SUPWIND Deliverable D 4.1
Report on Findings of Working Package 4

Identification of overall scenarios on the European electricity market

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1 Introduction

This report is part of the research project SUPWIND (Decision Support for Large Scale Integration of Wind Power), which is supported by the European Commission under the Sixth Framework Programme (Contract No. TREN/05/FP6EN/S07.61830/020158 SUPWIND) and summarises the findings of Work Package 4.

The objective of this Work Package Report is to identify overall scenarios on the future of the European electricity market, embedded in the development of the European and World economy and based on scenarios already in use in the EU policy advisory process. Since the ambitions in SUPWIND are to aid decision-making on power markets with large-scale integration of wind power, it is of importance to analyse the scenarios already in use from this specific perspective. Finally, a limited number of SUPWIND scenarios which reflect possible evolutions of the power systems in the future are developed and corresponding key scenario parameters are identified.

After providing a brief description of the project, this report proceeds as follows: In section 2 scenarios for the European electricity market already in use are identified. In section 3 a limited number of scenarios, which reflect possible evolutions of the power systems in the future, will be extracted and corresponding key scenario parameters will be quantified.

1.1 Project description

The SUPWIND project was launched in October 2006 with an overall project duration of 36 months. The key objective of the project is to demonstrate the applicability of decision support tools based on stochastic analysis and programming for operational management of grids and power plants. Besides, the applicability of strategic analysis tools for decision support for long-term management of grids will be demonstrated and a detailed analysis of improved coordination mechanisms between grid operators, power plant operators, power exchanges etc. will performed.

More specifically the evaluation of regional and trans-national transmission line investments caused by large scale introduction of wind power will be analysed in detail. However the strategic issues at hand can only be addressed adequately if a good understanding of the operational management of grids with high wind energy penetration is achieved. Therefore the project simultaneously aims at demonstrating the applicability of tools for the operational management of grids and power plants under large scale wind power generation and corresponding tools for strategic analysis. In the operational management the inclusion and use of online wind-power data is a particular focus. By also including load uncertainty and stochastic outages, the operational tools will be able to estimate the need for power reserves in the system as a function of the precision of the wind power forecast and load forecast and the probability of outages. This will enable transmission system operators responsible for securing power reserves to optimise the reservation of power reserves and correspondingly minimise the costs connected to the reservation of power reserves.

In order to achieve the objectives of the project, two phases comprising a total of nine work packages are foreseen. Phase I covers the first 18 months of the project duration and is completed, when the key research activities, being WP 2 and WP 3, are completed. Phase II is entirely devoted to the application of the developed extended tools in several case studies. The work package structure is as follows:

WP1 covers the general project management activities.

WP2 and 3 are key research activities, since the tools necessary to achieve the objectives of the project are developed there. In WP2 the functionality of the Wilmar Planning Tool is extended to include evaluation of transmission line and power plant investments. WP3 extends the Wilmar Planning Tool by including online status information of power plants and transmission lines and online wind power forecast data. The tool will be extended to include load uncertainty and stochastic outages in the stochastic optimisation.

As part of the demonstration of the applicability of the tools, the input data to these decision support tools has to be collected. This includes data for the existing power systems in the EU and scenarios for the development of the power systems in the future. WP4 takes care of the scenario generation, and WP5 addresses the collection of data for the present power systems.

WP4 develops possible overall scenarios on the future of the European electricity market. First, the work package aims at identifying overall scenarios on the future of the European electricity market, being embedded in the development of the European and World economy and based on scenarios already in use in the EU policy advisory process. Furthermore, existing scenarios are synthesized and own scenarios are built based on those. Using the inventory of European scenarios and the perspective on large scale integration of wind power, key parameters are identified which describe major elements for the future electricity system development. Thereby interdependencies between the different parameters are first discussed qualitatively, and then a set of exogenous parameters is selected – whereas other parameters may be endogenously determined in the strategic model. Finally, a limited number of scenarios is extracted, which reflect possible evolutions of the power systems in the future. Thereby some contrasting developments will be retained to illustrate the impact of political decisions on the integration of wind energy and to enable the system operators to identify robust decisions when using the strategic planning tool in WP6.

WP5 extends the data bases constructed in the WILMAR and GreenNet/GreenNet-EU27 projects to cover EU27 except Cyprus and Malta but including Norway and Switzerland. Furthermore the data needed to analyse more specific operational cases, such as the operation of the Nordel system in a situation with large scale installation of onshore and offshore wind power in the Nordic countries, will be collected in close corporation with the relevant TSO.

In WP6 the European Power System scenarios developed in WP4 are analysed with the strategic planning tool complemented with input from the analysis of selected operational cases. The scenarios will focus on large scale deployment of wind power and the resulting need and costs of investments in transmission lines and new flexible generation facilities including storages. Covering EU27, the tool will enable analysis of the bottlenecks arising in the European power system as a result of the location of wind power in high wind resource areas being in some cases remotely situated relatively to the high consumption centres.

In WP7 selected operational cases will be analysed in close corporation between model developers and TSOs. The results from the strategic planning tool will provide boundary conditions for the geographical cases selected. Each case will be evaluated with regard to the usefulness of the operational tool in helping with the day to day planning especially the estimate of the need for power reserves. The specific issues related to inclusion of online power system data in the operational tool will be analysed for each case. Furthermore the ability of the operational tool in testing the robustness of the power system towards extreme events will be evaluated.

WP8 will analyse changes in the market design for day-ahead and regulating power markets and use the tools developed in WP2 and WP3 to see how much this influences the feasibility and costs of wind power integration.

These WPs are complemented by WPs devoted to internal and external communication issues, notably project management (WP1) and dissemination (WP9).

Figure 1 shows a graphical presentation of the work packages.

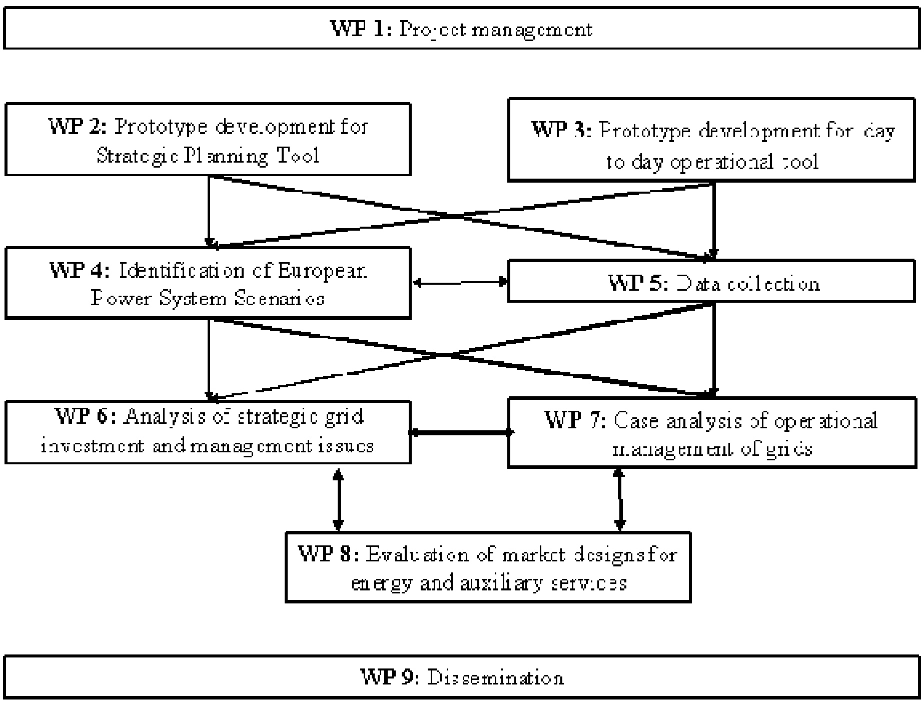

Figure 1. Graphical representation of the work packages in the SUPWIND project.

2 Overview of existing scenarios

This chapter identifies overall scenarios on the future of the European electricity market already in use in the EU policy advisory process. More specifically, the European Energy and Transport Trends to 2030 – Update 2005 will be compared with the World Energy Outlook 2006.

2.1 European Energy and Transport Trends to 2030 – Update 2005

The Baseline Scenario of the Trends to 2030 report simulates current trends and policies implemented by the EU-25 Member States by end of 2004 including energy efficiency, renewable and nuclear phase-out policies. CO2 prices are set at 5 €/ t CO2 and corresponding CO2 emissions arise from the modelling results (as the renewable shares do) and do not take into account possible (post) Kyoto commitments. Economic growth is assumed to be 2% p.a. on average until 2030 and oil prices are projected to increase from 55 $/bbl in 2005 to 58 $/bbl in 2030 measured in real 2005 terms (see Figure 2).

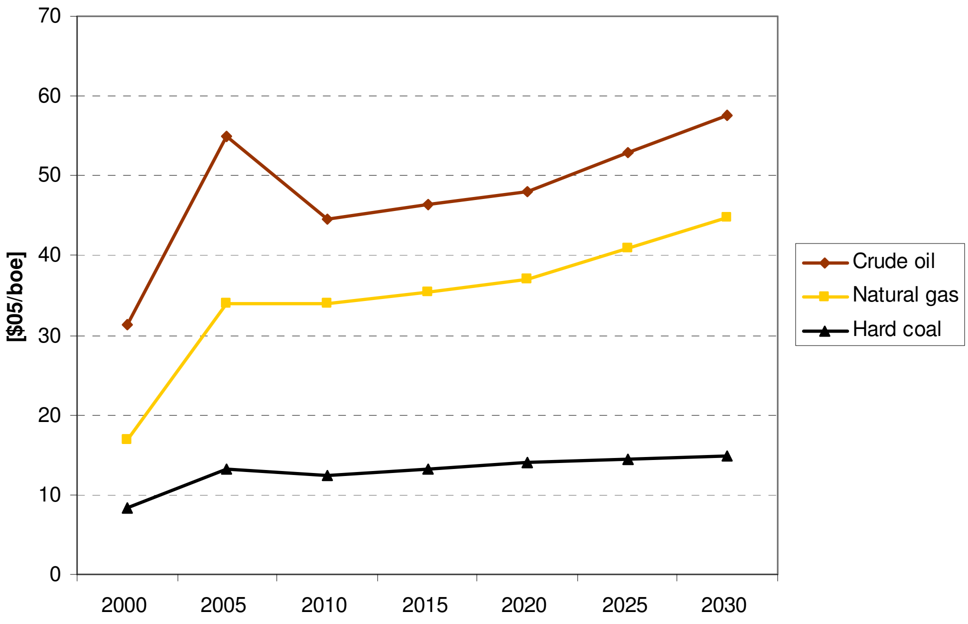

Figure 2. Primary energy price assumptions. Source: EC (2006)

Total primary energy consumption increases by 9% from 2005 to 2030 with decreasing annual growth rates and stagnation after 2020 due to lower economic growth and a stagnating population. The major part of the consumption increase will be met by an increased use of natural gas and renewables. With current policies renewables will exceed the share of nuclear between 2020 and 2025. Together, these carbon free resources amount to 23% of the total primary energy consumption. Oil stays the most important fuel until 2030 with a rather constant share of about 35% (see Figure 3).

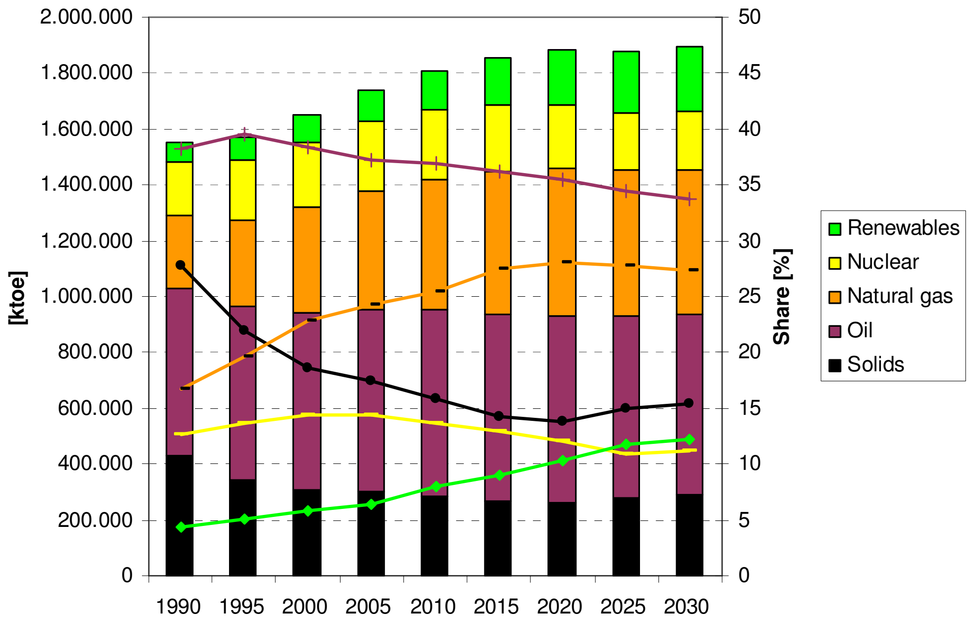

Figure 3. Evolution of primary energy consumption in the EU-25 and relative fuel shares in the Baseline Scenario. Source: EC (2006)

Figure 4 depicts the evolution of renewable energies in the primary energy consumption. Biomass represents the most important renewable energy source with a share between 60 and 65%. Still, in terms of relative increases, wind energy is in the lead becoming the second most important source after 2025. Hydro remains constant in absolute terms leading to a decreasing relative share. Geothermal and solar energy show a low contribution in the energy mix over the whole considered period.

