ALTERNATIVE ELECTRICITY SUPPLY SCENARIOS FOR EUROPE-12 1990-2020

Analysis Based On MIDAS-ELEC Model

by

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1. INTRODUCTION

The current context for power generation is characterised by a continuous increase in demand, as electricity is seen as a simple, flexible and clean alternative for end-use energy requirements. The annual rise of demand in the European Union amounts to more than of 2% in the mid-90s.

This increase in demand, combined with the age-related retirement of a considerable segment of the existing park in the next 15-20 years, requires a good amount of decision making on new plant investment.

Unlike the use of electricity, its generation is an important source of pollution, and, in times of growing environmental concern, suppliers are faced with constraints on emission quantities.

The power industry also faces a trend towards deregulation with privatisations of the electricity utilities and increased trade between countries.

This study was conducted using a new version of the MIDAS-ELEC model. According to DG-XVII/A2 requirements the study focuses on electricity generation for Europe-12 up to 2020. Both the time horizon and the character of scenario analysis were defined in accordance with the broader Energy-2020 project sponsored by DG-XVII/A2. The outcome of this study was designed to support two objectives: to prepare partly the modelling infrastructure for the broader Energy-2020 study; and to provide preliminary results for the electricity generation sector, that scan the possible future perspectives and give insight on various possibilities.

2. MAIN ISSUES

The aim of this study is to facilitate the discussion of the issues associated to planning and operating the electricity generating system.

The decision domain in Europe-12 for the next 25 years is considerable: about 500GW of new plants are required (half for replacing plants to be decommissioned and half to cover new electricity demand), from which up to 400GW will probably be fossil fuel plants.

The prevailing political climate is in favour of limiting future nuclear capacity expansions for reasons of health and safety standards, waste disposal, plant decommissioning procedures, and public reluctance to nuclear energy sites.

Planning decisions are constrained by growing ecological concerns that are mainly focused on greenhouse gas (CO_2 quantity and tax) and air toxics (NO_x and SO_2 emission standards). There already exist decisions for the stabilisation of CO_2 and the establishment of strict emission standards for NO_x and SO_2 in large firing plants.

These concerns led to the emergence of new 'cleaner' technologies for power generation. These technologies, currently starting commercialisation, comprise mainly:

- new coal technologies: integrated coal gasification combined cycle, atmospheric stationary/circulating fluidized bed combustion, pressurised fluidized bed combustion etc.
- new gas technologies: gas turbine combined cycle.

Furthermore, a new role for industrial auto-producers and combined heat- power generation (CHP) is proposed, concerning both large scale district heating and small scale industrial use. Often the merits of decentralised production are emphasised, considering also renewable energy sources (e.g. wind power).

Natural gas firing plants present major advantages in terms of environmental characteristics, construction lead times, efficiency characteristics and price, so extensive use is foreseen even in the near future. The appearance of natural gas as a source of cheap and clean fuel presents us with the issue of the system's vulnerability to gas price and availability.

The overall competitiveness of electricity as measured by total and marginal cost is to be explicitly quantified within the above context, reflecting both generating costs and opportunities for trade.

3. OVERVIEW OF THE APPROACH

3.1 CONTRASTED SCENARIO APPROACH

As described above, the context in which power generating companies plan their future development, is characterised by a considerable degree of uncertainty. There is no established strategic choice, although current decisions favour gas-fired plants of new technology. The fact is that a strategy based on natural gas would largely depend on the stability of the supply patterns, which are still in transition. There is little confidence in fuel prices, although optimism prevails at present.

The evolution of new coal technologies is still not fully matured, and renewables still have high costs and are limited by their irregular supply patterns. The policy towards the polluter's pay principle is still under debate (e.g. carbon tax) and so is the issue of systems interconnection. This uncertainty leaves little room for "reliable" forecasting over a useful time horizon.

The planning approach adopted instead, is based on contrasted scenarios for the time period 1990-2020 and for the EU-12 countries. The scenarios are quantitatively evaluated by using the MIDAS-ELEC model. MIDAS-ELEC is a new version of the MIDAS electricity submodel, constructed to simulate the power generating system of each country. The result is the economic optimisation of the planning and dispatching of the generating capacities, given electricity demand and fuel prices. The model is fed with a set of contrasting scenarios to search the limits and understand the effects of various conditions.

3.2 SOURCES AND METHODS FOR DATA

The database used to construct the model and the scenarios for each country draws from a variety of sources:

- EUROSTAT (energy balance sheets, electricity production statistics)
- OECD - IEA (fuel prices)
- EPIC (generating capacities)
- ESAP (technical and economic characteristics of plant types including efficiency, life-time, investment-fixed-variable costs; existing capacities as well as planned investment and decommissioning; imports and exports per load level)
- FRET, DG-XVII/A2 (new technologies)
- IEA (renewables potential)
- HECTOR (emission factors)
- COOPERS & LYBRANT (gas market projections)
- DRI (macroeconomic data)
- "A VIEW TO THE FUTURE ", DG-XVII/A2 (reference scenario 1990-2005)

3.3 DEFINITION OF COMMON ASSUMPTIONS

The approach is based on partial analysis and involves only electricity sector-specific projections. The demand as well as the fuel prices are considered exogenous and there is no feedback from the power generation sector. In the next stage of the study the MIDAS-ELEC model will be integrated with the other parts of the MIDAS model (demand, refineries, gas supply etc.), so to form an energy sector partial equilibrium model.

The macroeconomic environment is considered fairly stable and in any case constant between the alternative scenarios.

The technology is also regarded as mainly constant. Although room is left for the penetration of new fossil fuel technologies and CHP, no radical technological change is allowed.

3.4 SCENARIO DESIGN

The basic scenario called the New Conventional Scenario is a business-as-usual projection of the current situation and trends. It is characterised mainly by the increase in demand as projected in the ‘A view to the future, DG-XVII/A2’ study, and plentiful fuel supply including all required quantities of cheap natural gas.

Three variants of the New Conventional Scenario are also constructed to account for:

- A probable increase in natural gas price to reflect exploding demand;
- The possibility to face reduced electricity demand reflecting DSM policy and energy saving measures;
- The adoption of more ecologically oriented priorities in planning, to reflect growing environmental concern.

Thus, in total, four contrasted scenarios are quantified with the MIDAS-ELEC model, for 1990-2020 and for the 12 members of the European Union.

3.5 MODEL CONSTRUCTION AND USE

The MIDAS-ELEC model addresses the power supply problem at three levels. Firstly, at the planning level, it identifies the supply gaps in the load demand pattern and determines the strategic capacity expansions required to fill these gaps. Then, at the operational level, the dispatching order of the generating capacities is decided, on a least-cost basis, for each individual plant. Finally, the total and marginal costs are computed, both as averages and in four load bands, to allow for pricing considerations.

As mentioned above, the model requires as exogenous inputs fuel prices and electricity demand both in terms of energy and load pattern. Imports and exports per load level are also exogenously supplied, although some peak imports are endogenously decided for reasons of system reliability. A maximum tolerated loss-of-load probability and a minimum reserve margin are imposed. The existing park including any already decided investment and decommissioning is exogenously defined, together with technical and economic characteristics of plants. A maximum number of candidate units for investment per plant type is set by the user, as well as any dispatching system constraints. Finally, the emission factors per fuel and plant type are given. New capacities are assumed to incorporate, to some degree, abatement technologies for NO_x and SO_2 emissions.

The model produces projections for the electricity supply system in detail, including:

- total and new generating capacities per plant type, electricity produced and load factor per plant type;
- overall loss-of-load probability and system reserve margin;
- fuel consumption and emissions of pollutants;
- investments, total and marginal operating cost, marginal cost per load band.

The model executes in five main steps:

a) CONSTRUCTION OF THE LOAD CURVE: A piece-wise linear approximation of the annual load duration curve is constructed using the electricity demand and load pattern for each country. The electricity demand is given for the domestic sector (residential, tertiary and agriculture), transports, iron & steel, non-ferrous industries, building materials, paper & pulp, chemicals and other industries. The assumed load pattern for each sector is piece-wise linear with four points at 8760, 6000, 2000 hours and peak. These load patterns, together with the patterns for exports and system losses, are combined to form the annual load duration curve. The load duration curve is then adjusted for the non-dispatchable plants. These include imports, plants that have randomly available energy source (run of river hydroelectric, solar thermal, solar photovoltaic, geothermal, wind power, tidal and wave energy), and plants that use non-stockable fuels (wastes, refinery gas, liquified petroleum gas, gasoline, kerosene, blast furnace gas, gasworks gas, coke-oven gas, coke and other fuels). For these plants a pre-defined load profile is considered. This profile differs by country and is quantified in the calibration process. The area defined by the profile and the expected electricity production of these plants, is then geometrically extracted from the load duration curve. In the case of pumping this process results in the displacement of an area of different shape from the peak to the base.

b) PLANNING DECISIONS: The dispatchable plants include 50 plant types and sizes. Investments on necessary capacity expansions are decided on the basis of long-term marginal cost compared with the short-term marginal cost of the existing plants. The long-run marginal cost includes an annuity for capital cost augmented by the interests during construction and divided by the load factor, the annual fixed cost also divided by the load factor, and the annual operating cost (variable and fuel cost). At each load level, from base to peak, the marginal costs of candidate plants are compared and the selected plant unit is allocated. Given the plant forced outage rate, the expected operation time and expected electricity production are computed in a convolution process. The planning is constrained by fuel availability and hour operation limits. Some exogenous capacity expansions are considered to cover short-run inertia and planned investments.

c) OPERATION DECISIONS: Plant dispatching on the load curve is decided upon the short-term (operational) cost of the available plants. The expected electricity produced is computed following a convolution process combining a two-stage probabilistic model with the normalised inverse load duration curve. The dispatching is constrained by autoproducers (hour operating range), CHP (range and minimum required heat), fuel quantities and peak devices (priorities). A convolution process calculates the expected electricity produced by plant and the system loss-of-load probability. The optimum fuel shares for multifuel plants are also computed, based on fuel prices. Total consumption by fuel is computed while the final LOLP is covered by peak imports.

d) COST COMPUTATION: For the dispatchable plants the long-run marginal cost (LRMC) is calculated as described above, based on load factor, capital amortization, fixed cost, variable cost and fuel price. These LRMCs are connected to the load level on the load duration curve. The non-dispatchable plants are charged at their cost in base or at the avoidable cost in the peak outside the base. Total cost is also calculated based on total investment. The average total and the average long-run marginal costs per kWh are computed. The average long-run marginal cost is also produced for four load bands (base, 2000-6000h, 0-2000h and peak).

e) EMISSIONS COMPUTATION: Emissions are computed for CO_2 , NO_x and SO_2 based on exogenous emission factors. These emission factors differ per equipment vintage, as new plants are assumed to incorporate abatement technologies for NO_x and SO_2 pollutants.

3.6 TYPE OF RESULTS AND COMPARISONS

The largely detailed results produced by the model are aggregated in a set of report tables that include:

i. ELECTRICITY PRODUCTION STATISTICS (demand for electricity by sector, energy branch consumption and losses, electricity exchanges, electricity production, final system reserve margin, final LOLP, emissions of pollutants)

ii. INPUT / OUTPUT (gross electricity production by fuel, fuel consumption)

iii. CAPACITIES (generating capacities and capacity expansions per plant type)

iv. COSTS (investment costs per plant type, production average total cost, long-term marginal cost and average long-term marginal cost per load level).

These results are provided for each country (11 countries - EU 12 except Luxembourg) and consolidated to produce the results for the European Union.

4. POWER GENERATION PERSPECTIVES

4.1 DEVELOPMENTS IN DEMAND

The demand for electricity continues to exhibit a positive growth rate. The share of electricity in total final energy consumption was 18% in 1990 and is expected to reach 20% by the year 2005 (according to “A View to the Future”, DG XVII). The final electricity demand grows currently at a rate of 2.4% p.a.

and this growth rate is expected to fall to about 1.6% p.a. by the year 2005. This in turn leads to growing share of primary energy consumed for electricity production, and while efficiency gains are obtained in the use of fossil fuels, electricity intensity also has a growing trend.

The industrial sector has the lowest growth rate for electricity demand, both because of the slowdown in industrial production and the efficiency efforts in energy intensive industries. However a substantial growth of electricity use is expected in the domestic sector, where the new generation of more efficient electric appliances is far from achieving commercial maturity. Demand-side management efforts are envisaged by certain utilities in an attempt to reduce peak power demand and total electricity demand, leading to generating cost reduction. On the other hand, in other sectors, like public transport, further substitution by electricity is pursued.

The overall conclusion is that the power generation sector should plan expansion to meet a continuously increasing demand. It is unlikely that DSM policy could reverse such a trend. One should also consider that substantial decommissioning of existing capacities will take place in the coming 25 years.

The context in which power generation planning operates is complemented by the following considerations concerning fuels, prices and technologies.

4.2 FUEL AVAILABILITY AND PRICES

a) COAL is a source of plentiful and cheap fuel but is limited by its environmental consequences as a source of CO_2 , NO_x , SO_2 emissions and dust. The share of electricity produced by coal was 35% in 1990 and is expected to remain at that level throughout 2005.

b) OIL has in recent years been a fairly stable source in terms of both supply and price, but always causes concern for over-dependence and is not generally considered as a base-load fuel. Its share of production was 10% in 1990 and is expected to be around 6% in year 2005 ("A View to the Future", DG XVII).

c) GAS has unquestionable advantages in terms of investment cost, price and environmental impact and the only concern is related to the security of supply. The emerging issue is that of a 'european' dependence on gas suppliers and their ability to meet demand at reasonable prices. The share of production for natural gas was 8% in 1990 and is expected exceed 20% in year 2005.

d) RENEWABLES form a diverse group of environmental-friendly fuel sources, but are limited by high production costs. Possibilities for further penetration exist, particularly if costs are imposed on polluters. Their electricity production share was 0.2% in 1990 and is expected to rise to 1% in year 2005.

4.3 ELECTRICITY SUPPLY

4.3.1 Generating capacities

a) NUCLEAR: Nuclear plants represent one quarter of total generating capacity in Europe, and produce a third of total electricity in 1990. They have an important role in the generating mix for the countries that use them. New investments have slowed considerably in recent years, for reasons of public concern for health and safety standards, waste disposal problems, decommissioning procedures and sites for location. Two postulates are considered in the present study with respect to capacity expansions. The first considers that the share of production from nuclear energy is maintained in France while nominal capacities are maintained in Belgium, Germany and the United Kingdom. The second case allows no investment in nuclear capacities and current plants are decommissioned at the end of their expected life-time.

b) COAL: Coal and lignite fired plants represent the main base-load capacity for some countries. Although faced with environmental concern, coal is expected to maintain its contribution. Issues arise from the availability of low sulphur coal in international markets and the penetration of new coal technologies. The latter involve several techniques that allow for considerably higher efficiency rates. These techniques, based on fluidization of combustion, on gasification and the use of combined cycle and other innovative processes, are not yet fully mature commercially. Generally, they should cope with environmental constraints, however, at higher capital costs. Costs are expected to decrease as they will gradually penetrate in the market.

c) OIL: The contribution of oil plants is expected to remain limited for strategic reasons related to price risk, imports dependence and environmental effects. Multifuel plants is perhaps the only case where the use of oil is encouraged, but no major expansion is expected, even if the price seems really attractive.

d) GAS: Gas fired capacities represent only 5% of total in 1990 but the expansion is anticipated to accelerate, as the investment and operating costs are very attractive -through the combined cycle technology- and the pollutant emissions low. At present it appears that most of the currently known investment decisions of electric power companies involve gas combined cycle plants. The expansion is constrained by thoughts of security, gas availability, and price of incremental increase of supply.

e) DECENTRALISED PRODUCTION AND CO-GENERATION: Decentralisation of power generation is emerging in several countries as facilitated either by the conditions of electricity trade or by the availability of cheap CHP technology. Industrial co-generation can be profitable both in economic and environmental terms, particularly in relation with new higher efficiency technologies. Nevertheless CHP is heavily constrained for location and administration reasons.

f) HYDRO: There is little room for further expansion of hydroelectric capacities as the main resources have been exploited. There is public reluctance to such large scale developments, for reasons of very high investment costs and protection of natural sites. Small hydroelectric plants are seen as promising, but are limited in total potential.

g) RENEWABLES: The increased effort in recent years gives interesting prospects to a variety of renewable-based capacities. The issues of high unit cost and intermittent supply remain, and some acceleration could be achieved if costs were imposed on pollutants (e.g. carbon tax). First priority is given to wind power in several countries.

