide (CO_2), nitrogen oxides (NO_x), and sulfur dioxida (SO_2). Among other fossil fuels, coal is a more carbon-intensive fuel per energy unit, and thus the increase in carbon dioxide emissions from coal combustion is higher than the increase in emissions from natural gas or oil.

Some 94% of man-made CO_2 emissions in Europe are attributable to the energy sector as a whole. Fossil fuels are the prime sources. In absolute terms, oil consumption on its own accounts for 50% of CO_2 emissions within the EU, natural gas for 22% and coal for 28%. In terms of consumer sectors, electricity generation and steam raising are responsible for 37% of CO_2 emissions and

[2] *For example, in 2002 the German's average operating cost was 150 €/ton while over the same year the imported coal price was 41 €/ton.*

transport for 28%. Some 90% of the projected growth in CO_2 emissions will be from the transport sector. Almost 75% of coal utilization in Europe is for electricity generation. In 2002, of 2,670 TWh (Terrawatt hour) power generation, coal accounted for some 26% of the electricity supplies, others are oil (6%), natural gas (16%), nuclear (33%) and renewable resources (17%).

Combating climate change and minimizing its potential consequences requires substantial reductions in global greenhouse gas emissions. Three steps are adopted in Europe to reduce emission of GHGs from coal burning, including reducing emissions of pollutants, increasing thermal efficiency, and reducing CO2 emissions to near zero levels through carbon capture and storage. In practice, this will require in reducing coal consumption and or deploying lower emission technology.

Energy policy predominantly security of supply is backed in fashion in Europe. The events in Ukraine in the beginning 2006, where it witnessed gas supply cuts from Russia (Gazprom), the slow progress to liberalize European energy markets, and the growing European fossil fuel import dependency, have contributed to a sense of unease with reliance solely on market forces and conventional regulation. The tripling of oil prices in 1999 and its high prices[3] in the first semester of 2006 reinforced this nervousness.

The European Union is now consuming and importing more and more energy products. If no measures are taken, in the next 20 to 30 years, 60% of the Union's fossils energy requirement as opposed to the current 35% will be from imported products. As a result, external dependency on energy is constantly increasing. In geopolitical point of views, 45% of the EU-15 oil imports are from the Middle East and 40% of natural gas from Russia, while for coal, the imports are not dictated by certain countries (Green Paper, the European Commission, (EU), 2001). The fact that the price of crude oil has increased in the last two years may reveal the European Union's structural weakness regarding security of energy supply. In reality, security of supply does not seek to maximise energy self-sufficiency or to minimise import dependence, but aims to reduce the risk linked to such dependence.

The above circumstances would give any government pause for thought. However, they also occur in a context of climate change, and the requirement to cut greenhouse gas emissions. While gains were made on the environmental front as a result of the rapid contraction of the coal mining and utilization in the 1990s, the EU Environmental Council's suggest that cuts of the order of 65% in CO2 emissions below the 1990 level might be needed by the middle of the century (European Environmental Agency, (EEA), 2005).

Security of energy supply is now becoming one of the actual concerns in every country in the World, including the EU-15. Moreover, through a common agreement known as the Lisbon Strategy, which was announced in 2000, Europe has committed to make European Union as region with "the most dynamic and competitive knowledge-based economy in the world, capable of sustainable economic growth with more and better jobs and greater social cohesion, and respect for the environment". Optimum and secure energy supplies will be needed to achieve these targets and, inevitably, this will mean a significant growth in electricity demand.

Faced with the above challenges, the European Union has unfortunately few non-renewable resources and hardly any effective policy instruments to meet these challenges. The amounts of indigenous fuels available to Europe are limited. Oil reserves are very unevenly distributed across the world, and the European Union in particular has very few, with only 1% of global reserves. Natural gas reserves are more evenly distributed on the global level, but the European Union is once again unfortunate, with just 2%. The European Union is home to barely 1% of the world's natural uranium

[3] *In the beginning of the second semester of 2006, Brent crude oil reached more than $70/barrel*

reserves, however last uranium production was stopped in France (in 2001) and Spain (in 2002) following the decommissioning of some other mines in Sweden and Poland. More uranium could be made available, but only at a higher price. About 80% of Europe's fossil fuel reserves are solid fuels (including hard coal, lignite, peat and oil shale). At present production level, coal might last for more than 100 years. However, this optimism has to be tempered by the fact that the quality of solid fuels is variable and under current mining methods production costs particularly for hard coal are high.

The appropriate energy policy in securing energy supply is extremely important to achieve the Lisbon targets. Nowadays, there is still no common energy policy in Europe. The Europe's external energy policy remains within the competence of EU member states' foreign policies and a matter of national sovereignty. Addressing the security of supply problems will require a major investment program across Europe and much greater cooperation among EU member countries, and between EU and its partners. In these circumstances, it is time for Europe to launch a review for its energy policy.

The production of fossil energy in Europe is projected to decline over the next two decades (2030) while the consumption will increase (IEA, 2004; EIA, 2006; WETO, 2004). The International Energy Agency's (IEA's) reference scenario shows that the energy consumption in the EU-15 in 2030 will reach 2,191 Mtoe, where oil will represent 36% of EU-15 energy consumption, 33% of gas and 13% of hard coal and lignite. It argues that the EU-15 still depends heavily on fossil energy for the forthcoming decades.

All those dilemmas have to be solved. Governments in Europe should better seek ways to balance the social, economic and environmental needs of society. Government policies need to provide long-term strategic solutions for achieving sustainable energy use and economic growth. To secure the energy supply and reduce its emission, all possible energy option has to be left open. Policy on rapid decline of coal mining and utilization together with nuclear moratorium might only exacerbate problems of energy supply. In this context, government support for Energy policy involves three main components in general: low supply costs, security of supply and environmental considerations.

In regard to the future of coal industry in Europe, it has to separate the issues between indigenous coal mining and coal utilization (consumption). It is undoubted that high mining costs and the lack of competitiveness of European coal-mining have led several Member States to abandon coal. However, concerning coal utilization, the coal industry has a proven track record of developing technology pathways, which have successfully addressed environmental concerns at local and regional scales. Ongoing research under the title of Clean Coal Technology (CCT) puts efforts into improving the efficiency of coal-fired electricity generation and technologies for carbon capture and storage (CCS). They offer routes to reduce carbon dioxide (CO2) emissions now and in the future. They are enabling the energy security benefits of coal-fired power generation to continue to be realized. The future of coal industry is largely pinning its hopes on the Clean Coal Technologies and on policy of energy supply security.

Nowadays, the issues of security of energy supply and the high prices of oil and gas, in one hand, and the progress of clean coal technology, in other hand, have evoked the EU-15 to rethink its energy policy, in particular the future of coal utilization. Coal is still likely called in for balancing the energy supply inside the Community and even more called in for helping to meet Kyoto's target.

Research objective

The quest for the future of coal industry in the lines of an energy policy in the European Union is unavoidable. This research tries to portray and to investigate the current status of (hard) coal mining and its utilization in the EU-15. In addition, by using a simulation analysis this research attempts to forecast the state of coal industry in the EU. Having understood the actual and the future roles of coal, it is hoped that the results of this research may contribute in analysing appropriately the future of (hard) coal and in determining an appropriate energy policy in Europe.

Fundamentally, the research will seek answers for four questions. A profound enquiry requires to seeking the appropriate response to the following question 1) Does the European Union still need coal? 2) If coal is going to play a part in the EU, where should the EU get the coal from? 3) What should be done to diminish negative environmental impacts of coal mining and utilization? and finally 4) concerning the CO2 emission, what will the states of the coal industry in the future?

In this dissertation, the European Community is particularly defined as the European Union pre-May 2004, which consists on 15 countries (Fig. 1). It is defined as such because the Kyoto's targets bind principally to the EU-15 countries. And also the word "coal" refers to mainly hard coal.

Research approaches

Two approaches will be used in this research. They are a profound investigation analysis and a simulation analysis. The purpose of the first analysis is to examine the present and the future roles of coal in Europe and to seek answers to the first three main inquires above.

In the second approach, a Coal model, called the Dynamic Coal for Europe (the DCE) is developed by using system dynamics. The DCE is an Energy-Economy-Environment model. It synthesizes the perspectives of several disciplines, including geology, technology, economy and environment. It integrates several modules including exploration, production, pricing, demand, import and emission. Finally, the model emphasizes the impact of delays and feed-back in both the physical processes and the information and decision-making processes of the system.

The goal of the simulation by the DCE is to simulate and to understand the behaviour of coal industry in Europe as well as to predict the impact of implementation of emission reduction policies, i.e carbon taxes and permit instrument, under the frame of Kyoto Protocol. The DCE model's focus is on long-term dynamics and is primary meant as a tool for analysis, and clearly not for exact prediction. It aims to fill at least partly a gap in understanding the coal industry in the EU-15.

Dissertation structures

This dissertation is divided mainly in two parts. The first is entitled *Coal in Europe: What Future?* and the second part is called *Modelling Coal Prospect in Europe*.

The first part of the dissertation consists of three chapters: Coal as an Energy System (Chapter 1), Inquiries on Coal Prospect in Europe (Chapter 2) and European Community and Climate Change Protection (Chapter 3). The first chapter mainly investigates some fundamental knowledge of coal, including the understanding of coal, world coal reserve, mine exploitation and global coal market. The second chapter will be dedicated to seek answers of three important questions about coal in Europe. Those are: (1). Does the European Union still need coal, (2), If coal is going to play a part in the Union Where should EU get the coal from? (3). and finally what should be done to diminish negative environmental impacts of coal mining and utilization? The last chapter will discuss several issues on climate change, the Kyoto Protocol and its impact on coal. Each chapter will be completed by a section of analysis and discussion where the subject of discussion will follow to the chapter's theme.

The second part of the dissertation is dedicated to the modelling and simulation of coal prospect in Europe by using the DCE model. The construction of the model is very much assisted by knowledge of current coal status acquired from the investigation's result in the first part. This part consists of three chapters, namely System Dynamic for Energy Modelling (Chapter 4), System Dynamic Model for Coal (Chapter 5) and Application of the DCE model for Simulation of Carbon Tax Policies (Chapter 6). Chapter 4 explains briefly a fundamental of system dynamics and the use of the methodology for modelling energy systems. Chapter 5 will mainly discuss structure of the DCE model. The model itself consists principally of four main modules, which are energy demand, supply/production, price, and policy analysis module. Several sub-modules are also developed to support the main modules. The dynamic behaviour of the coal system industry will be investigated in the section on dynamic behaviour of the system.

The last chapter will be dedicated to simulating the implementation of emission reduction policies. The aim of the last chapter is also to compare the performance of each emission reduction instrument, including constant carbon tax, adaptive carbon tax and permit instrument, targeted to the coal industry in the EU-15. The aim of this simulation is also to forecast the trend of coal import dependence in the region.

Figure 1. The European Union pre-May 2004

Chapter 1:
Coal as Energy Systems

1.1. Introduction to coal

1.1.1. What is coal

Coal is a solid, brittle, combustible, carbonaceous rock formed by the decomposition and alteration of vegetation by compaction, temperature, and pressure. It varies in colour from brown to black and is usually stratified. Coal deposits are usually called seams and can range from fractions of a half to fifty of meters in thickness.

Coal is found on every continent in almost seventy countries and world coal reserves is nearly 1 trillion tons. However, the largest reserves are found in the U.S., former Soviet Union, and China. Currently, coal is produced in nearly 50 countries.

Coal is generally classified according to rank. Rank classifications are based on a coal's content of fixed carbon, volatile carbon compounds, water, and ash, its heating value, and its coking properties. In the coalification process, coal first takes the form of peat, then progresses through lignite (brown coal), bituminous, and finally to anthracite and graphite. Lignite has a low heating value and a high moisture content of 30 to 40%. Bituminous coal is black and contains bands of both bright and dull material. The moisture content of bituminous coal is usually under 20%. Anthracite is shiny black with a high luster. It is the highest rank of economically usable coal with moisture content less than 15%. Fig. 1.1 summaries the different types of coal.

Bituminous coals are dense black solids, frequently containing bands with a brilliant lustre. The carbon content of these coals ranges from 78 to 91% and the water content from 1.5 to 7%

Sub-bituminous coals usually appear dull black and waxy. They have carbon content between 71 and 77% and a moisture content of up to 10%.

Brown coals or lignites have high oxygen content (up to 30%), a relatively low carbon content of 60-75% on a dry basis, and a high moisture content of 30-70%. These lower ranked coals are browner and softer.

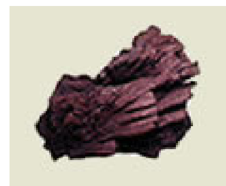

Figure 1.1. Different types of coal
Source: World Coal Institute (WCI) (2002)

1.1.2. Origin of coal

Coal is found in deposits called seams that originated through the accumulation of vegetation that has undergone physical and chemical changes. These changes include decaying of vegetation, deposition and burying by sedimentation, compaction, and transformation of the plant remains into the organic rock found today. Coal differs throughout the world in the kinds of plant materials deposited (type of coal), in the degree of metamorphism or coalification (rank of coal), and in the range of impurities included (grade of coal).

The beginning of most coal deposits started with thick peat bogs where the water was nearly stagnant and plant debris accumulated. Vegetation tended to grow for many generations, plants materials settling on the swamps became submerged and were covered by sedimentary deposits, and a new future coal seam was formed. When this cycle was repeated, over hundreds of thousands of years, additional coal seams were formed. These cycles of accumulation and deposition were followed by diagenetic (i.e., biological) and tectonic (i.e., geological) actions and, depending upon the extent of temperature, time, and forces exerted, formed the different ranks of coal observed today.

A part from the theory that assumes the coal formed insitu1[1], as explained above, there is another theory that assumes coal appearing to have been formed through accumulation of vegetal matter (such as wood) that has been transported by water. According to this theory[2], the fragment of plants have been carried by streams and deposited on the bottom of the sea or in lakes where they build up strata, which later become compressed into solid rock.

Major coal deposits formed in every geological period since the Upper Carboniferous Period, 350 to 270 million years age (Miller, 2002). The considerable diversity of various coals is due

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1 it is known as the theory of autochthonous process
2 it is known as the theory of allochthonous process

to the differing climatic and botanical conditions that existed during the main coal-forming periods along with subsequent geophysical actions.

1.1.3. Coalification

The geochemical process that transforms plant material into coal is called coalification and is often expressed as:

Peat→ lignite→ subbituminous coal → bituminous coal → anthracite

Coalification can be described geochemically as consisting of three processes (Miller, 2002): (1). microbiological degradation of the cellulose of the initial plant material, (2). conversion of the lignin of the plants into humic substances, and (3). condensation of these humic substances into larger coal molecules.

The kind of decaying vegetation, condition of decay, depositional environment, and movements of the Earth's crust are important factors in determining the nature, quality, and relative position of coal seams. Of these, the physical forces exerted upon the deposits play the largest role in the coalification process. Variations in the chemical composition of the original plant material contributed to the variability in coal composition. The vegetation of various geologic periods differed biologically and chemically. The conditions under which the vegetation decayed are also important. The depth, temperature, degree of acidity, and natural movement of water in the original swamp are important factors in the formations of the coal.

1.1.4. Classification

Two types of coal classification system arose. Some schemes are intended to aid scientific studies, and others are designed to assist coal producers and users. The scientific systems of classification are concerned with origin, composition, and fundamental properties of coals, while the commercial systems address trade and market issues, utilization and technological properties.

The commercial systems typically consist of two primary systems, the American Society for Testing Materials (ASTM) system (ASTM, 1992) and United Nation Economic Commission for Europe (UNECE, 1988).

1.1.4.1. Types of coal

Generally, coals are grouped according to particular properties as defined by their "rank" (degree of metamorphism or coalification), "type" (constituent plant materials) and "grade" (degree of impurities and calorific value). Of these, rank is a fundamental concept that involves a qualitative expression of the coalification sequence and is universal to all classification schemes. Coalification is a term that describes the maturation of plant tissues from peat through different stages of lignite/brown coal, sub-bituminous and bituminous coals to anthracites. Apart from these classifications, coal can be classified based on its uses in industry, such as coking coal (metallurgical coal) and steaming coal.

Direct and indirect utilization of coals for production of energy and chemicals as well as for smelting of base metals is the foundation upon which the interest in classifying this resource is built. However, heterogeneous nature and the variety of coals used throughout the world, classification of different types of coal into practical categories for use at an international level is a difficult task. This because divisions between coal categories vary between classification systems both national and international based on calorific value, volatile matter content, fixed carbon content, coking properties, or some combinations of these criteria. Currently, there are several coal classifications developed by either certain countries or organization (JORC, 2004; ASTM, 1992; UNECE, 1988).

1.1.4.2. Characteristic of coal

Coals can be distinguished by their physical and chemical characteristics. These characteristics determine the suitability of coal for various uses. Coal is mainly composed of carbon and may also generate volatile matter when heated to decomposition temperatures. In addition, it contains moisture and ash-forming mineral matter. The elements of carbon, hydrogen, nitrogen, sulphur and oxygen are present in the coal matter. The combination of these elements and the shares of volatile matter, ash and water vary considerably from coal to coal. It is the fixed carbon content and associated volatile matter of coal that control its energy value and coking properties and make it a valuable mineral on world markets.

Some important characteristics of coal are:

- *fixed carbon content* influences the energy content of the coal. The higher the fixed carbon content, the higher the energy content of the coal
- *volatile matter* is the proportion of the air-dried coal sample that is released in the form of gas during a standardised heating test. Volatile matter is a positive feature for thermal coal. Yet high volatile matter can be a negative feature for coking coal
- *ash content* is the residue remaining after complete combustion of all organic coal matter and decomposition of the mineral matter present in the coal. The higher the ash content the lower the quality of the coal. High ash content means a lower calorific value (or energy content per tonne of coal) and increased transport costs. Most export coal is washed to reduce the ash yield (beneficiation) and ensure a consistent quality. The ash in residue can be broken down as the series of metal oxide, i.e. $SiO2$, $Al2O3$, CaO, MgO, $P2O5$, $Fe2O3$, $SO3$. These data are important in determining how a coal, steaming and coking coal, behave.
- *moisture content* refers to the amount of water present in the coal. Transport costs increase directly with moisture content. Excess moisture can be removed after beneficiation in preparation plants but this also increases handling costs
- *sulphur content* increases operating and maintenance costs of end users. High amounts of sulphur cause corrosion and the emission of sulphur dioxide for both steel producers and power plants. Low sulphur coal makes installation of desulphurisation equipment to meet emission regulations unnecessary. Southern hemisphere coals generally have low sulphur content relative to Northern hemisphere coal
- *Clorine* usually occurring as the inorganic salt of sodium, potassium and calsium chloride. The relatively high amount of chlorine causes corrosion in boiler and when present in flue gas it contributes to pollution
- *Phosphorous* is undesirable for large amounts of phosphorous to be present in coking coals to be used in the metallurgical industry as it contributes to producing brittle steel

There are other minerals that may be present in coal which affect its potential use. Significant amounts of quartz in dust affect the incidence of silicosis. The mineral matter in the coal will also affect the washability of coal and consequently the ash content of the clean coal. Mineral impurities affect the suitability of a coal as a boiler fuel; the low ash fusion point causes deposition of ash and corrosion in the heating chamber. The presence in coal of phosphorous minerals causes slagging in certain boiler and steel produced from such phosphorous-rich coals tends to be brittle. Trace elements may be present also in coal. Several of them, notably boron, titanium, vanadium and zinc, can have detrimental effect in the metallurgical industry.

1.1.4.3. Classification based on the degree of coalification

The degree of "metamorphism" or coalification undergone by a coal, as it matures from peat to anthracite, has an important bearing on its physical and chemical properties, and is referred to as the "rank" of the coal. Low rank coals, such as lignite and sub-bituminous coals, are typically softer, friable materials with a dull, earthy appearance. They are characterised by high moisture levels and a low carbon content, and hence a low energy content. High rank coals, such as bituminous and anthracite coals are typically harder and stronger and often have a black vitreous lustre. Higher rank coals have lower levels of moisture and volatile matter. They contain more carbon, have lower moisture content, and produce more energy.

Increasing rank is accompanied by a rise in the carbon and energy contents and a decrease in the moisture content of the coal. Anthracite is at the top of the rank scale and has a correspondingly higher carbon and energy content and a lower level of moisture. Between anthracites and peat there are three broad coal rankings: lignite, sub-bituminous and bituminous. Table I-1 shows different coal classifications based on its degree of coalification.

Table I-1. Different coal classification based on the degree of coalification

USA	Peat	Lignite	Sub-Bituminous	Bituminous High volatile	Bituminous Low volatile	Anthracite
ECE		Browncoal	Hard coal			
France	Tourbe	Lignite	Flambant sec	Flambant gras	Gras	Anthracite
Rank	Low	Low	Medium	Medium	High	High
Fixed Carbon, %	< 38%	38-42%	42-64%	64-75%	75-84%	84-95%
Caloric value GJ/t	4.19 – 6.28	14.65-18.84	18.84 – 27.22	27.22 – 32.65	27.22 –32.65	32.65-35.59
Humidity %	>50%	25-50%	14-25%	5-10%	5-10%	1-6%
Volatile matter %	>75%	50%.	25-50%	30-40%	15-25%	<10%.
Ash content	50%.	30-50%	20-30%	10-20%	10-20%	0-10%

Source: ASTM D388 (1992), UNECE (1988), Giraud (1983)

In the international commodity market, coal quality classification is more complex than that of crude oils. Analysis of crude oils price differentials has focused on two main properties: the specific gravity and the percentage of sulfur content by weight. Lighter crudes are expected to sell at a premium over heavier crudes. A high sulfur content has an adverse effect on the value of crudes, because it leads to higher operating costs for refineries. In general, a high-sulfur crude is expected to sell at a discount relative to a low-sulfur (sweet) crude.

1.1.4.4. Classification based on the trade and its uses

A number of coal classification schemes that relate to use, rather than science, have devised in different countries, as for example the American Society for Testing and Materials (ASTM), the UN Economic Commission for Europe (UNECE) or the British Industry. In general most are based on coal rank, often expressed as content of volatiles, sub-classified by calorific value, ash content, sulphur content. The International Coal Classification of the Economic Commission for Europe (UNECE, 1988) recognises two broad categories of coal:

- *Hard coal*
  Coal with a gross calorific value greater than 5,700 kcal/kg (23.9 GJ/t) on an ash free but moisture bases and with a mean random reflectance of vitrinite of at least 0.6. Within this category is including Bituminous coal and Anthracite.

- *Brown coal*
  Coal with a gross calorific value less than 5,700 kcal/kg (23.9 GJ/t) containing more than 31% volatile matter. Sub-bituminous is coal with a gross calorific value between 5,700 kcal/kg and 4,165 kcal/kg (17.4 GJ/t) containing more than 31% volatile matter. Lignite, with a gross calorific value less than 4,165 kcal/kg (17.4 GJ/t), is reported in this category.

The fundamental classification of hard coal by end-use and also by trade category is into thermal or steam coal and coking or metallurgical coal. The fist type is used for burning in power stations and in other industrial and domestic uses, while the other type is used in the steel to de-oxidise iron ore in the blast furnace.

The properties that determine the economic viability and end-use category of coal are its rank (degree of coalification), chemistry and physical properties. The most basic properties of coal in respect of its uses are its content of moisture, volatiles, ash and fixed carbon (and sulphur). In general, the range of properties necessary in a coking coal are much more tightly constrained than those required for a steam coal.

- *Coking coal (metallurgical coal)*
  This type of coal when heated in large ovens will produce coke and gases. Coke is a porous solid composed mainly of carbon and ash. Coke quality is related positively to coke strength. For the purposes of blast furnace applications, the coal used must be able to form large angular coke that retains its form despite constant heat, pressure, abrasion and collision in the blast furnace. Coking coal is classified as hard, soft or semi-soft. Hard coking coal, the highest quality coking coal, tend to have moderate volatile matter content, low inherent moisture, low ash and low sulphur levels. Hard coking coal commands the highest prices in world markets. Soft and semi-soft coking coals have lower fixed carbon content and higher levels of inherent moisture and volatile matter than hard coking coal.

  Coking coal comes from the bituminous category. To be used as a coking coal it has to be capable of being converted to coke in a coke oven or other carbonisation process. This limits the number of coals that can be categorised as coking coal. Whilst all coking coals can be burnt in suitably designed power plants to generate electricity the reverse is not true in that not all bituminous steam coals can be converted into coke. An important feature of all coals used by the steel industry is that they should have as low a level of ash and sulphur.

- *Steam coal (thermal coal)*
  This coal is burnt to have its heat. Higher the levels of ash, moisture, and sulphur, lower the quality of thermal coal. All categories of coal can be used for electricity generation, although power plants have to be designed to handle specific types of coal. For example a plant designed to burn bituminous coal would not be capable of burning brown coal.

  The lower the quality, the lower the price received on world markets. Much of the world's thermal coal is not of sufficient standard to be traded and its use is restricted to mine-mouth power stations. Also classified as thermal coals, pulverised coal injection (PCI) coal is used as a supplementary fuel injection into modern blast furnaces to increase the productivity of the coke used in the furnace. PCI coal has low levels of inherent moisture and ash but high levels of volatile matter.

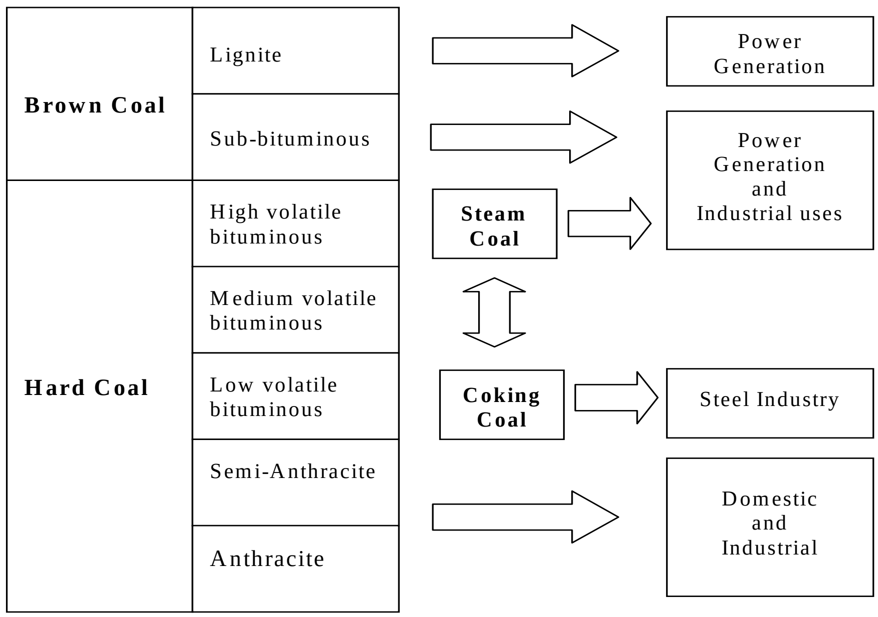

Figure 1.2. Different coal uses by coal type

1.1.4.5. Coal analyses

Coal can be regarded as being made up of moisture, pure coal and mineral matters. The moisture consists of surface moisture and chemically bound moisture and the pure coal is the amount of organic matter present. The mineral matter is the amount of organic matter present which, when coal is burnt, produce ash.

To understand the quality of coal, basically there are three types of coal analyses, which are chemical properties analyses (incl. proximate, ultimate and special purpose analysis), combustion properties analyses (incl. Calorific values, ash fusion temperatures, caking, coking analyses) and physical properties analyses.

Proximate analysis is an analysis which determined the amount of moisture, volatile matter, fixed carbon and ash. Ultimate analysis is the determination of chemical elements in the coal, i.e. carbon, oxygen, nitrogen and sulphur. Special purpose analysis is an analysis to determined more detail the forms of sulphur, chlorine content, phosphorous, ash analysis and trace element.

The determination of the effects of combustion on coal will influence the selection of coals for particular industrial uses. Test are carried out to determined a coal's performance in furnace, i.e. caloric value test – to know how much the amount of heat produced per unit mass of coal when combusted - and ash fusion temperature – to know how coal's ash residue reacts at high temperature. In addition, the caking and coking properties need to be determined if coal is intended for use in the metallurgical industry. The caking properties can be determined by free swelling index – a measure of the increase in the volume of coal when heated, without the restriction of the exclusion of air.

While the coking properties can be determined by Gieseler plastometer – to know the fluidity of coal in order to obtain improved coking properties.

Coal evaluation for commercial use requires the determination of several physical properties. It includes density, hardness and grindability, abrasion index, particle size distribution and float-sink analyses. In commercial operation, coals are required to be crushed to fine powder before being fed into a boiler. Hardgrove Grindability Index measures the strength of coal to be crushed. Coal with a high HGI are relatively soft and easy to grind. The float-sink analyses is used to design the coal preparation plant. The objective of the test is to calculate the obtained amount of coal after being sinking at a certain liquids density.

1.2. Reserves

1.2.1. Coal resources/reserves classification system

In order to use precisely terms of mineral resource, to have a common understanding and to compare accurately resource data, several organizations (and countries) have developed standardized classification systems. The goal is to derive and to coordinate a standardized method of resource estimation. However, the standardized classification system developed by an organization is quite often not compatible with other classification systems developed by other organization.

To illustrate the coal resource/reserve classification, Fig. 1.3 presents one of the straightforward classification systems developed by US Geological Survey (USGS, 1983). Other known classifications are United Nations Economic Commission for Europe (UNECE, 1997), The Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves (The JORC code, 2004, Fig. 1.4). These classifications apply for coal as well for other minerals.

The USGS system employs a concept by which coal deposits are classified in terms of their degree of geologic identification and economic and technologic feasibility of recovery. In the Fig. 1.3 showing the relationship of the various factors involved, coal resources are located on the horizontal scale, increasingly to the left, according to their degree of geological assurance of existence, and on the vertical scale, increasingly upward, according to their degree of economic and technologic feasibility of recovery.

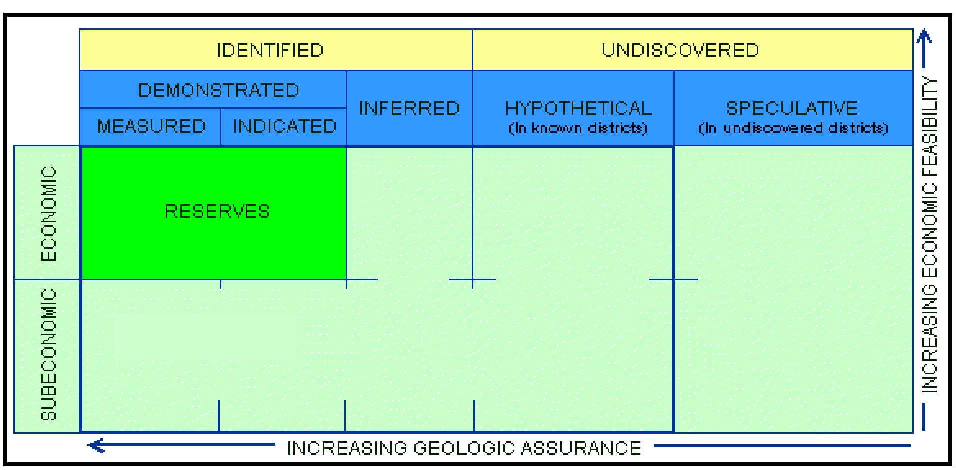

Figure 1.3. Coal Resources Classification System.
Source: USGS (1983)

Within this system, the term "coal resource" designates the estimated quantity of coal in the ground in such form that economic extraction is currently or potentially feasible. The "coal reserve" is that part of the resource for which rank, quality, and quantity have been reasonably determined and which is deemed to be minable at a profit under existing market conditions.

Other important definitions of coal classification terms are as follows (USGS, 1983):

- *Resources:* Concentrations of coal in such forms that economic extraction is currently or may become feasible.
- *Identified Resources:* Specific bodies of coal whose location, rank, quality, and quantity are known from geologic evidence supported by engineering measurements.
- *Reserve:* That portion of the Identified Coal Resource that can be economically mined at the time of determination.
    - *Measured (proved):* Coal for which estimates of the rank, quality, and quantity have been computed, within a margin of error of less than 20 percent, from sample analyses and measurements from closely spaced and geologically well-known sample sites.
    - *Indicated (probable):* Coal for which estimates of the rank, quality, and quantity have been computed partly from sample analyses and measurements and partly from reasonable geologic projections.
    - *Inferred:* Coal in unexplored extensions of Demonstrated Resources for which estimates of the quality and size are based on geologic evidence and projection.

Estimation of the different classes of coal resources and reserves using USGS classification are arbitrarily based upon three criteria: (1) thickness, rank, and quality of the coal, (2) depth of the coal deposit, and (3) the proximity of the coal resource data upon which the estimate was based.

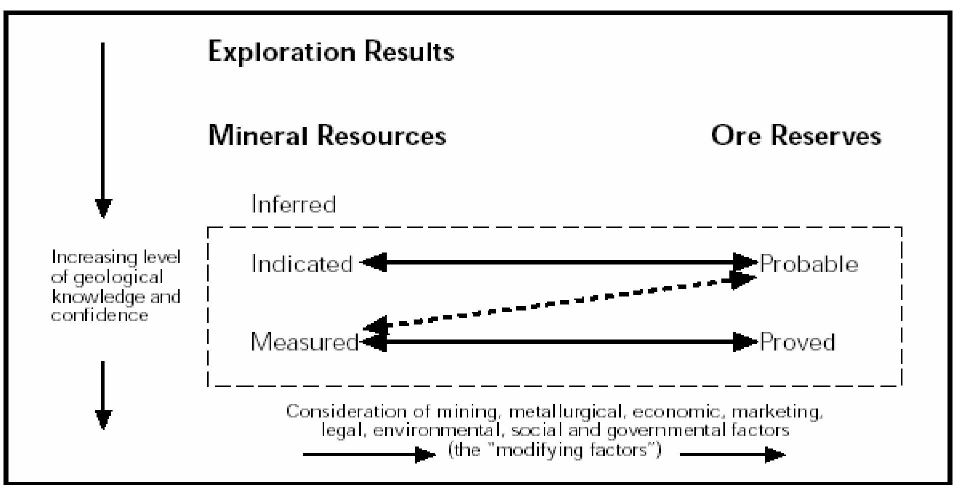

Figure 1.4. Coal Resources Classification System.
Source: The JORC (2004)

The 'JORC Code' sets out minimum standards, recommendations and guidelines for Public Reporting of Exploration Results, Mineral Resources and Ore Reserves (JORC 1989, 1992, 1996, 1999, 2004). The Code requires the Competent Person(s), on whose work the Report is based. The Code applies also to coal reporting, but the terms ‘Coal Resource(s)’ and ‘Coal Reserve(s)’ and the appropriate subdivisions may be substituted. The Code is applicable to all solid minerals, including diamonds, other gemstones, industrial minerals and coal. Therefore, ‘Ore Reserve’ and ‘Mineral Resource’ estimates for coal may be reported as ‘Coal Reserve’ and ‘Coal Resource’ estimates.

Fig. 1.4 sets out the framework for classifying tonnage (and grade) estimates to reflect different levels of geological confidence and different degrees of technical and economic evaluation. Mineral Resources can be estimated mainly on the basis of geo-scientific information with some input from other disciplines. Ore Reserves, which are a modified sub-set of the Indicated and Measured Resources, require consideration of the Modifying Factors affecting extraction. The ‘Modifying Factors’ is defined to include mining, metallurgical, economic, marketing, legal, environmental, social and governmental considerations.

A ‘Mineral (coal) Resource’ is a concentration or occurrence of material of intrinsic economic interest in or on the Earth’s crust in such form, quality and quantity that there are reasonable prospects for eventual economic extraction. The location, quantity, grade, geological characteristics and continuity of a Resource are known, estimated or interpreted from specific geological evidence and knowledge. It is sub-divided, in order of increasing geological confidence, into Inferred, Indicated and Measured categories.

An ‘Ore (coal) Reserve’ is the economically mineable part of a Measured and/or Indicated Resource. It includes diluting materials and allowances for losses, when the material is mined. Assessments and studies have been carried out by realistically assumed mining, metallurgical, economic, marketing, legal, environmental, social and governmental factors. Ore Reserves are sub-divided in order of increasing confidence into Probable Reserves and Proved Reserves.

Measured Mineral Resources may convert to either Proved or Probable Ore Reserves. It may be convert Measured to Probable because of uncertainties associated with some or all of the Modifying Factors which are taken into account in the conversion from Mineral Resources to Ore Reserves. The Code provides for a direct two-way relationship between Indicated Resources and Probable Reserves and between Measured Resources and Proved Reserves. In other words, the level of geological confidence for Probable Reserves is similar to that required for the determination of Indicated Resources, and the level of geological confidence for Proved Reserves is similar to that required for the determination of Measured Resources.

The Code also provides for a two-way relationship between Measured Resources and Probable Reserves. This is to cover a situation where uncertainties associated with any of the Modifying Factors considered when converting Mineral Resources to Ore Reserves may result in there being a lower degree of confidence in the Ore Reserves than in the corresponding Mineral Resources. Such a conversion would not imply a reduction in the level of geological confidence.

Other common terminologies in reporting coal reserves are mineable insitu reserves, recoverable reserves (also called extractable reserves) and marketable reserves (also called saleable reserves). Mineable insitu reserves are the tonnage of insitu coal contained in seams for which sufficient information is available to enable detailled mine planning. It should be quated separately for opencast and underground mines together with an outline of the proposed mining methods. And it should exclude coal which is prohibited from mining. Recoverable reserves are the proportion of mineable insitu reserves that are expected to be recovered or be extracted. Marketable reserves are the tonnages of coal that will be available for sale. If the coal is to be marketed raw, the marketable reserves will be the same as recoverable reserves. If the coal is beneficiated, it is calculated by applying the predicted yield to the recoverable reserves.

The JORC Code has been currently accepted as a best practice, but some countries still reluctant. All Australian and New Zealand companies and all international companies listed ii these two countries must report their resources/reserves according the JORC Code. The UK Institution of Mining and Metallurgy, the European Federation of Geologist and the Institute of Geologist of Ireland promulgated their joint reporting code, which basically followed the JORC Code. The SME Guide for reporting Exploration Information, Mineral Resources and Mineral Reserves, which is closely follows the JORC Code, is accepted but not mandatory in the US mining industry. Other country, like South Africa still adopt the South African Code for Reporting of Mineral Resources and Reserves (the SAMREC Code), but is reviewing the possibility of utilization of the JORC Code.

The basic different between the USGS Classification and the JORC Code is that the first provides a "rules based" approach, while the other uses a "methods based" approach. The rules based approach established specific rules regarding what could constitute resources/reserves, including minimum coal thickness, maximum parting thickness, and maximum distance from data points. This system allows for coal in the ground to be considered as original in-situ resources (measured, indicated, and inferred), while in a mine plan, a quantification of relative economic reserves could be developed as reserves and marginal reserves. Reserves were considered to be part of Resource Base, that was intentionally set up to allow not only for economic, but also marginal, as well as some sub-economic coal in the event of price/cost changes. The USGS Circular uses other terms that are not standard industry practice such as "inferred reserves."

The methods based approach, which the JORC based on, relies on the use of relevant and accepted geologic and engineering methodologies, including the demonstration of overall positive project economics, as applied by an experienced professional (Competent Person). In contrast to the rules based approach, the methods based approach does not attempt to institute any specific quantitative restrictions for coal, but leaves this to the discretion of the Competent Person.

1.2.2. World Coal Reserves

Coal is one of the most significant fossil fuels resources in the world, estimated in 2003 at around one thousand billion (0.909×10^{12}) tonnes of coal reserves[4] economically accessible using current mining technology (BP *Statistical Review of World Energy, 2006)* (Table I-3). More than half (52%) of these reserves are classified as hard coal (bituminous and anthracite), while the remaining (48%) is low rank coal (sub-bituminous and lignite) (Fig. 1.5)

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[4] Several difficulties are appeared when estimating reserves. First is in determining economic factors, i.e price and operating costs. The difficulty appears at what costs estimation is based on. Second difficulty is in knowing geologic conditions of deposit or in determining mining methods. It is because the conditions of sub-surface is difficult to predict accurately. The more difficult geologic conditions are the more uneasy the exploitation is and the more reserves are rest unexploited. What is more, the geologic conditions in each mine or location is hardly ever similar.

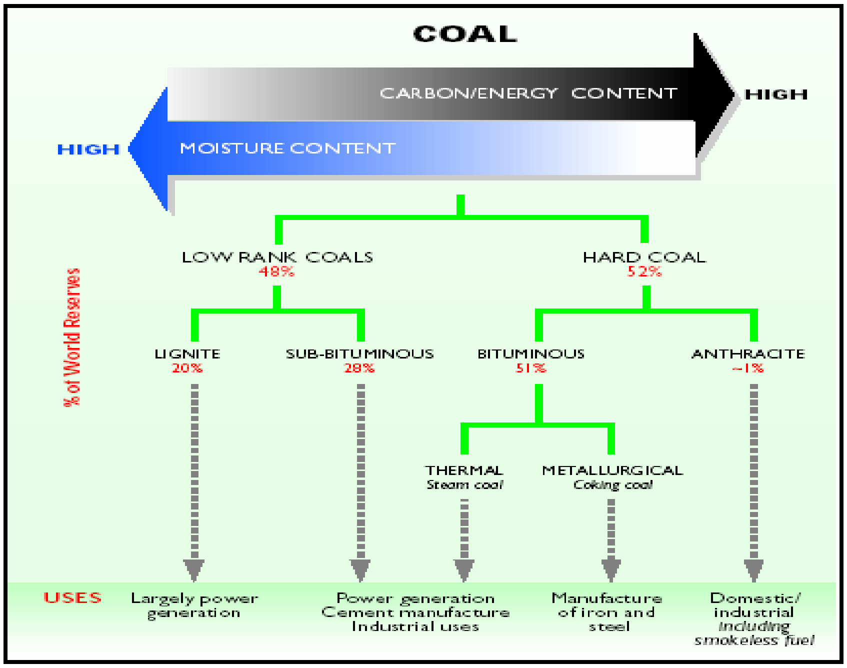


Figure 1.5. Composition of world coal reserve.
Source: World Coal Institute (WCI) (2002)

Coal deposits are present in almost all continent (Fig.1.6). The world's coal major reserves are in the USA (27%), Russia (17%), China (12%), India (10%) and Australia (9%). With regard to the region, the world's coal major reserves are in Europe and Eurasia (32%), Asia Pacific (33%) and North America (28%) (Table I-3). At current production levels, there is enough coal to last over 160 years, not taking in account other reserves which might be proved by on-going exploration or become accessible through improvements in mining technology. In contrast, known world oil and gas reserves will be depleted within 40 to 60 years time consecutively.

1.3. How to mine coal

Coal is produced from mainly two distinct types of mining methods: surface (open cut or cast) and underground. Generally, coal seam more than 100 metres below the surface will be mined by underground methods. Coal nearer to the surface will be exploited by surface mining techniques. As technology changes, the line between viable surface and underground mines is becoming less well defined.

Currently, almost two-thirds of hard coal production worldwide comes from underground mines, but the distribution differs from one country to others. In US about 46% of all coal production are coming from underground mines while for Australia and Indonesia are nearly 24% and 95% consecutively. In country like China, most of the mining is pursued in underground mines. It is because its coal deposits are marked by strong seam inclines, so that the reserves minable in opencast pits are relatively low. While in Germany and Poland, almost all hard coal mining is underground operations at an average working depth of some 600 m. In those countries talked about, the costs of mines differ in each country and each type of extraction, as illustrated in Table I.2.

Table I-2. Different free mine cost in several hard coal producing countries

Country	Region Extraction method	Cost free mine $/t
Australia	Queensland, Opencast	11-22
	Queensland, Underground	22-33
	New South Wales, Opencast	17-29
	New South Wales, Underground	19-31
Canada	British Colombia, Opencast	26-36
China	Underground	29-39
Colombia	Opencast	22-24
Indonesia	Kalimantan, Opencast	14-26
Germany	Underground	110-130
Russia	Opencast	15-16
United Kingdom	Underground	50-70
Unites States	Central Appalachians, underground	30-48
Venezuela	Opencast	16-20

Source: Ritschel and Schiffer (2005) and Piper (2002)
Note. Cost free mine is all mining costs for producing one ton of coal

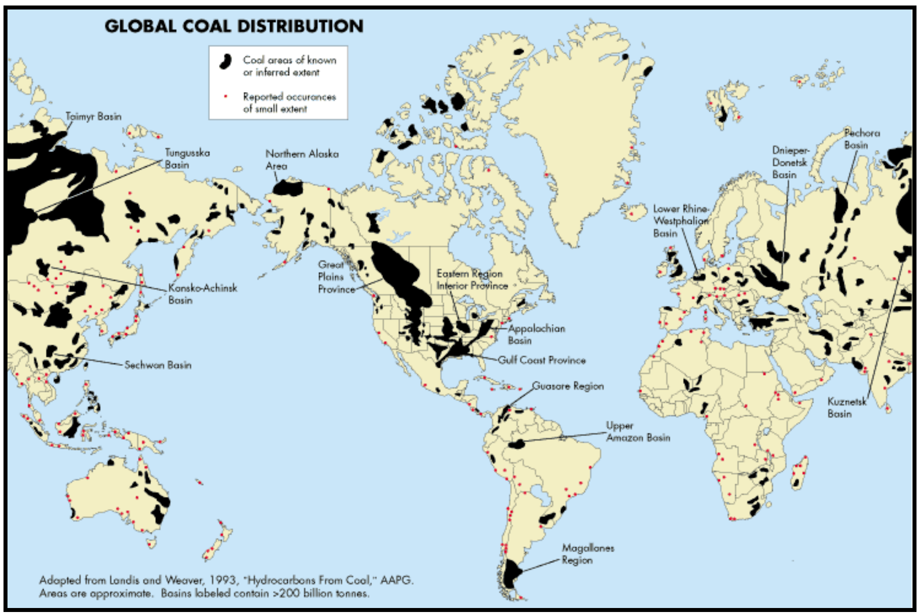


Figure 1.6. Global coal deposits
Source: Landis and Weaver (1993)

1.3.2. Surface mining techniques

It is the cheapest and most productive method for mining coal. This technique can extract up to 95% of coal insitu. Surface mines exist in two general situations.

Open cut (cast) strip mining

Almost all lignite production in Germany and Greece are being produced from open cut mining. In Australia, open cut mining accounts for over 70% of production while in the United States it accounts for about 60% of production. Large open cut strip mines can be a number of kilometres long and up to a kilometre wide. Strip mining exists in three general situations (Kennedy, 1990):

- *area mines* : where the terrain is flat, or gently undulating, and coal seams are at a relatively constant depth;
- *contour mines* : which most often exist where the terrain is undulating and a number of coal seams exist interspersed with other strata; and
- *mountain removal* : where coal-bearing strata exist near the top of large hills or mountains. In this case the entire mountain may be excavated to get the coal.

Table. I-3. Distribution of World coal reserves in country in Million tons (Mt)

	Anthracite and bituminous	Sub-bituminous and Lignite	Total	Share of total	R/P ratio
USA	111,338	135,305	246,643	27.1%	245
Canada	3,471	3,107	6,578	0.7%	100
Mexico	860	351	1,211	0.1%	135
Total North America	**115,669**	**138,763**	**254,432**	**28.0%**	**235**
Brazil	-	10,113	10,113	1.1%	*
Colombia	6,230	381	6,611	0.7%	120
Venezuela	479	-	479	0.1%	53
Other S. & Cent. America	992	1,698	2,690	0.3%	*
Total S. & Cent. America	**7,701**	**12,192**	**19,893**	**2.2%**	**290**
Bulgaria	4	2,183	2,187	0.2%	84
Czech Republic	2,094	3,458	5,552	0.6%	90
France	15	-	15	w	17
Germany	183	6,556	6,739	0.7%	32
Greece	-	3,900	3,900	0.4%	55
Hungary	198	3,159	3,357	0.4%	240
Kazakhstan	28,151	3,128	31,279	3.4%	360
Poland	14,000	-	14,000	1.5%	87
Romania	22	472	494	0.1%	16
Russian Federation	49,088	107,922	157,010	17.3%	*
Spain	200	330	530	0.1%	26
Turkey	278	3,908	4,186	0.5%	87
Ukraine	16,274	17,879	34,153	3.8%	424
United Kingdom	220	-	220	w	9
Other Europe & Eurasia	1,529	21,944	23,473	2.6%	341
Total Europe & Eurasia	**112,256**	**174,839**	**287,095**	**31.6%**	**242**
South Africa	48,750	-	48,750	5.4%	201
Zimbabwe	502	-	502	0.1%	154
Other Africa	910	174	1,084	0.1%	490
Middle East	419	-	419	w	399
Total Africa & Middle East	**50,581**	**174**	**50,755**	**5.6%**	**204**
Australia	38,600	39,900	78,500	8.6%	215
China	62,200	52,300	114,500	12.6%	59
India	90,085	2,360	92,445	10.2%	229
Indonesia	740	4,228	4,968	0.5%	38
Japan	359	-	359	w	268
New Zealand	33	538	571	0.1%	115
North Korea	300	300	600	0.1%	21
Pakistan	-	3,050	3,050	0.3%	*
South Korea	-	80	80	w	25
Thailand	-	1,354	1,354	0.1%	67
Vietnam	150	-	150	w	6
Other Asia Pacific	97	215	312	w	34
Total Asia Pacific	**192,564**	**104,325**	**296,889**	**32.7%**	**101**
TOTAL WORLD	**478,771**	**430,293**	**909,064**	**100.0%**	**164**

* More than 500 years

w Less than 0.05%

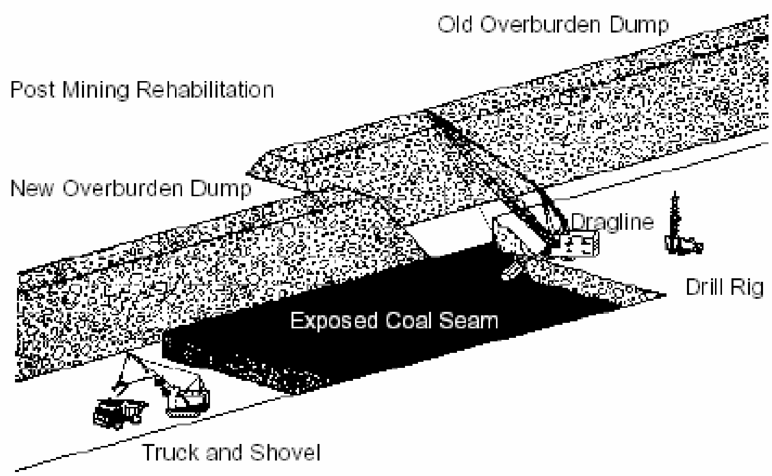
Source: BP Statistical Review of World Energy (2006) ; R/P : reserve to production

The first process of surface mining method is a pre-strip. Bulldozers and scrapers are used to remove vegetation and to roughly level the surface. Top soil is stripped and stockpiled for use in rehabilitation works, after mining is completed. Holes are then drilled in the overburden and explosive charges set and fired. This weakens the overburden for easier removal in the next process.

Overburden removal (stripping) is carried out by a number of methods, including dragline, excavator, shovel, or bucket wheel, depending on overburden depth and the precise characteristics of the mine. Removing the overburden exposes the coal seam below. When exposed, then coal seam can be mined by wheel loaders and trucks or other combinations of plant. Again, this can involve drilling and blasting to loosen the coal seam for extraction. Fig. 1.7 shows a profile of a typical open cut strip mining operation.

Highwall

This technique may be adopted in the latter stages of area mines or contour mines. It is used to recover additional resources that cannot be extracted economically by further surface mining. A remote-controlled auger or continuous miner is bored into the exposed coal seam in the highwall of an open cut and extracts coal on to a conveyor system. Highwall techniques are being used occasionally in Australian and Indonesia open cut mines to extract residual coal reserves.



Source: United Mine Workers of America (1997).

Figure 1.7. Open Cut Coal Mining.
Source: Energy Information Administration (EIA) (1997)

1.3.2. Underground mining techniques

The design of underground coal mining is governed by a set of factors, amongst which are : geological nature of deposits, characteristics of the roof and floor of the seam, depth and geotechnical properties of the overburden, hydrology of the area, economic ramification and effect of environment. Underground mining technique in coal is mainly Room and Pillar, Long-wall and Short-wall.

Room and Pillar

This method is viewed as uncompetitive and becoming obsolete in the face of newer techniques, such as Long-wall. It is still used where the geology is unsuitable for Long-wall mining.

This system involves excavation of a series of rooms or bords directly into coal seam. The roofs and ribs (walls) of access tunnels are bolted to increase their strength. In the advance phase, pillars of coal are left to help support the roof of the mine. In the retreat phase, these pillars can be removed to increase the total amount of coal extracted. As the pillars are removed, the roof is allowed to collapse and mined areas are sealed off.

The technique utilises machines known as continuous miners to cut coal from the working face using a revolving drum covered in hardened teeth or picks. The picks are positioned on the drum concentrically, such that the coal is worked towards the centre of the miner, gathered up by gathering arms and conveyed through the body of the miner to conveyor belts linked to the surface. Alternately, coal is loaded into shuttle cars to be transported to the mine opening. Fig. 1.8 shows the basic sketch Room and Pillar.

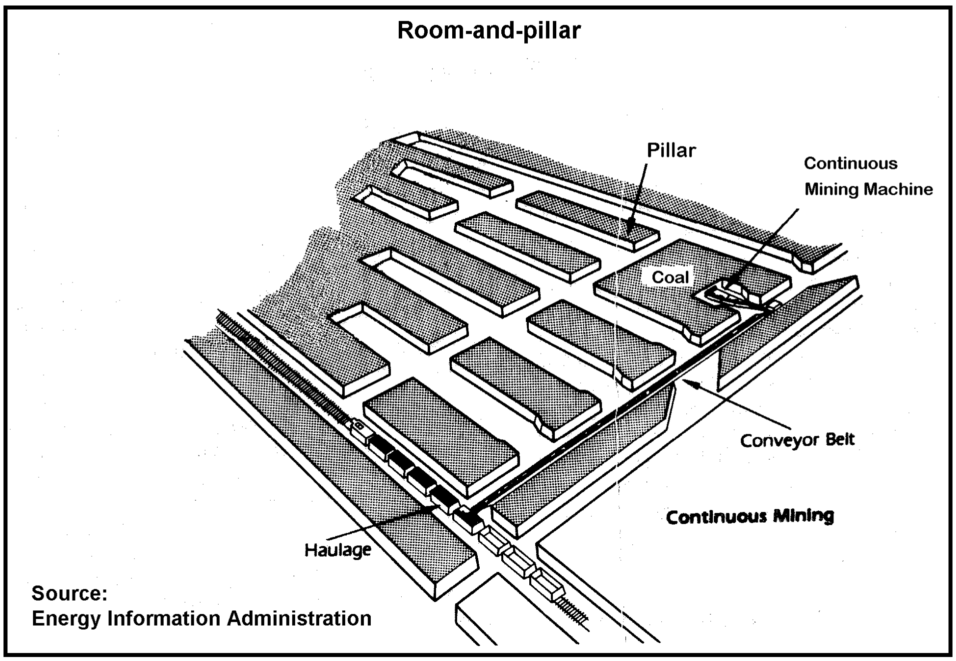


Figure 1.8. Room and Pillar Coal Mining.
Source: Energy Information Administration (1995)

Longwall mining

A Longwall mining unit is employed to extract the bulk of the coal. Continuous mining machines are used in development work on roads and ventilation tunnels. Two parallel access roads are developed directly into coal seam from a central access system using a continuous miner. The two entries, which can be up to 400 metres apart (panel's width), are then joined by a crosscut tunnel at their far ends. The length of panel can be up to 3,000 meters. The face that is formed by this crosscut is referred to as the Longwall.

A Longwall mining machine is installed in the crosscut. The machine has a rotating shearer laced with picks, which moves laterally and vertically shearing coal from the face. The pick lacing works the coal off the face on to a conveyor belt in a single operation and allows the coal to be extracted continuously from the face and transported to the surface by conveyor. Longwall systems generally have their own self-advancing hydraulic roof supports. As the machine advances and mining proceeds, the roof is allowed to fall behind the advancing machine.

Longwall mining is the most productive method of underground mining[5] in the absence of major geological complications. However it is capital-intensive and the approach of individual mines can vary considerably although they adopt the same general techniques. Fig. 1.9 shows basic view of a Longwall mining method.

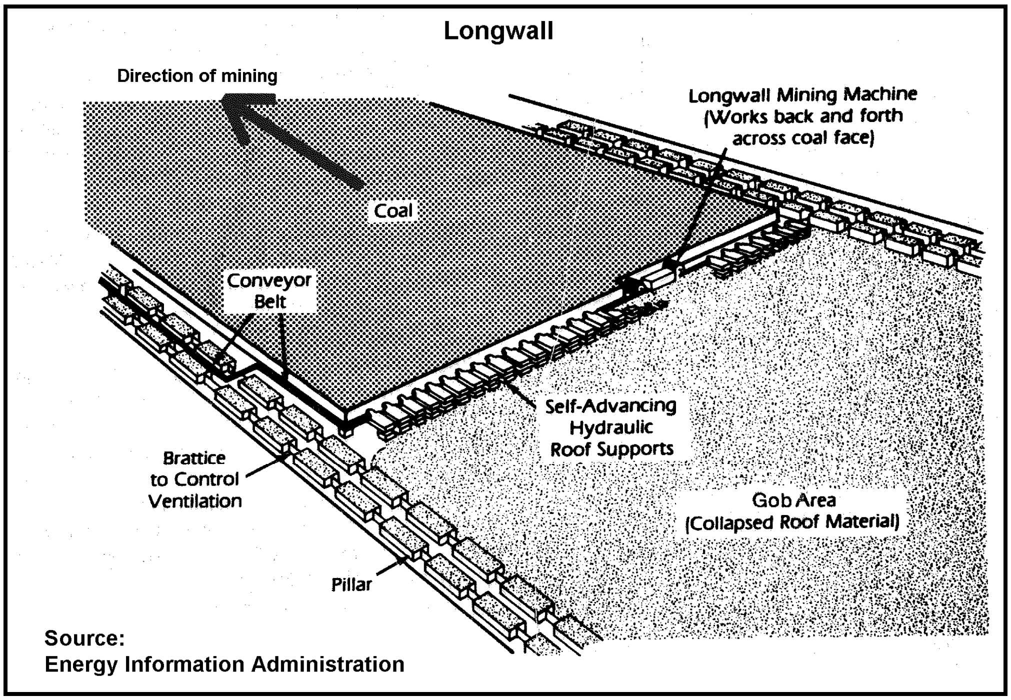


Figure 1.9. Long Wall Coal Mining.
Source: Energy Information Administration (EIA) (1995)

Shortwall mining

Shortwall mining, a specialized coal exploitation technique, represents a compromise between room and pillar and longwall system. Its flexibility makes it applicable to small reserves of varying geological conditions where coal seams are shallow under a strong roof. Continuous miners used in conjunction with longwall chocks provide a system of continuous pillar recovery.

In development process, three-entry shortwall panel, which represents a compromise between the desired rate of development and the numbers of entries needed for airways and escapeways, are developed. The middle entry allows for the installation of a belt and track; and one outer entry is used as a return airway. Optimum panel dimensions for length and width appear to be 600-1200 m and 45-60 m respectively.

One the development work is concluded, the shortwall supports are installed along the full width of the pillar and then mining commences, as seen in Fig. 1.10a. A panel belt conveyor for transporting coal is usually utilized. The chocks are extendible, forward beam that permit a continuous mining machine to make a cut from the headgate to tailgate entries in front of the chock

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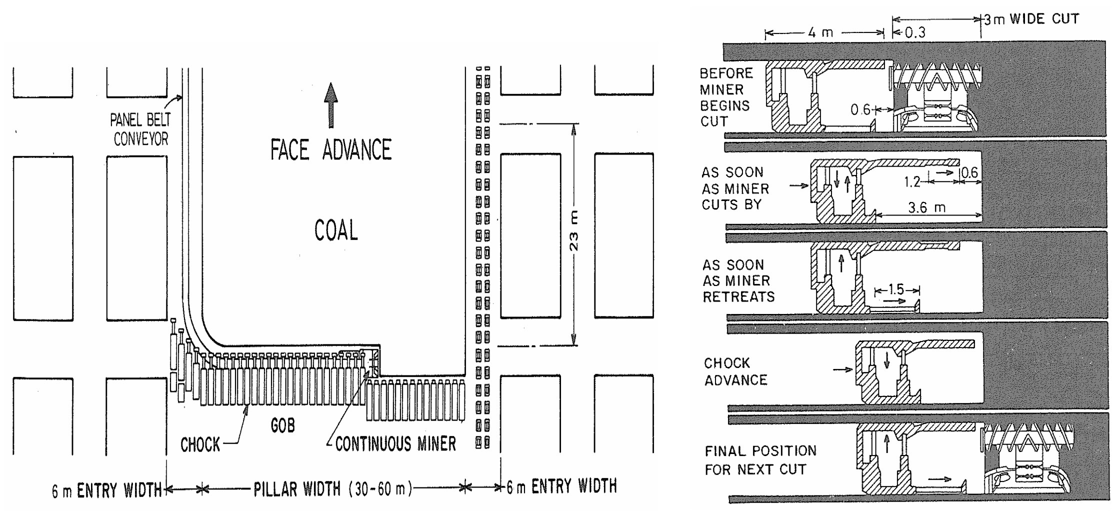
[5] In US the productivity of longwall coal mining can reach 6.0 tons per worker-hours in 2005, which was almost double than that of in 1995

base. Following the cut across the face, the machine is trammed back to the headgate entries, and the chocks are advanced after the machine passes. Fig. 1.10b shows the five-step sequence of chock operation on a shortwall face.



a. a typical shortwall face *b. sequence of chock operation*

Figure 1.10. Shortwall mining

Extraction of irregular coal seams with the three types of underground mining methods above is generally considered to be expensive. Therefore, in addition to three mining methods there are several others non-conventional coal mining techniques, including these techniques is hydraulic mining. In the hydraulic mining technique, coal and soft rock are broken and excavated from a solid face by utilizing the kinetic energy of a fluid jet. The effectiveness or cutting rate is primarily a function of nozzle size, flow rate, pressure, force and power. This technique is suited to the mining of mechnically unstable coal seams which are locked in severely disturbed areas where conventional methods are ineffective. This method is also adaptable as a supplementary method to the conventional methods for unstable coal seams.

In this method, coal seams is divided into several panels which are services by two main entries, an intake-flume road and a return panel. During production, thick pillars are extrated by hydraulic monitor and feeder breaker. A high pressure water jet is provided to cut, break, load and transport the coal. The caved coal is flushed to the feeder breaker for sizing and the flumed out of the mine as a slurry.

1.3.3. Methane extraction in coal seams

Instead of mining coal, there are several techniques to extract methane trapped in coal seam, including these techniques are Coal Mine Methane (CMM) and Coal Bed Methane (CBM). Instead of exploiting coal, these two methods aim to recover methane that is absorbed on the internal surface of the coal.

The purposes of extracting methane are either for safety or production reasons. Safety reason can be explained as methane is colorless and odorless in its natural state. Therefore, it is possible that some natural gas may leak around the coal bed gas facilities. If the leaking gas flows into the air, it dissipates quickly and poses no danger. However, if it is confined and ignited by a fire source it can explode and will burn.

The popularity of extracting of coal methane has increased lately because of the increased demand for natural gas and the ease through which natural gas can be recovered from coal seams. Coal methane can be used as an energy source that is environmentally more acceptable than traditional mining and combustion of coal.

The production of coal gas from coal mines falls into three following methods: Pre-mine drainage (in-mine), Post-mine drainage (in-mine) and Gob vent wells. In the post-mine drainage methods, for example, gas invades a coal mine through mining induced fractures. In this example, cross measure boreholes are drilled into underlying strata prior to Longwall extraction. As Longwall mining occurs, the underlying strata are fractured from the mining itself (floor heave and other stress release) and gas released from these sub-strata invades the mine through these fracture sets. Gas is withdrawn from the post-mine drainage boreholes using a vacuum pump, collected into a pipeline network and pumped to the surface. Fig. 1.11 illustrates methane production by post-mine drainage.

Coal bed methane is the name given to methane found in coal seams. It is often called coal seam gas. CBM production is an in-situ process of producing coal gas in non-mining areas generally by desorbing the coal gas by dewatering and lowering the water table in wells drilled for that purpose.

Current CBM activity is concentrated in North America mainly in San Juan Basin and Power River Basin in US (McCurdy, 2001). In US, CBM production was about 1,350 Bcf (Billion cubic feet) in year 2000, most of it (an estimated 1,100 Bcf) from the mature producing basins (San Juan Basin, Warrior Basin and Central Appalachian Basins). Emerging CBM producing basins, including the Powder River, Raton, and Uinta basins, contributed to the 2,000 CBM well production.

In Europe, one of the intensive researches of ECBM is the RECOPOL project. It is an EC-funded research and demonstration project to investigate the technical and economic feasibility of storing CO2 permanently and safely in subsurface coal seams in Europe. The project started in 2001,at Silesia basin, Poland. CO2 from fertilizer plant is brought in by trucks and stored on site in liquid form in containers. The CO2 is heated and than by a pump injected into underground coal seams at a depth of 1050-1090 m. The CO2 will adsorb to the coal, which will release its methane gas simultaneously. This methane will be produced from the second well, with the pump-jack. Injection tests in the drilled well started in 2004. It is hoped that the lessons learned in this operation can help to overtake start-up barriers of future CO2 sequestration initiatives in Europe.

Other ECBM research is being conducted at Mecsek Mountains in Hungary. An enhance CBM production method is now being successfully tested using CO2 injection to preferentially adsorb this gas in the coal and desorb the stored methane. The estimation of gas resource on this area gave 142.5 Bn cu.m (Billion cubic meter) gas (Varga, et. all, 2006).

Scientific understanding of, and production experience with, these methane extraction techniques are both in the early learning stages. Few studies exist and few models are available for planning the development of the techniques on a broader scale.

The main concern is that increased production of methane from coal beds carries with it technological and environmental difficulties and costs. In a conventional oil and gas reservoir, gas lies on top of oil which, in turn, lies on top of water. An oil or gas well can be drawn without producing water. But water permeates coal beds, and its pressure traps methane within the coal. To produce methane, water must be drawn off first, lowering the pressure so methane can flow out of the coal and to the well bore. This saline water must be disposed of in an environmentally manner. Surface disposal of large volumes of water can affect streams and other habitats, and subsurface reinjection makes production more costly. In addition, methane is a greenhouse gas; in the atmosphere it acts to trap heat and thus contributes to global warming.

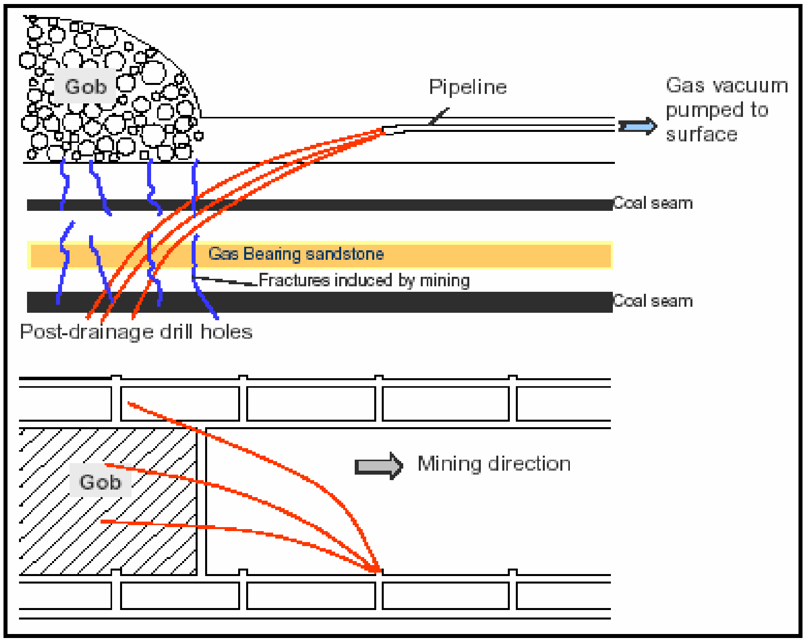


Figure 1.11. Post mine gas drainage
Source: McCurdy (2001)

1.4. Global Coal industry

1.4.1. Coal utilization

The use of coal as an energy source has been known from ancient times, although it was a minor resource until the Industrial Revolution. Coal had been used on a small scale in Western Europe for thousands of years, as evidence shows from discoveries of a Bronze age corpse that was cremated with coal in South Wales, as well as remains of Roman coal-fueled fires on their northern English frontier along Hadrian's Wall.

It was during the Industrial Revolution in the 18th and 19th centuries that demand for coal increased. The great improvement of the steam engine was largely responsible for the growth in coal use. The history of coal mining and use is linked with that of the Industrial Revolution – iron and steel production, rail transportation and steamships.

Steam coal

The major use of this type of coal is for fuel for thermal power stations. It is pulverised and burnt in steam generating boilers. The steam is then used for the generation of electricity (Fig. 1.12). It can be also used to produce heat in cement kiln and to produce industrial process steam. Thermal coal is also known as energy or steaming coal.

Steam coal has three main end-uses:

- an input in the power sector to produce electricity and heat where it is sold to third parties (mostly as district heat)
- as a fuel in the final consumption sectors for production of heat and/or steam (i.e. in the industry residential, commercial and public services, agriculture and transport sectors)

- small but increasing amounts of steam coal are being used as PCI coal in blast furnaces and as well as for blending with coking coal.

Steam coal can be used to produce electricity and heat in three types of power stations: those that are only designed to produce electricity (referred to as electricity plants), those that are designed to simultaneously produce both electricity and heat (referred to as combined heat and power (CHP) plants or cogeneration plants) and those that are only designed to produce heat (referred to as heat plants).

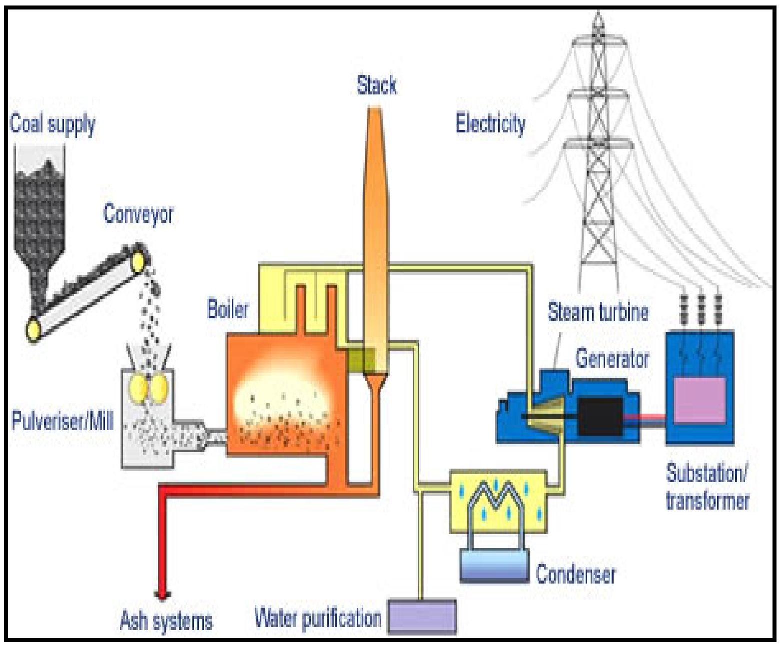


Figure 1.12. Electric generation by coal.
Source: World Coal Institute (WCI) (2002)

Coking coal

It is used in blast furnaces to produce iron and steel. It is also used as a reductant in the refining of other metals such as aluminum. A reductant allows a chemical reaction which separates the metal from its ore. Almost all coking coal is transformed into coke in coke oven and used in blast furnaces for the production of pig-iron. Pig-iron is then subsequently converted to steel in an oxygen steel furnace (Fig. 1.13). Hence, demand for coking coal and coke is derived mainly from the demand for pig-iron and less directly from the demand for steel.

Coking coal has three main end-using:

- used as an input for the production of coke in coke ovens
- some coking coal is used as an input in the power sector to produce electricity and heat where the heat is sold to third parties
- small amounts are used as a fuel in the final consumption sectors for the production of heat and/or steam

1.4.2. Coal Consumption

Global consumption

Coal consumption in 2004, primarily in the electric power and industrial sectors, accounted for 23% of total world energy consumption. Of the coal produced worldwide, 73% was shipped to electricity producers, 12% to steel industry, and most of the remaining 15% to coal consumers in the residential, commercial sectors and heat market (Table I-4).

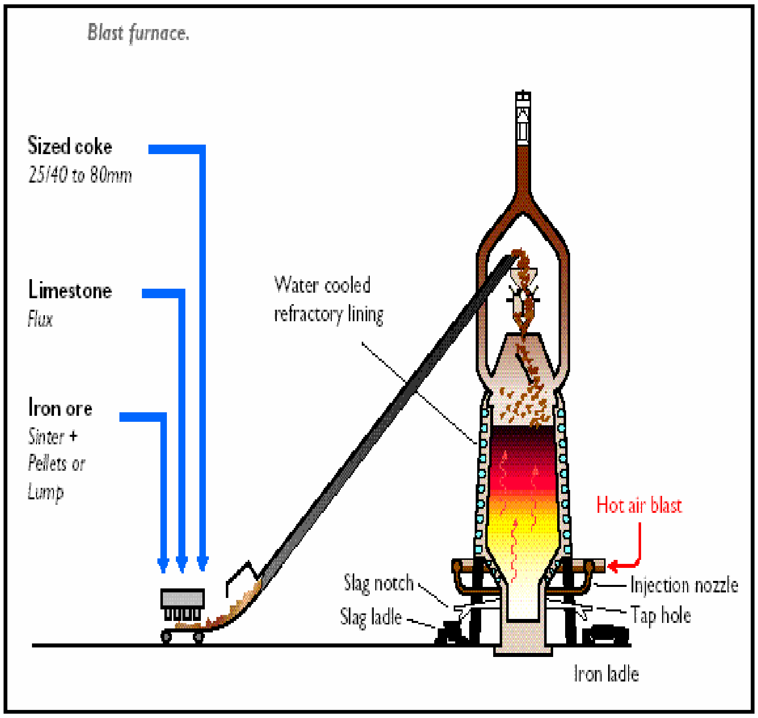


Figure 1.13. Coke from coking coal for Blast furnace.
Source: World Coal Institute (WCI) (2002)

In the industrial sector coal is an important input for the manufacture of steel and for the production of steam and direct heat for other industrial applications. Coal plays a limited role in the residential and commercial sectors; and its use for transportation is now virtually nonexistent.

Table. I-4. World hard coal consumption

	1980		2004	
	Mt	%	Mt	%
Total	2,800		4,600	
Of which				
Power plants	1,000	36	3,350	73
Steel Industry	600	21	550	12
Heat market	1,200	43	700	15

Source: Federation of Germany Hard Coal Importer, from RWE Power (2005)

Hard coal worldwide consumption grew by significantly from 2,800 Mt in 1980 to 4,600 Mt in 2004. Hard coal's share in worldwide primary energy consumption in 2004 was some 22%. The recorded consumption increase is mainly accounted for by China, although other mining regions have pressed ahead.

World hard coal output (production) was about 4.600 Mt in 2004. This can be subdivided between approximately 4,100 Mt (88%) steam coal and 550 Mt (12%) coking coal. Most of the steam coal goes into power generation. The share is about 3,400 Mt or 73% of world hard coal consumption. Some 35% of power generation worldwide is based on hard coal.

The heat market, i.e. customers outside the electricity sector and the steel industry, comprises cement works, paper mills and other industrial consumers. This market consumed coal at 700 Mt worldwide in 2004, although its share contracted from 43% in 1980 to about 15% of world hard coal consumption in 2004, and further decline is expected.

The metallurgical area, with a share of 12% or 550 Mt has grown by some 50 Mt since 2001. The increase in the consumption of coking coal was noted, above all, in China and in Russia and was largely satisfied from domestic output in each case. The blast furnace process for the production of pig iron is the method essentially deployed in China, since alternative processes are not feasible owing to a scarcity of scrap. In view of the present high prices for coking coal and coke, work is proceeding on optimizing the blast furnace process, and the technology for injecting pulverized coal (PCI coal) has received a new boost up to save coke.

Consumption by region

The most important market for hard coals is the Asian Pacific economic area. Hard coal consumption in this region in 2004 was 2,600 Mt. It accounts about 57% of world consumption (Table I-5). Dynamic consumption developments were particularly noted in China, where the main driver behind the growing demand for coal, as in other Asian states, is the striking rise in electricity needs. The most important hard coal consumer after China is India, where over two thirds of the coal consumed is for power generation.

Along with China, the US, India, Russia and South Africa, Japan is one of the biggest hard coal consuming countries, covering practically its entire coal needs with imports, mostly from Australia. Some 44% of the coal consumed in Japan is being used in the steel industry; Japan is the world's second largest steel producer (after China). Also, coal in Japan makes a considerable contribution to power generation, with more than one quarter of the country's power supply being based on imported hard coal. Other important hard coal consumers in the Asian Pacific economic area are South Korea, Taiwan, Indonesia and Thailand.

Table I-5. Hard coal consumption, by region

	1980		2004	
	Mt	**%**	**Mt**	**%**
Asia	900	32.4	2,610	56.7
- of which China	626	22.5	1,700	37
North America	633	22.8	1,000	21.7
South/Central America	16	0.6	50	1.1
Europe	571	20.5	400	8.7
CIS	529	19.0	290	6.3
Australia	36	1.3	80	1.7
Africa	95	3.4	170	3.7
World	**2,780**	**100**	**4,600**	**100**

Source: International Energy Agency (IEA) Coal Information 2003 (2003) and other sources

The second largest hard coal regional consumer is North America. Over 90% of hard coal consumption in North America totalling some 1,000 Mt is accounted for by the US. In this country more than 50% of power generation is based on coal. In Central and South America, coal's share in the region's total energy consumption is nearly 4%. More than 60% of coal consumption in Central and South America is accounted for by Brazil, the country with the world's eighth largest steel industry. The other main coal consumers are Colombia, Chile, Argentina, Peru and Venezuela.