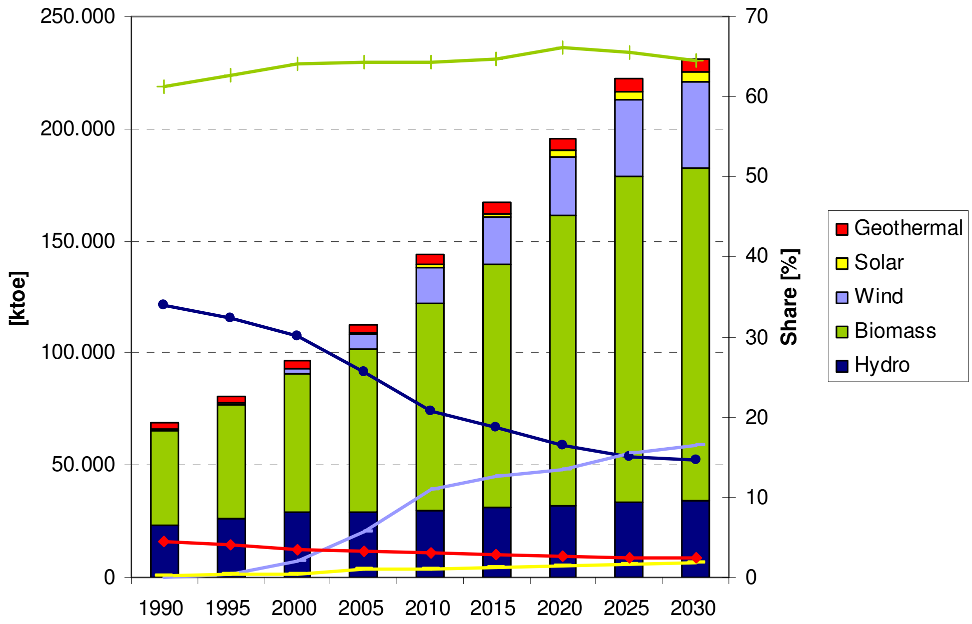

Figure 4. Evolution of renewable energies in the EU-25 and relative fuel shares in the Baseline Scenario. Source: EC (2006)

The development of energy related CO2 emissions is shown in Figure 5. Overall, total CO2 emissions increase by 5% compared to 1990 levels in the Baseline Scenario. The energy sector remains the largest emission source followed by the transport sector which showed large growth rates in the last years. Industry as third largest emitter is projected to slightly decrease its CO2 emissions. Industry and the energy sector – both subject to the European Emission Trading Scheme (EU-ETS) – account for 53% of total EU emissions between 2005 and 2030.

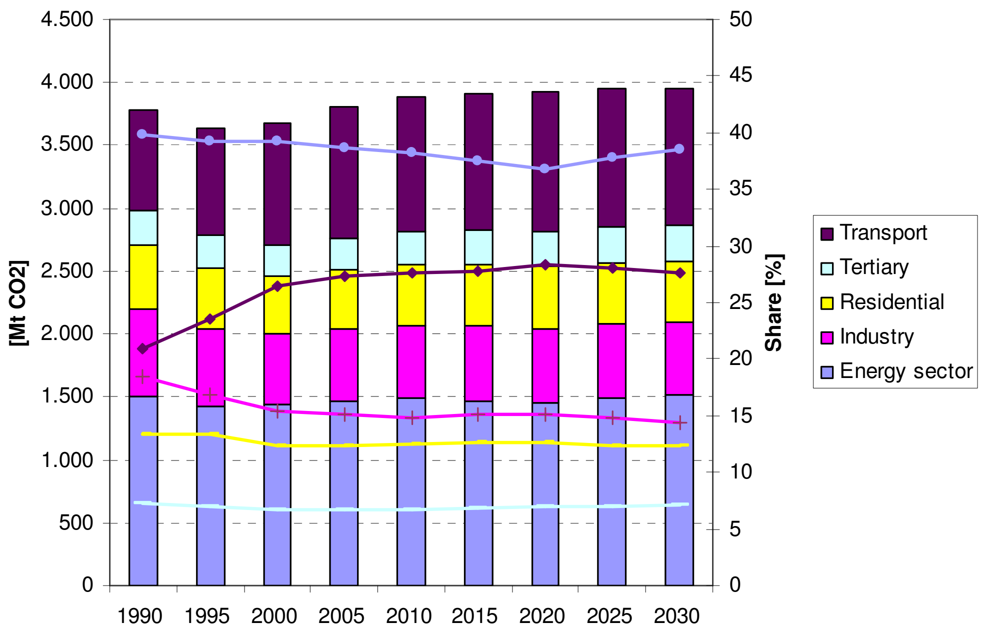

Figure 5. Energy related CO2 emissions in the Baseline Scenario. Source: EC (2006)

Figure 6 depicts the electricity consumption in the sectors industry, households, tertiary and transport. From 2000 to 2030 electricity consumption increases by 58%. In comparison total final energy demand rises by 25% clearly indicating strong penetration of electric appliances in the residential and tertiary sectors.

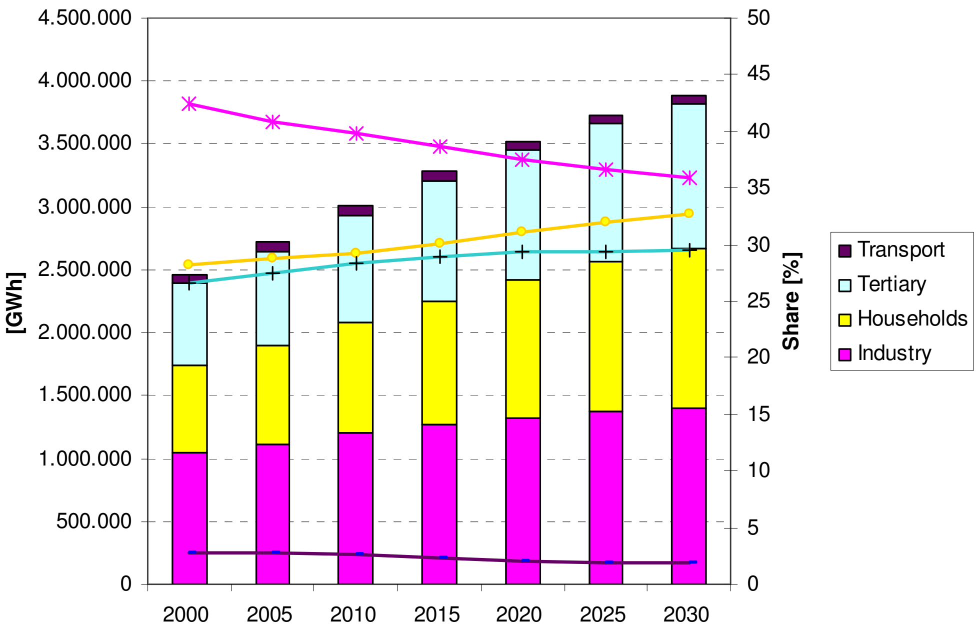

Figure 6. Deployment of electricity consumption in final demand sectors. Source: EC (2006)

Conventional generation sources represent the major part to meet rising electricity consumption (see Figure 7). Total power generation increases by 50% between 2000 and 2030. RES-E technologies show a rising deployment from 15% of total generation in 2000 to 28% in 2030 with high increases of wind and biomass generation. Still, the 20% target set out in the renewables directive will not be met in 2010. Nuclear generation shows a significant decline in relative terms due to phase out decisions in some Member States. The carbon free generation technologies keep a constant share of 46% over the considered period.

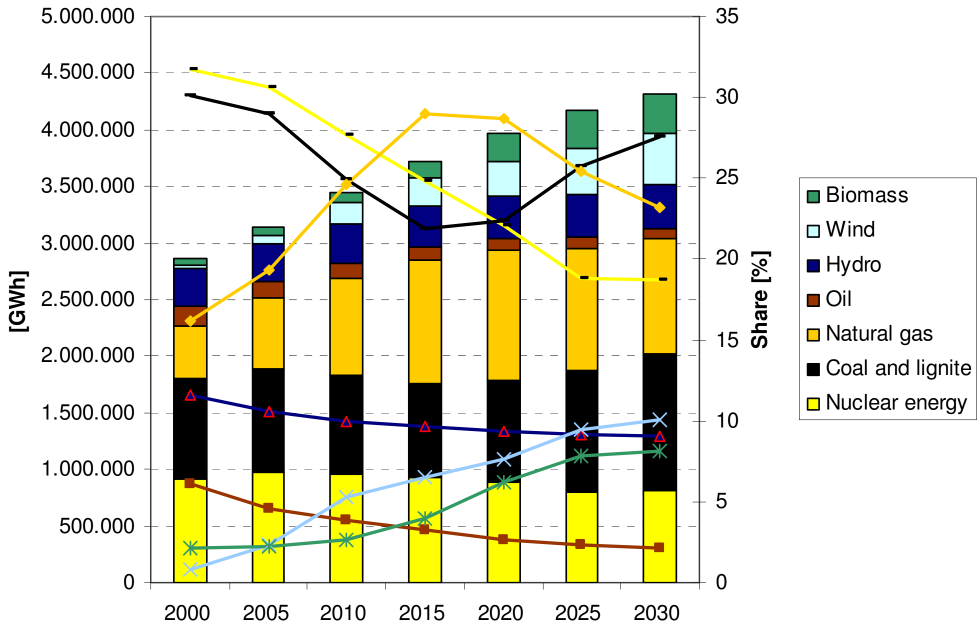

Figure 7. Evolution of electricity generation in the Baseline Scenario. Source: EC (2006)

Figure 8 shows the corresponding development of installed generation capacities. In total, installed capacities increase by 66% between 2000 and 2030. Due to phase-out decisions the share of nuclear power plants declines in the coming decades. Wind and biomass plants as well as gas fired plants show high growth rates. Still, due to primary energy price developments, coal fired plants also increase their share from 2015 on as a consequence of phase-out of nuclear plants.

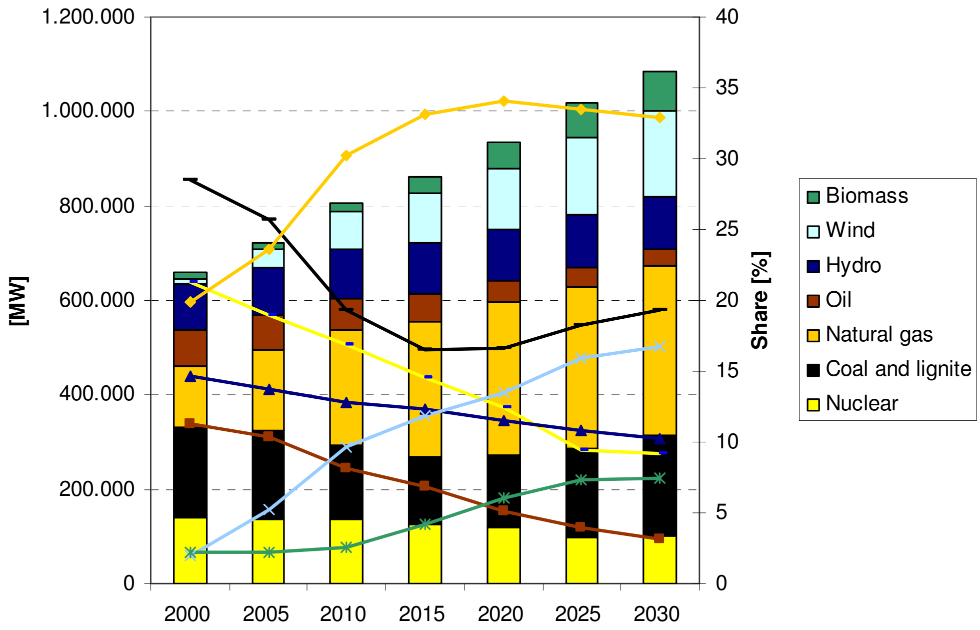

Figure 8. Development of installed generation capacities. Source EC (2006)

The Baseline Scenario indicates need for action for energy policy makers with respect to energy efficiency, renewables, import dependency and CO2 emissions. Fossil fuel imports increase as much as 58% from 2000 to 2030 with an import dependency of 67% in 2030 caused by a primary energy consumption increase of 15% from 2000 to 2030. Both 2010 targets for renewables are not met in the Baseline Scenario. Also CO2 emissions follow a rising pattern.

