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

Commissioned by the

European Commission
Directorate-General Energy and Transport

Carried out by

KEMA Consulting (Bonn, Germany)

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Acronyms and Abbreviations

ATC	Available Transfer Capacity
ETSO	European Transmission System Operators
EU	European Union
EURPROG	Statistics and Prospects for the European Electricity Sector
IEA	International Energy Agency
IEM	Internal Electricity Market
NTC	Net Transfer Capacity
OECD	Organisation for Economic Co-operation and Development
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
UCTE	Union for the Co-ordination of Transmission of Electricity
UPS	Unified Power System

1 Executive Summary

Since the passage of the first Electricity Directive, the gradual establishment of the Internal Electricity Market (IEM) has resulted in a remarkable growth of cross-border trade in electricity. As a result, market actors are increasingly facing congestion on several cross-border lines, limiting their opportunities to exploit the existing economic export and import potential between different markets to the benefit of European consumers. The reasons for congestion include network constraints both at cross-border lines and within the network of individual countries, as well as different rules and methodologies for cross-border capacity allocation.

To ensure that common rules and market standards apply regarding capacity availability and that an adequate infrastructure is available to the market actors, the European Commission had already committed a first study in 2001 into measures to be taken to increase capacity. However, while that first analysis had concentrated on the Member States at that point of time, ten new countries joined the European Union in May 2004 and thus became part of the IEM. In addition, Bulgaria, Romania and Turkey have been granted the status of Candidate Countries and may join the EU in the future. As a result, this has led to the necessity to extend the previous analysis to these new Accession Countries.

Therefore, the European Commission has contracted KEMA Consulting to perform a comprehensive analysis of the network capacities and possible congestion of the electricity transmission network within the Accession Countries. The main objectives of this study can be summarised as:

- Determining the economic export and import potential for the new parts of the Internal Electricity Market, covering exchanges between the Accession Countries, and of the Accession Countries with those countries that had already been part of the IEM before May 2004;
- Investigating the methods applied by the Transmission System Operators (TSOs) in the Accession Countries for determining the cross-border capacities that can be made available to the market, and for allocating the corresponding capacities to individual market participants;
- Analysing possible measures to increase cross-border transmission capacities, and identifying those projects that offer the largest net benefits to European consumers, particularly taking account of those projects that have been put forward as projects of common interest in the framework of the Trans-European Networks.

In accordance with these general goals, the current study has been structured along the following three lines:

- Firstly, the study estimates the future import and export potential within the Accession Countries, with existing parts of the Internal Electricity Market, and with further neighbouring systems during the study period (i.e. up to 2020). Simultaneously, it identifies potential congestion at different borders. These investigations are based on the use of a production simulation tool, taking into account the existing generation plants and their expected future development, available cross-border capacities, and forecasts of future fuel prices.

- Secondly, this study describes and analyses the methods that the TSOs currently use for defining and allocating available cross-border capacities. Where possible, this is based on direct information received from the corresponding TSOs, or personal meetings. Additionally or, in some cases, alternatively, use has been made of other, publicly available documents.

- Thirdly, the study identifies a number of projects that are being planned or considered, in order to improve the existing physical infrastructure. For projects being considered as promised by the TSOs, as well as combinations thereof, it also provides estimates of both the resulting costs and benefits. While these cost estimates are based on a cost engineering approach, the market model previously developed has been used to assess the economic benefits to consumers. Based on the combination of the cost and benefit analysis, the study finally establishes an indicative evaluation of each project's importance and economic benefits for the successful extension of the IEM to the Accession Countries.

With a view to the economic import and export potential, the investigations performed under this study confirm the assumption that network constraints represent a major barrier to the free exchange of electricity within the IEM. Considering the frequency and severity of congestion, the calculations show major network constraints at the following borders:

- From Central Eastern Europe (Poland, Czech Republic, Slovakia) to Germany, Austria and Hungary;

- From Austria and Slovenia to Italy; and

- From Bulgaria and Serbia & Montenegro (respectively Macedonia) to Greece.

While the simulations show the main flow patterns and areas of congestion to largely remain the same, one can also observe a general trend towards *increasing congestion* in the future. Notably, this also includes several borders within former Yugoslavia or between the Czech and Slovak Republic, which have so far not been considered as primary areas of concern. At the same time, the simulations indicate a *decreasing* degree of congestion at the Italian borders, due to an increased reliance on natural gas throughout Europe.

An interesting observation relates to some remarkable differences between the economic export and import flows resulting from the market model, and those commercial exchanges currently observed in practice. We believe that these differences indicate remaining inefficiencies within the IEM. Apart from regulatory intervention or the impact of comprehensive power-purchase arrangements in some countries, this view is especially related to the current lack of liquid markets and short-term trading within the region. Continued efforts to develop and strengthen the IEM can thus be expected to render substantial benefits to consumers, even in the absence of any additional capacities.

Considering the determination of available cross-border capacities, the analysis has shown a considerable degree of harmonisation within those countries being members of the UCTE. Despite differences in detail, most TSOs apply similar procedures and use a comparable set of information and assumptions. In contrast, the situation in the Baltic States is still characterised by an integrated approach as commonly found in vertically integrated markets. At the same time, the structured application of special protection systems in the Baltic States represents, in our view, an important means of increasing the use of the existing network infrastructure at limited risk and costs. Despite some concerns about the need for effective coordination between different TSOs, we believe that the use of special protection systems should be considered as an alternative solution before investing in new cross-border capacity. The cost of contracting generators for taking part in special protection arrangement can be substantially lower than e.g. the annual costs of new investments into the network.

In contrast, we only see a limited scope for the application of phase shifters. While phase shifters allow for more effective use of existing lines, they may easily shift problems to other places in a meshed transmission network like that of the UCTE. Given proper coordination between all affected TSOs, phase shifters may nevertheless help to increase available transmission capacities even without a dramatic increase of thermal losses.

A third area where TSOs may be able to make additional capacities available relates to the setting of thermal limits for transmission lines. We note that only a few TSOs currently apply flexible limits. While we agree that the use of different thermal line limits may not have a tangible effect e.g. during the summer or at night. However, the use of differentiated values during winter periods could increase the available transfer capacities during the winter, i.e. at a time when it is generally most needed. Therefore we believe that using different thermal limits for overhead lines should be seriously considered as an alternative for investments in cross-border connections.

The description and analysis of the allocation mechanisms applied by the Accession Countries has revealed that there still remain a number of countries without any formalised and/or market-based mechanisms. At the same time, we note the recent efforts by CEPS, PSE and VE-T to establish a truly coordinated auction scheme that leaves further flexibility to the market for deciding on the allocation of transfer capacities to individual borders. Although being far from perfect, we believe that this move towards increased coordination represents an important step forward as it helps to create additional flexibility for the market, thus enabling a more efficient use of scarce cross-border capacities. Hence, we recommend that the TSOs of the Accession Countries should increase their efforts in establishing coordinated allocation schemes on a regional basis.

Based on the assessment of the costs and benefits of individual projects, this study has established an indicative ranking of those projects that may offer the largest benefits to the IEM. In the following, we briefly comment on different projects that are still in the planning phase and assign different priorities:

- The projects in the first group represent those investments, which we believe to provide the largest benefits to the Internal Electricity Market. Moreover, it should be feasible to realise most of these projects within a few years. In detail, we suggest to focus on pursuing the following reinforcements:
  - Insufficient network capacity especially in the Southern and Western part of the **Polish transmission grid** represents a major source of congestion. Priority should be given to removing the existing constraints in the Polish grid, namely to complete the planned reinforcements from Dobrzeń to Wielopole, and further on Rogowiec via Trebaczew and Ostrow to Plewiska.
  - Transfer capacities in the region can be increased at limited costs by investing into a new link between **Poland and Slovakia**. Specifically, we recommend to realise the planned link from Byczyna (Poland) to Varin (Slovakia).
  - Internal network constraints in the **Austrian transmission grid** represent a major source of congestion both for the Austrian and the regional electricity market. Realisation of the planned reinforcements within Austria should therefore receive the highest priority.
  - Irrespective of the internal reinforcement of the Austrian grid, the addition of a second circuit to an existing line between **Austria and the Czech Republic** will result in increased cross-border capacity at very limited costs.
  - The **Slovakian-Hungarian** border is notoriously congested, while the simulations show a considerable economic benefit for increased cross-border exchanges.
  - Similarly, the analysis shows that a new link between **Slovenia and Hungary** could not only be constructed at limited costs, but would also render substantial economic benefits to the IEM.
  - The borders between **Hungary and Serbia**, and between **Hungary and Romania** both represent links between the former first and second synchronous zones of the UCTE. Investing into new interconnections between Hungary and the two other countries will likely result in substantial benefits to the IEM at limited costs.
  - Construction of the planned link between **Bulgaria and Greece** would help to reduce congestion at this highly congested border and render significant savings to the European economy. Since these benefits will likely be further increased by the parallel construction of a new link between Serbia and Macedonia, this project should be pursued with priority.
- The second group combines projects that are likely to provide less significant benefits to the IEM, that are dependent on the prior completion of other investments, or which may still require further study:

  - The cost-benefit analysis provides inconclusive results on the planned interconnection between **Lithuania and Poland**, especially when considering further internal reinforcements of the Polish transmission grid may be required in addition to the link itself. On the other hand, the combination of this link with the planned cable between *Finland and Estonia* is likely to provide significant benefits to the IEM. The recent decision for construction of the latter link may thus positively influence this project. However, we do not believe that this new line could be fully exploited before 2010.
  - The analysis shows that the new link between **Slovenia and Italy**, which has been under study for a long time already, would potentially result in considerable benefits especially for the Italian market. However, the real potential will strongly depend on the development at the remaining Italian borders. While we are generally convinced of the advantages of this project, we recommend that this investment be evaluated in combination with other projects at the Italian border.
  - The market simulations show a potentially significant benefit of a new connection between **Greece and Turkey**. However, it should be considered that this link might be primarily used for bilateral exchanges and thus remain without any significant impact on the IEM. We therefore recommend that a final decision should be subject to further study.

- The final group includes projects that, while being profitable, may still require further study, or that can realistically only be expected after 2010:
  - While the reinforcement of the cross-border connection between **Germany and Poland** would enable potential savings for the IEM, these benefits will only become available after completion of some basic internal reinforcements of the Polish power grid.
  - The market simulations show considerable benefits for additional transfer capacities between **Austria and Slovakia**. However, there currently seems to be limited demand as there obviously are sufficient transfer capacities between Slovakia and the Czech Republic. Moreover, we doubt whether a new line between these countries could be fully used without the prior completion of the planned North-South connection in Austria. Conversely, we believe that it should first be studied whether this link would really provide a substantial increase in NTC, especially after a potential upgrading of the Austrian grid, and the interconnection between the Czech Republic and Austria.

2 Introduction

2.1 Scope and Background

The opening up of the Internal Electricity Market has increased the cross-border exchanges within the Internal Electricity Market (*IEM*) of the European Union (*EU*) remarkably. Not only the exchanged volumes of electric energy have increased, the flow patterns have become more dynamic and less predictable. As a consequence, congestion on several cross-border-lines, sometimes caused by internal network constraints within individual countries, prevents market actors from exchanging electrical energy between different markets. Different rules and methodologies for cross-border capacity allocation hinder the establishment of a truly IEM.

For the completion of the IEM it will therefore be necessary that not only common rules and market standards apply but also that an adequate infrastructure is available to the market actors. Insufficient capacities of cross-border-lines (interconnectors) could limit the international exchange of electric power and could thus potentially create new "bottle-necks" in the IEM. Since cross-border-transmission capacities have been defined with national rules at national level, the European Commission adopted two Communications on the European Energy Infrastructure in 2001 and 2003. In these documents, a number of measures were put forward to increase transmission capacities, to reduce congestion and to proceed further towards a single European Market for Electricity.

A first study on the network capacities and congestions of the existing transmission systems in the IEM that was finished in 2001 had concentrated on the Member States at that point of time.[1] In May 2004, however, ten new Member States (the *Accession Countries*) joined the European Union and became part of the IEM. Moreover, Bulgaria, Romania and Turkey have been granted the status of Candidate Countries and may join the EU in the future. It has thus become necessary to also consider the network capacities and congestions within the new and, potentially, future part of the IEM. The main objective of this project thus is to describe the available transmission capacities between the Accession Countries, including their borders with the pre-2005 Member States, and to identify the most effective measures for the establishment of the IEM with regards to the availability and determination of network capacities within the Accession Countries. Corresponding measures may be 'soft' (e.g. policies, IT) or 'hard' (new transmission infrastructure) and need to be assessed and, ultimately, ranked by their importance and efficiency.

Overall, this study has been focused on electricity trade and transmission between the Accession Countries as well as between them and other EU or neighbouring countries. The primary interest therefore is on network constraints that limit cross-border exchanges. Transmission constraints within individual countries are therefore only relevant insofar as they cause congestion for cross-border trade of electricity.

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[1] European Commission (2001).

Within this study, we have concentrated our analysis on those Accession Countries that are highlighted in Figure 1: Besides eight of the Accession Countries (Estonia, Latvia, Lithuania, Poland, the Czech Republic, Slovakia, Hungary, and Slovenia), we have also considered the Candidate Countries Romania and Bulgaria and, to some extent, Turkey. In contrast, we have excluded Malta and Cyprus from this study since these two countries are not physically interconnected with the rest of the EU, and thus represent true island networks. In the following, the terms '*Accession Countries*' or '*Study Countries*' are used to describe those countries that are the subject of this report. Conversely, we use the term '*Member States*' when referring to those countries that are already members of the EU before May 2005.

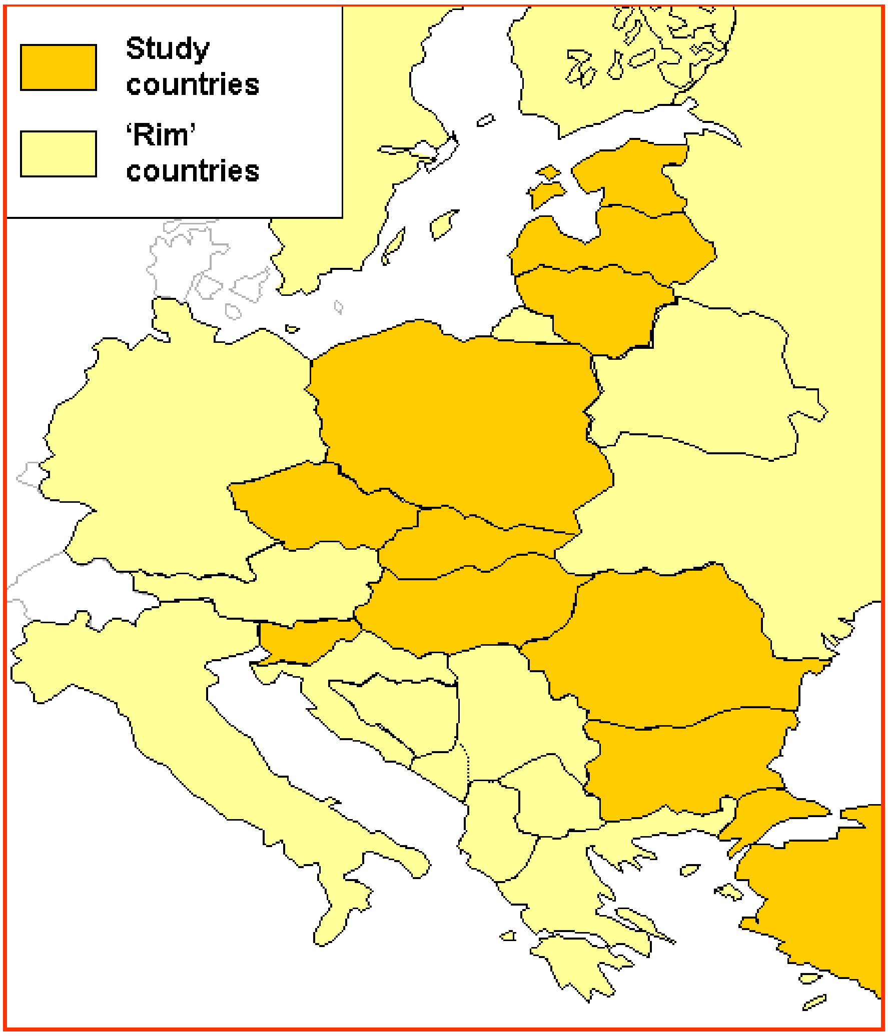

Figure 1: Countries analysed in this study

Figure 1 also shows a number of 'rim' countries. These need to be taken into account, in order to obtain a complete picture of the physical electricity flows and their possible variations due to changes in the generation pattern within the Accession Countries and their neighbours. Besides the Member States Germany, Austria, Italy, Greece and, to some extent, Sweden and Finland, we have also included (where appropriate) Albania, Belarus, Russia, Ukraine and the remaining successor states of former Yugoslavia in our analysis. Especially the transmission networks in former Yugoslavia have a potentially major impact on the flows between Accession Countries in Southern and South-eastern Europe. From a technical point of view, these markets have become an integral part of the IEM with the successful resynchronisation to the UCTE in October 2004 and may thus influence congestion within the IEM. Similarly, the power systems of Belarus and Russia have a major influence on the Baltic States.

2.2 Approach and Structure of the Report

To identify the most effective measures for the establishment of the Internal Electricity Market within the Accession Countries, it is necessary to perform an in-depth analysis of the current network structure and generation pattern as well as possible long-term developments. Interdependencies between injections and withdrawal of electricity and the resulting cross-border flows have to be taken into account when determining existing and possible future bottlenecks within the European grid. In order to assess the effectiveness of already planned or proposed investments, and to propose additional measures that may not yet have been considered, this project has been developed in three steps:

- Firstly, we have determined, which cross-border trade patterns may reasonably be expected within the Accession Countries, with existing parts of the Internal Electricity Market, and with further neighbouring systems during the study period (i.e. up to 2020). For this purpose, we have developed forecasts of the economic export and import potential in each relevant country, and the resulting economically desired cross-border flows. Due to the extended study period, we have considered different scenarios to reflect the impact of different fuel prices, environmental factors, the future of nuclear energy, and the desire to increase the share of renewable energy sources.
- Secondly, limitations may be caused by both physical factors, e.g. insufficient capacities, as well as by the procedures, which Transmission System Operators (TSOs) apply to determine available capacities. Besides modelling of the future market and careful analysis of the transmission grids, we have described and analysed what methods the TSOs currently use for definition of available cross-border capacities and what allocation mechanisms are applied. In this context, we have proposed some so-called ‘soft-measures’ that may help to increase transmission capacity.
- Thirdly, based on the analysis of current and expected constraints, and possible short-comings of the way available capacities are determined by the TSOs, this study has analysed a set of possible solutions that may make additional cross-border

capacities available to the market. Based on the fundamental analysis of the economic export and import potentials, our final recommendations thus particularly consider the trade-off between the expected costs and economic benefits of each alternative. Finally, we have assessed a number of projects that have been put forward as projects of common interest in the framework of the Trans-European Networks and given an indicative view on their importance and economic benefits for the successful establishment of the IEM also in the Accession Countries.

These three steps towards the identification of the existing and possible future constraints to the successful extension of the Internal Electricity Market (IEM) to the Accession Countries constitute the structure of this study. Following this introduction, chapter 3 focuses on the future generation patterns and the import and export potential of the study countries to identify the possible trade patterns up to 2020. In the following chapter 4, we analyse the mechanisms used for the determination and allocation of transmission capacity. As a third step, chapter 5 examines the main areas of congestion within the Accession Countries and planned reinforcements. The analysis of the costs and benefits of proposed network extensions in chapter 6 then enables us to prioritise the proposed extension projects. In chapter 7, we summarise the main results of this study.

2.3 Data and Information Sources

The quality of this study, and thus the correct determination of necessary investment projects, crucially depends on the quality of the input data used for the models and simulations. We have therefore spent considerable time and efforts on collecting and verifying the data required for our analyses. Moreover, we have contacted both UCTE as well as the TSOs of the Accession Countries, selected Member States and some other neighbouring countries, and asked them for selected power system data and information on current procedures for determining and allocating cross-border transfer capacities.

Unfortunately, however, some TSOs, including UCTE, did not agree to provide the requested data to us. Amongst others, we have therefore not been able to perform load flow calculations of the entire region, in order to better assess the technical impacts of future changes in generation on the regional power flows, as originally envisaged. Consequently, we had to rely on a more qualitative analysis of publicly available information, the results of previous studies and, most importantly, personal interviews with all relevant system operators that agreed to meet us. In this context, we would like to express our gratitude to those TSOs that have been supporting this study.

To supplement the information received from the TSOs, we have also made extensive use of other publicly available studies and data, including those published by international organisations like UCTE, ETSO, IEA, OECD or EURPROG. In addition, the European Commission has made available to us a selection of previous reports.

3 Future Generation Patterns and Import/Export Potential

3.1 Overview

As explained in section 1 above, the objective of this task has been to analyse current and future generation and load patterns, with a view to defining the economic export and import potential in the enlarged EU and in the Accession Countries up to 2020. For this purpose, we have developed a market model that includes all relevant Accession Countries as well as the neighbouring EU and non-member states. Based on this model, we have simulated potential market outcomes, as well as the resulting cross-border flows, for the years 2003, 2010 and 2020. The results have then been used to identify the most important areas of congestions in terms of volume and value. Additionally, we have performed supplementary simulations to check for the sensitivity of our results to changes in certain input parameters, and for the influence of strategic bidding. Finally, this model has subsequently been used to assess the economic value of additional interconnection capacity under Task 4 (see section 6).

The remainder of this chapter 3 is structured as follows: First, section 3.2 provides a general overview of the methodology underlying the market model. Given that the future market development is subject to considerable uncertainty, we then describe the different scenarios that we have considered in section 3.3. Following a description of the tools and assumptions that we have used (section 3.4), section 3.5 presents the main results of our simulations. Within the last section 3.5, we also comment on the supplementary sensitivity analysis and our findings on the impact of strategic bidding.

3.2 General Methodology

After liberalisation, the price of electricity and the utilisation of different power plants are determined through the power market. As in any other market, prices may deviate from costs, e.g. due to imperfect information, strategic behaviour or market power. However, at least in the long run, one may still reasonably expect prices to follow production costs, and that power plants will only be used if their marginal costs are below market prices. Furthermore, while the underlying technical and cost data are available for most countries, or can at least be estimated with reasonable accuracy, there do not exist any (reliable) statistics of electricity market prices for many of the Study Countries.

In consequence, we have decided to simulate market behaviour by means of a production simulation tool that allows determining the least-cost dispatch of power plants while taking account of limited cross-border capacities. Based on existing data and information and the expertise of our regional and technical specialists, we have built a European market model in the well-known production simulation tool PROSYM. This tool is based on a least-cost

cost dispatch where the underlying power system is described with power plant characteristics and cross-border network constraints. Besides the technical parameters to describe production and main network characteristics, the main remaining input factors are costs/fuel prices and demand.

To ensure consistency with existing studies on behalf of the Commission, we have used the PRIMES dataset as the basis for both generation and demand, supplemented by other information received from different TSOs, as well as publicly available data e.g. from UCTE, ETSO, annual reports and other sources. As an output, PROSYM provides information on the marginal costs in each country, the cross-border flows between different countries, and the total costs of the entire system (i.e. all countries covered by the model). Based on this information, it is possible not only to determine constrained transmission interconnectors, but also to calculate country price differentials and potential cross-border congestion rents.

To calibrate the model and to check its accuracy, we have first performed simulations for the year 2003 (the reference year) where information on actual market prices and (physical) cross-border flows is available. Thereafter, we have run additional simulations for the years 2010 and 2020 to analyse the future development of generation, export and import patterns, and to assess the influence of new interconnector projects. Due to uncertainty about future development, we have additionally tested the sensitivity of our base case to changes in e.g. the rate of growth in generation capacity and demand, the future generation structure, or the development of fuel prices.

In a few cases, we have refrained from detailed market modelling but instead used a simple price forecast. This approach has been used mainly for Finland and Sweden, which both have a limited degree of interconnection with the study countries. Similarly, we have not modelled the generation and load of Belarus, Moldova, the Russian Federation and Ukraine in detail since preparation of a detailed model of the entire Russian power system would have extended well beyond the scope of this study.

As mentioned above, experience from liberalised electricity markets demonstrates that market prices often exceed marginal costs. In contrast, unit commitment models, such as PROSYM, typically set prices equal to marginal costs. As a result, one can often expect that market prices will be (substantially) higher than (marginal) costs, i.e. that electricity is sold at a mark-up. Especially in price-based markets, this mark-up may be increased through the exercise of market power; market prices may thus be affected by strategic bidding where producers are able to enforce higher prices by offering above their costs. Such abuse may be caused by high market concentration and can lead to a situation where e.g. low-cost countries export less electricity, or may even start importing. Hence, export and import patterns may be affected by strategic market players. To analyse the scope for strategic bidding, we have additionally studied selected scenarios by making use of the SYMBAD model, which is a proprietary model of KEMA Consulting.

3.3 Scenarios

3.3.1 Overview

To take account of uncertainty about future development, we have combined a baseline scenario with a number of supplementary scenarios for sensitivity analysis. These additional scenarios are supposed to cover changes in the most important input factors that may be subject to uncertainty. As further explained below, we have grouped the scenarios into three groups:

1. Reflecting changes in the future generation structure (generation scenarios);
2. Prices (price scenarios); and
3. General economic development (development scenarios).

Finally, several changes may coincide, e.g. there may be slower economic growth than expected with higher prices and a different generation structure than originally foreseen. Since the number of possible combination increases exponentially, it is impossible to consider all of them. Alternatively, our strategy has therefore been to proceed in a way that is sometimes also used for long-term network planning, namely to base our simulations on realistic but extreme developments. As illustrated by Figure 2, the range of extreme

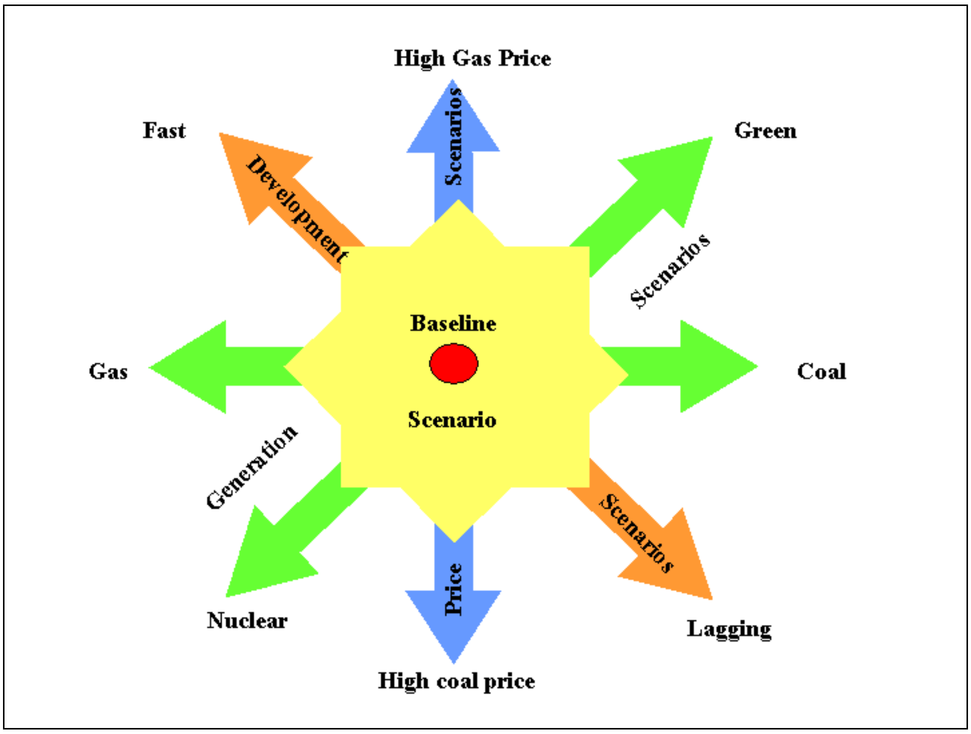

Figure 2: Use of extreme scenarios to cover the range of possible outcomes

scenarios encompasses a multitude of possible outcomes around the baseline scenario.[2] Furthermore, we assume that the impact of combining several scenarios will be somewhere between the individual impact of the extreme scenarios. Based on these assumptions, it seems reasonable to assume that consideration of the extremes will already suffice to cover most scenarios that are likely to occur in practice.

As a reference scenario, we have chosen the baseline scenario from the PRIMES dataset,[3] which had originally been established for a different study on the long-term energy outlook on behalf of the Commission. In addition, we have defined a total of 8 additional future scenarios as illustrated by Figure 2. These include a total of four *generation scenarios*, representing changes in generation structure (i.e. share of power produced from natural gas, coal, nuclear and green energy), three *price scenarios* with variations in gas, oil and coal prices, and two *development scenarios* to take account of faster or slower economic growth and development.

In short, these scenarios can be summarised as follows:

1. *Baseline scenario*

   Scenario based on the assumptions of the PRIMES dataset.

2. *Generation scenarios: Gas, hard coal, nuclear and green scenarios*

   The fuel mix has considerable impact on electricity prices. The four generation scenarios therefore consider differences in the generation structure. While coal and nuclear energy already play a significant role in the European power system, natural gas is expected to become a more important fuel source in the future. Finally, the EU and national initiatives for the promotion of renewables may result in an even larger share of 'green energy' than anticipated under the base case.

3. *Price scenarios: High gas price, high coal price and decoupled gas price scenarios*

   Future fuel prices represent a major source of uncertainty. We therefore consider variations in both natural gas and hard coal prices, which would have a significant impact on a substantial share of generation capacities. However, it is uncertain whether the current link between gas and oil prices will continue once European gas markets have been effectively opened up. In a third scenario, we thus consider a situation where gas prices remain 'stable' even under increasing oil prices.

4. *Development scenarios: Fast and lagging scenarios*

   Differences in economic growth can have a major impact on electricity consumption, especially in the Accession Countries with the previous fall of

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2 Please note that the extreme scenarios may not necessarily be symmetrically located around the baseline scenario.

3 PRIMES is a partial equilibrium model for the European Union energy system developed by, and maintained at, the National Technical University of Athens.

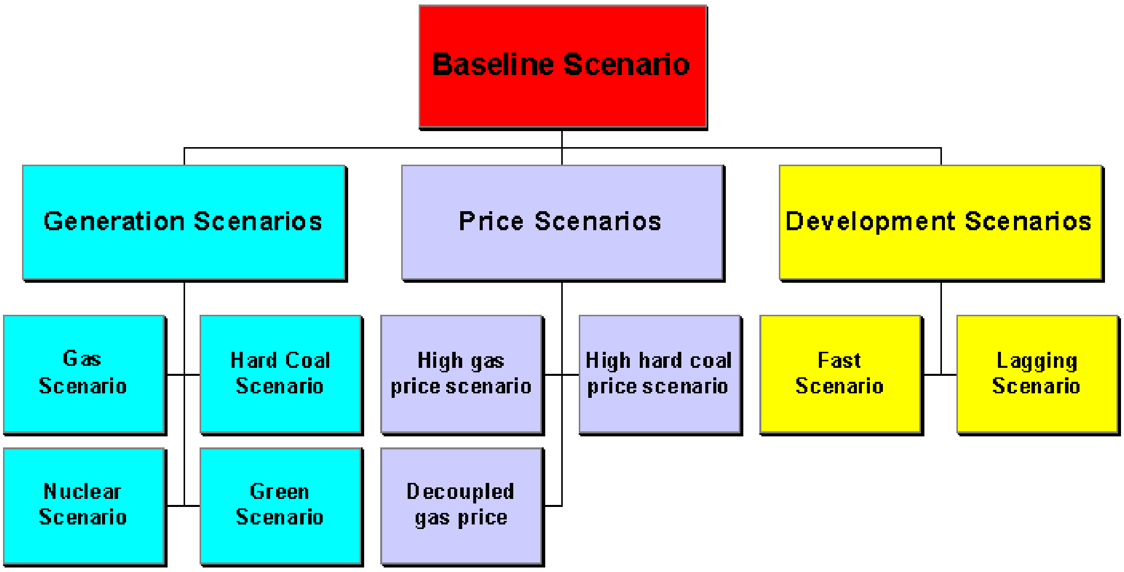


Figure 3: Development scenarios used in this study

demand in the early 1990s. Hence, current demand forecasts may turn out to be either overly optimistic or pessimistic. In the long-term, this should have corresponding effects also on the construction/replacement of production capacities. Here, we consider two possibilities, namely fast and lagging growth. In the lagging growth scenario, there are limited investments into power plants that may not be replaced at the end of their economic lifetime.

3.3.2 Baseline Scenario

The baseline scenario is based on the European Commission's PRIMES dataset. This dataset is based on a number of assumptions on, among others, demography, climate, macroeconomic development, and environmental policy. The dataset includes information about the development of the energy sector in the existing Member States, the Accession Countries and some neighbouring countries for some selected years until 2030. As illustrated by Figure 4 electricity demand in the study countries is assumed to increase by 2.0% annually until 2010, and by 2.6% annually between 2010 and 2020. Simultaneously, the expected growth in generation capacities amounts to 2.1% and 2.4%, respectively.

Figure 4 also shows that thermal power plants will contribute most to electricity production (70-75%). As illustrated by Figure 5 this can be further differentiated into plants fired by hard coal, lignite and gas. Despite a decrease in the coming years, hard coal will remain the main source of electricity produced from fossil fuels, with an increasing share in the next decade. This development is expected for all countries except the Czech Republic. In contrast, the share of lignite will decrease in all countries, while natural gas is expected to

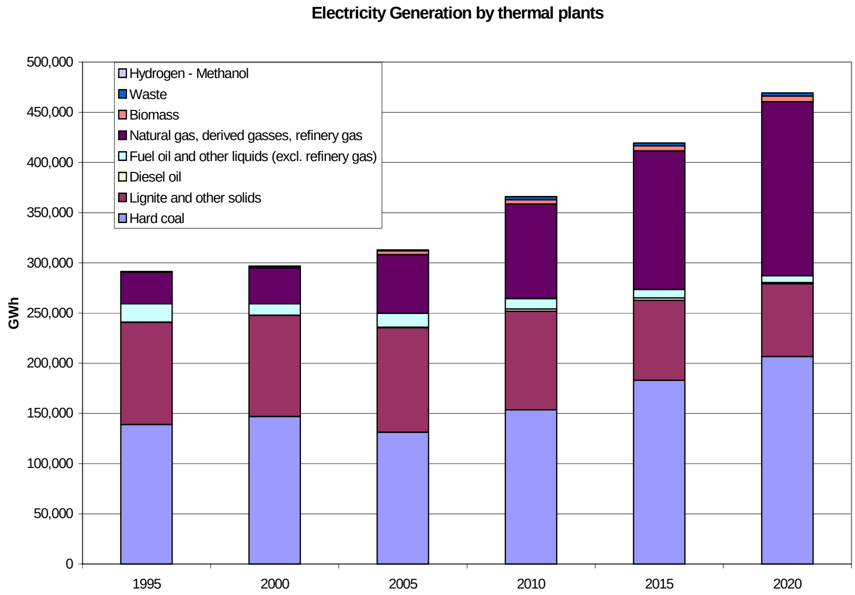


Figure 5: Electricity generation by thermal plants (source: PRIMES data)

become an increasingly most important fuel in the future: The share of natural gas in electricity generation is expected to increase from 9% in 2000 to 28% in 2020.

These developments are also reflected in Figure 6 showing the expected development for each of these three groups of plants until 2020. In particular, this figure illustrates the massive growth of gas-fired power plants, which is expected to increase by more than 400% between 2000 and 2020. In this context, it should also be noted that a significant share (around 30%) of electricity generation is also used for heating. According to the

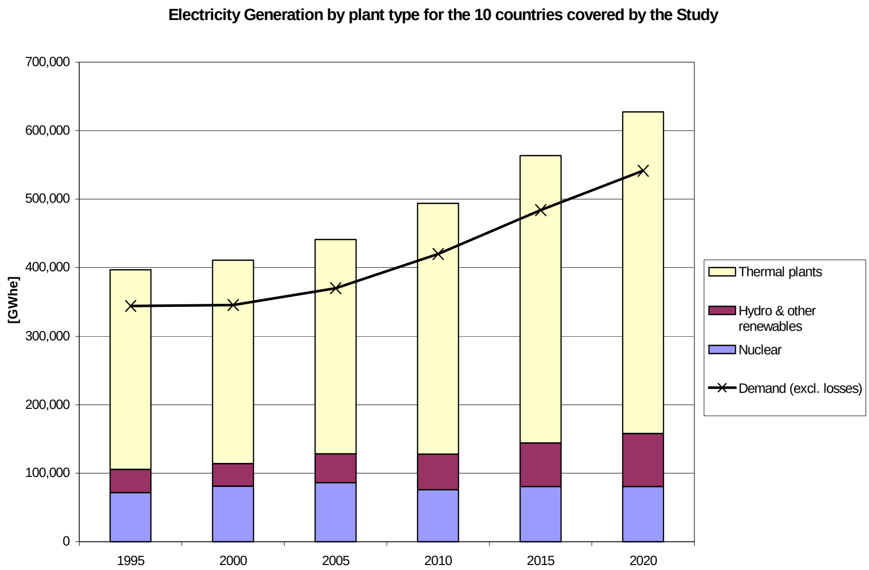


Figure 4: Electricity generation by plant type for the study countries (source: PRIMES data)

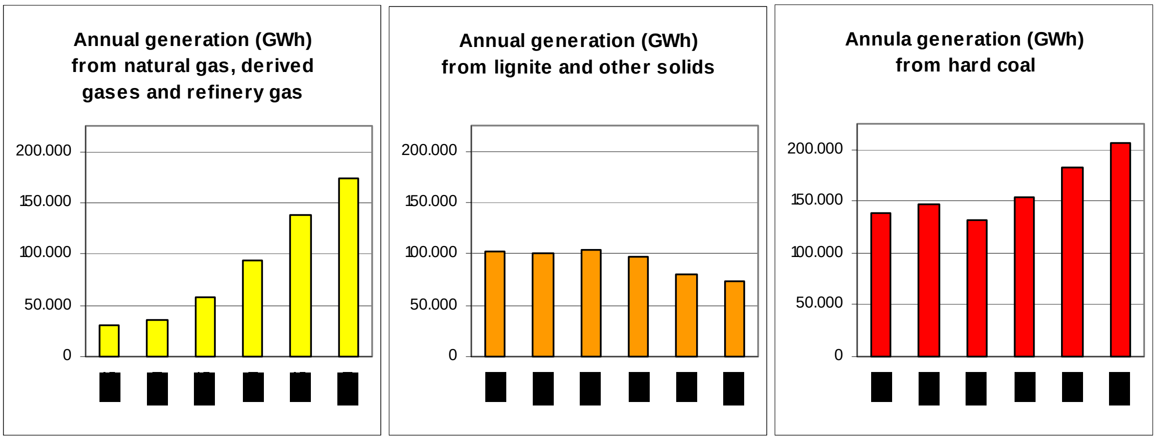


Figure 6:Electricity generation by major fuel (hard coal, lignite, gas) (source: PRIMES data)

PRIMES database, electricity generated by CHP plants will increase by 2.5% annually between 2000 and 2010, and by 2.2% from 2010 to 2020. This increase is similar to the growth in total electricity generation. The share of CHP will therefore remain largely constant during the study period.

While Figure 4 shows the relative importance of different fuel sources, Figure 7 illustrates the individual development of nuclear power plants on the one side, and hydro and other renewable energies, on the other side. The amount of nuclear generation is expected to slightly decrease until 2010 but be stable thereafter, mainly due to the decommissioning of existing plants in accordance with corresponding agreements between different Accession Countries and the EU. In contrast, electricity production from renewable sources is expected to grow by 4 – 5 % annually, i.e. considerably faster than demand.