4.3.2 ENVIRONMENTAL CONSTRAINTS

The 5th Environmental Programme in 1992 set strict standards for the emissions of SO_2 and NO_x pollutants. In this study new capacities are assumed to incorporate abatement technologies that reduce SO_2 emission factors up to 98% and NO_x emission factors up to 40% with respect to 1990 values.

For the main greenhouse gas, CO_2 , the ambitious target was set to stabilise the overall system emissions in year 2000 to 1990 levels. Within such a target the role of electricity is twofold: electricity in final energy use may contribute to the reduction of CO_2 emissions if substituted to fossil fuels (this depends on the structure of power generation); in power generation the increased use of natural gas and CO_2 -free electricity sources permits a further reduction of CO_2 emissions. In this study a carbon tax (as defined by the Commission's proposal) is introduced in the ecologically driven variants of the scenario.

4.3.3 ELECTRICITY TRADE

Electricity trade through interconnection of national grids is not fully treated in this study. Trade is only considered based on existing and expected contracts and extrapolated in the long-term. However, diversification advantages and economic benefits may be achieved by electricity trade.

5. A NEW CONVENTIONAL SCENARIO

The New Conventional Scenario reflects the continuation of recent trends and considerations, as stated before, concerning the availability of fuels and technologies.

5.1 DEMAND PATTERN

The demand pattern for this scenario essentially constitutes an upper limit of demand based on 'A View To The Future' and revised to accommodate:

- Current economic recession in the short-term
- Future increase in use of electricity in the long-term (electric vehicles, increased penetration in the tertiary sector).

The average annual increase for the 1990-2020 period is 1.63%. The percentages for the industrial and domestic / tertiary sectors are 1.3% and 1.87% respectively.

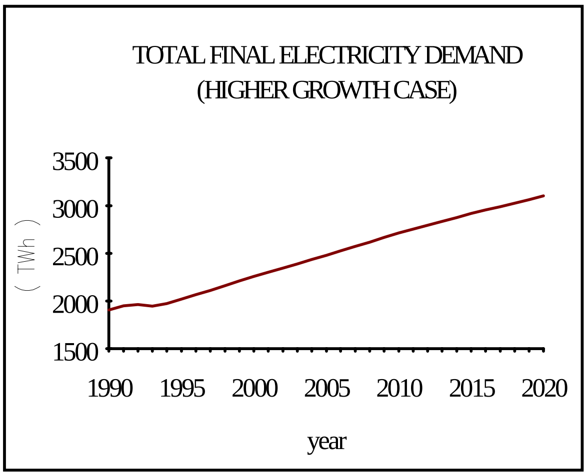


Fig. 1 - Electricity Demand

5.2 SUPPLY PATTERN

The following assumptions are made for the supply pattern in this scenario:

- Nuclear power maintains its share of production in France, and it's capacity in Belgium, Germany, and the UK. The life of current units is extended to the maximum possible.
- Use of advanced fossil fuel technologies (fluidised bed combustion, integrated coal gasification combined cycle, combined heat-power) and flexible units (multifuels, gas combined cycle).
- The supply of fossil fuels remains plentiful keeping prices relatively low. This includes all required quantities of natural gas. A short-lived price spike for oil is included, with its price rising by 32.5% in year 2000 and falling by 18.2% the year after.
- Reduced SO_2 and NO_x emissions for new capacities, as already mentioned.

5.3 EXPANSION AND OPERATION OF CAPACITIES

The New Conventional Scenario results to the addition of about 500 GW of new capacities. Half of this is required to cover existing plant decommissioning and the other half to satisfy increasing demand. Exhibit 1 shows the development of total installed capacity and the annual additions.

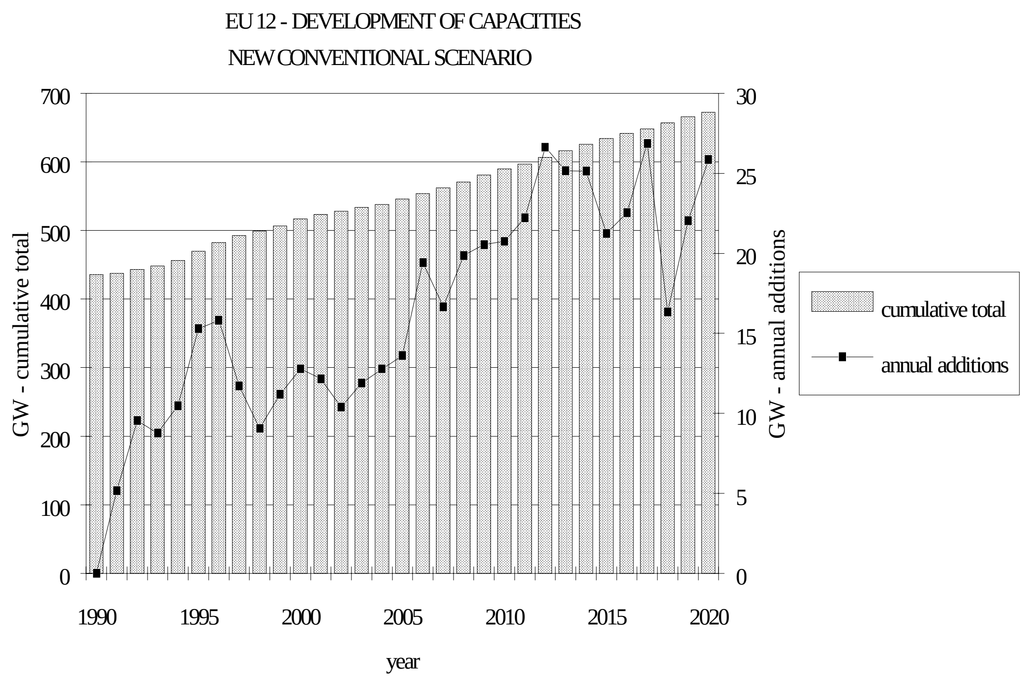


Exhibit 1 - Development of capacities

About 80% of new capacities is fossil fuel investment. This can be decomposed in natural gas combined cycle, potentially solid fuels (including polyvalents with coal), conventional fuel and gas, and new technologies as in Exhibit 3.

The prevalence of combined cycle is more important in the medium term (2000-2012) and is moderated afterwards with an increase in solids.

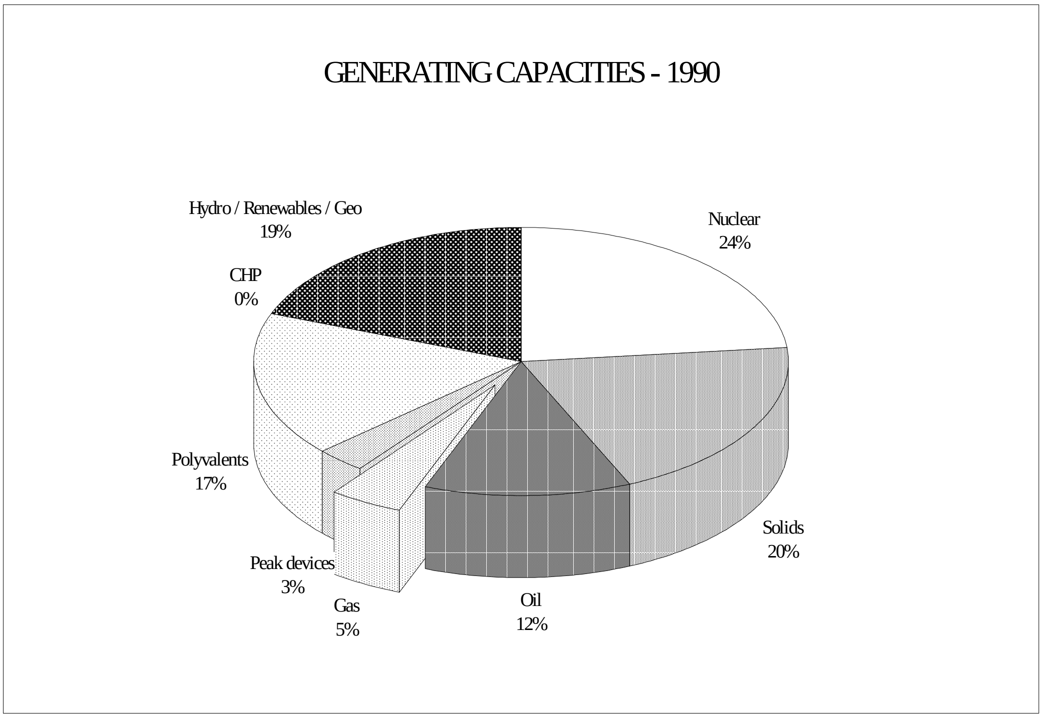
Gas fired plants end up with one third of total capacity (Exhibit 2) and an equal share of total production in year 2020.

In terms of dispatching and fuel use, combined cycle and solids compete on the load curve after the nuclears, as shown in Exhibit 4, where a preference for the commitment of solid fuel plants is clear in the longer term.

In countries with no nuclears the base is covered by solids, followed by combined cycle. In any case conventional fuel-gas are restricted to the upper parts of the load curve.

The resulting consumption of fossil fuel is shown in Exhibit 5. While use of solids remains fairly stable, natural gas increases drastically in favour mainly of liquids. The demand for natural gas in year 2020 reaches 186 Mtoe for power generation.

The behavioural pattern differs by country. Small countries with expensive supply of base load are more inclined to invest in gas combined cycle. For example in the Netherlands at the end of the 30-year period, combined cycle represents about 50% of total thermal capacity while the average for the European Union is 38%.



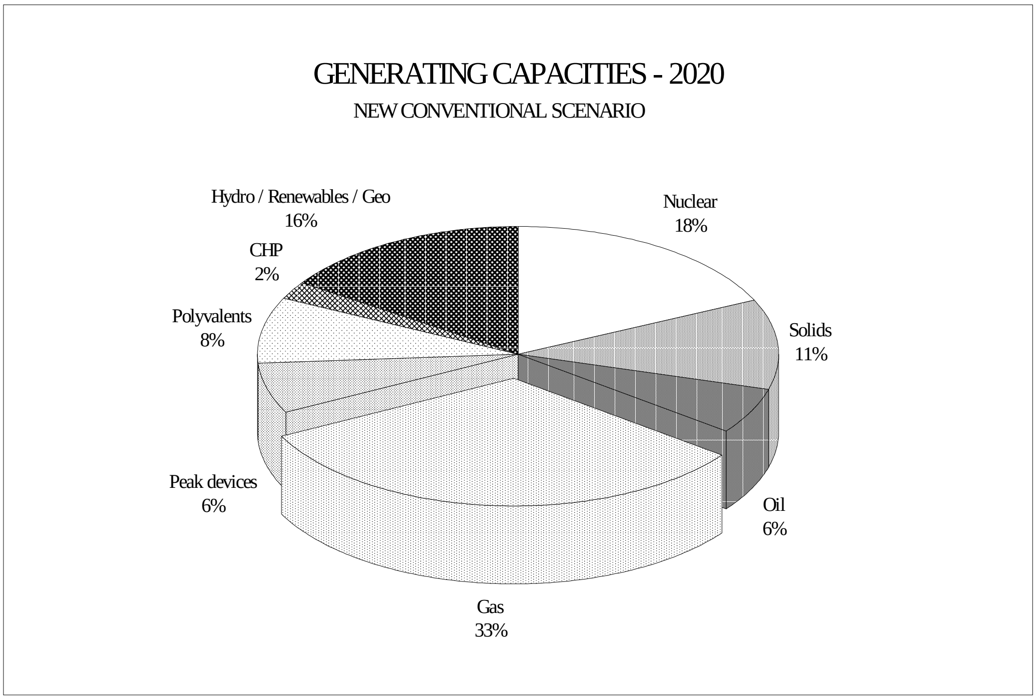
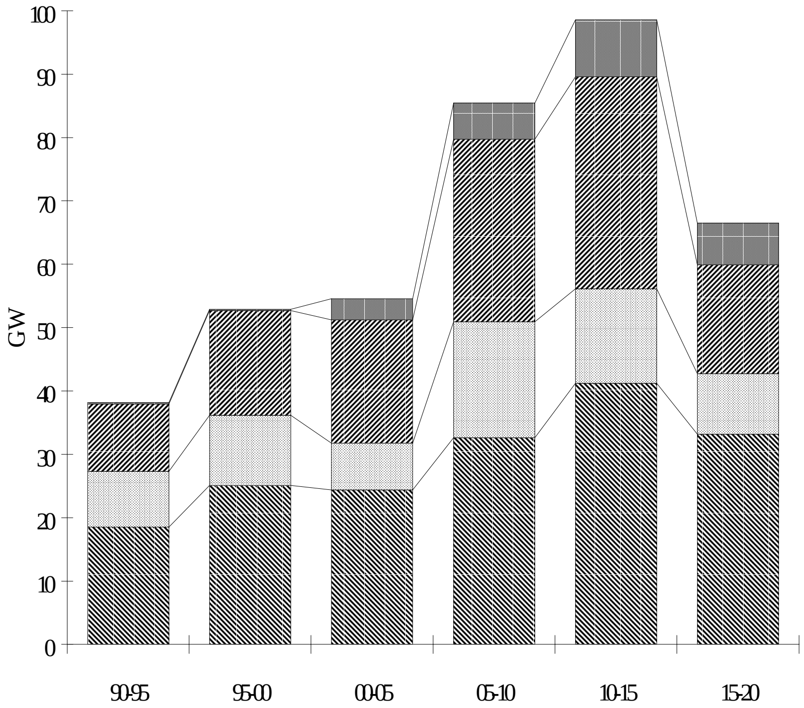


Exhibit 2 - Structure of Capacities



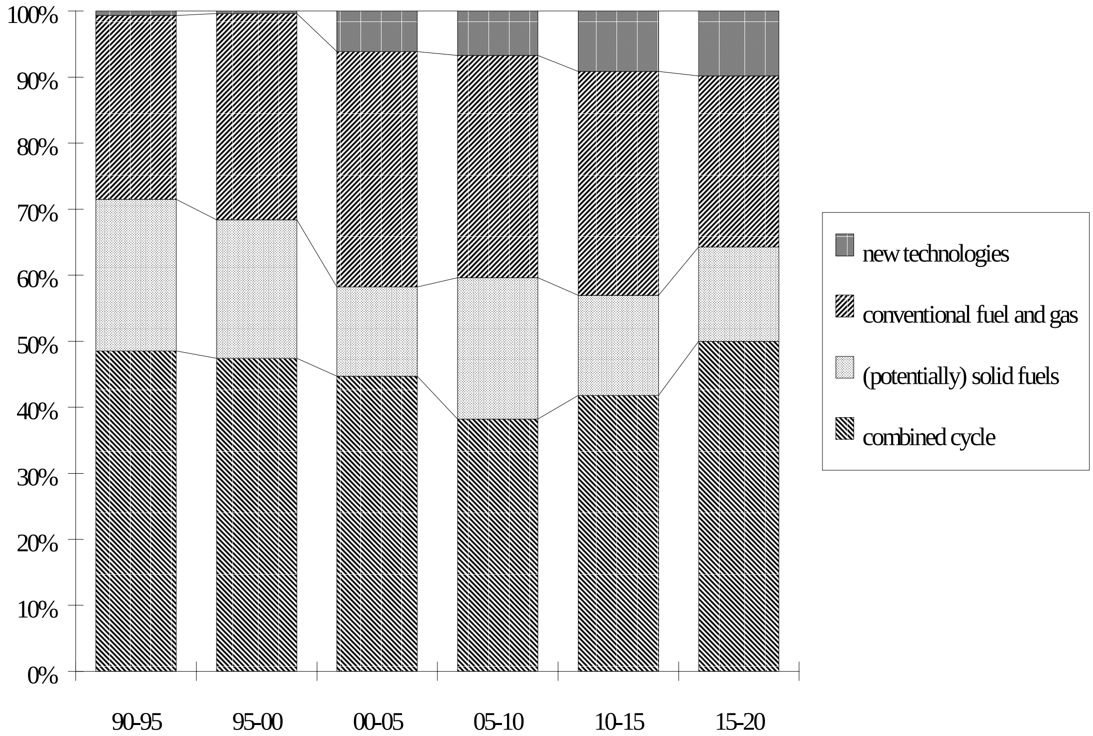


Exhibit 3 - Fossil Fuel Capacity Expansion Decisions

The capacity expansion decisions lead to a dominance of combined cycle plants. Significantly less investment is made in solid and multifuel plants, while there are some investments in fuel and gas plants for peak load demand. The penetration of new coal technologies is marginal.