2.2 World Energy Outlook 2006

The Reference Scenario takes into account policies adopted by mid-2006. Economic growth is assumed to be slightly higher than 2% p.a. on average until 2030 and oil prices are projected to increase from 51 $/bbl in 2005 to 55 $/bbl in 2030 measured in real 2005 terms (Figure 9). No price for carbon is assumed.

In addition, the Alternative Scenario analysis the energy market development if countries adopt all considered energy security and CO2 emission policies.

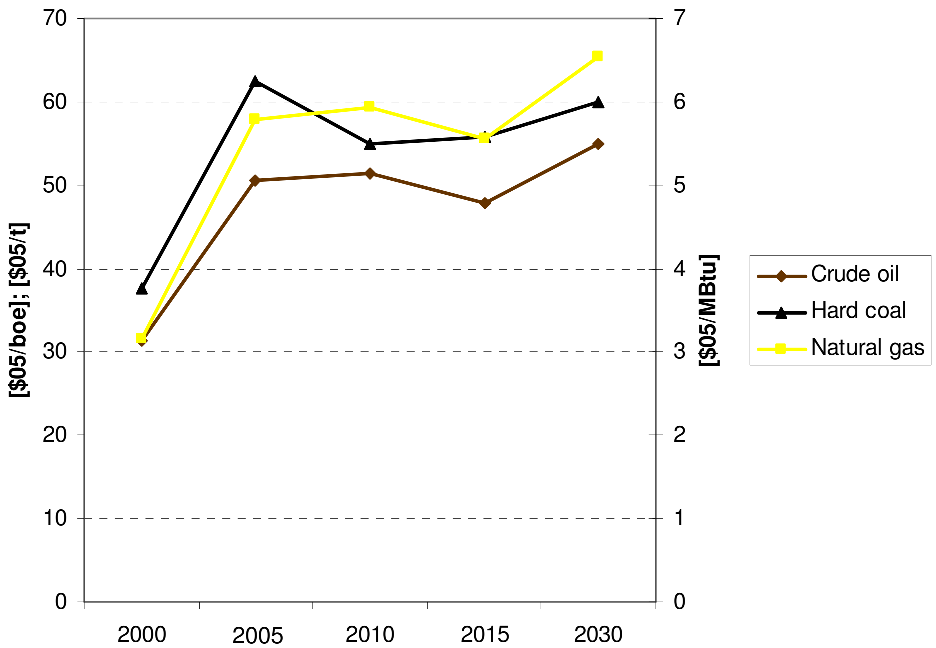

Figure 9. Primary energy price assumptions. Source: IEA (2006)

In the Reference Scenario, total primary energy consumption increases by 12% from 2004 to 2030 with decreasing annual growth rates. The major part of the consumption increase will be met by an increase in natural gas and renewables. With current policies, renewables will exceed the share of nuclear between 2015 and 2030. Together, these carbon free resources amount to 20% of the total primary energy supply in 2030. Oil stays the most important fuel until 2030 with a slightly decreasing share to 35% in 2030 (see Figure 10).

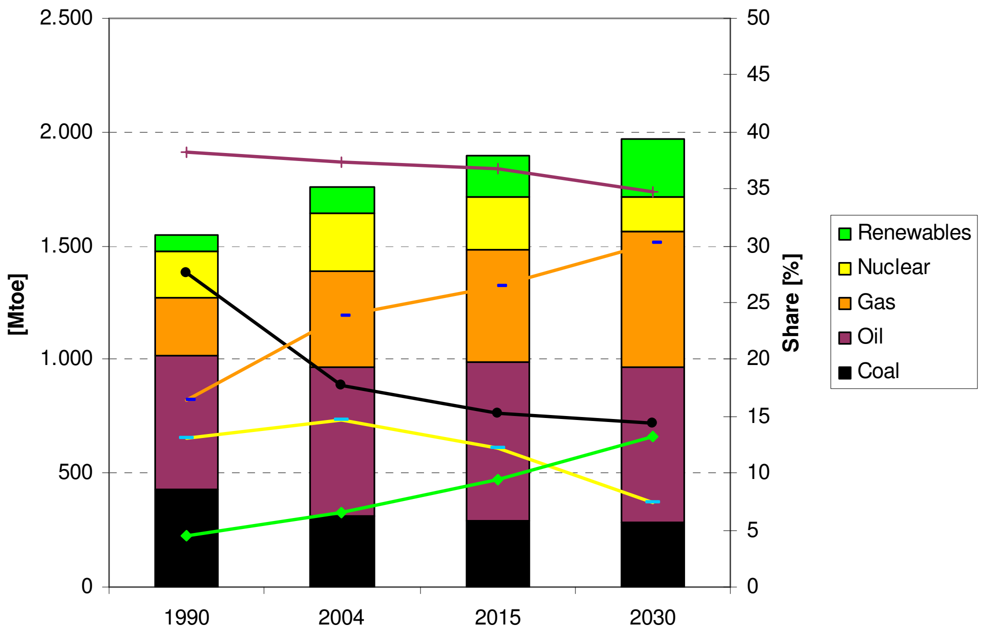

Figure 10. Evolution of primary energy consumption in the EU-25 and relative fuel shares in the Reference Scenario. Source: IEA (2006)

In the Alternative Scenario, total primary energy consumption increases by 5% from 2004 to 2030 with negative growth rates past 2015. Renewables represent the third largest energy source in 2030 accounting for 17% of total supply. Nuclear declines only slightly to a 12% relative share in 2030. Together, these carbon free resources amount to 28% of the total primary energy supply in 2030. Oil remains the most important fuel in 2030 but declines further to 34% in 2030 (see Figure 11).

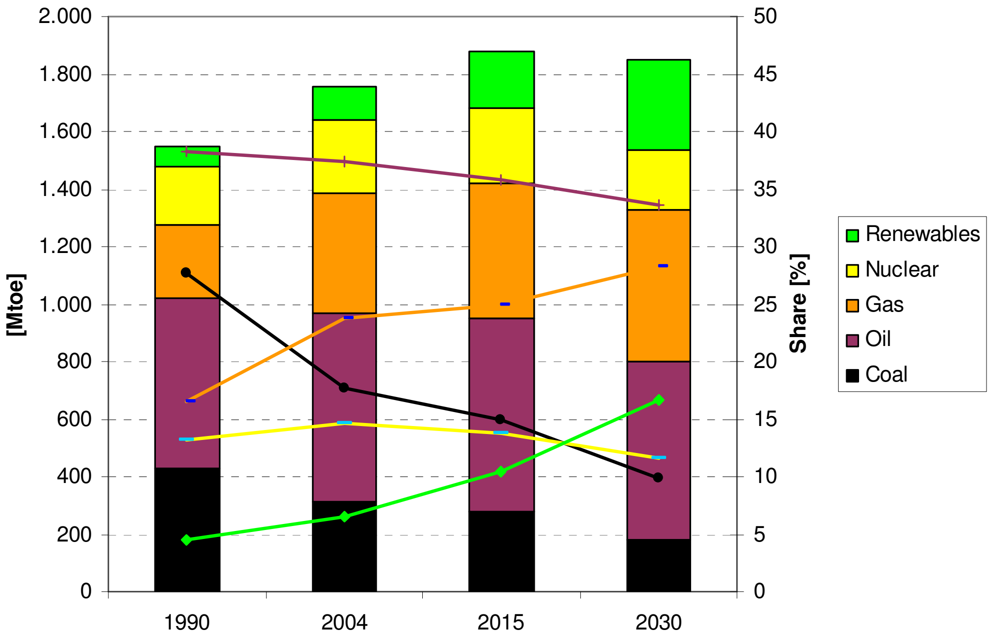

Figure 11. Evolution of primary energy consumption in the EU-25 and relative fuel shares in the Alternative Scenario. Source: IEA (2006)

The development of energy related CO2 emissions is shown in Figure 12. Overall, total CO2 emissions increase by 11% compared to 1990 levels in the Reference Scenario clearly indicating a non sustainable Scenario concerning greenhouse gas emissions. The energy sector remains the largest emission source representing about 36 to 38% of total emissions.

Contrary, in the Alternative Scenario total CO2 emissions decrease over the considered period by 9% compared to 1990 levels. Still, this indicates a large gap to the long-term reduction goals of the EU and a lack of policies to be implemented.

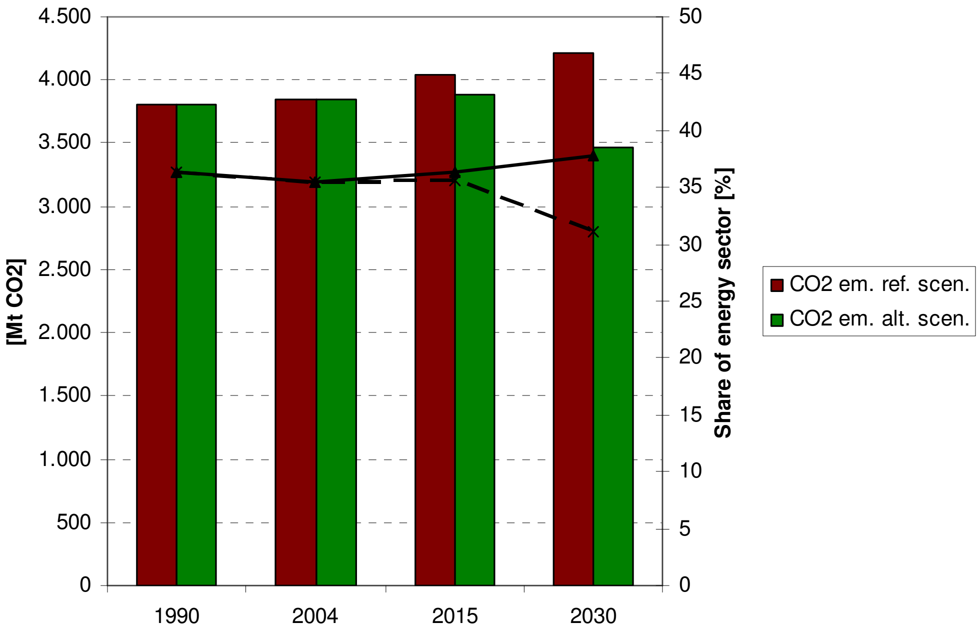

Figure 12. Energy related CO2 emissions in the Reference and Alternative Scenarios. Source: IEA (2006)

From 2004 to 2030 electricity consumption increases by 40% to about 3700 TWh. In comparison total final energy demand rises by 21% clearly indicating strong penetration of electric appliances in the residential and tertiary sectors.

Conventional generation sources represent the major part to meet rising electricity consumption (see Figure 13). Total power generation increases by 36% between 2004 and 2030. RES-E technologies show a rising deployment from 14% of total generation in 2004 to 28% in 2030 with high increases of wind and biomass generation. Still, the 21% target set out in the renewables directive will only be met in 2015. Nuclear generation shows a significant decline in relative terms due to phase out decisions in some Member States. The carbon free generation technologies keep their share between 46 and 41% over the considered period.