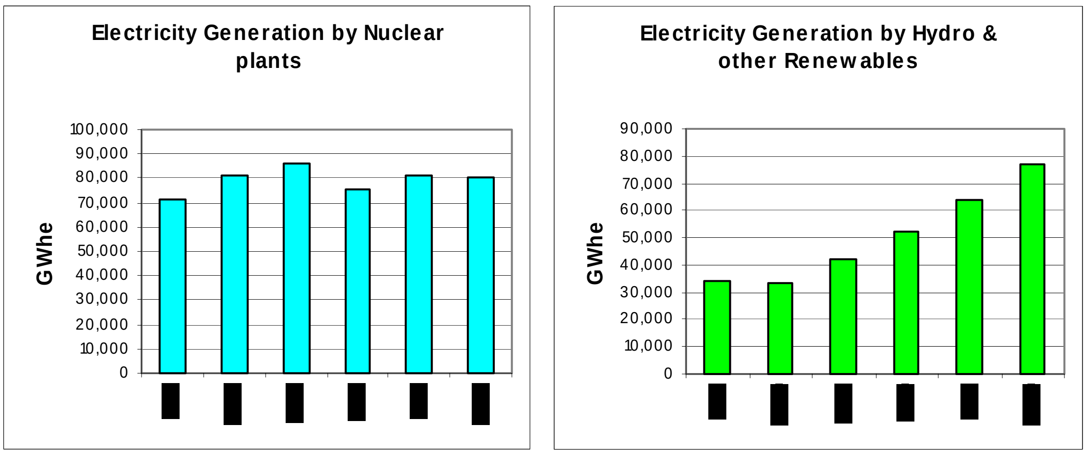


Figure 7: Development of nuclear plants, and hydro and other renewables (source: PRIMES data)

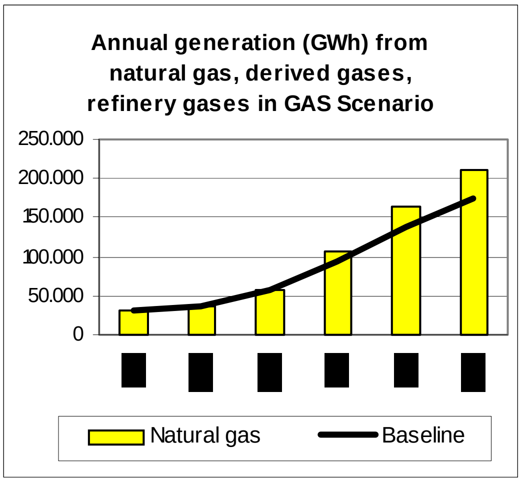
3.3.3 Generation Scenarios

As explained in section 3.3.1 above, the generation scenarios are meant to take account of possible differences in the fuel mix, i.e. the underlying generation structure. While the current generation structure is known, it may change in the future. The extended life cycle of generation equipment implies that such changes may only occur gradually. However, the long time horizon of the study provides room for considerable uncertainty. Besides new-built stations to cover load growth, this observation especially applies to the need to replace existing plants after the end of their lifetime. In this context, it is worth noting that the average age of power plants in many of the study countries is relatively high, indicating a considerable need for replacement over the next decade. Even if many of the future power plants may still be tied to the existence of indigenous fuel sources, the resulting generation structure may thus be quite different from the base case.

To keep the number of additional scenarios limited, we have decided to focus on changes in the three major sources of electricity, namely *natural gas*, *hard coal* and *nuclear power*. To also take account of the political objectives and commitments for increasing the share of renewable energy sources in electricity production, we have added a fourth scenario to study the impact of *over-achieving* these goals, namely a *green scenario*.[4] In summary, we have thus considered the following four scenarios as further explained below:

- Gas scenario;
- Hard coal scenario;
- Nuclear scenario; and
- Green scenario.

In the *gas scenario* (Figure 8), the growth of electricity production from natural gas is



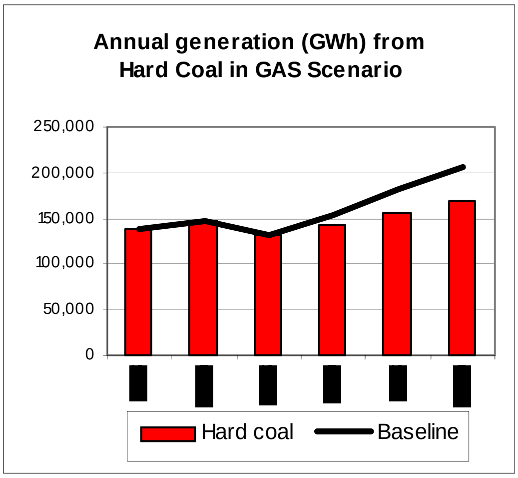


Figure 8: Changes in generation under the Gas scenario

4 The PRIMES study already took account of the objective towards the promotion of renewable energies.

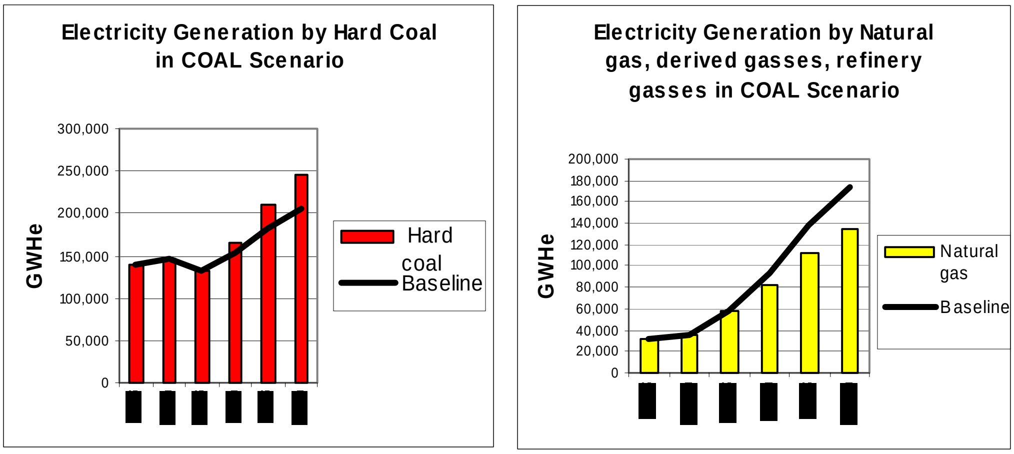


Figure 9: Changes in generation under the hard coal scenario

assumed to be some 40% higher than in the baseline scenario.[5] In order to ensure that total production is similar to the baseline scenario, the extra growth of gas-fired generation capacity is compensated by a corresponding reduction in the growth of power plants based on hard coal.

The *hard coal scenario* (Figure 9) is the opposite of the gas scenario. In this case, we assume that the growth of gas-fired generation is two-thirds lower than in the baseline scenario, this is compensated by a correspondingly larger share of coal-fired generation. Similar to the gas scenario, the total generation capacity remains constant.

The baseline scenario shows that in some countries the amount of electricity generated by nuclear fuels increases, while in other countries it decreases. However, it is possible that concerns about an increasing reliance on natural gas, combined with existing commitment

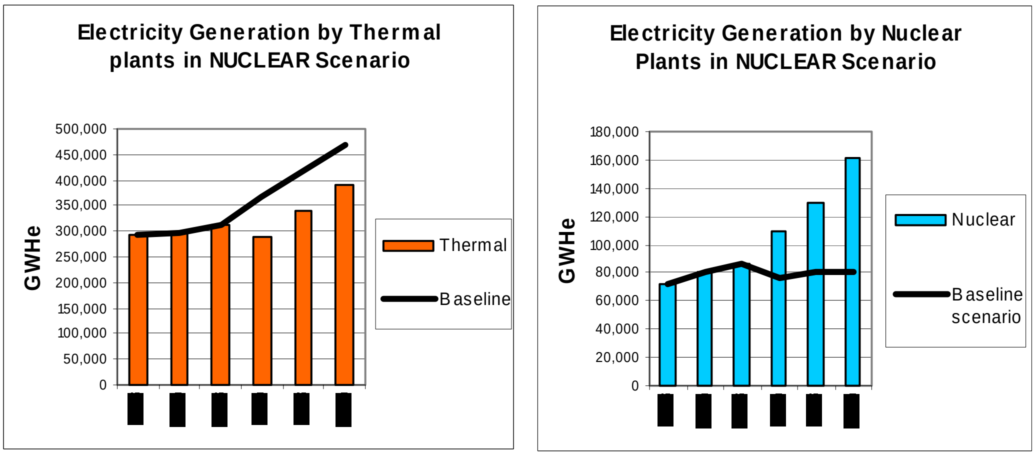


Figure 10: Changes in generation under the nuclear scenario

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5 It is assumed that the 2005 scenarios are accurate and that deviations from the forecasts occur in the 2005 - 2010 period.

to reduce CO_2-emissions, may result in a revival of nuclear energy. The *nuclear scenario* (Figure 10) therefore assumes that the capacity of nuclear power plants is twice of that forecasted by the PRIMES study in 2020, with a linear increase between 2005 and 2020. The additional electricity generated by nuclear plants is compensated for by a pro-rata reduction of thermal electricity generation.

The baseline scenario already shows a significant growth in hydropower generation and other renewables. To consider an extreme development, the green scenario (Figure 11) assumes that the growth of the hydro and other renewables is more than twice the growth from the baseline scenario. The additional electricity generated from 'green energy' is again compensated for by a pro-rata reduction of thermal electricity generation.

3.3.4 Price Scenarios

In contrast to the generation structure, prices are subject to considerable volatility. This may result in fuel prices being fundamentally different from the baseline scenario, thus creating a high degree of uncertainty. To some extent, this uncertainty is less critical for the current study, which focuses on the (physical) volumes of cross-border exchanges of electricity, rather than an accurate forecast of future market prices. However, variations in the fuel mix will cause a different impact on the competitive situation and thus the import/export position of the different study countries. For instance, coal-fired generation represents the main source of electricity generation in Poland, while natural gas plays a greater role in other countries. Depending on the relative price of coal against natural gas, Poland may thus experience a change in its competitive position on the European electricity market. Clearly, such variations will influence cross-border electricity exchanges, as traders will be looking for the least expensive source of electricity throughout the region.

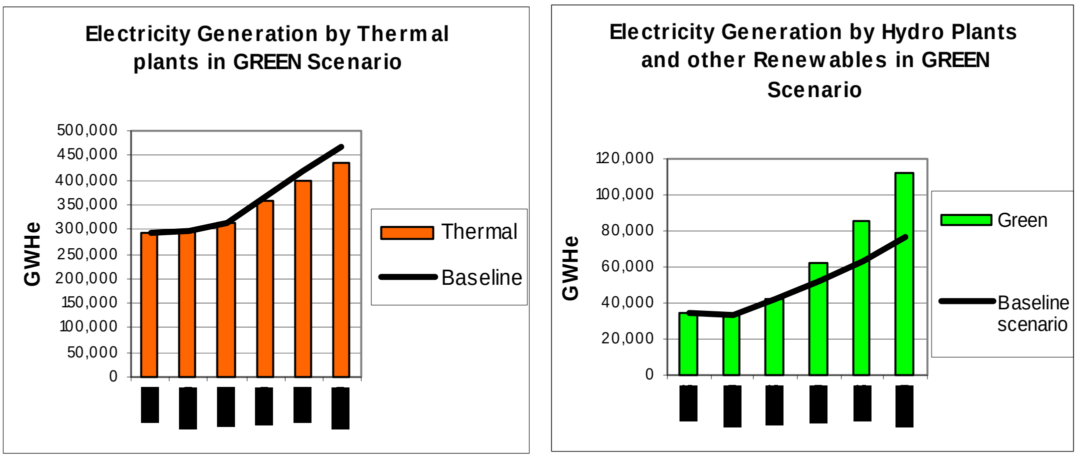

Figure 11: Changes in generation under the green scenario

Despite many types of generation technologies, it seems possible to limit the range of additional scenarios to just three. Our market model is based on a least-cost dispatch. Hence, the market outcome, and thus cross-border flows, will depend on variable costs only, but be independent from differences in fixed costs. As a result, there is no need to specifically consider variations in the price of hydropower or nuclear energy as both technologies can be considered to have far lower variable costs than any of the main competing technologies.[6] Conversely, it seems reasonable to consider the price of fossil fuels, namely coal, oil and natural gas. Here again, we believe that lignite can be neglected for two reasons: First, lignite is a purely local fuel that cannot be transported over long distances in an economic way, such that there does not exist anything like a market price across different countries or the entire region. Secondly, the construction and operation of lignite-fired power plants is often closely linked to the operation of the associated mining operations. Similar to the case of nuclear energy, one may thus assume that the main uncertainty is related to the underlying investment decision, but less the actual operation of an existing mine and plant.

In summary, we have thus decided to limit the price scenarios to differences in the price of hard coal, oil and natural gas. In continental Europe, the price of natural gas has traditionally been linked to the price of oil, such that variations in the price of one fuel (oil) will be followed by a corresponding variation in the price of the other (natural gas). However, the liberalisation of the gas market, and the increasing importance of LNG could result in an end of this price-coupling. We have thus studied the following three scenarios:

- *High hard coal price*
  Price of hard coal being twice as high as in the baseline scenario; The case of low oil prices is not considered since oil and coal are competing fuels and we already consider the case of higher coal prices.
- *High gas price*
  Price of oil and natural gas being based on a high oil price scenario;
- *Decoupled gas prices*
  Price of oil being based on a high oil price scenario; price of natural gas being the same as in the baseline scenario.

3.3.5 Development Scenarios

The two previous groups of scenarios have considered changes in the relative share and price of different energy sources and generation technologies. In addition, it is also the absolute volume of generation and load that may change. In fact, the assumptions on the future load growth are of fundamental importance for the simulation of the 2010 and 2020

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6 Please note that the impact of different fixed costs, which are a measure of the investment costs, is already covered by the generation senarios, which are based on the assumption of different investment decisions.

scenarios. Any changes in the growth of load could hence result in a situation with either drastic over- or under-capacities, or a considerably smaller or larger amount of generation capacity being built in the different countries. This may again have an influence also on the export or import potential of each country, and thus the economically desirable cross-border flows of electricity.

The average annual load growth in the study countries is forecasted to be about 2.0% between 2000 and 2010, and 2.6% in the period 2010 to 2020. Depending mainly on the future economic development in the region, growth may also be higher or lower. To show the influence of such lagging or faster development in these countries, we finally consider the following two scenarios:

- *Fast development*
  Both demand and generation capacity grow twice as fast as in the baseline scenario.
- *Lagging development*
  The growth of both demand and generation capacity is only 50% of that in the baseline scenario.

These scenarios are modelled by shifting the timescale of the forecasts. For instance, the 2007 forecast is used for the 2010 lagging development scenario, while the 2017 forecast (interpolated) is used for the 2010 fast development scenario.

3.4 Tools and Assumptions

3.4.1 Tools: PROSYM and SYMBAD

As already mentioned in section 3.2 above, we have used two different models for this study. First, we have used the unit commitment model PROSYM to perform all relevant market simulations. In addition, we have made use of our proprietary model SYMBAD that allows to analyse the potential impact of strategic bidding. In the following, we briefly summarise some of the main features of both models. Further technical details on PROSYM and SYMBAD are given in sections 8.1.1 and 8.1.2, respectively.

PROSYM is a probabilistic, hourly chronological power market simulation model that uses marginal costs for its calculations. PROSYM is primarily used to compare the economics and operating characteristics of power system configurations. The hour-by-hour model allows for the simulation of chronological events, such as start-up times, thermal plant ramp rates, thermal plant up and down times, and hourly spinning reserve constraints. In addition, it allows us to define the available transmission capacities between different market areas, thus making it possible to simulate a constrained generation dispatch.

PROSYM can be used for daily operations, for short-, medium- and long-term planning. Based on the existing infrastructure, the expected future power demand and the pre-selected future power units, power system configurations can be composed to meet future demand. Within PROYSM, the power system configuration is a representation of a scheme of available power units and distribution capacity. In addition, specific modules allow to stimulate a multi-area model with given transmission constraints. Most of these characteristics may change every hour of the year.

SYMBAD is a proprietary model of KEMA Consulting that has been developed to allow for the simulation of strategic bidding in power markets. The model incorporates the game-theoretical background of the Nash equilibrium and is based on the concept of the supply function equilibrium (SFE). SYMBAD is thus able to simulate a situation where players will compete in both price and quantity (i.e. defining a supply function) rather than competing only on price or quantity. Since this assumption fits well with the bidding rules used in most organized power markets (e.g. pools or power exchanges), the model allows for a better understanding of bidding behaviour in markets where market participants bid repeatedly. In contrast to other models based on the SFE approach, SYMBAD is able to handle asymmetric companies when there are more than two strategic companies.

3.4.2 *Generation of Electricity and Heat*

3.4.2.1 Grouping of power plants and approximations

The market model for this study covers about 20 different countries with thousands of different power plants. In theory, it would be necessary to model these plants individually, with the corresponding technical data, age and efficiency. Doing so would however require an enormous amount of work that would extend well beyond the scope of this project. Moreover, it seems difficult to defend such efforts with respect to the major degree of uncertainty associated with the simulation of the market outcome in 2010 and 2020. As an alternative, we have decided to model generation units on an aggregated level per country, thus drastically reducing the number of power plants. Simultaneously, this approach has the advantage of also reducing the computation time, thus making it possible to study a larger number of different scenarios. The plant groupings differ by technology, fuel, age and generation capacity.

While we have tried to use the PRIMES dataset as the basis for the generation modelling, we have not had access to the underlying input data, but only the outputs. Thus, it was not possible to directly derive e.g. data on the installed capacity of (future) plants, the load profiles or costs and efficiency. We have therefore supplemented this dataset by information from various other sources, most importantly a dataset of all European power plants from Platts,[7] as well as different reports and on-line data from UCTE.

Table 1: Generation technologies represented by the PRIMES dataset

- Nuclear	- Polyvalent units	- Supercritical polyvalent units
- Large hydro (excl. pump storage)	- Monovalent coal-lignite	- Gas turbines combined cycle
- Wind	- Monovalent oil-gas	- Small gas turbines
- Other renewables	- Monovalent biomass-waste	- Fuel cells
	- Clean coal and lignite	- Geothermal

As a starting point, the PRIMES dataset contains information about the share of different generation technologies (see Table 1) in different years, namely for 1995, 2000, 2005 etc. until 2030. It has thus been possible to use the data for 2010 and 2020 for our study, whereas we have interpolated the data for 2003 from 2000 and 2005 data. Since the PRIMES dataset does not provide information on individual plants, we have used the UDI dataset to extract information about the number of power plants and their capacities. To reduce the number of power plants and obtain a simplified representation of the power systems, we have grouped the power plants according to the following categories, separately for each generation technology:

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7 UDI (2000)

1. 25 MW ≤ $P_{installed}$ < 100 MW;
2. 100 MW ≤ $P_{installed}$ < 250 MW;
3. 250 MW ≤ $P_{installed}$ < 500 MW; and
4. $P_{installed}$ < 500 MW.

These categories can be believed to be a reasonable representation of different plant size that are characterised by differences in efficiency and costs. Moreover, this grouping ensures a somewhat even distribution of plants to the different categories, as each group contains between 14 – 32% of installed capacity. For each of these groups, we calculated the number of power plants and their average capacity and age within each category. In PROSYM, we then specified each group as a single power plant with 10 equal units.[8] For each country, generation technology and plant category, our model thus effectively consists of 10 different power plants.

Implicitly, all plants with an installed capacity of less than 25 MW represent a fifth category, which we have chosen to ignore for our simulations. Besides the small aggregate share of such plants of the total generation capacity, one may also reasonably assume that their use will not be determined by daily market prices, but rather be subject to self-generation, standing agreements or regulated prices. Furthermore, we had to take into account the fact that most of these plants are not considered in the either of the PRIMES, UDI or UCTE datasets.[9] For instance, the PRIMES dataset only contains information about large (public) power plants, where the UDI dataset provides information about all sizes of power plants. Likewise, the UDI database showed substantially more generation capacity for Germany than specified by UCTE. To ensure consistency between the PRIMES dataset and the plant groupings created from the UDI database, we introduced a slight re-rating of the resulting groupings where necessary. In the particular case of Germany, we completely left out category 1 (25 - 100 MW) and de-rated parts of category 2 (100 – 250 MW) to match the UCTE generation capacity.

3.4.2.2 Treatment of technical parameters and constraints

In order to set up the production simulation tool, it is necessary to define a variety of technical parameters. These include data about technical capabilities, efficiency and availability and are differentiated by generation technology, fuel, age of the power plant and, partially, its location (country) as further specified in section 8.1.3. Some of this information is already contained within the UDI database. Due to the grouping of plants into different categories and the establishment of 'virtual' plants by category and country,

8 This categorization has importance for thermal power plants where efficiency, availability and maintenance must be considered.

9 The PRIMES and UCTE power plant datasets mainly contain large power plants over 100 MW generation capacity in Germany.

this information cannot be directly associated to these 'virtual' plants. Moreover, in addition to the equipment-related parameters, it is also necessary to define e.g. the maintenance and outage rates, which can only be estimated but which may have a major impact on the resulting generation dispatch. Based on these considerations, we have decided to exclusively rely on the knowledge and experience of our own generation experts. This approach allows us to rely on a set of standardised assumptions for all countries concerned, and avoids any undesirable distortions by the use of input data from different sources and with a different degree of accuracy.

The fuel cost of a thermal plant depends on its efficiency, respectively heat rates. The efficiency of a thermal plant is determined by its technology, fuel and average age. Furthermore, this usually varies depending on the current production of a unit. Within this study, we have considered plants based on different technologies and with a very diverse age structure. Consequently, we have differentiated the average efficiency of different technologies and fuels as a function of age (i.e. years in operation), separately for different levels of production. Our main assumptions, which are generally based on KEMA Consulting's database on generation technologies, are summarised in section 8.1.4.

The use of power plants should normally be determined purely based on economic costs. In the case of hydropower, CHPs and wind power plants, the situation is however different because these plants depend on the availability of the corresponding form of primary energy, or may have to operate in accordance with the associated heat load. For these three types of power plants, we have therefore relied on the following assumptions and constraints regarding their use:

- Hydropower plants may be further differentiated into run-of-river, storage hydro and pump storage plants. Each of these three types represents specific problems when establishing a production simulation model. Generally speaking, the possible output of hydropower plants depends on the total hydro inflow and its distribution during the year, and may thus be subject to considerable variations both during a single year as well as across several years:
    - Storage hydro is characterized by a monthly energy amount in GWh and generation capacity in MW. The variation over the year of hydro inflows is specified by a monthly energy pattern that is profiled, based on selected years from UCTE data and Kema assumptions. The storage hydro amount and generation capacity were estimated from various sources such as UCTE generation data, and country specific energy agencies or generation companies.
    - The production of run-of-river is entirely dependent on the actual water inflow and is thus of a largely stochastic nature. We have therefore modelled run-of-river plants with maximum monthly generation capacities that may vary according to a monthly pattern that is profiled based on selected years from UCTE data and Kema assumptions. Run-of-river plants are energy restricted with an upper energy limit in GWh. Information about

generation capacity for run-of-river plants is obtained in a similar way as for storage hydro.

- Pump storage is treated hydro storage capacity, in order to avoid a significant increase of computational time.

- CHP is modelled by using electricity and heat generation energy data from Eurelectric. These data are available on fuel type level for most countries. For the remaining countries, we used information from the Kema database. The CHP generation capacity is multiplied by an annual CHP pattern and subtracted from the maximum generation capacity for the units that are defined as CHP generation. Based on data from the Kema database three annual profiled patterns were generated: the western European countries, Italy and the Baltic States. The pattern for the western European countries is a mix of industrial CHP and district heating. The pattern for the Baltic States is mainly district heating, while the pattern for Italy is approximately ¾ CHP and ¼ district heating. If several plants (and units) use the same fuel, the total CHP generation capacity is distributed among the power plants on a pro-rata basis.

- Wind power has been modelled as thermal plants with high forced outage rates and must run commitment. Minimum and maximum generation capacity constraints are set equal. The forced outage rates for wind power were calculated as the ratio between the simulated energy from the PRIMES dataset and the maximum generation capacity times the number of hours in a year. The number of wind power units is set equal to 10 for all to allow for that wind power generation is between an "all or nothing" outcome.

3.4.3 Demand and Load Growth

Electricity markets may clear at different prices for every hour of the year. Consequently, the value of cross-border capacities, when defined as the difference in market prices on both sides of a border, may also vary hour by hour. This again may result in changing cross-border trade patterns over time, possibly also on an hourly basis as also confirmed by practical experiences from published data for some Western European borders. In order to obtain a realistic assessment of both international trading patterns and the value of cross-border capacities, market simulations should therefore best be run with an hourly time increment and associated load data. Conversely, using average or net values, e.g. on a weekly or monthly basis, may not allow to accurately determine the real economic value of transmission.

Unfortunately, hourly load data are published by very few TSOs only. In our questionnaires, we therefore asked the TSOs to provide historic load data on an hourly basis or, alternatively, a combination of (typical) daily load curves and annual load patterns (energy per month) for the last five years. However, many TSOs did not return corresponding information to us. As a solution we have therefore relied on other sources, such as from UCTE or annual reports. For instance, the UCTE publishes the aggregate monthly load and the load profile for the third Wednesday of each month; this information is provided separately for most of its members. In addition, the UCTE website also contains weekend (Saturday, Sunday) load profiles on a monthly basis for most UCTE members. For other countries, such as the Baltic States, Bulgaria, Romania, Turkey, Albania or Scandinavia, we have either relied on direct information for the corresponding TSO (e.g. Latvia), published reports (Lithuania) or made an expert estimate based on information from neighbouring countries.

In summary, we have thus relied on the following approaches for determining the hourly load profiles for the year 2003:

- Where available, we have used the hourly load pattern for the entire year, adjusted to the total annual electricity demand in 2003;[10]
- Where we had information on the monthly energy consumption and daily load patterns, we assigned the relevant load patterns to each day of the month and then re-rated the resulting hourly load pattern for the entire month to actual consumption in that month;
- For all study countries where we had neither of this information, we created an estimated load profile based on the load profile of a 'similar' country, adjusted to the actual annual and/or monthly consumption of the respective country.

To obtain the respective load profiles for the years 2010 and 2020, we relied on information mainly from the PRIMES dataset and the UCTE System Adequacy Forecast (UCTE 2004). The UCTE forecast was used to escalate both generation and load for the year 2010. Where the UCTE forecast did not provide any data for 2010, and for the year 2020, we used the escalation of the PRIMES dataset. In case where neither of these sources contained the required information, we occasionally calculated values based on other information. Similarly, we extrapolated the 2020 data from the 2003 and 2010 values for those countries that were not covered by the PRIMES dataset.

3.4.4 Consideration of Cross-Border Capacities

The main objective of this study is to assess the value of transmission, and the costs of congestion caused by transmission constraints. As explained above, the PROSYM tool allows for the simulation of a constrained generation dispatch, i.e. under consideration of network constraints. In order to obtain a real least-cost dispatch, the preferable choice would thus have been to use the TOPS-module of PROSYM (see section 3.4.1) that can determine the full optimal power flow solution. However, in contrast to e.g. Northern

[10] For instance, where the sum of all hourly values across the year was x% below the actual load for the year 2003, we have divided all values by (100-x)% to adjust the profile to actual annual demand.

America, the continental European power markets are based on a separation between the allocation of network capacities and the decision on the generation dispatch. That is, in most countries, market participants are generally free to decide on the production of their power plants within the corresponding country, while all potential constraints are solved by the TSO.[11] In contrast, the commercial use of cross-border capacities is limited to the net transfer capacities (NTC) that have been published by the corresponding TSOs in advance, even if there remains any spare capacity. These NTCs however are a purely commercial measure, i.e. their commercial use is no longer subject to physical laws.

Broadly speaking, the European power market thus consists of various markets – typically a country – that are interconnected by single links between two (or in some cases more) countries or markets. Mathematically speaking, the commercial market can thus be described as a graph with a number of nodes and links in between. While each node represents a market or country with all associated generation and load, the links can be interpreted as the NTCs between those market areas. Within our market model, we have thus defined each country as a single market area. All power plants and load of that country are assigned to this single area (or node) such that we do not model any internal congestion. For the links between these market areas we have used the NTC values as published by ETSO or the corresponding system operators; with a potentially different value for each direction. Where different system operators have specified several values, we have generally applied the lower one, i.e. a conservative approach. Where no realistic values can be given (e.g. for exports from Italy to Austria and Slovenia), or for the unconstrained runs, very large interconnector capacities are assumed. For the 2010 and 2020 simulations, we have adjusted the network topology and NTC values based on information about planned interconnector projects In accordance with current ETSO procedures, we have specified different NTC values for summer and winter months.

[11] Naturally, the corresponding actions by the TSO will still have an influence on the generation dispatch, e.g. by asking certain generation units to increase or decrease their output. However, this interference is different from a co-optimisation of generation and transmission. Furthermore, such actions typically occur only after the submission of schedules to the TSO, i.e. after the closig of the day-ahead market.

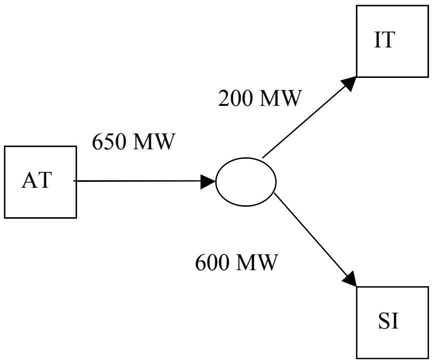

Figure 12. Illustration of how multiple transmission constraints are modelled by introducing a dummy node.

For some of the NTCs, two or more countries are specified simultaneously at the origin or destination nodes. In these cases, we have introduced additional dummy nodes into our market model. For illustration, an example is given in Figure 12: We assume that there is a joint transmission constraint of 650 MW from Austria to Italy (IT) and Slovenia (SI), combined with a transmission constraint from Austria to Italy of 200 MW, as well as a transmission constraint from Austria to Slovenia of 600 MW. To account for these interrelated transmission constraints we have introduced a dummy node between Austria, Italy, and Slovenia (see Figure 12).

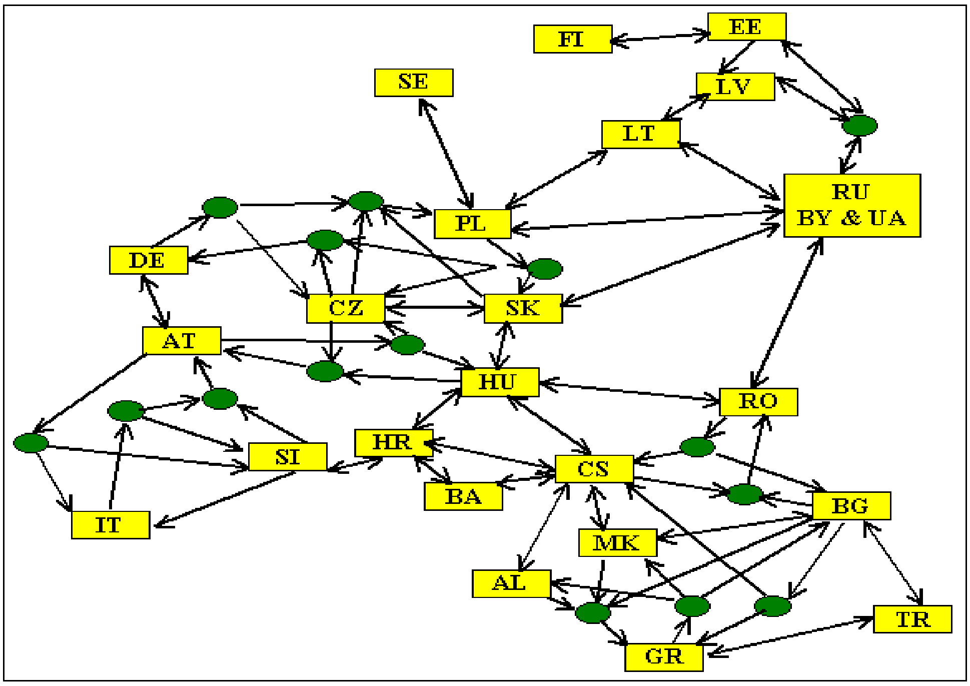

Figure 13: Modelling of transmission constraints in the market model

Based on these assumptions, we have created a complete representation of the study countries and the neighbouring power markets, and the (potential) interconnections, as illustrated by Figure 13. This graph shows all existing interconnections, as well as potential future links, between the different countries and the use of dummy nodes to take account of 'regional' NTC values. For comparison, Figure 14 additionally shows the actual interconnections between the countries under study.

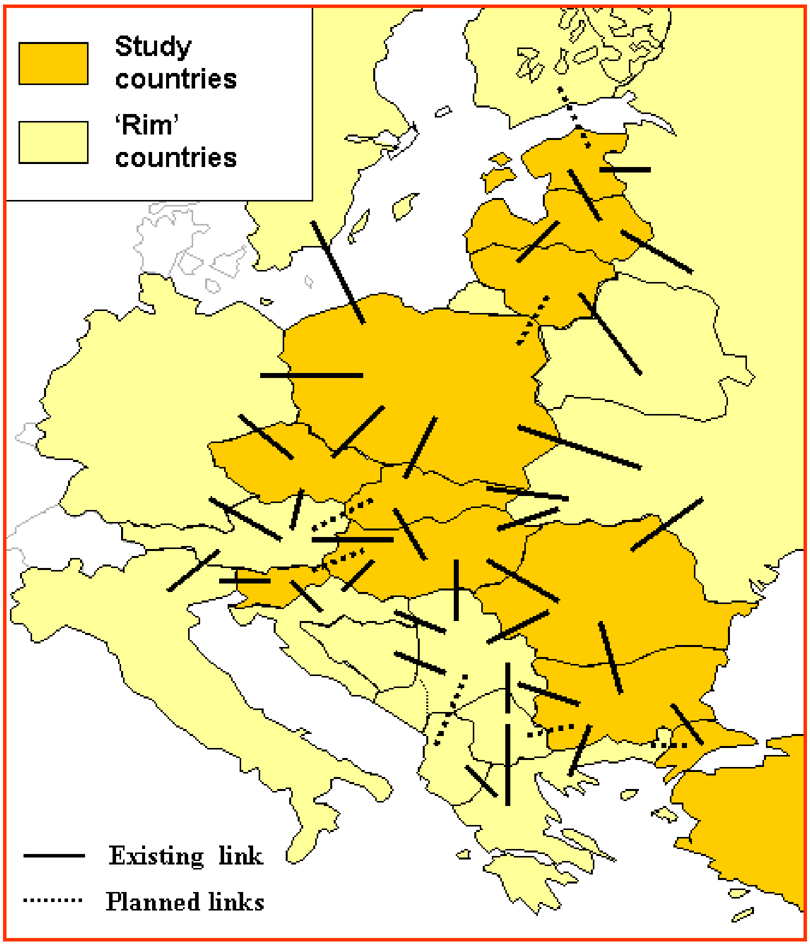

Figure 14: Interconnections between the countries under study

Note: Several interconnections between the same countries shown as single link only.

3.4.5 Costs Assumptions

3.4.5.1 Fixed and variable operating and maintenance costs

The costs considered in this study are fixed and variable operating and maintenance costs. We describe each of them in the following:

Fixed costs, start-up costs, and variable operating and maintenance costs are specified in the PROSYM tool. The most important variable operating cost is the fuel cost, which will be described in the next section. The other costs are specified as:

- Start-up costs in Euro per start and in GJ/MW and start fuel, which is the amount of fuel used to commit a unit.
- Variable costs in Euro/MWh and fixed costs in Euro/MW for maintenance and operation.

In our simulation these are based on technical information from the Kema database. In principle, we could adjust the fixed costs and variable operating and maintenance costs with an index depending on the general economy of each country such as gross domestic product to reflect, for example, differences in wages. However, the most important costs are the fuel costs, which determine the marginal costs and country prices.

3.4.5.2 Fuel costs

This study considers the years 2003 (the reference year), 2010 and 2020. The price of fuel represents one of the main parameters influencing the results of this study. It is therefore important to define a set of reasonable price estimates for each year, whereas additional variations of (future) prices are taken account of through the use of different price scenarios as discussed in section 3.3. For the year 2003, we have been able to use historic prices. Conversely, we have had to rely on price forecasts for the years 2010 and 2020. To facilitate comparison of the results between different years, all fuel costs are expressed in real 2003 prices.

The most important fuels used in the study are:

- Anthracite and bituminous coal (hard coal)
- Lignite (brown coal)
- Heavy and light fuel oil
- Natural gas
- Uranium

In addition, we consider the following fuels respectively groups of fuels as follows:

- Oil shale (only relevant for Estonia, current prices are available)
- Fuels with prices similar to coal: blast-furnace gas, coal gas (from coal gasification), coke oven gas, coal-water mixture, digester gas (sewage sludge gas), refinery off-gas, waste heat, and geothermal
- Fuels with prices similar to natural gas: liquified petroleum gas (similar to natural gas prices), light fuel oil (50% extra of natural gas prices)

- Fuels with prices similar to oil: naphta (similar to light fuel oil prices), gasified fuel oil (similar to heavy fuel oil prices), distilled oil (in between heavy and light fuel oil prices), and oil (similar to heavy fuel oil prices)

For 2003, we have generally used historic prices based on data from the International Energy Agency, supplemented with information from various other sources, such as energy agencies and the KEMA database. There are however few sources about country-specific prices for oil, natural gas and coal prices. Yet, fuel prices may differ due to differences in the costs of purchase or exploitation/mining, transportation and levies. Moreover, prices in many Central and Eastern European countries are still subject to regulatory control. For example in Romania, the price of hard coal is set by the government and may change over the year. Similarly, the price of lignite is set by the government and has a cap that also may change over the year. Therefore, we have adjusted the world market prices based on our knowledge about the specific country.

Due to the long time horizon of this study, it has been impossible to use any fuel prices quoted in the forward markets. For some fuels, namely oil, natural gas and hard coal, we have relied on data published by the International Energy Agency. In contrast, we have assumed the price of e.g. nuclear fuel (uranium) to remain stable. With a view to regional differences, we generally expect prices to converge to the world prices during the study period. When estimating country-specific prices for 2010 and 2020, we have thus used the following general philosophy:

- Fuels from world markets, like oil and imported coal, are equal in 2010 and 2020 for all countries, except for transportation cost where applicable;
- Levies will have been harmonised throughout the EU;
- Gas prices are linked to oil prices, except for the ‘Decoupled gas prices’ scenario where we assume gas-to-gas competition;
- Prices of domestic fuels will rise due to rising cost of exploitation (level of wages).

One of the major uncertainties is related to future oil prices, which traditionally show substantial volatility. In accordance with our definition of different price scenarios, we have thus used two different scenarios for future oil price development: a reference price forecast for e.g. the base case scenario, and a high price forecast for the ‘high gas price scenario’ and the gas-to-gas competition scenario.

A summary of our different assumptions and the resulting price forecasts for the years 2003, 2010 and 2020 is given in section 8.1.5.

3.5 Results

3.5.1 2003 Reference Scenario

In order to test our market model, we have first performed a simulation of the year 2003 as the reference case (2003). By comparing the results of our simulation to actual flows in the year, we have been able to verify and, where necessary, calibrate the model. Only following the building, testing and calibration of the model for the year 2003, we have used then this model to forecast the potential cross-border flows in the years 2010 and 2020. In this section, we therefore briefly summarise some of our main observations for the year 2003, before discussing the main findings for the years 2010 and 2020 in the following sections.

In general, our simulations for the year 2003 show flow patterns and areas of congestion that are largely comparable to those observed in practice (compare also section 4.2). For instance, our simulations show severe congestions from Austria and Slovenia to Italy, from the Czech Republic to Austria, from Slovakia to Hungary, or from Bulgaria and Macedonia to Greece. Similarly, we observe a more balanced exchange of electricity and/or lack of congestion on the borders between e.g. Bulgaria and Romania or between Croatia and Slovenia. When comparing these patterns to the actual situation in 2003, the results of our market simulations thus appear quite realistic.

However, it should also be noted that there are several instances where the outcome of our simulations is different from reality. For instance, our market model results in Poland both exporting and importing power over time, whereas Poland hardly ever is a net importer in reality. Similarly, the simulations show Italian exports to Austria and Slovenia, even if only for a very limited amount of time. While these observations seem to put into question the accuracy of our market model, there are reasons to explain these differences between the theoretical (i.e. modelled) and actual outcome.

First, one has to consider that PROSYM is an hourly unit commitment model, which calculates the least-cost despatch for every single hour. Hence, it will also consider situations where it is cheaper to keep a more expensive unit in operation than to import from another, low-cost country.[12] Such cases typically occur during the hours where the load is picking up quickly, i.e. during the morning. This may result in a reversed flow for just one or two hours. In reality, however, most power markets have not yet reached a corresponding degree of coordination and efficiency to fully exploit corresponding potentials. Nevertheless, one may already observe corresponding flow patterns between the Netherlands and their surrounding countries.

Secondly, most international trading, especially between the Accession Countries or between the Accession Countries and the ‘old’ Member States, is still based on base load

[12] I.e., due to start-up costs.

products. Thus, electricity is generally traded in constant amounts for a day, if not weeks, days or months. Consequently, current trading practices do not necessarily allow to take full advantage of corresponding opportunities, which will result in less efficient trading, and thus generation and flow patterns in practice.

