T E N-ENERGY- I n v e s t

Energy Infrastructure Costs and Investments between 1996 and 2013 (medium-term) and further to 2023 (long-term) on the Trans-European Energy Network and its Connection to Neighbouring Regions with emphasis on investments on renewable energy sources and their integration into the Trans-European energy networks, including an Inventory of the Technical Status of the European Energy-Network for the Year 2003

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GLOSSARY

CAES: compressed air energy storage

DC Baltija: association of the Baltic system operators of Estonia, Latvia and Lithuania

ETSO: European Transmission System Operators. Association of the European electricity system operators

FACTS: Flexible Alternative Current Transmission Systems

GTC: Gross Transfer Capacity, related to the mere summation of the capabilities of tie-lines

GTE: Gas Transmission Europe. Association of the European gas system operators

HVDC: High Voltage Direct Current; link, consisting of cable or overhead line where current is transmitted as direct instead of alternative current

IEM: Internal Electricity Market

ISO: Independent System Operator. He is the responsible for the management of the system, but he doesn't own the assets.

IT: Information technology

LNG: Liquefied Natural Gas

NORDEL: association of the Nordic electric system operators that include Denmark, Finland, Norway, Sweden and Iceland

NTC: Net Transfer Capacity equal to: TTC-TRM. NTC is the maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions. These values are periodically published by ETSO.

RES: Renewable Energy Source

TPA: Third Party Access

TSO: Transmission System Operator. He is the owner of the assets and the responsible for the management of the system

UCTE: Union for the Coordination of the Transport of Electricity. It is the electricity pool of central and western Europe

Units of measure

toe = Tons of oil equivalent
Mtoe = Million of tons of oil equivalent
bcm = billion of cubic metres
TWh = Terawatthour equal to 1 billion of kWh
GWh = Gigawatthour equal to 1 million of kWh
MWh = Megawatthour equal to 1 thousand kWh

Executive Summary

Overview and scope of the study - The Project "EU-TEN ENERGY INVEST" is aimed at providing a comprehensive overview of past investment patterns and envisaged medium-term and long-term investment trends in the Trans-European Energy networks (TEN-E) of the enlarged European Union with particular emphasis on investments on renewable energy sources and their integration into the Trans-European energy networks. The analysis covered the EU 30[1] states and the western Balkan states[2], the energy infrastructures of which are embedded in the European grids.

Methodology – At first, an extensive data collection and elaboration have been carried out to have a clear view of the current technical status of the electricity and gas transmission grids, the past investment patterns as well as the prospective investments. Data were retrieved by examining publicly available documents issued by international organizations and through questionnaires sent to gas and electricity Transmission System Operators (TSOs).

In addition to the information provided by national TSOs, the future investment needs have been evaluated by applying specific models. In the electricity sector the total investments internal to the EU30 have been estimated referring to some key parameters, namely evolution of the demand, country surface and load density. For the assessment of future investment needs in cross-border lines, an optimization algorithm has been used minimizing the net present value of capital and fixed operation and maintenance costs of new generation and transmission facilities, plus the variable costs of existing and new generation facilities. As for the gas sector, the increase of import capacity, and, consequently, the need for new gas pipelines, has been evaluated on the basis of the evolution of the gas demand and the gas production internal to the EU30.

Mid-long term scenarios - The evaluations of future investment trends have been based on some already available scenarios providing as an input the development of electricity and gas demand, power generation mix and fuel cost. The "*Baseline scenario*" has been derived from the output of the study "*European Energy and Transport Trends to 2030*" carried out on behalf of E.C and based on the PRIMES model[3]. In addition to the "*Baseline*", a number of variants have been examined to assess the future needs of investments in the energy infrastructures. In the electricity sector, further scenarios were considered, the most important of which are the following:

- '*Kyoto for ever + nuclear expansion*' scenario, which evaluates the effect of maintaining carbon emissions constraints according to Kyoto Protocol commitments along the whole planning horizon, allowing unconstrained nuclear generation expansion after year 2015 as a means of complying with Kyoto targets.
- *'New generation optimized'* scenario, which considers a joint optimization of both transmission expansions and installed generation capacity. This scenario is particularly meaningful since it overcomes the limitations of the PRIMES model, which estimates the optimal energy trends in each country taking electric interconnection capacities as an input. Consequently, all the scenarios modeled on the basis of generation capacity-demand balances taken from PRIMES envisage a low development of cross-border capacity. On the contrary, the "*new generation optimized*" scenario and related variants give a clear idea on how much the EU countries shall be integrated each other when passing from a national to a continental perspective in the location of new generation.

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[1] EU 30 is composed by EU 25 member states, plus Norway, Switzerland and the three candidate states of Bulgaria, Romania and Turkey.

EU 25 is composed by the EU 15 old member states and the new EU members : Estonia, Latvia, Lithuania, Poland, Slovakia, Czech Republic, Hungary, Slovenia, Cyprus, Malta.

EU 15 refers to the following member states : Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, UK.

[2] Western Balkan states are Albania, Bosnia-Herzegovina, Croatia (new candidate member from October 2005), Serbia-Montenegro, Macedonia.

[3] PRIMES model is a mathematical model prepared by the National Technical University of Athens, E3M-Lab, Greece, for the DG TREN

ELECTRICITY

Current technical status of energy infrastructures - The European power transmission grid is composed of seven power pools (UCTE, NORDEL[4], Great Britain, the Irish system, the DC Baltija pool[5], IPS/UPS[6], Turkey). These power pools are weakly interconnected with each other through HVDC (High Voltage Direct Current) links, with the exception of DC Baltija, which is synchronously and strongly interconnected with the IPS/UPS pool. The UCTE power pool, including the Central and Western European Countries plus the westernmost region of the Ukraine, is synchronously interconnected with Morocco, Algeria and Tunisia from 1997. The total gross consumption in the EU30 and Western Balkan countries has been around 3,300 TWh in the year 2003 with an installed power exceeding 800 GW.

Cross-border energy exchanges have been increasing in these last years. However, in some cut-sets they are limited due to the insufficient transmission capacity (bottlenecks). In the UCTE pool the exchanged energy is around 12% of the total consumption, while in NORDEL this ratio attains 25% and in DC Baltija it is about 47%. By referring to the EU priority axes, the most congested cut-sets (bottlenecks) are the following: EL 1 (France-Belgium-Netherlands), EL 2 (Italy-rest of Europe), EL 3 (France-Iberian Peninsula), EL 4 (Interface between former 1st and 2nd UCTE synchronous zones and Bulgaria-Greece); EL 5 (France-Great Britain), EL 7 (Denmark-Germany; Finland-Sweden; Norway-Sweden), EL 8 (Poland-Czech rep., Poland-Slovakia, Czech rep.-Austria, Slovakia-Hungary, Hungary-Slovenia).

Investment patterns during the years 1996 till 2004 and financing sources – In the period from 1996 to 2004 the **average yearly investment** has been **3.1 b€/yr** (billion of Euro per year) with an increasing level of expenditure in the last two years. The largest part of the investments has been in substations (40%), internal lines (33%) and other assets (23%), such as telecommunication, protection and control, special equipment, while only 4% of the total has been devoted to cross-border lines. Most of the expenses in cross-border links are concentrated in HVDC interconnections through submarine cables. The investment level is quite uniform in the EU 30 countries with the exception of Bulgaria, Romania and Turkey, where investments are low in relationship to the extension of the national electricity transmission grid. Information gathered from western Balkan countries, not belonging to the EU 30, though rather incomplete, shows low investments too. Countries with the highest investments with respect to the extension of the grid are: Lithuania, Poland, Greece, Ireland and Cyprus.
Main reasons for investments have been: lack of generation capacity and consequent need to connect new power plants, improving security of supply and fostering the implementation of the electricity market. Furthermore, one emerging factor prompting additional investments is related to the ageing of the system.

The composition of the **financing sources** for power transmission projects is the following: TSOs equities (39% of the total investments), EIB loans and other EU funds (16%), loans from banks other than EIB (37%); the remaining 8% of financing is obtained by other sources (e.g.: international institutions, private investors). TEN-Energy funding is used essentially to support feasibility or pre-feasibility studies and not for project realization.

Ageing of the system and need for repairs and upgrades - A substantial need for replacement, refurbishment, upgrade and re-design is expected in the next two decades. In many cases TSOs estimate that their transmission system will be able to operate safely and reliably up to 10 years ahead without taking any countermeasure. Already now a remarkable part of investments is related to maintaining the present reliability level. This happens not only in the Eastern European countries but also in the West. To smooth the need for investments while ensuring the requested reliability level, it is recommended to adopt measures based on "life extension techniques".

[4] NORDEL : Norway, Sweden, Finland, Denmark and Iceland
[5] DC Baltija : Estonia, Latvia and Lithuania
[6] IPS/UPS : Russia and most of the other CIS countries

Medium term and long term investment patterns – The analysis aimed at identifying the total investments with specific concern to the reinforcement of the cross-border capacities. Information on the total investments has been retrieved by TSOs, while investments on cross-border infrastructures have been computed by applying a modeling technique in conjunction with the various scenarios mentioned above. A general estimation on investments internal to the countries has also been carried out.

Total investments according to the TSOs forecasts - A clear indication of an increasing investment effort for the next years (up to 2013) emerges from the investment plans declared by TSOs with an envisaged **yearly investment level around 4 b€/yr**. Much more difficult is to estimate a clearly defined investment pattern for the long-term (up to 2023), but averaging the available information and comparing it with the past and mid term investments, we can conclude that also in the second decade ahead (up to 2023) a steadily high investment level is to be expected.

Cross-border investments – Investments in cross-border infrastructures are expected to decrease from the present level exceeding 120 M€/yr to a level **below 70 M€/yr** during the next decade when considering the "*Baseline*" and variant scenarios, such as "*High efficiency*" in demand, "*High efficiency&RES (Renewable Energy Sources)*", "*Soaring oil and gas price*" and "*Kyoto for ever and nuclear expansion*" scenarios, which assume as an input the generation evolution of the PRIMES model. The "*High RES penetration*" scenario, based on the EU FORRES 2020 project, entails high investments in cross-border lines in the long run, i.e. after the year 2013 **(>150 M€/yr**). When optimizing both new generation and cross-border transmission capacity, very high investments turn out to be necessary, especially in the long run **(>480 M€/yr**).

By analyzing the cumulated cross-border investments, we can identify three possible investments levels: a) low investments related to scenarios where each country preserves, to some extent, its self-sufficiency and the generation mix converges to a quite uniform composition, essentially based on gas-fired combined cycle; b) mid investment level related to the high penetration of RES; the largest part of the additional cross-border capacity is located along the axis Netherlands-Germany-Denmark; c) high investment level related to the joint optimization of generation and transmission; higher investments are due to the location of new generation closer to the availability of primary energy resources, thus requiring higher power transfers from generation to consumption centers.

Internal investments – The annual investments in assets internal to the countries are in the range **from 3.3 b€ in 2005 to 3.2 b€ in 2023**. The annual investments slightly decline when approaching the year 2023 because of the lower rate of demand growth. However, this estimation cannot take into account investments related to the connection of new generation and to the geographical distribution of additional load; hence, these values shall be seen as a low bound of investments needed within the countries.

GAS

Current technical status of energy infrastructures - The European gas infrastructure has developed gradually, first in countries with national gas production and much later in countries without any significant gas production, e.g. Greece, Portugal, Spain and Sweden. Whereas, historically, many nations produced the majority of their gas within their own national borders, most European countries are nowadays gas importers.

The expected increase in gas demand and current bottlenecks call for continuous investments in the European gas transmission system.

Investment patterns during the years 1996 till 2004 and financing sources – For the past nine years, the investment level in the EU 30 gas transmission has been **about 2.6 b€/yr**. This includes investments internal to the gas transmission systems of each country, excluding investments in gas storages, LNG (Liquefied Natural Gas) terminals, import pipelines and new interconnectors (only investment type 1 "*Internal TSO Investments,*" as described later).

The background justifying the historic investments is: lack of transmission capacity, extension of pipeline systems to new areas, need to connect power plants, diversification of energy supply, new cross-border points, development of international transit, need to solve the problem of air pollution in the cities and improvement of the security of supply.
EU loans or other aid instruments have been widely used to support gas transmission projects as about half of the TSOs have reported positively on this. According to what reported by a large majority of TSOs, financing is not slowing down investments in gas transmission projects.

Ageing of the system and need for repairs and upgrades - The average age of gas transmission networks in Europe varies significantly in the range between 6 and 31 years. TSOs generally expect their gas transmission systems to be able to work safely and reliably for the next 20 years, with two exceptions: Bosnia-Herzegovina and Romania where the remaining lifetime is expected to be below 10 years.

Medium-term and long-term investment patterns – Future investments in gas infrastructure can be divided into the following 5 groups:

1. **Internal investments in each country**: These constitute investments that the TSOs are expected to make in their own national gas transmission grid in order to extend, upgrade and maintain the current system. Investments in gas storage, LNG terminals and major import pipelines have been subtracted from these investments.
2. **Storage**: investments in new gas storage facilities are necessary to cope with the yearly variation of gas demand and to utilize the gas import pipelines system with a high load factor.
3. **Interconnectors and gasification** include pipelines connecting the gas infrastructures of two EU member states (interconnector) and introduction of gas into geographical areas, which are presently not recipients of gas.
4. **Ongoing import projects** comprise recently finalized and ongoing gas projects aiming at an increase of Europe's gas import capacity.
5. **Import pipelines and LNG** receiving terminals for the EU 30. The object of these projects is to ensure that Europe is provided with sufficient gas transmission or LNG facilities to meet the future gas demands.

The table below summarizes the expected total investments for the *Baseline scenario* and some variants.

EU 30: Expected investments in b€ in the period 2005-2023	TSO internal Investment	Storage	Interconn. & gasificat.	Ongoing Projects	Import Pipelines & LNG	Total Investment
Baseline Scenario	48	22	6	1	23	100
High RES	46	17	6	1	21	91
High energy efficiency	42	11	6	1	15	75
High RES and energy efficiency	40	9	6	1	14	70
Soaring oil and gas price scenario	36	5	6	1	3	51

In the *Baseline scenario*, the investments are expected to be 48 b€ in the TSO transmission system, 22 b€ in storage, 6 b€ in future interconnectors, 1 b€ in already started gas import projects and 23 b€ in import pipelines and LNG terminals, reaching 100 b€ in total. The "*soaring oil and gas price scenario*" has the lowest expected investment costs, i.e. 51 b€, which is about 50% less than the *baseline*. The reason is that gas demand will only increase by 40 bcm, compared to 215 bcm in the *Baseline scenario*. Scenarios considering "*high efficiency*" in consumption also show lower investment needs with respect to the *Baseline scenario* because of a more moderate increase in gas demand (156 bcm in the period 2005-2023).
For large parts of 2005, the oil price has been above 50 US$/bbl with peaks around 70 US$/bbl (e.g. in August 2005). This constitutes a higher oil price than in the "*soaring oil and gas price scenario*". If the oil and gas prices continue to keep such high levels, the "*soaring oil and gas price scenario*" with a total investment level of about 50 b€ will be the most probable scenario in future. If, on the contrary, the current high prices just turn out to be a short-term phenomenon and the prices actually fall to the *Baseline scenario* prices, then the most probable investment level will be about 100 b€.

INTEGRATION OF RES INTO THE ENERGY NETWORKS

As for wind generation, the following possibilities have been investigated: combination of **wind generation with gas-fired combined cycles** (CC) and combination of **wind generation with storage facilities**, namely pumping storage plants and storage through air-compressed reservoirs. The only economically feasible solution turned out to be the combination of wind generation with CC plants, which give prices competitive with power generated fully by CC. A possible massive coupling of wind and CC generation will have an impact on power flow exchanges among Germany, Denmark, Netherlands and neighbouring countries (EL1 and EL7 axes) and between Spain and its neighbouring countries (EL3 axis).

As for **solar energy**, despite the high potential of solar energy in North Africa and the perspective development of South-North corridors across the Mediterranean basin (EL9 axis), export of solar energy to Europe is not economically profitable.

Finally, the possibility to transport both **biogas** and **hydrogen** in pipeline networks with the technologies existing today was examined. Transportation of biogas in dedicated networks or in natural gas pipelines is not economical feasible without any subsidies due to the lower calorific values of biogas with respect to natural gas. Transport of hydrogen mixed with natural gas is also not economically and technically feasible.

NON-CONVENTIONAL TECHNOLOGIES FOR INCREASING CAPACITY IN TRANSMISSION NETWORKS

Non-conventional technologies can be classified in two broad categories: hardware technologies, which rely on the adoption of a new generation of components or the adaptation of already existing equipment to new operating conditions, and software solutions, based on information technology (IT) and advanced communication protocols. The conclusions can be summarized as follows:

Hardware solutions

- **Electricity -** The most mature non-conventional solutions are based on the installation of:
  - high voltage extruded polyethylene cables; applications in densely populated or environmentally protected areas;
  - HVDC thyristor based connections, mainly along EL3, EL6, EL7, EL9 axes;
  - phase shifter transformers, mainly along EL1, EL2, EL3 axes and internally to Poland.
- **Gas**
  - Ultra deep-water offshore pipelines and high-pressure on-shore pipelines are the most favourable solutions for the construction of new gas routes and for enhancing the capacity of the existing ones.

Software based solutions

In the electricity sector, change of operating procedures and dynamic rating of components are two possible feasible ways to enhance transfer capacities in the mid-term perspective allowing postponing investments in new lines.

In the gas sector, the adoption of new meters coupled with satellite communications will favour the on-line collection of a large amount of reliable data as required by the EU gas market. Moreover, the design of new gas pipelines can be eased by the use of satellite three-dimensional charts.

1. OVERVIEW AND SCOPE OF THE STUDY

The main objective of this study is to provide a comprehensive overview of past and envisaged medium-term and long-term investments in the Trans-European Energy networks (TEN-E) of the enlarged European Union with particular emphasis on investments on renewable energy sources and their integration into the Trans-European energy networks. The analysis covered the EU 30[7] states and the western Balkan states[8] the energy infrastructures of which are embedded in the European grids.

The study addressed the following topics:

- *Topic 1:* the current technical status of energy infrastructures with a breakdown by energy sectors (electricity & gas), by country and by interface between countries (cross-border corridors);
- *Topic 2:* the investments patterns in the period from 1996 to 2004 and the main sources of financing;
- *Topic 3:* the ageing of the energy transmission networks and its impact on the future developments of the transmission grids and related investments;
- *Topic 4:* the medium-term trend (up the year 2013) for the development of energy infrastructures and related investment needs;
- *Topic 5:* the long-term perspectives (up to the year 2023) for an enhanced integration of the energy infrastructures among the countries of the enlarged EU with an estimation of the necessary investments;
- *Topic 6:* the long-term perspectives for massive integration of renewables energy sources in the EU, taking into consideration their particular characteristics;
- *Topic 7:* the use of non-conventional technologies for increasing capacity in transmission networks.

The analyses related to mid-long term perspectives have been based on some development scenarios worked out by the European Commission. Special consideration has been set on the perspective development of RES and its integration into the Trans-European energy grids. All that in line with the mid-term target set by the EU to increase the share of future consumption of electricity produced by RES from its current level of 6% to 12% by 2010. In addition to a baseline scenario, further mid-long term scenarios have been examined considering different penetration levels of RES.

The outcome of the study shall help the Commission to assess energy policies by estimating costs of the energy transmission infrastructure and the necessary funds to be made available for this sector. In particular, it will help to assess the costs of improving the cohesion of the EU as well as the functioning of the Single Market and the cost-benefit of improving transmission networks with a view on the integration of renewable energy sources.

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[7] EU 30 : is composed by EU 25 member states, plus Norway, Switzerland and the three candidate states of Bulgaria, Romania.

EU 25 : is composed by the EU 15 old member states and the new EU members : Estonia, Latvia, Lithuania, Poland, Slovakia, Czech Republic, Hungary, Slovenia, Cyprus, Malta.

EU 15 : refers to the following member states : Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, UK.

[8] Western Balkan states : Albania, Bosnia-Herzegovina, Croatia (new candidate member from October 2005), Serbia-Montenegro, Macedonia.

2. INTRODUCTION

As above outlined, the objective of this study is to provide a clear view on the past investments patterns and on the perspectives of energy grid evolution in the next two decades. To this purpose, consistency had to be kept with:

- Projects already decided by the national TSOs/ISOs or, in general, entities responsible for planning;
- TEN-E Priority Projects.

Consequently, on the mid-term (up to 10 years ahead) the already planned developments of the electricity and gas infrastructures are displayed together with the estimation of related investments. Usually, actions on network reinforcements defined by planner responsible cover only few years in advance (from three to a maximum of ten years, according to the national regulations). Then, the Consultant worked out a more general view on the needs of energy infrastructure developments and related investment patterns, covering the period up to the year 2023. To this purpose, a series of assumptions has been fixed at the beginning of the analysis and a number of external conditions likely to affect the investment costs have been taken into account. Concerning the assumptions, a "*Baseline scenario*" for the development of electricity and gas demand, generation mix and fuel cost is taken as input. This "*Baseline scenario*" is the output of a previous energy study carried out on behalf of the European Commission (E.C.), namely the one defined in the "European energy and transport - trends to 2030" [1], which is based on the PRIMES model.

In addition to the reference "*Baseline scenario*", further variants have been considered, namely:

- "*high penetration of Renewable Energy Sources* (RES)", based on the FORRES report [2];
- "*high energy efficiency*", based on PRIMES model;
- mixed scenario with combination of "*high RES penetration and high energy efficiency*", based on the PRIMES model;
- "*soaring oil and gas prices*", based on PRIMES model.

Furthermore, for the electricity sector a sensitivity analysis with respect to some crucial parameters (e.g.: nuclear generation expansion, high coal prices, high fuel prices, high transmission costs, etc.,) has been carried out in order to check the impact on the need for investments in the transmission grids.

In the above evaluation, a number of "perimeter issues" affecting the generation-demand sectors and, consequently, the needed infrastructures have been taken into account. The most relevant issue is relevant to the environment. The commitment of Europe in fully implementing Kyoto Protocol and a possible escalation of carbon prices beyond 2012 can lead to a remarkable modification of long-term generation patterns and in particular to the revision of Europe's attitude towards the nuclear option. As a matter of fact, Europe is presently planning to decommission its nuclear plants. Moreover, high costs, long lead times to build and public's negative attitudes make any new development highly unlikely before 2010, with few exceptions (e.g.: Finland). Nevertheless, with strict adherence to Kyoto, Europe may reach a point around 2015-2020, when the nuclear option becomes necessary to avoid increasing Greenhouse Gas emissions. It is self-evident as well, that such modifications to the European generation pattern may lead to remarkable modifications of the pattern of power exchanges among European Countries and the related investments in transmission infrastructures.

Environmental concerns can affect the penetration level of RES, then, as already mentioned, variants of the baseline scenario have been analysed. The main focus in this case addresses the wind energy and the costs for integrating it into the transmission grid. The integration costs are closely related to a number of factors such as:

- level of penetration of wind energy;
- location of wind energy (on-shore vs off-shore)
- regulatory framework defining the cost allocation methodology (e.g.: "shallow basis" vs. "deep basis").

Other kinds of RES (biomass, solar energy) are examined with the specific target of investigating their impact on the transmission networks.

The possibility of combining wind and gas generation (combined-cycle plants) has also been investigated comparing the costs of energy production with the combination wind-gas against the cost of producing the same energy only with combined-cycles. Possibility of coupling wind generation with energy storage facilities has also been examined in order to highlight the conditions on the basis of which wind generation can be considered as firm generation for baseload output or as firm capacity for peak hours. Detailed numerical analyses considering the coupling of wind generation with pumping storage plants or compressed air energy storage (CAES) have been carried out.

Concerning solar energy, the most appropriate technologies and the potential of power export have been addressed in the project together with the most feasible solutions for the connections between North Africa and Europe.

Finally, considering the huge investments involved in the energy transmission corridors, the adoption of new technologies, which allow enhancing the efficiency of the transmission, has been investigated highlighting the priority axes that are likely to be most affected. First, a classification of new technologies for gas and electricity transmission has been carried out together with the related costs, whenever available. Then, the feasibility of applying such new technologies in the European electricity and gas transmission networks has been assessed. The measures to enhance the transmission network capacity can be classified in two broad categories:

- hardware technologies, which rely on the adoption of a new generation of components or the adaptation of already existing equipment to new operating conditions,
- software solutions, based on IT and advanced communication protocols.

In the electric networks the possible measures can be grouped as follows:

- undergrounding of overhead EHV lines;
- installation of new equipment electronically controlled such as HVDC links, flexible series compensation (e.g.: TCSC), PST transformers and, in general, FACTS devices. Reference has been made to the more mature technology in order to provide indications on investments that are technically feasible and commercially viable;
- operational solutions, such as Special Protection Systems and Dynamic Loading.

Concerning gas, the main new technologies, whose impact into the grid has been investigated, are:

- ultra-deep water offshore pipelines;
- high pressure onshore pipelines,
- electrically driven compressors,
- plastic and composite materials for pipelines,
- trench less technology and new construction methods,
- new meters and communication systems, satellite imaging and other IT based design methods.

The attitude of TSO's to adopt new technologies for gas or power transmission has also been investigated through direct contacts with the TSOs. This allowed having a clear view on the most recent and perspective installations of FACTS devices, EHV cables, operational solutions, high pressure pipelines, electrically driven compressors, compressors driven by gas turbines and gas storage facilities.

After a description of the adopted scenarios (chapt. 3), the presentation of the study results is arranged as follows:

➢ Chapter 4: Electricity sector
  - *current technical status of the European power transmission networks;*

- *investment patterns in the last years;*
- *trends for mid-long term investments.*

➢ Chapter 5: Gas sector
- *current technical status of the European gas transmission networks;*
- *investment patterns in the last years;*
- *trends for mid-long term investments.*

➢ Chapter 6: Integration of Renewable Energy Source in the European transmission grids

➢ Chapter 7: Use of non-conventional technologies for increasing capacity in transmission networks.
- *current technical status of the European power transmission networks;*
- *investment patterns in the last years;*
- *trends for mid-long term investments.*

➢ Chapter 8: Sources of information.

2.1 Overview of the European strategy on energy infrastructures

European society and industry are becoming more and more dependent on the availability of energy supplies and on the good functioning of energy transmission networks. The recent blackouts that took place in many European countries have shown very well the necessity to establish a Europe-wide integrated energy network free of bottlenecks. On the other side, the process of liberalisation that marked recently the development of nearly all the national energy markets, in Europe as well as outside, has further stressed the necessity to dispose of reliable and well dimensioned interconnection electricity networks, able to widen the range of power offer in the markets, and, therefore, at least potentially, increase competitiveness and lower prices, with a general benefit of all the people. To these needs, some additional requirements can be added: the necessity to connect the renewable resources (currently in a very strong reinforcement phase, especially in some European countries) and the need to reinforce security of supply. These ideas are boosting even more the on-going process of creation of an Internal Electricity Market (IEM) of the European Union.

As far as gas networks are concerned, one-quarter of present Energy consumption is based on natural gas and gas demand is estimated to double by 2030, with a significant need to enhance import capacities. According to the EU Baseline scenario [1], the EU-25 external dependence in terms of natural gas is projected to increase sharply, reaching 81.4% by 2030, compared to 49.5% in 2000. Thus, again the availability of reliable and correctly dimensioned networks plays a key role for the economic future of Europe.

In 2000, the Commission adopted a Green Paper entitled "*Towards a European strategy for the security of energy supply*". This document presented an analysis showing a future significant dependence increase of energy supply in all the European countries from third countries. In this scenario, Trans-European networks can play a key role in increasing the level of efficiency of the energy systems. Development of alternative routes can reduce specific dependencies on individual countries. The most important links must be developed to and from third countries as well as within EU with the new member states.

The list of these priority projects (see [3]) has been last updated in December 2003 in order to take into account the EU enlargement with the new members that entered in May 2004 and to face some bottlenecks occurred frequently in the interconnection networks. For instance, Poland and the Czech Republic already exported electricity to Germany and Italy, but the related interconnection network were saturated most of the time. Furthermore, new connections need to be built between Baltic States and other EU members.

The resulting projects, related to priority axes, will be funded by EU mainly for preparatory and feasibility studies and pre-construction development. However, building and maintaining the networks must be typical

tasks of energy transmission companies. Total investment is estimated around 28 billion Euro for the networks to be built between 2007 and 2013. The axes individuated for these investments are the following (see *Fig 2.1* and *Fig 2.2*):

- **Electricity priority projects already agreed:**
  1. EL1: France-Belgium-Netherlands-Germany;
  2. EL2: Borders of Italy with France, Austria, Slovenia and Switzerland;
  3. EL3: France-Spain-Portugal;
  4. EL4: Greece-Balkan countries-UCTE System;
  5. EL5: United Kingdom-continental and northern Europe;
  6. EL6: Ireland-United Kingdom;
  7. EL7: Denmark-Germany-Baltic Ring.

- **Proposed additional electricity priority projects:**
  8. EL8: Germany-Poland-Czech Republic-Slovakia-Austria-Hungary-Slovenia;
  9. EL9: Mediterranean Member States-Mediterranean electricity ring.

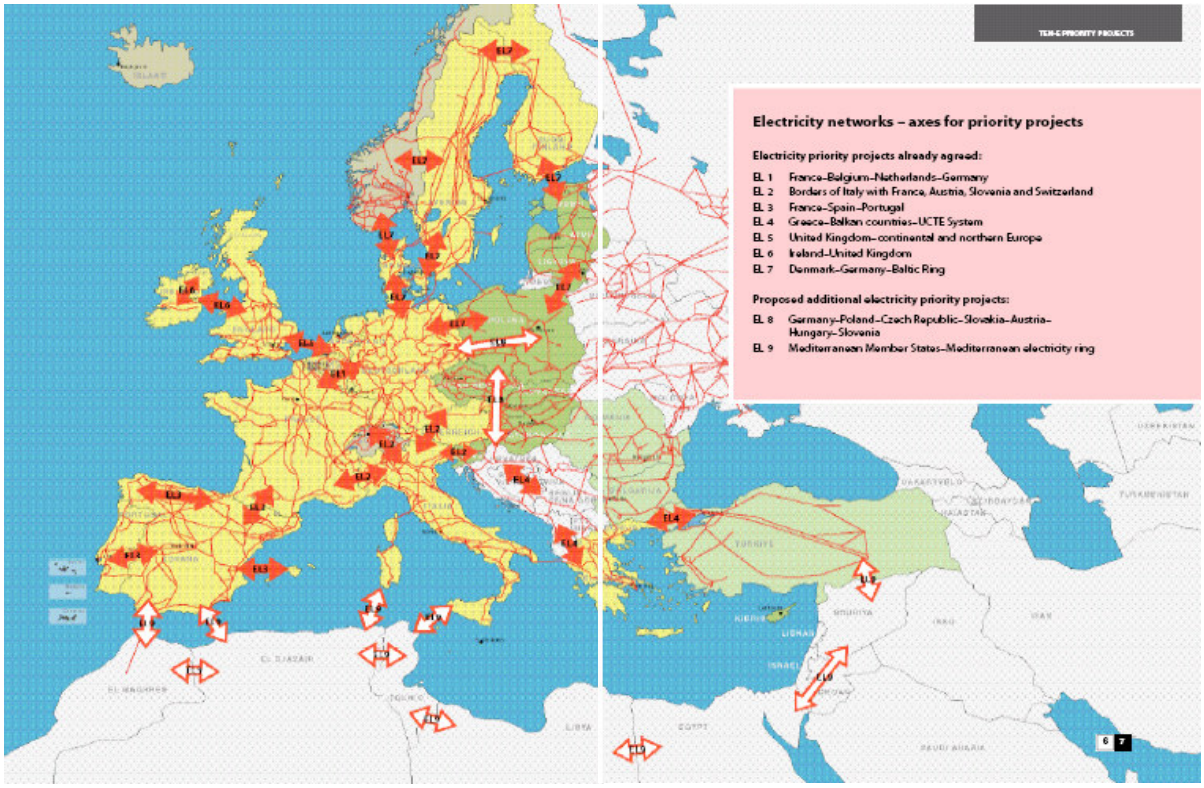


Fig 2.1 - EU-TEN projects in the electricity field

- **Natural gas priority projects already agreed:**
  10. NG 1 United Kingdom–northern continental Europe, including Netherlands, Denmark and Germany (with connections to Baltic Sea region countries)–Russia
  11. NG 2 Algeria–Spain–Italy–France–northern continental Europe
  12. NG 3 Caspian Sea countries–Middle East–European Union
  13. NG 4 LNG terminals in Belgium, France, Spain, Portugal and Italy
  14. NG 5 Underground storage in Spain, Portugal, Italy, Greece and the
  15. Baltic Sea region

- **Proposed additional natural gas priority project:**
  16. NG 6 Mediterranean Member States–east Mediterranean gas ring

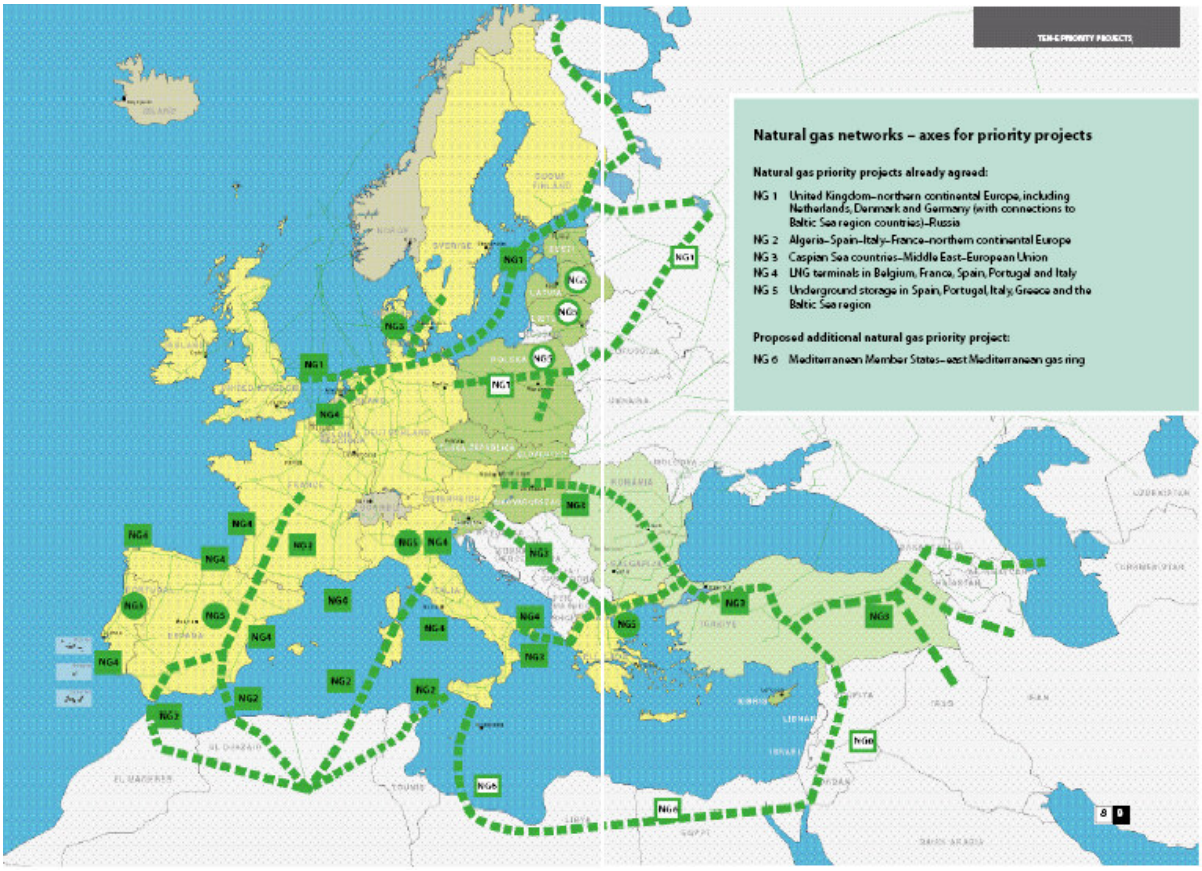


Fig 2.2 - EU-TEN projects in the gas field

2.2 Methodology applied to perform the assignment

To achieve the study objectives, two main phases are foreseen:

- **data collection**;
- **analysis and elaboration of the collected data**.