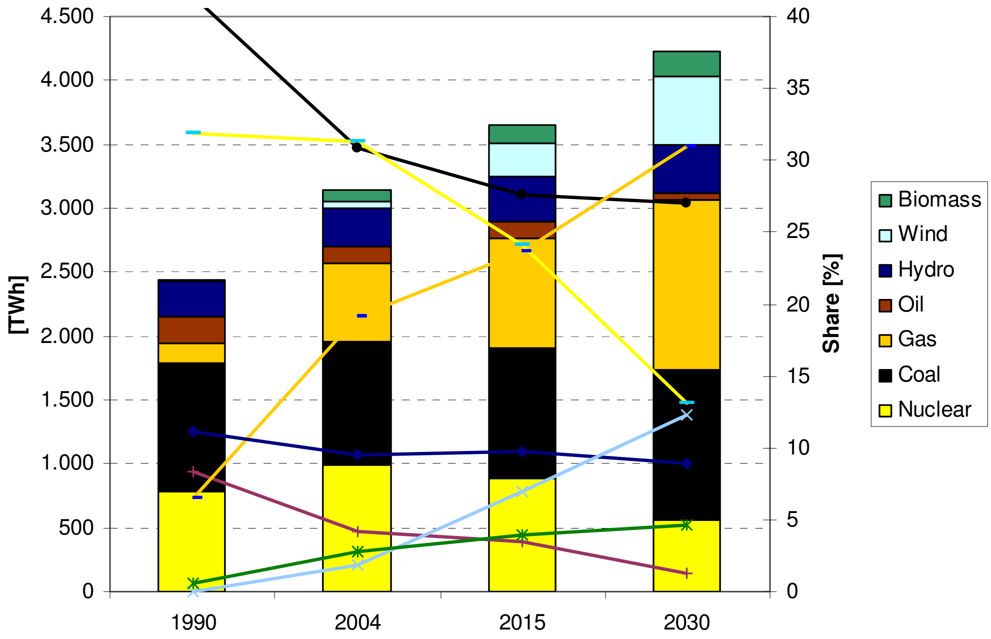

Figure 13. Evolution of electricity generation in the Reference Scenario. Source: IEA (2006)

In the Alternative Scenario, electricity consumption increases by 20% to about 3170 TWh. In comparison total final energy demand rises by 13% clearly indicating strong penetration of electric appliances in the residential and tertiary sectors.

Conventional generation sources represent the major part to meet rising electricity consumption (see Figure 14). Total power generation increases by 17% between 2004 and 2030. RES-E technologies show a rising deployment from 14% of total generation in 2004 to 35% in 2030 with high increases of wind and biomass generation. Nuclear generation shows a lesser decline in relative terms compared to the Reference Scenario and amounts to 22% of the total generation 2030. In the Alternative Scenario, generation in nuclear power plants is 46% higher in 2030 compared to the Reference Scenario whereas RES-E generation is just 9% higher than in the Reference Scenario. The carbon free generation technologies increase their share from 46% in 2004 to 57% in 2030. Generation in coal plants decreases by 44% compared to the Reference Scenario in 2030 whereas generation in gas plants decreases by 36%.

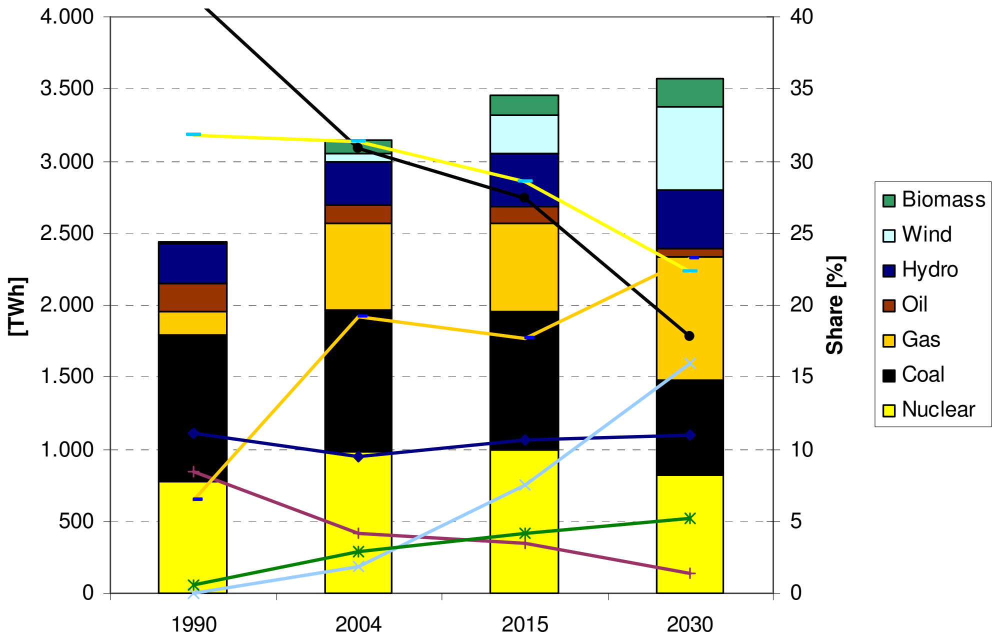

Figure 14. Evolution of electricity generation in the Alternative Scenario. Source: IEA (2006)

Figure 15 shows the development of installed generation capacities in the Reference Scenario. In total, installed capacities increase by 60% between 2004 and 2030. Due to phase-out decisions the share of nuclear power plants declines in the coming decades. Wind and gas fired plants show high growth rates. Coal fired capacities increase by 18% from 2004 to 2030. Still, relative shares of coal plants decline to 20% in 2030.

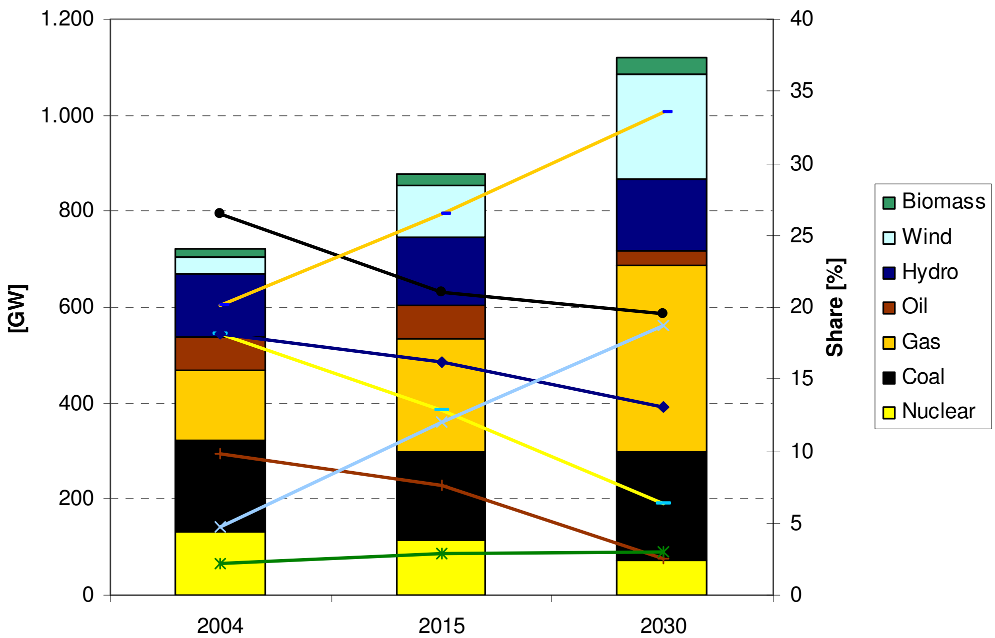

Figure 15. Development of installed generation capacities in the Reference Scenario. Source: IEA (2006)

Figure 16 shows the development of installed generation capacities in the Alternative Scenario. In total, installed capacities increase by 38% between 2004 and 2030. Wind becomes the second largest capacity increasing by 557% from 2004 to 2030. Gas plant capacities are expanded by 92% (27% less gas plants than in the Reference case in 2030) and show the highest market share. Coal fired capacities decrease considerably by 43% from 2004 to 2030.

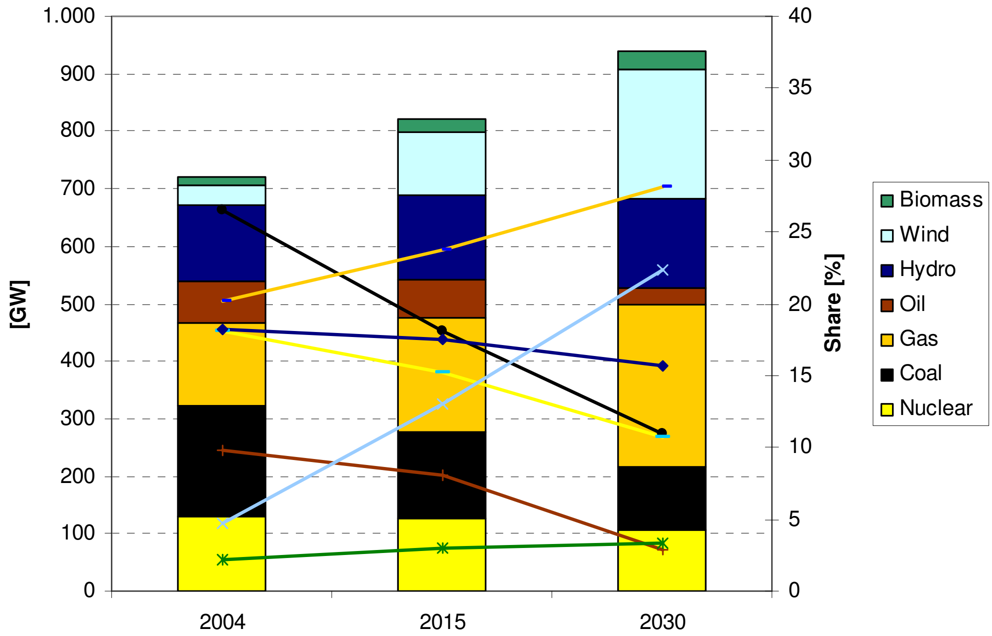

Figure 16. Development of installed generation capacities in the Alternative Scenario. Source: IEA (2006)

2.3 Comparison of European Energy Trends and World Energy Outlook

In the following, the Baseline Scenario of the European Energy Trends and the Reference Scenario of the World Energy Outlook will be compared with respect to major assumptions and results.

In real times, crude oil prices are assumed to increase by 84% in EC (2006) and by 75% in IEA (2006) from 2000 to 2030. In 2030, assumed crude prices are 5% higher in IEA (2006) than in EC (2006). Prices for natural gas increase by 166% in EC (2006) and 107% in IEA (2006). Coal prices increase by 77% in EC (2006) and 60% in IEA (2006).

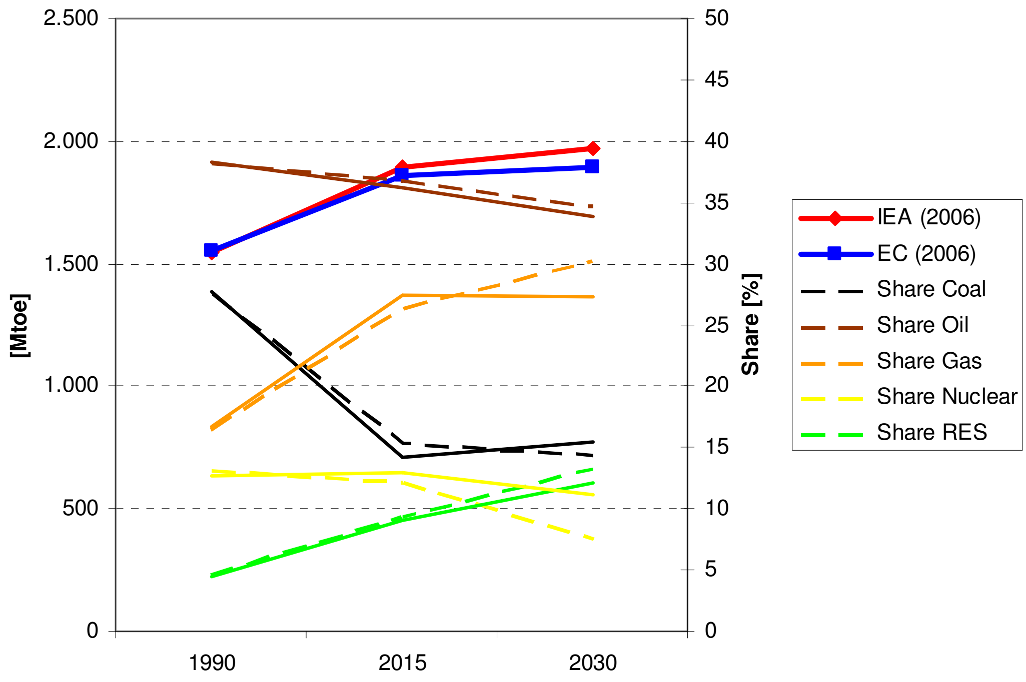

Figure 17. Comparison of primary energy consumption in EC (2006) and IEA (2006) and corresponding relative fuel shares (EC…full line, IEA…dotted line). Source: EC (2006), IEA (2006)

Projections for primary energy consumption are very similar in EC (2006) and IEA (2006) (IEA assumes a 4% higher consumption in 2030, see Figure 17). Due to different price assumptions, relative fuel shares differ especially in case of natural gas but also projections for nuclear energy show an alternative evolution after 2015.