Thirdly, the power markets in several study countries are still fully regulated (e.g. Serbia & Montenegro, Bosnia & Herzegovina), or subject to extensive power purchase agreements (PPAs) that cover most of the demand. For instance, most of the demand in e.g. Poland, Hungary and Romania is still served under corresponding PPAs. Since such arrangements effectively provide producers with a guarantee to sell, they will often produce even if it would be more efficient for the economy to purchase electricity from other sources. Last but not least, there are also reasons to believe that some generators try to sell 'cheap' base load power at certain prices, even if this requires them to use more expensive plants to cover their existing, regulated contracts. Although this is inefficient, we know from experience in Central Eastern Europe that corresponding cases are not uncommon.

In summary, we thus believe that the deviations between the simulated results and actual trading patterns in 2003 are rather a result of current inefficiencies in despatch and trading than indications for a major inaccuracy of our market model. Moreover, it should be considered that these deviations are limited, whereas our simulations results in the same major flow patterns and areas of congestion as observed in practice.

3.5.2 2010 Baseline Scenario

In addition to 2003, we have also created a new reference scenario for 2010, which we have then used to compare different transmission projects. For this scenario, and the subsequent analysis of investment projects, we used the official NTC values published for the summer 2004 and the winter 2004/2005 or, where these were not available, expert estimates. In this section, we briefly summarise the main results and observations from our corresponding simulations for the 2010 baseline scenario.

Figure 15 illustrates that there continue to exist major differences in congestion, separately in each direction as well as in total. While some borders are congested for most of the time, others show very limited or no congestion at all. To facilitate the subsequent discussion, we differentiate three groups of borders:

- Severe congestion - borders where congestion persists for more than 40% of time;
- Medium congestion - borders where congestion persists for 15 - 40% of time;
- Limited congestion - borders where congestion persists for less than 15% of time.

Based on Figure 15, it is easy to see that the most congested borders are those from Bulgaria to Greece, from Austria and Slovenia to Italy, and from Serbia & Montenegro to Croatia. Similarly, we observe major network constraints from the Czech Republic to

Slovakia, from Slovakia to Hungary, from Hungary to Serbia & Montenegro, from Serbia & Montenegro to Macedonia, and from Bulgaria to Romania.

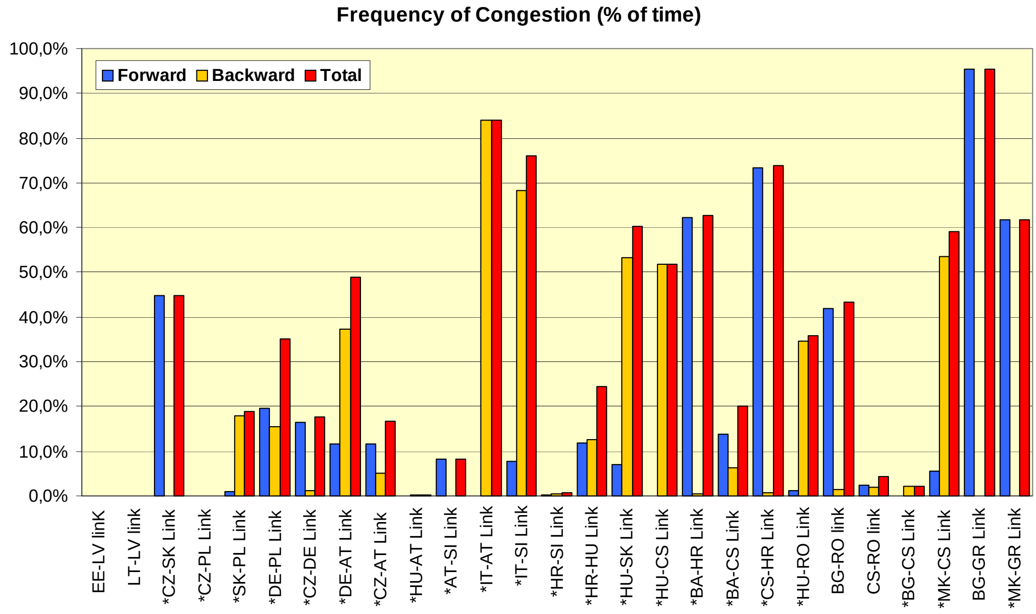

Figure 15: Frequency of Congestion at different borders in the 2010 baseline scenario

In the group of intermediate congestion, we find e.g. the borders from Slovakia and Poland, Czech Republic to Germany and Romania to Hungary. While all these borders show a predominant flow, there also are several other borders within this group that show substantial flows into both directions. The latter include the borders between Germany and Poland, Croatia and Hungary, Bosnia & Herzegovina and Serbia & Montenegro. Finally, the borders between the Baltic States, the Czech Republic and Poland, Austria and Slovenia, Croatia and Slovenia, Serbia & Montenegro and Romania, and Bulgaria and Serbia & Montenegro do not show any, or only limited congestion.

When comparing these results to the actual situation of 2003, or with our results for the 2003 reference year, it is obvious that many areas of congestion have remained, whereas others are new or have decreased over time. Amongst others, a major reason is the reconnection of the two synchronous zones of the UCTE in 2004, which allows for substantial exchanges of power in 2010 where previously no or only a strictly limited exchange was possible. Besides the directly adjacent countries, such as Hungary, Croatia or Serbia & Montenegro, this naturally also has an influence on neighbouring states. Overall, it thus seems likely that the reconnection of UCTE I and II will result in changing flow patterns over time.

Secondly, one has to note that the 2010 scenario is based on changing demand and generation structures, such as the increased use of gas throughout the region. In combination, these effects thus lead to a changing situation at different borders, while the main areas of congestion and the situation at many other borders remain unchanged.

3.5.3 2020 Baseline Scenario

Finally, we have also run a simulation for the 2020 baseline scenario. Although many flow patterns and areas of congestion remain the same, comparison of Figure 15 and Figure 16 also reveals some interesting variations. The most striking case certainly is the severe congestion at the Czech-Slovakian border but closer analysis reveals that this link was already heavily used in 2010. The other major change relates to the Italian border where congestion has been reduced dramatically. This can be explained by the increasing use of natural gas throughout Europe. Combined with the construction of new plants, this helps to increase the relative competitiveness of Italy.

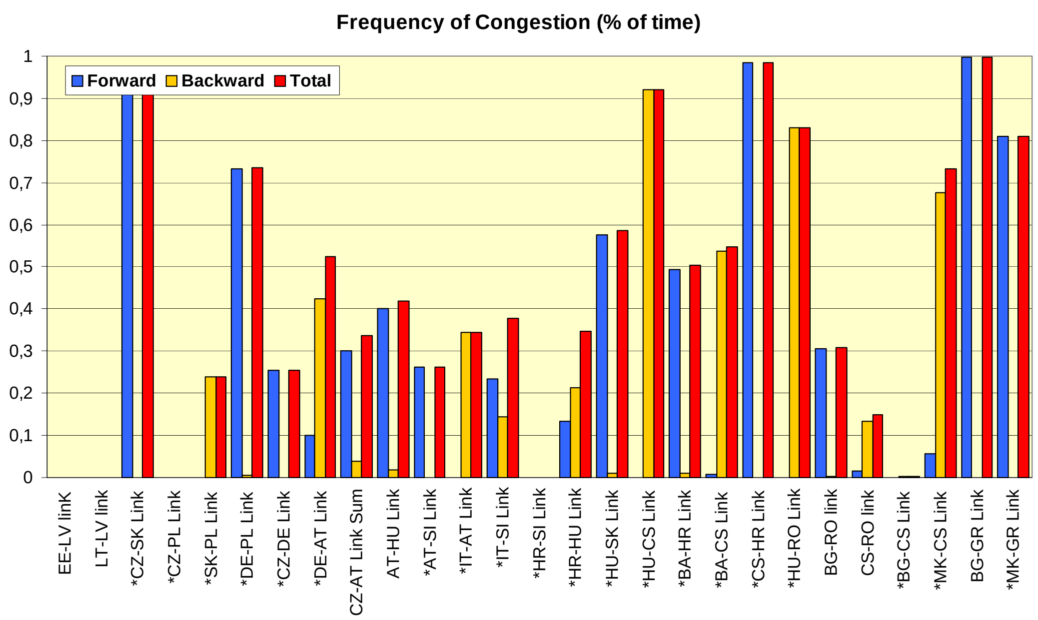

Figure 16: Frequency of Congestion at different borders in the 2020 baseline scenario

As also illustrated by Figure 17, we basically see increasing congestion at other borders, including at the connections from Germany to Poland, the Czech Republic to Austria, Austria to Hungary and Slovenia, Serbia & Montenegro to Hungary and Croatia, from Romania to Hungary, from Serbia & Montenegro to Macedonia, and into Greece. This does not come as a surprise since the 2020 scenario is based on substantially higher generation and demand than the 2010 scenario. Hence, it seems logical that there will be more constraints within the same network as a decade before. The main implication of these observations however is that, with the exception of Italy, the long-term forecasts do not show any fundamental changes in regional trading patterns.

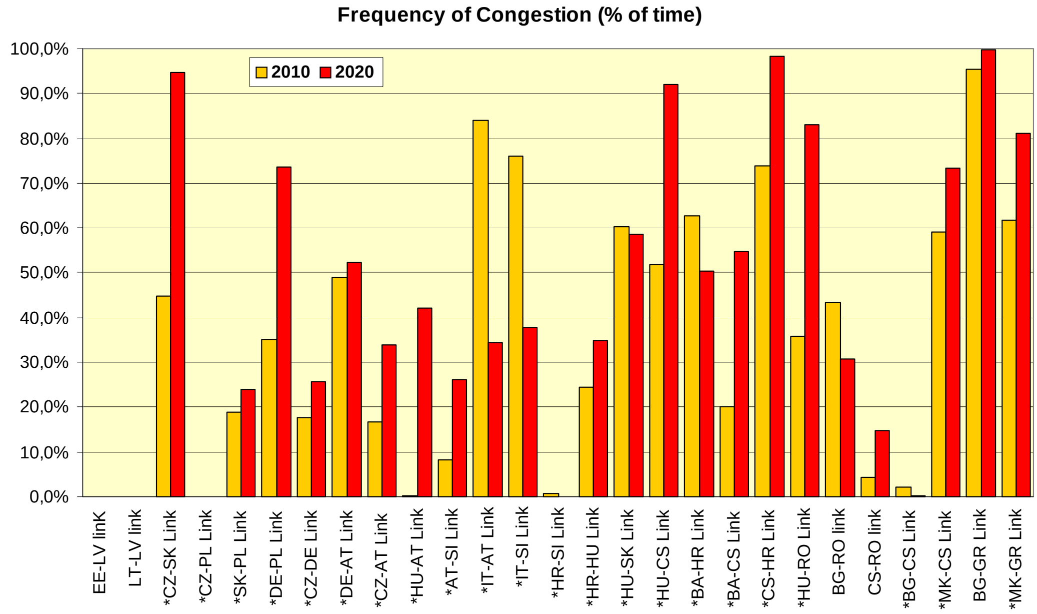

Figure 17: Change in Congestion between 2010 and 2020

3.5.4 Sensitivity Analysis

As described in the previous sections, we have used our market model to forecast the potential cross-border flows in the years 2010 and 2020. Based on the comparison of our results for the reference year 2003, we believe that the outcome of our forecasts represent a good assessment of the future market outcome under the assumptions made. In principle, though, a change in these underlying assumptions could result in substantial changes to the market outcome, including the cross-border electricity flows between different countries. In accordance with our general approach discussed in section 3.2, we have therefore performed an additional sensitivity analysis through the calculation of 9 scenarios that reflect possible changes in generation structure, prices or the general economic development with its influence on generation and demand. Similar to the assessment of investment projects (see section 6), our analysis has focused on the year 2010. In the following, we briefly describe the approach that we have used to analyse the regional flow patterns and the degree of congestion. Thereafter, we briefly summarise the main results of our sensitivity analysis, while a more detailed discussion can be found in section 8.2.

For comparison of different scenarios, as well as the analysis of flow patterns and congestion, we utilise some kind of '*flow duration curves*'. Similar to the well known case of load or price duration curves, the flow duration curves shows for many hours in a year the cross-border flow (in a certain direction) has been at least as high as the value indicated on the vertical axis. For instance, Figure 18 illustrates an example for the cross-border flow between Hungary and Romania.

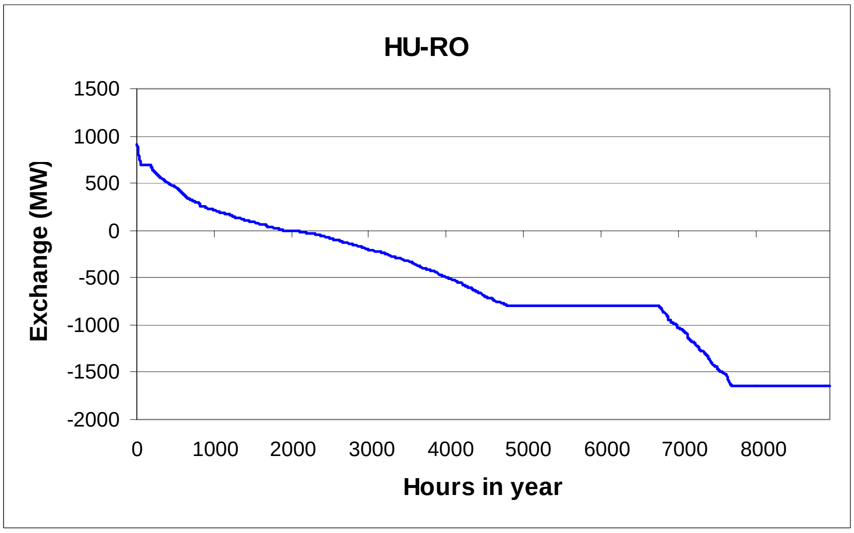

Figure 18: Example of flow duration curve

This curve shows that the flow across this border has been in the direction from Hungary to Romania for some 2000 hours during the year, with a maximum of 1100 MW, which however was reached for a few hours only. Conversely, there have been extended periods of time, namely some 1500 and 2000 hours where the export from Romania to Hungary amounted to 1650 MW and 800 MW, respectively. These horizontal line segments can be easily identified as periods of congestion. In contrast, the line segment where the curve ‘moves’ from approx. +700 MW to –800 MW obviously represents those periods where this line was not congested. In summary, the flow duration curve thus provides for a suitable means of measuring and visualising congestion. Moreover, the areas above respectively below the horizontal axis also give a good indication of the total flow in both directions.

The results of our sensitivity analysis basically confirm that our market model can be regarded as a reasonable representation of the Internal Electricity Market. In most cases, the changes under different assumptions remain moderate to negligible, thus generally supporting the results of our 2010 baseline scenario. The only exceptions are the nuclear scenario and the fast development scenario, which both show a significant, even if still limited influence on a number of individual flows. Despite the numerous variations of individual flows, though, we believe that our baseline scenario provides for a reasonable representation of the future market outcome. To start with, it should be considered that we have chosen rather extreme scenarios. The actual future development will thus likely remain somewhere between the extremes of our nine different scenarios. Consequently, one may also reasonably expect the resulting changes to be less marked than in any of our cases. At the same time, none of these scenarios, not even those with the most significant changes, results in a fundamental changes of regional flow patterns. This observation indicates the robustness of the main results of our market simulations against changing circumstances in the short to medium term.

Nevertheless, especially the nuclear scenario also highlights the fact that the prevailing flow patterns may be subject to change over time. Combined with the changing behaviour of market participants in the emerging Internal Electricity Market, those borders that are highly congested today may face less constraints in the future, whereas new bottlenecks may occur at other places, even if only for a limited amount of time. Moreover, our sensitivity analysis indicates that it is especially the future development of nuclear power plants that may have a significant influence on future flow patterns. More precisely, a renaissance of nuclear power in the future could result in fundamental changes to the export and import potential of different countries, especially in a region with largely smaller power systems. However, it is beyond the scope of this study to assess the likelihood of corresponding developments, or their impact on individual countries.

In summary, we believe that our market model can be regarded as a reasonable representation of the possible future development of the prevailing cross-border flow patterns in the region, and that this conclusion is confirmed by the results of the sensitivity analysis within this section 3.5.4. However, we also emphasise that the robustness of our results critically depends on the future evolution of nuclear power in the Accession Countries. Any fundamental change in the use of nuclear power plants would have the potential of drastically changing the economic export or import potential of individual countries, thus potentially causing major changes in the prevailing flow patterns.

3.5.5 Impact of Strategic Bidding

In this section, we use the SYMBAD model to simulate the impact of strategic bidding on market prices in Romania, Hungary and Poland. Our objective is to illustrate how strategic bidding can influence market outcomes in oligopolistic markets. For this purpose, we performed several simulations for each of these three markets, allowing us to study the difference between the cost- and bid-based prices in selected countries. In the following, we first explain our choice of three countries and determine the so-called Herfindahl-Hirschman Index (HHI) for each of these countries. The HHI allows for a first assessment of the level of concentration in each market, which is of particular importance for the potential of strategic bidding. Second, we present the merit order curve for the three different countries. Third, we characterize the different assumptions used in our simulations. Finally, we then present the results from our simulations and examine the effect of strategic bidding on market prices.

As explained above, SYMBAD is based on the theory of oligopoly competition and the supply function equilibrium (SFE). By definition, this model can thus only be used for oligopolistic markets. Conversely, it would be meaningless (if at all possible) to apply a model like SYMBAD for the analysis of a monopolistic market. Indeed, under the assumptions of such a model, the monopolist will always exploit its dominant position, in order to maximise its profits; the results would thus be extreme prices. Such results would however not be realistic since the monopolist will not be able to fully exploit its situation in practice due to the threat of regulatory intervention. Most Accession Countries are however characterised by a monopolistic, or nearly-monopolistic market structure. We have therefore had to restrict our simulations to three selected countries, which all have a less concentrated market structure. Besides Hungary and Romania, which both have already created and partially privatised several generation companies, we have also selected Poland where this process is still ongoing.[13]

As a first screening tool for measuring the potential for strategic bidding (or the exercise market power) we have determined the so-called Herfindahl-Hirschman Index, or HHI. The HHI is an index of market concentration, defined as the sum of the squares of the market shares of individual participants. The HHI is widely used as a first approximation for the distribution of the shares throughout the market. The HHI index may range between 0 for an atomistic market and 10.000 for a pure monopoly. In general, an HHI below 1.000 is considered a loose oligopoly, while an HHI above 2.500 as reflecting substantial scope

[13] Strictly speaking, most Romanian and Polish generators are still state-owned. Theoretically, they could thus be considered as a single company. For modelling purposes, and due to our practical experiences in Central Eastern Europe, we assume that these different companies will behave independently.

for market power. As illustrated by Table 2, all three markets can be considered rather unconcentrated, especially in comparison to most Western European electricity markets. At first glance, the scope for strategic bidding thus appears rather limited.

Table 2: Herfindahl-Hirschman Indices for Romania, Poland and Hungary

Country	HHI
Hungary	1909
Poland	870
Romania	1740

Next, we have estimated the generation merit order of each country. As shown by Figure 19, the cost structure in the three countries is quite different. For instance, in Poland most power plants have comparable marginal costs, with only very few cheap respectively very expensive units. Conversely, the cost structure of both Hungary and Romania appears to be much more diverse.

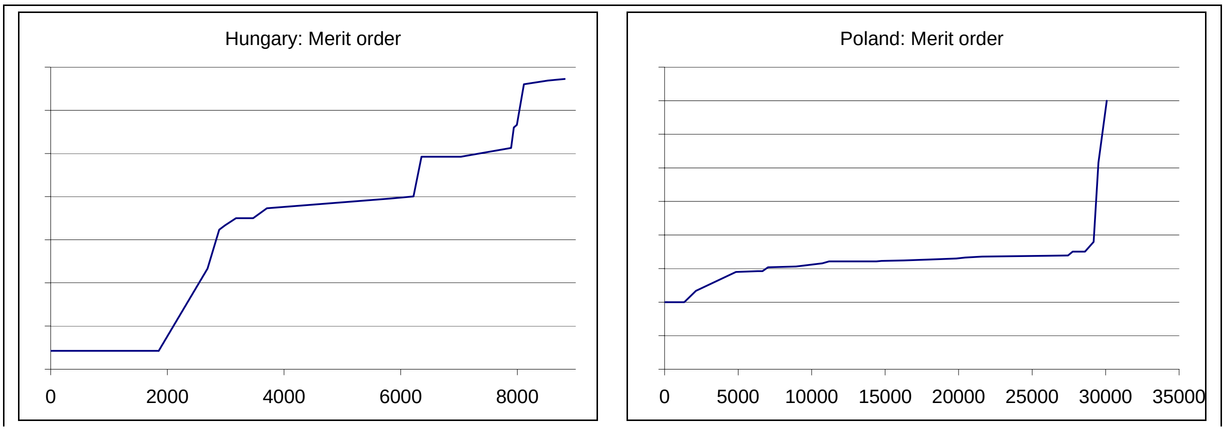

Figure 19: Estimated generation merit order for Hungary, Poland and Romania

In the first step of modelling, we entered all larger power plants of each country into the model and assigned them to the corresponding owners. In contrast, we ignored very small units, which can be considered to be without relevance for the price determination in each countries', exports and imports.[14] All firms are assumed to behave strategically. In a second step, we have defined different levels of availability (according to different technologies, season of the year, and maintenance schedules). Finally, we differentiated

[14] Given that these simulations are meant to show the potential benefits of cross-order trade, it would not have been useful to consider potential cross-border exchanges.

between different levels of demand (peak and off-peak hours) and used actual load data to estimate demand values and assign different slopes (elasticities) to demand segments.

In Figure 20 we have summarised our results from the simulation of the Hungarian power market. On average, prices under strategic behaviour remain close to the perfectly competitive outcome, as illustrated by relatively low mark-ups. As notable exception we observe a mark-up of approx. 20% for a demand of close to 6 GW. Comparison with Figure 19 shows that this range is characterised by a major step in the production cost curve. Hence, it appears that increasing utilisation of the lower-cost mid-merit plants allows their owners to increase their bids until close to the costs of the higher-costs mid-merit plants. This interpretation is also supported by the fact that the mark-up decreases for increasing demand, but at comparable market prices. Despite this particular case of (limited) strategic bidding, the Hungarian power market appears as relatively robust against the threat of market power.

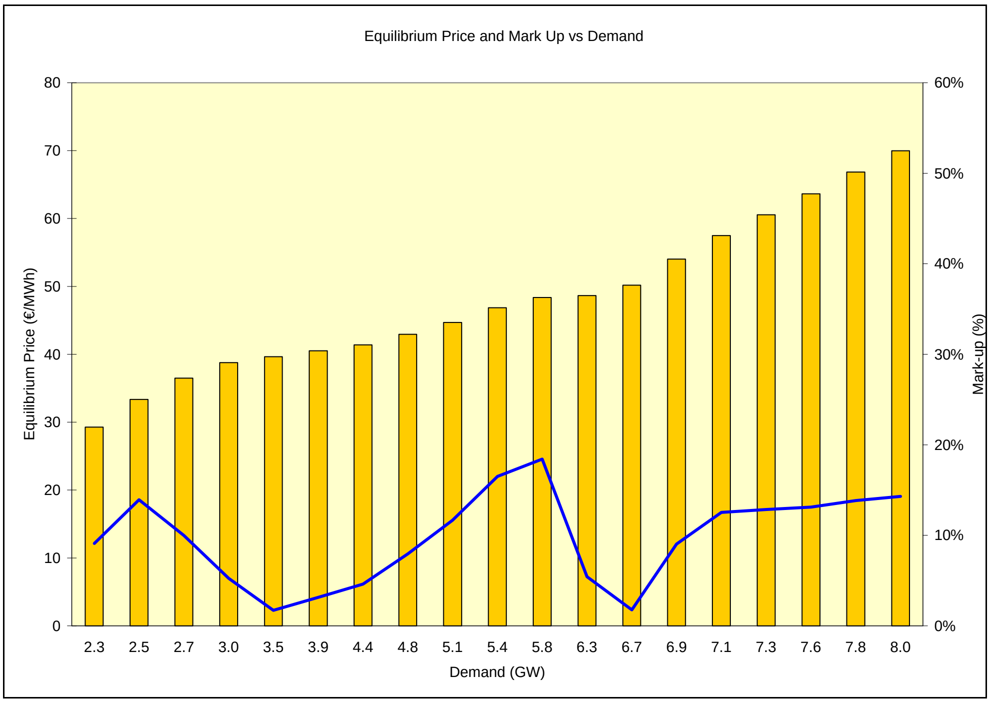

Figure 20: Impact of Strategic Bidding on Market Prices in Hungary

As illustrated by Figure 21, the scope for strategic bidding is generally even more limited for Poland; for the largest part of the demand range, mark-ups remain below 5%, i.e. virtually equal to the cost-based prices. This outcome can be explained by two factors: First, the fragmented structure of the Polish generation sector and, secondly, the 'flat' merit order as shown in Figure 19 above. Both factors imply that there are several players able to compete. However, the same particular form of the Polish merit order also allows for a considerable scope for the exercise of market power in case of increasing demand: The small amount of peaking capacity and a major difference in marginal costs mean that other generators are potentially able to increase prices until close to the peak price level for the upper part of the demand range.

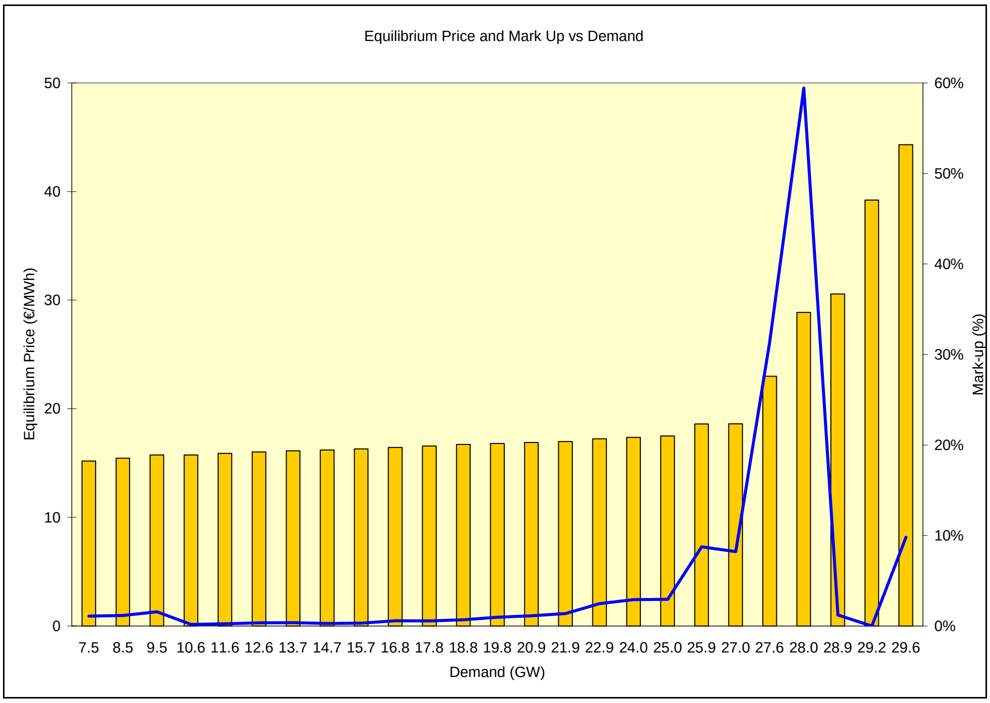

Figure 21: Impact of Strategic Bidding on Market Prices in Poland

Finally Figure 22, shows the results of our simulations for the Romanian market. In this case, mark-ups differ significantly for different levels of demand, and are generally higher than in the two other countries. The fact that hydro and nuclear units are each owned by a single company enables the exercise of market power at low levels of demand, albeit at still low prices. But in addition, we also observe mark-ups above 20% during peak load periods. In other words, the owners of peaking units may potentially bid at prices significantly above their costs. However, one should take care when interpreting these results. Most importantly, in contrast to our PROSYM market model, these simulations do not take into account must-run obligations for nuclear and hydro units, as well as for CHP or because of (internal) network constraints. But in practice, the Romanian market is characterised by an extreme share of corresponding must-run obligations. These arrangements however imply that a considerable share of high-cost generators is used even at low levels of demand. In turn, the volume of the 'free market' accessible to the remaining generators is reduced substantially. In consequence, one may reasonably expect more competition by less expensive generators. In addition, one also has to consider the huge over-capacities in the Romanian market. In fact, actual load in 2003 ranged between 3.8 and 7.5 GW, i.e. far below the upper part of the demand curve with a potential exercise of market power.

In summary, we conclude that the results of the market simulations with SYMBAD are consistent with our initial view that the scope for strategic bidding is limited in all three

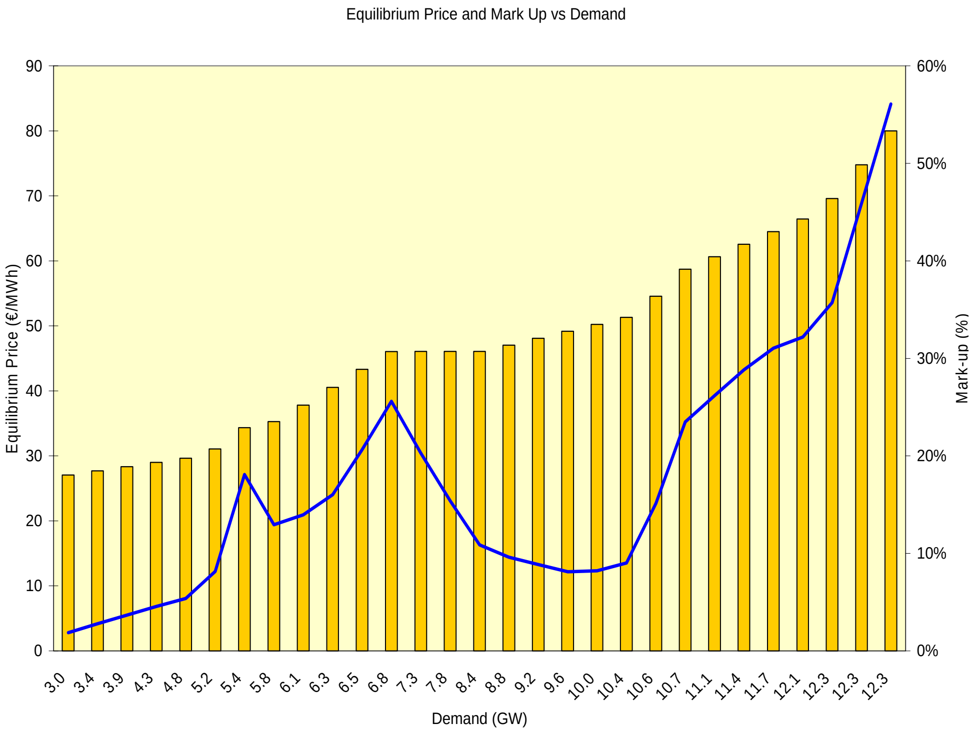

Figure 22: Impact of Strategic Bidding on Market Prices in Romania

countries considered. This is illustrated by generally low mark-ups, which largely remain below 15% and thus represent a limited increase of market prices only. Compared to e.g. some Western European markets, where similar simulations often show substantially higher mark-ups, one may thus conclude that there only is limited scope for the exercise of market power in these three countries. Consequently, one may argue that the influence of available cross-border capacities may be less critical for these countries than e.g. for Germany, Austria, Italy or the Netherlands. However, the situation may change over time, namely in the course of the restructuring of the generation sector in different countries.

4 Determination and Allocation of Transmission Capacities

4.1 Determination of Transmission Capacities

This section 4.1 describes the determination of the Transmission Capacities that are available for imports and exports between the different countries, i.e. the so-called Net Transfer Capacities (NTC). It describes and compares current practises within the Accession Countries. Furthermore, we describe possible adaptations that may sometimes help to increase NTCs.

The discussion in this chapter is based on the responses to our questionnaire received from the TSOs of Bulgaria (NEK), the Czech Republic (CEPS), Latvia (Latvenergo), Romania (Transelectrica) and Slovakia (SEPS). Additional information we have gathered through interviews with NEK, CEPS, Transelectrica, the TSOs of the Baltic States (Eesti Energia, Latvenergo, Lietuvos Energija) and the Baltic regional coordinator DC Baltija, and the system operators of Austria (APG), Bosnia & Herzegovina (ZEKC), Eastern Germany (VE-T), Poland (PSE-O) and Slovenia (ELES).

4.1.1 Approach

In order to calculate Total Transfer Capacities (TTC) and Net Transfer Capacities (NTC) there are several methodologies possible. By interviewing the TSOs of UCTE countries it has been discovered that they are all using the same methodology. Even the countries connected to the UPS/IPS system (i.e. Estonia, Latvia and Lithuania) are using a similar methodology[15].

Before detailing the methodology used for calculating TTC we stress that TTC values are related to Commercial Transactions. Such a transaction only means that the electricity generated in country A can be used in country B: Only these two countries are involved here. The technical flow from country A to country B resulting from this commercial transaction, can however be quite different. This is due to the physical laws: In meshed transmission networks the electricity flows are distributed among more than one line. These lines could be located in different countries, which could result in physical flows following from country A to country B via different countries.

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15 The TSOs of Estonia, Latvia and Lithuania are calculating the values available for Cross-border transactions together with their colleagues of Russia and Belarus. In principle the methodology is similar. This means that generation is increased in country A and decreased in country B until the safety limits are breached. The methodology does not include a separate publication of the TRM values. However, these margins are taken into account by the used scenarios.

In this section we describe the methodology for calculating the Total Transfer Capacities (TTC). These capacities are used for Commercial Transactions. However, for calculating these capacities, technical flows need to be taken into account. This is the reason why the starting point of TTC assessment is a load and generation situation of the European interconnected system, referred to as the basic scenario. Starting from this scenario, the commercial exchange between two countries is increased until network security limits are breached. This is done by increasing the power generation in the exporting country and decreasing power generation in the importing country at the same time. The TTC between the two countries corresponds to the maximum admissible commercial power exchange.

Because the TTC assessment does not take into account the reliability margin, the TTC is not the capacity that could be offered to the market. Therefore the TTC is reduced with the so-called Transmission Reliability Margin (TRM). This results in the Net Transfer Capacity (NTC) (see Figure 23). The NTC represents the best-estimated limit of transfer capacity available between two countries.

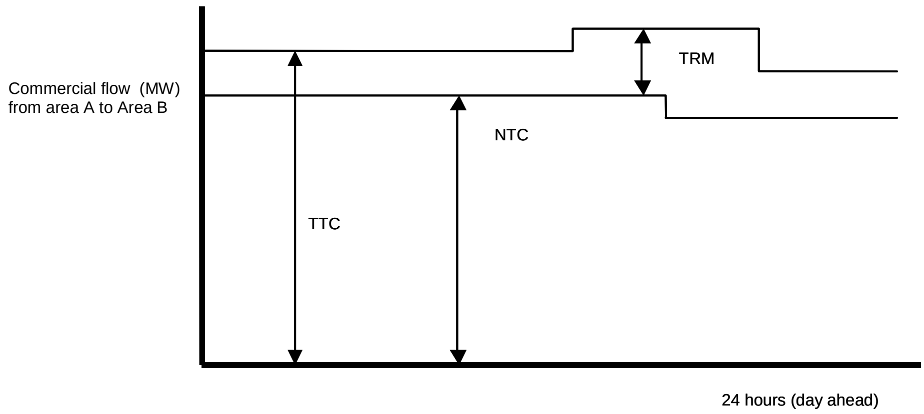

Figure 23: Relation between Total Transfer Capacity, Net Transfer Capacity and Transmission Reliability Margin.

The following sections will detail different parts of the methodology and will highlight differences in the approach of different TSOs. Following a brief summary of the Baltic States (section 4.1.2), we discuss the Power System Data considered in the TTC assessment (section 4.1.2), the Network Safety Limits (section 4.1.4), Technical Limits (section 4.1.5) and Transmission Reliability Margin (section 4.1.6).

4.1.2 Situation in the Baltic States

The 330/750 kV networks of Estonia, Latvia and Lithuania are not currently connected to the synchronous power system of the UCTE. Instead, the Baltic States are operated in parallel with Belarus and the Unified Power System (UPS) of Russia. As a matter of fact, the Baltic States, Belarus, Kaliningrad and the North-Western part of Russia represent one zone within the synchronous area of the Unified Power System (UPS) of Russia. In fact, the high-voltage networks of all three Baltic countries were not originally built as independent national systems, but largely as an integrated part of the former Soviet unified power system. This history has some important implications on both the current way of operation, and the design and capacity of the current transmission infrastructure. Amongst others, and in contrast to the UCTE, frequency control for the UPS is centrally performed by the Russian System Operator, whereas the contribution of the local areas is generally limited to manual interactions in order to maintain the agreed intra-area exchanges.

The operation and dispatch of the Baltic power systems follows a two-level hierarchy. Within each country, the national utility and/or system operator is responsible for planning, construction, maintenance and operation of the national transmission grid. These functions are currently fulfilled by the transmission divisions of the still vertically-integrated companies Eesti Energia in Estonia and Latvenergo in Latvia, and the already unbundled Lietuvos Energija in Lithuania. However, the planning and operational authority of the three national TSOs is generally limited to domestic operations. Conversely, international coordination of the operation of the three power systems between the Baltic States and with neighbouring Russia and Belarus is under the authority of DC Baltija in Riga, a joint-venture of the three Baltic TSOs.[16] Hence, it is necessary to differentiate between the national and international functions when analysing the rules and procedures for the determination and allocation of cross-border capacities.

In contrast to most other European TSOs, the Baltic system operators do not yet publish any NTC values, or any equivalent information on available cross-border capacities. Amongst others, this can be explained by the fact that the Baltic countries are not connected to the rest of the European electricity market but only to Russia, and combined with the continued existence of a vertically integrated national monopoly in both Estonia and Latvia. As a result, there is not yet an established functioning and liquid power market in any of the Baltic States, Belarus or Russia.[17] The determination and allocation of cross-border capacities thus follows the traditional scheme commonly applied before the advent of liberalisation and unbundling: Both the initial calculation and the subsequent allocation are jointly performed and/or agreed between the TSOs of Russia, Belarus and the Baltic States. The final allocation of cross-border capacities is then fixed in multi-lateral agreement between these five TSOs. However, due to the lack of a functioning market, these values largely serve operational purposes, i.e. they are used for assessing network security during operational planning and actual operations, rather than being allocated to individual market participants as the basis for commercial transactions.

[16] Strictly speaking, DC Baltija is owned by the three Baltic utilities mentioned above.

[17] Although the Russian Federation started its ‘Transitional Wholesale Market’ in November 2003, this market has so far remained a purely national scheme. Most importantly, exports and imports are still subject to a monopoly.

For calculation of the transfer limits, the Baltic TSOs consider a number of different scenarios that are assumed to represent a realistic choice of possible situations, including various contingencies. This process has not however been formalised in a way similar to the determination of NTC-values by ETSO members. Moreover, a number of these transfer limits are not expressed as single absolute numbers, but rather as a function of some other variables, such as the production of certain power plants or the flows on others lines. Besides reductions in case of maintenance, the final value may thus take the form of e.g. an absolute value, plus or minus a certain percentage of the production of a certain power plant. These functions primarily take into account the possibilities to replace energy exchanges by additional production (or reduced consumption) in the 'importing' and reduced production on the 'exporting' side of the constraint.

While the calculation of these transfer limits is based on the (n-1)-criterion, the Baltic and Russian system operators take into account so-called 'emergency automation systems' as an additional network element (compare section 5.2.2.1). Strictly speaking, the concept of (n-1) thus slightly deviates from the definition commonly applied elsewhere, i.e. where the range of network elements is usually limited to e.g. power stations, lines, transformers and switching elements. These emergency automation systems are made up of special protection systems that limit the load on specific lines in case of a logical combination of events and/or pre- or post-fault conditions: e.g. a protection scheme can be activated after a particular trip if the pre- and post fault load of other lines exceed some predefined limits. The range of possible actions may include line switching, load or generation shedding, activation of reserves (increasing generation) or pumping. Such special protection systems have traditionally been widely used in the former Soviet power system, but are also applied by some Western European TSOs under certain circumstances, e.g. in Scandinavia or England & Wales.

4.1.3 Power System Data

Use of UCTE dataset

Currently, UCTE issues two complete datasets for the entire interconnected UCTE system per year:[18] One for a summer situation and one for a winter situation. These data sets contain the topology and characteristics of the network and a forecasted load and generation situation of the UCTE network. They are in a format that can be used by the load flow software that is applied by the different TSOs for TTC assessment calculations.

All interviewed TSOs with networks, which are part of the UCTE network are using the UCTE dataset as a basis. For countries connected to other non-UCTE countries, e.g. Romania to Ukraine, similar datasets are exchanged with these countries. The TSOs of

[18] Note that the datasets are composed using all individual contributions of the different TSOs.