The process of **data collection** has been based on the following steps:

a) set up of the list of information necessary to achieve the project. This work has seen the involvement of all the partners that together formulated a common framework for the repository of the information;

b) creation of a common data repository where the collected documents and information are uploaded and downloaded by each partner.

c) Gathering publicly available information relevant to international organisations such as:
   - UCTE, NORDEL, DC Baltija, etc. for information concerning the main European Power Pools,
   - ETSO and SETSO for information relevant to cross-border Transfer Capacities,
   - Eurelectric. In particular, reference has been made to the working groups SYSTINT and SYSTMED that, among other issues, examined the present and planned interconnections in Europe including the interconnections towards neighbouring CIS countries and the Southern and Eastern Mediterranean countries,
   - Documents issued in the framework of the Athens Forum (South-Eastern Europe: SEE) for information dealing with the creation of the electricity market in SEE, the set-up of a regional Cross-Border trade mechanism and the monitoring of the electrical infrastructures;
   - Gas Transmission Europe (GTE);

d) Gathering publicly available information from the national ISOs and TSOs to have a detailed view of the transmission assets, the past investments on the transmission grids and the perspectives on the network expansion projects with special focus on the cross-border lines;

e) Documents produced from the European Commission and, particularly, from DG TEN

f) In case of lack of information retrievable from available public documents or to get updated information, direct contacts with the national ISOs/TSOs and/or international organisations have been undertaken. More in detail, concerning the electricity grids, direct contacts with the representatives of CIGRE SC C1 "Power System Development and Economics" have been taken. As a matter of fact, CESI is actively participating to the CIGRE SC C1 activities and can target the request of information to the various responsible of power system planning.

g) For a better standardisation of the information and to have a common approach towards the entities to be contacted, two questionnaires have been prepared and agreed among the project partners: one questionnaire for gas grids and one for electricity grids. The questionnaires addressed the following issues:
   - Past and expected future investments; description of the major transmission projects recently achieved or scheduled in the near future together with their investment costs and source of financing
   - Aims of the past and expected future investments;
   - Impact of the single market on past and future investments;
   - Technical status of the transmission system: average age and average design life of the components, needs for repairs and/or upgrades;

- Financial issues: source of financing, cost of capital;
- Obstacles preventing a rapid construction of the needed transmission capacity;
- Attitude to invest in new technologies.

Fig 2.3 and *Fig 2.4* give a view of the replies received by the electric and gas responsible for investments, who, in most of the cases, are the Transmission System Operators. In few cases (e.g.: Italy, Hungary, Greece) the responsible for investments is the asset owner (TransCo), who is separated from the system operator.

In the electricity sector, in addition to the information provided by national TSOs, the total investments internal to the EU30 have been estimated referring to some key parameters as explained later. For the assessment of future investment needs in cross-border lines, a specific mathematical model has been applied. The main features of this model are recalled in chapter 4

As for the gas sector, the increase of import capacity, and, consequently, the need for new gas pipelines, has been evaluated on the basis of the evolution of the gas demand, the gas production internal to the EU30 and considering a load factor of 0.8 of the pipeline nominal capacities and a load factor of 0.6 for LNG regasification terminals. Finally, concerning the gas storage facilities, the estimations of additional needs have been carried out with the assumption of maintaining a level not exceeding specified thresholds for the ratios "internal gas production"/"gas storage capacity" and "gas import capacity"/"gas storage capacity".

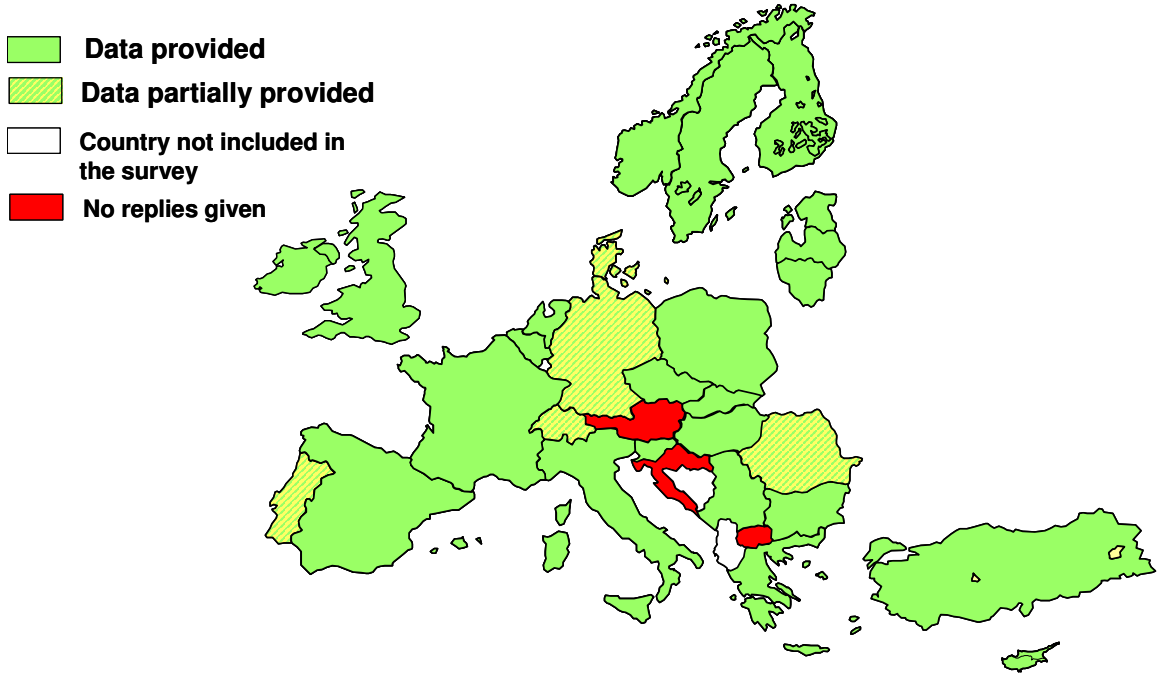
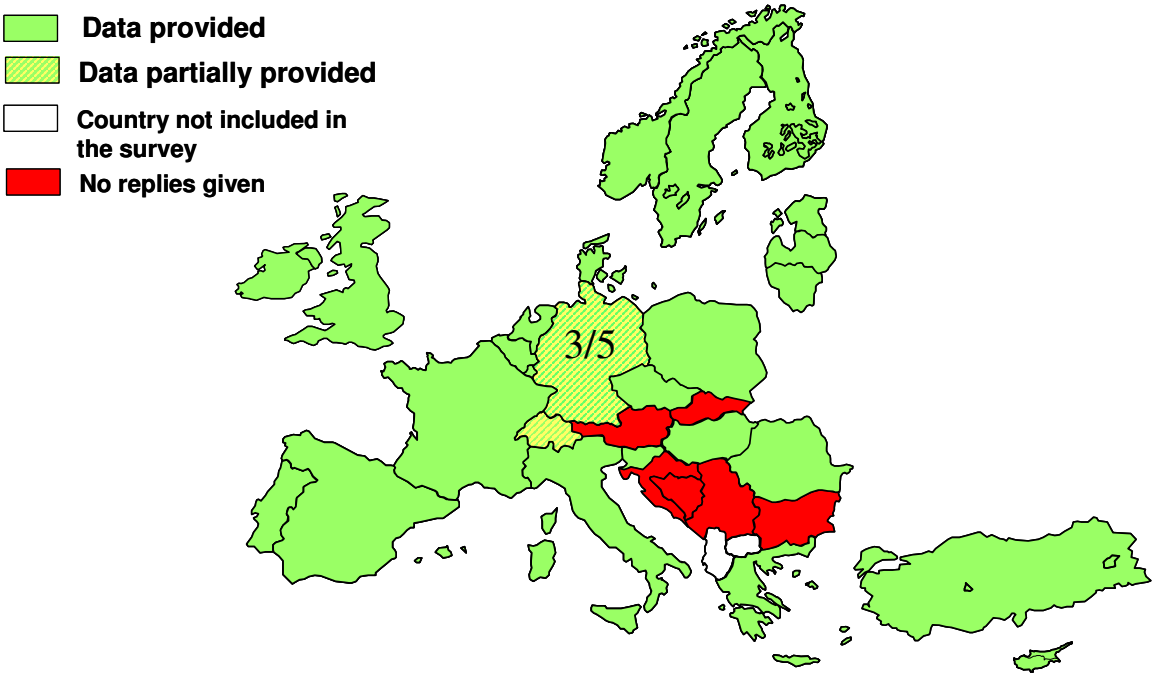


Fig 2.3 – Status of the replies concerning electric transmission grids received by the planning responsible of the various European countries



Note: 3/5 means that three Gas TSOs provided their replies out of five

Fig 2.4 – Status of the replies concerning gas transmission grids received by the planning responsible of the various European countries

2.3 Geographical area under examination

The analysis addressed the investigation of the technical status and the past and perspective investments patterns for **all the EU member states**, including the three candidate states of **Bulgaria, Romania and Turkey**. Moreover, the **countries neighbouring to the EU** have been considered too, with the criterion to include all the infrastructures that:

a) are **embedded with the EU power pools**, namely: Switzerland, Norway and the Countries of the Western Balkans (Croatia, Serbia-Montenegro, Macedonia, Albania and Bosnia-Herzegovina[9]);

b) **allow electricity exchanges with the EU states**. Thus, the interconnections between Europe and the countries of the Southern side of the Mediterranean basin have to be taken into account. Concerning the connection with the CIS states, the status of the cross-border existing infrastructures between the Russian Federation, Belarus, Ukraine, Moldova and the enlarged EU countries is presented, though most of the existing interconnecting lines are not in operation.

For gas it has also been included:

[9] As a matter of fact, Bosnia-Herzegovina is not a neighbouring country with the enlarged EU, but the use of its infrastructures is essential for the transit of energy in South-East Europe.

a) The major gas supplying countries from outside the European Union. E.g. supplying gas from Russia to the European Union entails a need for significant gas pipeline transmission capacity inside the production country.
b) Transit countries of gas to Europe. In fact, the needed transmission capacity in the transit countries is also of significant importance to have an overview of the needed transmission capacity.

3. SCENARIOS

3.1 Scenarios for medium and long term investments patterns

As mentioned, the "*Baseline scenario*" for the development of electricity and gas demand, generation mix and fuel cost is taken from the output of a previous energy study carried out on behalf of the European Commission (E.C.), namely the one defined in the "*European energy and transport - trends to 2030*" [1], which is based on the PRIMES model. The "*Baseline scenario*" reflects a continuation of current trends and policies into the future. It takes into account existing policies and those in the process of being implemented at the end of 2001.

In addition to the "*Baseline*" scenario, a number of variants have been examined to assess the future needs for investments. These correspond to a high penetration of Renewable Energy Sources (RES), based on the FORRES 2020 project [2], the adoption of high energy efficiency measures, the combination of high efficiency measures and high RES penetration and a case where oil and gas prices soar. These scenarios have been identified as *"high penetration of Renewable Energy Sources (RES)"*, *"high energy efficiency"*, *"combination of high efficiency and RES penetration"* and *"soaring oil and gas prices"*.

In the particular case of the electricity sector, a number of "sensitivity scenarios" have been examined to assess the impact of some important parameters on the cross-border investment needs. Most of these scenarios are based on the variants of the "*Baseline scenario*" worked out by the E.C. using the PRIMES model [3].

The scenarios details are discussed in the next sections: Section 3.1.1 describes the "*Baseline scenario*". Section 3.1.2 presents the sensitivity scenarios used in this study. Section 3.1.3 analyses critically the data provided by PRIMES model and FORRES model in order to understand the project results. Section 3.1.4 highlights the most relevant scenarios used to obtain significant conclusions on cross border development. Finally, in section 3.1.5 input data of the optimisation model applied to determine optimal cross-border expansion is described in detail.

3.1.1 Baseline Scenario

The selected *"Baseline scenario"* is characterized by the following key assumptions:

- Electricity demand in accordance with the *"Baseline"* scenario of the PRIMES simulation
- Reference expansion of generation capacity in accordance with the *"Baseline"* scenario of the PRIMES simulation
- Carbon emissions limit: PRIMES simulation
- Cross-border transmission expansion cost in correspondence with the lower limit set for the distance between national systems. This is termed the '*average transmission cost*' assumption.
- Fuel prices as described in section 3.1.5.4.

- Development of renewable energy resources in accordance with the *"Baseline"* scenario of the PRIMES simulation.
- Expansion of nuclear generation capacity beyond that forecasted in the PRIMES simulation is not allowed.

3.1.2 Sensitivity scenarios

In addition to the *Baseline scenario*, four alternative scenarios, applied both to the electricity and gas sector, were simulated as sensitivity analyses in order to take into consideration most significant uncertainties regarding the assumptions made for the Baseline. In the electricity sector six additional alternative scenarios were simulated. However, a subset of '*relevant scenarios'* was finally selected to draw the conclusions.

Since most of them are based either on PRIMES model or on FORRES project results, these assumptions are discussed in the next section, which focuses mainly on those aspects that are relevant for the electricity sector. Simulated sensitivity scenarios are:

- **The 'Kyoto for ever' scenario (S1)** shows the consequences of imposing constraints on carbon emissions. This scenario evaluates the effect of constraining carbon emissions according to the Kyoto Protocol commitments along the whole planning horizon.
- **The 'Kyoto for ever + nuclear expansion' scenario (S2)** allows unconstrained nuclear generation expansion in the long run as a means of fulfilling Kyoto targets. This means that the expansion of nuclear generation is larger than that forecasted in the baseline scenario of the PRIMES simulation. The remaining hypotheses are similar to those in the S1 scenario.
- **The 'High Renewable Energy Sources –RES- penetration' scenario (S3)** assumes a development of Renewable Energy Sources (RES) according to the Policy Scenario analysed in "FORRES 2020: Analysis of the renewable energy sources' evolution up to 2020", see report [2]. The remaining hypotheses are similar to those in the baseline scenario.
- **The 'High RES + Kyoto for ever' scenario (S4)** combines scenarios S1 and S3, assuming carbon emissions limits according "Kyoto for ever" scenario, with all remaining hypotheses similar to S3 scenario.
- **The 'New generation optimized' scenario (S5)**. This scenario allows a joint optimization of both transmission expansions and installed generation capacity. Generation expansion is the result of a least-cost optimisation process where all available technologies compete to meet the expected demand. Only generation data for year the 2005 were taken from PRIMES. For thermal generation, notably gas and coal fired, different fuel prices were assumed for each country using net-back pricing from international hubs (f.i. Zeebrugge for natural gas, ARA for coal). In order to avoid unrealistic unbalances, a maximum[10] was imposed to the generation expansion in each country per year.
- **The 'New generation and high transmission cost' scenario (S6)** considers, in addition to the optimization of the generation capacity, the cost of developing each cross-border interconnector and the costs associated with the required reinforcements in the domestic grids. In this regard, it was assumed that reinforcing the interconnection between two countries is equivalent in terms of cost to building a

[10] For each country it was assumed that generation expansion in a given year should be less or equal to the maximum value between a) 3% of total installed generation capacity in the previous year, and b) the domestic peak load increase expected for that year.

line between the load barycentres of the two countries. Consequently the transmission expansion unit cost (€/kW) considered in this scenario is higher than that in the previous case. See section 3.1.5.7.

- **The 'High coal prices in NE' scenario (S7)** assumes that coal prices in North eastern Europe are higher than those at ARA location. See details on coal price modelling in section 3.1.5.6 below.
- **The 'High efficiency of energy consumption' scenario (S8)** considers both the generation expansion plan and the electricity demand forecast included in the "*high efficiency of energy transmission*" scenario that is part of the PRIMES simulations.
- **The 'High efficiency of energy consumption + High RES' scenario (S9)** considers both the generation expansion plan and the electricity demand forecast of the scenario named "*mixed scenario with high RES penetration and high efficiency in energy consumption*" of the PRIMES simulations.
- **The 'Soaring oil and gas prices' scenario (S10)** considers that the evolution of oil and gas prices over the simulation period corresponds to that in the scenario named "*soaring oil-gas prices*" of the PRIMES simulations.

Scenarios S4, S3, S9 and S10 have been applied to assess future investments needs both in the gas and electricity sectors, while the remaining ones are relevant only for the electricity sector. *Tab 3.1* summarizes the assumptions made in each scenario.

Scenario	Key assumptions	Carbon emissions limit	Transmission expansion cost	RES penetration	Additional Nuclear expansion after 2015	Generation expansion plan	Coal prices in NE Europe (PL)	Fuel International Prices
BASELINE		Primes (Baseline)	average	Primes (Baseline)	No	Primes (Baseline)	lower than ARA	Primes (Baseline)
S1	*"Kyoto for ever'*	Kyoto for ever	average	Primes (Baseline)	No	Primes (Baseline)	lower than ARA	Primes (Baseline)
S2	*Kyoto for ever + Nuclear expansion*	Kyoto for ever	average	Primes (Baseline)	Yes	Primes (Baseline)	lower than ARA	Primes (Baseline)
S3	*High Renewable Energy Sources (RES) development*	Primes (Baseline)	average	**Forres** (Policy scen)	No	**Forres** (Policy scen)	lower than ARA	Primes (Baseline)
S4	*Kyoto for ever + High RES*	Kyoto for ever	average	**Forres** (Policy scen)	No	**Forres** (Policy scen)	lower than ARA	Primes (Baseline)
S5	*New generation optimized*	Primes (Baseline)	average	Primes (Baseline)	No	Simultaneously Optimized	lower than ARA	Primes (Baseline)
S6	*New generation optimized + High transm.cost*	Primes (Baseline)	high	Primes (Baseline)	No	Simultaneously Optimized	lower than ARA	Primes (Baseline)
S7	*High coal prices in NE Europe (PL)*	Primes (Baseline)	average	Primes (Baseline)	No	Primes (Baseline)	higher than ARA	Primes (Baseline)
S8	*High Efficiency development*	Primes (Baseline)	average	Primes (High Effic)	No	Primes (High Effic)	lower than ARA	Primes (Baseline)
S9	*High RES + High Efficiency development*	Primes (Baseline)	average	Primes (H-RES+Ef)	No	Primes (H-RES+Ef)	lower than ARA	Primes (Baseline)
S10	*High fuel prices*	Primes (Baseline)	average	Primes (Baseline)	No	Primes (Baseline)	lower than ARA	Primes (soaring oil and gas prices)

Tab 3.1 – Summary of scenarios

In addition, *Tab 3.2* provides the main figures characterizing the PRIMES scenarios used as an input in our simulations.

PRIMES SCENARIOS		Refe-rence	Baseline		High efficiency		High efficiency + RES		Soaring oil and gas prices	
		2005	2025	2025 vs reference	2025	2025 vs reference	2025	2025 vs reference	2025	2025 vs reference
EU-25										
Gas - Production	bcm	211	136	-35%	136	-35%	138	-35%	149	-29%
Gas - Net imports	bcm	257	532	107%	450	75%	423	64%	347	35%
Total gas demand	bcm	464	668	44%	586	26%	560	21%	496	7%
Electricity Generation	TWh	3041	4173	33%	3644	20%	3590	18%	4272	36%
Installed generation capacity	GW	703	1034	44%	903	28%	932	33%	1089	52%
Final electricity demand	TWh	2583	3673	38%	3203	24%	3162	22%	3760	41%
Europe-30										
Gas - Production	bcm	283	262	-8%	275	-3%	266	-6%	290	3%
Gas - Net imports	bcm	222	504	127%	392	77%	367	65%	274	23%
Total gas demand	bcm	505	766	52%	667	32%	632	25%	565	12%
Electricity Generation	TWh	3473	4935	38%	4309	24%	4254	22%	5036	41%
Installed generation capacity	GW	824	1257	50%	1097	33%	1131	37%	1316	57%
Final electricity demand	TWh	2903	4248	42%	3703	28%	3662	26%	4337	45%

Tab 3.2 – Main figures of PRIMES scenarios

3.1.3 Comments on the FORRES project and the PRIMES model

As commented above, several hypotheses and assumptions were taken from both the FORRES project and the PRIMES model. This section discusses some key elements of these projects that have a significant impact on the estimation of investments in the expansion of electricity transmission, particularly cross-border interconnectors. Moreover, the fact that some simulated scenarios show similar results led us to select some relevant scenarios as discussed in the next section..

3.1.3.1 FORRES project

The FORRES project relies on the computational programme Green-X and econometric projections for its calculations. The Green-X model produces annual results up to 2020. This model determines the level of supply and demand in the equilibrium within each considered market segment (e.g. tradable green certificate market, electricity power market and tradable emissions allowance market). In this project, two main scenarios were considered (*Tab 3.3*):

- Business-as-usual scenario (BAU), which estimates the future development of supply and demand based on present policies and currently existing barriers and restrictions, e.g. administrative and regulatory barriers. Future policies, which have already been agreed but have not yet been implemented yet, are also considered.
- Policy scenario (PS), which models the future evolution of supply and demand assuming that the currently available best practice strategies are in place in all EU Member States. Strategies that have proven to be most effective in the past to maximize the penetration of RES have been assumed for all countries. Furthermore, the policy scenario assumes that currently existing barriers will be overcome.

Both scenarios include the effects of technology learning and economies of scale, which have a higher impact in the policy scenario. The main result of the FORRES project used as input in our study is the expected development of RES technologies. The expected energy from RES injected into the grid, is summarized in the table below.

Electricity [TWh]	2001	BAU 2020	Policy 2020
EU-25			
Wind energy	34	385	461
Hydro power	326	337	354.4
- large-scale	288	293	306
- small-scale	38.0	44.3	48.4
Photovoltaic	0.2	8.8	17.9
Solar thermal electricity	0	12.7	21.7
Wave & tide	0	8.4	33.2
Biomass, biogas, biowaste	37	141	338
Geothermal	6.3	7.5	8.2
TOTAL RES-E	403.5	900.4	1234.0

Tab 3.3 – Forecasted RES electricity generation in the long run. Source: FORRES project

3.1.3.2 The PRIMES Model

The background information yielded by the PRIMES model has a remarkable influence in the results obtained This is specially true for the future evolution of cross-border capacity for electricity exchanges. Although PRIMES is a comprehensive energy model, it does not provide information on the optimal development of cross-border transmission capacity, as stated in the "European energy and transport - trends to 2030" report:

"An in-depth study of trade developments in electricity would necessitate further work on the PRIMES model, which goes beyond the scope of this study. Thus, the country-by-country modelling, performed in the context of the study, has focused on the dynamics of the energy system within a country, while considering electricity trade between countries on the basis of current infrastructure and trends"

No further details on the expansion of interconnections are provided jointly with PRIMES results. Apparently, PRIMES estimates the optimal generation mix in each country taking electric interconnection capacities as an input. The model used in our study computes the optimal expansion of cross-border interconnections using as an input the generation and demand levels forecasted by PRIMES for each country. Therefore, that fact that our model concludes that no significant investment is transmission capacity is needed should come as no surprise.

As for the data provided by PRIMES on cross-border exchanges, *Tab 3.4* shows the net electricity imports into each country. Values of the table refer to the energy imported annually. For instance, the net import into Italy is forecasted to be 37.1 TWh in 2005, according to PRIMES. Imports decrease to 26.9 TWh in 2030. As it can be noted, the forecasted increase in cross-border electricity exchanges is very low: cross-border exchanges in the period 2005-2030 only increase for 8 countries. In fact, only in Germany and Turkey power exchanges increase by more than 10%. Moreover, the evolution of cross-border electricity exchanges is the same for all those scenarios obtained from the PRIMES model that have been analyzed, which denotes that this is an input to the PRIMES model rather than an output.

PRIMES assumes that the countries will remain well balanced during the whole planning horizon. Therefore, the required level of investments in new cross-border capacity will probably be very low in all those scenarios where information on the internal balance in each country has been taken from PRIMES.

Cross-border exchanges of electricity [TWh/year] - PRIMES / Baseline scenario

EU25	2005	2010	2015	2020	2025	2030	2030 vs 2005
Austria	-1.05	-0.58	-0.47	-0.58	-0.58	-0.58	reduction
Belgium	4.54	4.54	4.54	4.54	4.54	4.54	=
Denmark	1.16	1.28	1.28	1.28	1.28	1.28	increase 10%
Finland	8.84	6.51	6.51	6.51	6.51	6.51	reduction
France	-61.99	-56.87	-55.59	-54.89	-54.54	-54.31	reduction
Germany	4.19	5.12	6.28	6.40	6.51	6.63	increase 58%
Greece	0.00	0.12	0.12	0.23	0.23	0.23	increase
Ireland	0.12	0.12	0.12	0.12	0.12	0.12	=
Italy	37.22	32.68	29.89	28.73	27.33	26.98	reduction
Luxemburg	5.12	4.88	4.77	4.77	4.65	4.65	reduction
The Netherlands	19.54	19.89	20.24	20.47	20.59	20.59	increase 5%
Portugal	0.93	0.81	0.81	0.81	0.81	0.81	reduction
Spain	1.98	1.05	0.93	0.93	0.81	0.81	reduction
Sweden	4.30	4.30	4.19	4.19	4.07	4.07	reduction
United Kingdom	14.30	14.42	14.54	14.65	14.65	14.65	increase 2%
Cyprus	0.00	0.00	0.00	0.00	0.00	0.00	=
Czech Republic	-9.42	-8.61	-8.61	-8.61	-8.61	-8.61	reduction
Estonia	-0.93	-0.81	-0.81	-0.81	-0.81	-0.81	reduction
Hungary	3.37	3.49	3.49	3.49	3.49	3.49	increase 3%
Latvia	1.74	1.74	1.74	1.74	1.74	1.74	=
Lithuania	-0.58	0.12	0.12	0.12	0.12	0.12	reduction
Malta	0.00	0.00	0.00	0.00	0.00	0.00	=
Poland	-6.63	-6.75	-6.86	-6.86	-6.86	-6.86	increase 4%
Slovakia	-2.44	-2.21	-2.09	-2.09	0.58	0.93	reduction
Slovenia	-1.16	-1.05	-1.05	-0.93	0.35	0.58	reduction
Candidates	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**	**Change 2030/2005**
Bulgaria	-4.42	-4.19	-4.07	-4.07	-4.07	-4.07	reduction
Norway	-18.96	-18.96	-18.96	-18.96	-19.07	-19.19	increase 1%
Romania	-0.70	-0.58	-0.58	-0.58	-0.58	-0.58	reduction
Switzerland	-6.98	-6.75	-6.75	-6.28	-5.82	-4.88	reduction
Turkey	3.37	3.84	4.19	4.77	5.00	5.47	increase 62%

Tab 3.4 – Cross-border power exchanges assumed in PRIMES.

Note: positive values mean energy import; negative values mean energy export.

Talking about FORRES, the import / export balance of RES in each country is a result of this model. Therefore, significant imbalances exist between installed generation and power demand in those countries where RES are more developed. For this reason, the level of investments in updating interconnections are higher in those scenarios produced by the FORRES model.

3.1.4 Relevant scenarios

Due to the fact that PRIMES results were used as an input to our model, results for some scenarios were very similar. Therefore, although this report includes results for all the scenarios, it focuses on those obtained for some representative scenarios, i.e. the main conclusions in the report arise from results corresponding to these scenarios.

Tab 3.5 depicts the key assumptions for the "Baseline" scenario and the variant key scenarios.

Scenario	Carbon emissions limit	RES penetration	Generation expansion plan	Fuel International Prices scenario
BASELINE	Primes (Baseline)	Primes (Baseline)	Primes (Baseline)	Primes (Baseline)
High Renewable Energy Sources (RES) development	Primes (Baseline)	Forres (Policy scen)	Forres (Policy scen)	Primes (Baseline)
High Efficiency development	Primes (Baseline)	Primes (High Effic)	Primes (High Effic)	Primes (Baseline)
High RES + High Efficiency development	Primes (Baseline)	Primes (H-RES+Ef)	Primes (H-RES+Ef)	Primes (Baseline)
Soaring fuel and gas prices	Primes (Baseline)	Primes (Baseline)	Primes (Baseline)	Primes (soaring oil and gas prices)

Tab 3.5 – Selected 'relevant' scenarios.

3.1.5 Model Input Data

This section describes the set of data that has been used as an input to our model. First, subsection 3.1.5.1 explains the information sources and criteria used to obtain the input data. Subsection 3.1.5.2 explains the limitations of the information that has been made available for the study. Subsection 3.1.5.3 discusses how we modelled the demand curve of each country and subsection 3.1.5.4 explains how we computed the primary fuel prices in each scenario, country and period of time. Finally, subsection 3.1.5.7 presents the methodology used to compute the typical length and cost of cross-border connections.

3.1.5.1 Information sources and criteria to define model input data

The PRIMES report has been the main source of information to build the input data set fed into our model. Mainly, input data used in the base case were obtained from the following information included in the PRIMES report:

- Demand growth
- Expansion of generation facilities
- Fuel prices
- Capital cost of generation plants

However, it was necessary to process the information contained in the PRIMES report so as to obtain:

- Fuel prices by country
- Load-duration curves for demand within each country

Information on present capacities of cross-border links (NTC: Net Transfer Capacity) was downloaded from the ETSO Association web page. Unit costs for building new transmission lines were obtained from references [5] and [6]. We had to get and process some additional information to produce the following input data for the model:

- Typical lengths and costs of cross-border links.
- Renewable energy scenarios
- Fixed O&M expenses of generation facilities

Our model is able to jointly optimize the expansion of generation and cross-border interconnection capacity, thus minimizing the total cost. When modelling the installation of new generation capacity the following standard parameters were assumed:

- Cycle life of new plants: 20 years

- Planning horizon: 2005-2023
- Discount rate: 8%

3.1.5.2 Limitations of the available information

The following paragraphs highlight some main features of the input data used in the study.

- The main source of information for existing power plants was the PRIMES report, which only includes very aggregate information. Only data on the following categories of power plants was available from PRIMES: nuclear, wind and hydro, thermal (including coal fired, oil fired and steam oil/gas fired) and combined cycle.

  Planning the system expansion more accurately requires using more detailed information on the existing generation capacity of each fuel type and on the age of facilities. Furthermore, in order to obtain reliable variable costs of generation units it is necessary to use typical heat rates for each technology.

- Fuel prices apply to the whole system. No discrimination by country exists. We prepared a simple model to obtain gas prices in each country, assuming that a competitive gas market will develop in the region based on an increase in the liquidity and volume of trade in the Zeebrugge hub. Although it was not possible to get accurate information on coal prices for each country, we prepared a similar model for this fuel thus estimating a reasonable distribution of coal costs across countries according to international transportation rates.

  Electricity trading is basically based on the diversity of marginal costs/prices in each country. As long as it is not possible to get reliable information on the efficiency and fuel prices of generation plants, the identified patterns of cross-border trading could be non reliable as well.

- During the preliminary runs of the model we realized that the optimal expansion of generation is highly dependant on the emissions limit (or the market price of emission certificates). Consequently, we considered two scenarios for emissions, both obtained from the PRIMES report. The first corresponds to the PRIMES' baseline scenario and the second one is the "Kyoto for ever" scenario, which provides information on the total amount of emissions allowed in the EU30 system.

TOTAL CARBON EMISSIONS [million ton /year]

Scenario	2007	2010	2015	2020	2025	2030
EU trends 2030 (Baseline Scenario)	1,360	1,375	1,420	1,580	1,700	1,860
EU trends 2030 (Kyoto "for ever")	1,273	1,231	1,190	1,158	1,126	1,125

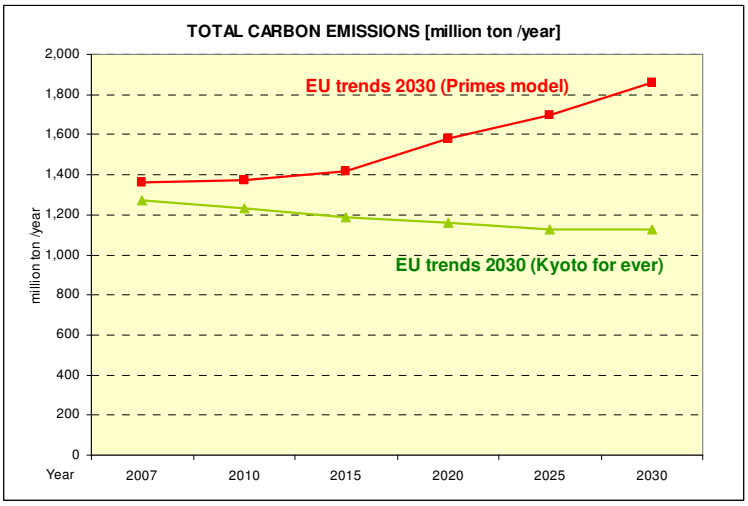


Fig 3.1 – Total allowed carbon emissions for EU power sector

- As mentioned in section 3.1.3, the PRIMES baseline scenario assumes that generation and demand in each country are well balanced. In fact, some excess generation capacity exists during the last 10 years of the planning horizon. The next figure shows the peak demand as forecasted in the PRIMES report, as well as the total installed generation capacity net of decommissioned capacity. The reserve margin varies between 50% and 55% of the total installed capacity. These values are rather high. The curve labelled 'Reserve-ww' does not include wind capacity and assumes that hydro contributes only 75% of its capacity to the reserve. In this case the reserve margin is about 22%, i.e. a still rather high value.

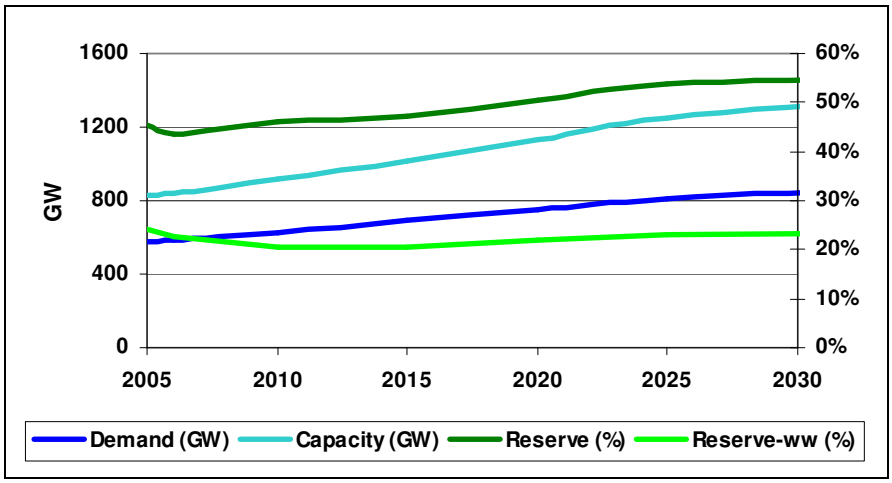


Fig 3.2 – Demand vs installed generation capacity

- Our model proposed 1800 MW of additional generation capacity in Ireland compared to PRIMES results. In all the other countries the PRIMES expansion program is appropriate to meet the load and fulfil the emissions targets during the period 2005-2023.
- In scenario S6 we estimate the optimal expansion of generation when no investment in generation is decided from the outset. This means that the model is the only responsible for the expansion of generation during the period 2005-2023. At the end of the planning horizon, the total installed capacity is 11% below PRIMES expansion program while emission costs are the same. The expansion of cross-border transmission capacity computed for this scenario is much larger than that in the PRIMES

baseline scenario. Therefore, we conclude that the excess of investment in generation in the PRIMES baseline scenario reduces the amount of new transmission capacity that is advisable to install.

- Expansion of renewable generation for scenarios S3 and S4 "High Renewable Energy Sources –RES– penetration" was taken from FORRES 2000 study [2].