The lower share of CO2 free energy sources in IEA (2006) in 2030 also reflects in total CO2 emissions which are 7% higher than in EC (2006).

In terms of power generation, IEA (2006) and EC (2006) show a similar development of total generation whereas the share of generation sources differs in the two scenarios (see Figure 18). Most notably, the share of gas generated power decreases after 2015 in EC (2006) while this share continues to increase in IEA (2006). Differences in assumed primary energy prices seem to be the main reason behind this increasing spread. To compensate the decrease in gas fired electricity generation in EC (2006) coal generated power show higher growth rates after 2015.

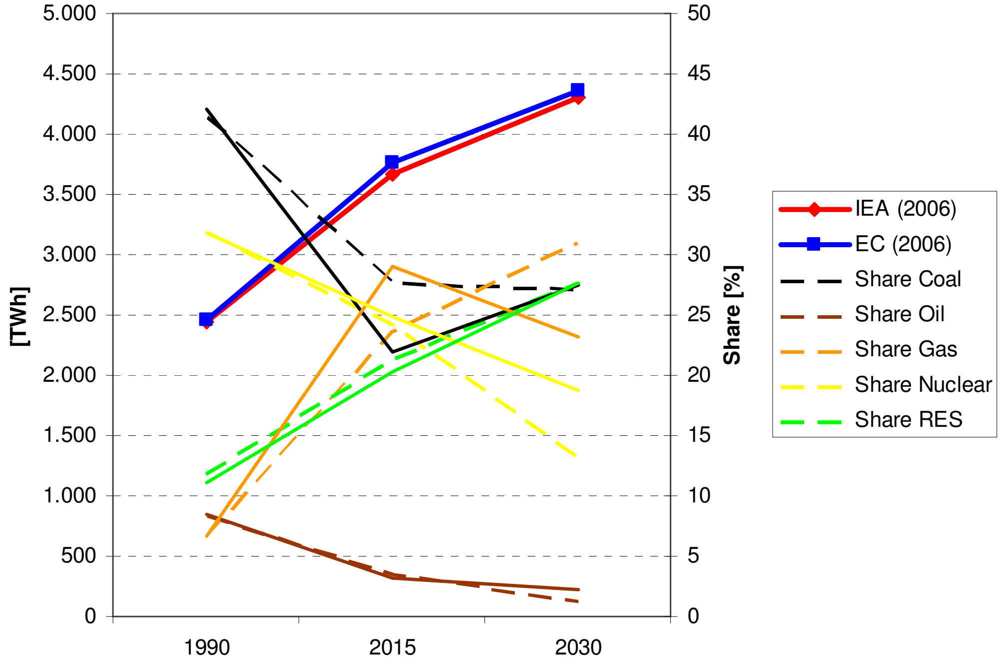

Figure 18. Comparison of electricity generation in EC (2006) and IEA (2006) and corresponding relative fuel shares (EC…full line, IEA…dotted line). Source: EC (2006), IEA (2006)

In 2030 installed generation capacities are 6% higher in IEA (2006) than in EC (2006) (see Figure 19). In line with power generation deployment, capacity shares differ most notably concerning gas fired and coal fired plants. Shares of installed nuclear capacities decrease more slowly in EC (2006).

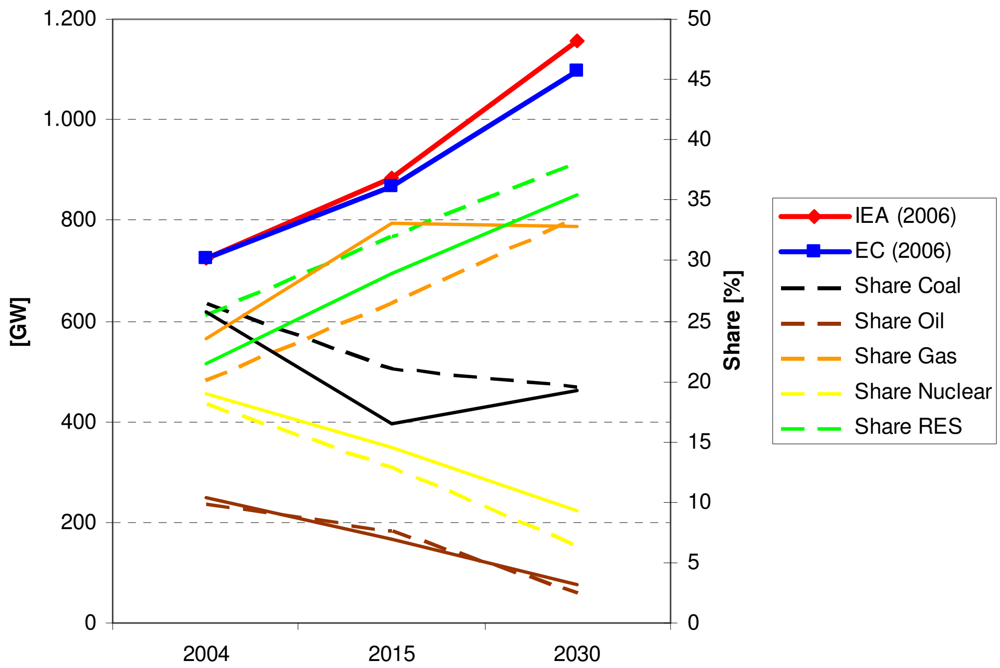

Figure 19. Comparison of installed electricity generation capacities in EC (2006) and IEA (2006) and corresponding relative fuel shares (EC…full line, IEA…dotted line). Source: EC (2006), IEA (2006)

Figure 18 and Figure 19 reveal a considerable difference in the development of various renewable electricity generation sources. In 2030 total installed RES-E capacities are 6% higher in IEA (2006) compared to EC (2006) whereas total RES-E generation is 1% lower in the former study. This gap can be explained by a much higher share of intermittent generation sources like wind power and solar power in IEA (2006) while biomass shows a steeper expansion in EC (2006) (see Figure 20).

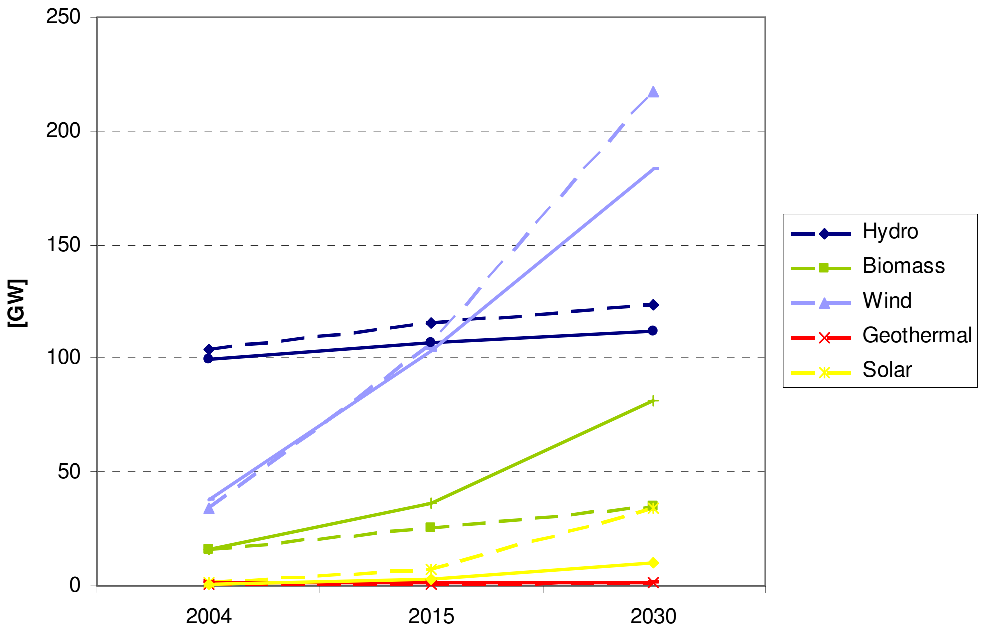

Figure 20. Comparison of installed RES electricity generation capacities in EC (2006) and IEA (2006) (EC…full line, IEA…dotted line). Source: EC (2006), IEA (2006)

3 SUPWIND scenarios and key scenario parameter

In the following four scenarios are built using the inventory of European scenarios and the perspective on large scale integration of wind power. Key parameters are identified which describe major elements for the future electricity system development. These four scenarios reflect possible evolutions of the power systems in the future. Thereby some contrasting developments will be retained to illustrate the impact of political decisions on the integration of wind energy and to enable the system operators to identify robust decisions when using the strategic planning tool in WP6.

3.1 SUPWIND scenarios

3.1.1 "Conflict"

Unresolved conflict of interests, especially between environmentalists and businesses and combines and competitors characterise the European energy sector; market power of big players is not effectively limited. No clear direction of energy policy is visible which results in half-hearted climate policy. Renewable energy support schemes remain subject to different national policies. Nuclear policies, implemented as of 2005, continue in the EU's Member States and supply security constitutes only selective issues.

3.1.2 "ClimateRen"

In this scenario, energy policy focuses on renewable energy sources and energy efficiency as the main goal is a strong reduction of greenhouse gas emissions. Additional deployment of renewables occurs within Europe but RES-E is also imported which goes along with an effective management and modernisation of the electricity network ("Smart Grids"). On the other hand CCS technologies are not considered in the EU whereas LNG constitutes an important transitional energy source. Phasing out of nuclear energy occurs throughout Europe and considerable efficiency gains yield from reduced conversion losses in the final demand and energy sectors.

3.1.3 "ClimateComp"

This scenario is characterised by an efficient and ecological competition brought about by consequent acting of competition authorities. Climate protection is considered as ambitious whereas objectives are achieved through market mechanisms (e.g. emission trading). There are neither social nor political restraints concerning deployment of nuclear energy and sustainability goals are reached exclusively via market mechanisms. Hence, RES-E, CHP, CCS, etc. are only considered as soon as they are cost-efficient.

3.1.4 "Secure"

In this scenario supply security is considered as a top priority. Domestic as well as globally diversified energy sources are the primarily used energy carriers (e.g. coal and nuclear power). Climate protection fades into the background and is characterised purely by a stabilisation goal for Europe. Still, due to autonomy reasons, renewable support continues especially in the heat sector and only to a lesser extent in the electricity sector because of negative impacts on system security and stability.

3.2 Key parameters

In order to characterise the abovementioned SUPWIND scenarios for the future electricity system development, key parameters have to be identified and compared between existing scenarios.

Important endogenous variables which will be determined in the strategic planning tool comprise power plant investments and electricity wholesale prices. The evolution of the demand for energy services and, subsequently, the demand for electricity limits the scope of the electricity supply system development. In turn, when assessing planning and operation of electricity systems with increasing wind shares, RES-E policies are of special relevance for Transmission System Operators (TSOs). Finally, the deployment of the conventional generation park, affected by primary energy prices, CO2 allowance prices, fixed costs and various energy policies, and the location of these plants must be considered in the TSOs' planning.

Therefore parameters for the scenario development must include:

- Demand (and energy efficiency policies)
- Renewable energy and other environmental policies
- Primary energy prices
- CO2 emission allowance prices
- Costs of power plants and the role of interest and discount rates
- Nuclear energy policies
- Security of supply policies

Table 1 summarises all basic data and scenario parameters for the considered parameters qualitatively.

Table 1. Overview of general data and scenario parameters for the four considered scenarios.