Countries with less expensive base load are less committing in combined cycle investment. Thus in France the share of combined cycle in total thermal capacity remains at 23%.

Big countries are diversifying by investing in polyvalents and monovalent fuel-gas plants (Spain, Italy, Germany). New coal technologies also penetrate mainly in big countries. For example, Germany realises almost half of total european investment in new fossil fuel technologies.

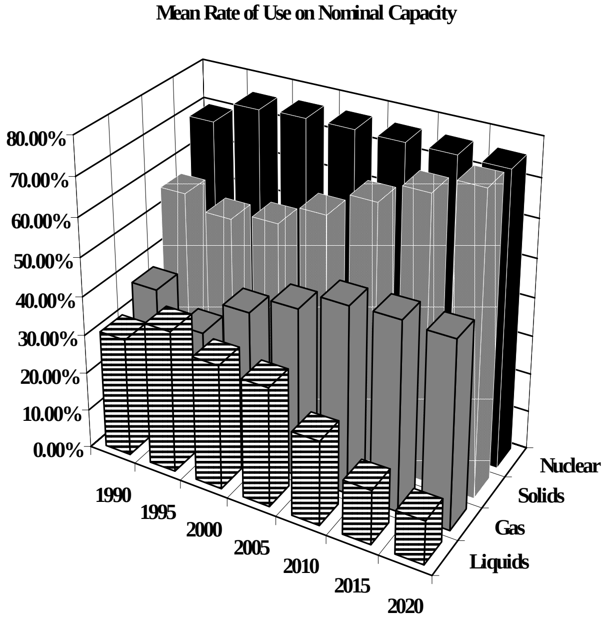


Exhibit 4 - Mean Rate of Use

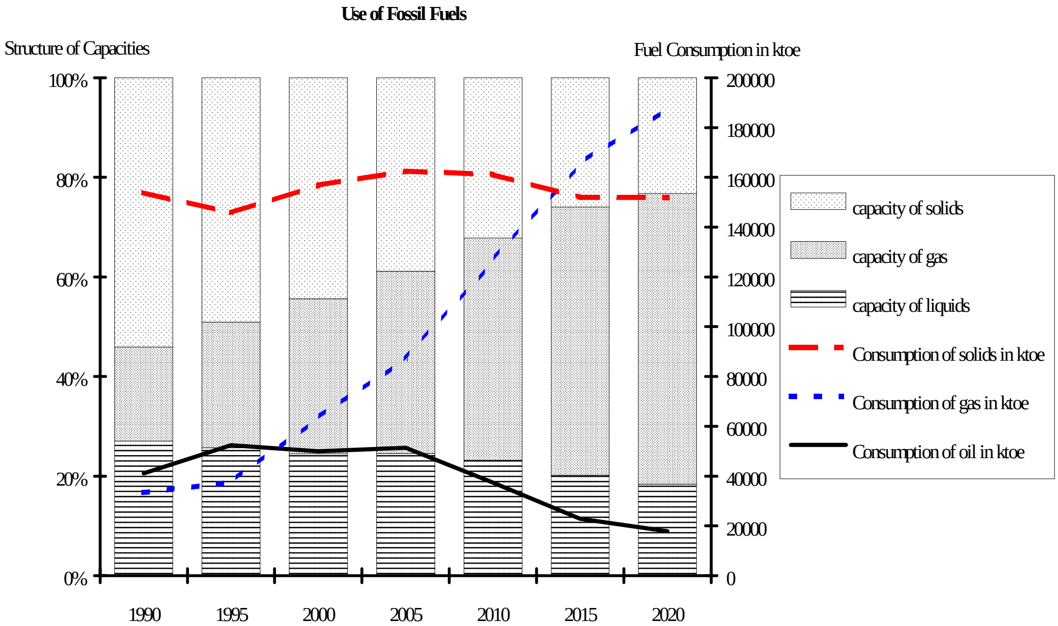
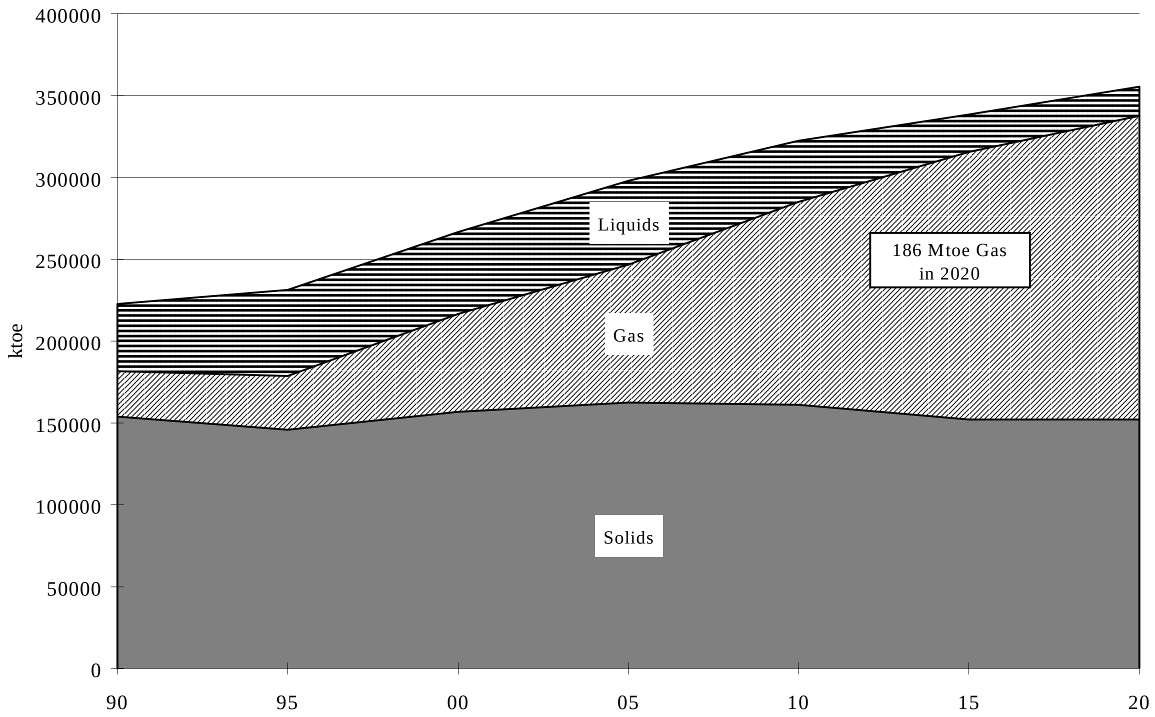
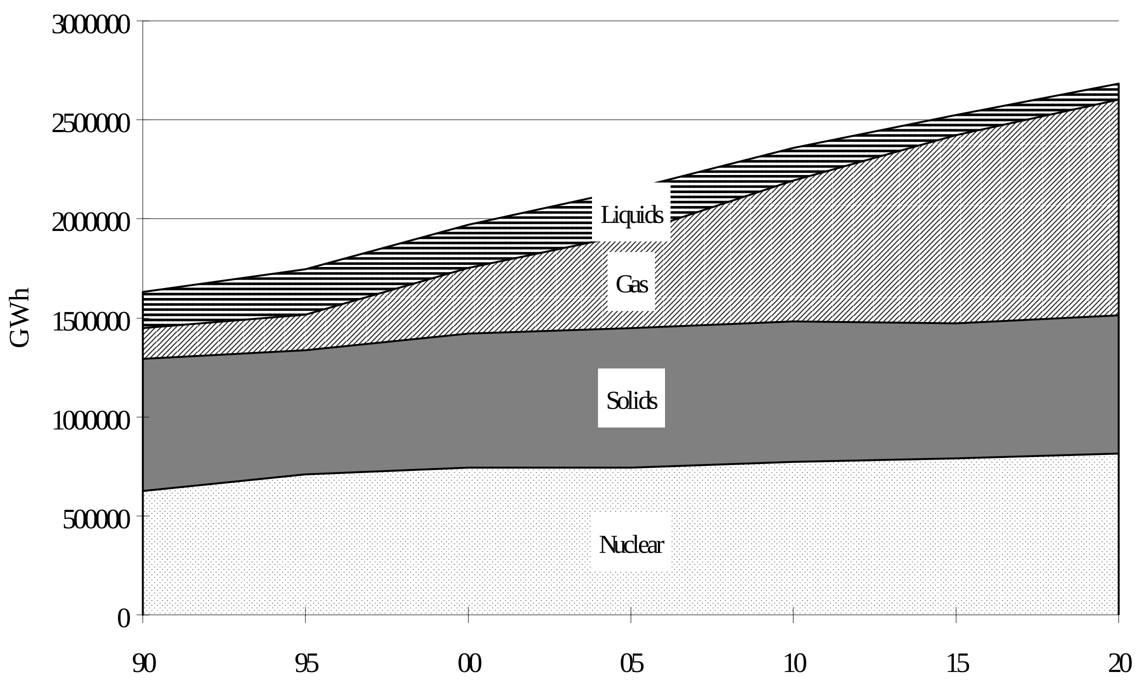


Exhibit 5 - Use of Fossil Fuel

Fuel Consumption - New Conventional Scenario EU12



Electricity Produced by Fuel, New Conventional Scenario, EU12



<u>Exhibit 6 - Consumption and Electricity Production by Fuel</u>

5.4 ECONOMICS

A total of approximately 500 billion ECU-90 is invested in new generating capacities through the 30-year period, although half of it is realised in the last decade 2010-2020.

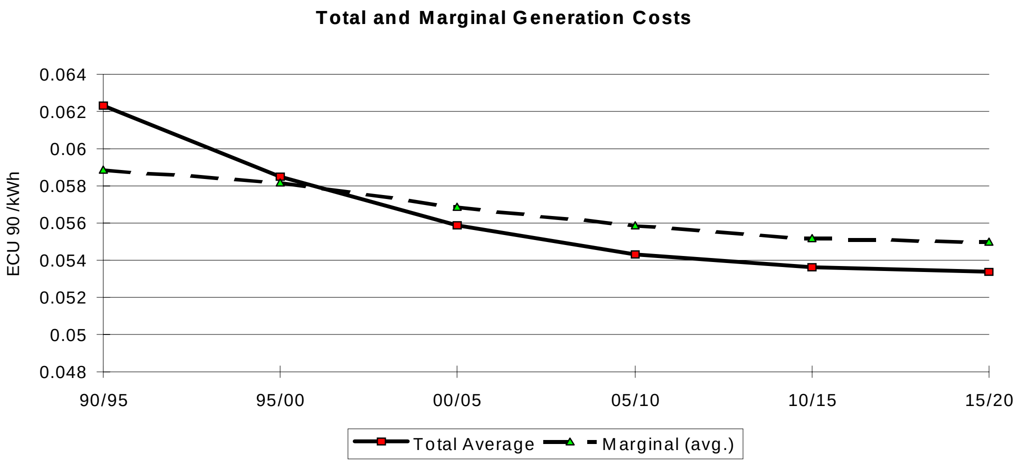
About 70% of it is in thermal plants, and combined cycle represents 25% of total investment.

There is a general reduction in generating costs (Exhibit 7). The average long-run marginal cost falls by 6% at the end of the period (in constant currency).

5.5 ENVIRONMENTAL CONSEQUENCES

Exhibit 8 shows the emission quantities based on fuel consumption and the exogenous emission factors as discussed above. SO_2 is reduced 4 times by year 2020, attributed partly to abatement technologies incorporated in new capacities, and partly to the fuel shift towards natural gas. NO_x remains stable throughout the 30-year period, as any abatement is offset by increased demand and the fuel mix.

CO_2 emissions increase by 30% by the end of the period. As we can see in table 1, the increase in CO_2 is attributed primarily to non-nuclear countries. The rise of CO_2 emissions is 12% in year 2000 with respect to year 1990. This means that the shift to natural gas was not able to compensate for the 18% rise in electricity demand over the same period. We remind that in order to achieve the overall stabilisation target, the demand side must over-compensate for the increase of CO_2 emissions in power generation.