3.1.5.3 Electricity demand by country

Electricity demand projections were based on the outcome reported in reference [1] and summarized in *Tab 3.2*, which corresponds to results produced by the PRIMES and ACE mathematical models.

In our model, electricity demand is defined as the sum of electricity generation and net imports into each country. This represents the gross electricity demand of each country. Information on the amount of generation and net imports for each country was obtained from the aforementioned report for the base year (2005) and the different countries included in the study. Our study focuses on the EU25 member states (excluding the offshore territories of Malta and Cyprus) plus Norway, Switzerland, Turkey, Bulgaria and Romania.

3.1.5.4 Fuel Price Assumptions

International coal, natural gas and oil prices used in our study are based on prices considered in [1] with the sole exception of the first year simulated (2005), for which real prices registered until May were taken into consideration.

In accordance with the PRIMES report, we have assumed that global energy markets will remain well supplied at a relatively modest cost from 2010 to 2030. Once this optimistic view is accepted we are in the position to employ the projection of prices provided in the PRIMES report. Price projections in the PRIMES report result from the output of the POLES[11] model[12]. In order to compute annual prices we carried out a linear interpolation using the projection included in the PRIMES report.

Prices for the base year were computed from real market values recorded in the months[13] before the writing of this report. Prices between 2005 and 2010 were forced to converge to 2010 POLES values. The spread between Fuel oil #6 or Diesel oil #2 prices and the crude oil price was assumed constant throughout the period. *Tab. 3.1* depicts the estimation of annual fuel prices fed into our model.

We assumed that oil prices are the same all over Europe since this simplification does not affect the outcome of our model. This is not the case of natural gas and coal prices since in many countries the marginal price of electricity is set either by CCGTs or coal fired power plants. In addition, most of the expansion of generation corresponds to investments in CCGTs.

[11] IEPE-CNRS (2002) World Energy Scenarios and International Energy Prices. Final Report to NTUA in the context of the Long- Range Energy Modelling project, March 2002.

[12] That report states that the crude oil price decreases from its actual levels to reach 20.1 $/bbl in 2010.The reason for the gradual increase of oil prices beyond 2010 to 27.9$/bbl in 2030 is the higher marginal costs of exploiting new sources of oil.

[13] Crude oil price was set at BRENT price. Representative hard coal prices was assumed as 6000 Kcal – 1% CIF ARA while gas prices were obtained from Zeebrugge spot prices.

PRICE ASSUMPTIONS

	2005	2006	2007	2008	2009	2010	2011
Crude Oil [EUR/bbl]	**45.00**	40.02	35.04	30.06	25.08	**20.10**	20.47
Natural Gas [EUR/MBTU]	**5.47**	5.08	4.68	4.29	3.90	**3.51**	3.53
Hard Coal [EUR/t]	**65.00**	58.23	51.45	44.68	37.90	**31.13**	31.04
FUEL OIL #6 [EUR/bbl]	**31.50**	28.01	24.53	21.04	17.56	**14.07**	14.33
DIESEL #2 [EUR/bbl]	**51.75**	46.02	40.30	34.57	28.84	**23.12**	23.54
	2012	2013	2014	2015	2016	2017	2018
Crude Oil [EUR/bbl]	20.84	21.21	21.58	21.95	22.32	22.69	23.06
Natural Gas [EUR/MBTU]	3.56	3.58	3.61	3.63	3.65	3.68	3.70
Hard Coal [EUR/t]	30.96	30.87	30.78	30.70	30.61	30.52	30.43
FUEL OIL #6 [EUR/bbl]	14.59	14.85	15.11	15.37	15.62	15.88	16.14
DIESEL #2 [EUR/bbl]	23.97	24.39	24.82	25.24	25.67	26.09	26.52
	2019	2020	2021	2022	2023	2024	2025
Crude Oil [EUR/bbl]	23.43	**23.80**	24.21	24.62	25.03	25.44	25.85
Natural Gas [EUR/MBTU]	3.73	**3.75**	3.80	3.85	3.89	3.94	3.99
Hard Coal [EUR/t]	30.35	**30.26**	30.26	30.26	30.26	30.26	30.26
FUEL OIL #6 [EUR/bbl]	16.40	**16.66**	16.95	17.23	17.52	17.81	18.10
DIESEL #2 [EUR/bbl]	26.94	**27.37**	27.84	28.31	28.78	29.26	29.73
	2026	2027	2028	2029	2030		
Crude Oil [EUR/bbl]	26.26	26.67	27.08	27.49	**27.90**		
Natural Gas [EUR/MBTU]	4.04	4.09	4.13	4.18	**4.23**		
Hard Coal [EUR/t]	30.26	30.26	30.26	30.26	**30.26**		
FUEL OIL #6 [EUR/bbl]	18.38	18.67	18.96	19.24	**19.53**		
DIESEL #2 [EUR/bbl]	30.20	30.67	31.14	31.61	**32.09**		

Tab. 3.1 - Annual projection of fuel prices

3.1.5.5 Gas natural prices by country

We used a simplified netback model to compute transport costs of gas by pipeline. It is assumed that the projection of natural gas prices shown in *Tab. 3.1* applies only to the Zeebrugge hub. The model computes the cost of transport to the different countries assuming linear distances and standard costs of pipelines (€/MBTU-km) applicable in Europe. *Fig 3.3* represents the outcome of this model.

Netback prices were assumed to be stable during the period studied. Hence, the price of gas in any country and for any year is obtained as the corresponding gas price in *Tab. 3.1* plus the negative netback cost.

Fig 3.3– Natural gas price differentials at each country in respect of Zeebrugge location

3.1.5.6 Coal prices by country

A simplified model was implemented that took the ARA price as a reference. Standard and uniform maritime and ground shipping rates were assumed in order to define price differentials for each country with respect to the ARA location.

Higher prices than that at ARA were assumed for European countries located further from the main international coal suppliers (i.e. South Africa, Colombia) than ARA, while lower prices than that at the ARA location were assumed for those European countries closer to these suppliers (i.e., Spain, Portugal). In addition, in view of the relatively significant potential of Poland as a regional coal supplier, prices were assumed to decrease along the North Sea and Baltic coasts, as we get closer to the Polish seaports.

Price differentials between the main European seaports and ARA are provided in *Fig 3.4*.

Coal prices in the location of the reference production plant within each country were calculated by adding the corresponding inland transportation cost to the respective CIF price.

3.1.5.7 Typical length and costs of cross-border connections

Given the significant development achieved by domestic grids, reinforcing a cross-border electrical interconnection often requires the construction of fewer kilometres of new lines than what would be required to join the barycentres of the neighbouring systems involved. It is extremely difficult to compute the exact cost of reinforcing the interconnection between all pairs of countries analyzed. Consequently, we assumed in the reference scenario (*Baseline scenario*) that building a new interconnector (or reinforcing an existing one) is equivalent in terms of cost to building a 400 kV line whose length is 30% of the distance between the barycentres of the two countries involved. This is considered to be the lower limit for this cost. In S6 scenario (*New generation optimised and high transmission costs)*, we assumed that reinforcing an interconnection was equivalent to building a line of the required capacity between the barycentres of both systems (thus covering

100% of the distance between them). This is taken as the upper limit of the cost of increasing the transfer capacity between neighbouring systems. *Fig 3.5* graphically shows both extreme options. Dmax is the distance between the barycentres of the French and German systems shown in the figure.

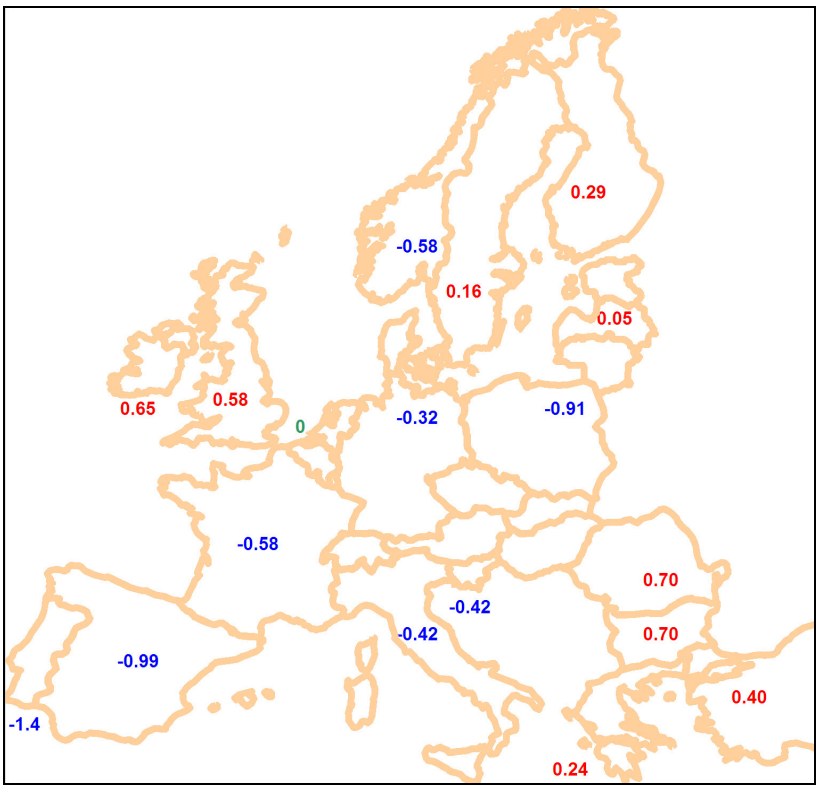


Fig 3.4 – CIF coal price differentials of the main seaports with respect to ARA

In the case of submarine interconnectors, the lower limit considered is the minimum between the submarine distance to be covered and 30% of Dmax.

Unit costs used to compute the required investment in new interconnectors were taken from [5] and [6]. The latter one was used for submarine interconnectors.

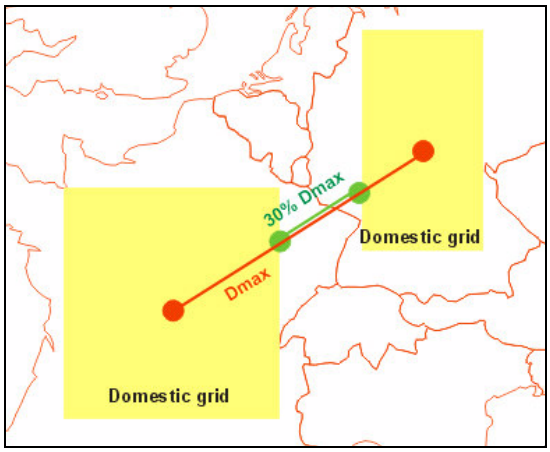


Fig 3.5 - Upper (Dmax) and lower limits assumed for the cost of building an interconnector

4. THE ELECTRICITY SECTOR

Problem statement

- *identification of the current technical status of the electricity transmission grids in the EU 30;*
- *display of investment patterns in the period from 1996 to 2004 and main sources of financing;*
- *assessment of the ageing of the electricity transmission grids and its impact on the future investment needs;*
- *assessment of mid-long term investment trends.*

Methodology

- *Data collection and elaboration;*
- *Specific mathematical modeling for estimating investments on cross-border infrastructures in relationship with some selected scenarios*

Major results

Current status:

- *the European electricity transmission grid is composed by power pools;*
- *most of the power pools are weakly connected through Direct Current links;*
- *several bottlenecks still exist causing congestion on cross-border cut-sets;*
- *to manage insufficient cross-border capacity, congestion management mechanisms are adopted by System Operator. These mechanisms are presently evolving to fully comply with the EU regulation 1228/2003.*

Investment patterns during the years 1996 till 2004 and financing sources

- *In the period 1996-2004 the investment level has been in the average around 3.1 b€/yr, with a tendency of a slight increase from the year 2001;*
- *Investments are quite uniformly distributed among the EU 30 countries with the exception of Bulgaria, Romania and Turkey where they are low in relationship to the extension of the national grids;*
- *In most of the cases, investment projects are financed by TSO equities or bank loans;*
- *in many cases even in the absence of EU loans (EIB, EU-funds) or aid instruments, projects would have been built*

Ageing of the system

- *Ageing of the system is becoming one of the major concerns of TSOs*
- *Many components of the transmission grid need repairs and upgrades since they are approaching their expected end of the life and without appropriate measures some transmission systems will be able to operate safely and reliably only up to 10 years ahead.*
- *To smooth the investment effort while ensuring the requested reliability level, measures based on "life extension techniques" shall be adopted*

Mid-long term investment patterns

- *according to TSOs forecasts, in the mid term (up to year 2013) investments are expected to increase around 4 b€/yr; a steadily high investment level is to be expected also for the second decade ahead (up to 2023);*
- *estimations based on demand evolution and accounting for country surface and load density indicate the need for investments in infrastructures internal to the EU 30 countries at a level similar to the present one: 3.3 b€/yr;*
- *cross-border investments are expected to decrease to a level below 70 M€/yr when assuming the generation evolution of the PRIMES model;*
- *high RES penetration will cause high investments on cross-border lines in the long-run (>150 M€/yr);*
- *when optimising both new generation and cross-border transmission capacity, very high investments turn out to be necessary, especially in the long-run (>480 M€/yr);*
- *the investments required to connect offshore wind farms to onshore grids are in the range 0.9÷1.3 b€/yr in the mid-term. In the long term a sharp increase of investments is needed (1.7÷2.5 b€/yr).*

4.1 Current technical status of the European Power Transmission Networks

This section is devoted to provide an overview of the situation of the European electricity networks updated at the end of the year 2003; newer information is also included whenever available. In particular, the recent event concerning the reconnection between the two UCTE synchronous zones, which took place last Oct. 2004, has been considered.

The main focus in the presentation of the existing infrastructures is addressed to the cross-border infrastructures, either between EU countries or between EU countries and the neighbouring regions.

4.1.1 Methodology

The above objective has been attained through a two-step procedure:

a) **data collection**;

b) **analysis and elaboration of the collected data**.

Firstly, a comprehensive set of data has been retrieved by examining the most updated documents issued by international organisations, representatives of individual TSO's and associations of TSO's, direct access to documents issued by TSO's or other documents on energy interconnections prepared by dedicated Working Groups (e.g.: the Working Group SYSTINT-SYSTMED inside EURELECTRIC).

Starting from this first data set, a preliminary analysis and elaboration has been carried out to check possible inconsistency (e.g.: inconsistent data on cross-border lines collected from different sources of information) or lack of data. Moreover, a common framework for the data presentation has been set up.

Then, direct contacts with the concerned TSO's have been undertaken to solve the above-mentioned possible inconsistency or lack of data. All that allowed having a complete picture of the present status of energy infrastructures.

4.1.2 Current status of the electricity power pools

The European power transmission system is presently divided in several synchronous blocs. *Fig 4.1* shows the situation updated at the end of the year 2004. As it can be seen, the main synchronous blocs are:

- the bloc composed by the UCTE (Union for the Co-ordination of Transmission of Electricity), which includes the Central and Western European Countries plus the westernmost region of the Ukraine;
- the NORDEL composed by the Scandinavian Countries: only eastern Denmark is synchronously connected with NORDEL, while the remaining region (Jutland peninsula) is synchronously connected with UCTE. In the following this region will be referred to as "Western Denmark". Iceland, though being member of NORDEL, is not interconnected with any other systems;
- the England-Wales-Scotland system, interconnected through HVDC submarine cables with France and Northern Ireland;
- the Irish system (ESB: Electricity Supply Board), synchronously interconnected with Northern Ireland (NIEB: North Ireland Electricity Board);
- The DC Baltija pool, comprising the power systems of Estonia, Latvia, Lithuania, synchronously interconnected with the UPS of Russia. The region of Kaliningrad is in its turn synchronously interconnected with the DC Baltija pool;

- the Turkish system, interconnected with Bulgaria through two 400 kV AC lines for regional exchange of electricity (transfer of energy from Maritsa East TPP to the area of Istanbul). Other interconnections are operated for regional exchanges of energy, such in the case of 154 kV tie-line with Nakhicevan, used to supply the demand of this region from Turkey;
- the IPS/UPS system of Russia, Belarus, Ukraine, Moldova, the trans-Caucasus republics of Georgia and Azerbaijan, the central Asian republics of Kazakhstan, Uzbekistan, Kyrgiztan, Tadjikistan and Mongolia14. The westernmost part of Ukraine (Burshtin region) is operated since June 2003 synchronously with UCTE. Regional power exchanges between Moldova and Romania takes occasionally place through 110 kV cross-border lines;
- the Mediterranean isolated systems, among them the most relevant are those of Cyprus and Malta, the only two EU states, the power system of which is operated in islanded mode. Other Mediterranean systems, such those of Sicily, Sardinia and Corsica are linked to the mainland either through AC cables (Sicily) or DC cables (Sardinia and Corsica). As for Balearic islands, their power systems, presently, isolated, will likely be interconnected to the mainland through a submarine DC cable.
- Finally, it is worth mentioning that the Maghreb countries of Morocco, Algeria and Tunisia are operated synchronously with UCTE since 1997 through a 400 kV cable between Tarifa and Ferdioua (Strait of Gibraltar).
- In the following paragraphs the main characteristics of each pool is displayed.

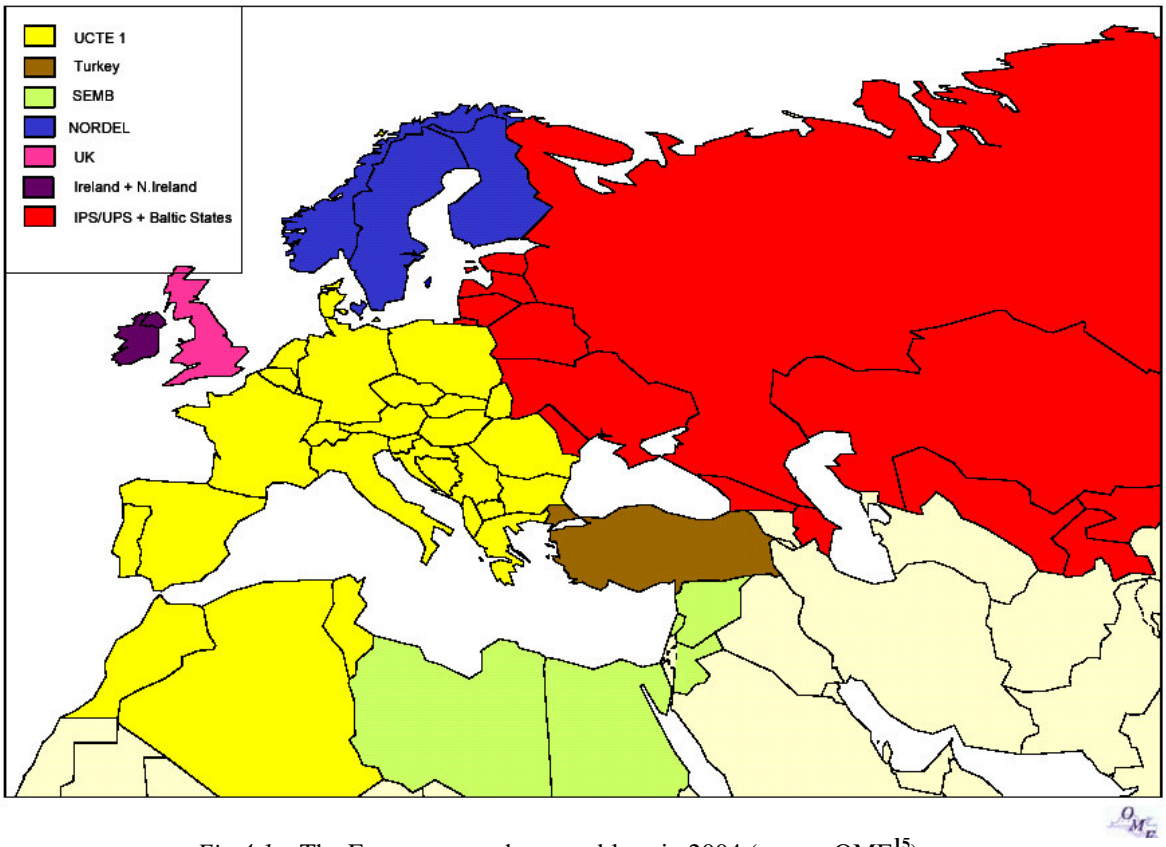


Fig 4.1 – The European synchronous blocs in 2004 (source OME[15])

[14] The CIS republics of Armenia and Turkmenistan (this latter from June 2003) are operated interconnected with Iran.
[15] OME : Observatoire Méditerranéen de l'Energie.

4.1.3 The UCTE power pool

The Union for the Co-ordination of Transmission of Electricity (UCTE) [7] co-ordinates the interests of transmission system operators in 23 European countries. Their common objective is to guarantee the security of operation of the interconnected power system. Through the networks of the UCTE 450 million people are supplied with electric energy with an annual electricity consumption exceeding 2300 TWh (year 2003). To ensure a high level of security of operation, the UCTE has developed a number of rules and recommendations that constitute the basis for the smooth operation of the power system. Moreover, a series of analyses have recently been undertaken by UCTE to anticipate the future needs to comply with the established standards of security and reliability. The recently issued report "System Adequacy Forecast 2005-2015" [8] aims, namely, at:

- Providing all European electricity market players with an overall view on system load evolution, as well as on the resources available to satisfy the system load, as an early input to investment decisions;
- Providing all European electricity market players with an overview on the main changes expected in the UCTE transmission grids;
- Providing TSOs, which co-operate within UCTE, with a prospective view of supply reliability developments throughout the network.

The key figures of the biggest European pool can be summarized as follows:

- 33 Transmission System Operators (TSO)
- 23 European Countries
- 450 million Customers served by the represented power systems
- 585 GW: Installed capacity
- 2345 TWh: Electricity consumption in 2003
- 265 TWh: Sum of electricity exchange between member TSOs
- more than 210.000 km: Length of high-voltage transmission lines managed by the TSOs

The UCTE pool includes the following countries:

a) EU members (16 countries):
Portugal, Spain, France, Belgium, Luxembourg, Netherlands, Western part of Denmark, Germany, Italy, Austria, Czech Republic, Slovenia, Poland, Slovakia, Hungary, Greece;

b) Candidate states:
Romania, Bulgaria and Croatia (new member state from October 2005);

c) non EU nor candidate states
Switzerland, Bosnia-Herzegovina, Serbia-Montenegro, Macedonia.

Furthermore, UCTE is synchronously connected with Albania, Burshtin region (Ukraine) and with the three Maghreb countries of Morocco, Algeria and Tunisia.

The following tables, derived from [7] and [9] summarize the basic data on countries belonging to the UCTE zone.

UCTE Countries			
Country	Installed Capacity (GW)	Peak Load (GW)	Consumption (TWh/year)
Albania (*)	1.63	1.20	4.33
Austria	18.30	10.42	57.00
Belgium	15.80	12.78	86.50
Bosnia Herzegovina	4.00	1.70	12.60
Bulgaria	13.18	6.00	36.70
Croatia	3.70	2.60	15.40
Czech Republic	16.20	9.58	59.90
Denmark (West)	7.60	6.10	35.60
France	114.30	76.36	464.80
Germany	111.20	80.77	541.00
Greece	11.80	8.69	53.60
Hungary	8.00	5.86	38.40
Italy	78.30	51.37	320.70
Luxembourg	1.70	0.89	6.20
Macedonia FYR	1.30	1.28	7.20
Netherlands	20.60	15.49	109.60
Poland	31.70	22.14	138.30
Portugal	11.60	8.19	46.80
Romania	16.40	7.54	49.40
Serbia and Montenegro	10.30	6.98	40.80
Slovakia	8.10	4.19	26.40
Slovenia	2.80	2.02	13.00
Spain	58.80	37.92	238.40
Switzerland	17.30	9.18	59.30
Ukraine (West)	2.40	0.85	4.10
TOTAL	587.01	390.01	2466.03

Tab 4.1: UCTE - Installed capacity, peak demand & annual electricity consumption (Source [7])

Note: peak load is referred to the 3rd Wednesday of December 2003
(*) country not member of UCTE

The total length and voltage of EHV lines in the UCTE system are shown in *Tab 4.2*.

length and voltage of EHV lines in the UCTE			
Country	Voltage	Lines (km)	
Austria	400 kV 225 kV	2474 3765	Data referred to the year 2000
Belgium	400 kV 225 kV	1.298 415	
Bosnia Herzegovina	400 kV 225 kV	766 1507	
Croatia	400 kV 225 kV	1159 1248	
Czech Republic	400 kV 225 kV	3422 1926	
Denmark (West	400 kV 225 kV	833 39	
France	400 kV 225 kV	20966 26265	
Germany	400 kV 225 kV	18700 17500	
Greece	400 kV 225 kV	4459 11078	
Hungary	400 kV 225 kV	2090 1188	
Italy	400 kV 225 kV	9891 11705	
Luxembourg	400 kV 225 kV	0 236	
Netherlands	400 kV 225 kV	2003 683	
Poland	400 kV 225 kV	4830 7887	
Portugal	400 kV 225 kV	1403 2692	
Romania	400 kV 225 kV	4626 4131	
Serbia and Montenegro	400 kV 225 kV	1814 2589	
Slovakia	400 kV 225 kV	1753 962	
Slovenia	400 kV 225 kV	510 328	Data referred to the year 2002
Spain	400 kV 225 kV	16951 16244	
Switzerland	400 kV 225 kV	1641 5031	
TOTAL	**400 kV 225 kV**	**105979 111732**	

Tab 4.2: EHV transmission lines in UCTE - Total length of existing lines subdivided by voltage level. Data are referred to the year 2003 with the exception of Austria and Slovenia

4.1.4 The NORDEL power pool

NORDEL [10] is a body for co-operation between the transmission system operators (TSOs) in the Nordic countries (Denmark, Finland, Iceland, Norway and Sweden), whose primary objective is to create the conditions for, and to develop further, an efficient and harmonised Nordic electricity market. The organization has been established in 1963, even though the history of progressive integration of electrical infrastructures among the Scandinavian countries dates back to the beginning of the XX century.

NORDEL's tasks fall mainly into the following categories:

- system development and rules for network dimensioning
- system operation, operational security, reliability of supply and exchange of information
- principles of transmission pricing and pricing of ancillary services
- international co-operation
- maintaining and developing contacts with organisations and regulatory authorities in the power sector, particularly in the Nordic countries and Europe
- preparing and disseminating neutral information about the Nordic electricity system and market.

NORDEL serve about 24.5 million of people spread in a geographical area of 1258 sq.km. The "per capita yearly consumption" is the highest in Europe: 15.8 MWh/capita/year with a peak of 28.3 MWh/cap/year in Iceland followed by Norway with 25.0 MWh/cap/year. Basic data of NORDEL pool are shown in *Tab 4.3* .

Basic data of NORDEL pool							
		Denmark	Finland	Iceland	Norway	Sweden	NORDEL
Installed capacity	MW	12.830	16.893	1.476	28.081	33.361	**92.641**
Generation	GWh	43,754	79,855	8,495	107,122	132,547	**371,773**
Imports	GWh	7,163	12,262	-	13,472	24,367	**57,264**
Exports	GWh	15.707	7.415	-	5.586	11.438	**40.146**
Total consumption	GWh	35,210	84,702	8,495	115,008	145,476	**388,891**
Breakdown of electricity generation:							
Hydropower	%	0	12	83	99	40	**47**
Nuclear power	%	-	27	-	-	50	**24**
Other thermal power	%	87	61	0	1	10	**27**
Other renewable power	%	13	0	17	0	0	**2**
- Data are nonexistent							
0 Less than 0.5 %							

Tab 4.3 – Basic data of NORDEL referred to the year 2003

The transmission grid of NORDEL is characterised by several voltage levels:

- HV level: 110-132-150 kV
- EHV level: 220-300-400 kV.

The total length of the transmission lines split by voltage level is shown in *Tab 4.4*.

total length of the transmission lines split by voltage level			
	400 kV, AC og DC/km	220-300 kV, AC og DC/km	110,132,150 kV/km
Denmark	1,300	500	4,100
Finland	4,000	2,400	15,300
Iceland	100 1)	500	1,300
Norway	2,100	5,600	10,500

Tab 4.4 – Length of the transmission lines in service in Dec. 31st 2003 [11]

The western part of Denmark is a separate TSO area. This region is a member of the NORDEL cooperation and also an associate member of the UCTE as this area is in synchronous operation with the rest of the UCTE. For historical reasons, there is no electrical interconnection between the eastern and western part of Denmark. Moreover, the Nordic transmission system is characterised by a high number of HVDC interconnections. There is a one-way HVDC interconnection from the UPS system of Russia to Finland, and reversible HVDC interconnections between Poland and Sweden, Germany and Sweden and Germany and the eastern part of Denmark.

4.1.5 Eastern Baltic Region

The Interconnected Pool of the Power Systems of Estonia, Latvia, and Lithuania (Baltic IPS) was founded after regaining complete independence of the Baltic countries in 1992. The Baltic countries cover 175,015 sq.km area with approx. 7,5 mil inhabitants (Estonia - 45,215 sq.km and 1,44 mil.inhab.; Latvia - 64,600 sq.km and 2,37 mil.inhab.; Lithuania - 65,200 sq.km and 3,69 mil.inhab).

Baltic IPS includes state owned power systems of Estonia, Latvia and Lithuania and operates in parallel (on a synchronous AC grid) with the Unified Power System of Russia and the Power System of Belarus [12].

The current total installed capacity of the Baltic IPS is 11,381 MW on 1st Jan. 2004 and includes a wide spectrum of generation types: nuclear power plant (Ignalina nuclear power plant (NPP)), hydro power plants (HPP), thermal/condensing power plants (TPP/CPP), combined heat and power plants (CHP) and pumped storage power plants (PSPP) as well as two wind farms (WPP). In 2003, the annual peak demand of the Baltic IPS was 4577 MW and comprised 1708 MW in Lithuania, 1472 MW in Estonia and 1397 MW in Latvia.

The transmission network of the Baltic IPS consists mainly of 330 kV transmission lines, which in January 2004 had a total length of 4210.2 kilometres. Regional power transmission is based on 110 kV line, the only exception being the Estonian power system where there is also a 220 kV network (*Tab 4.5*).

Length of the transmission lines							
Power System	Length of HV Lines (km)			Installed capacity of network autotransformer and transformers (MVA)	Installed shunt reactors (MVAr)		
	110 kV	220 kV	330 kV	110 kV	220 kV	330 kV	10.5/35 kV
Estonia	3262.0	508,0	1290.0	3359,0	1270.0	1995	200/40
Latvia	3947.1	—	1247.9	3974.5	—	2825	180/0
Lithuania	5004.0	—	1665.0	5449.0	—	3850	—
Baltic IPS	12213.1	508.0	4202.9	12782.5	1270.0	8670	380/40

Tab 4.5– Length of the transmission lines in service in January 2004 [12]

4.1.6 The British Islands

4.1.6.1 United Kingdom

The power system of the United Kingdom is divided in three distinct geographical regions:

- England and Wales;
- Scotland
- North Ireland.

The installed capacity is over 76 GW with an annual consumption exceeding 384 TWh, out of which about 9 TWh are imported from France.

The English-Welsh system in interconnected to Scotland through AC lines (3x400 kV, 1x275 kV and 2x132 kV lines with a total exchange capacity of 2500 MW), while Scotland is interconnected to North Ireland through a DC submarine cable (the Moyle Interconnector) having a capacity of 500 MW. National Grid Transco [13] is the sole holder of an electricity transmission license for England and Wales and owns and operates the high voltage transmission system. As a System Operator, National Grid Transco is regulated under an incentive scheme, where benefits of cost savings in system operation are shared with customers. In Scotland, electricity transmission assets are owned by private companies, Scottish Power and Scottish Southern Energy, while the grid is operated by National Grid, who performs the role of System Operator for the whole Great Britain. The electricity supply in Northern Ireland is also in private hands. Northern Ireland Electricity (NIE) Board is responsible for power procurement, transmission, distribution and supply in the region. The existing links between NIE and the Irish system have finally been re-established following the stabilization process of the region triggered by the "Good Friday Agreement" in 1998.

The British transmission grid is developed on three voltage levels: 132-275-400 kV.

4.1.6.2 Ireland

The Irish transmission system is managed by ESB (Electricity Supply Board), established in 1927. ESB was the vertically integrated company of Ireland up to the starting of the liberalisation process.

The installed generation capacity is shown in *Tab 4.6*; data are referred to the year 2003. The annual consumption is about 22 TWh.

installed generation capacity		
Installed capacity by fuel, MW (excludes 132MW of CHP)		
	Thermal	5 091
	Hydro	15
	Nuclear	0
	Renewables	223
	Total(2003)	5329

Tab 4.6 – Installed generation capacity in Ireland (source [9])

The Irish national grid was originally constructed as a 110 kV network but, as the demand for electricity grew, 220 kV and 400 kV lines were built. The 400 kV lines are used to carry power to Dublin from the large Moneypoint coal-fired generation station in the Shannon Estuary. The length of the transmission lines and cables is shown in *Tab 4.7*. The grid is interconnected with that of NIE Board through two single circuit lines at 110 kV (Letterkenny-Strabane and Corraclassy-Enniskillen) and a double circuit line at 275 kV (Louth-Tandragee). The lines at 110 kV are normally in stand-by and are used in the event of circuit outages.

The length of the transmission lines and cables		
Voltage (kV)	Overhead lines (km)	Underground cables (km)
400	440	2
220	1700	80
110	5600	140

Tab 4.7 – Length of the transmission lines in the Irish grid [9]

4.1.7 Turkey

In the year 2003, the installed capacity in Turkey was below 36 GW with an annual consumption around 140 TWh *(Tab 4.8)*. The country is experiencing a remarkable increase in the internal demand; the most recent surveys point out a total expected consumption for the year 2005 of 163 TWh, corresponding to an average growth rate around 8%/yr. To meet the internal demand, new units, mainly combined cycled are commissioned. By end of 2005 the total installed capacity is expected to be 41400 MW. Investments in new generation assets are fostered by opening to local and international private investors the possibility of building new power plants.

annual consumption		
Installed capacity by fuel, MW		
	Thermal	22 974
	Hydro + Renewables	12 528
	Total	**35 502**
Yearly generation fuel by fuel, TWh		
	Thermal	104.8
	Hydro + Renewables	35.5
	Total	**140.3**
Annual consumption, TWh		**140.8**
Imports, TWh		**1.2**
Exports, TWh		**0.5**
Annual Peak Deman d (MW)		**21 729**

Tab 4.8 – Installed generation capacity and consumption in Turkey. Data referred to the year 2003 (source [9])

The present status of the transmission grid is shown in *Tab 4.9*. The grid in based on voltage levels 380 kV, 220 kV (at one interconnector only), 154 kV and very few 66 kV.