There are not a large amount of coal reserves in Africa. The reserves in this region share only 5.6% of world reserve. Among these South Africa's reserves share 5.4%. It explains why Africa has little (almost 4%) share in coal consumption worldwide. The crucial market there is South Africa, which accounts for over 90% of coal consumed by the entire continent. Demand is covered by domestic output. South Africa is also one of the world's major exporters of hard coal.

Consumption and mining in the former Soviet Union are concentrated on Russia, Ukraine and Kazakhstan. Coal needs in each case are covered by domestic output. In all of these countries, coal makes a significant contribution toward power generation. Developments in consumption in the last ten years, after recorded falls in consumption owing to restructuring inside these economies, are marked by consolidation.

In Western and Central Europe, the requirements of environmental and, specifically, climate protection are increasingly acting as a damper on the use of coal in its principal deployment area, power generation. Furthermore, European hard coal mining industry is unable to compete with world coal market conditions. Some of the fall in domestic coal output is offset by imports. Today, the major consumer countries in this region are Germany, Poland, UK, Spain, Turkey, Italy and Denmark.

1.4.3. Coal supply

In the Pacific market[6], steam coal supply accounted for 297 Mt in 2004. The situation continues to be dominated by Australia, Indonesia and China, which accounted for 90% of supplies (Ekawan, et.all, 2006b). Smaller quantities are shipped by Russia and Vietnam. In 2004, Atlantic suppliers, South Africa and Colombia, supplied only about 7 Mt (2%) to the Pacific market. The Pacific production exceeds requirements in this area and in 2004 provided some 26 Mt for the Atlantic market. Indonesian coal, in particular, enjoys growing acceptance in North America and Europe (e.g. Italy) on account of its low price and low sulphur content.

Now, considerable expansion potential can be seen in Australia and Indonesia. China is hard to assess, owing to its own heavy demand, but wishes to export steam coals at least on the present scale of 75 - 80 Mt. The trend in domestic Chinese logistics is toward improvement and could eventually lead to the dismantling of excessively high safety stockpiles and greater flexibility.

Vietnam has ambitious expansion plans and intends to increase exports to 20 Mt in the next few years. The exported quantities, primarily semi-anthracites, are sold in Southern China to power plants and cement works, which are accustomed to these qualities. Russia is also expanding its mining and logistics capacities in the Far East to share in the Pacific steam coal market.

In the Atlantic market, steam market traded at 208 Mt in 2004, South Africa, Colombia and Russia play the leading role and supply 75% of the market (Ekawan and Duchene, 2006a). Besides

[6] There are two types of international coal market, which are the Pacific market and the Atlantic market. Detail discussion about these coal markets are disccused at Chapter 2.2.2. Supply from outside community

supplies the Pacific market of 26 Mt, Poland, Venezuela and the US serve the Atlantic market. The expansion potential in Atlantic suppliers refers to Colombia, South Africa und Russia. The US has the capacity for higher exports but, in spite of high world market prices, American steam coal mines are aiming for its coal on the North American market than in exports.

Whereas there is a steady uptrend in Colombia's exports, South Africa is stagnating. The export terminal Richards Bay currently has a capacity of 72 Mt and is to be expanded to 86 Mt. At present, however, only some 65 Mt of capacity is being used, since the railway infrastructure is not well functioning yet. The mining potential exists, however, and the problems in land-bound transportation should be capable of solution in the foreseeable future.

1.5. Discussion: Coal future: an opportunities under gloominess

1.5.1. Impact coal utilization on Environment

Coal has constraints that put it in a weak position in respect of oil and gas. Being a solid and heavy material, it is bulky and requires large storage areas. With a lower calorific value than oil and gas, it does not have the ease of use of a liquid or gaseous fuel. It generates pollution at every stage of the production and utilization.

Burning coal will produce carbon dioxide (CO2) and other gases. CO2 is the main source Greenhouse Gases and these gases have played a major role in the global warming. Combustion of coal contributes 37% of total world CO2 emission. Furthermore, among other fossil fuels, coal is more carbon-intensive fuel per energy unit, and therefore the increment in carbon dioxide emissions from its combustion is higher than the increment in emissions from natural gas or oil. In chapter 3, it will be discussed more detail about coal and climate change.

The value of coal is partially offset by the environmental issues it raises. Some of these environmental issues also have impacts on human health. Table I-5 summaries the effect of coal usage on the environment at stage of the production and utilization.

Facing the environment challenges, nowadays coal industry is developing Clean Coal Technologies (CCT). Deploying CCT, which would improve the thermal efficiency of coal use and reduce emissions, could minimize investment risks and give a major improvement to prospects for coal demand. In power generation, CCT responses the environmental challenges through three ways, reducing emission of pollutants, increasing thermal efficiency and reducing CO2 emission to near zero level. More detail discussion about CCT can be seen in Chapter 2 (part 2.3) and Chapter 3. While attention is focused on power generation technologies, continuous technological advances are being made along the entire coal chain.

New techniques have been developed for coal mining (i.e. CMM and CBM) and the preparation of coal for use in power stations (i.e. Pulverized Flue Bed Combustion and Pre-drying Coal), as well as for coal combustion, emissions control and the disposal of solid waste. These techniques are able to minimize the environment impacts. Technologies on the horizon such as carbon capture and storage (CCS) could achieve near-zero emissions of pollutants from coal-fired power plants (more explanation about CCS can be seen in Chapter 5).

Table I-6. Main impacts of coal

Stage	Main Impacts
Mining - Underground - Surface	 Subsidence Generation of gases (mainly CH4) Liquid effluent/Acid Mine Drainage Hydrologic impact Health effect of miner: respiratory diseases (e.q. pneumoconiosis or silicosis) caused by dust Surface disturbance (e.q. changed of natural land surface) Liquid effluent/Acid Mine Drainage Hydrologic impact Solid waste
Beneficiation	Water contamination from preparation plants Air contamination from preparation plants Refuse contamination from preparation plants
Transportation	Depend on types of transport, mainly air pollution (dust), and surface disturbance
Combustion - By product - Emission	 Fossil fuel combustion waste : fly ash, bottom ash, boiler slag, Flue Gas Desulphuration material Sulfur Oxides Nitrogen Oxides Particulate matter Carbon monoxide Trace elements (potentially toxic): chromium, arsenic, lead, cadmium etc Greenhouse Gases: i.e Carbon Dioxide

Source: from various sources

1.5.2. Global Coal Demand

Under the pressure of ecological concerns, coal has fallen from grace and seems set to play less of a role in the production of electricity. However, given the present facilities and technologies and energy market situation, reducing immediately this source of energy could give rise to economic tensions and threaten supply without an active policy of demand management. Many countries (i.e. China, India, US, Germany, Poland) still depend in the future on coal to power their electricity. And where in the power generation sector coal is not a dominant source of energy, several countries (i.e. Norway, Sweden, Italy) still use it as a back-up fuel.

Various institutions (IEA, 2004; WEC, 2004; EIA-DOE, 2005; WETO, 2005) predict that coal will continue to play a key role in the world energy mix. Table I-7 indicates main results of their predictions. The four institutions point to an increase in world coal consumption over the next decades, with a total consumption of about 3,000 Mtoe in 2010. For the longer term, the WETO and WEC projections show structurally higher coal consumption than the IEA and DOE projections for 2025. They projected that the rise of coal continues in the 2020-2030 decade, with average growth rates slightly higher than 2% per-year. In both cases, coal consumption reaches a level of more than 4,500 Mtoe in 2030, corresponding to a doubling from current level.

IEA in its well-known report of World Energy Outlook 2004 (WEO, IEA, 2004) predicts that coal demand is projected to grow to 2030 at an average annual rate of 1.4%. At that time, coal will meet 22% of global energy needs, which is only 1% less than it does today. There is, however, significant variation growth between regions in the demand prospects for coal (Table I-8).

Table I-7. Coal demand projection

Institution	%/year			Mtoe		
	2000-10	2010-20	2020-30	2010	2020	2030
WETO	2.07%	2.42%	2.48%	2,931	3,723	4,757
EIA-DOE	1.88%	1.50%		2,878	3,340	
IEA	1.74%	1.74%		2,763	3,193	3,601
WEC A2	2.13%	2.31%	2.22%	2,949	3,707	4,616

Source: Energy Information Administration (EIA) (2005), International Energy Agency (IEA) (2004), World Energy Council (WEC) (2004), EU Commission World Energy Technology Outlook (2003)

Table I-8. World Coal Demand

Region	2002	2030	Avg annual rate of growth 2002-2030
	Mt	Mt	%
OECD	**2,237**	**2,461**	**0.8**
OECD North America	1,051	1,222	0.5
OECD Europe	822	816	0.0
OECD Pacific	364	423	0.5
Transition Economies & Developing Countries	**2,554**	**4,568**	**2.0**
East Asia	160	456	3.8
South Asia	396	773	2.4
Latin America	30	66	2.8
Middle East	15	23	1.6
Africa	174	264	1.5
World	**4,791**	**7,029**	**1.4**

Source: International Energy Agency (IEA) World Energy Outlook 2004 (2004)

EIA-DOE US in the International Energy Outlook 2005 (EIA, 2005)'s reference case, predicts that world coal consumption is projected to increase from 4,900 Mt in 2003 to 6,600 Mt in 2015, at an average rate of 2.5% per year. From 2015 to 2025, the projected rate of increase in world coal consumption slows to 1.3% annually, and total consumption in 2025 is projected at 7,500 Mt (Fig. 1.14). World GDP and primary energy consumption also are projected to grow at a more rapid pace during the first half than during the second half of the forecast period, reflecting a gradual slowdown in growth of the economies of emerging Asia, which currently are expanding at a rapid pace.

It is expected that the coal demand will be driven primarily by the surging energy needs of developing Asia, particularly China and India. In OECD North America and the OECD Pacific region, coal use will grow at a slower rate. In OECD Europe, coal demand will increase slowly over periods 2004-2030.

WEO 2004 predicts that consumption of steam coal will grow by 1.5% per year over 2002-2030. Demand for coking coal, which is mainly used for making iron and steel, will increase by 0.9%. Lignite or brown coal, a fuel with low calorific value which is used in power generation, will grow by 1.0%. Yet, the use of brown coal is limited by its high moisture content, which makes long-distance transportation uneconomic, and also by its propensity to self-ignition. High ash content, which makes lower energy content per tons, will also limit the utilization of this type of coal.

1.5.3. Sectoral Demand

The power sector's share of global coal demand will rise from 69% (or 3,306 Mt) in 2002 to 79% (or 5,500 Mt) by 2030 (Fig. 1.15). Despite this growth, coal's share of global electricity production will decline slightly, from 39% at present to 38% in 2030. The main contributor to demand growth will be the rapid expansion of coal-fired generation capacity in China and other parts of developing Asia.

Renewed interest in coal-fired power plants is also becoming apparent in several mature markets, particularly the United States and Europe. In the EU-15 some 200,000 MW of generating capacity, including coal-fired power plants, will have to be replaced over periods 2010-2020 (RWE Power, 2005). In the long term, coal use in the power sector will be driven by an assumed reduction in its price relative to gas, as well as by the gradual development and deployment of advanced clean coal technologies. The main barrier to investment in coal-fired capacity will be the cost of meeting climate change targets and other environmental requirements.

Industrial coal use, principally the use of coking coal for the manufacture of iron and steel, will increase by about 0.5% per year over the 2003-2030. This modest growth reflects increased use of recycled steel and continuing improvements in the efficiency of iron production and blast-furnace technology. As with steam coal, growth in the coking coal market will be most robust in developing Asian countries, where construction, car production and demand for household appliances will increase as incomes rise.

1.5.4. Production Prospects

Global coal production will increase by 1.4% per annum over the 2003-2030, reaching 7,000 Mt in 2030 (EIA, 2006). China will still be the world's leading producer, accounting for around half the increase in global output over that period (Fig. 1.16). The other major producers in 2030 will be the United States, India and Australia. Coal production in Europe will continue to decline as subsidies are reduced and uncompetitive mines are closed.

Some 80% of incremental coal production over 2002-2030 will be steam coal. By 2030, steam coal production will reach 5,212 Mt, compared with 3,417 Mt in 2002. Steam coal output will continue to be widely dispersed geographically. Production of coking coal will grow more slowly, from 485 Mt in 2002 to 624 Mt in 2030. Coking coal production will be increasingly concentrated in China and Australia. These countries will account for about 60% of global coking coal supply in 2030 (EIA, 2006).

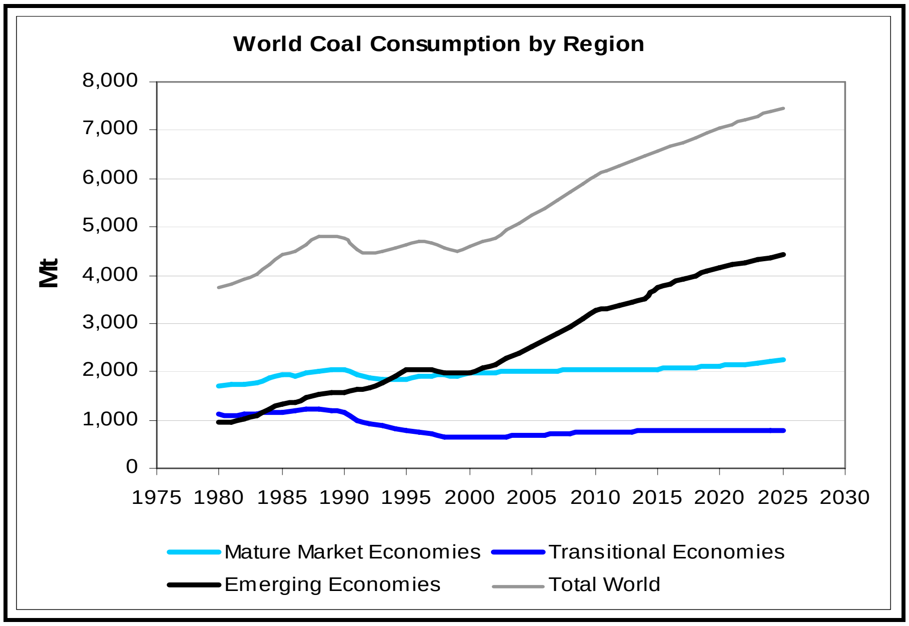


Figure. 1.14. World Coal Consumption by Region.
Source: Data from EIA International Energy Outlook 2006 (2006)

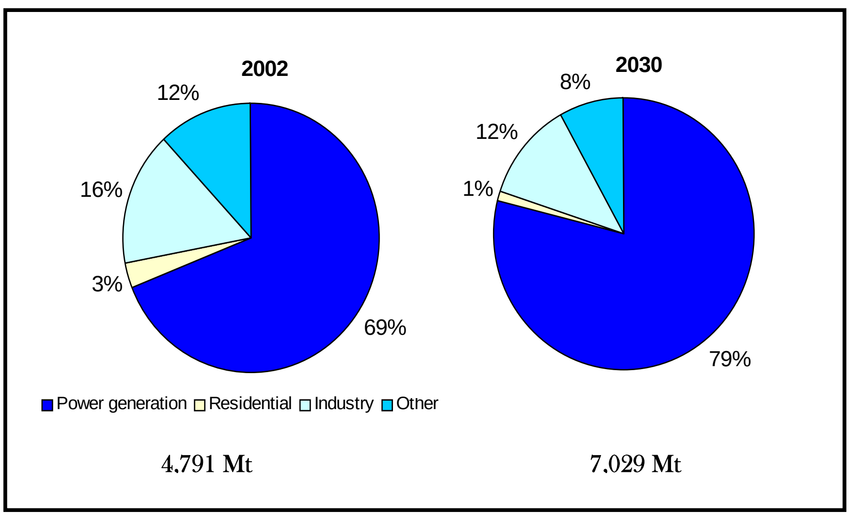


Figure 1.15. World Coal Demand by Sector
Source: Data from IEA World Energy Outlook 2004 (2004)

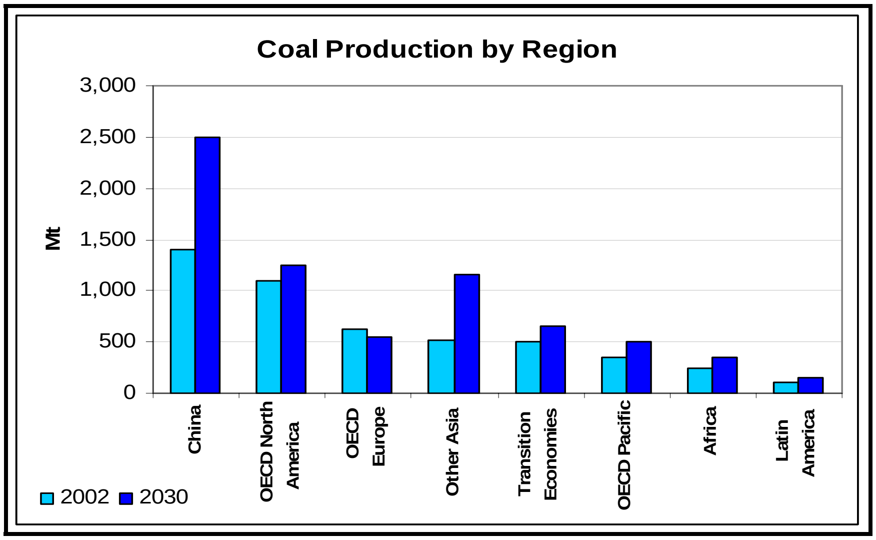


Figure. 1.16. Coal Production by Region.
Source: Data from IEA World Energy Outlook 2004 (2004)

1.6. Closing remarks

Even though coal's share in the global energy market will drop slightly in the next two decades, coal will continue to play a key role in the world energy mix. In 2030, coal will meet almost 22% of all energy needs, essentially the same proportion as today. All the increase in coal consumption will be for power generation, and coal will remain that sector's main fuel, despite a loss of market share to natural gas.

Power stations will absorb most of the increase in coal demand, though coal will continue to lose market share in power generation in all OECD regions and in some developing regions. Coal consumption will increase slowly in end-use sectors. Industry, households and services in non-OECD regions will use more coal, more than offsetting a continuing decline in OECD final consumption.

Coal demand will increase most in developing Asian countries mainly because of booming demand in China and India, while in OECD countries demand growth in the OECD will be minimal.

Coal use worldwide is projected to increase by 1.5% per year between 2002 and 2030. By the end of 2030, coal demand, at just over 7,000 Mt, will be just about 50% higher than at present.

Cost is the major barrier to the adoption of clean coal technologies. Government actions, including increased research and development, could help reduce costs. If they do, coal could remain a low-cost source of electricity generation in a carbon-constrained environment. The main uncertainty surrounding the future for coal demand is the impact of government policies and measures to address environmental concerns.

Chapter 2:
Inquiries on coal prospect in Europe

This chapter tries to portray and to investigate the current status of (hard) coal mining and utilization in the EU-15. Having understood the actual and the prospect roles of coal, it is expected that the investigation on this chapter may help to analyses appropriately the future of (hard) coal and may assist in determining an appropriate energy policy in Europe.

Fundamentally, this chapter will try to seek some answers for three questions. A profound enquiry requires to seek the appropriate response of the following question: Does the European Union still need coal? If coal is going to play a part in the Union, where should coal come from? What should be done to diminish negative environmental impacts of coal mining and utilization?

2.1. Inquire nº 1 : Does Europe still need coal ?

This first inquire will discuss three main subjects, which are the energy scene in Europe, the roles of coal in Europe and it will be closed by a discussion. First subject will investigate several matters of coal contribution to primary energy consumption. Second subject will discuss evolution of coal demand and supply and several different roles of coal. The discussion will focus on the topic of security of energy supply and position of coal in this topic.

2.1.1. Energy scene in Europe

2.1.1.1. Primary energy consumption

For over one decade the Primary energy consumption in the EU-15 has grown almost 0.8% per year from 1,557 Mtoe[7] in 1990 to 1,726 Mtoe in 2003 (Fig. 2.1). In 2003 the fossil energy

[7] *Mtoe is Million tonne oil equivalent. Mtoe is an energy unit that is used to express energy content in one million ton of oil. 1 toe contains 41.86 GJ or 10.7 x 10^6 kcal of energy. To obtain toe, all oil products have to be converted into their energy contains before they are sum up. A toe is a typical unit to express energy*

contribution was clearly significant, which share 78% of the total primary energy consumption. The contribution was shared out by oil (39%), natural gas (24%) and coal - hard coal and lignite - (15%) (Tabel II-1).

EU-15 accounts for 15% of world energy consumption, though it is home to only 6% of the world's population. In particular it represents 19% of world oil consumption, 16% of natural gas, 10% of coal and 35% of uranium. On the other hand, the region only produces oil 3% of world production, 7% for natural gas, and 6% for coal (BP Statistical Energy Review, 2006). The EU imported 16% of the natural gas in 2000 (450 billion m3), a quarter of coal (150 out of 500 Mtce) and almost 25% of oil (9.7 out of 40.4 million barrels a day). Therefore, there is an unbalance situation where the EU-15 consumes energy fossils more than it can produce.

Table. II.1. Primary Energy Consumption (2003)

Mtoe	Oil	Gas	Nuclear	Coal	Renewables
Total : 1,726	646	408	252	314	103
% Total	37.4	23.6	14.0	18	6.0

Source : Data from Eurostat, Energy Statistics (2005)

The primary energy consumption from all energy resources in the EU-15 is significantly higher than it can produce. In 2003 the EU-15 consumed 1,730 Mtoe of primary energy and imported about 800 Mtoe. In 2004, the import dependence for all energy resource reached 55% (Fig. 2.2).

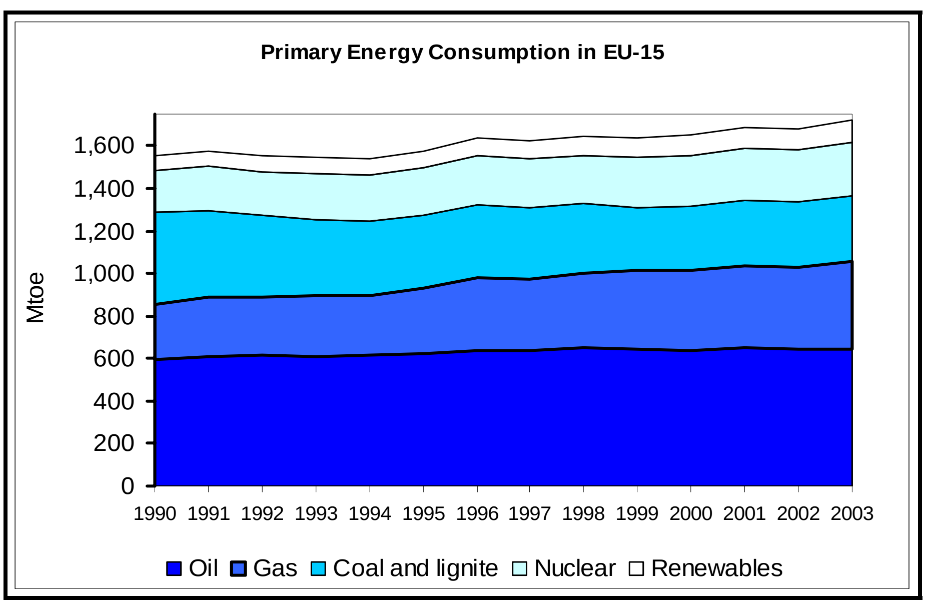


Figure 2.1. Primary Energy Consumption in the EU-15.
Source : Data from Eurostat, Energy Statistics (2005)

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consumption and/or production. 1 toe is equal to 1.528 tce. A tce is ton coal equivalents and one tce equivalent to 29.3 GJ or 7 x 10^6 *kcal of energy.*

It is projected that the production of energy fossils in Europe will decline over the next two decades (2005-2030) while their consumption increases (EIA, 2006; IEA, 2004; WETO, 2004). The IEA's reference scenario shows that the EU-15's energy consumption in 2030 will reach 2,191 Mtoe, where at that time among that quantity oil represents 36% of EU-15 energy consumption, 33% for gas and 13% for coal. It argues that the EU-15 still depends heavily on fossil energy for the forthcoming decades.

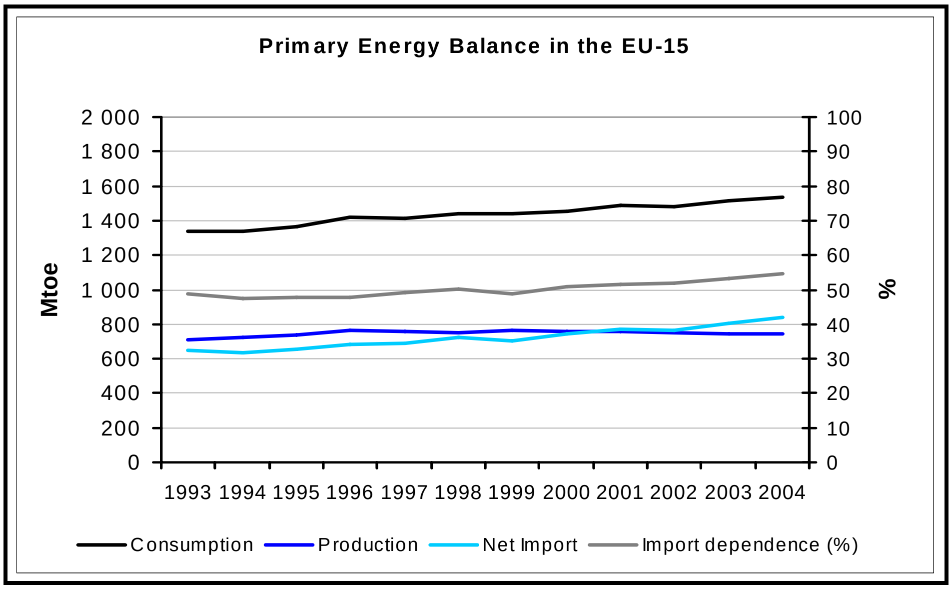


Figure 2.2. Primary Energy Balance in the EU-15
Source : Data from Eurostat, Energy Statistics (2005)

2.1.1.2. The impossibility of energy self-sufficiency

While world energy consumption has been rising since the first oil crisis, the EU succeeds in balancing its energy consumption by reducing its energy import dependence, from 60% in 1973 to 55% in 2003. Energy import dependence is defined as a ratio (in percentage) between net imports of certain energy to total consumption of this energy. Up to now policies focusing on demand management (energy conservation), development of internal resources (e.g. North Sea oil and gas) and diversification (revival of nuclear programmes, research into renewable energies, etc.) have borne considerable fruit.

Despite the considerable progress made in producing fossils energy reserves in Europe, their levels remain low and they are expensive to extract. In the future, domestic fossil fuel resources and production are likely to decline quite sharply. Two reasons explain this declining (EU Commission, 2000): limited amount of indigenous fuels available to Europe and declining oil, gas and coal production.

The amounts of indigenous fuels available to Europe are limited. Oil reserves are very unevenly distributed across the world, and the Western Europe in particular has very few, with only just 1.4% of world reserves; and available for 8 years' production at present rates (assuming no change in consumption patterns and/or related technologies). Most of these reserves are located in the Norway (60%), UK (27%) and Denmark (10%) (BP, 2006; WEC, 2004). Today, the cost of extracting one barrel of oil in Europe ranges between USD 7-11, compared to a range of USD 1-3 in the Middle East.

Natural gas reserves are more evenly distributed on the global level, but Europe is again unfortunate, with barely 2.7%; and natural gas is available for 16 years' production at present rates. Most of these reserves are located in Norway (48%), the Netherlands (30%) and the UK (12%).

At present production level, indigenous coal reserve in the EU-15 might last for 35 years (see Table II-2). Referring to Euracoal (Euracoal, 2003), probable coal reserve in the EU-15 in 2003 was 24,200 Mt or 16,900 Mtoe. However, this optimism has to be tempered by the fact that its quality is variable and under current mining methods production costs for hard coal, particularly, are high. Difficult geological conditions and the rules governing social insurance in the European Union cause the average cost of producing European coal to be 2-3 times the international market price (see Fig. 2.17. Operating cost). This gap has led producing countries either to react in three different actions:

(1). Cease all production as in Netherlands (1975), Portugal (1995), Belgium (1995) and France (2004)

(2). Restructure the industry so as to gradually reduce mining activity (Germany and Spain)

(3). Cease uneconomic mines and make domestic production more competitive with that of imported coal (United Kingdom).

Table II-2. Fossil fuel reserve in Western Europe, 2005

	Unit	**Oil**	**Gas**	**Coal**[a)]
Proven Reserve	Mtoe	2,200	4,290	7,868
% world reserve	%	1.4	2.7	1.3
Production	Mtoe/year	270	246	217
R/P	Year	8	16	35

Source: Data from BP, Statistical Review of World Energy (2006) after unit conversion to Mtoe
Note. For coal 1 Mtce=0.69 mtoe; for gas 1 Billion cu metres = 0.9 Mtoe; a) Based on Euracoal (2003), hard coal probable reserves reach at about 24,200 Mt (16,900 Mtoe) or more than two times of BP's estimation.

For oil and gas, the rate at which Community energy resources, which are depleting depends not only on the quantity of known reserves, but also on the prices on the world market, and on technological progress. Higher the price of oil, more energy companies, including coal companies, will invest in prospecting and production. If current oil and natural gas prices sustain (for crude oil around USD 70 in the beginning of second semester of 2006) then large energy reserves would be brought into production. Amid such uncertainties, however, one thing is clear: if production continues at its present rate, in the optimist (high) scenario, oil daily production in North Sea will reach its peak in 2010. And beyond 2010 production will decline progressively (EU Commission, 2000).

If no measures are taken, the overall energy import dependence of the EU is likely to rise once again, reaching 60% within 20 to 30 years. In the case of oil, the dependence could reach 80%, for gas 70%, and for coal 55%. There is an increasing trend of external dependence for all forms of energy. Fig. 2.3 shows the projection of external energy dependence for the European Union (EU-25) according to fossil fuels.

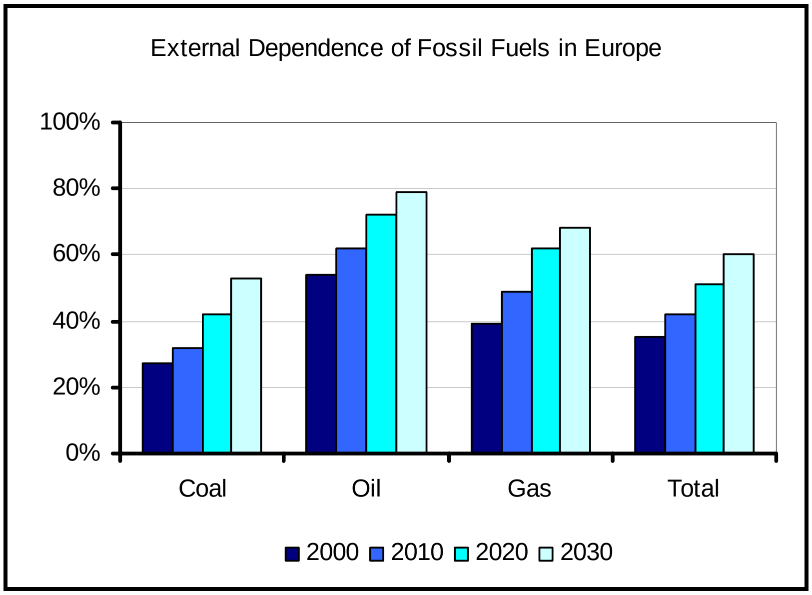


Figure 2.3. External dependence of fossil fuel in the EU-25
Source: Data from EU Commission, Green Paper (2000)

2.1.2. Role of coal in Europe

2.1.2.1. Introduction

Coal as an energy source was one of the factors that shaped Europe's economic and political development in the nineteenth and twentieth centuries. It is especially significant for the power-generation sector and steel making as well as steam raising.

The EU's power supply system is currently based on a mix of nuclear energy, coal, gas and hydroelectric power. Coal has been an essential part of the European energy primer consumption and electricity production. Indigenous coal production and imported coal together supply 15% of the European primary energy consumption. About 26% of the EU's electricity is coal based, while large quantities of coal are also required by steel making industry and raw-materials industries, namely cement works, paper mills and briquetting.

The lack of competitiveness of European coal mining has led several member states to abandon coal. Three reasons may explain the declining production in the Community. First is a competition with other fuel sources. Other fuels, particularly natural gas, have gained economic advantages over coal. Second is high operating cost. The operating cost of most hard coal exploitations in Western Europe is relatively higher than those either in other countries or imported coal price. This has called member countries to import rather than to produce to supply their domestic demand. Other factor is the growing environmental concerns. Environmental concerns has lead Europe to reduce both coal production and consumption.

2.1.2.2. Evolution of demand and supply

From the beginning of the industrial revolution to the 1960s, coal was massively consumed and its utilization was constantly raised. In the late of 1960s, its role as energy source was then overtaken by oil. Since years its demand has been depressing in the EU-15. The hard coal demand in

Western Europe declined from 353.4 Mt in 1980 to 265 Mt in 2004. The evolution of hard coal consumption is shown in Table II.3. Fig. 2.4. shows the role of coal in world energy consumption.

With regard to coal utilization, coking coal shares for iron steel industry, which accounted for 32.1% of total hard coal demand (111.3 Mt) in 1980, shrink to 23.3% (60.7 Mt) in 2002. Steam coal demand went also down from 240.1 Mt to 200.0 Mt over the same period (Ekawan, et.all., 2005b; International Energy Agency (IEA) Coal Information, 2003). Fig. 2.6. illustrates the evolution of hard coal consumption and production over the last two decades.

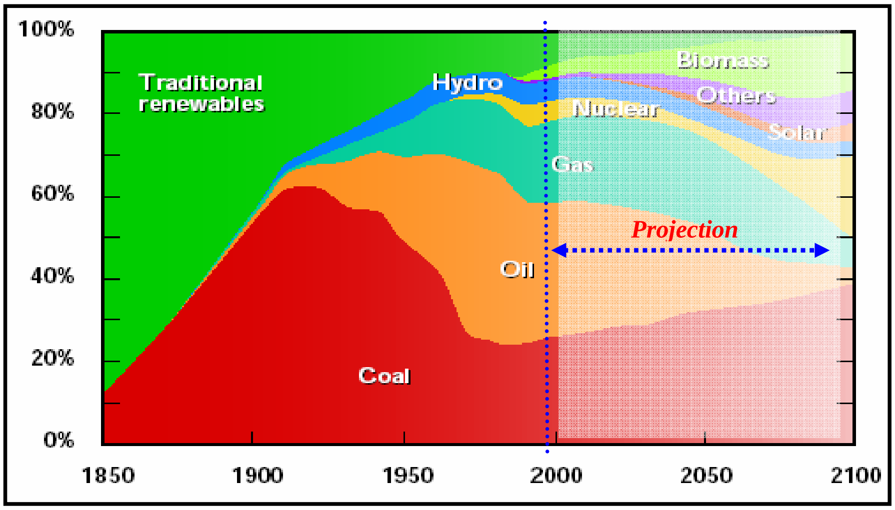


Figure. 2.4. Role of coal in World Energy consumption
Source: World Energy Council (WEC) (2005)

Since the 1960s, all have seen coal output in the Community decline. After reaching a peak in the 1950s, coal production in the United Kingdom continues to decrease from 225 Mt in 1955 to 29.5 Mt in 2002. Similar situation has taken place in Germany (from 152 Mt to 30 Mt) and France (from 55.3 Mt to 1.5 Mt) (Fig. 2.5 and Table II-4). In 2003, indigenous hard coal production in the EU-15 was at about 71 Mt.

In line with the declining production and consumption, hard coal import to the EU-15 increased from 116.0 Mt in 1990 to 166.0 Mt in 2002. Since the 1990s, main exporter countries to Europe are South Africa, Australia, Poland and Colombia. In 2003 hard coal import to the Community was at 192.1 Mt. The main importers were Germany (34.9 Mt), United Kingdom (31.9 Mt), Spain (21.5 Mt), Italy (20.5 Mt) and France (16.6 Mt). Import from these five countries represents 65% of total imports. In the same year the main exporters were South Africa (56.8 Mt), Australia (30.3 Mt), and Colombia (22.9 Mt) (Table II.5).

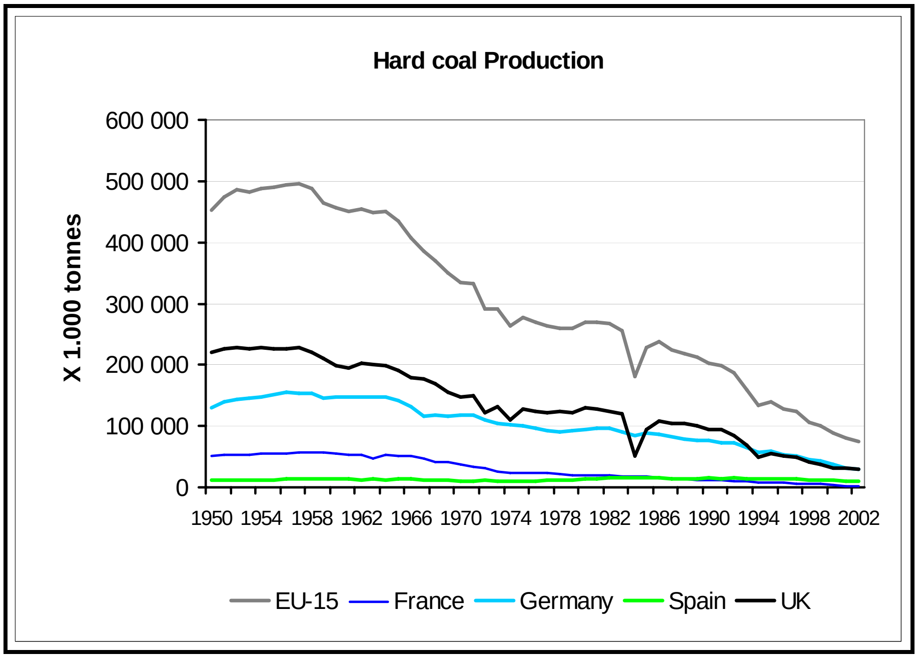


Figure. 2.5. Hard coal production in EU-15
Source: Data from International Energy Agency, Coal Information 2003 (2003c)

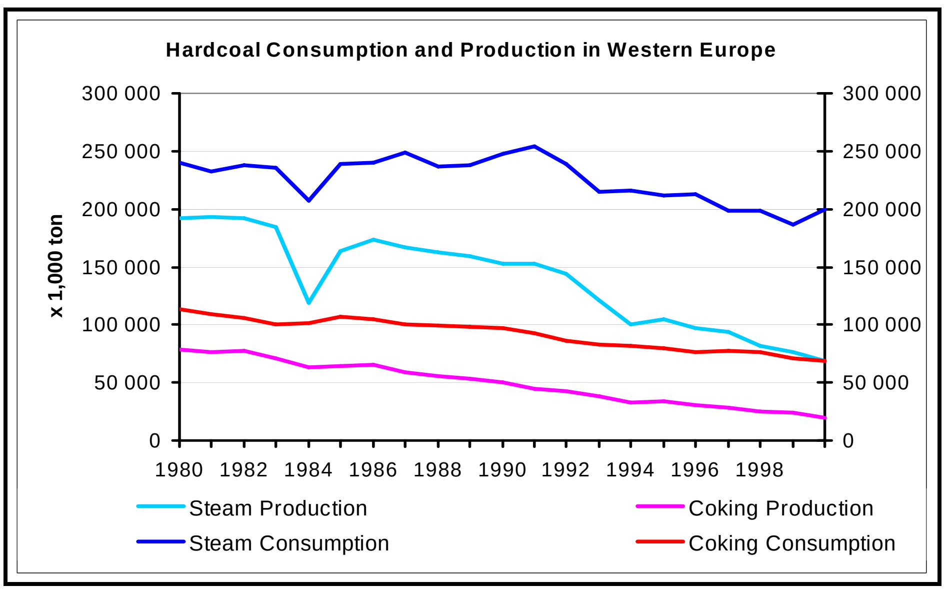


Figure. 2.6. Hard coal consumption and production in EU-15
Source: Data from International Energy Agency, Coal Information 2003 (2003c)

Table II-3. Hard coal consumption in the EU-15 (thousand tons)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Share
Belgium	15,477	16,112	12,394	12,116	11,682	11,401	10,021	11,046	10,141	9,040	8,663	8,423	3.2%
Denmark	12,147	9,992	11,003	14,946	11,079	9,387	7,672	6,641	6,991	6,905	9,533	7,327	2.8%
Germany	93,466	86,965	74,224	75,362	72,236	73,379	66,655	68,963	67,338	62,767	66,382	67,922	25.6%
Greece	1,750	1,380	1,480	1,484	1,153	1,278	1,032	1,121	1,228	964	833	776	0.3%
Spain	31,478	30,514	32,168	27,022	32,494	30,136	34,800	37,251	32,969	37,503	34,886	37,635	14.2%
France	36,826	29,230	22,611	23,758	20,675	24,612	22,427	21,801	18,218	19,270	20,942	20,780	7.8%
Ireland	1,585	3,252	2,689	2,985	2,887	2,877	2,474	2,828	2,903	2,716	2,600	2,638	1.0%
Italy	22,130	21,327	17,446	16,335	16,006	16,988	17,069	18,013	19,425	19,998	21,146	24,280	9.1%
Luxembourg	200	197	217	242	194	152	153	171	152	127	106	129	0.0%
Netherlands	9,295	14,270	14,660	14,963	14,793	14,987	12,089	12,928	13,460	13,414	13,667	13,551	5.1%
Austria	3,177	4,158	3,391	3,794	4,077	3,731	3,457	3,710	3,948	3,832	4,325	4,252	1.6%
Portugal	1,049	4,397	5,522	5,471	5,555	5,099	6,126	6,154	5,145	5,668	5,362	5,514	2.1%
Finland	5,318	5,648	6,540	7,704	6,995	5,203	5,255	5,131	6,122	6,617	8,862	8,082	3.0%
Sweden	4,158	3,709	3,444	3,637	3,123	2,989	2,859	2,861	3,271	3,021	2,923	3,329	1.3%
United Kingdom	105,649	106,722	75,916	70,833	63,423	62,871	55,445	58,663	64,037	58,490	61,991	60,805	22.9%
TOTAL	343,705	337,873	283,705	280,652	266,372	265,090	247,534	257,282	255,348	250,332	262,221	265,443	100.0%

Source : *Data from Eurostat, Energy Statistics (2005)*

Table II-4. Hard coal Production in the EU-15 (thousand tons)

	1985	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	% Share
Belgium	6,237	1,036	0	0	0	0	0	0	0	0	0	0	0.0%
Germany	88,849	76,553	58,858	53,157	51,212	47,208	43,848	37,376	30,669	29,209	28,753	29,151	44.0%
Spain	22,371	19,440	17,627	17,688	17,878	16,212	15,435	14,947	13,960	13,308	12,583	12,334	18.6%
France	15,124	10,487	7,014	7,312	5,779	4,862	4,532	3,166	1,972	1,483	1,730	160	0.2%
Ireland	57	25	1	0	0	0	0	0	0	0	0	0	0.0%
Italy	0	58	0	0	0	0	0	0	0	163	250	98	0.1%
Portugal	238	281	0	0	0	0	0	0	0	0	0	0	0.0%
Sweden	13	11	0	0	0	0	0	0	0	0	0	0	0.0%
United Kingdom	90,793	91,033	51,519	48,538	46,981	40,046	36,163	30,600	31,513	29,539	27,759	24,536	37.0%
TOTAL	223,682	198,924	135,020	126,695	121,850	108,328	99,978	86,089	78,114	73,702	71,075	66,279	100.0%

Source : Data from Eurostat, Energy Statistics (2005)

Table II-5. Hardcoal Trade Balance in the EU-15 in 2003 (thousand tons)

Export to	**EU-15**	**Share Export**	**Belgium**	**Denmark**	**Germany**	**Greece**	**Spain**	**France**	**Ireland**	**Italy**	**Luxem**	**Nether-lands**	**Austria**	**Portugal**	**Finland**	**Sweden**	**United Kingdom**
Import from																	
Share Import	**100.0%**		**4.9%**	**5.0%**	**18.2%**	**0.4%**	**11.2%**	**8.7%**	**1.3%**	**10.7%**	**0.1%**	**11.3%**	**2.1%**	**2.8%**	**5.3%**	**1.7%**	**16.6%**
Australia	30,332	**15.8%**	2,339	569	5,006	0	3,805	4,527	583	2,874	0	2,561	0	668	525	1,208	5,664
Canada	3,809	**2.0%**	377	0	0	0	200	250	0	848	0	1,139	0	0	156	0	839
China	2,746	**1.4%**	91	394	178	0	146	394	0	574	0	227	0	0	528	0	210
Colombia	22,873	**11.9%**	12	2,681	6,175	0	1,478	2,322	441	0	0	4,362	0	1,945	59	0	3,398
Former SU	20,127	**10.5%**	915	980	2,656	244	2,097	328	0	1,087	0	288	0	0	5,766	677	5,089
Indonesia	8,868	**4.6%**	0	289	405	0	0	684	0	5,006	0	2,082	0	0	0	0	402
South Africa	56,842	**29.6%**	3,607	2,971	9,052	0	8,835	4,003	786	4,765	45	8,094	0	2,079	412	0	12,193
United States	11,945	**6.2%**	1,744	246	381	0	1,479	2,109	216	2,468	0	1,181	0	354	266	346	1,154
Venezuela	4,685	**2.4%**	0	0	0	0	0	427	0	2,939	0	973	0	0	0	346	0
Others	29,845	**15.5%**	305	1,385	11,064	503	3,512	1,599	459	1	61	713	3,959	298	2,434	618	2,942
TOTAL	**192,072**	**100.0%**	**9,390**	**9,515**	**34,917**	**747**	**21,552**	**16,643**	**2,485**	**20,562**	**106**	**21,620**	**3,959**	**5,344**	**10,146**	**3,195**	**31,891**

Source : Data from Eurostat, Energy Statistics (2005)

2.1.2.3. Coal for Energy and Industry

2.1.2.3.1. Coal for balancing energy sources for power sector

Coal is especially significant for the power generation. In the EU-15, in 2002, of 2,670 TWh (Tera-Watt-hour) power generation, coal accounted for some 26% of the electricity supplies, others were oil (6%), natural gas (16%), nuclear (33%) and renewable resources (17%). The role of this solid fuel for electricity supplies in new member (accession) countries is more significant, which accounts 63% of the total power generation (357 TWh). Its importance after the enlargement of the Community slightly increases to become 30% of the 3,027 TWh power generation (Euracoal, Coal and Europe, 2004). Furthermore, in Germany, Greece, Poland, Czech Republic, Estonia and Serbia coal provides more than 50% of their electricity supply. Table II.6 shows the composition of electricity generation in the European Union. Here the availability of coal balances energy sources for power generation and reduces the region's dependence on oil and natural gas imports.

Concerning hard coal, its contribution to electricity generation has been slightly declining over the last decade. Currently, hard coal contribution to electricity generation is at about 18%, lower than in 1993, which was around 22% (Fig. 2.7).

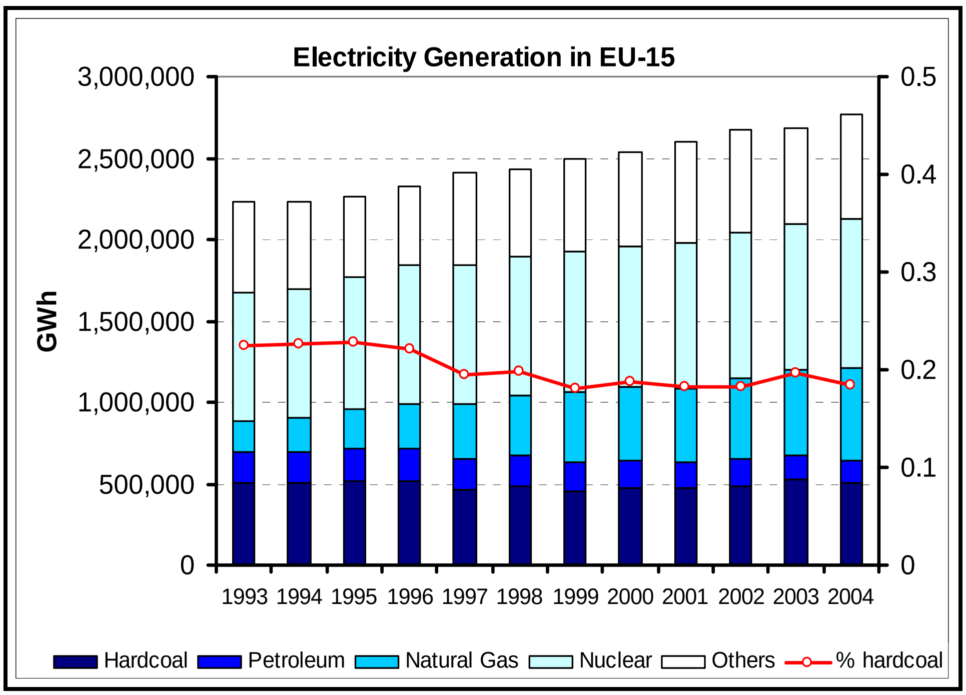


Figure 2.7. Electricity generation in the EU-15
Source :Data from Eurostat, Energy Statistics (2005)

Table II-6. Electricity generation in the European Union, 2002

	Power Generating	Coal[a]		Oil	Gas	Nuclear	Renewable
Country	**TWh**	**TWh**	**%**	**%**	**%**	**%**	**%**
Austria	62	8	12	3	14	0	71
Belgium	80	10	12	2	20	58	8
Denmark	38	18	47	11	25	0	17
Finland	75	17	23	1	15	30	31
France	549	27	5	1	3	77	14
Germany	582	291	50	1	10	29	10
Greece	54	36	66	16	11	0	7
Italy	279	31	11	27	37	0	25
Ireland	25	9	36	21	36	0	7
Luxemburg	1	0	0	0	60	0	40
Netherlands	94	27	28	3	59	4	5
Portugal	46	14	29	20	16	0	35
Spain	238	72	30	10	10	27	23
Sweden	162	3	2	2	0	45	52
United Kingdom	385	131	34	2	37	23	4
EU-15	**2670**	**691**	**26%**	**6%**	**18%**	**33%**	**17%**
Czech	74	53	72	1	4	20	4
Hungary	36	9	25	12	24	39	1
Poland	145	130	90	2	1	0	7
Serbia	32	15	49	7	2	0	36
Slovakia	32	7	19	2	9	54	16
Slovenia	14	5	35	1	1	35	29
Estonia	7	6	93	3	3	0	1
Latvia	5	0	0	9	23	0	68
Lithunia	9	0	0	6	11	74	9
Malta	2	0	0	100	0	0	0
Accession	**357**	**224**	**63%**	**4%**	**6%**	**16%**	**11%**
EU-25	**3 027**	**916**	**30%**	**6%**	**16%**	**31%**	**17%**

[a]Coal includes hard coal and lignite. *Source: Euracoal (2004)*

2.1.2.3.2. Coal as a raw material for Steel Industry

Coal is essential for iron and steel production. Some 65% of Europe steel production comes from iron made in blast furnaces (BF), which uses coal. A further 33% of steel is produced in electric arc furnaces (EAF) (International Iron and Steel Institute (IISI), 2003, 2005). Much of the electricity used in EAF is produced from coal. A blast furnace uses iron ore, coke and small quantities of limestone. Some furnaces use cheaper (lower quality) steam coal – known as pulverized coal injection or PCI.

The EU-15's crude steel production was at about 168 million tonnes in 2004 (International Iron and Steel Institute (IISI), 2005). The industry consumed nearly 53 Mt of hard coal. Even though fluctuating, steel production in the EU-15 has been growing nearly 1% per-year for over almost two decades (Fig. 2.8). In general, steel production growth follows economic growth (Gross Domestic Product); as GDP grows so as steel production.

For decades coke consumption to produce 1 ton of steel has been decreasing (Fig. 2.9). Higher thermal efficiency process depresses coke consumption. Now, to produce 1,000 kg of steel needs in average 400-600 kg of coke (about 800-1,000 kg of coking coal) and 100-150 kg of steam coal.

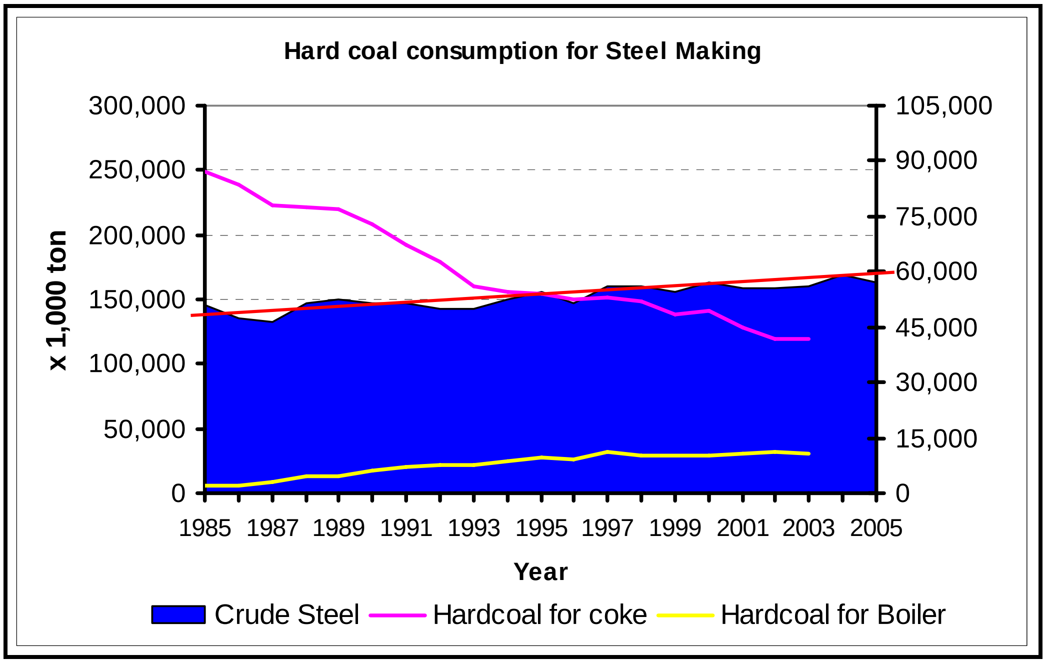


Figure 2.8. Hard coal consumption for steel making in the EU-15
Source : Data from Eurostat, Energy Statistics (2005)

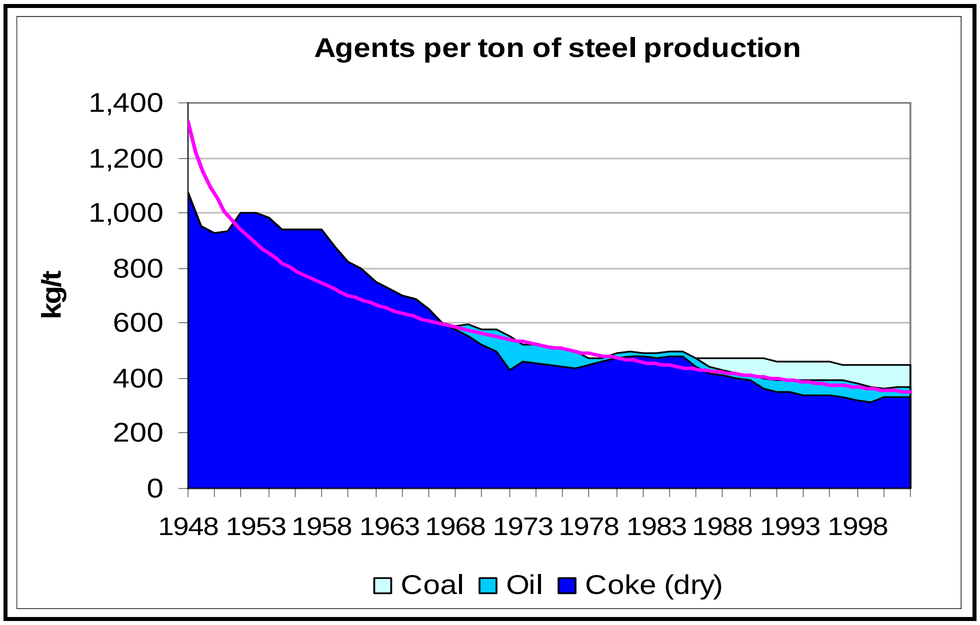


Figure 2.9. Agents consumption per ton of steel production
Source: Redraw from Stephany (2004)

2.1.2.4. Coal for other uses

Apart from power generation and steel production, coal in Europe is also used in cement works, paper mills, briquetting and other industries. These activities presently consume almost 10-15% of total coal demand.

Coal can be used as an energy source in cement production. Rotary Kilns usually burn coal in the form of powder and consume around 350-450 kg of coal for about 900 kg of cement produced. Yet, coal is not the only energy sources to heat Kilns. Coal is likely to remain an important input for the global cement industry for many years to come. In 2004, cement production in Western Europe was nearly 198.5 Million ton (USGS, 2005).

Coal can be converted into a liquid fuel – a process known as liquefaction. The liquid fuel can then be refined to produce transport fuels and other oil products such as plastics and solvents. In this way, coal can act as a substitute for crude oil. The cost effectiveness of coal liquefaction depends to a large extent on the world oil price with which, in an open market economy, it has to compete. Even though during the World War II, Germany produced substantial amounts of coal-derived fuels, currently this activity is still unimportant in Europe. Nowadays, the leader of this converted coal in worldwide operation is South Africa[8].

Although still not important, other users of coal include alumina refineries, paper manufacturers, and the chemical and pharmaceutical industries. Several chemical products can be produced from the by-products of coal. Refined coal tar is used in the manufacture of chemicals, such as creosote oil, naphthalene, phenol, and benzene. Ammonia gas recovered from coke ovens is used to manufacture ammonia salts, nitric acid and agricultural fertilizers.

[8] Because of world embargo during apartheid policy, South Africa could not import oil and as a consequent developed coal liquefaction. After the end of embargo, the coal liquefaction is still continuing. The cost of oil from coal liquefaction is believed to be 30-40 $/barrel.

2.1.3. Discussion: Europe still needs coal at least for the next two decades

2.1.3.1. Coal for satisfying future electricity demand and steel production

The EU Commission estimates (Eurocoal, Coal and Europe, 2004) that demand of the electric power in the EU-15 will increase by approximately 36% until 2020 (Fig. 2.10). There are many propositions how to cover this demand. Gas use will increase significantly in absolute and relative terms, but coal-based generation will still remain a major player as well.

The open European market for electric power will in principle strengthen the industrial base and offer electricity to the consumer at a reasonable price. The goal must be to maintain ample and competitive supplies of power and coal can help to make a major contribution to this.

In the medium term, between 2010 and 2020, many existing power plants will reach their end of operating lives and will then have to be replaced. In the EU-15, this concerns some 300,000 MW of generating capacity (VGB PowerTech, 2004) (Fig. 2.11). Against the background of the development in electricity demand and in view of the few technological risks involved, further decisions on the construction of new facilities can be expected within the framework of the existing market economy. The construction of new facilities also will be based on known and optimized technologies and that promise even greater levels of efficiency, A realistic estimate of the required capital investment and fuel costs will put coal in a strong competitive position, and this will be a significant boost to further development. However, this presupposes that there will be no political discrimination against solid fuel.

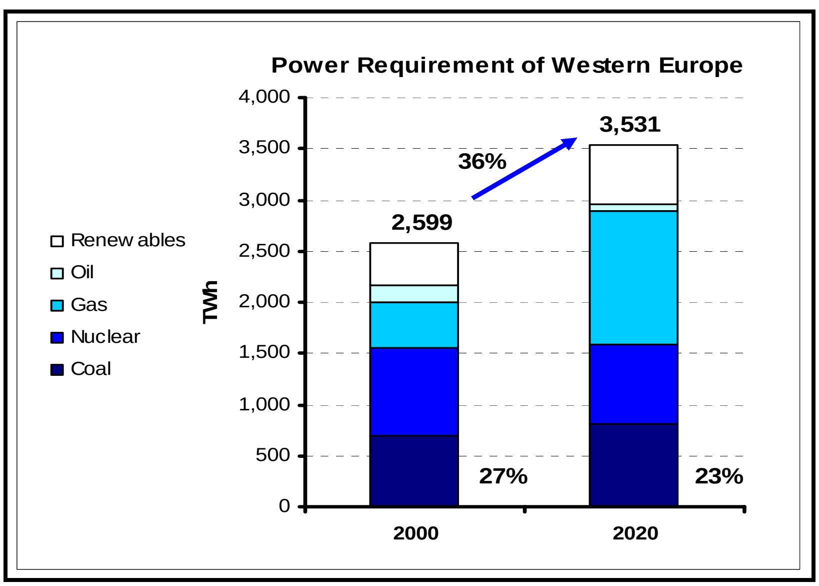


Figure 2.10. Power requirement in the EU-15
Source: Data from Eurocoal, Coal and Europe (2004)

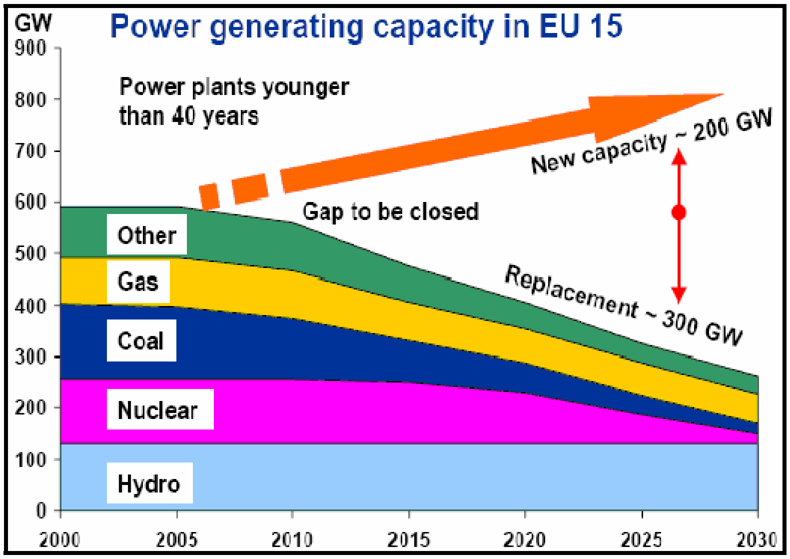


Figure 2.11. Power generation capacity in the EU-15
Source: VGB PowerTech (2004)

2.1.3.2. Coal for balancing security of energy supply

2.1.3.2.1 High concern on security of energy supply

Nowadays, the subject of energy supply security has taken on a new relevance as far as the EU is concerned. Europe has to support every effort that is directed towards improving security of energy supply. It is important to achieve the correct balance, meaning that the supply side must be included as a key element in the energy- security structure, which means that coal also has to be part of the equation. It is important to note that the EU today has only a limited supply of own primary energy resources. And for this reason, about 40% of the fossil fuel demand is imported. It is predicted that the imported fossil fuel will increase in the future.

In 2002, the Commission Green Paper on security of energy supply drew a picture of the EU's energy situation. If no action is taken, it is predicted that the EU's energy dependency will climb from 50% in 2000 to 70% in 2030 (European Union, (EU), 2000). The particular situation for the main imported fossil fuels is described as follows:

- Oil: in 2000, about 45% of EU oil imports originate from the Middle East; by 2030, 80% consumption will have to be covered by imports
- Gas: in 2000, nearly 40% of EU gas imports originate from Russia (30% Algeria, 25% Norway); by 2030, over 60% of imports are expected to come from Russia, while at the same year the contribution from Algeria and Norway will decline, with overall dependency expected to reach 80%.
- Coal: in 2000, about 45% of EU needs are covered by import. In the same year about 70-75% hard coal demand in the EU-15 was imported. by 2030 about 65% of all coal demand in EU will be covered by imports.

The ultimate challenge for setting an energy policy in Europe is therefore an increase in import dependence of fuels. Other is the fuels long-term availability. The expected gas production is going to peak in the next decade due to an anticipated depletion of own European gas resources, while oil production was already reached its mature.

World demand for oil and gas is expected to grow over the foreseeable future. This growth will predominantly take place in the emerging economies and developing countries and to a lesser extent in industrialized countries. In the latter countries, it is mainly the demand for gas that will grow. In non-OECD countries like China and India, demand for oil is rapidly increasing in association with economic growth and transport needs. The relative contribution of gas will grow, while the role of oil will decline slightly (International Energy Agency (IEA), 2003a).

Up to today fossil fuel production (Oil, Gas and Coal) satisfy more than 85% of the European demand, in which coal shares 15%, gas 24%, and oil plays the dominant role with about 39%. All projections to the future (e.g. EIA, 2006; IEA, 2004; WETO, 2004) expect that this tendency will not change substantially over at least the next two decades (Hein, 2003). However, fossil energy carriers have limited resources. On the basis of recent estimates of proven oil and gas reserves, at current prices and technology, have reserves to production ratios of 40 and 60 years, respectively. It suggests that it should not expect supply problems to arise over the medium term (BP, 2006).

For the past two decades Europe has focused on the completion of its internal energy market, and on liberalization of electricity and gas markets. Part of Europe's energy is now supplied by private companies competing in liberalize markets. Though the internal energy market has yielded benefits, it has been hampered by the fact that there is still no integrated European market yet, but rather a string of national markets with bilateral connections. Thus physical trade has been limited, and as a result Europeans have not reaped the full benefits of an integrated internal market.

This major gap did not matter so much in the 1980s and 1990s because most member states had excess capacity, and world energy prices were low. But now it does matter, because the energy sector in Europe has changed. The decades of abundant low-priced fossil fuel, essentially oil and gas, combined with the overhang of the power stations built in the 1970s and early 1980s, has given way to a new set of challenges.

Until the end of 1970s, it was assumed that energy markets were characterized by market failures which were necessitate to regulate monopolies for at least electricity industries (and the onshore gas), and significant government intervention in the conduct of offshore oil companies. In several countries in Europe, these monopolies were typically nationalized stakes. For example in the UK British National Oil Company (BNOC) negotiated options on North Sea oil, as well as directly participating in fields, and acted as a price fixer. The National Coal Board (NCB) in UK (Helm, 2002) as well as Charbonnage de France (CdF) in France had the coal monopoly. Then the new market philosophy, with its belief that competition was the effective way to allocate resources, motivated the two main policies in the 1980s and 1990s: privatization and promotion of competition.

The appeared problem in the privatization and promotion of competition may be security of supply. Supply can almost be made equal to demand, provided the price is allowed to adjust. Since the oil embargoes of the 1970s, however, much of Europe has not faced any serious threat to the security of its energy supplies. These conditions have now changed, and security of supply in Europe is threatened in a number of ways (Helm, 2005):

- the external dependency on gas, notably from Russia, and the reliance on long pipelines through sometimes politically difficult territories
- the external dependency on oil supplies, with production increasingly concentrated in the Middle East

- terrorist threats to key energy installations
- aging oil refineries and power stations, and low investment in the last two decades
- poor interconnections between Europe electricity grids
- lack of effective European-wide mechanisms for addressing security of supply risks and coordinating of infrastructure investment.

2.1.3.2.2 Actions to strengthen security of energy supply

Researchers (Chevalier, 2006; Ekawan, et.all., 2006c) have been proposing several actions to improve security of energy supply in Europe, which are energy efficiency, energy diversity, common regulation and international and bilateral dialog.

Energy efficiency

Good energy policy begins with the efficient use of energy. Energy efficiency is an actual essential for at least three major reasons: growing concern for climate change implies a reduction of greenhouse gas emission; the expectation of persisting high prices for oil and gas increases the economic value of efficiency improvement which could become a serious competitive advantage; reduction in energy consumption should lessen market tightness and therefore improve the volume and price dimensions of security of energy supply.

In 2005, EU published a report 'Green Paper on energy efficiency" that outlines European initiatives in the field of energy efficiency, including R&D in increasing the efficiency of fossil fuel-based power production (European Commission, (EC), 2005). Concerning with energy efficiency in coal utilization, a new coal-fired power plant facility in Germany - called BoA technology - has a thermal efficiency up to 43%. This is higher than the current average efficiency in Europe (38%) and in the world (30%). High thermal efficiency will reduce coal consumption per energy unit generated.

Energy diversity

There is no perfect energy source and technology for producing and supplying energy. Each form of energy has an economic cost but also a social cost, which covers all the negative externalities. The uncertainties that surround the energy industry provide a strong argument for energy diversity and also for greater flexibility in inter-fuel substitution. None knows precisely what will be the fuel prices and the exact economic and social cost of each energy technology. Risk will be reduced through the diversification of sources of supply. To increase security of energy, all energy types have to be left open to supply energy in Europe. Coal may have then a role in providing the demand of a secure supply of energy.

Common Regulation

The European Commission, national governments, local entities and the energy industry have to develop together a common approach of security of energy supply, which is founded upon more coordination and international action. The absence of agreement on a common direction in political strategic issues could jeopardize the formulation of the EU security of energy supply policy and will drive the preference for adverse national approaches. Given the dynamics of international political and economic relations, a static singular approach to energy security may not suffice.

International and bilateral dialog

Because EU imports part of its energy demand from other countries, there is interdependence, both internationally and bilaterally, between EU and exporter countries. The dialogue is needed on the assumption that interdependence between the two partners will grow.

From the EU for reasons of security of supply and from its partners to secure foreign investment and facilitate its own access to EU and world markets.

The EU-Russia energy dialog is an example of a bilateral cooperation. Russia is important for Europe as Russia is the main supplier of hydrocarbons, essentially gas and oil. Launched in October 2000, this bilateral energy dialogue is aimed at securing Europe's access to Russia's huge oil and gas reserves. The dialogue is based on the assumption that interdependence between the two regions will grow - the EU for reasons of security of supply, Russia to secure foreign investment and facilitate its own access to EU and world markets. However, this type of Energy Dialogue is still not perfect. The events in Ukraine in the beginning 2006, where it witnessed gas supply cuts from Russia have contributed to a sense of unease with reliance on this type of energy dialog.

The new dialog, both internationally and bilaterally, that based on the achieving of long-term and mutual concerns in the energy sector has to be addressed. And the similar dialog has to be enlarged for other types of energy, including coal, with other exporter countries to EU.

The message of the above discussion emphasis that all energy sources and technologies and all policy instruments need to be screened in order to find the right energy mix and the right form of organization to meet these objectives. The most promising orientations are: to improve energy efficiency – to diversify energy supply in terms of technologies, primary sources and geographical diversity of import – to reinforce the common European energy vision through a process of common regulation.

Regarding to coal, it shows that commercially exploitable reserves are widely distributed around the globe and it covers roughly 55% of the proven fossil fuel reserves. This distribution is in contrast to the situation of other primary energy sources with the unavoidable consequence of oil and gas reserves to become exhausted within a much shorter time period than solid fossil fuels. Therefore, if Europe wants to secure the energy supply and reduce its emission, all possible energy option have to be left open, including coal and its clean coal technologies as well as nuclear. Other ways in which security of supply can be achieved is to seek diversity in energy sources. The diversification of energy supplier will reduce impacts of supply failure.

Coal may have then a role in providing the demand of a secure supply of energy. The future of coal-uses industry is largely pinning its hopes on policy of energy supply security as well as on development of clean coal technology.

2.1.4. Global warming: a major challenge from coal to Environment

A major environmental challenge facing the world today is the risk of 'global warming'. Human activities, such as the combustion of fossil fuels, produce additional greenhouse gases (GHGs) which accumulate in the atmosphere. Scientists believe that the increase of these gases is causing a greenhouse effect, which could cause global warming and climate change. The major greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride.

Coal is one of many sources of greenhouse gas emissions generated by human activities and the industry. Greenhouse gases associated with coal include methane, carbon dioxide (CO_2) and nitrous oxide (NO_2). Methane is released from deep coal mining. CO_2 and NO_2 are released when coal is used in electricity generation or industrial processes, such as steel production and cement manufacture.

Some 94% of man-made CO_2 emissions in Europe are attributable to the energy sector as a whole. Fossil fuels are the prime sources. In absolute terms, oil consumption accounts for 50% of CO_2 emissions, natural gas for 22% and coal for 28% (EEA, 2005d) (Fig. 2.12). In terms of consumer sectors, electricity generation and steam rising are responsible for 37% of CO_2 emissions and transport sector for 28%. Some 90% of the projected growth in CO_2 emissions will be from the transport sector.

Under the Kyoto Protocol, the EU-15 committed to reducing its greenhouse gases emissions by 8% comparing to the 1990 emissions level during the first commitment period (2008-2012). This target is shared between the member states under a legally binding burden-sharing agreement (Fig. 2.13). On May 31st, 2002, the EU and all its member states ratified the Kyoto Protocol. The EU's 8% target, however, only refers to the 15 member states (UNFCCC, 1998).

In 2002, aggregate greenhouse gas emissions from the EU-15 were 0.9% below the base-year level (Fig.2.13), while in 2003 were 1.9% below base year level with an increase of more than 1% from 2002 to 2003 (EEA, 2005a)

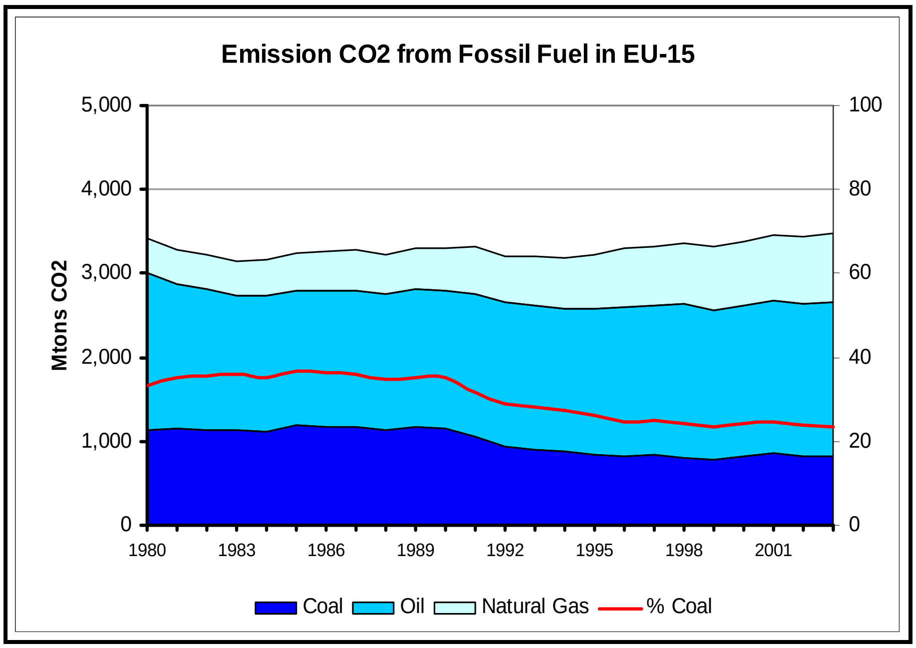


Figure 2.12. Emission CO_2 from fossil fuel combustion in the EU-15
Source :Data from European Environmental Agency (EEA) (2005d)

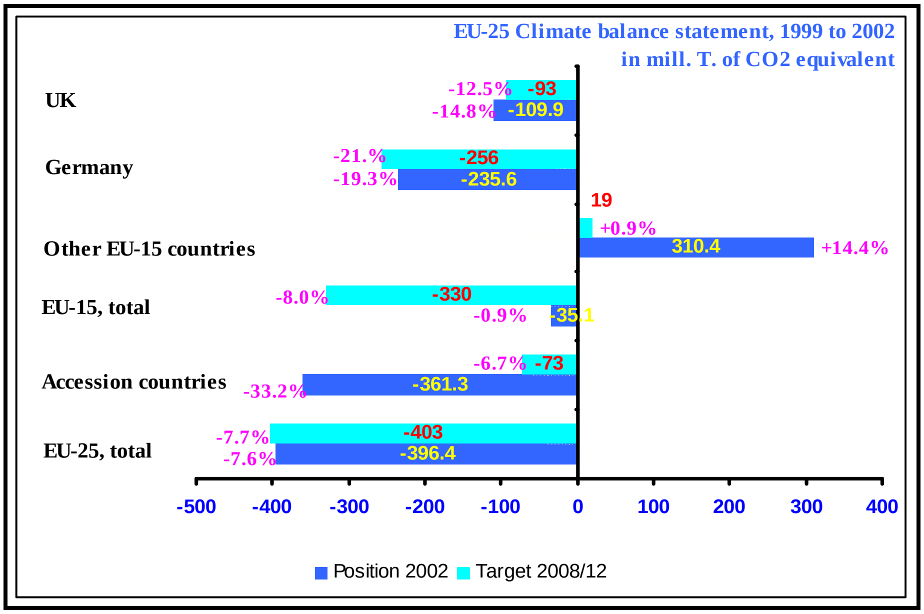


Figure 2.13. Climate balance statement in the EU-25
Source: Data from European Environmental Agency (EEA), (2005a)

2.2. Inquiry nº 2: Where should EU get the coal from?

In this second inquiry will be discussed two main subjects, which are the possibility of coal supply both from indigenous production and from outside the EU-15. First part will investigate several matters of indigenous supply, including coal reserve and its quality, present coal mining activity, operating cost and subsidy. The later will discuss opportunity of world coal market to fulfill coal demand in the EU-15. This includes history and evolution of world coal trade, mechanism of coal transaction and price formation.

