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CO_2 ABATEMENT IN WESTERN EUROPEAN POWER GENERATION

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Abstract

In this report the potential role of power generation technologies in the future Western European energy system is analysed. Various levels of CO_2 emission abatement and a range of other scenario conditions are considered. The study aims mostly at the identification of technological directions and less at instruments and policies to implement technologies. A wide range of energy technologies has been considered, and the possible role of these technologies has been assessed for each scenario and for each variant.

First the potential role of power generation options under circumstances without a carbon tax is analysed. After that, scenario runs with various carbon tax levels are analysed. In the absence of carbon taxes gas and coal fired power are the main options, with a competitive edge for gas fired power in the first decades of the next century, and the opposite in the remaining decades. Only a few renewables other than hydro could become competitive, such as biomass fueled power and wind turbines.

In case of moderate carbon taxes, gas fired power would become the power generation option of choice, and coal fired power would loose its market share. However, highly efficient coal fired power technology would remain economically viable. Nuclear power would be competitive under such circumstances, just like hydro power. Of course, the development of nuclear power depends on public acceptance. The scope for 'new' renewables is expanded under conditions of moderate carbon taxes. A strategy for moderate CO_2 reduction would require an RD&D portfolio based on highly efficient fuel conversion technologies and renewables (wind energy, biomass fueled power, photovoltaic power).

In case of more stringent carbon taxes (100 ECU/ton CO_2) coal fired power would be phased out rapidly. Nuclear and hydro power would be still more economic than under moderate carbon taxes. Biomass fueled power, on-shore and off-shore wind energy, and solar power in southern Europe would be introduced on a large scale. A strategy for stringent CO_2 reduction would require an RD&D portfolio based on highly efficient conversion technologies for natural gas, as well as a number of renewables, including photovoltaic power and off-shore wind energy.

CONTENTS

SUMMARY

Power generation sector is an important element of the energy infrastructure. In the long term, e.g. the year 2050, power generation could fulfil a key role in CO_2 abatement, as there are various options to generate electricity with negligible CO_2 emission. If the focus is on power generation in the long term, a Western European scope is preferable to a national one, as power generation is more and more internationalised.

In this report the potential role of power generation technologies in the future Western European energy system is analysed. Various levels of CO_2 emission abatement and a range of other scenario conditions are considered. The study aims mostly at the identification of technological directions and less at instruments and policies to implement technologies.

Two scenarios have been prepared for Western Europe, with the year 2050 as the time horizon. The scenarios have different discount rates, different levels of energy demand, and different fuel price projections. In addition, a set of alternative cases has been analysed with different rates of CO_2 emission abatement. A wide range of energy technologies has been included in the scenarios and the possible role of these technologies has been assessed for each scenario and for each variant.

First of all, the potential role of power generation options under circumstances without a carbon tax is analysed. In that case gas and coal fired power are the main options, with a competitive edge for gas fired power in the first decades of the next century, and the opposite in the remaining decades. The main gas fired options are combined cycle plants for district heating and gas turbine plants for industrial CHP. With respect to coal fired technologies, Integrated Coal Gasification Combined Cycle (IGCC) seems to be more economic than pulverised coal fired power. Hydro and nuclear power are marginally more costly than the alternatives.

In the absence of carbon taxes only a few ‘new’ renewables could become competitive, such as biomass fueled power and wind turbines. However wind energy is not competitive at a high discount rate (15%). Some other renewable options are not competitive without carbon taxes: off-shore wind energy and solar power.

A modest carbon tax of 20 ECU/ton CO_2 would cause a substantial shift in the power technology mix. At a low discount rate (5%) hydro and nuclear power would become competitive. At the higher discount rate (15%) the threshold value is 50 ECU/ton CO_2. Coal fired power would be phased out for some decades in scenario RP. At the high discount rate (15%) coal fired power remains favoured over nuclear power up to 50 ECU/ton CO_2. IGCC based on hard coal or lignite could be a strategic investment option, if the carbon tax does not exceed 20 ECU/ton CO_2.

The scope for ‘new’ renewables is expanded under conditions of moderate carbon taxes. Solar power at lower latitudes would become competitive at 50 ECU/ton CO_2. Off-shore wind energy would remain uneconomic. A

strategy for moderate CO_2 reduction would require an RD&D portfolio based on highly efficient fuel conversion technologies (e.g. IGCC) and renewables (wind energy, biomass fueled power, photovoltaic power).

A carbon tax of 100 ECU/ton CO_2 would need a widespread consensus about the need for drastic CO_2 reduction to prevent global climatic changes. Coal fired power would be phased out rapidly. Hydro and (possibly) nuclear power would be expanded rapidly. Biomass fueled power, onshore and off-shore wind energy, and solar power in southern Europe would be introduced on a large scale. A strategy for stringent CO_2 reduction would require an RD&D portfolio based on highly efficient conversion technologies for natural gas, as well as a number of renewables, including photovoltaic power and off-shore wind energy.

For reasons of sensitivity analysis, cases with a relaxed attitude towards nuclear power, acceptance of CO_2 capture and disposal, and a higher upper bound for solar power in southern Europe, are considered. Nuclear power would become the power option of choice under such circumstances. Some coal fired power would be economically viable at a carbon tax of 50 ECU/ton CO_2 or more, as CO_2 capture and geological disposal is considered feasible. At such carbon tax levels nuclear power is already applied at its perceived maximum. Generally, ‘new’ renewables would be used at a lower rate or introduced at higher carbon taxes.

1. INTRODUCTION

For a number of reasons the power generation sector is an important element of the energy infrastructure. Generally, power generation has a relatively large share in total primary energy production. Electricity demand shows a steady growth, despite efforts to conserve energy and electricity. In the long term, e.g. the year 2050, power generation could fulfil a key role in CO_2 abatement. This is because there are various options to generate electricity with a very low or negligible (indirect) CO_2 emission. If the focus is on power generation in the long term, a Western European scope is preferable to a national one, as power generation is more and more internationalised.

New and improved energy technologies are expected to play a key role in abating emissions of greenhouse gases. Various technologies comprise the capacity to significantly reduce CO_2 emissions. The extent of the (ultimate) CO_2 reduction by each of the technologies depends among others on:
- improvement of performance and reduction of cost;
- market potential;
- development of fossil fuel prices;
- level of future energy demand;
- environmental policy;
- level of integration of the European energy system;
- support for energy technologies by the actors in the energy system;
- barriers to the introduction and deployment of technologies.

The objective of this report is to assess the potential role of power generation technologies in the future Western European energy system. Various levels of CO_2 emission abatement and a range of other scenario conditions are considered. As such, an assessment will be made of the potential of individual energy technologies to reduce the emissions of CO_2.

The present study is a technical economic assessment which explores long term strategies to develop a more sustainable energy system with low CO_2 emission levels. It aims mostly at the identification of technological directions and less at instruments and policies to implement technologies.

Until a few years ago energy policies were mostly based on a national perspective. Even if the objectives of energy policy in European countries would not differ much, efforts to conserve energy, and to develop indigenous and renewable resources are not equal for all countries. In some countries the focus is on the supply side more than on energy conservation and renewables. In other countries the opposite can be observed. National policies are particularly relevant if environmental effects are more locally than regionally or globally. However, environmental policy is increasingly dealt with at the European Union level, especially with respect to the global warming issue. From this perspective a Western European approach could be more cost effective than the sum of national policies. In the same way scenarios at the Western European level gain importance over scenarios at the level of individual countries.

Therefore, the Western European[1] power sector is considered as part of an integrated energy system study. This report focuses on the prospects of new and improved energy technologies for power generation. Other reports deal with the prospects of all new energy technologies (the main report), the prospects of technologies in industry, and of those in transport.

The scenarios that are developed intend to support the dialogue on the favoured development of the energy system. Two scenarios have been prepared for Western Europe, going from the year 1990 to the year 2050 in steps of 10 years. The scenarios have different discount rates, different levels of energy demand, and different fuel price projections. In addition, a set of alternative cases has been analysed with different rates of CO_2 emission abatement. A wide range of energy technologies has been included in the scenarios and the possible role of these technologies has been assessed for each scenario and for each variant.

Chapter 2 focuses on the recent development of power generation in Western Europe. In Chapter 3 the scenario assumptions are described, and the methodology that was used to construct scenarios is explained. Chapter 4 covers the data with respect to power generation technologies. The results of the baseline projections - the scenarios without constraints for the emissions of CO_2 - are presented in Chapter 5. In Chapter 6 the results of emission abatement scenarios are given. Chapter 7 contains a discussion of the results, and in Chapter 8 conclusions are drawn.

1 The study covers Western Europe. This includes the countries of the European Union (Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom) and Iceland, Norway, and Switzerland. This group of countries is equal to OECD Europe minus Turkey.

2. HISTORICAL TRENDS AND EXPLANATION

2.1 Introduction

The Western European power sector is an amalgam of power generation mixes of different countries. Even within countries the generating mix of different power companies can show large differences. Power generation based on fossil fuels is important for almost all of the countries. A range of fossil fuels is used, from hard coal and lignite to residual oil and natural gas. Each fuel has different cost, a different heating value, and a different carbon content. Nuclear power is the main source of power in a number of countries, and it is the most important single source of power in Europe since a few years. Also hydro power is rather important in Europe.

Power generation has more or less strong linkages with national energy policies. Until now the boundaries of power companies and of countries coincide to a large extent. However, power generation will be more and more internationalised, due to liberalisation and privatisation. With respect to the physical boundaries, power exchanges between countries are rather important, notably between Scandinavian countries on one hand and the rest of Europe (except Ireland) at the other hand. In the next decades differences in power generation in Western Europe will be more based on economics than on national priorities, if liberalisation becomes effective.

2.2 Main sources of power

Twenty years ago the three main sources of power in Western Europe were solid fuel (hard coal and lignite), hydro power, and residual oil. These energy sources represented more than 80% of power generation. Nuclear power was far less important than today. Figure 2.1 shows the development of power generation in Europe during the last twenty years.

The average growth of electricity consumption during this period was about 2.5% per year. During the period 1975-1985 average growth was about 3% per year, and during the last ten years somewhat less than 2% per year.

Hydro power showed an increase of about 1.5% on average. In 1994 its share of total power production was about 19%. Nuclear power increased very fast until about 1993, ending up at about 33% of power generation in 1994. Production from solid fuels, mainly hard coal and lignite, as a percentage of total power generation increased slightly from 32% in 1975 to 37% in 1980. After that, coal fired power lost some market share to nuclear power, although power from solid fuels increased in absolute figures until 1991. In 1994 solid fuels represented 30% of power generation.

Oil fired power, which supplied 23% of power in 1975, lost against nuclear power and coal fired power, both in relative and absolute terms. In 1994 oil fired power supplied 8% of power in Europe, and gas fired power about 9%.

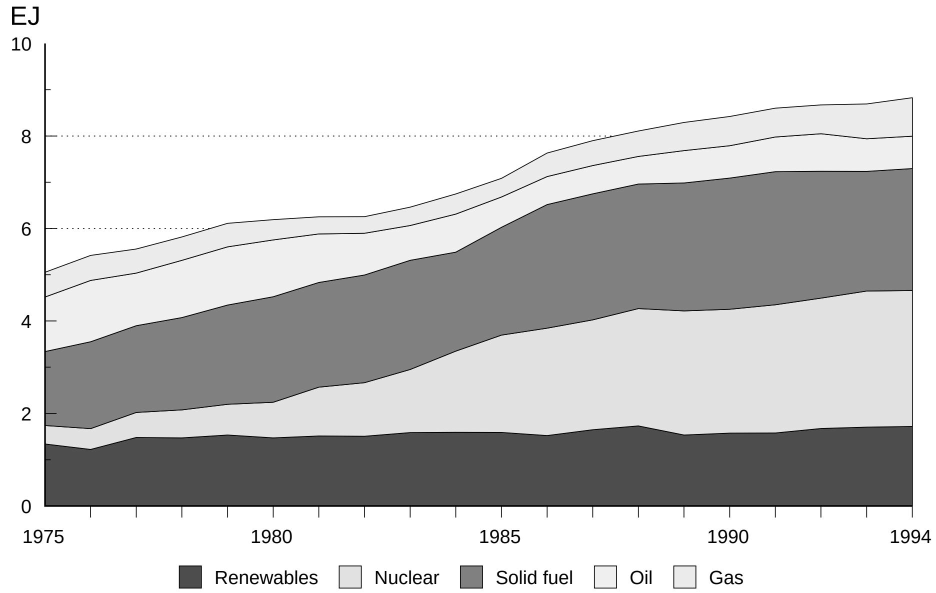

Figure 2.1 *Main sources of power in Europe, 1975-1994 (EJ electric/y)*

Note: Power production in the former German Democratic Republic has been included since 1986.

Most of renewables, notably hydro power, are included in 'renewables' in Figure 2.1. 'New' renewables are geothermal power, tidal power, and wind energy. Their contribution is very small up to now. Waste and biomass are considered under solid fuels.

2.3 Main trends in Europe

Despite large differences in the power generation mix between European countries, some general trends can be observed. One of them is the spectacular growth of nuclear power until 1993. In France and Belgium nuclear power became the main power source. Nuclear power also made substantial inroads in power generation in a number of other countries. However, some countries, notably Denmark, opted for a non-nuclear future.

Some thirty years ago several countries in Europe adopted nuclear power as the power source of choice. This decision proved to be strategic at the time of the oil price hikes in the seventies. Nuclear power became one of the cheapest options available. In France the nuclear programme was even strengthened after the first oil price crisis. However, electricity consumption did not grow as fast as the national power company, Electicité de France, had projected. In order to reduce overcapacity, surplus power is sold to neighbouring countries.

Although nuclear is an important power generation option, its future is clouded. In some countries referenda have been organised about nuclear energy. The result was a de facto moratorium in Sweden and Switzerland, and a veto against nuclear power in Austria. In other countries, e.g. Italy, Germany, and the Netherlands, public acceptance virtually disappeared in the wake of the Chernobyl accident in 1986. Moreover, the economic advantage of nuclear power over fossil fueled power, which was substantial in the beginning of the eighties, diminished after the oil price slide in 1985.

The development of the power generation mix of France and Denmark is shown in the Figures 2.2 and 2.3 respectively.

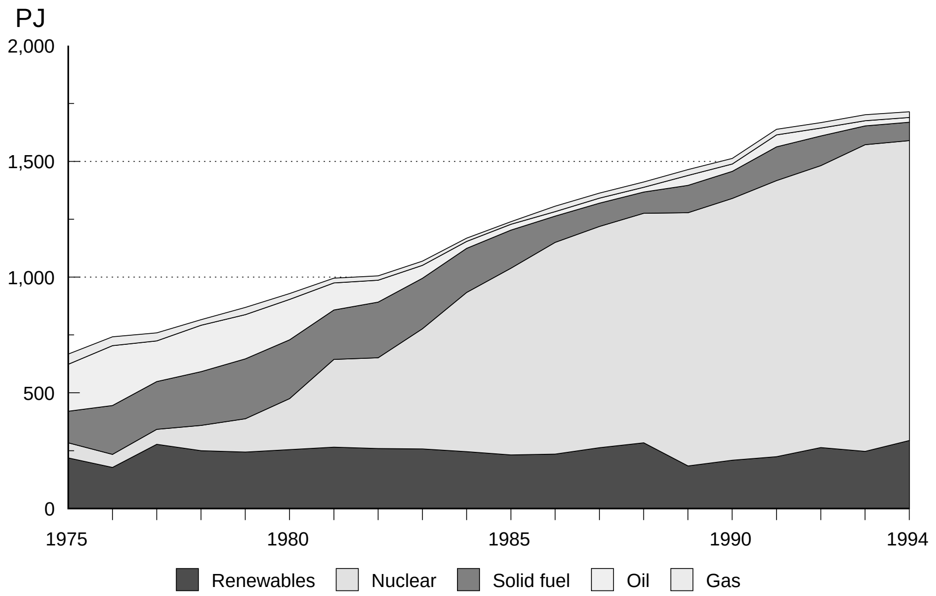

Figure 2.2 *Main sources of power in France, 1975-1994 (PJ electric/y)*

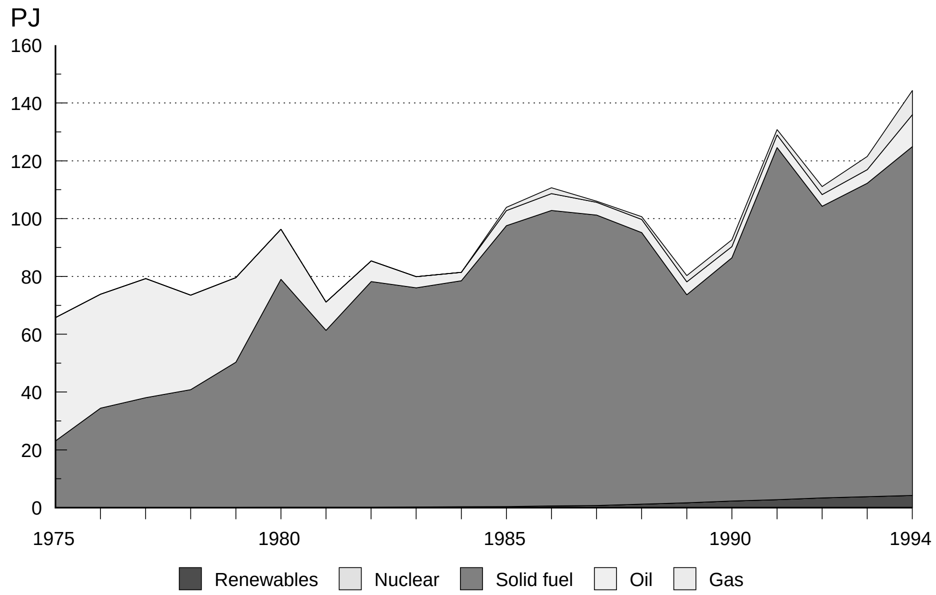

Figure 2.3 *Main sources of power in Denmark, 1975-1994 (PJ electric/y)*

Note: Differences in total power production from year to year are mainly due to fluctuations in import of hydro power from Norway.

In 1975 10% of electricity in France was produced by nuclear power plants, 33% by hydro power and the remaining 57% by power plants based on fossil fuels. Nowadays, 76% of power is produced by nuclear power plants, 17% by hydro power plants, and only 7% by power plants based on fossil fuels.

Power generation in Denmark showed a quite different development over the last twenty years (Figure 2.3). After the first oil crisis the contribution from coal fired power increased fast, ending up at more than 90% in 1982. Since then the share of solid fuels declined somewhat, levelling off at about 84% in 1994. Oil fired power, which had a market share of 65% in 1975, fell back to only 8% in 1994, slightly more than the share of gas fired power (6%). In Denmark renewable power options are waste and biomass, which are comprised in solid fuels, and wind energy. In 1994 the contribution from wind energy to total power generation was almost 3%.

One observation is that nuclear power has got a strong foothold in some countries, culminating in a 75% share of electricity generation in France. In many countries nuclear power plays a vital role, although its future is clouded. Another observation is that some other countries (notably Denmark) switched to coal for the bulk of their electricity demand. ‘New’ renewables (biomass, wind) are implemented all over Europe, with a remarkable 3% share from wind power in Denmark in 1994.

2.4 CO_2 emission in perspective

CO_2 emission from power generation depends on the market share of fossil fueled power generation. Also the distribution between coal, oil, and gas is important. The data shows that the share of nuclear power in power generation increased fast during the last twenty years. This is the main reason for the steadily decreasing CO_2 per kWh in Europe (Figure 2.4). The market share of gas fired power remained stable, whereas that of oil fired power showed a rapid decline. Solid fuels increased their market share until about 1980; after that, solid fuels lost against nuclear power. All in all, the CO_2 emission per kWh in Europe decreased from about 540 g/kWh in 1975 to about 370 g/kWh in 1994.

Figure 2.4 also shows the diverging developments of CO_2 emission per kWh in France and Denmark. In France the CO_2 emission decreased very fast from 450 g/kWh in 1975 to about 60 g/kWh in 1994, due to the rapid and complete switch to nuclear power. In Denmark, however, the CO_2 emission per kWh increased until 1982, when coal reached its maximum share of more than 90%. After that, the CO_2 emission per kWh fell back to about 800 g/kWh in 1994. This is slightly lower than the emission per kWh in 1975. It appears that efficiency improvement in the Danish power sector largely offset the tendency to a higher CO_2 emission per kWh from switching to coal. Also the growing importance of gas fired power (6%) and wind power (3%) in 1994 contributed to a lower CO_2 emission per kWh.