Length of the transmission lines				
Lines	**Voltage levels**			
Description	66 kV	154 kV	220 kV	380 kV
Length (km)	718.9	31,430.0	84.6	13,958.0
Substations	**Voltage levels (*)**			
	66 kV	154 kV	220 kV	380 kV
Number	22	450	--	45
Transformation capacity (MVA)	734	46,240	--	20,120

(*) High voltage side is indicated

Tab 4.9 – Length of the transmission lines in the Turkish grid and transformation capacity of substations

Presently, the Turkish system is operated in an "islanded" mode, though with several regional connections with the neighbouring regions. More in particular, interconnections exist with Bulgaria, Georgia, Armenia, Iran, Iraq, Syria and Nahicevan (Azerbaijan) (*Fig 4.2*). However, some of these interconnections are not currently in operation. *Tab 4.10* shows the *NTC across the Turkish borders.*

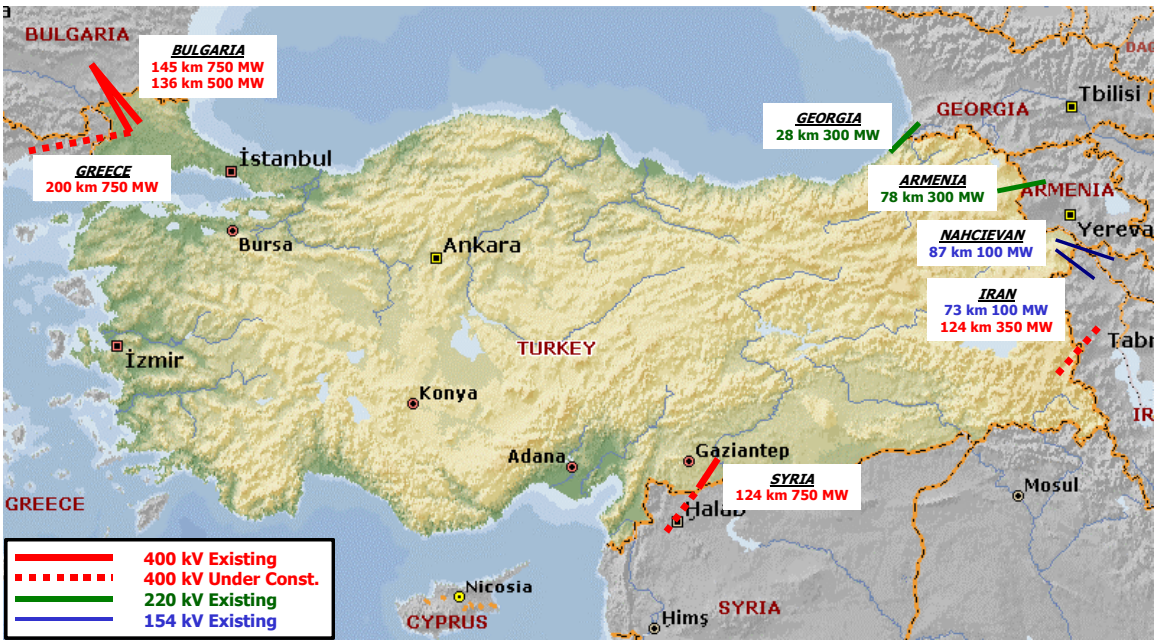


Fig 4.2 – Interconnections between Turkey and neighbouring countries

Interconnections between Turkey and neighbouring			
Nb of connection	From	To	Net Transfer Capacity (MW)
1	Turkey	Bulgaria	700
2	Bulgaria	Turkey	630
3	Turkey	Georgia	50
4	Georgia	Turkey	150
5	Turkey	Armenia	300
5	Armenia	Turkey	300
6	Iran	Turkey	125
7	Turkey	Iraq	350
8	Syria	Turkey	230
8	Turkey	Syria	230
9	Turkey	Nahicevan (Azerbaijan)	100

Tab 4.10 – Interconnections between Turkey and neighbouring states and relevant NTC

Finally, it is worth mentioning that Turkey made an application to UCTE for membership since March 21st, 2000.

4.1.8 Cyprus

The transmission system of Cyprus is managed by the Electricity Authority of Cyprus (EAC). EAC, a vertically integrated company, is undergoing a restructuring process to comply with the EU Electricity Market Directive.

Generating units in Cyprus use fossil fuels only with a total installed capacity of about 1 GW and a production exceeding 4 TWh/yr (see following table). Internal consumption has been around 3.8 TWh in 2003 (see *Tab 4.11*)

Installed generation capacity		
Installed capacity by fuel, MW		
	Thermal	988
	Hydro	-
	Nuclear	-
	Renewables	-
	Total	**988**
Yearly generation fuel by fuel (TVVh)		
	Thermal	4.0437
	Hydro	-
	Nuclear	-
	Renewable	-
	Total	**4.0437**
Annual consumption (TWh)		**3.7687**
Imports (TWh)		**-**
Exports (TWh)		**-**

Tab 4.11 – Installed generation capacity and yearly consumption in Cyprus (source [9])

The backbone of the transmission system is operated at 132 kV with some regional HV lines at 66 kV, mostly in radial configuration. Also, there are 132 kV lines, which are operated at 66 kV and a very short line designed at 220 kV line, but operated at 132 kV. *Tab 4.12* shows the main characteristics of the electric grid of Cyprus.

Length of the transmission lines				
Overhead Lines	**Voltage levels**			
Description	66 kV	132 kV	132 kV (operated at 66 kV)	220 kV (operated at 132 kV)
Route length (km)	324.6	358.3	124.7	1.4
Circuit length (km)	324.6	711.6	230.4	2.8
Underground cables	**Voltage levels**			
Route length (km)	1.7	50.3	3.7	--
Circuit length (km)	1.7	76.4	3.7	--
Substations	**Voltage levels**			
	66/11 kV	132/11 kV	132/66 kV	--
Number	66	56	12	--
Transformation capacity (MVA)	622.5	1,744.0	585.0	--

Tab 4.12 – Length of the transmission lines in service as at 31st Dec. 2004 [14]

4.1.9 Energy exchanges, bottlenecks and screening indexes

International energy exchanges through the tie-lines in Europe are closely related to the trading between generator and demand side. As a matter of fact, interconnecting lines are used only to a limited extent for mutual support between countries at the occurrence of large perturbations; on the contrary, nowadays, they represents the "electric highways" that allow the free exchange of electricity in compliance with the market mechanisms. A useful index to monitor the variation of energy exchanges can be the ratio between the yearly total exchanged energy (EnEx) and the yearly consumption (Cons). This ratio has been assessed for three European power pools (UCTE, NORDEL and DC Baltija); the following values were obtained:

UCTE: (EnEx/Cons) = 12%
NORDEL: (EnEx/Cons) = 25%
DC Baltija: (EnEx/Cons) = 47%

The above differences in the exchange levels with respect to the consumption denote a different approach undertaken in the past concerning the planning of the national system. In the UCTE a typical "national perspective" approach was adopted, while in NORDEL and DC Baltija an integrated planning was implemented in the past years.

Cross-border energy exchanges have been increasing in these last years, however, in some cut-sets they are limited due to the insufficient transmission capacity (bottlenecks). Some screening indexes have been evaluated to assess potential bottlenecks in cross-border power exchanges; namely, the following indexes have been adopted in the study process:

- **Index 1**: Ratio of the import capacity of each country16 to the total installed generation capacity. This index measures how dependent a country is upon the interconnections with other countries: the lower this index is, the less important the interconnections are to guarantee the supply of electricity.
- **Index 2**: Ratio between the physical import flows to a country and the national consumption. This index measures how much a country has used its interconnection capacity over a certain period of time. In contrast to the ratio import capacity/total installed generation capacity, this index takes into account not only reliability issues, but also market opportunities the agents have taken advantage of.
- **Index 3**: Ratio of the "remaining generation capacity" (i.e. not used generation) within a country to the total transmission capacity between the country and the rest of the system. This screening index is intended to investigate if the transmission system is sufficiently sized in order to enable the potential imports and exports resulting from the various national power balances, improving in this way the reliability of the European Power Pool.

According to the E.C. on European Energy Infrastructure in 2001, the E.C. holds the view that a reasonable level of electricity interconnection capacity should be achieved. In this way, for Index 1 a minimum level of 10% is recommended by the European Commission to warrant a sufficient capability for power trade, with a higher level desirable for key transit countries.

Concerning Index 2, a group of national energy regulators of peripheral European countries (six peripheral zones can be pointed out in Europe in the EU15: the Iberian Peninsula, Italy, Great Britain, Nordel, Ireland/Northern Ireland and Greece) has estimated that a minimum level of interconnection with neighbouring countries of around 20% of peak demand would be necessary in any area to significantly reduce the presence of bottlenecks and segmented markets. In addition, situations where Index 2 is bigger than Index 1 may represent a sign of congestion.

Concerning the "remaining capacity", according to the recent UCTE study17, an acceptable value to limit the risk of shortfall at 1% is equal to 5% of the generation capacity, referring the evaluation at the monthly peak load. Only for some systems more sensitive to random factors this value shall be higher up to 10%. Remaining capacity higher than 40% of the country total transmission capacity may represent an obstacle to the power trade.

It should be noted that these indexes are by no means appropriate to determine the optimal level of interconnection capacity of a country. The optimum level of cross-border flows depend on many factors, such as the difference in the energy price among different areas that cannot be measured with these too simple indexes. Therefore, the indexes should be used only for a first screening. By applying the above indexes to the present situation we can draw the following conclusions:

- Index 1: countries below the threshold of 10% are: Ireland, UK, Poland, Greece, Turkey, Spain, Portugal and Italy;
- Index 2: "physical import flows/national consumption" ratio is higher than that obtained from "import capacity/total installed generation capacity" in UK and Norway;
- Index 3: remaining capacity is higher than 40% of the Gross Total Capacity in France, Italy, Portugal, Spain and Poland.

By referring to the priority axes, the most congested cut-sets (bottlenecks) are the following:

- EL 1: France-Belgium-Netherlands

[16] Import capacity has been evaluated with reference to NTC (Net Transfer Capacity) values corresponding to year 2004 published by ETSO.
[17] UCTE "System adequacy forecast 2005-2015", January 2005

- EL 2: Italy-rest of Europe
- EL 3: France-Iberian Peninsula
- EL 4: Interface between former 1st and 2nd UCTE synchronous zones (Hungary-Serbia and Romania) and Bulgaria-Greece
- EL 5: France-Great Britain
- EL 7: Denmark-Germany; Finland-Sweden; Norway-Sweden
- EL 8: Poland-Czech rep./Poland-Slovakia/Czech rep.- Austria/Slovakia-Hungary/Hungary-Slovenia

The main reasons for congestions are due to:

- High level of power import (e.g.: EL 2, EL 5);
  Wheeling of power across countries (e.g.: France-Belgium-Netherlands);
- Power fluctuations originating by wind generation (e.g.: some cut-sets on EL 7).

To solve possible conflicts in the allocation of cross-border capacities, the definitions of transfer capacities have been agreed within ETSO. Two sets of transfer capacities have been defined: for commercial purposes, used by market operators to set up contracts for cross-border transactions, and for operational purposes, managed by System Operators to check that the physical capacity of lines is not exceeded. Whenever the available transfer capacity is insufficient with respect to the requests, several methods of congestion management have been put in place. Methods for capacity allocations shall fulfil a set of requirements. More specifically, network congestion problems shall be addressed with purpose of non-discriminatory market based solutions, which give efficient economic signals. They shall preferentially be solved with non-transaction based methods and be as transparent as possible in accordance to the EU regulation 1228/2003 on "*Conditions for access to the network for cross-border exchanges in electricity*".

4.2 Investment patterns in the last years

According to the work plan of this Project, a remarkable effort has been undertaken to display the investment patterns during the years 1996 till 2004 in the energy transmission systems in the EU-30 countries including some of the Western Balkan countries. The data on past investments were collected basically through direct contacts with TSOs, replies from the questionnaires circulated to TSOs and planning responsible as well as from publicly available documents such as Annual Reports. Depending on the adopted unbundling choices, a variety of different models exist in Europe for the planning and the decisions on grid investments. Basically, the various models can be classified as follows:

- the System Operator is responsible for the planning, definition of related investments and realization of the new infrastructures. This model requires that the S.O. is the owner of the assets (e.g. : REE in Spain, RTE in France, NGT in England and Wales) ;
- the System Operator is responsible for the planning, definition of related investments, but it is not in charge of the realisation of the new infrastructures. Model based on the Independent System Operator (ISO) and a number of TransCo owning the assets (e.g. : DESMIE in Greece and GRTN, up to the year 2004, in Italy) ;
- the System Operator is not responsible for planning (e.g.: MAVIR in Hungary). This activity is completely in charge of the TransCo.

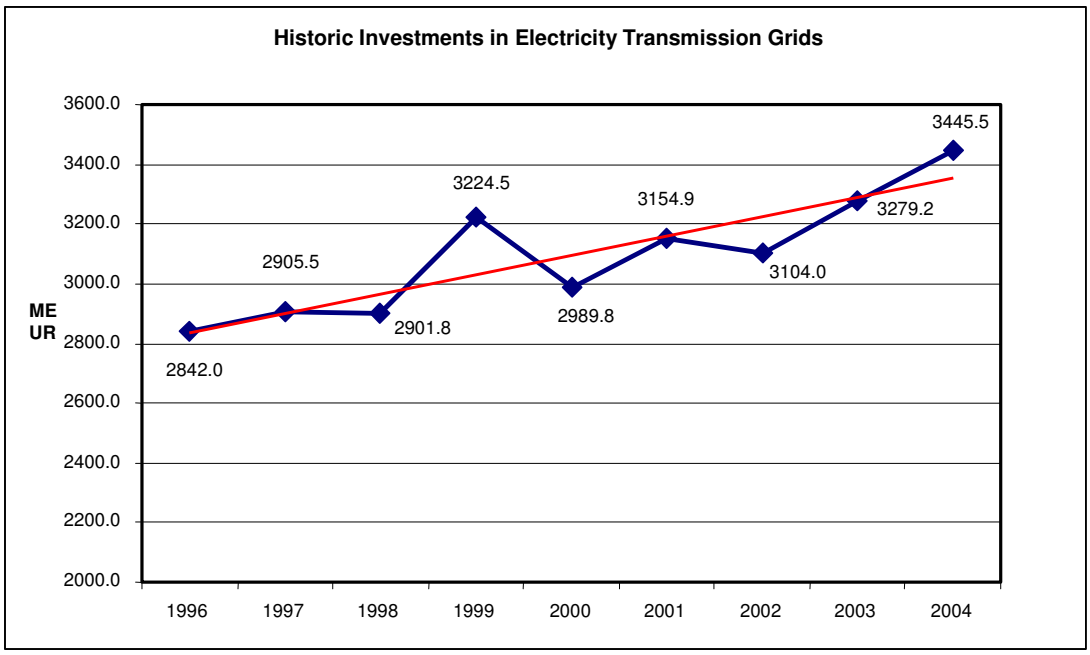
Even more diversified is the situation about the authorisation procedure of the investment plans decided by the SO, ISO or the TransCo. In some cases, the plans are approved by the Energy Ministry18, in other cases they are approved by the Regulatory Body, in further situations the procedure involves both Ministry and Regulatory Body (e.g.: the Ministry approves the investment plans and the Regulatory Body defines the transmission tariffs to recover the investments on open access lines).

All that made very challenging the retrieval of information on past and perspective investments.

Moreover, as a consequence of the starting of the liberalisation process in the period 1996-2004, the former vertically integrated company underwent profound reorganisations with creation of new companies and transfer of assets. This added further obstacles in tracking past investments.

The pattern of investments from 1996 to 2004 (*Tab 4.13*) shows an increasing level of expenditure. In the period under examination the average investment has been 3.1 b€/yr. The breakdown of expenditure is shown in *Fig 4.3*. Investments on cross-border links turned out to be in the order of 1.1 b€, i.e. slightly below 4% of the total investments. Most of the expenses in cross-border links are concentrated in HVDC (High Voltage Direct Current) interconnections through submarine cables; the most relevant projects have been: SwePol (Sweden-Poland; 295 M€); Italy-Greece (300 M€) and Moyle interconnector (North Ireland-Scotland; 220 M€).

[18] Or equivalent body in countries, like Italy, where the Energy Ministry does not exist.



Note 1: the investment values have been updated taking into account of the inflation rates for each year in each country. Data on inflation rates have been retrieved from the European Commission web site: http://epp.eurostat.cec.eu.int/portal.

Note 2: for countries not belonging to the Euro zone, conversion from local currency to Euro has been made directly by the entities involved in the investment plans

Note 3: whenever yearly investments were not available, estimations have been made on the basis of the "equivalent length" of the country transmission grid.

Tab 4.13 – Historic investments in electricity transmission grids.

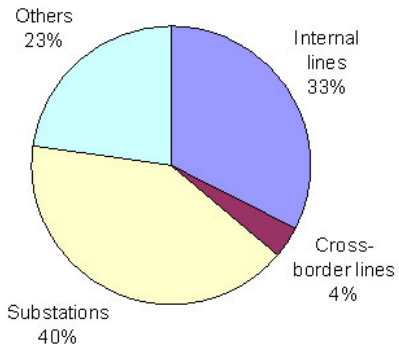


Fig 4.3 – Breakdown of past investments.

Note : « others » refers to investments on TLC system, protection&control, Phase Shifter transformers, etc.

Tab 4.14 shows in detail the patterns of past investments in the transmission grid from 1996 to 2004 for each country. Data were retrieved from all the EU member states with the exception of Austria. Two other EU countries were excluded from the survey: Luxembourg, who has a very limited transmission system (236 km of lines at 225 kV), and Malta, who is an isolated system with local generation and consumption and distribution network only. From Germany, data are relevant to grid investments including also voltage levels lower than that used for bulk power transmission (400-220 kV); indeed, in this country the situation is particularly complicated by the fact that the grid is managed by several TSOs. A similar situation is experienced in Switzerland, where

the transmission grid is run by 7 TSOs (ATEL, NOK, CKW, EGL, BKW, EWZ, EOS) and so far no "Swiss TSO" as single point of contact exists. Contacts have been taken with ETRANS, who responded to the questionnaire, but, being only the coordinator of network operations, they couldn't provide much of the requested data. Information from Denmark is relevant to the western part (Jutland), managed by ELTRA and synchronised with Germany. In the presentation, the results were grouped by cluster of countries as follows:

- Eastern Baltic countries: Estonia, Latvia and Lithuania;
- Nordic Countries: Denmark, Finland, Norway and Sweden;
- Continental Europe countries: Austria, Belgium, Czech Rep., France, Germany, Greece, Hungary, Italy, Netherlands, Poland, Portugal, Slovakia, Slovenia, Spain, Switzerland, including also the candidate countries, Bulgaria, Romania and Turkey, and the Western Balkan countries. Among these latter countries, concerning the electricity sector, information has been retrieved by Serbia-Montenegro, who is the biggest country in the region;
- Islands: Cyprus, Great Britain, Northern Ireland and Republic of Ireland.
- The reason for the above clustering is related to the historical background of the respective countries that had an impact on the design of the grids and the way of operating the system. E.g.: in the time period under examination, the Eastern Baltic countries were in a transition phase from the post-Soviet era to the western models for energy production, transmission, distribution and trading; candidate countries in south-east Europe have been strongly affected by the war events and economical crises occurred along the '90s, while Nordic and European continental countries followed a much smoother evolution, with some exceptions relevant to the countries belonging to the former Centrel bloc (Poland, Czech and Slovak Rep, and Hungary).

The investment values have been updated taking into account of the inflation rates for each year in each country. Data on inflation rates have been retrieved from the European Commission web site: http://epp.eurostat.cec.eu.int/portal. For countries not belonging to the Euro zone, conversion from local currency to Euro has been made directly by the entities involved in the investment plans.

The following bar charts (*Fig 4.4 ÷Fig 4.9*) depict the pattern of past investments in the European countries, clustered according to the criterion above explained.

Eastern Baltic Countries

In the Eastern Baltic countries there isn't any decline in investments. On the contrary, in Lithuania we are witnessing a trend of increase. In this country investments are mainly concentrated on renewal of substations and interconnecting transformers, rather than in internal transmission lines.

A similar situation is experienced in Estonia where the larger amount of investments is concentrated on the reconstruction and renewal of substations. The sharp increase of investments in the year 2004 is mainly related to the reconstruction of Balti 330 kV substation (14,89 M€ in 2004-2005) and other projects related to construction of new s/s, renewable of the exiting ones around the city of Tallinn as well as the laying down of 110 kV cables for a total of 10,29 M€ in three years (2003-2005).

Investments are mainly concentrated on s/s also in Latvia, who had a quite stable investment pace in these last years.

None of the above countries have invested in cross-border lines, being these power grids already strongly meshed among them and with the Russian Federation for historical reasons.

Tab 4.15 shows the distribution of investments among lines, substations and interconnecting transformers.

HISTORIC INVESTMENTS (M€)									
COUNTRY	1996	1997	1998	1999	2000	2001	2002	2003	2004
Eastern Baltic Countries									
ESTONIA (EE)			5,0	14,1	18,0	22,8	17,1	15,9	41,1
LATVIA (LV)	4,3	15,5	12,5	17,2	14,7	18,8	20,2	16,7	18,0
LITHUANIA (LT)							35,0	42,5	43,0
Nordic Countries									
DENMARK-WEST (DK)								68,4	
FINLAND (FI)			77,6	32,8	41,4	36,2	40,6	41,1	39,0
NORWAY (NO)	8,0	7,0	28,0	9,0	4,0	9,0	34,0	58,0	81,0
SWEDEN (SE)	74,8	33,4	18,7	43,9	64,9	41,1	49,6	38,4	44,0
Continental Europe Countries including candidate and western Balkan countries									
AUSTRIA (AT)									
BELGIUM (BE)									21,0
BULGARIA (BG)	60,5	10,1	5,2	23,1	22,2	35,6	28,2	16,7	25,0
CZECH REPUBLIC (CZ)				27,0	22,7	27,0	17,3	47,5	41,0
FRANCE (FR)		720,2	743,9	690,9	592,0	556,6	548,9	431,7	394,3
GERMANY (DE)*	3431,7	3271,9	2927,4	2692,1	2231,0	2397,5	2880,7		
GREECE (GR)	81,7	73,8	91,2	105,0	107,6	84,3	84,1	90,5	89,1
HUNGARY (HU)				48,9	25,1	24,8	26,6	58,2	71,8
ITALY (IT)						291,4	105,2	92,1	150,0
NETHERLANDS (NL)	188,7	25,2	5,9	42,8	20,4	19,4	6,2	77,1	21,0
POLAND (PL)	625,2	593,9	425,7	432,8	359,5	399,0	347,5	340,8	367,0
PORTUGAL (PT)					52,3	77,6	105,6	121,2	137,1
ROMANIA (RO)						45,8	74,8	91,8	112,0
SERBIA and M. (CS)			15,3	4,5	30,0	18,2	8,1	4,0	2,5
SLOVAKIA (SK)	35,7	63,0	40,3	22,6	7,8	16,4	9,5	26,7	27,2
SLOVENIA (SI)	20,7	19,9	15,5	19,5	17,9	21,7	17,9	25,1	21,3
SPAIN (SP)		88,9	21,5	39,8	88,2	143,0	215,7	221,4	243,0
SWITZERLAND (CH)									
TURKEY (TR)	106,5	164,8	194,8	168,6	84,3	58,3	45,2	65,5	66,7
Islands									
CYPRUS (CY)							4,1	8,9	17,7
GREAT BRITAIN (UK)(**)	268,5	288,6	352,4	452,9	546,0	555,0	558,0	584,0	528,0
IRELAND (IE)	38,8	38,3	37,5	36,6	34,8	100,2	138,2	122,8	180,0
NORTH IRELAND (UK)	7,8	15,3	18,3	243,0	16,8	16,6	12,3	14,2	18,0

(*) Investment data are relevant also to voltage levels lower than EHV (400-220 kV)

(**) Investment data are relevant to England and Wales. Moreover, investments are shown by "financial year" from April to end-March. Form example, the figure for 2000 covers the period from April 2000 through to the end-March 2001

Tab 4.14 – Patterns of investments from 1996 to 2004

Nordic Countries

In Finland investments in the transmission grid have been stable in the last 5 years, while in Sweden yearly investments have been quite variables with some peaks related to the construction of "heavy" infrastructures such as the submarine cable SwePol in HVDC between Sweden and Poland, project commissioned in the year 2000. In western Denmark investments are mainly concentrated on the reinforcement of the 400 kV grid (70%) of the total investments in the year 2003 and, to a lesser extent, on the 150 kV grid. In Norway, after low investments in the late '90s (less than 10 M€/yr, with the exception of the year 1998), a rapid increase in the investments has been experienced starting from the year 2002. Investments have been shared in a quite balance way between lines and substations. This positive trend in the investments is expected to continue also in the next decade with level bigger than 100 M€/yr.

Breakdown of past investments									
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004
ESTONIA	**INVESTMENTS IN M€**								
Internal Transmission Lines			0,00	2,20	10,46	10,80	3,53	2,94	6,12
Substations			0,00	1,07	6,41	1,88	6,83	7,89	28,95
Transformers and other equipment (*)			4,97	10,88	1,09	10,08	6,72	5,11	6,01
LITHUANIA	**INVESTMENTS IN M€**								
Internal Transmission Lines							2,19	3,19	3,00
Substations							18,58	24,43	25,00
Transformers and other equipment (*)							17,49	16,99	15,00
LATVIA	**INVESTMENTS IN M€**								
Internal Transmission Lines	0,35	2,50	0,72	3,80	3,56	2,81	5,50	2,53	3,70
Substations	3,31	9,45	7,65	9,66	7,23	11,56	1,20	9,20	11,60
Transformers and other equipment (*)	0,12	1,52	2,38	1,64	2,34	2,61	1,80	4,15	2,70

(*) E.g.: fixed shunt Var compensation devices, SVC and other electronically controlled devices, etc.
Tab 4.15 – Breakdown of past investments from 1996 to 2004 in the Eastern Baltic Countries

Countries of continental Europe

In the analysis we split the countries in three main groups:

- large size countries: France, Italy, Poland, Spain (*Fig 4.6*) and Germany;
- mid-small size countries: Portugal, Belgium, the Netherlands, Greece, Slovenia, Czech Republic, Slovakia and Hungary (*Fig 4.7*);
- South-East European countries: Bulgaria, Romania, Serbia-Montenegro and Turkey (*Fig 4.8*)

Among the large countries, France is showing a decline in the pace of investments all along the period from 1997 to 2004. In Poland, after a decline in investments in the late '90s, the annual investments are now stable, even though to a lower level with respect to the '90s. A similar trend has been experienced in Germany. In Italy, investments turned out to be quite low, especially in consideration of the extension of the grid. This low level is not caused by a lack of willingness to invest, but to the difficulty in advancing the already decided projects. On the contrary, in Spain we are witnessing an increasing trend of investments, especially starting from the year 2000; while in the '90s investments were more concentrated on lines, recently, around 2/3 of the investments have been related to substation (increasing of transformation capacity and renewals).

Among the mid-small size countries, Belgium didn't make any reinforcement of its 400 kV grid in the last five years with the exception of the installation of a second circuit on an existing 400 kV -line to feed a 400/70 kV-transformer rated 220 MVA (total cost: 21 M€). Quite different is the situation in the Netherlands that had some peaks in the investments related to: the new line Zwolle-Eemshaven (1995-1996) and the installation of PHS (Phase Shifter Transformers) in Meeden s/s (2000-2003). Greece and Slovenia have both a stable investment pattern in the period under examination. In Greece most of the expenditure has been recently (2004) concentrated on substations, while in Slovenia investments have been shared on nearly equal basis between lines and substations. Czech Republic, Hungary and Slovakia are witnessing an increase of annual investments in the last two years with respect to those made in 2000-2002. The largest part of these investments is related to the renewal or reconstruction of substation (e.g.: in the Czech Rep. all the investments in the year 2004 were devoted to substations). As in the case of the Eastern Baltic states, this concentration of investments on renewal and replacement of substation is related to the need to transform these infrastructures to match the most advanced standards already adopted in the western European countries. Finally, concerning Portugal, a trend of increasing investments very similar to the Spanish one has been experienced from the year 2000.

In the South-East Europe region the situation is remarkably different from one country to another. Romania has undertaken a huge effort to modernize its network and enter to the European IEM (Romania is already a member of ETSO). Bulgaria shows in the average a stable investment rate in the period under examination. Turkey has also a stable investment level in the last five years, but at a level much below to that of the period 1996-1999. Moreover, taking into account of the high growth rate of the internal demand and the grid extension, the yearly investment levels turned out to be poor. Finally, concerning Serbia-Montenegro, despite the urgent need for rehabilitation of existing infrastructures and construction of new lines and transformers, investments are very limited and still decreasing in these last years. This situation is becoming particularly critical considering the lack of investments made in the '90s. Insufficient performances of the Serbia-Montenegro grid (e.g.: high fault rates, inadequate telecommunication and remote control systems) may be an obstacle to the development of an integrated electric regional market as envisaged in the framework of the "Athens Process" started at the end of 2002.

Islands

In the Republic of Ireland investments have grown in the last five years with respect to the levels of the '90s. This is the consequence of the remarkable growth of the internal demand. Recent investments have been mostly concentrated on transformation capacity (e.g.: Cashla-OldStreet 400/220 kV: 38 M€ in 2003) and undergrounding in the Dublin area (laying down of 220 kV cables in Dublin in 2002 with an expenditure of 30 M€).

As far as UK is of concern, we see a quite stable investment pattern in North Ireland, managed by NIE (North Ireland Electricity). Investment peak highlighted in 1999 is related to the commissioning of the HVDC link between North-Ireland and Scotland: the Moyle interconnector.

In Great Britain the transmission grid is operated by National Grid Electricity Transmission plc, belonging to the group National Grid (until recently know as National Grid Transco). National Grid Electricity Transmission plc is the holder of an electricity transmission licence under which it owns the high voltage electricity transmission system in England and Wales and performs the role of GB System Operator. Electricity transmission assets in Scotland are owned by Scottish Power Transmission Ltd and Scottish Hydro-electric transmission Ltd. Values of past (as well as perspective) investments have been communicated by National Grid with reference to England and Wales including the Anglo-Scottish transmission circuits. As it can be seen, there has been a quite constant increase of investments in the recent years with respect to the '90s. *Tab 4.16* depicts the breakdown of past and future expenditure in England and Wales. It is worth noting an increase in investments in underground cables while investments related to s/s equipment (transformers, switchgear, protection and control) are on the whole constant.

Breakdown of past and perspective capital expenditure in England and Wales

	Actual Expenditure (2004 prices)					Forecast Expenditure (2004 prices)						
	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Categories	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)	(M€)
LOAD RELATED EXPENDITURE												
Entry	23.1	19.4	22.9	6.7	0.1	0.0	0.0					
Supergrid system extension (infrastructure) excl TSS	140.8	172.3	188.8	182.5	130.6	180.9	253.2					
TSS		7.2	24.8	17.5	1.6	0.8						
Exit	83.9	118.1	80.8	93.0	92.0	126.3	147.0					
Abatements						-14.5	0.0					
Total Load Related	247.8	317.0	317.4	299.6	224.3	293.6	400.2					
NON-LOAD RELATED EXPENDITURE												
Asset Replacement:												
Transformers	5.1	4.4	12.3	11.0	14.9	20.0	28.3	42.3	44.1	31.3	32.5	43.9
Switchgear	26.7	28.9	23.2	29.4	29.9	39.4	51.9	127.6	189.4	248.0	311.8	300.2
Sub-station and other	17.7	12.0	8.8	8.0	8.7	13.8	24.5	21.6	20.9	22.2	25.8	17.0
Overhead Lines	53.2	48.9	41.3	58.7	99.6	181.4	204.2	169.2	214.7	195.0	169.4	157.5
Underground Cables	15.2	27.8	36.5	57.6	44.5	46.1	80.0	104.8	132.4	111.7	117.7	164.4
Protection & Control	67.0	50.8	46.5	42.9	28.1	43.9	47.4	40.9	50.5	59.9	47.7	53.8
Abatements	0.0	0.0	0.0	0.0	0.0	-16.0	0.0	0,0	0.0	0.0	0.0	0.0
Other TO	72.6	43.4	52.3	58.6	50.0	51.2	54.1	54.4	48.3	42.9	33.9	31.2
SO excl BETTA	40.2	21.9	19.0	18.3	4.8	17.5	20.3	15.2	12.2	12.0	0.0	0.0
Total Non-Load Related	297.7	237.9	240.1	284.5	280.6	397.4	510.7	576.1	712.4	723.0	738.8	767.9

Tab 4.16 – Breakdown of past and perspective capital expenditure in England and Wales (source National Grid)

Finally, concerning Cyprus, we see an acceleration of investments in these last years mainly on new substations to increase the transformation capacity in consideration of the high growth rate of the demand in the island.