Estonia, Latvia and Lithuania are using similar files that are exchanged with their neighbours.

Maintenance activities of transmission lines in which connections need to be taken out of operation, could influence the TTC. However, maintenance activity is not the same during the entire year. Therefore, TSOs usually do not take maintenance into consideration for the bi-annual TTC assessment. In their monthly and daily TTC assessments however, maintenance activity is considered and could lead to different TTCs.

Commercial Exchanges

An initial commercial exchange needs to be defined for the basic scenario. Therefore some knowledge on these exchanges should be available at the TSOs. Because in the liberalised markets, TSOs are not involved in commercial transactions, the individual transactions are not known by the TSOs. However, all interviewed UCTE TSOs state that they hold information about commercial exchanges on an aggregated level. This information is used in the TTC assessment.

Because in Estonia, Latvia and Lithuania the Dispatch is still centralized, the TSOs in these countries do still have detailed information about these exchanges.

Modelling of Generation Units

As discussed in section 4.1.3, the main part of the TTC assessment is shifting generation from one country to another. Important in this 'generation shift' is that this is performed realistically. Therefore, all interviewed TSOs have available and are using detailed information of the generating units, both in their own networks and the networks of their neighbouring networks. This information consists of information of the locations of the generating units and the installed capacity of these units.

In order to perform the 'generation shift', generation in one country will be increased, while in parallel the generation in another country will be decreased. The way this is performed by all interviewed UCTE countries is similar. For increasing the generation, the TSOs are using the remaining capacity of the generating units in the area in which the generation should be increased. The increment of the individual generating units is assumed to be proportional to this remaining capacity.

By shifting generation proportionally to the remaining capacity of the generators, the different market potential of the individual generators is neglected. In order to get more realistic scenarios, one could perform the generation shift by using a simple merit order. In this merit order, for every unit the remaining capacity and an estimated price is included. The TSOs could use the cheapest plants first in the generation shift and afterwards more expensive ones. This method could lead to more accurate TTCs, which could be both higher and lower that the TTCs calculated using the methodology used by the TSOs today.

4.1.4 Network Safety Limits

The TTC calculated with the described methodology is the value of power exchanged across the border at which the network safety limits are not breached. All interviewed TSOs are taking the so-called (n-1) criterion into account, which in general means that a single failure should not lead to unstable system operation. I.e. the (n-1) analysis successively takes each element out and calculates whether thermal or voltage limits (see section 4.1.5) are breached. There are some differences between the TSOs in which elements are to be considered in the (n-1) criterion. These differences are described below.

(n-1) failures in own transmission network

One of the topics where interpretation of the (n-1) criterion is different for different TSOs is the definition of elements that are considered in the (n-1) analysis. The types of elements (lines, cables, transformers, generators) are different from TSO to TSO. Furthermore, some TSOs include only failures in their own network, while other perform an (n-1) analysis also for selected failures outside the country.

As illustrated by Table 3, all interviewed TSOs include failures of single circuit connections (underground cable or overhead line) and transformers in the (n-1) analysis. However, some TSOs also take into account simultaneous failures of both circuits of one line. Although this generally leads to very conservative results, in some cases it seems to be necessary to take these failures into account. E.g. Polish TSO PSE Operator takes the failure of double circuit line Wielopole/Dobrzen (Poland) to Albrechtice/Nosovice (Czech Republic). According to PSE Operator, this double circuit line seems to trip occasionally because of the severe weather conditions. As a direct consequence of this trip, the double circuit 220 kV-line from Liskovec (Czech Republic) to Kopanina/Bujakow (Poland) will trip on overload as well. Another example is that the Bulgarian TSO NEK also takes the trip of the 400 kV double circuits line Blagoevgrad –Chervena Mogila into consideration. Romanian TSO Transelectrica states that in some exceptional circumstances, double line failures are included in their (n-1) criteria.

Table 3: Components taken into account in the (n-1) criterion

	Single circuit lines	Double circuit lines	Transformers	Busbars	Generating units
Baltic States	yes	no	yes	no	yes
Bulgaria	yes	yes	yes	yes	yes
Czech Republic	yes	no	yes	no	no
Poland	yes	yes	yes	yes	only largest unit
Romania	yes	rare	yes	no	only largest unit
Slovakia	yes	yes	yes	no	partly
Slovenia	yes	no	yes	no	yes

In general, the likelihood of double circuit line failures can be considered as very low. Therefore, taking into account double circuit line failures in the TTC Assessment leads to TTC values, which are too conservative. In our opinion as a rule, double circuit failures should not be taken into account. However, in exceptional situations, the high possibility of a double circuit line failure could be an exception of this rule and therefore taken into consideration in the TTC Assessment.

The discussion for busbar failures is similar. Also busbar failures can significantly reduce the TTC values. Of the interviewed TSOs only Bulgarian NEK and Polish PSE Operator apply busbar failures in their TTC assessment. Usually, busbar failures are extremely uncommon. In our opinion, they should not be taken into consideration in the TTC assessment as a rule. However, in some rare situations, exceptions should be made.

While many TSOs (see Table 3) take failures of generating units into account, other TSOs treat generator failures differently. E.g. Poland and Romania only take the largest generating unit into consideration, while the Czech Republic does not take any generating units into account at all. This does not automatically mean that the TSOs of these countries are satisfied with lower security limits. The reason for not taking into account generators (Czech Republic) is that generator failures are not considered critical in the TTC assessment. I.e. according to the experience of Czech TSO Ceps, a generator failure will never limit the TTC. The situation in Poland and Romania is similar: Events in which a random generating unit will fail, is never worse than the situation in which the largest generator or another network element fails.

As discussed above, in their (n-1) analysis all TSOs are taking failures into account in their own network. The same applies on the lines they share with their neighbouring TSOs, namely the interconnecting lines. Some of the TSOs take selected failures in other countries into consideration as well. This is necessary because of the meshed structure of the European Transmission network: a failure on one side of the border can influence the flows on the other side of the border. However both Czech TSO Ceps and Slovak TSO Seps only take failures in their own network into account.

The scope of every TSO's TTC Assessment is the impact of failures on its own system. Therefore, TSOs should take into consideration all the failures that have significant impact on their system. By this, it is not important for TSOs to address possible constraints in other networks. These constraints are taken care of by the TSO responsible for this network.

Adaptations after trips

This is caused by failures of elements such as changes in the topology or load and generation patterns. E.g. after a generator trips, the generation of other generators will be increased in order to keep the energy balance in the system. Another example is a network failure that triggers (automatic) switching actions. As these adaptations are made in real, the adaptations should also be taken into consideration in the TTC Assessment.

However, of the interviewed TSOs only the Baltic States consequently take these changes into consideration. This is most probably caused by the fact that corrective switching actions are largely used in the network of the Baltic States, Belarus and the North-West of Russia. I.e. because of single high capacity 750 kV-lines in parallel with 330 kV-lines with a lower capacity, the most severe (n-1) situation is always the situation in which a 750 kV-line fails. This implies that using a simple (n-1) criterion results in a very limited safe transfer capacity. In order to mitigate this problem special protection systems are installed. These systems limit the load on the lines in case of a logical combination of events and pre- or post-fault conditions: e.g. a protection scheme can be activated after a particular trip if the pre- and post fault load of other lines exceed some predefined limits. The action can be load shedding, generation shedding or activating reserves (increasing generation) and pumps. This special protection system is installed on the Northern 750 kV-connection between Russia and the Baltics (Kalininskaya – Lenengradskaja line) and the Southern connection between Russia and the Baltics via Belarus (Smolenskaya-Belorusskaya/Roslavl/Krichev/Talashkino). Furthermore, a special protection system is installed which responds on a trip of a 1300 MW unit in Ignalina[19]. The special protection systems automatically change generation patterns and trip some circuit breakers in the network in order to reduce the flow on overloaded lines.

Because these special protection systems do their job very quickly, the short overload in the (n-1) situation can be accepted. Because of this, the flow under normal conditions can be higher, which results in significantly higher available capacities for imports and exports.

Although not as widely spread as in the UPS/IPS system, some special protection systems are in place in the UCTE system. E.g. on the tie-lines from Hungary to Romania and Serbia, a protection system is installed which trips two lines in case the load of both tie-lines together reaches 1000 MW.

4.1.5 Technical Limits

In the TTC Assessment the flows resulting from the (n-1) calculations are compared to the technical limits. Furthermore, some TSOs check whether Voltages will stay within their limits. This section describes how different TSOs are applying both thermal limits and Voltage limits in their TTC assessment.

Thermal Limits

Thermal limits of overhead lines are usually calculated taking the environmental situation into account. Important here are the Ambient Temperature and wind. Generally speaking, lines are able to transport more power if the temperature is lower and the wind blows

[19] From January 1, 2005, only unit Ignalina 2 (1300 MW) will be in operation as Ignalina 1 (1300 MW) will be decomissioned.

harder. The second column of Table 4 shows the ambient temperature that is taken into consideration in the different countries. It shows different ambient temperatures used by different TSOs. Of the interviewed TSOs, only Poland uses a variation of ambient temperature in the TTC Assessment. Other TSOs consider the ambient temperature constant during the year. There are different reasons for this: Slovak TSO Seps and Czech TSO Ceps refer to the national standards (e.g. Czech standard CSN50182) in which an Ambient Temperature of 40°C is fixed, even during winter time. Other TSOs, namely the Baltic States, are using the additional capacity in case of lower ambient temperature but only for operation planning as a kind of reserve.

Table 4: Thermal limits

	Based on: Ambient Temperature	Variation over the year?	Variation useful for summer/winter	Variation useful for day / night
Baltic States	25 ºC	No	Only in Operational planning	Only in Operational planning
Bulgaria	40 ºC	No	No	No
Czech Republic	40 ºC	No	Obliged to use standard	Obliged to use standard
Poland	0-30 ºC	Yes	Yes	Yes (limited extent)
Romania	30 ºC	No	In areas with large variation of ambient Temperature	No Congestion during the night
Slovakia	40 ºC	No	Obliged to use standard	Obliged to use standard
Slovenia	not available	No	Currently investigated	Currently investigated

The TSOs that do not currently use flexible limits are reluctant to convert to use flexible thermal limits for their lines. While some TSOs refer to their obligation to meet the national standards, others state that it does not bring a great deal of additional TTC. Nevertheless some TSOs state that it brings additional TTC when there are no congestions. The last reason could be definitely valid for the night when the load is low. However, for winter periods a lower ambient temperature than stated in Table 4 for many countries is rather likely. In the case of congested borders this should lead to increased TTC values.

We note that only Slovenian TSO ELES, Polish TSO PSE Operator and Romanian TSO Transelectrica seriously consider using different thermal limits for summer and winter. We agree that for some TSOs the most severe network situation is during the summer season, because in this season maintenance takes place. However, this does not imply that the thermal limits in the winter could not be increased by considering a lower ambient temperature. This will probably not reduce the internal need for investments in transmission lines, but could increase the TTC in the winter, when it is most needed.

Therefore we seriously think that using different thermal limits for overhead lines, should be considered as an alternative for investments in cross-border connections.

Voltage Limits

The other technical limit to be checked in the TTC Assessment is Voltage. In day-to-day operation the TSOs keep the Voltage on their nodes within some specified limits. These limits are usually 380 kV[20] and 420 kV for 400 kV networks and 198 kV and 242 kV for 220 kV networks.

In the majority of the countries, the TTC is not restricted by these Voltage limits. E.g. when during the ‘generation shift’ process, thermal limits are breached before the Voltage limits are reached. Because of this, some TSOs do not check the Voltage limits in their TTC assessment. The only two interviewed TSOs, which state that Voltage limits could reduce their TTC, are Bulgaria and Romania. However, according to Romanian TSO Transelectrica thermal limits usually determine the TTC.

4.1.6 Transmission Reliability Margin (TRM)

As shown in Figure 23, the Total Transmission Capacity (TTC) is reduced with the Transmission Reliability Margin (TRM) in order to obtain the Net Transmission Capacity (NTC). There are quite a lot of differences in the definition of the TRM between the different countries. Starting from the south, the Romanian TSO Transelectrica and the Bulgarian TSO NEK are using 100 MW, constant over the year. This value is mutually agreed by the TSOs in the south-eastern area of Europe and should cover any uncertainties in the flows. The Czech Republic and Slovakia are using a TRM that is taking into account the consequences of a trip of a generator, i.e. primary regulation, secondary regulation and so-called emergency contracts. The Polish TSO PSE Operator again includes primary and secondary regulation as well, but adds inadvertent exchanges instead of emergency contracts to this. It should be noted that the TRM used in Poland, the Czech Republic and Slovakia will usually be higher (several 100s MWs) than the 100 MW that is used in the southern part of Europe. In our opinion this difference does not imply that the differences between the TRMs in the southern and the northern part of Europe should be adapted.

In the Baltic States TRM is not explicitly calculated. However, because of e.g. the modelling of special protection systems including the response of generators, the TRM is not explicitly mentioned, but implicitly included in the methodology.

[20] Some TSOs are using 360 kV as a lower limit for the Voltage of the 400 kV network.

4.2 Allocation of Transmission Capacities

4.2.1 Introduction

This section summarises the different methods applied for the allocation of transmission capacities in the Accession Countries, as well as the main results. Besides a brief description of the different methods applied in each country, we also present the capacities made available to and obtained by the market, and the prices paid for capacity rights in 2004 and, where already known, also for 2005. In summary, this information allows for a good overview on the existence of current constraints for the international commercial exchange of electricity due to limited cross-border transmission capacities.

In contrast to this more descriptive summary, we have refrained from a more fundamental discussion of the different possible approaches and concepts, and their theoretical merits and drawbacks. These issues have already been extensively studied on a theoretical level in a previous study on the network capacities and possible congestion in the 'old' Member States, as well as in another recent study on congestion management methods for the Directorate General Energy & Transport,[21] and various other paper and publications presented e.g. by ETSO or EUROPEX. Instead of generally repeating the corresponding arguments, we therefore limit this section to a discussion of some more practical aspects, and highlight a few issues, which we believe may be prospective measures for increasing the efficiency of the allocation process and the utilisation by market participants.

4.2.2 Capacity Allocation by Individual TSOs

4.2.2.1 Czech Republic (CEPS)

The Czech system operator CEPS (www.ceps.cz) performs the following auctions for the allocation of transfer capacities at the four Czech borders:

- Slovakia (SEPS): CEPS is responsible for a coordinated auction of yearly and monthly capacities. In addition, CEPS uses an electronic portal (Damas) for daily auctions, where capacity is offered for individual hours.
- Austria (APG): Annual and monthly capacities are allocated by Austria (see 4.2.2.8), whereas CEPS is responsible for the daily auctions of hourly capacities. Similar to the Slovakian border, CEPS uses its electronic portal Damas for these daily auctions.
- Germany, 2004: In 2004, cross-border capacities between Germany and the Czech Republic were allocated by the corresponding German TSOs, see section 4.2.2.9.

[21] CONSENTEC (2004)

- Poland (PSE-O), 2004: Until April 2004 VE-T had conducted unilateral auctions for the border Poland/Germany/Czech Republic. In May 2004 PSE started with unilateral monthly auctions from the Polish side, see section 4.2.2.2.
- Germany (VE-T) and Poland (PSE.O), 2005: For 2005, the three system operators CEPS, VE-T and PSE-O have agreed on a common regional auctioning procedure. CEPS has set up a separate auction office that organises yearly, monthly and daily auctions (www.e-trace.biz). However there still was no agreement with SEPS, which still conducts its own unilateral auctions.

With the exception of Austria, all annual and monthly auctions are for base load capacities, whereas daily capacities are allocated on an hourly basis.

The new concept for coordinated auctions between Germany (VE-T), the Czech Republic, Poland and Slovakia represents an interesting approach for introducing a truly regional and coordinated auction.[22] Most importantly, while the corresponding TSOs coordinate the determination of the NTC values and the auction process, the allocation of at least some of the available transfer capacities to individual borders is left to the market. Through this added flexibility, this new scheme potentially allows the market to determine a more efficient output than through an administrative ex-ante allocation by the TSOs. For a better understanding of how the technical profiles in this region are defined for the joint auction, we refer to Figure 24. This depiction shows the borders (in red), or combination of borders, on which the so-called 'technical profiles' are defined by the corresponding TSOs. These technical profiles form in fact the NTC between one country and another country, or a combination of countries. E.g., PSE defines only one NTC for export from Poland to Germany plus the Czech Republic plus Slovakia. The German TSO VE-T does the same for its total border with Poland and Czech Republic, while the Czech CEPS uses separate NTC values for the border with Poland and the border with Germany. Market parties submit offers for capacity on each individual border (no combinations). These offers are selected according to the merit order and restricted by the technical profiles.[23]

[22] In 2005, Slovak TSO SEPS will not be involved in the auction organized by CEPS. Therefore, the auction of the export capacity from Poland to Slovakia will be unilaterally, which means that separate permits from SEPS have to be obtained for power to enter Slovakia.

[23] CEPS (2004)

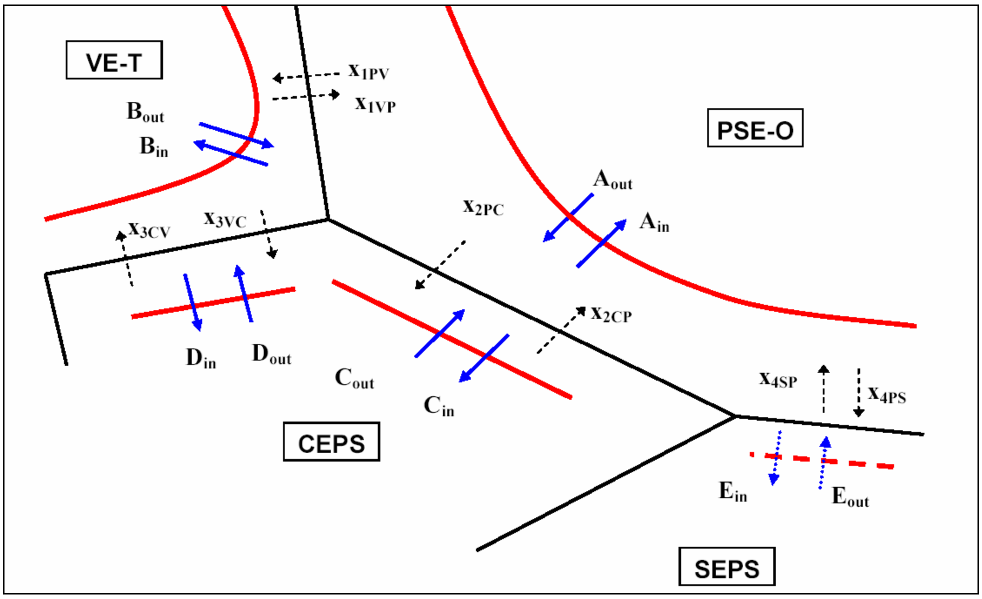

Figure 24: Capacity products in the joint Czech-German-Polish auctions

4.2.2.2 Poland (PSE-O)

Most transfer capacities at the Polish borders are not allocated by the Polish system operator PSE-O (www.pse.pl) but by foreign system operators:

- Germany (VE-T) / Czech Republic, until April 2004: A unilateral auction was conducted by Vattenfall in coordination with CEPS, see section 4.2.2.9.
- Germany/Czech Republic/Slovakia, May – December 2004: In May 2004, PSE started its own unilateral auction for transmission capacity towards the German/Czech/Slovakian border. The introduction of this auction had not been coordinated with CEPS/VE-T and led to the termination of the monthly auctions previously conducted by VE-T.
- Germany/Czech Republic/Slovakia, 2005: Since May 2004, the activities on the joint border between Germany (VE-T), Poland and the Czech Republic have been coordinated between VE-T, CEPS and PSE, such that there will be a common auction of capacities, see section 4.2.2.1.
- Sweden: There is a connection between Poland and Sweden with 600MW capacity available in each direction. 550MW of the capacity is reserved by Vattenfall [1], the remaining capacity can be bought for a fixed tariff, depending on availability coordinated by SwePol Link (www.swepollink.se).

4.2.2.3 Slovakia – SEPS

The Slovakian TSO SEPS (www.sepsas.sk) conducts the following activities on congestion management on the Slovakian borders:

- Czech Republic (CEPS): There is a coordinated auction for yearly and monthly capacity operated by CEPS. Additionally CEPS uses the Damas ePortal for daily auctions.
- Hungary (MAVIR): The capacity at this border is split between MAVIR and SEPS. Both TSOs perform an independent auction on their part of the capacity. SEPS performs yearly and monthly auctions.
- Poland (PSE-O): The capacity is coordinated with PSE-O. Capacity is allocated by unilateral auctions on side PSE-O and SEPS. SEPS performs yearly and monthly auctions.
- Ukraine (WPS UA): The capacity is determined by SEPS and allocated by unilateral auctions on SEPS side (yearly and monthly). No information is available on Ukrainian activities.

All annual and monthly auctions are for base load capacities, whereas daily capacities are allocated on an hourly basis.

4.2.2.4 Hungary – MAVIR

The Hungarian TSO MAVIR (www.mavir.hu) conducts the following activities on congestion management on the Hungarian borders:

- Slovakia (SEPS): MAVIR auctions his part of the capacity in yearly and monthly auctions.
- Ukraine (Ukrenergo): MAVIR’s auction rules contain the direction Ukraine → Hungary, but no capacity has been offered for 2005.
- Romania (Transelectrica): Until November 2004 no capacity had been offered on the border to Romania. From November 2004 on MAVIR performs monthly and yearly auctions (in both directions). No information is available from Transelectrica on activities on the Romanian side.
- Serbia Montenegro (EPS): Until November 2004 no capacity has been offered on the border to Serbia Montenegro. From November 2004 on MAVIR performs monthly and yearly auctions (in both directions). No information is available from Electric Power industry of Serbia.
- Croatia (HEP): MAVIR performs auctions for yearly and monthly capacity. No information on Croatian activities is available.

- In 2004 MAVIR was responsible for the auctioning of the capacity (Austria → Hungary) and APG was responsible for the capacity (Hungary → Austria).
- Austria (APG): In 2005 there is a coordinated auction conducted by APG (www.auction-office.at), who performs yearly and monthly auctions. For 2005 there shall also be daily auctions operated by MAVIR via the system "KAPAR". Bids can be specified for peak or base load.

All auctions (except with Austria) are for base load capacities. MAVIR's auction rules state that peak and baseload is distinguished but no data on allocated peak capacities is available.

4.2.2.5 Slovenia – ELES

The Slovenian electricity market operator Borzen (www.borzen.si) performed an auction for cross-border capacity in 2003, however the result and scope of this auction is unclear. The daily available capacity for all borders is published by the Slovenian TSO ELES (www.upo.eles.si) on its web page but no information on currently applied congestion management methods is available.

There are borders with transmission capacities towards:

- Austria (APG): From 2005 the Austrian auction office operates auctions on his part of the capacity, see section 4.2.2.8.
- Croatia (HEP): According to [1] there are no congestions between Slovenia and Croatia and capacity of >1000MW is available. The used method is first-come-first serve.
- Italy (GRTN): According to [2] each party is responsible for 50% of the capacity, while Italy uses pro rata method (on a daily basis [1]). According to [1] there are no congestions from Italy to Slovenia; capacity is allocated on a yearly basis.

In order to improve transmission capacity allocation and their use, extensive discussions are currently undergoing among all partners in that area (mainly Slovenia, Croatia, Italy, Austria and Hungary) to apply some kind of "coordinated transmission capacity auctioning". This auction could be similar to the one between Belgium, France, Netherlands and Germany where serious congestions and loop flows are recorded in certain regimes as well. Furthermore, harmonisation of cross-border transmission capacities maintenance program, and introduction of phase shifters are considered as an option.

4.2.2.6 Croatia

The Croatian TSO is HEP (www.hep.hr), however HEP did not publish any information on congestion management activities from their side. The following information is available on the activities on congestion management of Croatian borders:

- Slovenia (ELES): According to [1] there are no congestions between Slovenia and Croatia as capacity of >1000MW is available in both directions. The used method is first-come-first serve.
- Hungary (MAVIR): MAVIR performs auctions for yearly and monthly capacity.

4.2.2.7 Baltic States

The allocation of cross-border capacities in the Baltic States is still largely based on bilateral or multilateral agreements between the corresponding TSOs and vertically-integrated utilities. Hence, there do not yet exist any formal allocation procedures, nor is there any real demand from third parties. Nevertheless, we are aware of at least one case where an independent company has been able to obtain cross-border capacities for transporting power from Lithuania through Latvia to an Estonian customer. While we have been informed by Eesti Energia that official regulations would foresee a pro rata reduction of capacity reservations in case of excess demand, we have been unable to obtain corresponding information from either Latvia or Lithuania.

4.2.2.8 Austria (APG)

The Austrian TSO APG (http://www.verbund.at/at/apg/) has established an auction office (www.auction-office.at) for the allocation of capacities on the following borders:

- Slovenia (ELES): From 2005 the Austrian auction office operates auctions for yearly, monthly and daily capacities but allocates only that part of the capacity APG has responsibility for. For yearly and monthly auctions base and peak load is distinguished.
- Czech Republic (CEPS): The Austrian auction office operates coordinated yearly and monthly auctions for the Czech/Austrian border. In the direction (CEPS → APG) peak and base load is distinguished while the other auctions are for base load only. The daily auctions are operated by CEPS, see section 4.2.2.1.
- Hungary (MAVIR): In 2005 there is a coordinated auction conducted by APG (www.auction-office.at), who performs yearly and monthly auctions. MAVIR plans to perform daily auctions, see section 4.2.2.4. Bids can be specified for peak or base load.

In 2004 MAVIR was responsible for the auctioning of the capacity (Austria → Hungary) and APG was responsible for the capacity (Hungary → Austria).

4.2.2.9 Germany (E.ON and VE-T)

German TSOs E.ON Netz (www.eon-netz.com) and Vattenfall Europe Transmission (transmission.vattenfall.de) perform the following activities on their borders towards accession countries:

- Germany (E.ON Netz) / Czech Republic (CEPS): For the Czech border to the control area of E.ON, there are coordinated auctions of yearly, monthly and daily capacities, which are performed by E.ON Netz.
- Germany (VE-T) / Czech Republic (CEPS) / Poland (PSE-O), 2004: In 2004, all capacities at this border were allocated by the German side, separately for yearly, monthly and daily capacities. Until April 2004 (inclusive), these auctions were organised for a combined transfer capacity between the control area of VE-T, on the one side, and Poland and the Czech Republic, on the other side as explained in more detail in section 4.2.2.1. Following the introduction of unilateral auctions by PSE in May 2004 (section 4.2.2.2), VE-T has continued these auctions for monthly and daily capacities between Germany and the Czech Republic only. From 2005 CEPS has responsibility for the auction on the Czech/German/Polish border.

All auctions are for base load capacity, except daily capacity, which is offered on an hourly basis.

4.2.2.10 Other Countries

We have not been able to obtain any information on any formal procedures for the allocation of cross-border capacities for the borders of the remaining Accession Countries. Based on discussions with market participants and anecdotal evidence, we thus assume that corresponding capacities are either allocated through direct negotiations (in case of still vertically-integrated utilities), existing (long-term) contracts or some priority measures like first-come-first served.

4.2.3 Summary of Capacity Allocation Mechanisms Used in the Region

Based on information from the corresponding TSOs and various other sources (mainly [1], [2], [3]), Table 5 provides a summary of some important features of the capacity allocation mechanisms used within the Accession Countries. For each border where corresponding information is available, we list the responsibility for the allocation procedure, the allocation method and frequency, whether the use-it-or-lose principle is applied, the existence of long-term contracts and the degree of congestion.

Table 5: Overview on cross-border allocation methods

Border		Responsible TSO	Allocation method[24]	Alloc. Frequency[25]	Use it or lose it	Long term contracts	Congested
Sweden	Poland	?	(JEA/R)	y	n.a.	92% reserved by Vattenfall	Seldom (→) Frequently (←)
Poland[26]	De(VE-T)[27] /CR[28] /SK	CEPS (2005)	JEA	y,m,d	Yes	Probably (→) No (←)	Frequently (→) Seldom (←)
Czech Republic	De(E.ON)	E.ON Netz	JEA	y,m,d	yes	Yes (→) No (←)	Always (→) Seldom (←)
Czech Republic	Slovakia	CEPS	JEA	y,m,d	?	Probably (→) No (←)	Seldom (↔)
Czech Republic	Austria	APG	JEA	y,m,d	Yes	Yes (→) No (←)	Frequently (→) Seldom (←)
Slovakia[29]	Hungary	MAVIR	EA	y,m	Yes	Probably (→)	Always (→) Seldom (←)
Slovakia	Hungary	SEPS	EA	y,m	yes	Probably (→)	Always (→) Seldom (←)
Slovakia[30]	Ukraine	SEPS	EA	y,m	yes	? (↔)	Seldom (↔)
Hungary[31]	Romania	MAVIR	EA	y,m	yes		
Hungary	Serbia & Montenegro	MAVIR	EA	y,m	yes		
Hungary[32]	Croatia	MAVIR	EA	y,m	yes		
Hungary[33]	Austria[34]	APG	JEA	y,m	yes		Always (→) Frequently (←)
Hungary	Austria	MAVIR	JEA	d			Always (→) Frequently (←)

[24] JEA: Joint explicit auction; R: Retention; EA: Explicit auction; FF: First come first serve

[25] (y)early; (m)onthly; (d)aily

[26] From the perspective of PSE, Germany, the Czech Republic and Slovakia are considered as a common border (import and export).

[27] From the perspective of VE-T, Poland and the Czech Republic is considered as a common border (import and export).

[28] CEPS distinguishes capacities on the borders to VE-T, E.ON and PSE (import and export).

[29] Coordinated, but capacity is split 50%-50% with slightly different rules (import and export).

[30] Unilateral auction by SEPS (import and export)

[31] Confirmation by ERS, Romania required (import and export)

[32] Coordinated, but capacity is split 50%-50%, no information on CROISMO's activities (import and export)

[33] Peak and base load can be specified

[34] Peak and base load can be specified; in 2004 MAVIR was responsible for import into Hungary

Slovenia[35]	Austria	APG	EA	y,m,d	yes	No (→) Probably (←)	Seldom (→) Always (←)
Slovenia[36]	Croatia	?	FF				
Slovenia[37]	Italy	GRTN (→)	Pro rata (→)	d (→) y (←)	Yes (→)	Probably (→) Yes (←)	Always (→) Never (←)

4.2.4 Summary of Auction Results and Proceeds

Cross-border capacity auctions are a good indicator of congestion as well as the congestion rent between the corresponding countries. Moreover, as experience from Western Europe shows, these auctions may render a substantial financial income to TSOs. In this section, we therefore summarise information on the capacities that have been made available to the market in 2004 and the average per-MW prices paid for capacity rights at each border. In addition, we have also calculated the financial income at each border from the different types of auctions, including annual and monthly capacity auctions.

Table 6 summarised the capacities auctioned in yearly and monthly auctions as well as the averaged capacity prices and the auction income for 2004. Due to the limited availability of data on daily auctions, we have considered daily auctions when calculating the resulting average prices and congestion rents. In summary, such auctions have rendered an income of some 150 M€ in 2004, with two thirds of this amount arising at the borders between the Accession Countries Czech Republic and Poland to Germany.

35 Coordinated but capacity is split 50%-50%, no information on ELES' activities (import and export)

36 No congestions according to [1] (import and export)

37 Coordinated but capacity is split 50%-50%, no info on ELES' activities (import and export)

Table 6: Auction results for 2004

Border		Available capacity (MW)[38] Annual	Available capacity (MW)[38] Monthly	Average price (€/MW/a) Annual	Average price (€/MW/a) Monthly	Total income (million €)
CZ	AT	200	25	34,281	53,592	4.89
AT	CZ	600	192	36	7	0.02
AT	HU	100	117	62,895	7,986	7.22
HR	HU	100	147	3,569	258	0.39
HU	HR	200	316	18,352	1,733	3.78
SK[39]	HU	250	312	72,963	36,202	29.32
HU	SK	600	600	4,087	136	2.50
CS	HU	-	25	N/A	252	0.01
HU	CS	100	108	0	670	0.02
RO	HU	-	25	N/A	1,008	0.02
HU	RO	50	67	0	653	0.02
CZ	DE(E.ON)	750	175	36,298	64,095	38.44
DE(E.ON)	CZ	450	193	132	58	0.07
SK	UKR	-	150	N/A	0	0.00
UKR	SK	-	15	N/A	45	0.00
CZ	SK	800	328	4,541	554	3.62
SK	CZ	800	443	4,131	651	3.46
PL[40]	CZ	400	34	5,016	5,302	1.97
CZ	PL	800	133	88	0	0.07
DE(VE-T)	CZ	450	180	212	86	0.11
CZ[41]	DE(VE-T)	800	304	36,499	64,557	32.06
PL[42]	DE(VE-T)	800	113	36,499	60,263	16.28
PL[43]	DE(VE-T) /CZ/SK	-	385	N/A	13,647	5.25
DE(VE-T) /CZ/SK	PL	-	158	N/A	8,649	1.37
Total						**150.88**

Similar to the case of 2004, we have also summarised the corresponding information for the year 2005 in Table 7. Although this information only considers annual auctions that have already taken place, the total income of 147.5 M€ is almost as high as the total auctions revenues from 2004. This indicates that demand for capacity is increasing and we expect that capacity costs in 2005 will be substantially higher than in 2004.

38 On the Czech/Austrian border: base + peak load

39 No annual data from SEPSAS available (↔)

40 January – April (↔)

41 Until May 2004 only combined available capacity for CEPS/PSE->VE-T

42 January – April

43 May – December (↔)

Table 7: Auction results for 2005

Border		Available annual capacity (MW)[44]	Average price, annual auction (€/MW/a)	Total income (million €)
CZ	AT	200	46,172	4.78
AT	CZ	600	0	0.00
HU	AT	200	17,581	2.39
AT	HU	100	3,504	0.35
SI	AT	325	1,170	0.28
AT	SI	212	15,358	2.58
HR	HU	50	1,092	0.05
HU	HR	300	5,389	1.62
SK	HU	450	49,783	22.40
HU	SK	400	354	0.14
CS	HU	50	6,394	0.32
HU	CS	25	2,233	0.06
RO	HU	50	11,116	0.56
HU	RO	50	1,786	0.04
CZ	DE(E.ON)	750	58,674	44.01
DE(E.ON)	CZ	400	15	0.01
SK	UKR	450	0	0.00
UKR	SK	450	1	0.00
CZ	SK	800	1,664	1.31
SK	CZ	800	312	0.25
PL	CZ	?	0	0.00
CZ	PL	?	8,935	0.71
DE(VE-T)	CZ	?	0	0.00
CZ	DE(VE-T)	?	53,261	17.04
DE(VE-T)	PL	?	0	0.00
PL	DE(VE-T)	?	101,187	48.57
PL[45]	SK	450	0	0.00
SK	PL	100	438	0.04
Total				**147.51**

[44] For Austrian borders: base + peak load

[45] Only data from SEPSAS available (↔)

To highlight, at which borders and most notably in which direction congestion is the most severe, we have visualised the average per-MW prices for annual cross-border capacity in 2005 in Figure 25. This depiction clearly confirms our previous statement that there exists considerable congestion from the Accession Countries to Germany. In addition, we also see strong demand for export capacities from the Czech Republic and Hungary to Austria, from Austria to Slovenia, and from Slovakia to Hungary. These observations highlights the general belief that the demand for cross-border is the highest in the direction of North-Eastern Central Europe to Germany, on the one hand, and the direction of Italy, on the other hand. However, in addition, we note that network constraints have also become an issue e.g. at the borders from Romania or Serbia & Montenegro to Hungary,

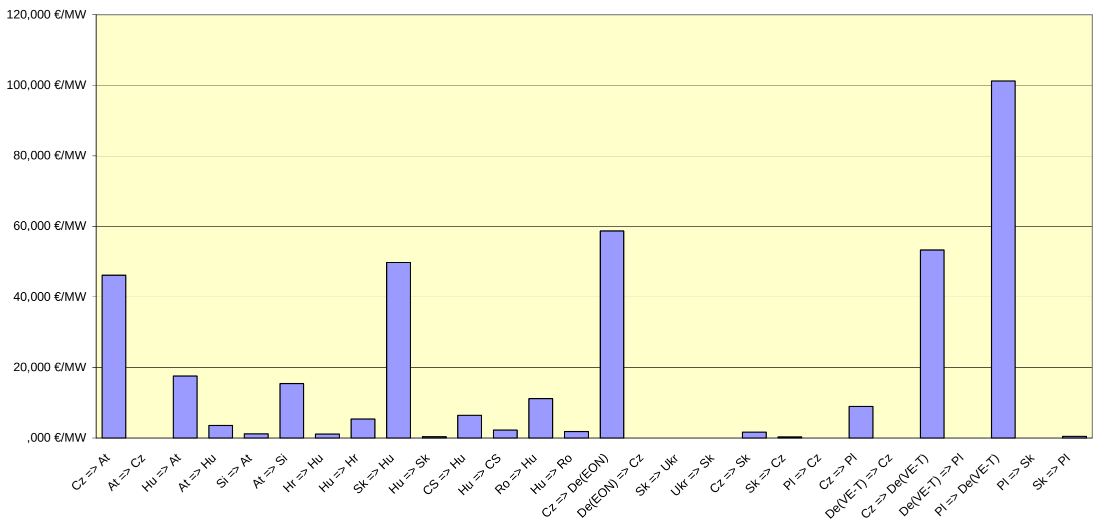

Figure 25: Comparison of average annual capacity prices per border (2005)

Finally, Figure 26 illustrates the total auction proceeds for each border in 2004 and 2005. This depiction clearly shows that most income is generated at just three borders, namely from Slovakia to Hungary, from the Czech Republic to Germany, and from Poland to Germany. Taken together, the corresponding auctions represent some 90% of total auction proceeds. In contrast, the total volume at the Austrian borders, even if characterised by high prices (see above), is substantially smaller. Secondly, Figure 26 also reveals an interesting shift in income from cross-border capacities between the Czech Republic and Eastern Germany (VET) to the Polish-German border. However, this development does not come as a surprise when taking into account the fact that PSE did not participate in the allocation of annual capacities for the year 2004.

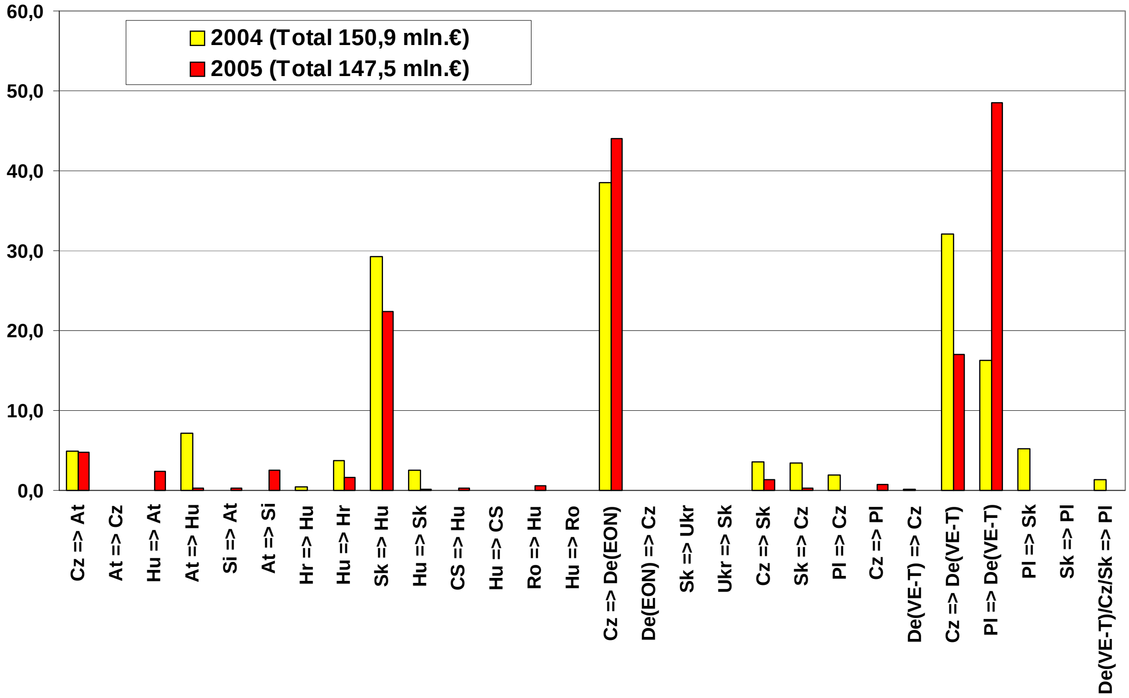

Figure 26: Total auction proceeds: 2004 – 2005 (million €, per border)

4.3 Possible Improvements

4.3.1 Special Protection Systems

As discussed in section 4.1.2 above and in section 5.2.2.1, only the Baltic States are applying special protection systems on a large scale in order to mitigate load problems. Special Protection Systems automatically limit the load on the lines in case of a logical combination of events and pre- or post-fault conditions: e.g. a protection scheme can be activated after a particular trip if the pre- and post fault load of other lines exceed some predefined limits. The action can be load shedding, generation shedding or activating reserves (increasing generation) and pumps. Because these special protection systems do their job very quickly, the short overload in the (n-1) situation can be accepted. Assuming that sufficient generation reserves and/or load management options are available on both sides of the lines in question, the flow under normal conditions can therefore be higher, which results in significantly higher NTC values.