2.2.1. Supply from indigenous production is declining

2.2.1.1. Reserves and quality

Presently, the availability of hard coal resources in the EU-15 is at about 191,300 Mt, whereas among these nearly 24,200 Mt are considered as probable (indicated) reserves (Table II-7). By the enlargement of the EU, its resources reach 313,550 Mt and nearly 37,150 Mt are classified as probable (indicated) reserves. However, based on BP study (BP Statistical Review, 2006) the quantity estimation for hard coal proven (measured) reserves is much lower than these figures, which is at about 618 Mt (for Antrachite and bituminous coal). The hard coal reserves appearance unfortunately is not equally distributed in all member countries. Most of those are located in Germany (60.90%) and Poland (33.60%).

In the BP statistical energy review, proved reserves of coal is defined as those coal quantities that geological and engineering information indicates with reasonable certainty. These reserves of coal can be recovered in the future from known deposits under existing economic and operating conditions. While from the report of Euracoal, coal reserve is defined as reserves portion of known coal reserves that can be profitably mined and marked with today's mining techniques. Yet, in the

Euracoal's definition no explanations about the certainty of geological and engineering information In addition, the reserve report in Euracoal is mainly based on the report provided by each member countries of the EU. It is difficult to have a reconcile comparison of coal reserves between these two reports.

With regard to lignite, in 2002 the availability of its resources in the EU-15 was at about 84,210 Mt, while among these some 44,750 Mt were considered as probable (indicated) reserves (Table II-7). Similar to hard coal, lignite reserves appearance, however, are not equally distributed in all member countries. Most reserves (73.7%) are located in Germany and others are in Greece (6.1%), Serbia (6.1%), Hungary (5.6%) and Czech Republic (4.5%) (Ekawan, et.all., 2005b).

In terms of quality, hard coal resources can be classified mostly as bituminous and sub-bituminous with their calorific value between 18,000 and 33,000 kJ/kg (Table II-8). The sulphur content is generally less than 1%, albeit for some member countries, as in the United Kingdom and Poland, it is greater than 1%. The ash content is relatively modest (6%-8%). However, for some countries ash content may reach 28% (Czech Republic) and 30% (Poland).

Lignite resources have various calorific values between 3,700 and 19,640 kJ/kg. Although there are some lignite with sulphur content less than 1%, in most countries sulphur content is relatively high, reaching 2.0-2.6%. The ash content is also particularly high (5%-19%). In several countries, the ash content may reach extremely high values, as 41% (Spain) and 33.9% (Slovakia). The low calorific value of lignite is translated from high water content, which reaches 21% to 60% (Euracoal, 2001).

Table II-7. The EU-15 and the EU-25 : Coal Resources and Reserves (2004)

	Lignite			Hardcoal			Production	
Country	**Resource (Mt)**	**Probable**	**Reserve (Mt)**	**Resource (Mt)**	**Probable**	**Reserve (Mt)**	**Lignite (Mt)**	**Hardcoal (Mt)**
Germany	77,600	41,300	73.69%	186,000	23,000	60.94%	182	29
Greece	6,700	3,400	6.07%	-	-	0.00%	71,9	-
Spain	80	50	0.09%	4 200	600	1.59%	8,2	12,3
United Kingdom				5,000	220	1.59%		25
EU-15	**84,213**	**44,752**	**79.85%**	**191 299**	**24 200**	**64.12%**	**262.1**	**66.3**
Czech Republic	3,873	812	4.49%	4,123	295	3.26%	49	13,3
Hungary	9,000	3,400	5.64%	450	198	0.52%	12	12
Poland	31,000	2,423	3.49%	113,300	12,113	32.10%	61	99
Serbia	23,115	3,434	6.13%	-	-	0.00%	32	-
Slovakia	698	83	0.15%	-	-	0.00%	3	-
Slovenia	240	150	0.27%	-	-	0.00%	5	-
Accession	**73,584**	**11,296**	**20.15%**	**122 257**	**13,540**	**35.88%**	**162**	**124.3**

Source: Euracoal (2003 and 2006)

Table II-8. Coal Qualities in the EU-25

Country	Reserve (Mt)		Quality: Hardcoal				Quality: Lignite			
	Hardcoal	Lignite	CV (kJ/kg)	Ash (%)	Water (%)	Sulphur (%)	CV (kJ/kg)	Ash (%)	Water (%)	Sulphur (%)
Germany	23 000	41 300	27,400 - 33,000	6.0 - 7.0	8.0 - 9.0	0.8 – 1.0	8,810 - 10,830	5.6 - 10.6	48.0 - 54.0	0.9 - 1.7
Greece	-	3 400					3,770 - 9,630	15 - 19	41.0 - 60.0	0.5 - 1.0
Spain	600	50					7,640 - 8,040	26.7 - 41.1	37.5 - 50.8	1.3 - 2.6
United Kingdom	600		22,500 - 27,000	8.0 - 18.0	7.0 - 17.0	0.4 – 2.5				
Serbia		3 434					6,780 - 7,400	18 - 25	43.0 - 50.0	0.5 - 0.9
Czech Republic	1 229	2 515	18,560 - 28,700	7.6 - 28.5	8.2 - 12.6	0.3 – 0.6	10,700 - 19,640	10.9 - 40.2	25.5 - 41.2	0.5 - 2.5
Slovakia		83					10,700 - 11,600	15.2 - 33.9	20.7 - 33.9	1.4 - 2.0
Slovenia		15					9,800	18.60	35.60	1.40
Hungary	198	3 159					7,000 - 8,000	17.50	47.70	1.50
Poland	12 113	1 955	18,000-30,000	7.0 - 30.0	7.0 - 11.0	0.6 - 1.2	7,400 - 10,300	7.2-16	50.0 - 52.0	0.2 - 1.4

Source : Ekawan (2005) from various sources including Euracoal (2001 and 2003)

2.2.1.2. Present Coal mining in Western Europe

In line with depletion of coal reserves and tight competition with other energy sources, currently there are not many active coal mines in Europe. In the EU-15, only four countries are still mining coal. In 2004, coal production from those countries reached 66.28 Mt of hard coal and 337.2 Mt of lignite (Fig. 2.14). The figure of hard coal production is lower than the figure in 2002, where the production reached 77.9 Mt of hard coal, while in the same year the production of lignite reached 262 Mt. Detail information of coal mining activities in four countries in Europe, namely German, Greece, Spain and UK can be seen in Appendix A.

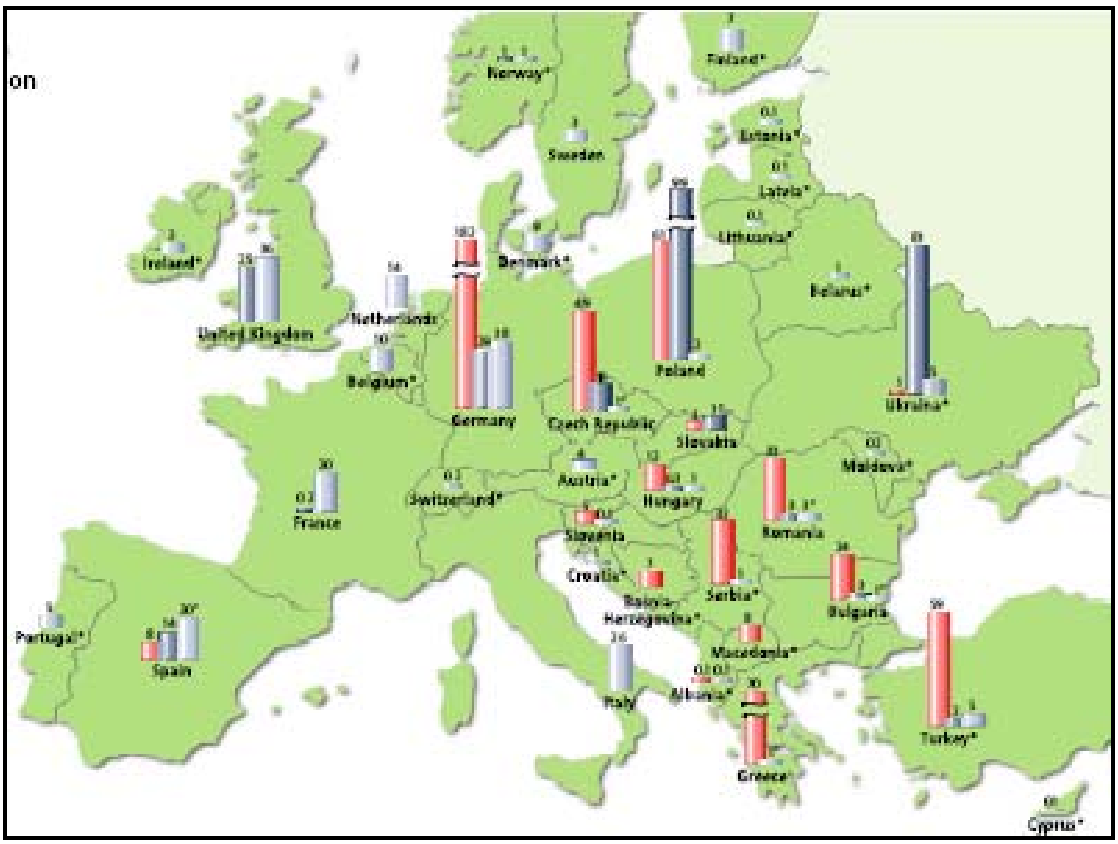


Figure 2.14. Coal production and import in Europe in 2004
Source: Euracoal (2006)

Since WW II, European mining employment trend has particularly followed a similar pattern to the declining trend of coal production. In Germany, for example, from 1945 to 1957, employment increased from about 294,000 to 604,000, and declined by more than 90% to 59,000 in 2004 (Euracoal 2005; Storchmann, 2004). Fig. 2.15 shows the mining employment in Europe. In 2004, the mining industry in the EU-15 employed about 92,000 people. Furthermore, over the last 50 years, mining industry in the EU-15 has been experiencing profound structural changes. For example, again in Germany, the most important event was the establishment of Ruhr-kohle AG (RAG) in 1969. RAG was a merger of many small mining companies in the Ruhr area. It was showed that the merger, followed by technology innovation, could lead to a significant increase in efficiency and productivity (Fig. 2.16). The productivity has increased almost double in the last three decades to 520 tons per employee per year in 2000 from 350 in 1960s. In 1998, the concentration process of restructuring was resumed with the formation of Deutsche Steinkohle AG, German hard Coal (DSK).

In UK the restructuring process was concluded by the setting up of the UK Coal plc in 1994 when UK COAL acquired the English coalfield assets in the privatization of State-owned British Coal. The company now is employing 4,000 people and producing more than 60% (9.1 Mt) of all the coal in UK with its collieries or surface mine sites principally located in the West and East Midlands, Yorkshire and the North East.

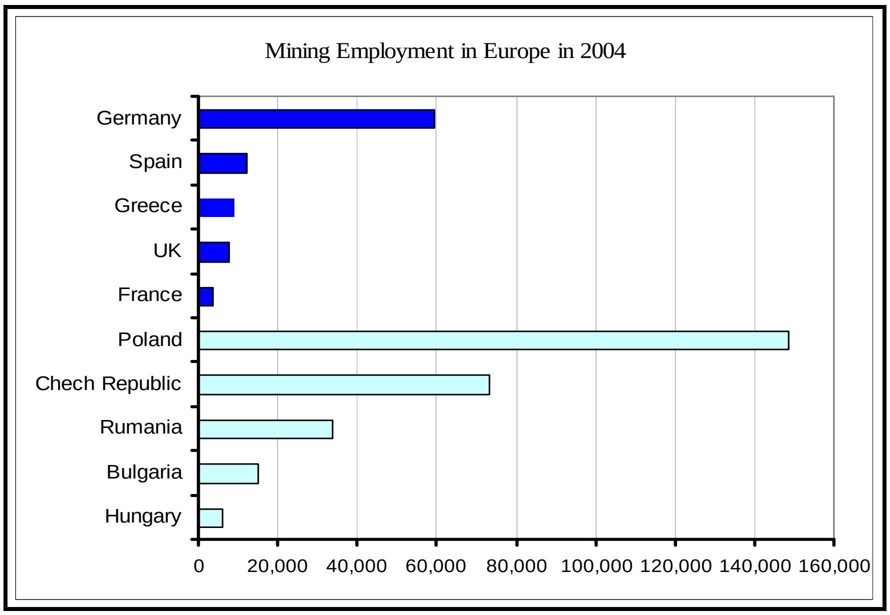


Figure 2.15. Employee in coal mining in Europe in 2004
Source: Data from Euracoal, 2005

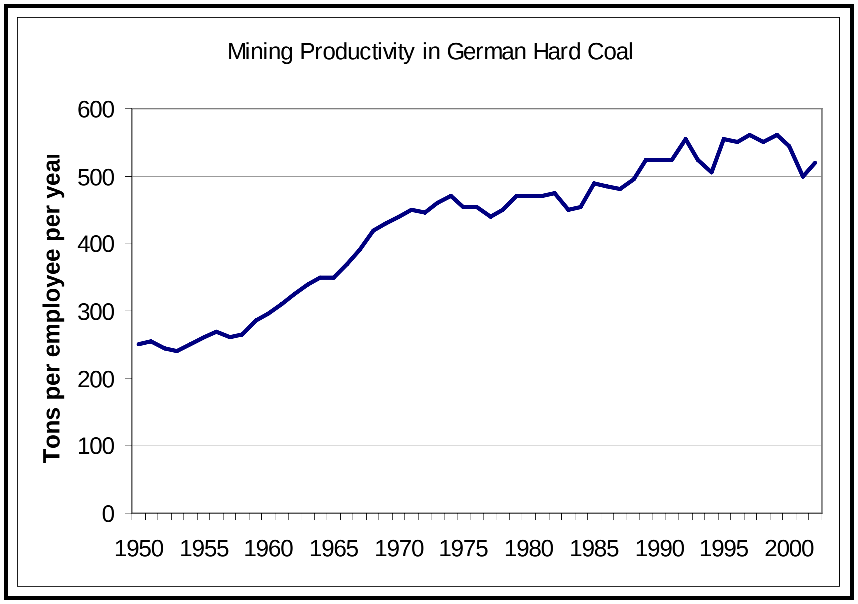


Figure 2.16. Mining Productivity in German Hard Coal
Source: Redraw from Storchmann (2004)

2.2.1.3. Supply from indigenous is under pressure

After reaching a peak in the 1950s, coal production in all countries in Western Europe is declining. In 2002, the indigenous hard coal production in the EU-15 was at about 75 Mt. This production fulfills only 30% of total consumption. Therefore, most consumption has to be imported. All countries in the Community import hard coal to satisfy their demand. In 2002, the imported coal to this region was at 172.4 Mt (or 70% of total consumption).

The enlargement of Community will add two main producers of hard coal: Poland and the Czech Republic. In 2002, Poland's hard coal production reached 102.3 Mt, while in Czech Republic the production achieved at 19.6 Mt. The production in these accession countries can fulfil almost their domestic consumption. Others, like Slovakia and Slovenia, however have to import coal. Of 104.9 Mt total hard coal consumption in the accession country nearly 11.1 Mt (or 10.5%) is imported (Ekawan, et.all., 2005b).

Among the EU-25 members, only Poland and Czech Republic export their hard coal to the neighbouring countries. In 2002, Poland exported 22.6 Mt, whilst Czech Republic's export was 6.0 Mt. Poland and Czech Republic, however, have to import coking coal, although not significant quantity, mainly for their steel industry. Overall, in 2002, the EU-25 community produced 196.8 Mt of hard coal and imported some 183.5 Mt, which was 52% total community consumption (VGE, 2004).

Lignite production in the EU-15 also continues to decrease nearly 40% from 437.1 Mt in 1990 to 337 Mt in 2004. The significant production drop over period 1990-1995 was mainly due to coal industry restructuring in Eastern Germany, following the reunification of Germany. Today, three countries in the EU-15 still mine lignite at various levels of production. The main lignite producers are Germany and Greece, where both contributed to 95% of total production, by producing 181.8

Mt and 70.8 Mt respectively in 2002. Because lignite has low energy value, it is mostly consumed by the power generation close to the mine. In general, lignite has been neither exported nor imported.

In the accession countries, lignite production also continues to decrease nearly 33% from 242.7 Mt in 1990 to 161.0 Mt in 2002. At present, in Europe, six countries mine lignite at various levels of production. The main producers in the accession countries are Poland, Czech Republic and Serbia, that all contribute to 87% of total production.

2.2.1.4. Operating Cost

The possibility of EU's coal industry to compete commercially on the international markets appears to be receding, despite efforts made by producers on both the technological and organisational fronts to improve productivity. There are two main reasons for this. First, as the most easily accessible seams are depleted therefore hard coal has to be mined under current mining methods in increasingly difficult geological conditions and at greater and greater depths (in some cases exceeding 1,500 metres). These situations increase the operating cost. Fig. 2.17 shows coal mining operating cost for several countries in the Community. For example, in 2002 the German's average operating cost was at about 150 €/ton while over the same year the imported coal price was nearly 45 €/ton. The operating cost is also exacerbated by more stringent regulations on mining health and safety and environmental protection, application of which has inevitably increased costs, with the result that production costs are higher than imported price.

Secondly, several non-European producers already operating on the international markets, for example Australia and the US have adopted more efficient extraction methods, assisted by more favourable geological conditions; Furthermore, the specific economic situation in other traditionally exporting countries, such as Indonesia and South Africa, where the national currencies are undergoing substantial devaluation and there is an urgent need to obtain hard currency, have put pressure on price to drop. Therefore, many coal exploitation in Europe has to severely compete with the imported coal.

Since the 1960s, the above situations have driven the coal mining industry in Europe to go into rapid decline due to competition from coal from outside the Community as well as the advent of other fuels to produce electricity and heat.

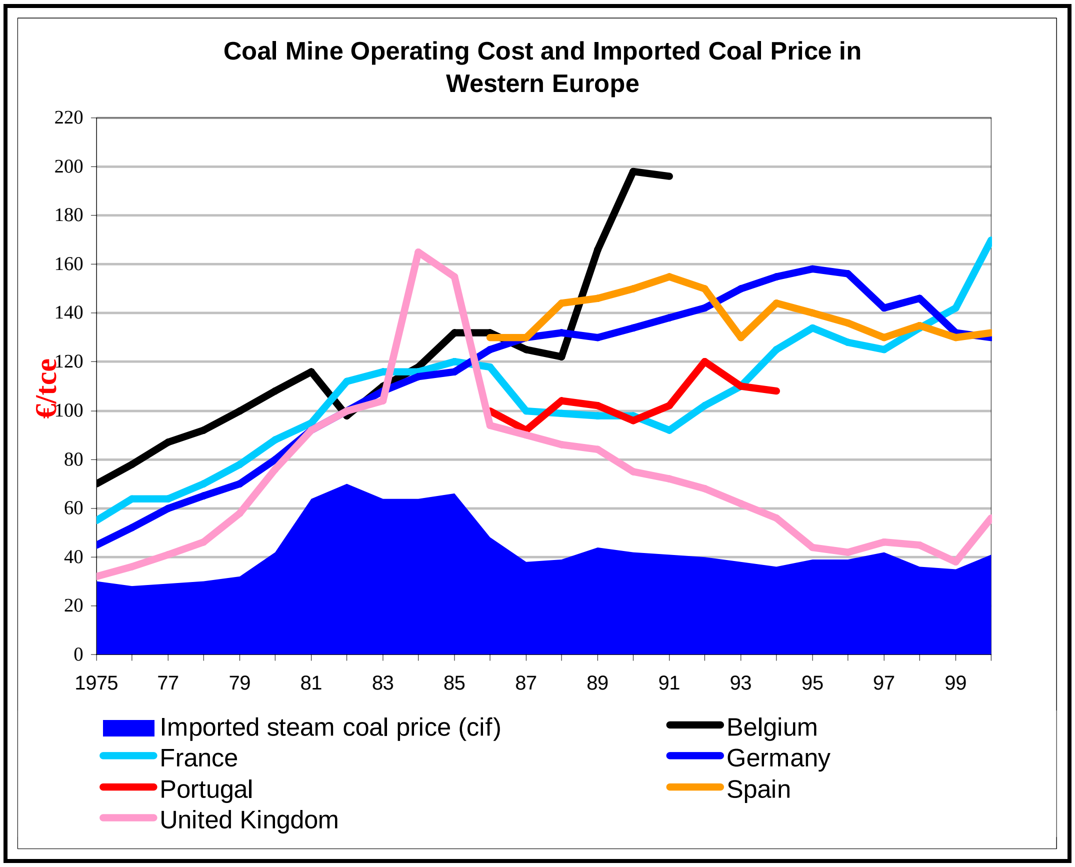


Figure 2.17. Coal Mine Operating cost and Imported Coal Price in coal mining in the EU-15
Source: Data from Piper (2002)

2.2.1.5. Subsidy

In order to support the industry, coal industry has been subsidized since several decades. Before 2002, the financial aids were authorized under the European Coal and Steel Community (ECSC) treaty that was signed in Paris on April 18th, 1951. Faced with a big decline in demand for coal and steel in the post-war period which could have plunged Western Europe into an economic recession, the ECSC functioned by striking the balance between production and distribution. Subsequently, when the coal and steel industry went into crisis in the 1970s and 1980s, the ECSC was able to lead a response which made it possible to carry out the industrial restructuring.

Fig. 2.18 shows the evolution of coal subsidy in Western Europe and Table II-9 shows the financial aids to the coal industry in several countries in the EU-15. For instance, since decades, the survival of the German hard coal sector depends on financial aids from Federal Government and mining states. And in 2002, the subsidy was at about 3,560 million euros or nearly 122 euros/ton of hard coal produced (EU Commission, 2002a). In general coal subsidy can be categorized into three purposes, which are for operating aid, for reduction activity and for inherited liabilities (Fig. 2.19)

On July 23rd, 2002, the ECSC Treaty with its legal basis of coal subsidy expired. However before the treaty was expired, on June 2nd, 2002 the EU Council Energy Ministers approved a regulation for government aids to the coal industry. The new regulation caps subsidies at the 2001 level and runs until 2010. After 2010, coal subsidies will be subjected to the normal rules for government aids in the EU (EU Commission, 2002a). Nowadays subsidy is somewhat unacceptable and some member countries are currently taking steps to reduce subsidy payments, acknowledging that some losses in coal production are inevitable.

The issue is particularly relevant for the two principal producers in the accession countries, namely Poland and the Czech Republic. The Polish coal industry is in a very similar position to the German coal industry, the geological conditions often being very similar. A significant proportion of Polish coal can thus no longer compete with coal from non-European countries. The Polish coal industry will thus depend increasingly on aid granted by the public authorities.

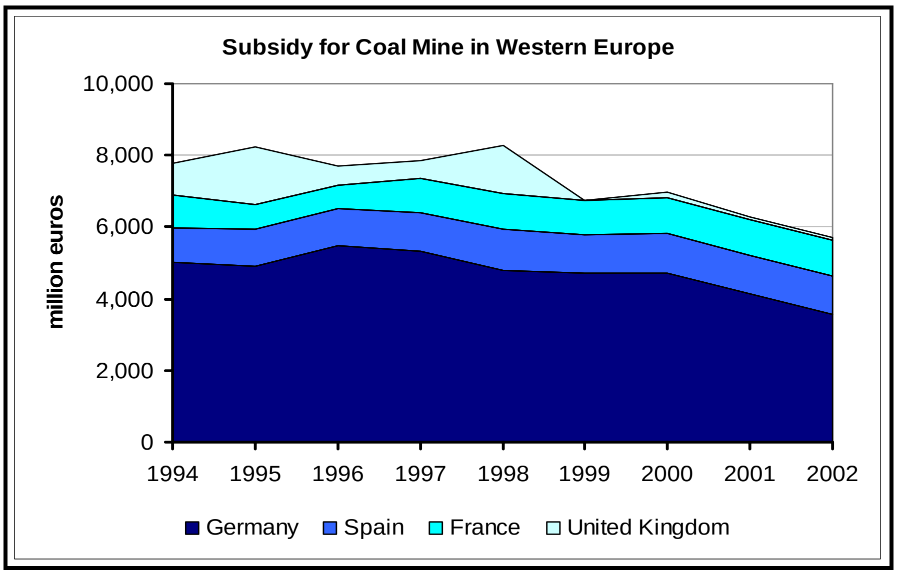
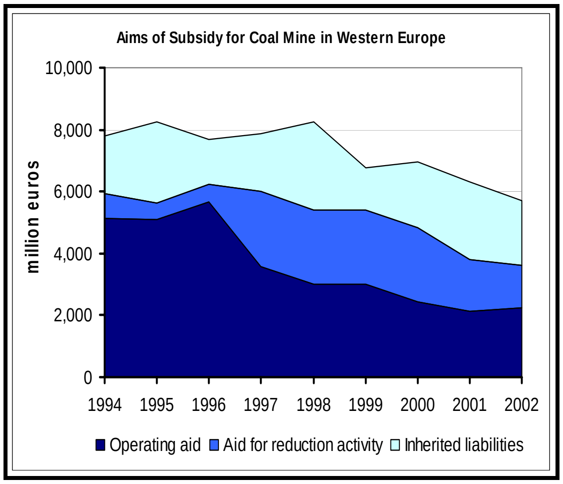


Figure 2.18. Subsidy for coal mining in the EU-15
Source: Data from EU Commission (2002a) (2002b)

Although the gap between coal production costs in the Community and coal price on the international markets has narrowed slightly, but it is still wide. Reductions have been seen in the United Kingdom which, while maintaining a degree of mining activity, has cut production drastically and has kept open only the most profitable mines. Even if Germany and Spain have not taken a final decision and are adopting a more cautious approach, those two countries are also making substantial restructuring efforts dictated by social and regional concerns rather than any kind of realistic prospect of their coal industry achieving economic equilibrium.

Following the initial phase of restructuring in 1993, accompanied by a significant wave of privatisation, the Czech Republic is currently in the process of a second restructuring phase of its coal industry. Poland adopted a restructuring plan for the period 1998-2002, providing for a lowering of production and a reduction of miners. The current restructuring plan will further reduce in national production targeting mines with the largest deficits.



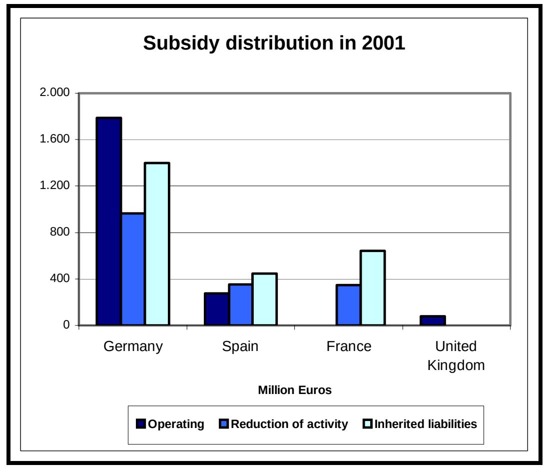


Figure 2.19. Aims of subsidy for coal mining in the EU-15
Source: Data from EU Commission (2002a) (2002b)

Table II-9. Coal Industry Subsidies in Western Europe, 2001

Country	Subsidies *million USD*	Hard Coal Production *million tons*	Subsidies *USD/ton*	Imported Coal Price *USD/ton*
Germany	4,643	32.4	144	43
Spain	1,194	15.9	75	40
UK	91	34.7	3	47
France[1)]	1,073	2.2	494	47

1) The closure of last coal mine is on May 2004. And the high subsidy in France was for mainly closuring the mines.
Source: EIA (2003) ; *EU Commission (2002a)*

2.2.2. Supply from outside community for balancing demand

2.2.2.1. World coal trade in a way to maturity

The beginnings of the world hard coal trade date back to the century 19th – with the beginning of steamship navigation – when depots had to be built in all world ports to store bunker coal. Since supplies from a nearby mine were not always possible, some coal had to be obtained across oceans and by sailing ship, e.g. from England to Cape Town and Suez, or from Australia to Dhaka (India).

The oil price increase in 1973 initiated a new phase in international hard coal trade, providing a strong incentive to convert power stations and other installation from oil, and resulted in decision to construct new coal-fired plants to use relatively inexpensive imported coal. The trend was reinforced by the oil price increase in 1979. Since then the international market for hard coal has developed into its present form.

There are two types of international coal trade, cross-border (land trade) and maritime. Although coal land trade still continues in US-Canada or Poland-EU, the percentage of this type of trade is not significant comparing with maritime trade. The world maritime coal market has grown in average by 4.3% per annum from 120 Mt in 1975 to 674 Mt in 2003. Fig. 2.20 shows the development of world coal trade. The strongest contributor of this growth has been the steam coal trade, which has increased at an average annual rate of nearly 6.4%, while the average annual growth rate of seaborne coking coal is about 2.3%.

Fig. 2.21 shows the main trade flows in maritime hard coal trade in 2004. In 2003, total hard coal traded was at about 685 Mt, including steam coal (484 Mt) and coking coal (190 Mt). The Atlantic market contributed 277 Mt of the trade (40% of total trade) while the Pacific market was 397 Mt (60% of total trade). Fig. 2.22 summaries the mechanism of world hard coal trade in 2003.

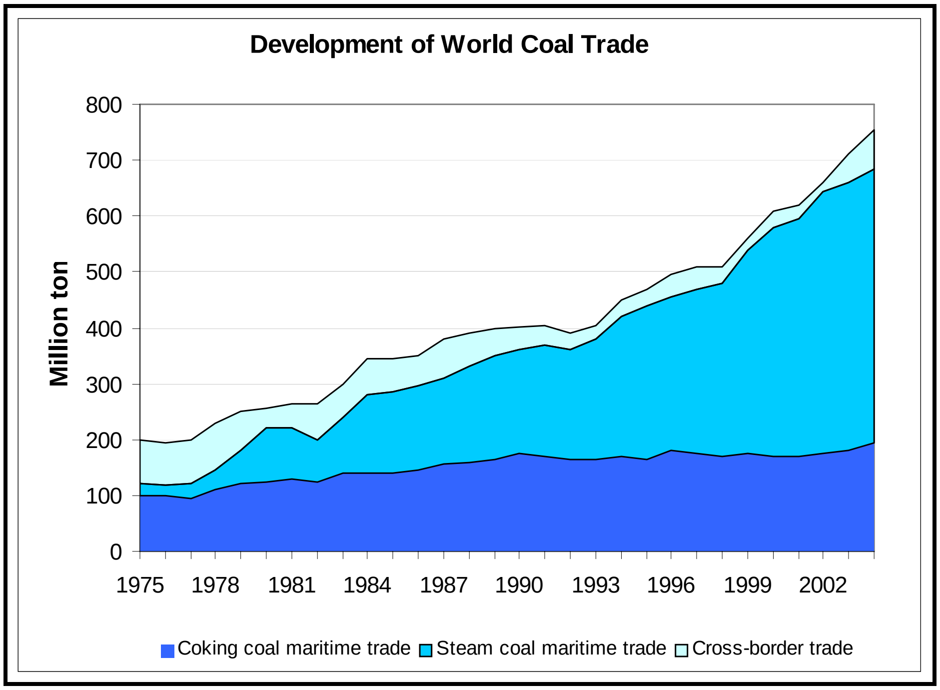


Figure 2.20. Development of world hard coal trade
Source: Data from Schiffer and Ritschel (2005)

The coal being traded on international markets is small in comparison with total coal consumption. It accounted for about 8.0% of world coal production in 1979 to 16.0% in 2004. In recent years, international coal trade has been characterized by relatively stable demand for coal imports in Western Europe and expanding demand in Asia.

With regard to regional markets, coal from any of the major exporters will find markets in either Europe or Asia, depending principally on freight costs. Sea-borne transport costs tend to contribute to the operation of two regional markets: the Pacific (Asia) and the Atlantic (Europe). The Pacific market – Japan and north and south Asia – is supplied preferentially by Australia, Indonesia and China because of the geographic proximity. For the same reason, the Atlantic market is supplied preferentially by South Africa, Poland, US, Colombia and Venezuela.

In 2003, of the 674 Mt total international trade 60% and 40% of hard coal trade was in the Asia-Pacific and the European-Atlantic regions respectively. Total coal trade into the Asia-Pacific area rose by 9.4% from year 2001 to 2002. Conversely, imports entering the European-Atlantic market declined by 13.5%. It is likely that the Pacific market will continue to expand and become the most important market whereas the Atlantic market will continue to decline. Table II-10 shows the growth of hard coal trade in 2002.

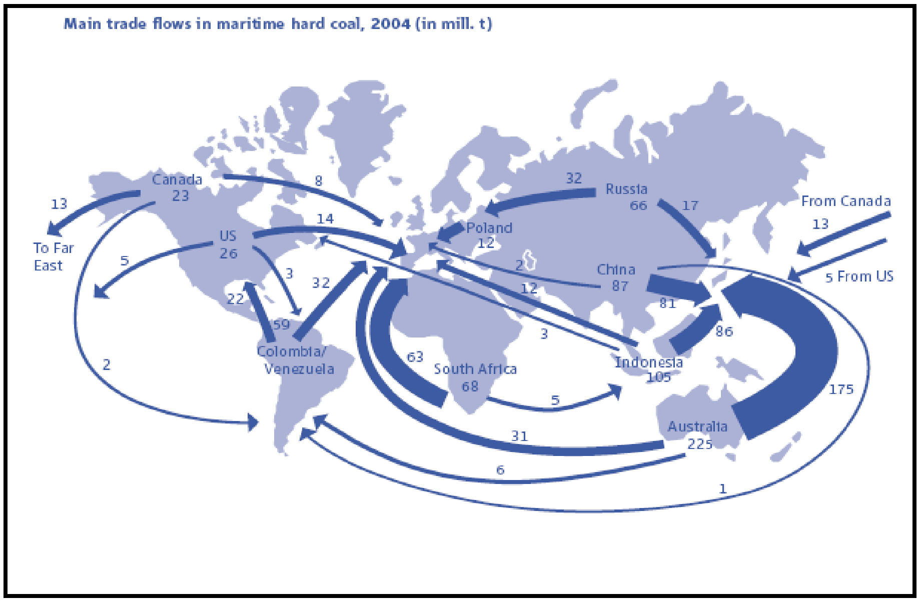


Figure 2.21. Main trade flow in maritime hard coal trade in 2004
Source: Schiffer and Ritschel (2005)

Table II-10. World hard coal trade (Mt)

	2001	2002	Growth (%)
World	620.8	622.9	0.3
Asia-Pacific	310.1	339.3	9.4
Europe-Mediterranean	250	216.2	- 13.5
North America	40.6	38.8	- 4.4
Latin America	20.6	19.9	- 3.4

Source : IEA (2003c)

2.2.2.2. The evolution pattern of hard coal trade in Atlantic

There are two essentially different markets for internationally traded hard coal, which are steam and coking coal markets. The first is for heat-raising in power generation (and industrial steam uses), where now it represents almost 70%, or 182 Mt, of total coal consumption in Western-Europe. The significant growth in these coal uses is occurring particularly in Asia where growth outweighs the coal use reduction in Europe. In 2001 of 2,671 TWh (Terra Watt hour) of the electricity demand in the EU-15, 670 TWh (25%) was supplied by coal whilst nuclear energy and gas provided 892 TWh (33.4%), and 443 TWh (16.6%) respectively (Ekawan et.al, 2005b).

The declining coal production in Europe has created the potential for significant increases in coal imports. However, environmental concerns and increased electricity generation from natural gas, nuclear, and hydropower may curtail the growth in coal imports.

The second category of coal is coking coal- a coal, with special qualities, that is used to produce coke for steel industry. In 2001, almost 23% (60.7 Mt), of the EU-15's total coal consumption was dedicated for steel manufacturers. Since the late 1950s, a redistribution of the geographic pattern of steel manufacturing has occurred. There was a slow growing of production in

Europe and North America, and high rates of growth in the emerging economics of Asia. Of 771 Mt world's crude steel production in 1991, about 20.2% was produced in the EU-15, while in 2001 the ratio was 17.6% of 845 Mt world's productions (IISI, 2003).

In the second half of the 1980s, Pulverised Coal Injection technology (PCI) became more widespread in the steel industry. This technology requires lower quality coking coal and has created another coal category called "weaker" or "semi-soft" coking coal. In Europe, PCI technology is mainly used in Belgium, France, Germany and the Netherlands.

Before the 1960s, international coal market was primarily land-based, and was traded between neighbouring countries. Germany was the major exporter to Western Europe, and Poland and the Former Soviet Union were the major suppliers to Eastern Europe. Since the 1980s, most coal traded on the international markets is transported by ship – either cape-size (100.000-200.000 dwt), panamax size vessel (60.000-75.000 dead weight ton or dwt) or handy-size vessels (20.000-35.000 dwt). There are several main ports in the EU-15 region to receive coal shipments, including Amsterdam and Rotterdam in Netherlands, Antwerp port in Belgium, known as ARA ports, and Dunkerque in France.

Hard coal trade in the Atlantic market is now progressing to become a perfect market. Several characteristics can be described to explain coal market advantages. Abundant and wide distribution of world's coal reserves can avoid any cartel mechanism. World coal reserves account for about 980 billion tonnes and under current production level, these may be used for over 160 years. Now, almost 50 coal producing countries fulfil the world coal consumption (WCI, 2002). These reserve conditions have made coal prices vary according mainly to quality and transport costs. However, coal prices fluctuations are relatively modest than the fluctuations of oil and gases prices. The fluctuations may reflect mainly the interaction between supply-demand.

The availability of trading platform and commodity market, the utilisation of over-the-counter (OTC) and the cost indexes systems have allowed coal market to be transparent and be simply in its operation. The market has also a possibility to avoid risk, such as increasing sea freight cost and exchange rates, by implementing a risk management technique called hedging. The availability of spot market has made the transaction bring into the line to the actual market situations.

The transporting costs, particularly ocean freight rates, are a significant element affecting the final delivered price of coal. These costs also influence the geographic extent and operation of the market. Seaborne coal is not the only ocean freight market so that coal delivered price has to compete with other bulk-traded commodities, including oil, iron, phosphate rock, alumina and grains. Fig. 2.23 shows the evolution of coal freight rates over the last decades from US to Japan and Europe (HR/Japan and HR/ARA) and from Australia to Japan and Europe (QLD/Japan and QLD/ARA) (IEA Coal Information, 2003c). Ocean freight rates are highly responsive to the available capacity in the fleet. Ocean freight rates for coal rose steadily from 1978, peaking in 1981 and declining to 1983. Rates remained fairly stable until the commencement of second cycle from 1987. The second peak, reached in 1989, was lower than experienced in 1981 and the decline was also slower. The rates recovered slightly in 1993 and climbed steeply in 1994. Seagoing freight rates for bulk mineral products declined sharply in the last half of 2002 before entering a recovery in the beginning of 2002.

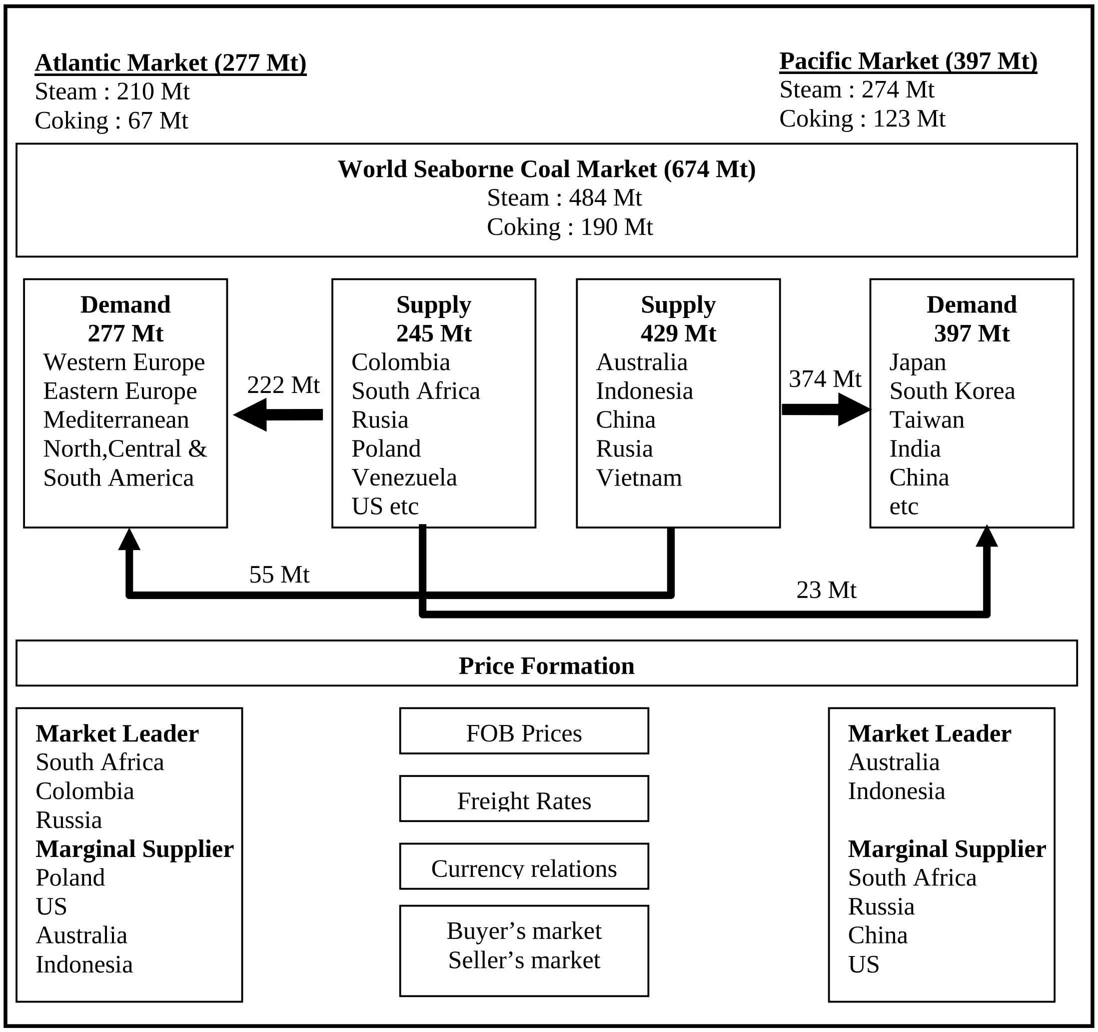


Figure 2.22. World hard coal market mechanism in 2003
Source: from various sources

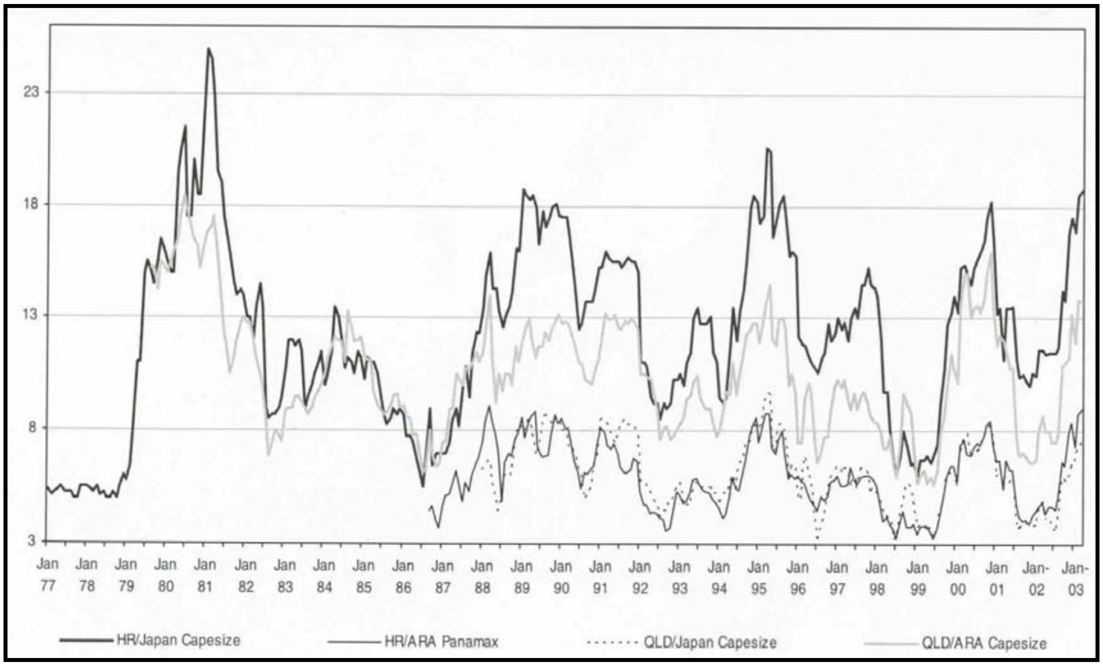


Figure 2.23. Spot coal freight rates (in $/ton)
Source: IEA (2003a) from SS&Y Research Services Ltd., London

2.2.2.3. Mechanism of coal transaction: move forward to be a transparent market

Since the 1990s, in the Atlantic market, the character of long-term contracts has changed under growing pressure of spot transactions, especially for steaming coal. Today, contract terms rarely go beyond five years. They are merely used to underpin long-term cooperation between contracting parties within the scope of potential selling or purchasing rights for specific contract quantities. It is usual to agree on spot or on long-term quantity arrangements at the spot price applicable upon delivery.

Supply contracts with long-term price fixing are now an exception. Spot deals are no longer arranged exclusively between producers or dealers and consumers in the traditional manner. In the case of steaming coal, these functions are increasingly being performed by firmly established trading platforms, commodity markets and brokers that work for them. In Europe, a number of trading houses are performing as an agency function, such as RAG Trading GmbH, RWE Trading GmbH and the TFS broker.

In 2002, of the total transactions, transactions through spot market have risen from 40% in 1988 to 67% in 2002 (Fig. 2.24). In 2003 it is estimated to be rise to 80%. There are at least three factors contributing to this increasing trend. The first factor is an excess coal supply capacity. Since the early development of coal trade, the market is dominated by an excess export capacity. Fig. 2.25 shows an excess export supply capacity in the coal market over 1985 to 2005. It is likely that the excess capacity may continue in the beginning of 21st century. This circumstance has made some buyers feel confident to settle the transaction by spot contract (Ekawan and Duchene, 2005a).

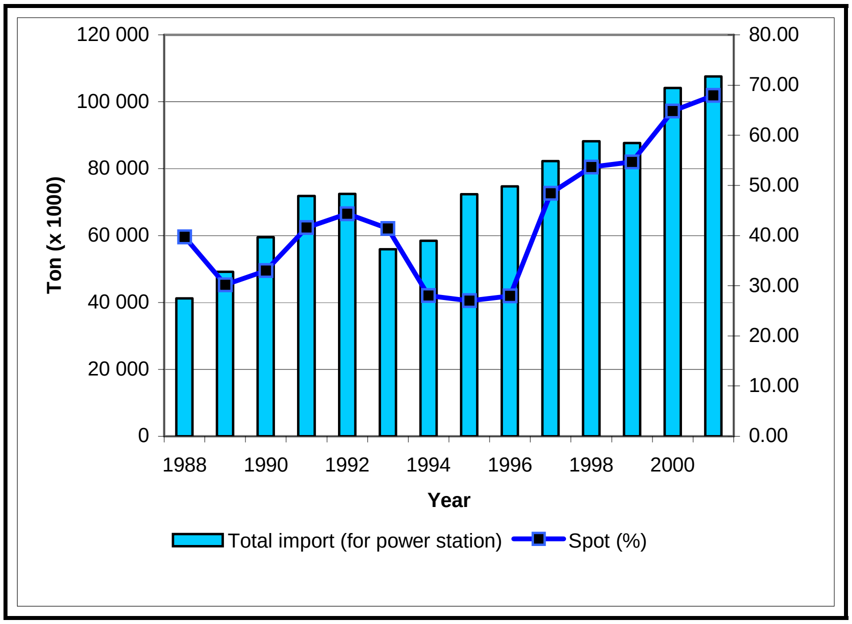


Figure 2.24. Spot transaction in the Atlantic market
Source: Data from European Commission (EU) (2001)

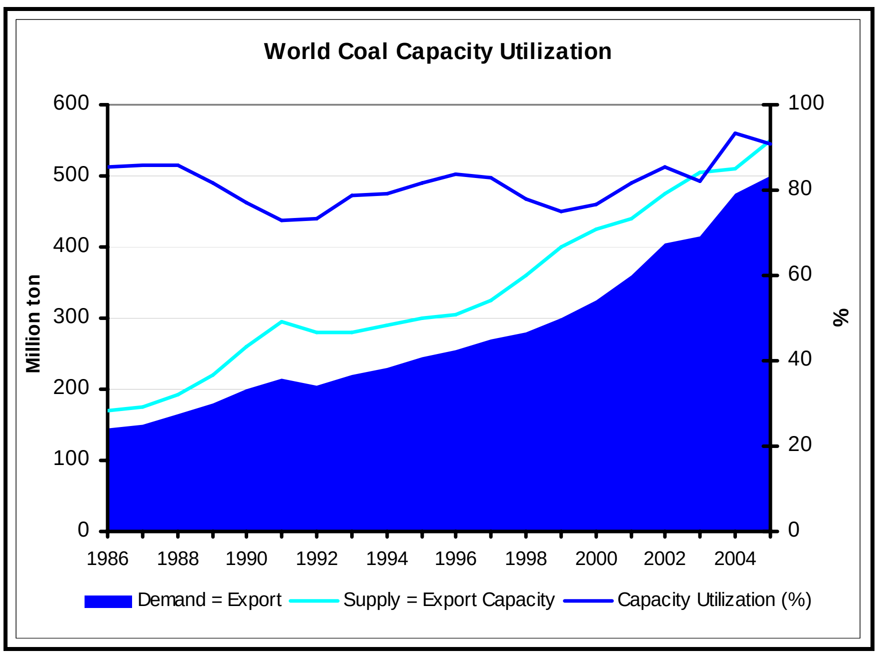


Figure 2.25. World coal supply capacity
Source: Data from Schiffer and Ritschel (2005)

The second factor is a progressive development in "coal-chain". With the intention to increase the security of supply, several countries in Europe have changed their coal purchasing policy. GKE (Gemeenschappelijke Koleninkoopbureau voor de Electriciteitsbedrijven), which is responsible for coal purchasing and supplying for the Dutch electricity company has improved its coal-chain facilities by enlarging sites for stockpiling and blending, increasing port capacity and spreading risk across several exporter countries. By adopting these purchasing policies, GKE has ensured most of its transaction through spot contract (Cameron, 1998).

The last factor is a fiercer competition on electricity market. Electricity market in Europe has undergone radical changing by liberalization of the market. In 2005, 10 countries in the EU-15, including Germany, Spain and the United Kingdom, have reached a 100% market liberalisation. Others, like France and Greece have opened less, approximately 70% (Euractiv, 2006) of their electricity markets in competition. The EU-15 as a whole reports nearly 90% degree of market opening. Liberalization and deregulations have abolished traditional market structures and created free competition among power producers. What matters for them is that they offer competitive electricity prices by making optimal use of their own power plants and reducing their fuel costs, including imported coal. They pass on market pressure to coal suppliers, which then the supplier have to find ways to reduce the cost, including adopting the spot contract.

Tenders are no more representative in the market, since they may be avoided because of high transaction cost for failed bids. Tenders are commonly used by big buyers purchasing large volumes, often state owned buyers. An Italy's electric company, ENEL, for example has adopted 70% of its purchase on this type of contracts running for one year or less.

In recent times, steam coal is becoming an accepted and traded commodity on commodity markets and international trading platforms. The physical preconditions for this have been created by a number of coal indexes that define and standardize provenance, quality, place of delivery and conditions. One of the indexes is API#2, an index for CIF delivered to ARA ports, that trade coal for certain specifications as 6,000 kcal/kg (min) calorific value in nar, 14% (max) total moisture, 15% (max) ash content and 1% (max) sulphur. It argues that the existence of coal commodity markets and international trading platforms has driven coal market to become more transparent (Ekawan and Duchene, 2005a).

2.2.2.4. Price formation

In the beginning of the international coal trade era, deals were done by producers and coal trading companies, as intermediaries between producers and consumers. In the 1990s, there was a declining importance of coal trading companies. Contract price are now directly settled between producer and consumer. They both define the annual quantities to be purchased as well as the fixed prices for each current year. The contract year is started in December and ended in December a year after. Unlike the Pacific market, in the Atlantic market there is no price function as a benchmark price.

Spot prices pertain to specific cargoes (i.e. one time transaction) and reflect more short-term market conditions. The contract price is now an exception in the Atlantic market. It is usual to agree on spot contract or on longer-term quantity arrangements at the spot price applicable upon delivery. As the market is becoming more transparent, the power utilities tend to prefer the spot contract for the transaction.

The price in the Atlantic market is governed by a number of coal indexes that define and standardize certain conditions. Recently, indices, such as the EU (Union European index), the MCIS (McCloskey Coal Information Services) the SARC (South African Coal Report) Rotterdam Barge and the BAW (Bundesamt fûr Wirtschaft) indexes are becoming spot price indicators and becoming more important in price setting. Another important index is the CWI (Coal Week International), a quarterly average of prices range, published by Coal Week International for Amsterdam/Rotterdam FOB Barge. The relations between price indexes in the Atlantic market is shown in Fig. 2.26.

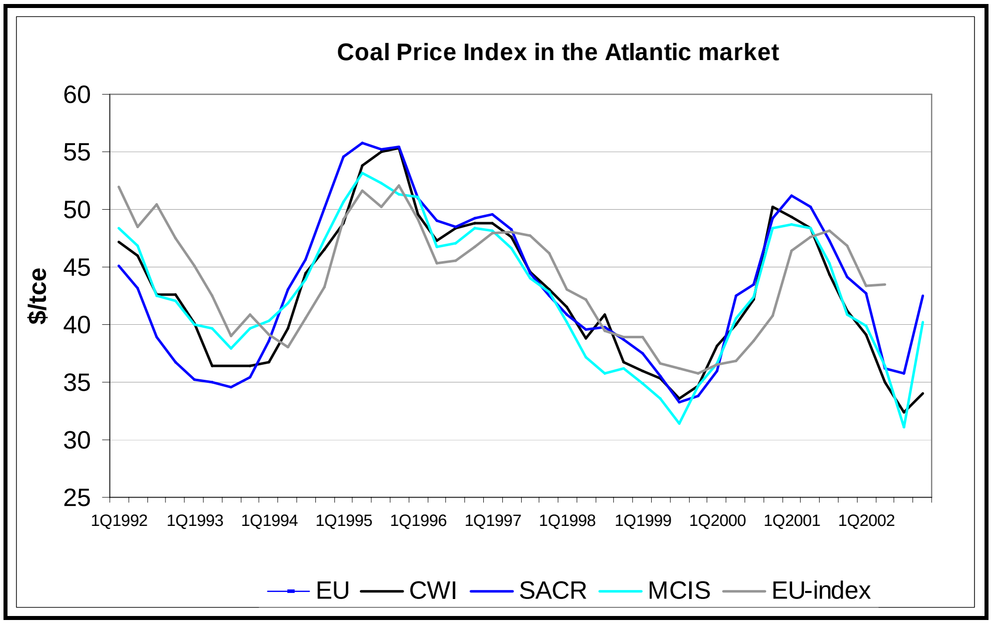


Figure 2.26. Relation coal price indexes in the Atlantic market
Source: Data from International Energy Agency (IEA) (2004)

In some contracts, price indices are written into contract price adjustment formulas and weighted to reflect the contract nature, either spot or long-term. Fig. 2.26 illustrates how all the indices show a close relation on the relative movement. It also shows the impact of the collection and publication frequency, where the EU index shows a time lag against the MCIS and the SACR indices. The differential between the SACR and the MCIS index can be explained by the results from the coal transferring cost into barges (The Commission of the European Union, 2001).

The EU index is collected by the European commission from returns submitted by all member states. It covers the delivered price of imported coal and records separately short-term contracts and contracts which are longer than one year in duration. All coals are corrected to a common calorific value of 7,000 kcal/kg in net air received (nar). The index is produced on a quarterly basis but six months after submission of information. The MCIS index is produced on a weekly basis. The index relates to coal delivered into NW European ports in maximum size vessels suited to those ports. It is collected from market information obtained by MCIS from coal buyers and sellers. Information is obtained from all the major coal supply countries and weighted to account for the different levels of trade. It incorporates the latest prices in its calculation. All prices are adjusted to a calorific value of 6,000 kcal/kg nar.

The SACR barge price is produced by the 'South African Coal Report' and relates to South African coal delivered into Rotterdam and then transferred to barge for inland European destinations. It is produced on a monthly basis and relates to two coal grades with calorific values of 5,900 and 6,200 kcal/kg nar. All the utilities in Germany are obliged to make returns to the Bundesamt fûr Wirtschaft (BAW) of the border price of imported coal on a monthly basis. Coal is then adjusted to a calorific value of 7,000 kcal/kg nar as the BAW index.

Two characteristics of spot transactions are that when the market situation is tense, mark-ups are charged on long-term contract prices. Conversely, when the market situation relaxes, price reductions are allowed. Hence, the spot prices in buyers' markets, as those that existed in the early

1990s and after the mid 1990s, were generally below long-term contract prices. Another spot price characteristic is that they have an impact on the contract prices of future deliveries.

One new variant for establishing coal prices involves the future prices: the price being offered by trading platforms and commodity markets for spot quantities. These prices can be agreed in advance. The physical preconditions for this have been created by a number of coal indexes that precisely define and standardize provenance, quality, place of delivery, etc. Among these coal indices are API#2, API#4, PRB 8800 and Nymex Coal Index. The coal indices also permit trade on commodity markets and trading platforms involving coal derivatives, for instance paper transactions with temporary fluctuating bid and over-the-counter (OTC)[9] prices. Here, deals on a swap, future and options basis are possible.

The OTC prices have created a transparency on the world hard coal market, and now determine the spot trade in steaming coal and its price trends on the Atlantic market. The deals are handled by broker firms or trading platforms, such as the digital platform global-COAL. In 2005, global-COAL had 57 members and reported total sales of approximately 14 million ton in 2003 or about 2% of the world's seaborne.

Coal prices have historically been lower and more stable than oil and gas prices, and despite the growth of index and derivative based sales in recent years, this has typically remained the case (Fig. 2.27). Placing a cost on carbon emissions more directly will, in certain circumstances, put pressure on this inter-fuel cost relationship. However, coal is likely to remain the most affordable fuel for power generation in many developing and industrialized countries for several decades.

In Fig. 2.27 it is shown that hard coal prices fluctuate in cycles. Price swings depend mainly on the course of demand, which is determined by the utilization of existing export capacities and by price movements affecting the market leader, crude oil. The second oil crisis in 1979/80 led to an increase in the demand for hard coal and, and so to better utilization of supply capacities. The result was a rise in hard coal prices (and gas), which, in turn, triggered a mobilization of existing, and the development of new export capacities. It was then followed further market cycles with prices first rising and then falling again, particularly between 1973 and 1987, 1988 and 1993, 1994 and 1999.

Prices peaked in 2000/2001 at USD 42/ton cif ARA, and dipped again to USD 28/ton cif ARA[10] in 2002. With a simultaneous weaker dollar rate, these prices were hardly capable of absorption by steam coal mines in South Africa. In 2003/2004, however, the special factors identified triggered leaps in demand, which led to peak prices of USD 78/ton cif ARA. In the meantime – mid-2005 – prices are USD 60 - 62/ton cif ARA. The present price level offers incentives for producers to increase their supplies to meet market demand in order to maintain and extend the supply range.

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9 OTC market is a market of commodities or securities (stock or bond) not listed on a stock exchange, where market participants trade over the telephone, facsimile or electronic device instead of a physical trading floor. There is no central exchange or meeting place for this market. The trading occurs via an intermediary, called dealers who will buy at a bid price and sell at an asked price that reflects the competitive market conditions. Now in coal trading, the OTC markets become more liquid and traditional coal prices adapt to the real-time price signals provided by the OTC market. There are several standardized coal specifications that are actively traded OTC. In US, the largest producing region is the Powder River Basin, and contracts for PRB 8400 and PRB 8800 are traded actively in OTC NYMEX.

10 Hard coal prices in the Atlantic market usually are referred as a cif (cost insurance and freight) price at three biggest ports in Europe which are Amsterdam, Rotterdam and Antwerp (ARA)

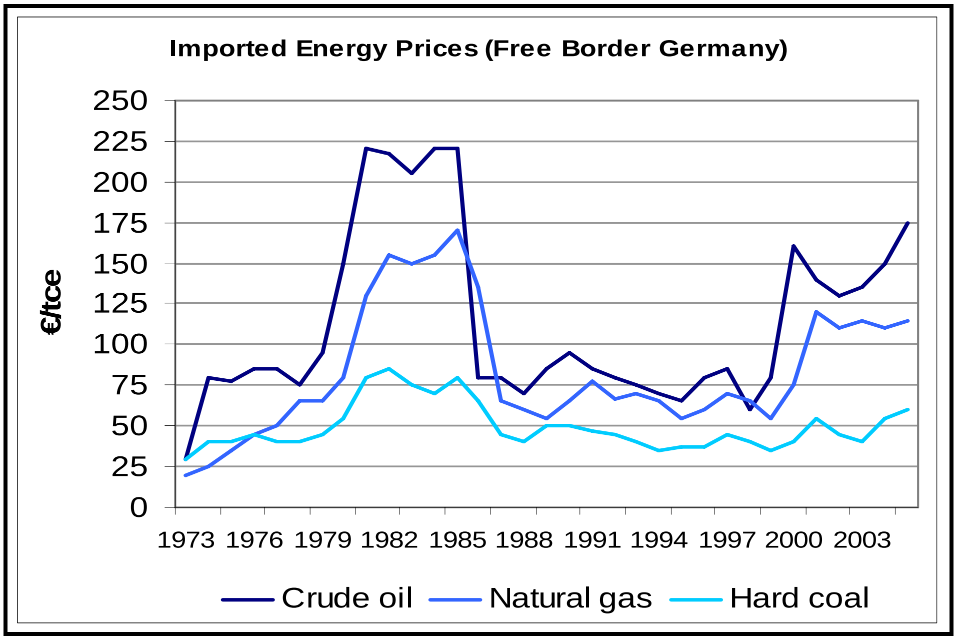


Figure 2.27. Evolution of fossil fuels in Europe
Source: Redraw as of the data from Schiffer and Ritschel (2005)
Note. Prices for all fossil fuels energy have been converted to ton coal equivalent (tce) to have equal comparison

2.2.3. Discussion: while indigenous is in doubt supply from exteriors is secured

2.2.3.1. World coal reserve can secure the demand

World coal reserves are abundant. Among total fossil fuel reserve (1,335 Gtce), it represents 55% of world fossil fuel, higher than oil (28%) and natural gas (17%) (Schiffer and Ritschel, 2005). Fig. 2.28 exhibits world coal reserves distribution.

The advantage for coal reserve is that it is more abundant and much more widely and evenly dispersed than other fossil fuels. It can be found on every continent and there is no geopolitical problem on its supply. It is in contrast with oil and gas, where their reserves are tightly concentrated in the Middle East and the Former Soviet Union. To day almost 70 countries now have coal reserves and 50 countries exploit coal.

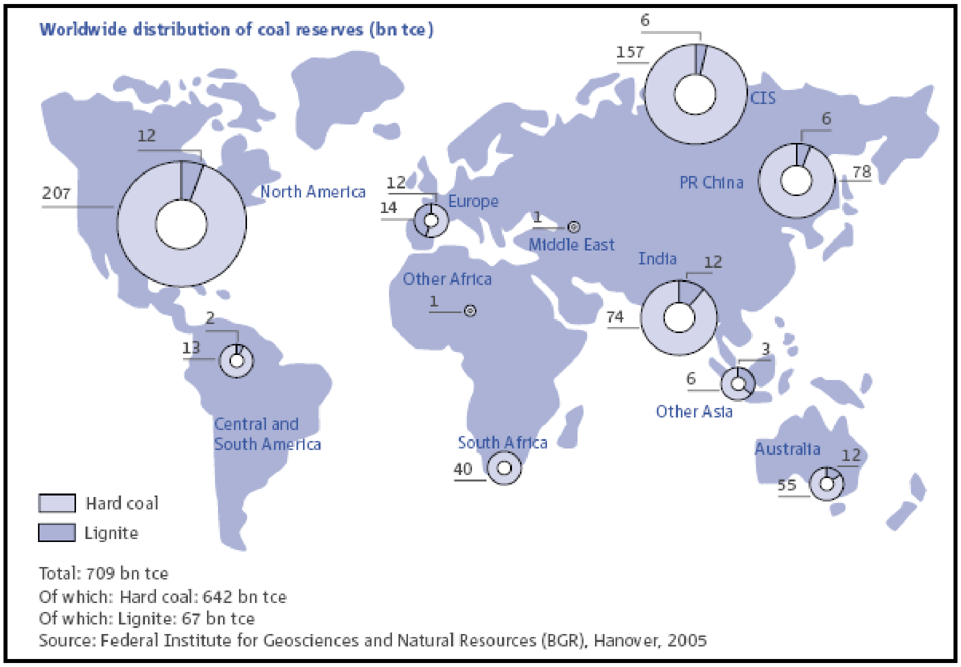


Figure 2.28. World coal reserve distribution
Source: Federal Institute for Geosciences and Natural Resources, from Schiffer and Ritschel (2005)

2.2.3.2. Supply can fulfill demand in the Atlantic coal market

While projected reductions in indigenous coal production in the United Kingdom, Germany and Spain are likely to be replaced by equivalent volumes of coal imports, in 2002, the leading coal suppliers to Europe were South Africa, Australia, South America and the United States. Over the forthcoming decades, low-cost coals from Colombia and Venezuela are projected to meet part of an increasing share of European coal import demand, displacing some coals from the United States and Poland. Fig. 2.29 exhibits major coal importers to the EU-15 in 2002.

South Africa is likely to remain a main provider for the Atlantic coal market in the future. In 2001, it had exportable production capacity of 73.5 Mtpa that could increase in the medium term. South Africa is setting for rise in handling capacity to 82 Mtpa at the Richard Bay Terminal and in the supplying rail link. Once this increasing capacity has been reached, an increase in coal export of up to 90 Mtpa in 5-10 years can be assumed. According to the World Energy Council in 2001, its commercially mineable hard coal reserves amounted to 49.5 billion tonnes.

Colombia is now the second largest steaming coal supplier after South Africa to the Atlantic market. Of its total output amounting to 43 Mt in 2001, 38 million was exported. Some 24 Mt was mainly sold to Europe. Colombia has four export ports that are deep enough to take cape-size freighters. Those export ports have an annual handling capacity of 52 Mt. Plans providing and developing new infrastructures are unlikely to be realized in the short time. Coal resources are put at 9.8 billion tonnes, 6.6 billion tonnes of which the World Energy Council (WEC 2001, 2004) reckons as measured and mineable reserves.

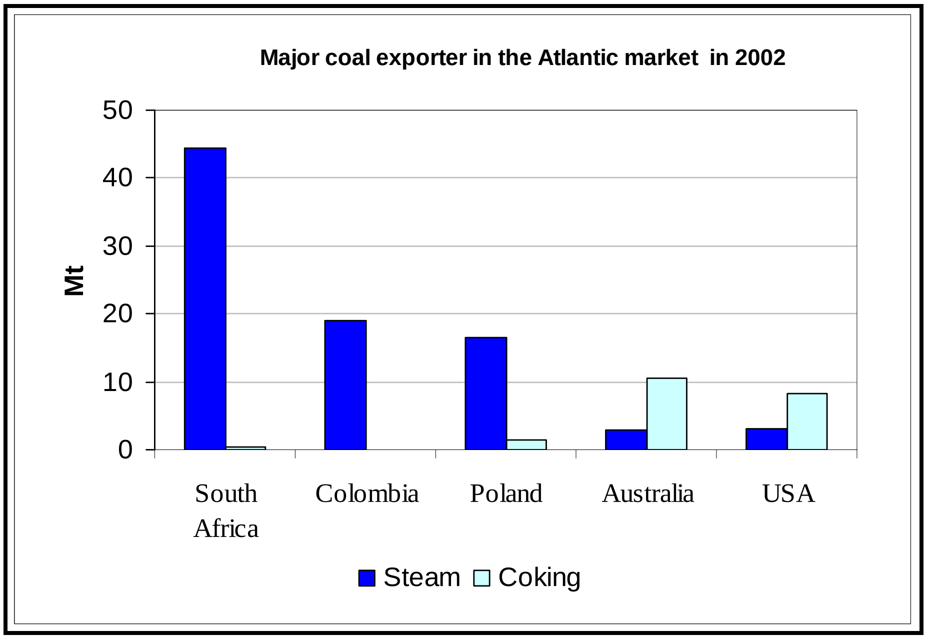


Figure 2.29. Major coal exporter in the Atlantic market
Source: Data from International Energy Agency (IEA) Coal information 2003 (2003)

Australia is now the main coking coal supplier to the Atlantic market. Australia's coal mining sector is underpinned by proven reserves of 82 billion tonnes: a share of 8.3% of world reserves. Of this, 42 billion tonnes is reserves: 19 billion tonnes located in New South Wales (NSW) and 23 billion tonnes in Queensland (BP, 2003). On the basis of present output (315 Mt per annum of run-of-mine coal), where the chief producing states are NSW and Queensland, these reserves could satisfy the production for the next 133 years (Gruss, 2002). Australian's saleable hard coal grew significantly from 43.16 Mt in 1980 to 197 Mt in 2002.

Although most its coal production (nearly 95%) is absorbed for domestic market, the US have a capacity to supply world trade market as "a swing exporter". Once the export coal price is higher than domestic price, US will export some of their production to the international market (Ellerman, 1995). Coal output in 2001 totalled 1,017 Mt, of which 980 Mt was for domestic consumption and the remaining was exported. The US have 19 coal ports with an annual total handling capacity of 269 Mt. The country's coal deposits are huge. These are almost 25% of the world's measured and mineable coal reserves and 27% of the world's hard coal reserves. The hard coal reserves are put at 217 billion tonnes, according to the World Energy Council in 2001 (WEC, 2001).

Concerning the domestic coal supply, since the 1960s, coal mining industry in Europe has gone into rapid decline due to competition from coal from outside the Community and the advent of other fuels to produce electricity. It might be argued that the unprofitable coal mines could be maintained by closing them. However, the decision to close permanently the mines has to be taken carefully, including anticipating the implementation of an under-development of novel methane extraction methods, such as Coal Mine Methane (CMM) and Coal Bed Methane (CBM). Once the mines are flooded, they cannot be reopened. Furthermore, the immediate and rapid closing of many coal mines in the short term will only deteriorate the energy supply balance in the Europe.

A mix of imported coal and indigenous coal has a vital role in maintaining a balanced energy policy. The exploitation of indigenous coal reserves, to some extent, may enhance the security of energy supply by reducing the external dependence.

For almost two decades, world coal market characterizes by excess supply, where export capacity is always higher than demand. In 2004, the excess capacity reached almost 50 Mt (see Fig. 2.25). This excess supply situation may secure almost all coal demand. However this market situation is not without problem. The considerable efforts for seeking capital to funding the investment are challenges that need to be addressed by coal exporters as well as importers. Some $400 billion needs to be invested in the world coal industry over the period 2001-2030: 88% in coal mining, 9% in shipping and 3% in ports (World Energy Investment, IEA, 2003b).

South Africa's coal exports are expected to expand moderately to 83 Mt in 2010, before increasing to 103 Mt in 2020 and 110 Mt in 2030. In 2000, 59 Mt of total production (108 Mt) carried by rail from the Transvaal to Richards Bay export terminal (580 km). Rail freight rates rose by around 40% between 1995 and 2002. Part of these freight rates was used to finance the large capital expenditures incurred by the railroad operator. Coal exports are predominantly shipped through the Richards Bay terminal, which had a capacity of 72 Mt per annum in 2000 (Gruss, 2002). The export capacity depends heavily on the railroad capacity to Richards Bay terminal and Richards Bay export capacity itself. New investments, either for maintaining or enlarging the infrastructures, are needed to guarantee their export capacity.

It is predicted (World Energy Investment, IEA, 2003b) that coal mining investments are in order to add 366 Mt of new production capacities, to replace capacities at depleted mines and to meet a growth of demand. Of this capacity, 173 Mt will be required to replace production capacities from mines that will deplete their economic reserves. The new capacity to meet a demand growth is around 193 Mt. Coal exports and imports will require an additional 40 Mt of coal handling facilities. To meet export growth until 2010, the 10 Mt per annum expansion of capacity at Richards Bay will be needed.

Furthermore, the investment in the coal industry over three decades to 2030 in Africa will account around $22 billion (World Energy Investment, IEA, 2003b). South Africa accounts for almost all of this investment. The investment is mainly for maintaining existing mines and expanding new mines, as well as for expanding export facilities at ports, most likely at Richards Bay.

In Latin America, coal production is expected to grow at 2.6% per annum, from 54 Mt in 2000 to 115 Mt in 2030. Coal production in this region in 2000 was headed by Colombia (71%), followed Venezuela (15%) and Brazil (13%). Exports come mainly from Colombia (81%) and Venezuela (18%). With abundant coal, reaching 6.6 billion tonnes of proven reserves, Colombia could satisfy coal demand in the EU-15. The coal industry in the country has a potential to increase exports to 50 Mtpa by 2005. The achievement of such an export target will depend upon market availability and further development of rail and port infrastructure. The main production comes from the El Cerrejon Norte mine (17 Mtpa), which has plans to increase exports to 21 Mtpa in the next few years.

At present there are two rail links, with annual capacity of 34 million ton, available to transporting coal to the coast. However, the use of this link is confined to the major producers, El Cerrejon and Mina Pribbenow, so that smaller exporters are still depending on costly transportation to the coast by truck. In spite of favourable deposit conditions and the proximity of coal deposits to the coast, further development of the mining sector and its coal chain infrastructures is making only slow progress. The reasons for this are the inadequate control of large sections of the country by the government and potential investors are unnerved by ongoing guerrilla activity.

Latin America will need to invest some \$9.8 billion in coal mining and port infrastructure over the 2001-2030 period. Of this, \$9.2 billion will be distributed between Colombia and Venezuela (World Energy Investment, IEA, 2003). Investments in coal mining will account for \$8.6 billion for new capacities to meet demand growth and to replace depleted capacity, as well as for sustaining capital investment to maintain and increase the mine productivity.

Even though the role of coal suppliers, such as South Africa and Colombia, is important to cope with the expected growth in the EU demand in the forthcoming years, challenges need to be addressed. One of the importance challenges is to seek capital to fund the investment. Energy projects, such as coal mining, are more capital-intensive than projects in most other industries. They involve large initial investments before production can begin and expose to differing types and degrees of risk. Furthermore, coal mining has relatively low return on investment (8% in average).

Project financing is likely to play a much smaller role in the coal industry than in gas, oil and electricity sectors. Coal producers in South Africa and Colombia therefore have to compete for seeking capital with a portfolio of projects across mining sectors. Moreover, the growing concern on environmental impact from coal utilisations, the excess of export capacity, and the declining trend of real coal prices in recent years have greatly increased risks for new investment projects. In these circumstances, for projects to be approved, coal producers will need to show an adequate rate of return even under worst-case scenarios.

2.3. Inquire nº 3: What efforts to reduce coal environmental impacts?

After the previous discussion has argued that the EU-15 still needs and burns coal for at least for the next two decades, the next important question is therefore how to reduce environment impacts of coal utilization. This part will discuss two topics, which are the environmental challenges of coal utilization and how to response them; and a roadmap of technology development for coal. A further discussion on this topic can be seen in Chapter 3, particularly on the topic of Europe strategy in realizing vision of less-CO2 emission from coal utilization.

2.3.1. The environmental challenges

Coal can have significant environmental impacts at every stage of its production and utilization. This, however, can be mitigated. The coal industry is continuing to improve its environmental performance by working to ensure that coal is produced and used efficiently and that the opportunities for technological advancement are fully and vigorously pursued.

Almost all man-made CO2 emissions in Europe are attributable to the energy sector. Fossil fuels are the prime sources. In absolute terms, coal consumption accounts for 28%. In terms of consumer sectors, electricity generation and steam raising are responsible for 37% of CO2 emissions. This CO2 emission challenge has to be dealt with by policy and technology progress as well. Table II-11 shows main environment challenges of coal utilization, including particulate, NOx, SOx and CO2 emissions, and explains how the technology response those challenges.

The EUs policy makers are supporting initiatives geared to reduce the impact of coal use on the environment. For example, the European Commission was sinking EUR 68 million over period

1998-2006 within the fifth and sixth Framework Programme (FP5 and FP6[11]) into research on CO2 capture and storage. The target is to reduce costs from € 50-60 to € 20-30 per tonne of CO2 captured, whilst aiming to achieve capture rates above 90% (EU Commission, 2004).

The potential technology exists for very low emissions of NOx, SOx, particulate and CO2. The IGCC (Integrated Gasification Combine Cycle) power station, coupled with CO2 capture and sequestration are an option to reduce emission of CO2 to atmosphere. The captured CO2 can either be used for direct storage or for Enhanced Oil Recovery (EOR). The technology for sequestration is being proven as a pilot project in the Sleipner facility in the North Sea, which can sequestrate nearly 1 Mt CO2/year in a deep saline aquifer. The cost of Carbon Dioxide capture and sequestration from IGCC is now at around $20-50/t CO2.

Nowadays modern coal-fired power plants are capable of achieving thermal efficiency levels of up to 45%. This is an approximately 10-15% improvement on plants built in the 1970s, which are now need to be replaced. A lignite-fuelled power station, as an example, with its optimised plant technology (known as the BoA system in Germany) has a thermal (operating) efficiency up to 43%. The next development phase of this plant will include optional lignite pre-drying that is expected to reach a thermal efficiency level of some 47% (Eurocoal, 2003). Fig. 2.30 shows development in the capacity and thermal efficiency for coal-fired power plants in Europe.