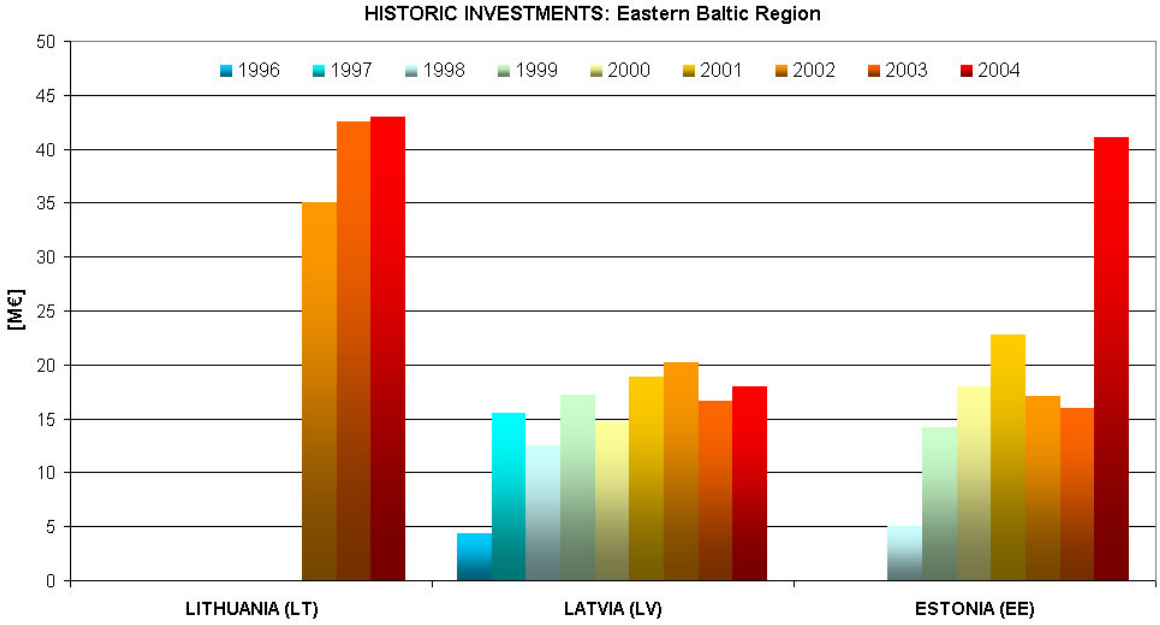


Fig 4.4 - Past investments in the Eastern Baltic Region

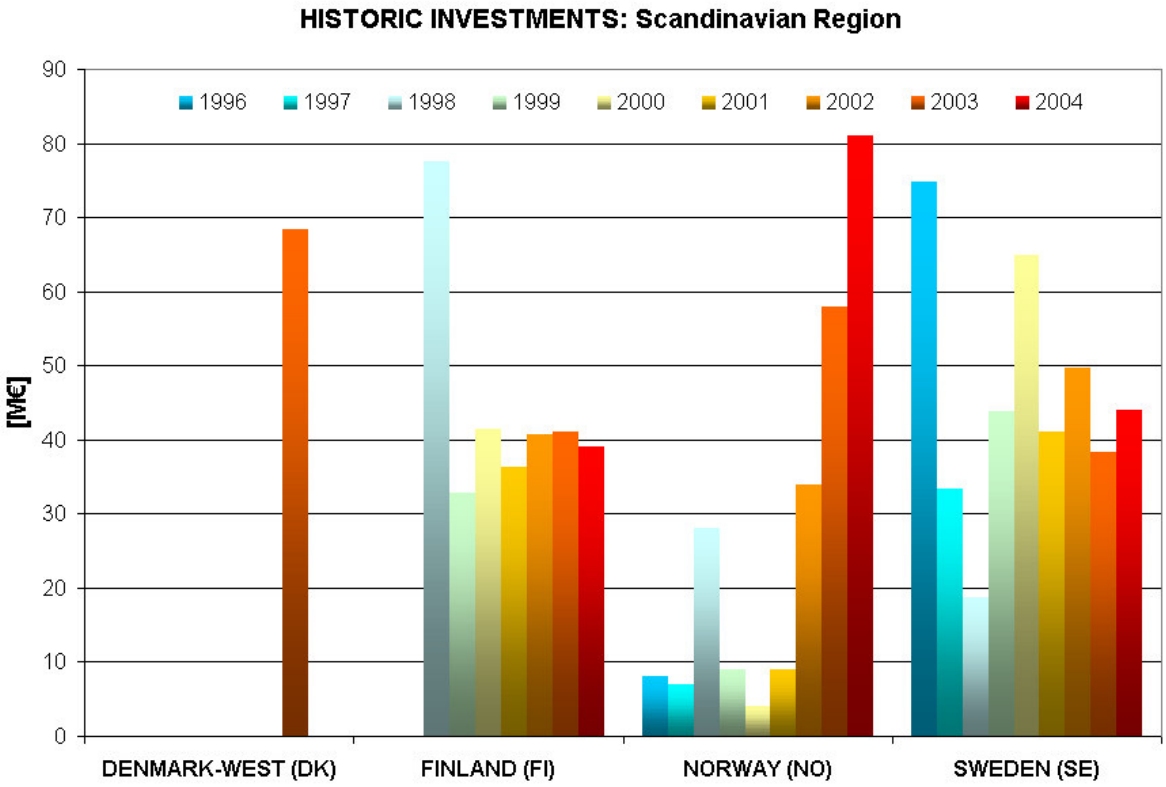


Fig 4.5 - Past investments in the Nordic Countries

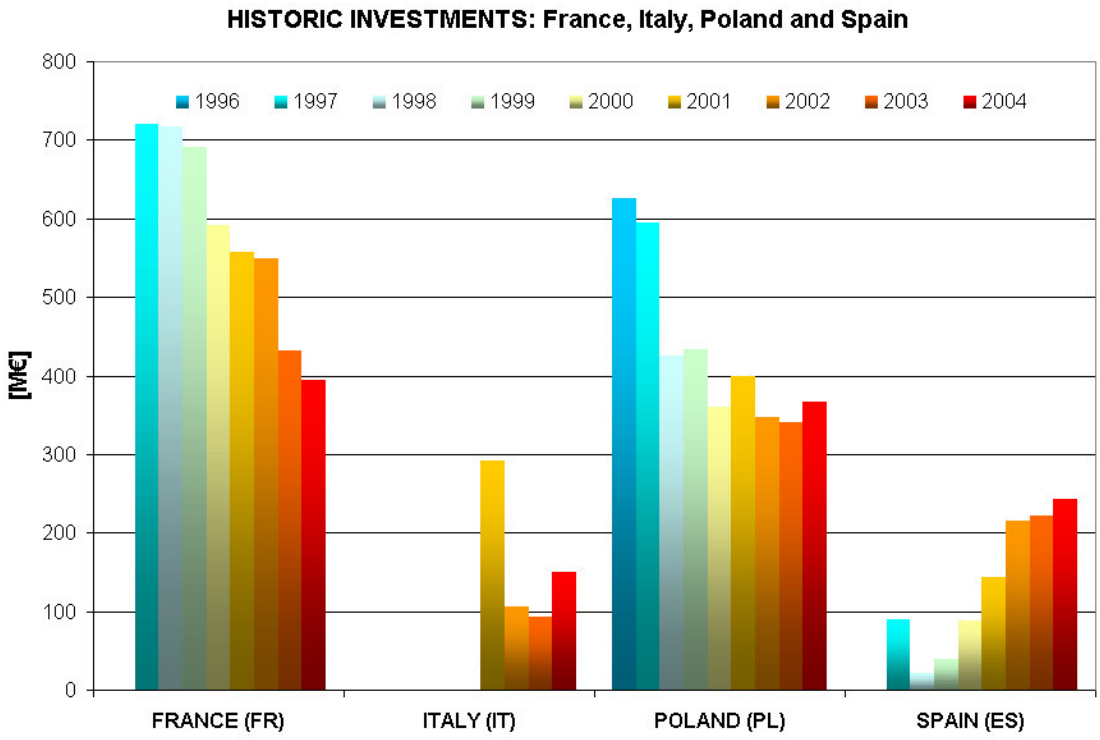


Fig 4.6 Past investments in large size countries of the continental Europe

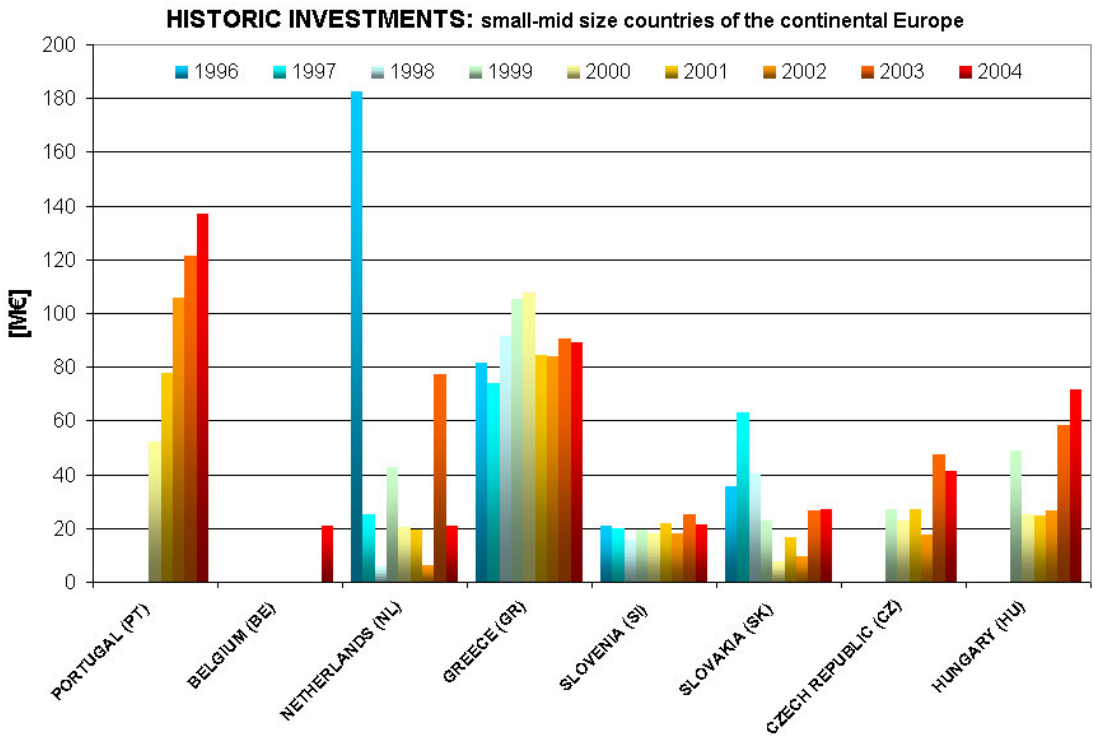


Fig 4.7 - Past investments in mid-small size countries of the continental Europe

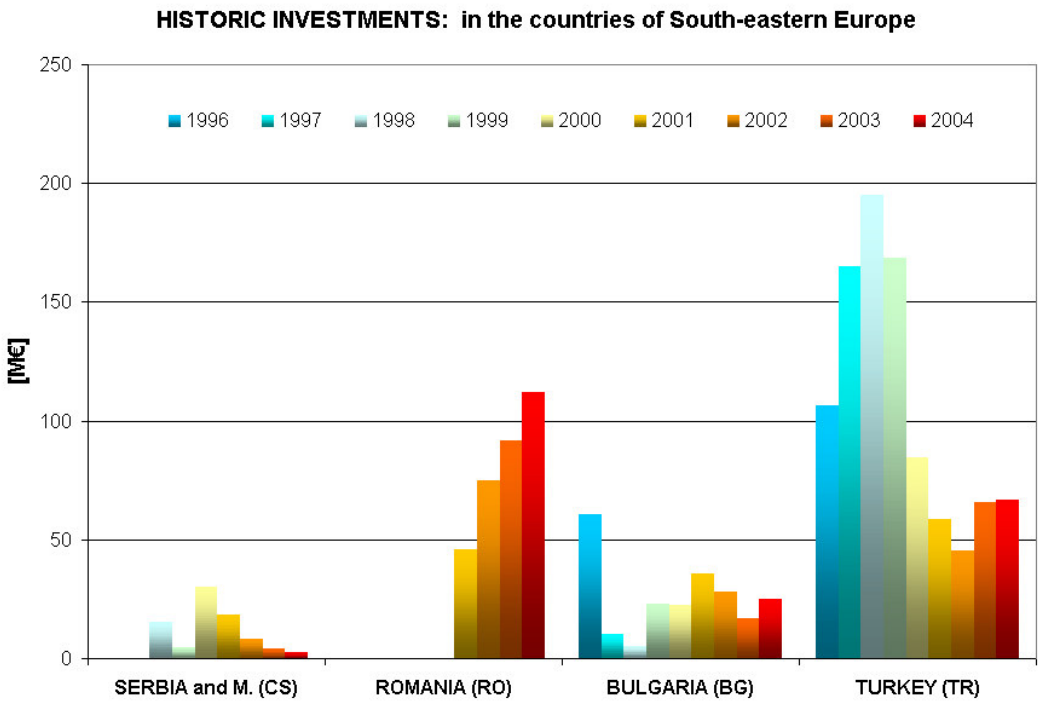


Fig 4.8 - Past investments in the countries of South-eastern Europe

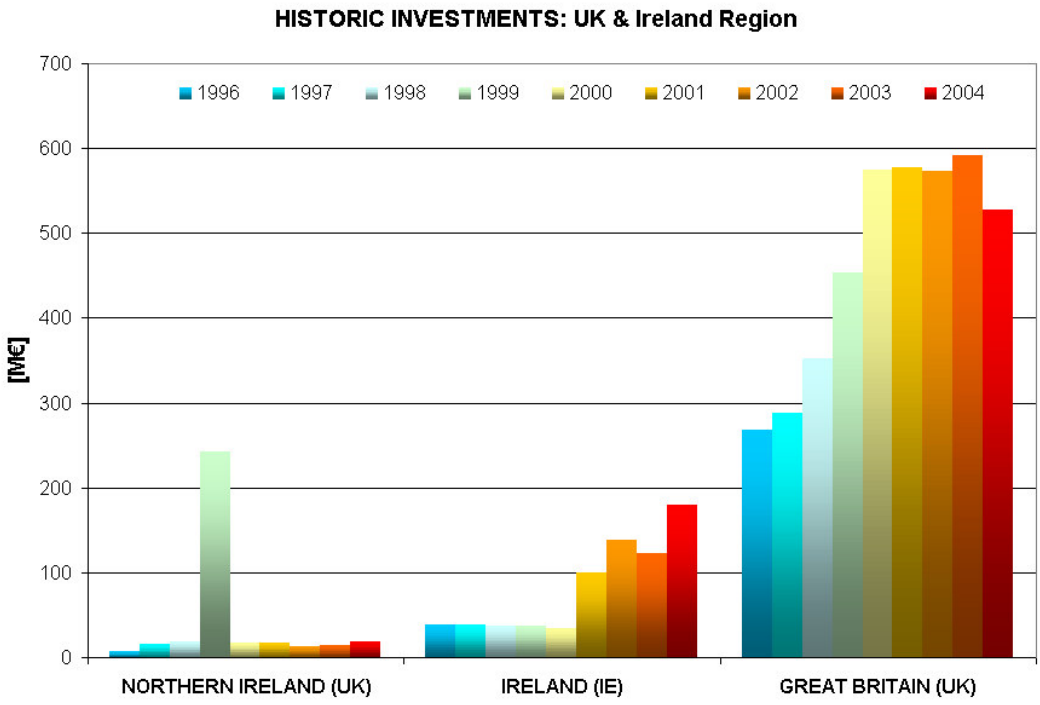


Fig 4.9 - Past investments in the British Islands

To have a criterion for comparing the investment patterns in the various countries, the absolute values have been normalised with respect to the "equivalent" length "*EL*" of the grid. The "equivalent" length "*EL*" is referred to the capacity of a 400 kV line by adopting the following relationship:

$$EL = L_{400} + \sum_{i=1}^{Nv} L_i * \left(\frac{V_i}{400} \right)^2$$

with:

L_{400}: physical length of the 400 kV lines;

L_i: physical length of the lines at voltage level "V_i".

In the above formula it is assumed that the transport capacity changes in a quadratic way with the voltage as it normally happens when referring to the "natural power" of a line. The above relationships for the calculation of the « equivalent » length is obviously an approximation not being possible to take into account the different transport capacity of lines having the same voltage level, depending on the conductor section, number of bundles, electric tower design, etc. However, the derived « normalised » values are a sufficiently good indication for comparing the amount on investments in relationship to the size of the grid.

For the calculation of the "equivalent" length, the EHV levels have been considered (400-225/220 kV) with the exception of Turkey, the transmission system of which is based on 400 kV[19] and 154 kV, and Cyprus, which has a transmission system at 132 and 66 kV. *Tab 4.17* shows the "equivalent" length for the countries under examination.

[19] 400 kV is the operation value, while 380 kV is the rated voltage level

LENGTH AND "EQUIVALENT LENGTH" OF THE TRANSMISSION GRID							
COUNTRY	kV	km	kV	km	kV	km	Eq. km
Eastern Baltic Countries							
ESTONIA (EE)	330	1290	220	508			**1032**
LATVIA (LV)	330	1665					**1133**
LITHUANIA (LT)	330	1247,9					**849**
Nordic Countries							
DENMARK-WEST (DK)	400	747	225	39			**759**
FINLAND (FI)	400	4000	220	2400			**4726**
NORWAY (NO)	400	2100	220	5600	132	10500	**4937**
SWEDEN (SE)	400	11100	220	4600			**12492**
Continental Europe Countries including candidate and western Balkan countries							
AUSTRIA (AT)	400	2474	225	3765			**3665**
BELGIUM (BE)	400	1298	225	415			**1429**
BULGARIA (BG)	750	85	400	2266	220	2650	**3366**
CZECH REPUBLIC (CZ)	380	3422	220	1926			**3671**
FRANCE (FR)	400	20966	225	26265			**29276**
GERMANY (DE)	400	18700	225	17500			**24237**
GREECE (GR)	400	4459	225	11078			**7964**
HUNGARY (HU)	400	2090	225	1188			**2466**
ITALY (IT)	380	9891	220	11705			**12467**
NETHERLANDS (NL)	400	2003	225	683			**2219**
POLAND (PL)	400	4830	225	7887			**7325**
PORTUGAL (PT)	400	1403	225	2692			**2255**
ROMANIA (RO)	750	155	400	4630	220	4132	**6425**
SERBIA and M. (CS)	400	1814	220	2589			**2597**
SLOVAKIA (SK)	400	1753	225	962			**2057**
SLOVENIA (SI)	400	510	225	328			**614**
SPAIN (SP)	400	16951	225	16244			**22091**
SWITZERLAND (CH)	400	1641	225	5031			**3233**
TURKEY (TR)	380	13958	220	84,6	154	31430	**17281**
Islands							
CYPRUS (CY)	132	1500,8	66	560,4			**179**
GREAT BRITAIN (UK)	400	10000	270	13500			**16151**
IRELAND (IE)	400	442	220	1780			**980**
NORTH IRELAND (UK)	275	2104					**994**

Tab 4.17 – Physical and equivalent length of the transmission grid in the European countries

By applying the above "normalization factors", the per-unit investments in k€/km-eq/yr are derived (see *Tab 4.18*). The table shows the "normalized" values only for countries where data have been retrieved. For an

easier examination, diagrams of the "normalized" investments are displayed in *Fig 4.10* to *Fig 4.16* for clusters of homogeneous countries.

HISTORIC INVESTMENTS (k€/km)									
COUNTRY	1996	1997	1998	1999	2000	2001	2002	2003	2004
Eastern Baltic Countries									
ESTONIA (EE)			4,8	13,7	17,4	22,1	16,6	15,5	39,8
LATVIA (LV)	3,8	13,7	11,0	15,2	13,0	16,6	17,8	14,7	15,9
LITHUANIA (LT)							41,2	50,0	50,6
Nordic Countries									
DENMARK-WEST (DK)								90,1	
FINLAND (FI)			16,4	6,9	8,8	7,7	8,6	8,7	8,3
NORWAY (NO)	1,6	1,4	5,7	1,8	0,8	1,8	6,9	11,7	16,4
SWEDEN (SE)	6,0	2,7	1,5	3,5	5,2	3,3	4,0	3,1	3,5
Continental Europe Countries including candidate and western Balkan countries									
BELGIUM (BE)									14,7
BULGARIA (BG)	18,0	3,0	1,5	6,9	6,6	10,6	8,4	5,0	7,4
CZECH REPUBLIC (CZ)				7,4	6,2	7,4	4,7	12,9	11,2
FRANCE (FR)		24,6	25,4	23,6	20,2	19,0	18,7	14,7	13,5
GREECE (GR)	10,3	9,3	11,5	13,2	13,5	10,6	10,6	11,4	11,2
HUNGARY (HU)				19,9	10,2	10,1	10,8	23,6	29,1
ITALY (IT)						23,4	8,4	7,4	12,0
NETHERLANDS (NL)	85,0	11,4	2,7	19,3	9,2	8,7	2,8	34,7	9,5
POLAND (PL)	85,4	81,1	58,1	59,1	49,1	54,5	47,4	46,5	50,1
PORTUGAL (PT)					23,2	34,4	46,8	53,7	60,8
ROMANIA (RO)						7,1	11,6	14,3	17,4
SERBIA and M. (CS)			5,9	1,7	11,5	7,0	3,1	1,5	1,0
SLOVAKIA (SK)	17,3	30,6	19,6	11,0	3,8	8,0	4,6	13,0	13,2
SLOVENIA (SI)	33,8	32,5	25,3	31,8	29,2	35,3	29,1	40,9	34,7
SPAIN (SP)		4,0	1,0	1,8	4,0	6,5	9,8	10,0	11,0
TURKEY (TR)	6,2	9,5	11,3	9,8	4,9	3,4	2,6	3,8	3,9
Islands									
CYPRUS (CY)							23,1	49,6	99,1
GREAT BRITAIN (UK)	16,6	17,9	21,8	28,0	33,8	34,4	34,5	36,2	32,7
IRELAND (IE)	39,5	39,1	38,2	37,3	35,5	102,2	141,0	125,2	183,6
NORTH IRELAND (UK)	7,8	15,4	18,4	244,3	16,9	16,7	12,4	14,3	18,1

Tab 4.18 – Past investments "normalised" with respect to the extension of the grid (only for countries where investment data were available)

The analysis of the investments in relationship to the grid size shall be done for homogeneous groups of countries, because of the different characteristics of the grids (e.g.: in the Eastern Baltic countries a substantial

role for transmission of power is played by the 110 kV lines) and different needs of network expansions and/or renewal.

In the Eastern Baltic countries, yearly investments are in the range of 10÷20 k€/km-eq with the exception of Lithuania that is doing a bigger and increasing effort in renewal and reconstruction of substations. In Sweden, Finland and Norway investments turn out to be rather low (<10 k€/km-eq) in comparison to the extension their grids, even though Norway is showing a rapid increase stating from the year 2002. Similarly, Western Denmark starting from 2003 undertook an intensive plan of investments (≈90 k€/km-eq) on the 400 kV transmission grid and a similar level is scheduled for the next 10 years with a peak in the years 2009-2011. In the other continental European countries yearly investments are in the range 10÷30 k€/km-eq with some exceptions:

- Portugal, with a rapid increase in investments, which exceeded 50 k€/km-eq starting from the year 2003
- Poland, with investments in the range 45÷85 k€/km-eq, concentrated mainly on substations;
- Slovenia, characterised by high investments (30÷40 k€/km-eq). This country has to face a strong increase of wheeled power from North-East to South-West, in addition to the growth of the internal load;
- Czech Republic and Slovakia, having investments around or below 10 k€/km-eq.

Considering the countries of South-Eastern Europe, we see that investments are very low in relationship to the extension of the national grids (*Fig 4.14*). With the exception of Romania, investment level in Bulgaria, Serbia-Montenegro and Turkey are quite poor (< 10 k€/km-eq), with a further declining trend in Serbia-Montenegro.

Looking at the islands, we see an investment level in the range 10÷20 k€/km-eq in North Ireland, in line with the Continental Europe countries, high investment level in England and Wales (30÷40 k€/km-eq) and very high investments levels in Ireland and Cyprus (>50 k€/km-eq in the last years). As for Ireland, it is worth recalling that such a high figures can be partially biased by the facts that a non-negligible part of the investments can have been related to the 110 kV voltage level, which has not been considered in the evaluation of the "equivalent length" of the grid.

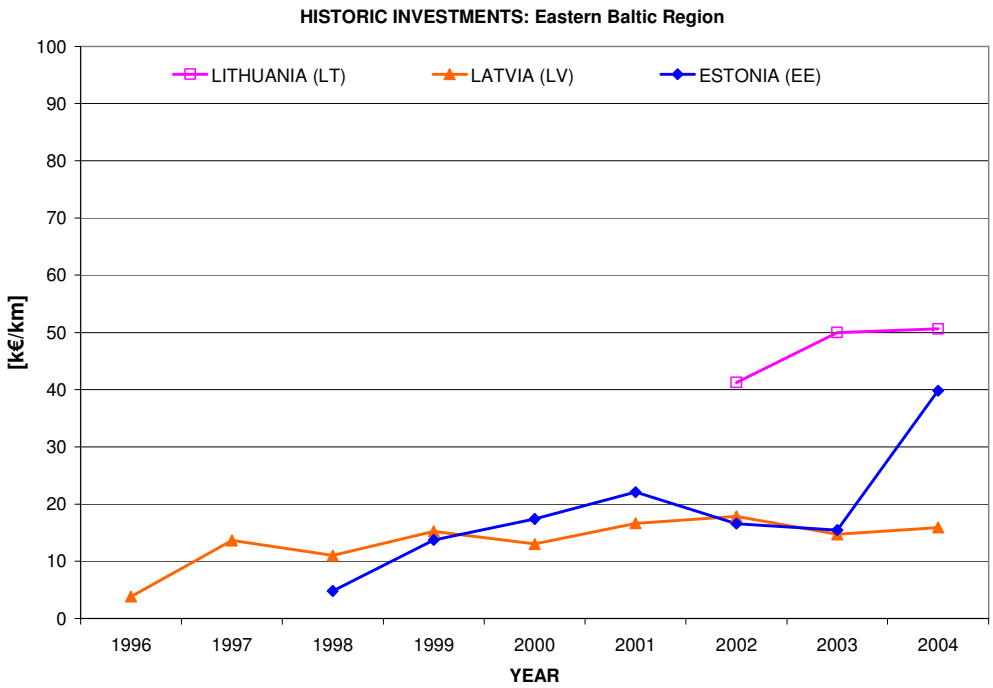


Fig 4.10 - Normalised past investments in the Eastern Baltic countries

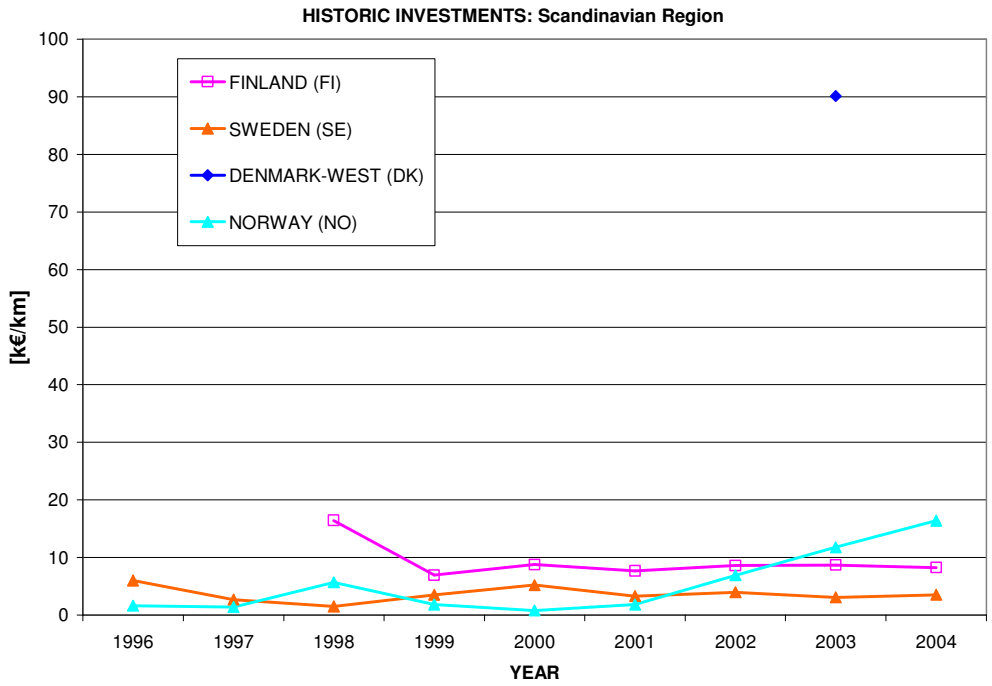


Fig 4.11 - Normalised past investments in the Nordic countries

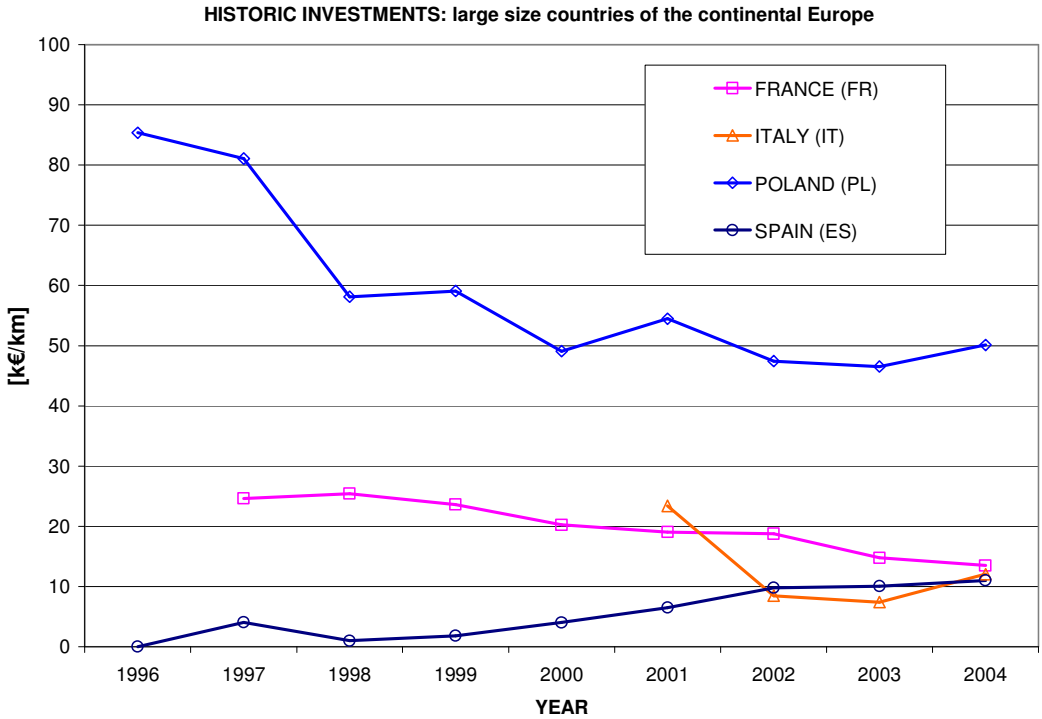


Fig 4.12 - Normalised past investments in large size countries of the continental Europe

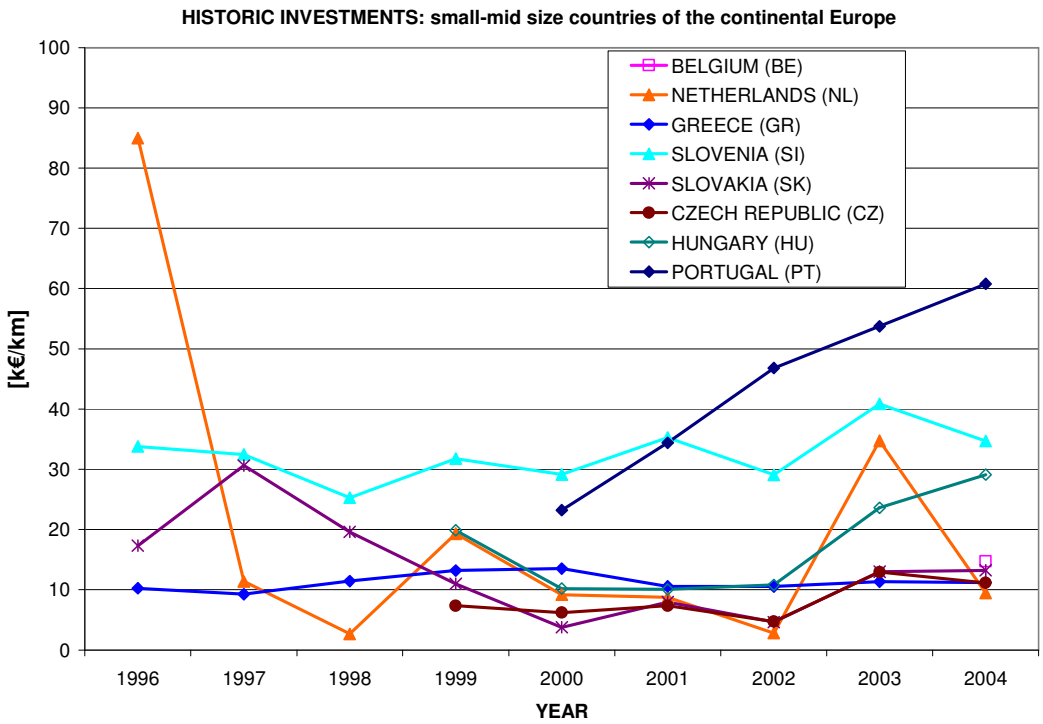


Fig 4.13 - Normalised past investments in small-mid size countries of the continental Europe

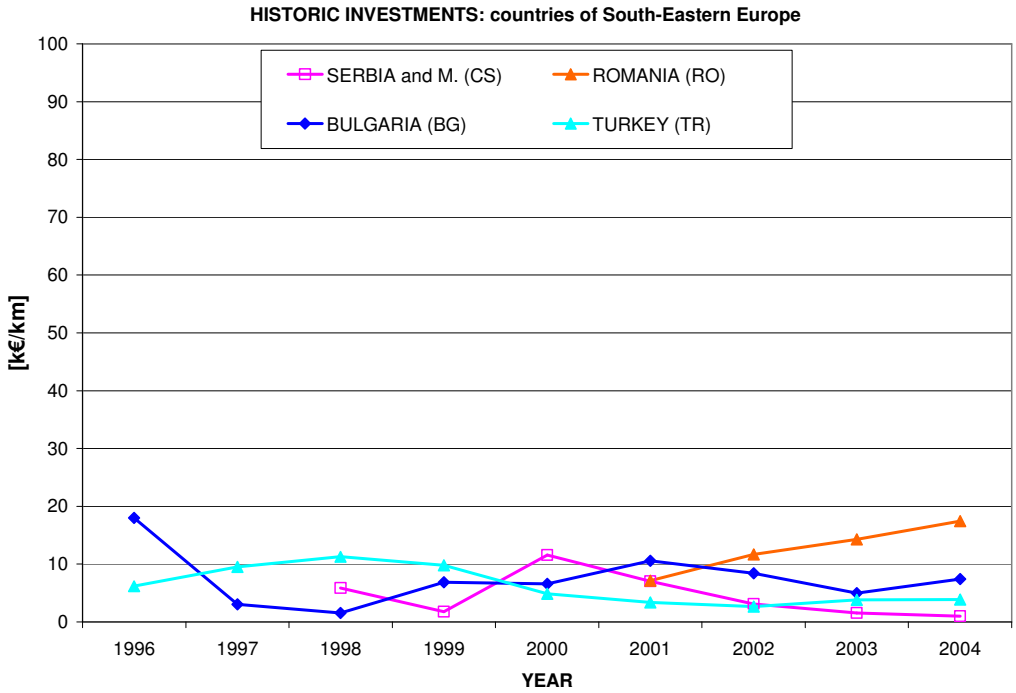


Fig 4.14 - Normalised past investments in countries of South-East Europe

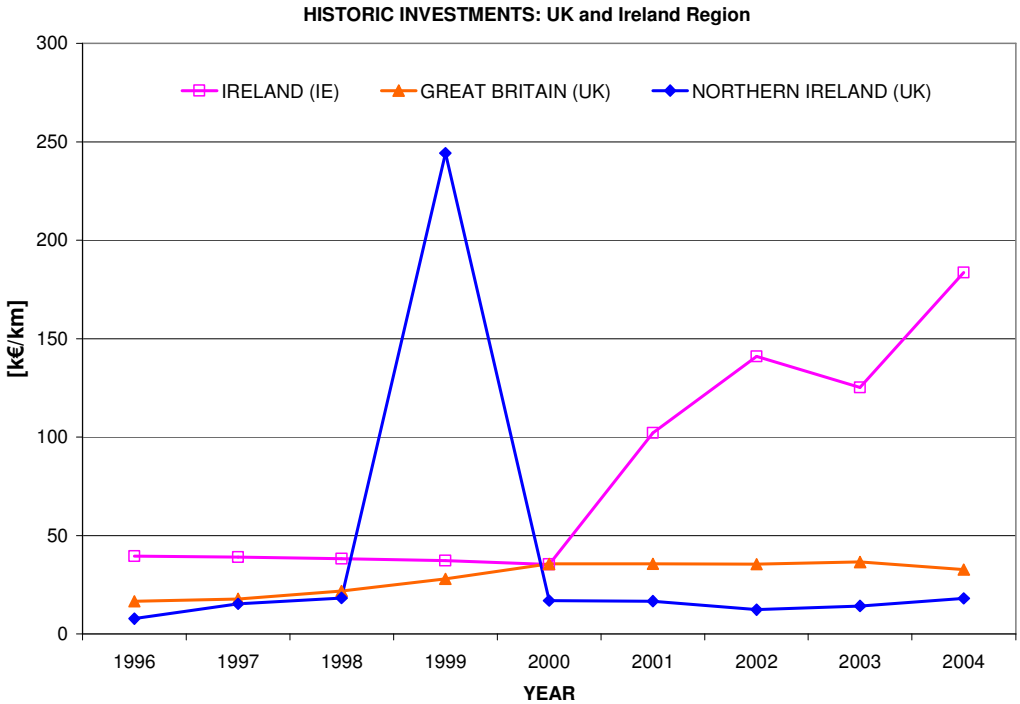


Fig 4.15 - Normalised past investments in the British Islands

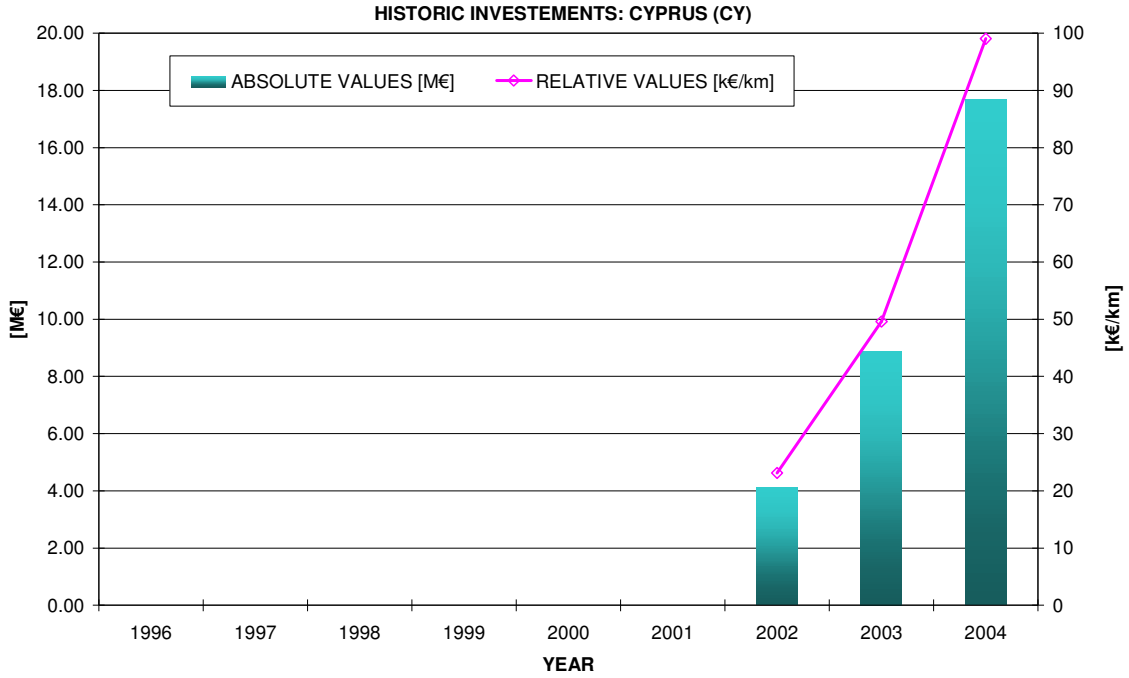


Fig 4.16 - Absolute and normalised past investments in Cyprus

4.3 Financing sources

The analysis was aimed at giving an overview on:

- *typical way of financing*, e.g. source or category of finance, which in practice is EIB loans, EU funds, World Bank loans, EBRD, etc. This issue deals also with the importance of EU funds for the development of the trans-European energy networks.
- *Analysis of the cost of capital in European projects of electric infrastructures*. The analysis tried to highlight if some regions/countries or some type of investments have a lower or higher cost of financing.
- *Impact of financing on the pace of investments in electric transmission projects;*
- Possible difficulties in *financing large projects* and/*or cross-border projects*;
- Need for *new guarantees or financing mechanisms* in particular for projects with the main purpose of integrating renewable energy or enhancing security of supply
- *Examples on financing of some recently achieved projects in the transmission network.*

Information has been essentially retrieved by direct contacts with the national TSO involved in defining and investing in transmission grid projects. In some cases, information on financial issues was retained as confidential and, then, not disclosed. Moreover, further difficulties in collecting information have been met:

- in some countries, due to the fragmentation of ownership among several TransCo information was not available on a single point (e.g.: Germany, UK, Switzerland);
- in other countries, because the responsible for the network planning and definition of related investments is not also the responsible for the execution of the projects (e.g.: Italy, Greece, Hungary).