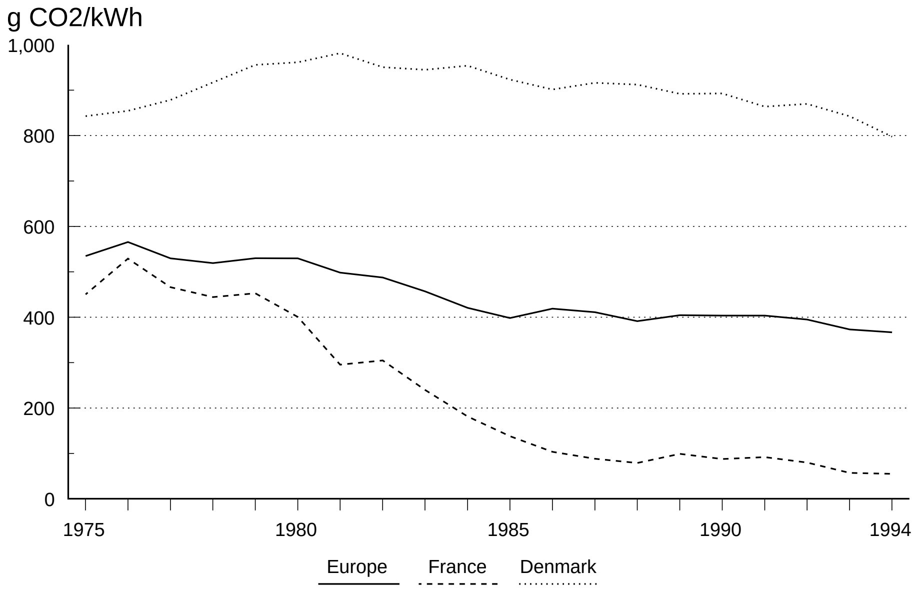

Figure 2.4 *Average CO_2 emission per kWh in Western Europe, France, and Denmark, 1975-1994 (g CO_2/kWh)*

3. SCENARIO APPROACH AND DEMAND PROJECTIONS

This chapter briefly describes the scenario assumptions, methodology of demand projections, and technologies used for this study. First, the general approach and the modelling tool are explained (Sections 3.1 and 3.2), then the assumptions for the scenarios are given (Section 3.3).

3.1 General approach

The objective of this report is to assess the potential role of a range of energy technologies in the future Western European power generation system, with various levels of CO_2 emission abatement, and under a range of scenario conditions. Emphasis is on the technical potential to reduce the emissions of CO_2 in the long term, while considering the cost consequences of emission mitigation technologies. It is acknowledged that technology is not the only means to reduce emissions of CO_2 and that non-technical aspects are also of key importance. To become successfully implemented, technology needs to be embedded in society and the new more sustainable energy technologies have to be picked by the various actors involved in decisions on energy use. However, in order to construct strategies for emission reduction, the technical potentials have to be known first. Once these are known, the implementation issues can be considered. Therefore, identification of attractive emission mitigation technologies should be regarded as an important part of the development of emission mitigation strategies. Complete mitigation strategies also include a selection of policies and measures to implement the energy technologies and estimates of the macro-economic costs.

Energy technologies compete with one another if they can deliver the same type of energy carrier or the same type of energy service. Economic considerations are crucial for decisions on the use of one technology or an alternative. As the pattern of energy use changes with seasons and with time of day, as costs of fuels vary over time, and since decisions in different areas in the energy system interact, identification of optimal investment decisions for energy technologies is not simple. If energy decisions are considered for the entire energy system, one needs to use integrated energy models that can incorporate such aspects especially relevant to power generation. This study applies the MARKAL model (see Section 3.2), which enables us to model the competition of technologies within a level playing field.

The level of energy demand, energy price development, and environmental policy will affect the potential role of energy technologies. Each of these factors is uncertain. With two different scenarios, this study respects the uncertainty in discount rate, energy demand and fuel prices (see Section 3.3). Uncertainty in future environmental policy is comprised by considering three different levels of CO_2 taxes. Emissions of CO_2 will be reduced more and more with increasing CO_2 tax levels.

3.2 Modelling tool

The model that has been developed for the analysis is called MARKAL-EUROPE 1.0, and it is based on a frequently used linear programming model (MARKAL). The model has been defined for Western Europe (European Union member countries, Norway, Switzerland, and Iceland) and for a time span from 1990 to 2050.

MARKAL is a widely applied linear optimisation model. The main characteristic of an optimisation model for the energy system is the concept of a predefined network of demands, sources and technologies of energy interconnected by flows of energy carriers. The networks typically cover the various stages from *Primary Supply* (mining, import) of energy carriers through *Conversion and Processing* (power plants, refineries, etc.) to obtain user-ready energy products) to *End-Use Devices* (boilers, cars, lighting, etc.) that serve to satisfy *Demands for Energy Services* broken down by (sub-)sectors and functions (residential lighting, commercial air conditioning, industrial drive power, etc.). The network concept is also referred to as a reference energy system (RES).

All prespecified links between sources, technologies and demands can be selected by the optimisation model. The costs and conversion efficiencies of all technologies are defined exogenously. The optimal solution found by the model is the configuration of the energy system with minimal costs that meets the specified energy demand. There is no solution with lower costs. The model applies an integrated approach. This implies that synergy and competition between technologies at the supply side and the demand side of the energy system are explicitly considered.

New technologies to satisfy demands for energy services that consume less energy and/or other types of energy carriers will be indispensable to cut back greenhouse gas emissions. Technology oriented models like MARKAL aim to identify which are the options of choice and how big their role could become over time. The Western European system-wide (all sectors, from primary source to energy service) and dynamic (capital stock changes; load patterns) scope implies that systemic interactions like synergies, competition and load management are considered. Synergies can occur between supply and demand options, for example better prospects for electric cars if power generation with low CO_2 emission would be affordable.

The *dynamic* nature implies that past decisions and future expectations are taken into account in decisions to expand or decrease capital stocks at any point in the time horizon considered in the analysis. *Structural changes* are thus allowed, but the rate at which the potential flexibilities are exploited is limited to what is both technically and economically viable.

Environmental considerations can be addressed in various ways, such as through sectoral or Europe-wide emission limits on an annual basis or cumulative over time. Alternatively by imposing fees on emissions, e.g. reflecting carbon taxes or external costs of pollutants.

If constraints are placed on the penetration of technologies or on the total level of emissions of pollutants linked to the use of energy, the configuration of the energy system will change. In such a situation, MARKAL will again seek the configuration that has the lowest cost and that meets the constraints.

Maximum penetration of technologies can be regulated in the model by imposing maximum bounds on total capacities or maximum bounds on new capacity. Examples of technologies that have bounds in MARKAL-EUROPE 1.O are wind turbines, photovoltaic (PV) systems, geothermal energy, and district heat. The bounds can be justified on the base of different real constraints: public planning constraints (e.g. wind turbines), limited manufacturing capacity (e.g. PV systems), physical constraints (geothermal reserves), heat demand in areas with high heat demand (district heat), etc..

The overall optimisation *ignores stakeholders* with conflicting interests operating on markets in real life situations. Allocation of benefits and losses is thus no issue.

The capability of MARKAL to *mimic 'real world'* behaviour, for instance as observed in the past, is limited. The reason is that MARKAL is not aiming to simulate the behaviour of all the actors involved in energy investments and use. Instead it aims to calculate an optimal situation that could occur if only one actor would make optimal decisions about the configuration of the energy system. Thus, MARKAL is typically more suited to explore alternative strategies to reach a desired situation than to forecast the future level of energy use.

MARKAL-EUROPE takes the overall overview of Western Europe as the perspective for model calculations. This assumes a situation that only one actor decides how the structure of the energy system will look like. The model assumes free competition of the technologies fully based on the cost-effectiveness of the technologies. With its dynamic nature, MARKAL performs an optimisation of the energy system for the full period 1990-2050 in one set of iterations. This implies perfect foresight, which means for instance that the structure of the energy system in 2020 anticipates on the constraints that have to be met in 2030.

Western Europe does not have a homogenous energy and power generation system; there are large differences between the kinds of end use and the primary energy mixes of the various countries. Up to a certain level, regional detail could be included in the model definition. Renewable energy potentials have been considered in tranches depending on the potential supply of wind, solar energy, etc. at different sites.

The existing stock of capital and the associated energy use is considered as the starting point for the development of the energy system. The model has been calibrated to reflect the historic energy balances in the year 1990.

3.3 Scenario assumptions

To frame the analysis of the energy system, one or more scenarios are required. For this study two new energy scenarios were developed. The two scenarios are named *Rational Perspective* (RP) and *Market Drive* (MD). The two scenarios have different discount rates, different levels of energy demand and different fuel price projections. Assumptions for the cost and performance of technologies are the same for the two scenarios. The maximum and minimum potentials of supply technologies are - in absolute terms - the same for the two scenarios.

General scenario background

Rational Perspective is the ecologically driven scenario. The process of global economic integration will lead to more collective public action. The cooperation between countries will be more efficient in order to deal with complex shared problems. Heavy polluters and energy intensive industries will decline compared to more environmentally friendly sectors like services. Strong penetration of new, more efficient demand and supply technologies is facilitated. This strong penetration will be reached by setting public standards, removing existing barriers for the introduction of efficient technologies, and active energy service companies, etc. The above mentioned policy shifts are driven by environmental concerns and concerns about efficiency throughout society.

Market Drive is the market driven scenario. In this scenario the market mechanism is seen as the best way to produce wealth and handle complexity in uncertainty. The penetration of new, more efficient demand and supply technologies totally depends on market forces and the behaviour of the actors. The environmental protection agenda is also set by the market and thus not by public policy. Moreover, energy policy is driven by the desire to minimise government control and to maximise efficient operation of free markets. Efficiency gains will only be made for competitive reasons.

Discount rates

A discount rate is needed to annualise the capital cost in order to compare the costs of alternative technologies with different ratios of initial capital expenditure to annual running costs. One can choose one uniform discount rate for all technologies or different discount rates for different sectors.

In one of the two scenarios a single uniform discount rate has been applied. By applying a uniform rate to all technologies, all technologies at the demand side of the energy system were allowed to compete with energy supply technologies as if in a perfect market. The scenario where this is allowed is the *Rational Perspective* scenario. In other words, the scenario Rational Perspective assumes a market that works rationally, without barriers and with perfect information.

The other scenario acknowledges that in reality, more stringent investment criteria apply for many energy related decisions and that hidden cost and market barriers do play a role. This *Market Drive* scenario assumes different discount rates per type of energy end-use. The discount rates reflect representative hurdle rates representative to the kind of end-use considered.

End-use energy demand levels

For most kinds of energy end-use, demand for energy services has been assumed to be higher in the MD scenario than in the RP scenario. The RP scenario assumes a world where growth in energy demanding services, which have important negative external effects on environment and health, are restricted. In the MD scenario this is not the case. Therefore, demand in road transport, air transport and the heavy industry is significantly lower in RP than in MD. Energy demand in the residential sector is assumed to be the same for most kinds of energy services that are discerned in the residential sector. Table 3.1 gives the energy demand projections for selected energy demands. It is noted that demands are given in physical terms, not in financial terms. Despite this difference in orientation, it has been assumed that the level of GDP growth is similar for MD and RP.

Table 3.1 *Useful energy demand for selected energy demands in the scenarios RP and MD*

		Energy demand in 2040, index of 1990 demand	
	1990	Rational Perspective	Market Drive
Agriculture traction	100	100	100
Steel production	100	90	107
Steam other industries	100	127	145
Space heating commercial sector	100	158	192
Space heating Northern Europe	100	120	120
Average for electric appliances	100	180	200
Passenger cars	100	175	240
Trucks	100	164	355
Aircraft	100	200	220

Energy price projections

From the past oil price crises (1973, 1979) it is evident that oil prices can vary with wide margins. The same holds for gas prices, as far as they are linked with oil product prices, which is common until now ('net-back pricing'). The *level of* fossil fuel prices, and the *margins* between the prices of oil and gas on one hand and the coal price on the other hand, have a large influence on the cost-effectiveness of energy technologies, especially for power generation. With a high energy price level, technologies that can reduce fossil fuel consumption - energy conservation, renewables, nuclear energy - become more cost-effective than with low fossil fuel prices. At low fossil fuel prices, energy conservation and substitution of coal or nuclear energy for oil and gas are not very attractive. The margin between the price of oil or natural gas versus the price of coal is determining for the question if coal or gas fired power generation is economically attractive. If 'net-back pricing' were based on the price of coal, results would be different.

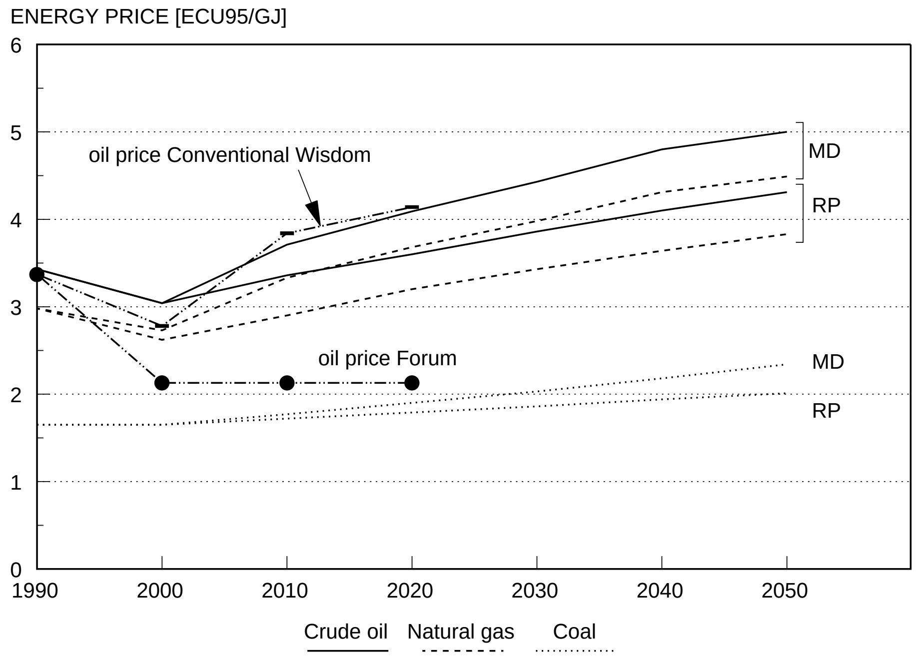

Figure 3.1 *Energy price projections for scenarios Market Drive and Rational Perspective*

Figure 3.1 shows the energy price projections of this study. The two developments of fossil fuel prices are both considered as fairly central energy price projections. Each of the energy price scenarios is equally plausible from different views on energy supply and demand in Europe and the world in general. The projections refer to real prices in ECUs of 1995. Carbon taxes are not included in the projections.

For comparison, the oil price projections up to the year 2020 of a recent study for the European Commission are also included in Figure 3.1. The price projections for crude oil in the MD scenario and the Conventional Wisdom scenario are very similar. The price projection of the Forum scenario is lower than the price projections of the present study.

4. ENERGY TECHNOLOGIES

4.1 Introduction

Western Europe does not have a homogenous power generation system. Some countries depend on nuclear power to a large extent. In other countries the power generating mix is mainly based on fossil fuels and hydro power. Other renewable power options, like wind energy and biomass fueled power, are implemented in a number of countries.

Modelling of the power generation sector means simplification and standardisation. Not all of the power plant types are relevant. It is not sensible to take a power plant type into account for modelling purposes, if it is based on redundant technology or used on a modest scale. Therefore, power plants in Europe are categorised, and a limited number of power plant types are selected. There are wide differences in commissioning date of power plants. As the generating efficiency of a power plant based on fossil fuels depends on the commissioning date, a distinction is made between new and existing power plants based on fossil fuels.

Power generation options can be divided in the following categories (Table 4.1).

Table 4.1 *Main categories of power generation options*

Category	Number of options		
	Power only	District heating/Total Energy	Industrial CHP
Coal fired	2	2	1
Oil fired	1		1
Gas fired	1	3	2
Nuclear	1		
Hydro pumped storage	1		
Hydro	2		
Wind	2		
Biomass	2		
Solar (photovoltaic)	3		
Geothermal	1		
Waste	1		

In the next sections the power generation options are shortly described. More detailed information is provided in Annex A.

4.2 Coal fired power

Emphasis is on very efficient power plant, for gas fired power and for coal fired power as well. In case of coal fired power, either the power plant has demanding steam conditions - so-called Ultra supercritical Steam Conditions (USC) or USC-boilers - or it is based on Integrated Coal Gasification Combined Cycle (ICGCC or IGCC). The latter technology is assumed to be applicable to hard coal as well as lignite. IGCC power plants based on hard coal or lignite could be commercially available in 2000.

An IGCC based on hard coal is assumed to have an ultimate efficiency of 52% in 2040. This is considerably higher than the highest efficiency of a coal fired power plant with USC-boiler today, namely 45%. It is also higher than the highest efficiency considered here for such power plants, i.e. 48%. These efficiencies are year average figures for the capacity available in a certain period. This means that the efficiency of IGCCs in 2040 is based on the average for IGCCs commissioned in 2020, 2030, and 2040. As the efficiency improvement is assumed to level off in 2020, the ultimate efficiency mentioned for 2040 is equal to that of capacity built from 2020.

The abovementioned efficiencies (52% and 48% respectively for hard coal fueled IGCC and hard coal power plants with USC boilers) are very high from the current point of view; currently, CO_2 reduction is not yet considered as very important. However, the technologies should not only be representative of ‘business-as-usual’ conditions. They should also apply to a scenario with much more emphasis on CO_2 reduction. As a consequence of the focus on highly efficient coal fired power plant, investment costs are relatively high. Investment cost of coal fired power based on USC is estimated at ECU 1,290/kW_e, and IGCC investment cost is estimated at ECU 1,380/kW_e. For lignite fired power plants investment cost is still higher than for hard coal fired plant.

Hard coal fired power plants can supply district heating to a certain extent. For lignite fired power plants district heating is not considered, because of the relatively low heating value of lignite, making mine-mouth power plants inevitable. The fifth coal option is a hard coal fired Fluidised Bed Combustion (FBC) plant for Combined Heat and Power (CHP). This technology is already commercially available today.

4.3 Oil fired power

Oil fired power plants are mainly used for peak or medium load. The drive for higher efficiencies will be less pronounced compared to power plants fired with hard coal or lignite, as their relatively low load factor does not leave room for higher investment costs. However, oil prices are high compared to prices of hard coal and lignite.

Efficiency of oil fired power plant can be boosted by conventional technology with USC boilers, or by IGCC technology. IGCC based on residual oil is assumed to be used for industrial CHP, mainly in refineries. The efficiency and investment cost of such plant are roughly comparable with corresponding figures for coal fired IGCC.

4.4 Gas fired power

Gas fired power plants are mainly used for medium and peak load. However, the load factor of district heating plants can be relatively high (about 50%). Six options for gas fired power are considered. One is the existing mix of conventional plant, based on a steam boiler or on a similar plant repowered with a gas turbine. Most of the other options are more efficient options with long term perspective. One of them is a combined cycle plant for district heating. Investment costs are low (ECU 670/kW_e), and the generating efficiency is high: 60% in the condensing mode in 2020 (the efficiency is assumed to level off at 60% in 2000).

For industrial CHP, gas turbine plants and combined cycle plants are assumed to be available. Generally, industrial cogeneration is characterised by high load factors. Industrial gas turbine plants are overall less efficient than combined cycle plants, as they have a relatively low power to heat ratio. However, their investment costs are rather low (ECU 760/kW_e).

At last a gas turbine for peaking power is assumed to be available, and Total Energy based on a gas engine for small scale combined heat and power (low temperature heat for the residential and commercial sector).

4.5 Nuclear power

With respect to nuclear power, only the Light Water Reactor (LWR) is taken into account. The investment cost is based on German practice in the late eighties. Also operation and maintenance cost is based on estimates for German practice. Nuclear power plants have been built in France at (considerably) lower investment cost. However, the numbers of identical plant built in France were exceptionally high. Despite the current French-German cooperation in the development of a standard European Pressurised Water Reactor (EPR), it will be difficult to build such high numbers of identical nuclear power plants as realised in France. Moreover, nuclear power plants in Western Europe have to fulfil very demanding safety requirements, which add to the overall investment cost.

4.6 Hydro pumped storage

In order to match electricity supply from power plants and the demand for electricity, which shows large differences between day and night, some power storage option should be available. Therefore, a hydro pumped storage plant is assumed to be available. It can be used to match supply and demand for power during day and night. This type of power plant is already widely available in countries with hydro power potential.