BASIC DATA	Planning horizon Strategic planning tool: 2030 (base year 2005) Operational planning tool: up to 2012			
	Discount rate (real): unique rate for investment in power plants, grid; Method for calculation: WACC			
	Geographical coverage E2M2s: EU27 w/o Cyprus, Malta, + Norway, +Switzerland WILMAR: regional			
	Currency: €2005			
	Exchange rates: Average of the year 2005			
SCENARIOS	***Conflict (BAU)***	***ClimateRen***	***ClimateComp***	***Secure***
Demand	O	-	O	O
RES-E development	O BAU OPTRES	++ OPT OPTRES	O BAU until 2010, after 2010 no support – only via CO2	+ focus on biomass and geothermal
Primary energy prices				
Coal	O	O	O	O
Gas/Oil	+ strategic behaviour of suppliers	+	O price cap due to LNG	++
CO2				
Allocation caps	-	--	--	O low target in Europe
Price caps	O	++	++	-
CO2 allocation plan	equal to NAPII	auctioning of allowances from 2015	auctioning of allowances from 2015	equal to NAPII, after 2015 fuel specific benchmark
Nuclear policy	BAU	nuclear phase out in Europe	nuclear option throughout Europe	nuclear option throughout Europe

These key factors and their realisations in the four SUPWIND-scenarios will be described shortly in the following.

3.2.1 Demand (and energy efficiency policies)

Since 1990, electricity consumption in the EU-25 has shown yearly growth rates between 1.8 and 2.1%. Future baseline projections indicate decreasing growth rates from 2.1% to 1% in 2030. Nevertheless, the actual development may somehow look different as the EC's action plan on energy efficiency proposes a 20% demand reduction by 2020. Figure 21 summarises electricity demand deployment in the Baseline, Efficiency and Renewables scenarios of DG TREN.

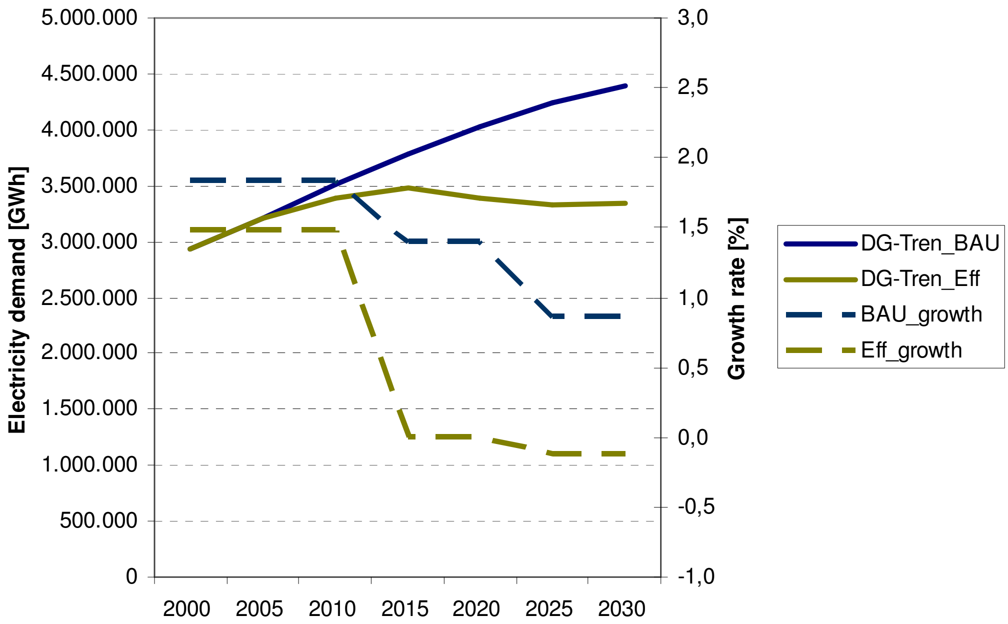

Figure 21. Electricity consumption deployment in the Baseline and Efficiency DG-TREN scenarios. Source: EC (2006)

In the Conflict, ClimateComp and Secure scenarios a baseline development of electricity demand is assumed. Hence, growth rates of the EC (2006) Baseline scenario are used.[1] This corresponds – on an EU-25 level – to declining growth rates from 1.8 % p.a. in 2010 to 0.9 % p.a. in 2030. The ClimateRen scenario assumes a strong focus on energy efficiency policies. Hence, growth rates of the EC (2006) Efficiency scenario are used where average growth rates decline from 1.5 % p.a. in 2010 to -0.1% p.a. in 2030.

3.2.2 Renewable energy and other environmental policies

Renewable energy sources have the potential to serve about one third of the EU's electricity demand by 2020. Considering the targets set out in the strategic energy package of the Commission and the current status of renewables it becomes clear that especially RES-E will play a key role in future renewable energy policies within Europe. For RES-E development results of the European research project OPTRES are used within SUPWIND.

[1] Demand growth rates are distinguished on a country level. Hence, all values mentioned in this report represent merely the general trend which is valid for all Member States.

Figure 23 compares the relative share of RES-E in satisfying gross electricity demand for a BAU and an improved national policies scenario.

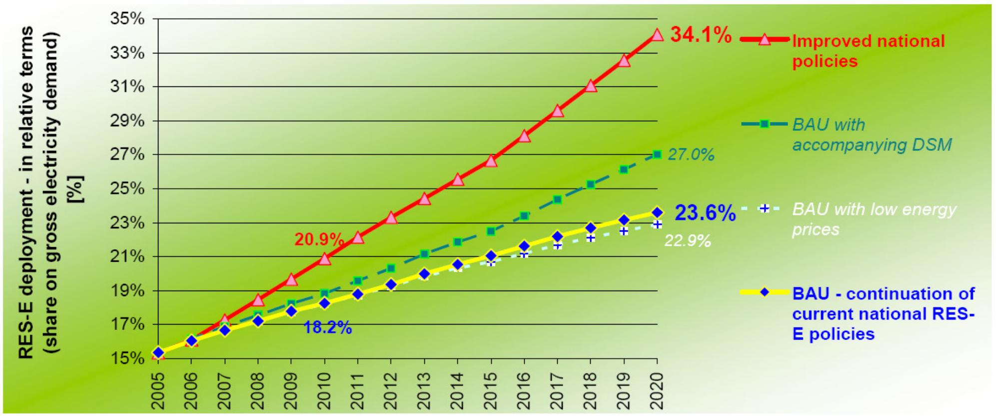

Figure 22. Total RES-E deployment until 2020 in a BAU and improved national policies scenario. Source: Ragwitz et al. (2007)

The development of RES-E generation by different technologies in the EU-25 until 2020 is compared in Figure 22 for a BAU and an improved national policies scenario. Figure 22 reveals a strong increase of wind energy production followed by an increase in biomass energy production for the EU-25.

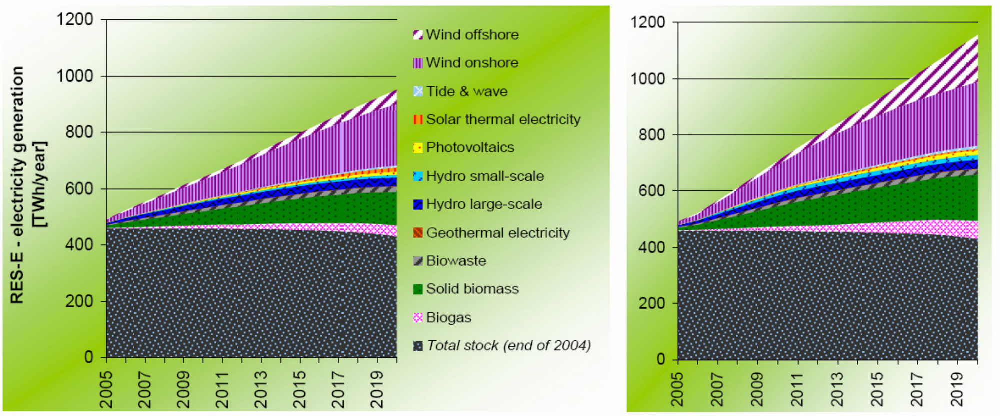

Figure 23. Total RES-E generation until 2020 in a BAU (left) and improved national policies scenario (right). Source: Ragwitz et al. (2007)

For the Conflict scenario a BAU development is foreseen for RES-E (see Figure 23 left part). Similarly, the ClimateComp scenario foresees a BAU development until 2010, whereas from 2010 on market forces will determine RES-E deployment. The ClimateRen scenario assumes an increased RES-E share over time (see Figure 23 right part). In the Secure scenario biomass and geothermal technologies will constitute major parts of renewables deployment due to security of supply considerations.

3.2.3 Primary energy prices

Concerning scenario development one has to be aware of the uncertainty associated with fuel cost forecasts.[2] For operation of power plants, fuel prices clearly represent a crucial parameter.

In a baseline development, prices for gas and oil are expected to reach 23 €'05/MWh and 30 €'05/MWh in 2030 respectively in a DG TREN projection. In the Conflict, ClimateRen and Secure scenarios within this project, higher prices are assumed. EC (2006) finds gas prices increasing to 29 €'05/MWh and 38 €'05/MWh in the year 2030 in a medium and high price case whereas oil prices reach 51 €'05/MWh in the high price scenario at the end of the considered period (see Figure 24).

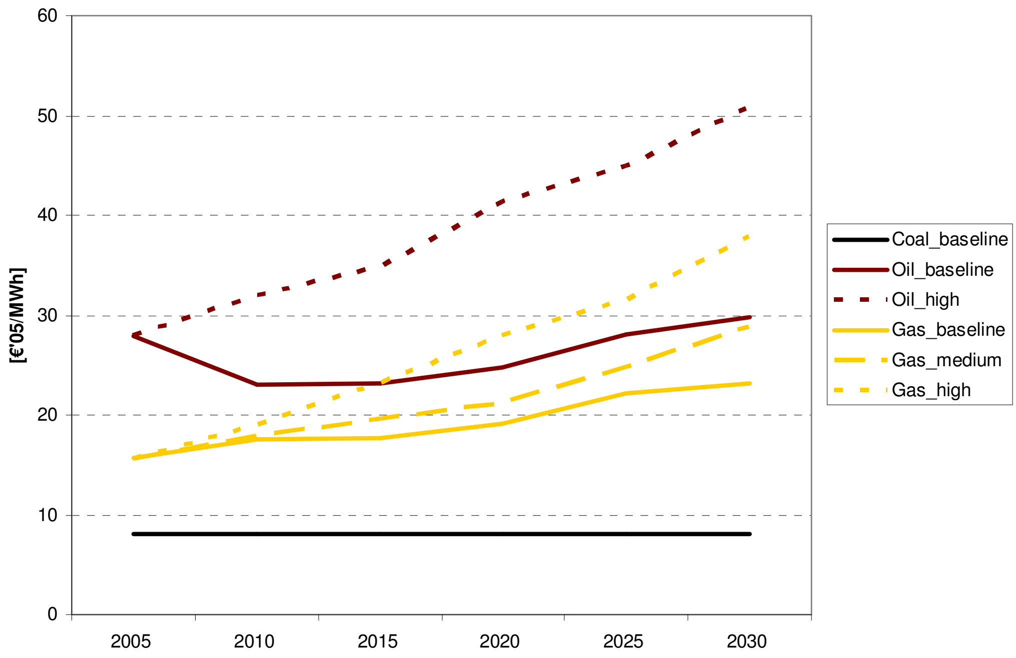

Figure 24. Fuel price assumptions for coal, gas and oil. Source: EC (2006), EC (2006a), SUPWIND

Coal prices are set, in real terms, at ca. 8 €/MWh in all scenarios (adjusted for transportation cost). Gas and oil prices are assumed to follow the EC (2006) Baseline development in the ClimateComp scenario (i.e. gas prices rise from 16 €'05/MWh in 2005 to 23 €'05/MWh in 2030 and oil prices rise from 28 €'05/MWh in 2005 to 30 €'05/MWh in 2030) whereas higher prices are set in the Conflict, ClimateRen and

[2] Primary energy prices are distinguished on a country level. Hence, all values mentioned in this report represent merely the general trend which is valid for all Member States.

Secure scenarios (see Figure 24). In the Conflict scenario gas prices rise from 16 €'05/MWh in 2005 to 29 €'05/MWh in 2030 and oil prices rise from 28 €'05/MWh in 2005 to 51 €'05/MWh in 2030. In the ClimateRen scenario gas prices rise from 16 €'05/MWh in 2005 to 29 €'05/MWh in 2030 and oil prices rise from 28 €'05/MWh in 2005 to 30 €'05/MWh in 2030. Finally, the Secure scenario assumes rising gas prices from 16 €'05/MWh in 2005 to 38 €'05/MWh in 2030 and rising oil prices from 28 €'05/MWh to 51 €'05/MWh in 2030.