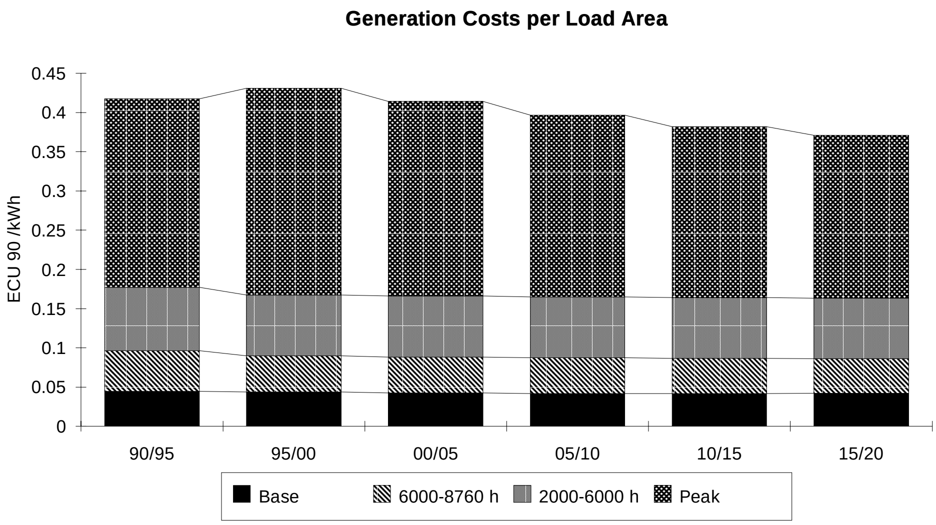


Exhibit 7 - Generation Costs

Table 1 - Emissions of CO2 in Mtons

	1990	1995	2000	2005	2010	2015	2020
BE	25	24	27	30	31	28	30
DK	23	31	32	34	34	33	32
FR	44	38	56	62	58	50	39
GE	252	255	289	295	302	300	295
GR	34	36	40	46	50	54	56
IR	11	13	13	14	14	16	16
IT	123	139	175	198	218	233	247
NL	46	52	47	53	58	55	55
PO	15	16	21	25	27	29	33
SP	65	70	78	93	106	111	123
UK	221	197	185	196	189	188	206
EU-12	**858**	**871**	**963**	**1046**	**1088**	**1096**	**1132**

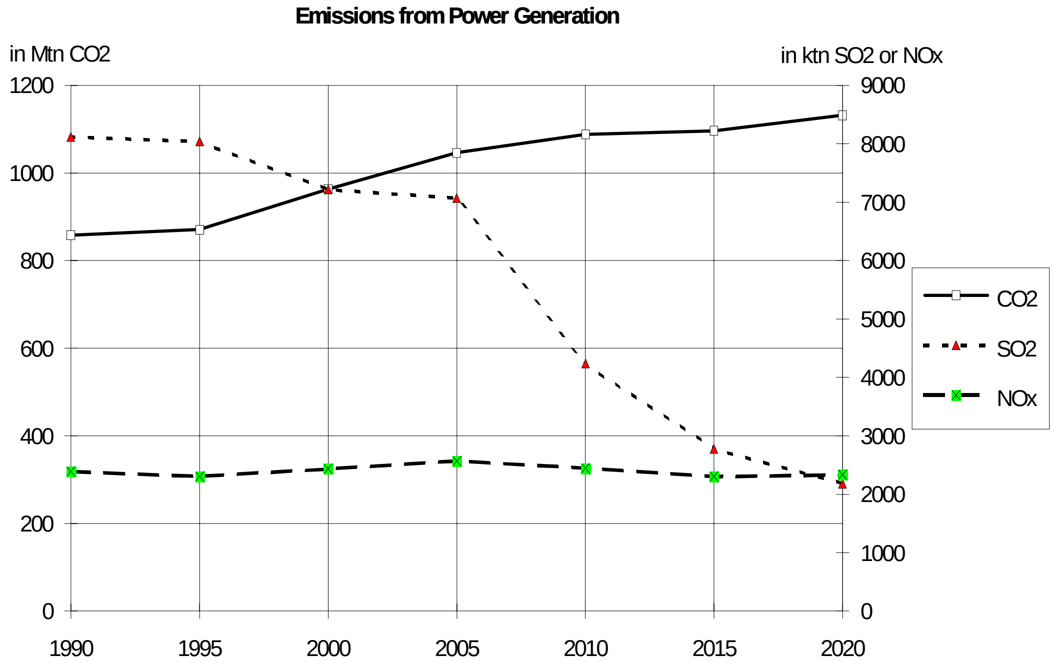


Exhibit 8 - Emissions of Pollutants

6. SENSITIVITIES

6.1 VARIANT-1 : HIGH GAS PRICE

This variant introduces a significant increase of natural gas price between 2000 and 2010 reflecting the inability of supply to meet the growth of demand at low prices. The gas price in year 2010 is 40% higher than that of the conventional scenario.

6.1.1 EXPANSION AND OPERATION OF CAPACITIES

In terms of capacity investment decisions the difference from the conventional scenario is marginal. Only 1.5% of total expansions is transferred from gas monovalents to polyvalents and new technologies.

Significant changes occur in the dispatching process and the choice of fuels in polyvalents. As can be seen in Exhibit 9, the mean rate of use for gas plants is reduced significantly. The base load demand is covered by nuclear and solid fuel plants, followed by liquid fuels, while gas is displaced to the peak and medium load.

The consumption of fossil fuel is shown in Exhibit 10. The quantity of gas in 2020 is 134 Mtoe, 30% less than in the conventional scenario. The reduction in year 2010 is about 50% which indicates an own price elasticity of -1.27 for gas.

Exhibit 10 shows the substitution of gas by solid and liquid fuels. We observe that two thirds of the electricity previously produced by gas is now produced by liquid and the remaining by solid fuels.

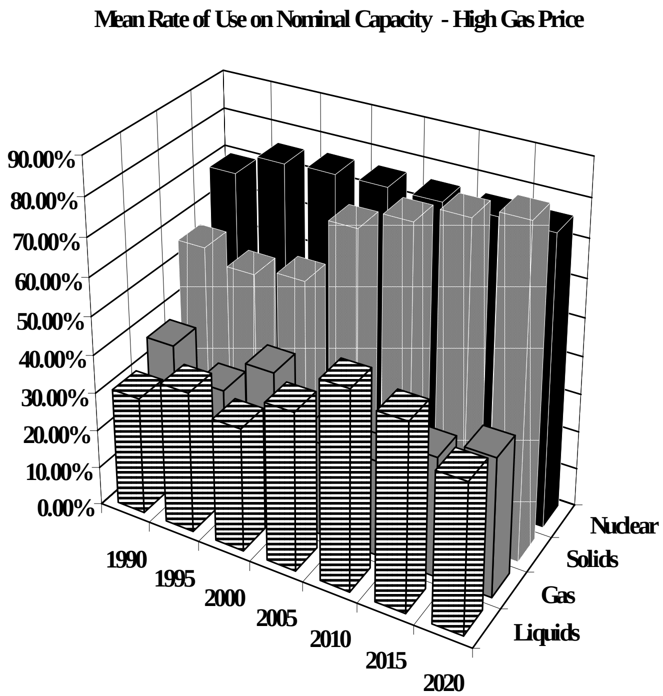


Exhibit 9 - Mean Rate of Use - High Gas Price

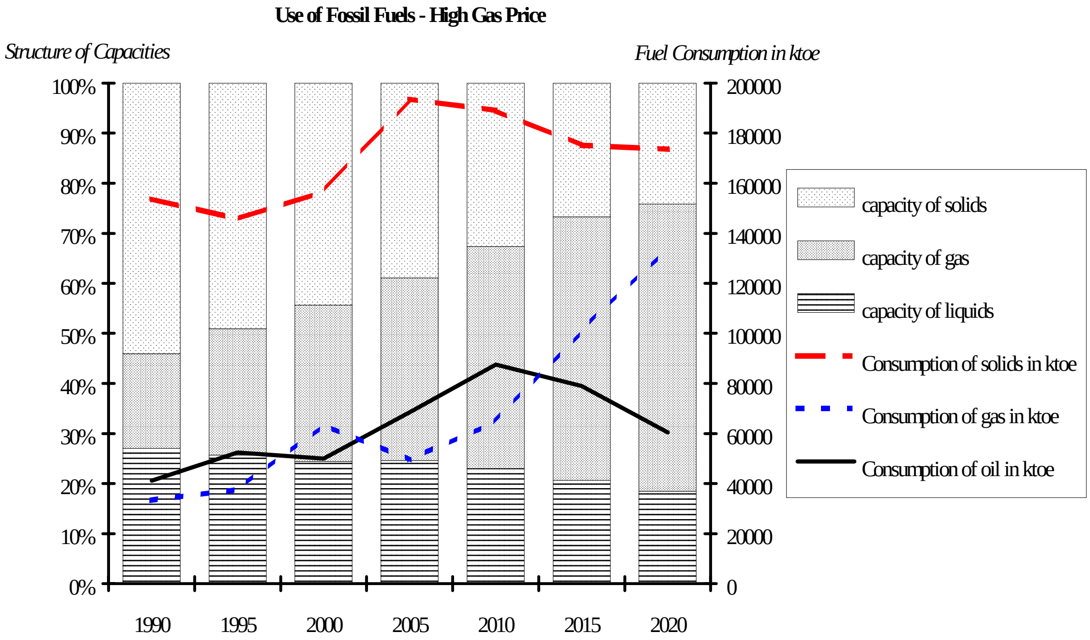
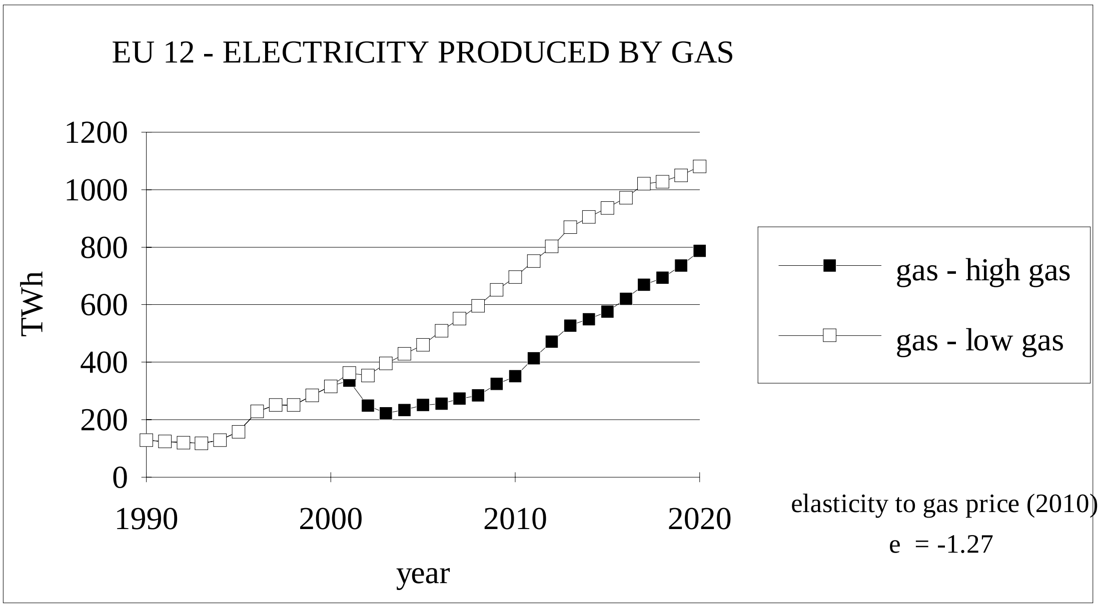
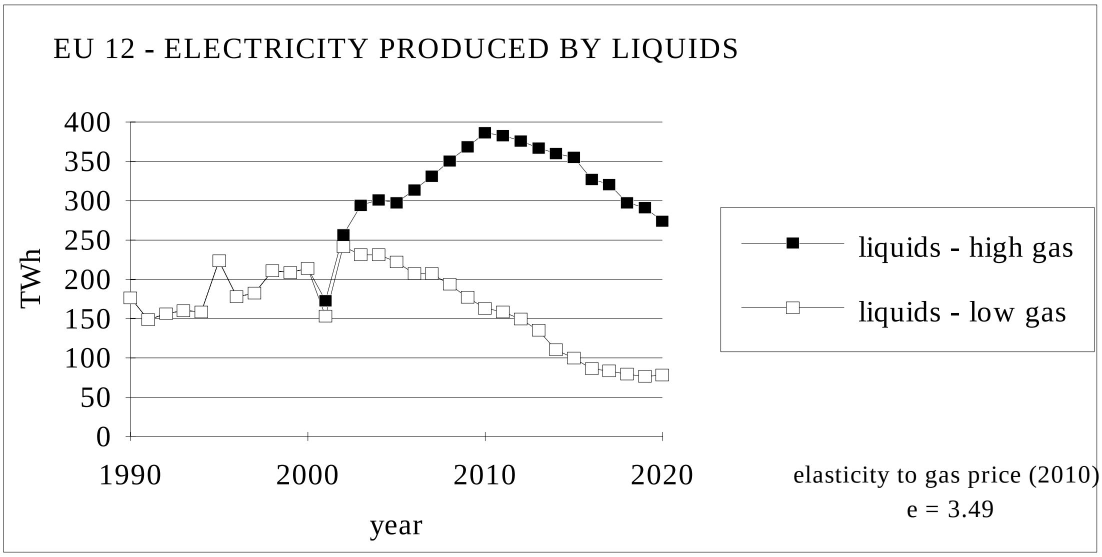


Exhibit 10 - Use of Fossil Fuel - High Gas Price





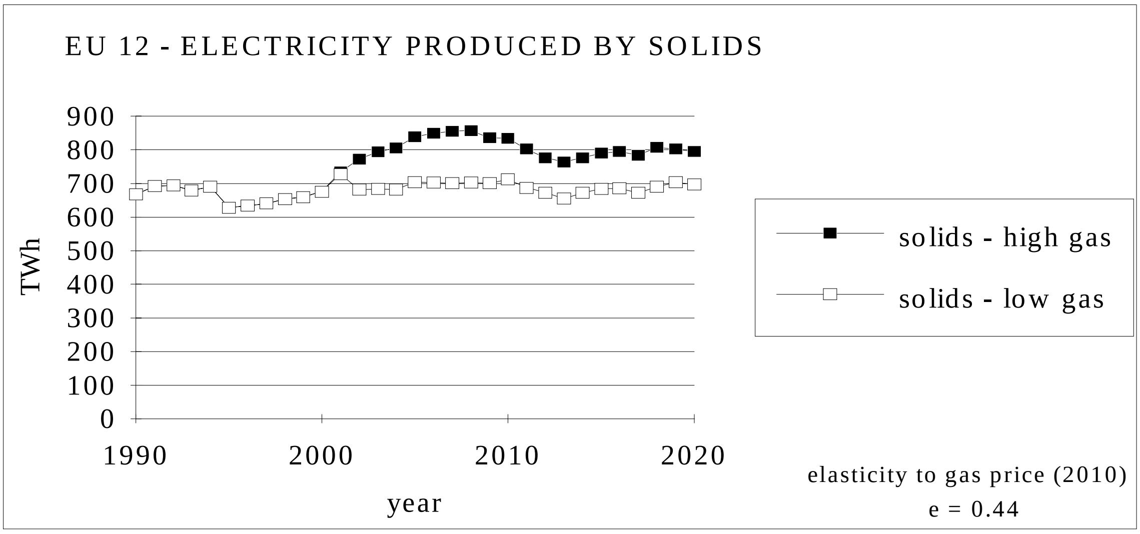
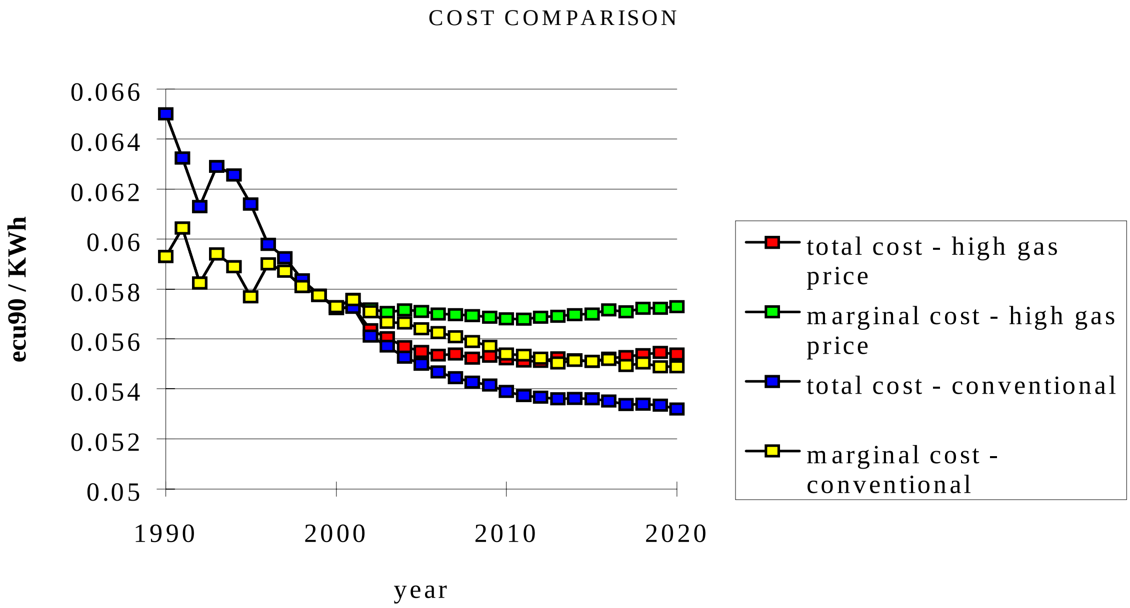


Exhibit 11 - Fuel Substitution

6.2 ECONOMICS

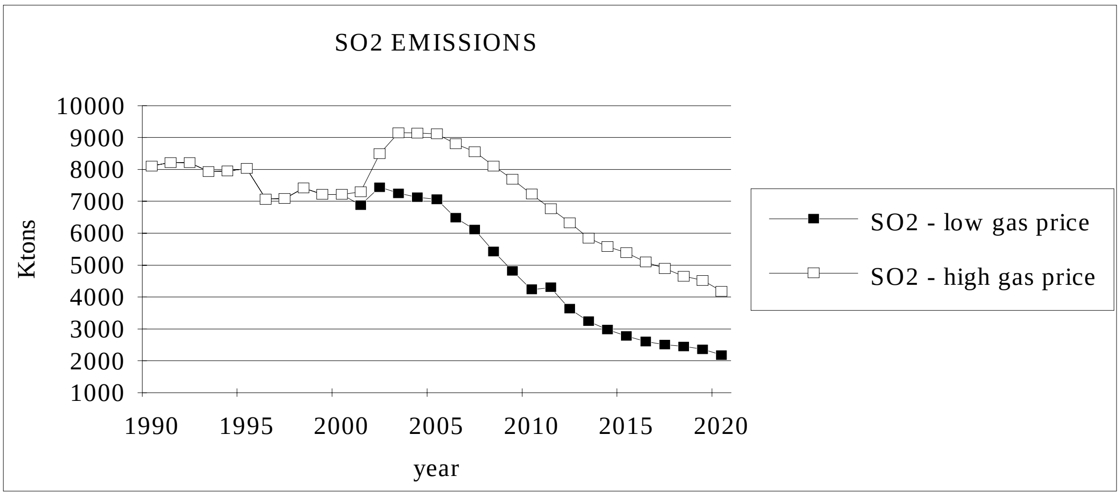
The generating costs are affected by the gas price rise. On the average there is still a decrease (Exhibit 12), but the long-run marginal cost is in 2020 is now about 3% less the 1990 value. This represents an increase of 4% with respect to the conventional scenario.