Although not as widely spread as in the UPS/IPS system, some special protection systems are in place in the UCTE system. E.g. on the tie-lines from Hungary to Romania and Serbia, a protection system is installed which trips two lines in case the load of both tie-lines together amounts to 1000 MW.

We believe that there are more situations within the UCTE network where special protection systems could be installed. Especially in situations in which a rare event dramatically reduces the TTC values. In this case a special protection system could probably make it possible to 'ignore' when automatic switching actions and automatic adaptations of generation schedules could mitigate the temporary overload. Because of the low probability of such an event, the chances for generation toe adapt immediately are very small as well, which should reflect in the remuneration to be paid to the operators of the generating units. I.e. the cost of such an agreement could be limited.

However, some remarks have to be made. Firstly, special protection systems need to have perfect coordination between all parties involved. I.e. in a meshed transmission network like the UCTE network, every change in topology or generation pattern will influence flows in other countries. This can easily result in shifting the problem from one country to another, which of course should be prevented. The second remark is that usually generating units are involved in the switching actions. Often, a corrective action will need to be performed by a selected group of generating units. As these units are in the liberalised markets and are not (like in the Baltic States) part of vertically integrated utilities anymore, their owners should therefore receive remuneration for the corrective adaptation of their generation schedule. Preferably, the remuneration would be fixed using a kind of market mechanism. However, special protection systems will adapt generation patterns within a specified area. Possibly the number of generating unit owners in this area will be small, which implies that the possibility to use a market mechanism will be small as well. A third remark here is that these special protection systems do not add extra capacity to the network, the only thing is that the existing capacity is better utilised. This leads to higher line loads and operation closer to the safety limits.

Despite these concerns, we believe that the use of special protection systems should be considered as an alternative solution before investing in new cross-border capacity. Possibly, the cost of contracting generators for taking part of the special protection system is lower than the annual costs of new investments into the network.

4.3.2 Use of Phase Shifters

Throughout Europe, TSOs consider installing phase shifters in order to mitigate congestions and increase the NTC values with their neighbours. By using phase shifters, TSOs have the possibility to influence the flows in the transmission networks. By doing this, the flow in overloaded lines can be reduced, while the flow in lines that are not fully used, can increase.

A disadvantage of phase shifters is that phase shifters usually increase the thermal losses in the network[46]. A calculation by Polish TSO PSE shows that a phase shifter installed in Mikulowa (Poland) could increase the thermal losses in both Poland and Germany with 10's of MWs. When used during normal operation, this can lead to huge costs. E.g. continuously 10 MW of network losses will cost the TSO several millions of Euros per year. However, because the angle of phase shifters can be changed within minutes, phase shifters could also be used for a quick mitigation of occasional overloads. Therefore, these overload situations could be acceptable, which could result in higher NTC values. When phase shifters are used only for mitigation of overload caused by special events, they only result in increased thermal losses in case of these events. Because these events are rare, increased network losses caused by phase shifters are rare as well. The related costs are limited as well, e.g. several hundreds of Euros an hour in case of 10 MW extra losses.

In order to speed-up the mitigation of overloads, switching phase shifters could be included in special protection systems. I.e. in case some event in a network is taking place, the angle of the phase shifter will be automatically adapted in order to reduce the load on overloaded lines. This will increase the response time on an event, which makes an overloaded line in the (n-1) situation more acceptable.

Although a phase shifter can be applied for a more effective use of the existing lines, it does not result in any extra capacity. Furthermore, in a meshed transmission network like the UCTE network, phase shifters need perfect coordination between many different TSOs and could easily shift problems from one place to the other. We note that not only TSOs operating the line with the phase shifter should be involved, because the phase shifter can influence flows in a wide area. E.g. the phase shifters of the Dutch TSO TenneT recently installed on their border with Germany could shift their problems easily to the border between Belgium and France. Therefore, some TSOs consider phase shifters only as a measure of last resort that would only be used on a temporary basis. However, we believe that in some cases, with proper coordination between all affected TSOs, phase shifters can really increase the NTC even without increasing the thermal losses dramatically.

4.3.3 Variable Thermal Limits

As discussed in section 4.1.5, most TSOs that do not currently use flexible limits are not too eager to use flexible thermal limits for their lines. While some TSOs refer to their obligation to meet the national standards, others state that it does not bring too much additional TTC. Furthermore some TSOs state that it only brings additional TTC when there are no congestions. The last reason could be definitely valid for the night when the load is low. However, for winter periods a lower ambient temperature than stated in Table

[46] This is true for networks consisting of mainly overhead lines, like the UCTE network. In case a significant share of the connection consists of underground cables, phase shifter could be used for reducing losses as well.

4 is rather likely for many countries. In case of congested borders, this should lead to increased TTC values.

We note that only Slovenian TSO ELES, Polish TSO PSE Operator and Romanian TSO Transelectrica are seriously considering using different thermal limits for summer and winter. We agree with some other TSOs that the most severe network situation could take place during the summer season, because in this season maintenance takes place. However, this does not indicate that the thermal limits in the winter could not be increased by considering a lower ambient temperature. This will most likely not reduce the internal need for investments in transmission lines, but could increase the TTC in the winter, when it is most needed. Therefore we seriously think that using different thermal limits for overhead lines should be considered as an alternative for investments in cross-border connections.

4.3.4 Possible Improvements in Capacity Allocation

The description and analysis of the allocation mechanisms applied by the Accession Countries has revealed that many countries have already implemented explicit auction schemes, similar to the example of most Member States. However, there still remain a number of countries without any formalised and/or market-based mechanisms, such as the Baltic States, Bulgaria, Romania or Turkey. Hence, it seems clear that the most obvious potential for improvement at many borders lies in the basic introduction of transparent and non-discriminatory allocation schemes.

Secondly, the recent disputes between CEPS, PSE and VE-T clearly illustrate the need for further coordination. But at the same time, the new solution for 2005 provide an interesting example for possible improvement. Most existing auctions rely on an ex-ante allocation of national NTC values to individual borders, including e.g. the case of the 'coordinated auctions' at the Dutch borders. In contrast, the new auction scheme applied by CEPS, PSE-O and VE-T does not pre-empt this allocation but leaves it to the allocation mechanism, and thus the market, to determine the most valuable distribution of transfer capacities to different borders. Without going into detail, we believe that the underlying concept represents an important improvement as it helps to create additional flexibility for the market, thus enabling a more efficient use of scarce cross-border capacities.

At the same time, we note that this approach has only been made feasible through a common agreement between all participating TSOs not only on a joint mechanism, but also on transferring the exclusive responsibility for operation of this mechanism to a single TSO. In contrast, our analysis of many other borders has revealed that many TSOs still insist on allocating 'their' cross-border capacities, as demonstrated by the various cases where both TSOs are responsible for either a share of the total capacity, or one of the two directions. While it goes without saying that bilateral agreement on a common mechanism should be a minimum requirement, the example of the Polish-German-Czech auctions also indicates the advantages of a coordinated regional scheme, with a single, centralised point of allocation. Hence, a second area of potential improvement would be the introduction of centralised allocation schemes for certain regions.

Nevertheless, we also note that these potential improvements, as positive as they may be, do not by themselves suffice to avoid the drawbacks associated to the explicit auction schemes currently applied in most of Continental Europe. Thus, we support the general preference for implicit auctions and would like to emphasise the potential benefits of netting or the use of regional allocation based on power transfer distribution factors (PTDF). However, the corresponding issues have already been extensively discussed in a recent report for DG-TREN, such that we refer to this document for a more fundamental discussion of the associated issues.

5 Measures to Increase Transmission Capacities

5.1 Overview

The scope of this chapter is to analyse the projects planned by the TSOs and other relevant parties, including those included in the list of projects of common interest in the framework of the Trans-European Networks, and to put forward the most important projects of common interest, which should be realised. It thus represents a key part of this study. Given the large geographical range of the area under study, we first discuss the borders and network areas that have been designated as (potential) areas of congestion by the transmission system operators of the study countries, as well as possible measures for mitigating these network constraints (section 5.2). To obtain a better view of the costs and benefits of those investments that have been designated by the TSOs as being the most important and/or realistic, we then perform a cost-benefit analysis in section 6. Besides analysing the overall value of individual investments, we subsequently use the results of this analysis for establishing an indicative ranking of those network extensions that can be considered to be of the highest value and most importance for the establishment of the Internal Electricity Market in the Accession Countries (section 6.5).

5.2 Analysis of Congested Network Areas and Planned Reinforcements

5.2.1 Approach and Data Sources

To analyse potential areas of congestion and planned reinforcements into the transmission grids, we asked the TSO of all Accession Countries and most neighbouring countries on their own views in our initial questionnaire. Based on the responses, we then visited all TSOs that were willing to cooperate and performed a series of personal interviews with relevant management, planning and operational staff. In addition, we asked a number of our own experts from the Baltic States, South-Eastern Europe, Germany and the Netherlands for a supplementary analysis of the information received from the TSOs and other, public sources. In a few cases, we have also been granted access to previous studies of specific projects.

In the following, we briefly summarise the main findings for different countries and regions. Due to the large numbers of countries under study, we have divided the relevant parts of the transmission grid into a total of six regions. While the first group generally deals with the situation in the Baltic States, we have separated the potential connection between Poland and Lithuania since this link would also have major implications on the Polish network. The third group consists of the borders between the Czech Republic, Slovakia, Poland and Germany, which include a number of important network constraints.

Fourthly, we discuss the situation of the network in and around Austria, which is widely regarded as one of the most severe areas of congestion in the region. Following a discussion of the borders between the North-Western part of former Yugoslavia, Italy and Hungary, we finally comment on the situation in South-Eastern Europe, including the (potential) links with Turkey.

5.2.2 Baltic States

5.2.2.1 Current Situation

The transmission grid of the Baltic States is shown in Figure 27. This depiction clearly shows that the three networks were not originally planned as three independent power systems, but rather as an integral part of a larger grid.[47] Moreover, prior to the restoration of Baltic independence in 1992, this system served a load that was significantly higher than the current generation and load. Consequently, the three Baltic transmission networks still face overcapacity, which becomes apparent in high voltage problems. Hence, we have been informed by DC Baltija and all three national TSOs that, under normal operational conditions, there is usually no congestion within the system of the Baltic Countries. Only in case of maintenance on specific transmission lines, the transfer capacity of the network may become restricted due to thermal limits. Such cases are occasionally solved through re-dispatch of generation units; but this not a common practice. As a result, the TSOs do not currently see any need for strenghtening the cross-border network before 2012.

[47] The same is true for the generation structure; e.g. the nuclear power plant at Ignalina could only be built as part of a large, integrated power system.

Figure 27: Transmission grid of the Baltic States

Courtesy of DC Baltija

Table 8 contains a summary of the main transfer capacities between the Baltic States, Russia and Belarus. As explained in section 4.1.2, these limits have been calculated based on the (n-1) criterion, while taking into account special protection systems used to increase available transfer capacities. Since these values have been jointly determined, agreed upon and allocated between all five TSOs, respectively utilities they are also considered during operational planning, such that there does hardly arise any congestion in operation. Moreover, as mentioned before, the Baltic transmission networks currently serve a load that is substantially smaller than in the late 1980s, also indicating the availability of sufficient transfer capacities. While there exist some problems with high voltages, these are largely of a local nature and do hardly impact the international power exchange.[48]

48 All three Baltic States currently face the low-load problem, i.e. high voltages during the nights in summer. They are exporting reactive power to Belarus and Russia, but install shunt reactors as well. In addition, SVCs and generation units (hydro power plants and Ignalina 2) are used for reactive power compensation as well. In some situations, lines are switched off during the night to mitigate these voltage problems.

Table 8: Approximate transfer capacities in the Baltic States (including contracted reserves)

Direction	MW	Direction	MW
Estonia/Pskov to Latvia	1500	Belarus to Lituania	1400
Latvia to Estonia/Pskov	1200	Russia-Belarus	1200
Latvia to Lithuania	1000	- maintenance on 750 kV line	800
Lithuania to Latvia	± 2000	- maintenance on 330 kV line	900
Lithuania to Belarus	2200	Belarus-Russia	1000

Source: DC Baltija

As discussed in section 5.2.2.1, the determination of these transfer capacities is based on the consideration of special protection systems. In fact, there are three cases where the (n-1) criterion can only be met by using special protection systems. While one of them is related to the need for a sufficient amount of fast-starting reserves in case of the single largest loss of generation, the other two are related to limited transmission capacities. More precisely, these three cases are related to the following constraints:

- *Trip of one unit of the Ignalina nuclear power plant (1300 MW):* To cover the loss of this major generation unit, special protection systems are used to start up all available hydro units in Lithuania (pump storage) and Latvia (run-of-river with daily/weekly storage capacity).
- *Transmission line (750 kV) Kalininskaya (Russia)-Leningradskaya (Russia)*
- *Transmission line (750 kV) Smolenskaya (Russia) – Belorusskaya (Belarus), with parallel 330 kV link to Roslavl / Krichev / Talashkino*

It should be noted that the two cases of network congestion are caused by bottlenecks for transporting energy from Central Russia not only to the Baltic States but also to North-Western Russia and Belarus. Hence, both constraints are clearly outside the transmission grid of the Baltic States. Moreover, they are more generally related to power exchanges between Central Russia and other areas, rather than only to the Baltic States. Nevertheless, the expected load growth in the Baltic area could result in these limitations becoming increasingly critical for the reliability of supply in the Baltic States.

5.2.2.2 Expected Future Development

The current lack of congestion implies that there is no imminent need for strengthening of the cross-border capacities between the Baltic States. Given the fact that the Baltic transmission grid was serving a substantially higher load before the dissolution of the Soviet Union, one may also reasonably assume that there are considerable reserves in the system. Nevertheless, there are a number of developments that indicate the likeliness of changing flow patterns over the next decade. These include the rapid load growth in the major urban centres (e.g. Tallinn, Riga, Vilnius, Kaunas and Klaipeda), the construction of new and the rehabilitation of existing power plants, as well as the decommissing of the nuclear power plant (2 x 1,300 MW) at Ignalina.[49] The closure of Ignalina will especially have a substantial impact, as it will reduce the currently high level of overcapacity in Lithuania.

To study the impacts of these different developments, and to assess the security of supply (network) in general, the three Baltic TSOs are soon to complete a joint study to analyse the possible development until 2012.[50] Within this project, staff from the three system operators has established a comprehensive load flow model of the Baltic transmission systems and simulated a large number of scenarios.[51] We have been informed that these scenarios comprised a variety of ‘normal situations’, different import and export settings (typically varying the flow between two countries by ±1000 MW), and an analysis of specific investment projects. For the modelling of generation, these scenarios have used a base case provided by each country. On the network side, this project did consider various options for the Estlink Cable (see section 5.2.2.7) and a possible link between Poland and Lithuania (see section 5.2.3).

Although the final results of the study have not yet been approved or published, we have been told that the simulations had confirmed the general expectation that the Baltic transmission networks would be strong enough to handle all expected cross-border flows for the foreseeable future. Similarly, the project has also confirmed the bottlenecks on the two 750 kV links from Central Russia to Belarus and North-Western Russia (St. Petersburg), respectively. In conclusion, it appears that the potential power exchange between the Baltic States and Russia could only be increased by investments within Russia or between Russia and Belarus, i.e. several hundred kilometres outside the Baltic borders.

5.2.2.3 Estonia

Besides its participation in the Baltic load flow study, the Estonian utility Eesti Energia has prepared a parallel analysis for the Estonian power system until 2025. Similar to the Baltic study, Eesti Energia does not expect any serious bottlenecks on its borders with Russia and/or Latvia. But in addition to a more thorough analysis of the Estlink-project (see section 5.2.2.7), Eesti Energia has used its own study to also assess the need for internal network reinforcements within Estonia.

Generally speaking, the import capacity at the Estonian borders is not constrained by lack of transmission capacity but rather by the need to secure system operation in case of islanding. We have been told that existing protection systems does not allow for more than

[49] In accordance with Lithuania’s commitment under EU Accession, the first unit will be shut down at the end of 2004, but the second one before 2010.

[50] We have been informed that the study is scheduled to be completed by the end of 2004.

[51] Overall, the TSOs have run some 3000 simulation runs.

40% load shedding. To avoid a major shortage of generation in case of the Estonian system becoming islanded, and a subsequent fall of frequency, Eesti Energia does therefore limit import to 40% of actual load.[52] Given the current status of Estonia as an exporting country, and the fact that this constraint seems to be more critical than the availability of transfer capacities, it seems fair to conclude that there is no economic rational for additional import capacities for the foreseeable future.

Similarly, Eesti Energia does not expect any need for increasing export capacities to either Russia or Latvia.

In contrast, the Estonian TSO is already faced with potential internal congestion, which is expected to become increasingly critical in the future. Following the initial drop of demand in the early 1990-s, the Estonian capital Tallinn and the surrounding area have seen a rapid load growth for a number years; by now, the consumption in the Tallinn area is already larger than during Soviet times. In the medium term, Eesti Energia expects similar problems around Pärnu in South-Western Estonia. Eesti Energia therefore plans a number of major network extensions as follows:

- Before 2007, the existing 220 kV double-circuit line (ca. 250 km) Balti (Narva) and Veskimetsa (Tallinn) shall be upgraded to 330 kV, and continued until Harku;
- By 2012, a new 330 kV link between Tartu and Sindi; and
- After 2017, a new 330 kV link between Sindi and Harku.

Although these investments concern internal connections only, they are also relevant for the international power exchange. As a matter of fact, the new subsea cable to Finland is expected to connect to the Estonian power system at new Harku substation, i.e. close to Tallinn. At the same time, Eesti Energia expects this new cable to be primarily used for exports. In turn, construction of this new link will add new problems to the already existing problems in ensuring the reliability of supply to the Tallinn area. This is also confirmed by another information from Eesti Energia, noting that the link between Sindi and Harku would not be required without increasing Estlink capacity to 500 MW. Conversely, increasing the capacity of the Estlink cable by 500 MW would lead to immediate congestion within the Estonian power system.

In summary, our discussions with the Estonian TSO have thus not revealed any needs for increasing the cross-border capacity with either Latvia or Russia at least until 2012. In contrast, it appears that the planned construction of the new subsea cable between Finland and Estonia will require additional, or at least earlier investments within Estonia of a significant volume. Based on an assumption of some 100,000 €/km for building a new 330 kV transmission line, the new costs only for building the new line from Tartu via Sindi to Harku may amount to some 40 M€. Hence, these costs should at least partially be taken into account when assessing the Estlink project (see section 5.2.2.7).

[52] Please note the dynamic nature of this import capacity as it changes during the day.

5.2.2.4 Latvia

The Latvian utility Latvenergo has largely confirmed the results of the Baltic load flow study (section 5.2.2.2), i.e. that there is no imminent need for increasing the network capacities between Latvia and its neighbours. In this context, it should also be noted that net imports to Latvia are expected to decrease following the reconstruction of the two combined heating plants in the capital Riga. After these investments, Latvia may get into a position where it is able to fully supply its electricity needs itself, thus effectively reducing the need for cross-border capacities.

Latvenergo has mentioned the possibility of building an additional link between Sindi (Southern Estonia) and a substation close to Riga,[53] but this investment would not be needed until after 2012. Moreover, in a discussion with Eesti Energia, the Estonian TSO voiced its reservations about this project, as it would aggravate the internal problems on the Estonian side. This project would thus only be feasible after construction of the new transmission lines Tartu-Sindi and Harku-Sindi. Furthermore, in the opinion of Eesti Energia, the new line would only be required to handle major flows between the North and South, i.e. in case both the Estlink cable and the Poland-Lithuania link had been built. Consequently, Eesti Energia does not expect that a new transmission line between Sindi and Riga will be built before 2017.

The potential costs of a new transmission line between Sindi and Riga have been specified by the Estonian side as approx. 500 million EEK (~32 M€). Due to bottlenecks within Estonia, the additional transfer capacity would be limited to some 100 – 300 MW in the direction from Estonia to Latvia.

5.2.2.5 Lithuania

Similar to Latvia, the Lithuanian TSO Lietuvos Energija considers the national transmission grid and its links with neighbouring countries to be strong enough to handle all expected cross-border flows both today and in the future. Moreover, the commissioning of an additional 330 kV line in Belarus (Grodno-Rossij) will result in an increased transfer capacity between Belarus and Lithuania. In case of imports, though, these will continue to be limited (in the opinion of Lietuvos Energija, at a sufficiently high level) by the network constraint between Russia and Belarus.[54] The increased export potential, on the other side, is unlikely to be fully utilised as Lithuanian exports to Belarus are expected to decrease after the decommissioning of Ignalina-1. Similarly, the Lithuanian side does not see the need for increasing the transfer capacities to Latvia.

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[53] As an alternative, Latvenergo also mentioned a possible link between Sindi and Ventspils in Western Latvia, using a subsea cable. However, given the additional costs of such a solution, we are rather sceptical about this variant.

[54] Given that Belarus is a major importer of electricity, it seems unrealistic to expect any net exports from Belarus to the Baltics.

The only international investment that Lietuvos Energija actively pursues thus is the link between Poland and Lithuania, which we discuss in section 5.2.3 below. The impacts of this additional link on the power flows within the Baltics have also been studied within the Baltic load flow study (section 5.2.2.2). However, it seems that these scenarios have not included a situation where Lithuania would be in the position of a pure transit or even an importing country. It thus appears that the Baltic load flow study may have failed to take account of some situations that could occur in the future, especially after the possible construction of the Poland-Lithuania link.

5.2.2.6 Kaliningrad Region

Today, there is a considerable transit of electricity from Russia through the Baltic States to the Kaliningrad area, with an annual volume of some 3 TWh, or almost 350 MW on average. As a matter of fact, the power supply of Kaliningrad with a peak load of approx. 700 MW but installed generation of less than 200 MW can only be ensured by Lithuania. To reduce the dependency on Lithuania, the Russian side has therefore started to construct a gas-fired CHP in Kaliningrad, with an installed capacity of 400 MW. This plant was originally scheduled to start operations in December 2004, but the completion of this project has now been postponed to late 2005.

In the medium to long term, this new CHP will also result in an increase of available transfer capacities within the Baltic States, respectively for imports from Russia. Given that the current transit flow has to be transported via the bottlenecks from Central Russia towards the Baltic States, the new power plant may thus make up 500 MW in additional import capacity available to the Baltic States.

5.2.2.7 Subsea Cable Estonia-Finland (Estlink)

The construction of a subsea cable between Estonia and Finland has already been under discussion for about a decade. Amongst others, this project was analysed within the *Baltic Ring* study where it was identified as one of the crucial connections for linking the Baltic States to the Scandinavian market. As the primary objective of this project, the Estonian TSO has cited a reduced dependence of the Baltic power systems on Russia and thus an increased security of electricity supply. Further arguments include the creation of additional trading potential between the Baltics and Scandinavia, including the potential exchange of system services (reserves), and more generally the establishment of a common power market around the Baltic Sea. According to Eesti Energia,[55] the feasibility of the DC connection from Finland to Estonia is based on surplus generating capacity in Estonia until 2012. Eesti Energia estimates that 2 TWh will be sold annually through this cable to the Nordic Countries.

In July 2004,[56] the three Baltic power utilities and two Finnish companies agreed to establish a new joint venture, AS Nordic Energy Link, in order to build and operate the new connection. The shareholders are Eesti Energia (39.9%), Latvenergo and Lietuvos Energija (25% each), and Pohjolan Voima and Helsingin Energia (10.1% each). In addition, the shareholders have already signed a cooperation agreement with Fingrid regarding the connection of this new link to the Finnish transmission grid. The parties plan to finance this cable as a private venture and held preliminary meetings with the regulators of Estonia, Finland and Latvia to apply for a corresponding exemption from the EU. The project is currently in tendering phase and is planned to be in operation in autumn 2006.

Technically, Estlink is planned as a 150 kV direct current cable with a total length of about 100 km, including 70 km of marine cable and some 30 km underground cable (9 km in Estonia and 20 km in Finland). It is planned to connect to Finnish 400 kV grid at the Espoo substation, and the new 330 kV substation Harku in Estonia. While the original plans foresaw a transport capacity of 600 MW, the size of the project has by now been reduced to 350 MW, at an estimated cost of 110 M€. This estimate does not yet cover additional reinforcements in both the Finnish and Estonian transmission grids. For the Finnish side, earlier studies concluded that it would be sufficient to construct a third 400 kV line out of the Inkoo substation. On the Estonian side, the TSO Eesti Energia will initially have to invest into a new 300 kV substation at Harku. As already discussed in section 5.2.2.3 above, it will furthermore be necessary to upgrade the existing 220 kV line from Püssi to Kiisa to 330 kV and extend it until the Harku substation. However, reconstruction of the existing 220kV line is also required due to internal needs, i.e. continued load growth in the Tallinn area and the deteriorated condition of the existing 220 kV line.

There also exist plans for either increasing the capacity of the new interconnection, or more likely building a second submarine cable to Finland from a place in Eastern Estonia. However, these plans are still at a very early stage.

Figure 28: DC Subsea Cable Estonia-Finland (Estlink)

Source of map: DC Baltija

[55] Eesti Energia (2004a)

[56] Eesti Energia (2004)

5.2.3 North-Eastern Europe: Poland and Lithuania

5.2.3.1 General

Currently the transmission networks of Poland and Lithuania are not connected at all. Moreover, the two power systems belong to two different synchronously connected areas. Whereas the Lithuanian power system, together with Estonia, Latvia and Belarus, is connected and synchronous operated with the Russian power system (the UPS/IPS system), Poland is a member of the UCTE system. As of today, there are thus no possibilities for exchanging electric power between the two EU member states Poland and Lithuania. Similar to the Estlink project, there has been a discussion about a possible link between Poland and Lithuania since the early 1990s. This project was also analysed under the Baltic Ring study and identified as critical for creating a common power market in the region.

In principle, there exist three different alternatives for connecting the power systems of the Baltic States with the UCTE system:[57]

1. Asynchronous interconnection between Poland and Lithuania;
2. Synchronous connection (AC) between Poland and the Baltic states;[58] or
3. Synchronous connection between UCTE and the UPS/IPS system through the existing transmission links to Ukraine.

In the following, we focus on the alternative of an asynchronous connection. While we also comment on the second option, we discuss the third alternative in section 5.2.3.4.

Building an asynchronous connection between Poland and Lithuania has long been discussed as the most realistic option. Various studies have analysed different alternatives, including an AC line with a back-to-back station, a DC link, or an AC line with radial operation of the pump storage plant at Kruonis. Especially the first alternative has received continued attention in the recent past, as e.g. documented by a recent feasibility study financed by the EBRD.[59] Generally, all these plans foresee to build a new line between Elk (Poland) and Alytus (Lithuania).

Besides the general goal of establishing the EU Internal Electricity Market, the second initial rationale for this project was the desire to make the flexible use of the pump storage plant at Kruonis available to the Polish power system with its less flexible plants. The original idea thus was to use the line for the main purpose of exporting Lithuanian peak power to Poland, while refilling the plant's reservoir by cheap electricity from the nuclear

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57 Please note that the second and third alternative could also be combined.

58 Including Kaliningrad.

59 IPA Energy Consulting (2003)

power plant at Ignalina during the night. However, the decommissioning of Ignalina before 2005 (unit 1) and 2010 (unit 2), respectively, will largely remove this cheap source of energy. Consequently, Lietuvos Energija has decided against the further extension of the power plant at Kruonis.[60] In turn, this decision has likely also had a negative impact on the economics of the planned link to Poland.

5.2.3.2 Alternative 1: AC-Link with Back-to-Back Station (500/1000 MW)

Most plans for an asynchronous connection between Lithuania and Poland are based on the construction of a 400 kV-line (double circuit) from Elk (Poland) to Alytus (Lithuania) with a capacity of 1000 MW. On the Lithuanian side, this line would be connected to the Lithuanian 330 kV grid by a back-to-back converter.[61] In addition, the project would require further investments in both the Polish and Lithuanian grids. While the reinforcement of the Lithuanian system would be limited to a new 330 kV line (53 km) from Alytus to Kruonis, the relatively weak network in North-Eastern Poland would require substantial investments. Current plans foresee the construction of two new 400 kV lines on the Polish side, from Elk to Olsztyn Matki and Narew, respectively.[62] In addition, we have been told by PSE-Operator that it would also be necessary to reinforce the links to the South and West of Poland as well as the interconnection to Germany.

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[60] The projected capacity of the pump storage plant was 1 600 MW (8 units, 200 MW each); currently, the installed capacity of the plant amounts to 800 MW in 4 units.

[61] The reason for building a 400 kV line, despite a lower voltage on the Lithuanian side, are lower transmission losses.

[62] These lines need to cross an environmentally sensitive part of Poland, which makes it very hard to obtain the necessary permits. Probably, the route of the existing 220 kV-line from Ostroleka to Elk could be used for the connection from Matki to Elk, which however almost doubles the line length.

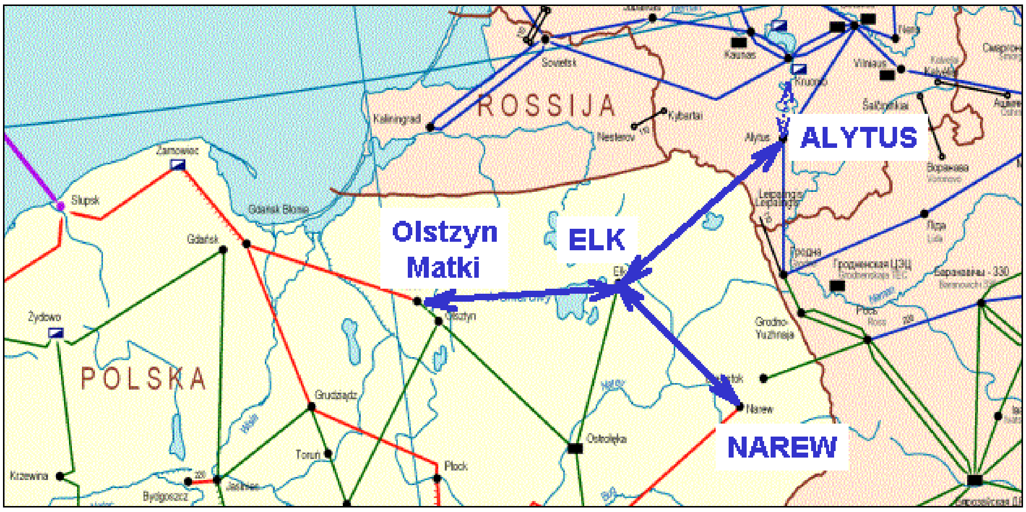

Figure 29: AC-Link between Poland and Lithuania with Back-to-Back Station (500/1000 MW)

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

Overall, this new link would therefore require substantial investments. Overall, a recent submission by the Polish and Lithuanian TSOs estimates the total project costs at some 434 M€. These include the costs of the new interconnector (154 M€), the new line between Alytus and Kruonis (approx. 50 M€) and some 300 M€ for building the new 400 kV lines between Matki, Elk and Narew and upgrading of the Elk substation. Notably, these estimates do not include the cost of any further reinforcements in the Polish power system.

In order to reduce costs and improve the economics of the project, one might also split the construction of this new connection into two stages. In the first stage, a connection from Narew to Elk, one circuit of the Elk-Alytus connection and a 500 MW back-to-back converter in Alytus would be built. Only in the second phase, the project would then be fully realised as described above. Due to the limited load of Elk, this option would not require full realisation of network reinforcements on the Polish during the next years. The immediate investments could thus possibly be reduced to some 140 M€[63] for the interconnector, plus the connection from Narew to Elk 50 M€. The total calculated costs of 190 M€ can be considered the absolute minimum as the network from Narew to the South of Poland would probably still need to be reinforced.

5.2.3.3 Alternative 2: DC Interconnection

Previous studies, including the Baltic Ring study and the EBRD feasibility study, have also discussed the option of building a DC link. Although more expensive, the Baltic Ring study prefers the DC link because of lower transmission losses and 'higher flexibility and wide acceptance by all project partners'. Since a DC line and a back-to-back converter are both resulting in an asynchronous connection, we do not see why a DC line should be more

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[63] The cost estimations are based on a double circuit line of which only one circuit is installed.

acceptable than an AC line with a back-to-back converter? Furthermore, building an AC line would leave the possibility of converting it into a synchronous connection, e.g. in case of a possible future synchronous connection of the UCTE and UPS/IPS systems.

Given that the benefits of a DC or AC link are the same, we thus believe that the alternative of an AC link with a back-to-back to converter clearly is superior.

5.2.3.4 Alternative 3: AC-Link with Radial Operation of Kruonis PSP

A low-cost alternative of the planned link between Poland and Lithuania would be the radial operation of the Kruonis pump storage. This option would require the installation of autotransformers at Kruonis instead of a substantially more expensive back-to-back converter in Alytus. The plant could then be synchronised with the UCTE system during the night for pumping, using cheap base-load electricity from Poland. Conversely, the Kruonis plant could provide peaking power to Poland and the Baltic States during peak loads, by flexibly connecting the most efficient number of units in parallel to the UCTE, and the remaining to the UPS/IPS system.

The main advantage of this solution would be that the expensive back-to-back converter in Alytus could be replaced by cheaper autotransformers in Kruonis. This would save about 100 M€.[64] Furthermore, the losses of autotransformers are significantly lower than the losses in back-to-back transformers, which would result in additional savings. The disadvantage of this solution would be a decrease in flexibility, as it would completely rely on the operation of Kruonis. In other words, all import and export over the connection would be limited by the energy storage capacity of the Kruonis plant. This storage capacity would be sufficient, in case the energy flows in both directions compensated each other over the course of one or a few days.[65] Furthermore, this alternative would not remove the need for reinforcements in the Polish network, which are estimated to be far more expensive than the costs of the interconnection itself.

Finally, it needs to be considered that the Kruonis units are essential for providing reserves in case of a trip of one of the nuclear units of Igalina (1300 MW per unit). Therefore, this radial connection could only be in operation after the closure of the second Igalina unit, i.e. not before 2010.

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[64] The costs could be reduced even more, if the connection was made without redundancy. This means that only one line and autotransformer would be installed. The additional cost reduction would be around 30 M€.

[65] Another possibility is that the Kruonis plant will act like a back-to-back converter, i.e. with two pumping units synchronously connected to the UCTE network and two generating units connected to the UPS/IPS network. However, with an efficiency of around 70%, it is assumed that an electronic back-to-back converter would be more economic within a few years.

5.2.3.5 Synchronous Connection of the Baltic States to the UCTE-Network (excluding Russia)

Instead of building a DC connection between the Baltic States and Poland, another solution could principally be to provide for a synchronous connection of the Baltic States to Poland, without however including Russia. In our view, nevertheless, this alternative does not seem to be realistic for the time being. As discussed in section 5.2.2.1 above, the transmission system of the Baltic States are completely integrated with the transmission networks of North-West Russia and Belarus. A disconnection from Russia would thus most likely require substantial investments, in order to maintain a reasonable reliability of the remaining system. Secondly, one has to take account of different technical and operational standards. Most importantly, both generation units would have to be adapted to the UCTE requirements, in order to provide the Baltic TSOs with automatic frequency control. Besides investments at the plant level, one has to consider that frequency control within the UPS/IPS system is currently exclusively performed by the Russian SO, whereas DC Baltija only performs some manual frequency control.[66] Thirdly, a coupling between the Baltic States and the UCTE based on a single connection would be extremely weak. Maintaining a minimum level of system security for the Baltic area would thus require special measures, such as additional reserves. We expect that the costs of such measures would outweigh the benefits of a synchronous connection.

Besides the technical and economic considerations, one finally has to take account of the fact that the Russian enclave of Kaliningrad is only connected to the Lithuanian power system. Disconnecting the Lithuanian power system from the UPS/IPS would thus also physically separate the power supply of Kaliningrad from the Russian power system. We have been told that the Russian side has already stated that a direct transmission line between Kaliningrad and Russia would thus be a (political) precondition for disconnecting the Baltic power systems from the UPS/IPS.

In summary, we thus believe that a synchronous connection of the Baltic States to the UCTE without Russia is currently not a realistic alternative.

5.2.4 North Central Europe: Czech Republic, Slovakia, Poland and Germany

5.2.4.1 Current Situation

Current commercial flows of electricity in the area of the Czech Republic, Slovakia, Poland and Germany usually are in the direction from the Czech Republic, Slovakia and Poland to Germany. Physically, this results in a major export from Poland to the Czech Republic and Slovakia, and a transit through the Czech Republic to the Czech-German border. Due to the

[66] E.g. ramping up fixed amounts of reserves, in case the frequency drops, or vice versa.

location of generating units close to the border and the weakness of the transmission network in the West of Poland, Germany is physically exporting power to Poland.

The borders from the Czech Republic to both Slovakia and Germany do not seem to be very congested at this moment. This also implies that the corresponding TSOs do not currently have any plans or studies for increasing these cross-border connections.

Exports and imports to respectively from Poland are mainly restricted by a contingency situation, in which a trip of the double circuit line between Wielopole/Dobrzen (Poland) and Albrechtice/Nosovice (Czech Republic). According to PSE Operator (PSE-O), the Polish TSO, this double circuit line seems to trip occasionally because of the severe weather conditions. As a direct consequence of this trip, overload on the double circuit 220 kV-line from Liskovec (Czech Republic) to Kopanina/Bujakow (Poland) will cause this line to trip as well.

The existing 750 kV line between Poland and the Ukraine is not used at the moment. While a synchronous operation of the UCTE and UPS/IPS system is not expected for the coming years, the line could already be used for exchanging power between Ukraine and Poland. For instance, the line could be used for connecting the Ukrainian nuclear plants to the Polish grid in radial operation, similar to the Burshtin island. Such a scheme would allow selected plans to operate synchronously to the UCTE network and export their power to UCTE countries. Another, more expensive solution would be to invest in a back-to-back coupling, which would allow generators on both sides of the border to export their power.

Similar to the Polish-Ukranian border, the existing connection between Poland and Belarus currently is out of operation. Moreover, the existing 220 kV line is already 40 years old, which means that it is on the end of its technical life. However, it might be possible to use the route of that line for building a new 400 kV connection for radial operation or a back-to-back converter.

5.2.4.2 Increasing Cross-Border Capacity between Poland and Germany

As discussed before, exports from Poland to Germany mainly flow through the transmission grid of the Czech Republic. Moreover, while Germany is commercially importing from Poland, it is physically exporting, i.e. the physical flow on the Polish-German border typically is opposite to the commercial exchange. More precisely, the power generated in the south of Poland flows through the Czech Republic and Germany into western Poland. This flow further increases the physical transit of electricity through the Czech Republic. In consequence, any investments on the Polish-German border are unlikely to increase the available transfer capacities, if not supplemented by major reinforcements in the Polish network itself. Otherwise, electricity produced in the south of Poland will continue to flow through the Czech Republic, rather than taking the direct route to the German border.

Many reinforcements are planned within Poland. Important for the Poland-German border are the connections for linking the south of Poland to the west, including a line between

Dobrzeń to Wielopole. This connection will be in operation in 2004. Furthermore, there exist plans for new connections from Rogowiec via Trebaczew and Ostrow to Plewiska, which are planned to be built in 2006-2008.

Only after these reinforcements, any investments in direct links between Poland and Germany would have a tangible effect. Several alternatives have been studied, of which the idea of upgrading the existing 220 kV-line Neuenhagen (Germany)-Vierraden (Germany)-Krajnik (Poland) to a 400 kV-line seems to be the most promising.[67] This project will not be realised before 2010. Due to uncertainty about future development in this part of Europe, most importantly about the future growth of wind power, it is hard to accurately estimate the potential increase in NTC resulting from this investment. However, assuming that the internal reinforcements in the Polish grid have been made we estimate that a new link with Germany might add several hundred MW in NTC between Germany and Poland.