Despite the above problems, it has been possible to provide a general overview of the situation on financing of power transmission projects covering the entire European region. One of the clear upshots that can be drawn up from the questionnaires is that most of the countries are expecting a major funding supported by the EU[20]. However, according to the answers, in the past, the EU funding seemed not to be critical in transmission investment. It is worth observing the case of Northern Ireland, since it is the historic larger investor in cross-border lines in the sample of TSOs that gave information on financing issues. North Irish TSO states that, in effect, the EU funding is decisive for the projects and that transmission investments are being lowered because lack of finance, viewpoint that it is not agreed for most of the TSOs with few exceptions (Italy, Poland, Slovakia, Spain and Turkey).

Enquiries about finance outline for investments in transmission were provided. The share of the different financing sources was requested (both historic and planned). These sources were classified in six types: loans from the European Investment Bank, EU funds, TEN-E funds, Equity, Commercial bank loans (including non-European multilateral agencies) or other sources. Eleven TSOs submitted[21] answers to this question and mainly related to forecasted investment, so that the conclusions that can be derived should not be generalised to all the remaining EU countries..

The arithmetic average of the financing sources shows that around 40 % of the future investment is expected to be financed by equity as well as approximately a 37% through bank loans.

The remaining 23 % would be financed by means of EU funds (9 %), EIB loans (6 %) and other sources (8 %). No funding from TEN-E funds is likely in the near future. TEN-E funding is mostly used for feasibility o pre-feasibility studies.

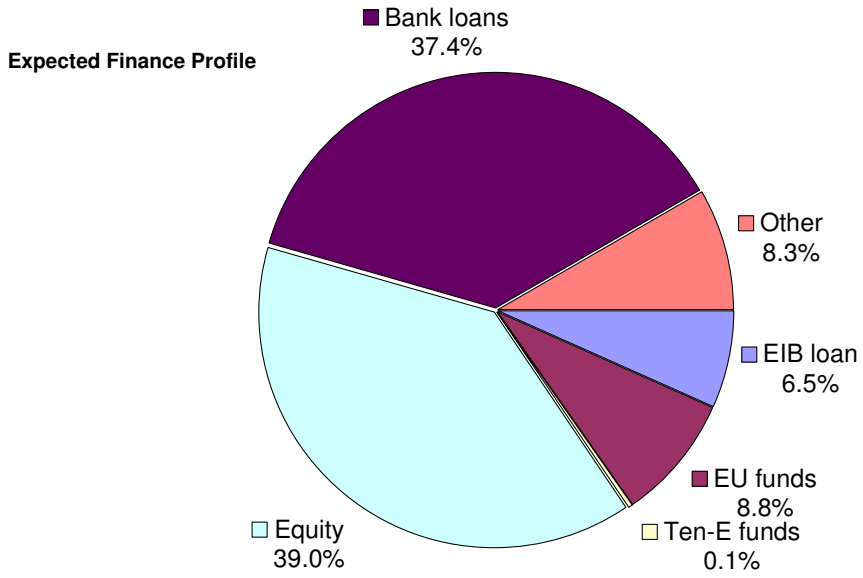


Fig 4.17 - Sharing of the expected financing among different financing sources

[20] There may be biased answers from the TSOs because of the kind of question.

[21] In cases in which only information for a specific project was supplied, this figure was considered as reference for the country. In the cases in which information for several projects was submitted, the weighted average, considering the size of them, was employed as country reference.

4.3.1 Comments on financing electricity projects

The following comments can be drawn from the information collected:

- the large majority of the countries make use of EU loans or other aid instruments to support transmission projects. In most cases even in the absence of EU loans or aid instruments, the same projects would have been executed. However, some countries declared that some projects would not have been executed without EU loans or aid instruments (Italy, North Ireland-UK, Poland, Slovakia, Spain and Turkey). This latter country is heavily dependent on international funding. Not all the new member states declare to have access to loans from EIB or other international financing institutions.
- TEN-Energy funding is used essentially to support feasibility or pre-feasibility studies;
- In a non-negligible number of cases, financing is slowing down investments in transmission network projects. Problem related to financing is particularly critical in small countries (e.g.: Belgium, Slovenia, Slovakia, Poland, Lithuania, Hungary, Northern Ireland –UK) with a small number of customers;
- In general, there are no more difficulties to obtain finance for larger projects compared to smaller ones. In large projects the main problem is the impact of the related costs in the transmission tariffs that must be approved by the national regulators;
- Concerning cross-border projects, it is, in general, more difficult to get their financing with respect to national projects. This because of a series of reasons:
  - there is the need to agree between two System Operators,
  - normally cross-border project requires high investments (e.g.: HVDC links),
  - there is the need to reach an agreement between the regulators for the recovering of the investments in the regulated transmission fees,
  - in some cases there are no common planning standards.
- In some countries, planning responsible highlighted the need for new guarantees or financing mechanisms to speed up the pace of realisation of transmission network projects, but without indicating any proposal.
- As for the cost of capital, no wide differences have been detected between the EU-15 member states and the new EU member states. The values of the WACC (weighted average cost of capital) are in the range 4.5 % to 8.0 %, only in two countries there are higher values (11% in Poland and 9.0 in Serbia-Montenegro), while Lithuania declares a very low value (2%), which is out of the expected range. The cost of debt is in the range of 3.2%÷5.6% with the exception of Sweden, who has a cost of debt of only 2.2% and Hungary (8.5%). By adjusting the data that looked inconsistent or out of the expected ranges, new indexes were derived. The outcomes obtained from the sample under consideration showed a WACC of 7.3 % real pre-tax considering 5.2 % of cost of debt and 8.6 % of cost of equity.
- In some countries (e.g. France and Sweden) all the projects are financed from internal resources (TSO equity) without resorting to external loans.

4.4 Ageing of the electric system and needs for upgrades and repairs

An important phase of the analysis on the status of the electricity grids at the EU levels concerned the examination of the age of the assets to estimate the needs for repairs and replacements entailing additional investments essentially related to maintain the required level of reliability. The analysis has been carried out on one side retrieving information from national System Operator on the average age of their assets and average design life, on the other side by investigating the most recent strategies and solutions to deal with ageing of the system. For the formulation of proposals of possible solutions to mitigate the future investment effort related to the ageing of the system, reference is primarily made to the activities carried out at CIGRE (Conseil International des Grands Réseaux Electriques - International Council of Large Electric Systems).

4.4.1 Mean life of equipment

As a first step the mean asset life of equipment has been examined in order to be able to compare these data with those of the average age of the assets in the EU transmission grids.

Installed equipment is subject to two kinds of phenomena: deterioration and obsolescence that both lead in the time to the end of the life of a component. Deterioration is a process whereby a material degrades to a point where it is no longer able to satisfactorily comply with its original specification. Obsolescence is closely linked to the availability of spare parts and skills of technicians to perform repairs on old equipment. In fact, as the time passes, the ability of manufacturers to support older items of equipment is diminishing and, if spare parts exist, they become expensive. On the basis of the above considerations and feedback from the field (e.g.: failure rate vs age of the component), the mean life of equipment is defined. *Tab 4.19* shows the mean asset life for each component with a description of the reasons for the asset life limitation.

Component	Mean asset life (yr)	Reason for asset life limitation
Circuit breakers (all types)	**38-42**	Rating requirements, fault duty changes maintenance costs, spare obsolescence, mechanical wear, safety, seal problems (SF6 see as "less robust", environmental concern reuse SF6)
Bay Assets (earth switches, disconnectors)	**42**	Rating equipment, maintenance costs, corrosion, mechanical wear
CT's	**39**	Design weaknesses, seal
Transformers	**42**	Design loading, insulating paper and oil degradation, system faults, spares, rating requirements, high temperature, moisture levels
Indoor GIS	**42**	Rating requirements, fault duty changes, maintenance costs, spare obsolescence, mechanical wear, safety, seal problems, environmental concern reuse SF6
Electromechanical protections	**32**	Wear, contact erosion, reliability, temperature extremes, skilled labour, spares, functionality , system design changes
ACSR-OHL "normal environment"	**54**	Climate, environment, corrosion, creep, mechanical fatigue, insulator failures, wind, precipitation, ice loading, pollution levels
ACSR-OHL "heavily polluted environment"	**46**	Degradation of material quality, high temperatures due to loading, joints
Tower (steel lattice)	**63**	Climate, environment, corrosion, maintenance, poor galvanizing, ground condition, concrete spalling, grillage corrosion, steel/concrete junction
Cables (oil filled)	**51**	Environmental concerns (oil leaks), sheath (oil reinforcing tape) corrosion, electrical/thermo-mechanical stress, loading

Tab 4.19 Mean life of equipment used in transmission grids (source [17])

4.4.2 The impact of ageing on the transmission gridThe primary effect of equipment ageing is a declining reliability of the power supply. Decline in reliability is caused by two combined effects. On one side, delayed replacement of operational equipment results in an increasing number of faults, which, in turn, will cause longer repair times. On the other hand, intensifying the exchange of operational equipment will cause the reliability to decline, since the network is temporarily in an unreliable condition due to replacement activities.

Moreover, on certain assets, an increase in age can lead to inefficiencies in operation. This can affect its loading capability and in some cases lead to down-rating

4.4.3 The average age of components in the European transmission systemsLooking at the development of the electric system in Europe during the last 50 years, one can observe that a large portion of the overhead lines

was first installed as early as in the '50s during the recovering period after the end of World War 2 and the subsequent economic boom in Western Europe all along the '60s. A quite significant share of the installations, however, was commissioned in the '70s up to the beginning of the '80s. As an example, *Fig 4.18* shows the investments pattern in Great Britain from the year 1950 to 2002; it can be seen that bulk of the existing system was installed from early '60s. Similar investment patterns are valid also for most of the other European countries including also the new EU member states of East Europe, who developed their assets adopting the design of the IPS/UPS interconnected system.

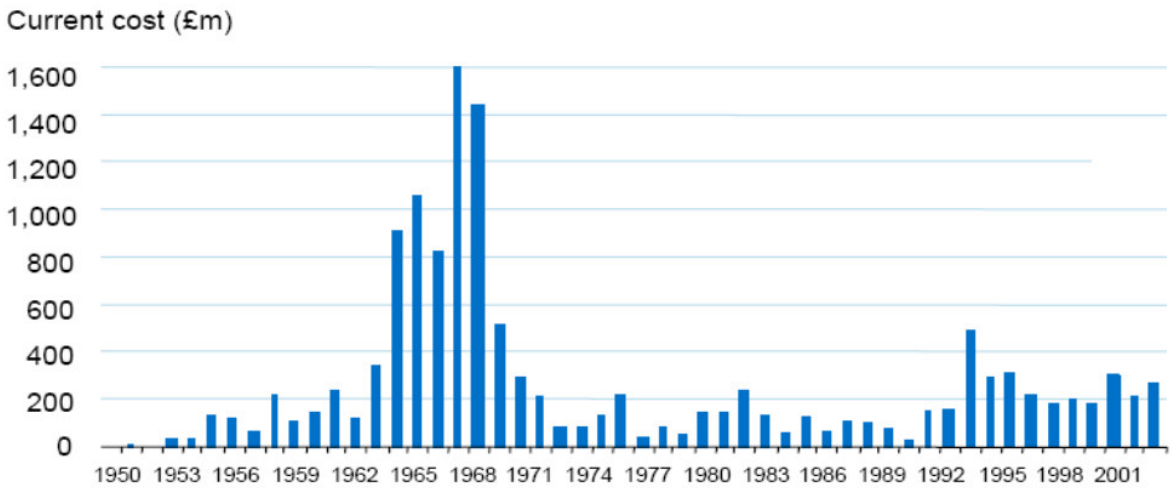


Fig 4.18 – Investments in the network of England and Wales from to '50s onwards (source [15])

Considering that an estimated service life of overhead lines is around 44 to 63 years and the estimated service life for substations is between 38 and 43 years, the age distribution reveals that a large number of devices will enter in the next few years into the critical "time window" and, consequently, needs to undertake investments for replacing old assets may become very urgent in the coming years unless alternative solutions are adopted.

For a more detailed view, a survey among the European System Operator has been launched to get information on the average age of the asset and the average age of the design, which can be relevant to estimate the obsolescence of the components. In some cases, the breakdown of the age by category of assets has been retrieved. From the data supplied by System Operators, it is confirmed the old average age of the assets (see *Tab 4.20*), generally in the range 20-40 years. The 220 kV level is very old (40-47 years); in some cases it is going to be progressively dismantled (e.g.: Italy) or reconstructed step by step (e.g.: Czech Rep.). Ireland, Cyprus, Slovakia and Greece (400 kV grid and related s/s) are the countries showing the lowest average age (around 20 years).

Transmission System Age (Years)		
COUNTRY	Average Age	Average Design Life
BELGIUM (BE)	28	
CYPRUS (CY)	15	20
CZECH REP. 400 kV (CZ)	30	40
CZECH REP. 220 kV (CZ)	47	
ESTONIA (EE)	25/31	27/50
FINLAND (FI)	26	50
GREAT BRITAIN-Lines (UK)	30/40	35/55
GREAT BRITAIN – S/S (UK)	30/45	35/55
GREECE-400 kV (GR)	20	
GREECE-150 kV (GR)	28	
GREECE-Transf. (GR)	19	30
HUNGARY (HU)	26	28/35
IRELAND (IE)	20	40
ITALY (IT)	30/40	60/80
LATVIA (LV)	45	50
LITHUANIA (LT)	24	32
NETHERLANDS (NL)	28	50/30
NORTH IRELAND (UK)	44	40
NORWAY-Lines (NO)	30	40/70
NORWAY-S/S (NO)	25	40
SERBIA and M. (CS)	30	30
SLOVAKIA (SK)	17	
SLOVENIA (SI)	30	40
SPAIN (SP)		40
SWEDEN (SE)	35	

Tab 4.20 - Average age and average design life in some EU countries

4.4.4 Strategies and solutions to mitigate the effort in investment for component replacement

Considering the average age of the equipment and its expected lifetime, without any appropriate actions an enormous demand for replacements will have to be met in the coming years, as shown in *Fig 4.19*, who depicts in a qualitative way the potential trend for replacing switchgear components.

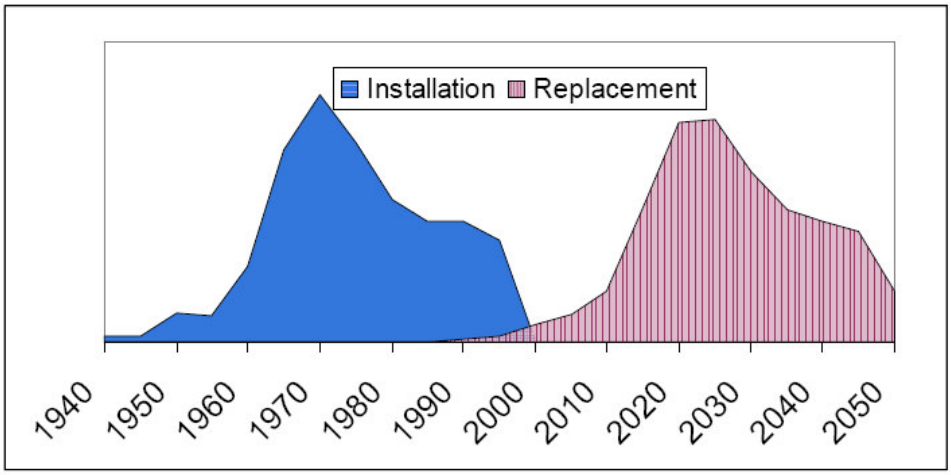


Fig 4.19 – Installation and replacement distribution for switchgears (source [16])

The strategies and solutions to deal with ageing can be based on life-extension techniques. Life-extension strategies can be achieved by different solutions:

- Increased maintenance;
- Increased monitoring;
- "wait and see"
- action when breakdown occurs.

Before adopting a life extension strategy, the assessment of cost and resources implications as well as the risks is necessary. In general, extension of the component life can be achieved by implementing an "optimal maintenance policy", which balances at the best the inherent increase of risk, when operating with aged components, with the costs for replacement/renewable/upgrading/re-design. Maintenance policies can be classified as follows [17].

4.5 Concluding remarks on current status of electricity grids and past investments

The European power transmission grid is composed by seven power pools (UCTE, NORDEL, England-Wales-Scotland, the Irish system, the DC Baltija pool, IPS/UPS, Turkey). These power pools are weakly interconnected each other through HVDC links, with the exception of DC Baltija, which is synchronously and strongly interconnected with the IPS/UPS pool of the Russian Federation and the other CIS countries. The UCTE power pool, including the Central and Western European Countries plus the westernmost region of the Ukraine, is synchronously interconnected with Morocco, Algeria and Tunisia from 1997. This synchronous interconnection will be likely extended eastward up to Syria in the near future. Turkey, at his turn, has already made the application for UCTE membership: the study on the technical feasibility of a synchronous interconnection between UCTE and Turkey is in progress. Two EU member states are operating their power systems in isolated way: Cyprus and Malta. At the moment there are no projects of interconnection of these systems with the mainland. The total consumption in the EU30 and Western Balkan countries, which are members of the UCTE with the exception of Albania, has been around 3300 TWh in the year 2003 with an installed power exceeding 800 GW.

Cross-border energy exchanges have been increasing in these last years, however, in some cut-sets they are limited due to the insufficient transmission capacity. In the UCTE pool the exchanged energy is around 12% of the total consumption, while in NORDEL this ratio attains 25% and in DC Baltija it is about 47%.

Concerning the investments on the power transmission grid, in the EU 30 they have been around 3.2 billion € in the year 2003 and increased to slightly less than 3.4 billion € in 2004, which means an average yearly investment of 16.5 k€/km-eq in 2003 and 17.5 k€/km-eq in 2004 referring the expenditure to the length of the transmission lines "normalised" at the transfer capacity of 400 kV lines. The analysis by homogenous regions shows that:

- in the Eastern Baltic countries (Estonia, Latvia and Lithuania) the investments in the year 2004 have been 102 M€. From 1996, yearly investments are in the range of 10÷20 k€/km-eq with the exception of Lithuania that is doing a bigger and increasing effort in renewal and reconstruction of substations;
- in Sweden, Finland and Norway investments have been around 214 M€ in 2004. They turn out to be rather low (<10 k€/km-eq) in comparison to the extension of their grids, even though Norway is showing a rapid increase starting from the year 2002. Similarly, Western Denmark starting from 2003 undertook an intensive plan of investments (≈90 k€/km-eq) on the 400 kV transmission grid and a similar level is scheduled for the next 10 years with a peak in the years 2009-2011;
- in the continental EU countries investments in 2004 have been about 2.1 billion €. In the period under examination yearly investments have been in the range 10÷30 k€/km-eq with some exceptions:
  - Poland, with investments in the range 45÷85 k€/km-eq, concentrated mainly on substations;
  - Slovenia, characterised by high investments (30÷40 k€/km-eq). This country has to face a strong increase of wheeled power from North-East to South-West, in addition to the growth of the internal load;
  - Czech Republic and Slovakia, having investments around or below 10 k€/km-eq;
- in the candidate countries of South-Eastern Europe (Bulgaria, Romania and Turkey), investments are quite poor (204 M€ in 2004) in relationship to the extension of their national grids. With the exception of Romania, investment level in Bulgaria and Turkey are lower than 10 k€/km-eq. Very low level of

investments have been experienced also in Serbia-Montenegro (only 2.5 M€ in 2004) with a sharp decline of investments starting from the year 2000;

- looking at the British Islands and Cyprus, the investment level is in the range 10÷20 k€/km-eq in North Ireland, in line with the Continental Europe countries, high investment levels are experienced in England and Wales (30÷40 k€/km-eq) and very high investment levels in Ireland and Cyprus (>50 k€/km-eq in the last years). In absolute terms the investments in the year 2004 have been: 546 M€ in England-Wales-North Ireland, 180 M€ in Ireland and 17.7 M€ in Cyprus.

The pattern of investments from 1996 to 2004 shows an increasing level of expenditure, particularly in Great Britain, Ireland, Norway, Portugal, Romania and Spain. Two countries, France and Poland, showed a decline in the investments. However, it is worth mentioning that Poland has high investments levels all over the period under examination comparing the absolute values with the grid extension. In general, planning responsible (TSO or TransCo) highlighted that the on-going implementation of the European IEM is not a hinder for the investments. On the contrary, in some cases (e.g.: Netherlands, Lithuania, Italy, Spain) projects have been motivated by the need of improving the functioning of the internal market through the increase of TTC and the relief or mitigation of congestion. Particularly in NORDEL, the main focus since 1992 has been to increase the capacity between the Nordic countries to improve the Nordic electricity market. On the other hand, all planning responsible highlighted difficulties in the construction of new infrastructures both inside the country and across the borders. Obstacles can be summarised as follows:

- difficulties in finding the right-of-ways
- slow procedures to get the necessary authorisations
- general opposition of the local population
- in some cases, further delays are caused by need of co-ordination between TSOs for international lines;
- differences in regulatory practice and TSO objectives.

All the above factors cause a remarkable mismatch in the time between the planned investments and those that are really spent.

Main reasons for investments have been: lack of capacity, improving security of supply and fostering the implementation of the electricity market. Furthermore, one emerging factor prompting additional investments is related to the ageing of the system. The mean life of high voltage equipment is between 30 and 50 years, whereas the information technology has a shorter lifetime of about 10-25 years. From the survey carried out at the TSOs the average age of the exiting infrastructure is about 30-40 and it is approaching its expected end of life with very few exceptions such as Cyprus and the 400 kV lines and s/s in Greece. Comparing the mean asset design life of equipment with the average age of the network assets of the European power pools, a substantial need for replacement, refurbishment, upgrade and re-design is expected in the next two decades. All the TSOs stressed that the network they manage requires upgrades and repairs and already now a remarkable part of investments are related to maintaining the present grid and substations. This happens not only in the Eastern European countries but also in the West (e.g.: in western Denmark 1/3 of investments are devoted to maintain the present grid and s/s situation). The process of replacement of network components, refurbishment, upgrade and re-design shall be undertaken as a continuous action to warrant an acceptable level of security and reliability in the coming years.

To smooth the need for investments while ensuring the requested reliability level suitable measures shall be adopted. These are mainly based on life extension techniques.

Concerning the financing of the power transmission projects, the following conclusions can be drawn from the information collected:

- the large majority of the countries make use of EU loans or other aid instruments to support transmission projects;
- in most cases even in the absence of EU loans or aid instruments, the same projects would have been executed. However, some countries declared that some projects would not have been executed without EU loans or aid instruments (Italy, North Ireland-UK, Poland, Slovakia and Turkey). This latter country is heavily dependent on international funding. Not all the new member states declares to have access to loans from EIB or other international financing institutions;
- TEN-Energy funding is used essentially to support feasibility or pre-feasibility studies;
- In a non-negligible number of cases, financing is slowing down investments in transmission network projects. Problems related to financing are particularly critical in small countries (e.g.: Belgium, Slovenia, Slovakia, Poland, Lithuania, Hungary, Northern Ireland –UK) with a small number of customers;
- In some countries (e.g. France and Sweden) all the projects are financed from internal resources (TSO equity) without resorting to external loans;
- In general, there are no more difficulties to obtain funding for larger projects compared to smaller ones. In large projects the main problem is the impact of the related costs in the transmission tariffs that must be approved by the national regulators;
- it is, in general, more difficult to get financing for cross-border projects with respect to national projects, because of a series of reasons such as: need to agree between two or more System Operators and Regulators; in some cases there are no common planning standards; normally, cross-border projects requires higher investments;
- as for the cost of capital, no wide differences have been detected between the EU-15 member states and the new EU member states. The values of the WACC (weighted average cost of capital) is in the range 4.5 % to 8.0 %, only in two countries there are higher values (11% in Poland and 9.0 in Serbia-Montenegro), while Lithuania declares a very low value (2%). The cost of debt is in the range of 3.2%÷5.6% with the exception of Sweden, who has a cost of debt of only 2.2% and Hungary (8.5%). By adjusting the data that looked inconsistent or out of the expected ranges, new indexes were derived. The outcomes obtained from the sample under consideration showed a WACC of 7.3 % real pre-tax considering 5.2 % of cost of debt and 8.6 % of cost of equity.

4.6 Medium and long term investments patterns on electricity

4.6.1 Introduction

This section addresses the optimal future investment patterns in electrical transmission and compares them to the investments already scheduled by TSOs. To that purpose, a comprehensive analysis of the cross-border transmission development that will be needed in the future was carried out using a mathematical model. This model computes the necessary amount of grid investments both in the medium and the long run. Accordingly, a "*Baseline scenario*" describing the future evolution of the electricity demand, the generation mix and fuel costs is taken as an input. This scenario is in line with the one used to evaluate the needs for new gas infrastructures.

The main part of the study is focused on cross-border interconnections. However, we also provide an estimate of the total amount of investments in transmission grids that will be needed within each country as well as the transmission investments required for connecting off-shore generation. Hence, a comprehensive picture is drawn of the transmission investments that will be needed in Europe over the next 19 years.

The section is organized as follows. First, the expected development of cross border transmission is provided in section 4.6.2. Investments associated to the connection of offshore wind generation are dealt with in section 4.6.3. Section 4.6.4 includes an estimate of the expansion of internal transmission required, thus providing some information on the total transmission investment needs in the mid and long term. Finally, the investments plans provided by TSOs are displayed in sect. 4.6.5.

4.6.2 Expected development of cross-border transmission

This section has been structured in different sub-sections that are listed below:

- Section 4.6.2.1 displays the planned and already decided grid reinforcements. Information has been obtained from the answers to questionnaires sent to the electricity TSOs. Answers by TSOs were compared to the information contained in the latest documents issued by the European Commission and the UCTE as well as in other documents on energy interconnections prepared by dedicated Working Groups such as the joint EURELECTRIC-UCTE SYSTINT-SISTMED Working Group.
- Section 4.6.2.2 provides a theoretical background about the different alternatives and difficulties encountered when developing a grid investment plan at regional level.
- Sections 4.6.2.3 and 4.6.2.4 provide technical details on the mathematical model used for cross border transmission planning.
- Section 4.6.2.5 summarizes the results produced by our model for the optimization of the grid expansion.

4.6.2.1 Display of medium term and long term investment patterns

Using the information provided by the different TSOs of the enlarged European Union, this section presents an overview of the mid and long term grid investments that the TSOs plan to undertake within their transmission systems to enhance the interconnection capacity between countries. These enhancements shall facilitate the electricity trade within the EU. In addition, we summarize the results of several other studies on the development of energy interconnections in order to compare these results to the ones yielded by our model. To this purpose, reference is made to the following documents:

- **Trans-European Energy Networks TEN-E priority projects**, which defines nine priority axes for investments in transmission grids 'where priority should be given to upgrading/extension projects that have been identified and agreed by the EU's institutions'
- **UCTE system adequacy forecast 2004-2015**, where the main developments of international interconnections over the period from 2004 to 2015 are identified and the expected increase in electricity exchange capacity is displayed.
- **NORDIC GRID Master Plan 2002** that investigates important cross-sections within the NordPool and suggests possible reinforcements to transmission links.
- "**Analysis of the network capacities and possible congestion of the electricity transmission networks within the accession countries**", a study performed by KEMA, which investigates possible congestion among the ten new accession countries of the EU plus the three candidate countries Bulgaria, Romania and Turkey.

4.6.2.1.1 TSOs plans

According to the answers received by TSOs, a series of cross-border interconnections are scheduled to be reinforced. *Tab 4.21* summarizes the cross-border interconnectors expected to be built. All the information collected has been included in the table. Blank cells indicate that no investment projects were specified.

Country	Border	Substation From	Substation To	Expected year of commissioning	Expected costs [M€]
Belgium	Belgium-France	Avelgem	Avelin	2005	15.5
		Monceau	Chooz	2006	12.9
Czech Republic	Czech Rep.-Germany	Slavětice	Dürenrohr	2006	3.7
Estonia	Finland	Tallin	Helsinki	2007	110
France	Not specified	-	-	2005 - 2010	30.0/year
Greece	Greece - Turkey	Philippi	Babaeski	2006	55.0
Hungary	Hungary - Slovenia	Hévíz	Cirkovce	2007	-
	Hungary - Romania	Békéscsaba	Oradea	2008	10
	Hungary - Slovakia	Sajóivánka	Rimavska Sobota	2008	20
	Hungary - Croatia	Pécs	Ernestinovo	2009	19.4
	Hungary - Slovakia	Szombathely	Pod.Biskupice	2010	10
	Hungary - Romania	Békéscsaba	Arad	2010	10
Ireland	-	-	-	-	-
Italy	Italy - France	Piossasco	Grand Ile	after 2010	30.6
	Italy – Austria	To be determined	Linez	after 2010	50
	Italy – Slovenia	Udine Ovest –	Okroglo	2009	28
Latvia	Latvia - Estonia	Sindi	TEC-2	after 2015	48
Lithuania	Lithuania - Poland	Kruonis	Alytus	2008-2009	143
Netherlands	-	-	-	-	-
Poland	-	-	-	-	-
Slovenia	Slovenia - Hungary	Cirkovce	Hevitz	Construction begins 2007	37
	Slovenia- Italy	Okroglo –	Udine Ovest	Construction begins 2008	38
Sweden	Sweden - Norway	Järpstr	Nea	2009	38
	Sweden - Finland	Finnböle	Rauma	2010	260
Turkey	-	-	-	-	-
United Kingdom	Great Britain – Netherlands (Britned Interconnector)	Grain Substation, Southeast (England)	Maasvlakte, (Rotterdam)	2008	300-400
	Great Britain - Norway (North Sea Interconnector)	Hawthorn Pit Substation (England)	Kvilldal, (Southwest Norway)	2010	854

Tab 4.21 – Foreseen Interconnections reinforcement according to TSOs

According to the collected information, the cost of total expected investments in international interconnectors over different periods of time is shown in *Tab 4.22*. It must be noted that the most significant contribution comes from two planned submarine interconnectors to link the UK both to the Netherlands and Norway.

Accumulated amount of expected investments on interconnectors [M€]			
	Up to 2007	*Up to 2010*	*Up to 2015*
UK submarine interconnectors included	211.2	2043.6	2172.2
Without UK submarine interconnectors	211.2	1050.8	1179.4

Tab 4.22 -Foreseen Investments on interconnectors according to TSOs

4.6.2.1.2 Trans-European Energy Networks TEN-E priority projects

- European Union's institutions have agreed a number of axes where priority should be given to upgrading/extension projects. These axes correspond to *"certain key transmission routes, which need to be strengthened to ensure that the internal market for energy functions efficiently and/or to secure supplies of energy to the Union from third countries"*. A recall of these priority axes has been made in sect. 2.1.

4.6.2.1.3 UCTE system adequacy forecast 2005-2015

According to UCTE system adequacy forecast 2005-2015 report, "*noticeable increases of exchange capacities are expected according to the development of interconnections:*

- *Between main UCTE and Spain+Portugal (+1200 MW in 2007)*
- *Between main UCTE and Italy (+800 MW in 2007, +1600 MW in 2010)*
- *Between Spain + Portugal and Morocco (+ 400 MW in 2007)*
- *Between JIEL*[22] *+Greece and Turkey (+500 MW in 2010)*
- *Between Romania & Bulgaria and IPS/UPS (+1100 MW in 2009)*"

The main grid developments in UCTE countries over the period 2005 to 2015 are displayed in *Tab 4.23*.

[22] JIEL : bloc composed by Serbia-Montenegro and FYR of Macedonia

Line or equipment	Voltage level	Date of commissioning	Cross-border
Avelgem – Avelin – Mastaing (second circuit)	400 kV	2005	B-F
Chooz – Jamiolle – Monceau	225/150 kV	2006	B Fr
PST Zandvliet + Kinrooi	400 kV	2006	B-NL
Upgrade of line Audorf – Kasso - **+500 MVA**		2008	D - DK
Upgrade of 400 kV line Isar – St Peter **+ 1800 MVA**		>2010	D - A
Double AC line Thaur – Bressanone through Brenner Basis Tunnel	400 kV	2015	A – I
Single line Nauders – Curon/Glorenza		> 2010	A - I
PST Hagenwerder - Mikulowa		>2010	D - PL
2nd line Slavetice - Durnrohr	400 kV	2006	CZ - A
Lienz – Cordignano Line	400 kV	2008	A -I
Double AC tie-line Robbia – San Fiorano	400 kV	2005	CH -I
2x400 kV Okroglo - Udine	400 kV	2011	SLO - I
Cirkovce – Pince Line	400 kV	2010	SLO - H
OHL Nadab –Bekescsaba	400 kV	2007	RO -H
Single line	400 kV	2010	SCG - H
Single line Podgorica – Tirana	400 kV	2007	SCG - AL
Single line Nis – Skopje	400 kV	2007	SCG - FYROM
Single line Mitrovica - Ugljevic	400 kV	2007	SCG - BA
Stip-Cervena Mogila	400kV	2005	FYROM – BG
Bitola-Lerin Line Meliti –Bitola	400kV 400kV	2006 2006	FYROM – GR
Bitola - Zemjak	400kV	2015	FYROM – AL
Vrutok-Bureli	220kV	2006	FYROM - AL
Line Philippi – Turkey	400 kV	2006	GR -Turkey
OHL Suceava – Balti	400 kV	2009	RO - MD
France – Spain : eastern reinforcement	400 kV	2007	F -E
BALBOA – ALQUEVA line	400 kV	2004 - 2005	E -P
Nadab - Bekescsaba	400 kV	2007	H-HR
Line Ernestinovo - Pecs	400 kV	2007 - 2008	HR-H
Line Valdigem – Douro Intal - Aldeadavilla	400 kV	2010	E - P
ESTRECHO-FARDIOUA (2nd CIRCUIT), Interconnection	400 kV	2005	E - Morocco

Tab 4.23 – Main grid developments in UCTE countries over the period 2005 to 2015 (source "UCTE System Adequacy Forecast 2005-2015 report")

4.6.2.1.4 NORDIC GRID Master Plan 2002

Based on a selected number of scenarios representing peak load and extreme situations, the "Nordic Grid Master Plan 2002" assesses the transmission grid adequacy of the NORDEL. The study covers the period of time up to the year 2010. Important north-south and south-north cross sections identified in the report are displayed in *Fig 4.20*.