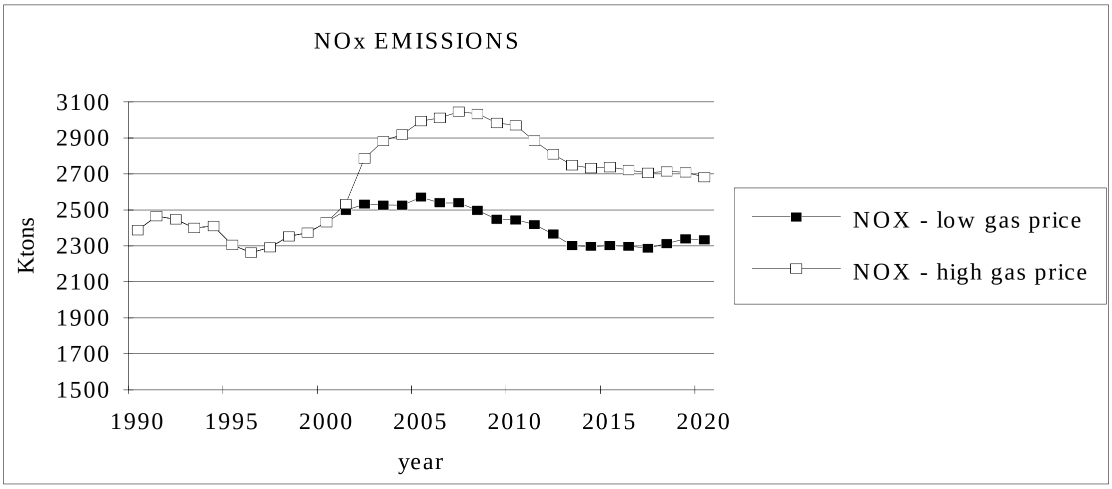


<u>Exhibit 12 - Effect on Generating Costs</u>

6.2.1 ENVIRONMENTAL CONSEQUENCES

The effects on pollutant emissions are, as expected, adverse. SO_2 is reduced to half instead of to a quarter in the conventional scenario. NO_x fails to be stabilised and is slightly increased. CO_2 rises by 10% more than it did in the conventional scenario (Exhibit 13).





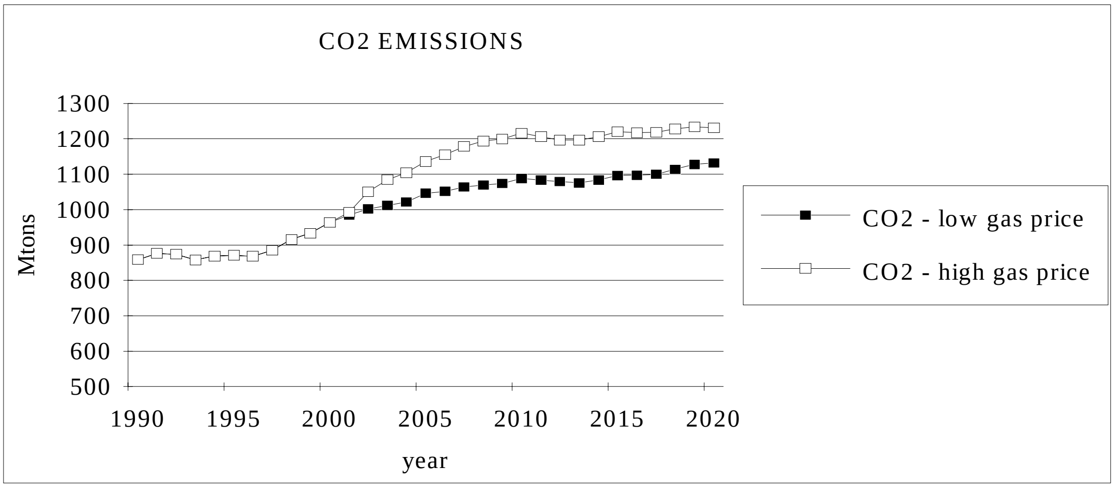


Exhibit 13 - Emissions Comparison

6.3 VARIANT-2 : LOW DEMAND - LESS NUCLEAR - ECOLOGICAL CONCERN

This variant aims to explore the benefits of high demand control efforts combined with a more ecologically-oriented approach on the supply side. This variant is deliberately extreme to analyse consequences coming from the demand side, in contrast with the conventional scenario.

6.3.1 DEMAND PATTERN

The demand pattern for this variant essentially constitutes a lower limit of demand based on 'A View To The Future' and revised to incorporate the effects of electricity conservation measures, such as demand-side management and end-use efficiency, both in industrial and domestic / tertiary sector.

It is postulated that the average annual increase for the 1990-2007 period is 1.1%, followed by an equal average annual fall in the remaining period. Conservation effects are stronger in the domestic/tertiary sector.

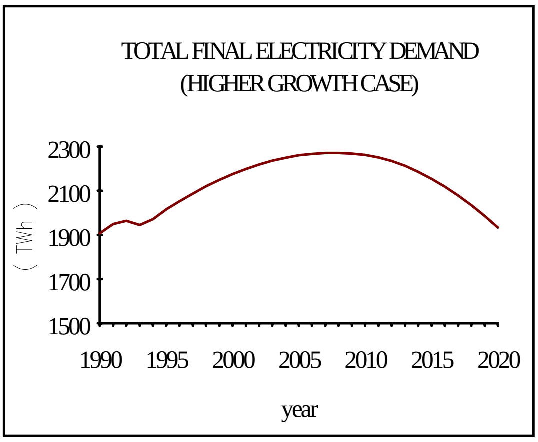


Fig. 2 - Electricity Demand

6.3.2 SUPPLY PATTERN

The supply pattern for this variant is characterised by the absence of investments in new nuclear capacities beyond year 2005. Existing plants are decommissioned at the end of their expected life time. Only France makes the investments necessary to maintain the capacity required to cover base-load demand.

In addition, carbon tax (based on Commission's proposal) is introduced in 1994 to CO_2 polluters. The tax on each fuel is at an equivalent of $3/bbl, increased by $1.5/bbl in both 1995 and 1996, and by $1/bbl annually afterwards.

There is increased demand for heat to be produced by CHP plants, and encouragement of independent producers and industrial auto-producers. The use of renewables is extended to reflect the emergence of fuels like urban waste and biomass.

6.3.3 EXPANSION AND OPERATION OF CAPACITIES

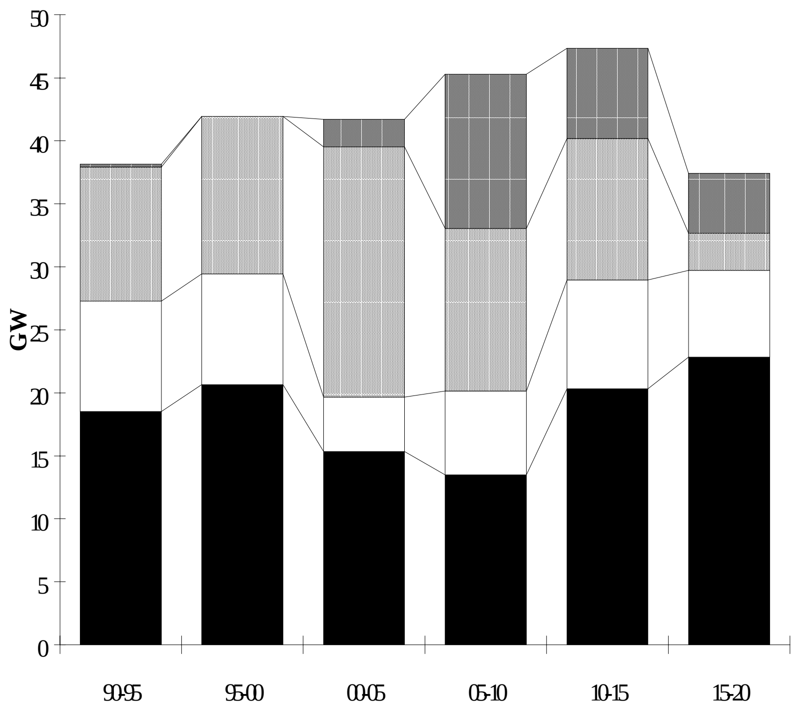
The behaviour of the system is generally dominated by the reduction in electricity demand.

The new capacity additions for this variant are about 300 GW, 60% of the conventional scenario requirements. Almost all of this (90%) is to cover the decommissioning of existing plants.

The absence of nuclears is compensated by the falling demand and the increased investment in renewables. Hydroelectric and renewable plants are increased by 10% with respect to the conventional scenario, and end up with 25% of total capacity in 2020 (Exhibit 15).

The decomposition of fossil fuel expansions (Exhibit 14) is similar to the conventional case, and shows an increase in new technologies attributed to the increased demand for CHP.

The consumption of all fuels is reduced (Exhibit 16) and the demand for natural gas in year 2020 falls to 135 Mtoe. This figure foe gas demand in year 2010 is within the accepted range in current prospects for gas supply.



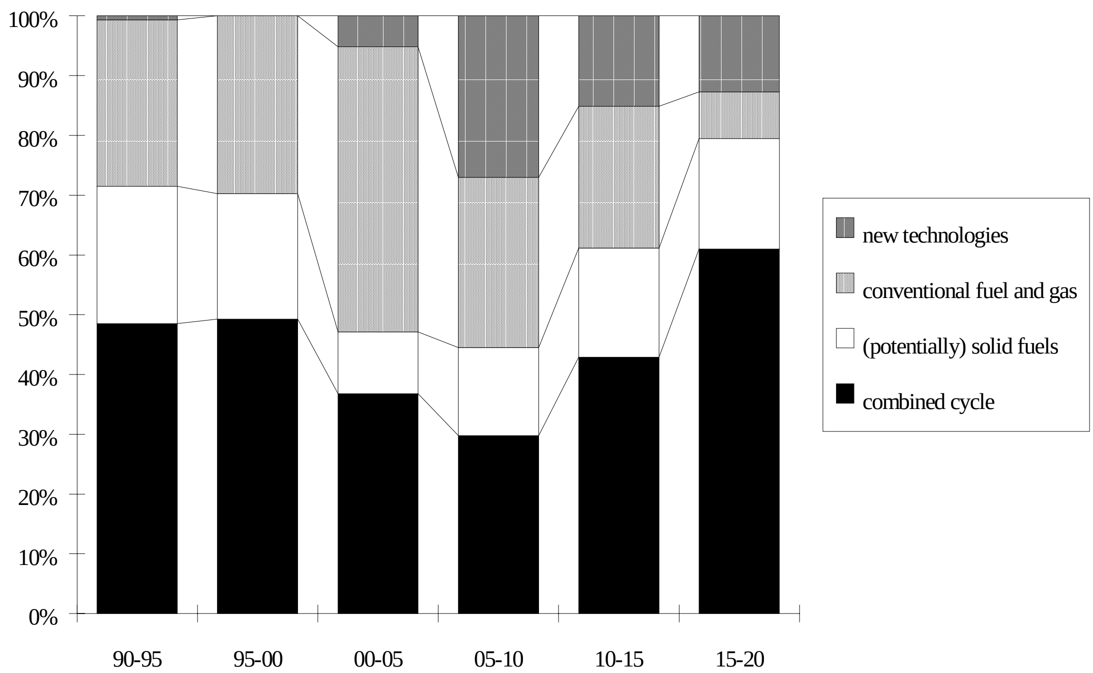
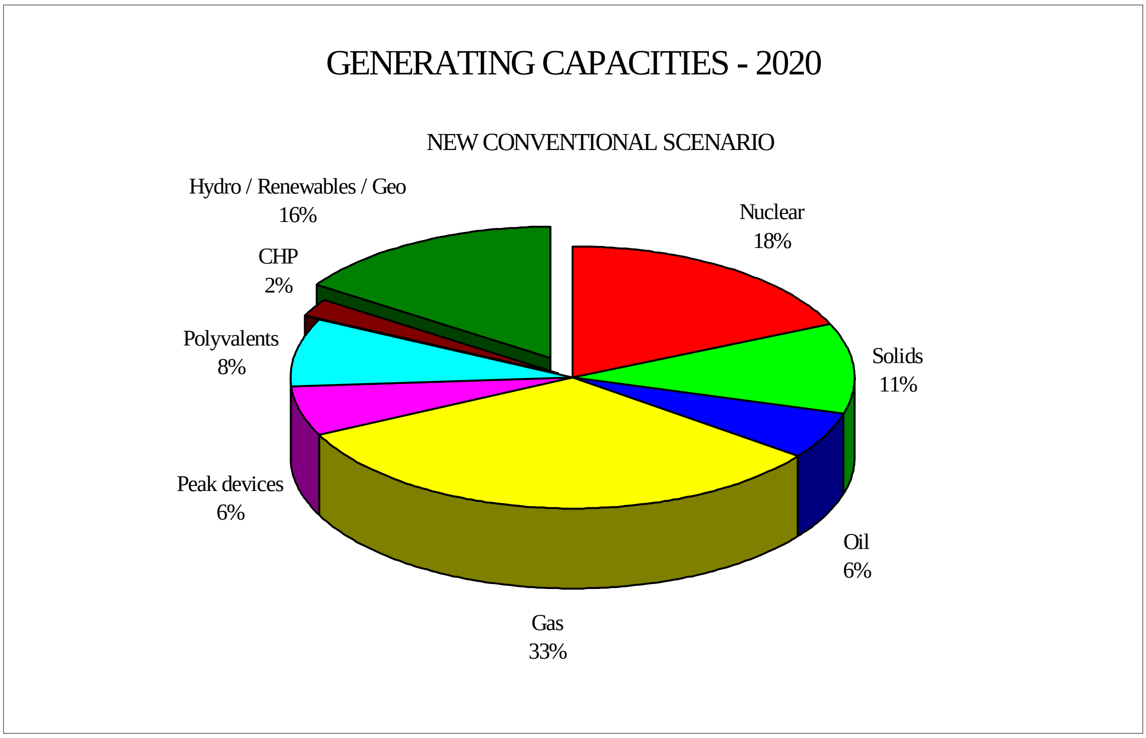