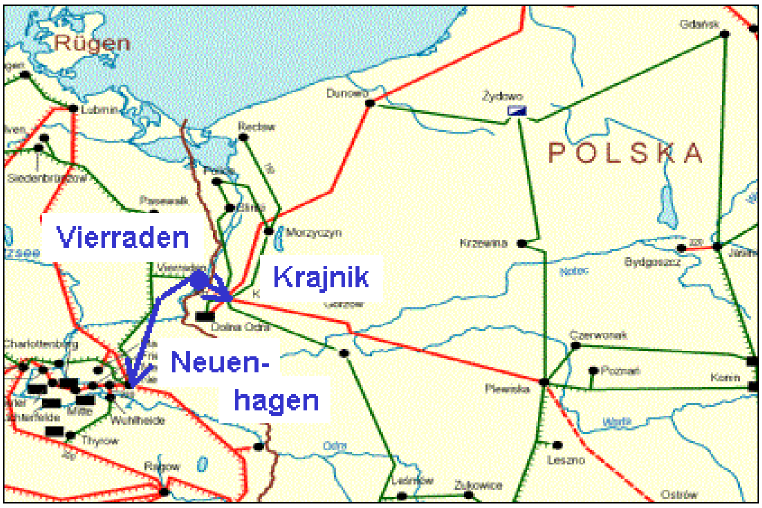

Figure 30: Possible link between Germany and Poland

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

Another reinforcement under study is the installation of a phase shifter in Mikulowa. While a phase shifter can be a useful tool in order to direct some flows and mitigate congestions, it has serious disadvantages. The first major disadvantage is that in transmission networks with many similar overhead lines, phase shifters may increase thermal losses. In this case, load flow calculations performed by PSE have shown that the use of the phase shifter could increase the losses on both sides of the Polish German border by a double-digit number of MW. Secondly, phase shifters need perfect coordination between the different TSOs and may easily shift problems from one place to the other. Nevertheless, investing into a phase

[67] Another idea was building a new 400 kV-line from Plewiska (Poland) to Preilack (Germany). This project will be far more expensive and could be considered only after the realisation of the upgrade of the line Neuenhagen-Vierraden- Krajnik

shifter might be a useful means for increasing the NTC, especially in case of high price differences. However, according to load flow calculations of Vattenfall and PSE, it seems questionable whether a phase shifter would add much extra NTC.

5.2.4.3 Increasing cross-border capacity on the Polish-Slovak/Czech Border

As discussed, the connection between Wielopole/Dobrzen (Poland) and Albrechtice/Nosovice (Czech Republic) forms an important bottleneck for the export of power from Poland. Long-term plans exist for a new 156 km, double circuit 400 kV-line from Byczyna (Poland) to Varin (Slovakia).[68] This connection will most probably mitigate the bottleneck and will increase the NTC. Due to major uncertainties in this region (e.g. German wind power), it is not possible at this moment to give an accurate estimation of the possible increase of NTC. However, we believe that a new double circuit 400 kV-line almost in parallel to the existing 400 kV-line between Wielopole/Dobrzen and Albrechtice/Nosovice, which is the determining factor for congestion at the moment, will add at least 1000 MW to the NTC.

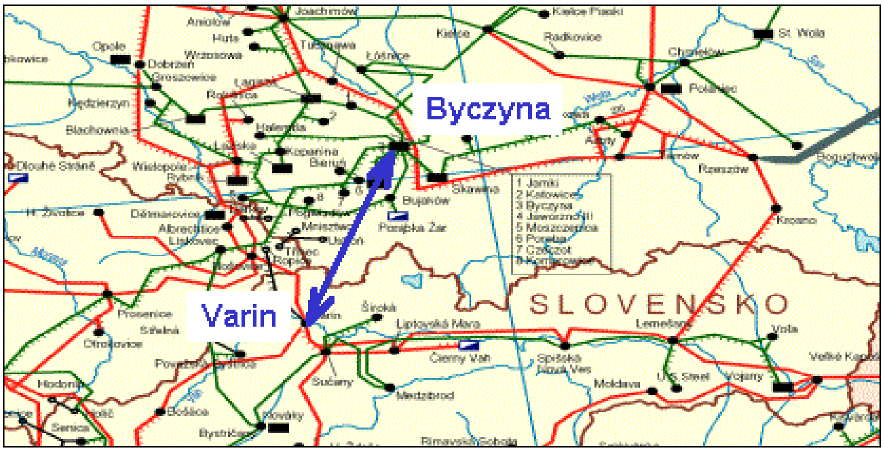

Figure 31: Possible link between Poland and Slovakia

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.4.4 Internal Reinforcements in Eastern Poland (Tarnów-Krosno)

The internal reinforcement in the eastern part of Poland (400 kV-line from Tarnów to Krosno) will be a back-up for the internal Polish line Rzeszów-Krosno. This line will be in operation in 2005. With the completion of the line, the cross-border connection from

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[68] The substation Byczyna is currently operated on 220 kV. Therefore, additional investments would be required to upgrade the existing substation to 400 kV.

Lemešany (Slovakia) to Rzeszów via Krosno will consist of two circuits. According to PSE Operator, this will however only have a positive influence on the NTC during times of maintenance.

5.2.4.5 Wind Power

Wind power generated in the north of Germany has a major impact on the physical electricity flows in this part of Europe. It is the unpredictability of this renewable energy source that makes network planning quite challenging and uncertain. Furthermore, the volatile production by wind power plants in Northern Germany is balanced through the use of generating units in the remainder of the country, including those located in the south of Germany. This compensation regularly causes power flows from the North of Germany to the South. In accordance with physical laws, these flows partially follow a route through Poland and the Czech Republic. This has a major impact on the NTCs in this region.

In the future, further growth of wind power plants in the North of Germany is expected and large off-shore wind parks are under planning. Furthermore, there are plans for constructing wind parks in (Northern) Poland as well. Without investments in the network, it would likely become impossible to handle the flows resulting from this additional wind power. Presumably, this will also result in changes to the NTCs in this region. While it seems understandable that the TSOs are not yet able to quantify the consequences of these developments on future NTC values, it seems fair to conclude a continued growth of wind power will likely lead to decreasing transfer capacities.

5.2.5 Central Europe: Austria, Czech Republic, Slovakia and Hungary

5.2.5.1 General

In this part of Europe, four countries are located close to each other. In terms of network planning, the transmission grids of the Czech Republic, Slovakia and Hungary have been connected to the Austrian network only recently. For Austria, this implied that it became a country in the centre of the interconnected UCTE network, instead of a country on the outskirts. Together with the abandoning of the central generation planning due to the opening of the electricity markets this has lead to highly increased (transit) flows over the Austrian transmission network.

In response to these developments, the Austrian TSO (APG) started construction of the Austrian 400 kV transmission network. At the moment, a proper East-West connection is already in place, while investments into North-South connections are blocked by environmental and political problems. Especially the planned connection between Südburgenland and Oststeiermark faces a lot of opposition but is crucial for increasing transport capacities. Without this connection, there will persist major congestion from the

Northern part to the Southern part of Austria. With the decommissioning of three plants in Southern Austria and the expected introduction of wind power in the North-east of Austria this congestion will become even more severe.[69]

This internal congestion in Austria has a huge influence on the NTC from the Czech Republic and Hungary to Austria, and from Austria to Slovenia and Italy. Before realisation of these connections, all planned investments on the Czech-Austrian, Slovakian-Austrian and Slovenian-Austrian border will only have a limited effect. Moreover, after decommissioning of the plants in the southern part of Austria and the installation of a wind park in the north-west of Austria, the NTCs are likely to decrease.

According to the results of the auctioning of the cross-border connection between the Czech Republic and Austria, there is a standing potential for export from the Czech Republic to Austria. The limiting factor seems to be internal congestion in the Austrian transmission grid. However, additional imports from the Czech Republic would be beneficial especially during the summer, when the combined heat and power plants in the Vienna region do not provide an efficient means of generation.

The connection between Hungary and Slovakia currently exists of two lines. These lines account for an NTC of 1100 MW in the direction of Hungary. This capacity is used for a very large part and therefore this cross border connection can be considered to be congested in the direction from Slovakia to Hungary.

5.2.5.2 Second circuit Slavetice (Czech Republic)-Dürnrohr (Austria)

As discussed before, increasing the NTC between the Czech Republic and Austria will only have a limited effect, as long as the connection between Südburgenland and the Oststeiermark has not been realised. However, during the summer when the CHP plants in the northern part of Austria are not really cost-effective, it would be efficient to increase imports from the Czech Republic. The required costs for increasing the NTC accordingly would likely remain limited since this reinforcement has already been prepared: The towers of the existing single circuit line between Slavetice (Czech Republic) and Dürnrohr (Austria) are built for two circuits.

[69] Zeltweg and St. Andrä power plant were decommisioned in 2003/2004 and the decommissioning of Voitsberg power plant is expected in 2006

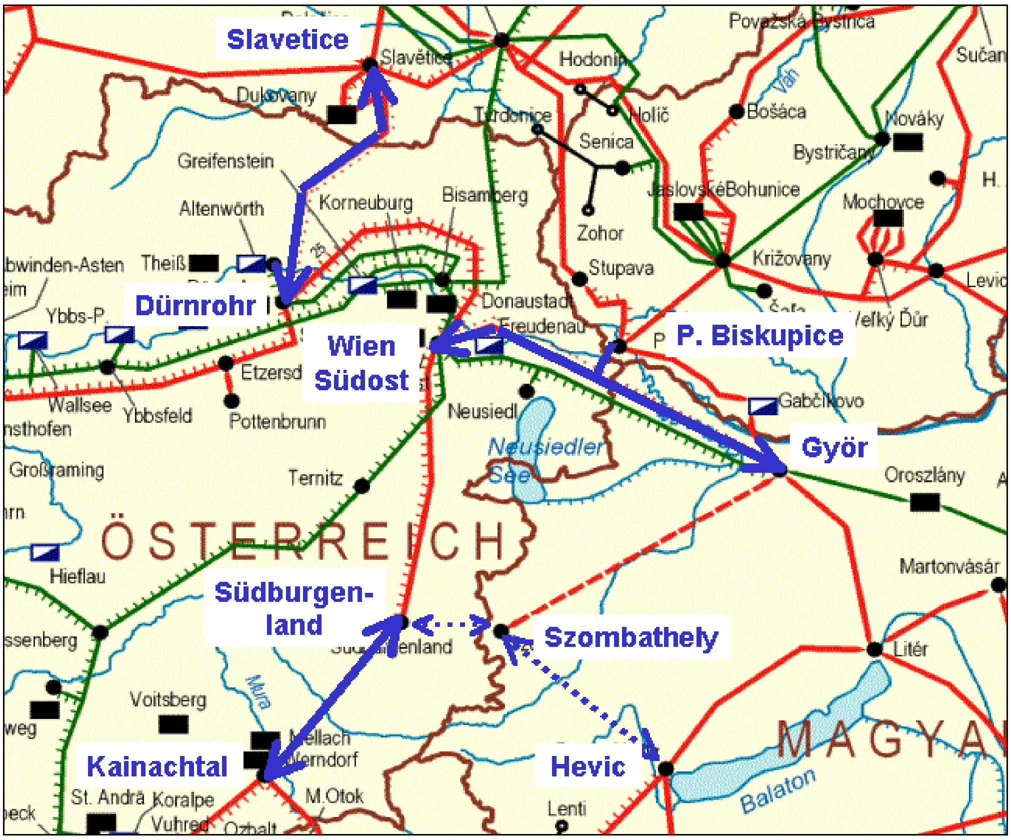

Figure 32: Possible links between Austria and neighbouring countries

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.5.3 New connection Austria - Slovakia

Currently, the transmission networks of Austria and Slovakia are not connected directly. However, plans exist for connecting the substation Wien-Südost (Austria) with either Biskupice (Slovakia)[70] or Stupava (Slovakia).[71,72] The first solution has been presented to us by the APG and would make optimal use of the existing infrastructure: The idea is to use the existing line between Wien-Südost (Austria) and Györ (Hungary), which was built for two circuits. Between Wien-Südost (Austria) and the Austrian-Hungarian border, only one circuit is in place, while between the Austrian-Hungarian border and Györ (Hungary) two circuits exist, of which only one is used. Since this line is close to the Austrian-Slovakian border, the idea is to connect the line by a two-circuit line of around 15 km to

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70 Source: Verbund APG

71 Source: SEPS

72 APG has also informed us that the different alternatives are the subject of preliminary studies on a bilateral respectively trilateral basis by the corresponding TSOs (A, SK, HU). There does not yet exist any definitive statement of any of these countries as to which of the different alternatives would be the best under technical / economic considerations.

Biskupice (Slovakia). One of these circuits would be connected via the second circuit of the existing Wien-Südost–Györ line to Wien-Südost (Austria), while the other would be connected to Györ (Hungary). Although only few new investments are needed, the area in which the new line should be built is environmentally sensitive.

Since we were not able to discuss this with the Slovakian and Hungarian TSO, we are not yet convinced of the value of the connection between Austria and Slovakia. Especially without the Südburgenland – Oststeiermark connection in Austria, it seems uncertain whether investing in cross-border capacity between Slovakia and Austria would have sizeable benefits. Furthermore, the connections between the Czech Republic and Slovakia and the Czech Republic and Austria seem to be strong enough to allow for trade between Slovakia and Austria, especially after reinforcement of the connection between the Czech Republic and Austria.

5.2.5.4 Increasing cross-border capacity between Austria and Hungary

In Szombathely, located in the western part of Hungary, large industry is planned.[73] This industry needs more electricity than what the current transmission network in this part of Hungary can provide. Therefore, the network should be reinforced. Mavir plans to connect Szombathely to the 400 kV network by building a 400 kV-line to the Györ substation. This line will be about 90 km long. According to list of TEN projects, this line is planned to be in operation in 2008. After 2011, current plans foresee to connect the new Szombathely substation with substation Héviz in the south of Hungary. This will undoubtedly have a positive influence on the existing connection between Hungary and Croatia and, when the connection between Héviz (Hungary) and Cirkovce (Slovenia) is realised (see section 5.2.6) on the NTC between Hungary and Slovenia.

An alternative for connecting Szombathely to Györ, is connecting Szombathely with the Austrian substation Südburgerland. The advantage of this connection is that the distance of Szombathely to Südburgerland is less than half the distance of Szombathely to Györ. Like in the original plans, the Szombathely substation could be connected to the Hévic substation afterwards.

Without performing loadflow calculations, it is hard to tell whether the connection Györ-Szombathely-Hévic contributes more to the transmission network than the connection Südburgenland-Szombathely-Hévic. While the original solution has the advantage to close an internal loop in the Hungarian system, the solution via Austria provides a stronger connection between the Austrian and Hungarian system.[74] Furthermore, the Austrian TSO APG has been facing considerable delays in obtaining permits for the Südburgerland-

[73] This section is based on information received from Austrian TSO Verbund APG and the TEN-E project. We did not have the possibility to discuss this with Hungarian TSO Mavir.

[74] Although the connection Südburgerland-Szombathely-Hévic will mitigate the 'North-South' congestions in Austria (see section 5.2.5), it will not replace this connection.

Kainachtal connection. Authorisation of the Südburgerland-Szombathely connection could therefore be subject to similar obstacles. Since the alternative solutions has both advantages and disadvantages, which we cannot specify without performing loadflow calculations, we recommend taking this alternative seriously into consideration.

5.2.5.5 Connection Slovakia - Hungary (Moldova - Sajóivánka)

Plans exist for building a 70 km 400 kV connection from Moldova in Slovakia to Sajóivánka in Hungary. It is not clear how much this investment will add to the existing NTC of 1100 MW in the direction of Hungary. This is largely related to flows and congestions within Hungary and Slovakia. We estimate an increase in NTC of some 500 - 1000 MW.

Figure 33: Possible link between Slovakia and Hungary

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.6 South Central Europe: Slovenia, Croatia and Hungary

5.2.6.1 General

South Central Europe has been known for its loop flows for more then 25 years. From the early 1970's, during operation of the former JUGEL power system, loop flows appeared from Austria to Italy via Slovenia. This was due to contracted energy deliveries in this direction on one hand, and absence of direct interconnection lines of respective capacity on the other hand. This problem persisted throughout this period, and became even more serious after the CENTREL countries became interconnected with UCTE for parallel operation, and when Italy continued to increase its energy imports. The relatively new 400 kV line between Zerjavinec (Croatia) to Hévic (Hungary) only partially reduced this undesired but inevitable distribution of power flows.

The Slovenian power system is mainly self-sufficient from an energy balance point of view. However, being a very small country, the transports in the Slovenian transmission networks are dominated by transits. The energy is mainly flowing from CENTREL and Austria in the direction to Italy and Croatia. Because of its history as an integrated network, the connection with Croatia is rather strong and does not show major congestions. However, on the borders with Austria and Italy, congestion exists during significant parts of the year. The network on the Austrian border is mainly resulting from internal congestion within Austria, caused by the absence of a connection between Südburgenland and Oststeiermark. The congestion on the Slovenian-Italian border is also mainly caused by internal Italian constraints, which are more severe in summer than in winter because of maintenance in summer.

In order to improve transmission capacity allocation and their use, extensive discussions are currently undergoing to apply some kind of "coordinated transmission capacity auctioning" (compare section 4.2.2). Furthermore, better harmonisation of maintenance on the cross-border lines as well as the introduction of phase shifters are considered as additional options.

5.2.6.2 Connection Slovenia - Hungary (Hevic - Cirkovce)

A new 400 kV single circuit line from Hevic (H) to Cirkovce (SLO) is planned to be in place in 2009, in order to directly connect the Hungarian and Slovenian networks. This planned line would utilise the existing infrastructure in Hungary as much as possible. However, in Slovenia a 400 kV substation will be added to the existing 220 kV-substation Cirkovce. Furthermore, an additional 80 km of 400 kV line from Cirkovce to the Slovenian-Hungarian border has to be built. Following this investment, the cross-border capacity with Hungary will increase by 600 MW.[75]

The new substation Cirkovce will be located only 10 to 15 km from the 400 kV substation at Maribor. The reason for this is that the 400 kV substation in Maribor does not have enough space for additional bays. The 400 kV substation in Cirkovce will be connected by two 400 kV lines from Maribor, one 400 kV-line from Krsko and one 400 kV-line from Podlog. In addition to the possibility to make the Hungarian connection feasible, 400 kV substation Cirkovce will strengthen the supply for the increasing demand in this region.[76]

[75] This figure is based on the cross-border capacity between Hungary and Croatia at this moment, which is 600 MW as well (Source: ELES).

[76] The big aluminum factory Kidrecevo (10% of annual Slovenian electricity consumption, load > 200 MW) is located here. New 400-110 kV transformers will be installed in this substation as well.

Figure 34: Possible links between Slovenia at neighbouring countries

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.6.3 Connection Slovenia – Italy (Udine - Okroglo)

Connecting the substations Udine (Italy) to Okroglo (Slovenia) has already been planned for decades, but never performed. The idea is to connect the two substations with a double 400 kV line of 90 km. Because of the environmentally highly sensitive region, it is expected that the cable be built partly underground, which has a significant influence on the costs. Realization is expected in 2011 and the plan will increase the NTC from Slovenia to Italy with 1000 MW or even more[77].

[77] Source ELES.

5.2.7 South-Eastern Europe: Romania, Hungary, Bulgaria, Serbia, Greece, Macedonia and Turkey

5.2.7.1 General

Typical energy flow pattern in South-Eastern Europe before the reconnection of the former UCTE Second synchronous zone to the main UCTE grid in October 2004

Before the reconnection of the former UCTE Second synchronous zone to the main UCTE grid,[78] the entire area was more or less balanced. The UCTE Second synchronous zone was divided into strictly exporting power systems (Romania, Bulgaria and part of Bosnia & Herzegowina), strictly importing power systems (Greece, Albania and Montenegro) and seasonal (winter) importers (Macedonia and Serbia), which sometimes could also have some surpluses for export (mainly in spring and summer season). Accordingly, the critical power transfer corridor was from the north of the region to the south. Typical load flows for certain regimes were recognized. For these regimes congested directions were known. Furthermore operational measures that could be applied to mitigate those congestions were defined.

NTC values on the borders were calculated with respect to the border zone of the neighbouring power system only. This was not sufficient for such a small geographical (and electrical) area. Therefore, critical congestions quite often occurred at some internal transmission lines (e.g. 400 kV line Nis – Kosovo in Serbia).

Another critical point was the transmission network of Albania, which is predominantly 220kV, with only one 400kV line towards Greece. During huge power import programs of Albania, most of the power flows were across the power system of Greece. This was due to the fact that the only Albanian interconnection on 400 kV is with the power system of Greece. As electricity flows tend to choose this 400 kV line, rather than the 220 kV interconnections with Serbia and Montenegro this caused additional burden to the already heavily congested northern border of Greece.

As discussed above, during the period before synchronisation of the second UCTE, zone limitations for NTC between two countries were mainly caused by bottlenecks on a north-south corridor. These bottlenecks were located both on interconnection lines and internal lines. Because this was recognized, many infrastructure projects are foreseen or already started construction on this north-south corridor.

Early 2005, the construction of a 400 kV-line from Bulgaria to Macedonia will continue. Until now, the part of this line in Macedonia from Dubrovo to Stip has been completed and until the new 400 kV-subtation Stip is constructed is operating under 110kV. The works are due to be completed by the end of 2005 or mid-2006. This line will be the first interconnection line between these two countries, except for one 110kV line, which is used

[78] The second UCTE zone was consisting of power systems of Romania, Bulgaria, Greece, Serbia, Montenegro, Macedonia, Albania and Republic of Srpska which is part of Bosnia and Herzegovina

only for island mode operations in case of emergencies. Effects of the commissioning of this line are double: it will release internal Bulgarian congestions at the internal line 400kV Cervena Mogila – Blagoevgrad, and at the same time establish a direct line between Bulgaria and Macedonia.

At the same time, the final phase of upgrading the existing 150kV overhead line between Florina (Greece) and Bitola (Macedonia) to 400kV is scheduled. This line is linking two major generation areas in two countries, and strengthening existing capacities at the north-south corridor: 400kV substation Bitola (Macedonia) is connected to Dubrovo, which is further connected to Thesalloniki (Greece). At the same corridor, new 400kV line Niš (Serbia) – Skopje (Macedonia) and 400kV lines Podgorica (Montenegro) – Elbasan (Albania) are planned to be constructed by 2007. Obviously, it is not possible to analyse isolated impact of either of those projects to NTC values at each border.

Typical energy flow pattern in South-Eastern Europe after the reconnection of the former UCTE Second synchronous zone to the main UCTE grid in October 2004.

It is quite difficult to predict what kind of development will occur in the future concerning power flows from or to the region, especially due to the fact that even after the reconnection, power transactions have remained controlled for some time. In the meantime, most of the annual export/import contracts have been concluded among the former partners within the region. The most reasonable scenario is that the region might not export power. At least not physically, meaning that some entities might import and others export, but overall power flow in export direction is rather unlikely. Import is a more realistic scenario, especially during years with low hydrology. It even becomes more likely after the year 2007, i.e. the planned decommissioning of two units at the nuclear power plant Kozloduy (Bulgaria). New generation units in the region are not foreseen for the time being, except for the second unit in nuclear power plant Cernavoda in Romania.

Ukraine connection[79]

The recently commissioned new substation Isaccea (Romania) has also been used to redirect the existing 750 kV line between Varna (Bulgaria) and the Ukraine. Currently, the only connection of the power system of Ukraine to Romania/Bulgaria is the transmission line Muchacevo (Burshtyn island in Ukraine) – Rosiori (Romania). Further reinforcements of the connection between Ukraine and Romania or Bulgaria are not currently being discussed, because the Burshtyn island, Romania and Bulgaria all have a significant surplus of generation.

More recently, the substation Isaccea (Romania) has also been used to redirect the 400 kV line Vulcanesti (Moldova) – Dobruja (Bulgaria). This 400kV line is in parallel operation

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[79] The transmission network of the Burshtyn island is the only part of the Ukrainian transmission network that is operating in parallel with the UCTE network.

between Romania and Bulgaria. The line between Romania and Moldova is used either in the consumption island mode from the Romanian side, or for islanded generation injections from the Moldovskaya power station. [80]

Turkey connection

Currently, in spite of the fact that Turkey is not in parallel operation with UCTE, there are two interconnection lines between Bulgaria and Turkey. ETSO has published a virtual value for the NTC of 587 MW from Bulgaria to Turkey and 625 MW in the other direction.[81]

5.2.7.2 Connection Romania - Hungary (Nadab - Békéscaba)

Since the reconnection of the second UCTE zone, Romania and Hungary are connected again. The existing connection between Arad and Sandorfalva is currently congested in the direction of Hungary. The congestion is caused internally in the Hungarian network and is protected by a thermal protection on the Hungarian side of the border. Therefore, only 800 MW can be exported from Romania to Hungary.[82]

Because it is expected by Romanian TSO Transelectrica that the potential for cross-border trade between Romania and Hungary will also exist in the next years, for 2008 a new connection between Nadab (Romania) and Békéscaba (Hungary) is planned. Because 400 kV substation Nadab is not existing yet, this substation has to be built and connected to the Romanian transmission network. This is planned to be done by building new connections to Arad (Romania) and Oradea (Romania). The NTC from Romania to Hungary is expected to increase with 850 MW,[83] which could be higher without an internal constraint in Hungary. More than half the investment costs are related to the lines from Arad to Nadab and Nadab to Oradea, which are located entirely in Romania. However, these lines are not necessary for mitigating internal congestions. Therefore, these investments should be considered as completely related to the extension of the NTC.

[80] According to the delimitation contract prepared by UCTE and signed by TEL and NEK prior to their inclusion in UCTE

[81] ETSO (2004)

[82] Source ETSO.

[83] Source Transelectrica

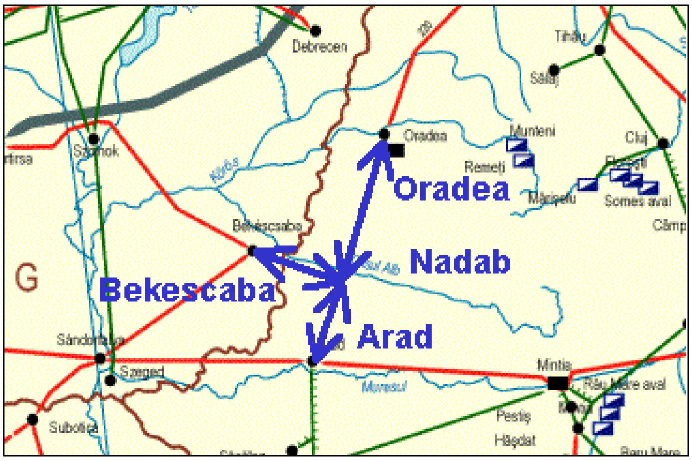

Figure 35: Possible link between Hungary and Romania

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.7.3 Connection Bulgaria – Greece (Maritsa East 3 - Filippi)

The design is completed for a new line from Bulgaria to Greece. This line of around 200 km will connect the substations of Maritsa East3 in Bulgaria and Filipi in Greece. However, the line will be built by 2007. Some estimations say that this line will increase the NTC values with 100 to 200 MW.

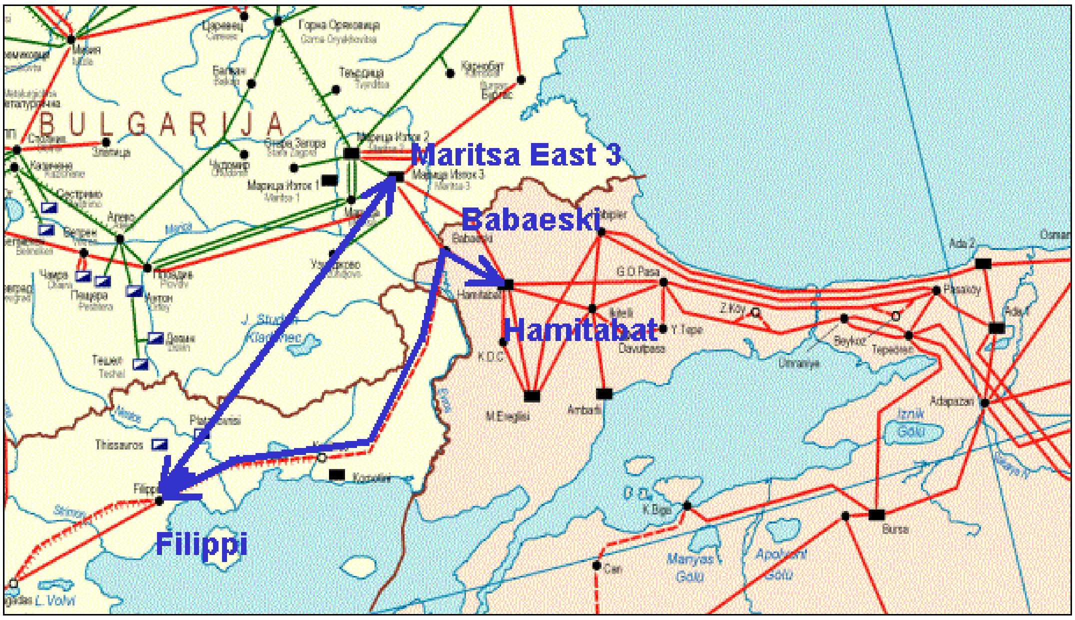

Figure 36: Possible links between Bulgaria, Greece and Turkey

Source of map: UCTE (Courtesy of ZEKC, Sarajevo)

5.2.7.4 Connection Greece – Turkey (Filippi – Babaeski/Hamitabat)

The first 400 kV-connection between Greece and Turkey is planned and will be constructed in the next few years, but without any firm commitment so far, mainly due to the fact that both Greece and Turkey import electricity. Furthermore, there are some concerns about possible loop flows in case this line is constructed, which will influence the Greek northern border to Bulgaria and Macedonia.

5.3 Summary of the Projects Considered in this Study

The previous sections describe the situation of current areas of congestion between the countries considered in this study. Moreover, new connections and connections under study are described. In the following chapter 6, we assess the feasibility of different projects that are currently under study but where a final decision has not yet been made. Below, we briefly summarise all corresponding projects.

For the Baltic region, the following projects are taken into consideration:

- *Second Estlink connection:* Construction of a second 150 kV, 350 MW DC link from Espoo (Finland) to Harku (Esonia).[84] This line has a total length of 100 km of which 70 km submarine cable and the rest underground cable. AC-DC convertors (two directions) are installed on both sides of the cable, connecting the DC line with the 330 kV-network in Estonia and the 400 kV-network in Finland.
- *Connection between Poland and Lithuania:* We take two scenarios into consideration: a 500 MW scenario and a 1000 MW scenario. The 500 MW scenario includes a new 400 kV AC double circuit line from Elk to Alytus, 500 MW back-to-back converters in Alytus and connection to the 330 kV-network of Lithuania. The 1000 MW alternative adds another 500 MW back-to-back converters in Alytus to the 500 MW. These costs are considered including the directly related reinforcements in the Polish network (Elk to Narew in both cases, Olsztyn Matki to Elk only for the 1000 MW scenario). Other necessary reinforcements, which will most likely be needed in the Polish network, are not included.

In North Central Europe, we consider the following projects:

- *Upgrading of the existing line Neuenhagen (Germany) - Vierraden (Germany) - Krajnik (Poland) from 220 kV to 400 kV.*

[84] It has been decided to build the first 350 MW DC link between Finland and Estonia already. This project is now in its tendering phase. Our studies assume that this link will be in operation before 2010.

- *Byczyna (Poland) to Varin (Slovakia):* Construction of a 400 kV new double circuit line from Byczyna (Poland) to Varin (Slovakia).

The projects considered for Central Europe are:

- *Slavetice (Czech Republic) to Dürnrohr (Austria):* The existing connection between Slavetice and Dürnrohr has been prepared for installation of two circuits on the existing towers. This project consists of adding the second circuit.
- *Connection between Austria and Slovakia:* This investment consists of the creation of a 400 kV-connection between Austria and Slovakia by adding a second circuit from Wien-Südost to the Austrian-Hungarian border on the existing line Wien-Südost (Austria) to Györ (Hungary), building a new double circuit 400 kV-line from the Austrian-Hungarian border to Biskupice (Slovakia) and connecting one circuit each to the new second circuit on the line to Wien-Südost and the existing second circuit of the line to Györ.
- *Moldava (Slovakia) to Sajoivanka (Hungary):* Construction of a single circuit 400 kV line from Moldava (Slovakia) to Sajoivanka (Hungary).

For South Central Europe, we consider the following projects:

- *Hevic (Hungary) to Cirkovce (Slovenia):* In order to realise this project, a new single circuit 400 kV line from Cirkovce (Slovenia) to the Slovenian-Hungarian border needs to be built. For the other part of the connection on the Hungarian side, an existing circuit from the line Hevic-Zerjavinec (Croatia) can be used.
- *Udine (Italy) and Okroglo (Slovenia):* For this connection, we take two scenarios into consideration: a single circuit scenario and a double circuit scenario. Furthermore, because of environmental sensitivity of the area, we assume that 10% of the connection is built as an underground cable.

South Eastern Europe:

- *Nadab (Romania)-Bekescaba (Hungary):* This investment consists of a new substation at Nadab plus three new 400 kV single circuit lines: Arad (Romania)-Nadab (Romania), Nadab (Romania)-Oradea (Romania) and Nadab (Romania)-Bekescaba (Hungary).
- *Maritsa East3 (Bulgaria) to Filippi (Greece):* This investment consists of building a new connection between Maritsa East3 and Filippi, using guyed towers.
- *Filippi (Greece) to Babaeski and Hamitabat (Turkey):* New single circuit 400 kV line from Filipi (Greece) to Hamidabad (Turkey), using guyed towers.

- *Pécs (Hungary) to Sombor (Serbia):* New single circuit 400 kV line from Pécs (Hungary) to Sombor (Serbia), using guyed towers.
- *Pécs (Hungary) to Ernestinovo (Croatia):* New single circuit 400 kV line from Pécs (Hungary) to Ernestinovo (Croatia), using guyed towers.

6 Costs and Benefits of Proposed Network Extensions

6.1 Overview

Well-founded investment decisions can only be taken with a clear view on both the costs and benefits of alternative projects. In this section, we therefore develop and apply a methodology for assessing both aspects, first separately and then in combination. Based on the discussion in section 5.2, we have selected a number of projects that have been designated by the TSOs as being important and/or realistic. Within this section 6, we now perform a cost-benefit analysis of these planned developments. Following the assessment of project costs in section 6.2, we estimate the economic benefits of future projects in section 6.3. This finally allows us to combine both measures in the subsequent section 6.4, in order to identify and assess the most important investments. As already discussed above, this analysis considers both individual projects on a stand-alone basis as well as combinations of different changes in the network.

6.2 Assessment of Project Costs

6.2.1 Methodology and Cost Assumptions

The overall costs of any project can be divided into three categories: investment costs, maintenance costs and the costs of network losses. These costs arise at different stages during the lifetime of the corresponding equipment. To enable a comparison between different projects, it is necessary to use a comparable measure of costs. In practice, there exist a number of different concepts, including the net present value or the internal rate of return. In accordance with common practices in the electricity industry, we have decided to compare different investments based on their annual costs and benefits. This concept allows for easy comparison of investments into electricity networks, which usually come up in large increments and with long time spans in between, and the annual benefits as determined from our market simulations. Moreover, by expressing all numbers in real 2003 terms, we ensure that all numbers can be compared easily.

The investments into network reinforcements considered within this study consist of costs for connections, bays and additional equipment. The costs for connections (lines and cables) are estimated by multiplying standardised costs per km for the connection type together with the length of the connection. The respective TSOs provided information regarding line length, however when no information was received or was deemed inaccurate, we used the distance of a straight line between two substations and increased this distance by 15%.

While in the rest of the UCTE network, 400 kV lines are usually built using *non*-guyed (self standing) towers, in the South Eastern part of Europe, 400 kV single lines are usually built as guyed lines. These lines consist of a simple steel construction, which needs to be fixed to the ground with guy ropes. The costs of such constructions are significantly reduced, because only about half the steel of other tower types is needed. Furthermore, no foundation is required, although there are higher labour costs. In general, these lines are about 30% cheaper than lines using *non* guyed, i.e. self standing towers. The big disadvantage of guyed lines is that they need sufficient space around the tower because of the guy ropes.

For bays we added two bays per circuit: One on each end of each circuit. The costs of bays include all high-voltage equipment (circuit breaker, disconnector, earthing switch, measurement transformers), supporting structures, foundations and all costs for protection and control. Furthermore, our cost estimates include an equal share of the general substation costs, e.g. the busbar(s), local buildings etc. In order to enable a comparison of different projects from an objective point of view, we used, per voltage level, only one value for cost per bay. This means that we did not take into account the difference in costs between conventional and gas-insulated (GIS) equipment. The cost per bay is based on conventional (open-air) substations. Furthermore, in case a new substation is needed, we only included the number of bays in our cost calculation.

The additional equipment mainly exists of AC/DC converters or so called back-to-back converters. This equipment not used yet. Therefore, the price of this equipment is less stable than the price of conventional equipment. We based our cost estimations on data recently published by different TSOs and investors. The costs for filters, supporting structures, foundations and buildings are included in the estimated costs for AC/DC converters.

For each investment, we have calculated two types of costs: Investment costs and annual costs. The investment costs include all costs related to realisation of the project. The per-unit of these costs are differentiated for different types of equipment (compare Table 9) and are expressed in real 2003 terms (€$_{2003}$). In order to make these investment costs comparable to other annual costs (e.g. maintenance) and the benefits of increased NTC, we transform all investment costs into annual costs. These annual costs have been calculated as an annuity, based on a given depreciation period and interest rate. In our calculations, we have used an interest rate of 8%, which is based on low risk capital investments. The depreciation period is based on the average expected technical-economic lifetime of the equipment under consideration. Average maintenance costs can be determined based on maintenance cost factors. The maintenance cost factors are expressed as a fixed percentage of the investment costs. Similar to the standard costs of equipment, the maintenance cost factor varies per type of equipment.

In Table 9, we have summarised our main assumptions for the standardised unit costs of different types of equipment, depreciation periods and the maintenance factors. All costs are expressed in real 2003 terms and are based on information from the cost database of KEMA. This cost database is populated with both public information and information gathered in previous studies. It is our experience that cost data for conventional equipment such as lines, transformers, cables and bays is more accurate than the cost data for equipment where AC/DC converters are involved. Therefore, we estimate an error margin of our cost data for lines, transformers, cables and bays at 30%, whereas we assume a lower accuracy for AC/DC converters (50% error margin).

Table 9: Unit costs, depreciation periods and maintenance costs used in this study

Equipment	Investment cost			Estimated average depreciation period [years]	Maintenance cost in percentages of investment cost
	Accession countries + Greece, FYROM, Serbia, Finland	Austria, Italy, Germany	Unit		
Overhead lines AC (Steel latticed non guyed towers)					
220 kV single circuit	250,000		€/km	25	1%
330 kV single circuit	300,000		€/km	25	1%
400 kV single circuit	350,000	450,000	€/km	25	1%
400 kV double circuit	450,000	550,000	€/km	25	1%
Overhead lines AC (Steel latticed guyed towers)					
400 kV single circuit	225,000		€/km	25	1%
Additional Circuit[85]	150,000	150,000	€/km	25	1%
Bays					
220 kV	1,000,000		€/bay	25	2%
330 kV	1,500,000		€/bay	25	2%
400 kV	1,600,000	1,800,000	€/bay	25	2%
Submarine cable DC					
150 kV	400,000			25	0.10%
400 kV	450,000			25	0.10%
Convertor AC/DC (including filters & buildings)					
	125,000		€/MW	15	2%
Underground cable DC					
150 kV	750,000		€/km	25	0.10%
Underground cable AC					
400 kV single circuit	2,700,000	2,700,000	€/km	25	0.10%
400 kV double circuit	5,000,000	5,000,000	€/km	25	0.10%

All costs are expressed in real 2003 terms.

85 No reinforcements to towers

While we consider the cost of investments and maintenance, we do not take the costs of network losses into account. The determination of losses would require detailed load flow studies since the amount of losses depends on the utilisation of lines and cables. Moreover, the new cross border connections may influence the present load flows in the existing networks, which may also change losses on other connections. Since it is thus impossible to obtain a reasonably accurate estimate of the additional losses, we exclude these costs from our analysis.

6.2.2 Cost Estimates for Projects Considered under this Study

Based on the methodology and cost assumptions explained in the previous sections, we have assessed the costs of most projects identified in section 6.2.2 above. The resulting cost estimates are summarised in Table 10. Besides a brief project description, this tables provides information on the initial investment costs, the cumulative annual costs, consisting both of annualised investment costs and annual maintenance costs, as well the corresponding accuracy of those cost estimates.