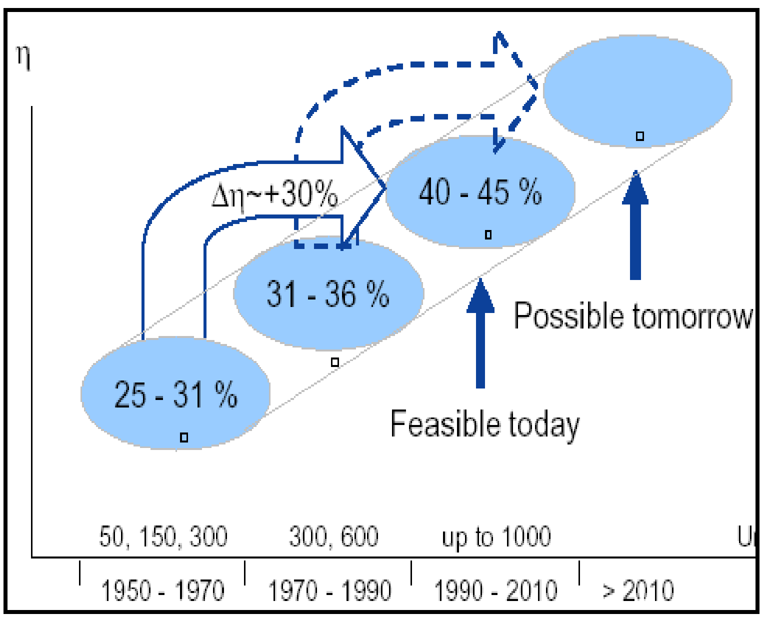


Figure 2.30. Development in the capacity (MW) and thermal efficiency (%) of coal-fired power plant.
Source: Böcker (2004)

[11] The CO2 capture and storage was part of the seven thematic priorities in FP6 under the title 'Sustainable development, global change and ecosystem". Of 16,270 million € FP6 budget, about 700 was dedicated for global change researches.

Table II-11. Environmental Challenges and technology responses for coal-fired power plant. *Source: from various sources*

Core Element	Environmental Challenges	Technology Response	Status
Technology for reducing emissions of pollutants	Particulate emissions	- *Activated carbon Injection ; Electrostatic Precipitators; Fabric Filters* - Technologies have removal efficiencies of over 99%.	Technologies developed, commercialized and widely applied both in developed and developing countries.
	NOx emission	- *Flue Gas Desulphurisation ; Integrated Gasification Combined Cycle ; Selective Catalytic Reduction* - Over 90% of NOx emissions can be removed by treating the NOx in the flue gas.	Technologies developed, commercialized and widely applied in developed countries. The application of NOx control techniques is less prevalent in developing countries.
	SOx emission	- *Flue Gas Desulphurisation ; Wet Particle Scrubers ; Coal benefiation ; Integrated Gasification Combined Cycle* - Emissions can be reduced by over 90% and in some instances by over 95%.	Technologies developed, commercialized and widely applied in developed countries. The application of desulphurisation techniques is less prevalent in developing countries
	Combustion waste	- *Coal benefiation (cleaning)* - Reduces waste, SOx emissions and increases thermal efficiencies. It can be reprocessed into construction materials (e.g. fly ash in cement making)	Technology developed, commercialized and widely applied both in developed and developing countries
Efficient Combustion Technologies	CO2 emission	- *Pulverised Coal Combustion (PF) ; Fluidised Bed Combustion (FBC); Integrated Gasification Combined Cycle (IGCC); Pressurised Pulverised Coal Combustion; Supercritical Pulverised Fuel (S. PF)* - In the short to medium term, substantial reductions in CO2 per megawatt hour of electricity produced can be achieved by increased combustion efficiency (megawatt hours per tonne of coal consumed).	Technologies developed, commercialized and applied in some developed and developing countries. Average thermal efficiency in OECD is 38% and in developing countries is 30%. Current new technology can achieve 45% of efficiency Tech. PF coal : proven to be excellent; commercially Tech. S. PF and FBC: proven to be good; commercially Tech. IGCC : not yet proven, demonstration stage
Reduction CO2 Emission	CO2 emission	- *Carbon Capture (pre-combustion; oxyfuel combustion; post-combustion capture) ; Carbon Storage (geological reservoir, saline aquifer); liquifaction; gasification* - Zero-emissions technologies' to enable the separation and capture of and its permanent storage in the geological subsurface;	Technologies have been developed beyond the stage of technical feasibility, even though still not yet commercialized Researchers are planning to improve these component technologies and demonstrate them in integrated configurations. Deployment may start within a decade.

2.3.2. Discussion: A road map of Clean coal technology

Clean Coal Technologies (CCT) are technologies employed and being developed to meet coal's environmental challenges. It represents a developing range of options to suit different coal types, different environmental problems, and different levels of economic development.

The future of the industry is now holding its hopes on the Clean Coal Technologies, including CO2-free emission and better efficiency for coal power plants. The vision of CO2-free facilities is therefore sustained by the necessities of climate policy.

Coal's technical response to its environmental challenges is to have three core elements:

1. Reducing emissions of pollutants such as particulate matter and oxides of sulphur and nitrogen
2. Increasing thermal efficiency to reduce gases emissions, including CO2 per unit of electricity generated
3. Reducing CO2 emissions to near zero levels through carbon capture and storage

There is a roadmap along which offers a route to meet the main challenge of reducing greenhouse gas emissions. The first step is improvements in efficiency, which can reduce emissions of both pollutants and carbon dioxide per unit of power generated. The efficiency of plants in many European countries is now around 38%, compared with the developing countries average of only 30%. New supercritical plant can achieve overall thermal efficiencies more than 40% range. In some countries, e.g. Germany, Netherlands, such plants are already fully commercial.

The increased efficiencies offered by the state-of-the-art technologies offer the reductions prospect in CO2 emissions from coal-fired power generation over the short to medium term. In the longer term, technologies for carbon capture and storage (CCS) have the potential not only to be an economic and environmentally acceptable to a low carbon but also to enable coal to form the basis of a future hydrogen economy. Fig. 2.31 resumes a route to reduce CO2 emission from coal burning.

These technologies enable emissions of carbon dioxide to be captured and stored; that is stripped out of the exhaust stream from coal combustion or gasification and disposed of in such a way that they do not enter the atmosphere. The concepts provide for the CO2 to be stored in liquid form in former oil or gas deposits, in deep layers carrying salt water (saline aquifers) or in not mineable coal seams (Fig. 2.32). Carbon storage is not currently commercial but the required technologies are already proven and have been used in commercial applications in other contexts.

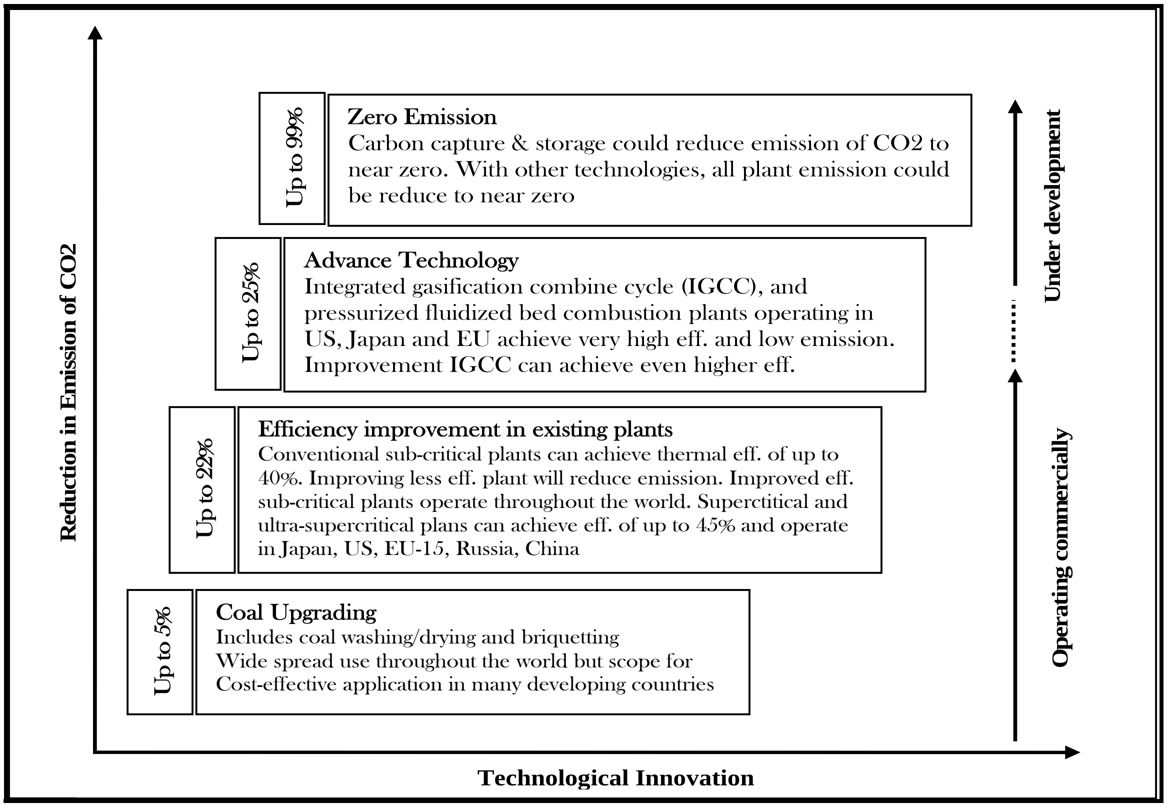


Figure 2.31. Coal-fired route to CO2 reduction.
Source: Redraw from World Coal Institute (WCI) (2004)

2.4. Closing remarks

Energy is vital to human development. Access to modern energy services not only contributes to economic growth but also to the improved quality of life that comes with better education and health services.

Concerning Europe, through the Lisbon Strategy, which was announced in 2000 (Euractiv, 2006), Europe has committed to make EU the most dynamic and competitive knowledge-based economy in the world, capable of sustainable economic growth with more and better jobs and greater social cohesion, and respect for the environment. An appropriate energy policy is important to achieve these targets. Since the oil embargoes of the 1970s, much of Europe has not faced any serious threat to the security of its energy supplies. However, energy policy predominantly security of supply is now backed in fashion in Europe. The slow progress to liberalize European energy markets, high oil prices and the growing European fossil fuel import dependency, have contributed to a sense of unease with reliance on market forces and conventional regulation.

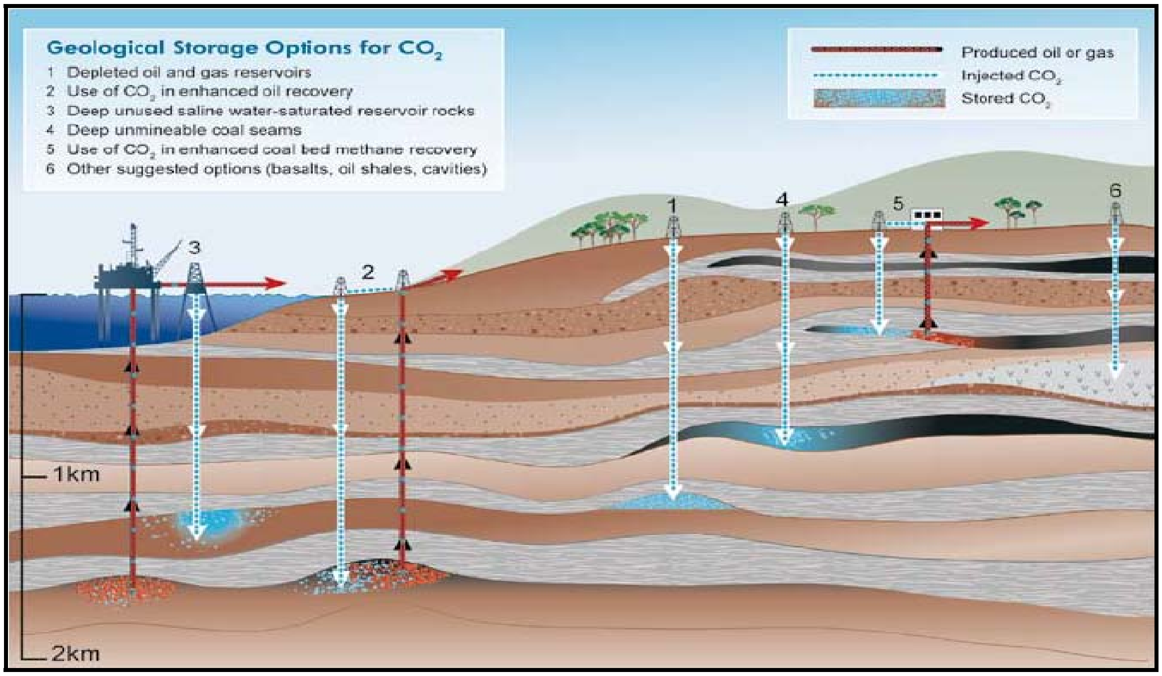


Figure 2.32. CO2 capture and storage
Source: International Energy Agency , (IEA) (2004)

Europe's energy sector will have to face considerable challenges if it is to ensure security of supplies and invest in replacement power plants and new plants, transmission and distribution systems. By 2020, the EU-25 will need to replace some 200,000 MW of power plant capacity for age reasons and install an extra 100,000 MW to meet growing demand. Therefore, if Europe wants to secure the energy supply, all possible energy options have to be left open.

In addition, the power demand in the EU-15 will increase by approximately 36% until 2020. Gas use will increase significantly in absolute and relative terms, but coal-based generation will still remain a major player as well. The open European market for electric power will strengthen the industrial base and offer electricity to the consumer at a reasonable price. The goal must be to maintain ample and competitive supplies of power and coal can help to make a major contribution. Coal may have a unique role in providing the demand of a secure supply of energy.

In view coal in Europe, the concern about indigenous coal production is that it is not competitive due to high operating costs. It argue that the debate is not how to maintain or even more to increase the indigenous production, rather it is how to manage its production decline in the way to balance between import, demand and production so that Europe can always meet its energy demand securely.

Any decision to close permanently coal mines has to be taken carefully, including anticipating the implementation of non-conventional coal or methane extraction methods. The technologies as Coal Mine Methane (CMM) and Coal Bed Methane (CBM) can extract methane gas trapped in coal beds and then the gas can be use as energy. Once the mines closed by flooding it, it is very costly to be reopened. In addition, any immediate permanent closing of many coal mines in the short term will only deteriorate the energy supply balance in the Europe.

In the periods that world faced with an always-changing energy scene, the security of supply is a predominant factor. To enhance the security of supply, it is argued that the domestic non-economic coal mines has to be closed temporary rather than permanently. Closed mines have to be maintenance during certain periods awaiting for the maturation of non-conventional coal or methane extraction methods or for a preparedness should the prices of other energy shocks.

Coal does face environmental challenges. Being a solid and heavy material, coal is bulky and requires large storage areas. With a lower calorific value than oil and gas, it does not have the ease of use of a liquid or gaseous fuel. It also generates pollution at every stage of the production and utilization. The physical disadvantages of coal have considerably reduced its markets for expansion.

In regard to decision of the future of coal industry in Europe, it has to separate the issue between indigenous coal mining and coal utilization (consumption). It is undoubted that, high mining cost and the lack of competitiveness of European coal-mining have led several Member States to abandon coal. However, concerning coal utilization, the coal industry has a proven track record of developing technology pathways which have successfully addressed environmental concerns at local and regional scales. Ongoing research efforts into improving the efficiency of coal-fired electricity generation and technologies for carbon capture and storage (CCS) offer routes to reduce carbon dioxide (CO2) emissions now and in the future, enabling the energy security benefits of coal-fired power generation to continue to be realized.

Finally, the future of coal industry is largely pinning its hopes on the Clean Coal Technologies and on policy of energy supply security. If these technologies are success to be implemented in the immediate times in the Community, certainly coal will become part of the Europe's solution to meet its emission target, rather than of the problem.

Chapter 3:
European Community and Climate change Protection

3.1. What is climate change

Climate is the average weather over a long time period. The climate is not static: it has changed in the past, over centuries, millennia and even longer periods of time. The term "climate change" is sometimes used to refer to all forms of climatic inconsistency. The term is more properly used to imply a significant change from one climatic condition to another. In some cases, climate change has been used synonymously with the term global warming, a major environmental challenge facing the world today.

Recent research into past climate (Mann et.all., 1999; International Panel on Climate Change, IPCC, 2001) reveals a period of about 8,000 years of overall stability, with global average temperatures moving only by small fractions of a degree Celsius. Over the last millennium, the first 900 years saw only small fluctuations in average global temperatures in the northern hemisphere of less than 1 °C, followed by rapidly rising temperatures in the last 50 years or so (Fig. 3.1).

3.1.1. The greenhouse effect

The initial scientific concerns that global warming might be due to emissions of greenhouse gases (GHGs) caused by human activities. The important factor is the large rise in concentrations of GHGs in the atmosphere. These gases trap heat that is radiated from the surface of the Earth and prevent it escaping to space. The effect has been known for more than a century, and is now directly measurable in the atmosphere. The prime cause is carbon dioxide (CO2), a gas emitted when fossil fuels are burnt. The main fossil fuels are coal, oil and natural gas. Another cause of the increase of CO2 in the atmosphere is the large-scale cutting of forests (deforestation).

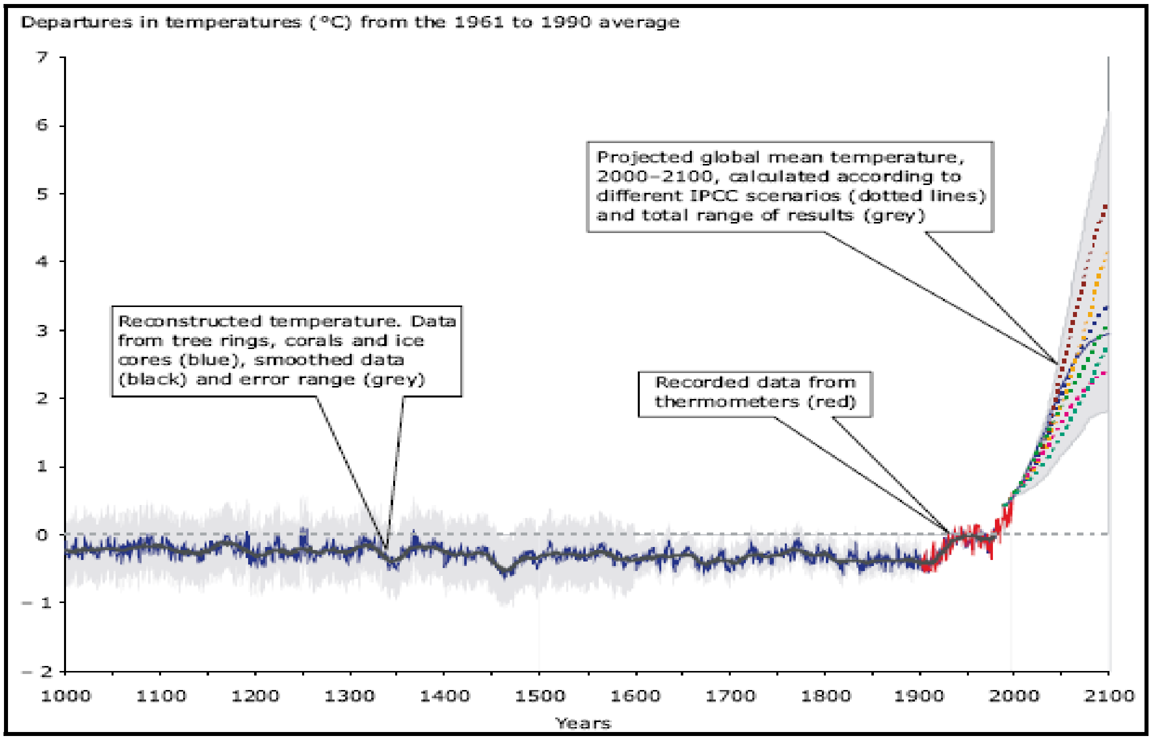


Figure 3.1. Reconstructed, measured and projected temperature in Northern hemisphere.
Source: European Environment Agency (EEA) (2005a)

Human activity is currently sending around 25 x 10^9 t CO2 per year, the most relevant GHGs, into the atmosphere each year. The gas typically persists in the atmosphere for around a century before being absorbed by the oceans and ecosystems on land. Because of its long atmospheric lifetime, these CO2 emissions have caused a steady rise in concentration of the gas in the atmosphere: the current rate is between one and two parts per million (ppm) each year.

A pre-industrial atmospheric concentration of the gas of between 250 and 280 parts per million (ppm) has risen to around 375 ppm today. Man-made emissions of other GHGs such as methane, nitrous oxide and fluorocarbons have raised concentrations of these gases in the atmosphere. These increases have been sufficient to have the same warming impact as a further 50 ppm of CO2. The IPCC scientists have concluded that these accumulations of GHGs are the prime cause of recent climate change and the likely cause of future warming (European Enviroment Agency (EEA), 2005d).

The greenhouse effect is, however, a natural physical phenomenon that is essential to life on earth. Without it, the average temperature of the earth's surface would be around –18°C, rather than the current 15°C.

The GHGs trap infrared radiation; with the atmosphere acts in the same way as the glass of a greenhouse. Among these gases, the most significant are water vapor and carbon dioxide (CO_2) and, to a lesser extent, ozone (O_3), methane (CH_4) and nitrous oxide (N_2O) (Fig. 3.2)

Effects of Global Warming on Society

Global warming causes the oceans to warm and expand, inducing a rise in sea level. Eventually, the rising waters could take away land inhabited by people, forcing them to move. In addition, higher temperatures threaten dangerous consequences: drought, disease, floods, and lost ecosystems. And from sweltering heat to rising seas, global warming's effects have already begun.

Indications of climate change are already visible across the world. Most obviously, warming is leading to most of the world's mountain glaciers and the Greenland ice sheet melting. In general, warming is highest in Polar Regions. There, melting ice means that more of the solar energy reaching the Earth's surface is absorbed, and less is reflected back into space. Rises in Arctic winter temperatures have reached 5 °C in some places already, seven times the global average rise.

There are other indications that weather patterns are shifting around the world, due to extra heat energy in the climate system caused by rising temperatures. In the Pacific Ocean, the periodic fluctuations known as El Niño events appear to be becoming more frequent and intense. Tropical storms are afflicting new areas.

In the Southern Ocean, weather systems that once brought rain to south-west Australia now often do not make landfall. Other weather systems are hitting the Antarctic Peninsula where once they were unknown. The greater energy in the atmosphere is also causing a rise in extreme conditions, including drought, heavy rain, heatwaves and sometimes even intense cold.

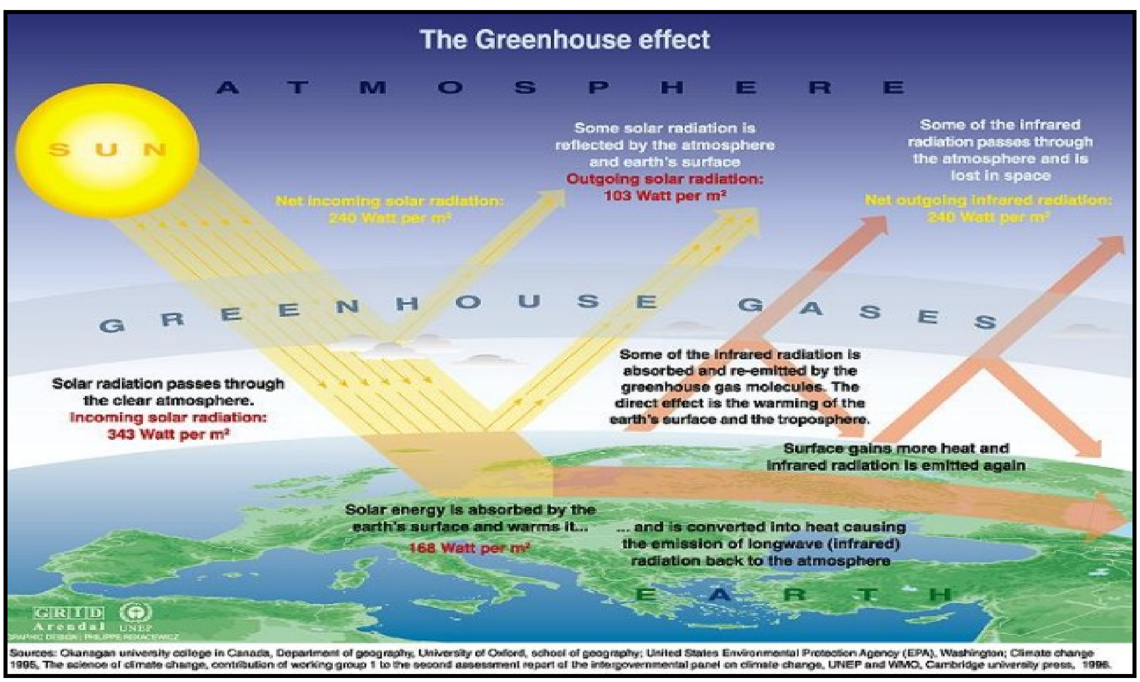


Figure 3.2. Greenhouse effect
Source. United Nation Environment Programme (UNEP) (1996)

3.1.2. Origin emission of greenhouse gases

Human activity raises levels of greenhouse gases primarily by releasing carbon dioxide and other gases. The concentrations of several greenhouse gases have increased over time due to mainly human activities, such as:

- burning of fossil fuels and deforestation leading to higher carbon dioxide concentrations,
- livestock and paddy rice farming, land use and wetland changes, pipeline losses, and covered vented landfill emissions leading to higher methane atmospheric concentrations, many of the newer style fully vented septic systems that enhance and target the fermentation process also are major sources of atmospheric methane.
- the use of CFCs in refrigeration systems. The use of CFCs and halons in fire suppression systems and various manufacturing processes.

Greenhouse gases from industry and agriculture have played a major role in the recently observed global warming. CO2 is the main source GHGs which accounts 72% of total, while Methane and Nitrous Oxide contribute respectively 18% and 9% of total. Some of the origin of the GHGs can be traced as follows:

- CO2 mainly from the combustion of fossil energy, linked to transport and the production of electricity or heat; certain industrial processes, and also from tropical deforestation
- N2O mainly from agriculture, the chemical industry and combustion activities
- CH4 mainly from agriculture, oil and gas activities, and waste disposal activities
- SF6, PFCs and HFCs mainly from certain specific industrial process (manufacturing of aluminum or magnesium, the semi conductor industry), and from aerosols, air conditioning and insulating foam.

The emission shares and changes by main sectors activity in the EU-15 are presented in Fig. 3.3. The most important gases and main emission sources based on its activity are:

- energy supply and use excluding transport : CO2 from fossil fuel combustion in electricity and heat production, refineries, manufacturing industries, households and services;
- transport : CO2 from fossil fuel combustion, but also N2O from catalytic converters;
- agriculture: CH4 from enteric fermentation and manure management, and N2O from soils and manure management;
- industrial processes: CO2 from cement production, N2O from chemical industry, HFCs from replacing CFCs in cooling appliances and from production of thermal insulation foams;
- waste management: CH4 from waste disposal sites.

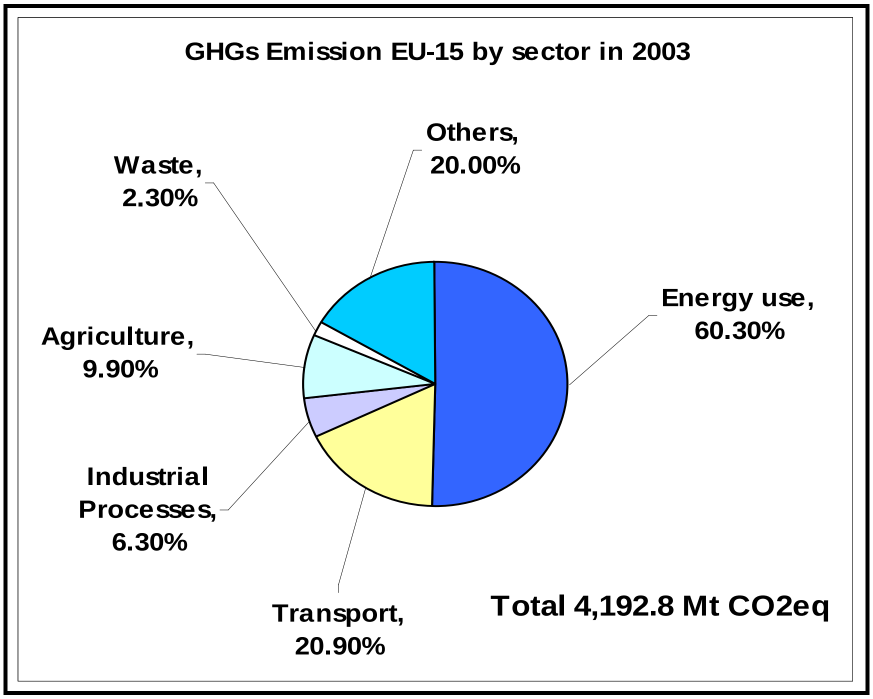


Figure. 3.3. EU-15 Greenhouse Emissions by sector in 2003
Source: Data from European Enviroment Agency (EEA) (2005b)

3.1.3. Coal and climate change

Coal is primarily used as a solid fuel to produce heat through combustion. World coal consumption is at about 5,500 million tones annually in 2005, of which about 75% is used for electricity production. Approximately 40% of the world electricity production now uses coal.

Combustion of coal, like other fossil fuels - gas and oil - produces carbon dioxide (CO2), nitrogen oxides (NO_x), sulfur dioxide (SO_2). Among other fossil fuels, coal is more carbon-intensive fuel per energy unit (Table III-1), and therefore the increment in carbon dioxide emissions from its combustion is higher than the increment in emissions from natural gas or oil.

In 2003, world CO2 emission by fossil fuel was approximately 25 x 10^9 tons. Oil contributes 42% of total while gas and coal account respectively 37% and 21% of total (Fig. 3.4). In the *IEO2006* reference case (Energy Information Administration (EIA), US DOE, 2006) world CO2 emissions from the consumption of fossil fuels will grow at an average rate of 2.1% per year from 2003 to 2030. Emissions in 2030 total 43.67 x 10^9 tons. Combustion of petroleum products contributes 5.03 10^9 tons to the increase from 2003, coal 8.801 10^9 tons, and natural gas 4.80 10^9 tons (Fig. 3.4).

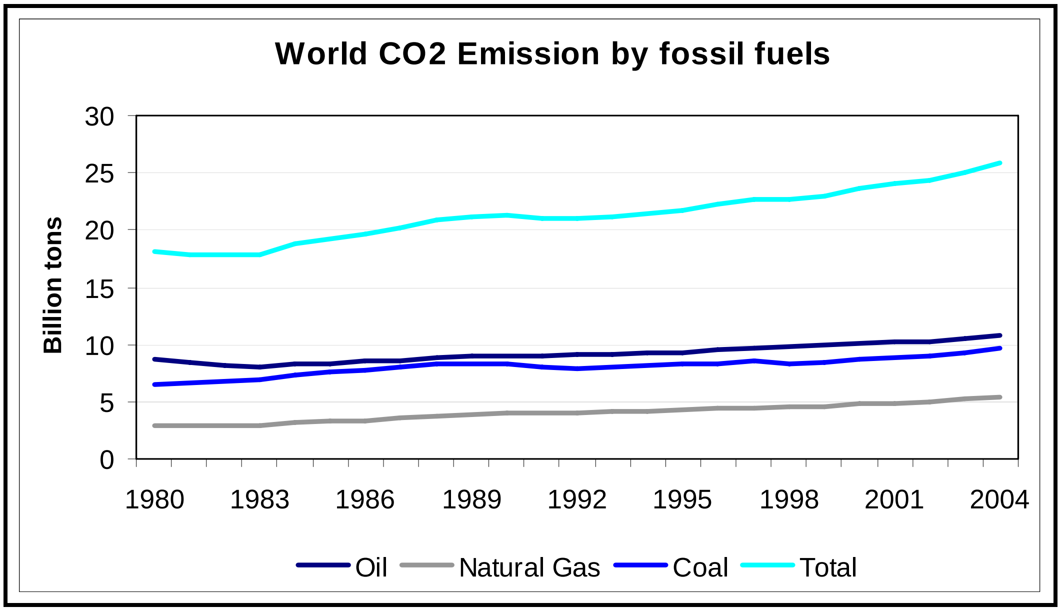


Figure. 3.4. World CO2 Emission by fossil fuels
Source: Data from Energy Information Administration (EIA) (2006)

In the absence of carbon constraints, coal use is projected to grow at about the same rate as natural gas use. However, coal is more carbon-intensive fuel than natural gas. Coal has higher carbon content of 24.5 kg per GJ of heat. While gas has just 13.8 kg per GJ and crude oil has 19 kg per GJ (Table III-1). One ton of coal burning emits about 2.7 ton of CO2. A 600 MWe coal-fired power station operating at 38% efficiency and 75% overall availability will consume Bituminous coal (caloric value 6,000 kcal/kg) approximately 1.5 Mt/year and emit more or less 4 Mt/year of CO2 (World Coal Institute, (WCI), 2002).

Table III-1. Carbon content of different fossil fuels

	Tonnes of carbon per million tones of oil equivalent	Tonnes of carbon per GJ
Natural gas	0.61	0.0138
Crude oil	0.84	0.0190
Bituminous coals	1.09	0.0245
Antrachites	1.14	0.0155
Oil Products		
Gasoline	0.80	0.0180
Kerosine	0.82	0.0185
Diesel/gas oil	0.84	0.019
Fuels oils	0.88	0.10

Source: Gruub(1990); Van Kooten (2004)

Emissions from coal-fired power plants represent the largest source of CO2 emissions. Modern power plants utilize a variety of techniques to limit the harmfulness of their waste products and improve the efficiency of burning. An average efficiency of Europe coal-fired power plant is now about 38%, 8%-10% higher than those in 1970s. To eliminate CO2 emissions from coal burning, apart from increasing thermal efficiency of power plant, carbon capture and storage has been proposed but has yet to be commercially used. The base technology for sequestration of CO_2 is currently being proved as a pilot project in the Sleipner facility in the North Sea with can sequestrate nearly 1 Mt CO_2/year in a deep saline aquifer.

3.2. Action against climate change

3.2.1. A global binding commitment: International efforts to halt climate change

To act against the global phenomenon of climate change, two major agreements have been adopted by the international community.

The first is the United Nations Framework Convention on Climate Change (UNFCCC), signed in Rio de Janeiro in 1992 (UNFCCC, 1992) acknowledged that climate change is a major environmental issue. It sets as its long-term objective "the stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system". In addition, it stipulated that in year 2000, forty countries that were developed or undergoing the process of transition to a market economy, as well as the European Union, should reduce their GHGs emissions. These countries are referred to as "Annex 1 Parties." The UNFCCC came into force in early 1995, after ratification by 175 countries.

The second is the UNFCCC implementation rules and criteria were specified by the Kyoto Protocol in 1997. This implementation has been the subject of an annual international meeting, known as a "Conference of the Parties" (COP), since 1995. The most significant meeting was COP7 in November 2001, concerning the implementation of project mechanisms (UNFCCC, 1998). The Protocol came into force in early 2005, after ratification by 141 countries.

The Kyoto Protocol sets quantified commitments to limit or reduce GHC emission for 40 developed countries, known as "Annex B Parties," and listed in Annex B the Kyoto Protocol. The commitment of industrialized countries in the Kyoto Protocol was to reduce their emissions of a basket of six greenhouse gases to 5.2 % below their levels in a given base year (1990 in most cases) by the period 2008–2012.

The Protocol covers six GHGs of anthropogenic origin: CO_2, CH_4, N_2O, SF_6, PFCs and HFC. The gases are each allocated a global warming potential (GWP) coefficient, reflecting their respective different warming capacity. The coefficient is used to compare various GHG emissions based on a common measurement unit, which by convention, is one metric ton of carbon dioxide equivalent (tCO_2-eq). GWPs measure the relative global warming contribution due to atmospheric emission of a kg of a particular greenhouse gas compared to emission of a kg of carbon dioxide, integrated over a chosen time period. Table III-2 enables a comparison of the GWPs of the six GHGs covered by the Kyoto Protocol.

The Protocol also introduced 3 new international mechanisms, referred to as the "flexible mechanisms" or "Kyoto mechanisms", that are essential components of the Protocol as a whole, and without which the Protocol is unlikely to enter into force. These mechanisms are intended to facilitate the cost-effective implementation of the Protocol. One of these mechanisms is the international trading of greenhouse gas emissions ("emissions trading"), that would become operational from the year 2008.

Table III-2. Global Warming Potential (GWP) coefficient

Gas	Lifetime (y)	GWP for 100 years per tonne,
Carbon dioxide, CO2	100	1
Methane, CH4	12	23
Nitrous oxide, N20	114	296
Fully fluorinated, SF6	2,600 – 50,000	5,700 - 22,200
Ether, PFC	0,015 - 150	1 to 14,900
Hydrofluorocarbons, HFC	0,3 - 150	12 to 12,000

Note. The lifetime of a gas is residence time in the atmosphere. It is determined by its chemical composition and its reaction with other elements of the climate system.

Source : International Energy Agency (IEA), Beyond Kyoto (2002)

Countries are meant to meet their targets by cutting domestic emissions by their own policies and measures but are entitled to also use the Protocol's 'flexible mechanisms'. These include direct trade in emissions permits (called Assigned Amount Units, or AAUs) between countries with targets, and investment in projects in other developed or developing countries, that cut emissions which would otherwise be made. Countries are also allowed to use increasing carbon uptake by forests and other ecosystem sinks.

3.2.2. The Kyoto Protocol and European community: Ratification and its currents status of GHG's Emission

3.2.2.1. Ratification

Combating climate change and minimizing its potential consequences by achieving stabilization of atmospheric greenhouse gas concentrations as well as avoiding dangerous interference with the climate system are key objectives of the world communities. These represent also high priority for the EU. This requires substantial reductions in global greenhouse gas emissions.

As a first step, as Parties to the UNFCCC in 1997, the EU-15 adopted the Kyoto Protocol. Under the Protocol, the European Community committed itself to reducing its emissions of six greenhouse gases by 8% during the period 2008 to 2012 in comparison with their levels in 1990 (EU Council Decision 2002/358/EC). In practice, this will require an estimated reduction of 14% compared to "business as usual" forecasts. Within this overall target, differentiated emission limitation or reduction targets have been agreed for each of the pre-2004 member States under an EU accord known as the 'burden-sharing agreement'[12] (Table. III-3).

[12] The level of European internal burden sharing was determined by "Triptych Approach". Levels were determined by dividing emissions into three parts (electricity generation, heavy industry, and domestic sectors), and then establishing targets for each sector and for each country – which were then aggregated to determine a national objective.

3.2.2.2. Currents status of GHGs in the EU-15

To help meet the Kyoto target, the EU-15 countries have adopted a portfolio of policies and measures (i.e. carbon tax, permit price, increase efficiency of power plant, etc) and the three Kyoto mechanisms. Some countries have to prepare other measures (i.e. European Emission Trading) in order to achieve their target. It is estimated that reduction emissions from domestic policies and measures up to 2003 were not sufficient for many EU-15 member States to be on track to meeting their targets. Greenhouse gas emissions in 2003 of most member States are well above their hypothetical target paths from their base-year emissions to their 2010 targets. Therefore, the Kyoto mechanisms together with additional domestic policies and measures have been planned by several member States to meet the EU-15 target.

Table III-3. Greenhouse Gases' emission target for the EU-15 and its status in 2004

Country	Year		Change	Burden Sharing
	1990 (Base)	2004	1990 to 2004	Base year to 2008/12
	million tonnes	Million tonnes	%	%
Austria	78.3	91.3	15.7	-13
Belgium	146.9	147.9	0.7	-7.5
Denmark	69.3	68.1	-1.8	-21
Finland	71.1	81.4	14.5	0
France	567.1	562.8	-0.8	0
Germany	1,230	1,015.3	-17.5	-21
Greece	111.1	137.6	23.9	25
Ireland	55.8	68.5	22.7	13
Italy	518.9	582.5	12.3	-6.5
Luxembourg	12.7	12.7	0.3	28
Netherlands	214.3	217.8	1.6	6
Portugal	60	84.5	41	27
Spain	289.4	427.9	47.9	15
Sweden	72.5	69.9	-1.5	4
United Kingdom	767.9	659.3	-12	-12.5
EU-15	**4,265.3**	**4,227.5**	**-0.9**	**-8.0**

Source: European Enviroment Agency (EEA) (2005d)

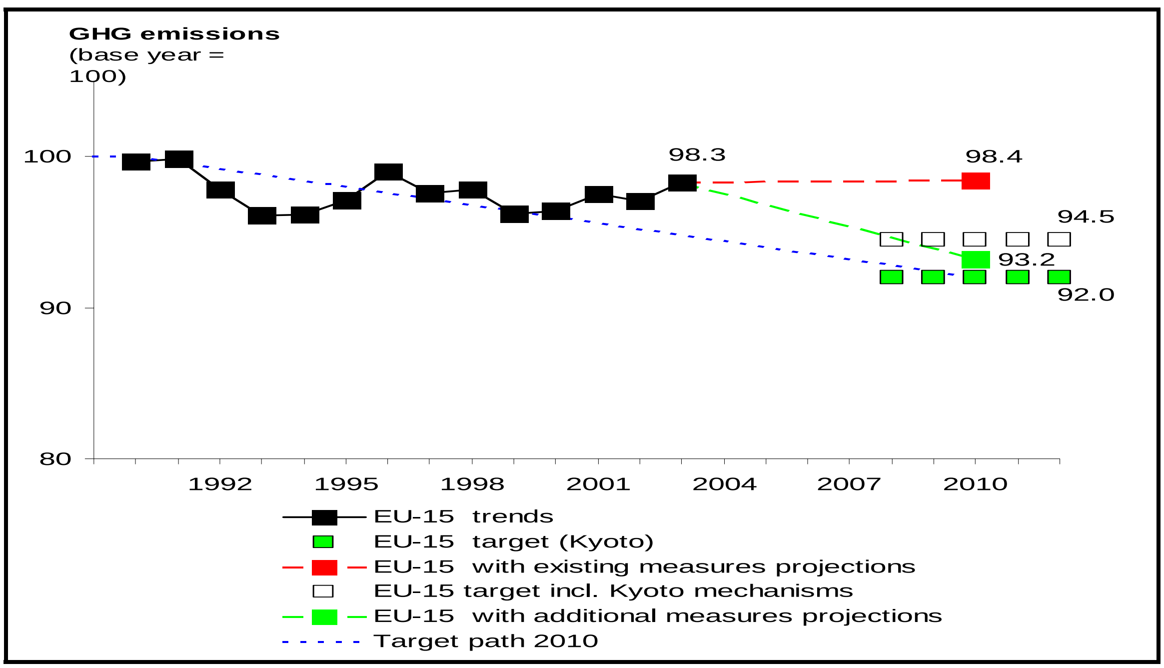
In 2003, the aggregate greenhouse gas emissions of the EU-15 member States were 1.7% (from 100 to 98.3) below base year level with an increase of more than 1% from 2002 to 2003 (Fig. 3.5). After the fall of nearly two thirds of the period, between 1990 and the first commitment period (2008–2012), the reduction by 2003 is about a fifth of that needed to reach the EU-15 greenhouse gas emission target of an 8% reduction (European Environment Agency (EEA), 2005b).

Under the Kyoto Protocol, Member States can use flexible mechanisms, Joint Implementation (JI), Clean Development Mechanism (CDM) and European/international Emission Trading, to help meet their targets. Several countries have intentions to use these instruments, but only a few are in an advanced stage of implementing Kyoto mechanisms.

In 2010, the aggregate projections for the EU-15 of greenhouse gas emissions based on existing domestic policies and measures are 1.6% below base-year levels. This means that the current emission reduction of 1.7% achieved by 2003 from the base-year level is projected to increase by 0.1% by 2010 (Fig. 3.5). This development leads to a shortfall of 6.4 % from 98.4% to 92%, assuming only existing domestic policies and measures in meeting the EU-15 Kyoto commitment. The use of Kyoto mechanisms is expected to deliver an additional 3.9 % emission reduction. Therefore, the combination of domestic policies and the use of Kyoto mechanisms would reach emission to 94.5%. In addition adapting additional measures may reduce emission up to 1.3% from 94.5% to 93.2% from base level. All current measures and policies lead to a shortfall of 1.2% to 92%.

Only two member States, Sweden and the United Kingdom, expect that existing domestic policies and measures alone will be sufficient to meet their burden-sharing targets. All others are projected to be significantly above their commitments with their existing domestic policies and measures.

Additional domestic policies and measures planned by several member States would be sufficient to meet the EU-15 target, but only if Kyoto mechanisms are also included and assuming over-delivery by several Member States (Austria, Belgium, France, Greece, Luxembourg, the Netherlands, Sweden and the United Kingdom) compared to their burden-sharing targets. Key additional policies and measures reported by member States are measures promoting electricity generation from renewable energy sources, cogeneration policies and energy efficiency policies.



Note: Target paths are used to analyze how close emissions were to a hypothetical path of emission reductions, assuming domestic policies and measures as well as use of Kyoto mechanisms. The EU-15 target including Kyoto mechanisms is based on an estimated projected use of Kyoto mechanisms, equal to about 2.5 % of the target of 8%. This target for the EU-15 including Kyoto mechanisms is presented in the graph as 92 + 2.5 or 94.5%

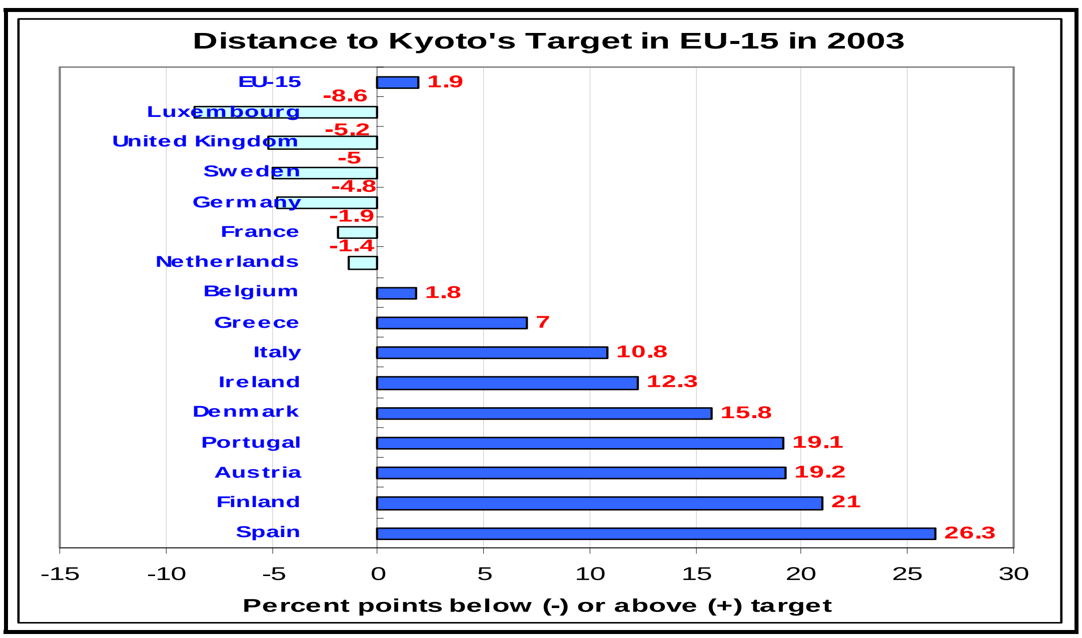
Figure 3.5. Actual and projected EU-15 GHGs compared with Kyoto target
Source: Redraw as of the data from European Environment Agency (EEA) (2005b)

It is predicted that greenhouse gas emission reductions only from domestic policies and measures up to 2003 were not sufficient for many EU-15 member States to be on track to meeting their targets. Greenhouse gas emissions in 2003 of most Member States are above their hypothetical target paths from their base-year emissions to their 2010 targets (Fig. 3.6). To help to meet the target of Kyoto, EU-15 has to use the three Kyoto's instruments.

The emission reductions in the early 1990s were largely a result of increasing efficiency in power and heating plants, including coal-fired power plant, the economic restructuring in the new federal states in Germany, the liberalization of the energy market and subsequent changes in the choice of fuel used in electricity production from oil and coal to gas in the United Kingdom, and significant reductions in nitrous oxide emissions in the chemical industry in France, Germany and the United Kingdom (European Environment Agency (EEA) (2005b).

The favorable picture for the EU-15 has been determined largely by considerable emissions cuts in Germany and the UK, the EU's two biggest emitters, which together account for 40% of total EU-15 GHGs emissions. The 1990 to 2003 reductions amounted to 18.5% in Germany and 13.3% in the UK. France and Italy the third and fourth largest emitters decreased (-1.9 %) and increased (9.0%) their emissions between 1990 and 2002.

Four member States (France, Germany, Sweden and the United Kingdom) were below their burden sharing target paths excluding Kyoto Mechanisms. Several member States were above their burden-sharing target paths excluding Kyoto Mechanisms: Austria, Belgium, Denmark, Finland, Greece, Ireland, Italy, Portugal and Spain (Spain by more than 25 index points).



Note. The distance-to-target indicator (DTI) measures the deviation of actual emissions in 2003 from a (hypothetical) linear path between base-year emissions and the burden-sharing target for 2010. A positive value suggests an under-achievement and a negative value an over-achievement by 2003. The DTI is used as an early indication of progress towards the Kyoto and Member States' burden-sharing targets.

Figure 3.6 Distance to the Kyoto's target for EU-15
Source: Data from European Environment Agency (EEA) (2005b)

3.3. Policy Strategy for combating climate change in the EU-15

To fight against climate change, countries have adopted a portfolio of policies and measures. Most policies tend to come from three policy "families": policy processes (strategic planning, disseminating information, and consultation), fiscal instruments (taxes, tax exemption or credit, incentives, subsidies), regulatory instruments (mandates, standards and regulations). These policy types are familiar as they are commonly used in areas other than climate change. In addition, two instruments are quite common in new climate policies – voluntary agreements with industry, such as the Kyoto Protocol mechanisms and tradable permit systems, such as emission trading (EU Directive 2003/87/EC).

3.3.1. The Kyoto Protocol Mechanisms

To enable the Annex 1 Parties to meet their objectives cost-effectively, the Protocol has defined three international mechanisms, known as "flexible mechanisms", which are designed to limit the costs of measurement to act against climate change. These are international trading of national GHG emission allowances, or "Assigned Amount Units (AAU)", Joint Implementation (JI) and the Clean Development Mechanism (CDM).

As of 2008, the international trading of Assigned Amount Units will allow Annex 1 Parties to purchase AAU from other Annex 1 Parties. The JI mechanisms will grant emission credits to Annex 1 countries that invest in emission reduction projects in another Annex 1 country. CDM is the only mechanism that associates developing countries which, with respect to the "common but differentiated responsibilities" mentioned in the Kyoto Protocol, have no greenhouse gas emission reduction targets (Fig. 3.7).

Emissions trading:
Trade in emission allowances is possible between industrialized countries.

Joint Implementation (JI):
Lower emission thanks to investment by one industrialized country in another are credited entirely to the emissions account of the investing country

Clean Development Mechanism (CDM):
Lower emissions thanks to investment by an industrialized country in a country without reduction obligations are credited to the emissions account of the investing country.

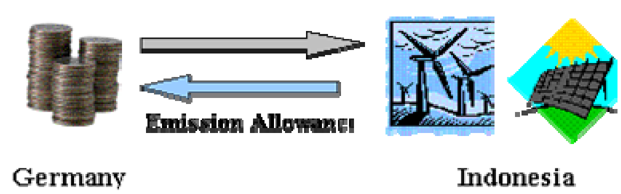


Figure 3.7. The Kyoto Protocol mechanisms
Source: UNFCCC, 1987

JI enables developed countries to work together to meet their emission targets by means of project activities. The CDM enables a developed country to meet its target, while project activities must be hosted by a developing country. International Emission Trading allows countries that have achieved emissions reductions over and above those required by their Kyoto targets to sell the excess to countries finding it more difficult or expensive to meet their commitments. In this way, it seeks to lower the costs of compliance for all concerned.

JI and the CDM are called "project mechanism" and fall within the rationale of GHG emission control at a global level, thus reflecting the type of challenge faced by the planet and enabling the generation of credits by all players (States, project developers), based on the reduction effectively achieved via the projects. These "projects mechanisms" are sometimes called "Kyoto projects".

All EU-15 member States have provided information on their intended use of the flexible mechanisms of the Kyoto Protocol to achieve their targets for the commitment period 2008–2012.

Member States provided information on the intended use of Kyoto mechanisms through a questionnaire under the greenhouse gas monitoring mechanism (EU Directive 2004/280/EC), the third National communications under UNFCCC and national allocation plans of the EU Emission trading scheme. After the assessment of the national allocation plans the European Commission evaluated the state of advancement of financial and institutional preparations for the use of Kyoto mechanisms. The European Commission has raised no objections against the intended use of Kyoto mechanisms in the national allocation plans of Austria, Belgium, Denmark, Ireland, Italy, Luxembourg, the Netherlands and Spain.

For the EU-15, the intended use of Kyoto mechanisms amounts to 106.8 million tonnes of CO2-equivalents per year of the commitment period. This amount corresponds to over 30 % of the total required emission reduction for the EU 15 of about 340 million tonnes CO2-equivalents per year during the first commitment period or 2.5% of the EU-15 Kyoto target of -8 %.

Nine member States have already allocated resources for the use of Kyoto mechanisms (Austria, Belgium, Denmark, Finland, Germany, Italy, the Netherlands, Spain and Sweden). Austria, Italy, the Netherlands and Spain allocated the largest budgets (€ 288 million, € 1,320 million, € 606 million and € 200 million for the five-year commitment period). The total budget allocated by the nine Member States amounts to about € 2,730 million.

3.3.2 European Mechanisms: ETS, Carbon Taxes and Policies and Measures to promote energy efficiency

3.3.2.1. Emission Trading Scheme (ETS)

Building on the innovative mechanisms set up under the Kyoto Protocol, the EU has developed the largest company-level scheme for trading in emissions of carbon dioxide (CO2), making it the world leader in this emerging market. The emissions trading scheme started in the 25 EU Member States on 1 January 2005 (EU Directive 2003/87/EC).

According to Article 1:

"This Directive establishes a scheme for greenhouse gas emission allowance trading within the Community (hereinafter referred to as the 'Community scheme') in order to promote reductions of greenhouse gas emissions in a cost-effective and economically efficient manner."

Emissions trading, both internally within the Community and externally with other industrialized countries, will help to reduce the cost to the Community of respecting its commitments. Together with other polices and measures, emissions trading will be an integral and major part of the Community's implementation strategy.

Creating the emissions trading scheme and linking it to JI and the CDM has been identified by the European climate change programme as a particularly cost-effective way to reduce greenhouse gas emissions. This programme has brought together all relevant stakeholders to develop policies and measures to help the EU meet its Kyoto target.

The directive of EU emissions trading scheme covers, so far, CO2 emissions from large stationary sources including the power and heat generators, oil refineries, ferrous metals, cement, lime, glass and ceramic materials, and pulp and paper.

On June 2005, the European Commission accepted the last of the 25 national allocation plans, finishing the allocation process for more than 11,450 installations. Almost 80% of the installations covered are located in EU-15 Member States. These large scale CO2-emittants in industry and the electricity sector will now have to hold certificates equivalent to the amount of their CO2 emissions.

The emission trading accounts for more than half (52%) of the total CO2 emissions in the EU. The European Commission has approved the allocation of about 2.19 billion allowances per year in the trading period 2005 to 2007. In August 2005, there was approximately 25 Mt of emissions have been traded with the price of emission at about €22/ton of CO2 (Fig. 3.8).

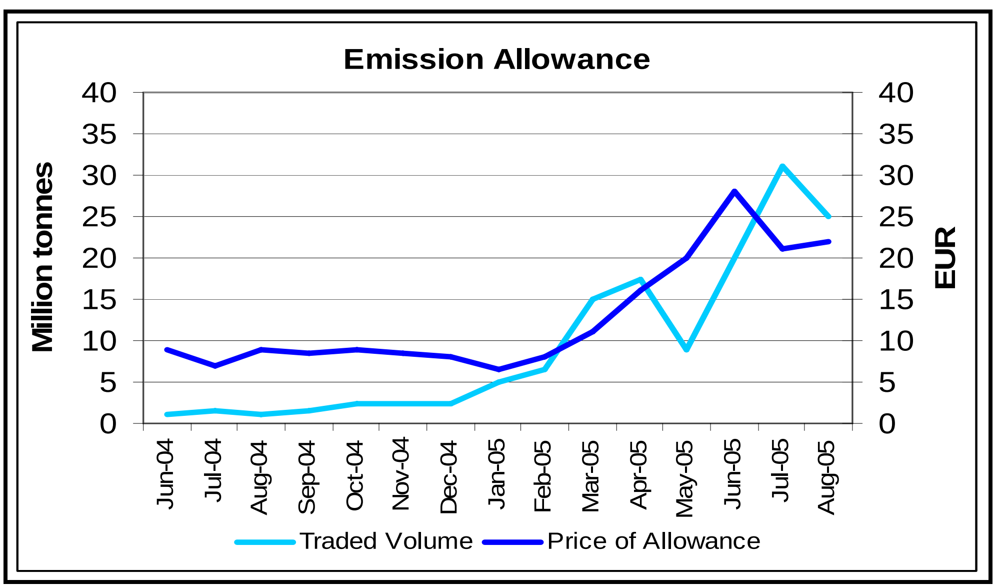


Figure 3.8. Traded of Emission Allowance and its price
Source: Data from European Enviroment Agency (EEA) (2005c)

Principles of emission trading scheme in Europe

An emission trading is a scheme whereby companies are allocated allowances for their emissions of greenhouse gases according to the overall environmental ambitions of their government, which they can trade subsequently with each other. These emission allowances are sometimes called "quotas", "permits" or "caps". The total of all these allowances allocated to all the companies included in the scheme represents the overall limit on emissions allowed by the scheme.

Emissions trading allows individual companies to emit more than their allowance on condition that that they can find another company that has emitted less than allowed and is willing to transfer its "spare" allowances. The overall environmental outcome is the same as if both companies used their allowances exactly, but with the important difference that both buying and selling companies benefited from the flexibility offered by trading, without disadvantage to the environment. Both companies involved incur lower compliance costs than they would have been able to do without the possibility of trading (the "selling-company" receiving payment for the allowances transferred, and the "buying-company" incurring less costs than would have been implied by adhering to the pre-determined emissions allowance). As emissions trading will induce competition between companies to find cost-effective ways to reduce their emissions, an additional boost will be given to environmentally friendly technologies.

During the first trading period from 2005 to 2007, the ETS covers only CO2 emissions from large emitters in the power and heat generation industry and in selected energy-intensive industrial sectors: combustion plants, oil refineries, coke ovens, iron and steel plants and factories making cement, glass, lime, bricks, ceramics, pulp and paper. These industrial sectors would cover approximately 50% of EU carbon dioxide emissions. In the case of the cement industry, the number of cement plants in the EU is small, and so all plants could be included. In the heat and power sector it seems feasible to include all plants with thermal capacity of greater than 50 MWth.

At the heart of the ETS is the common trading 'currency' of emission allowances. One allowance represents the right to emit one tonne of CO2. Member States have drawn up national allocation plans for 2005–07 which give each installation in the scheme a certain number of allowances free of charge, thus allowing it to emit the corresponding amount of CO2 without any cost. Decisions on the allocations are made public.

The limit or 'cap' on the number of allowances allocated creates the scarcity needed for a trading market to emerge. Companies that keep their emissions below the level of their allowances are able to sell their excess allowances at a price determined by supply and demand at that time.

Those facing difficulty in remaining within their emissions limit have a choice between taking measures to reduce their emissions, such as investing in more efficient technology or using a less carbon-intensive energy source, buying the extra allowances they need at the market rate, or a combination of the two, whichever is cheapest. This ensures that emissions are reduced in the most cost-effective way.

The EU ETS is basically a cap and trade scheme. By facilitating trade, the European Commission estimates that Kyoto targets can be achieved at an annual cost of €2.9 to €3.7 billion, representing less than 0.1% of the GDP in the EU, compared to double that cost estimated with €6.8 billion without the EU ETS.

The emissions trading system is set to cut CO_2 emissions where it costs least to do so. Economic sectors and each plant concerned are given concrete reduction targets and allocated emission allowances. These allowances are tradeable. If the company achieves its targets by taking low-cost CO_2 reduction measures of its own, it can sell any allowances surplus to requirements on the market. Alternatively, it must buy in more allowances if its own reduction measures would be more expensive.

Most allowances are allocated to installations free of charge, at least 95% during the initial phase and at least 90% in the second phase from 2008 to 2012. Though only plants covered by the scheme are given allowances, anyone else - individuals, institutions, non-governmental organizations - is free to buy and sell in the market in the same way as companies.

Initial allowances in a trading scheme must be allocated either by auctioning, sales or "grandfathering", which means free of charge. In the European Union, allowances in the allocation period before 2012 will be allocated mainly by grandfathering. According to the ETS Directive, member States have only an option to auction a small proportion (up to 5% 2005-07 and up to 10% 2008-12). The initial allocation for existing industries was exclusively organized through grandfathering, meaning free allocation of allowances based on emissions in a selected time period.

If the company fails to meet its reduction duties, sanctions threaten, amounting to €40 per tonne CO_2 in the first trading period, rising to 100 euros three years after their entry into the scheme, and the underachieved reduction target must still be met after the event in the following year.

In 2005, the Commission published its approval of member States' allocation plans. Table III-4 gives an overview on the allowances accepted and the number of installation in member States.

The EU emissions trading scheme (ETS) is based on recognition that creating a price for carbon through the establishment of a liquid market for emission reductions offers the most cost-effective way for EU member States to meet their Kyoto obligations and move towards the low-carbon economy of the future.

The scheme is based on six fundamental principles.

- It is a 'cap-and-trade' system.
- Its initial focus is on CO_2 from big industrial emitters.
- Implementation is taking place in phases, with periodic reviews and opportunities for expansion to other gases and sectors.
- Allocation plans for emission allowances are decided periodically.
- It includes a strong compliance framework.
- The market is EU-wide but taps emission reduction opportunities in the rest of the world through the use of the CDM and JI, and provides for links with compatible schemes in third countries.

Table III-4. Emission Trading in EU for period 2005-2007

EU Member State	Allocated CO2 Allowances	Share in EU Allowance	Installation Covered	Kyoto Target
	Million tonnes	%		%
Belgium	188.8	2.9	363	-7.5
Czech Republic	292.8	4.4	435	-8
Denmark	100.5	1.5	378	-21
Germany	1,497	22.8	1,849	-21
Estonia	56.85	0.9	43	-8
Greece	223.2	3.4	141	+25
Spain	525.3	8.0	819	+15
France	469.5	7.1	1,172	0
Ireland	67	1.0	143	+13
Italy	697.5	10.6	1,240	-6.5
Cyprus	16.98	0.3	13	-
Latvia	13.7	0.2	95	-8
Lithuania	36.8	0.6	93	-8
Luxembourg	10.07	0.2	19	-28
Hungary	93.8	1.4	261	-6
Malta	8.83	0.1	2	-
Netherlands	285.9	4.3	333	-6
Austria	99	1.5	205	-13
Poland	717.3	10.9	1,166	-6
Portugal	114.5	1.7	239	+27
Slovenia	26.3	0.4	98	-8
Slovakia	91.5	1.4	209	-8
Finland	136.5	2.1	535	0
Sweden	68.7	1.1	499	+4
United Kingdom	736	11.2	1078	-12.5
T O T A L	**6,572.4**	**100**	**11,428**	

Source: EU Directive 2003/87/EC

3.3.2.2. Carbon and energy taxation

Carbon and energy taxes have been considered as a policy instrument for reducing carbon dioxide emissions. In the practice of environmental policies an increasing number of Western European countries have implemented taxes based on the carbon or energy content of the energy products (Sweden, Norway, The Netherlands, Denmark, Finland, Austria, Germany and Italy). Several other countries, like Switzerland, France and the United Kingdom, are currently discussing proposals for their implementation.

An adaptation of carbon taxes in the EU is based on the Directive of 27 October 2003 (EU Council Directive 2003/96/EC), restructuring the Community framework for the taxation of energy products and electricity. With this Directive the system of taxation was extended to all products including oil, coal, natural gas and electricity. The directive sets minimum rates of taxation for motor and heating fuels. Moreover, the member States are required to tax electricity at the minimum rate defined in the Directive. The member States are free to charge energy products used for electricity generation not only with the mandatory output tax but also, for environmental reasons, with an input tax.

Carbon taxes, as specific environmental taxes, generate direct payments to the administrative body based on the carbon content of the fuel being consumed. Carbon taxes affect the externality (carbon) directly. Coal generates the greatest amount of carbon emissions and is therefore taxed in greater proportion than oil and natural gas, which have lower carbon concentrations and lead to lower carbon emission per unit of energy.

Carbon tax differs from emission allowance. Carbon taxes fix the marginal costs for carbon emissions, and generate specific revenues for the state budget, while tradable permits fix the total amount of carbon emitted and allow price levels to fluctuate according to market forces.

Energy taxes include taxes on energy products used for both transport and stationary purposes. The most important energy products for transport purposes are petrol and diesel. Energy products for stationary use include fuel oils, natural gas, coal, and electricity. Concerning CO2 taxes, they are included under energy taxes rather than under pollution taxes because they partly substitute for other energy taxes.

Taxes on energy products and the derived 'implicit' carbon taxes vary significantly between countries (Table III-5), and thus the average price of a ton of carbon is relatively different from country to country. This is one of the main problems to implement European coordinated carbon taxes.

Table III-5. Rates of CO2 taxation in European countries which introduced carbon taxes

	Treatment of Industry	Electricity Use		Coal	Natural Gas	Fuel Oil	Diesel	Petrol
		€/ MWh		€/tones of CO2			€/tones of CO2	
		House-hold	Industry				Car	
Austria	Tax payments capped at 0.3 per cent of firm's net sales	15	0	0	19	25	110	181
Denmark	Lower rates in exchange for abatement agreement. 85 per cent refund if energy tax exceed 3.5 per cent	9.7	11	Between 0.4 and 131			141	241
Finland	At value added	7.4	4.5	14.5	8.7	23	121	260
Germany	Carbon tax payment capped	21	12	0	17	20	179	289
Ireland	Likely to received exemption. No tax on quantities above 10 GWh	0	0	Tentatively 15 to 20			124	177
Netherlands	For electricity & gas. Only emission above negotiated targets are liable	64	0	0	80	66	-	93

Norway	Special rate for: Metal processing, dom. avitiation & shipping, fishing, pulp and paper process., off shore activ.	12	0	Between 0 and 40			106	201
Sweden	Reduced rates	11	0	78		104	132	220
United Kingdom	Only 20 per cent of the climate levy & abatement targets are agree to	0	4	5	11	10	203	312

Source: Organization for Economic Co-operation and Development (OECD) (2004)

Table III-5 also shows that there are large differences between the taxation levied on different energy products. Some fuels, like petrol and diesel, are heavily taxed. The main reason is that those energy products possess low demand elasticities, and taxing them is an easy way to collect fiscal revenues. With respect to the carbon content of energy products, it should also be noted that, in almost all countries (except Sweden and Denmark), coal has a particularly low implicit carbon tax. In fact, coal is even still heavily subsidised in countries like Germany and Spain. More in general, fossil fuels with higher carbon content often have lower implicit carbon taxes than those with lower carbon content.

In Europe the characteristics of carbon or energy taxes are mainly as follow:

- usually only one instrument in a variety of measures aimed at reducing emissions or curbing energy consumption in general.
- often part of a general fiscal reform; replacing other taxes on energy and reducing the distortion impacts of traditional taxes (e.g. on labour and capital).
- usually gradually phased-in and adjusted over time to account for inflation.
- including exemptions and exceptions have been granted to energy-intensive industries or to industries facing international competition.

3.3.2.3. Promote energy efficiency and other measures

The key to switching from the trajectory to a low-emissions development pathway will ultimately lie primarily in reducing energy consumption and improving energy efficiency, and changing the way Europe generates and uses energy for all purposes, including transport. There are a number of ways which can be proposed to do this, including increase energy efficiency, fuel switch, cogeneration and renewable energy and carbon capture and storage.

Energy efficiency

Many cost-effective strategies for improving energy efficiency remain heavily underused. This occurs on both the energy supply side, where more efficient power stations could be employed (those, for example, that use heat that would otherwise be wasted), and on the demand side.

In the case of coal-fired power plant, the average thermal efficiency has increased from 30% in 1970s to 38% in 2005. In some countries, i.e. Germany, there is now coal-fired power plant – BoA technology - which has 43% of efficiency and can be increased to 45%.

Fuels switch, co-generation and renewables

If the EU is to make the progress it desires towards a low-emissions economy, a change in the fuel mix, especially for electricity generation, appears inescapable. Including to these is a deployment coal-fired cogeneration technology which is able to provide reliable and environmentally power and heat (Combine Heat Power, CHP).

In Europe, an example of operation of most advance coal-fired cogeneration is at Mladá Boleslav Power Plant in the Czech Republic (World Coal Institute, (WCI), 2000). The Plant utilizes hard coal to fuel two base load circulating fluidized bed boilers. The boilers generate steam for two steam turbines. The turbines can also be fed by a back-up boiler, which can burn either natural gas or fuel oil. Natural gas is also used for start-up and support in the fluidized bed boilers. As a result of cogeneration overall fuel utilization efficiency is approaching 80%, which means the energy content of the fuel is being utilized to a far greater extent than in normal condensing power plants

Carbon capture and storage

An emerging new option is the capture and storage of CO2 from power stations and industrial stacks. The technology could potentially contribute significantly to the mix of measures that is required to meet the tough long-term targets on cutting emissions.

The International Energy Agency estimates (IEA, 2004b) that by 2030 substantial amounts of CO2 could be captured in Europe. The gas would be sent by pipeline or tanker for burial in geological formations that are impermeable to CO2, and so kept out of the atmosphere for a long period of time. These stores might include emptied oil and gas wells, unmineable coal seams and saline aquifers.

3.3.2.4. The Green Paper on Energy: way to move to a common energy policy

The EU Commission in March, 2006 issued a draft of "Green Paper: a European Strategy for Sustainable, Competitive and Secure Energy" spelling out options to achieve "sustainable, competitive and secure" energy supplies in the EU (European Commission COM (2006) 105 Final). This Paper completes previous Green Paper in 2000. The Green Paper identifies six key areas where action is necessary to address the challenges of energy in Europe. The Paper proposes a common European strategy for energy, where sustainability, competitiveness and security should be the core principles to underpin the strategy.

The proposed energy strategy is developed based on most fundamental questions in each six key areas, as follow:

1. *Competitiveness and the internal energy market*
   Is there agreement on the fundamental importance of a genuine single market to support a common European strategy for energy? How can barriers to implementing existing measures be removed? What new measures should be taken to achieve this goal? How can the EU stimulate the substantial investments necessary in the energy sector? How to ensure that all Europeans

enjoy access to energy at reasonable prices, and that the internal energy market contributes to maintaining employment levels?

2. *Diversification of the energy mix*
   What should the EU do to ensure that Europe, taken as a whole, promotes the climate-friendly diversification of energy supplies?

3. *Solidarity.*
   Which measures need to be taken at Community level to prevent energy supply crises developing, and to manage them if they do occur?

4. *Sustainable development.*
   How can a common European energy strategy best address climate change, balancing the objectives of environmental protection, competitiveness and security of supply? What further action is required at Community level to achieve existing targets? Are further targets appropriate? How should we provide a longer term secure and predictable investment framework for the further development of clean and renewable energy sources in the EU?

5. *Innovation and technology*
   What action should be taken at both Community and national level to ensure that Europe remains a world leader in energy technologies? What instruments can best achieve this?

6. *External policy*
   Should there be a common external policy on energy, to enable the EU to speak with a common voice? How can the Community and Member States promote diversity of supply, especially for gas? Should the EU develop new partnerships with its neighbors, including Russia, and with the other main producer and consumer nations of the world?

The Green Paper has set out the suggested possible actions at the European level. In taking the debate forward, it is essential to act in an integrated way. Each member State will make choices based on its own national preferences. However, in a world of global interdependence, energy policy necessarily has a European dimension. Therefore, Europe's energy policy should have three main objectives:

- *Sustainability*: (i) developing competitive renewable sources of energy and other low carbon energy sources and carriers, particularly alternative transport fuels, (ii) curbing energy demand within Europe, and (iii) leading global efforts to halt climate change and improve local air quality.

- *Competitiveness:* (i) ensuring that energy market opening brings benefits to consumers and to the economy as a whole, while stimulating investment in clean energy production and energy efficiency, (ii) mitigating the impact of higher international energy prices on the EU economy and its citizens and (iii) keeping Europe at the cutting edge of energy technologies.

- *Security of supply:* tackling the EU's rising dependence on imported energy through (i) an integrated approach – reducing demand, diversifying the EU's energy mix with greater use of competitive indigenous and renewable energy, and diversifying sources and routes of supply of imported energy, (ii) creating the framework which will stimulate adequate investments to meet growing energy demand, (iii) better equipping the EU to cope with emergencies, (iv) improving the conditions for European companies seeking access to global resources, and (v) making sure that all citizens and business have access to energy.

To achieve these objectives, it is important to put them in an overall framework, in the first Strategic EU Energy Review. This could be augmented with a strategic objective which balanced the goals of sustainable energy use, competitiveness and security of supply; for example, by aiming for a minimum level of the overall EU energy mix to come from secure and low-carbon energy sources. This would combine the freedom of Member States to choose between different energy sources and the need for the EU as a whole to have an energy mix that, overall, meets its three core energy objectives.

3.3.3. Strategy of development of Clean Coal Technology in Europe

Presently research programs and budgets on CCT are still concentrated at the national level. The EU's main instrument for R&D funding in Europe is the multi-annual framework program. Continuing the research on CO2 capture and storage through the fifth and sixth Framework Program (FP5 and FP6), the European Commission has launched a follow-up research.

Through the FP7, which will run for 2007 to 2013, the research activities on the clean coal technology continues together with research on CO2 capture and storage technologies for zero emission power generation, as part of activities in the energy theme. The objective is to substantially improve plant efficiency, reliability and cost through development and demonstration of clean coal conversion technologies. Whereas the research objective on CO2 capture and storage technologies is to significantly reduce the environmental impact of fossil fuel use aiming at highly efficient power generation plants with near zero emissions, based on CO2 capture and storage technologies. The EU Commission intends to make available €2.96 bn for projects in the energy theme in FP 7, including to funding for those two research activities.

The concept clean coal technology in Europe embraces 3 strategies designed to minimize the impact of coal utilization on environment (Euracoal, 2003 ; RWE Power, 2005).

Strategy I: It seeks to promote the technology for the eco-friendly combustion of coal on a Europe-wide basis. This means reducing emissions of dust, NOx and CO2 as well as increasing power station performance. The example of this strategy includes the replacement of older plants by state-of-the-art facilities in Germany like BoA technology - a lignite-fuelled power station with a thermal efficiency up to 43%

Strategy II: It provides for a series of developments based on the improvement of power-station efficiency. Coal-fired power stations have already benefited from an improvement in efficiency over the last 30 years. There are some paths to follow in order to increase efficiency as the priority target: raising steam parameters as for example pre-drying of raw lignite and combined-cycle gas turbine plants. The BoA-Plus, for example, will include optional lignite pre-drying that is expected to reach a thermal efficiency level of some 47%

Strategy III: It takes the future with the visionary concept of the low-to-zero CO2 power station including for coal-fired power plant. The technical and economic challenges that have to be overcome to develop the concept of CO2 capture and storage include the key question of how CO2 can be safely stored in suitable underground deposits. This strategy has high potential for CO2 reduction, but can only be achieved at the expense of cost, efficiency and resource consumption. Studies for the development of zero-CO2 power plants have highlighted three main areas of research: post-combustion technology with CO2 scrubbing; IGCC technology with integrated CO2 capture; and the oxyfuel steam power plant.

An example of development projects for clean coal technology carried by RWE Power, one of Power leaders in Europe, is shown in Fig. 3.9 Those projects are mainly supported both European Union (EU) and Germany government (D).