The Grid Master plan "*identifies important cross-sections within the NORDEL area in which high cost benefits have been found (…) attaching priority to the further study of the following cross sections:*

- *An increase in the transmission capacity of the HVDC interconnection between Denmark West and Norway South through the establishment of an additional interconnection should be considered.*
- *Expansion through the establishment of an HVDC interconnection from Norway South to Denmark East or Sweden South should be considered.*
- *An increase in the transmission capacity of the HVDC interconnection between Denmark West and Central Sweden through the establishment of an additional interconnection should be considered.*

- *An increase in the transmission capacity on the Hasle cross-section between Norway East and Central Sweden should be considered.*
- *An increase in the transmission capacity between Central Sweden and Central Norway should be considered.*
- *Any need for additional initiatives aimed at improving the transmission capacity on internal Swedish cross-sections between Central Sweden and Sweden South should be established.*"

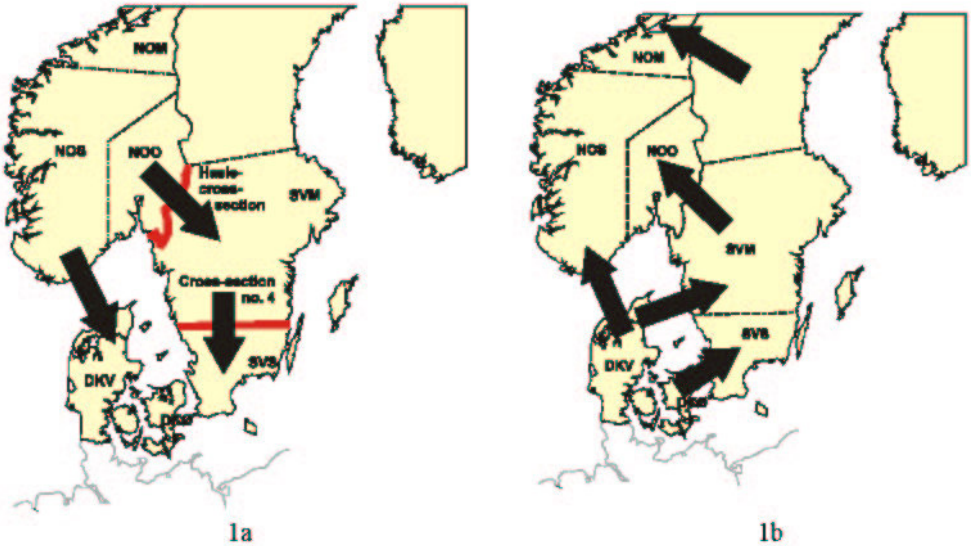


Fig 4.20 – High-load cross-sections within the NORDEL area in 2005.
1a) For southbound transports: Cross-section no. 4 in Sweden and the Hasle cross-section.
1b) For northbound transports. (source "Nordic Grid Master Plan 2002")

Concerning interconnections between the NORDEL region and others, the Nordic Grid Master Plan report identifies bottlenecks on the border between:

- Poland-Sweden, where grid constraints exist in Poland.
- Germany-Sweden, where grid constraints exist in Germany.
- Denmark West-Germany, where grid constraints exist in Germany for exports and in Denmark West for imports."

Other interconnections, which may play an important role regarding the increase of the import capacity into the NORDEL region, are:

- An interconnection between Norway and the UK.
- An interconnection between Finland and Estonia.
- An interconnection between Norway and Holland.
- The expansion of Kontek between Denmark East and Germany.
- The further expansion of the interconnection between Finland and Russia."

4.6.2.1.5 Analysis of the network capacities and possible congestion of the electricity transmission networks within the accession countries

The study "*Analysis of the network capacities and possible congestion of the electricity transmission networks within the accession countries*", commissioned by the E.C. DG Energy and Transport and finished in 2005, focuses on the analysis of congestion within the ten new accession countries and the three candidate countries of

Bulgaria, Romania and Turkey as well as between these countries and the Central-Western part of Europe; the analysis covered a time horizon up to 2020.
According to the study, the main congested borders are:
"-From Central Europe (Poland, Czech Republic, Slovakia) to Germany, Austria and Hungary
-From Austria and Slovenia to Italy"
The study defines three groups of advisable grid reinforcements according to their priority:

- **High priority group**: corresponds to the upgrading of the internal transmission grids of Poland and Austria, and the cross-border interconnections Poland-Slovakia, Austria-Czech Republic, Slovakia-Hungary, Slovenia-Hungary, Hungary-Serbia, Hungary-Romania and Bulgaria-Greece.
- **Medium priority group**: upgrading of the inter-connections between Lithuania-Poland, Slovenia-Italy and Greece-Turkey.
- **Group that requires further study**: upgrading of the inter-connections between Germany-Poland and Austria-Slovenia.

4.6.2.2 Methodology for the analysis of the required development of cross-border transmission capacity

This section addresses the methodology used to identify the investments in cross-border electricity transmission capacity that are most useful in order to optimize the trading of energy among the EU countries.
The expansion of cross-border transmission capacity is closely linked to the existing and envisaged generation pattern. The generation pattern depends both on the existing and future generation units as well as the variable costs of these plants. We have used the database of the PRIMES model as a reference for the expansion of generation in Europe in the medium and long term. Using a simplified optimisation model is the only way to define reasonable patterns of expansion of the cross-border transmission capacity in the region.
The adopted model aims at minimizing the investment and operation costs required to meet the system demand during the planning horizon. In principle, the decision variables in this model are the amounts that should be invested in cross-border transmission capacity in the different corridors. However, if necessary, the model also considers the possibility of installing new generation capacity beyond what is specified in the PRIMES expansion program.
Moreover, sensitivities are computed in order to assess whether it is efficient to replace some of the investments in generation specified in the PRIMES program with other investments in generation or cross-border transmission facilities.
Last but not least, we also analyze the reason why we used a simplified optimization model. Such a model represents a satisfactory trade-off between accuracy and complexity of a more sophisticated model, which would require some input data that were not available in the project, and the simplicity and limitations of just performing a conceptual analysis. All analyses were carried out for the EU-30 countries.

4.6.2.2.1 Development of an indicative investment plan

As explained below, new transmission lines may be proposed by a centralized entity in charge of expanding the grid, or they may be the result of the initiative of private promoters. Lines built by a centralized entity whose costs are recovered from the grid users are known as *regulated lines* whereas those built by private promoters are called *investments at risk*.
The development of an investment plan for a large-scale system is a challenging and very complex task. Besides being a problem of a large size, much of the information required in the process is not available since it refers to the future conditions in the system (load and generation pattern, etc).

Planning the expansion of the transmission grid has become much more challenging in the new deregulated environment. Investment decisions in generation and transmission are closely interrelated. In fact, transmission and generation should be considered to be substitutes of one another in many cases. However, investment decisions in generation are no longer the responsibility of a central planner but of independent investors whose siting alternatives depend on the availability of the required transmission facilities. Within the context of this study, generation expansion is provided as an input to our model. An estimate of the future investments in generation facilities in Europe has been obtained from the PRIMES report.

Both planned investments and investments at risk should pass the regulatory test. The regulatory test is a set of rules aimed at computing the benefits and costs associated with investment projects in the transmission grid. It serves two main purposes. On the one hand, it may help the System Operators, or the entities in charge of planning the expansion of the grid, to identify the most efficient investment projects. On the other hand, it provides the regulatory authorities with a tool for deciding whether a proposed investment should be authorized.

In the traditional regulatory framework, grid investments were thought to be profitable if the reduction in the system operation costs yielded by the investment project was higher than the investment cost.

Like any other optimisation problem, the design of an investment plan can be tackled using two different techniques: mathematical programming or heuristic algorithms. The mathematical programming relies on well-studied algorithms, based on the theory of operations research, to solve an optimization problem, which consists of an objective function to maximize or minimize and a set of constraints. This objective function measures either the increase in the global social welfare or the cost of supplying the electricity demand. Heuristic algorithms are normally iterative and make use of non-proven methods to arrive at the optimum solution. In fact, they cannot guarantee obtaining the global optimal solution unless all the possible solutions have been explored. They need a method to compute the benefit associated with a particular investment and may or may not use simulation to compute this benefit.

Mathematical programming guarantees convergence and provides the global optimum of linear problems with continuous variables. Some non-linear problems with integer variables can also be solved.

The regulatory test must take into account benefits of all types: those related to the efficiency of the economic dispatch, reliability benefits, the improvement in the management of the generation reserve of the region, etc. In practice, only those benefits related to the improvement in the economic efficiency of the dispatch are included in the objective function. Reliability is taken into account forcing the dispatch to comply with certain restrictions representing security rules such as the 'n-1' and 'n-2' rules. Optimizing the management of the generation reserve at regional level has never been an objective since most countries have traditionally opted to guarantee, to the maximum extent possible, that they have enough generation capacity to serve the local load thus avoiding being dependent on others. As mentioned above, a number of possible future scenarios are studied when identifying the most beneficial investments.

4.6.2.2.2 Definition of the number and identity of the scenarios to use in the study

Before defining reinforcements to the transmission grid in the medium and long term we need to decide how many scenarios are necessary to assess the impact of possible network investments and how to choose these scenarios. The European Commission has supplied the scenarios considered in the study so this task is not relevant in this case though it would be if we were in charge of planning the expansion of the grid.

Strictly speaking, the set of scenarios considered should cover all the operating conditions that may occur. The relevant information in each scenario is the amount of generation capacity of each type available in each zone, the pattern of load and the mechanism applied to solve congestion in the system or carry out the generation dispatch.

4.6.2.2.3 The congestion management mechanism employed in the region

One first selection must be made between bilateral or coordinated methods. We assumed that the most efficient solution will be adopted in the long term and planned the expansion of the grid accordingly. The adoption, due to political considerations, of other less efficient solutions, such as bilateral agreements, may cause a non-optimal expansion of generation and the transmission grid in the region.

4.6.2.2.4 Using a simplified model of the European grid

A simplified network model of the regional grid may consist of a set of 'uniform' non-congested areas, each represented by a single node, and a set of likely to be congested corridors that connect such non-congested areas among themselves. Additionally, we need aggregated economic information on the generation and demand within each area. This information should include the generation mix that is expected to exist in the future within each of the areas.

If we wanted to consider the physics laws that determine the paths followed by the power on the grid we would need to compute or obtain electrical parameters for each of the corridors. Otherwise, we would have to accept the hypothesis that power flows through the lines like a fluid in a pipeline system. This is of course not true but it may be a reasonable assumption considering the very simplified nature of the study. A list of the main simplifications that must be accepted to create an "equivalent" network model follows:

- There are sets of nodes and lines (zones or areas in the system) that can be represented with enough accuracy using only one node since no major congestion exists within these areas. These are called Single Price Areas (SPAs) because the energy price computed for all the nodes within each area is the same.
- Parallel or loop flows are neglected since electrical parameters of cross-border corridors are not represented.
- The number and location of SPAs in the system are not affected by the installation of new lines.

4.6.2.2.5 Description of the solution implemented in the context of the project

The European electric system has been modelled as a transport or 'pipeline' system where nodes represent national systems that are interconnected by links. These links take the form of 'pipelines' or transport corridors that enable an amount of power exchanges among the different nodes below a specified limit. The transmission capacity of these corridors was derived from the physical interconnection capacity that exists between countries. Capacities actually used may be smaller than the total transmission capacity between countries to reflect the fact that congestion may happen within the countries.

Fig 4.21 shows the simplified representation of the European grid that was used as an input to our model in order to identify those grid reinforcements that will be most beneficial for the system in the future. Single nodes were used to represent each country. Nodes were linked by equivalent electrical corridors. Therefore, reinforcing the interconnection capacity between two countries meant increasing the capacity of the corresponding corridor. In reality, reinforcing the interconnection between two countries normally involves building both new cross-border and internal lines. However, this does not necessarily mean that we need to reinforce the whole transmission grid lying between the two geographical centres of both countries.

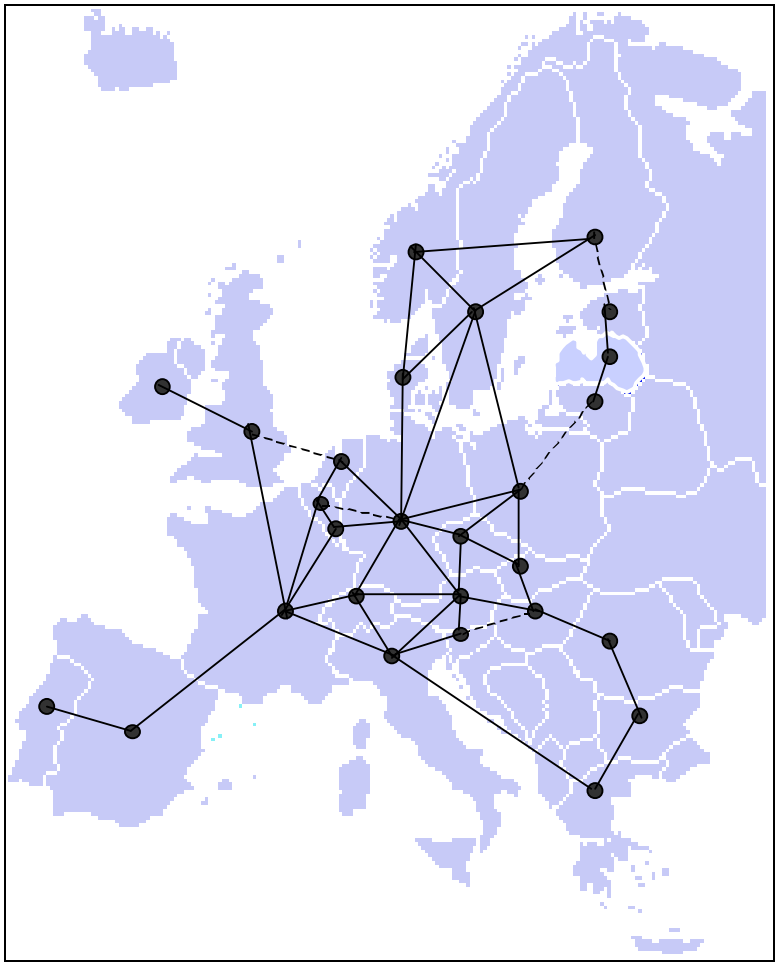


Fig 4.21 – Simplified representation of the European transmission system originally used in the study

4.6.2.3 Description of the model used

This section presents the formulation of the optimization problem solved by our model in order to define an optimal expansion plan for the European grid.

4.6.2.3.1 Basic Assumptions

The following simplifying assumptions have been made when building the model:

- Each country can be represented as a SPA;
- Each cross-border corridor has a transmission capacity that is independent of flows in other corridors;
- All the countries have competitive electricity markets;
- TSOs have implemented an efficient congestion management method;
- All the market participants expect the same rate of return on their investments in generation and transmission facilities;
- Capacity of the corridors can be represented as a continuous variable.

The two first assumptions were already analyzed in the previous sections. Here we analyze the remaining ones.

- **Competitive markets: equivalence between the bilateral and pool models:**

The model assumes that a centralized dispatch, i.e. a mandatory pool, is in place. However, presently and during the planning horizon cross-border flows will mainly result from bilateral physical transactions. One or several balancing markets will resolve imbalances resulting from unexpected outages or changes in existing conditions.

It may be thought that the outcome of a pool market differs from that of a bilateral market. However, Smeers et al. demonstrated [19] that if some assumptions hold both structures are equivalent: "*The relation between the bilateral and pool organisations of the market received considerable attention in the literature. … . The general conclusion of this discussion is that the two systems are equivalent when there is no market power*". This means that prices and quantities produced by each generation unit are the same whether the market is organized as a pool or it is based on bilateral transactions. Therefore, it is possible to replicate the results of a bilateral market simulating the operation of a mandatory pool.

- **TSOs have implemented an efficient congestion management methodology:**

It is reasonable to assume that EU and national regulations will converge to an efficient congestion management scheme, i.e. one that optimizes the use of available transmission capacity. Efficient congestion management may be achieved either through a centralized dispatch that takes into consideration the relevant transmission constraints, or through a market for transmission rights that entitle their holder either to i) inject some power in a node/SPA of the regional network and to withdraw the same amount in another node/SPA; or to ii) receive an amount equal to the price differential between such nodes/SPAs times the transported power. The European market mainly is a bilateral one. Thus, the establishment of a market for rights seems to be the more reasonable option. Assuming the existence of some kind of efficient congestion management mechanism is necessary in order to prove the equivalence between the bilateral and pool models.

- **All the market participants expect the same rate of return on their investments in generation and transmission:**

If the expected rate of return is the same for all the market participants and the market is competitive, it is possible to demonstrate that decisions resulting from the centralized planning and operation of the system (comprising the expansion plan as well as the determination of prices and the production level of plants) are coincident with the decisions made by private investors. Therefore, we can replicate the competitive market equilibrium using the results of centralized planning.

- **The capacity of the corridors can be represented as a continuous variable:**

This assumption is useful in order to make the model simpler but is also necessary for the previous assumption to be valid.

4.6.2.3.2 Handling of demand, generation and cross-border data

1. **Load modelling**

Demand is represented using an annual load-duration curve comprised of several blocks of uniform load.

2. **Generation units**

The existing generation capacity is grouped by generation type: (1) Nuclear; (2) Coal fired steam turbines; (3) Oil fired steam turbines; (4) Gas fired steam turbines; (5) Oil fired gas turbines; (6) Gas fired gas turbines; (7) Gas fired combined cycles; (8) Hydro; (9) Wind; (10) Pumping storage. The characteristics of each type of unit are explained next:

- Peak units are not subject to any type of constraint.
- Base plants must produce during the base block of hours at least a certain fraction of their total annual output.

- Hydro plants: their total power production is estimated from the average amount of power they generate. At least a fraction of their total energy output must be produced in the base block of hours.
- Wind units: three different states exist: (i) maximum production with probability p1; (ii) medium production with probability p2; (iii) zero production with probability (1-p1-p2).
- Pumping storage: the amount of energy produced in the peak hours must be equal to the amount of energy consumed by the pumping process times the pumping cycle efficiency. Pumping takes place in the base hours.

Although it would have been desirable to use a more detailed model of the existing generation units, we could not obtain more information than that included in the PRIMES report. *Tab 4.24* summarises the main assumptions made related to thermal plants.

Technology	Gross Efficiency [%]	Investment Cost [€/kW]	Carbon emissions rate [ton/GWh]	O&M variable cost [€/MWh]
Hard coal steam turbine	39%	1400	0.90	3.5
Brown coal steam turbine	39%	1400	1.10	3.5
Fuel oil steam turbine	39%	1400	0.75	3.5
CCGT	57%	550	0.33	2.5
Open cycles GT	33%	300	0.75	0.5
Diesel motor	41%	900	0.75	9.0
Nuclear	39%	2000	0.00	2.0

Tab 4.24 – Standard parameters assumed for thermal power plants

3. Renewable Energy Modelling

Modelling of energy production from renewable energy sources requires considering that the availability of the primary energy source is stochastic. We took into account two types of renewable energy plants: wind farms and hydroelectric plants.

Characterizing the availability of the renewable energy source is particularly important for wind farms. Three typical scenarios have been defined: (i) maximum production; (ii) medium production and (iii) zero power production. The latter situation corresponds to the lack of any wind or to wind speeds above the maximum allowed by windmills. A probabilistic model has been used to compute the production level and probability for each of these three scenarios. Wind speeds at a given location have been characterized using a Weibull distribution function with a coefficient k = 2, which is a typical value for European places with high wind potential like the Nord Sea.

Scenario	Average output as % of maximum capacity	Probability (%)
Low wind speed	5	50
Average wind speed	25	30
High wind speed	70	20

Tab 4.25 – Wind generation scenarios

Regarding hydroelectric generation, we have also defined typical scenarios for dry, average and wet hydrological conditions as detailed in the table below.

Scenario	Energy as % of average	Probability (%)
Dry	90	25
Average	100	50
Wet	110	25

Tab 4.26 – Hydro generation scenarios

Finally, we have defined nine different scenarios combining the possible wind and hydrological conditions.

4. Cross-border transmission facilities

It was assumed that the cost of reinforcing the existing interconnections is equal to a unit cost (€/km) multiplied by a typical distance. The unit cost was estimated based on information extracted from [5]. For submarine interconnections, typical costs were extracted from [6]. Defining the length of each corridor is more complex, especially when we take into account the fact that reinforcing a corridor typically involves constructing or upgrading some lines within some countries. Since it was not possible to carry out an analysis on a case-by-case basis, we defined an upper and a lower limit for this length and then computed sensitivities with respect to the value adopted. The upper limit was defined as the distance between the barycentre of loads in the two interconnected countries and the lower limit as the average length of the existing cross-border lines between them. The lower limit was taken to be 30% of the upper limit.

4.6.2.4 Mathematical Formulation of the Problem

4.6.2.4.1 Objective Function

The variable to minimize is the total incremental cost of meeting the increase in demand of the countries considered. This cost is calculated as the net present value (NPV) of capital and fixed Operating and Maintenance (O&M) costs of the new generation and transmission facilities plus the variable costs of existing and new generation facilities:

The minimization of this cost is subject to the constraints defined below.

- Demand meeting constraints
  - Total installed capacity must be equal to the forecasted peak demand plus an operative reserve margin
  - Energy produced during each block of hours must be equal to the forecasted energy demand for this block
- Upper bounds of variables
  - The power produced by each unit must be lower than or equal to its capacity
  - Flows on lines cannot exceed line capacities
- Maximum energy produced by hydro and wind plants:
  - Energy produced by renewable plants cannot exceed available primary resources
- Minimum generation by block
  - Some plants must produce a minimum volume of energy in each block of hours. This restrictions may be linked to: downstream constrains for hydro; ramp or minimum start-up times for thermal plants; must run obligations; etc.
- Maximum CO_2 emissions:

- Total CO2 emissions must be lower than or equal to emission limits

4.6.2.4.2 Interpretation of the results: dual variables

Dual variables associated to constraints related to generation-demand balance represent the market energy prices for each country, load level and scenario.

Dual variables of constraints related to CO_2 emission limits represent the marginal cost of complying with the emissions limit. This is an internal cost for the electricity sector, which is different from the market price of emission certificates. This cost results from having to substitute cheaper coal with natural gas. In the limit, it may be convenient to install additional CCGT plants to reduce emissions whenever this internal marginal cost is lower than the market price of the emission certificates.

4.6.2.4.3 Mechanism for developing new cross border lines

The process leading to the construction of new lines may be structured in very different ways. Here we advocate the adoption of a regulated model (central planning) combined with the construction of merchant lines whenever the private initiative finds business opportunities that have been overlooked by the TSO and the regulator.

In the case that the remuneration of private promoters is equal to that of regulated lines a competitive market in transmission may replicate the outcome of a centralized planning process. Assuming this property is true, we have computed the optimal expansion plan of the cross-border interconnections between the different EU countries as the solution of the dual problem of the one presented above.

Regulatory approaches used to plan the expansion of the grid in the EU are quite diverse. Some degree of harmonization is advisable at least for those investments relevant to the regional trade of energy.

4.6.2.5 Results on cross-border transmission expansion

4.6.2.5.1 Baseline Scenario

Figures below show the most relevant results obtained for the Baseline Scenario. *Fig 4.22* shows the resulting accumulated cross-border transmission capacity developed by our model both in the medium term (until 2013) and in the long run (2014 until 2023) as well as the total resulting energy exchanges between countries.

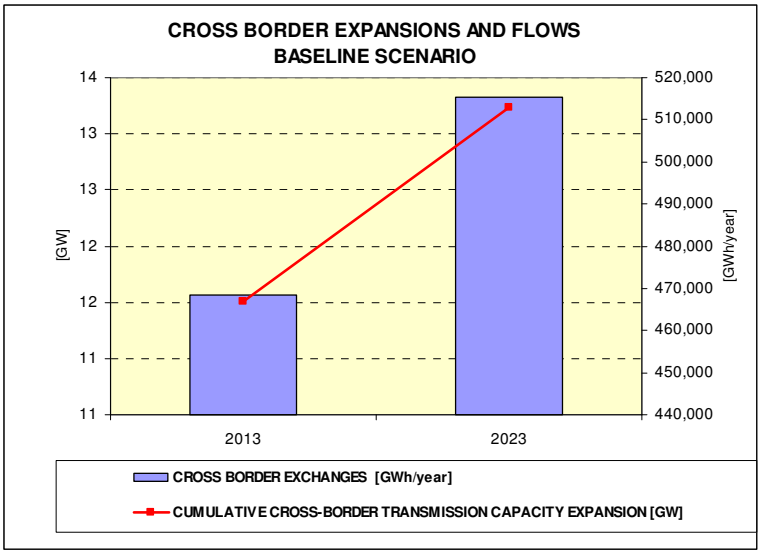


Fig 4.22 – Cross-border transmission capacity expansions and cross-border flows for the Baseline scenario

Fig 4.23 compares, for the same time periods, the evolution of total installed generation capacity, the expected peak load and the resulting reserve margin measured as the ratio between the difference between the installed capacity and the peak load and the peak load itself.

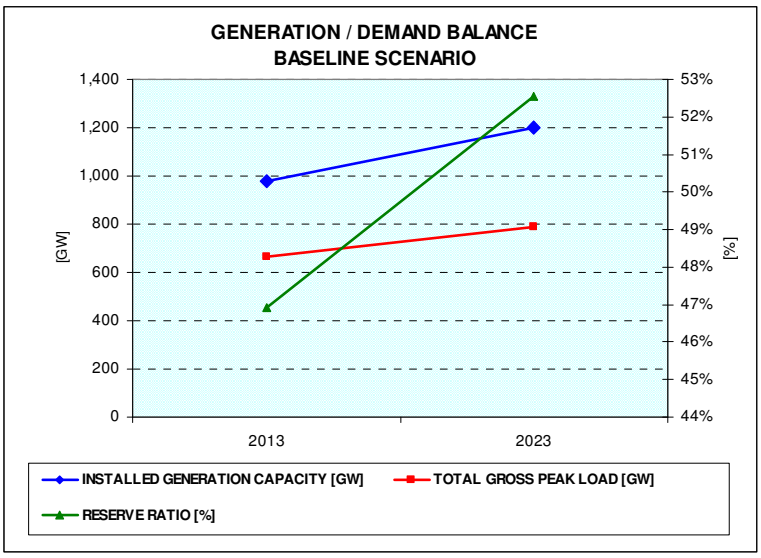


Fig 4.23 – Generation / Demand balance for the Baseline scenario

Finally, *Fig 4.24* shows the resulting total volume of carbon emissions and the corresponding marginal cost of a ton of CO2 in the dispatch.

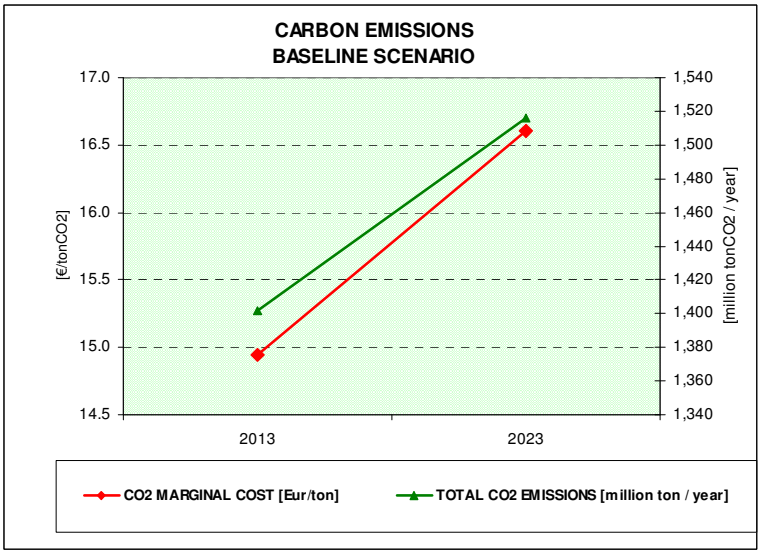


Fig 4.24 – Carbon emissions volume and internal price (marginal cost) of CO2 for the Baseline scenario

The expansion of generation is approximately the same as that considered in the expansion program of the PRIMES report for the baseline scenario. Simulations show that only some minor extra reinforcements are necessary in Ireland.

Using a cost of emissions in the range 15-17 €/t and considering some excess of generation, most of the time the marginal production cost turns out to be set by efficient coal fired plants burning coal. Therefore, differences in marginal costs among countries arise only from differences in coal transportation costs, which in some cases are lower than the cost of the transmission losses caused by cross-border trade.

The expansion of the cross-border transmission capacity amounts to less than 14,000 MW in the period 2005-2023. This low level of cross-border capacity expansion can be explained taking into account that:

1. The program of expansion of generation in Europe (Baseline of PRIMES simulations) assumes countries are well balanced.
2. Most of the expansion of generation relates to investments in CCGTs and wind farms.
3. Natural gas prices in the different countries are very similar.

Cross-border flows are very low in some cases, as it happens between France and the UK. This is motivated by the small difference existing between marginal production costs in both countries. *Fig 4.25* shows difference between marginal production costs in some selected couples of countries.

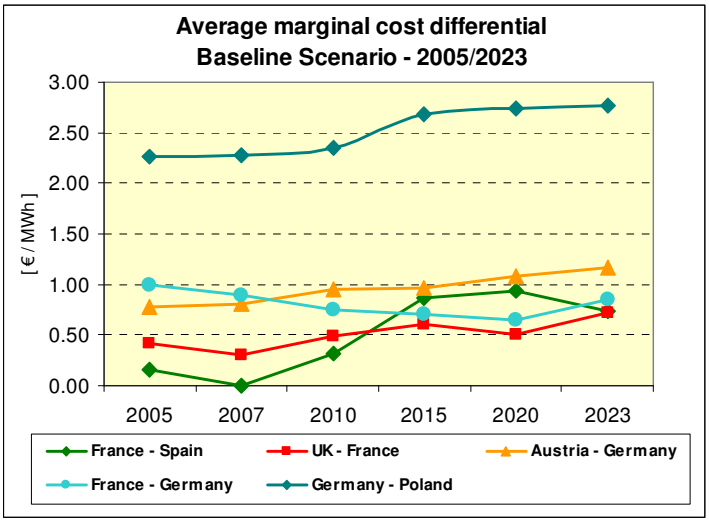


Fig 4.25 – Average marginal production cost differential for the Baseline scenario

Although these differences look very small when considering the present marginal production costs in each country, they are a direct consequence of the assumptions made in the study, where fuel costs are defined based on economic considerations.

4.6.2.5.2 Sensitivity (S1 to S10) and relevant scenarios

Although results are shown for all simulated scenarios (baseline + 10 sensitivity analysis), only those related to the set of scenarios identified as "relevant" are commented in detail. "Relevant" scenarios are the following:

- Baseline
- High RES (renewable energy sources) penetration (S3)
- High Efficiency (S8)
- Combined High RES + High Efficiency (S9)
- New generation optimized (S5)
- New generation optimized assuming high cost of cross-border transmission development (S6)

Resulting cross-border power exchanges

Tab 4.27 summarizes the resulting total energy exchanges through cross-border interconnections.

AVERAGE CROSS BORDER EXCHANGES [TWh/year]

Scenario	Key assumptions	2007	2013	2023
BASELINE		382.5	468.4	515.3
SCENARIO 1	'Kyoto for ever'	340.0	399.1	507.6
SCENARIO 2	'Kyoto for ever' + Nuclear expansion	347.4	381.0	428.8
SCENARIO 3	High RES (Forres)	395.2	445.3	534.0
SCENARIO 4	'Kyoto for ever' + High RES (Forres)	355.3	433.2	545.4
SCENARIO 5	**New generation optimized**	**330.8**	**401.2**	**715.7**
SCENARIO 6	**New generation optimized + Full transmission development**	**233.3**	**255.5**	**335.7**
SCENARIO 7	High coal prices in NE Europe (PL)	380.1	439.2	509.7
SCENARIO 8	High efficiency (Primes)	371.6	460.3	500.7
SCENARIO 9	Combined High RES + High effic. (Primes)	374.7	454.9	521.6
SCENARIO 10	Soaring oil and gas prices	389.6	375.5	400.9

Tab 4.27 – EU-30 Future cross-border electricity exchanges

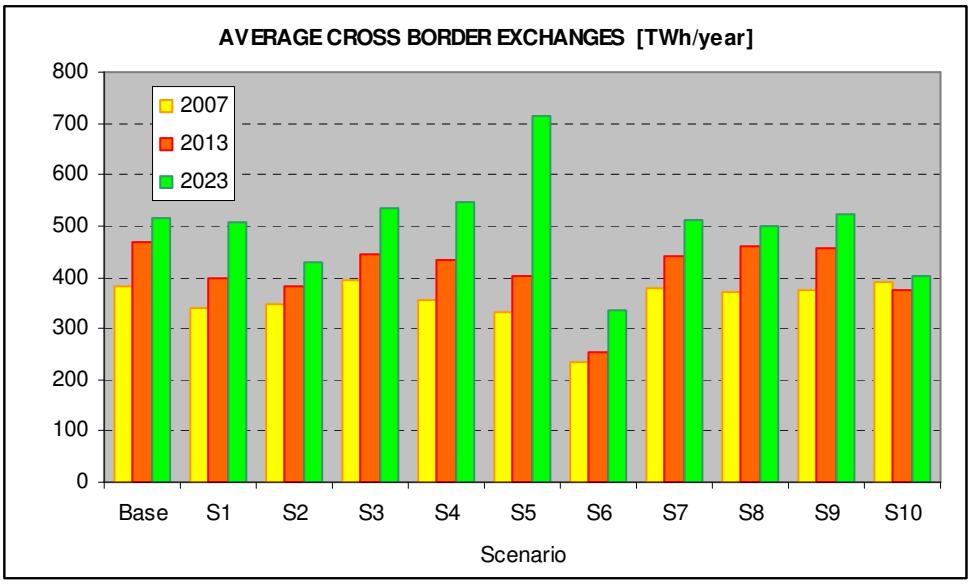


Fig 4.26 – Average cross-border exchanges

Only those scenarios where generation and transmission are jointly optimized show significant differences in cross-border exchanges. Exchanges in the long run are at the highest in S5, while they are at the lowest in S6 where the cost associated to the development of cross-border interconnectors is at the highest. Other scenarios show relatively similar energy exchanges, ranging between 300 and 550 TWh/year.

Development of new interconnection capacity between countries

Tab 4.28 and *Fig 4.27* show the increases of cross-border transmission capacity with respect to the year 2005.