4.7 Hydro power

There are several types of hydro power plant, such as run-of-river or reservoir type plants. Some have a relatively low head (most of run-of-river capacity), others have a relatively high head. Because of lack of detailed figures of capacities, numbers of full load hours, and investment costs, a distinction is made between ‘low head hydro’ (rather costly) at one hand and ‘medium and high head hydro’ (less costly) at the other hand. It seems that there is scope for some capacity expansion in both types considered.

4.8 Wind turbines

Wind turbines have been installed in a number of European countries. In all of these countries there is a lot of (technical) potential for wind turbines. However, implementation depends not only on the availability of suitable locations, but also on the commercial prospects. The maximum rated power of commercially available wind turbines rose from 500 kW_e five years ago to 1.5 MW_e today. The capacity factor is assumed to be 27% in year 2000. Investment costs were about ECU 1,140/kW_e in 1990, and are estimated at ECU 860/kW_e in 2000, and ECU 810/kW_e in 2010.

If the installed capacity reaches a certain threshold value, it is assumed that additional wind turbine capacity should be realised in conjunction with (enlarged) hydro pumped storage in a certain proportion of their capacities. Hydro pumped storage improves the match between supply and demand for power.

Investment costs of offshore wind turbines are significantly higher than for onshore wind turbines. The annual load factor is estimated at 27.8%. Investment costs could be ECU 1,750/kW_e. Note that these figures include the effects of hydro pumped storage, which not only adds to investment costs, but also reduces the annual output if conversion losses are included.

4.9 Geothermal power plant

Geothermal power is generated in Italy and Iceland. Both countries have relatively modest capacities, e.g. 570 MW_e in Italy. It is assumed that geothermal capacity could be trebled until 2050. Investment costs are estimated at \$ 1,200/kW_e (ECU 1,030/kW_e).

4.10 Waste-to-energy power plant

In most European countries municipal solid waste is incinerated, thereby generating power. Some countries, e.g. Denmark, Germany and the

Netherlands have a significant waste-to-energy power plant capacity. In most countries new capacity is under construction. It is assumed that total capacity will increase from 570 MW_e in 1990 to 3,530 MW_e in 2040. This is the minimum capacity assumed. Investment costs in 1990 are estimated at ECU 11,400/kW_e. In year 2000 investments costs are assumed to be approximately 20% lower (ECU 9,000/kW_e). This could be the result of development of a new waste-to-energy technology with a considerably higher generating efficiency.

4.11 Biomass fueled power

Gasification is an essential but uncertain element for future biomass application for power generation. Costs depend on variables like atmospheric/high pressure gasification; direct/indirect gasification; air/oxygen; tar removal; alkali removal; low/high temperature gas cleaning. The overall net gasification efficiency is estimated at 83%.

Biomass gasification is used as the base technology for different power generation options. One of them is the steam injected gas turbine with intercooler (STIG) and reheat (excluding gasification). Steam injection in the combustion chamber and cooling inlet air during combustion can enhance electric efficiency and capacity of gas turbines. Adding a reheat system results in further efficiency increase. All three technologies are to be developed in the next ten years.

4.12 Photovoltaic power

The contribution of Photovoltaic (PV) systems to power generation is still insignificant. It is expected that the role of solar power will increase when the costs of PV systems will come down and vice versa. The annual electricity generation of solar systems depends on the annual irradiation. In Southern Europe solar irradiation is significantly higher than in Middle Europe.

Three kinds of PV systems have been discerned:
- Solar PV installed in Middle Europe.
- Solar PV installed in Southern Europe.
- Solar PV installed in Southern Europe for export to Middle Europe, including transport costs.

Considerable cost reductions over time have been assumed.

5. BASELINE SCENARIO PROJECTIONS

5.1 Introduction

In Chapter 5 the baseline projections of the scenarios Rational Perspective (RP) and Market Drive (MD) are presented. These reference scenarios are characterised by the absence of carbon taxes on fossil fuels. Thus, there is no CO_2 reduction policy. Power generation based on fossil fuels and non-fossil power options - hydro power, nuclear power, and renewables other than hydro - compete with each other for the largest market share, irrespective of the CO_2 emissions of each option. Consequences of carbon taxes of varying height for both scenarios are dealt with in Chapter 6.

Section 5.2 presents an overview of the main sources of power (gas and coal fired power, nuclear power, hydro power, and other renewables) in the reference scenarios. The cost effectiveness of the main sources of power is analysed in Section 5.3. Finally, changes within clusters of technologies are highlighted in Section 5.4. Such clusters encompass gas fired power options, coal fired power options, and renewable power options.

5.2 Overview of main sources of power

The level of electricity demand for the baseline projection of scenario RP is different from that of scenario MD. Until 2020 electricity demand growth is somewhat higher for MD than for RP. After 2020 electricity demand growth is slightly higher for RP. In each of the periods considered the level of electricity demand is higher for MD than for RP (Figure 5.1).

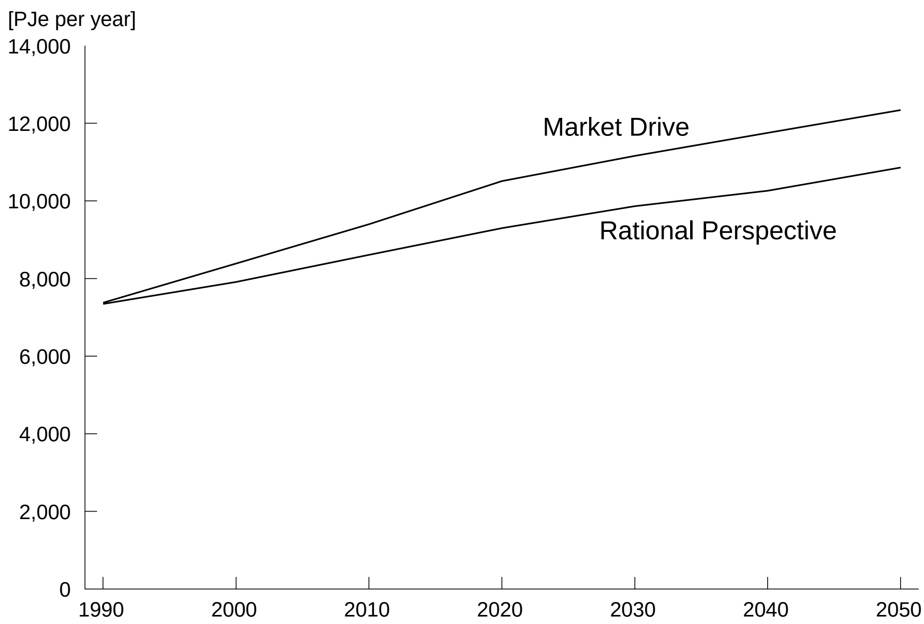

Figure 5.1 *Electricity demand for baseline projections, scenarios RP and MD*

Availability, and maximum and minimum bounds for technologies are the same for both scenarios. Sourcing of power generation options depends on a number of variables. One of them is the level of electricity demand. Other important variables are the level of interest rate and the fossil fuel price development. The interest rate is assumed to be low for RP (5%) and high for MD (15% for investments in power generation). A high interest rate is detrimental to capital intensive options. In principal, an increasing level of the gas price (compared to the coal price) over time favours coal fired power, nuclear power, hydro power, and other renewables over gas fired power. However, in the short term the level of the gas price in both scenarios is low enough to favour gas fired power over competing options.

In the baseline projection of scenario RP utilisation of hydropower is constant over time. Neither additional hydropower, nor additional nuclear power is cost effective. Investment cost of nuclear power plant is based on figures reported for German Light Water Reactors (LWRs) in the late eighties. If nuclear power is not competitive, it is assumed to decrease to a level which is equal to half of current capacity. The output of coal fired power shows some decline until 2010, and it remains stable until 2020. After that, it recovers fast, and ends up at almost twice the original level in 2050. Use of gas fired power more than trebles until 2020; it shows a gradual decline towards 2050. Oil fired power is rather insignificant, although it is never phased out. This is because power generation will remain a significant outlet for residual oil from refineries.

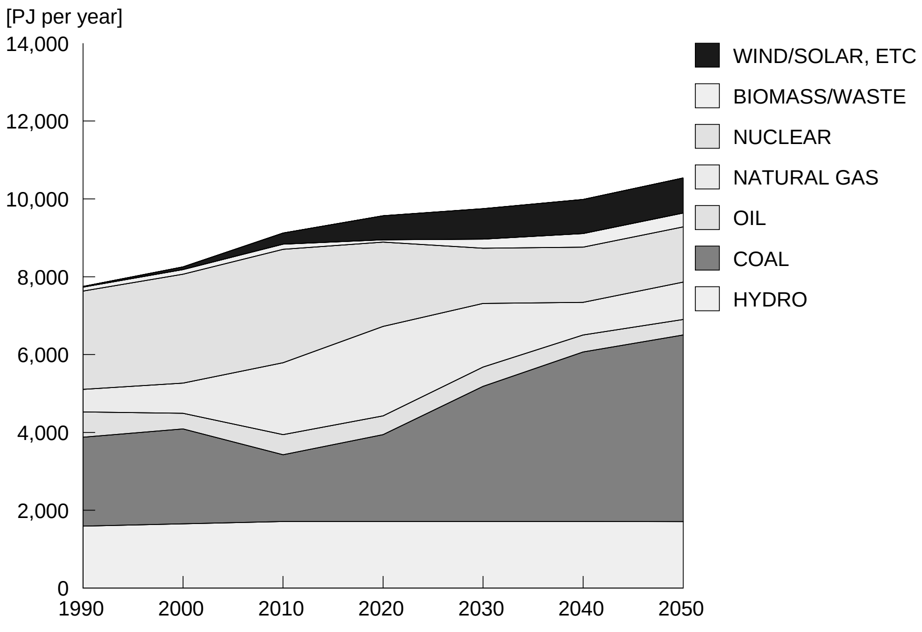

Figure 5.2 *Power generation 1990-2050, baseline projection scenario RP*

Use of renewable energy other that hydro becomes significant around 2010, when onshore wind energy becomes competitive. The output of wind energy is substantial in 2050 (approx. 800 PJ/y). Biomass fueled power is used to a somewhat lower extent. The combined output of wind energy and biomass fueled power is equivalent to 12% of total power production in 2050.

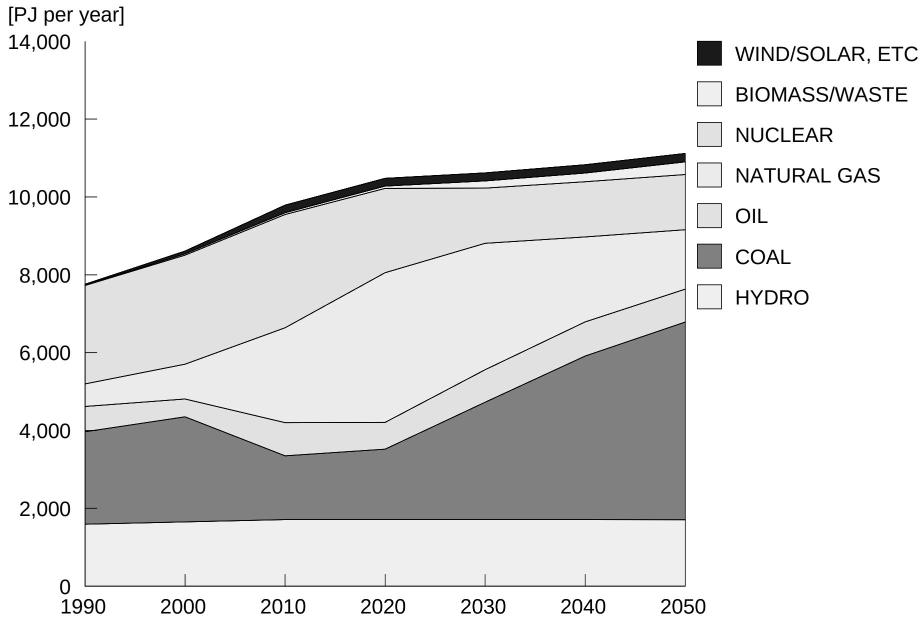

Figure 5.3 *Power generation 1990-2050, baseline projection scenario MD*

The reference MD scenario has the same main characteristics as that of RP, although there are remarkable differences. Hydropower doesn't show any growth. Nuclear power falls back to its perceived minimum level, which is equivalent to approximately 60 GWe. Coal fired power is used to roughly the same extent as in the reference RP scenario. Coal is the main source of power from 2030, while gas fired power peaks in 2020; after that, use of gas fired power declines gradually. Oil fired power is a minor power option.

Most renewables are not cost effective in the reference MD scenario. Only biomass fueled power shows about the same penetration as in scenario RP; it becomes competitive in 2030, while in RP penetration started in 2010. Wind energy clearly suffers from the high interest rate of scenario MD, as it is more capital intensive than biomass fueled power. The share of renewables other than hydro in total power production is only 5% in 2050.

5.3 Cost effectiveness of the main sources of power

In the baseline projections of RP and MD gas and coal are the main sources of power. Gas fired power is the most economic option in the first decades, and coal fired power in the last decades until 2050. This is because of the widening gap between coal and gas prices. The difference of interest rate between MD and RP is such that gas fired power is slightly more important in MD than in RP. From about 2030 the increasing price advantage of coal over gas offsets the difference in capital costs between coal and gas fired power plants, both in scenario RP and scenario MD.

Differences of interest rate do not influence the utilisation of hydro and nuclear power in the baseline projections: also in case of a low interest rate (5% in scenario RP) hydro and nuclear power are more costly than the cheapest alternatives. Nuclear power declines to approximately half of current capacity, the minimum level considered. Use of oil fired power is somewhat higher in MD than in RP; in MD oil consumption for transport is high, and surplus residual oil is used for power generation.

An interest rate as high as 15% is unfavourable for renewable power options. In the reference RP scenario onshore wind energy becomes competitive in 2010; both wind energy and biomass fueled power show substantial outputs in 2050. However, wind energy is not competitive in the reference MD scenario. Biomass fueled power, which is less capital intensive than wind energy, becomes competitive in 2030.

5.4 Competitiveness of selected technologies

5.4.1 Gas fired power

Gas fired power is one of the main options for power generation in the next decades. At least until 2020 it is the most competitive option without CO_2 reduction policy. Competition comes from coal fired power, onshore wind (only in case of a low interest rate), and biomass fueled power.

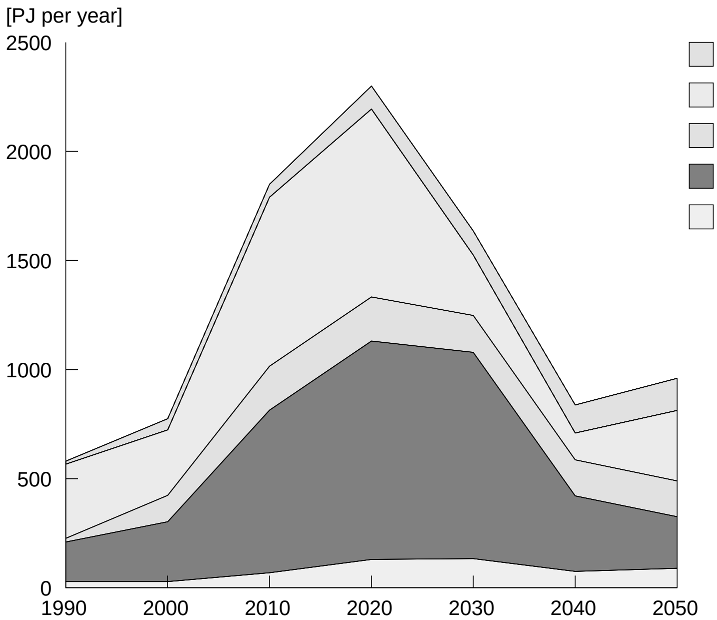

Figure 5.4 *Gas fired power generation options 1990-2050, baseline projection scenario RP*

The penetration of gas fired options in the baseline projection of RP is shown in Figure 5.4. Combined Heat and Power (CHP) based on gas turbines, and combined cycle plants for district heating are the main options. Combined cycle plants for CHP and total energy (gas engines) are used to a smaller extent. From 1990 to 2020 the output of gas fired power more than trebles; after that it declines to roughly the original level in 2040.

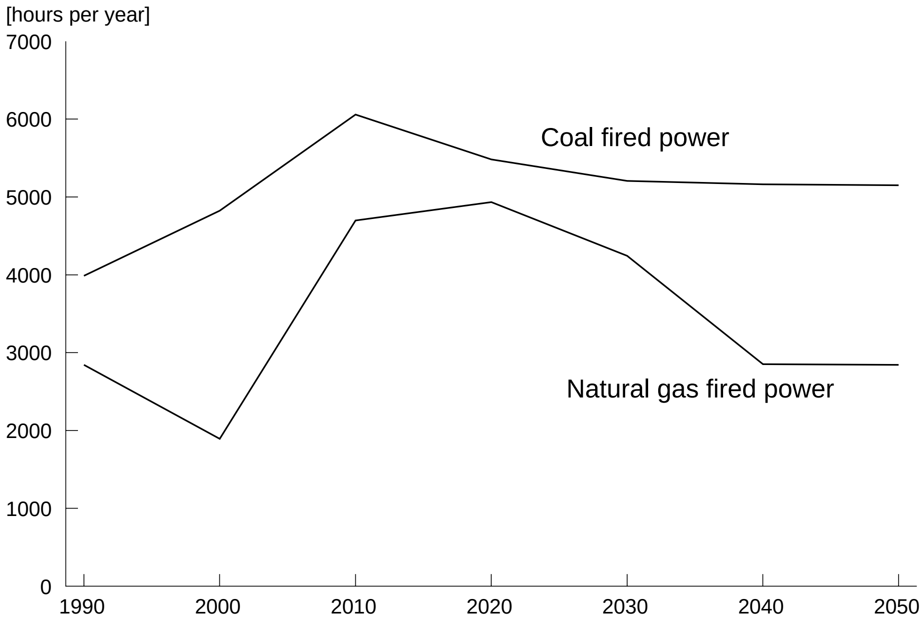

Figure 5.5 *Full load hours of gas fired power and coal fired power, baseline projection scenario RP*

Gas fired power has a lower load factor than coal fired power, as shown in Figure 5.5. Gas fired industrial cogeneration, however, has a high load factor. By nature of the flexible operation of gas fired power plants, a power generation mix with gas fired power is able to absorb a large amount of renewably produced power (hydro, biomass fueled power, wind energy, and solar power). It should be borne in mind that gas fired power is applied in industrial cogeneration and district heating. This will be a limiting factor to the flexibility.

5.4.2 Coal fired power

The number of coal fired power generation options is rather low. Both hard coal and lignite are considered. Besides, Integrated Coal Gasification Combined Cycle (ICGCC or IGCC) as an alternative to conventional coal fired power is deemed to be available for hard coal and for lignite. Fluidised Bed Combustion (FBC) is considered as an option for industrial CHP.

Figure 5.6 shows the development of coal fired power generation options in the reference RP scenario. From 2020 IGCCs are substituted for pulverised coal fired power plants, both for hard coal and for lignite. IGCC plants are able to compete with pulverised coal fired power plants due to their higher net generating efficiency, although they are assumed to have higher investment cost.

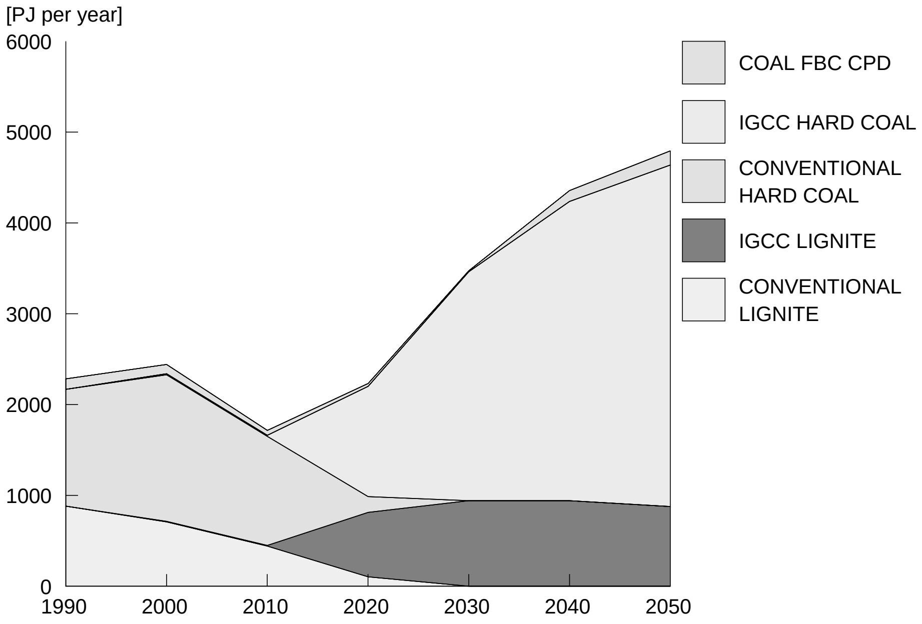

Figure 5.6 *Coal fired power generation options 1990-2050, baseline projection scenario RP*

For scenario MD the picture is different (Figure 5.7).