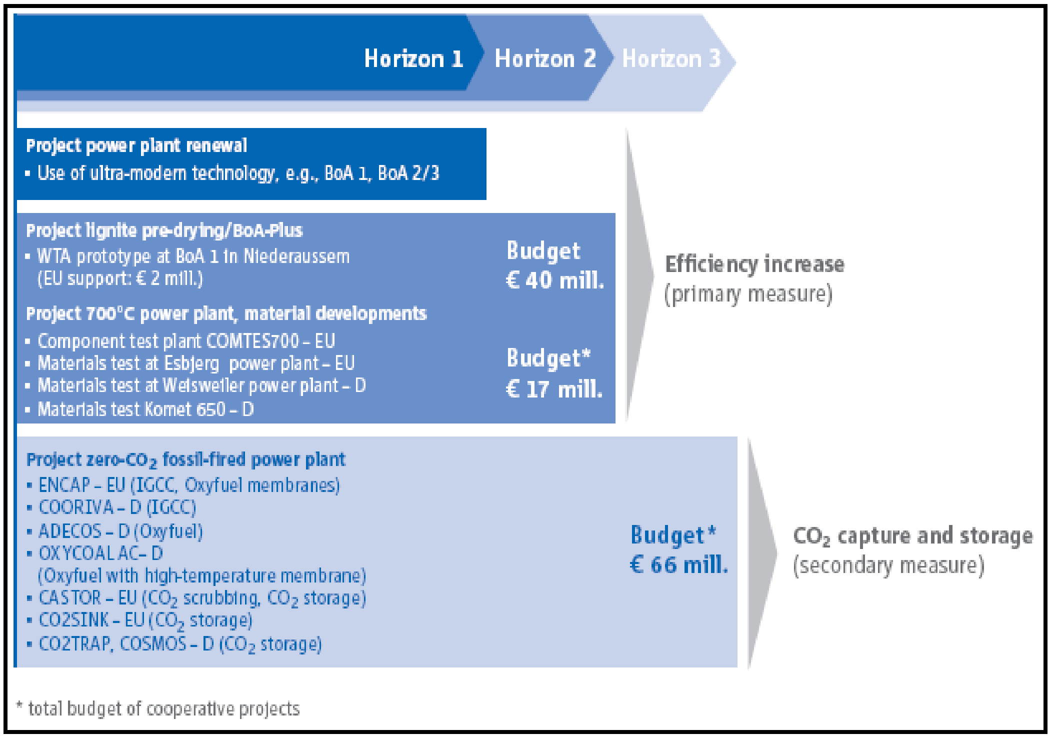


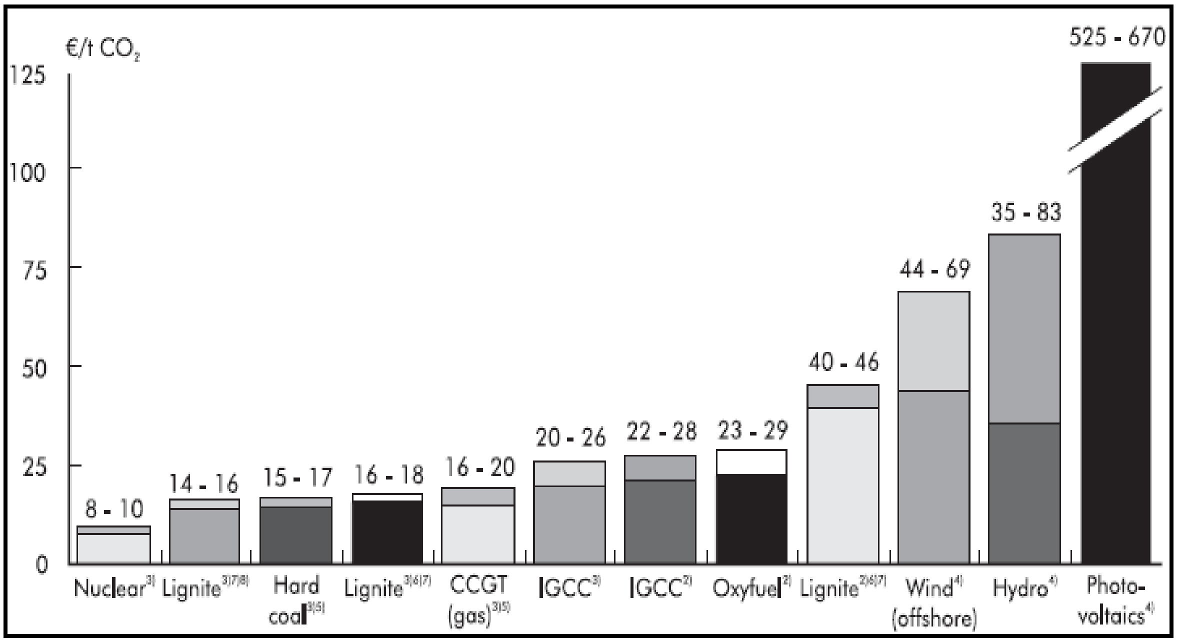
Figure 3.9. Use and Development of Clean Coal technology
Source: RWE Power (2005)

3.4. Discussion: Climate change economics

3.4.1. Cost of avoidance

In order to achieve security of energy supply, economic efficiency as well as environmental compatibility goals, domestic energy resources need to be given appropriate consideration within a well-balanced energy mix. This requires that efficient, environmentally compatible coal-based power plant technology be further developed and replace old coal-fired plants.

Figure 3.10 indicates the specific CO2 avoidance costs in comparison with an old 150 MW lignite-fired power plant (as a reference plant), taken from the report "Reducing greenhouse gas emissions–the potential of coal" (Coal Industry Advisory Board, CIAB, 2005b). The CO2 avoidance costs are the result of the difference between specific electricity generation cost divided by the difference between specific CO2 emissions. Variations in relative prices of coal and gas would affect the above picture. The cost margins shown reflect the uncertainties with regard to fuel prices and costs of new technologies.



Note. 1. Price basis 2004, 2. New technologies incl. CO2 capture and storage, based on a new 1.05 GW lignite-fired power plant, 3. New power plants, 4. Funding of renewables is not considered, 5.CO2 emissions of mining and transport not considered, 6. Pre-drying technology, 7. BoA technology, 8. Based on a lignite-fired with a total 2.1 GW

Figure 3.10. Specific CO2 avoidance costs
Source: Coal Industry Advisory Board (CIAB) (2005b)

For renewables, plant sizes and locations are additional factors in determining the cost margin. As the costs of the reference plant, only the reducible costs were used (*i.e.* fuel costs and costs for inspections). In the case of hydropower stations and, also, for the construction of new installations including nuclear and fossil power plants (with and without CO2 capture technologies), variable and fixed costs of the reference plant are reducible costs since no reserve capacity is required. Wind and solar energy, however, may temporarily not be available, so that there must be a fossil-fired plant as a reserve. Here, only the short-term variable costs (*i.e.* costs that only account for a fraction of total lignite-specific variable costs) of the reference plant are reducible.

For a hard coal power plant based on imported coal as a reference power plant, the fuel costs, unlike lignite which is mined by the operator, are completely variable costs. This means that the CO2 avoidance costs would be different. This comparison of the specific CO2 avoidance costs shows that the most cost-efficient means of CO2 mitigation are the use of nuclear energy and the renewal of power plants based on fossil energy sources.

Investing in new power plants with higher efficiencies enables us to tap considerable CO2 reduction potentials. For example, the construction of a new 1,000 MW state-of-the-art lignite-fired power plant that replaces existing units yields an annual CO2 reduction of some 3 million tonnes. The expansion of renewables with massive financial aid increases the costs of the power supply because it is not the most cost-effective means of reducing CO2 emissions.

3.4.2. Economics of Clean Coal Technology

A large number of coal-fired plants in Europe was built in 1970s and will end its economic life in around 2015 (Fig. 3.11). Therefore, significant new coal-fired capacity is expected to be built after 2015 as previous coal-fired plants have to be replaced and tighter gas markets push up gas prices to a point which makes coal-fired plant competitive. But there exists a risk that new climate change policies, including demand-side policies, could alter this picture and mean that much of this growth in coal demand might not be materialized.

There remain a number of barriers to the adoption of clean coal technologies, but the most important of these is their high cost. The pace at which clean coal technologies penetrate the market will be crucial to future coal trends.

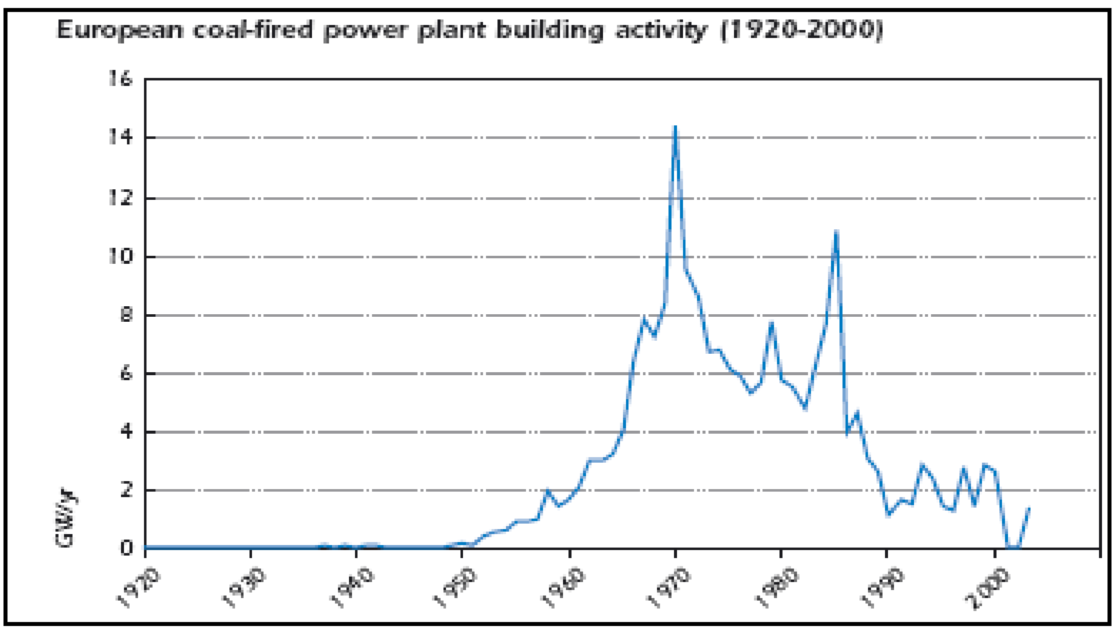


Figure 3.11. European coal-fired power plant building activity (1920-2000)
Source: International Energy Agency (IEA) (2004b)

The lower CO2 emitted from coal-fired power plant generally fall with higher capital costs (Fig. 3.12). Although the most efficient coal-fired technology, integrated gasification combined cycle (IGCC), emits twice as much CO2 per kWh generated as a combined cycle gas turbine (CCGT) plant, it produces a concentrated stream of CO2 which has advantages when it comes to sequestration. IGCC plants are currently in the demonstration phase of their development and are not commercially viable at this stage.

Among other fossil fuels, coal-fired suffers by higher capital cost than those diesel-fired or gas-fired. Capital cost to build coal-fired is about 800-1,300 $ per kW, while for gas-fired and diesel-fired are 350-450 and 400-500 per kW respectively (Table III-6).

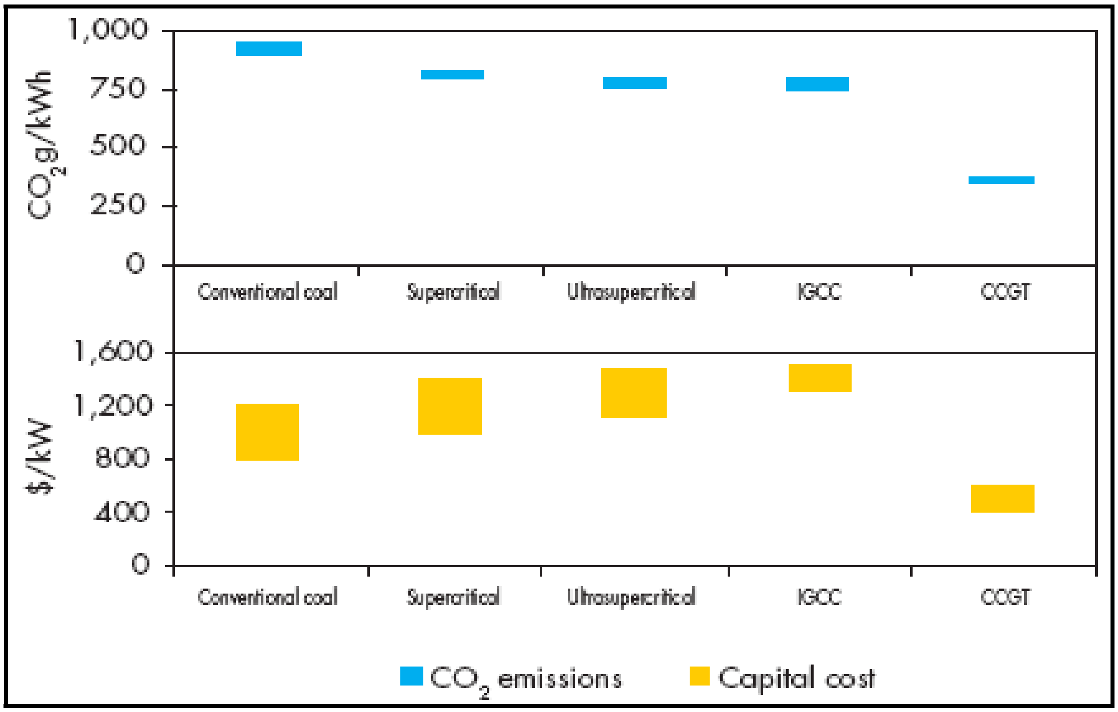


Figure 3.12. CO2 Emissions and Capital Costs by Electricity Generating Technology
Source: International Energy Agency (IEA) (2003)

Table III-6. Current Capital Cost Estimates for Power Plant

Technology	Capital cost ($ per KW)
Gas combined cycle	400-600
Conventional coal	800-1,300
Advance coal	1,100-1,300
Coal gasification	1,300-1,600
Nuclear	1,700-2,150
Gas turbine - central	350-450
Gas turbine - distributed	700-800
Diesel engine - distributed	400-500
Fuel cell – distributed	3,000-4,000
Wind onshore	900-1,100
Wind offshore	1,500-1,600
Photovoltaic - distributed	6,000-7,000
Photovoltaic - central	4,000-5,000
Bioenergy	1,500-2,500
Geothermal	1,800-2,600
Hydro	1,900-2,600

Source: International Energy Agency (IEA) (2001)

Beside the capital costs, investment decisions take into account fuel costs and operation and maintenance costs. Indicative generating costs for four key energy options (gas, coal, nuclear and wind) are shown in Fig. 3.13. These estimates are based on current technologies. The fuel component of gas and coal plants shows low and high values, reflecting prices in different markets and likely future price increases. While there is no significant variation in total costs, their composition varies widely. Some conclusion can be derived from this figure:

- Combined-cycle gas-turbine (CCGT) plants have the lowest capital-cost component but the highest variable costs. They are, therefore, quite sensitive to changes in natural gas prices
- Coal plants have relatively high capital cost. Fuel costs account for a smaller percentage of their total costs, and they can be quite low in coal-producing regions. Coal prices tend to be somewhat more stable than gas prices.
- Nuclear plants have high investment requirements but very low running costs.
- The generating cost of electricity from wind turbines depends on wind speed. Wind turbines generally have high transmission costs. The need for backup capacity also tends to increase costs.

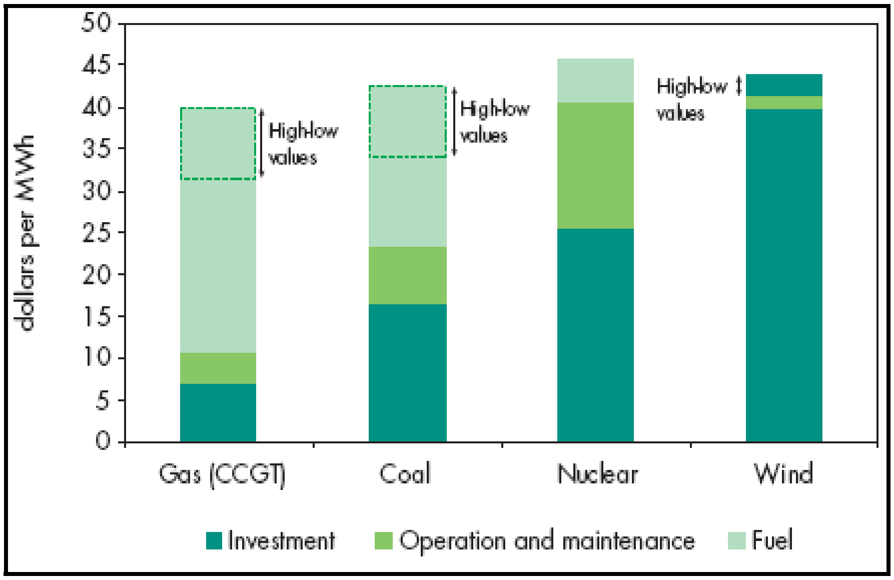


Figure 3.13. Indicative Generating Cost Ranges, 2000
Source: International Energy Agency (IEA) (2002)

3.4.3. Price or Quantity instruments?

Prices and quantities when abatement costs are certain

Economic theory provides insights into choosing between two types of economic instruments to deal with pollution problems, including emission: price instruments such as taxes, and quantity instruments such as tradable permit schemes.

Economists use graphs like the one shown in Fig. 3-14 to define the "optimal level" of pollution. It considers that the marginal benefit of abatement decreases with the level of abatement, because it is common that when pollution increases, its marginal environmental cost increases too. Marginal benefits[13] here represent the present value of all future benefits arising from mitigating emissions over an infinite horizon. The graph considers price and quantity instruments are equivalent when costs are known.

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[13] Marginal costs (benefits) are the most common to be used, instead of total costs (benefits), in calculation of cost (benefits) of abatement. If each additional tonne of pollution is worse for the environment than the previous one, the marginal cost of pollution increases. But in this case, when one looks at the marginal benefits of abatement, the opposite happens: the marginal benefit of abatement decreases when its volume increases – while of course, the total benefits of abatement continue to increase.

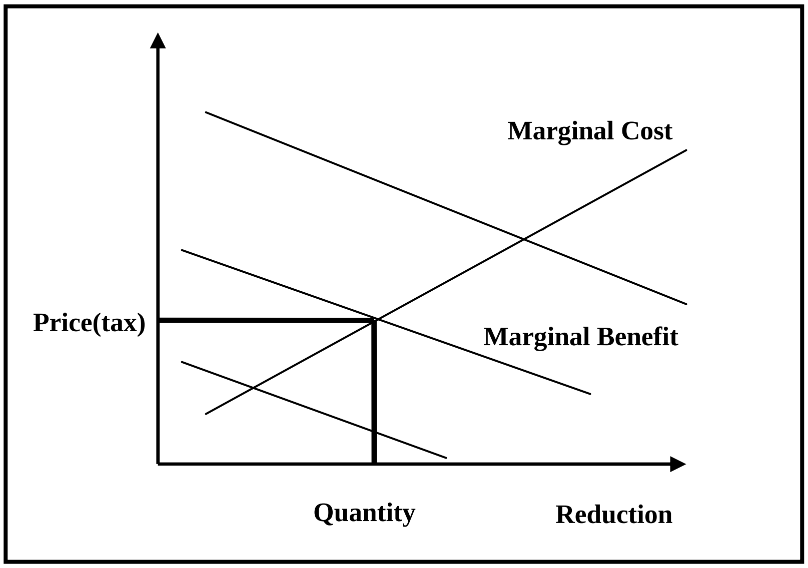

Figure 3-14. Balance on marginal cost and benefit

Conversely, the marginal cost of abatement increases with the level of abatement. The first tonne of a pollutant is easier to eliminate than the last one. Over time things may change. But graphs in Fig. 3-14 do not represent how costs and benefits may evolve over time – but how they relate to the level of effort undertaken at some point in time. In this case the optimal abatement quantity should be fixed at the point where the increasing marginal cost of abatement curve crosses the decreasing marginal benefit curve, according to the best estimate. Beyond that point, abatement costs are too high for too little additional environmental benefit.

The significant point is that if abatement costs are known with certainty, fixing a quantity fixes a price. Conversely, fixing a price would define a quantity. Thus, price and quantity instruments (taxes or tradable quotas) are equivalent from an economic standpoint. This remains true even if the benefits are uncertain.

Prices and quantities when abatement costs are uncertain

If abatement costs are not known with certainty, price and quantity instruments are no longer equivalent. It is the relative slopes of the benefit and cost curves that are important in this case (Weitzman, 1974; Kooten, 2004). If the marginal damage cost (benefit) curve is steep, the damage rapidly increases with the level of pollution. In this case it is worth determining the level of pollution rather than risk suffering too much environmental damage. If, on the contrary, the marginal benefit curve is flat, it means that the damage increases slowly with the level of pollution. It is then preferable to get certainty on the marginal cost of abatement, rather than a risk of paying too high a price for too small an incremental environmental benefit. A steeper benefit curve calls for quantity instruments, a steeper cost curve calls for price instruments (Fig. 3-15).

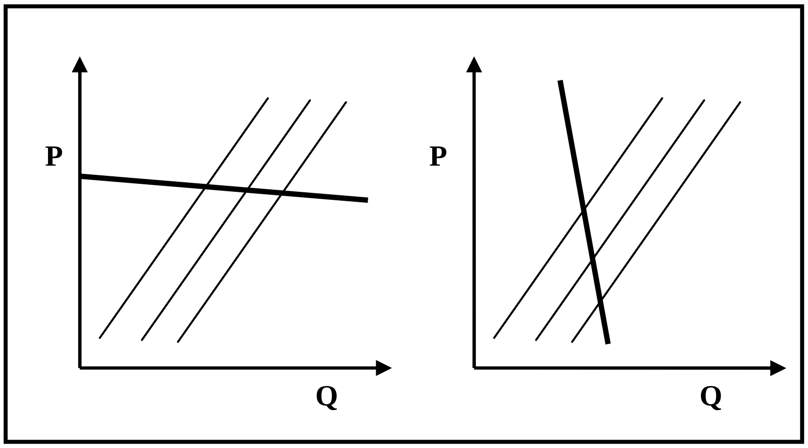

Figure 3-15. *Balance on marginal cost and benefit when cost uncertain*

While price instruments seem to be preferable from an economic perspective, quantity instruments have one key advantage from a political economy perspective. In particular, they allow for emissions reductions to be undertaken wherever they are cheapest – as long as the total quantity reduced remains unchanged. Further discussion on these two instruments will be discussed in Chapter 6.

Extreme cases make these results more intuitive: an extreme case of the first situation would be that of infinite damage, a catastrophe arising when concentrations exceed certain thresholds. With such a vertical benefit curve, a quantity instrument would be absolutely necessary (Fig. 3-15, right-hand side). An extreme case of the second situation would be that of constant marginal damage costs. With a flat horizontal marginal benefit line, fixing a tax at this exact level would ensure optimality regardless of the abatement cost curve. A price instrument would thus be the best choice (Fig. 3-15, left-hand side).

The case of climate change

How does this theoretical preference for price instruments relate to the suggested decision to aim at a low GHG concentration level under cost conditions? The amount of abatement actually undertaken under a price instrument would depend on abatement costs. If costs turn out to be higher than expected, the amount of abatement can be reduced. If they turn out to be lower than expected, the amount of abatement can be increased. Aiming at a low level under a price cap allows essentially the same thing – with some variations.

Climate change is a “stock” externality of GHG concentrations. Given the importance of the “stock” (7,400 Gt of C in atmospheric) compared to annual emissions (80 Gt C), the concentration evolves only slowly. This is what makes the marginal benefit curve rather flat (reflecting a fairly constant marginal climate change damage cost).

A consequence of the “flatness” of the marginal benefit curve is that price instruments should be preferred over quantity instruments to combat climate change. Later on in Chapter 6, this argument will be proven. As shown in Fig. 3.16, a fixed quantitative objective might be far from the optimum quantity once uncertainty on abatement costs is resolved, whereas a tax would always be close to the optimum price. These adaptations take into account the persistence over time of expected benefit losses when price instruments are preferred over quantity instruments.

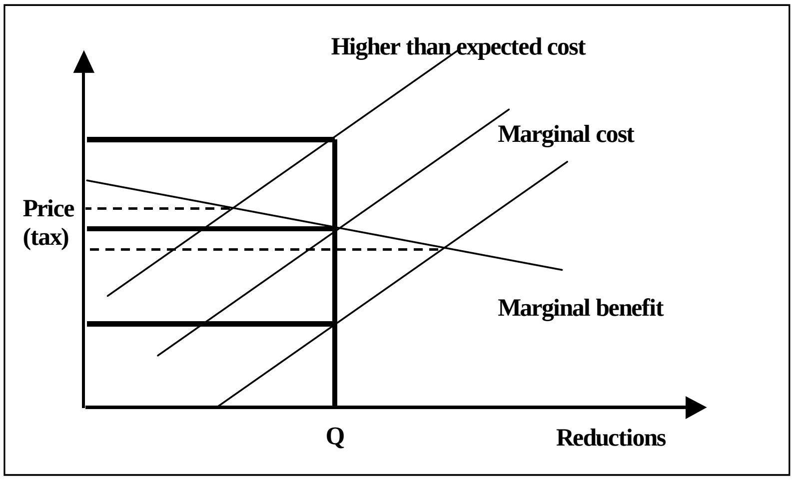

Figure 3.16. Price instrument to mitigate climate change

If a price instrument leads to less mitigation in one period, this has long-lasting effects on subsequent periods. Therefore, these adjustments tend to favor, in relative terms, quantity instruments. However, these may not suffice to reverse policy preferences. A general conclusion is that the performance of price instruments is always increased by the size of the externality stock – given that benefits are relative to concentration level changes while costs are linked to short-term emission reductions.

In the case of climate change, this suggests a strong preference for price instruments. The adaptation made to the original framework cannot reverse the dominance of the stock nature of the externality. However, quantitative instruments have a number of advantages. They help deal with sovereignty concerns; governments' fine-tuning between free allocations and auctioning in order to deal with vested interests. Moreover, they help integrate countries with uneven levels of development into one single framework. This makes hybrid instruments even more appealing.

3.5. Closing remarks

Fossil fuels will continue to be part of the energy mix for several decades to come in Europe. Therefore, in this region the focuses are increasingly on environmental improvement and global climate issues. Coal-fired electricity generation will be an important part of this situation, giving the access to a cost-efficient supply of energy and having the technological potential to make a significant contribution to reducing CO2 emissions over the short and longer term.

Effective research, development and demonstration of potential clean coal technologies are essential for the "clean" use of coal. There is a considerable potential to reduce CO2 emissions from coal use by deploying existing state-of-the-art technology.

Modern coal-fired power plants are capable of achieving efficiency levels of more than 40% on a higher heating value basis. This is about a 20% improvement on plants built in the 1950s and 1960s. Furthermore, modern installations emit less dust, sulphur and NOx than older plants, and their reduced coal usage contributes to management of increasingly scarce energy resources.

A study shows that replacing a capacity of 1,000 MW of old with modern coal-fired power plants increasing an efficiency to 43% can generate a saving of 3 million t CO2/year. Therefore, replacement of old power plants with new plants, given today's age and efficiency distribution in the European power plant fleet, would be equivalent to a saving potential of some 225 million t CO2/a (RWE, 2005), which amounts to 65% of the Kyoto target for the EU.

Electricity generating companies are constantly making plant investment decisions, whether to meet new capacity requirements, to improve environmental performance of existing plant, or to reduce overall costs. It is essential that these decisions are made within policy frameworks that recognize the CO2 reduction potential of increasing the efficiency of coal-fired electricity generation.

Successful R&D depends on stable energy policy frameworks. Market deregulation of energy and electricity markets has brought many benefits, but it has also had undesirable consequences for new technology development. Energy security is not adequately valued in energy markets and deregulation has lowered the returns to and increased the risk aversion of the major utilities, making the financing of new technology in coal-fired power plant more difficult – especially when that technology requires large investments of capital and relatively long capital-recovery periods.

In Europe, uncertainties around the future direction of environmental and global climate policies have slowed investment in coal-fired electricity generating plant. Commercial markets and financial institutions have not had the confidence to invest in newer coal technologies, which would reduce CO2 emissions but which have long payback periods. Instead, investment has tended to favor gas-fired electricity generating capacity with its shorter and less risky payback horizon. However, gas alone will not be able to fill the demand for new generating capacity, and excessive reliance upon it will drive prices higher and decrease energy security.

The development of near-zero emission technologies for coal needs means and political support. National and European policies supportive of advanced coal technologies transfer and exchange to other European member countries (and developing nations) is essential, including recognition of projects in the Joint Implementation and Clean Development Mechanism accounting frameworks under the Kyoto Protocol.

Governments in Europe should seek to balance the social, economic and environmental needs of society by maintaining the energy security, including continued coal use, needed to support its growth. Government policies need to provide long-term strategic solutions for achieving sustainable energy use and economic growth. In this context, government support for the demonstration of coal technologies may be appropriate, allowing these to compete on even terms with mature, commercialized technologies and thereby accelerating their deployment.

The co-ordination of technology development efforts by energy market regulators and participants is also important – lack of co-ordination, rivalry and duplication among research and development programmes will waste resources and delay new technologies.

Chapter 4:
System Dynamics for Energy Modeling

4.1. Fundamental of system dynamics

System dynamics was created during the mid-1950s by Jay W. Forrester of the Massachusetts Institute of Technology. His book Industrial Dynamics (Forrester, 1961) is still a significant statement of philosophy and methodology in the field. Since its publication, the span of applications has grown extensively.

System dynamics is a methodology for studying and managing complex feedback systems. Feedback refers to the situation of X affecting Y and Y in turn affecting X perhaps through a chain of causes and effects. One can study the link between X and Y and, independently, the link between Y and X and predict how the system will behave.

Stocks, Flows, Feedback and Delay

In system dynamics modeling, dynamic behavior is thought to arise due to the Principle of Accumulation. This principle states that all dynamic behavior in the world occurs when flows accumulate in stocks. The stock-flow structure is the simplest dynamical system in the world. According to the principle of accumulation, dynamic behavior arises when something flows through the pipe and faucet assembly and collects or accumulates in the stock. In system dynamics modeling, both informational and no informational entities can move through flows and accumulate in stocks.

Although stocks and flows are both necessary and sufficient for generating dynamic behavior, they are not the only building blocks of dynamical systems. The stocks and flows in real world systems are part of feedback loops, and the feedback loops are often joined together by nonlinear couplings that often cause counterintuitive behavior.

From a system dynamics point of view, a system can be classified as either "open" or "closed." Open systems have outputs that response to, but have no influence upon, their inputs. Closed systems, on the other hand, have outputs that both response to, and influence, their inputs. Closed systems are thus aware of their own performance and influenced by their past behavior, while open systems are not. The most prevalent and important, by far, are closed systems.

The information about a system's state that is sent out by a stock is often delayed and/or distorted before it reaches the flow (which closes the loop and affects the stock). Fig. 4.1 shows a basic stock-flow-feedback loop structure. The structure can be extended to more complex problems as illustrated in Fig. 4.2., in which information about the stock is delayed in a second stock, representing the decision maker's perception of the stock (i.e., Perceived_Stock_Level), before being passed on. The decision maker's perception is then modified by a bias to form his or her opinion of the stock (i.e., Opinion_Of_Stock_Level). Finally, the decision maker's opinion is compared to his or her desired level of the stock, which, in turn, influences the flow and alters the stock.

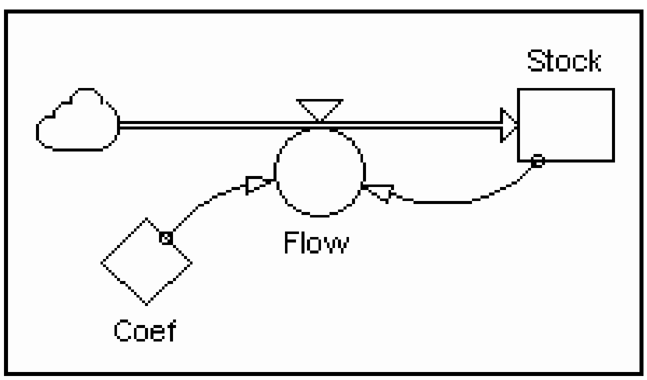

Figure 4.1. Stock-Flow-Feedback loop structure

The first order positive feedback loop system of Fig. 4.1 is a linear system. It possesses an exact analytical solution as (the derivation of analytical solution can be seen in Appendix B):

Stock: **$Stock(t) = Stock(0) * e^{coef*t}$** (4-1)

Flow: $Flow(t) = Stock(t) * Coef(t)$ (4-2)

Initial Stock: $Stock(0) \geq 0$ (4-3)

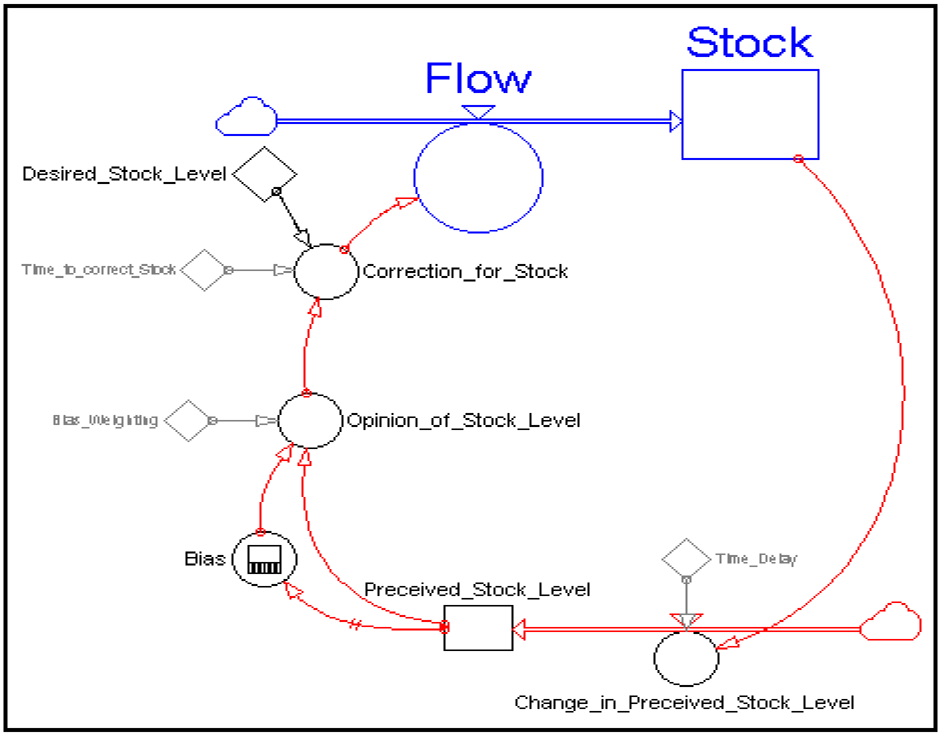

Figure 4.2. *Extended Stock-Flow-Feedback loop structure*
Source: Redraw from Radzicki (1997)

4.2. Modeling and Simulation

The goal of any modeling is to understand and to explain the behavior of a complex system over time. Knowing a system's patterns of behavior explains something about its structure. For a decision maker, understanding the structure of a system is a critical first step in designing and implementing effective policy.

There are ways in which a system dynamics model can aid in understanding complex problems. A completed model can be used to test alternative policy options (i.e. conduct experiments). However, it should be noted that there is great benefit to participating in the model building process itself. Practitioners have found that long-term learning tends to come from the model building process, so it is important to involve the decision maker from the beginning.

The modeling process in system dynamics is having the following steps:

1. Identify Problem
2. Develop Hypothesis
3. Test Hypothesis
4. Test Policy Alternatives

Identify Problem

One of the early lessons learned in building system dynamics models is the importance of modeling a problem rather than an entire system. Focusing on a particular problem provides a boundary to the modeling process and forces the modeler to consider only system variables that relate specifically to the problem in question. Although the understanding of the real problem might change as the process unfolds, it is still critical to begin with a focused problem statement.

Develop Hypothesis (mapping mental models)

With a clearly defined problem statement in hand, the first model building step is to develop a theory of why the system is behaving the way that it is. Tools such as causal loop diagrams and stock and flow networks can be used to map out a set of assumptions about what is causing the "reference modes" of the system to behave a particular way. The actual process of developing this theory (causal diagram) may vary from person to person.

Test Hypothesis (challenging mental models)

Once have developed a theory about the system it is time to develop a computer model of the theory to see if it will re-create the behavior over time seen in the reference modes. The mathematical representation requires a deal of precision around the relationships between different elements in the system. Being forced to shape a consistent mathematical model of a system often challenges and evolves mental model assumptions of how thought it worked. Before each simulation run of the model, think through how the model to behave. If it behaves differently, it either means something is wrong in the model or it has just discovered an opportunity to challenge the mental model.

Test Policies (improving mental models)

With a basic model that seems to be able to explain why the problem is behaving the way that it is, it can look for policy interventions that lead to more desirable long term system behaviors. A way to start this process is to first identify the key decisions (critical decisions/policies that the organization makes), indicators (what need to be seen from the system to assess the decision), and uncertainties (most fragile assumptions about the relationships or outside world) associated with the problem. Then try out different possible sets of decisions under different assumptions about the uncertainties. Look for tradeoffs between short term behavior and long term behavior.

4.3. Energy modeling by system dynamics

The Life Cycle Theory of King Hubbert

One of the first disaggregated, resource-specific, system dynamics analyses in energy modeling was a natural gas discovery and production model created by Naill (Naill, 1973). Naill based his model on the life cycle theory of oil and gas discovery and production put forth by petroleum geologist King Hubbert.

In formulating his theory, Hubbert took the physical structure of the fossil fuel system into account and assumed that the total amount of oil and gas (in the United States), and hence the "ultimately recoverable" amount of oil and gas is finite. According to Hubbert, the cumulative production of domestic oil and gas must be less than or equal to the ultimately recoverable amount of oil and gas.

Fig. 4.3 is a system dynamics stock-flow-structure that represents Hubbert's theory. The most important features of the structure are that (1) there is no inflow to the Ultimately_Recoverable stock (i.e., there is a fixed stock of oil and gas), and (2) the resource is being produced and consumed at an exponential rate.

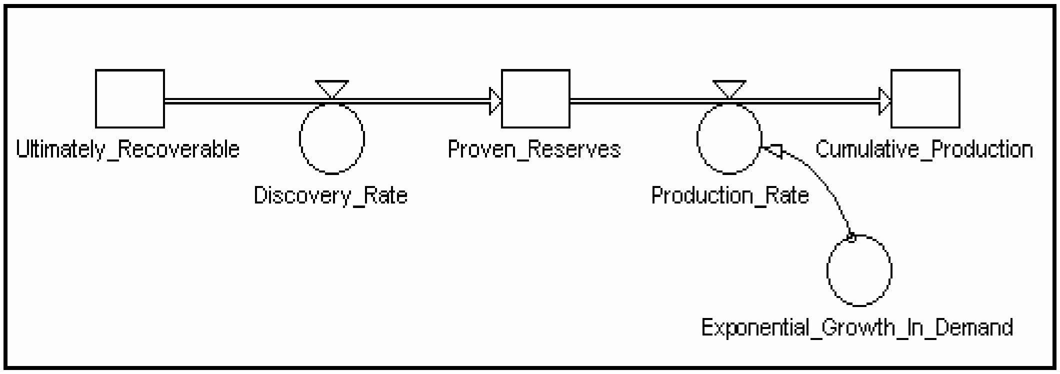

Figure 4.3. Simplification of Stock-Flow structure representing Hubbert's view of non-renewable resource discovery and production

An implication of Hubbert's theory is that a time series graph of either oil or gas production must, at a minimum, be "hump" shaped. That is, the area beneath the production curve for oil or gas is the cumulative production of the resource, and the cumulative production of the resource must be a finite number. Hubbert argued that the life cycle of oil and gas discovery and production yields a bell-shaped production curve, which describes a period of low resource price and exponential growth in production, a peaking of production as the effects of resource depletion cause discoveries per foot of exploratory drilling to drop and resource price to rise, and a long period of rising costs and declining production as the substitution to alternative resources proceeds. It argues that Hubert's theory is also valid for other non-renewable fossil energy resources. Fig 4.4 shows a graphical representation of Hubbert's life cycle theory of oil and gas discovery and production.

The results of Naill's study confirmed Hubbert's life cycle hypothesis. Indeed, Naill concluded that the production of US domestic natural gas, which peaked in 1973, will continue to decline well below the US natural gas discovery rate until depletion halts all domestic production sometime in the late twentieth or early twenty-first century.

The results of Naill's work brought to the forefront the following question among the system dynamicists who were working on energy modeling problems under the umbrella of the world modeling programs: Will US economic growth be impeded by an energy limit similar to those suggested in the Limits to Growth?

The COALX and FOSSILX Models

Naill's natural gas model represented the US gas system at a very aggregate level. The model was not broken down by region, technology, or type of gas. It did not allow for the substitution of fuels nor for endogenous technological change. Thus, although it helped to motivate the study of the US energy transition problem, it was inadequate for the study itself. A new, expanded, model was required.

In the next Naill's study (Naill, 1977), Naill expanded the boundary of his natural gas model to include all major US energy sources (energy supply), as well as US energy consumption (energy demand). He called his dissertation model COAL1, because his analysis showed that the best fuel for the US to rely on during the energy transition was coal.

The improved and extended version of COAL1 was called FOSSIL1. The US Department of Energy provided support to further improve and extend the FOSSIL1 model for use in government energy planning. This improved and extended model looked at the transition of an economy that is powered by fossil fuels (i.e., by oil, gas, and coal) to one that is powered by alternative energy sources.

The FOSSIL1 model was thus based on Hubbert's theory of resource abundance, depletion, and substitution, and used to analyze and design new legislation that would enable the US economy to pass through the energy transition smoothly. It consisted of four main sectors: (1) energy demand, (2) oil and gas, (3) coal, and (4) electricity.

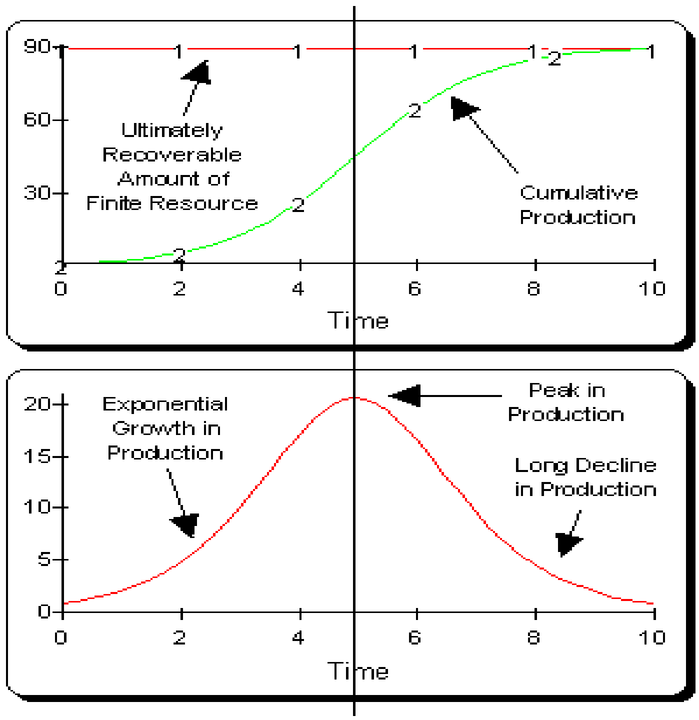

Figure 4.4. Hubbert's life cycle theory of non-renewable resource discovery and production
Source: Nail (1977)

In response to the United States' first energy crisis in 1977, the Carter Administration created the first National Energy Plan. Shortly thereafter, the Government evaluates the Plan using the FOSSIL1 model. To prepare the energy projections for future National Energy Plans, it is implemented FOSSIL1 so that national energy policy issues could be analyzed. The modified version of FOSSIL1 was called FOSSIL2. From the late 1970s to the early 1990s, the FOSSIL2 model was used to analyze, among other things:

- the net effect of supply side initiatives (including price deregulation) on US oil imports.
- the US vulnerability to oil supply disruptions due to political unrest in the Middle East or the doubling of oil prices.
- policies aimed at stimulating US synfuel production.
- the effects of tax initiatives (carbon, BTU, gasoline, oil import fees) on the US energy system.

In 1989, the DOE conducts a study of energy technology and policy options aimed at mitigating greenhouse gas emissions. FOSSIL2 was used for this purpose. In recent years, extensive improvements have been made to FOSSIL2's transportation and electric utilities sectors. The improved version of FOSSIL2 has been renamed IDEAS, which stands for Integrated Dynamic Energy Analysis Simulation.

Sterman's Model of Energy-Economy Interactions

During the late 1970s John Sterman worked to modify and extend the FOSSIL1 model into the FOSSIL2 model. During this work, Sterman realized that the FOSSIL2 model ignored important feedbacks and interactions between the energy sector of the economy and the economy itself. Sterman then built a system dynamics energy model that captured, for the first time, significant energy-economy interactions (Sterman, 1981).

Sterman noticed that in the COAL-FOSSIL-IDEAS family of models, the energy sector is modeled in isolation from the rest of the economy. That is:

- GDP is exogenous to the model. It is not affected by the price or availability of energy.
- Costs of unconventional energy technologies are exogenous to the model.
- Investment in energy is unconstrained by the investment needs of other sectors of the economy.
- Interest rates are exogenous to the model.
- Inflation is unaffected by domestic energy prices, production, or policies.
- World oil prices are unaffected by domestic energy prices, production, or policies.

Sterman addressed these deficiencies through his modeling and found that:

- The economic consequences of depletion are much more severe during the transition period (extending to approximately 2030) than during the long run or equilibrium state.
- The magnitude of the economic effects are substantial in absolute terms and include reductions in economic growth; increased unemployment; inflationary stress; higher real interest rates; reduced consumption per capita.
- Energy price increases (sudden or gradual) alone cannot produce sustained inflation. An accompanying increase in the money supply, relative to real economic activity, is also required (or an increase in the velocity of money).
- The model's major behavior modes are remarkably robust -- i.e., insensitive to parameter variations (uncertainties).
- In the model, a large excise tax on energy coupled with offsetting income tax reductions caused economic performance to improve; energy prices to fall; revenues to fall; short term inflationary pressures to worsen; income taxes to be reduced only during the transition.

Richardson and Sterman'a model in Estimating the Amount of Oil In-Place

Richardson and Sterman (Richardson and Sterman, 1985) produced an oil exploration, discovery, and production model that was similar in spirit to Naill's natural gas model, but that also had important extensions and improvements. More precisely, their model allowed for endogenous technological change and the substitution of synfuels for oil.

Richardson and Sterman first used their model to run a synthetic data experiment that addressed the following question: Which method of forecasting the world's ultimately recoverable supply of oil is more accurate, King Hubbert's life cycle method or the geological analogy method? Since the world's ultimately recoverable supply of oil is currently not known, and cannot be known until all of the world's oil has been depleted, a synthetic data experiment was required to answer the question.

The logic of Richardson and Sterman's synthetic data experiment was simple. First build a system dynamics model that accurately replicates the exploration, discovery, and production behavior of the world oil system and assume that it is the real world. Second, formally code and add the Hubbert and geologic analogy methods to the model so that they examine the "real world oil system" and create forecasts of the ultimately recoverable amount of oil in the world.

Sterman and Richardson, with the assistance of Pål Davidsen, went on to apply their model and synthetic data technique to the question of the amount of ultimately recoverable oil in the United States (Davidsen, et.all., 1990). As in the case of world oil, Hubbert's method was judged to be clearly superior and the model was able to replicate US oil discovery and production data extremely well. Sterman, Richardson and Davidsen's synthetic data experiment for the United States is perhaps best interpreted as supporting the argument that Hubbert's method is the most accurate.

The history of energy modeling by using system dynamics is illustrated in Fig. 4.5. It can be summarized as Forrester was also responsible for creating the WORLD2 model and initiating the world modeling projects. The world models, along with King Hubbert's work on oil and gas discovery and production, stimulated the creation of Roger Naill's natural gas model, his COAL1 model, and the improvements to COAL1 that have culminated in the IDEAS model and its offshoots (FOSSIL79 and DEMAND81).

Naill and Hubbert's work formed the basis for Sterman, Richardson and Davidsen's synthetic data experiments on analyzing techniques for forecasting the ultimately recoverable amount of oil in the world and in the United States, while knowledge of the weaknesses in the FOSSIL2 model caused Sterman to investigate the dynamics of energy-economy interactions during the energy transition. The world modeling projects also stimulated the study of the US electric power industry by Andrew Ford and the subsequent EPPAM models.

Fiddaman's Model of Economy-Climate Interactions

In 1997 Tom Fiddaman developed a new climate-economy system dynamics model called FREE - Feedback-Rich Energy Economy model- (Fiddaman, 1997), included a critique of existing (non system dynamics) climate-economy models. The FREE model explicitly incorporates the dynamics of oil and gas depletion as a "source constraint" on the energy-economy system (as do all of its system dynamics predecessors), as well as the dynamics of a "sink constraint" (i.e., climate change) on the energy-economy system. The FREE model is the first energy-economy model of any kind to explicitly examine the impact of a source constraint on energy-economy interactions.

The FREE model also explores a number of feedback processes (e.g., endogenous technological change and bounded rational decision making with perception delays and biases) that have not been previously explored in a climate change context. In addition, it is constructed so that a particular parameterization will yield the results found in neoclassical (traditional) climate-economy models. Fiddaman's recognition that, although the source constraints on the energy-economy system had been investigated by energy modelers, sink constraints had not, lead to the creation of the FREE model.

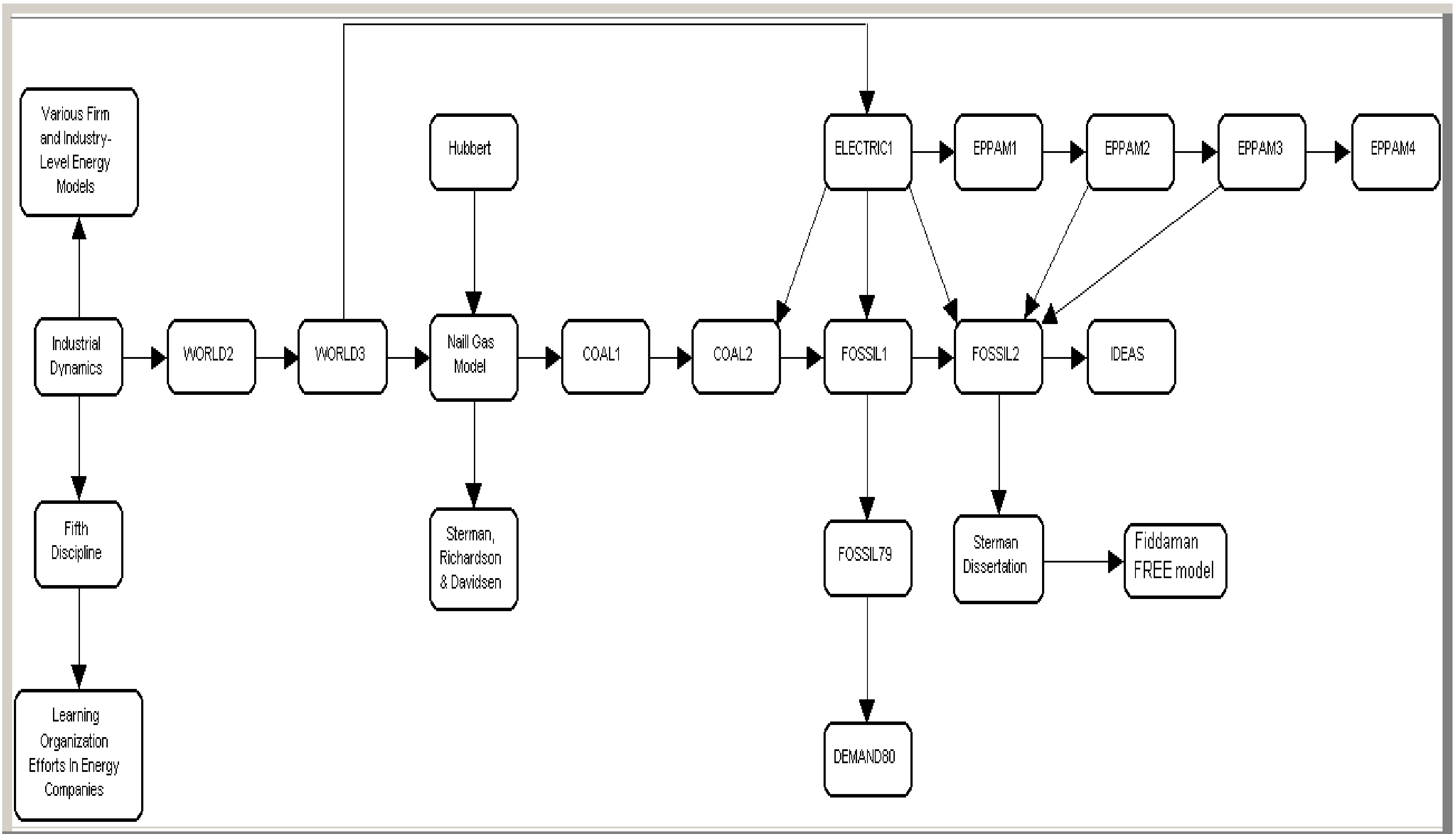

Figure 4.5. System Dynamics Energy Modelling
Source: System Dynamic Society (Radzicki, 1997)

Chapter 5:
System Dynamics Model for Coal

5.1. System Dynamics Model

5.1.1. Model description

This part describes the model for the coal industry in the EU-15 called the DCE (Dynamics Coal in Europe). Expanding on prior system dynamics models of fossil fuel resources (Naill 1973; 1977; Sterman 1981; Sterman and Richardson 1985; Davindsen, et.all., 1990; Fiddaman 1997, 2000, 2002), this model endogenously generates the coal industry in the EU-15. The DCE synthesizes the perspectives of several disciplines, including geology, technology, economy and environment. It integrates exploration, production, pricing, demand, and emission modules. Finally, the model emphasizes the impact of delays and feed-back in both the physical processes and the information and decision-making processes of the system. Vensim® version 5 (Ventana systems, inc.) – a simulation software based on system dynamics - was used to develop the DCE. All detail modules of the DCE can be seen in Appendix C.

With two major exogenous variables, Gross Domestic Product and Population, the model will try to portray the evolution of the EU-15 coal industry, starting from 1970 to 2080. The correspondence between simulated and actual data is examined through a statistical measurement. The DCE model was also used to show how the interactions among technological progress, depletion, demand portray the coal industry by altering the dominance of the feedback process in the system. The model is characterized by the declining of coal production driven by depletion, rising real costs of exploration and production followed by population and economic growth and technological progress. The coal demand is characterized by fluctuating pattern as a result of relation with other energy sources. The trend of CO_2 emission from hard coal tightly follows the coal demand trend.

The model is intended to provide a realistic simulation in which the geological and technical variables are known and can be varied to reveal alternative scenarios to reduce CO2 emission, including tax and permit instruments. The model may thus be applied in analyses:

- integrated forecasts of the demand, production, exploration activity, costs and CO2 emission can be made
- policy options such as permit controls and taxes can be evaluated in a dynamic environment that represents the important feedbacks in the real system
- the model is reasonably transparent and offers opportunities to teach resource management, dynamic modelling, and principles of feedback

5.1.2. Introduction to the DCE model

In the system dynamics approach, there are usually five basic steps of modelling. As the DCE model is based on this approach, therefore the modelling process in the model will follow the five successive steps, which are (1). Problem Definition, (2). Model Construction, (3). Parameters Calibration, (4). Model Simulation, and (5). Policy Simulation. The modelling process of the DCE is illustrated in Fig. 5.1.

The first step of the modelling is Problem Definition. The objective of the step is to portray and frame the faced system of coal industry as well as to outline the model wants to be developed. The step will include the following activities: determining objectives of the modelisation, delineating a boundary of the model, deciding a time horizon of the analysis and outlining expected model characteristics.

The second step is Model Construction. The objective of this step is to develop a preliminary model. It is called a preliminary model because the model may be modified after evaluating the results from following steps. The step will include identifying all parameters involved in the system, outlining relation between parameters, analysing causal loopes and feed-backs among parameters and finally determining mathematical relations and valuing initial value of parameters.

The two previous steps are such important steps in system dynamics approach. One of the early lessons learned in building system dynamics models is the importance of modeling a problem rather than an entire system Focusing on a particular problem provides a boundary to the modeling process and forces the modeler to consider only system variables that relate specifically to the problem in question. in system dynamics approach, it is still critical to begin with a focused problem statement

The next step is Parameters Calibration. This step is dedicated to adjusting the initial value of main parameters obtained from the previous step. It is done by executing the preliminary model and comparing the simulation results for several variables (GDP, population, electricity demand, steel production, hard coal production and demand, operating costs) to the historical data of these variables. The initial value of main parameters involved will be adjusted so that the simulation results for the mentioned variables are more or less similar to their historical data. In some cases, whenever the result for a variable is significantly different to its historical data, it may be possible to modify the preliminary model. Once the simulation result for several variables is fairly similar to their historical data, the simulation process can move forward to the step of Model Simulation.

The objective of the Model Simulation step is to forecast the behavioural of several main variables throughout the time horizon of the study. It is done by executing the preliminary model and comparing the simulation results for several variables (GDP, population, electricity demand, hard coal production and demand) to the simulation results of other study. In this research, the study of EU-15 Energy and Transport Outlook will be used to compare the DCE's result. Before the simulation is carried out, some basic assumption of the EU-15 Energy and Transport Outlook study are identified and tried to be adapted into the valuing process of the DCE's parameters (i.e. projection of hard coal demand and production). The ultimate result of the Model Simulation step is a final model called a base model. As a base model, this model can be used to serve coal policy study. By joining other policy model to the base model, for example environment policy model (taxation, policy permit etc), the model can be used to analyze the impacts of the policy to coal industry.

The fifth step is Policy Simulation. In this step, it will be carried out a simulation for examining the impact of emission reduction policy to the coal industry. Three emission reduction policy models will be developed first before being jointed to the base model. The process of policy model construction will follow several phase, including identifying all parameters involved in the system, outlining relation between parameters, analysing causal loopes and feed-backs among parameters and finally determining mathematical relations and valuing initial value of parameters.

Once the three policy models have been developed, they then can be jointed to the base model and thereafter the simulation can be done. The objective of the Policy Simulation is to understand the impact of emission reduction policy to the coal industry, particularly for variables of hard coal demand and production, CO2 emission, consumption per capita, the values of taxes and permit price.

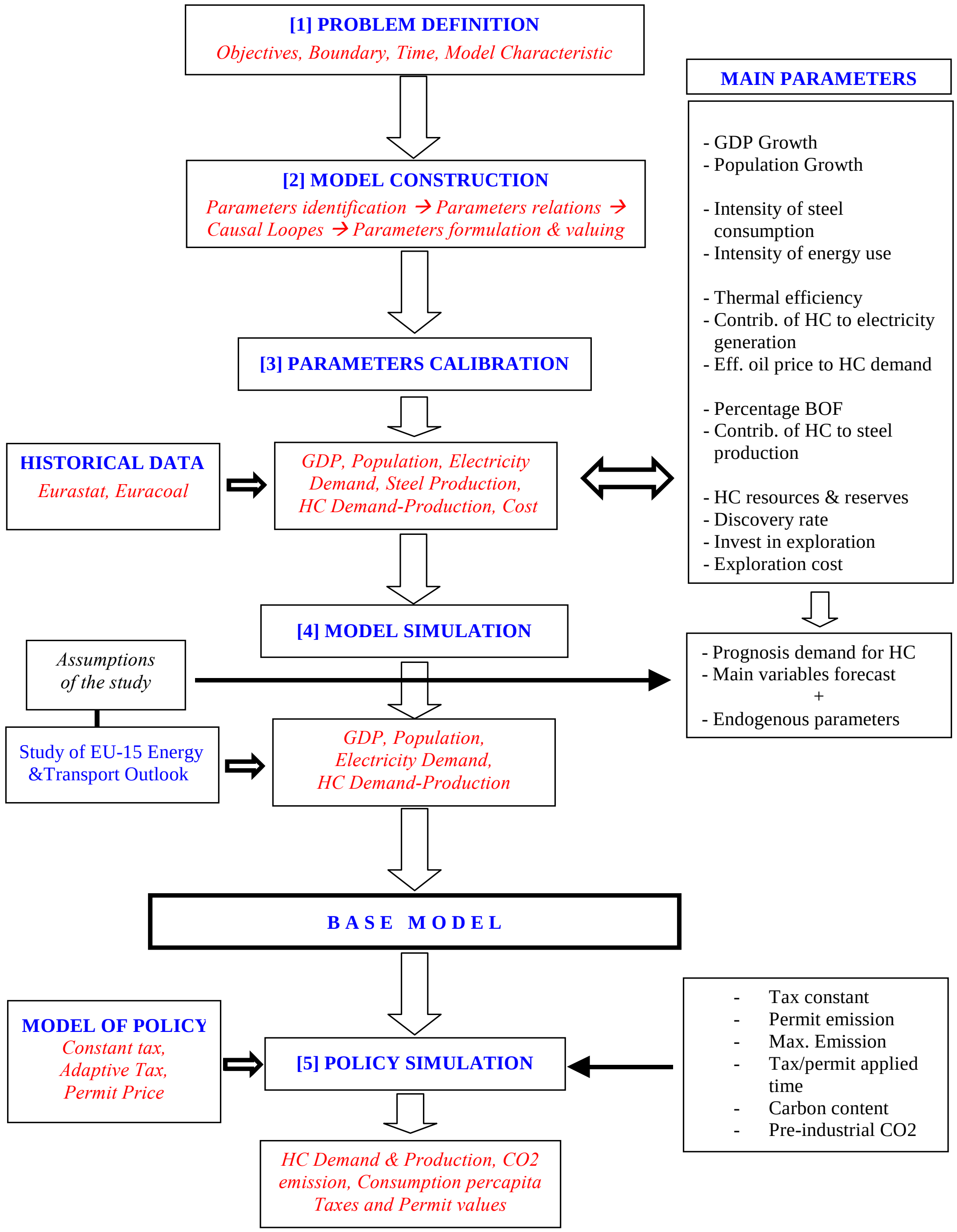

Figure 5.1. The steps of the DCE modelling process

5.2. Problem definition

5.2.1. *Objective of the model*

The ultimately objective of building the DCE system dynamics model is to improve the way to understand the systems of coal industry in Europe and improve decision making process in regard to this industry

5.2.2. *Time Horizon*

The nominal time horizon of the DCE model is 1970-2080. The historical period of the model is relatively long. While it was not the purpose of this study to estimate model variables from data, the comparatively long historical period provides a useful test of model behavior.

5.2.3. *Boundary*

The DCE model represents the energy(coal)-economy-environment system in the EU-15. The majority of structure in the model is endogenous. Generation of investment, coal demand and production, depletion, and technology progress are tightly coupled to one another. The carbon cycle (CO_2 emission) and climate are also endogenous, but are coupled to the rest of the model somewhat more sparsely. Table V-1 shows main model boundary used in the model.

Carbon tax and permit policies are formulated as endogenous feedback, rather than exogenous inputs. Several exogenous variables drive the model behavior. Population, Gross Domestic Product, subsidy and oil price are all exogenous. Cost-reducing energy production technology is normally endogenous.

The use of exogenous variables breaks feedback loops, which may have important policy implications. This occurs in several areas in the model. If population growth and Gross Domestic Product are dependent on increasing wealth, the model understates the importance of favoring current economic output over future welfare. On the other hand, to the extent that emissions of non-energy CO_2 and other greenhouse gases are coordinated with energy production and economic activity, the model understates the need for current abatement.

For simplicity, many features have been omitted from the model. While the regional boundary of the model is for the EU-15, there is no country disaggregating. The demand model includes coal conversion activity (as the generation of electric coal fired-power plant) and other coal uses (raw material for steel making). The model tries to simplify a complex problem by analyzing only one type of coal: hard coal. A number of economic structures that contribute to disequilibrium are omitted, such as sectoral labor and financial constraints.

Table V-1 Main Model Boundary

Endogenous	Exogenous
Coal Consumption	Population
Coal Production	Gross Domestic Product
Coal Price	Subsidy
Coal Depletion	Oil price
CO_2 emission	
Exploration investment	
Technology progress	
Carbon tax	
Permit price	

5.2.4. *Characteristics the model*

A model system dynamics like the DCE must meet certain requirements that a short-term forecasting model does not have to meet. The DCE has characteristics as following:

First, it is a structural model. In contrast to a model based on historical correlations i.e. econometric, the DCE represents the physical and causal structure of the processes modeled. Nonlinearities[14] and constrains may alter the historical correlations in the future. Physical delays, such as the time required to develop coal mining should be represented explicitly.

Second, the DCE model is a base model and can be used as a basis to serve as a coal policy tools in the EU-15, including the used to show how interactions among technological progress, depletion, demand portray the coal industry by altering the dominance of the feedback process in the system. It is a general-purpose model. It is conceived for forecasting, scenario construction and policy impact analysis.

Third, it is a behavioral model, portraying the information available to users and the procedures the users use to process it and arrive at decisions. If the model is to response to changes in the environment in the same way that real actors do, this bounded rationality should be incorporated. It generates its behavior endogenously. The exploration and production process is tightly interconnected with coal price, demand, and technology progress. A change in one part of the system may have ramifications throughout. A model that relies on exogenous variables is likely to produce inconsistent results as the feedback effects are ignored.

Fourth, the DCE is a modular model and allows either for unified model use or for partial use of modules to support specific energy study. The individual modules vary in the depth of their structural representation. The modularity feature allows each sector to be represented in the way considered appropriate, highlighting the particular issues important for the sector.

Fifth, several outputs (both historic and forecasting) are provided by the DCE model, including: coal production, demand and final cost ; population and Gross Domestic Product; electricity generation and steel consumption; CO_2 emission for coal burning;

Sixth, as a base model, the DCE can be used to serve coal policy study, including implication of policy instrument for the environment (taxation, policy permit etc) and implication of coal supply policy on import dependency. By joining other policy modules, for example Emission Trading System, to the model, it can be used to analyze the impacts of the policy to coal industry.

In addition to those general characteristics, a model of coal resources to be used in forecast evaluation should include the following specific features as endogenous components:

- *Demand and import.* Coal demand is sensitive to price. As the prices rise, demand for coal will be depressed. If the price of domestically produced coal rises above the import price, import is indicated. The pattern of demand and import will have a strong influence on production and investment in domestic exploration.

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[14] *When a system dynamicist looks for relationships in an actual system that prevent its stocks from going negative or growing infinitely large, he is usually looking for the system's nonlinearities. Frequently, a system's feedback loops will be joined together in nonlinear relationships. These nonlinear "couplings" can cause the dominance of a system's feedback loops to change endogenously. That is a system whose behavior is being determined by a particular feedback loop*

- *Depletion through exploration and production.* The total quantity of coal initially in place is finite. As it is discovered, produced, and consumed, the quantity remaining inevitably declines, and the marginal cost increases, ceteris paribus. Though improving technology may offset depletion and cause the real price of coal to decline, the limited nature of the resource base and its depletion should be treated explicitly.

- *Technology progress.* The ultimately recoverable reserve depends heavily on the recovery factor. Not all coal in place can be recovered economically with current technology, but the fraction recoverable has been rising and may rise substantially in the future. Similarly, there is a development of exploitation technology. The effect of investment in technology development should be treated explicitly.

The DCE model can be divided into a number of subsystems. Fig. 5.2 illustrates the sector boundaries. All detail modules of the DCE can be seen in Appendix C.

Population and Gross Domestic Product in the model are exogenous. Population is a stock, which grows over time at a diminishing population growth rate. GDP is also a stock, which each grows over time at a diminishing growth rate too. The welfare sector/sub-model provides a single indicator of social welfare for use in policy evaluation and optimization. It provides no direct feedback to the rest of the model. The welfare is influenced by economics factor (consumption of goods) as well as environmental factor (intangible environmental service/damage). Consumption of goods and environmental service/damage are aggregated by Cobb-Douglas production function.

Coal demand sector in the model consists of three basic categories: demand from electricity generation, steel plant and other coal-based activities. The volume of coal demand will affect mine production, exploration activity and reserve remaining. The DCE model incorporates two policies sectors that influence coal price. The carbon tax (constant and adaptive) and permit price policies are a simple control heuristic with a constant or parameter term and inputs from the perceived rate of CO2.

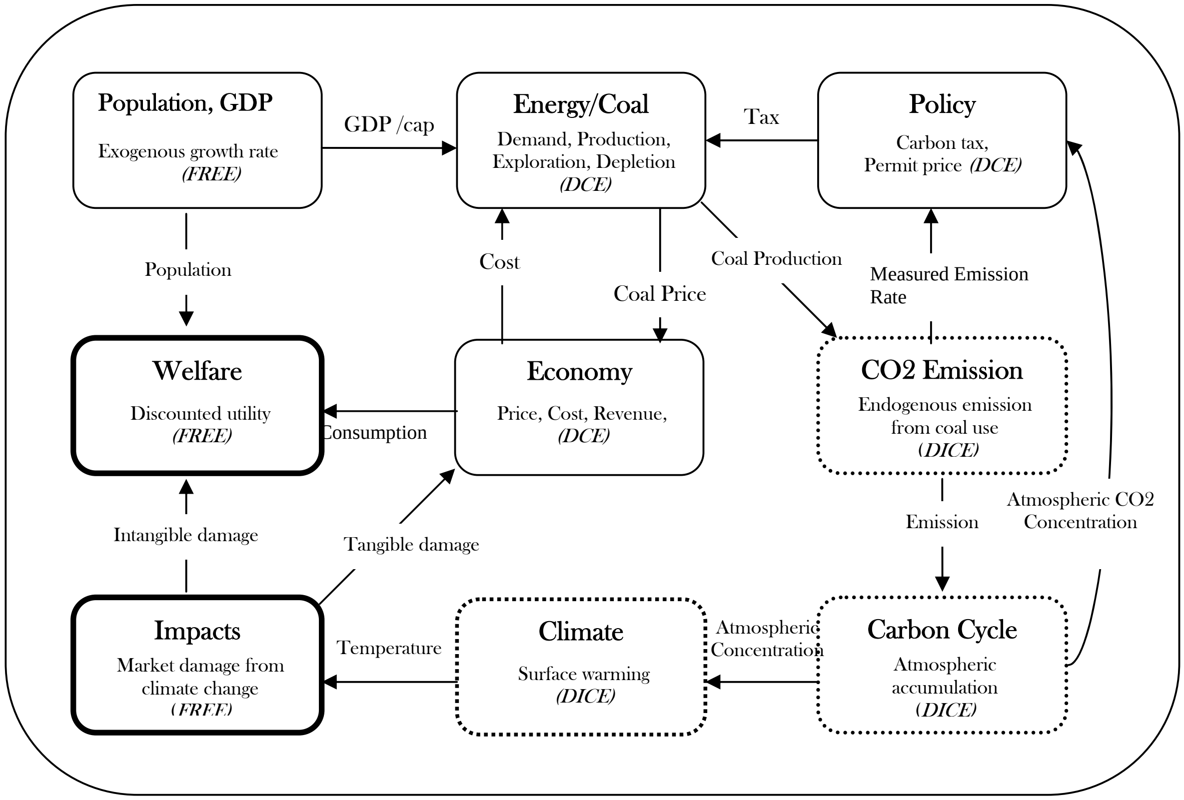


Figure 5.2. Sector boundary, internal parameters and external relationships

In the CO2 emission sector, emission of the greenhouse gas from coal burning is endogenous in the model. Emission from coal equals the rate of demand multiplied by the carbon content of the fuel. The carbon cycle sector includes an alternative carbon cycle drawn from the DICE model (Nordhaus, 1994). This is a first-order linear structure, in which a fraction of emission accumulates in the atmosphere in the short run, and is gradually stored in the deep ocean in the long run. The climate sector is also drawn from the DICE model. This is a second-order linear structure, with three negative feedback loops. Two loops govern the transport of heat from the atmosphere and surface ocean, while the third represents warming of the deep ocean. Deep ocean warming is a slow warming process. If the deep ocean temperature is held constant, the response of the atmosphere and surface ocean to warming is first-order. Climate impacts on the economy are the final output of the carbon cycle and climate sectors.

Climate damages are based on the FREE model (Fiddaman, 1997). The FREE climate damage allows separate treatment of tangible damages (loss of economic output) and intangible damages (loss of non-market environmental services). The impact of damages on output is a function of the absolute deviation of the temperature of the atmosphere and upper-ocean from adapted levels, as in the DICE model.

The economy sector consist of cost, price and revenue. A final cost is derived from the summation of the average variable cost, cost of exploration and tax. The selling price is obtained from an addition of a certain amount of cash as a profit margin to the final cost. This selling price will be used as a basis to determine revenue.

Several model behaviors arise from the main feedback structures shown in Fig. 5.3. The reinforcing process of capital accumulation drives economic growth (augmented by exogenous population and Gross Domestic Product). Climate change acts like a weak balancing loop that restrains economic growth. Economic activity requires energy input, including coal; coal burning thereafter leads to carbon emissions.

Emissions increase the concentration of CO2 in the atmosphere, causing temperature to rise. As the global temperature rises, climate change damages reduce economic output and divert it from other purposes. The energy and economy sectors interact through the exchange of goods for energy. Within the energy sector, learning (represented in the DCE as technology progress) and depletion drive coal production costs. Carbon taxes and permit emission raise coal prices in response to increasing CO2 emissions and atmospheric concentrations. These two instruments constrain the accumulation of CO2 in the atmosphere.

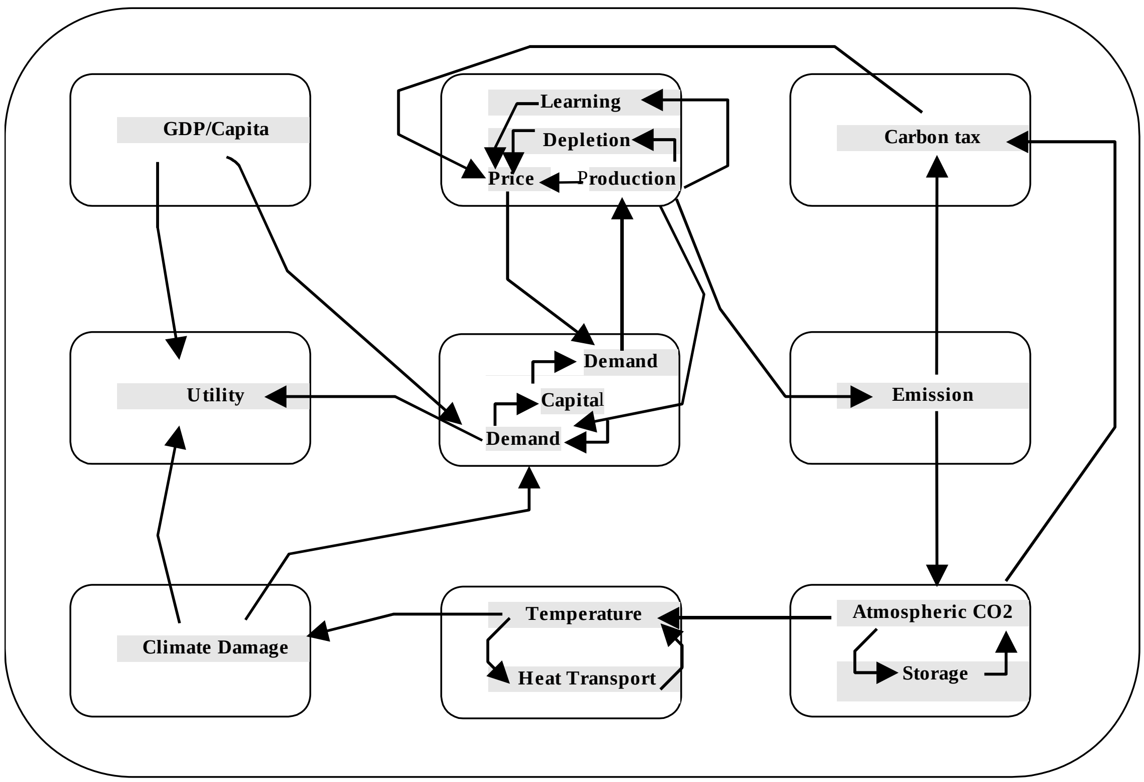


Figure 5.3 Major Feedbacks Processes

5.3. Model Construction

The DCE model draws on a number of preceding models for elements of its structure. Since the principal purpose of this study is to explore energy-economy-environment system, the DICE model was a primary source of structure in the climate system (Nordhaus 1994). While, welfare and environment impact subsystem are heavily based on FREE model (Fiddaman, 1997).

The foremost energy-economy systems in the model draw on Sterman's energy economy model (Sterman 1980; Sterman 1981). In general, the structures for capital investment and embodiment of energy requirements in capital have been closely copied, while most other disequilibrium features of these models have been omitted.

The DCE model consists mainly of four modules of coal: demand, supply, price and policy modules. In particular for supply module, it consist in-separately exploration, production and depletion sub-modules. Those four modules are tightly interrelated to construct a whole system dynamics of coal. Several sub-modules were also developed to support the four main modules.

5.3.1 Demand module

The model divides coal demand into three basic categories: as yet demand from electricity generation, steel plant and other coal-based industries (Fig. 5.4). With this dis-aggregation, finer coal demand is portrayed.

Coal demand from electricity generation is driven from electricity need to support the economic growth. The prediction of electricity demand in Europe is based on the projection of Gross Domestic Product and Population for the EU-15. The intensity of electricity use will then be used to estimate the need of electricity. Empirical research has found that the intensity of electricity use (defined as electricity consumption per unit Gross Domestic Product per Capita) can be described as a function of per capita income.

Nowadays, in the EU-15, coal supplies almost 26% of electricity generation (or 690 TWh). It is projected that the figure will slightly go down in the next decades, reaching almost 22% of total electricity generation in 2030. Coal demand is estimated from electricity demand generated from coal-fired power plant (state in Watt-hour). In average 1 GJ of energy in coal can generate about 275 kWh of electricity.

Coal demand from steel making industry is driven from pig iron demand needed as a result of the economic growth. The prediction of steel demand in Europe is based on the projection of Gross Domestic Product and Population for the EU-15. The intensity of steel use will then be used to estimate the need of steel. Empirical research has found that the intensity of steel use (defined as steel consumption per unit Gross Domestic Product per Capita) can be described as a function of per capita income.

In 2004, crude steel consumption in the EU-15 was 168 Mt. It is projected that the figure will slightly increase in the next decades. Coal demand is estimated from the need of coke and coal in Blast Furnace to produce steel. Nowadays, to produce 1 ton of pig iron it needs about 500-600 kg of coke and 150-250 kg of steam coal.

Fig, 5.4. shows a simplified causal diagram for coal demand module. An increased of income per capita (GDP per Capita) will boost the electricity consumption and will need a quantity of steel products (Steel-Demand). A standard expressing electricity demand per increasing of GDP (Intensity of Energy Use, Wh/€) will be used as a basis to estimate electricity demand (Electricity-Demand). In the case steel demand, an intensity of steel consumption (Intensity of Steel Consumption, Ton/Person) is used as a standard to project steel production. Electricity demand and steel consumption are used as a basis to estimate coal consumption.