CROSS BORDER CAPACITY EXPANSIONS [GW]

Scenario	Key assumptions	2007	2013	2023
BASELINE		6.0	11.4	13.3
SCENARIO 1	'Kyoto for ever'	5.6	8.4	22.8
SCENARIO 2	'Kyoto for ever' + Nuclear expansion	5.6	9.1	12.4
SCENARIO 3	High RES (Forres)	6.2	11.7	**36.2**
SCENARIO 4	'Kyoto for ever' + High RES (Forres)	5.1	11.2	**38.7**
SCENARIO 5	New generation optimized	4.6	**21.4**	**41.4**
SCENARIO 6	New generation optimized + Full transmission development	1.6	9.9	20.0
SCENARIO 7	High coal prices in NE Europe (PL)	6.2	9.2	12.9
SCENARIO 8	High efficiency (Primes)	5.4	10.6	20.8
SCENARIO 9	Combined High RES + High effic. (Primes)	5.6	12.3	27.9
SCENARIO 10	Soaring oil and gas prices	5.7	7.1	8.4

Tab 4.28 – Increase in cross-border capacity in EU-30 with respect to the capacity of the year 2005

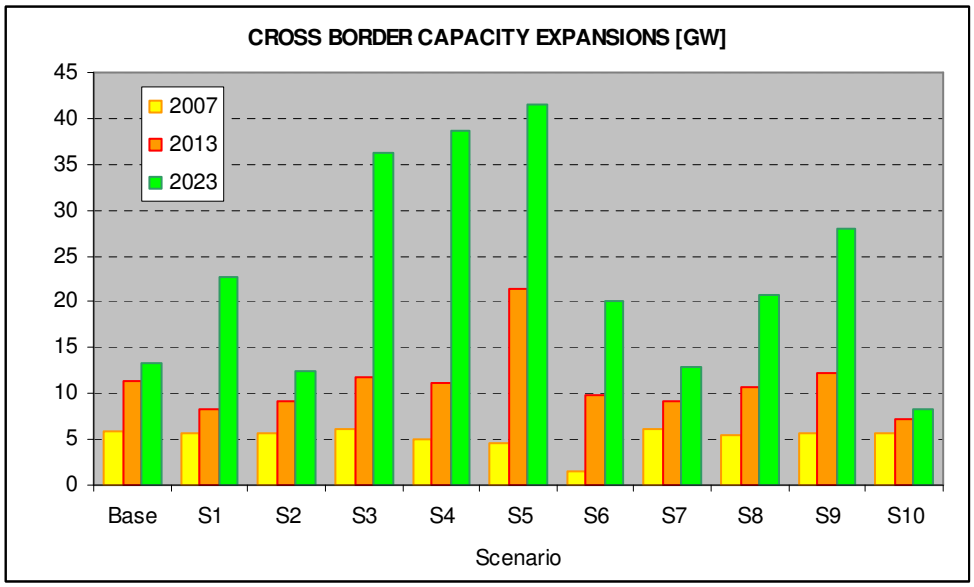


Fig 4.27 – Increase in cross-border capacity in EU-30 with respect to the capacity of the year 2005

Only High RES scenarios (S3 and S4) and those where generation and transmission are jointly optimized (S5) show significant levels of cross border capacity expansion in the long run (over 35,000 MW). Results for S5 also show a high development of interconnection capacity in the medium term (more than 15,000MW), while results for most scenarios correspond to the installation of 5,000 MW of new transmission capacity by 2007, and near 10,000 MW by 2013.

Tab 4.29 and *Tab 4.30* provide transmission expansion levels by border and priority axis for the relevant scenarios.

EU prority axe	Baseline		High RES		High Efficiency		High		Soaring oil and		Baseline +		Baseline + full	
			S3		S8		S9		S10		S5		S6	
	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023
EL1	4,400	100	3,100	7,000	4,600	1,500	4,200	1,400	2,100	0	2,900	100	1,000	0
EL2	0	0	0	0	0	0	0	700	0	0	700	0	100	600
EL3	200	0	100	1,000	800	2,100	1,000	2,600	200	0	800	3,100	300	100
EL4	3,500	1,300	2,300	1,500	2,900	3,200	3,100	2,900	3,100	900	400	2,600	300	2,900
EL5	0	0	0	0	0	0	0	0	0	0	1,600	2,000	1,600	1,000
EL6	0	0	0	0	0	0	0	0	0	0	1,100	2,100	1,100	2,100
EL7	100	500	2,000	4,700	200	600	1,200	1,200	300	300	1,500	4,200	200	1,400
EL8	3,000	200	3,100	9,000	1,300	3,600	1,100	8,500	1,200	300	6,900	10,500	1,000	4,000
EL9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	0	0	0	2,400	0	0	0	0	0	0	200	700	100	2,200
TOTAL	11,200	2,100	10,600	25,600	9,800	11,000	10,600	17,300	6,900	1,500	16,100	25,300	5,700	14,300

Tab 4.29 – Additional capacities in cross-border transmission by priority axis (values in MW)

Cross border interconnection between :		EU prority axe	Baseline		High RES		High Efficiency		High RES+Efficiency		Soaring oil and gas prices		Baseline + generation optimized		Baseline + full transmission development	
					S3		S8		S9		S10		S5		S6	
			2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005-2013	2014-2023	2005-2013	2014-2023
Austria	Germany	EL8	0	0	0	1,200	0	0	0	0	0	0	1,700	2,600	500	1,800
Austria	Switzerland		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Austria	Italy	EL2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Austria	Slovenia	EL8	0	0	0	0	0	0	0	300	0	0	0	0	0	0
Austria	Hungary	EL8	700	200	0	1,500	700	2,100	500	2,500	100	300	900	2,100	300	1,000
Austria	Czech Rep.	EL8	0	0	0	0	0	0	0	1,200	0	0	0	0	0	0
Belgium	Netherlands	EL1	0	0	0	4,200	0	0	0	0	0	0	0	0	1,000	0
Belgium	France	EL1	2,300	0	1,800	0	2,300	400	1,900	0	100	0	2,000	0	0	0
Czech Rep.	Germany	EL8	0	0	0	1,300	0	0	0	0	0	0	400	1,400	100	500
Czech Rep.	Slovakia	EL8	0	0	0	1,400	100	800	100	1,800	0	0	1,700	2,600	100	600
Czech Rep.	Poland	EL8	900	0	600	0	0	700	0	0	0	0	0	0	0	0
France	United Kingdom	EL5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
France	Spain	EL3	0	0	0	0	600	1,800	700	2,600	0	0	400	1,700	0	0
France	Switzerland		0	0	0	0	0	0	0	0	0	0	0	0	0	0
France	Italy	EL2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hungary	Slovakia	EL8	0	0	800	1,500	0	0	0	1,600	0	0	1,500	1,800	0	100
Germany	Netherlands	EL1	0	0	100	2,600	200	1,000	200	1,300	0	0	0	0	0	0
Germany	France	EL1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Germany	Denmark	EL7	0	0	1,200	4,100	0	0	0	0	0	0	400	800	200	1,000
Germany	Poland	EL8	0	0	0	1,900	0	0	0	0	0	0	0	0	0	0
Italy	Switzerland	EL2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Italy	Slovenia	EL2	0	0	0	0	0	0	0	700	0	0	700	0	100	600
Italy	Greece	EL9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poland	Slovakia	EL8	1,400	0	1,700	200	500	0	500	1,100	1,100	0	700	0	0	0
Poland	Sweden	EL7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portugal	Spain	EL3	200	0	100	1,000	200	300	300	0	200	0	400	1,400	300	100
Finland	Sweden	EL7	0	0	0	0	0	0	1,100	700	0	0	0	1,500	0	0
Finland	Norway		0	0	0	0	0	0	0	0	0	0	0	0	0	0
United Kingdom	Netherlands	EL5	0	0	0	0	0	0	0	0	0	0	1,400	1,000	1,400	0
United Kingdom	Norway	EL5	0	0	0	0	0	0	0	0	0	0	200	1,000	200	1,000
Switzerland	Germany		0	0	0	1,900	0	0	0	0	0	0	0	0	0	1,800
Ireland	United Kingdom	EL6	0	0	0	0	0	0	0	0	0	0	1,100	2,100	1,100	2,100
Estonia	Latvia	EL7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lithuania	Latvia	EL7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sweden	Norway		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Norway	Denmark		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turkey	Greece	EL4	1,300	500	800	0	900	700	900	1,100	900	100	0	1,300	0	1,300
Luxembourg	Germany	EL1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Luxembourg	Belgium	EL1	2,100	100	1,200	200	2,100	100	2,100	100	2,000	0	900	100	0	0
Romania	Bulgaria	EL4	1,200	200	800	1,000	900	1,400	1,100	1,100	1,200	200	100	700	0	800
Romania	Hungary		0	0	0	500	0	0	0	0	0	0	200	700	100	400
Bulgaria	Greece	EL4	1,000	600	700	500	1,100	1,100	1,100	700	1,000	600	300	600	300	800
Lithuania	Poland	EL7	100	500	800	600	200	600	100	500	300	300	1,100	1,900	0	400
Estonia	Finland	EL7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL		11,200	2,100	10,600	25,600	9,800	11,000	10,600	17,300	6,900	1,500	16,100	25,300	5,700	14,300

Tab 4.30 – Additional capacities in cross-border cut-sets (values in MW)

Accumulated investment in new interconnection capacity between countries

Total investments in interconnection capacity are largely dependent on whether the expansion of generation is optimized jointly with that of cross-border transmission or it is taken from PRIMES model. Accumulated investments are significantly higher for scenarios S5 and S6 because of this reason. The implementation of a

special policy for RES development (S3 and S4 –policy scenario of FORRES study–) also results in a significant development of interconnectors, particularly in the long run. Other relevant factor that increases total investments in transmission capacity is the application of low limits to carbon emissions (scenarios S1 and S4). *Tab 4.31* and *Fig 4.28* compare the results on investments in interconnectors obtained for each scenario and the ones resulting from the answers of the TSOs to the submitted questionnaire. These answers were summarized in section 4.6.2.1. Investments in most of the considered scenarios up to 2007 are lower than values reported by TSOs. This difference is specially significant for those scenarios where countries are well balanced.

ACCUMULATED INVESTMENTS ON
CROSS BORDER CAPACITY EXPANSIONS [million €]

Scenario	Key assumptions	Medium term 2005 - 2013	Long term 2014 - 2023
BASELINE		666	88
SCENARIO 1	'Kyoto for ever'	581	1,294
SCENARIO 2	'Kyoto for ever' + Nuclear expansion	688	133
SCENARIO 3	High RES (Forres)	661	1,564
SCENARIO 4	'Kyoto for ever' + High RES (Forres)	902	4,951
SCENARIO 5	New generation optimized	2,957	4,932
SCENARIO 6	New generation optimized + Full transmission development	2,570	4,838
SCENARIO 7	High coal prices in NE Europe (PL)	775	173
SCENARIO 8	High efficiency (Primes)	588	628
SCENARIO 9	Combined High RES + High effic. (Primes)	588	879
SCENARIO 10	Soaring oil and gas prices	291	48
TSO questionnaire, UK submarine interconnectors inclusive		**2,124**	**not reported**
TSO questionnaire, without UK submarine interconnectors		**920**	**not reported**

Tab 4.31 – EU-30 Investments on cross-border capacity expansions

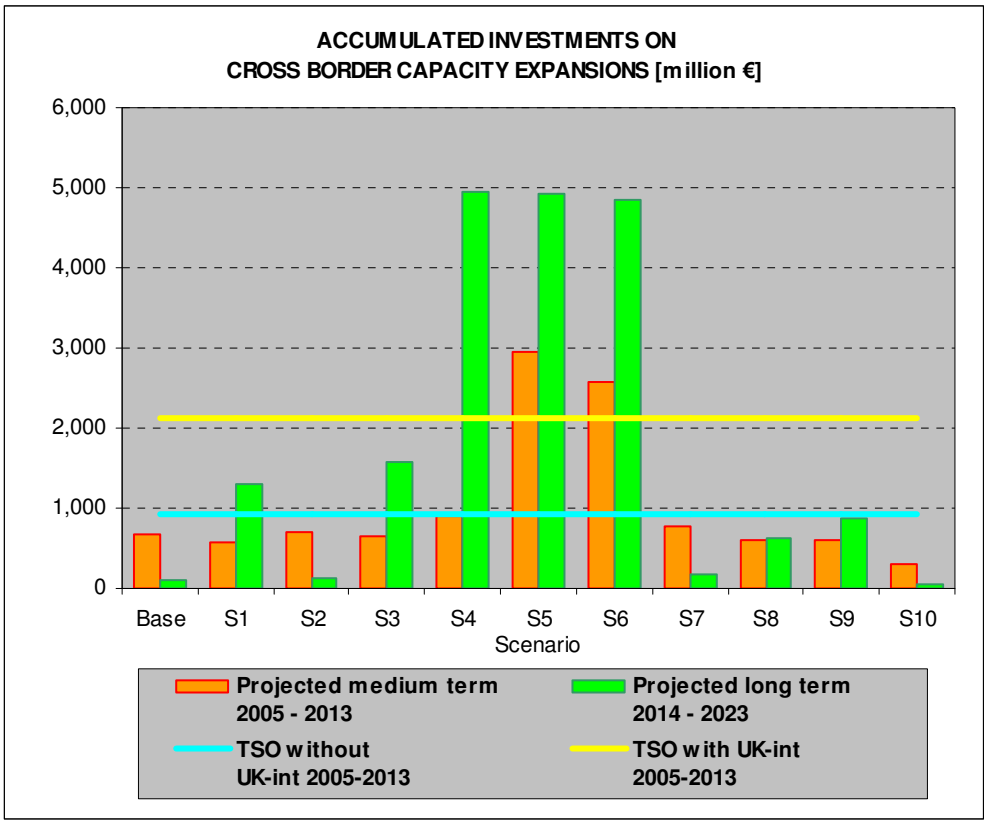


Fig 4.28 – Accumulated investments on cross-border transmission

Tab 4.32 summarizes the results obtained classifying them by priority axes and relevant scenarios.

EU prority axe	Baseline		High RES		High Efficiency		High RES+Efficiency		Soaring oil and gas prices		Baseline + generation optimized		Baseline + full transmission development	
			S3		S8		S9		S10		S5		S6	
	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023	2005 2013	2014 2023
EL1	309	2	232	225	326	93	279	82	83	0	236	5	58	0
EL2	0	0	0	0	0	0	0	34	0	0	35	0	23	94
EL3	9	0	6	43	87	245	102	334	9	0	70	279	48	19
EL4	164	65	108	26	123	118	129	132	125	30	37	478	36	500
EL5	0	0	0	0	0	0	0	0	0	0	1,385	1,805	1,354	1,058
EL6	0	0	0	24	0	0	0	0	0	0	699	1,373	699	1,373
EL7	5	15	155	424	7	23	36	35	10	10	80	187	84	361
EL8	180	6	161	653	45	150	42	262	64	8	352	558	231	926
EL9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	0	0	0	169	0	0	0	0	0	0	62	248	36	508
TOTAL	**666**	**88**	**661**	**1,564**	**588**	**628**	**588**	**879**	**291**	**48**	**2,957**	**4,932**	**2,570**	**4,838**

Tab 4.32 – EU-30 Investments in cross-border capacity expansions by priority axis (values in million €)

Accumulated investments in the medium term amount to around 0.6 b€ until year 2013 with the exception of scenario with 'soaring oil and gas prices', where investments amount to 0.3 b€, and the scenario where generation expansion is simultaneously optimized with high transmission costs, where investments are 3.0 b€.

The same tendency is showed in the long run (2014 onwards): the highest levels of expected investments in cross border transmission capacity correspond to those scenarios where the expansion of both generation and transmission is simultaneously optimized (near 5.0 b€ for 2014-2023 period). The high level of interconnection existing between countries in these scenarios makes new generation entries unnecessary. The cost of substituting a unit of generation capacity with transmission is between 30 and 40 €/installed-kW. This value turns out to be significantly lower than the unit cost of any available generation technology.

Scenarios which consider a pre-defined generation expansion plan (taken from PRIMES or FORRES models) result in a lower level of development of international transmission capacity. Investments for all these scenarios are between 0.1 and 1.5 b€ for the 2014-2023 period.

In all cases, the lowest investments in cross-border interconnectors occur in the scenario where fuel prices are high.

Evolution of installed generation capacity

Both installed generation capacity and electricity demand are input data to the cross border transmission expansion model with the sole exception of scenarios S5 and S6. *Tab 4.33* summarizes the values assumed in each scenario.

Generation / demand balance		Medium term (2013)		Long term (2023)	
Scenario	Scenario	Installed generation capacity [GW]	Net electricity demand [TWh/year]	Installed generation capacity [GW]	Net electricity demand [TWh/year]
BASELINE		976	3,516	1,201	4,134
SCENARIO 1	'Kyoto for ever'	976	3,516	1,254	4,134
SCENARIO 2	'Kyoto for ever' + Nuclear expansion	984	3,516	1,250	4,134
SCENARIO 3	High RES (Forres)	1,027	3,516	1,400	4,134
SCENARIO 4	'Kyoto for ever' + High RES (Forres)	1,027	3,516	1,400	4,134
SCENARIO 5	New generation optimized	904	3,516	1,074	4,134
SCENARIO 6	New generation optimized + Full transmission development	908	3,516	1,074	4,134
SCENARIO 7	High coal prices in NE Europe (PL)	976	3,516	1,201	4,134
SCENARIO 8	High efficiency (Primes)	969	3,251	1,184	3,648
SCENARIO 9	Combined High RES + High effic. (Primes)	992	3,213	1,216	3,609
SCENARIO 10	Soaring oil and gas prices	976	3,584	1,201	4,219

Tab 4.33 – EU-30 Total installed generation capacity and net demand. Installed generation is a result of the model in S5 and S6

As it may be expected, scenarios S5 and S6 result in a lower development of generation capacity than those where the generation expansion plan from PRIMES is used, like the Baseline scenario. Computing the cost of building transmission lines instead of local generation helps to assess how convenient is to follow this policy. Here we estimate this cost per unit of avoided generation capacity. Substitution of global generation with transmission becomes significant from 2015. *Tab 4.34* shows substitution unit costs for scenarios S5 and S6.

DIFFERENCE IN ACCUMULATED INVESTMENTS ON CROSS BORDER CAPACITY EXPANSIONS WITH RESPECT TO BASELINE [million €]

Scenario	Key assumptions	2005-2013	2014-2023
SCENARIO 5	New generation optimized	2,290	4,845
SCENARIO 6	New generation optimized + High transm.cost	1,903	4,751

REDUCTION IN INSTALLED GENERATION CAPACITY WITH RESPECT TO BASELINE [GW]

Scenario	Key assumptions	2005-2013	2014-2023
SCENARIO 5	New generation optimized	71.3	127.1
SCENARIO 6	New generation optimized + High transm.cost	67.2	126.8

EQUIVALENT COST OF ADDITIONAL TRANSMISSION CAPACITY [€/kW]

Scenario	Key assumptions	2005-2013	2014-2023
SCENARIO 5	New generation optimized	**32.1**	**38.1**
SCENARIO 6	New generation optimized + High transm.cost	**28.3**	**37.5**

Tab 4.34 – EU-30 Equivalent cost of cross-border expansions

The equivalent unit cost of additional transmission capacity is always lower than the investment costs of any generation technology (i.e. about 550 €/kW for CCGT power plants). This confirms that this solution is optimal from the point of view of total investment costs. Obviously, total investment in transmission in scenarios S5 and S6 is higher than that in other scenarios.

Marginal cost of carbon emissions

Tab 4.35 and *Fig 4.29* show the marginal cost of carbon emissions for each simulated scenario.

MARGINAL COST OF CARBON EMISSIONS [€/ton]

Scenario	Key assumptions	2007	2013	2023
BASELINE		14.91	14.94	16.60
SCENARIO 1	**'Kyoto for ever'**	**29.78**	**16.89**	**32.24**
SCENARIO 2	**'Kyoto for ever' + Nuclear expansion in the long-run**	**37.36**	**16.82**	**20.21**
SCENARIO 3	High RES (Forres)	14.73	11.83	12.28
SCENARIO 4	'Kyoto for ever' + High RES (Forres)	16.77	15.38	17.53
SCENARIO 5	New generation optimized	15.46	16.31	17.23
SCENARIO 6	New generation optimized + Full transmission development	14.63	16.53	17.44
SCENARIO 7	High coal prices in NE Europe (PL)	14.63	14.10	15.83
SCENARIO 8	High efficiency (Primes)	14.73	13.23	14.03
SCENARIO 9	Combined High RES + High effic. (Primes)	14.73	13.36	13.62
SCENARIO 10	**Soaring oil and gas prices**	**21.43**	**48.32**	**51.10**

Tab 4.35 – EU-30 Marginal cost of carbon emissions

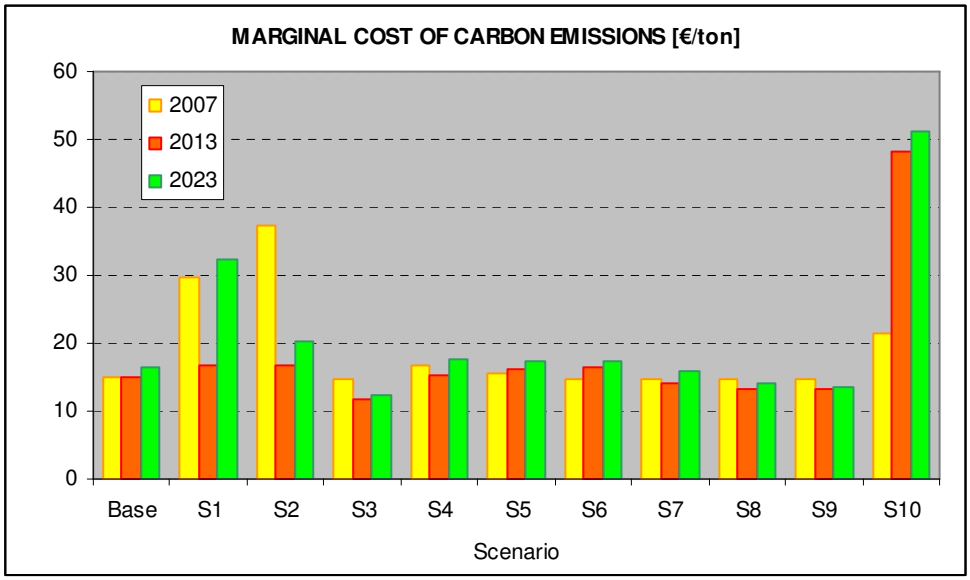


Fig 4.29 – Marginal cost of carbon emissions

As expected, scenarios with low emission limits (Kyoto for ever) show higher marginal cost of carbon emissions. This does not happen if special policies for RES development are implemented (S1, S2 compared with S3, where a special policy for RES development is implemented). In addition, high fuel (oil and gas) prices also cause the marginal cost of carbon emissions to be high (S10).

On the other hand, implementing a special policy for RES development (S3) when carbon emissions are less constrained than in the "Kyoto for ever" scenario results in the lowest marginal cost of carbon emissions in the long run. The remaining scenarios show similar marginal costs for 2010 and 2015. In the latter cases the marginal cost of carbon emissions is around 15 €/ton CO2 during the whole planning horizon.

4.6.3 Investments associated with the connection of offshore wind generation facilities

Offshore wind generation requires significant investments in transmission facilities, mainly submarine cables, in order to be connected to the onshore transmission grid. We have estimated the total cost of the grid investments associated with the installation of new wind farms in each mid and long run scenario. Our aim is to compare the resulting figures with the overall expansion cost of the European transmission grid.

4.6.3.1 Data sources

Calculations were performed using the following data sources:

- Unit costs were obtained from the document "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020", carried out by DENA (Deutsche Energie-Agentur GmbH) –the "DENA grid report"–.
- The expected evolution of investments in offshore wind facilities was obtained from the document of the FORRES project.

In the mid and long run scenarios where overall generation expansion was based either on the results of the PRIMES model (Baseline scenario) or on figures obtained from our own expansion model (Baseline + new generation optimized scenario), the future evolution of offshore wind generation was assumed to be equal to that predicted in the FORRES project for the Business as Usual (BAU) scenario. On the other hand, the evolution of

offshore generation considered in the High-RES scenario was that reported by the FORRES project for the "Policy" scenario.

The connection costs of offshore facilities are usually covered by the developers of wind farms through connection tariffs applied to these investment projects. Therefore, they are usually not considered as transmission investment costs but costs associated with the generation expansion investments. Having said that, this section intends to provide a general picture on the amount of connection costs related to off-shore wind farms.

4.6.3.2 Unit costs

According to the 'DENA' grid report, the development of offshore wind facilities both in the North and the Baltic Seas will reach 2.6 b€ until 2010, 5 b€ until 2015, and between 11 b€ and 12 b€ until 2020. *Tab 4.36* below recalls Tables 1 and 2 of the 'DENA' grid report. These tables provide an estimation of both the future installed capacity of wind farms in Germany and the amount of energy that these facilities will inject into to the grid during the same period of time.

Table 1: Development of installed wind capacity in Germany up to 2020 in GW

	Installed wind capacity in Germany, in GW				
Year	**2003**	**2007**	**2010**	**2015**	**2020**
Onshore	14.5	21.8	24.4	26.2	27.9
North Sea	0	0.4	4.4	8.4/8.1	18.7
Baltic Sea	0	0.2	1.0	1.4/1.7	1.7
Total	14.5	22.4	29.8	36.0	48.2

Table 2: Development of wind energy (W.E.) production up to 2015 in GWh

	Wind-power feed-in, in GWh			
Year	**2003**	**2007**	**2010**	**2015**
W.E. onshore	23,500	34,900	40,300	44,700
W.E. offshore	0	1,900	18,000	32,500
Total	23,500	36,800	58,300	77,200

Tab 4.36 – Expected wind power development in Germany. Source: DENA - "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020". Table numbering corresponds to the original source.

From these figures one may compute the average transmission connection cost incurred per unit of wind power installed offshore. The average unit cost over the period of time between 2003 and 2020 turns out to be 510 €/installed-kW, as shown in the *Tab 4.37*. The average load factor of wind farms is 38% as *Tab 4.36* above implicitly shows.

	2010	2015	2020	Average
Submarine cables [million €]	2600	5000	11000	
Installed capacity [GW]	5.40	9.80	20.40	
unit cost [€/kW]	481	510	539	**510**

Tab 4.37 – Off-shore wind generation: connection unit cost

4.6.3.3 Offshore wind generation expansion

As mentioned above, information on the evolution of offshore wind generation facilities was obtained from the documents of the FORRES project. *Tab 4.38* provides figures on the expected energy production from offshore wind generation facilities for the scenarios considered in the FORRES project.

FORRES - Expected wind power generation [TWh/year]

	----------EU-15----------			----------EU-25----------			----------EU-30*----------		
	2001	2010	2020	2001	2010	2020	2001	2010	2020
Policy scenario									
Wind onshore	33.0	163.0	250.0	33.1	167.0	270.0	33.1	168.1	271.7
Wind offshore	0.0	26.0	187.0	0.0	27.0	191.0	0.0	27.2	192.2
Total	**33.0**	**189.0**	**437.0**	**33.1**	**194.0**	**461.0**	**33.1**	**195.3**	**463.9**
BAU scenario									
Wind onshore	33.0	136.0	245.0	33.1	137.0	256.0	33.1	138.1	257.7
Wind offshore	0.0	17.0	129.0	0.0	17.0	129.0	0.0	17.0	129.0
Total	**33.0**	**153.0**	**374.0**	**33.1**	**154.0**	**385.0**	**33.1**	**155.1**	**386.7**

* Estimated

Tab 4.38 – FORRES: expected wind power generation in Europe

Considering a load factor of 38% for offshore wind power facilities, according to the information from the 'DENA' grid report, and figures on total energy production from the FORRES project, we are in the position to estimate the future evolution of total installed wind power capacity in Europe. This is shown in *Tab 4.39* below.

Estimated offshore wind installed capacity [MW]

	----------EU-15----------			----------EU-25----------			----------EU-30*----------		
	2001	2010	2020	2001	2010	2020	2001	2010	2020
Policy scenario	0	7,820	56,243	0	8,121	57,447	0	8,173	57,822
BAU scenario	0	5,113	38,799	0	5,113	38,799	0	5,113	38,799

* Estimated

Tab 4.39 – FORRES: expected off-shore wind power installed capacity in Europe

4.6.3.4 Investment cost for offshore wind power connection

Using the above information and the unit connection cost obtained from the DENA grid project, we can compute the total projected cost of grid investments associated with offshore wind facilities both in the medium and long terms (*Tab 4.40*).

Expected investment costs
for offshore wind power connection [million €]

	------- EU-30 -------		
	Mid term 2005-2013	Long term 2014-2023	Totals 2005-2023
Baseline scenario [1]	7,766	17,190	24,956
High RES [2]	11,771	25,336	37,108
New gen. optim. + full transm. developm. [1]	7,766	17,190	24,956

[1] based on FORRES - BAU scenario
[2] based on FORRES - Policy scenario

Tab 4.40 – Expected investment costs for the connection of off-shore wind power facilities

The estimated cost of the grid investments required to connect offshore wind facilities to onshore grids ranges between 7.7 b€ and 11.8 b€ for the period 2006-2013 (mid-term). In the second decade ahead (2014-2023) a sharp increase in investments is expected; the total investments would be in the range between 17.1 b€ and 25.4 b€.

4.6.4 Total investments in transmission grids

Our aim now is to provide some information on the total transmission investment needs in the EU-30 countries. We must first estimate the cost of investments needed to upgrade the internal transmission grids of countries. Adding this figure to the cost of investments in inter-connectors we obtain total investments needed.

4.6.4.1 Internal transmission grids

The cost of future investments in the enlarged EU power network was estimated using a regression model that relates the total equivalent length of lines within each country to some explicative variables. This model was developed during the course of the project. The dependant variable in the model is the total equivalent length of the high voltage lines built[23]. Initially, the following explicative variables were considered:

- Peak demand
- Energy demand
- Cross border flows
- Country surface
- Load density (TWh/inhabitants)

Regression analysis performed showed that the energy demand, the surface of the country and the load density within it are significant variables when explaining the total volume of transmission assets within a country. The formula finally adopted to forecast the total equivalent length of all the transmission lines is:

$$Leq = 0.0021 * E^{0.534} S^{.592} * LD^{-0.247} \qquad (1)$$

where:

E: energy demand (TWh)
S: country surface (km^2)
D: load density (TWh/inhabitant)

This formula was compared with a similar one used by the IIT in the context of a study to define a benchmark of electricity transmission tariffs [20]. Both formulas are quite similar. The formula considered in the project by the IIT is:

$$Leq = 0.0046 * E^{0.672} S^{0.614} * LD^{-0.259} \qquad (2)$$

In order to forecast the cost of total grid investments, we needed to make the following assumptions:

- The length of transmission lines built in year "n" within each country can be obtained as the difference between the total volume of transmission assets within the country in years "n" and "n-1".
- The unit cost for transmission lines was obtained from the report "Comparison of 380 kV costs – IFC consulting"
- The total transforming capacity installed is proportional to the demand in each country. The ratio used was 1 MVA/MW demand. This figure has been estimated based on information provided by ETSO on the installed transforming capacity and demand in a subset of EU countries for the year 1999.

[23] The "equivalent" length L_{eq} is referred to the capacity of a 400 kV line by adopting the following relationship: $Leq = L_{400} + \sum_i L_i \left(\frac{V_i}{400}\right)^2$, where L_i is the length of lines with "i" voltage level.

- Countries where the total equivalent length of transmission assets is below the EU average, which was obtained by applying formula (1) to data for the EU 30 countries, achieve average levels of transmission grid development by 2013.
- The renewal of old equipment amounts to 1.5% of total transmission assets.
- The length of cross-border lines was discounted from the total length of transmission lines since the former was separately forecasted.
- The average cost of transformation capacity has been assumed equal to 22000 €/MVA
- Other costs (communications, civil works, switching equipment, etc) amount to 23% of the total cost of lines and transformers.

Based on these assumptions, the following curve was obtained for the total accumulated investments in the internal grid of the EU 30 countries:

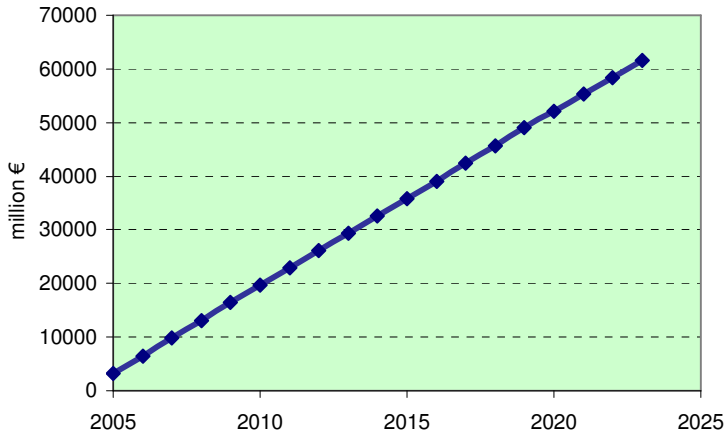


Fig 4.30 – Expected investments in the expansion of internal transmission grids over the period 2005-2023

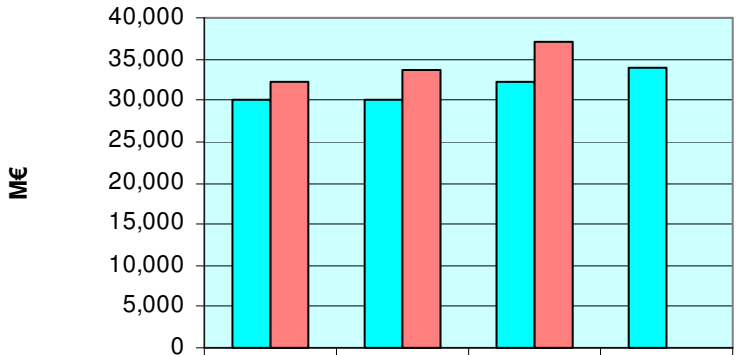
Annual investments varies between 3.35 b€ in 2006 and 3.15 b€ in 2023. Annual investments fall in the last years of the period of study because of the lower rate of demand growth. Accumulated investments over the period 2005-2013 are 29.3 b€.

4.6.4.2 Estimate of total grid investments

Finally, we have estimated the total grid investments in the EU. Figures for investments in cross-border lines were obtained from the analysis presented in the previous sub-sections. *Fig 4.31* shows the resulting total expected investments (internal + cross border) for three representative scenarios:

1. Baseline
2. High RES (S3)
3. Baseline + new generation optimized (S5).

Total investments were computed as the sum of those in internal and cross-border lines. In some scenarios, investments in cross-border lines include those reinforcements of the internal grids necessary to transport cross-border flows to the load/generation centre in each country and/or to accommodate transit flows.



	Baseline	High RES	New gen. Optimised	TSOs plans
2005-2013	29,978	29,973	32,269	34,000
2014-2023	32,338	33,814	37,182	

Fig 4.31 – Total expected investments on electrical transmission

4.6.5 Investment plans provided by TSOs

Tab 4.41 shows the future plans of grid investments obtained from the information provided by TSOs. Usually, plans for new investments do not extend beyond the medium term future (period 2005-2013). Planned investments reported are in line with those carried out in the past with the exception of the Nordic countries and, particularly, Spain, which show an increasing trend in the investments.

FUTURE INVESTMENTS				
COUNTRY	M€		k€/(km*year)	
	2005-2013	2014-2023	2005-2013	2014-2023
Eastern Baltic Countries				
ESTONIA (EE)	159,4	391,9	17,2	38,0
LATVIA (LV)	192,0	271,8	18,8	24,0
LITHUANIA (LT)	560,0	450,0	73,3	53,0
Nordic Countries				
DENMARK-WEST (DK)	683,0		99,9	
FINLAND (FI)	480,0	540,0	11,3	11,4
NORWAY (NO)	1155	247*	26,0	7,1
SWEDEN (SE)	910,0		8,1	
Continental Europe Countries including candidate and western Balkan countries				
CZECH REPUBLIC (CZ)	300,9		9,1	
FRANCE (FR)	3653,6		13,9	
GREECE (GR)	720-800		10-11,2	
HUNGARY (HU)	170,0		7,7	
ITALY (IT)	2100,0		18,7	
NETHERLANDS (NL)	206-387			
POLAND (PL)	3600,0		54,6	
ROMANIA (RO)	751,1		13,0	
SERBIA and M. (CS)	355,0	22,5	15,2	0,9
SLOVAKIA (SK)	72,3	96,3	17,2	4,7
SLOVENIA (SI)	480,0		3,9	
SPAIN (ES)	1900**		86,9	
TURKEY (TR)	1535,0	1465,0	9,9	8,5
Islands				
CYPRUS (CY)	82,4		57,6	
IRELAND (IE)	500,0		56,7	
NORTH IRELAND (UK)	130,0		14,5	

* *for the period 2014-2020*

** *for the period 2005-2009*

Tab 4.41 – Patterns of future investments (source: national SOs)

4.7 References

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