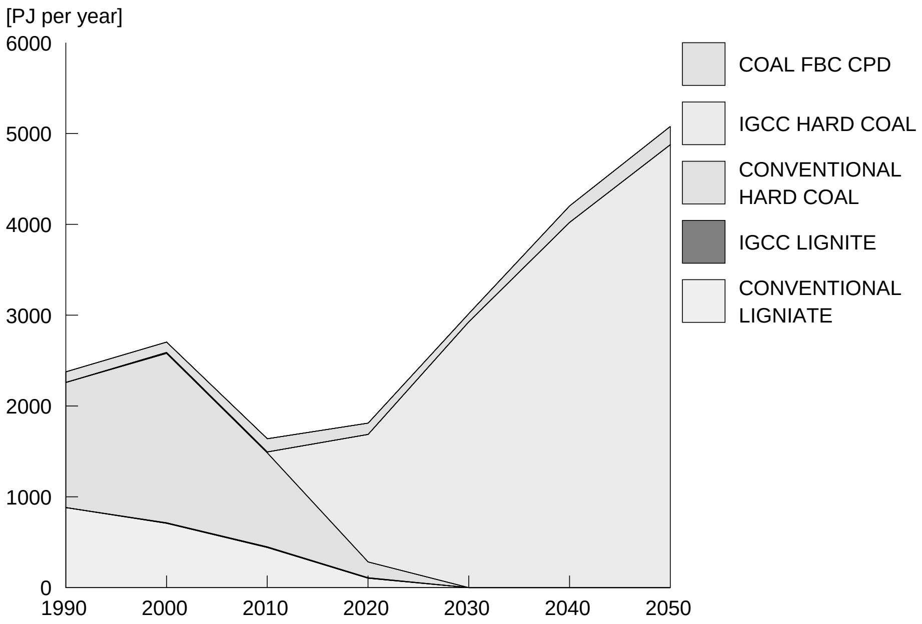

Figure 5.7 *Coal fired power generation options 1990-2050, baseline projection scenario MD*

In the reference MD scenario lignite fired power is phased out, while hard coal fired IGCC remains competitive. A high discount rate favours IGCCs based on hard coal over more expensive and less efficient IGCCs based on lignite. Lignite fired IGCCs have a lower overall efficiency than IGCCs on hard coal, while only the latter can feed district heating schemes: hard coal fired power plants can be built near urban areas as opposed to mine-mouth lignite fired power plants. The 15% interest rate tips the balance between technologies with low capital costs (gas fired power) and capital intensive technologies (wind energy, lignite fired power) in favour of the former.

5.4.3 Renewables

Renewable power encompasses the well proven hydro power plants, with capacities from tens of kW to hundreds of MW, and options in the stage of commercialisation, notably wind turbines and biomass fueled power. Some options, such as off-shore wind energy, highly efficient biomass fueled plants (based on gasification), and photovoltaic power (PV) deserve more research and development before large scale deployment (especially PV).

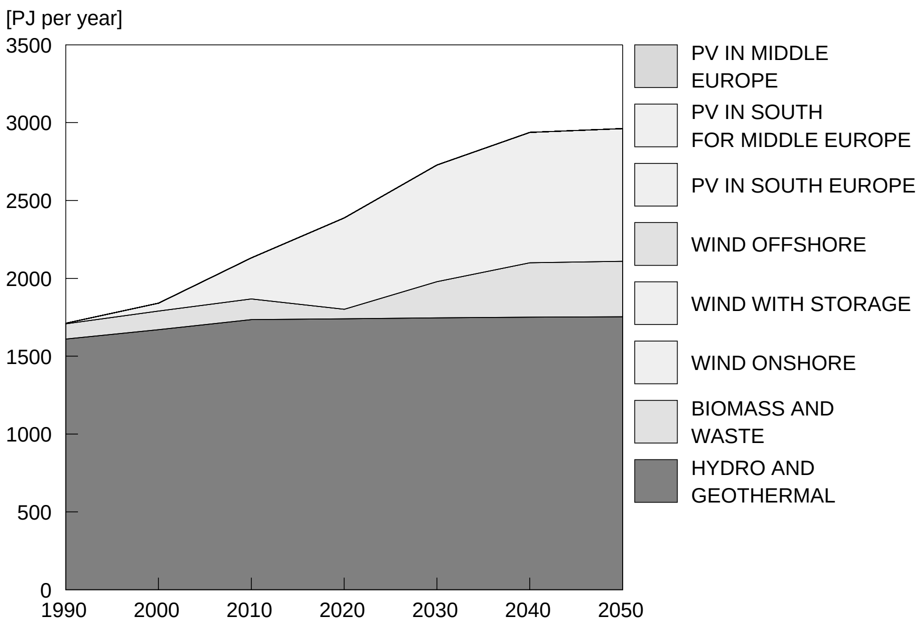

Figure 5.8 *Renewable power options 1990-2050, baseline projection scenario RP*

In the reference RP scenario onshore wind energy becomes competitive in 2010. Both wind energy and biomass have substantial outputs in 2050. However, the high interest rate of scenario MD is detrimental to wind energy. In case of scenario MD, biomass becomes competitive in 2030, twenty years later than in scenario RP. In scenario MD the high interest rate is an impediment to wind energy.

6. ABATEMENT STRATEGIES

6.1 Introduction

A CO_2 reduction policy can be based on more or less stringent CO_2 reduction targets. Such targets can be met by corresponding taxation of fossil fuels, according to the carbon content of the fuel. Here we examine the effects of carbon taxes on the technology mix for power generation. Generally, differences observed for the reference scenarios RP and MD will be increasingly overshadowed by the effects of higher and higher carbon taxes. However, the difference in interest rate remains important.

The cases of increasing CO_2 taxes are based on the reference scenarios RP and MD of Chapter 5. In all of the cases nuclear power is assumed to have an upper bound which is based on a political taxation rather than on resource constraints. Therefore, another set of cases is considered, with a more relaxed attitude towards nuclear power. In this set of cases, with the same levels of CO_2 taxes, not only the attitude towards nuclear power is deemed to be more relaxed, but also CO_2 capture and geological disposal for a number of options based on fossil fuels is considered feasible, and the upper bound for solar power in southern Europe is set at a higher level.

In Section 6.2 the focus is on changes in the main sources of power, such as gas fired power, coal fired power, nuclear, hydro, and other renewable power options. Section 6.3 addresses changes within clusters (gas fired power, coal fired power, and renewable power technologies). In Section 6.4 optimisation results are shown for various CO_2 taxes, presuming a relaxed attitude towards nuclear power, presuming that CO_2 capture is feasible and assuming a higher upper bound for solar power in southern Europe.

6.2 Main sources of power under increasing carbon taxes

6.2.1 Scenario RP

The main consequences of increasing carbon taxes for power generation are shown by comparison of the results of a specific carbon tax with those of a case with a lower carbon tax for scenario RP. Only the changes going from one carbon tax to another are described.

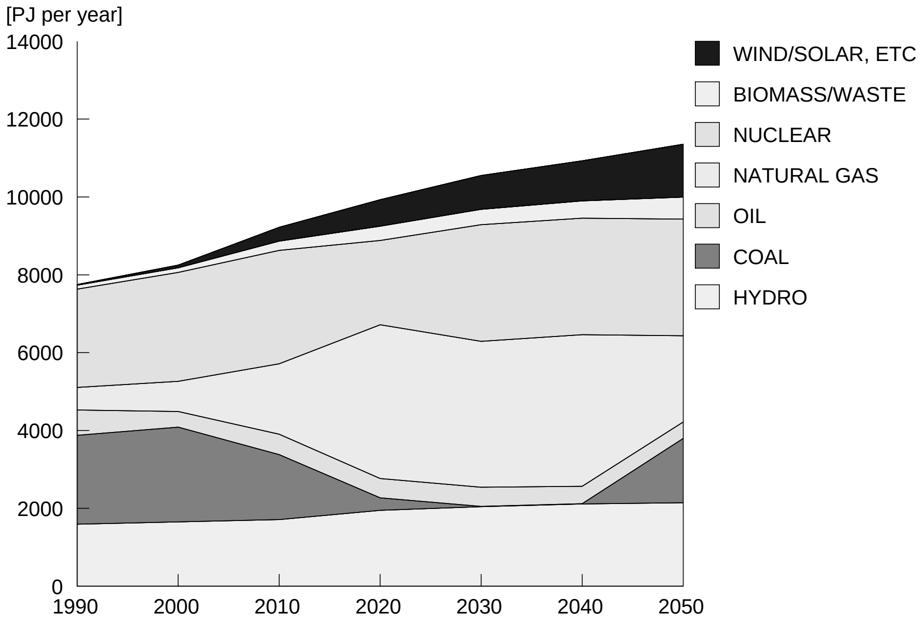

Figure 6.1 *Power generation 1990-2050, 20 ECU/ton CO_2 case RP*

Starting with a carbon tax of 20 ECU/ton CO_2, a substantial shift in the technology mix compared to the reference scenario can be observed. Use of hydro power increases from 2020: hydro power becomes competitive. Also nuclear power becomes competitive from 2030, after a decline until 2020. For nuclear power the highest capacity considered is roughly equal to the installed capacity in year 2000. Gas fired power expands dramatically, at the expense of coal fired power. In 2030 coal fired power is phased out; however, in 2050 it becomes competitive again, as the gap between coal and gas prices widens. CO_2 reduction by switching from coal to gas, which occurs in the first decades, is not cost effective any longer in 2050. Use of oil fired power remains relatively marginal.

In the 20 ECU/ton CO_2 case the output of wind energy increases to almost 1 EJ/y in 2050. Solar power at lower latitudes (southern Europe) becomes marginally competitive in 2040. Ten years later its output is almost 0.4 EJ/y, which is somewhat lower than for biomass fueled power. Output of renewables other than hydro increases from 12% of total power production in the reference RP scenario to 17% in the 20 ECU/ton CO_2 case.

In case of a carbon tax of 50 ECU/ton CO_2, the changes become more pronounced. Use of hydro power increases from 2010, and nuclear power is maximised from 2020. On one hand coal fired power is phased out around 2020. On the other hand gas fired power shows a surge until 2020, and remains relatively stable after that. Oil fired power doesn't show much change. Use of biomass increases slightly. Wind energy expands with a high growth rate, ending up at almost 2 EJ/y in 2050. Off-shore wind energy is not yet economic under these circumstances. Solar power becomes competitive in 2030. Output of renewables other than hydro increases to 27% of total power production.

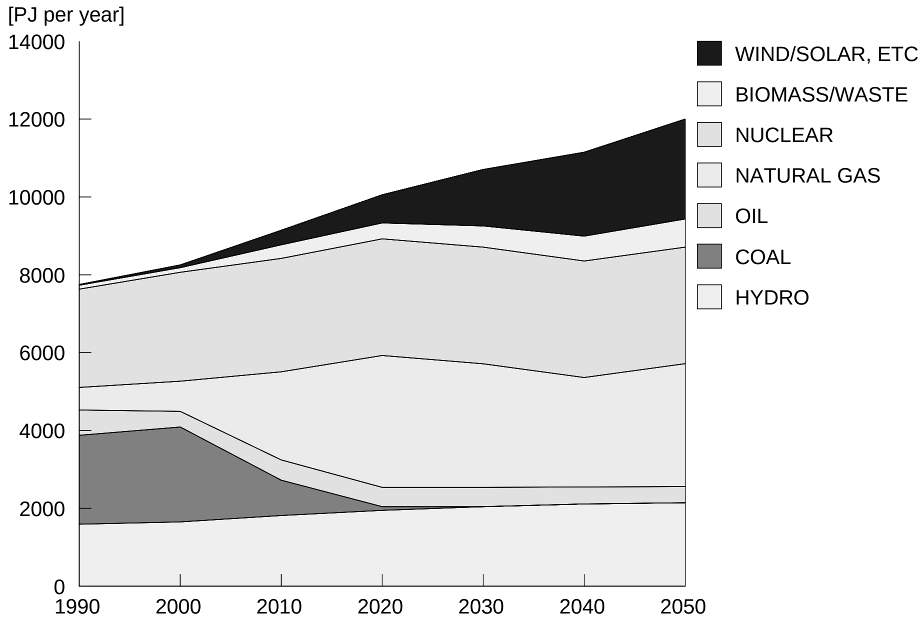

Figure 6.2 *Power generation 1990-2050, 50 ECU/ton CO_2 case RP*

If the carbon tax is as high as 100 ECU/ton CO_2 - equivalent to a tax of about $ 50/bbl - the changes in the technology mix become somewhat extreme. Going from the baseline projection to higher and higher carbon taxes, power production increases substantially. A lower CO_2 emission per kWh - due to the rising share of 'CO_2-free' power, notably (maximum) hydro power and nuclear power and (increasing amounts of) other renewables (biomass fueled power, wind energy, and solar power) - supports the substitution of e.g. electric heat pumps for gas fired equipment in the residential and commercial sector. Another effect of a decreasing CO_2 emission per kWh is that electricity conservation becomes less effective as a CO_2 reduction measure.

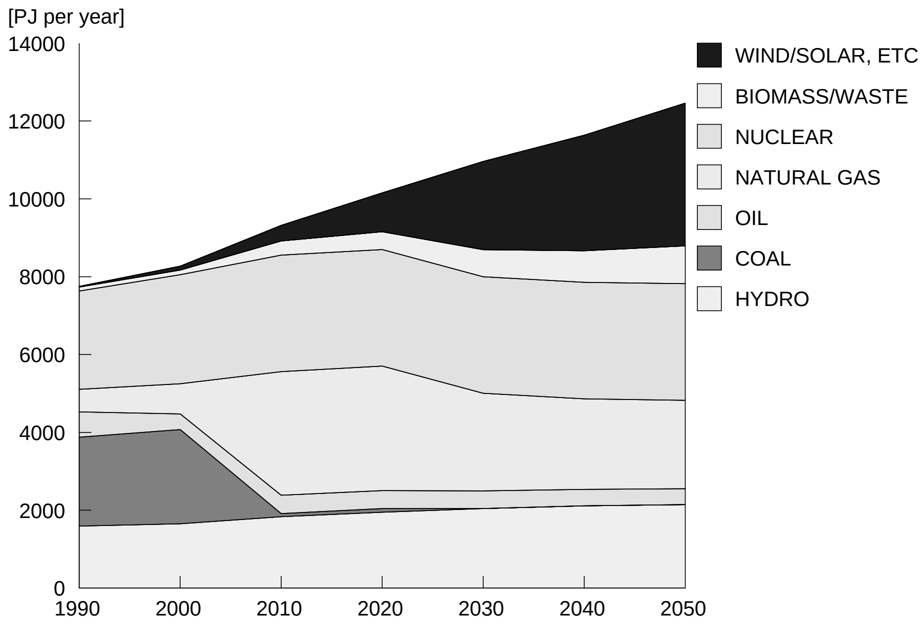

Figure 6.3 *Power generation 1990-2050, 100 ECU/ton CO_2 case RP*

In the 100 ECU/ton CO_2 case utilisation of hydro is unchanged, and nuclear power is maximised from 2010. Coal fired power is phased out rapidly. Gas fired power shows a plateau between 2010 and 2020, and a gradual decline after that. Oil fired power is unchanged. Use of biomass for power generation increases steadily, attaining approx. 1,000 PJ/y in 2050. Wind energy shows a sharp increase from 2020, when off-shore wind energy becomes competitive. Wind energy ends up at approx. 3,000 PJ/y in 2050. Solar power doesn't show any increase compared to the 50 ECU/ton CO_2 case. Output of renewables other than hydro increases to 37% of total power production.

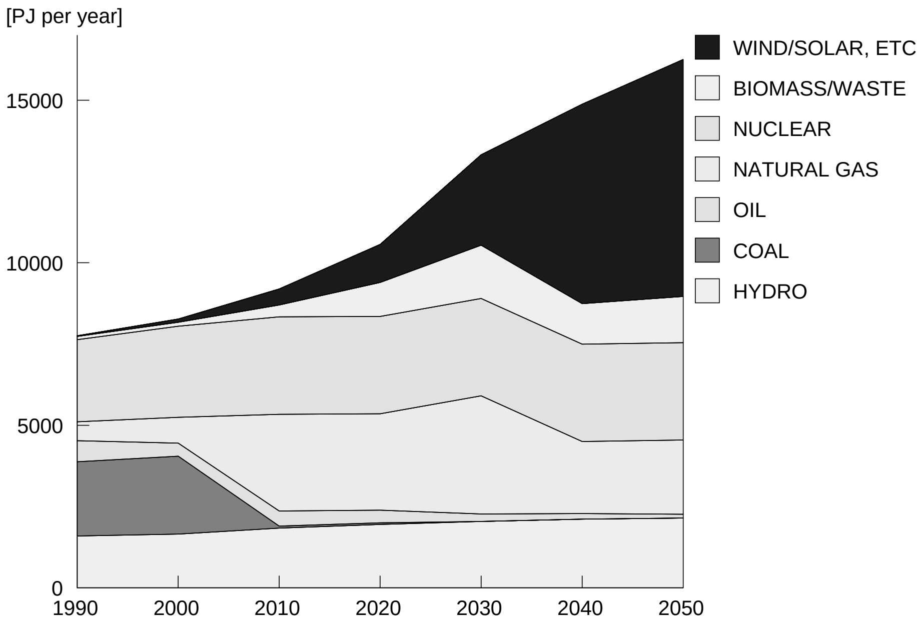

Figure 6.4 *Power generation 1990-2050, 200 ECU/ton CO_2 case RP*

Results of an ultimate carbon tax of 200 ECU/ton CO_2 are extreme indeed. The level of power production is high, and use of coal and oil is minimised, while that of CO_2-free power (nuclear, hydro and other renewables) is maximised. The (maximal) use of hydro and nuclear power and (minimal) use of coal fired power are unchanged. Gas fired power shows a peak in 2030, and a decline after that. Oil fired power is minimised from 2030.

Biomass fueled power generation peaks in 2030, and shows some decline after that. In 2050 biomass fueled power ends up at approx. 1,400 PJ/y. Utilisation of wind energy is maximised; off-shore wind is introduced as soon as 2010. In 2050 output from onshore and off-shore wind is more than 4,000 PJ/y. Solar power shows a fast growth around 2030. PV at lower latitudes (southern Europe) is used to fulfil demand in that area and for transmission to the middle of Europe. It seems to be cheaper to transmit PV based power from southern Europe to the middle of Europe than to produce power from PV in middle Europe. Solar power ends up at approx. 3,000 PJ/y in 2050. Output of renewables other than hydro increases to 54% of total power production.

6.2.2 Scenario MD

In the following, effects of carbon taxes for scenario MD are reported, starting from 20 ECU/ton CO_2, and ending with 200 ECU/ton CO_2. Graphic presentations for the main sources of power as a function of time are shown for the cases with carbon taxes of 20 and 100 ECU/ton CO_2.