A ratio of electricity generated by coal-fired power plants to total electricity generated from all energy sources will balance coal consumption from electricity demand growth (Coal Demand from Electricity). This ratio is expressing maximum electricity generated from coal source. A ratio of steel produced by Basic Oxygen Furnace method to total steel production will equilibrate coal demand from steel demand growth (Coal Demand from Steel). This ratio is expressing maximum coal demand from steel making.

Total coal demand (Total-Demand) is a summation of coal demand from mainly electricity, steel making and other coal-based industries. The increase total coal demand will increase coal production (Production Rate), ceteris paribus. However, the investment in production capacity (Investment in Production) and reserve depletion (Reserve Remaining) will restrain the coal production. Both coal price (Coal Price) and oil price (Oil Price) will also influence the demand of coal. High prices of coal and oil will balance coal demand growth.

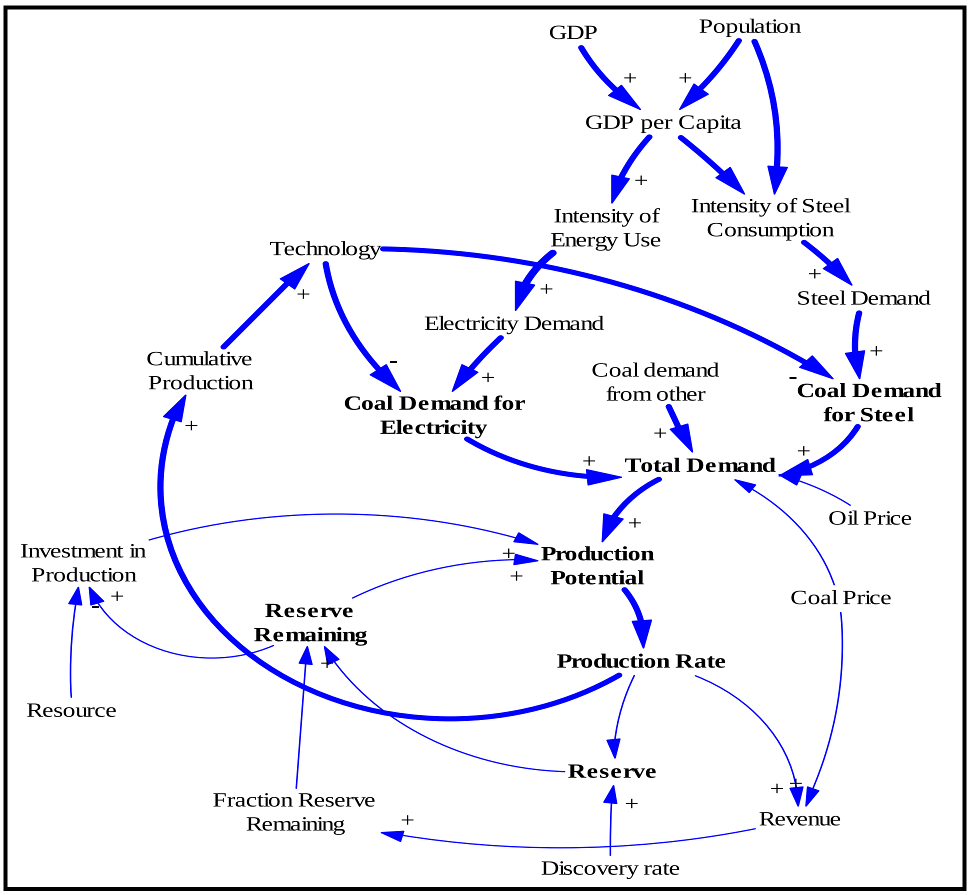


Figure 5.4. Causal diagram for coal demand module

5.3.2. Supply module

The supply module consists mainly of three sub-modules, which are exploration, production and depletion sub-modules.

Exploration

Fig. 5.5. illustrates a simplified causal diagram for exploration sub-modules. The model divides the total quantity of coal into three basic categories: as yet resources, reserve and cumulative production. Within these broad categories, several finer divisions are portrayed. The disaggregation

of the resource base follows the standard resource classification shown in the McKelvey reserve classification[15]. Successful exploration shifts the boundary between identified resources toward the right; improvements in technology shift the boundary between economic and sub-economic resources toward the bottom.

The productivity of investment in exploration (Productivity Investment in Exploration) is negatively influenced by the discovery rate (Discovery-Rate). Suppose that the coal discovery rate was increased, then less coal remains to be discovered with current technology, and the productivity of further investment in exploration (Productivity of Investment in Exploration) is reduced. It is assumed that the yield from exploration is exponentially decreasing with the increasing depletion of coal resource. The reduction in productivity feeds back to the rate of discovery rate potential (Discovery Potential), implying a reduction in the rate of coal discovery potential (Discovery Rate) provided by any given level of exploration activity.

As long as there is a demand for coal, more coal is produced. As a result, the productivity of investment in exploration (€/ton) will be exponentially reduced as more of the resource is discovered and as more of the identified reserve is recovered. At certain level of production, the declining of productivity of investment will balance the rate of depletion (Resource Remaining) through slowing down the rate of production.

There are only two more factors that may help to achieve equilibrium in discovery rate: changes in exploration effort and changes in technology. Increased investment in exploration (Investment in Exploration) increases the discovery rate. Better technology improves the productivity of investment by making more coal available.

[15] McKelvey reserve classification is a classification adopted by USGS as a USGS Classification (1983), see Chapter 1

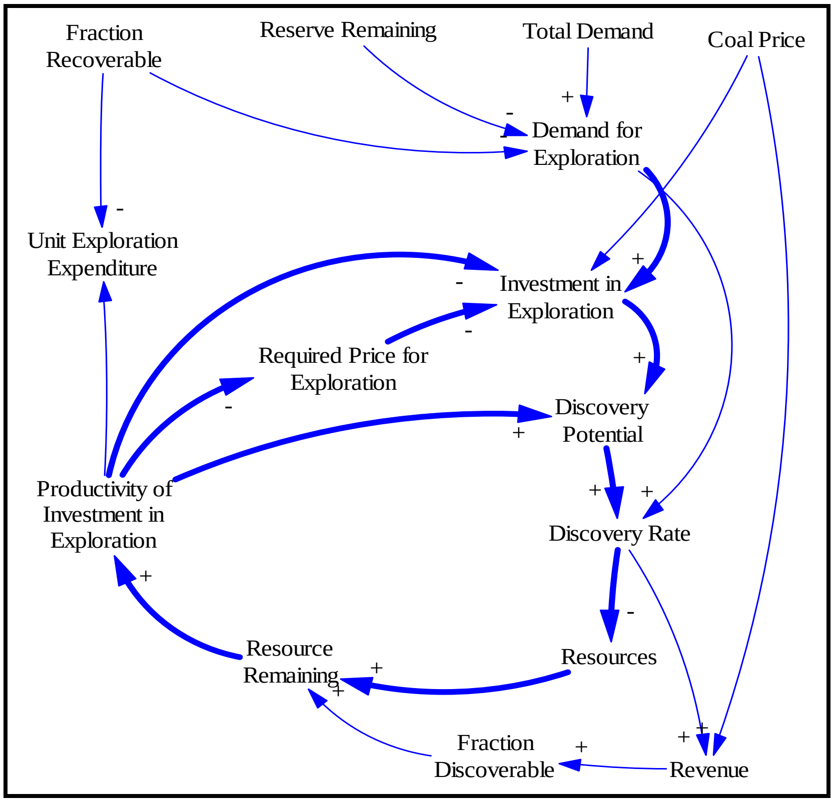


Figure 5.5. Causal diagram for coal exploration

Production

Fig. 5.6. illustrates a simplified causal diagram for production sub-modules. Successful exploration (Discovery Rate) shifts the boundary resource toward reserve (Reserve). Production will shrink the reserve base. The productivity of investment in production (Investment in Production) is influenced by the rate of production (Production Rate) and the remaining reserve (Reserve Remaining).

Suppose the production rate is increased, then less coal remains to be recovered. Thus, the productivity of investment in production is reduced because more difficult mining condition is faced. The technically recoverable reserves remaining constitute an upper limit for the rate of production. These underlying physical constraints tend to stabilize the discovery of coal. As long as there is a demand for coal, more coal is produced. As a result, the productivity of investment in production (Investment in Production, €/ton) will be exponentially reduced as more of the identified reserve is recovered. At certain level of production, the declining of productivity of investment will balance the rate of depletion (Reserve Remaining) through slowing down the rate of production.

As long as there is a demand for coal the production rate will increase, ceteris paribus. The increasing production (Production Rate) will increase company revenue (Revenue) and reduce reserve remaining (Reserve Remaining). The stock of money for investment in production (Investment in Production) will negatively balance the increasing of production rate.

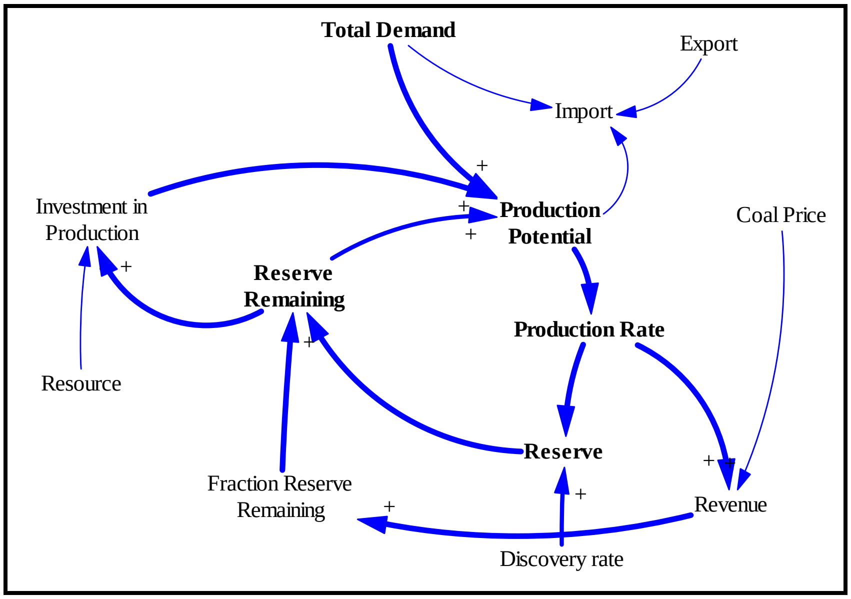


Figure 5.6. Causal diagram for coal production

Depletion

The reference module, originally used by Roger Naill (Naill, 1973) in the construction of natural gas model, was drawn from the oil and gas life cycle theory of King Hubert. Hubbert based his theory on the knowledge of the physical structure of the oil and gas system and hence on the assumption that there is a finite amount of oil and gas in the earth. According to Hubbert's theory, the discovery and production flows of natural gas, as well as the stock of proven reserves of natural gas rise, peak and fall over time, and the stock of unproven resources falls monotonically due to depletion. It is argued that theory is valid for all type of fossil energies. Therefore, this theory is applied in the construction of the DCE.

The depletion effect represents the diminishing productivity of non-renewable coal production as the resource remaining declines. The depletion effect will increase coal exploration and exploitation costs.

Fig. 5.7. illustrates a simplified causal diagram for depletion sub-modules. The depletion module is a balancing loop. Depletion in coal resources aggravate a fall in fraction of resource remaining (Frac-Remaining). The low resource remaining will then drive a rise in cost exploration factor (Eff-Frac-Remain-Cost-on-Expl), due to increasing difficulty condition in coal exploitation. The final result of this depletion is a rise in the exploration cost (Exploration-Cost).

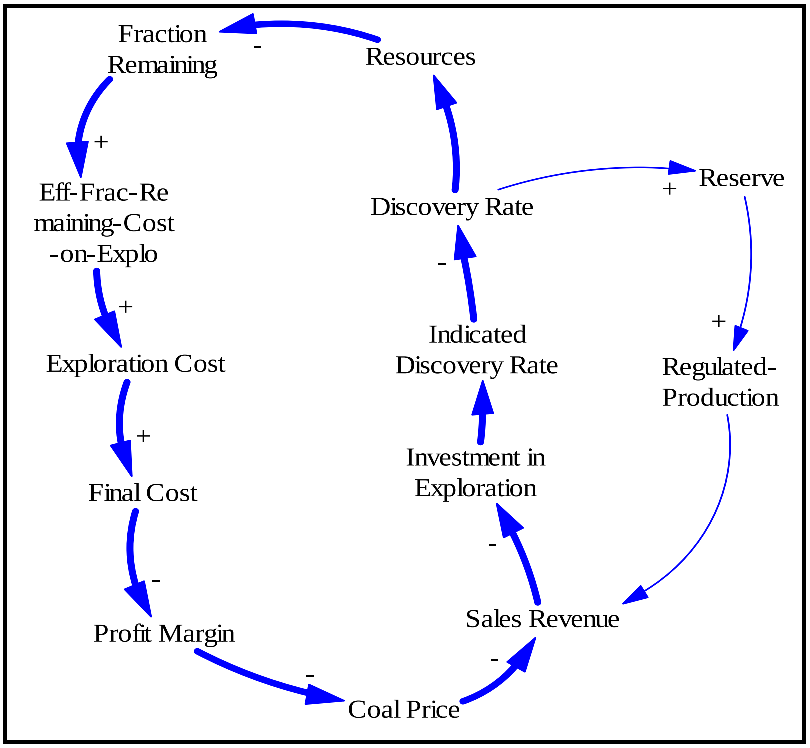


Figure 5.7. Causal diagram for coal depletion

High exploration cost causes a rise in the total cost of producing coal (Final-Cost). An increasing in cost production diminishes a company margin's profit and followed by a fall in the investment for exploration (Invest in Exploration). A decrease in investment for exploration reduce scoal discovery rate (Discovery Rate). A fall in the discovery rate ensures that reserve (Reserve) will be higher than they otherwise would have been.

5.3.4.Price module

The coal mining industry posts prices to the coal users. The prices to the users consist of all prices paid by the coal mining (operating cost) plus profit margin, distribution charges and taxes. In the price module, an average cost pricing will thereafter be used to estimate cost. By this average cost, producers allocate fixed cost across normal cost to calculate an overhead and add average short-term variable cost. In the module, the price will be also used to correct supply and demand pressure.

Fig. 5.8. illustrates a simplified causal diagram for price modules. A short run average cost (SR-Average-Cost) is calculated from summing up the capital cost (Capital-Cost) and the average variable cost (SR-Avg-Variable-Cost). The average variable cost will rise in condition of reserve depletion, indicated by low fraction reserve remaining (Eff-Frac-Reserve-Remain) because of increasing mining cost. A final cost pricing (Final Cost) is derived from the summation of the average variable cost (SR-Avg-Variable-Cost), cost of exploration (Exploration-Cost) and tax (Carbon-Tax).

In order to obtain the selling coal price (Coal-Price), the producers add a certain amount of cash as a profit margin to the final cost. Coal-price will influence coal demand (Regulated-Demand) and finally coal production (Regulated-Production). To end the loop, coal production scale will feedback to influence mining cost, both capital cost and average cost.

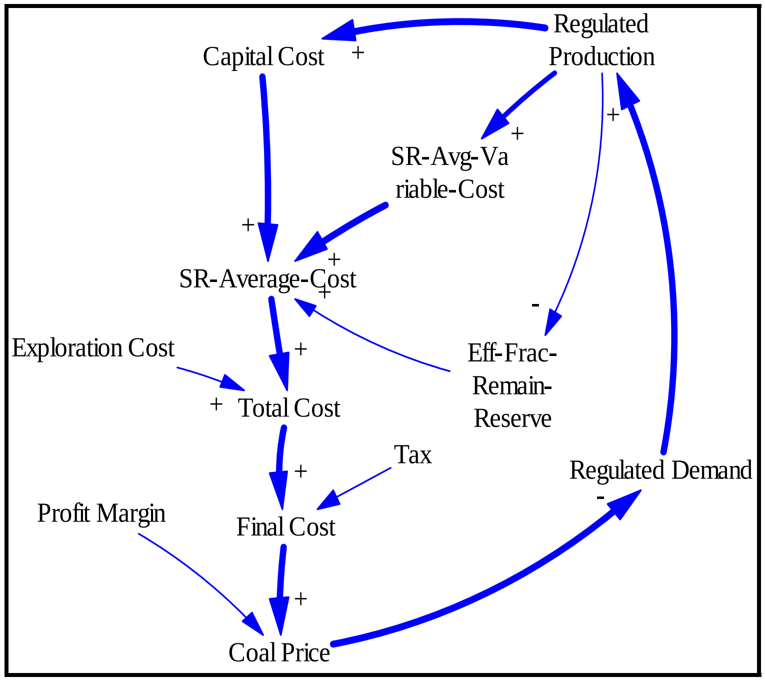


Figure 5.8. Causal diagram for coal price module

5.3.5. Policy module

The DCE model incorporates tax and permit policies that will influence coal price. A carbon tax may be applied to the non-renewable resource, such as coal. The carbon tax is a simple control with a constant term and inputs from perceived rate of CO2 emission and the atmospheric concentration of CO2.

Fig. 5.9 shows a simplified causal diagram for Policy module. The amount of CO2 emission (Total-Carbon-Emission) is estimated from the multiplication of certain tonnages of coal being burnt (Regulated-Consumption) and a quantity of carbon per ton of coal (Carbon-Content). Higher tonnages coal being burnt increase CO2 emission to the atmosphere. A 0.027 TonC/GJ is used as a standard of carbon contain in coal.

In carbon tax optimization runs, optimal values of the carbon tax constant and the coefficient on emission and atmospheric concentration are firstly sought before getting an estimated carbon tax (Indicated-Carbon-Tax). Higher carbon emission will act for government to increase adaptive carbon tax (Carbon-Tax). The aim of this process of increasing carbon tax is to decrease the emission and to balance the quantity of GHGs in atmosphere by reducing coal consumption (Regulated-Consumption) by increasing coal price (Coal Price).

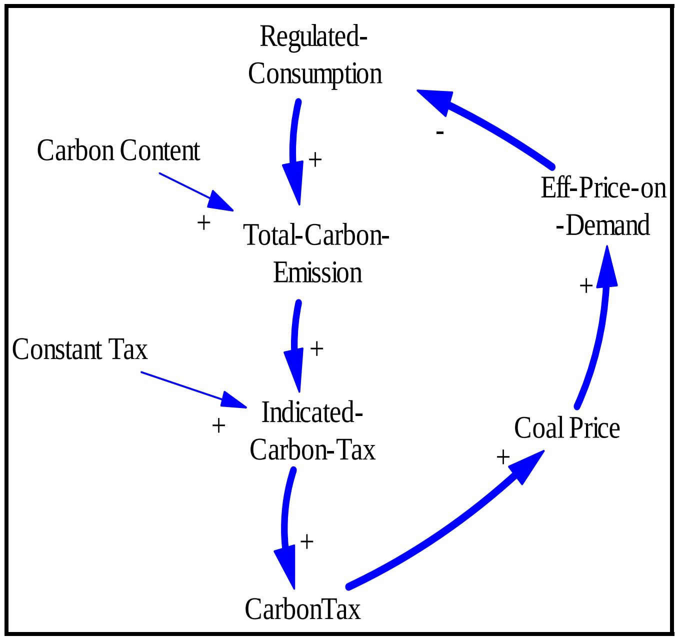


Figure 5.9. Causal diagram for coal policy module

5.4. The Dynamic behavior of the system

5.4.1. Parameters Calibration

In order to prove the accuracy of the DCE model and to find estimation values for several model variables, the model has been calibrated by comparing its simulation results to the historical data over period of 1970-2000. Because this is done by adjusting a set of model variables to give the best possible match, this process is referred as model calibration and not model validation.

Process of calibration for the Gross domestic Product (*GDP)*

This part explains the process of calibration for GDP variable. Similar process has been done for other variables. Fig. 5.10 shows the model of GDP as part of the DCE model. GDP in the model is exogenous. GDP is a stock, which grows over time at a diminishing GDP growth rate. In the model, the rate of declining of the GDP growth rate (GDP Growth Rt) is separated into historical value (Hist GDP Gr Rt Decline Rt) and forecast value (Forecast GDP Gr Rt Decline Rt).

During the process of calibration, the value for two GDP growth rates was adjusted so that it gives the best possible match to the real/data value of GDP rate. In the model, GDP is assumed to grow constantly over the study period (1970-2080), with the initial growth rate (Initial GDP Gr Rt) is 5.25% per year in 1970. This initial growth rate will decline over time. The year 2000 is set up as a year of the transition/switch time between these two declining growth rates (GDP Gr Switch time). The rate of GDP growth diminishes at roughly 1.75% per year over period 1970-2000. In the year 2000, the simulation results for GDP growth in the EU-15 was about 3.0%. For the period beyond 2000, the rate of GDP growth diminishes at approximately 3.5% per year.

Table V.2 and Table V.3 shows respectively GDP Variables and Result for Calibration process for GDP variable. Fig. 5.11 shows both historical and simulation results for Gross Domestic Product for the EU-15 for over period 1970-2000.

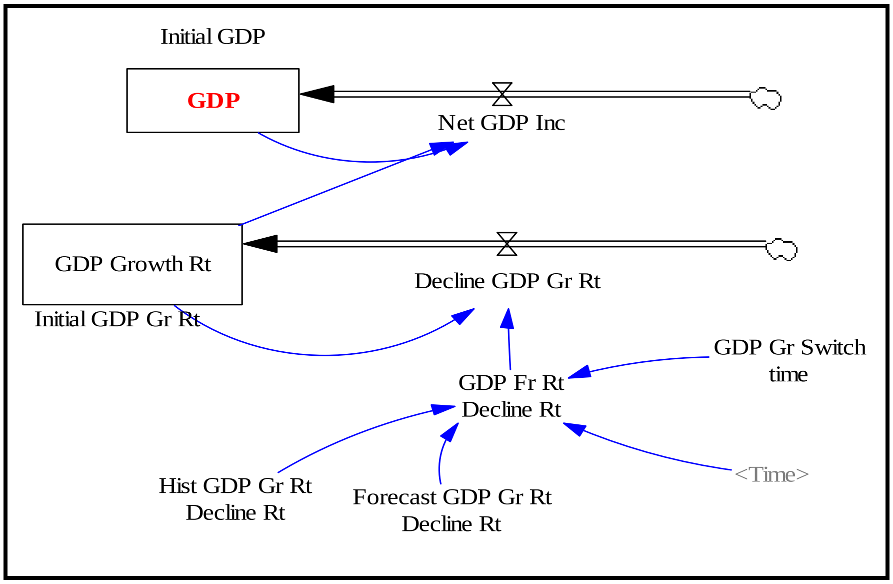


Figure. 5.10. GDP model (developed using Vensim® version 5)

Table V.2. GDP Variables for the EU-15

Parameter	Value	Units	Notes
Initial GDP (1970)	2.7e+012	€	Estimation based on back projection from 1990-2000's data[1]
Initial GDP Growth Rate (1970)	0.0525	1/year	Result from Calibration
Historic GDP Growth Rate Decline Rate	0.0175	1/year	Result from Calibration
Forecast GDP Growth Rate Decline Rate	0.035	1/year	Result from Calibration
Transition time of Declining Growth Rate	2000	Year	Result from Calibration

1) Data is taken from European Energy and Transport trend to 2030- update 2005 and Eurostat

Table V.3. Result for Calibration process for GDP variable

Year	1991	1992	1993	1994	1995	1996	1997	1998
GDP, x 10^{12} €								
Data from Eurostat[1]	5.83	6.11	6.13	6.43	6.72	7.05	7.42	7.76
Simulation result	6.77	7.02	7.27	7.53	7.79	8.05	8.32	8.6
Δ Diff	14%	13%	16%	15%	14%	12%	11%	10%
Year	1999	2000	2001	2002	2003	2004	2005	2006[2]
GDP, x 10^{12} €								
Data from Eurostat	8.15	8.71	9.02	9.34	9.49	9.92	10.28	10.65
Simulation result	8.87	9.15	9.44	9.72	10.0	10.3	10.6	10.8
Δ Diff	8%	5%	4%	4%	5%	4%	3%	2%

1) Data from Eurostat is taken from http://epp.eurastat.ec.europe.eu/
2) Eurostat estimation

Using similar approach, calibration has been done for other variables. Fig. 5.12 - 5.17 show both historical and simulation results after model calibration for Population, Electricity demand, Steel Production, Hard coal demand, Hard coal production and Hard coal cost (domestic price) for the EU-15 over period 1970-2000.

On the basis of the historical data for Population, Gross Domestic Product, Electricity demand (data taken mainly from Eurostat, http://epp.eurastat.ec.europe.eu/), Steel Production (data taken from Eurostat and International Iron and Steel Institute, IISI, 2003, 2005), Hard coal consumption and production (data taken mainly from International Energy Agency, IEA, 2003c) and Hard coal operating cost (data taken from Piper (2002), see Part I, Fig. 2.17), the DCE model reproduces past values on the scale well. Some of the historical data have minor differences (for example in case of Hard coal production). However, the objective with the model is not to exact reproduction of past trends; rather, it will concentrate on the long-term trend. Based on the results of calibration process for the earlier data, it can therefore be argued that the DCE model can be used to make a forecast for examining long-term behavior of coal industry in the EU-15.

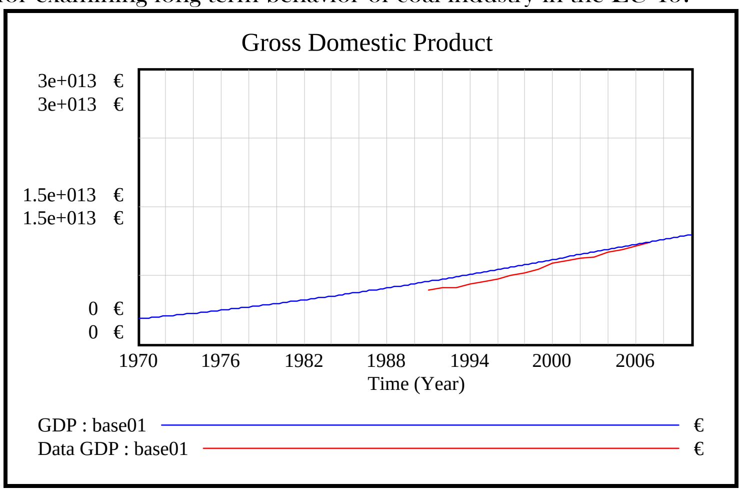


Figure 5.11. Comparison of data and simulation results for Gross Domestic Product in the EU-15

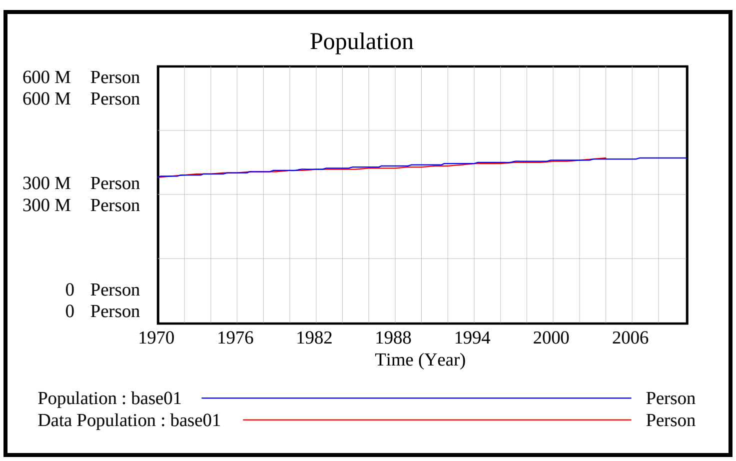


Figure 5.12. Comparison of data and simulation results for Population in the EU-15

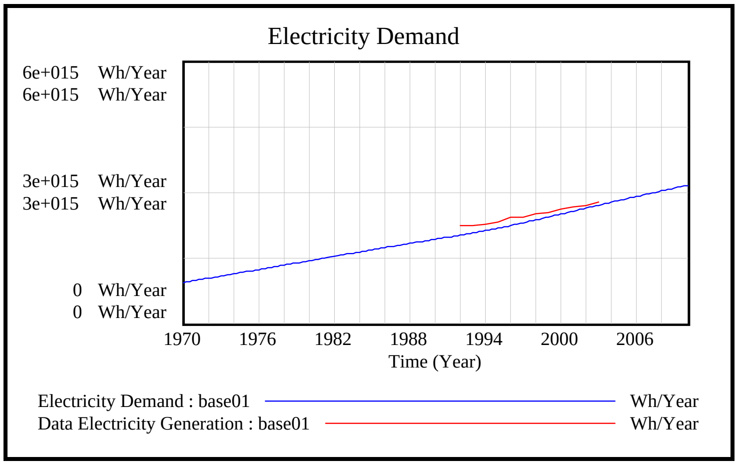


Figure 5.13. Comparison of data and simulation results for Electricity Demand in the EU-15

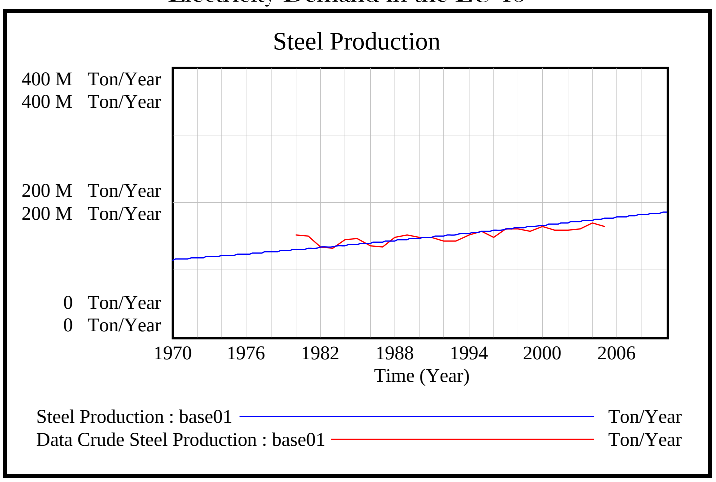


Figure 5.14. Comparison of data and results simulation for Steel Production in the EU-15

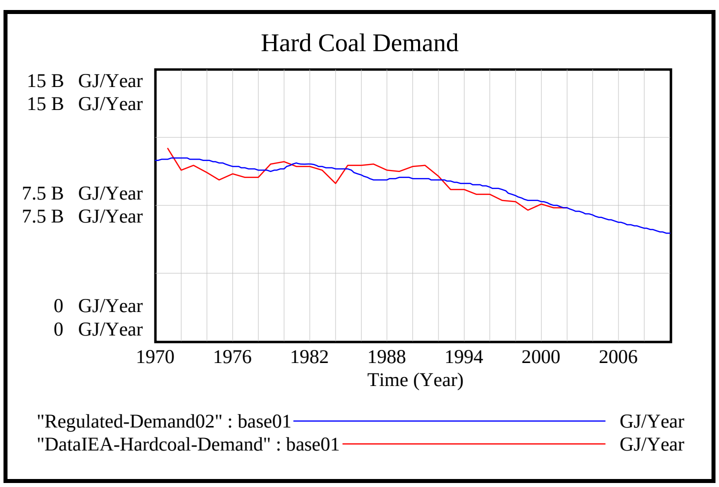


Figure 5.15. Comparison of data and simulation results for Hard coal demand in the EU-15

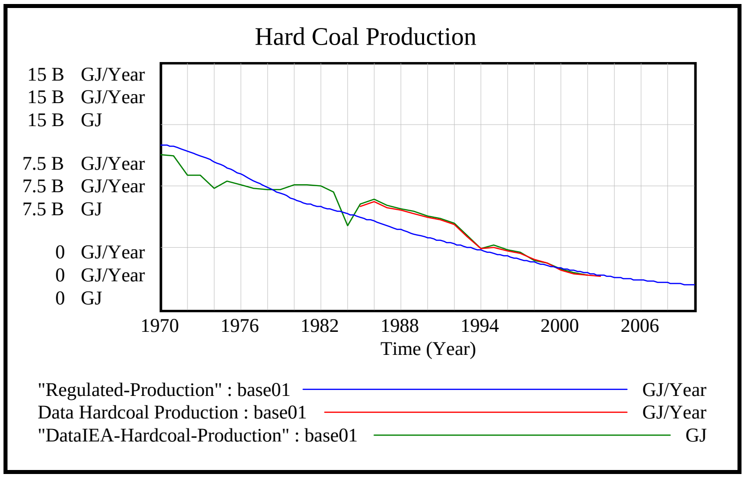


Figure 5.16. Comparison of data and simulation results for Hard coal Production in the EU-15

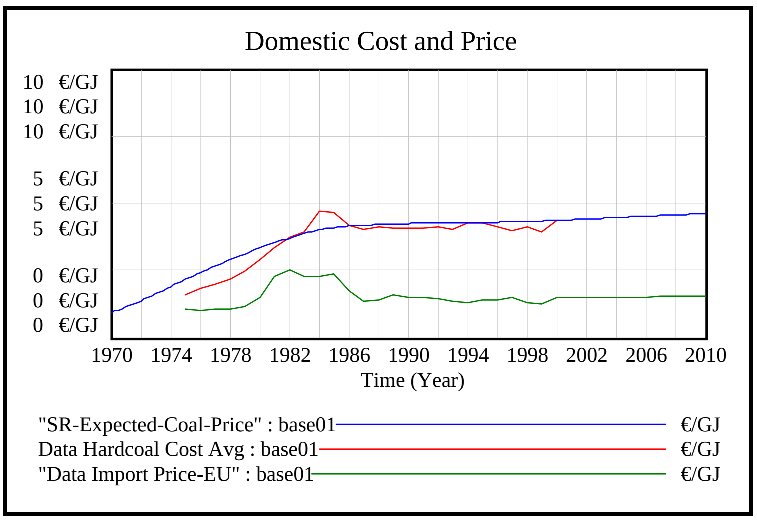


Figure 5.17. Comparison of data and simulation results for Hard coal Domestic Price in the EU-15

5.4.2. Model Simulation under deterministic variables (Base Case)

5.4.2.1. Comparison analysis

The first step of simulation is to run the DCE model and to compare its results with other studies. A comparison for simulation results for several main variables (Population, GDP per capita, Electricity demand, Hard coal demand and production and CO2 emission) to the results outlook from the report of EU-15 Energy and Transport Outlook to 2030 (EU, 2003b) is shown in Table V-4.

Population is one of important variables for energy consumption. As it can be seen in Table V-4., it is shown that the total population levels for the EU-15 over period 2000-2030 is projected to rise modestly from 377.86 million (2000) to 396.35 million (2030). The different results between simulation and data show up to 2% divergence over period 2000-2030. Furthermore the model also forecasts that population for the EU-15 in 2080 will reach 407.5 million.

The macroeconomic scenario, expressed in the DCE model as GDP per capita, simulates a dynamic path of the EU economy up to 2080. It is derived from endogenous assumptions about the evolution of technological progress, environmental context etc. As it can be seen in Table V-4, the total EU-15's GDP per capita is projected to increase modestly from 24,227 (2000) to 41,193 *€/capita/year* (2030). The different results between simulation and data show up to 8% divergence over the study period. Moreover the model also forecasts that GDP per capita for the EU-15 will double from 24,227 in 2000 to 51,766 €/capita/year in 2080.

Table V-4. Comparison results between Data and Simulation for certain main variables

Variable		2000	2010	2020	2030	2080
Population	Data	378.69	387.83	390.45	389.02	-
Million	Simulation	377.86	385.67	391.71	396.35	407.50
	Δ Diff	*-1%*	*-1%*	*1%*	*2%*	
GDP per capita	Data	22,565	28,000	34,937	43,494	-
€/capita	Simulation	24,227	30,875	36,585	41,193	51,776
	Δ Diff	*7%*	*8%*	*4%*	*-5%*	
Electricity requirement	Data	2,574	3,027	3,450	3,846	-
TWh	Simulation	2,499	3,154	3,703	4,133	5,077
	Δ Diff	*-3%*	*4%*	*7%*	*7%*	
Hard Coal Demand	Data	244.20	178.97	204.86	283.51	-
Mt	Simulation	269.21	205.64	215.75	295.75	228.04
	Δ Diff	9%	13%	5%	4%	
Hard Coal Production	Data	78.84	37.59	22.46	14.36	-
Mt	Simulation	85.07	41.96	25.54	14.68	4.94
	Δ Diff	7%	10%	12%	1%	
CO2 emission	Data	561.2	403.4	471	671.7	-
from Hard coal	Simulation	633.0	485.3	501.5	691.4	527.3
Mt CO2	*Δ Diff*	11%	16%	6%	3%	

Note:
Data is based on the report of EU-15 Energy and Transport Outlook to 2030 (EU, 2003b) with further author's estimation.
Simulation is based on the results of the coal model simulation for a base case. Simulation results for Hard coal demand and production are converted from GJ to Mt by a 28 GJ/t conversion factor, while for CO2 emission is converted from TonC to Ton CO2 by a 3.5 Ton CO2/TonC conversion factor

Overall, the demand for electricity under the base assumption is expected to expand by 1.15 per cent per year over 2000-2030. As it can be seen in Table V-4., total EU-15 electricity demand is projected to expand almost double from 2,499 (2000) to 4,133 TWh (2030). The different results between simulation and data show up to 7% divergence over period 2000-2030. In addition, the model also forecasts that electricity demand for the EU-15 by 2080 will continue to grow to reach 5,077 TWh.

The pattern of energy consumption in the EU-15 has changed significantly since 1980s. Solid fuels have experienced a continuous decrease, resulted from a market fall in consumption mainly in power generation. Hard coal contribution for total electricity generation in the EU-15 decreased from 30% in 1980 to 18% in 2000. Natural gas has partly replaced this decreasing. The use of coal (solid fuels) is expected to continue to fall until at about 2015 both in absolute terms and as a proportion of total energy demand for the most part due to environmental concern.

The demand assumption for coal in the DCE is mainly based on the assumption on baseline scenario of the European Energy and Transport Trend to 2030 (European Commission, 2006). The model assumes that the decisions on all capacity expansion and decommissioning plans in power generation and nuclear phase-out in some member states will be implemented as decided and that certain nuclear plants with safety concerns will be closed as agreed.

Nuclear production is projected to experience limited growth to 2010. Thereafter it is likely to decline steeply, as a result of the nuclear phase-out policies decided in Belgium, Germany and Sweden. This policy result is that, together with the decommissioning of old nuclear power plants at the end of their lifetimes with a default value of 40 years, nuclear electricity generation declines quite dramatically in the long run. Nevertheless, high fossil fuel prices encourage significant investment in new nuclear power stations (including the new EPR type) in several member states.

In the medium term the emerging gap is largely covered by greater use of natural gas, which in 2015-2025 is projected to become the main energy input for electricity generation. However, beyond 2020 gas use is assumed exhibiting a decline both as regards its share in electricity generation. In this term Novel energy forms, such as hydrogen and methanol, are not projected to make significant inroads in the EU-15 energy system in the period to 2030 (European Commission, 2003b).

In the long run, coal is projected to make a strong come back. Thus in 2030 it is solid fuels that become the main energy input for power generation, a trend largely related to the increasing cost-effectiveness of coal fired technologies expected in that period and the assumed absence of additional climate change policies in the Base case simulation that would negatively affect solid fuel use (EU, 2006).

Installed capacity for solids fired power plants is assumed to decline rapidly both in absolute terms and as a share of total installed capacity in the horizon to 2010. In the horizon to 2015 installed capacity of solid fuel fired power plants is projected to remain rather stable. Solid fuels are assumed to regain some market share in the EU-15 energy system beyond 2020. Higher natural gas and oil import prices, increasing competitiveness of imported coal, decommissioning plans in power generation and nuclear phase-out in some member states and maturity of advanced coal technologies (supercritical units and other clean coal technologies, e.g. IGCC and PFBC) are the key drivers for this result (EU, 2006).

It is projected that indigenous production of fossil fuel, including solid fuels is projected to decline continuously. The combine effect of increasing primary energy demand (in absolute terms) for fossil fuels and declining primary production results in a significant growth of import dependency for the EU-15 energy system.

The DCE simulation shows that hard coal demand in 2030 (295 Mt) will be slightly above its 2000 level (269 Mt). The different results between simulation and data show up to 13% of divergence over period 2000-2030. The increasing coal demand pattern might not continue beyond 2045. Beyond this year the demand will decrease. However, it is projected that the deployment of Carbon Capture and Storage Technology will prevent rapid decline of coal demand (IEA, 2004b) in decade 2040s. It is assumed that at that period, the current development of renewable energy sources will bear considerable fruit and will replace partly fossil fuels as sources of energy.

Since 1960s, indigenous coal (solid fuels) production has continued to decline as a consequence of the important restructuring of the mining industry (the raisons of its declining are explained more in Part I, Chapter 2). As it can be seen in Table V-4., indigenous production of hard coal is projected to undergo a significant decline over the period to 2030, from 85.07 Mt (2000) to

14.68 Mt (2030). The results difference between simulation and data show up to 12% divergence over period 2000-2030. In addition, the model also forecasts that hard coal production declining will continue until period 2080 (end of our study). Coal will be produced insignificantly in 2080 (slightly less than 5 Mt).

Regarding to CO2 emission from hard coal, the results of simulation show a good proximity with data. As it can be seen in Table V-4., CO2 emission rate is projected to undergo a significant decline up to 2010 and then increase at least until 2030. The results of simulation for CO2 emissions rates are 633 Mt CO2 for year 2000, 485 Mt CO2 (2010), 501 Mt CO2 (2020)and 691 Mt CO2 (2030) consecutively. The different results between simulation and data show up to 16%.

5.4.2.2. Deterministic policy analysis (Scenario Case)

In the second step of simulation, a deterministic policy analysis was carried out. The principal policy instruments in the DCE model are permits and taxes on carbon and energy use. These two instruments are in fact part of the emission reduction approaches in the Kyoto Protocol and European system. This part will analyze the model exploration for climate change policy. It simulates the introduction of constant carbon tax to the model in order to know its impacts on the coal industry behavior. The results can be used to identify an effective approach to reduce CO2 emission. More climate change policy analyzes will be provided in Chapter 6.

Fig. 5.18 to Fig. 5.23 illustrate the response of the model to a carbon tax of 135 €/TonC[16]. The tax is phased smoothly beginning in 2008. Table V.5 shows the summary response of the model to the introduction of a constant carbon tax for several variables in year 2030. For more detail explanation about the different values of variables between base scenario and tax scenario see Table V.I, Chapter 6.

Table V.5. Summary response of the model to the introduction of a 135 €/TonC constant carbon tax

Scenario	HC Price	HC demand	CO2 emission from HC	HC Production	Consumption per capita
result in 2030	€/GJ	million GJ	million TonC	million GJ	*€/capita*
Uncontrolled (base scenario)	5.26	8,413	207.80	436.58	44,154
Constant tax (tax scenario)	8.60	7,437	183.69	429.30	43,417
Δ Diff (%)	38.84	-13.12	-13.13	-1.70	-1.70

The introducing of a 135 €/TonC carbon tax will put in a 38.8% additional cost to hard coal price from 5.26 €/GJ to 8.60 €/GJ in 2030 (Fig. 5.18). The tax will reduce by 13.13% hard coal (HC) demand and CO2 emission from hard coal as well by 2030. The demand will go down from 8,413 million GJ (base scenario) to 7,437 million GJ (tax scenario) in 2030 (Fig. 5.19). The emission rate will decrease from 207.80 million TonC to 183.69 million TonC in the same year (Fig. 5.20). The decreasing rate of this CO2 emission is proportional to the decreasing rate of hard coal demand.

[1] This scenario was chosen because it represents a sanction if the company fails to meet its reduction target under the EU directive of Emission Trading Scheme. A 40-100 €/TonCO2 penalty is a sanction if the company fails to meet its reduction target. In the coal model, a 135 €/TonC, equivalent to about 40 €/TonCO2 or approximately 75 €/tce, is used as a base for testing the model.

At the same time the tax will drive hard coal production down by 1.7% from 436.58 million GJ to 429.30 million GJ (Fig. 5.21). The application of carbon tax reduces the pressure on hard coal reserve due to less coal demand. Less pressure on hard coal reserve will reduce pressure on decreasing its production. The tax also raises offering coal price and thereafter will decrease slightly coal production, ceteris paribus.

It has to be noted that the DCE model still does not introduce a sub-model of substitution between energy sources. Therefore, a pressure of coal demand and a suboptimal capacity of coal utilization will not be recovered by other energy source. This condition has explained why the increasing hard coal price of almost 38% has put a pressure on hard coal demand only about 13%.

The introduction of carbon tax from 2008 would decrease slightly welfare (shown in the DCE model as the consumption per capita) from 44,154 (base scenario) to 43,417 €/capita/year (tax scenario) in 2030, as illustrated in Fig 5.22. The tax suppresses hard coal demand, leads capacity utilization of coal utilization (burning) suboptimal and makes welfare slightly go down. Coal as an energy is one of many contribution sources for welfare. The model shows that after being introduced a 135 €/TonC coal demand decreased. However, in the long-term it will not be followed by sharp decrease of welfare.

In order to have a profound understanding about long-term coal industry behavior in the EU-15, the DCE model also introduces a forecast result for other variables. Fig. 5.23 illustrates further results of coal model for base scenario and tax scenario for quantity of CO2 in atmosphere (a), temperature (climate) difference between upper and deep ocean (b), technology progress factor (c) and reserve-resource-cumulative production relation (d). The sub-modules in the coal model for forecast long-term behavior of CO2 in atmosphere and temperature (climate) change are constructed mainly based on DICE and FREE models (Nordhaus, 1994; Fiddaman, 1997).

Fig. 5.23 (a) shows how the introducing of carbon tax for coal in the EU-15 would reduce slightly the quantity of CO2 in atmosphere, if other factors remain constant (ceteris paribus). This reducing amount of CO2 in atmosphere is actually equal to the reducing emission of CO2 produced by coal burning in the EU-15 less by CO2 removal from the atmosphere and storage by long-term processes (for more detail about this sub-model, see sub-model DICE Carbon of the DCE in appendix C).

Fig. 5.23 (b) and Fig. 5.23 (c) show how the introducing of carbon tax for coal in the EU-15 would change the difference between temperature upper and deep ocean by less than 0.10^{o}C (for more detail about this sub-model, see sub-model DICE Climate of the DCE in appendix C) and would change insignificantly the development progress of energy technology in coal (for more detail about this sub-model, see sub-model FREE Energy Technology of the DCE in appendix C).

Regarding coal reserve and production, from the point of view of Hubert King's theory, Fig. 5.23 (d) shows how coal reserve and production in the EU-15 had already reached their peak condition. Based on the IEA data (IEA, 2003c) the peak of coal production in the EU-15 was in decade 1960s. Over the period study (1970-2080), the trends for coal resource, coal reserve and production are to decline.

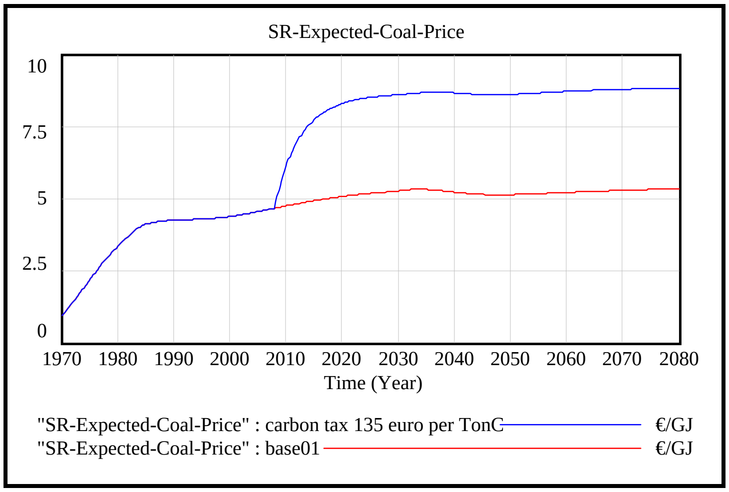


Figure 5.18. Comparison for base case and tax case for Hard coal domestic price in the EU-15

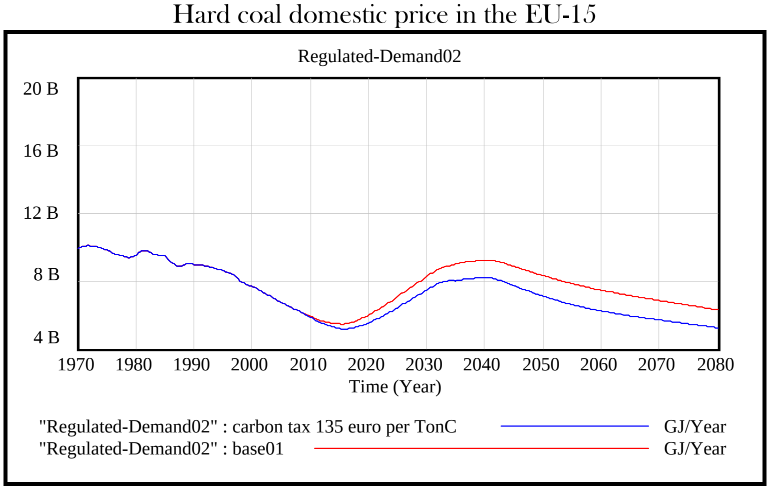


Figure 5.19. Comparison for base case and tax case for Hard coal demand in the EU-15

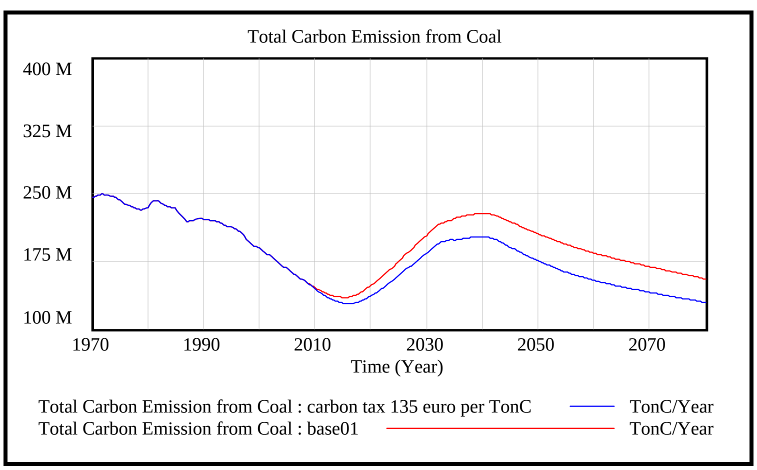


Figure 5.20. Comparison for base case and tax case for total carbon emission from Hard coal domestic price in the EU-15

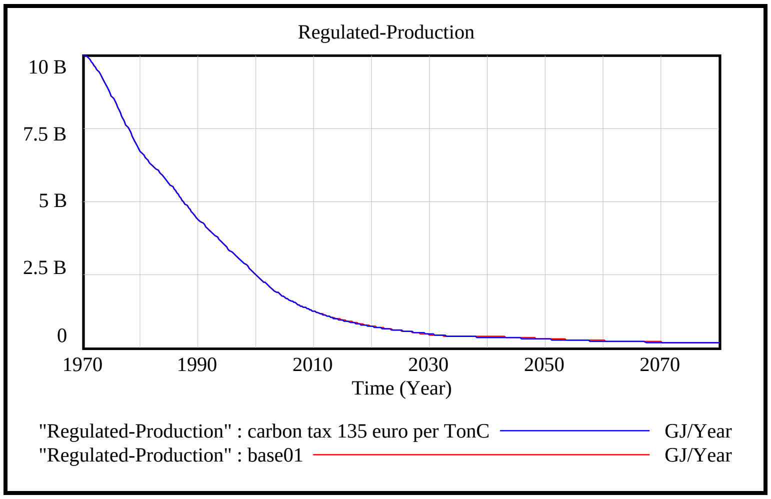


Figure 5.21. Comparison for base case and tax case for Hard coal production in the EU-15

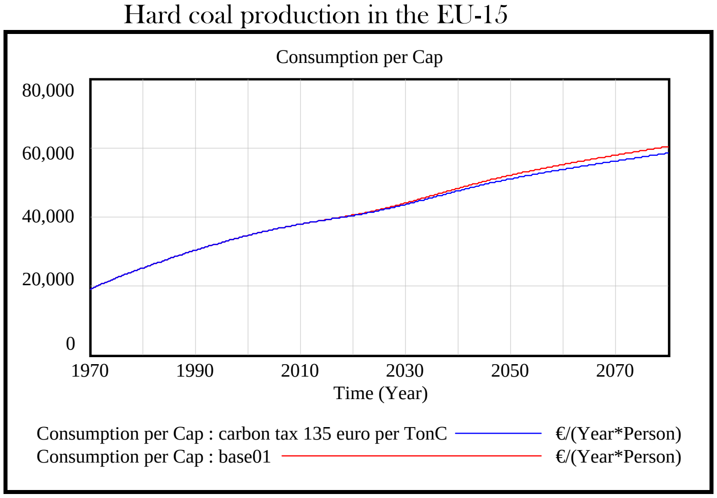
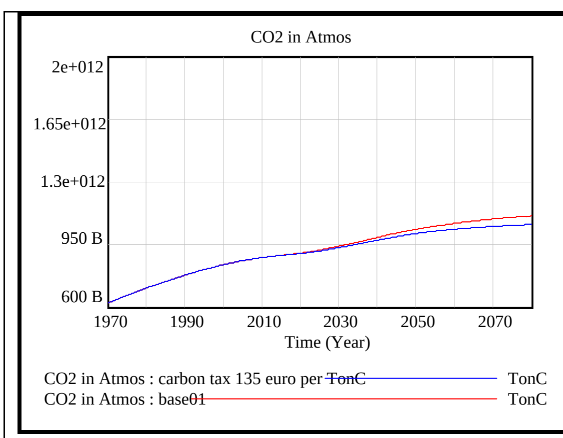
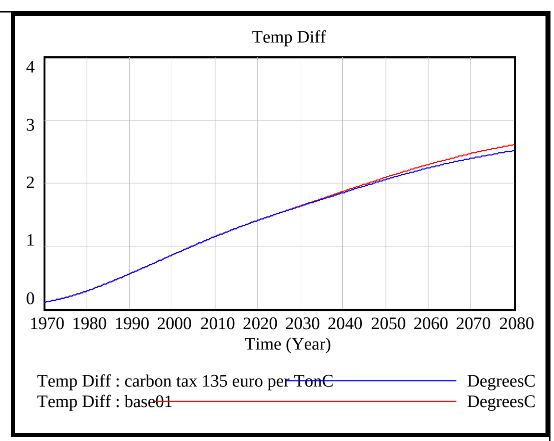


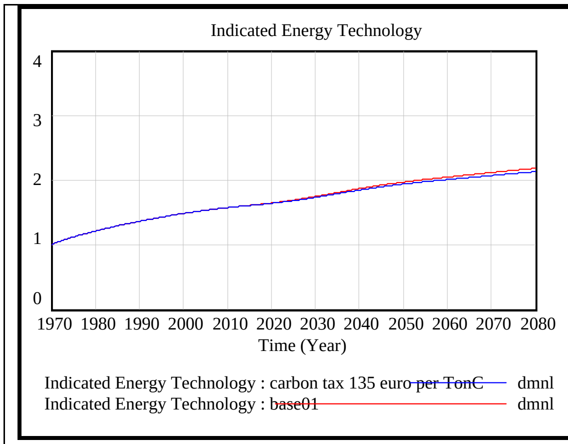
Figure 5.22. Comparison for base case and tax case for Consumption per capita in the EU-15



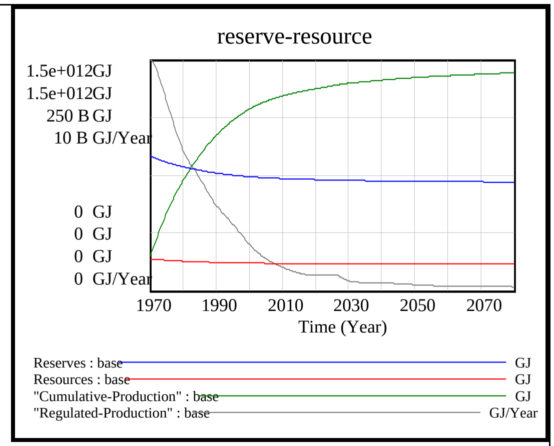
a. Comparison for base case and tax case for CO_2 in atmosphere



b. Comparison for base case and tax case for temperature change (Different) between upper and deep ocean



c. Comparison for base case and tax case for Energy technology progress factor in the EU-15



d. Comparison for base case for Reserve-Resource-Cumulative Production in the EU-15

Figure 5.23. Further results of coal model for base scenario and tax scenario

5.4.3. Model Simulation under uncertain variables (Scenario Case)

It is difficult to think about the long-term behavior of coal industry without considering uncertainty. An uncertainty analysis will help to look profoundly at the system and assist decision makers in setting up policy of the industry. The uncertainty analysis can be also considered as a scenario case. This part will test the DCE model under the uncertain conditions. Uncertainty conditions are implemented in the DCE model by using Monte Carlo simulation. This work should also be regarded as a more exploration of the DCE model.

Monte Carlo simulation

Monte Carlo is a numerical technique that makes use of random numbers to explain more a problem. It is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. By using random inputs, it is essentially turning the deterministic model into a stochastic model. The goal of Monte Carlo simulation is to determine how random variation, lack of knowledge, or error affects the sensitivity, performance, or reliability of the system that is being modelled. The users choose a distribution for the inputs that most closely matches data already have, or best represents our current state of knowledge. The data generated from the simulation can be represented as probability distributions (or histograms) or converted to error bars, reliability predictions, tolerance zones, and confidence intervals.

This method is often used when the model is complex, non-linear, or involves more than just a couple uncertain variables. The basic idea of the method is that by selecting correctly the points at which the function is evaluated one can reduce the error of the numerical value of the integral as compared to conventional methods so that much less points are needed in order to achieve the desired accuracy. Fig. 5.24 explains the steps of Monte Carlo simulation in VENSIM ®.

1: Create and select parametric models (variables) to be analyzed, $y = f(x_1, x_2, ..., x_q)$.

2: Generate a set of random inputs from selected probability distribution, $x_{i1}, x_{i2}, ..., x_{iq}$.

3: Select number of steps simulation , for $i = 1$ to n.

4: Evaluate (run) the models and store the results as y_i.

5: Analyze the results for selected models parameter (variables) using confidence intervals

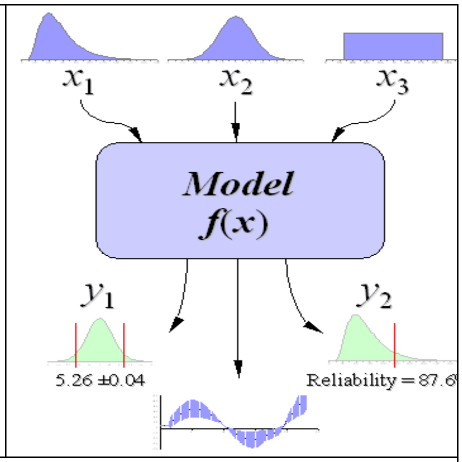


Figure 5.24. Steps of Monte Carlo simulation in the VENSIM®

Simulation the DCE model

Values for key variables for Monte Carlo simulation are drawn from subjective probability distribution. These distributions are then used to identify and to assess the model performance under uncertain conditions. Inputs subject to uncertainty include exogenous population growth, GDP (economic) growth, climate damage scale, variable cost reference, capital cost reference and profit margin (Table V.6). All variables subject to uncertainty are assumed to have either random normal distribution or random uniform distribution (with +/- 20% difference from its mean value). Identification of the uncertain distribution is not a focus of this research so that where possible, distributions are drawn from other modeler's work.

Table V.6. Variable Distribution

Variable	Distribution	Unit	Min	Max	Mean	SD	Note
Forecast Pop Growth Rt Decline Rt	Normal	dmnl	0.0	0.0685	0.0275	0.0137	Adapted from DICE
Forecast GDP Growth Rt Decline Rt	Normal	dmnl	0.0	0.0875	0.035	0.0175	
Climate Damage Scale	Normal	dmnl	0.0	0.032	0.013	0.11	Adapted from FREE
Variable Cost Ref	Uniform	€	1.2e+009	1.8e+009	1.5e+009	-	
Capital Cost Ref	Uniform	€	1.5e+009	4.5e+009	3e+009	-	
Profit Margin	Uniform	dmnl	0.05	0.09	0.07	-	

The results of simulation under uncertainty for several important variables are illustrated in Fig. 5.25 to Fig. 5.29. In this simulation, both hard coal demand and total carbon emission from hard coal grow by a factor almost six by 2080. Under uncertainty, domestic coal price grows by a factor nearly two by 2080, where the price reaches between 3.5 and 7.0 €/GJ (Fig. 5.25). Hard coal demand will reach between 5,000 million GJ (as minimum value) and 32,000 million GJ (as maximum value) by 2080 (Fig. 5.26). CO2 emission will attain to between 150 million TonC per year (as minimum value) and 800 million TonC per year (as maximum value) by 2080 (Fig. 5.27). For hard coal production, there is an insignificant changing of production under the uncertainty scenario by 2080 (Fig. 5.28).

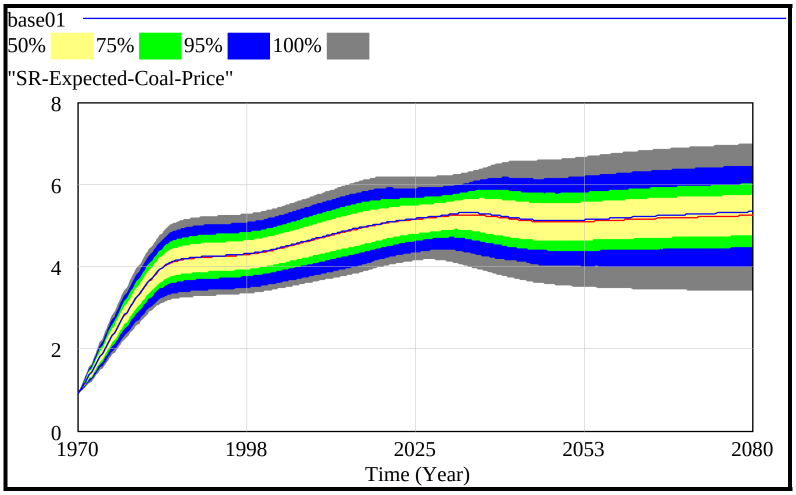


Figure 5.25. Hard coal domestic price (€/GJ) in the EU-15 under uncertainty scenario

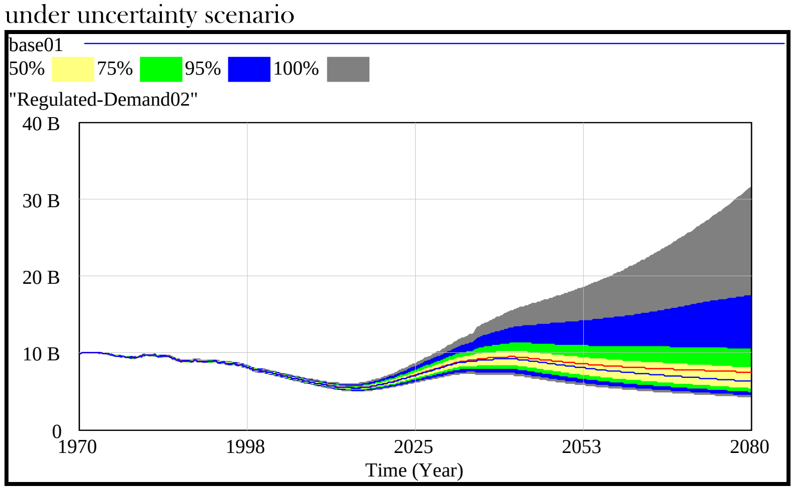


Figure 5.26. Hard coal demand (GJ) in the EU-15 under uncertainty scenario

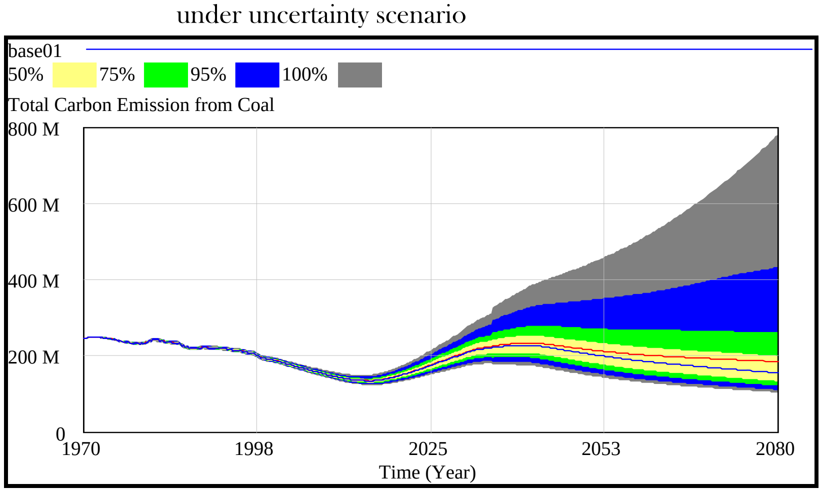


Figure 5.27. CO2 emission from hard coal (TonC/year) in the EU-15 under uncertainty scenario

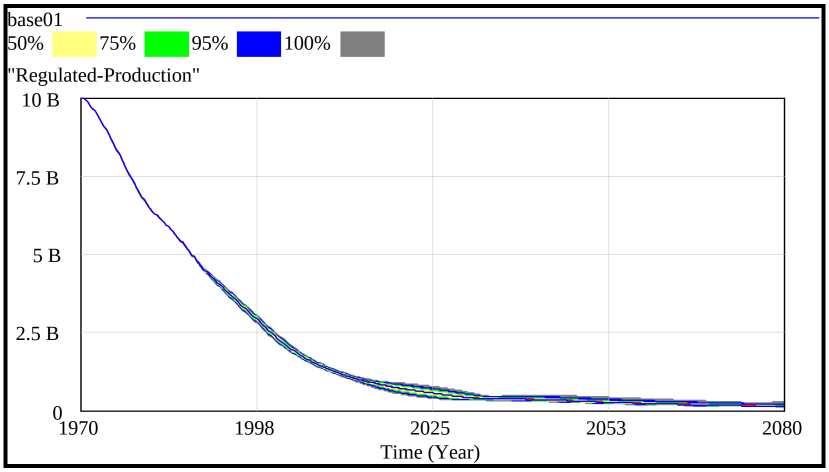
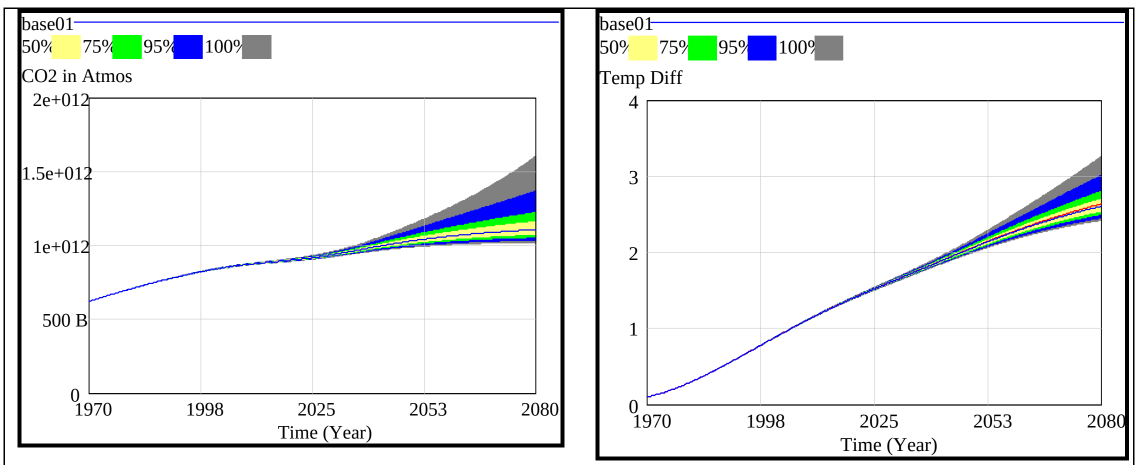


Figure 5.28. Hard coal production (GJ) in the EU-15
under uncertainty scenario



a. CO2 in atmosphere (TonC)

b. Temperature change (Degree C)

Figure 5.29. CO_2 in atmosphere and temperature change under uncertainty scenario

5.5. Closing remarks

5.5.1. Model robustness

As it is described in the previous section, the DCE model can reproduce the past reasonably well for a set of key variables in the EU-15, as population, GDP, electricity and steel demand, hard coal demand, hard coal production and domestic hard coal price. Therefore, based on the results of calibration process, it can be argued that the model can be used to do a forecast for long-term behavior of coal industry in the EU-15.

Since the model was designed to examine long-term dynamics, we could simulate future long-term behavior for coal industry in the EU-15 based on model variables derived from the calibration process. An evaluation analysis has been carried out by comparing the forecast values of the model (base case) to the estimate values of another study (EU-15 Energy and Transport Outlook to 2030) for a set of key variables. The result of the simulation shows that the DCE model can reproduce the forecast reasonably well for a set of key variables like population, GDP per capita, electricity demand, hard coal demand and hard coal production.

Yet, the DCE model still does not introduce a sub-model of substitution between energy sources. Therefore, a pressure of coal demand and a suboptimal capacity of coal utilization will not be recovered by other energy source. This condition has explained why the increasing hard coal price of almost 38% has put a pressure on hard coal demand only about 13%. Introducing a sub-model of energy substitution into the DCE model would ameliorate the analysis.

To enhance the analysis, an uncertainty is introduced into the DCE model by using Monte Carlo simulation. The uncertainty analysis can be also considered as a scenario case. Values for key variables for Monte Carlo simulation are drawn from subjective probability distribution. These distributions are then used to identify an effective carbon tax rule and to assess its performance under uncertainty. Inputs subject to uncertainty include exogenous population growth, GDP (economic) growth, climate damage scale, variable cost reference, capital cost reference and profit margin. All variables subject to uncertainty are assumed to have either random normal or random uniform distribution.

Identification of the uncertain distribution is not a focus of this research so that where possible, distributions are drawn from other modeler's work. More research and exploration to select the appropriate variables being simulated and to choose the proper distribution of those variables will enhance the model's result. Furthermore, the results of this uncertainty simulation may be helpful for policy makers to set up an appropriate decision for the coal industry in the EU-15 in regard to CO2 emission control.

The DCE model's focus is on long-term dynamics and is primary meant as a tool for analysis, and clearly not for exact prediction. It aims to fill at least partly a gap in understanding the coal industry in the EU-15. The simulation test indicates that the model is to be fairly well able to reproduce the long-term past trends in the 1970-2000 period. In addition, the other test shows that the DCE model imitates well a forecasted value of EU-15 Energy and Transport Outlook to 2030 for a set of key variables by 2030.

5.5.2. Import dependence

Coal (Energy) import dependence is defined as a ratio (in percentage) between net imports of coal (energy) to total consumption of this energy. Since 1960s, hard coal import dependence in the EU-15 has been aggravated. The hard coal import increases, while indigenous production decreases. Now, about 70-75% of hard coal demand in the EU-15 is satisfied by import. This circumstance will worsen due to pressure of high energy demand, particularly for hard coal after 2015, and at the same time the declining of domestic fossil fuel resources and production. Hard coal production has constantly declined since 1960s.

The result of the DCE model shows that, if there is no change of current policy, the import dependence for hard coal in the EU-15 will increase from 75% in 2000 to 80%, 85%, 92% in year 2010, 2020 and 2030 consecutively. Moreover it will reach almost 100% (98%) in 2080 (Fig. 5.30). The operation of carbon tax will not change significantly the situation.

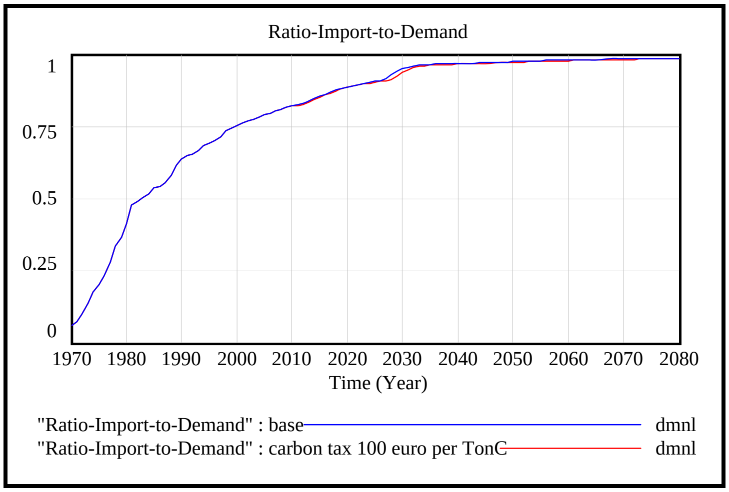


Figure 5.30. Comparison of base case and tax case for Import dependence for Hard coal

Security of energy supply can be defined as the availability of energy at all times in various forms, in sufficient quantities, and at reasonable and/or affordable prices (Clingendael International Energy Programme, (CIEP), 2004). Nowadays, the subject of energy-supply security has taken on a new relevance as far as the EU is concerned. Europe has to support every effort that is directed towards improving security of energy supply. It is important to achieve the correct balance: the supply side must be included as a key element in the energy-security structure. In regard to hard coal, the policy of rapid and massive declining rate of domestic supply has to be reconsidered in order to avoid security supply problems in the future (Ekawan, 2006c)

The question of security of energy supply has two dimensions: national dimension and European dimension, which clearly has to be strengthened. It is obvious that member states' energy systems and consumption patterns will never be similarly structured and that variations in their exposure to supply risk will continue to exist. Several countries in Europe are still heavily depending with coal for their electricity generation. Therefore, approaches to coal policy in Europe should be functional in respect to these different circumstances and allow the general objectives and priorities of energy policy to be met.

5.5.3. The need for a model for simulating the impact of CCS technology

As already explained previously in this Chapter, the DCE model has adopted an assumption from *the EU-15 Energy and Transport Outlook to 2030,* mentioning that in the long run, coal is projected to make a strong come back. Installed capacity for solids fired power plants is assumed to decline rapidly in the horizon to 2010. In the horizon to 2015 this installed capacity is projected to remain rather stable. Solid fuels are assumed to regain some market share in the EU-15 energy system beyond 2020. The increasing coal demand pattern might not continue beyond 2045 (IEA, 2004b). Beyond this year the demand will decrease. However, it is projected that the deployment of Carbon Capture and Storage (CCS) Technology will prevent rapid decline of coal demand

The DCE model still does not introduce a comprehensive sub-model for studying the impact of the technology progress of CCS on coal demand. It has to be noted that the progress of technology is of the uncertainties in Energy modeling. An integration of this kind of sub-model will enhance the analysis. This part will give a brief information background about CCS technology that will be useful afterwards for the development of the sub-model of CCS technology.

CO2 Capture and Storage (CCS): Technology and project

CCS involves three distinct processes. C*apturing* CO2 from the gas streams emitted during electricity production, industrial processes or fuel processing. T*ransporting* the captured CO2 by pipeline or in tankers; S*toring* CO2 underground in deep saline aquifers, depleted oil and gas reservoirs or unmineable coal seams.

The CCS technology is still under development. In most CO2 capture demonstration projects, existing technologies are applied. Various small-scale pilot plants based on new capture technologies are in operation around the world. Only one power plant demonstration project on a megatonne-scale has so far been announced: the FutureGen project in the US. This is a coal-fired advanced power plant for cogeneration of electricity and hydrogen. Its construction is planned to start in 2007.

Pilot projects suggest that CO2-enhanced coalbed methane (ECBM) and enhanced gas recovery (EGR) may be viable but the experience so far is not sufficient to consider these two as proven options. Coal-fired Ultra Supercritical Steam Cycles (USCSC) fitted with post-combustion capture technologies or various types of oxy-fueling technology (including chemical looping, where the oxygen is supplied through a chemical reaction), may emerge as alternatives.

In electricity generation, CO2 capture is most effective when used in combination with large-scale, high-efficiency power plants. The success of a CCS strategy could depend on the use of such plants. For coal-fired plants, Integrated Gasification Combined Cycle (IGCC) fitted with physical absorption technology to capture CO2 at the pre-combustion stage is considered to be promising. However, in Europe as a whole, electricity companies have so far been reluctant to invest in IGCC technology. To date, two IGCC demonstration projects have been built in the region, at Buggenum in the Netherlands and at Puertellano in Spain, each with a capacity of around 250 MW.

Currently there are approximately more than a hundred CCS projects in the world. It includes 11 commercial CO2 capture projects, 35 CO2 capture R&D projects, 26 geologic storage demonstration projects, 74 geologic storage R&D projects and nine deep ocean storage R&D projects.

At present, Europe already has advanced CO2 emission reduction policies in place. These include CO2 market mechanisms, demand-side policies, and support programmes for renewables and other emission reduction technologies. CCS is gaining increasing attention, as policy makers start to realize that significant emission reductions require a wider portfolio of emission mitigation strategies.

In Europe, the prospects for CCS differ by country. Norway, for example, is active in the field of sub-sea aquifer storage through the Sleipner demonstration project and the planned Snohvit LNG project. Norway has conducted a number of feasibility studies for gas-fired power plants with CO2 capture, and Denmark has studied the feasibility of CO2 capture for coal-fired power plants, but these studies have not yet resulted in any further demonstration plans. More interest is hoped for from the EU's CASTOR project, which began in 2004. The project aims to reduce the cost of capturing and separating CO2 from flue gases to 20-30 €/t.

The EU is co-funding various storage projects. One is the first CO2 storage in an onshore aquifer in Ketzin, close to Berlin, known as CO2Sink. Previously, the site was used for natural gas storage. The goal is to improve understanding of the behaviour of CO2 underground. The RECOPOL project in southern Poland is an EU-funded pilot/demo project for CO2 ECBM.