3.2.4 CO2 emission allowance prices

Besides fuel prices, CO2 emission allowance prices will crucially determine the development of electricity supply in Europe (both in terms of electricity prices and generation capacities). According to the Energy Package, the Commission proposed CO2 reductions equalling at least 20% until 2020 compared to 1990 levels. This indicates higher long term perspectives for carbon prices than in previous studies assuming reduction mainly within the EU.

CO2 emission allowance prices will be modelled endogenously within the SUPWIND project by using the E2M2s model. Reduction goals and corresponding allocation caps can be derived from the Commission's most recent proposals. The EU's objective is a reduction in greenhouse gases equalling at least 20% until 2020 compared to 1990 levels and a 30% reduction in case of successful international Post-Kyoto negotiations.

For the Secure scenario, which is characterised by a stabilisation target, updating of the Kyoto-target can be assumed; hence the overall reduction goal amounts to -8% in 2030 compared to 1990 levels. The Conflict scenario foresees overall greenhouse gas reductions of -8% to -16% in 2030 compared to 1990 whereas the ClimateRen and ClimateComp scenario assume overall reduction goals of -20% to -30% in 2030 compared to the 1990 levels.

Similarly, price caps of emission allowances set in the model can be linked inversely to the reduction goals. Exogenous price caps vary between 40 €/t CO2 and 60 €/t CO2 in the Conflict scenario, are set to 150 €/t CO2 in the ClimateRen and ClimateComp scenarios and vary between 10 €/t CO2 and 40 €/t CO2 in the Secure scenario reflecting the ambitiousness of the particular climate policy.

With respect to CO2 emission allowance allocation rules, the same provisions as in the National Allocation Plans (NAPs) of the second phase of the European Emission Trading Scheme (EU-ETS) are foreseen in the Conflict scenario. Both the ClimateRen and ClimateComp scenario assume full auctioning of allowances from 2015 on whereas in the Secure scenario a fuel specific benchmark is introduced in 2015.

3.2.5 Costs of power plants and the role of interest and discount rates

In addition to short run marginal costs, fixed costs are of importance when assessing investments in new power plants. Both the interest rate and the economic depreciation time influence the economy of new plants.[3] Especially when demand side technologies are taken into account as well, very high levels of subjective discount rates must be considered.

In the energy sector large amounts of capital are tied up for very long periods which may span for several decades: Power plants and electricity transmission grids may have life-times up to 60 years, or even longer. At the same time many uncertainties stemming from other markets (e.g. fossil fuels) and political decisions (e.g. regulation of grids or emission reduction targets) make it very difficult to assess the discounted cash flow (DCF) of an investment project. This implies that there are significant uncertainties when planning investments into new power plants or transmission grids. A high level of uncertainties is not advantageous for an investor, e.g. shareholder, who wants to be compensated for extra risks which exceed the average market level of risk. This additional compensation, often called risk premium, can be considered during the planning process of an investment through the use of an adequate interest rate on the deployed capital. Herewith, a distinction between borrowed and own capital seems advisable, because different providers of capital may have different claims regarding there risks. The standard concept of investment theory, which provides an adequate approach for quantifying the correct interest rates of investments, is the so called weighted average of capital cost (WACC), which is based on the standard model for capital markets: CAPM.

3.2.5.1 Capital Asset pricing model (CAPM)

The classical approach for describing capital markets is the capital asset market pricing model (CAPM) developed by Sharpe, Lintner and Mossin.[4] It is based on the basic Portfolio theory by Markowitz[5] and describes how risks, which can not be eliminated by diversification of investments, are considered by market participants. Thereby, a distinction between systematical and non-systematical risks is undertaken. Without any risks investments are calculated with a risk free return R_f, which can be granted on the capital market, e.g. by governmental bonds with guaranteed payments. Non-systematical risks are those risks which can be eliminated by the diversification of investments, as

[3] Swider and Weber (2004) give a detailed overview on interest rates.
[4] e.g. Sharpe (1964): Capital Asset Prices - A Theory of Market Equilibrium Under Conditions of Risk," The Journal of Finance, Vol. XIX, No. 3, September 1964, pp. 425-442.
[5] Markowitz (1952): Portfolio selection, pp. 77-92, efficient diversification, 1959.

described by Markowitz. If market players act rational and have sufficient information, they behave in a manner which eliminates all risks of this kind. Notwithstanding the diversification of investors, systematical risks depending on certain projects and market environments remain and can not be avoided in specific industries; for this kind of risk, investors ask for a risk premium on there investment, because without this investments would not be undertaken. The reason for this is that typical investors are risk-averse and demand a compensation for increased risks. The assumptions of the classic CAPM are the following:

- Investors are risk-averse and maximize their risk adjusted utility up to the end of the planning period (concave utility function)
- Investors have homogenous expectations regarding the return of an investment
- Returns are normally distributed
- Market prices can not be influenced by one single investor
- There exist risk free investment opportunities and risk free borrowing arrangements of capital (this implies a risk free rate of return)
- Investors are not restricted regarding debts and investments
- The number of investment and financing projects is given and discretionary separable
- There are no frictions on the capital market and transaction costs are negligible
- All necessary information is disposable
- There are no laws or taxes which constrain the capital market

As a result all investors choose the same investment portfolio, which maximizes their expected utility. Of course, these assumptions are not realistic, but they are necessary for the development of a theoretically basis of capital market description. Although capital markets are not perfect in reality, the results derived from the theoretical considerations of CAPM help to structure some components of the necessary returns of investments in electricity markets and elsewhere. In the following a graphical representation of the rational logic behind the CAPM will be given.

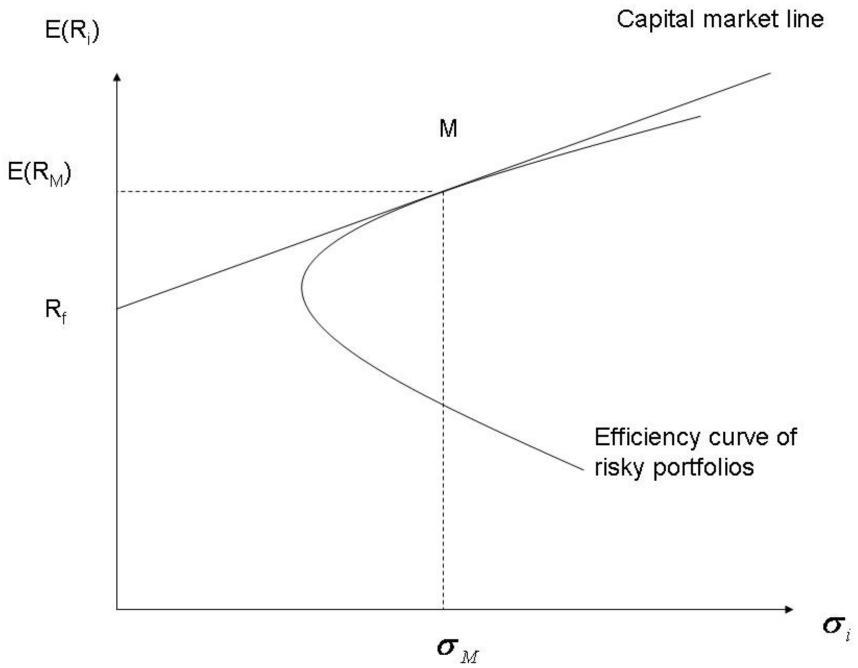

Figure 25. The Capital market line

On the abscissa the standard deviation of the expected return of a portfolio is imaged, while the ordinate describes the expected return of a portfolio. The efficiency curve describes the possibilities to combine different opportunity sets, whereby in the not dominated and therefore relevant part increased risk is accompanied with higher expected returns. The tangential point of the capital market line with the efficiency curve M describes the final market portfolio. All efficient utility maximizing portfolios have to lie on the capital market line, because all combinations bellow the capital market line with the same standard deviation have a lower expected return and therefore are not efficient. This result implies that there is a linear relation between risk and expected return. The origin of the capital market line is the risk free rate of return. The following expression describes the capital market line:

$$E(R_i) = R_f + (\frac{E(R_m) - R_f}{\sigma_m})\sigma_i$$

The slope of this equation describes the price change induced by increased risk. While the capital market line describes the expected return of efficient portfolios i, the CAPM describes the expected return of single investment alternatives j.

Hereby the security market line can be derived, which can be expressed with the following equation:

$$E(R_j) = R_f + (E(R_m) - R_f)\frac{\sigma_{jm}}{\sigma_m^2}$$

In this expression σ_{jm} stands for the Covariance of the expected return between the market portfolio and the investment alternative j and σ_m^2 describes the variance of the expected return of the market portfolio. This fraction is often labeled as the Beta (β_j) of an investment alternative j. Using Beta the security market line can be expressed as:

$$E(R_j) = R_f + (E(R_m) - R_f)\beta_j$$

Thus, Beta describes a linear relation between expected return and increasing risk. The risk-free alternative has a Beta value of zero while the market portfolio has a Beta of 1. A high level of Beta indicates a high risk in relation to the market portfolio and vice versa.

Beta values can be estimated by linear regressions or qualitative methods like scoring models and can be used for the quantification of risk adjusted returns on capital. They play an important role in the determination of interest rates for investment projects. As will be shown in the following section, Beta values are used for the calculation of the interest rate for shareholders' equity and the weighted average costs of capital (WACC).

3.2.5.2 Weighted average costs of capital (WACC)

Investment projects are mostly financed from different capital sources. Capital can stem from the outside and the inside of an investing company. Thereby, creditors and shareholders may have very differing claims regarding interest calculations. For this reason, the necessary interest rate for the calculation of an investment project depends on the capital structure of a company and the required interest rates for debts D and equity E. The weighted average cost of capital is a standard method for the determination of the interest rate for DCF calculations. Herewith, the required interest rates for equity i^e and debt i^d are weighted with their shares of capital D/C and (1-D/C) in relation to the total invested amount of capital C. Formally the post-tax level of costs of capital is given by:

$$\mathrm{WACC}^{\text{post-tax}} = \mathrm{i}^{\mathrm{d}}(1 - \mathrm{t}^{\mathrm{d}})\frac{\mathrm{D}}{\mathrm{C}} + i^e(1 - \frac{D}{C})$$

The employed share of debt is corrected with the term $(1\text{-}t^d)$, which is called tax-shield. The reason for this is that it is possible to set off debts against tax liability. t^d describes the tax rate which is tax deductible.

While interest rates for debt and all other parameters of the WACC can be monitored, it is more complicated to assess the height of the returns on equity deployed. For this reason we will go back to the CAPM, described in the former section and use this concept for the determination of the return on equity deployed. Using this concept, the post-tax WACC formula becomes:

$$\mathrm{WACC}^{\text{post-tax}} = \mathrm{i}^{\mathrm{d}}(1-\mathrm{t}^{\mathrm{d}})\frac{\mathrm{D}}{\mathrm{C}} + (i^{f} + (i^{m} - i^{f})\beta)(1-\frac{D}{C})$$

The return on equity is determined by a risk free interest rate and the difference between the market interest rate and the risk free interest rate multiplied with the Beta factor, which describes the deviation of the investment risk in relation to the average market risk. For the calculation of Beta it is necessary to assess the uncertainties in the electricity industry in comparison to the uncertainties of the capital market. The following picture summarizes the post-tax WACC concept:

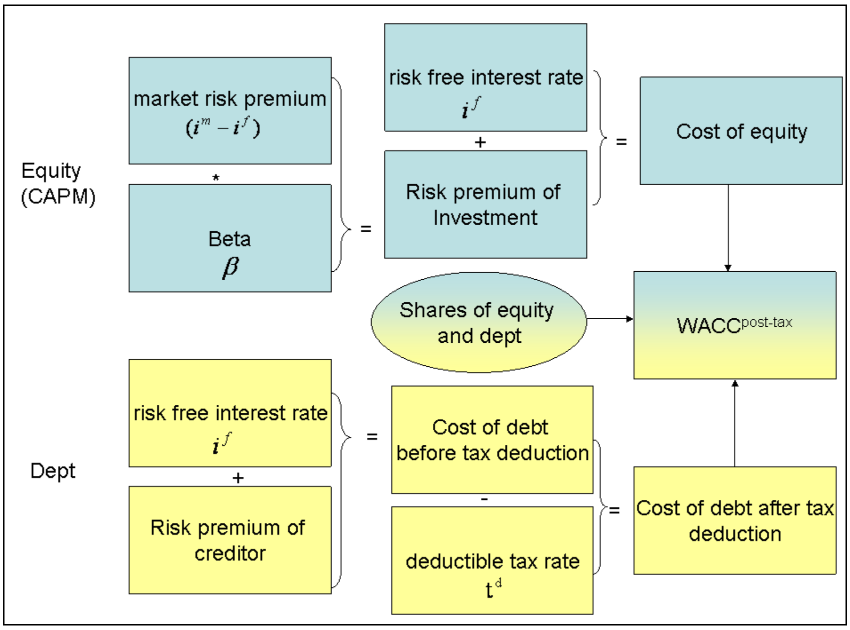

Figure 26. The post-tax WACC concept.