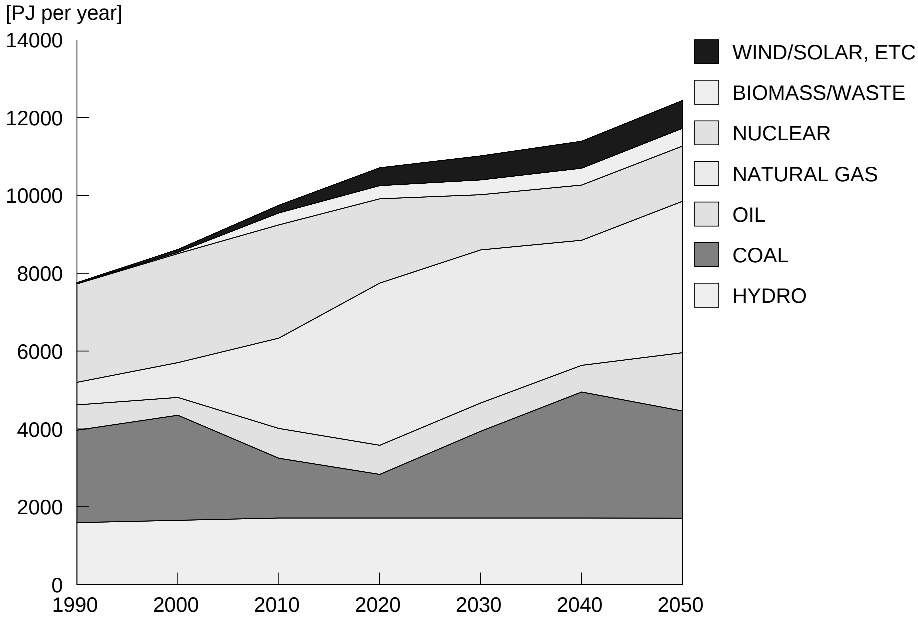

Figure 6.5 *Power generation 1990-2050, 20 ECU/ton CO_2 case MD*

With a carbon tax of 20 ECU/ton CO_2 a number of changes occur in the technology mix. Hydro power remains at its lower bound. The same holds for nuclear power. Hydro and nuclear power are not competitive due to the high interest rate in MD. Coal fired power is used at a much lower rate than in the reference scenario. However, it is not phased out for a number of decades as in the 20 ECU/ton CO_2 case for RP. It appears that coal fired power is more cost effective than nuclear power, if the carbon tax is low and the discount rate is high.

Gas fired power shows a surge until 2020; it remains rather stable after that. Use of oil fired power remains low. Biomass fueled power increases marginally. Wind energy becomes competitive in 2020, and increases steadily after that. Solar energy is not competitive due to the high interest rate. Output of renewables other than hydro increases from 5% of power production in the reference scenario to 9% in the 20 ECU/ton CO_2 case.

In case of a carbon tax of 50 ECU/ton CO_2, a number of changes occurs. Hydro and nuclear power become competitive from 2030 and 2020 respectively. Coal fired power is largely phased out in 2020. Gas fired power has a still higher penetration than for 20 ECU/ton CO_2. Oil fired power is essentially unchanged. Biomass fueled power and onshore wind energy become competitive as soon as 2010, and show a steady growth after that. Solar energy still suffers from the high interest rate. Output of renewables other than hydro increases to 13% of total power production.

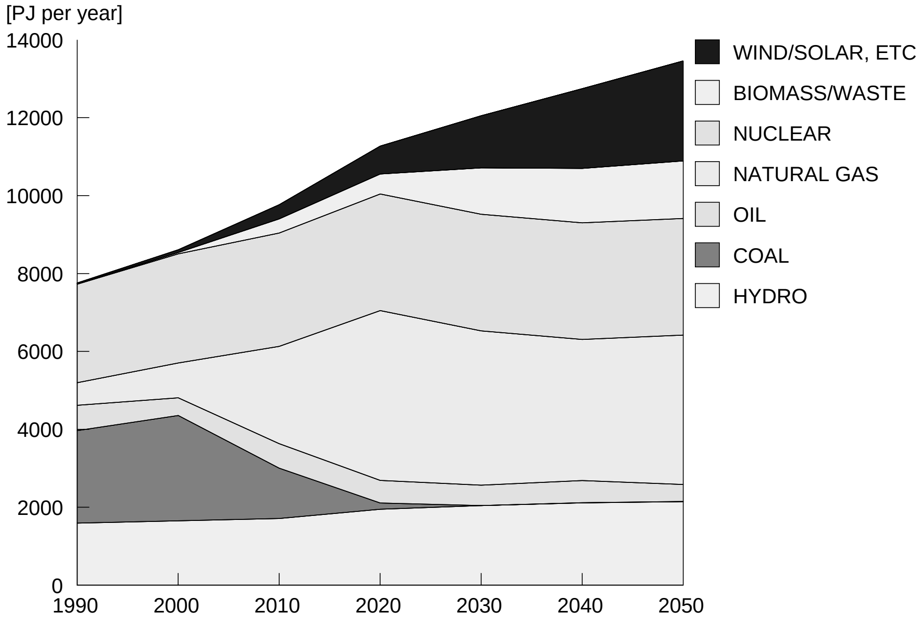

Figure 6.6 *Power generation 1990-2050, 100 ECU/ton CO_2 case MD*

If the carbon tax is as high as 100 ECU/ton CO_2, changes in the technology mix become rather extreme. Hydro power is maximised from 2020 and nuclear power from 2010. Coal fired power is phased out in 2020. Oil fired power is used to the lowest possible extent. Natural gas fired power shows a peak in 2020 and some decline towards 2050. Biomass fueled power increases fast until 2030, ending up at 2 EJ/y in 2050. Onshore wind energy also shows a high growth rate, reaching 2 EJ/y in 2050. Solar power becomes competitive in 2030 and shows a moderate growth. Output of renewables other than hydro increases to 30% of total power production.

In case of an ultimate tax level of 200 ECU/ton CO_2, changes in the generating mix become extreme. As has been explained in Section 6.2.1., at high carbon tax levels power production is much higher than in the original baseline projection, due to substitution of e.g. electric heat pumps for gas fired equipment. Hydro and nuclear power are maximised from 2010. Coal fired power is phased out in 2020, and oil fired power is minimised, while that of CO_2-free power options is maximised. Gas fired power peaks in 2010, and shows a falling trend after that. Biomass fueled power is surging until 2020, and is rather stable after that. Off-shore wind becomes competitive in 2010. Wind energy shows a high growth rate from 2020, and the ultimate level is approx. 4,000 PJ/y in 2050. Solar power is introduced in 2020, but the output in 2050 is the same as in the foregoing case. Output of renewables other than hydro increases to 45% of total power production.

6.3 Impact of increasing carbon taxes on clusters of technologies

6.3.1 Gas fired power

Gas fired power is favoured in many circumstances. In absence of carbon taxes, gas fired power is favoured up to 2020. If carbon taxes are in place gas fired power gets a higher competitive edge over coal fired power, and it remains competitive until really high carbon tax levels. The position of gas fired power is strongest for moderate carbon tax levels.

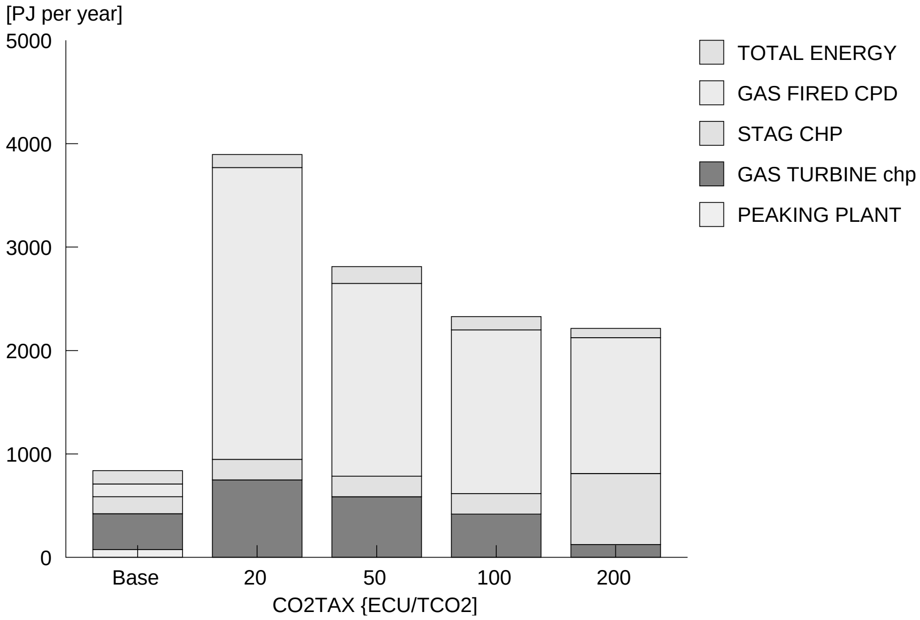

Figure 6.7 *Gas fired power in 2040 as a function of carbon tax, RP*

Note: CPD = Coupled Production, i.e. district heating
CHP = industrial Combined Heat and Power.

Output from gas fired power generally increases with rising CO_2 taxes, replacing the dwindling and eventually disappearing coal fired power (Figure 6.7). However, under demanding CO_2 tax conditions - a carbon tax of 50 ECU/ton CO_2 or more - gas fired power gradually looses its competitive edge over renewables, notably wind energy and biomass fueled power. Combined cycle power plants for district heating are highly competitive. Combined cycle plants for industrial CHP are second-best compared to gas turbine plants. At the ultimate tax level of 200 ECU/ton CO_2 combined cycle plants for CHP are favoured over gas turbine CHP plants.

The same trends can be observed in scenario MD (Figure 6.8). Gas fired power is competitive until stringent CO_2 taxes. Combined cycle plants for district heating are used to a large extent. At moderate carbon taxes gas turbine power plants are the main option for industrial CHP. From 100 ECU/ton CO_2 combined cycle plants for CHP are more cost effective.

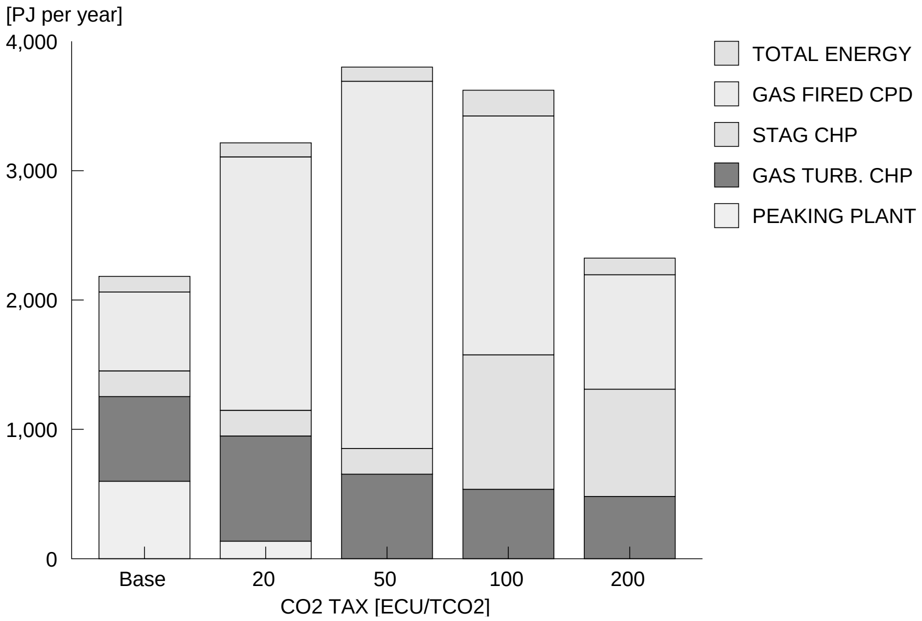

Figure 6.8 *Gas fired power in 2040 as a function of carbon tax, MD*

Note: CPD = Coupled Production, i.e. district heating
CHP = industrial Combined Heat and Power.

The gas fired power generation options are state-of-the-art. Particularly gas turbine CHP plants and combined cycle plants for district heating show high penetrations, even at relatively high carbon taxes. Some options offer room for improvement. Small, highly efficient gas turbines could succeed gas engines in the total energy market. Fuel cell technology is in the research and development stage (with a few demonstration plants in operation).

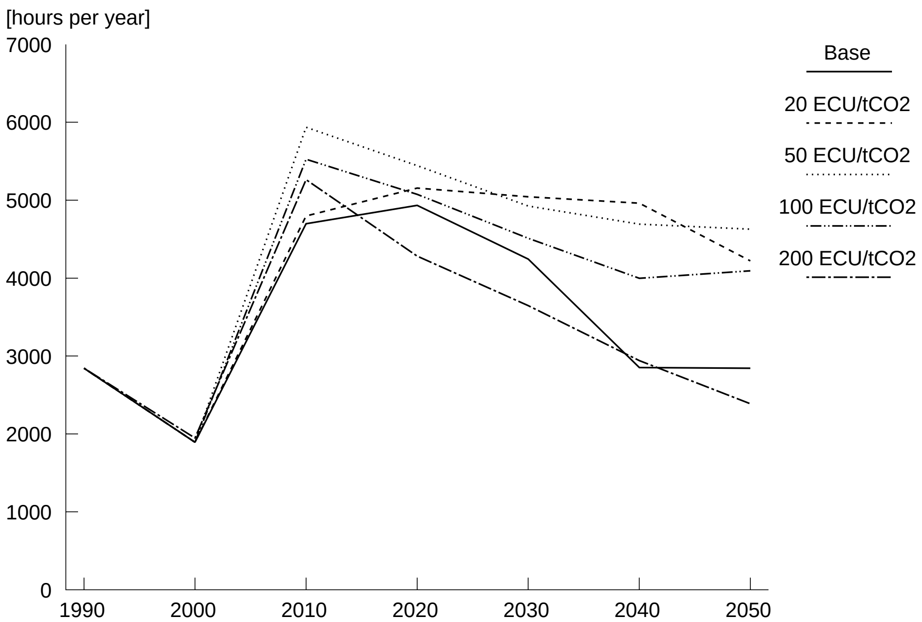

Figure 6.9 *Full load hours of gas fired power at various carbon tax levels, RP*

Renewable power (hydro, wind, biomass fueled power) can be absorbed by a technology mix with gas fired power to a certain extent. This is accomplished by adapting the output of such plants. As gas fired power is applied in industrial cogeneration and district heating, a high penetration of renewables has drawbacks for the operation of those plants. This has been partially accounted for, e.g. a lower load factor for district heating plants results in a correspondingly higher output from boilers used as back-up.

6.3.2 Coal fired power

Coal fired power is a very important option if carbon taxes are absent. If so, coal fired power will replace gas fired power in the last decades until 2050. Figure 6.1 showed that coal fired power first looses its market share at a carbon tax of 20 ECU/ton CO_2 (scenario RP), and then makes a come-back in 2050. This is due to the widening gap between coal and gas prices. At the high interest rate (15%) of scenario MD coal fired power is favoured over nuclear power at a modest carbon tax level (20 ECU/ton CO_2).

Figure 6.10 emphasises that coal fired power is very vulnerable to carbon taxes. IGCC power plants are competitive in the reference RP and MD scenarios. The higher efficiency of such plants offsets the higher investment costs. However, even at the lowest tax level considered (20 ECU/ton CO_2), such power plants are only competitive compared to gas fired options, if the discount rate is high (scenario MD), or if the gap between coal and gas prices has widened sufficiently (year 2050, scenario RP).

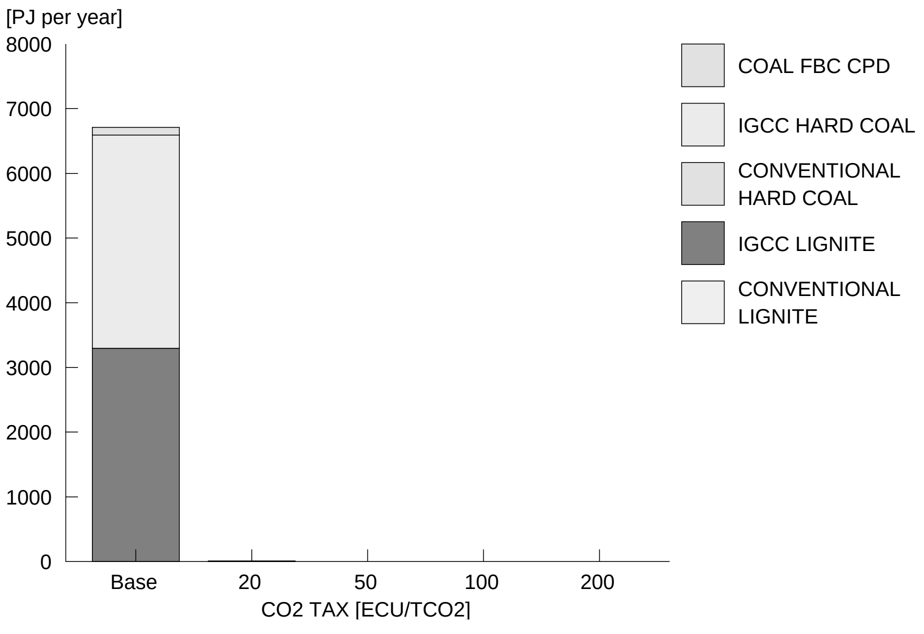

Figure 6.10 *Coal fired power in 2020 as a function of carbon tax, RP*

It has been shown in Section 5.4.2. that lignite fired power is phased out in the reference MD scenario, while hard coal fired IGCC remains competitive. This is due to the high discount rate in scenario MD. Generally, lignite fired power will be more vulnerable to carbon taxes than power plants based on hard coal. This is because of the higher level of CO_2 emission per GJ of lignite compared to hard coal. As a consequence, lignite fired power will be phased out soon in case of a relatively low carbon tax, also if the discount rate is low (scenario RP).

6.3.3 Renewables

Output from renewables shows a rapid expansion with increasing carbon taxes. Onshore wind energy becomes competitive in the baseline projection of RP, just as biomass fueled power. Results for increasing carbon tax levels in case of scenario RP are as follows. With increasing carbon taxes wind energy and biomass fueled power are applied on a larger and larger scale. Solar power becomes competitive at a tax level of 50 ECU/ton CO_2 (in 2030), at least at lower latitudes (southern Europe), and off-shore wind energy at a level of 100 ECU/ton CO_2. In case of the ultimate carbon tax of 200 ECU/ton CO_2, solar power is also used for transmission to the middle of Europe. It seems to be cheaper to transport PV based power in southern Europe to the middle of Europe than to install PV at higher latitudes.

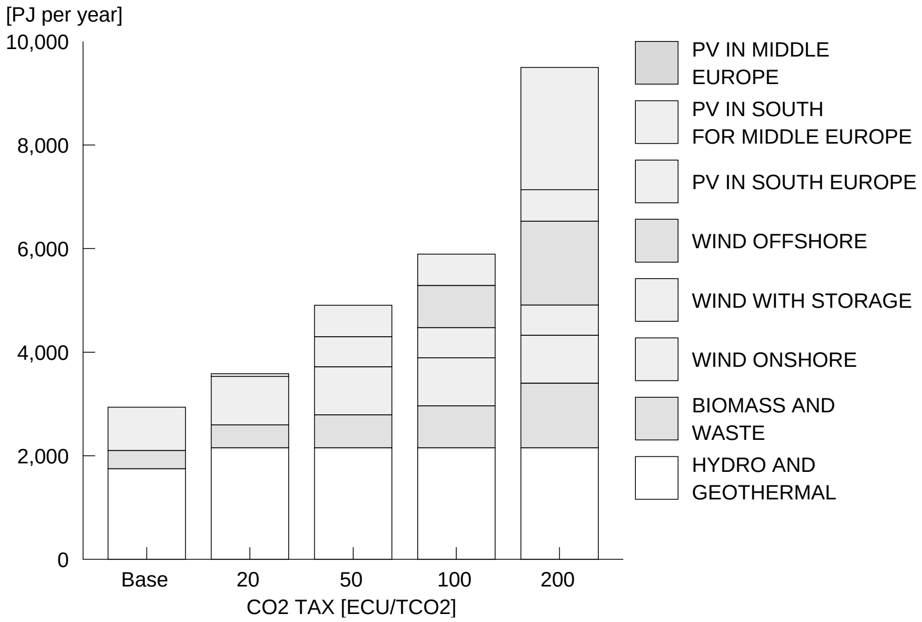

Figure 6.11 *Renewable power in 2040 as a function of carbon tax, RP*

In the baseline projection of scenario MD biomass fueled power is competitive, but wind energy not. This is due to the high interest rate (wind energy is more capital intensive than biomass fueled power). Generally, onshore and off-shore wind energy as well as solar power become competitive at higher carbon tax levels than in scenario RP.

At high penetrations of renewables, e.g. in case of a carbon tax of 100 ECU/ton CO_2, pumped storage should be added to the power plant mix in order to cope with fluctuations from wind and solar power. For wind energy this has been accounted for: two categories of onshore wind have been defined, the second of which is combined with pumped storage capacity. For off-shore wind, which is more expensive than onshore wind and therefore becomes competitive at a later stage, the same proportion between wind capacity and pumped storage capacity has been assumed.

6.4 Effect of increasing carbon taxes for a relaxed attitude towards nuclear power and CO_2 capture

6.4.1 Changes between clusters

A relaxed attitude towards nuclear power, acceptance of CO_2 capture and disposal at some fossil fuel based options, and a higher upper bound for solar power at lower latitudes (southern Europe) widens the scope of optimisation. In Figure 6.11 the optimisation results for the generating mix are presented. It shows the results under ‘normal’ conditions and under relaxed conditions for nuclear power and CO_2 capture for each of the carbon tax levels.