Costs of CCS

The cost for CCS can be split into cost of capture, transportation and storage. Current estimates for large-scale capture systems (including CO2 pressurization) are 25-50 USD per tonne of CO2 but are expected to improve as the technology is developed and deployed. If future efficiency gains are taken into account, costs could fall to 10-25 USD/t CO2 for coal-fired plants and to 25-30 USD/t CO2 for gas-fired plants over the next 25 years. With CO2 transportation, pipeline costs depend on the volumes being transported and on the distances involved. Large-scale pipeline transportation costs range from 1-5 USD/t CO2 per 100 km. If CO2 is shipped over long distances, the cost falls to around 15-25 USD/t CO2 for a distance of 5,000 km. The cost of CO2 storage depends on the site, its location and method of injection. In general, it is at around 1-2 USD per tonne of CO2. Table V.7 summaries the estimation of CCS costs.

Table V.7. Estimation of CCS costs

Activity	Cost (USD/t CO2)	Uncertainties
CO2 capture	5 to 50 (current) 5 to 30 (future)	Low end for pure streams that only need compression; high end for chemical absorption
CO2 transportation	2 to 20	Depends on scale and distance
CO2 injection	2 to 50	Low end for Mt size aquifer storage; high end for certain ECBM projects
Total	40 to 100	

Source: IEA, 2003b

Using existing technology, total CCS costs can range from a 40 USD/t in the most optimistic case to a 100 USD/t cost in cases of small-scale projects capturing CO2 from gas-fired power plants. By 2030, these costs should go down to 25-50 USD per tonne of CO2. Using CCS with new coal- and gas-fired power plants would increase electricity production costs by 2-3 US cents/kWh. It is projected that by 2030, CCS cost could fall to 1-2 US cents per kWh (including capture, transportation and storage).

Impact of the level of tax on CO2 emission

This part will summarize the simulation result from the IEA report on *Prospect on CO2 Capture and Storage* (IEA, 2003b), concerning the impact of the CO2 emission penalty on the CO2 reduction at global level. The model used in the study is called the Energy Technology Perspectives (ETP). It belongs to the MARKAL economic models. MARKAL has been developed over the past 30 years.

The CO2 emission penalties are invariably the costs incurred to deploy the relevant technologies (*e.g.*, because of regulations), but they can also be interpreted as the level of a tax on CO2 emissions or the price of a tradable emissions permit on the market. According to standard economic reasoning, firms confronted with such 'prices' for GHG emissions will deploy all technologies that cost less than these 'prices'.

In Figure 5.31, the cumulative emission reduction for the period 2000-2050 is shown as a function of the CO2 penalty. The level of CO2 capture increases as the penalty increases. At a penalty of 50 USD/t CO2, the CO2 capture reaches 350 Gt CO2 in 2050. Up to 2050, the cumulative reduction in CO2 emissions is one-fifth lower if CCS is not considered than it would be if CCS were applied. This shows the environmental benefits of CCS.

The Figure also shows the cumulative CO_2 capture in the period 2000-2050. The cumulative capture increases with the penalty level. The shape of the curve indicates that the additional cumulative capture decreases for each USD increase of the penalty. The area between the curves with and without CCS is smaller and indicates that the actual emission reduction of CCS is only 40-45% of the quantity captured.

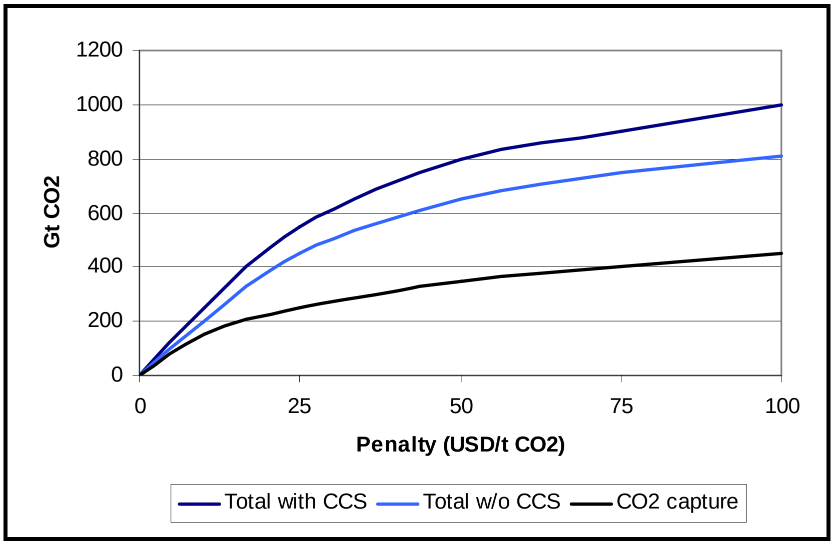


Figure 5.31. Cumulative emission abatement for 2000-2050 as a function of the penalty level

The EU Emissions Trading Scheme (ETS) that began in 2005 will provide incentives for CO2 emission reduction. CCS is mentioned in the relevant ETS Directive, but emission reductions must be proven. The penalties of 40 to 100 €/TonCO2 (equivalent to 135 to 350 €/TonC) are envisaged for the period 2007-2012 if the company fails to meet its reduction target under the ETS. These penalties are relatively in the same cost range with CCS costs. Therefore CCS may be possible to introduced, if other strategies do not result in sufficient emissions reduction.

CCS could potentially allow for the continued use of fossil fuels while at the same time achieving significant reductions in CO2 emissions. If CCS technology is already proven and is massively deployed in Europe, it might play a key role in achieving its Kyoto's emissions target. Regarding to coal, it is envisaged that CCS would result in an increase in the use of coal compared to a scenario where CCS is not considered. As coal is considered a more secure fuel than oil and gas, the fact that coal remains a viable energy option increases supply security.

The IEA report on *Prospect on CO2 Capture and Storage* (IEA, 2003b) has also analyzed the comparison of four alternative CO_2 policy targets, which are the penalty levels stabilize at a level of 10, 25, 50 and 100 USD/t CO_2 at global level. The impact these levels have on CO_2 capture is shown in Figure 5.32.

The results suggest that higher penalties result in increased CCS use. CCS would be a viable alternative on a large scale. Even at a penalty of 10 USD/t CO_2, the amount of CO_2 captured reaches 8.4 Gt by 2050. Even though this is likely to represent an overestimation because the model does not account for variations in reservoir geology and in site-specific CO_2 supply and demand within regions.

In Figure 5.32, the use of CCS keeps rising if the penalty is increased from 50 to 100 USD/t CO_2. This suggests that the technical potential is even higher, and the use of CCS is not limited by storage constraints or by capture possibilities, but by the cost of competing emission mitigation measures and by policy decisions regarding acceptable levels of climate change risk.

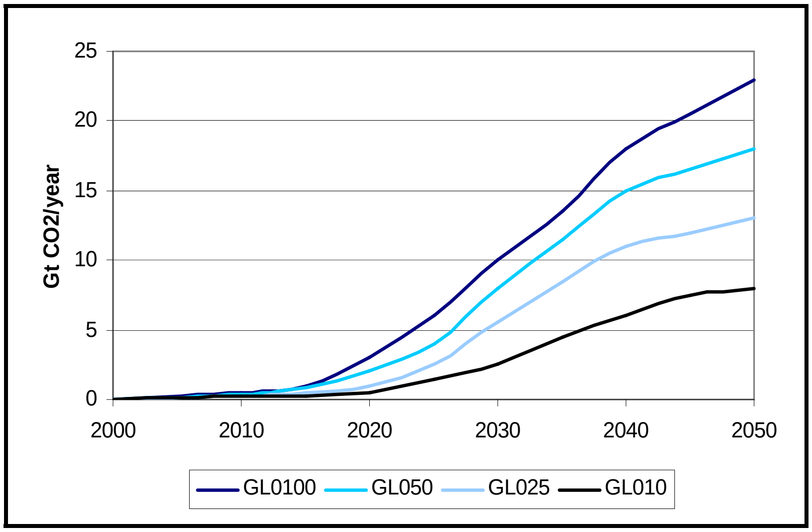


Figure 5.32. CO_2 capture at various policy incentive levels

Chapter 6:
Application of the DCE model for Simulating Carbon Tax Policies

As already explained in Chapter 5, as a base model the DCE can be used to serve coal policy study. Therefore by joining other policy modules into the model, it can be used to analyze the impacts of the policy to coal industry. In addition to a base scenario, the analysis can also be ameliorated by simulating several different scenarios.

The current international framework for greenhouse gas emissions reductions is the Kyoto Protocol, which sets targets for emissions slightly below 1990 levels. Curbing emissions implies substantial reductions in the carbon intensity of the economy as output grows, particularly as the first commitment period begins in 2008.

There are several features of the emission reduction approach in the Protocol and European system. Some of these features are Permit price - as part of quota instrument - and Carbon taxes – as part of price instrument.

This chapter will try to explore climate change policies for the case of coal in Europe. The DCE model will test tax policies and emission permit under a set of assumptions. The results are then used in identifying an effective approach to reduce CO2 emission and in assessing its performance under uncertainty. This work should also be regarded as more exploration of the DCE model.

It is difficult to think about the emission reduction approach without considering uncertainty. A major challenge faced is the need to commit to fixed emissions targets when there is great uncertainty about both the cost of those reductions and the likely future trend of emissions quantity. The presence of delays and rigidities in behavior in the system reduction increases the importance of uncertainty by raising the costs of policy implementation and increasing the urgency of taking near-term action to avoid later damage. Therefore, both a certainty and an uncertainty analysis will assist in setting up policy of emission reduction[17].

Uncertainty is included in the analysis through Monte Carlo simulation. Values for key variables for Monte Carlo simulation are drawn from subjective probability distribution. Inputs subject to uncertainty include exogenous population growth, GDP (economic) growth, climate damage scale, variable cost reference, capital cost reference and profit margin. The uncertainty value of these variables can be seen in Table V.5, Chapter 5. All variables subject to uncertainty are assumed to have either random normal distribution or random uniform distribution.

6.1. Constant carbon tax

One approach in controlling emission is by introducing a tax. Carbon taxes, as specific environmental taxes, generate direct payments to the governments based on the carbon content of the fuel being consumed. Carbon taxes affect the externality directly. Coal generates the greatest amount of carbon emissions and is therefore taxed in greater proportion than oil and natural gas, which have lower carbon concentrations and lead to lower carbon emission per unit of energy.

Carbon taxes differ from permit emission allowance in the sense that carbon taxes fix the marginal costs for carbon emissions, and generate specific revenues for the state budget, while tradable permits fix the total amount of carbon emitted and allow price levels to fluctuate according to market forces. The structure of constant tax (Tc) in the DCE model is based on following formula:

$$T_c(t) = \int \frac{DT_c(t) - T_c(t)}{\tau_t} dt \qquad (6.1)$$

DT_c = desired (indicated) carbon tax, τ_t = tax implementation time, and

$$DT_c = T_o + \frac{T_1 E}{E_0} \qquad (6.2)$$

Where T_0 = carbon tax constant, E = perceived CO2 emissions rate, T_1 = carbon tax emissions coefficient, and E_0 = reference emission rate

The sub-model for carbon tax (and so the sub-model for adaptive tax) can be seen in Fig. 6.7. Table VI-1 sums up a response of the DCE model to the introduction of a 135 €/TonC constant carbon tax. Fig. 6.1 - Fig. 6.3 show the impact of constant carbon tax on hard coal price, hard coal demand and CO2 emission rate from hard coal burning consecutively.

In 2080 the tax will reduce by 20.2% hard coal (HC) demand and CO2 emission rate from hard coal as well. The demand will go down from 6,284 million GJ to 5,228 million GJ in 2080. The emission rate will decrease from 155.22 million TonC to 129.12 million TonC in the same year. At the same time the tax will push hard coal production down by 2.4% from 138.94 million GJ to 135.72 million GJ. The application of carbon tax reduces the pressure on hard coal reserve due to

[17] For more detail explanation about uncertainty analysis in abatement cost see Chapter 3, part 3.4.3. Price or quantity instruments

less coal demand. Less pressure on hard coal reserve will reduce pressure on decreasing its production. The tax also raises offering coal price and thereafter decrease slightly coal production, ceteris paribus. It has to be noted that the DCE model still does not introduce a substitution between energy sources.

The simulation of economic part for carbon tax scenario results in an increasing hard coal price from 5.34 €/GJ to 8.83 €/GJ by 2080 after introducing tax scenario. Meanwhile, simulation of the DCE results welfare – indicated as consumption per capita – went down by about 3.4% from 60,289 €/capita to 58,332 €/capita by 2080.

Table. VI-1. Summary response of the model to the introduction of a constant carbon tax

Scenario	HC Price			HC demand			CO2 emission from HC			HC Production	Consumption per capita
	€/GJ			million GJ			million TonC			million GJ	*€/capita*
year	2010	2040	2080	2010	2040	2080	2010	2040	2080	2080	2080
Uncontrolled	5.06	5.21	5.34	5,971	9,208	6,284	147.5	227.44	155.22	138.94	60,289
Constant tax	8.29	8.66	8.83	5,509	8,162	5,228	136.07	201.62	129.13	135.72	58,332
Δ Diff (%)	39.0	39.8	39.5	-8.4	-12.8	-20.2	-8.4	-12.8	-20.2	-2.4	-3.4

Fig. 6.4 - Fig. 6.6. show the response to the best possible constant tax (a 135 €/TonC tax is introduced by 2008 with phased smoothly) under uncertain conditions. In a constant tax scenario the price of emission is fixed, but emission varies over a wide range. This carbon tax controls hard coal demand and subsequently as a result reduces CO2 emission emitted from hard coal burning.

In this simulation, hard coal demand grows by a factor almost five by 2080. The demand will reach between about 5,000 million GJ (as minimum value) and nearly 25,000 million GJ (as maximum value) by 2080. The mean value of hard coal demand is 5,228 million GJ by 2080 (Fig. 6.5).

The CO2 emission rate grows by a factor about four in 2080. The emission rate will reach between about 150 million TonC per year (as minimum value) and just about 600 million TonC per year (as maximum value) by 2080. Meanwhile, the mean value of CO2 emission is 129 million tons carbon by 2080, with a deviation of less than 5% due to uncertainty (Fig. 6.6).

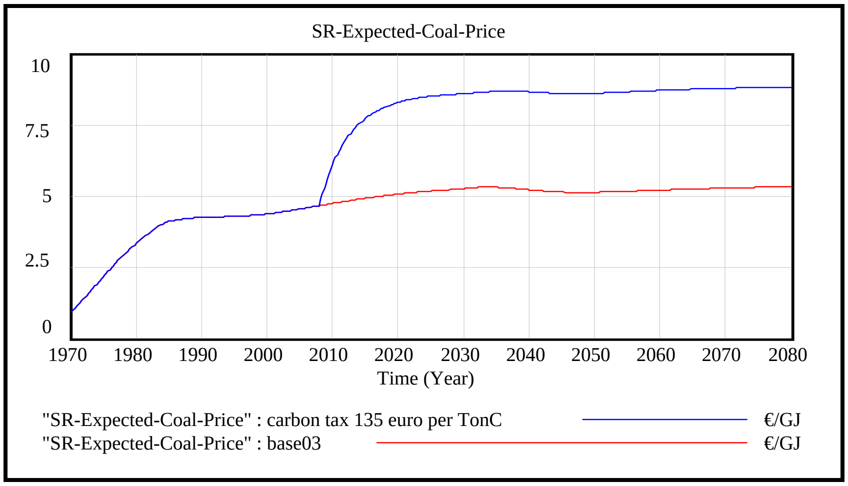


Figure 6.1. Hard coal price (€/G) after being introduced constant tax

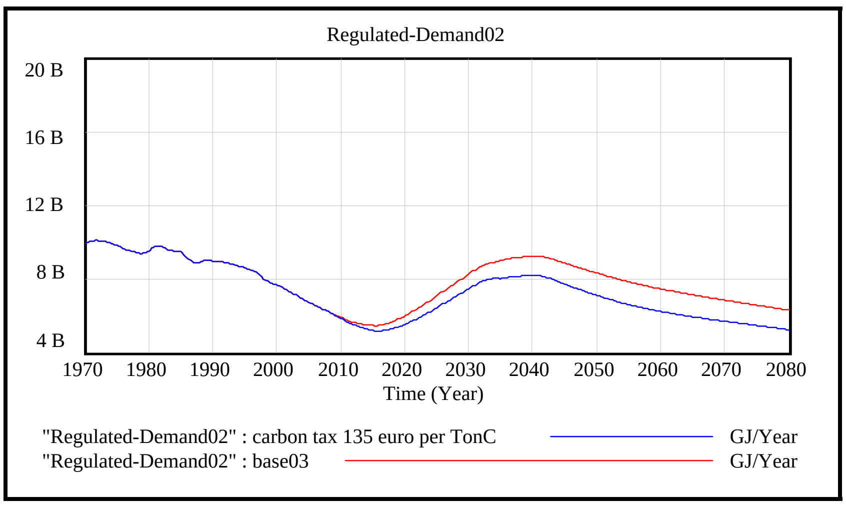


Figure 6.2 Hard coal demand (GJ/year) after being introduced Constant tax

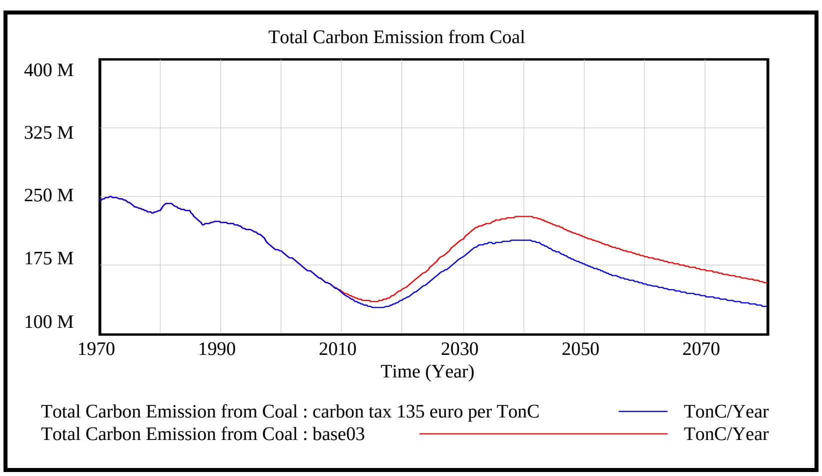


Figure 6.3 Carbon emission (TonC/year) from hard coal after being introduced Constant tax

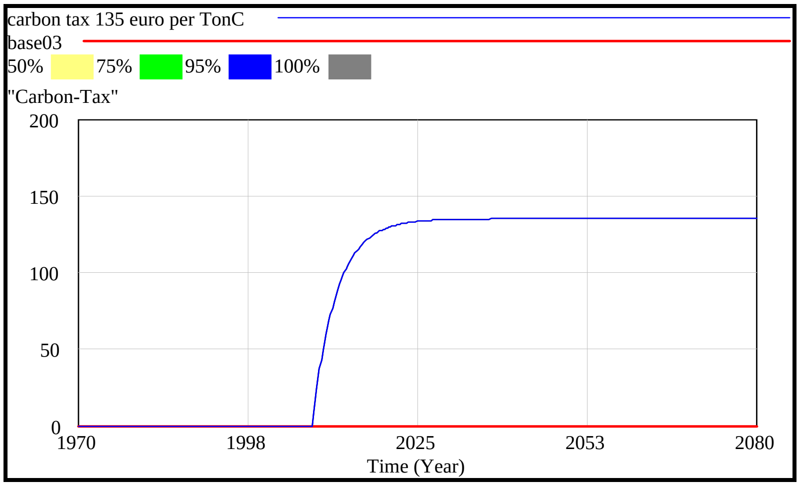


Figure 6.4. Constant carbon tax (€/TonC) under uncertainty scenario

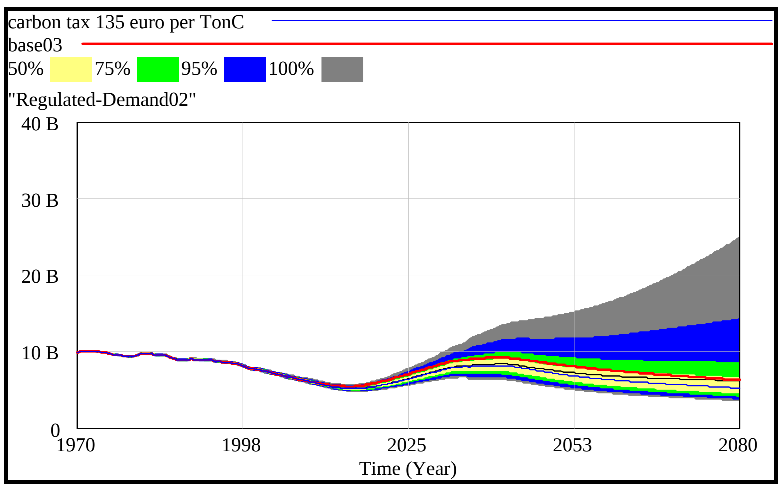


Figure 6.5. Hard coal demand (TonC/year) under uncertainty and constant tax scenarios

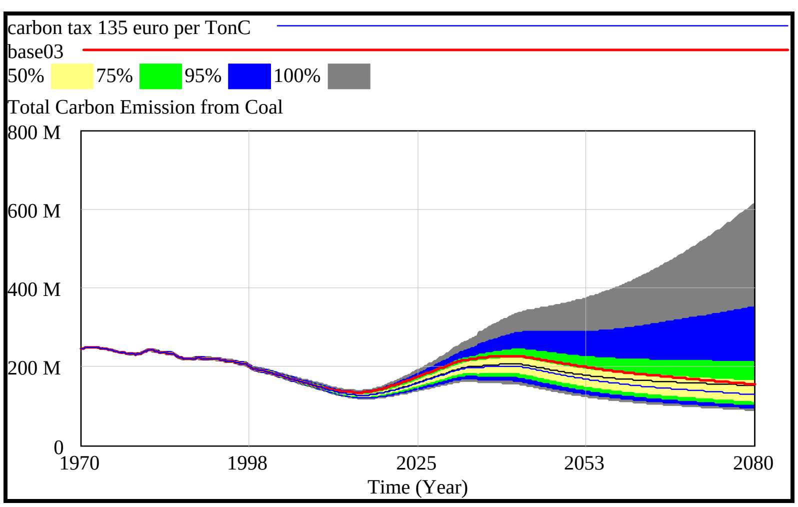


Figure 6.6. CO2 emission from hard coal (TonC/year) under uncertainty and constant tax scenarios

6.2. Adaptive carbon tax

There is no reason to suppose that a constant tax is optimal. A typical alternative is to explore taxes that change over time, by specifying a vector of taxes at specified times or constructing a tax as a function of time. However, this is still a strategy of selecting a tax that must fit all uncertain futures. An alternative approach is to create a feedback control rule. The tax is a linear function of perceived emissions rates and atmospheric CO2 concentrations, with an implementation delay. The structure of adaptive tax (Ta) in the DCE model is based on the following formula:

$$T_a(t) = \int \frac{DT_a(t) - T_0(t)}{\tau_t} dt \qquad (6.3)$$

DT_a = desired carbon tax, τ_t = tax implementation time, and

$$DT_a = T_o + \frac{T_1 E}{E_0} + \frac{T_2 C_a}{C_{a,0}} \qquad (6.4)$$

Where T_0 = carbon tax constant, E = perceived CO2 emissions rate, T_1 = carbon tax emissions coefficient, E_0 = reference emission rate, T_2 = carbon tax concentration coefficient, C_a = atmospheric CO2 content, and $C_{a,0}$ = reference atmospheric CO2 content.

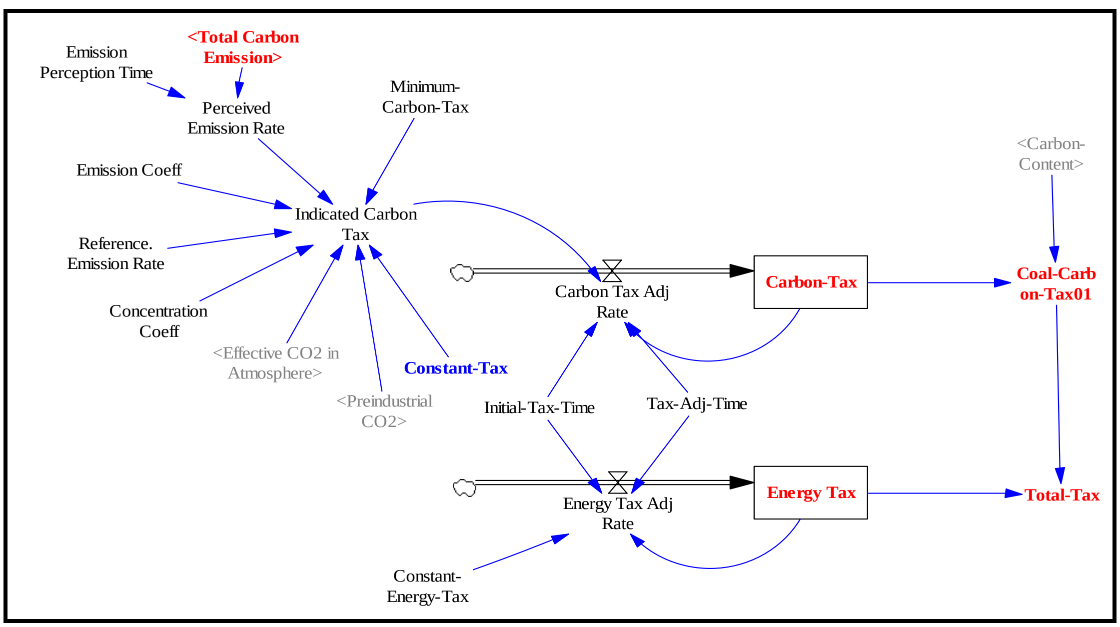


Figure 6.7. Adaptive and constant carbon tax sub-models (Vensim®)

The sub-model of adaptive tax can be seen in Fig. 6.7. Table VI-2. sums up the response of the model to the introduction of an adaptive tax (a 135 €/TonC maximum tax is introduced in 2008 with phased smoothly). Fig. 6.8 - Fig. 6.10 show the impact of adaptive tax on hard coal price, hard coal demand and CO2 emission from hard coal consecutively.

The tax will reduce by 19.5% hard coal (HC) demand and CO2 emission from hard coal as well by 2080. The demand will go down from 6,284 million GJ to 5,259 million GJ in 2080. The emission rate will decrease from 155.22 million TonC to 129.91 million TonC in the same year. At the same time the tax will push hard coal production down by 2.0% from 138.94 million GJ to 136.16 million GJ.

The simulation of economic part for adaptive tax scenario results an increasing hard coal price from 5.34 €/GJ to 8.67 €/GJ by 2080 after introducing tax scenario. Meanwhile, simulation of the DCE results a contracting welfare – indicated as consumption per capita – by about 3.3% from 60,289 €/capita to 58,337 €/capita by 2080.

Table. VI-2. Summary response of the model to the introduction of adaptive carbon tax

Scenario	HC Price			HC demand			CO2 emission from HC			HC Production	Consumption per capita
	€/GJ			million GJ			million TonC			million GJ	*€/capita*
year	2010	2040	2080	2010	2040	2080	2010	2040	2080	2080	2080
Uncontrolled	5.06	5.21	5.34	5,971	9,208	6,284	147.50	227.44	155.22	138.94	60,289
Adaptive tax	8.13	8.62	8.67	5,638	8,178	5,259	139.28	202.03	129.91	136.16	58,337
ΔDiff (%)	37.8	39.6	38.4	-5.9	-12.6	-19.5	-5.9	-12.6	-19.5	-2.0	-3.3

Fig. 6.11 - Fig. 6.13. show the response to the best possible adaptive tax under uncertainty scenario. The main benefit of adaptive tax is that the additional degrees of freedom allow the tax to start small, minimizing short-run disruption of the economy, and continue to rising to suppress increasing emission pressure from economic growth. In this simulation scenario, the tax grows from about 120 to 275 €/TonC in 2080 (Fig. 6.11).

In this adaptive tax simulation, hard coal demand grows by a factor almost five by 2080. The demand will reach between about 4,000 million GJ (as minimum value) and nearly 22,000 million GJ (as maximum value) by 2080. The mean value of hard coal demand is 5,259 million GJ by 2080 (Fig. 6.12).

The CO2 emission rate grows will by a factor about five in 2080. The emission rate will reach between about 100 million TonC per year (as minimum value) and just about 550 million TonC per year (as maximum value) by 2080. Meanwhile, the mean value of CO2 emission is 129 million tons carbon by 2080 (Fig. 6.13).

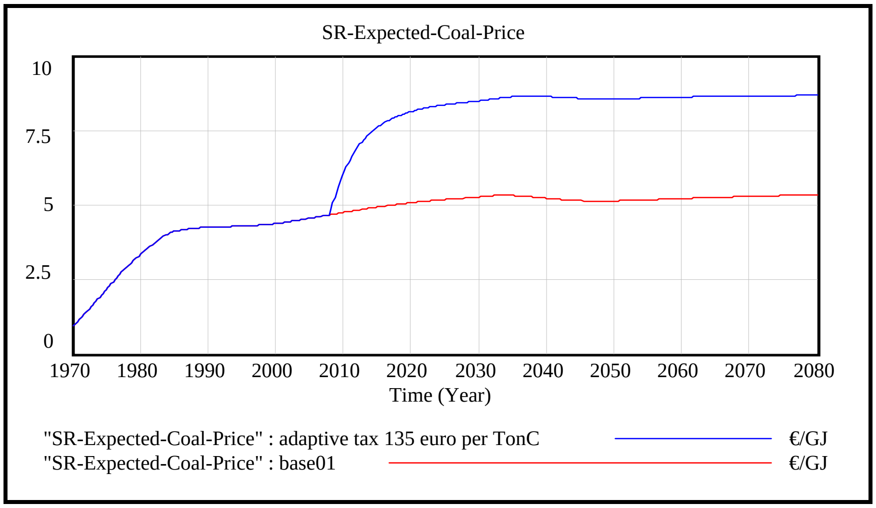


Figure 6.8. Hard coal price (€/G) after being introduced Adaptive tax

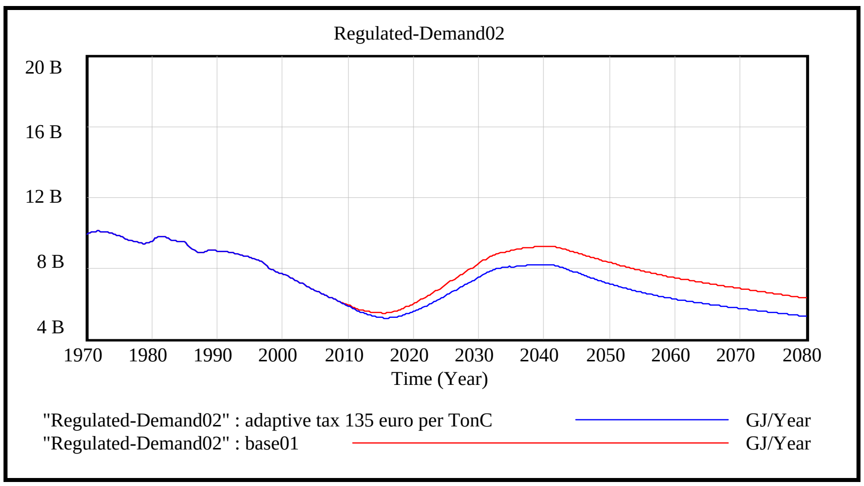


Figure 6.9. Hard coal demand (GJ/year) after being introduced Adaptive tax

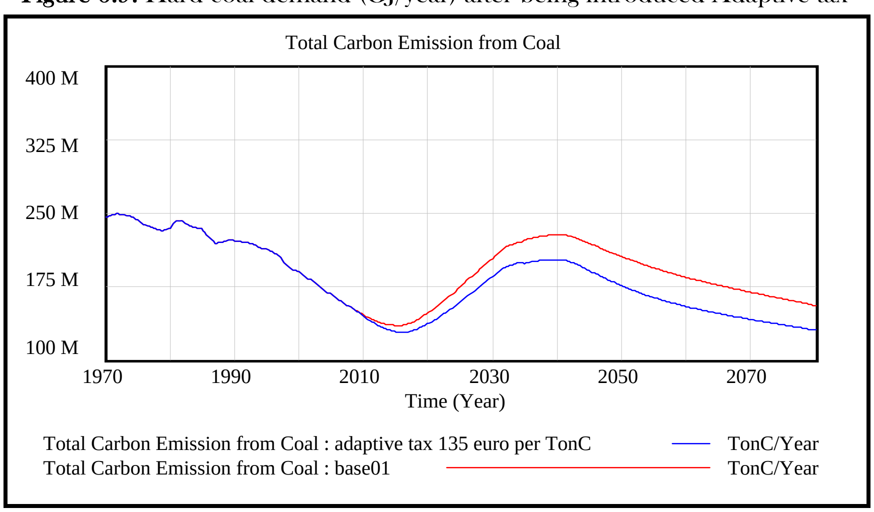


Figure 6.10. Carbon emission (TonC/year) from hard coal after being introduced Adaptive tax

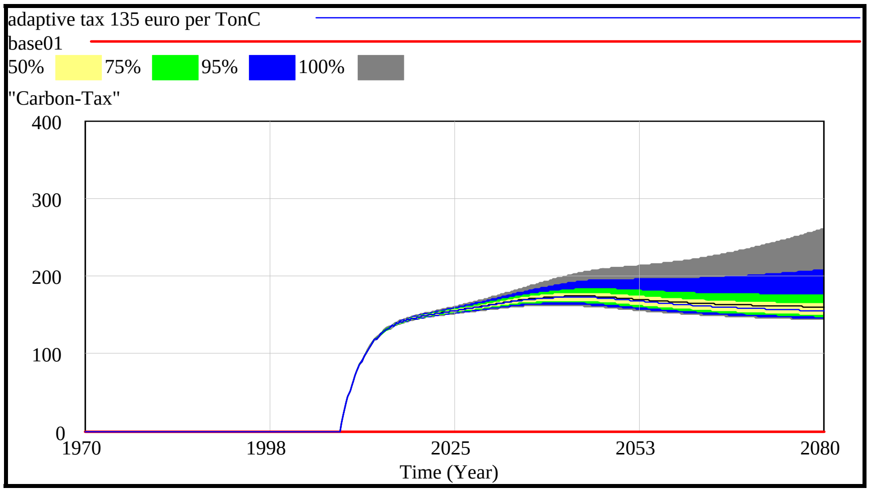


Figure 6.11. Adaptive carbon tax (€/TonC) under uncertainty scenario

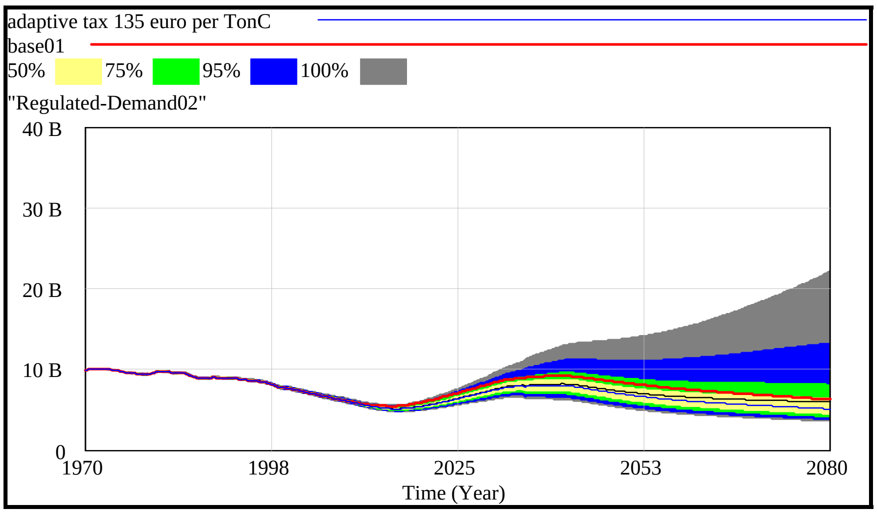


Figure 6.12 Hard coal demand (TonC/year) under uncertainty and adaptive tax scenarios

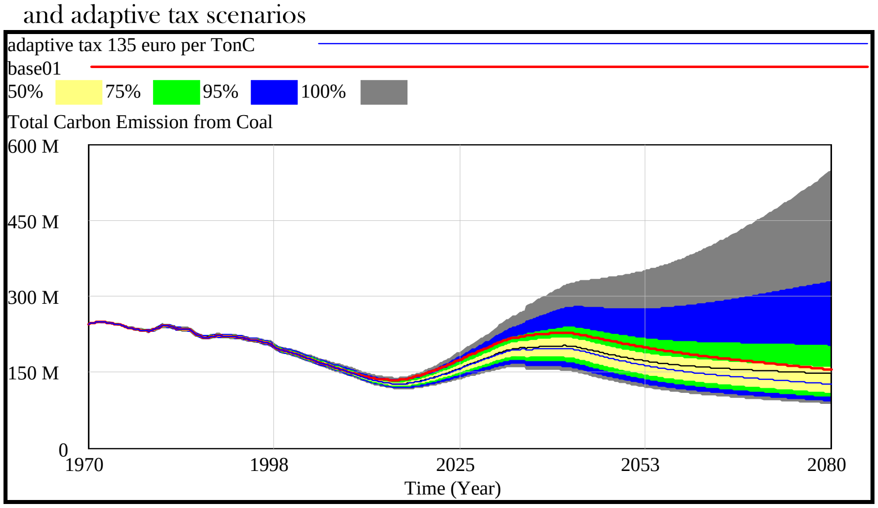


Figure 6.13 CO2 emission from hard coal (TonC/year) under uncertainty and adaptive tax scenarios

6.3 Permit price

Emissions can also be controlled by introducing a tradeable permit system into the model. In most models permit prices instantaneously equilibrate the level needed to restrict emissions to the permitted level. The market for permits is implemented somewhat abstractly as a proportional controller that rapidly adjusts permit prices to whatever level is necessary to meet the target. The structure of permit price (Pp) in the model is based on the following formula:

$$P_p(t) = \int \frac{DP_p(t) - P_p(t)}{\tau_p} dt \qquad (6.5)$$

DP_p = desired permit price, τ_p = permit implementation time, and

$$DP_p = P_o + \frac{P_1 E}{E_0} \qquad (6.6)$$

Where P_0 = permit price constant, E = perceived CO2 emissions rate, P_1 = permit price emissions coefficient, and E_0 = reference emission rate

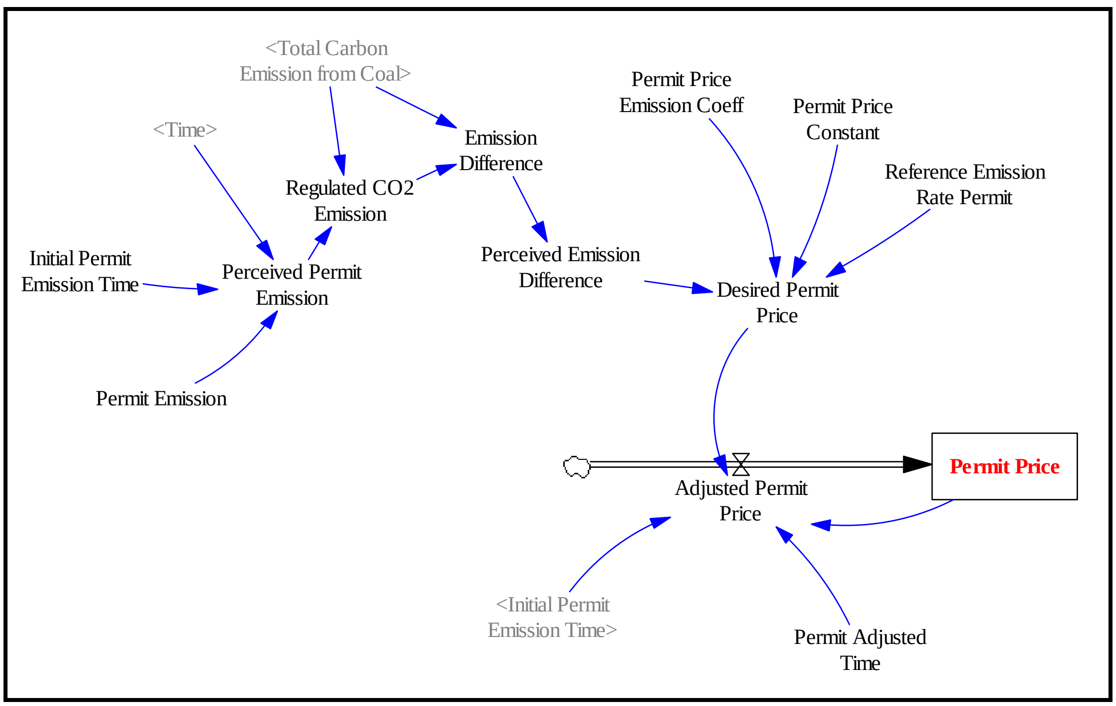


Figure 6.14 Permit Price sub-model (Vensim®)

The sub-model of permit price can be seen in Fig. 6.14. Table **VI**-3 sums up the response of the DCE model to the introduction of a permanent cap on hard coal emission at 195 million ton carbon per year (8% less than 1990's hard coal emissions level in the model) with a 135 €/TonC is set up as minimum permit price. Fig. 6.15-Fig. 6.17 show the impact of permit price on hard coal price, hard coal demand and CO2 emission rate from hard coal consecutively.

The tax will reduce by 20.2% hard coal (HC) demand and CO2 emission from hard coal as well by 2080. The demand will go down from 6,284 million GJ to 5,226 million GJ in 2080. The emission rate will decrease from 155.22 million TonC to 129.10 million TonC in the same year. At the same time the tax will push hard coal production down by 2.1% from 138.94 million GJ to 136.04 million GJ.

The simulation of economic part for permanent cap scenario results in an increasing HC price from 5.34 €/GJ to 8.83 €/GJ by 2080 after being introduced tax scenario. Meanwhile, simulation of the DCE results in a shrink of welfare – indicated as consumption per capita – by about 3.4% from 60,289 €/capita to 58,299 €/capita by 2080.

Table. VI-3. Summary response of the model to the introduction of a permanent cap on hard coal emission at 195 million ton carbon per year

Scenario	HC Price			HC demand			CO2 emission from HC			HC Production	Consumption per capita
	€/GJ			million GJ			million TonC			million GJ	*€/capita*
year	2010	2040	2080	2010	2040	2080	2010	2040	2080	2080	2080
Uncontrolled	5.06	5.21	5.34	5,971	9,208	6,284	147.50	227.44	155.22	138.94	60,289
Permit price	8.39	8.89	8.83	5,480	8,138	5,226	135.36	195.00	129.10	136.04	58,299
ΔDiff (%)	39.7	41.4	39.5	-9.0	-13.1	-20.2	-9.0	-16.6	-20.2	-2.1	-3.4

Fig. 6.18 - Fig. 6.20 show the impact of implementing a permanent cap on hard coal emission at 195 million ton carbon per year under uncertainty scenario. Unlike the tax instrument where the price of emission is fixed and emission varies over a wide range, in permit instrument the rate of (maximum) emission is fixed. Following activation of the permit scheme in 2008, emission constraints at 195 million per year are met throughout the study period and it will have an effect from year 2026 – 2080 (Fig. 6.20).

The side effect of controlled emissions is a wide range of permit price in different scenario. Permit price in some cases will grow approaching 600 €/TonC (Fig. 6.18). The high variance in permit price is due to the fact that permit is forcing futures with differing cost of emission reduction and growth driver to meet a common goal.

In this simulation, hard coal demand grows between about 4,000 million GJ (as minimum value) and nearly 8,000 million GJ (as maximum value) by 2080. The mean value of hard coal demand is 5,226 million GJ by 2080 (Fig. 6.19).

The emission rate will reach between about 90 million TonC per year (as minimum value) and just about 195 million TonC per year (as maximum value) by 2080. Meanwhile, the mean value of CO2 emission is 129 million tons carbon by 2080 (Fig. 6.20).

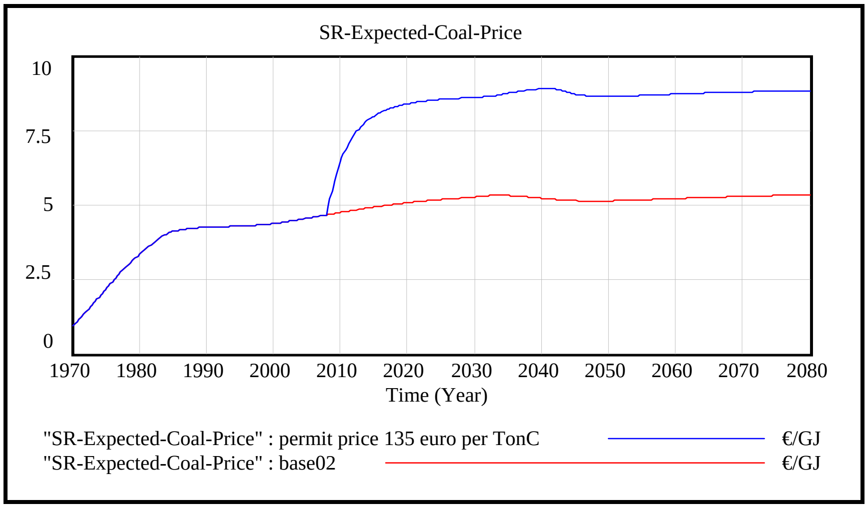


Figure 6.15. Hard coal price (€/G) after being introduced Permit price

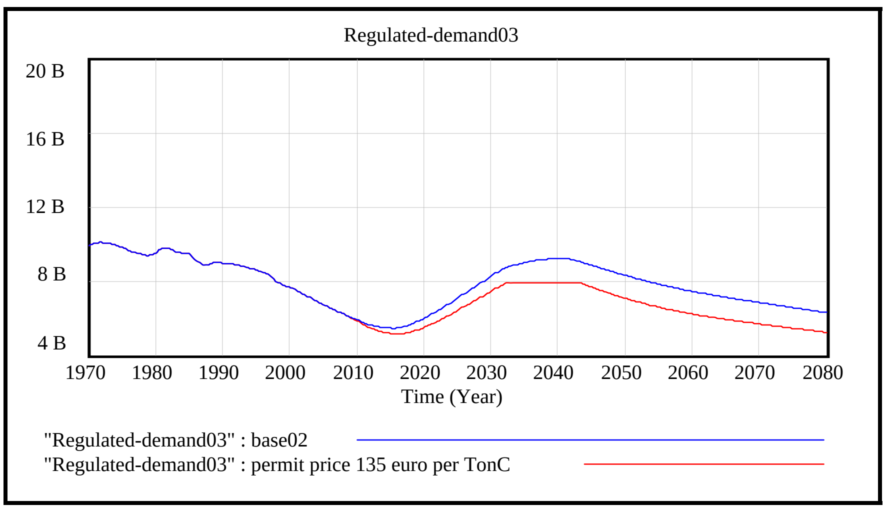


Figure 6.16. Hard coal demand (GJ/year) after being introduced Permit price

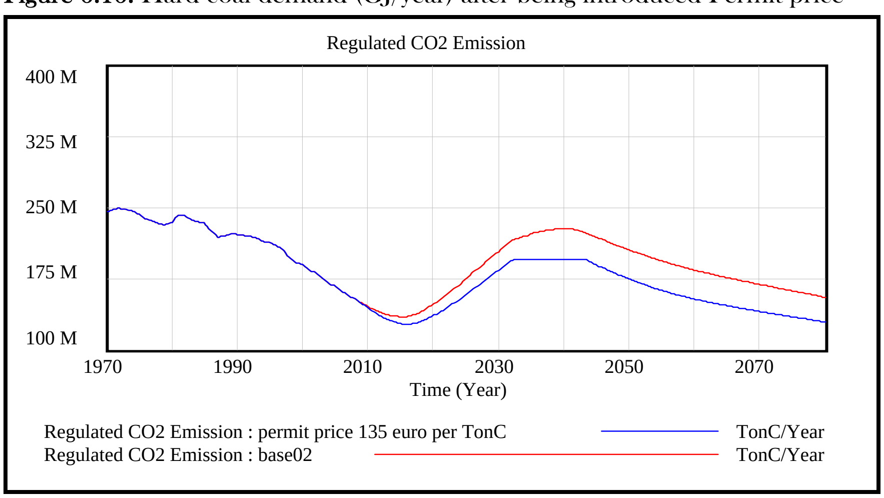


Figure 6.17 Carbon emission (TonC/year) from hard coal after being introduced Permit price

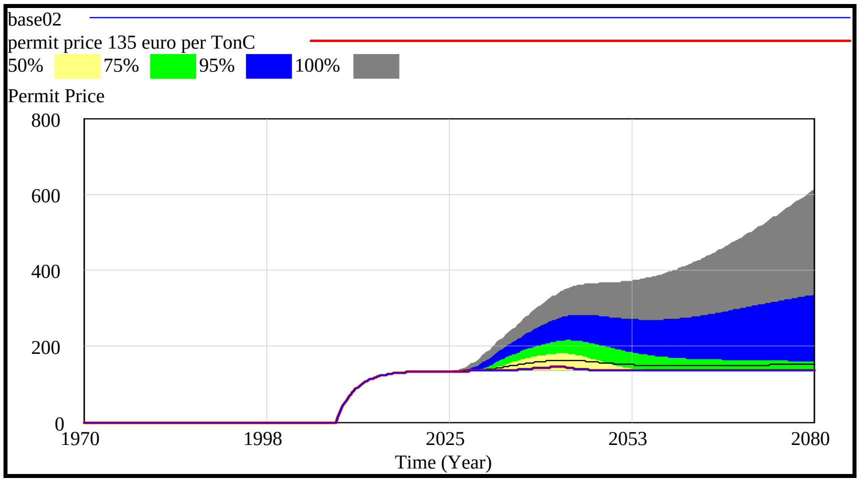


Figure 6.18. Permit Price (€/TonC) under uncertainty scenario

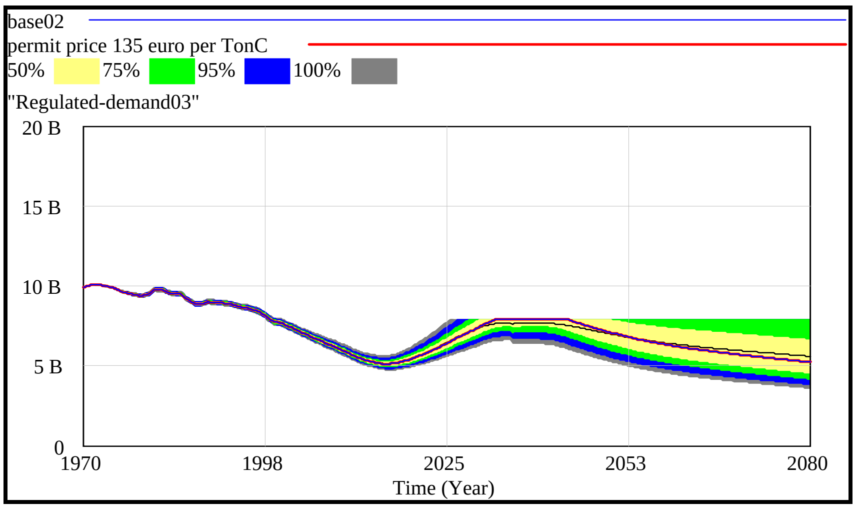


Figure 6.19. Hard coal demand (TonC/year) under uncertainty and Permit price scenarios

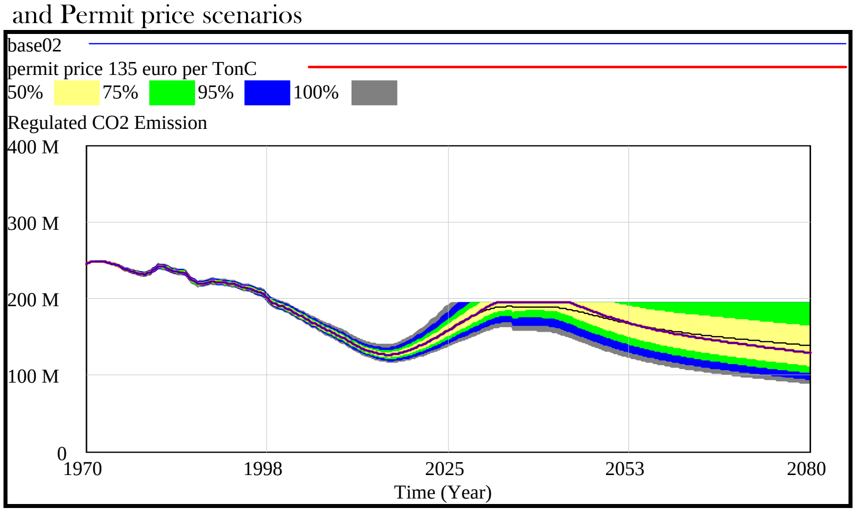


Figure 6.20. CO2 emission from hard coal (TonC/year) under uncertainty and Permit emission scenarios

6.4 Closing remark

Permit and carbon taxes are thought to be identical in the sense that the first targets quantity while the later targets price. By examining Fig. 6.21, the carbon tax determines the level of emissions; if the number of permits to be traded is the same as this level emission, the permit price should equal the tax. The government can choose the tax level (price) or the number of emission permit to be traded (quantity). If all is known the outcome will be the same – C* emission permit trade at a price P. However, when abatements costs (or benefits) are uncertain, selecting a carbon tax can lead to the 'wrong' level of emission reduction, while choosing a quantity can result in a mistake about the forecasted price that firms will have to pay (Weitzman 1974; Kooten 2004). If the demand curve for permit is relatively steep damages accumulate only slowly, as in the case of climate change.

If there is uncertainty about the marginal costs and benefits of abating climate change, the choice of a price-based or quantity-based instrument will depend on which type of uncertainty is most prevalent. It is therefore important to do uncertainty analysis in order to have good understanding about the situation before choosing the appropriate instrument.

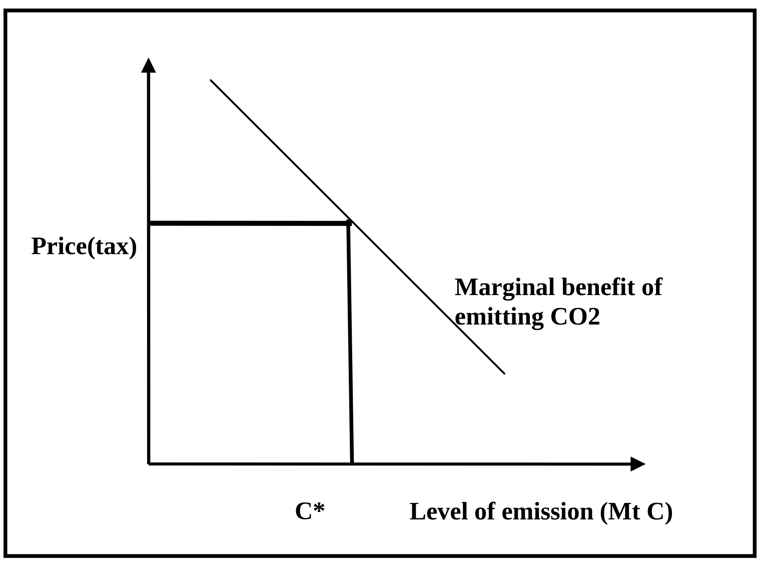


Figure 6.21. Controlling CO2 emission using economic incentives

With the aim to compare the performance of emission reduction instruments, a comparison study has been carried out. The conditions of three previous climate policy instruments are set up as close as possible among them before simulation is done. Fig. 6.22 and Fig. 6.23 show the evolution of carbon taxes and permit price over the study period. While Fig. 6.24 and Fig. 6.25 show the impact of those three policies on hard coal price and CO2 emission consecutively. Table VI-4. sums up simulation results for different emission control instruments.

Fig. 6.22 shows that the adaptive tax changes over time as a function of emission rate. While for the constant tax, the tax is stable whatever the level of emission rate is. In Permit policy, the price is adjusted to whatever level is necessary to meet the emission target. In Fig. 6.23, it is shown that permit price is stable up to the year 2035 because the perceived emission rate is still below the emission target (195 million tonC). During period 2035-2050 the permit price will go up as the perceived emission rate is over the target. This price will push the emission rate down to the target level of emission rate following the decreasing of hard coal demand. The impact of the variation of emissions reduction instruments on coal price, hard coal demand and CO2 emission can be seen in Fig. 5.24, Fig. 5.25 and Fig. 5.26 consecutively.

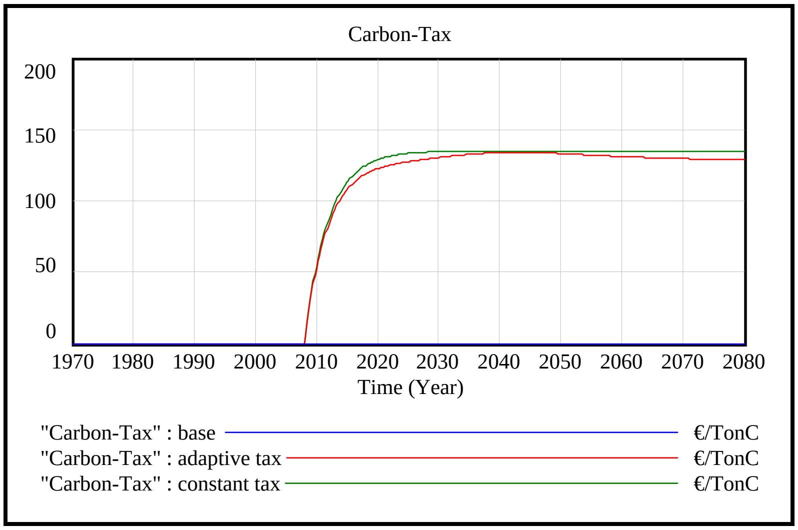


Figure 6.22. Carbon constant and adaptive tax (€/TonC) for comparison study

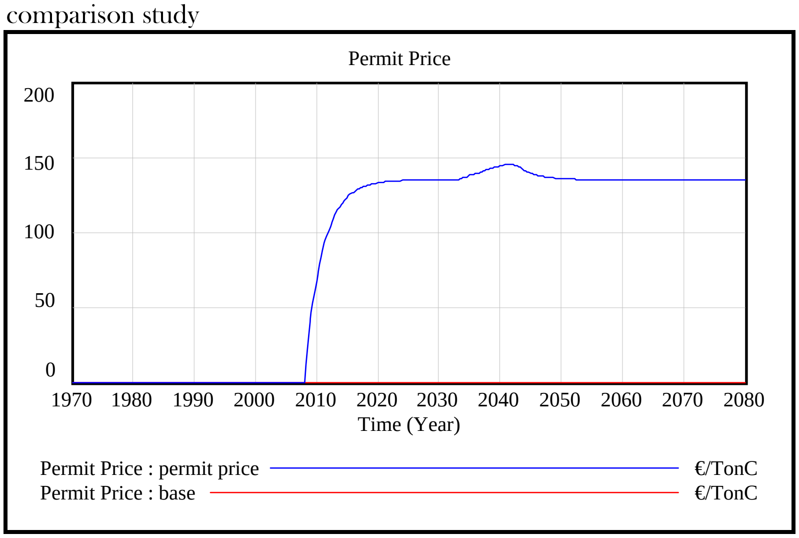


Figure 6.23. Permit price (€/TonC) for comparison study

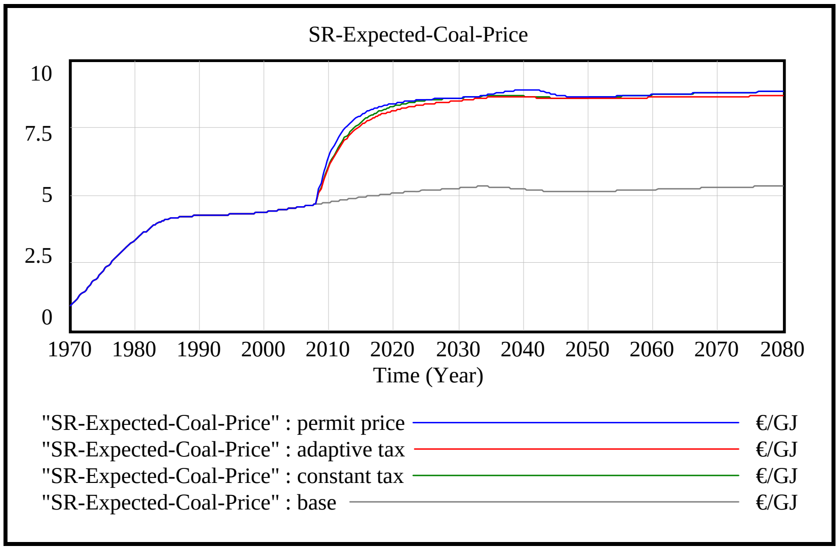


Figure 6.24. Hard coal prices (€/GJ) for comparison study

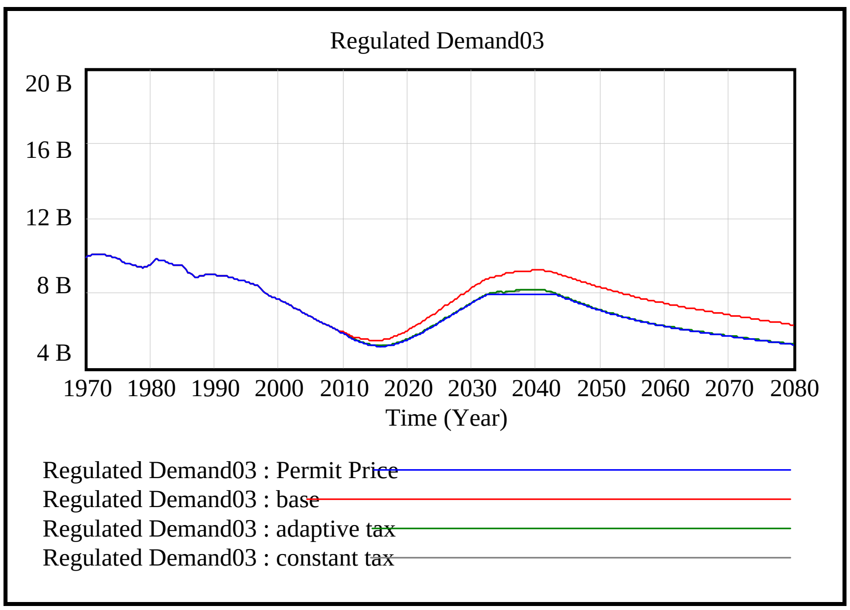


Figure 6.25. Hard coal demand (GJ) for comparison study

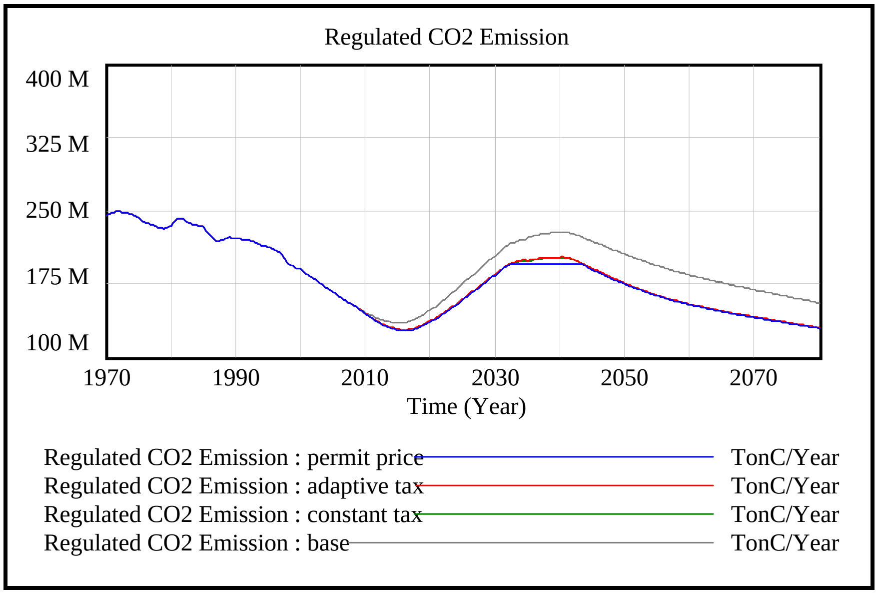


Figure 6.26. Total Carbon Emission (TonC/year) from hard coal for comparison study

Table VI-4. Summary of simulation results for different emission control instruments

Scenario	Tax or Permit Price	Tax or Permit Price	Emission	Temperature Change	Consumption Per capita	Cumulative Consumption Per capita
	€/TonC	*€/TonC*	million TonC	^{0}C	*€/capita*	*€/capita*
year	*2020*	*2080*				
Uncontrolled	-	-	155	2.60	60,289	4,638,000
Constant carbon tax	128.9	135.0	129	2.50	58,322	4,573,000
Adaptive carbon tax	122.5	128.65	129	2.51	58,375	4,575,000
Permit emission	132.9	135.0	129	2.49	58,299	4,572,000

The test results suggest that those three policy instruments have a net benefit in reducing CO2 emission. The carbon constant tax scenario, adaptive carbon tax scenario and permit emission scenario will reduce the emission rate by 26 million ton carbon per year from 155 million ton carbon to 129 million ton carbon by 2080. However, by the year 2080 adaptive carbon tax has higher value of consumption per capita (58,375 *€/capita)* and cumulative consumption per capita (4,575,000 *€/capita)* comparing to the two other instruments. In general carbon tax policies are found to outperform fixed emission permit.

Adaptive tax is the best possible instrument. The main benefit of adaptive tax is that it allows the tax to start small, minimizing short-run disruption of the economy, and continue to rising to suppress increasing emission pressure from economic growth. The adaptive tax responses positively to the atmospheric concentration of CO2, so that in scenarios with slow natural uptake of carbon, taxes will be higher. Similarly, the tax responses negatively to perceived emissions, so that abatement effort is restricted in scenarios with high abatement costs (emissions that resist policy).

There are several attractive features of the permit instrument. If it works, it guarantees that emissions will be cap. Permit trading provides a mechanism for transferring resources from developed to developing countries. It fits with both market and non-market economies (by contrast, taxes are usually to be spoken of with a price system). If permits are distributed by auction, they raise government revenue. Tradable permits thereafter transfer wealth among firms, rather than to governments. Furthermore, permits avoid the term “tax”, which is sometimes not politically acceptable.

At the same time, there are several features that are problematic. Permit trading has high transaction costs. Permits allocated based on past emissions institutionalize a distribution of emissions that is far from equitable. If permits are given away initially, they amount to a windfall for current emitters. Most importantly, both future baseline emissions and the costs of a given reduction are highly uncertain, making it difficult for politicians to make commitments.

General Conclusion

Coal once had a glorious role as one of the factors that shaped Europe's economic and political development. From the industrial revolution to the 1960s, this fossil fuel was massively consumed and its utilization was constantly raised. In the aftermath of the World War II, coal had also an important part in reconstruction of Western Europe's economy. In the late of 1960s, its role as an energy source was then overtaken by oil and gas. In the EU-15, since years the demand has been depressing. Three reasons explain this declining. First is a competition with other fuel sources. Second is high operating cost. Third, there is a general (mis)-conception that coal mining in Europe is unnecessary because of growing world coal trade and untapped possibilities for importing cheaply coal.

Faced with the above situations, a quest for the future of coal industry in the lines of an energy policy in the European Union is unavoidable. In the previous Green paper in 2000, EU Commission described coal as an "undesirable" fuel and the production of coal on the basis of economic criteria has no prospect.

This dissertation tried to portray and to investigate the current status of (hard) coal mining and utilization in the EU-15. In addition, by using simulation analysis the dissertation attempted to forecast the states of coal industry in the EU. We present here five important results of the study.

<u>The first</u> is that in order to get answers for three inquires on coal issue, a literature investigation has been carried out. The investigation study concludes that:

- *Concerning coal demand:* Power demand in the EU-15 will increase by approximately 36% over the next two decades. Gas use will increase significantly in absolute and relative terms as well as coal-based electricity generation will still remain a major player as well. The existing study shows that the energy consumption in the EU-15 in 2030 will reach 2,191 Mtoe, where oil will represent 36% of energy consumption, 33% of gas and 13% of hard coal and lignite. It argues that the EU-15 still depends heavily on fossil energy, including coal, for the forthcoming decades.

- *Concerning coal supply:* Supply from the international coal market is secured. Abundant and wide distribution of world's coal reserves, numerous and in-concentrated suppliers, modest price fluctuations and transparent market have made coal supply secure. Concerning the domestic coal supply, since the 1960s, coal mining industry in Europe has gone into rapid decline due to together a competition with coal from outside the Community and the advent of other fuels to produce electricity. It might be argued that unprofitable coal mines could be maintained by closing them. However, the decision to close permanently the mines has to be taken carefully. Once the mines flooded, they cannot be reopened. Furthermore, the immediate closing of many coal mines in the short term will only deteriorate the energy supply balance in the Union.

- *Concerning coal impacts on environment:* Through the Framework Programme, the EU-15 has set up 3 strategy responses to the emission challenges as follow: reducing emissions of pollutants such as particulate matter and oxides of sulphur and nitrogen, increasing thermal efficiency to reduce gases emissions - including CO2 per unit of electricity generated-, and reducing CO2 emissions to near zero levels through carbon capture and storage. In the case of coal these three strategies will be achieved through the current research of Clean Coal Technology. In addition, apart from the three Kyoto mechanisms, to combat climate change the EU has launched its own emission trading since 2005.

The second is that with the intention to know the current achievement status of the Kyoto Protocol's target in the EU-15, a literature investigation has been carried out. The investigation study concludes that the combination of existing domestic policies and measures and Kyoto mechanisms in the EU-15 are expected to deliver a 6.5% emission reduction in 2010. Therefore, all current measures and policies lead to a shortfall Europe's Kyoto target of 1.5% from 92% to 93.5%.

Additional domestic policies and measures planned by several Member States would therefore be needed to meet the Kyoto target. Key additional policies and measures reported by Member States measures promoting electricity generation from renewable energy sources, cogeneration policies and energy efficiency policies. In this circumstance, we argue that by deploying the recent progress of Clean Coal Technology would help the EU-15 to meet their Kyoto's target.

The third is that a Coal model, called the Dynamic Coal for Europe (the DCE) has been developed using system dynamics. The DCE is an energy(coal)-economy-environment model and shows how the interactions among technological progress, depletion, production, demand portray the coal industry by altering the dominance of the feedback process in the system.

The calibration process for the DCE shows that the model reproduces past numbers on the scale well for several variables: Population, Gross Domestic Product, Electricity demand, Steel Production, Hard coal demand, Hard coal production and Hard coal cost (domestic price) over period 1970-2000. Based on the results of this calibration process, it can be argued that the DCE model can be used to do a forecasting for examining long-term behavior of coal industry in the EU-15.

Further simulation step is to compare the model results with other study. A comparison for the DCE's results for several main variables (Population, GDP per capita, Electricity demand, Hard coal demand and production and CO2 emission) have shown that the model results are tightly close to the results outlook from the report of the EU-15 Energy and Transport Outlook to 2030.

Based on the two comparison processes above, we are convinced that the DCE model can well simulate the behaviour of coal industry in the past as well as in the future for the EU-15 region. Furthermore, we are persuaded that the model algorithm (construction) for the DCE model can be used to construct a similar model for other non-renewable energy sources for Europe.

The fourth is that the current framework for greenhouse gas emissions reductions is the Kyoto Protocol, which sets targets for emissions slightly below 1990 levels. There are several features of the emission reduction approach in the Protocol as well as in European system. These features are Permit price - as part of quota instrument - and Carbon taxes – as part of price instrument.

The simulation results of the DCE suggest that the carbon constant tax, adaptive carbon tax or permit emission have a net benefit in reducing CO2 emission. Through introducing a carbon tax or constant permit of 135 €/TonC, phased smoothly beginning in 2008, these three instruments, each will reduce the emission by 26 million ton carbon per year from 155 million ton carbon to 129 million ton carbon by 2080.

However, by the year 2080 (end of the study) adaptive carbon tax has higher consumption per capita comparing to two other instruments. We are convinced that in general carbon tax policies are found to outperform fixed emission permit. We also argue that an adaptive tax is the best possible instrument to reduce CO2 emission. The main benefit of adaptive tax is that it allows the tax to start small, minimizing short-run disruption of the economy, and continue to rising to suppress increasing emission pressure from economic growth.

The fifth, the DCE model's focus is on long-term dynamics and is primary meant as a tool for analysis, and clearly not for exact prediction. It aims to fill at least partly a gap in understanding the coal industry in the EU-15. Yet the DCE's results have helped to enlighten the outlook of coal status in the EU-15 as follow:

- Coal demand will decrease until about in year 2015 and will rise from period 2015-2040/45. Beyond the year of 2040/45, it will fall again until at least in year 2080 (end of the study).
- The trend of CO2 emission from hard coal will tightly follow to the coal demand trend;
- Coal production will constantly fall from the year 1970 (beginning of the study) to 2080 (end of the study). It would likely significantly go down from 357 Mt in 1970 to reach less than 138.94 GJ (5 Mt) in 2080;
- Coal import dependency in the EU-15 will constantly increase. The DCE simulation shows that it would increase from 75% in 2000 to 80%, 85%, 92% in year 2010, 2020 and 2030 consecutively.

Recommendation for future researches

Reducing greenhouse gases emissions is of ultimate concern in the world so is in Europe. In regard to CO2 emission from hard coal utilization, the DCE has explored the behaviour of coal system in response to the introduction of 135 €/TonC carbon taxes or permit price. The simulation results of the DCE suggest that those policy instruments have a net benefit in reducing CO2 emission.

However, the work leaves many key features of model unexplored. It is possible to test a variety of other policy and even more scenarios in the DCE model. Moreover, it is also important that the DCE structures be further improved by integrating a variety of other sub-models. Particular recommendations for future researches are paid to:

- conducting an optimization analysis in order to obtain an optimal tax or permit policies. A variety of carbon tax prices (or constant permit) have to be explored to get an optimal tax price (or permit price). The decisive factor for this policy selection is maximization of welfare (consumption per capita) over the simulation period.

- exploring other measures (scenario) to combat climate change, in particular an emission trading. The EU has developed the scheme for trading emissions of carbon dioxide (CO2), started on 1 January 2005. It is important to explore a response of the model in relation with this trading. An emission trading causal loop and module has first to be built to exhibit the system reality before being integrated into the DCE model. The primary objectives of this exploring are to get both optimal prices of emission permit and quantity of permit as well as to know the impact of the CO2 emission reduction on hard coal demand.

- introducing into the model an inter-fuels substitution sub-module. One of the DCE assumptions is that there is no substitution of energy requirement and coal demand is estimated separately from other fossil fuels demand. In reality when there are extreme changes in energy costs it will follow by a substitution for each major fuel. Making this process endogenous in the DCE, completed by delay and feedback processes, would yield a better understanding of the system.

- conducting research and exploration to select appropriate variables being simulated and to choose the proper distribution of those variables. Values for key variables for Monte Carlo simulation are drawn from subjective probability distribution. Identification of the uncertain distribution is not a focus of this research. More research and exploration to select appropriate variables being simulated and to choose the proper distribution of those variables will enhance the model's result. The results of this uncertainty simulation may be helpful for policy makers to set up an appropriate decision for the coal industry in the EU-15 in regard to CO2 emission control.

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Appendix A

Coal Mining in Western Europe

(Data mainly taken from Euracoal (2001) (2003), Ekawan (2004))

In line with depletion of the reserves and competition with other energy sources, currently there are not many active coal mines in Europe. In the EU-15, only four countries that are still mining coal, namely Germany, the United Kingdom, Greece and Spain. In 2002, coal production from those countries reached 74.7 Mt of hard coal and 337.2 Mt of lignite. Below is a brief description of the coal mining situation in those four countries.

A.1 Coal Mining in Germany

Germany has considerable probable reserves of hard coal (21.6 bill. tce) and lignite (12.8 bill. tce), making these the country's most important indigenous fuels. In 2002 Germany's primary energy production totalled some 127.6 Mtce (million ton coal equivalent). With an output of 83.4 Mtce in the same year, coal had a nationwide market share of 65.3%. Germany is to a large extent dependent on energy imports. In 2002 the German deep mining industry sold some 28.6 Mtce of coal and coke to the solid fuel market. Of this, the power generation industry consumed 20.8 Mtce, while 7.2 Mtce was supplied to the German steel industry. Sales to the heat market totalled 0.6 Mtce.