Exhibit 14 - Fossil Fuel Capacity Expansion Decisions



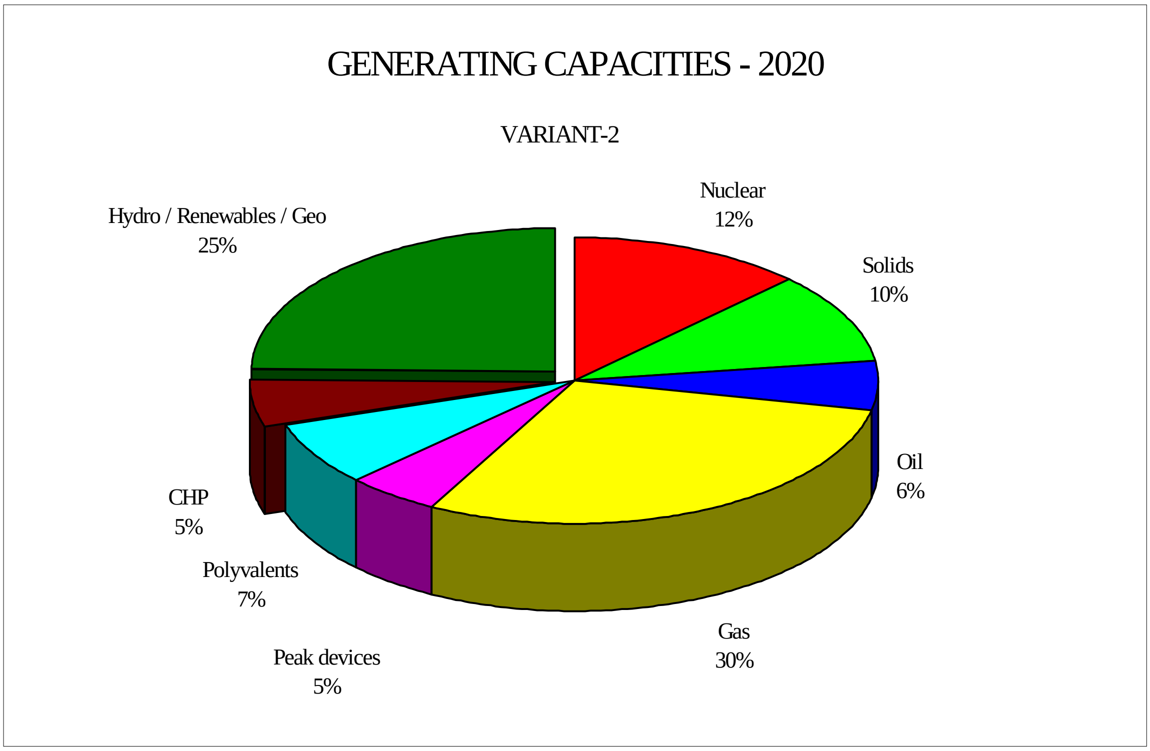


Exhibit 15 - Structure of Capacities

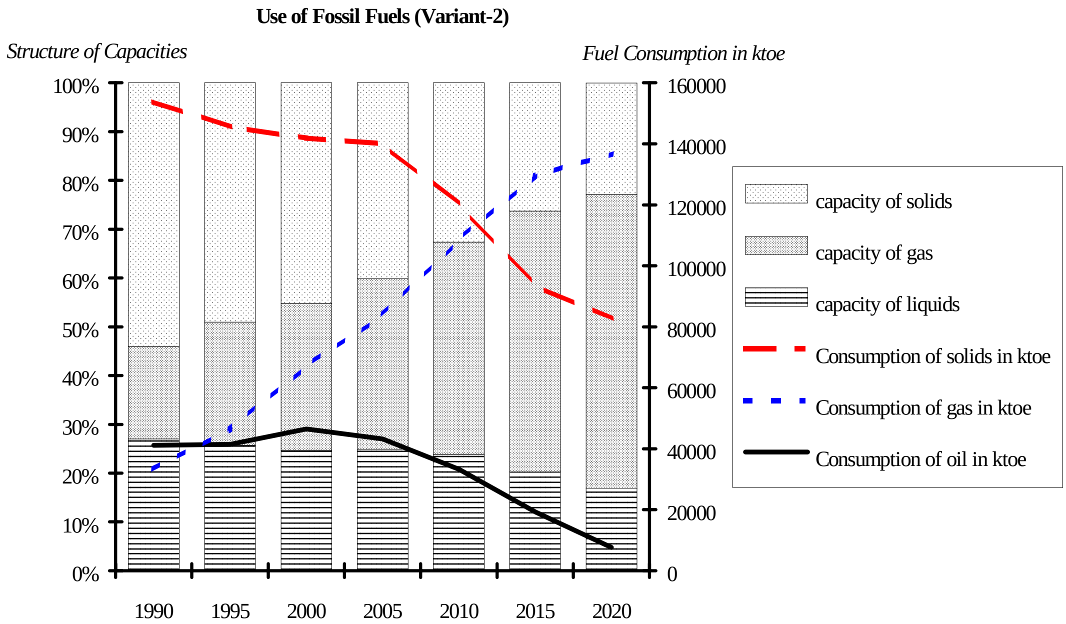


Exhibit 16 - Use of Fossil Fuel

6.3.4 ECONOMICS

The total investments required in this variant amount to just below 300 billion ECU-90 spread evenly throughout the 30-year period. This is 42% less than the conventional case.

The generating costs however are significantly increased (Exhibit 17). The long-run marginal cost shows an upward trend and in year 2020 is 15% higher than the conventional scenario. This is associated with the lower share of cheaper plants, in terms of operation, such as nuclear, and the use at some extent of new fossil fuel technologies which still have high investment costs.

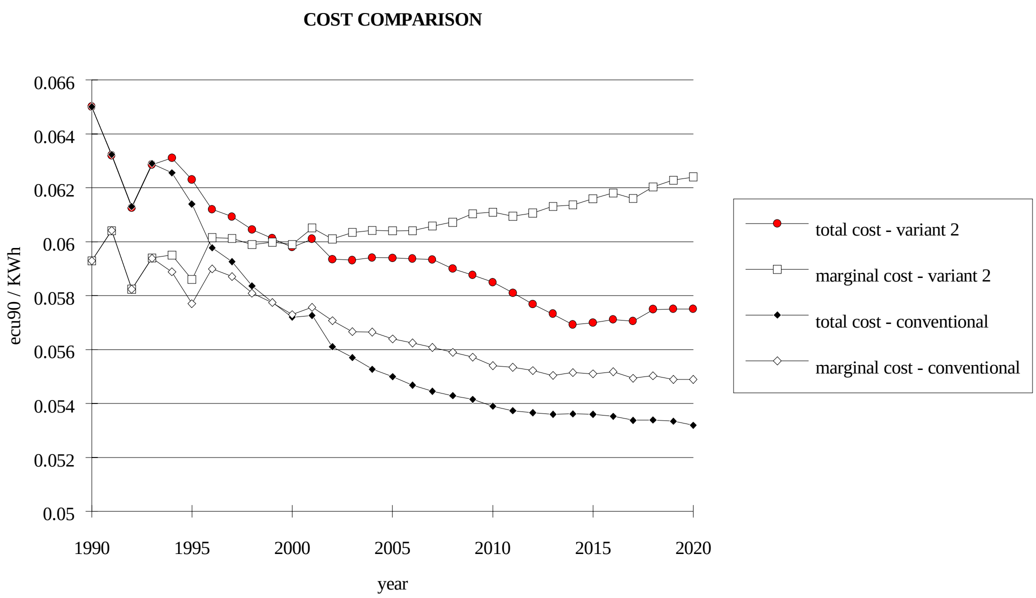
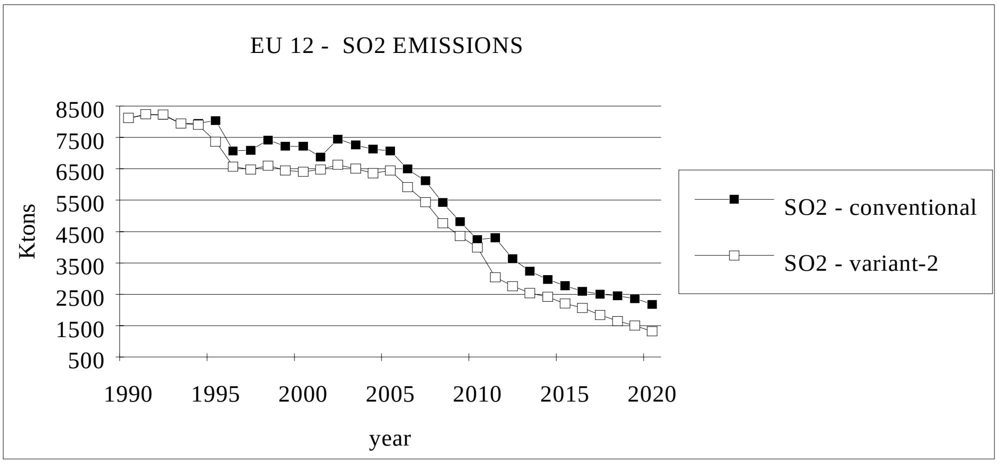
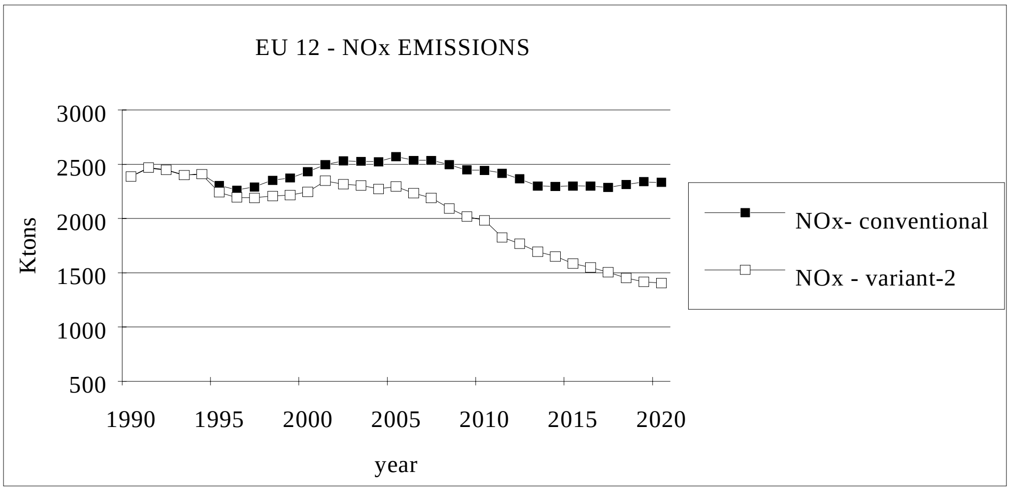


Exhibit 17 - Effect on Generating Costs

6.3.5 ENVIRONMENTAL CONSEQUENCES

All pollutant emissions face downward trends, as fuel consumption is reduced by a third. Especially for CO_2 , there is a small increase (5%) until year 2005, followed by a considerable reduction, which in year 2020 leads to a quantity 16% less than 1990 level.





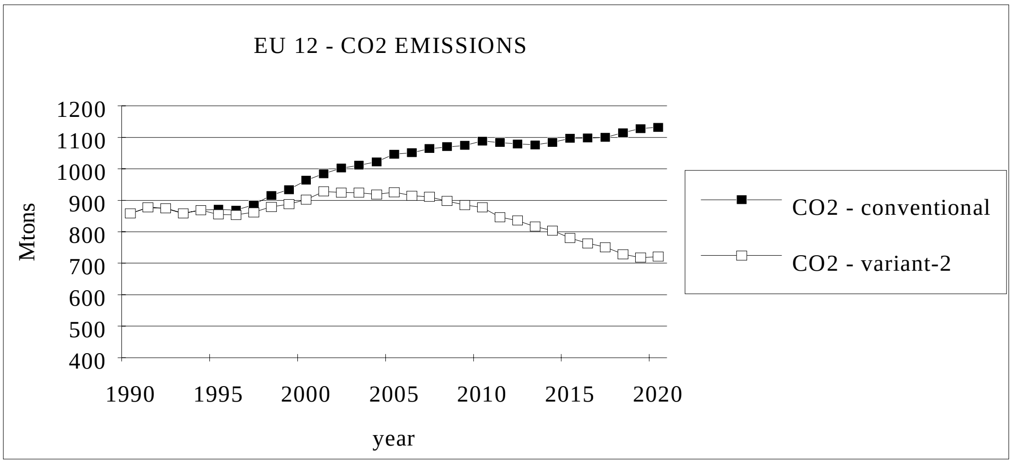


Exhibit 18 - Emissions Comparison

6.4 *VARIANT-3 : HIGH GAS PRICE - LESS NUCLEAR - HIGH DEMAND*

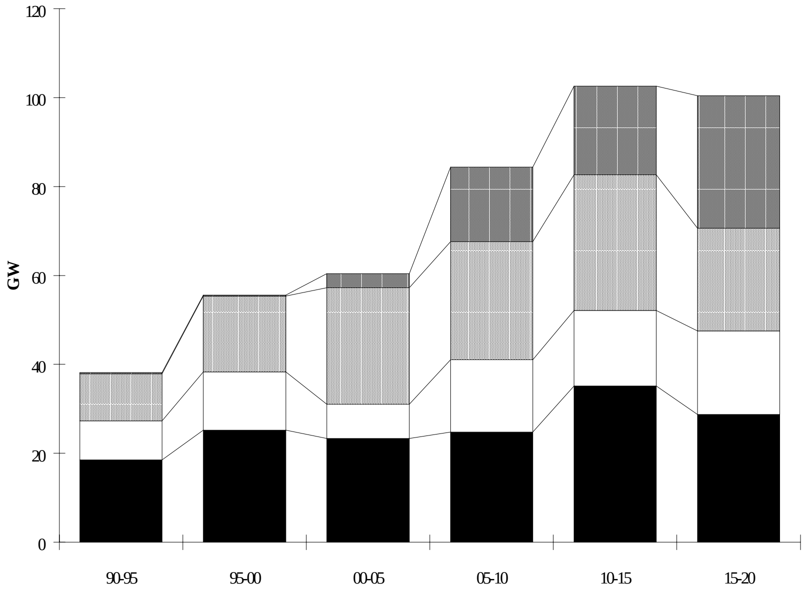
This variant combines the high gas price scenario of variant-1 with the environmentally focused supply pattern of variant-2. This may seem like a worst case scenario, but the two assumptions cannot be considered unlikely. The characteristics of this variant therefore are:

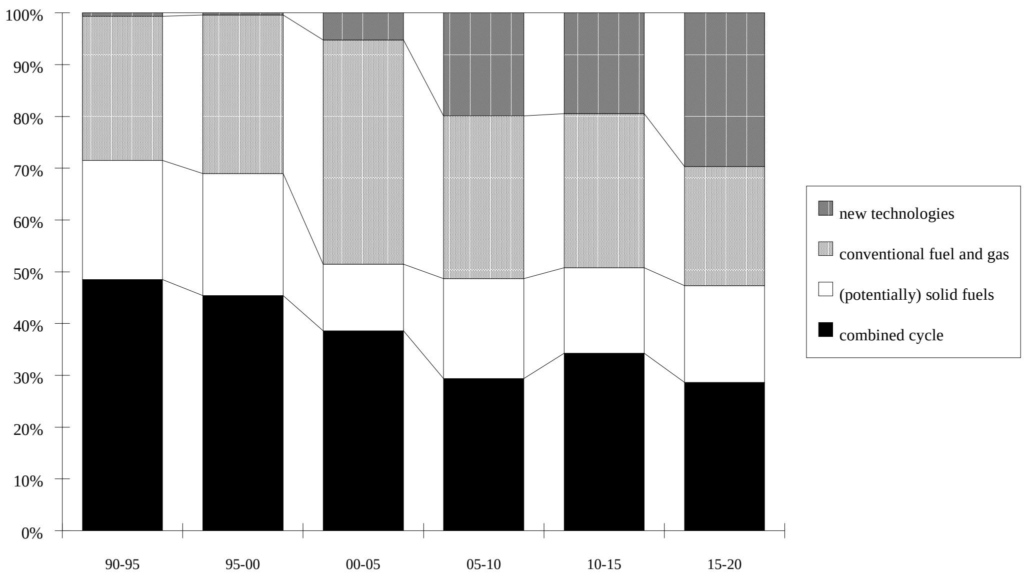
- High demand (as in the New Conventional Scenario)
- High gas price
- Absence of new nuclear capacities (except in France for base-load)
- Introduction of Carbon Tax
- Encouragement of auto-producers, CHP and renewables.