Sometimes not only the components of the WACC are relevant for investment decisions, and additionally other factors are considered in the determination of an interest rate for DCF analysis. For example, specific premiums for country specific factors might be added. In this section we assume that there are no additional factors which are taken into account. In the following part of this note we will discuss this again.

Also weighted tax rates on returns are often considered and included in the calculation of the necessary WACC. Therefore, the pre-tax WACC is relevant for the investment decision and not the post-tax WACC: The returns of a company are reduced by the corporate income tax and without consideration the post-tax WACC is not sufficient in order to fulfill the requested returns of the shareholders. For this reason, the calculation of the necessary pre-tax WACC equals the post-tax WACC multiplied with $1/(1-t^c)$ whereby t^c represents a weighted average of the relevant corporate income tax(es). The following equation describes this relation:

$$WACC^{post\text{-}tax} = WACC^{pre\text{-}tax}(1\text{-}tc)$$

With this relation we can ascertain the final pre-tax WACC, which is necessary for the assessment of investment projects.

$$WACC^{pre\text{-}tax} = i^d \frac{D}{C}\frac{(1-t^d)}{(1-t^c)} + (i^f + (i^m - i^f)\beta)(1-\frac{D}{C})\frac{1}{(1-t^c)}$$

Herewith, we derived a description of the pre-tax WACC, which will be calculated in the following. If $t^d = t^c$ holds true, returns form debts are considered as tax exempt. This tax exemption biases the capital structure in favor of debts.

Key parameters:

Information about the parameters of the pre-tax WACC is mostly freely available and can be observed directly. For example the interest rate postulated by a creditor is reported in the financial statement of a company. Unfortunately, in the SUPWIND project one single interest rate is needed for the calculation of heterogeneous investment decisions. There might exist different risks when new grid or new power plant capacities are considered. It might also be a significant distinction if a nuclear power plant or a small gas turbine is built. Additionally, differences between the EU-27 countries have to be neglected. If a specific risk in the electricity industry is assessed, the Beta value for the calculation of return on equity can not be quantified easily, because large electricity industries have combined activity-branches, like generation and retail, which can not be evaluated separately easily, because market rates are related to a company as a whole.

For this reason, average values for the parameters in question have to be found. In the following we will rely on typical values used by big companies, which are active in different branches of the electricity sector: The following table shows the used parameters of three big companies in Germany: RWE, E.On and EnBW, published in there annual financial reports of 2005. Unfortunately, other large electricity suppliers in the European Union do not publish data about their WACC. For this reason we have to rely solely on the available German data.

Table 2. WACC parameters of large electricity suppliers.

	E.ON	RWE	EnBW	Average
risk free interest	5.1%	5%	5.1%	5.1%
market premium	5%	5%	5%	5.0%
Beta	0.7	0.7	0.8	73.3%
costs of equity	8.6%	8.5%	9.1%	8.7%
interest rate for debt	5.6%	5.8%	5.7%	5.7%
deductible tax rate	35%	29%	32%	32.2%
tax shield	2.0%	1.7%	1.8%	1.8%
costs of debts after tax deduction	3.64%	4.10%	3.87%	3.9%
share of equity	45%	40%	40%	41.7%
share of debts	55%	60%	60%	58.3%
post-tax WACC	5.9%	5.9%	6.0%	5.9%
income corporate tax	35%	35%	35%	35.0%
pre-tax WACC	9.0%	9.0%	9.2%	9.1%

It can be seen that there are no significant differences between the used Parameters. Some like the market premium or the weighted income corporate tax do not deviate at all (which is, due to the complex corporate tax laws, not as trivial as it seems at first thought). The Beta values below 1 indicate that investments in the energy market are chancy below average. While the pre-tax WACCs calculated here are nominal, we need the WACC in real terms. For this reason the average inflation rate from 2005 has to be subtracted. In the European Union the average inflation rate was 1.9% in 2005, which yields a real average pre-tax WACC in the height of 7.2%.

Considering market power

The WACC derived in the section above describes the costs of capital employed. Therefore, the WACC is a lower bound for the returns of an investment. If this critical limit is undershot, the shareholders will not receive their expected returns. Nevertheless, it might be possible to use higher interest rates in the calculation of investments. A concept which can be applied here is the hurdle rate, which distinguishes between specific project risks, e.g. due to country specific circumstances. The use of differentiated internal interest rates is also necessary instrument for a company, in order to allocate capital to the most promising investment projects.

The models applied for the SUPWIND-project are fundamental models, which means that they are constructed with the premise of perfect competition in the electricity market. This means, that all companies have no opportunity to exceed the minimal return, which was determined in the sections above, because they are price-takers and the market prices under competition are not high enough to generate proceeds which allow returns above the WACC.

In this view, the models applied are normative models which represent the first-best outcome under predefined circumstances. The use of the WACC derived above is consistent with this view.

However, the objective of this project is the development of a tool for decision support for Transmission grid operators. In reality TSOs are confronted with situations, where competition is not sufficiently working. Reasons for this might be a lack of information, various uncertainties, political influences or market power in the electricity market. Especially the latter case might have significant impact on investment decisions and therefore future generation capacities. Recent research indicates that it is likely that there is a problem with market power in the electricity industry.[6] For this reason the applied models should be modified in a manner which allows the construction of positive scenarios which also consider market power. One rather simple way to represent market power in the SUPWIND tool is the use of interest rates which exceed the average costs of capital in the E2M2s model. The problem here is to quantify the markup which can be added to the costs of capital.

Interest rates for the SUPWIND project

Within the four SUPWIND scenarios “Conflict”, “ClimateRen”, “ClimateComp” and “Secure” only the scenario ClimateComp assumes perfect competition. In this scenario the use of the real WACC is self-evident. Meanwhile, for the other scenarios an interest rate with a non-competition markup is needed. The estimation of this markup is quite difficult, because due to technical complexity and lack of information it is not possible to determine optimal market results as a benchmark. For this reason, a rough estimate is needed for the consideration of possible market power.

An indicator for the returns of companies in the electricity businesses is the return on capital employed (ROCE) which is the ratio of the earnings before interest and taxes (EBIT) and the capital employed. In 2005 the large companies examined in section 5. had Roce values in the range of 13-15%. For several reasons the difference between the ROCE and the WACC in height of 4-6% can not be interpreted as a market power

[6] E.g. Schwarz, H.-G. and Lang, C. (2006): The Rise in German Wholesale Electricity Prices: Fundamental Factors, Exercise of Market Power, or Both? IWE Working Paper Nr. 02, Institut für Wirtschaftswissenschaft, Universität Erlangen-Nürnberg; and Müsgens, F.(2006): Quantifiying Market Power in the German Wholesale Electricity Market Using a Dynamic Multi-Regional Dispatch Model. The Journal of Industrial Economics, Vol. 54, No. 4, S. 471-498.

markup: On the one hand the electricity companies in view still have depreciated capital stemming from times before the market liberalization and on the other hand they benefit from the free allocation of CO2 certificates in the European emission trading scheme. Both circumstances increase the producer surplus from the selling of electricity. Therefore, the dimension of market power in the electricity market has to lie in the range between the WACC and the ROCE. In the longer run when depreciated capacities leave the market and emission allowances are at least partly auctioned, a markup beyond the WACC can only be obtained from market power.

Using this information, the estimates of the former mentioned studies and earlier E2M2s-results a non-competition markup in the height of 1-4% seems realistic. For the SUPWIND scenarios we will use a value in the upper middle of this range: 3%. When the model is finalized, a sensitivity analysis should be conducted in order to assess the impact of market power onto the model results. An assumption like this seems to be a strong and highhanded simplification, but considering the time span, which will be modeled, and the lack of information it seems inevitable.

Conclusion

The standard method of determining capital costs is the weighted average of capital cost. The WACC yields a suitable interest rate in the case of perfect competition. Some scenarios of the future power system in the SUPWIND project deny perfect competition and assume market power of generation companies. In this case a markup which exceeds the WACC is necessarily added to the WACC. Since the determination of this markup is difficult, a rough estimation stemming from own calculations and recent publications on market power was used. This analysis led to the conclusion that a markup in the height of 3% seems reasonable for the scenario analysis in the SUPWIND project. Hence, in the scenario “ClimateComp” an interest rate in to the amount of 7.2% is used, while in the other three scenarios an interest rate to the tune of 10.2% will be applied.

3.2.6 Nuclear policies

About one third of the EU’s current electricity demand is met by nuclear power plants. Since each Member State decides whether to use this form of electricity generation and this issue is part of a big debate in many Member States the future role of nuclear in Europe is unclear. Furthermore, currently only one new power plant is being built in the EU and view proposals concerning upgrading existing installations are being assessed. Considering the long lead time of nuclear investments huge additional investments will therefore not take place in the next 10 to 15 years. However, a big debate concerns the life time of existing power stations. Certainly, shortening or extending these has influences on power market development. EC (2007) provides an overview of nuclear activities in the Member States.

A baseline development of nuclear policies is assumed in the Conflict scenario. Nuclear phase out in Europe is assumed in the ClimateRen scenario whereas the ClimateComp and Secure scenarios foresee the nuclear option throughout Europe.

3.2.7 Security of supply policies

In the baseline scenario of EC (2006), fossil fuel imports increase as much as 58% from 2000 to 2030 with an import dependency of 67% in 2030 caused by a primary energy consumption increase of 15% from 2000 to 2030. To avoid such a development supply security policies may put in place (e.g. energy tax on fossil fuels, etc.) evidently having effects on the electricity supply sector development.

3.3 Summary of scenario parameters

Table 3 summarises the considered scenario parameters in the four SUPWIND scenarios.

Table 3. Scenario parameters within the SUPWIND project.

SCENARIOS	*Conflict (BAU)*	*ClimateRen*	*ClimateComp*	*Secure*
Demand	Declining growth rates from 1.8 to 0.9% p.a.	Declining growth rates from 1.5 to -0.1% p.a.	Declining growth rates from 1.8 to 0.9% p.a.	Declining growth rates from 1.8 to 0.9% p.a.
RES-E development	O BAU OPTRES	++ OPT OPTRES	O BAU until 2010, after 2010 no support – only via CO2	+ focus on biomass and geothermal
Primary energy prices[7]				
Coal	8 €'05/MWh	8 €'05/MWh	8 €'05/MWh	8 €'05/MWh
Gas	From 16 €'05/MWh in 2005 to 29 €'05/MWh in 2030	From 16 €'05/MWh in 2005 to 29 €'05/MWh in 2030	From 16 €'05/MWh in 2005 to 23 €'05/MWh in 2030	From 16 €'05/MWh in 2005 to 38 €'05/MWh in 2030
Oil	From 28 €'05/MWh in 2005 to 51€'05/MWh in 2030	From 28 €'05/MWh in 2005 to 30 €'05/MWh in 2030	From 28 €'05/MWh in 2005 to 30 €'05/MWh in 2030	From 28 €'05/MWh in 2005 to 51€'05/MWh in 2030
CO2[8]				
Overall reduction goals	-8 to -16% in 2030	-20 to -30% in 2030	-20 to -30% in 2030	-8% in 2030
Price caps	40 to 60 €/t CO2	150 €/t CO2	150 €/t CO2	10 to 40 €/t CO2
CO2 allocation plan	equal to NAPII	auctioning of allowances from 2015	auctioning of allowances from 2015	equal to NAPII, after 2015 fuel specific benchmark
Nuclear policy	BAU	nuclear phase out in Europe	nuclear option throughout Europe	nuclear option throughout Europe

7 Primary energy prices are distinguished on a country level. Hence, the values shown in Table 2 represent merely the general trend which is valid for all Member States.

8 See http://www.electricitypolicy.org.uk/TSEC/2/ for detailed information on NAPII.

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