A carbon tax of 20 ECU/ton CO_2 results in remarkable differences. Hydro power is maximised, just as in case of ‘normal’ conditions. Nuclear power increases with some 50% compared to ‘normal’ conditions, mainly at the expense of gas fired power. Output of coal fired power is rather insignificant, just as under ‘normal’ conditions. Output of wind turbines and biomass fueled power does not show any change. Solar power is not cost effective in this case.

At the carbon tax level of 50 ECU/ton CO_2, the output from nuclear power is boosted with more than 50% up to its perceived maximum. Some coal fired power remains in place, as opposed to ‘normal’ conditions, because CO_2 capture and disposal is considered feasible. Output from gas fired power decreases considerably. Output of biomass fueled power remains the same. Wind energy is used at about the same rate as under 20 ECU/ton CO_2, and at a lower rate than under ‘normal’ conditions. Also output from solar power is lower.

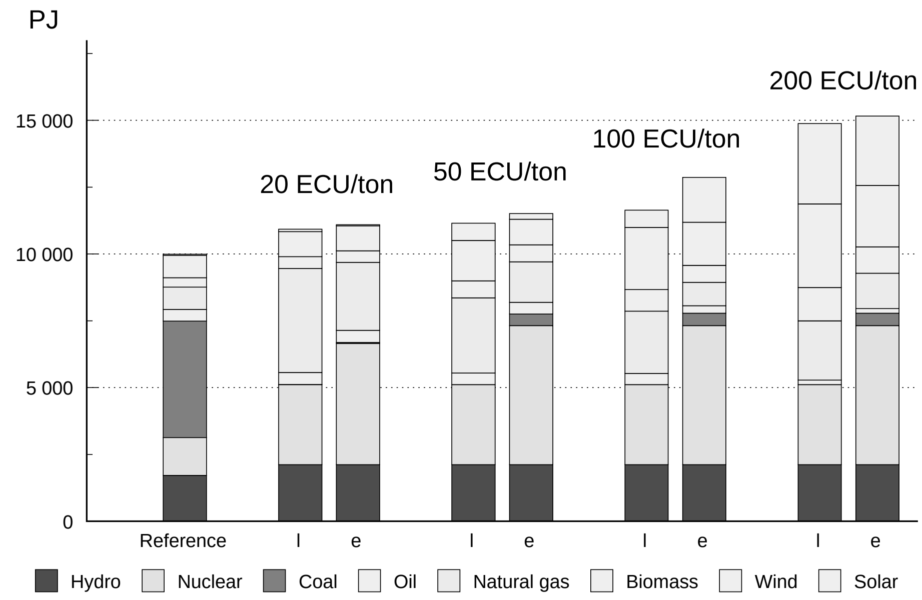

Figure 6.12 *Power generation mix in 2040 as a function of carbon tax, RP with or without relaxed attitude towards nuclear power, etc.*[1]

1 L = Limited (with constraints), E = Extended (with relaxed constraints).

In case of a carbon tax of 100 ECU/ton CO_2 changes compared to the case with a tax of 50 ECU/ton CO_2 are limited. The output from hydro power, nuclear power and coal fired power is (essentially) the same in both cases. Output from 'new' renewables, notably solar power and wind energy increases, mainly at the expense of gas fired power. If we compare the 'unbounded' 100 ECU/ton CO_2 case with the same case under 'normal' conditions, we observe a slightly lower output from oil fired power, a considerably lower output from gas fired power, and lower outputs for biomass fueled power and wind turbines. However, output from solar power is higher than under 'normal' conditions; this is because the upper level of solar power is higher than under 'normal' conditions.

At the ultimate carbon tax of 200 ECU/ton CO_2 the differences compared to the 100 ECU/ton CO_2 case are limited. Gas fired power is used to a slightly higher extent, just as biomass fueled power, wind energy, and solar power. The differences between the 'unbounded' case of 200 ECU/ton CO_2 and 'normal' conditions mainly apply to nuclear power, gas fired power, and 'new' renewables. Nuclear power is at its perceived maximum, whereas output from gas fired power is substantially lower. Output from biomass fueled power, wind turbines, and solar power is lower too.

6.4.2 Gas fired power

Gas fired power becomes the most important single source of power, if carbon taxes are imposed under 'normal' conditions. In case of a relaxed attitude towards nuclear power, acceptance of CO_2 capture and disposal at some fossil fuel based options, and a higher upper bound for solar power at lower latitudes (southern Europe), gas fired power is less dominant because of a larger capacity of nuclear power. The differences for each of the technologies are shown in Figure 6.13.

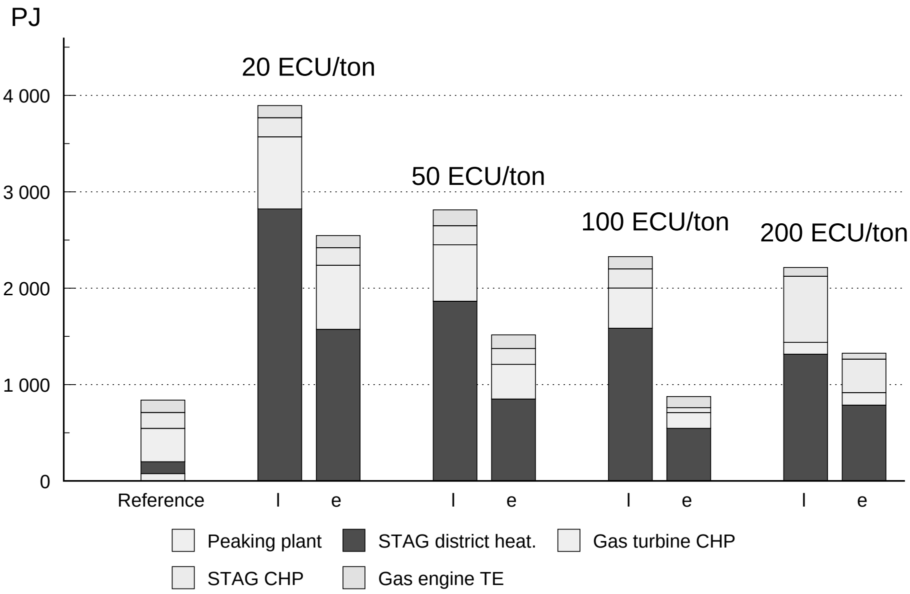

Figure 6.13 *Gas fired power in 2040 as a function of carbon tax, RP with or without relaxed attitude towards nuclear power, etc.*[1]

1 L = Limited (with constraints), E = Extended (with relaxed constraints).

It proves that all of the gas fired technologies are applied at a lower rate in case of a relaxed attitude towards nuclear power. Power production from most of them is roughly halved compared to ‘normal’ conditions, except for gas engines (total energy) which are more or less stable. At the ultimate carbon tax of 200 ECU/ton CO_2 the most efficient technologies - combined cycles for district heating and for industrial CHP - have a larger market share than at a lower tax level.

6.4.3 Coal fired power

Figure 6.14 shows the differences between the ‘unbounded’ CO_2 reduction cases of scenario RP compared to the same set of carbon tax cases for ‘normal conditions.

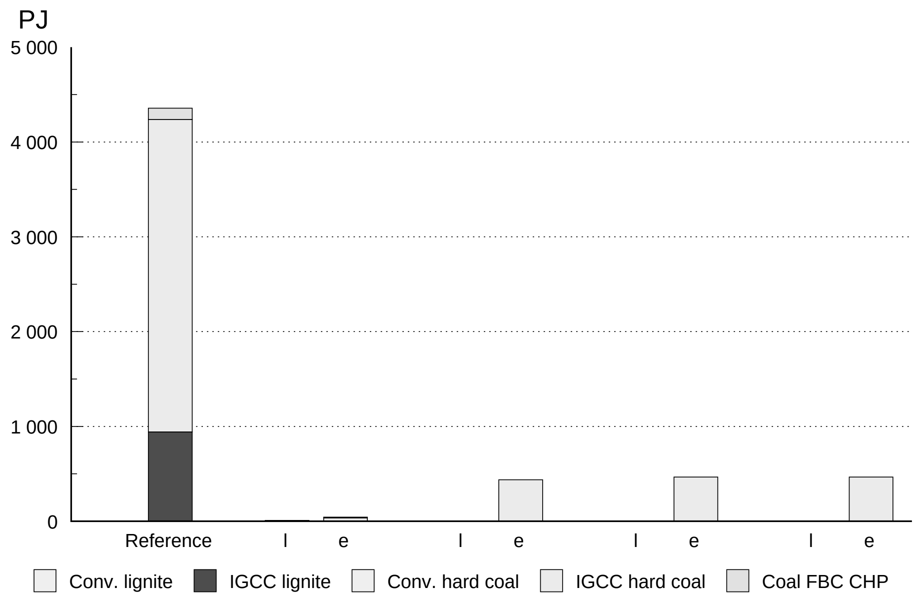

Figure 6.14 *Coal fired power in 2040 as a function of carbon tax, RP with or without relaxed attitude towards nuclear power, etc.*[1]

1 L = Limited (with constraints), E = Extended (with relaxed constraints).

From Figure 6.14 it can be concluded that coal fired power (IGCC based on hard coal) remains a competitive option from carbon tax levels of 50 ECU/ton CO_2, because CO_2 capture is considered feasible. At these carbon tax levels nuclear power is used at its perceived maximum.

6.4.4 Renewables

Figure 6.15 shows the differences between the 'unbounded' CO_2 reduction cases compared to 'normal' conditions for the same carbon tax levels.

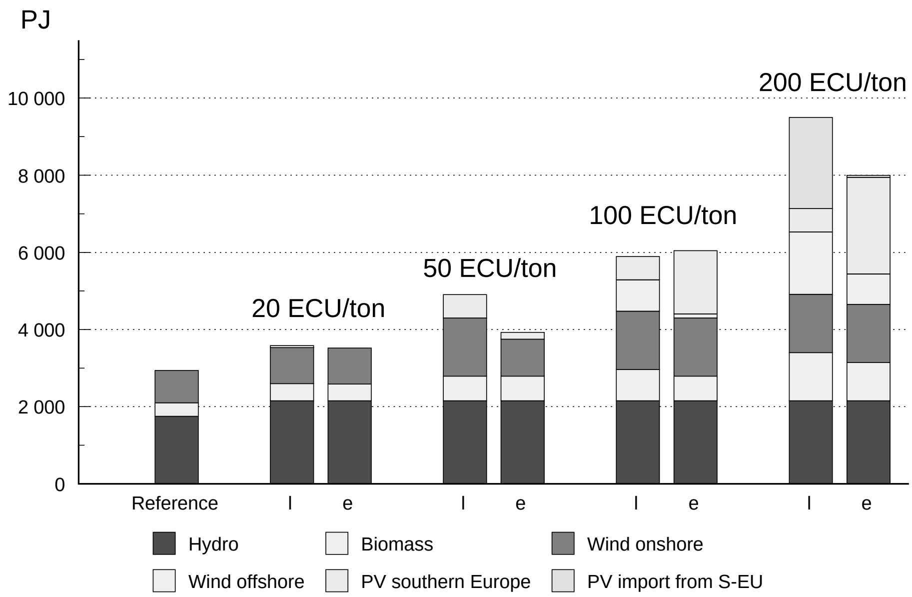

Figure 6.15 *Renewable power in 2040 as a function of carbon tax, RP with or without relaxed attitude towards nuclear power, etc.*[1]

1 L = Limited (with constraints), E = Extended (with relaxed constraints).

Differences for 20 ECU/ton CO_2 are negligible. At a carbon tax of 50 ECU/ton CO_2 output from onshore wind energy and solar power is lower than under 'normal' conditions, due to the higher contribution from nuclear power. At 100 ECU/ton CO_2 off-shore wind is used at a much lower level; however, solar power in southern Europe is used to a higher extent, which is consistent with the assumption in this case. At the ultimate carbon tax of 200 ECU/ton CO_2, the output from off-shore wind energy is lower; under 'normal' conditions a considerable amount of power from PV in southern Europe is transmitted to the middle of Europe, whereas in the 'unbounded' case almost all of PV is produced and used in southern Europe.

7. DISCUSSION

7.1 Introduction

The results of scenarios presented before are based on perfect foresight, which is hardly available in the real world, and certainly not for the time frame considered. The availability of fossil fuels is supposed to be ample, and demand is only curtailed by the fuel price: if the fuel price reaches a threshold value, a more efficient technology in the transformation process or at the end use level is used. However, very high levels of fuel input, e.g. natural gas imported from non-EU countries, could be difficult to realise. Or, the natural gas price corresponding to really high levels of consumption could be higher than has been assumed in this study.

For a number of power generation options significant cost reductions have been observed in the past. This holds for coal fired power plants and even more for gas fired power options (combined cycle plants, gas turbine CHP plants, gas engine Total Energy plants). Such cost reductions have been taken into account. However, it is difficult to predict if further cost reductions can be achieved. Therefore, the cost of equipment in recent years has been used as benchmark, except for technologies in the development stage (wind energy, solar power, etc.).

For nuclear power and renewables corresponding remarks can be made. Nuclear power has to deal with political obstacles in several countries. The bounds considered in this report could be representative of a somewhat divided Europe, with some nations committed to nuclear power and some other not. A relaxed attitude towards nuclear power (and acceptance of CO_2 capture and disposal, as well as a higher upper bound for solar power in southern Europe) should be regarded as an exception.

Perspectives for renewables are not very clear, because of implementation difficulties (wind turbines could cause visual intrusion) or poor economics (e.g. photovoltaic power). However, the costs and capacities assumed here are more or less representative of current views on these technologies.

In Section 7.2 the optimisation results of the reference scenarios are evaluated. Section 7.3 evaluates the cases with carbon taxes ('normal' conditions). The results of optimisations with a relaxed attitude towards nuclear power, etc., are discussed in Section 7.4. Finally, in Section 7.5 a summary of the results for different technologies is presented.

7.2 Optimisation without carbon taxes

Coal fired power is very important if carbon taxes are absent. If so, coal fired power will replace gas fired power to a large extent in the decades towards 2050, irrespective of the discount rate. Output from gas fired power trebles until 2020. After that it looses market share to renewables and coal fired power.

Neither additional hydro power, nor additional nuclear power is cost effective in the reference RP and MD scenarios. These major CO_2 free options are marginally more expensive than gas and coal fired power.

Biomass fueled power is marginally competitive in both of the reference scenarios. Wind energy becomes competitive in 2010 in the reference RP scenario, but it is not cost effective at the high interest rate (15%) presumed in the reference MD scenario. Off-shore wind energy and solar power are not competitive without CO_2 constraints.

7.3 Optimisation with carbon taxes

The optimisation results will be discussed for moderate carbon taxes (20 to 50 ECU/ton/CO_2) and for high carbon taxes (100 to 200 ECU/ton CO_2).

Moderate carbon taxes

The results for moderate carbon taxes are not so much different from the baseline projections. However, one of the most remarkable results is that coal fired power is rather vulnerable to even modest carbon taxes.

If a carbon tax of 20 ECU/ton CO_2 is imposed, gas fired power is favoured. The same holds for hydro power and nuclear power, if the discount rate is low. Coal fired power (IGCC) shows a comeback around 2050 in that case. If the discount rate is high (scenario MD), IGCC based on hard coal is favoured over (more capital intensive) nuclear power. Thus, IGCC based on hard coal (and lignite, if the discount rate is low) could be a strategic investment option, if the carbon tax does not exceed 20 ECU/ton CO_2.

Hydro and nuclear power become competitive at 20 ECU/ton CO_2, if the discount rate is low (scenario RP). At a high discount rate (scenario MD) the threshold value is about 50 ECU/ton CO_2. Wind turbines and biomass fueled power are competitive in the reference RP scenario. Under moderate carbon tax levels the prospects for such technologies are good. At a carbon tax of 50 ECU/ton CO_2 solar power at lower latitudes (southern Europe) becomes competitive. However, off-shore wind energy seems to need a still higher carbon tax.

For moderate carbon taxes (20 to 50 ECU/ton/CO_2) a portfolio with Research, Development & Demonstration (RD&D) on both technologies for efficient conversion of fossil fuels, e.g. IGCC, and renewable technologies seems adequate. Onshore wind energy, biomass fueled power, and solar power in southern Europe would become competitive under such circumstances.

High carbon taxes

A carbon tax of 100 ECU/ton CO_2 is regarded as high. The results of optimisations show that changes in the power generation mix would be rather extreme. For a tax of 200 ECU/ton CO_2 results would be extreme indeed. Therefore, the latter carbon tax level can be disregarded.

Coal fired power is far from economic under a carbon tax of 100 ECU/ton CO_2. The opposite is true for hydro power and nuclear power. The competitive edge of gas fired power over 'new' renewables dwindles. If such renewables (onshore and off-shore wind energy, biomass fueled power, photovoltaic power) could be made available on a large scale, the shifts in the power generation mix could be dramatic: 'new' renewables could capture 37% of the market in 2050 in case of scenario RP, and 30% in case of scenario MD. Off-shore wind energy would become economically viable.

A carbon tax of 100 ECU/ton CO_2 could be justified, if there would be a widespread believe that stringent CO_2 reduction is needed to prevent global climatic changes. Consequently, coal fired power would be phased out rapidly. Gas fired power and (possibly) nuclear power would fill the gap at first, and 'new' renewables would be added in the period until 2050.

Such a scenario would require an RD&D portfolio for very efficient fuel conversion processes (based on natural gas) and for a number of renewables, including photovoltaic power and off-shore wind energy.

7.4 Sensitivity analysis

A case with a relaxed attitude towards nuclear power is not representative of current conditions in Western Europe. The results of this sensitivity analysis show some characteristic differences compared to 'normal' conditions. Nuclear power would be the power generation option of choice. There would be some scope for coal fired power with CO_2 capture and geological disposal. Expansion of nuclear power would be mostly at the expense of gas fired power and 'new' renewables. 'New' renewables would be used at a lower rate or introduced at higher carbon taxes. Solar power in southern Europe would be applied on a larger scale if the upper bound would be higher (one of the assumptions of this sensitivity analysis).

7.5 Summary of findings

The results of various optimisations for a number of representative power generation technologies are summarised in Table 7.1.

Power generation based on natural gas seems to be rather robust from the current point of view: technologies like combined cycle power plants for district heating and gas turbines for industrial CHP are used on a large scale, both under 'tax-free' conditions and with moderate carbon taxes. There seems to be room for more efficient technologies (fuel cells), although such technologies have not been tested in the model runs.

Coal fired power is rather vulnerable to carbon taxes. However, highly efficient technologies like IGCC could remain competitive at a carbon tax level of 20 ECU/ton CO_2. Such advanced coal technologies seem to offer more perspective than less efficient pulverised coal fired power plants.

Hydro power and nuclear power are marginally more costly than gas fired power and coal fired power. However, they become competitive at moderate carbon tax levels. Large scale application of nuclear power depends on political constraints.

Onshore wind energy and biomass fueled power are the most competitive 'new' renewables. They could become cost effective, even without carbon taxes. For solar power in southern Europe a carbon tax level of 50 ECU/ton CO_2 is needed, and for off-shore wind energy a level of 100 ECU/ton CO_2. Such technologies would be indispensable if a large CO_2 reduction would be required.

Table 7.1 *Summary of optimisation results for various technologies*

Technology	Reference scenario	Carbon tax	Remarks
Combined cycle for district heating	++	++	favoured by modest carbon tax
Gas turbine for industrial CHP	++	++	favoured by modest carbon tax
Combined cycle for industrial CHP	+	+	generally less economic than gas turbine CHP
Conventional coal fired power	-	-	less economic than IGCC
IGCC	++	+/-	vulnerable to carbon tax
Hydro power	-	++	needs modest carbon tax
Nuclear power	-	++	needs modest carbon tax; deployment dependent on political constraints
Onshore wind	+	++	favoured by modest carbon tax
Off-shore wind	-	+	needs high carbon tax
Biomass fueled power	+	++	favoured by modest carbon tax
PV southern Europe	-	+	needs high carbon tax
PV middle Europe	-	-	less economic than PV in southern Europe

8. CONCLUSIONS

Various conditions for power generation in Western Europe towards 2050 are considered and tested with a MARKAL model adapted for Western Europe (EU countries, Norway, Iceland, and Switzerland). A number of options for power generation are selected. At first, reference scenarios without carbon taxes are considered. Secondly, moderate carbon taxes from 20 to 50 ECU/ton CO_2 and high taxes from 100 to 200 ECU/ton CO_2 are taken into account for both scenarios. Finally, as a sensitivity analysis, CO_2 reduction cases are considered with a relaxed attitude towards nuclear power, acceptance of CO_2 capture and disposal, and a higher upper bound for solar power in southern Europe.