6.4.1 EXPANSION AND OPERATION OF CAPACITIES

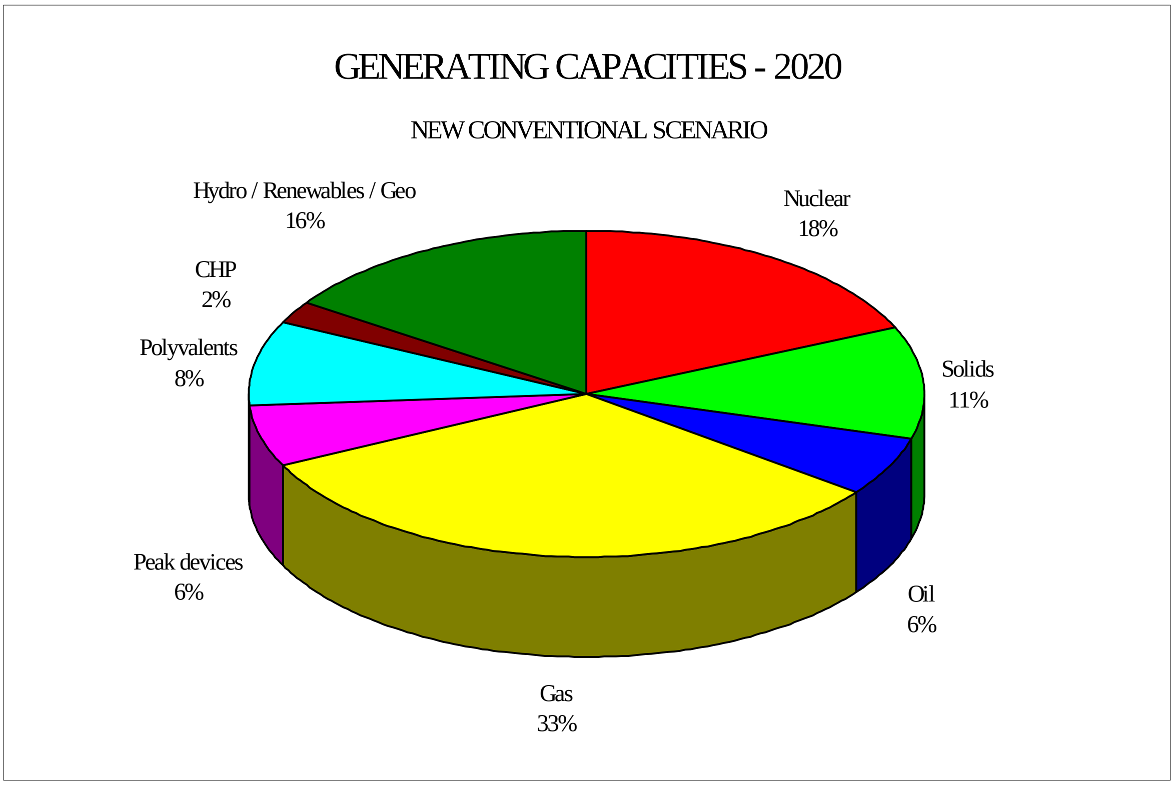
The new capacity requirements for this variant are the same as the conventional case. The gap from nuclear decommissioning and some shift-away from gas, is filled by new technologies (Exhibit 19), polyvalents, solids, and renewable sources. New technologies (new coal and CHP) represent now 14% of new capacity additions and end up occupying 10% of total capacity. In the end of the period though, the dependence on gas is still significant (Exhibit 20).

In terms of operation, solids take over the base and gas competes with liquid fuels for the medium and peak load (Exhibit 21). This leads to increased consumption for solids and gas while liquids maintain their share(Exhibits 22-23). The demand for gas in year 2020 reaches 190 Mtoe despite the price increase. This is attributed of course to the non-replacement of nuclear capacities, which implies that fossil fuels have to fill the gap.





<u>Exhibit 19 - Fossil Fuel Capacity expansion Decisions</u>



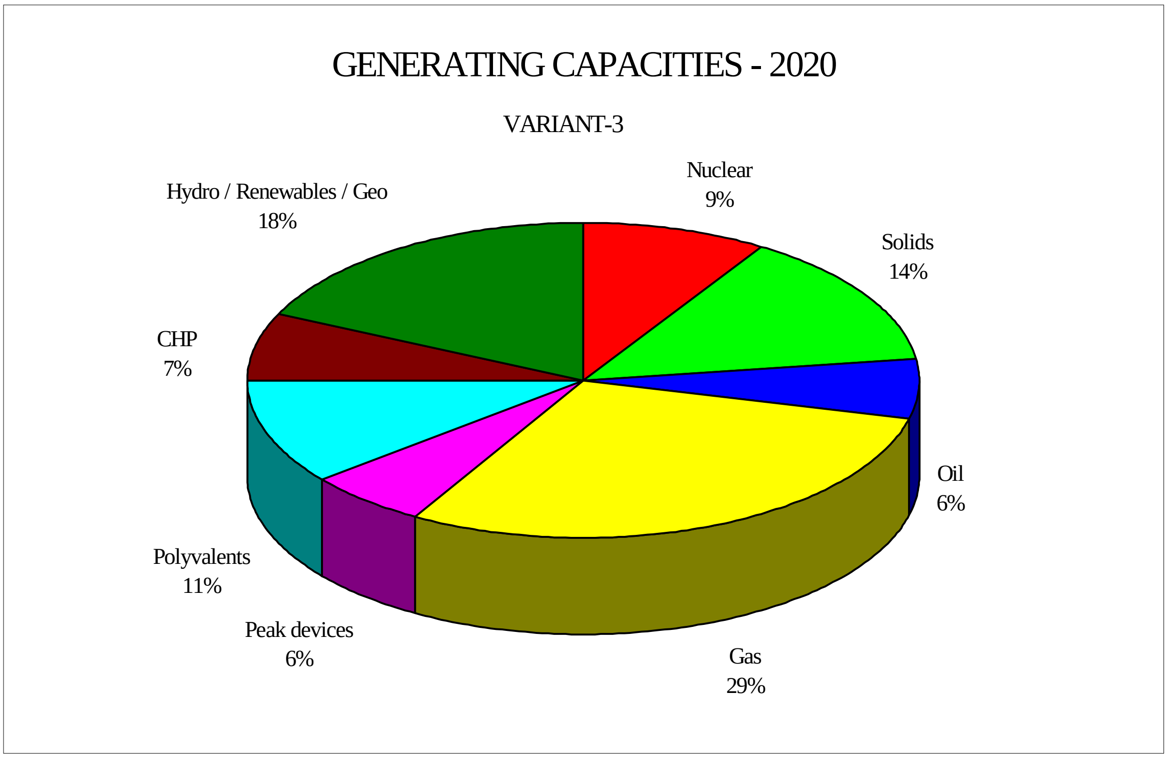


Exhibit 20 - Structure of Capacities

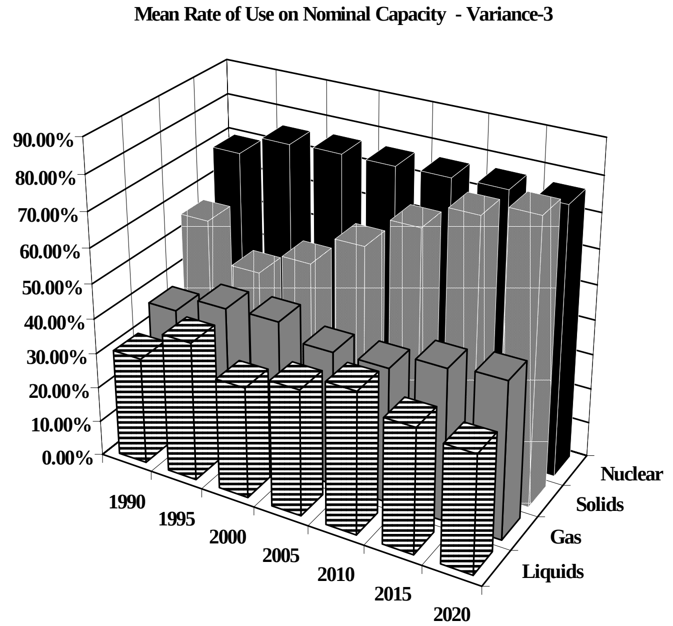


Exhibit 21 - Mean Rate of Use

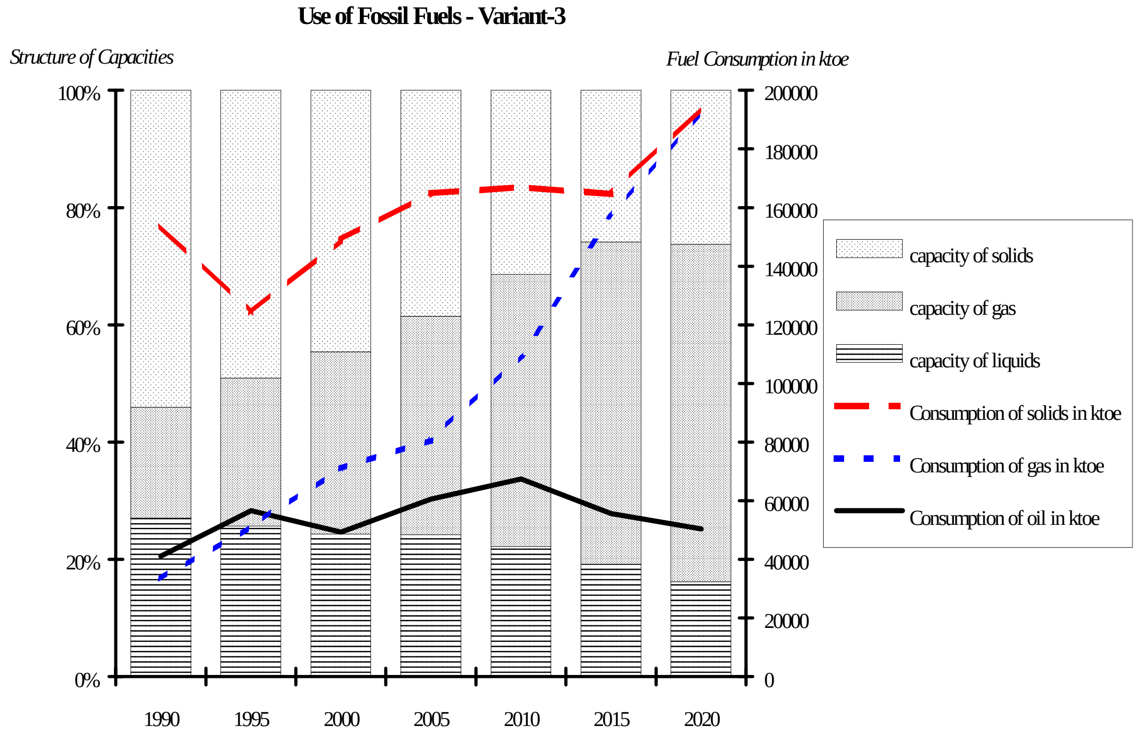
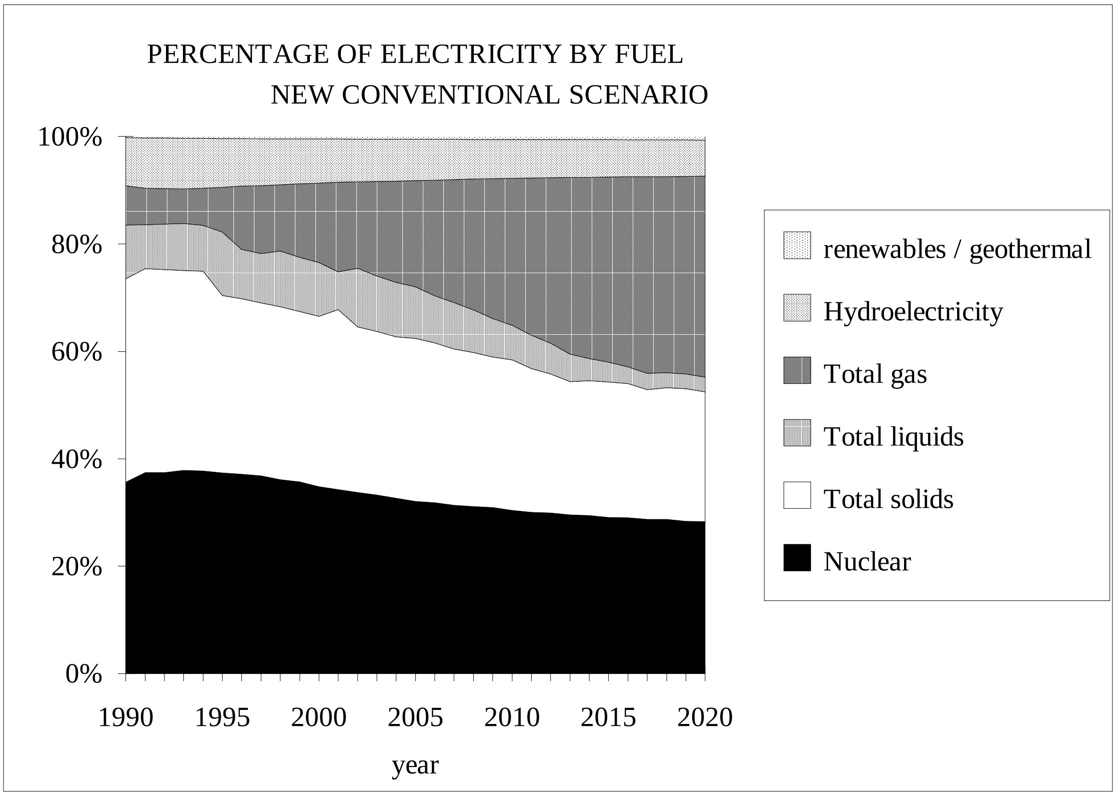