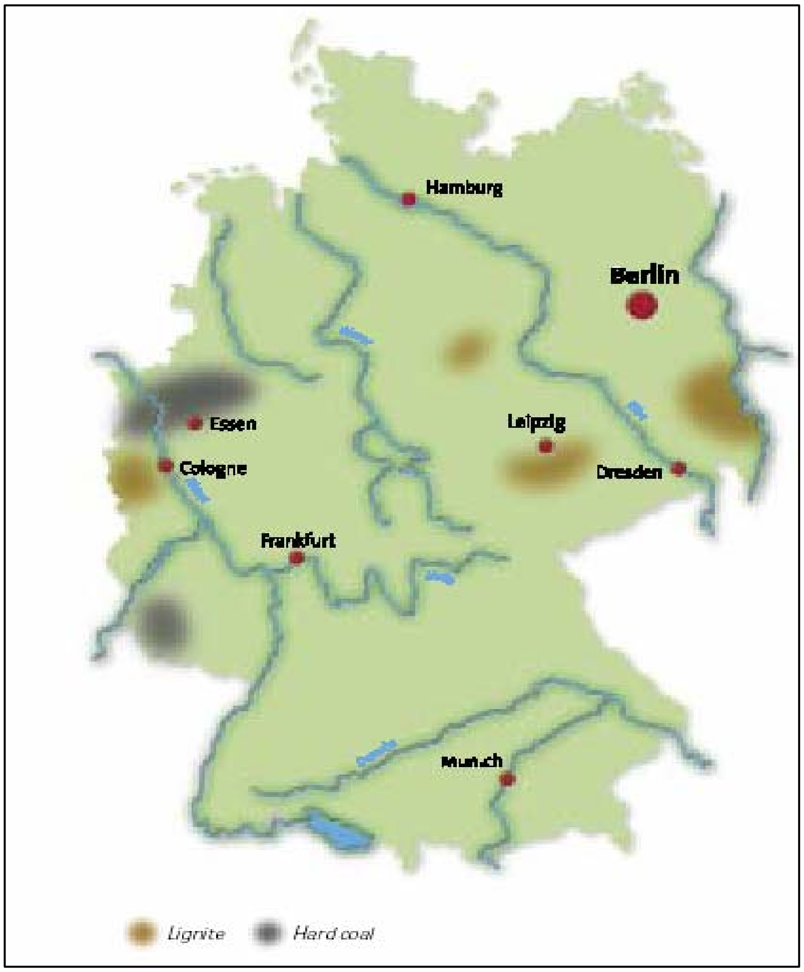
Coal mining in the Ruhr, Saar and Ibbenbüren coalfields is carried out by *Deutsche Steinkohle AG (DSK)* under the umbrella of *RAG Aktiengesellschaft, Essen*. DSK produced 26.1 Mt (million tonnes) of saleable hard coal in 2002. The only mine-industry coking plant still in operation produced about 2.0 Mt of coke in 2002. Steel industry coking plants produced some 5.2 Mt of coke in the same year.

At end-2000 Germany has ten deep mines (mainly longwall) in production, namely the collieries West, Walsum, Lohberg/Osterfeld, Prosper-Haniel, Lippe, Auguste Victoria/ Blumenthal and Ost, which are all in the Ruhr area, the mines of Ensdorf and Warndt/Luisenthal in the Saar coalfield and one further mine at Ibbenbüren. Production from these three coalfields breaks down as follows: 72% from the Ruhr area, 21% from the Saar and 7% from the Ibbenbüren coalfield. The number of employees in the hard coal mining sector decreased by 7.4% from 52,576 in December, 2001 to 48,673 as of December, 2002. Underground operations employ 24,635 mineworkers, or 51% of the workforce (as at end-2002). Efficiency levels, measured in terms of saleable output per man-shift below ground, rose by 4.7% from 6,244 kg in 2001 to 6,539 kg in 2002.

Hard coal sales to the power generation sector are expected to amount to some 20.6 Mtce, while supplies to the steel industry have a total of 6.8 Mtce. In 2003 workforce downsizing continues at the same rate as in the previous year. By late 2003 the industry has about 41,800 employees.

In 2002, the available lignite amounts totalled 56.8 Mtce, with domestic output accounting for close on 56.4 Mtce. The lignite-derived products are mainly destinated for domestic use. The main customers are the power and heat generators (more than four fifths). Lignite production which totalled 181.8 Mt in 2002 was centred on four mining regions, namely Rhineland around Cologne, the Lusatian mining area in south-east Brandenburg, the Central German mining area in south-east of Saxony-Anhalt as well as the Helmstedt mining area in Lower Saxony. In these four mining areas, lignite is exclusively extracted from opencast mines. Almost 90% of lignite production is used on power generation. The power plants were provided with 169.4 Mt of lignite.

In the Rhineland, *RWE Rheinbraun AG*, produced a total of 99.4 Mt of lignite in 2002. There are three opencast mines: Hambach, Garzweiler and Inden. Almost 90% of the coal was consumed by the company's own national grid power generation stations, while some 10.3 Mt was used for processed products. The generating capacity of RWE *Rheinbraun AG* consists of five lignite-fired power plants with a total capacity of 9,913 MW (at end-2002). Furthermore, a 1,000 MW lignite-fired power plant with optimised plant technology (BoA) went on stream at the Niederaussem in 2002. In these plants the lignite-derived power output amounted to around 75.5 TWh. At end-2002, *RWE Rheinbraun AG* had a total workforce of 12,693, including 9,121 employees in the mining segment and 3,572 employees working in the lignite-fired power plants. In 2003, *RWE Rheinbraun AG* merged with *RWE Power AG.* The new company is named *RWE Power AG.*



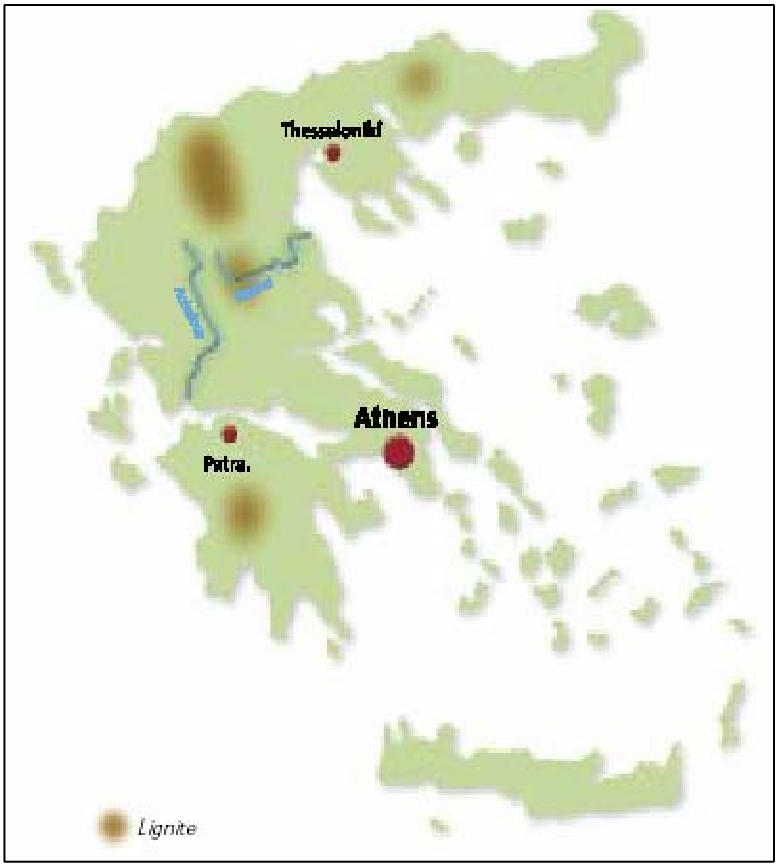
In the Lusatian and Central German mining areas, coal is today primarily used in new and modernised power plants. Coal output in this region decreased from some 300 Mt in 1990 to about 80 Mt in 2002. Personnel were cut by more than 90%.

In 2002, the Lusatian mines produced some 59.3 Mt of lignite. The only coal producer in this area is Vattenfall Europe Mining AG. The lignite is extracted in Jänschwalde, Cottbus-Nord and Welzow-Süd in Brandenburg as well as in the Nochten mine in Saxony. The quantity sales of lignite to public power plants amounted to 56.9 Mt, exceeding the previous year's level. These positive developments are primarily due to the stepped-up requirements of the power plants of Vattenfall Europe Generation AG & Co. At end-2002, Vattenfall Europe Mining AG had a total workforce of 5,553. In the Lusatian area, Vattenfall Europe Generation (VE-G) is operating three lignite-fired power plants with a gross rated capacity of a total of 6,500 MW.

The Central German mining area located in the surroundings of Leipzig yielded a total lignite output of 20.0 Mt in 2002. The most important company in this area is *Mit teldeutsche Braunkohlengesellschaft mbH (MIBRAG)*, Theißen. This company has two opencast mines, Profen (Saxony-Anhalt) and Schleenhain (Saxony). In 2002, MIBRAG produced about 19.5 Mt of lignite. In the same year, the recently built power plant in the neighbouring Lippendorf (1,850 MW) was also supplied with 10.6 Mt of lignite.

In the Helmstedt mining area, *BKB Aktiengesellschaft* produced 2.9 Mt of lignite in 2002. Extraction from the Schöningen opencast mine and the Buschhaus (380 MW) power plant will continue until 2017 with an annual lignite output of some 2 Mt. In December, 2002, BKB had a workforce of 572 employees working in the mining area.

A.2 Coal Mining in Greece



Greece has geological lignite reserves of 6.5 bn t, of which 3.4 bn t are economically workable. The most important deposits are located in the north of the country, at Ptolemais-Amynteon and Florina (2.0 bn t), at Drama (900 Mt) and at Elassona (150 Mt), and in the south at Megalopolis (270 Mt). Most of the major opencast mines belong to the electric utility Public Power Corporation (PPC). Only 28% of the total reserves have been extracted up to date.

Allowing for future developments in energy consumption patterns, existing reserves will be sufficient for about 45 years. Lignite is the most important indigenous source of energy, representing approximately 80% of primary energy production and accounting for about 28% of primary energy consumption (42.7 Mtce in 2001).

Source: Euracoal, 2003

Oil is still the most important fuel source overall, accounting for 55% of the country's primary energy consumption. The consumption of imported natural gas has a 5.6% share in the market. Hard coal imports of 1.3 Mtce still account for 2.7 % of primary energy consumption. Security of energy supply, low extraction costs and stable prices have helped lignite retain its place in the energy market.

Lignite deposits in Greece have an average total depth of 150 to 200 metres and typically comprise layers of lignite alternating with layers of soil. Lignite is exclusively extracted in open cast operations. The quality of Greek lignite can be characterised as follows: the lowest calorific values are recorded in the areas of Megalopolis and Drama (3,770 to 5,020 kJ/kg) and Ptolemais-Amynteon (5,230 to 6,280 kJ/kg). At Florina and Elassona the calorific value is between 7,540 and 9,630 kJ/kg. The ash content ranges from 15.1% (Ptolemais) to 19% (Elassona) and the water content from 41% (Elassona) to 57.9% (Megalopolis). The sulphur content is mostly low.

Lignite production for 2002 stood at 70.8 Mt, which was 6.8% up on the previous year's figure. Lignite is mostly mined by PPC, with 55.8 Mt being extracted at the West Macedonia Lignite Centre (WMLC) and 14.5 Mt at the Megalopolis Lignite Centre (MLC). In 2002 the WMLC operations removed a total of 196.5 mill. cbm of waste (overburden plus interburden), corresponding to an overburden-to-lignite ratio of 3.5 : 1 (cbm : t). At MLC, overburden plus interburden removal was 25.1 millios cbm, corresponding to an overburden -to-lignite ratio of 1.7 : 1 (cbm : t).

Some of the lignite extracted at the Ptolemais-Amyndeon Lignite Centre exhibits a wide disparity in calorific value and ash content. This results in deviations from the specified fuel properties required for optimum power station operation. For this reason high- and low-quality grades are blended and homogenised.

The extracted lignite is supplied to seven PPC-owned power stations, comprising 21 generating units and a total installed capacity of 4,958 MW. Some is also delivered to a nearby briquette factory.

Another lignite mining site at Florina in Northern Greece, which has an annual production level of 2.5 Mt, is currently up for development. A new power generating unit of 330 MW is also due to come on stream in the same area in 2003. The total capacity of lignite-fired plants is 5,288 MW.

Over the years the policy pursued by lignite mining companies has meant a significant increase in lignite production and in mining activities in general. Since 1988 manpower levels have remained fairly steady, despite the opening of a new production facility at Amyndeon mine in Northern Greece. The two mining areas of WMLC and MLC, and the head office in Athens, currently employ a total workforce of 6,023.

A.3 Coal Mining in Spain

Spain is one of Europe's fastest growing economies and is highly dependent on imported oil and natural gas. The only significant indigenous energy resource is coal, consisting of: hard coal: 3,234 Mtce, lignite: 20.7 Mtce. Prior to 1990 there were very few mine closures, but the industry is now due to be downsized by about one third by the year 2005.

Coal, the most important indigenous energy source, makes a 19% contribution to the national energy mix (187 Mtce). With electricity demand growing rapidly (6% per year) there has been an ever increasing investment in the power generating sector. Spain now has the fifth-largest energy market in Europe (behind Germany, France, the United Kingdom, and Italy). It is estimated that by 2010 Spain's energy requirements will have increased by some 30%. In 2002 solid fuel-fired plants generated 78.7 TWh of electricity (35.8 % of the total output). Hard coal contributed 63.1 TWh (28.7%) and lignite 15.6 TWh) to the country's gross power generation of 6 TWh. Spain continues to privatise its energy sector, process which began in 1994 with the LOSEN Electricity

In 2002, Spain produced some 13.8 Mt of hard coal, a large percentage of which was burnt in local power stations. A significant amount of coal (24.5 Mt) had to be imported, mostly for power generation. Hard coal is mined in several regions of the country, and especially in Asturias, León and Palencia - where 98% of Spain's coal deposits are to be found. Most of the deep mines are located in the Asturias coalfield near Oviedo. There are also many deep mines and opencast pits in other parts of the country, almost all of which are run by the state-owned Hunosa Company. Many mines have now been forced to close due to high production costs.

Source: Euracoal, 2003

At Santa Lucia there is a large opencast mine and a new colliery ("Nueva Mina"), which was built in the 1990s. Other opencast and deep mining operations are to be found at Tineo (west of Oviedo), Vega de Rengos and Monasterio de Hermo (south of Cangas de Narcea), and at several places south of Cordillera Cantabrica between Santa Lucia in the west and Barruelo in the east.

Spain's main lignite fields are located in the region of Galicia in the north-west of the Iberian Peninsula. There is also the Ginzo de Limia lignite deposit in the province of Orense in Southern Galicia and two minor deposits, Arenas del Rey and Padul, near Granada in the province of Granada. Estimated reserves in Andalusia are 40 Mt in each case, but like the Ginzo de Limia deposits these have not yet been exploited for economic reasons. Spain produced a total of 8.6 Mt of lignite in 2002.

The largest deposit is at the As Pontes mine, some 60 km north-east of La Coruña. This opencast mine, which was first developed in 1976, is operated by the largest of the four private utilities, ENDESA *(Empresa Nacional de Electricidad S.A.)*, and still has economic reserves of 40 mill. tonnes. In 2002 production from As Pontes totalled some 6 Mt. The product is extracted by German-made machinery and then transported out on a 25 km belt-conveyor line. The overburden-to-lignite ratio is 2.8 : 1 (cbm : t).

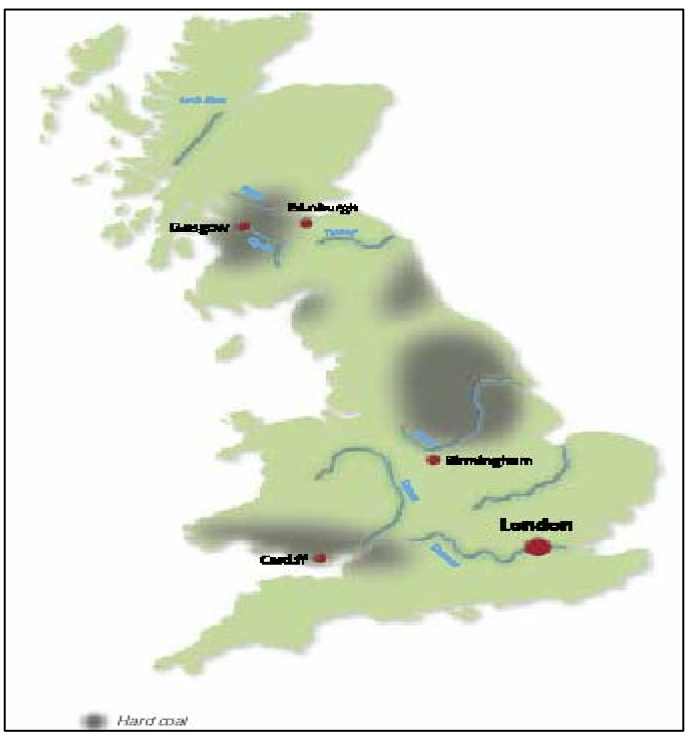
A second, much smaller opencast mine at Meirama has been in operation since 1980. This is located 30 km south of La Coruña and is owned by Spain's third largest utility company, *Unión Fenosa S.A.* The mine covers an area of 1.5 sq km (1.8 x 0.8 km). The remaining economical reserves are of 9 -10 Mt. The current working depth of 200 m is ultimately expected to reach some 250 m. In 2002 the Meirama mine produced a total of 2.6 Mt, with an overburden-to-lignite ratio of 1 : 1 (cbm : t).

All the lignite produced was used for power and district heat generation. The lignite-fired power stations are located close to the mines and have a total capacity of 1,950 MW. The As Pontes power station, which has a generating capacity of 1,400 MW (4 units of 350 MW each, in operation since 1976-1979), and the Meirama power plant, which generates 550 MW (1 unit, in operation since 1980), are both owned by the mine operators.

A.4. Coal Mining in the United Kingdom

The United Kingdom is rich in energy resources. It is by far the largest petroleum producer and exporter in the EU and is a significant producer of natural gas. The country has significant hard coal resources estimated at 1,000 Mt. About 600 Mt of reserves are available to existing deep mines or are in shallow deposits capable of being extracted by surface mining. In addition, currently unaccessed resources have the potential to provide many years of future production at present levels.

In 2002, the UK's primary energy production totalled 455.1 Mtce. The largest contributor was oil with 211.7 Mtce (46.5%) followed by natural gas with 174.4 Mtce (38.3%). Solid fuel production was 34.2 Mtce (7.5%) followed by nuclear with 33.9 Mtce (7.4%). The UK's primary energy consumption in 2002 was 381.9 Mtce with natural gas accounting for the largest share (41.5%), followed by oil (32.1%), hard coal (17%) and nuclear energy (8.9%). The UK imports slightly less than half of its hard coal requirements. No lignite is consumed locally in the country.



UK hard coal consumption and production have decreased dramatically over the last fifteen years due to an increase in gas-fired power generation and increased competition from imported coal. However, over the last three years, more competitive electricity trading arrangements and an increase in gas prices have led to some increase in demand. Production has stabilised as production costs have fallen towards levels that are internationally competitive due to dramatic increases in productivity.

Source: Euracoal, 2003

Consumption of hard coal in the UK in 2002 was 58.5 Mtce, of which 47.5 Mtce was used for electricity generation. Hard coal consumption in the steel industry was 6.4 Mtce. Hard coal supply totalled 58.2 Mt, with 30.0 Mt being accounted for by indigenous production and 28.7 Mt by imports. Imports supplied just under half of the overall market. South Africa accounted for about a third of all imports, the other main suppliers being

Australia, Colombia, Russia, Poland and the U.S.

Some 6.3 Mt of imports was coking coal. The UK no longer produces significant quantities of coal suitable for use in coke ovens. The share of imports of steam coal was somewhat lower at about 40%. Of total indigenous production, deep mines accounted for 16.4 Mt, with 13.1 Mt from surface mines. In 2003 the UK Government announced that a three-year coal investment aid scheme was to be introduced, providing around £60 mill. of support for "demonstrably viable" production. The scheme will offer producers up to 30% of the costs of opening new reserves.

The UK's coal mines are mainly located in central and northern England, south Wales and central and southern Scotland where there is the largest concentration of surface mines.

As at the end of 2002, there were 15 large deep mines in operation. Twelve of these were owned by UK Coal plc (Daw Mill, Thoresby, Welbeck, Harworth, Clipstone, Maltby, Rossington, Kellingley, Wistow, Riccall, Stillingfleet and Ellington). The other large deep mine producers were Coalpower Ltd. (Hatfield), Tower Goitre Anthracite Ltd. (Tower) and Betws Anthracite Ltd. (Betws). In addition, there were 10 smaller deep mines in production. UK Coal accounted for 15.2 Mt of the total of 16.4 Mt of 2002 deep mine production, with production from Tower and Hatfield being about 0.5 Mt and 0.3 Mt respectively. There are about 7,000 direct deep mine employees.

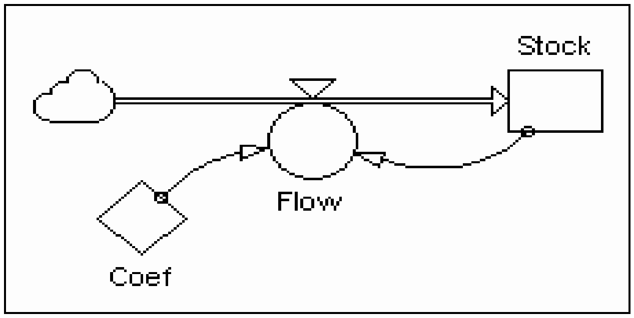
At any one time, there are about 50 surface mines in production and about 20 surface mine operating companies. The largest of these are UK Coal and Scottish Coal, each producing over 4 Mt a year out of the total 2002 output of 13.1 Mt. The regional surface mine production and manpower breakdown for 2003 was England with 5.0 Mt (manpower 1,119), Scotland with 7.1 Mt (manpower 1,221) and Wales with 1.0 Mt (manpower 348). Total direct employment in the industry is some 9,500 with over 7,000 in England and over 1,000 in each of Scotland and Wales.

UK Coal plc is by far the largest producer and is Europe's largest totally independently owned hard coal mining company. In 2002 the company produced 19.5 Mt (15.2 Mt deep mined and 4.3 Mt surface mined) and sold 18.9 Mt. UK coal directly employs some 7,000 people at over 20 locations and almost as many again on contract or in the supply of goods and services. The second largest UK producer is Scottish Coal, which directly employs some 700 people at 8 to 10 surface mines with an output of 4.0 Mt to 4.5 Mt annually.

Appendix B

The derivation of analytical solution for positive feedback system

A basic stock-flow-feedback loop structure can be illustrated as:



The relation of Stock-Flow is a first order positive feedback loop system. It is a linear system and possesses an analytical solution as follows:

$Stock_{(t)} - Stock_{(t-dt)} = dt * Flow_{(t-DT)->t}$ (b-1)

$Stock_{(t)} - Stock_{(t-dt)} = Stock_{(t)} * Coef * dt$ (b-2)

$d\ Stock_{(t)} = Stock_{(t)} * Coef * dt$ (b-3)

$$\frac{dStock_{(t)}}{Stock_{(t)}} = Coef * dt \quad \text{(b-4)}$$

$$\int_0^t \frac{dStock_{(t)}}{Stock_{(t)}} = Coef * \int_0^t dt \quad \text{(b-5)}$$

$\ln(Stock_{(t)})\ {}_0|^t = (Coef*t)\ {}_0|^t$ (b-6)

$\ln(Stock_{(t)}) - \ln(Stock_{(0)}) = Coef * (t-0)$ (b-7)

$$\ln\left(\frac{Stock_{(t)}}{Stock_{(0)}}\right) = Coef * t \quad \text{(b-8)}$$

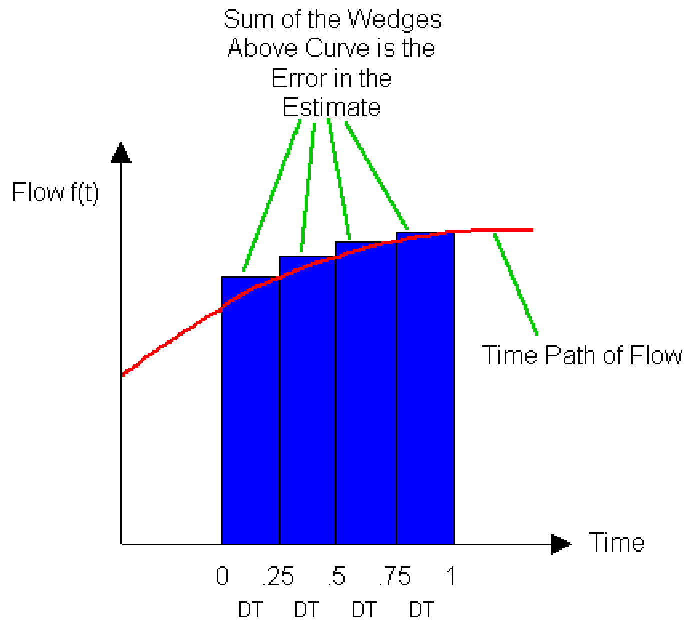
$$e^{\ln(\frac{Stock_{(t)}}{Stock_{(0)}})} = e^{Coef*t} \quad \text{(b-9)}$$

$$\left(\frac{Stock_{(t)}}{Stock_{(0)}}\right) = e^{Coef*t} \quad \text{(b-10),}$$

therefore:

$\mathbf{Stock_{(t)} = Stock_{(0)} * e^{coef*t}}$ **(b-11)**

Where, t = time, dt = time step, as illustrated in Figure below.


Sum of the Wedges
Above Curve is the
Error in the
Estimate
Flow f(t)
Time Path of Flow
Time
0
.25
.5
.75
1
DT
DT
DT
DT

Appendix C

Documentation of
The Dynamics Coal Europe (The DCE)

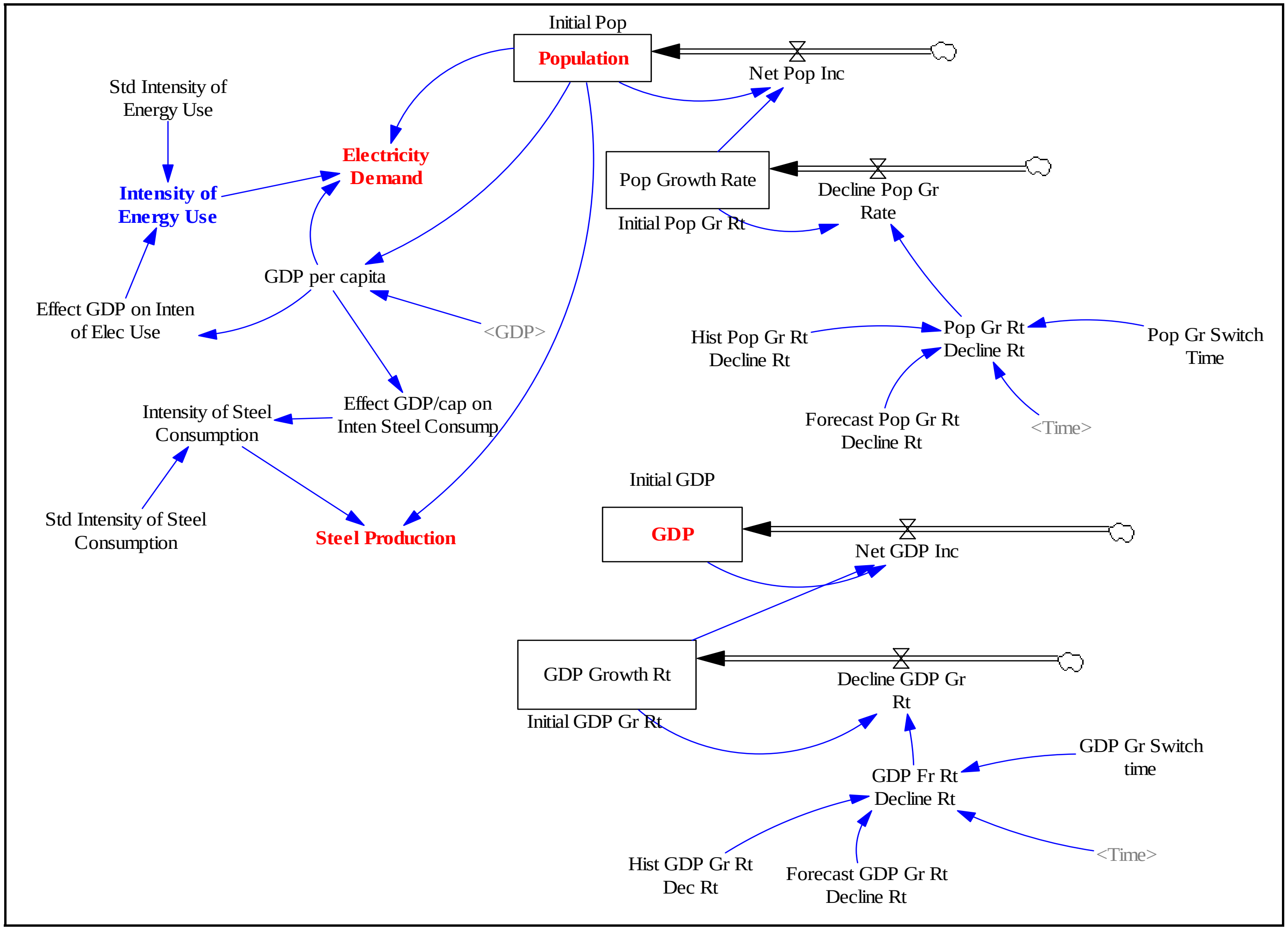
By using System Dynamics, Vensim ®

COAL-ENERGY-ECONOMIC-EMISSION MODEL

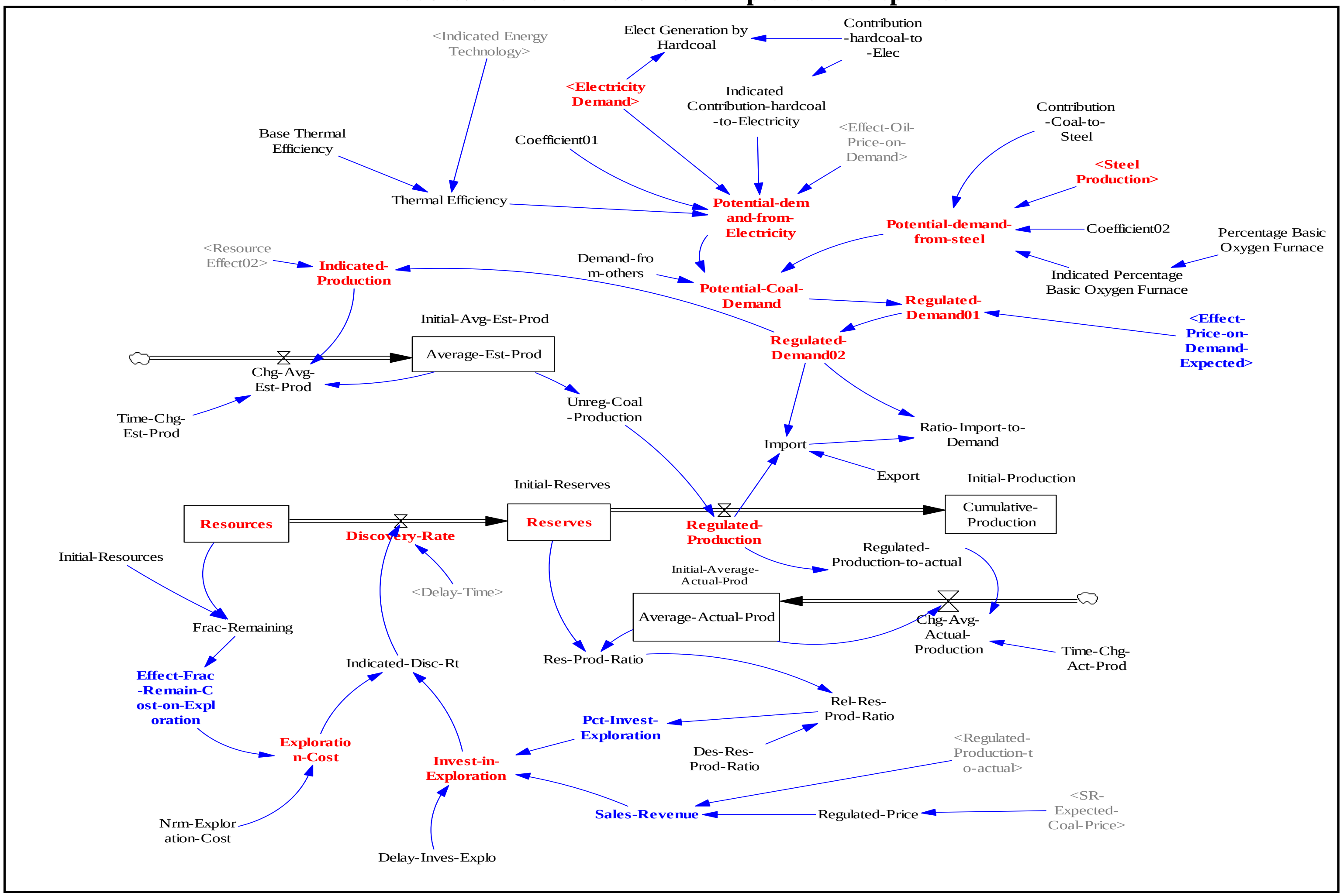
PhD Thesis, Ecole des Mines de Paris

Rudianto Ekawan

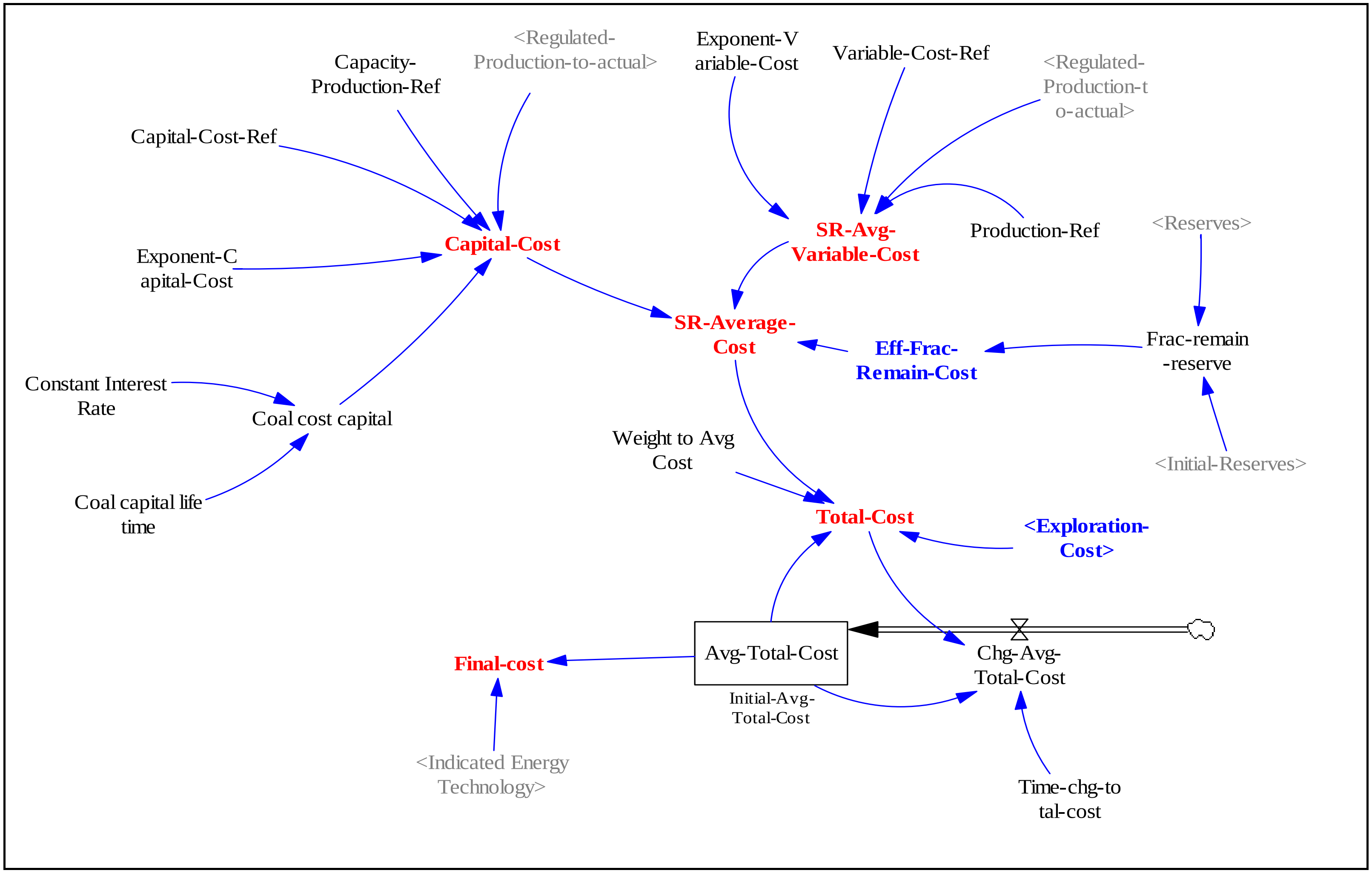
Module: Growth of Population and Gross Domestic Product



Module: Demand-Production-Exploration-Depletion



Module: Cost



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Variable-Cost-Ref
Capacity-
Production-Ref
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Variable-Cost
Production-Ref
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Remain-Cost
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Cost
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time
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Chg-Avg-
Total-Cost
Initial-Avg-
Total-Cost
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Technology>
Time-chg-to
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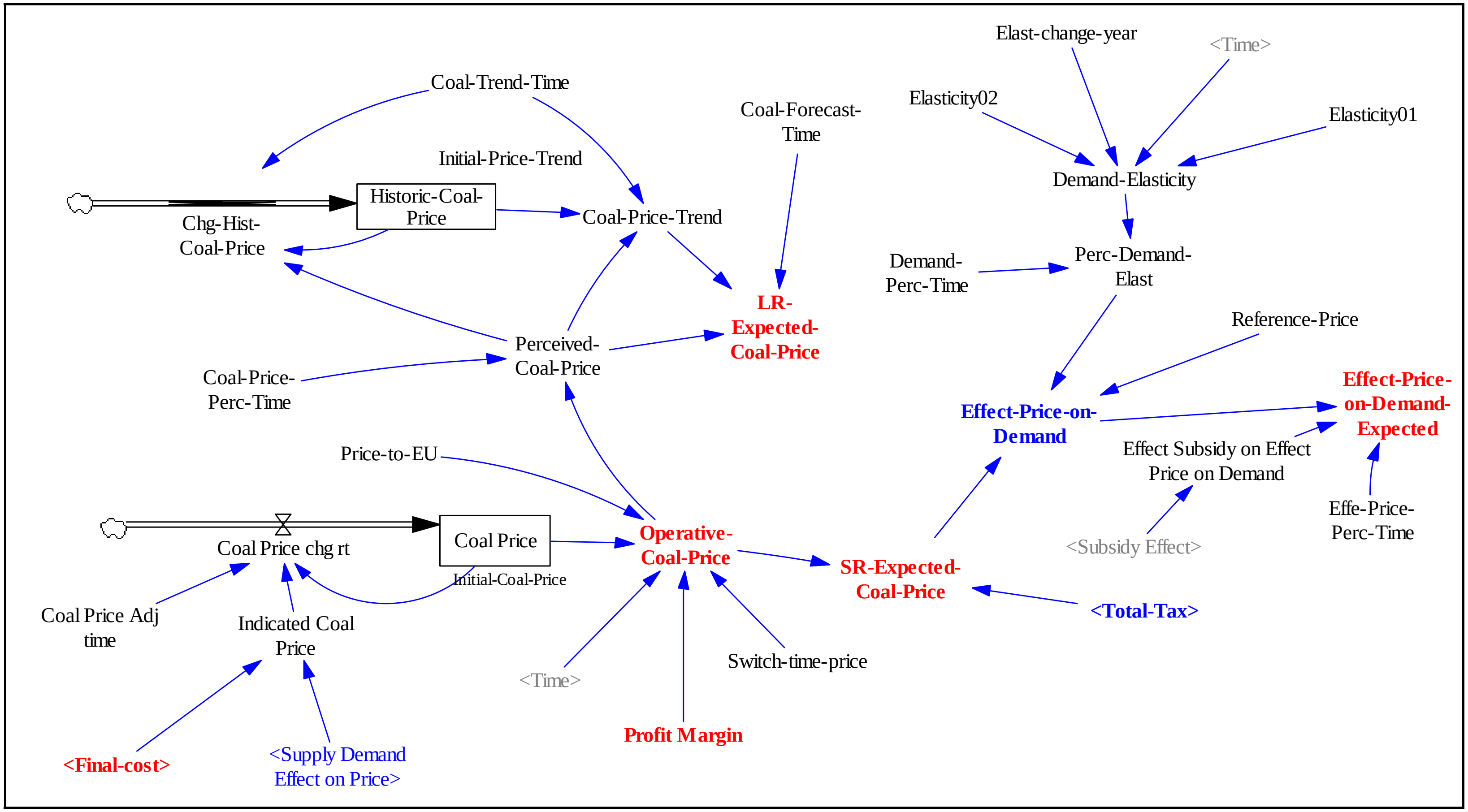
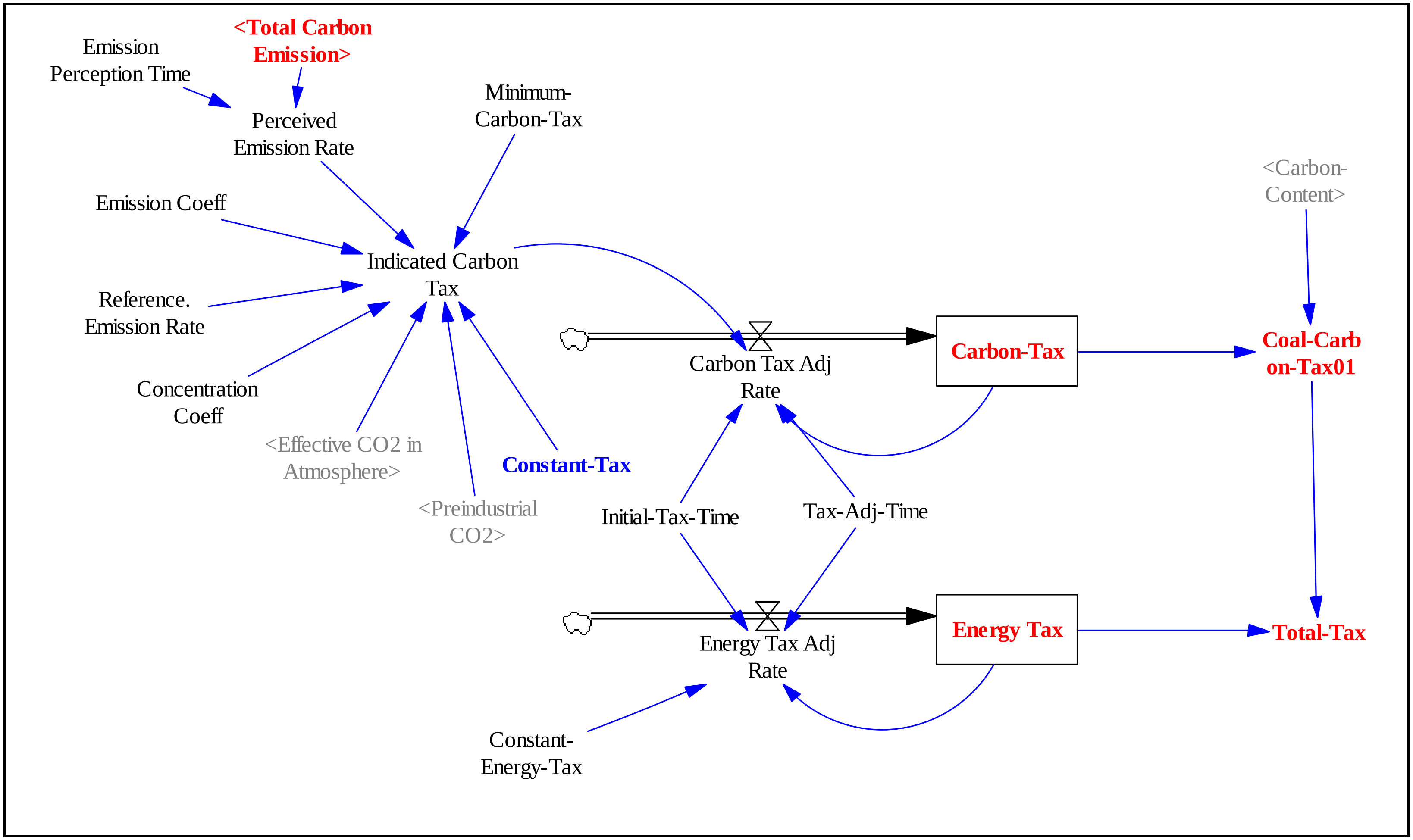
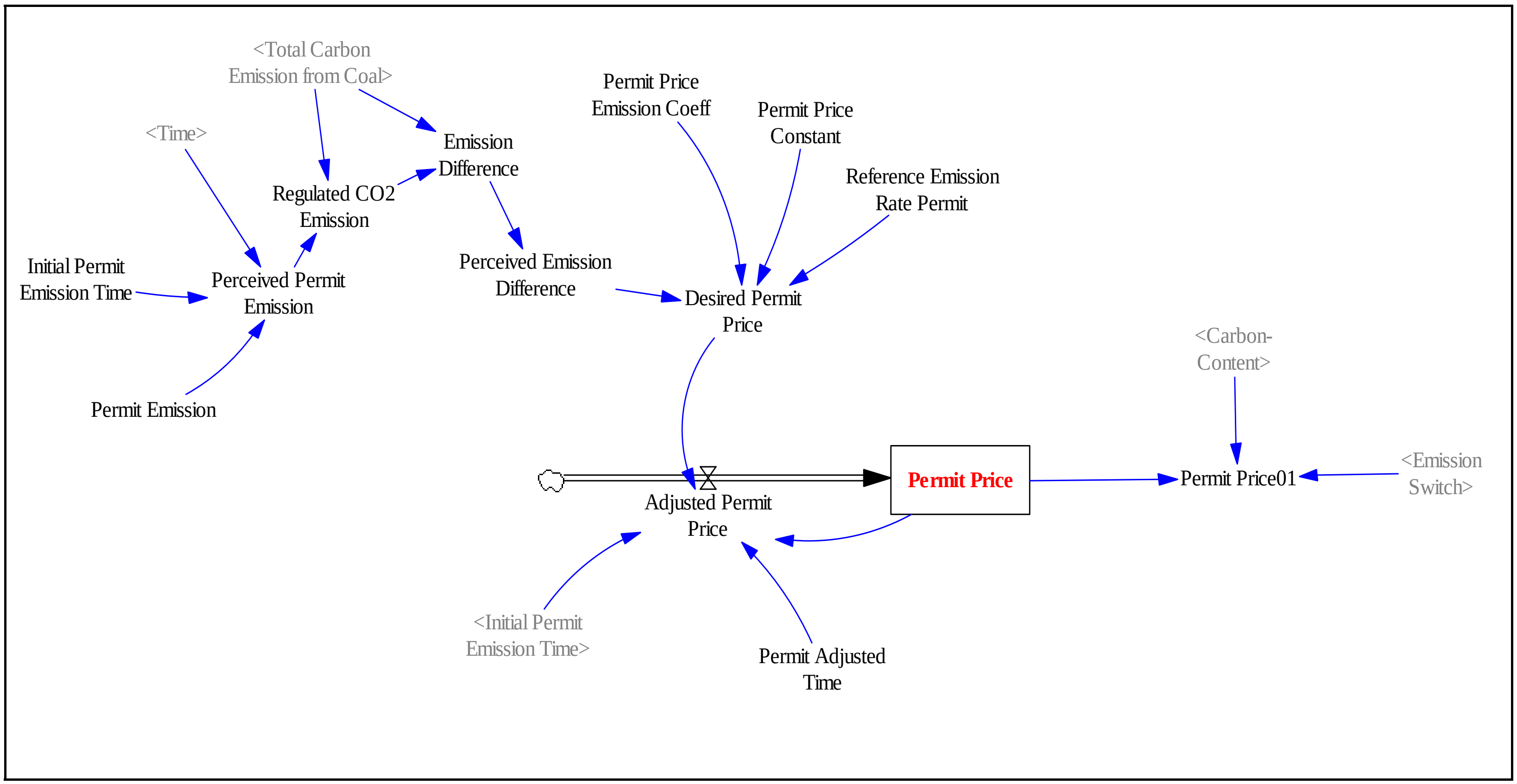
Module: Price



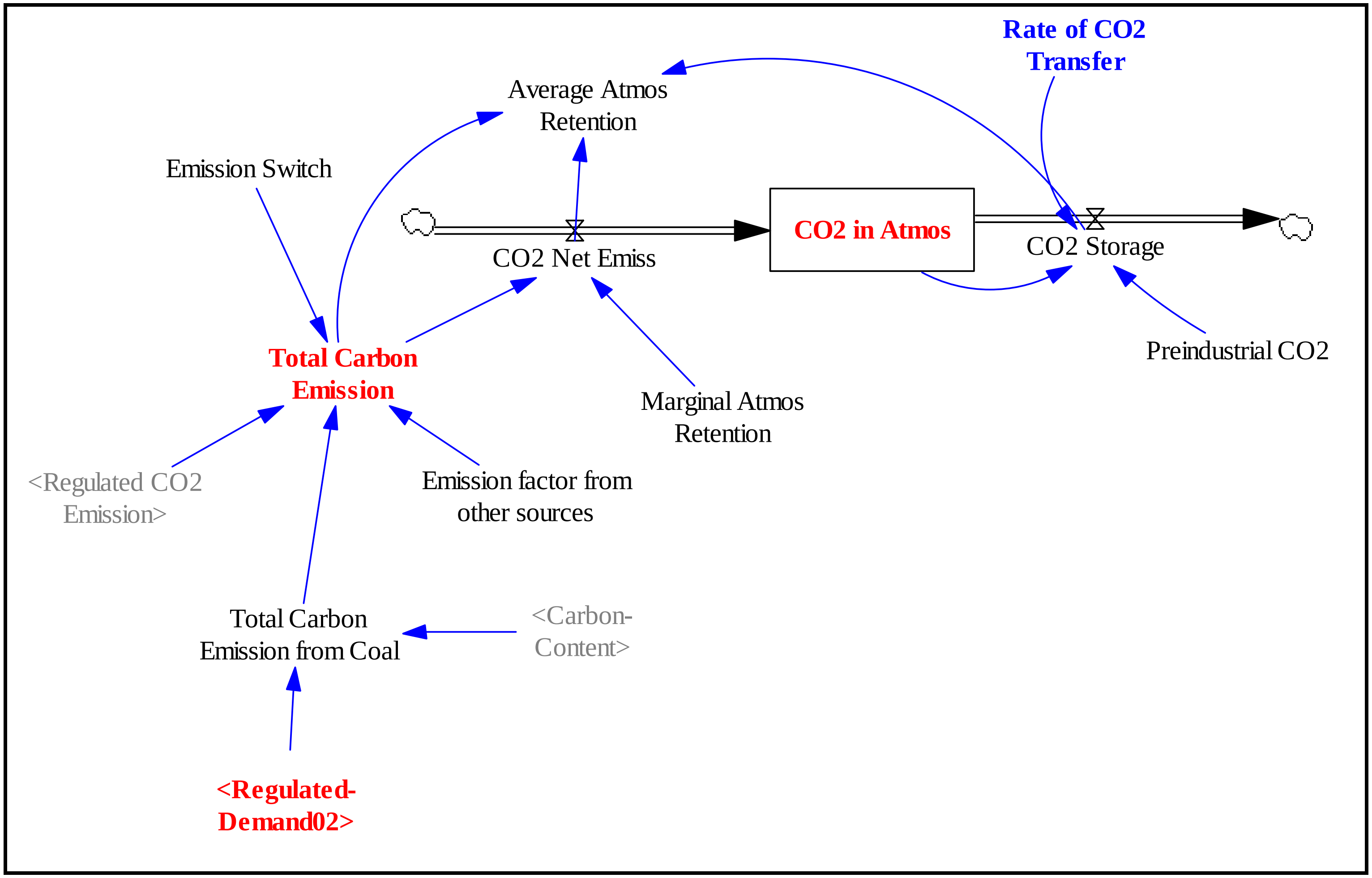
Module: Carbon tax



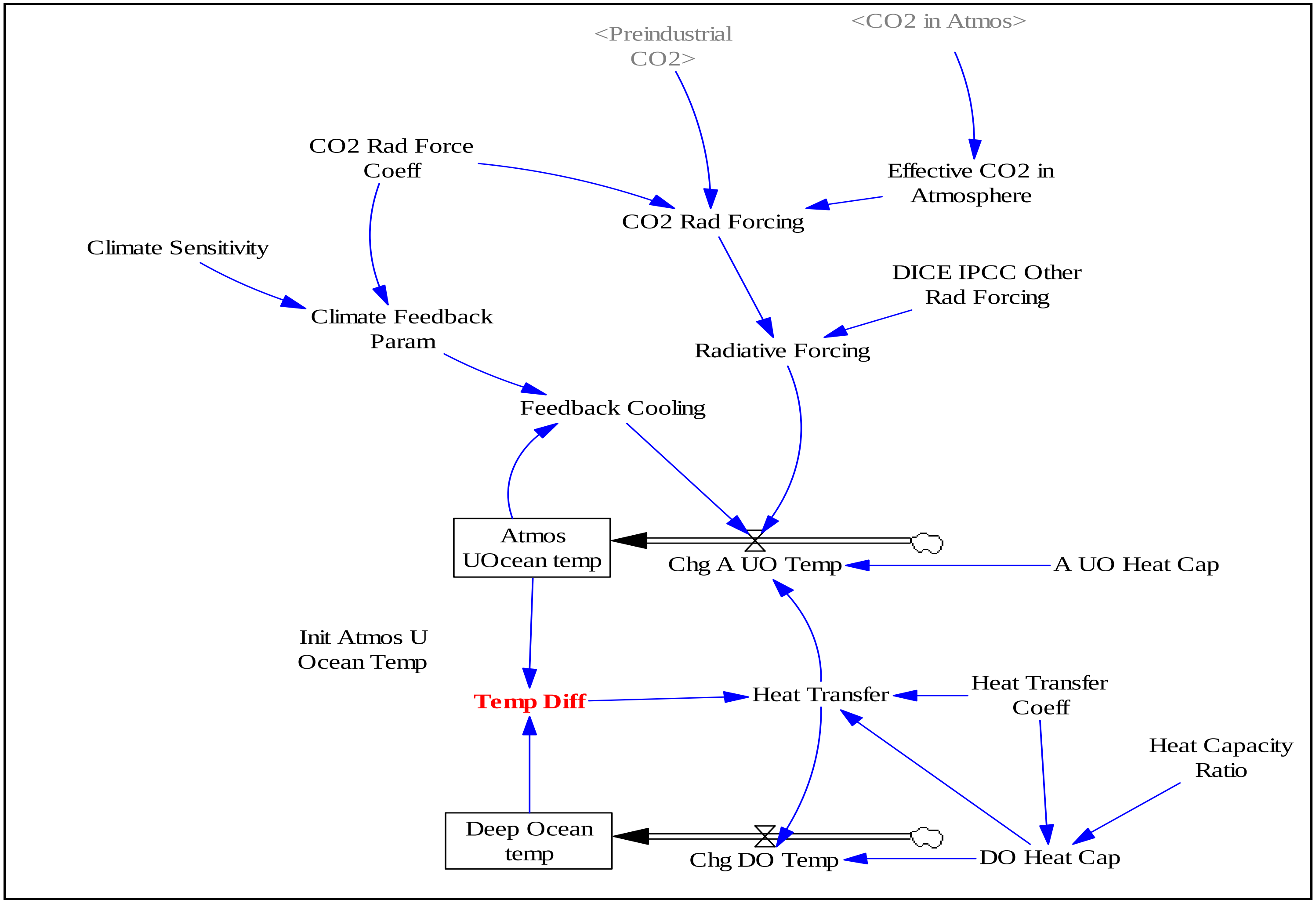
Module: Permit Price



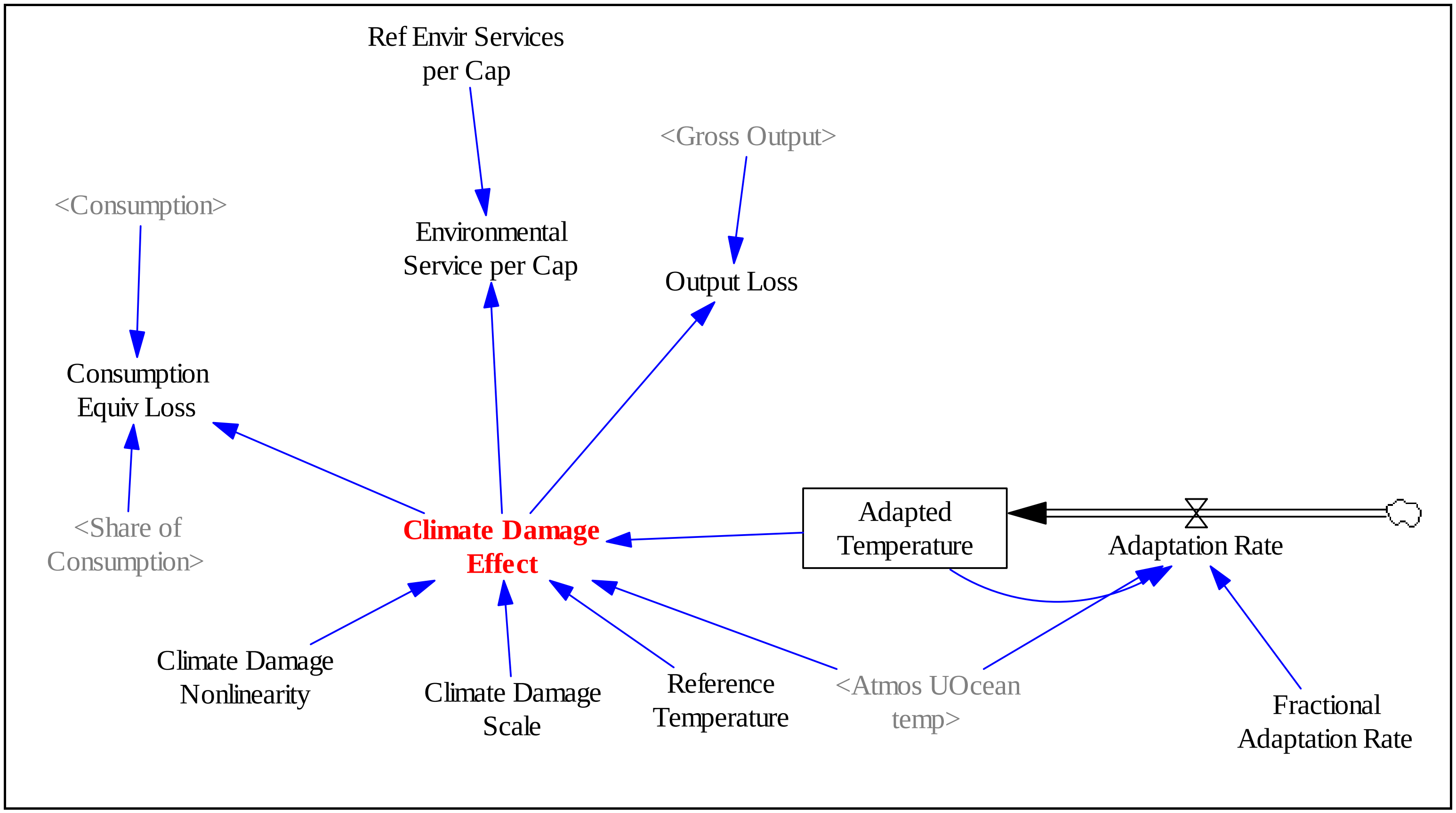
Module: DICE Carbon



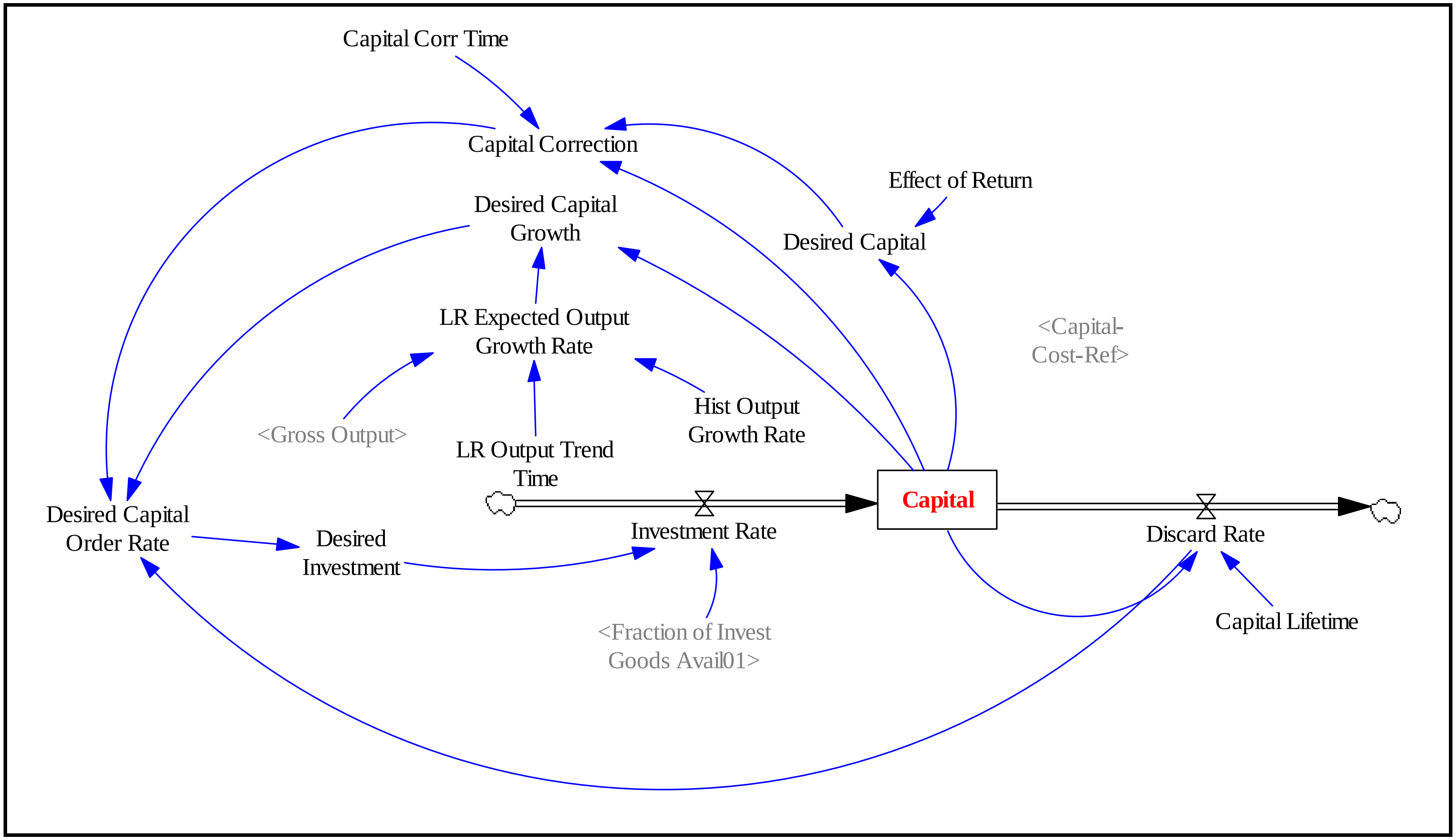
Module: DICE Climate



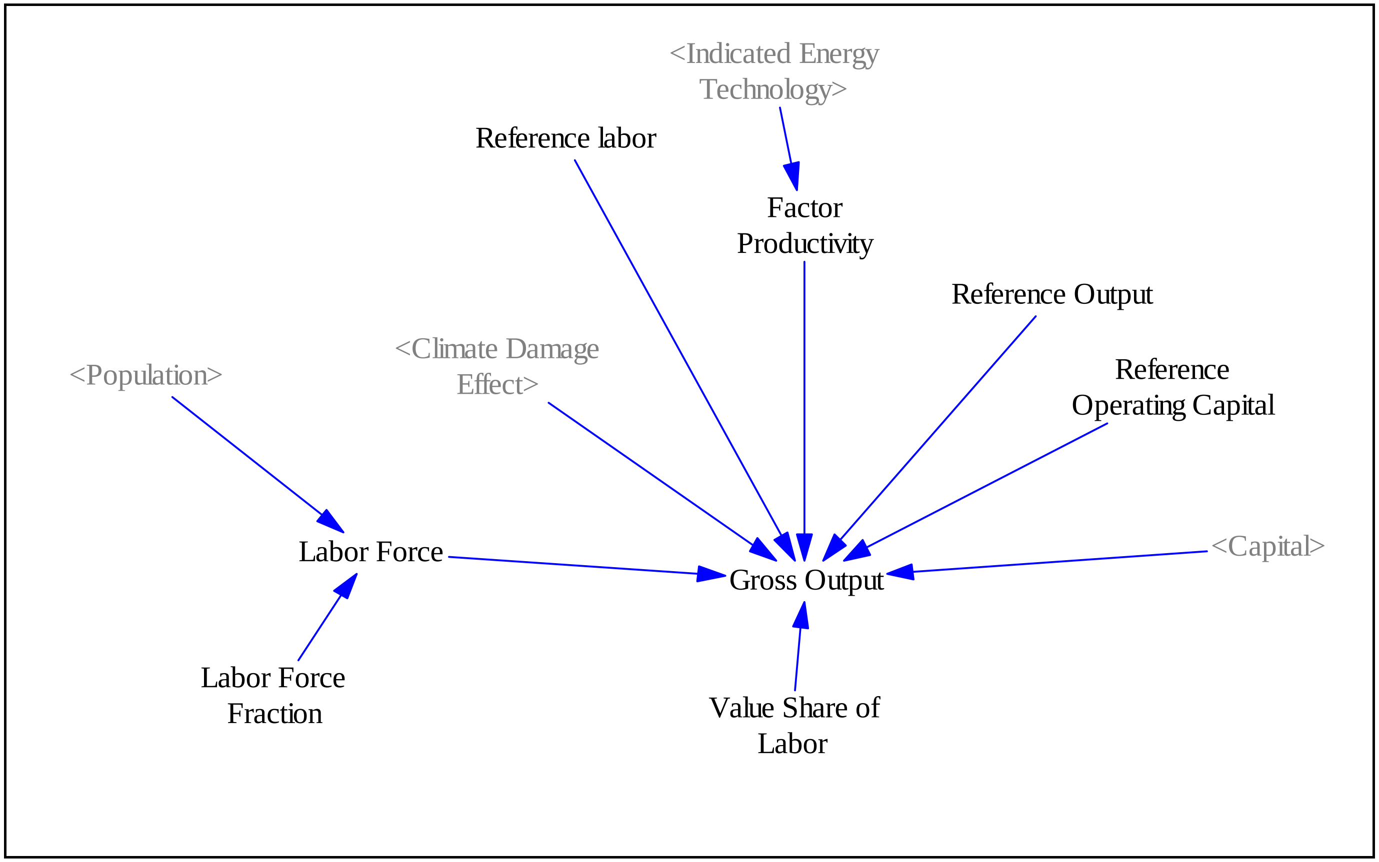
Module: FREE Impact



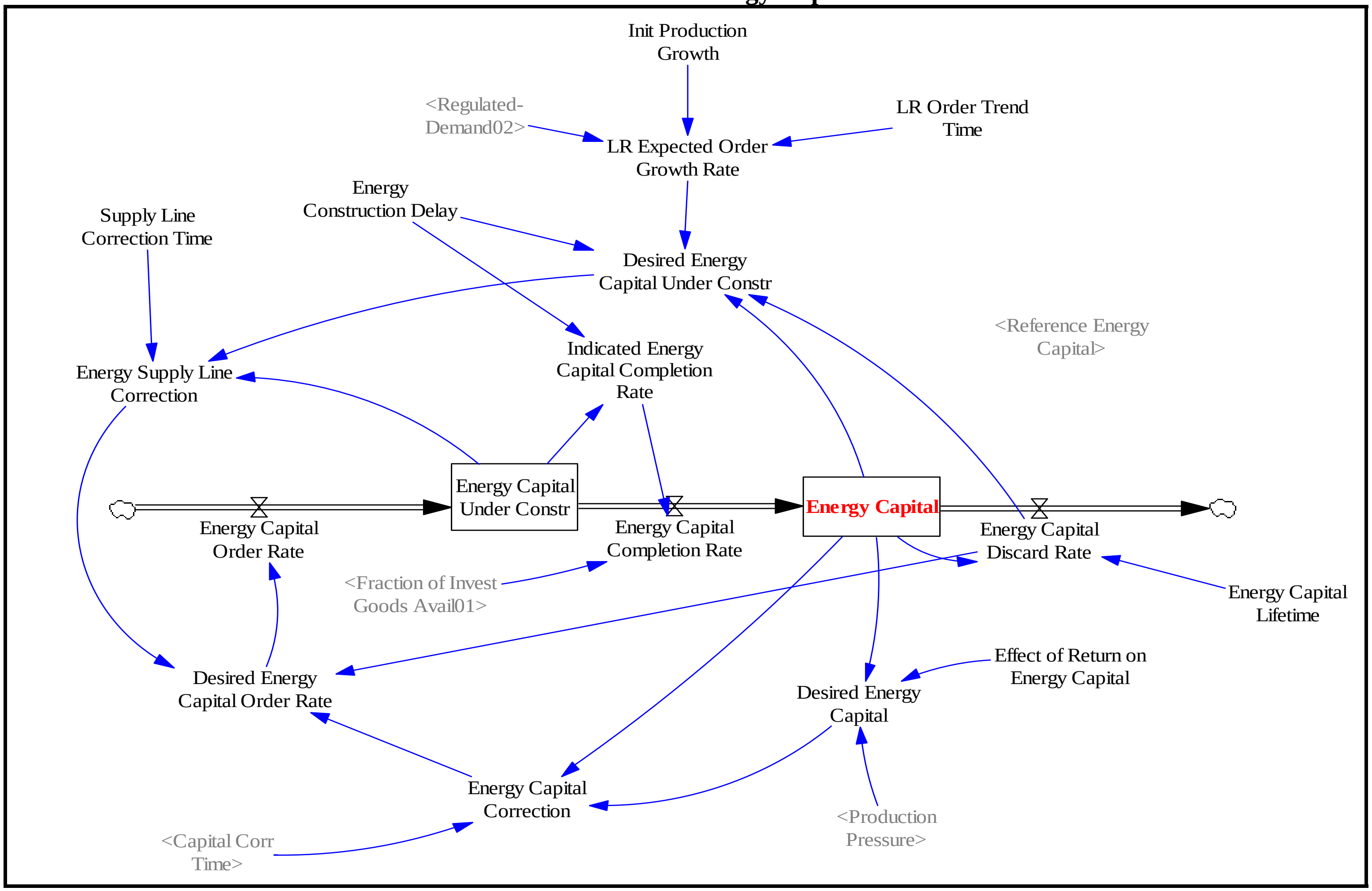
Module: FREE Capital



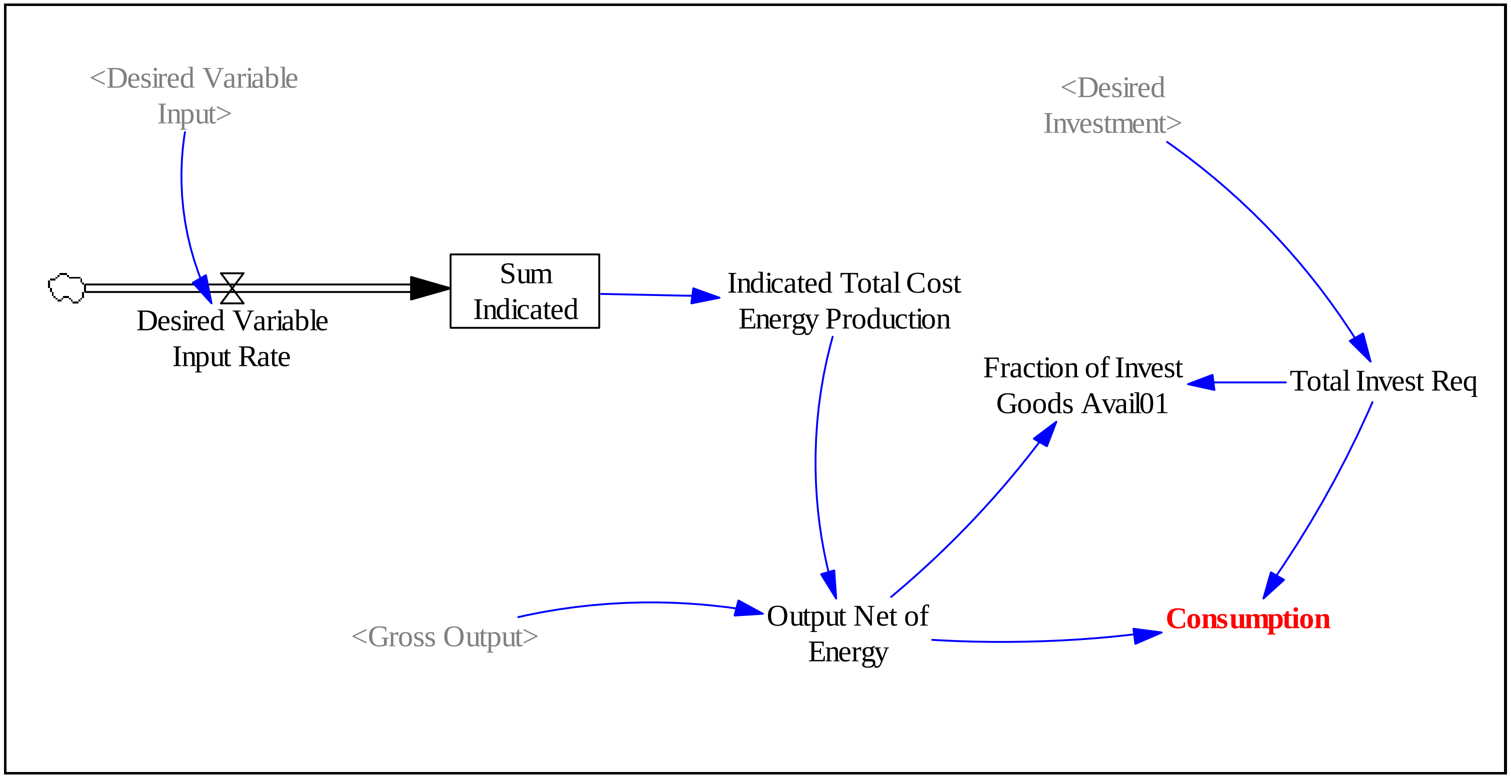
Module: FREE Gross Output



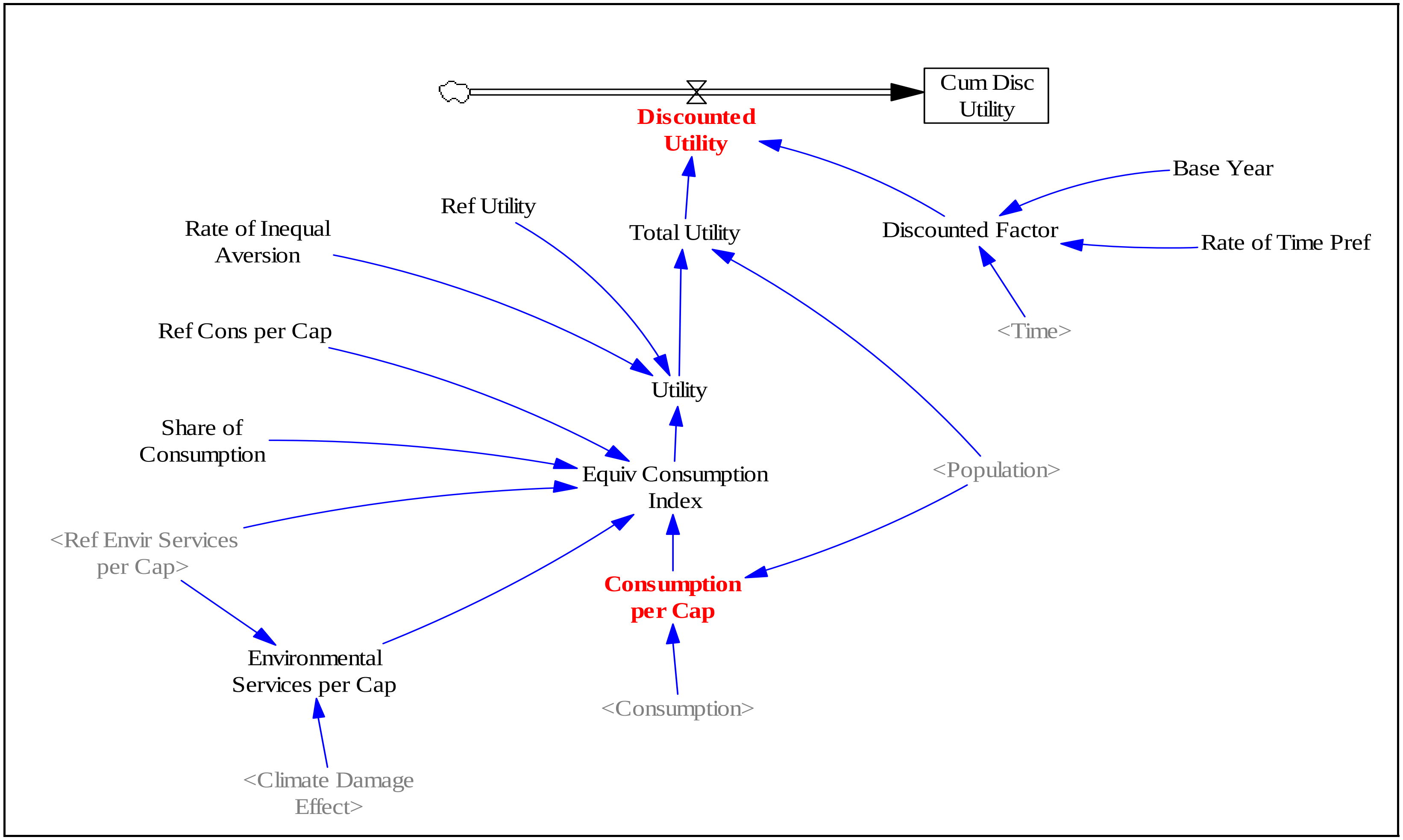
Module: FREE Energy Capital



Module: FREE Consumption



Module: FREE Welfare



Module: FREE Technology Progress