Table 10: Cost estimates for the projects under study

Country A	Country B	Description	INCREASE NTC	Source NTC Increase	Investment Costs [M€]	Total Annual Costs [M€/year]	Accuracy
Finland	Estonia	New 150 kV, 350 MW DC link from Espoo (Finland) to Harku (Esonia). This line has a total length of 100 km of which 70 km submarine cable and the rest underground cable. AC-DC convertors (two directions) are installed on both sides of the cable, connecting the DC line with the 330 kV-network in Estonia and the 400 kV-network in Finland.	+350 MW	Eesti Energia	**110**	**17.1**	40%
Lithuania	Poland	New 400 kV AC double circuit line from Elk to Alytus including ONE 500 MW back-to-back converters in Alytus and connection to the 330 kV-network of Lithuania. Internal reinforcements in the Polish network (Elk to Narew) and the Lithuanian network (Alytus to Kryonis) are included.	+ 500 MW	Additional KEMA scenario	**198**	**24.0**	40%
Lithuania	Poland	New 400 kV AC double circuit line from Elk to Alytus including two 500 MW back-to-back converters in Alytus and connection to the 330 kV-network of Lithuania. Internal reinforcements in the Polish network (Olsztyn Matki to Elk, Elk to Narew) and the Lithuanian network (Alytus to Kryonis) are included.	+ 1000 MW	Lietuvos Energija	**332**	**37.8**	40%
Romania	Hungary	New Substation Nadab plus three new 400 kV single circuit lines: 1) Arad (Romania)-Nadab (Romania), 2) Nadab (Romania)-Oradea (Romania) 3) Nadab (Romania)-Bekescaba (Hungaria)	+ 850 MW	Transelectrica	**68**	**7.2**	30%
Czech	Austria	Adding the second circuit to the existing 400 kV line from Dürnrohr	+ 250 MW (summer)	Verbund APG	**18**	**1.8**	30%

		(Austria) to Slavetice (Czech Republic).	+ 1000 MW [86]					
Bulgaria	Greece	Maritsa East3 (Bulgaria) to Filippi (Greece), using guyed towers	+ 500 MW (estimation)	KEMA estimate	**48**	**5.0**	30%
Austria	Slovakia	Creation of a 400 kV-connection between Austria and Slovakia by: 1) adding a second circuit from Wien SudOst to the Austrian-Hungarian border on the existing line Wien SudOst (Austria) - Györ (Hungary); 2) building a new double circuit 400 kV-line from the Austrian-Hungarian border to Biskupice (Slovakia); 3) connecting one circuit of the double cricuit line mentioned under 2) to the second circuit mentioned under 1); 4) connecting the other circuit of the double circuit line mentioned under 2) to the existing second circuit between the Austrian-Hungarian border and Györ of the existing line Wien SudOst (Austria) - Gyor (Hungary).	0 MW	KEMA estimate	**26**	**2.8**	30%
Slovenia	Hungary	New single circuit 400 kV line from Cirkovce (Slovenia) to Slovenian-Hungarian border; from the border to Hevic (Hungary), an existing circuit from the line Hevic-Zerjavinec (Croatia) is used.	+ 600 MW	ELES	**31**	**3.3**	30%
		New 400 kV AC connection between Udine (Italy) and Okroglo (Slovenia): two circuit 400 kV line (90% overhead; 10% underground)	+1000 MW	ELES	**97**	**9.7**	30%
		New 400 kV AC connection between Udine (Italy) and Okroglo (Slovenia): one circuit 400 kV line (90% overhead; 10% underground)	+500 MW	ELES	**62**	**6.3**	30%

[86] After realisation of Südburgenland-Kainachtal and St. Peter - Tauern

Slovakia	Hungary	Single circuit 400 kV AC line from Moldava (Slovakia) to Sajoivanka (Hungary)	+ 500-1000 MW	KEMA estimate	**28**	**2.9**	30%
Germany	Poland	Upgrade of existing 220 kV-line from Neuenhagen (Germany), via Vierraden (Germany) to a Krajnik (Poland) to 400 kV-line	+ 500-1000 MW (Poland to/from Germany+Slovakia+Czech)	KEMA estimate	**96**	**12.7**	30%
Slovakia	Poland	New double circuit line from Byczyna (Poland)-Varin (Slovakia)	+ 500-1000 MW (Poland to/from Germany+Slovakia+Czech)	KEMA estimate	**77**	**8.0**	30%
Greece	Turkey	New single circuit 400 kV line from Filipi (Greece) to Hamidabad (Turkey), using guyed towers	+800 MW	KEMA estimate	**64**	**7.0**	30%
Serbia	Hungary	New single circuit 400 kV line from Pécs (Hungary) to Sombor (Serbia), using guyed towers	+500 MW	KEMA estimate	**24**	**2.8**	30%
Croatia	Hungary	New single circuit 400 kV line from Pécs (Hungary) to Ernestinovo (Croatia), using guyed towers	+500 MW	KEMA estimate	**24**	**2.8**	30%

6.3 Analysis of Economic Benefits

6.3.1 Approach

For assessing the benefits of individual projects, we have relied on the results of our market simulations. For each investment, or a combination of several projects, we have adjusted the NTC values in our market model and re-run the simulations. We have then performed both a qualitative assessment of the impact on the regional flow patterns, as well as a quantitative analysis of the financial implications. While the former is helpful to study, verify and understand the practical implications of each modification, the latter approach allows to quantify the potential savings in total costs. Moreover, our simulations use a cost-minimising model, whereas prices in most European power markets are based on bids. We have therefore calculated both the underlying savings in *production costs*, and the savings in *market payments*, i.e. the total price to be paid by consumers.

For the qualitative assessment, we have again created annual flow duration curves for every border, and compared them to the 2010 baseline scenario. This allows to quickly identify any changes under the new scenario. Moreover, similar to the case of our initial model verification and sensitivity analysis, these flow duration curves provide useful insights into the overall regional flow patterns, and overall export and import potential between different countries. For each case, we have checked the potential changes on all borders. Due to the large number of borders and scenarios, we have however made a selection of only the most important changes for the subsequent discussion.

In order to assess the potential economic benefits, we have first used the total production costs of our European market model. For each simulation, we have extracted the total annual production costs for each country under study. This value can be understood as the true economic costs of serving the load of the study countries as it is defined by the least-cost despatch of the entire system. That is, the difference in production costs to the base case represents the real savings in fuel and other variable operating costs that have been achieved by reduced congestion. If expressed in relation to the total annual energy production, this value defines the average variable production costs of each country, or the entire system where appropriate.

In a market-based environment, however, consumers do not normally pay the average variable costs. Instead, economic theory suggests that the price consumers have to pay is defined by the costs of the most expensive unit that is required to run. Assuming that producers offer exactly at (marginal) costs, the total costs of the electricity market are then equal to the marginal price of the system multiplied by total demand (Figure 37). Consequently, we have also calculated a market-based assessment of the potential benefits based on the market payments. For each country, we have thus multiplied the marginal costs of each hour with the corresponding national load of the same hour.[87] By summing up the hourly costs across the entire year, it is possible to determine the total market payments for each country. These values can finally be aggregated for all study countries, in order to obtain the total annual market payments.

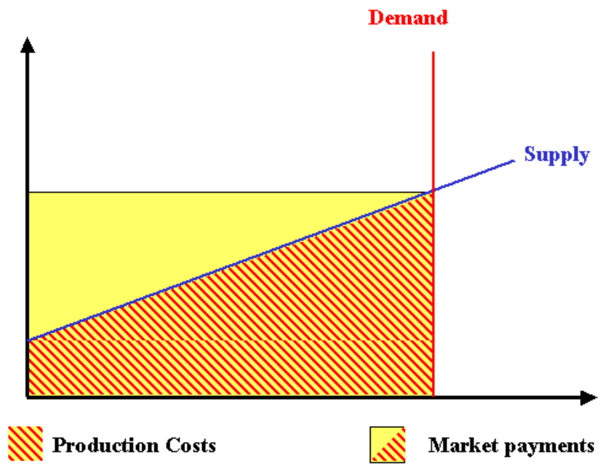

Figure 37: Relation between production costs and market payments

Not surprisingly, (marginal) market payments are substantially higher than (average) production costs; in our calculations, we have generally observed a ratio of 2:1. Nevertheless, this estimate of the market payments will generally still be lower than actual prices, which may often be above the marginal costs of the system. On the other side, it does not seem realistic to assume that the market will be able to make perfect use of all trading potentials, both on a national and regional scale. Our market model will re-optimise all flows throughout the entire region, e.g. a marginal change at the Romanian-Bulgarian border as a result of a change in cross-border capacities between Poland and Germany. But it seems rather unlikely that market participants will be able to fully and immediately exploit such marginal differences in practice. Moreover, most liberalised European markets are based on ex ante scheduling of generation, whereas our market model effectively assumes real-time scheduling and dispatch.

To take account of these uncertainties, we assume that the market will only be able to realise about 75% of the theoretical savings potential. In addition, we have also restricted our analysis to those countries directly adjacent to any change in cross-border capacities, as

[87] Please note that congestion will result in different marginal costs for different countries. It is thus necessary to perform these calculations on a country-by-country basis. Similarly, both demand and marginal costs will change from hour to hour, such that it also necessary to do hourly calculations.

well as their neighbours. In addition, we have also included other countries if the analysis of flow duration curves or marginal costs revealed a significant influence. Thus, while we would neglect Romania and Bulgaria in the mentioned case of a modification at the Polish-German border, we generally considered all Balkan countries when studying the impact of investments between Greece and its Northern neighbours.[88]

Another advantage of this approach is that it allows reducing the influence of any stochastic changes in the simulation results.[89] Based on our simulations, we have therefore defined an error margin relatively to the size of the market volume under study. Furthermore, we have generally excluded Germany from these calculations. Given the large size of the German market compared to the main countries under study,[90] even changes of a stochastic nature might otherwise outweigh any tangible cost changes in other countries. Moreover, Germany is not only a large market by itself but also well interconnected with other major markets (France) as well as several other countries. It thus seems reasonable to assume that changing cross-border capacities in the study area will only have a negligible impact on the price levels on the German market.

Consideration of market payments will not always result in lower cost if congestion is reduced. A corresponding case is illustrated by Figure 38, which shows the impact of an (additional) exchange between two countries. While exports lead to increased production costs in country 2, these are significantly lower than the corresponding reduction of production costs in country 1. In contrast, while imports have only a negligible impact on market prices and thus market payments in country 1, they result in marked increase of the market price and thus market payments in the much smaller country 2. Under these circumstances, the market may actually see higher costs; in some cases, we have actually observed corresponding effects in our simulations as well.[91] It is therefore important to note that any changes in market payments are not only a function of changes in costs, but that they also signal a redistribution of income between producers and consumers. Given that this study is focused on the implications for the entire economy, our cost-benefit analysis is therefore generally based on consideration of production costs.

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88 This can be explained by the fact that most of former Yugoslavia usually appeared as a single 'price zone'. Hence, any change in marginal costs for Serbia & Montenegro normally had a direct impact on e.g. Bosnia & Hercegovina, Croatia and Slovenia.

89 Although PROSYM is a deterministic model, convergence rules may cause slightly different results.

90 Germany alone represents about a third of total consumption in the study countries.

91 Namely in case of increasing exports to Italy from the much smaller markets in Slovenia and Austria.

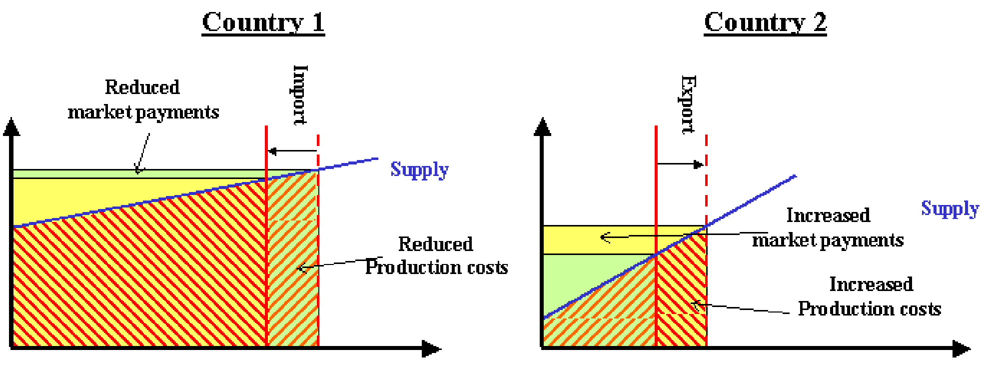


Figure 38: Case of increasing market payments under reduced congestion

6.3.2 Baltic States

For the Baltic States, we have studied the impact of two possible links: From Estonia to Finland, and between Poland and Lithuania, as well as combination of both projects. A summary of the different cases is shown in Table 11.

Table 11: Estimated change in transfer capacities by projects studied for the Baltic States

Project / Border	**NTC (MW)** *(New and/or change)*		
	(i)	**(ii)**	**(iii)**
a) Subsea cable between Finland and Estonia (Estlink)	350	700	-
b) Poland-Lithuania link	500	1,000	-
c) Combination of a-(i) and b-(ii)	N/A	-	-

Subsea cable between Finland and Estonia (Estlink) (350 MW)

First, we have considered the realisation of the planned link between Finland and Estonia (350 MW). As illustrated by Figure 39, the subsea cable shows a high utilisation, being fully used for some 6000 hours a year. Moreover, our results confirm the estimates of Eesti Energia, i.e. that the cable might be used to export some 2 TWh annually to Finland.[92] Simultaneously, we see almost unchanged cross-border flows in the Baltic States.

Our simulations show total benefits of some 6.7 M€/a in terms of production costs. Conversely, we estimate the savings in market payments at 33.1 M€/a. These numbers include some 20 M€/a in reduced costs for Finnish consumers (i.e. outside the study area).

[92] In detail, our calculations show an export potential of 2.2 TWh.

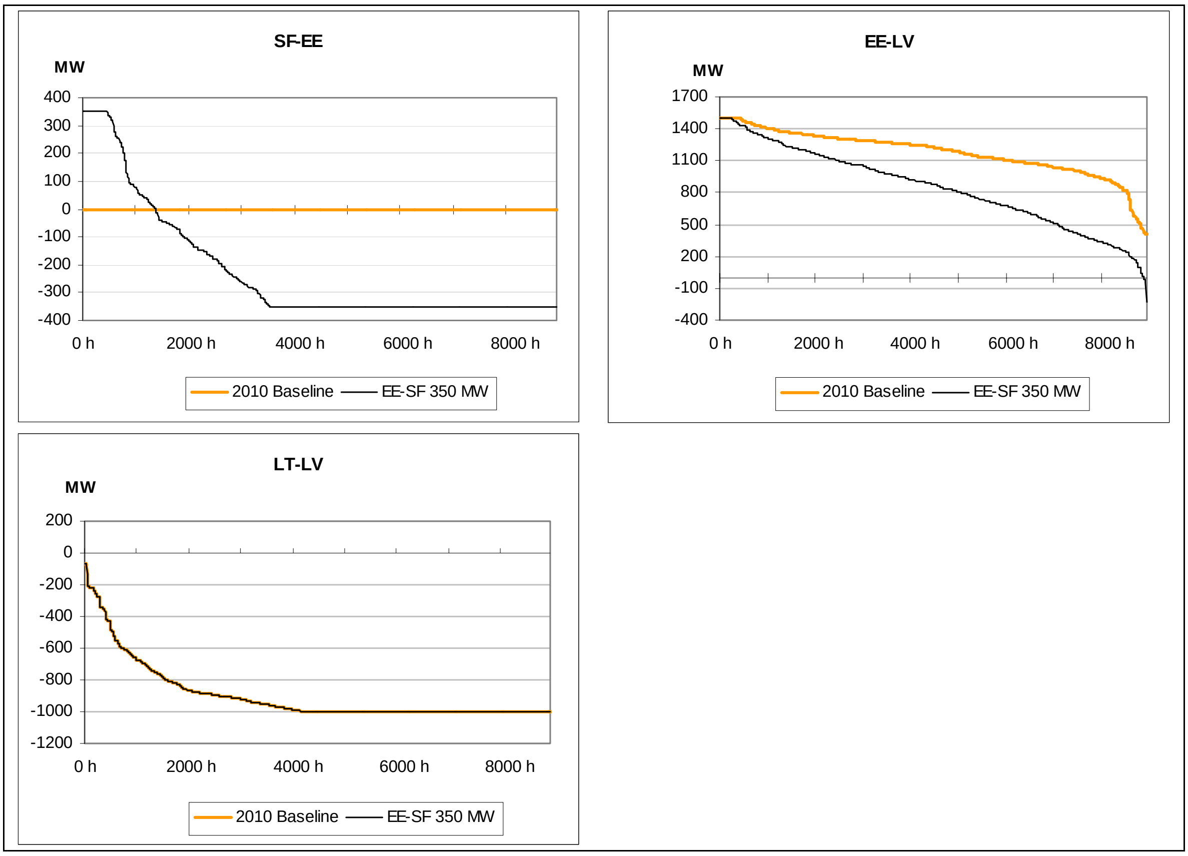


Figure 39: Changing flow patterns in case of a new link between Finland and Estonia (350 MW)

Subsea cable between Finland and Estonia (Estlink) (700 MW)

When adding a second link between Estonia and Finland, i.e. increasing the NTC to 700 MW, we receive the results presented in Figure 40. Although the new link is still fully utilised for some 4000 hours a year, the incremental use is less than for the first 350 MW. We also note that both other Baltic countries increase their imports from Estonia, even if only slightly. This observation, which seems surprising on first sight, can again be explained by the replacement of peak generation by cheaper imports from Finland. In fact, the maximum imports from Finland also show a strong increase.

Our market simulations show total savings of 14.7 M€/a in production costs. Conversely, we estimate the savings to consumers (market payments) at 34.3 M€/a. These numbers include 38 M€/a in reduced costs in Finland.

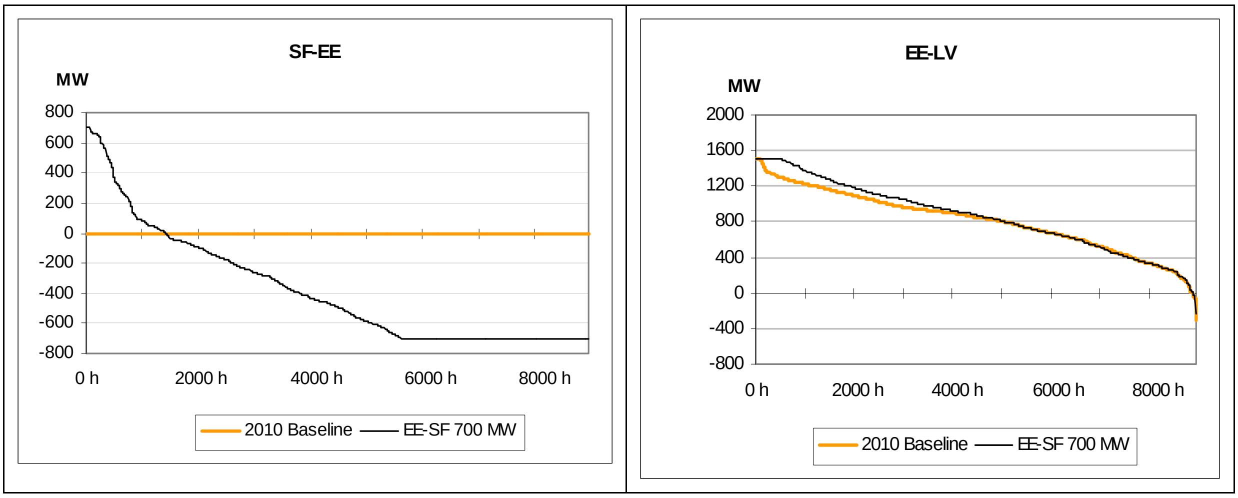


Figure 40: Changing flow patterns in case of a new link between Finland and Estonia (700 MW)

Poland-Lithuania link (500 MW)

Next, we have simulated the construction of the planned link between Poland and Lithuania.[93] Figure 41 shows that the new link is fully used for more than 6000 hours a year into the direction of Poland, whereas the flows in the opposite direction are negligible. At the same time, these imports only have a minor impact on Poland's exchanges with other countries, such as Germany. Within the Baltic States, this new link results in reduced flows in the South-bound direction, i.e. from Estonia into Latvia, and from Latvia to Lithuania.

Our market simulations show total savings of 27.8 M€/a in production costs and 82.2 M€/a in market payments.

[93] Please note that we have not taken into account any restrictions within the Polish transmission grid that might reduce the available transfer capacity from and to Lithuania.

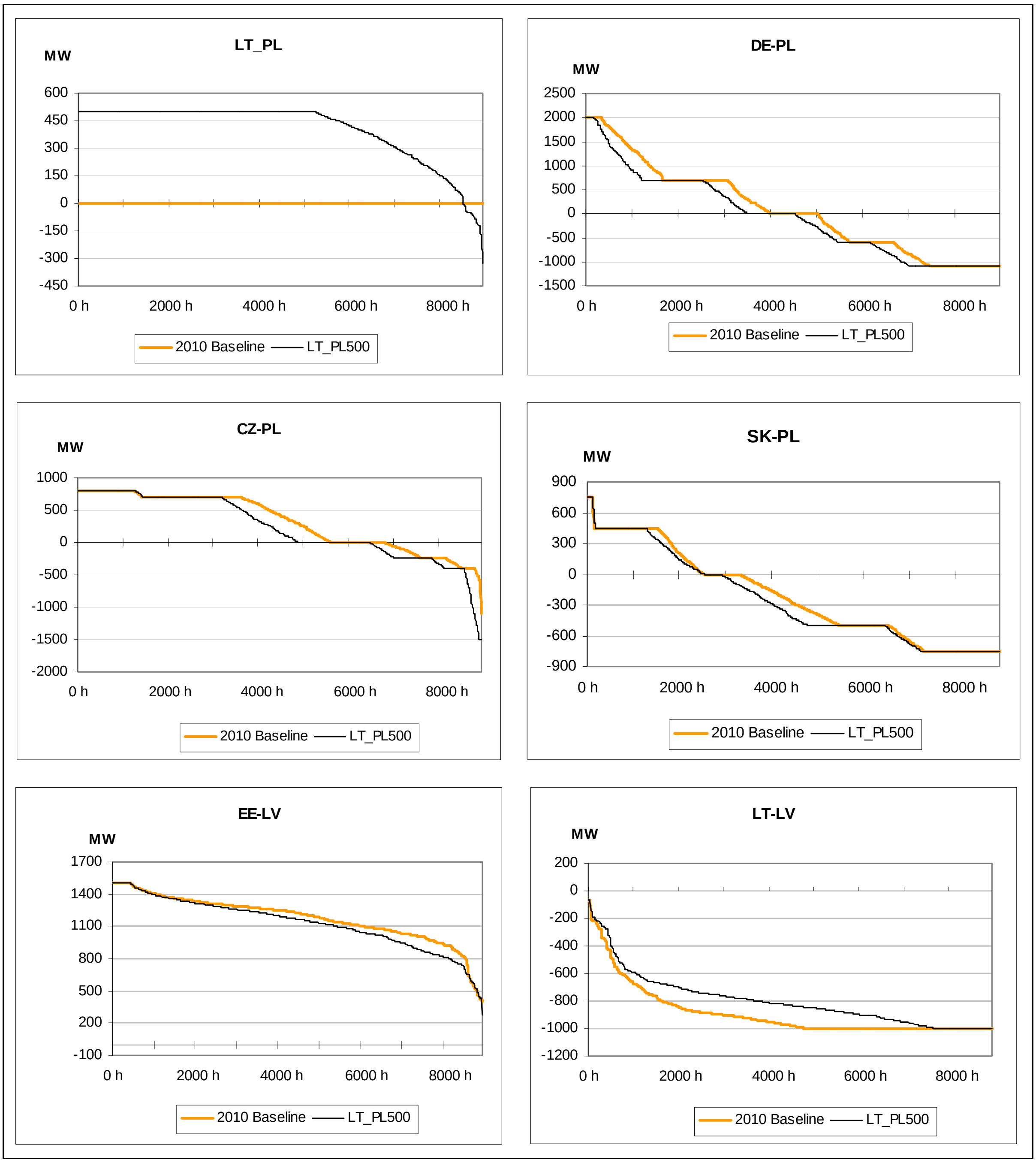


Figure 41: Changing flow patterns in case of a new link between Poland and Lithuania (500 MW)

Poland-Lithuania link (1000 MW)

When modelling the full capacity of the Poland-Lithuania link (1000 MW), we see increasing exports from Lithuania to Poland. However, the utilisation of the additional capacity is less than for the first 500 MW (see Figure 42). These huge imports now have a more visible, but still limited impact on the exchanges of Poland with its other neighbours, i.e. Germany, the Czech Republic and Slovakia. While the majority of the exports still comes from Lithuania, Estonia now also starts increasing its exports.

Our market simulations show total savings of 48.3 M€/a in production costs and 89.9 M€/a in market payments.

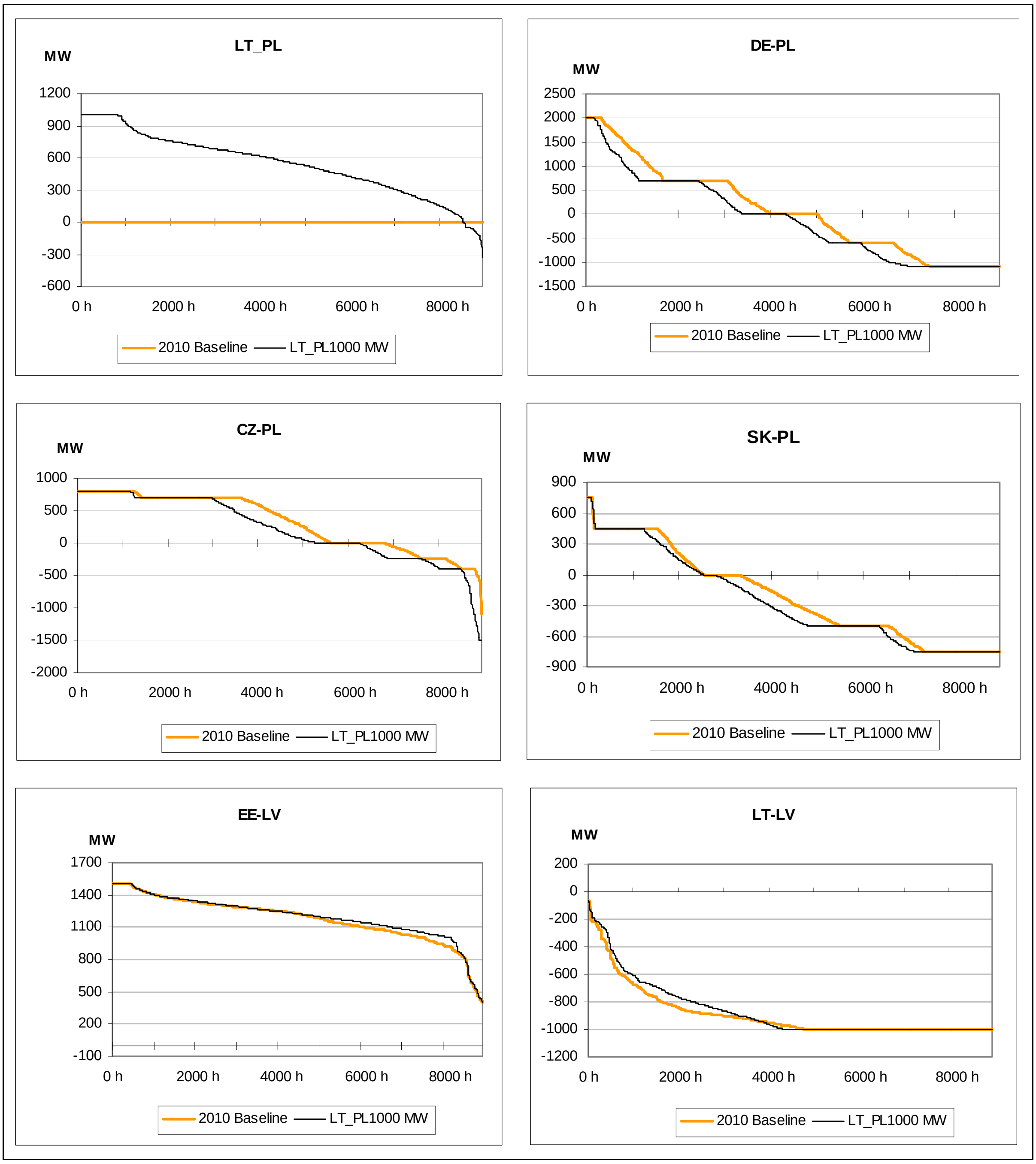


Figure 42: Changing flow patterns in case of a new link between Poland and Lithuania (1000 MW)

Estlink (350 MW) and Poland-Lithuania link (1000 MW)

Finally, we have simulated a case with both the Finland-Estonia (350 MW) and the Poland-Lithuania (1000 MW) links in place. At first sight, the results shown in Figure 43 are surprising: While the prevailing flow on the Estlink cable now goes from Finland to Estonia, Lithuanian exports to Poland also decrease. However, these observations simply imply that the Baltics are now partially used for transits from Finland to Continental Europe, which can also be seen from the changing flow patterns between Estonia, Latvia and Lithuania. At the same time, the Baltic export potential has obviously reached its limits, such that it does not suffice to make full use of the export capacities to both Finland and Poland at times of high prices (and high demand). Consequently, the impact on the other exchanges of Poland again becomes almost negligible.

Our market simulations show total savings of 102.5 M€/a in production costs and 146.9 M€/a in market payments, including some 16.0 M€/a in reduced costs for Finland.

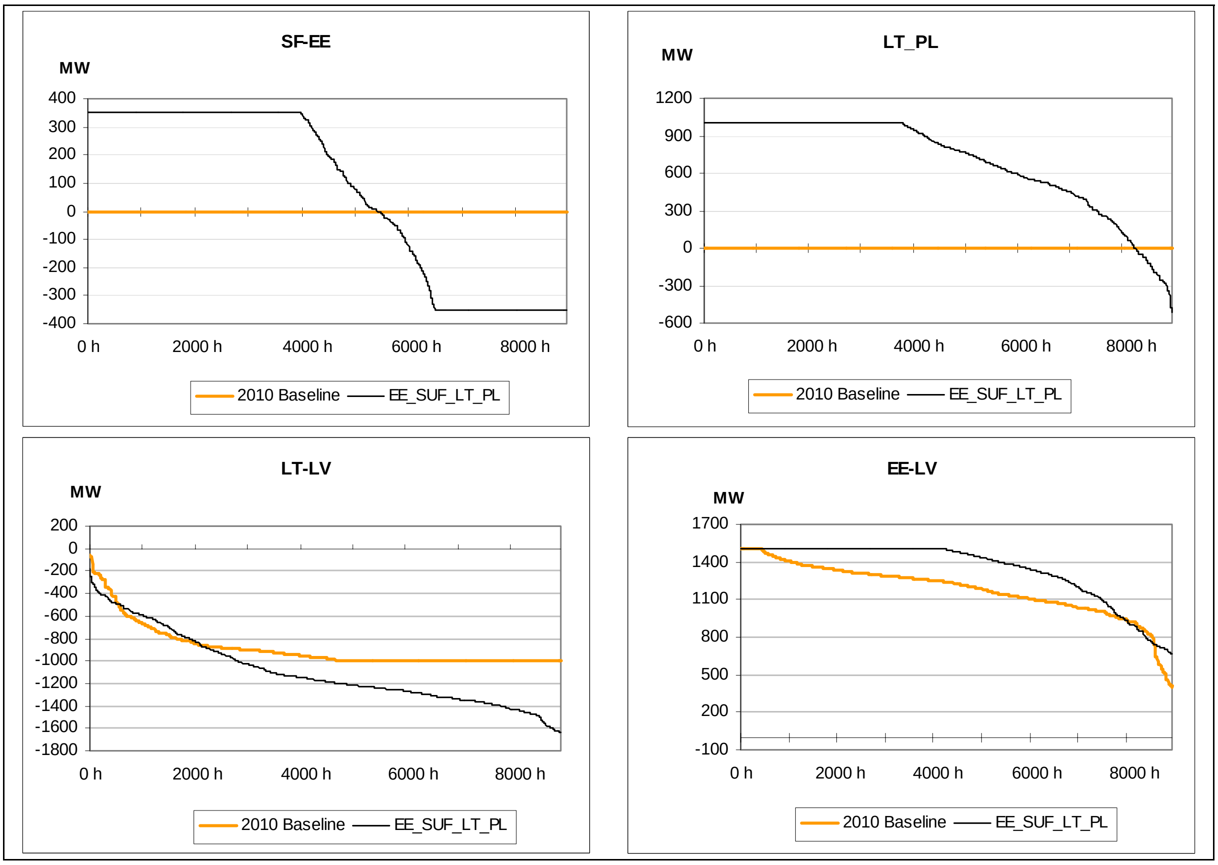


Figure 43: Changing flow patterns in case of new links EE↔SF and PL↔LT (350 / 1000 MW)

6.3.3 North Central Europe: Czech Republic, Slovakia, Poland and Germany

Table 11 summarises the changes in NTC-values that we have considered for the different projects and scenarios at the borders between Poland, on the one side, and Germany, the Czech Republic and Slovakia, on the other side.

Table 12: Estimated change in transfer capacities by projects studied for North Central Europe

Project / Border	NTC (MW) *(New and/or change)*		
	(i)	**(ii)**	**(iii)**
a) Reduced import capacities CZ/CZ/SK→PL for winter (i) and summer (ii) periods	200	700	
b) Increased capacities PL↔CZ/DE/SK	+500	+500	

Reduced import capacities CZ/CZ/SK→PL

For our baseline scenario, we have used the NTC values that were published by the Polish TSO for the summer and winter of 2003 and that applied to individual border. In 2004, PSE however published new NTC values that are now combined for exchanges with Germany, the Czech republic and Slovakia, and that are substantially lower than before. At the same time, we have not been able to obtain any reasons for this drastic change. Furthermore, it is not clear to us why imports of an exporting country are limited to an extremely low value of just 200 MW during the winter, whereas Poland allows for more than 2000 MW of exports into the opposite direction.

The result of this reduction clearly is reduced exports from all three countries to Poland. Decreasing exports from Poland to Slovakia furthermore indicate that at least a part of the cross-border capacity is obviously used for transit. Finally, it is interesting to note that this modification also results in limited additional exports from the Czech Republic to Germany, without however creating any congestion.

Our market simulations show no substantial changes in production costs but an increase of 1043 M€/a in market payments.

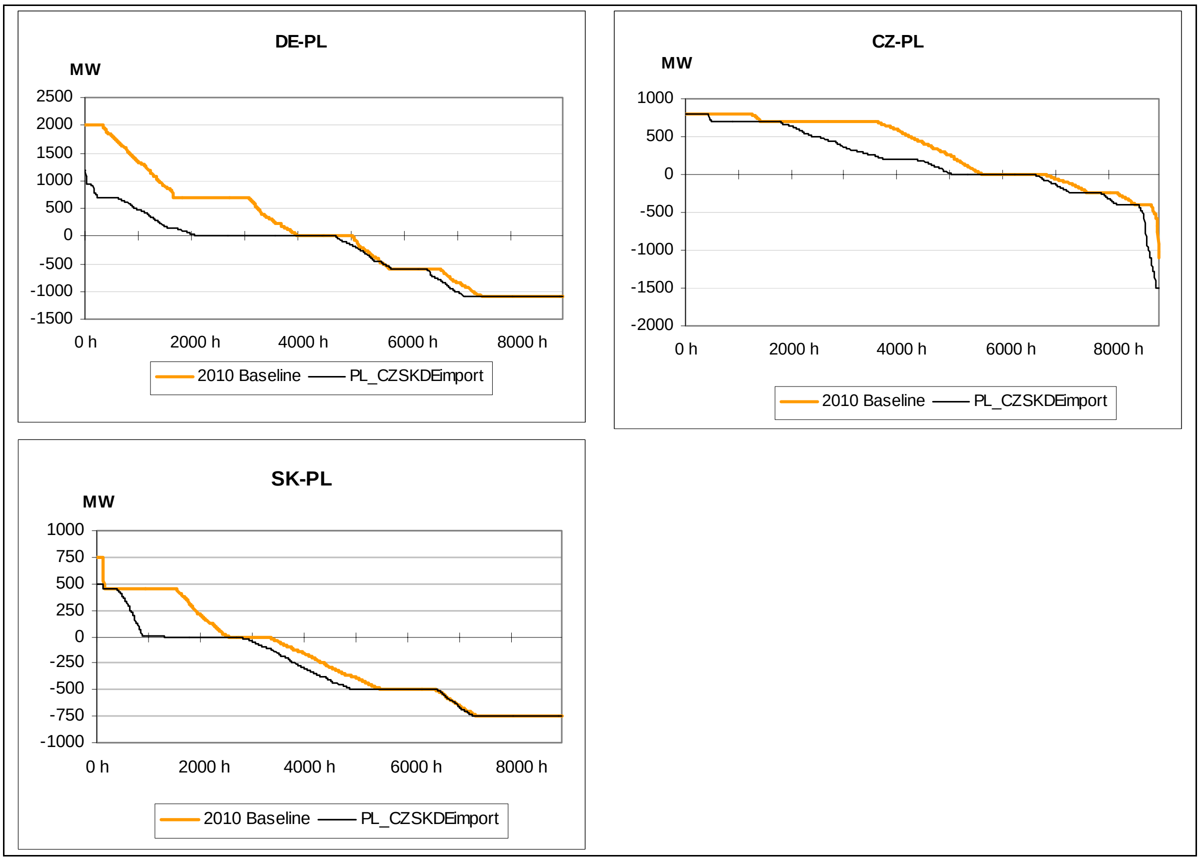


Figure 44: Changing flow patterns in case of reduced import capacities CZ/CZ/SK→PL

Increased import capacities CZ/CZ/SK↔PL (500 MW)

Next, we consider a case where the cross-border capacities at the Polish borders are increased by 500 MW each. We note that this additional capacity primarily serves to increase Czech exports, while Poland increases its own exports to Slovakia. Although this seems to indicate the use of Poland for transit, this is not the case as explained for the following case. For the Polish-German border, the results are inconclusive, showing both variations in both directions. The flows from the Czech Republic to Poland flows are constrained a large part of the year, while the two other country-to-country exchanges show less congestion.

Our market simulations show total savings of 30.6 M€/a in production costs and 98.2 M€/a in market payments.

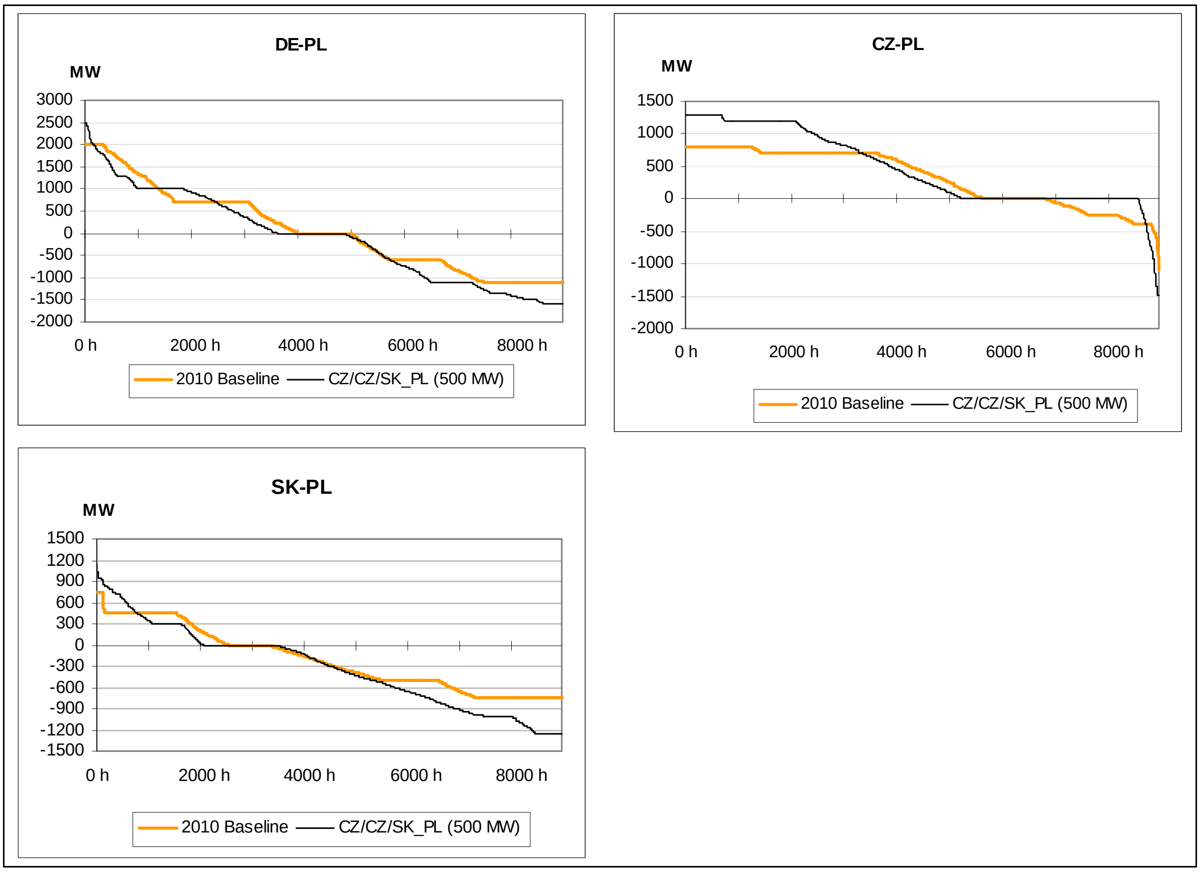


Figure 45: Changing flow patterns in case of increased import capacities CZ/CZ/SK↔PL (500 MW)

Increased import capacities CZ/CZ/SK↔PL (1000 MW)

When increasing the NTC values for the Polish border by a total of 1000 MW, we observe substantial variations in regional flows. As illustrated by Figure 46, both Czech exports to Poland as well as Polish exports to Slovakia further increase. However, closer analysis reveals that the Czech Republic simultaneously reduces its exports to Slovakia, while Slovakia exports more to Hungary. As a matter of fact, these results rather reflect a better inter-temporal use of different generation structures: While Poland imports more during peak load hours, i.e. when it would otherwise have to rely on more expensive domestic units, it exports more to both Slovakia and the Czech Republic during off peak periods. The increased flow to Slovakia furthermore does not only replace Slovakian imports from the Czech Republic, but also allows for transit to Hungary. In turn, this allows the Czech Republic to export additional amounts to Germany.