If no carbon tax is imposed, gas fired power and coal fired power are the main power options. Gas fired power is favoured by the relatively low gas prices in the first decades of the next century. It expands dramatically, mainly at the expense of nuclear power and coal fired power. The main technologies are combined cycle plants for district heating and gas turbine plants for industrial CHP. These technologies remain economically viable until high carbon tax levels. Coal fired power becomes more competitive in the last decades until 2050, at the expense of gas fired power. IGCC based on hard coal seems to be more economic than pulverised coal fired power. Hydro power and nuclear power are marginally more costly than gas and coal fired power under such conditions.

Some renewables other than hydro could become competitive, even if no carbon tax is imposed, such as biomass fueled power and wind turbines. However wind energy is not competitive at the high discount rate (15%) in scenario MD. Some other renewable options are not competitive without carbon taxes: off-shore wind energy and solar power.

A modest carbon tax of 20 ECU/ton CO_2 would cause a substantial shift in the power technology mix. If the discount rate is low (5%), hydro power and nuclear power would become competitive. For the higher discount rate (15%) the threshold value is 50 ECU/ton CO_2. Coal fired power would be phased out for some decades in scenario RP, but it would show a comeback in 2050, when the gap between coal and gas prices has become wide enough for coal fired power to compete with gas fired power. At the high discount rate coal fired power remains favoured over nuclear power up to 50 ECU/ton CO_2. It can be concluded that IGCC based on hard coal or lignite could be a strategic investment option, if the carbon tax does not exceed 20 ECU/ton CO_2.

The scope for 'new' renewables is expanded under conditions of moderate carbon taxes. Solar power at lower latitudes would become competitive at 50 ECU/ton CO_2. Off-shore wind energy would remain uneconomic. A strategy for moderate CO_2 reduction would require an RD&D portfolio based on highly efficient fuel conversion technologies (e.g. IGCC) and renewables (wind energy, biomass fueled power, photovoltaic power).

A carbon tax of 100 ECU/ton CO_2 would need a widespread consensus about the need for drastic CO_2 reduction to prevent global climatic changes. In that case the power generation mix could change dramatically. Coal fired power would be phased out rapidly. Hydro and (possibly) nuclear power would be expanded rapidly. Biomass fueled power, onshore and off-shore wind energy, and solar power in southern Europe would be introduced on a large scale. From the current perspective a carbon tax of 100 ECU/ton CO_2 is really high, and the changes occurring in the power generation mix are rather extreme. A strategy for stringent CO_2 reduction would require an RD&D portfolio based on highly efficient conversion technologies for natural gas, as well as a number of renewables, including photovoltaic power and off-shore wind energy.

For reasons of sensitivity analysis, cases with a relaxed attitude towards nuclear power, acceptance of CO_2 capture and disposal, and a higher upper bound for solar power in southern Europe, are considered. Nuclear power would become the power option of choice under such circumstances. Some coal fired power would be economically viable at a carbon tax of 50 ECU/ton CO_2 or more, as CO_2 capture and geological disposal is considered feasible. At such carbon tax levels nuclear power is already applied at its perceived maximum. Generally, ‘new’ renewables would be used at a lower rate or introduced at higher carbon taxes.

ANNEX A

Pulverised coal fired power plant

A large proportion of European electricity demand is met by coal fired power plants. Until a few years ago coal fired power plants had generating efficiencies of 40%. Today Ultra supercritical Steam Conditions (USC) enable efficiencies of 45% and more. The potential for efficiency improvement and the investment costs will be elucidated in brief, first for USC boilers and then for Integrated Coal Gasification Combined Cycle (ICGCC).

In Denmark a 385 MW_e coal fired power plant with USC boiler was commissioned in 1992 [1] [2]. Steam conditions (250 bar/560°C/560°C) applied and a net generating efficiency of 45% can be considered as state-of-the-art today [3] [4]. The next coal fired power plant in Denmark will have steam conditions of 290 bar/580°C/580°C and a net efficiency of 47.5% [1,3] [5]. Efficiencies of 55% are predicted for year 2010 [3].

Coal fired power plants with USC boilers are assumed to have efficiencies of 48% at full load and 46% on an annual basis in the year 2000. For 2020 a net efficiency on annual basis of 47.5% is assumed. Investment costs of coal fired power plants with supercritical and ultra supercritical steam conditions are about equal up to 45% efficiency [6]. In the Netherlands investment costs of coal fired power plants are about NLG 2,200/kW_e (ECU 1,050/kW_e). In Germany they range from DM 2,000/kW_e (ECU 1,050/kW_e) to DM 2,800/kW_e (ECU 1,500/kW_e) [7] [8]. The lowest figure for USC boilers is $ 1,400/kWe, equivalent to ECU 1,200/kW_e [9]. A representative investment cost figure for coal fired power plants with USC boilers is ECU 1,290/kW_e (NLG 2,700/kW_e) [10].

Generating efficiencies and investment costs are generally based on the 'SYRENE study' of ECN, KEMA, Dep. of Science, Techn. & Soc. University Utrecht on behalf of NOVEM (see for instance [11] and [12]). Upon request additional information on costs and efficiencies has been provided by Sep (N.V. Samenwerkende Elektriciteits-produktiebedrijven).

Table A.1: *Pulverised coal fired power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	36.0	46.0	47.5	48.0
District heating: - Electric [%]	33.8	43.3	44.7	45.2
- Thermal [%]	13.5	17.3	17.8	18.0
- Exergetic [%]	36.9	47.2	48.7	49.3
Investment cost [ECU_{1995}/kW_e]	1,290	1,290	1,290	1,290
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	37	37	37	37
- Variable [ECU/GJ_e]	0.26	0.26	0.26	0.26
Life [yr]	30	30	30	30
NO_x-emission [g/GJ]	300	250	200	170
SO_2-emission [g/GJ]	60[1]	60	60	60
Minimum potential [GW_e]	115.79	105.75	11.04	
Maximum potential [GW_e]	115.80	110.00		

[1] Based on 92% desulphurisation, 1% sulphur, 26.5 GJ/ton.

Integrated Coal Gasification Combined Cycle

Integrated Coal Gasification Combined Cycle (ICGCC) technology is in the demonstration stage: in the Netherlands a 253 MW_e plant has been commissioned at Buggenum, and in Spain a 315 MW_e plant is in the commissioning stage at Puertollano. Considering the potential of gas turbine development and of high-temperature gas cleaning, efficiencies could be boosted from 43-46% today to some 50% around year 2000, with development potential up to 55% around 2010 [13]. ICGCC plants offer lower emissions of SO_2 and NO_x than conventional coal fired plants. Due to their higher complexity, investment costs of ICGCC plants are higher than for pulverised coal fired power plants.

Investment cost estimations of an ICGCC range from ECU 1,330/kW_e (NLG 2,800/kW_e) in the Netherlands to $ 1,680/kW_e (ECU 1,430/kW_e) in Denmark [11]. ICGCCs are assumed to be available from year 2000. The generating efficiency is estimated at 50% at full load and 48% on an annual basis in year 2000. The year average net efficiency could increase to 52% in 2040. Investment costs are estimated at ECU 1,380/kW_e (NLG 2,900/kW_e).

Table A.2: *Coal fired IGCC*	New capacity			
	1990	2000	2020	2040
Year average net efficiency [%]		48.0	51.0	52.0
District heating: - Electric [%]		42.4	45.2	46.1
- Thermal [%]		34.5	36.7	37.4
- Exergetic [%]		50.2	53.4	54.5
Investment cost [ECU_{1995}/kW_e]		1,380	1,380	1,380
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]		31	31	31
- Variable [ECU/GJ_e]		0.3	0.3	0.3
Life [yr]		30	30	30
NO_x-emission [g/GJ]		50	50	50
SO_2-emission [g/GJ]		7[1]	7	7
Minimum potential [GW_e]		0.6	0.6	
Maximum potential [GW_e]		4.0	90.0	

1 Based on 99% desulphurisation, 1% sulphur, 26.5 GJ/ton.

Lignite fired power plant

Lignite is a major fuel for power generation in Germany, and to a lesser extent in Greece and Spain. Efficiency can be boosted by conventional technology with USC boilers, or by ICGCC technology. Investment costs of lignite fired power plants range from DM 2,690/kW_e (ECU 1,430/kW_e) to DM 3,260/kW_e (ECU 1,740/kW_e) [14] [15]. The generating efficiency of a lignite fired power plant with USC boiler is estimated at 44% on an annual basis in 2000, rising to 46% in 2040. Investment costs are estimated at ECU 1,550/kW_e (NLG 3,250/kW_e).

Table A.3: *Lignite fired power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	35.0	44.0	45.5	46.0
Investment cost [ECU_{1995}/kW_e]	1,550	1,550	1,550	1,550
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	37	37	37	37
- Variable [ECU/GJ_e]	0.26	0.26	0.26	0.26
Life [yr]	30	30	30	30
NO_x-emission [g/GJ]	300	250	200	170
SO_2-emission [g/GJ]	60	60	60	60
Minimum potential [GW_e]	38.69	29.90	4.35	
Maximum potential [GW_e]	38.70	29.92		

Lignite fired ICGCCs are assumed to have a generating efficiency of 46% on an annual basis in year 2000, rising to 50% in 2040. Investment costs are estimated at ECU 1,600/kW_e (NLG 3,360/kW_e).

Table A.4: *Lignite fired IGCC*	New capacity			
	1990	2000	2020	2040
Year average net efficiency [%]		46.0	49.0	50.0
Investment cost [ECU_{1995}/kW_e]		1,600	1,600	1,600
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]		31	31	31
- Variable [ECU/GJ_e]		0.3	0.3	0.3
Life [yr]		30	30	30
NO_x-emission [g/GJ]		50	50	50
SO_2-emission [g/GJ]		7	7	7

Minimum potential [GW_e]		0.25	0.25
Maximum potential [GW_e]		1.0	30.0

Oil fired power plant

A relatively small part of electricity in Europe is produced by oil fired power plants. Oil fired power plants are mainly used for peak or medium load. The drive for higher efficiencies will be less pronounced compared to power plants fired with hard coal or lignite, as their relatively low load factor does not leave room for higher investment costs. However, oil prices are high compared to prices of hard coal and lignite.

Efficiency of oil fired power plant can be boosted by conventional technology with USC boilers, or by ICGCC technology. It is assumed that the efficiency of new oil fired power plants with USC boilers will be 47% at full load and 45% on an annual basis in 2000. The same efficiency could easily be reached with IGCC technology based on residual oil. Investment costs are estimated at ECU 860/kW_e (NLG 1,800/kW_e).

Table A.5: *Conventional oil fired power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	37.0	45.0	45.0	45.0
Investment cost [ECU_{1995}/kW_e]	860	860	860	860
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	24	24	24	24
- Variable [ECU/GJ_e]	0.26	0.26	0.26	0.26
Life [yr]	30	30	30	30
NO_x-emission [g/GJ]	300	250	200	170
SO_2-emission [g/GJ]	35[1]	35	35	35
Minimum potential [GW_e]	67.33	46.87	1.36	
Maximum potential [GW_e]	67.34	46.88		

1 Based on 92% desulphurisation, 1% sulphur, 42.6 GJ/ton.

The IGCC technology developed for coal fired power plants (hard coal and lignite) has been applied in an earlier stage for residual oil, for instance by Texaco and Shell oil gasification processes. IGCC power plants based on residual oil are mainly used for cogeneration at refineries. There is much resemblance between oil based IGCC and coal based IGCC. One of the differences is the amount of oxygen needed: this amount is higher for coal than for residual oil. Investment costs are lower for oil based IGCC than for coal based IGCC. Oil based IGCC has been modeled with a fixed ratio between power an heat (high pressure steam). Therefore, investment costs and operation and maintenance costs are lower than for an oil based IGCC with condensing mode operation.

Table A.6: *Oil fired IGCC for CHP*	New capacity			
	1990	2000	2020	2040
Year average net efficiency [%]		46.0	52.0	54.0
CHP mode: - Electric [%]		36.0	40.7	42.3
- Thermal [%]		26.0	29.4	30.6
- Exergetic [%]		48.6	54.7	57.1
Investment cost [ECU_{1995}/kW_e]		1,520	1,520	1,520
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]		29	29	29
- Variable [ECU/GJ_e]		0.1	0.1	0.1
Life [yr]		25	25	25
NO_x-emission [g/GJ]		50	50	50
SO_2-emission [g/GJ]		17[1]	17	17
Minimum potential [GW_e]				
Maximum potential [GW_e]				

1 Based on 98.5% desulphurisation, 2.5% sulphur, 42.6 GJ/ton.

Conventional gas fired power plant

Gas fired power plants built in the seventies were based on conventional steam technology (supercritical steam conditions). Some ten years ago combined cycle technology entered the scene and became state-of-the-art. The latter type of power plant will be addressed in the following as ‘STAG power plant’ (STAG = STean And Gas turbine). First conventional power plants and power plants repowered with gas turbines are addressed.

Conventional steam power plants on natural gas generally have generating efficiencies of some 40%. Power plants repowered with gasturbines have generating efficiencies of 44-46%. It is not foreseen that any additional capacity of this type will be built. It is assumed that the year average net generating efficiency will increase slightly from 38% in 1990 to 42% in 2020 due to decommissioning of the least efficient power plants. Investment costs are estimated at ECU 810/kW_e (NLG 1,700/kW_e).

Table A.7: *Gas fired power plant*	Existing mix			
	1990	2000	2020	2040
Year average net efficiency [%]	38.0	40.0	44.0	
District heating: - electric [%]	33.6	35.3	39.0	
- thermal [%]	27.3	28.6	31.7	
- exergetic [%]	39.8	41.7	46.1	
Investment cost [ECU_{1995}/kW_e]	810	810		
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	21	21		
- Variable [ECU/GJ_e]				
Life [yr]	30	30	30	
NO_x-emission [g/GJ]	50	50	50	
SO_2-emission [g/GJ]				
Minimum potential [GW_e]	35.93	25.76	2.21	
Maximum potential [GW_e]	35.94	25.77	2.22	0

STAG power plant

Combined cycle plants (STAG) are state-of-the-art for gas fired power plants. Their generating efficiency increased steeply from some 46% around 1982 to 55% nowadays. The generating efficiency could increase to about 60% at full load and 58% on an annual basis in year 2000, due to the development potential of gas turbines. Higher efficiencies could be achieved with still higher gas turbine inlet temperatures. It is assumed that a level of 62% at full load and 60% on an annual basis could be reached by year 2020. Investment costs are estimated at ECU 670/kW$_e$ (NLG 1,400/kW$_e$).

Table A.8: *STAG power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	46.0	58.0	60.0	60.0
District heating: - electric [%]	40.5	52.3	54.0	54.0
- thermal [%]	34.5	36.3	37.5	37.5
- exergetic [%]	48.3	60.5	62.5	62.5
Investment cost [ECU$_{1995}$/kW$_e$]	670	670	670	670
O&M cost - Fixed [ECU$_{1995}$/kW$_e$/y]	10	10	10	10
- Variable [ECU/GJ$_e$]	0.45	0.45	0.45	0.45
Life [yr]	25	25	25	25
NO_x-emission [g/GJ]	30	30	30	30
SO_2-emission [g/GJ]				
Minimum potential [GW$_e$]	1.69	37.60	26.90	
Maximum potential [GW$_e$]	1.70	37.61		

Gas turbine peaking plant

A minor part of electricity in Europe is produced by gas turbine peaking units. As their load factor is low, investment costs should be kept low. It is assumed that the average net generating efficiency is 34.5% in 2000 and 40% in 2020. Investment costs are estimated at ECU 380/kW_e (NLG 800/kW_e).

Table A.9: *Gas turbine peaking plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	32.5	34.5	40.0	40.0
Investment cost [ECU_{1995}/kW_e]	380	380	380	380
O&M cost - Fixed [$ECU_{1995}/kW_e/yr$]	11	11	11	11
- Variable [ECU/GJ_e]	0.5	0.5	0.5	0.5
Life [yr]	25	25	25	25
NO_x-emission [g/GJ]	30	30	30	30
SO_2-emission [g/GJ]				
Minimum potential [GW_e]	17.64	18.81	0.61	
Maximum potential [GW_e]	17.65			

Gas turbine CHP plant

In some European countries a significant proportion of electricity demand is met by gas fired industrial CHP (Combined Heat and Power) plants. Most of current capacity is gas turbine based. A small fraction is based on combined cycle power plants, which will be addressed later on. A gas turbine with waste heat boiler proves to be a very reliable and efficient CHP technology. Gas turbine efficiency is assumed to be rise from 31% in 1990 to 37% in year 2020. Investment costs are estimated at ECU 760/kW$_e$ (NLG 1,600/kW$_e$).

Table A.10: *Gas turbine CHP plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]				
CHP mode: - electric [%]	31.0	35.0	37.0	37.0
- thermal [%]	53.9	49.3	47.4	47.4
- exergetic [%]	55.3	57.3	58.4	58.4
Investment cost [ECU$_{1995}$/kW$_e$]	760	760	760	760
O&M cost - Fixed [ECU$_{1995}$/kW$_e$/y]	11	11	11	11
- Variable [ECU/GJ$_e$]	0.5	0.5	0.5	0.5
Life [yr]	25	25	25	25
NO_x-emission [g/GJ]	30	30	30	30
SO_2-emission [g/GJ]				
Minimum potential [GW$_e$]	7.17	16.31	4.68	
Maximum potential [GW$_e$]	7.18	18.77	25.75	25.90

STAG CHP plant

Some ten years ago combined cycle (STAG) CHP plants have been introduced for industrial cogeneration. A significant part of new industrial CHP capacity is based on combined cycle technology. This type of power plant is highly efficient. It's applications are in chemical industries and refineries with large amounts of industrial gases and a large steam demand. At high load factors a combined cycle CHP plant gives lower generating costs than a gas turbine with waste heat boiler. The electrical efficiency is assumed to rise from 40% in 2000 to 47.5% in 2020, taking into account the back pressure operation mode of the steam turbine. Investment costs are estimated at ECU 670/kW_e (NLG 1,400/kW_e).

Table A.11: *STAG CHP plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]				
CHP mode: - electric [%]	40.0	45.0	47.5	47.5
- thermal [%]	35.0	30.0	28.0	28.0
- exergetic [%]	55.8	58.5	60.2	60.2
Investment cost [ECU_{1995}/kW_e]	670	670	670	670
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	10	10	10	10
- Variable [ECU/GJ_e]	0.45	0.45	0.45	0.45
Life [yr]	25	25	25	25
NO_x-emission [g/GJ]	30	30	30	30
SO_2-emission [g/GJ]				
Minimum potential [GW_e]	0.66	7.16	4.21	
Maximum potential [GW_e]	0.67	7.50	7.85	7.85

Coal FBC CHP plant

A minor fraction of industrial cogeneration is based on coal fired FBC (Fluidised Bed Combustion) plants. Techniques applied are Bubbling Fluid Bed Combustion (BFBC) and Circulating Fluid Bed Combustion (CFBC). It assumed that FBC boilers are used for power generation in conjunction with low pressure steam production (using a back pressure steam turbine). Investment costs are ECU 3,000/kW_e (NLG 6,300/kW_e).

Table A.12: *Coal FBC CHP plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]				
CHP mode: - electric [%]	11.5	11.5	11.5	11.5
- thermal [%]	75.0	75.0	75.0	75.0
- exergetic [%]	40.0	40.0	40.0	40.0
Investment cost [ECU_{1995}/kW_e]	3,000	3,000	3,000	3,000
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	120	120	120	120
- Variable [ECU/GJ_e]				
Life [yr]	30	30	30	30
NO_x-emission [g/GJ]	65	65	65	65
SO_2-emission [g/GJ]	75[1]	75	75	75
Minimum potential [GW_e]	4.57	4.03	0.40	
Maximum potential [GW_e]	4.58	4.50		

[1] Based on 90% desulphurisation, 1% sulphur, 26.5 GJ/ton.

Gas engine Total Energy installation

A relatively small, although growing, proportion of electricity in Europe is produced by gas engine installations, which produce low temperature heat (Total Energy). Most of low temperature heat is produced for the residential sector. Gas engines are also installed in growing numbers in the commercial and horticulture sector.

Electric efficiency of gas engine installations is estimated at 39% in 2000. Overall efficiency is assumed to be 90%. Investment costs are estimated at ECU 950/kW_e (NLG 2,000/kW_e).