Exhibit 22 - Use of Fossil Fuel



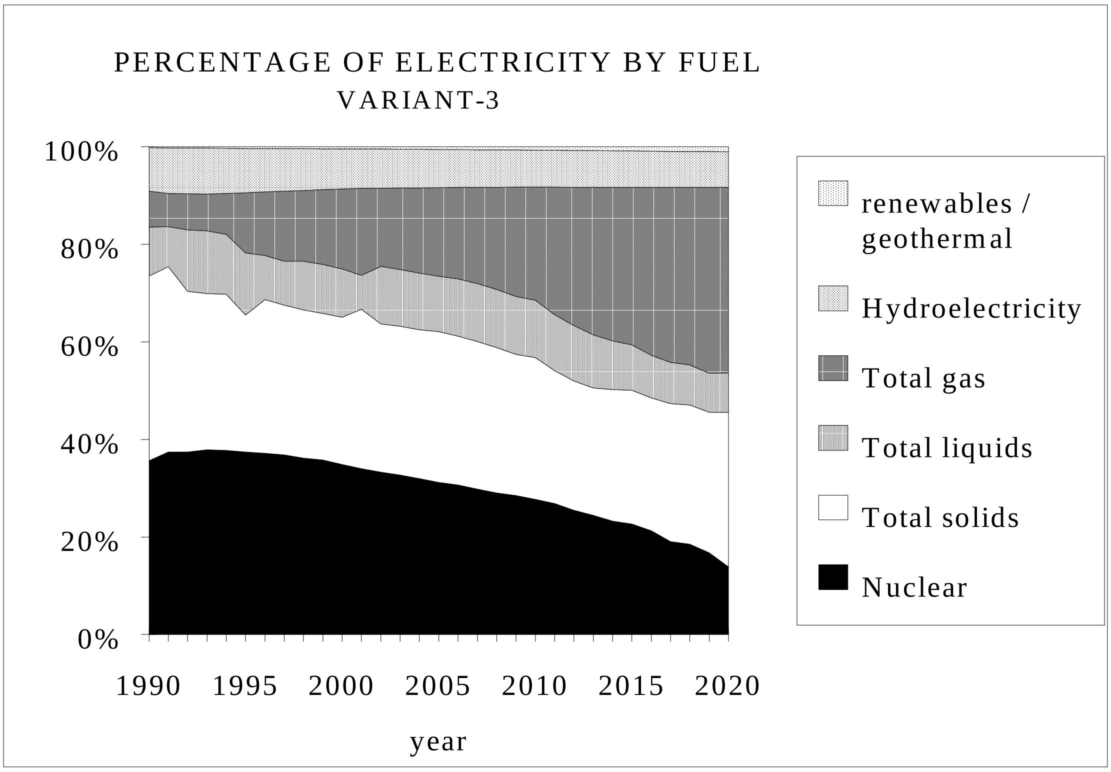


Exhibit 23 - Percentage of Electricity by Fuel

6.4.2 ECONOMICS

The total investment is marginally less than in the conventional case, at the absence of capital intensive nuclear additions. The generating costs though, are significantly increased. Long-run marginal cost faces a strongly upward slope and in the end of the period is 11% higher than in 1990, and 19% higher than the conventional case.

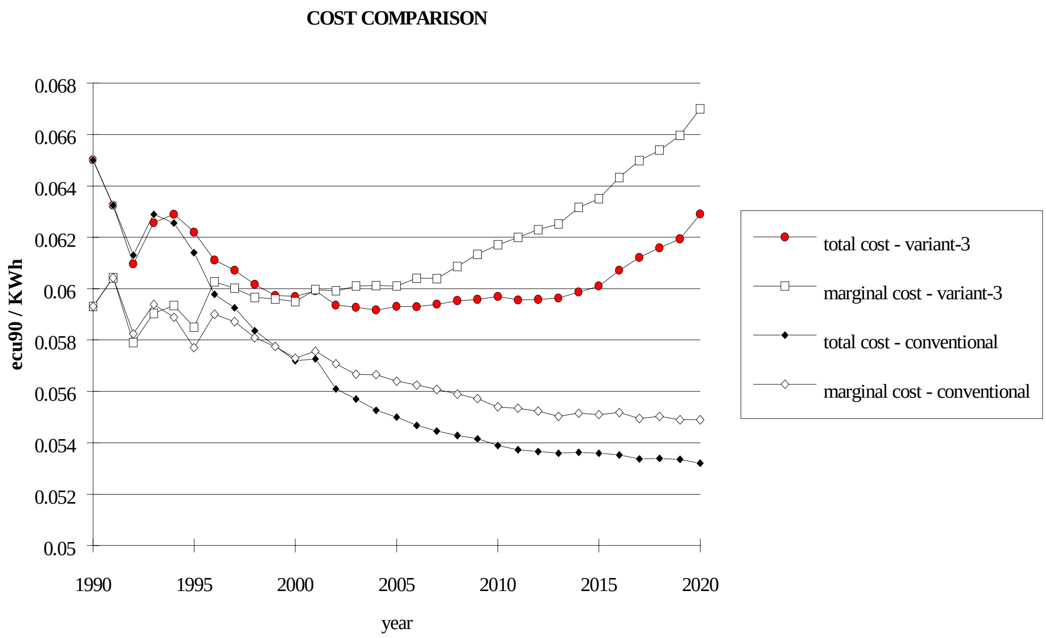
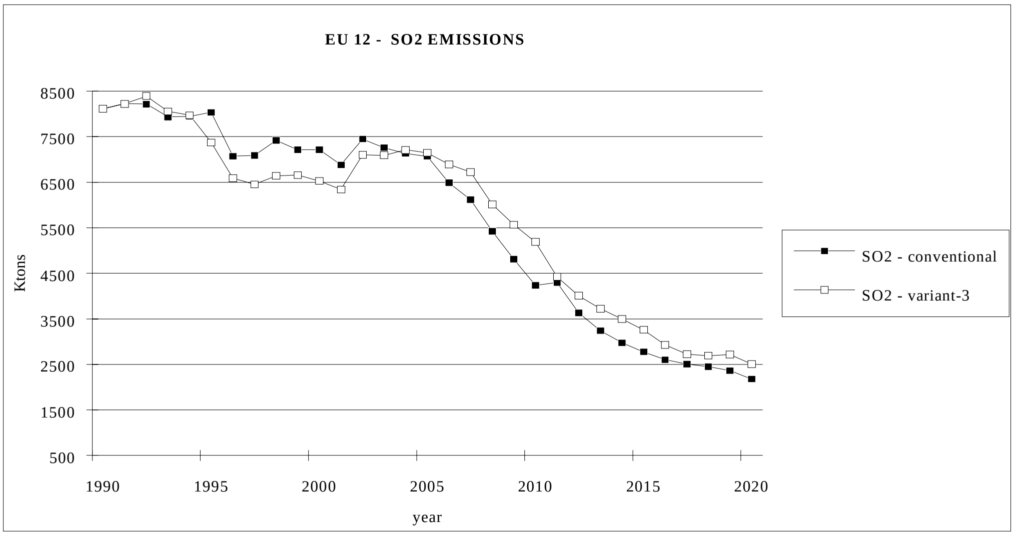
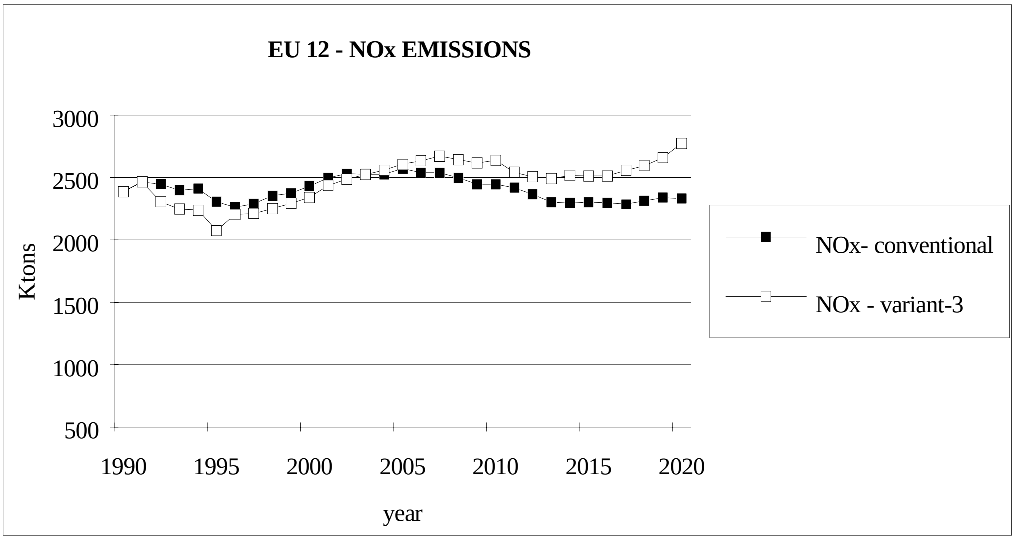


Exhibit 24 - Generation Costs

6.4.3 ENVIRONMENTAL CONSEQUENCES

The effect on emissions is, as expected, adverse. NO_x and SO_2 rise by approximately 17% each with respect to the conventional case, while CO_2 increases by 25% compared to the conventional, and 65% compared to the 1990 levels.





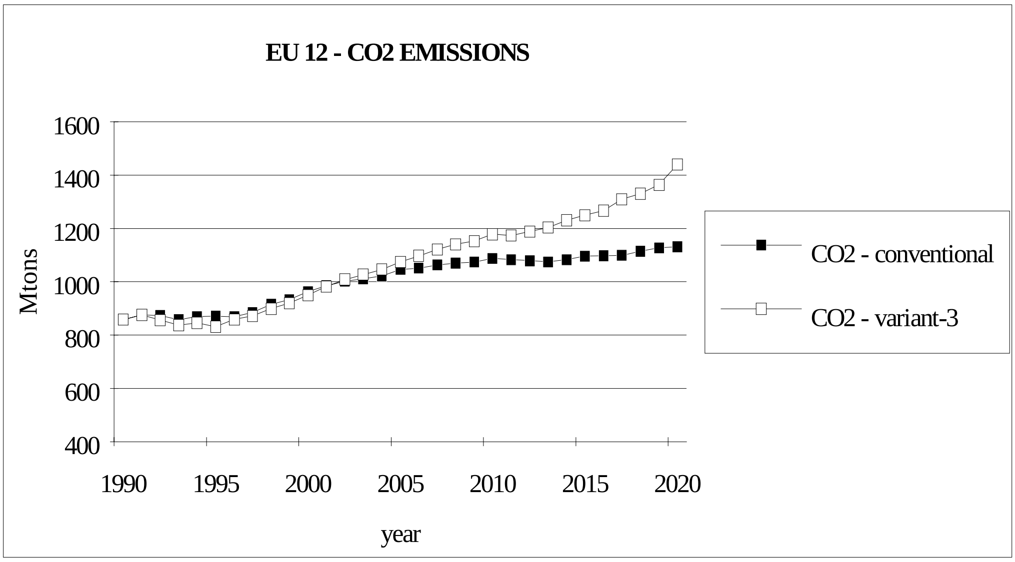


Exhibit 25- Emissions Comparison

7. FINAL COMMENTS

The use of natural gas in Combined Cycle plants seems to be a competitive solution for the medium term. This technique appears as transitional, though, as in the longer term (after 2010) there is a come back of solids even in optimistic gas price cases. Any difficulties in demand or fuel prices tend to favour solid fuel investments. The role of oil is not negligible throughout the period.

New coal technologies emerge when there is a gap to fill and gas price is high, but unless higher reductions are achieved in investment costs, they do not appear to make a significant penetration.

The low demand variant -be it optimistic as it may- indicates that the achievement of low CO_2 emissions lies on the demand side. Especially when nuclear energy is reduced, CO_2 emissions are increasing, in power generation, together with higher electricity demand (Exhibit 26). Reducing significantly SO_2 and stabilising NO_x emissions seems, on the other hand, feasible through abatement equipment.

In terms of generating costs (Exhibit 27), the combination of maintaining nuclear capacities and expanding on gas combined cycle, leads to cost reductions. In the alternative scenarios there is an increasing trend in costs.

Further activities

The following issues are to be addressed in the next versions of the MIDAS-ELEC model:

a) The relationship between gas supply quantities and price is an important exogenous element that has to be confirmed especially for the longer term.
b) Improvements in methodology concern anticipation in planning, endogenous retrofitting and life extensions considering repowering, topping, fuel cells etc.
c) A more detailed representation of renewable sources (other than hydro) needs also to be implemented.
d) The closure of the loop between electricity demand and power generation (as in the standard MIDAS model).

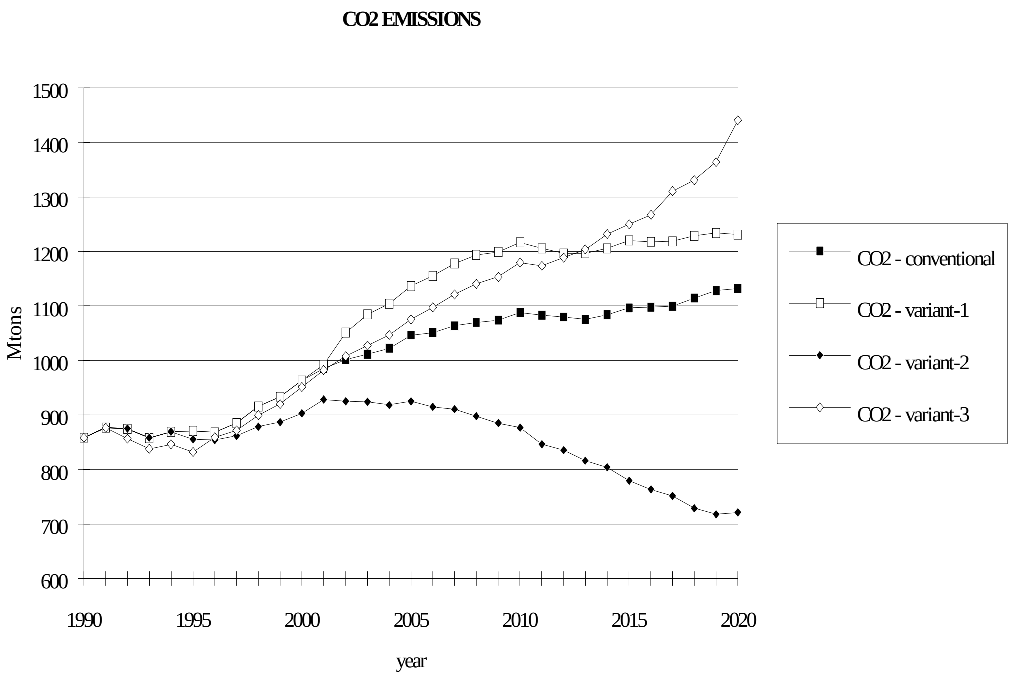


Exhibit 26 - CO2 Emissions comparison

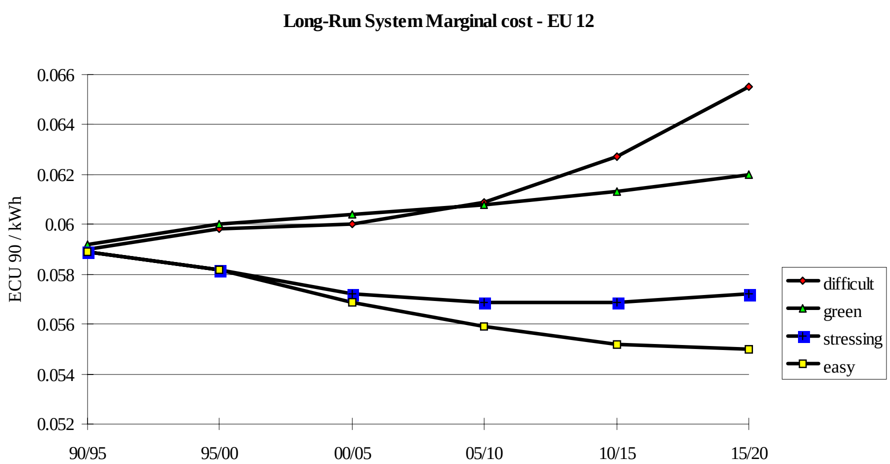


Exhibit 27 - Cost comparison