Table A.13: *Gas engine Total Energy installation*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]				
Tot. Energy mode: - electric [%]	34.0	39.0	39.0	39.0
- thermal [%]	53.0	50.8	50.8	50.8
- exergetic [%]	46.0	50.5	50.5	50.5
Investment cost [ECU_{1995}/kW_e]	950	950	950	950
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	24	24	24	24
- Variable [ECU/GJ_e]	0.2	0.2	0.2	0.2
Life [yr]	15	15	15	15
NO_x-emission [g/GJ]	100	100	100	100
SO_2-emission [g/GJ]				
Minimum potential [GW_e]	0.965	4.11	0.1	
Maximum potential [GW_e]	0.975	13.09	21.20	22.05

Light water reactor

A large part of European power is generated by nuclear power plants, most of which is based on Light Water Reactor (LWRs) technology: Pressurized Water Reactors or PWRs, and Boiling Water Reactors or BWRs. A relatively small fraction of nuclear capacity consists of other reactor types, notably gas-cooled reactors (UK) and sodium-cooled fast reactors (France).

For a number of years growth of nuclear power capacity has been slowing down. New capacity is restricted to France nowadays. Other countries like the UK and Germany are not able to expand their nuclear capacity, because of unfavourable economic perspectives (UK) and lack of public acceptance (Germany). For the next decades a virtual stabilisation of nuclear capacity seems inevitable. However, a scenario without nuclear power in Europe is not very likely. Therefore, the maximum is defined as the current nuclear capacity and the minimum as half current capacity.

Investments costs of nuclear power plants depend on the rated power and the number of power plants. In France relatively large numbers of identical plant have been built over the last two decades. Their capacity ranged from 900 MW_e in the seventies and eighties to 1,450 MW_e nowadays. For most European countries the optimum capacity is probably in the range of 1,000 to 1,500 MW_e. If such reactors would be built in sufficiently large numbers of identical units in order to generate a substantial series effect, investment costs could come down to the level experienced in France during the last decades. However, since a long time more and more tight safety requirements are driving up investment costs. It is questionable if investment costs as low as experienced in France until the nineties could be realised, even if standardisation develops as foreseen at the moment.

A more plausible scenario is that investment costs of recently built German LWRs are a yardstick for future investment costs. On one hand investment costs of so-called Konvoi reactors - Konvoi is the term used for three almost identical PWRs of some 1,300 MWe, commissioned in 1988-1989 - are rather high, due to the limited series effect. On the other hand cost reductions as a consequence of technical improvements and series effect could easily be offset by additional safety requirements (core catcher, containment venting system, more passive instead of active safety systems). Investment costs of modern LWRs [16] [17] [18] with possibly outstanding safety characteristics could be ECU 2,440/kW_e (NLG 5,120/kW_e), inclusive of first fuel, interest during construction and reservation for decommissioning. Investment costs of a representative Konvoi unit - Isar 2, 1,340 MW_e net - were DM 3,270/kW_e (DM 1988), inclusive of first fuel, but exclusive of interest during construction and reservation for decommissioning.

Table A.14: *Light Water Reactor*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	33.0	33.0	33.0	33.0
Investment cost [ECU_{1995}/kW_e]	2,440	2,440	2,440	2,440
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	47	47	47	47
- Variable [ECU/GJ_e]				
Life [yr]	40	40	40	40
Minimum potential [GW_e]	116.32	126.65	85.92	63.25
Maximum potential [GW_e]	116.33	126.66	126.5	126.5

Note that maximum capacity considered is 126.5 GW_e. In Figure 1 some forecasts for Western Europe are shown from IAEA [19] and the US Energy Information Administration (EIA) [20].

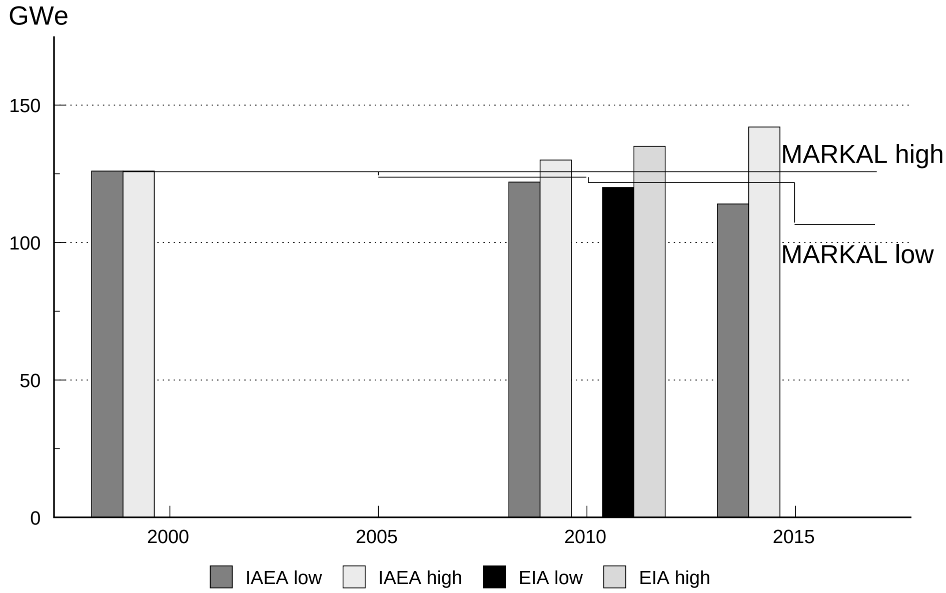

Figure 1 *Forecasts of nuclear capacity in Western Europe*

Sources: [19,20]

Hydro pumped storage

In several European countries hydro pumped storage fulfils an important role in load management. Such hydro pumped storage schemes can be combined with hydro power generation, if a river feeds the upper reservoir. Here, the scheme is assumed to be a pure hydro pumped storage system. The overall efficiency (pumping and generating) is 80%. Investment costs are estimated at ECU 1,900/kW_e (NLG 4,000/kW_e).

Table A.15: *Hydro pumped storage*	Existing mix	New capacity		
	1990	2000	2020	2040
Cycle efficiency [%]	80.0	80.0	80.0	80.0
Investment cost [ECU_{1995}/kW_e]	1,900	1,900	1,900	1,900
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	38	38	38	38
- Variable [ECU/GJ_e]				
Life [yr]	60	60	60	60
Minimum potential [GW_e]	30.34	34.34	40.48	42.18
Maximum potential [GW_e]	30.35	34.50		

Hydro power

There are several types of hydro power plants, such as reservoir type and run-of-river plants. Run-of-river plants have rather low heads, whereas reservoir type plants have medium to high heads. We assume the most of hydro capacity to be of the medium to high head type, and a smaller fraction of the low head type. Hydro power potential in Europe is generally based on [21], except for Norway [22] and Sweden [23].

Medium to high head hydro

The average annual load factor of medium to high head hydro is assumed to be 36% (3,150 hours/year). Investment costs are estimated at ECU 1,900/kW_e (NLG 4,000/kW_e).

Table A.16: *Medium and high head hydro power*	Existing mix	New capacity		
	1990	2000	2020	2040
Average annual load factor [%]	36.0	36.0	36.0	36.0
Investment cost [ECU_{1995}/kW_e]	1,900	1,900	1,900	1,900
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	38	38	38	38
- Variable [ECU/GJ_e]				
Life [yr]	60	60	60	60
Minimum potential [GW_e]	127.79	132.60	137.8	137.8
Maximum potential [GW_e]	127.80	132.87	155.8	169.1

Low head hydro

The annual load factor of low head hydro is estimated at 50% (4,400 hours/year), and investment costs at ECU 2,850/kW_e (NLG 6,000/kW_e).

Table A.17: *Low head hydro power*	Existing mix	New capacity		
	1990	2000	2020	2040
Average annual load factor [%]	50.0	50.0	50.0	50.0
Investment cost [ECU_{1995}/kW_e]	2,850	2,850	1,900	1,900
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	38	38	38	38
- Variable [ECU/GJ_e]				
Life [yr]	60	60	60	60

Minimum potential [GW_e]	8.22	8.55	8.75	8.90
Maximum potential [GW_e]	8.23	8.60	10.88	11.90

Wind onshore

Wind turbines have been installed in several European countries. Since a few years wind turbine capacity is growing all over Europe. The maximum rated power of commercially available wind turbines rose from 500 kW_e five years ago to 1.5 MW_e today. Due to technical improvements and a higher wind speeds at higher hub heights the capacity factor is increasing, and could 27% in year 2000. Investment costs were ECU 1,140/kW_e (NLG 2,400/kW_e) in 1990, and are estimated at ECU 860/kW_e (NLG 1,800/kW_e) in 2000, and ECU 810/kW_e (NLG 1,700/kW_e) in 2010.

Table A.18: *Wind onshore*	Existing mix	New capacity		
	1990	2000	2020	2040
Average annual load factor [%]	24.8	27.0	27.0	27.0
Investment cost [ECU_{1995}/kW_e]	1,140	860	810	810
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]	18	18	18	18
- Variable [ECU/GJ_e]				
Life [yr]	30	30	30	30
Minimum potential [GW_e]	0.44	6.0	20.0	20.0
Maximum potential [GW_e]	0.45	9.5	76.7	110.3

Wind energy can be accommodated in the generating system, if the installed capacity does not surpass critical limits. These depend on type and characteristics of conventional power plants and the availability of hydro pumped storage. Beyond those limits, a larger capacity of wind turbines can only be realised in conjunction with (enlargement of) hydro pumped storage.

A second class of wind onshore is defined, consisting of wind turbine capacity and hydro pumped storage capacity in a proportion of 5 to 1 (in MW_e). Part of wind power is stored at night, thereby decreasing net power fluctuations from wind turbines. The average annual load factor decreases slightly to 26.1%. Investment costs of wind turbines in conjunction with storage are estimated at ECU 1,190/kW_e (NLG 2,500/kW_e).

Table A.19: *Wind onshore/hydro pumped storage*	New capacity			
	1990	2000	2020	2040
Average annual load factor [%]		26.1	26.1	26.1
Investment cost [ECU_{1995}/kW_e]		1,190	1,190	1,190
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]		22	22	22
- Variable [ECU/GJ_e]				
Life [yr]		30	30	30
Maximum potential [GW_e]		0	8.7	70.6

Wind off-shore

Investment costs of off-shore wind turbines are significantly higher than for onshore wind turbines. Additional costs are due to off-shore constructions and transmission. The additional costs are partly offset by higher mean wind speeds at offshore locations. Probably off-shore wind turbine projects will materialise if onshore locations get scarce. This could happen around year 2010. It is assumed that off-shore wind power will be realised in conjunction with (enlarged) hydro pumped storage in a proportion of 5 to 1 (in MW_e). The average annual load factor is estimated at 27.8%. Investment costs are estimated at ECU 1,750/kW_e (NLG 3,680/kW_e).

Table A.20: *Wind off-shore/hydro pumped storage*	New capacity			
	1990	2000	2020	2040
Average annual load factor [%]		27.8	27.8	27.8
Investment cost [ECU_{1995}/kW_e]		1,750	1,750	1,750
O&M cost - Fixed [$ECU_{1995}/kW_e/y$]		31	31	31
- Variable [ECU/GJ_e]				
Life [yr]		30	30	30
Minimum potential [GW_e]				
Maximum potential [GW_e]		0	38.0	185.0

Geothermal power plant

Geothermal power is generated in Italy and Iceland. Both countries have relatively modest capacities, e.g. 570 MW_e in Italy. Maximum geothermal energy capacity is assumed to treble until 2050. Investment costs are estimated at \$ 1,200/kW_e, equal to ECU 1,030/kW_e [24] [25].

Table A.21: *Geothermal power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	15.0	15.0	15.0	15.0
Investment cost [ECU_{1995}/kW_e]	1,030	1,030	1,030	1,030
O&M cost - Fixed [ECU_{1995}/kW_e/y]	26	26	26	26
- Variable [ECU/GJ_e]				
Life [yr]	30	30	30	30
Minimum potential [GW_e]	0.78	0.85	0.85	0.85
Maximum potential [GW_e]	0.79	0.86	1.35	1.85

Waste-to-energy power plant

In most European countries municipal solid waste is incinerated, thereby generating power. Some countries, e.g. Denmark, Germany and the Netherlands have a significant waste-to-energy power plant capacity. In most countries new capacity is under construction. Waste-to-energy should compete with other options such as recycling of fractions of municipal waste. However, it is likely that some fraction remains to be used for power generation. It is assumed that total capacity will increase from 570 MW_e in 1990 to 3,530 MW_e in 2040. This is the minimum capacity assumed (maximum capacity is almost double that amount). Investment costs in 1990 are estimated at ECU 11,400/kW_e (NLG 24,000/kW_e) [26]. In year 2000 investments costs are assumed to be approximately 20% lower (ECU 9,000/kW_e). This could be the result of development of a new waste-to-energy technology with a considerably higher generating efficiency.

Table A.22: *Waste-to-energy power plant*	Existing mix	New capacity		
	1990	2000	2020	2040
Year average net efficiency [%]	22.5	26.0	28.0	30.0
Investment cost [ECU_{1995}/kW_e]	11,400	9,000	9,000	9,000
O&M cost - Fixed [ECU_{1995}/kW_e/y]	85	67	67	67
- Variable [ECU/GJ_e]				
Life [yr]	30	30	30	30
Minimum potential [GW_e]	0.565	1.50	2.55	3.53
Maximum potential [GW_e]	0.575	1.98	4.00	6.32

Biomass gasification

Gasification is an essential but uncertain element for future biomass application for power generation. Costs depend on variables like atmospheric/high pressure gasification; direct/indirect gasification; air/oxygen; tar removal; alkali removal; low/high temperature gas cleaning. The size of the installation determines the best gasification concept. Due to significant uncertainties, one set of data is used for large scale gasification for all power plant types. Data refer to an atmospheric circulating fluid bed gasifier, including alkali removal and tar cracking and including combustion gas compression. In [27] the energy content of the combustion gas is estimated at 78% of the energy content of the biomass (cold gas efficiency), while the sum of recoverable heat and tar heating value is estimated at 8 to 14% of biomass energy input. Besides, the own use of the gasifier is 1.6%. Therefore, the overall net efficiency is estimated at 83%.

Table A.23: *Biomass gasifier*

		2000	2020	2040
Average overall efficiency[1] [%]		83	83	83
Investment cost [ECU_{1995}/GJ_{gas}][2]		15	10	10
O&M cost[2]	- Fixed [$ECU_{1995}/GJ_{gas}/yr$]	0.75	0.5	0.5
	- Variable [ECU/GJ_{gas}]			
Life [yr]		25	25	25
NO_x emission [g/GJ]				

[1] Cold gas efficiency, corrected for additional outputs (steam, tar) and own use.
[2] The overall costs of biomass gasifier and power generation technology are addressed later on.

Biomass gasification is used as the base technology for different power generation options. One of them is the steam injected gas turbine with intercooler (STIG) and reheat (excluding gasification). Steam injection in the combustion chamber and cooling inlet air during combustion can enhance electric efficiency and capacity of gas turbines. Adding a reheat system results in further efficiency increase. All three technologies are to be developed in the next ten years. For example, in case of the General Electric (GE) LM-5000 gas turbine, an increase of the simple cycle efficiency from 33% today to 49% around year 2000 is foreseen (Table A.24 Simultaneously rated power could be boosted from 33 MW_e to 185 MW_e [28].

If advanced gas turbines would used, e.g. one of the type aforementioned, the amount of biomass used would be 0.65 million ton/year[2]. Assuming a yield of 20 t d.m. (dry matter)/ha, the area needed would be 32,500 ha.

[2] The way this number is derived is explained in [3], p. 63.

Investment costs of the power train of an ISTIG plant are estimated at about 810 ECU/kW_e (NLG 1,700/kW_e) in 2010, decreasing to ECU 710/kW_e (NLG 1,500/kW_e) in 2030. If a smaller gas turbine is used due to biomass availability problems, cost per kW_e will be slightly higher, while the efficiency will be (somewhat) lower (Table A.24).

Table A.24: *Integrated combined cycle for biomass gasification (power train only)*	New capacity			
	1990	2000	2020	2040
Year average net efficiency [%]		54.0	56.5	56.5
Investment cost [ECU_{1995}/kW_e]		700	700	700
O&M cost - Fixed [ECU_{1995}/kW_e/y]		11	11	11
- Variable [ECU/GJ_e]		0.5	0.5	0.5
Life [yr]		25	25	25
Minimum potential [GW_e]				
Maximum potential [GW_e]				

Overall investment costs are ECU 1,210/kW_e (NLG 2,550/kW_e) [29].

Photovoltaic systems

Photovoltaic cells convert sunlight directly into electricity. A PV module consists of various PV cells which have been put in a frame. A PV system contains a PV module and the balance of system (BOS). The BOS includes a set of other required equipment which varies per PV system. It may e.g. include supporting structure, inverter, other electronics, grid connection and battery storage.

Different types of PV cells are under development. For the medium to long term (after 2010) it is expected that thin film PV cells become least expensive. Until 2010 polycrystalline modules are expected to have the largest market share.

In this study three different PV-systems have been distinguished:
- PV systems in Middle Europe,
- PV systems in Southern Europe and
- PV systems in Southern Europe that serve electricity use in Middle and Northern Europe (electricity is transported by new HVDC connections).

The cost and lifetime of PV systems are assumed to be the same for Southern and Middle Europe. Total annual radiation also varies per region of Western Europe. The amount of seasonal production hours for PV systems for different regions in Europe have been estimated based on solar irradiation maps. For Southern Europe radiation figures for the region near Malaga in Spain have been used. The production of electricity with PV systems depends also on the availability of solar radiation which varies with season and time of day. Average losses in the electric system of PV systems have been estimated at 10%. The losses in the HVDC connection have been estimated at 3.6%. To achieve a maximum annual electricity production PV systems are assumed to be south oriented with a 30° inclination.

The cost estimates for future PV systems of the SYRENE study have been used [18]. Operation and maintenance cost have also been taken from [18]. The maximum annual growth in manufacturing capacity for PV cells has been assumed to amount to 30% per year.

Table A.25: *PV systems in Middle Europe*

	2000	2010	2030	2040
Average annual load factor	10.64	10.64	10.64	10.64
Investment cost [ECU_{1995}/kW_e]	5000	1980	1070	930
O&M cost [$ECU_{1995}/kW_e/y$]	20.5	14.8	8.1	7.6
Life [yr]	30	30	30	30
Load factor winter day [%]	7.14	7.14	7.14	7.14
Load factor winter night [%]	0	0	0	0
Load factor summer day [%]	24.56	24.56	24.56	24.56
Load factor summer night [%]	0	0	0	0
Load factor intermediate day [%]	16.12	16.12	16.12	16.12
Load factor intermediate night [%]	0	0	0	0
Average annual load factor [hours/yr]	932	932	932	932
Maximum potential [GW]	0.1	0.3	38	356

Table A.26: *PV systems in Southern Europe*

	2000	2010	2030	2040
Investment cost [ECU_{1995}/kW_e]	5000	1980	1070	930
O&M cost [$ECU_{1993}/kW_e/y$]	20.5	14.8	8.1	7.6
Life [yr]	30	30	30	30
Average annual load factor [%]	19.22	19.22	19.22	19.22
Load factor winter day [%]	15.42	15.42	15.42	15.42
Load factor winter night [%]	0	0	0	0
Load factor summer day [%]	42.19	42.19	42.19	42.19
Load factor summer night [%]	0	0	0	0
Load factor intermediate day [%]	28.86	28.86	28.86	28.86
Load factor intermediate night [%]	0	0	0	0
Average annual load factor [hours/yr]	1680	1680	1680	1680
Maximum potential [GW]	0.04	0.5	50	50

Table A.27: *PV systems in South Europe with HVDC connection to Middle Europe (cost and power losses of HVDC transport have been accounted for)*

	2000	2010	2030	2040
Investment cost [ECU_{1995}/kW_e]	5457	2437	1527	1387
O&M cost [$ECU_{1995}/kW_e/y$]	34	29.5	17.1	16.6
Life [yr]	30	30	30	30
Average annual load factor [%]	18.53	18.53	18.53	18.53
Load factor winter day [%]	14.86	14.86	14.86	14.86
Load factor winter night [%]	0	0	0	0
Load factor summer day [%]	40.67	40.67	40.67	40.67
Load factor summer night [%]	0	0	0	0
Load factor intermediate day [%]	27.82	27.82	27.82	27.82
Load factor intermediate night [%]	0	0	0	0
Average annual load factor [hours/yr]	1623	1623	1623	1623
Maximum potential [GW]	0.1	0.3	38	356

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Page 1

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