Our market simulations show total savings of 33 M€/a in production costs and 149.6 M€/a in market payments.

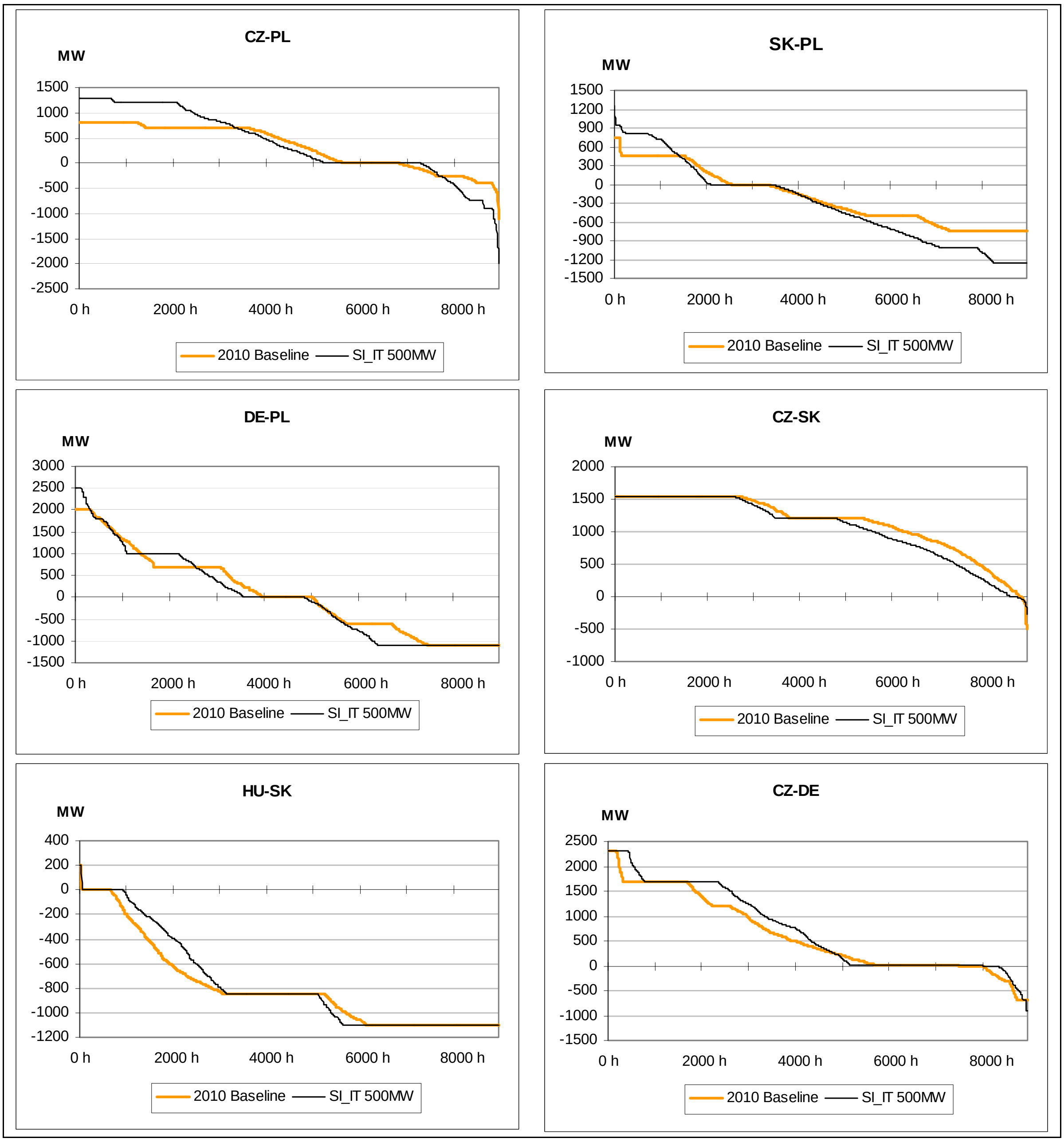


Figure 46: Changing flow patterns in case of increased import capacities CZ/CZ/SK↔PL (1000 MW)

6.3.4 Central Europe: Austria, Czech Republic, Slovakia and Hungary

Similar to the previous section, we consider real investments projects as well as other possible changes in the area of Central Europe. As illustrated by Table 13, we have added three scenarios (a-(i), b-(i), c) to represent the situation, in case no additional investments into the Austrian grid were made.

Table 13: Estimated change in transfer capacities by projects studied for Central Europe

Project / Border	NTC (MW) *(New and/or change)* (i)	(ii)	(iii)
a) Changed transfer capacity CZ→AT	-175	+250[94]	
b) Changed transfer capacity AT→SI	-175		
c) Combination of a and b	N/A		
d) Increased capacities CZ/AT↔AT and AT↔SI	+500 / +500	+1000 / +1000	
e) Increased capacity AT↔SK	+500		
f) Increased capacities CZ/AT↔AT, AT↔SI and AT↔SK	+500 each		
h) Increased capacity SK↔HU	+500	+1000	
j) Combination of f) and 3a	f + 3a-(i)	f + 3a-(ii)	

Reduced transfer capacity CZ→AT

The first case considers a situation where imports from the Czech Republic into Austria are reduced by 175 MW, i.e. where the planned internal reinforcements of the Austrian grid were not done. As illustrated by Figure 47, this limitation results in a corresponding reduction of Austrian imports at this border for almost 4000 hours, or almost 0.7 TWh annually. This reduction is partially compensated for by increased imports from Germany (0.4 TWh), which in turns increases its net imports from the Czech Republic.

For this modification, we did not consider the changes in cost since it does not represent an investment project. Instead, the objective was to consider the impact of outstanding network reinforcements on transmission flows.

94 Summer only

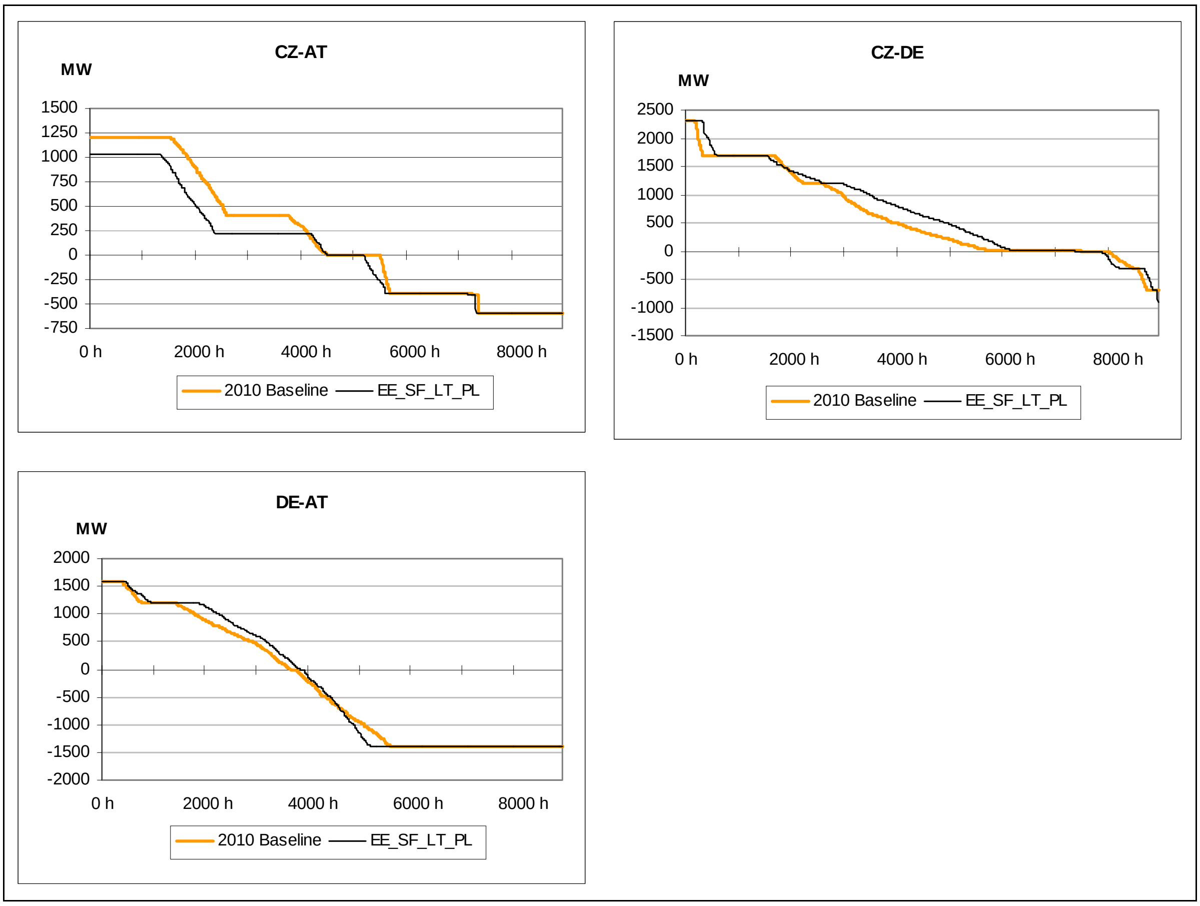


Figure 47: Changing flow patterns in case of reduced transfer capacity CZ→AT (-175 MW)

Blue line – 2010 base case; red line – Reduced transfer capacity CZ→AT

Increased transfer capacity CZ→AT (summer only)

Figure 48 shows some results for opposite case where we have increased the export capacity from the Czech Republic to Austria by 250 MW, but only during the summer. While the network constraint towards Austria still exists, the additional capacity is utilised to a substantial degree. Similar to the previous case, this change also impacts the border between Austria and Germany, as well as the exchange between the Czech Republic and Poland.

Our market simulations show total savings of 39.6 M€/a in production costs. Conversely, market payments increase by 2.6 M€/a, i.e. increased exports seem to result in higher market prices in the exporting countries.

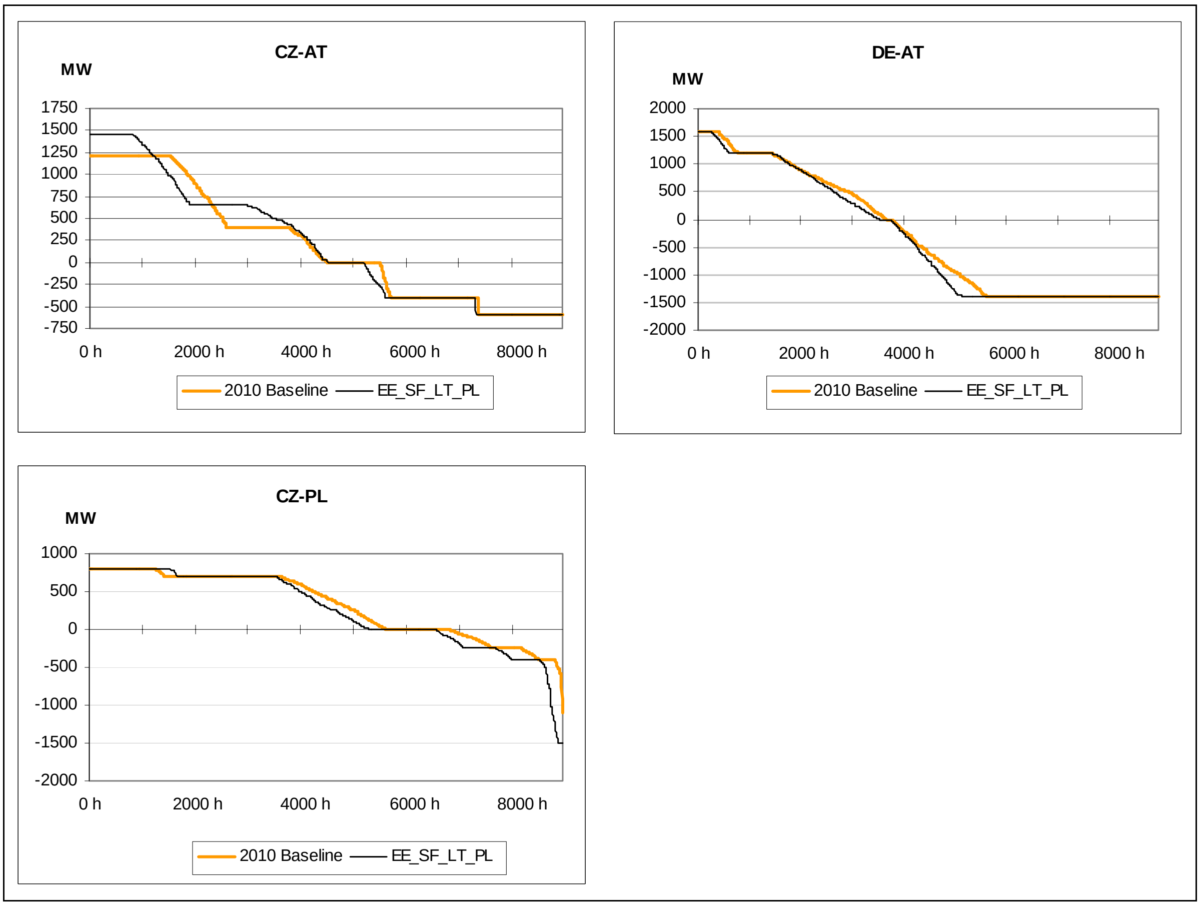


Figure 48: Changing flow patterns in case of increased transfer capacity CZ→AT (250 MW)

Reduced transfer capacity AT→SI

In parallel to a reduction of import capacities from the Czech Republic, the next case considers a corresponding decrease of export capacities from Austria to Slovenia. As Figure 49 shows, this change leads to a corresponding reduction of the cross-border exchange for almost 5000 hours annually, equivalent to 0.5 TWh or almost 30% of the previous flows towards Slovenia. At the same time, Figure 49 highlights the fact that exports from Austria to Slovenia have obviously not been restricted by insufficient capacities at this border, but rather by congestion at a different location, i.e. between Slovenia and Italy. Besides the direct impact, this change also has an impact on the borders between Austria and the Czech Republic, and between Slovenia and Italy.

For the same reasons as for the case of reduced transfer capacity between the Czech Republic and Austria, we did not consider the changes in cost for this modification.

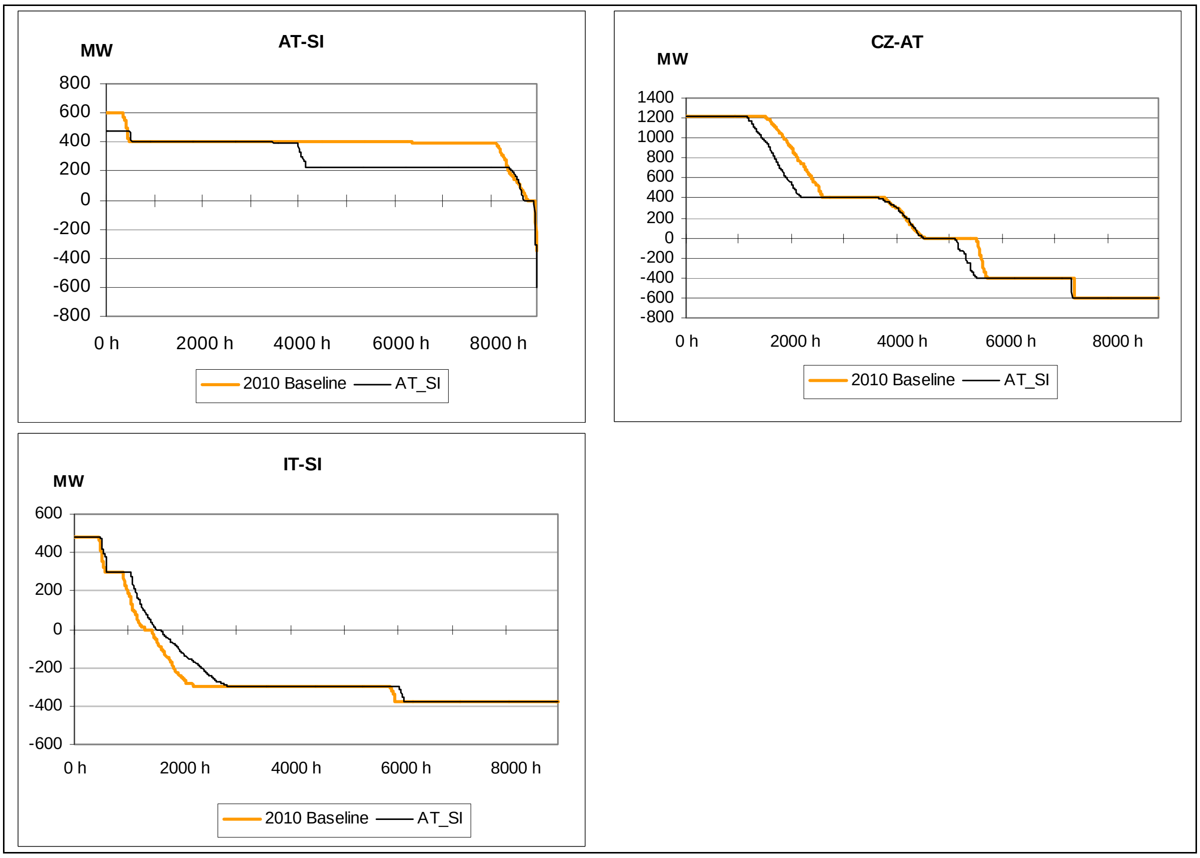


Figure 49: Changing flow patterns in case of reduced transfer capacity AT→SI (-175 MW)

Reduced transfer capacity CZ→AT and AT→SI

The fourth case reflects a combination of the first and third scenarios, i.e. a simultaneous reduction of export capacities from the Czech Republic to Austria, and from Austria to Slovenia. In this case (Figure 50), we see the same reduction of Austrian imports from the Czech Republic as under the first case (see Figure 47 and Figure 50). At the Austrian-Slovenian border, however, exchanges now decrease for almost 7000 hours a year, i.e. substantially more than under the previous case In addition, the combination of reduced transfer capacities at these two borders also has a market impact on exports from Austria to Italy and, to a lesser extent, from Slovenia to Italy.

For the same reasons as for the case of reduced transfer capacity between the Czech Republic and Austria, we did not consider the changes in cost for this modification.

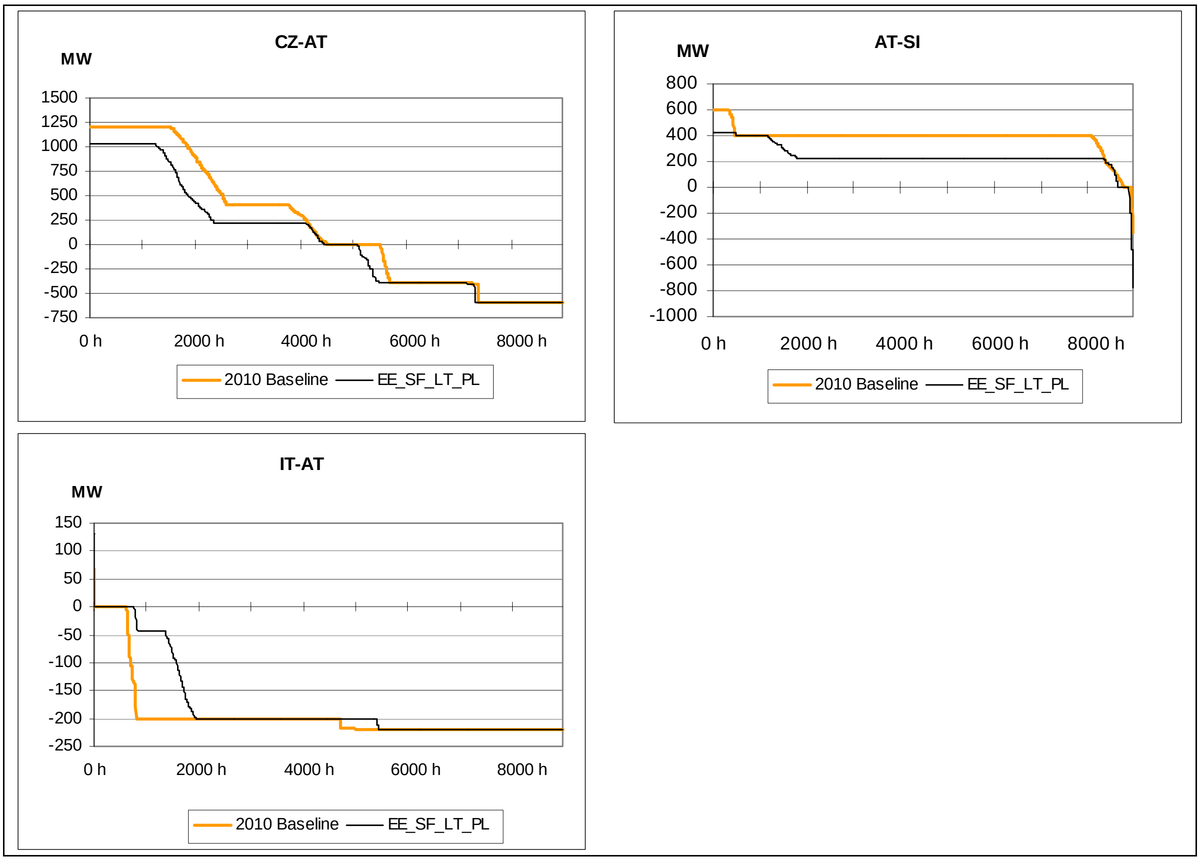


Figure 50: Changing flow patterns in case of reduced transfer capacity CZ→ AT→SI (175 MW each)

Increased capacities CZ/AT↔AT and AT↔SI (500 MW each)

Our next simulation has been based on a 500 MW increase each of the import capacities to Austria from Czech Republic and Hungary (combined), and from Austria to Slovenia. As illustrated by Figure 51, this combination results in significant changes at the corresponding border. Interestingly enough, the additional transfer capacity between the Czech Republic, Hungary and Austria is used in both directions, i.e. largely for transits from the Czech Republic through Austria to Hungary, in parallel with substantially increased Austrian exports to Slovenia. However, while the Austrian-Hungarian border remains congested for more than 70% of time, the capacity at the Austrian-Slovenian border is hardly ever fully used. The resulting net increase of exports from Austria is partially covered by imports from Germany, indicating an additional transit through

Austria of up to 1000 MW.[95] This large flow also replaces a part of Slovakian exports to Hungary and allows for a slight increase of Slovenian exports to Italy.

The market simulations show total savings of 111.6 M€/a in production costs, but an increase of 32.8 M€/a in market payments. Thus, increasing exports from low costs countries cause market prices in those countries to rise.

95 It seems questionable, whether the Austrian grid would be capable of handling such an amount of additional transit. However, this example clearly illustrates the importance of Austria as a crossroad for the transit of power in the Internal Electricity Market.

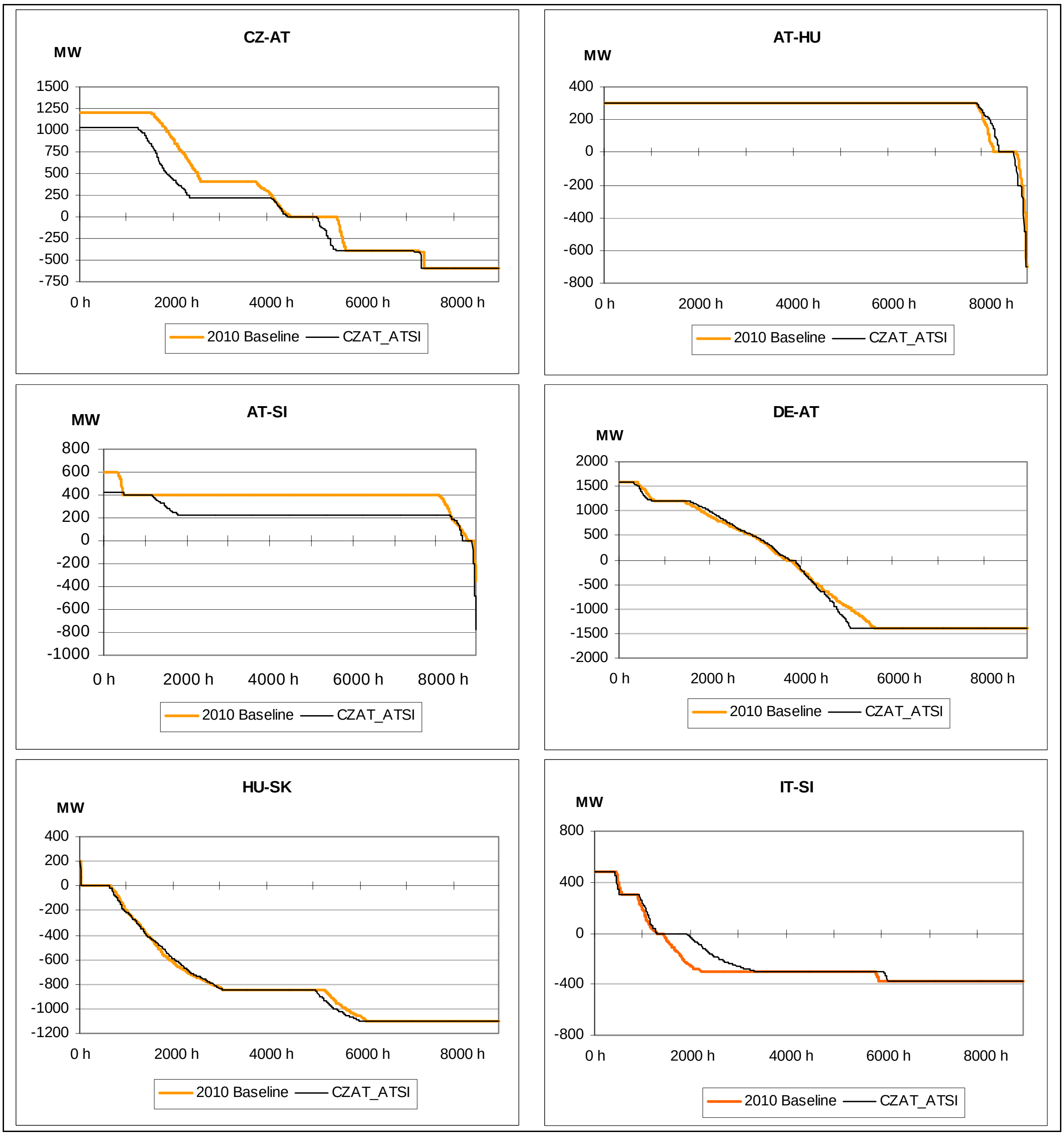


Figure 51: Changing flow patterns for increased capacities for CZ/AT↔AT and AT↔SI (500 MW)

Increased capacities CZ/AT↔AT and AT↔SI (1000 MW each)

The next scenario is equivalent to the previous one, except that we have increased the changes at both borders to 1000 MW each.[96] Not surprisingly, the results show a similar

[96] Please note that this alternative would only be feasible after both planned North-South links within Austria have been realised, i.e. the 380 kV lines Südburgenland - Kainachtal and St. Peter – Tauern.

effect on the international flow patterns, but at a larger scale. Moreover, these changes also have a wider regional impact as illustrated by Figure 52. While it seems logical that increasing Austrian exports replace Slovenian imports from Croatia. But at the same time, a reduced flow from Romania to Hungary or increasing exports from Serbia & Montenegro can more generally be seen as evidence for the displacement of electricity produced in South-Eastern Europe by increasing exports from the Austria, Germany and the Czech Republic.

Our market simulations show total savings of 138.7 M€/a in production costs and 123.1 M€/a in market payments. Compared to the previous project, savings in production costs increase by 27.1 M€/a, and savings in market payments decrease by 90.3 M€/a.

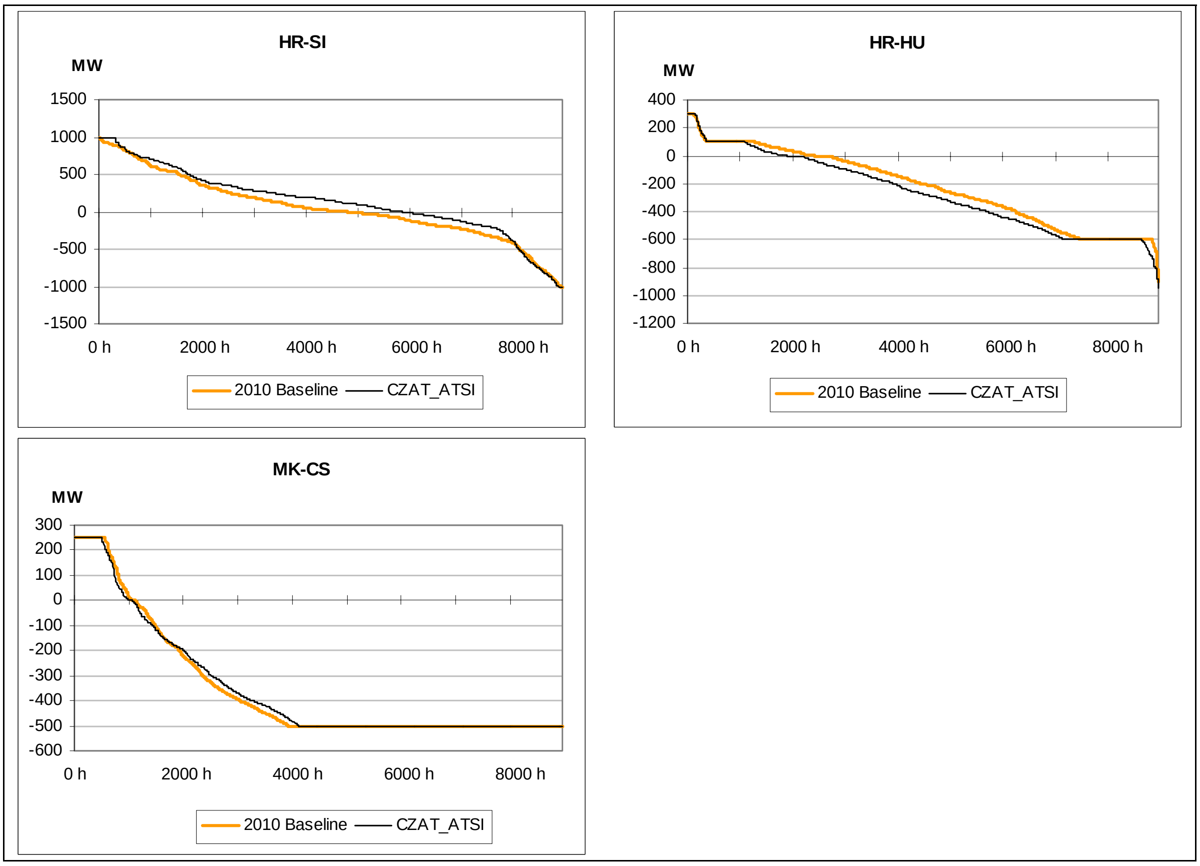


Figure 52: Changing flow patterns for increased capacities for CZ/AT↔AT and AT↔SI (1000 MW)

Increased capacity AT↔SK

In our next simulation, we have studied the case of additional capacity between Austria and Slovakia. As illustrated by Figure 53, this new transfer capacity shows a high utilisation, being congested for more than 50% of time. In addition, we observe flows from Austria through Slovakia to Hungary, partially replacing flows from Poland to Slovakia. At the same time, there is a slight reduction of flows from the Czech Republic to Austria and Poland, as well as from Germany to Poland.

Our market simulations show total savings of 59.9 M€/a in production costs and 6.2 M€/a in market payments.

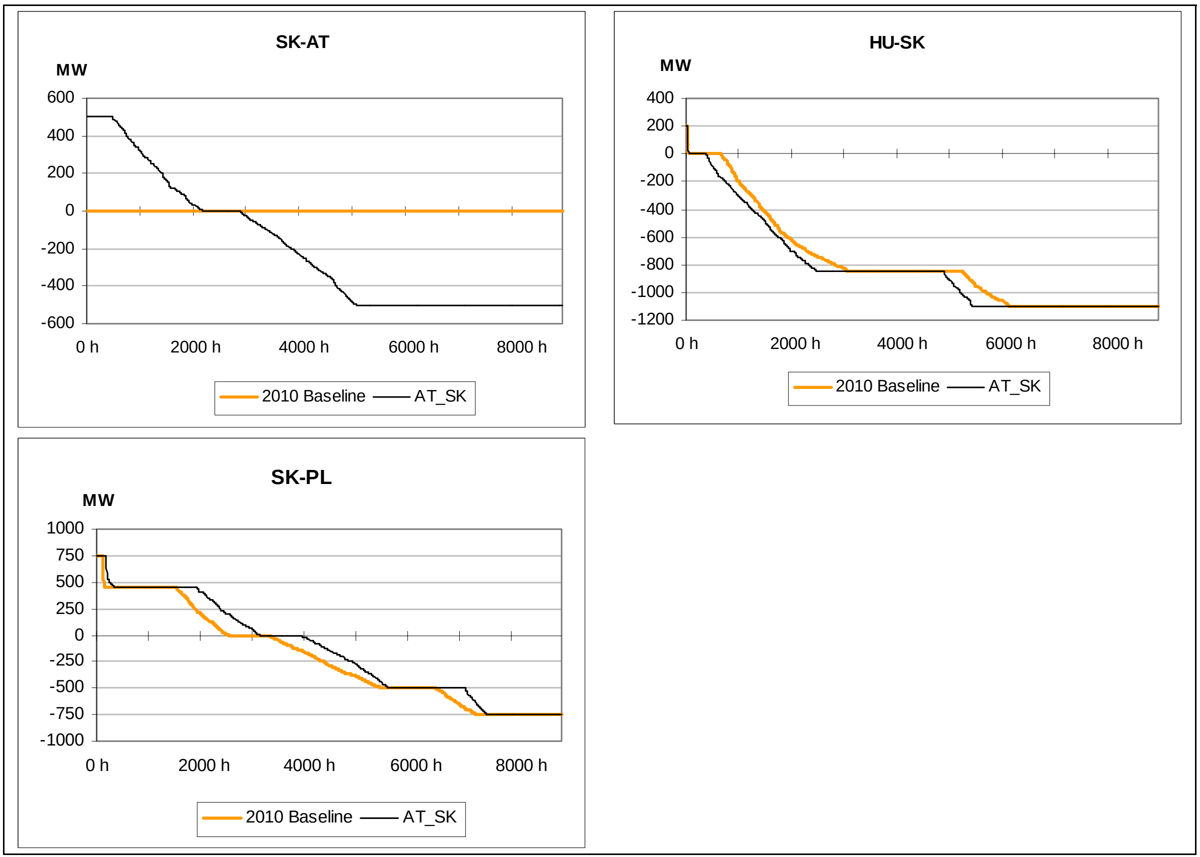


Figure 53: Changing flow patterns for increased capacities for AT↔SK (500 MW)

Increased capacities CZ/AT↔AT, AT↔SI and AT↔SK

Next, we have considered a combined scenario, where we have increased transfer capacities by 500 MW each at the borders between Czech Republic and Hungary (combined) to Austria, between Austria and Slovenia, and between Austria and Slovakia. Despite the addition of the new link between Austria and Slovakia, which shows a similar utilisation as in the previous case, this scenario basically shows the same results as the case without this particular link. In Figure 54, we have therefore compared the new situation with and without the link between Austria and Slovakia. Clearly, the effect is limited, with only slightly increased Slovakian exports to Poland and Hungary.

Our market simulations show total savings of 130.9 M€/a in production costs and 135.6 M€/a in market payments.

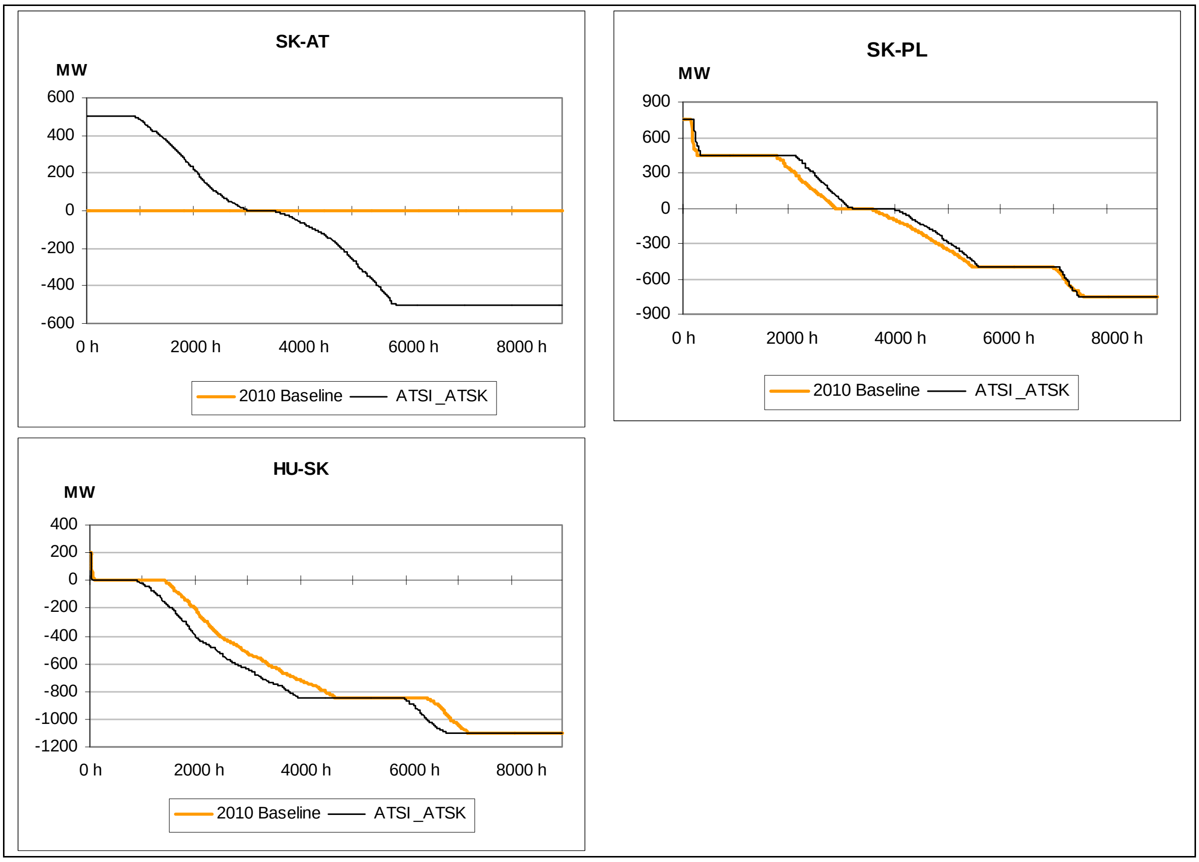


Figure 54: Changing flow patterns for increased capacities for CZ/AT↔AT and AT↔SI (500 MW) with and without additional capacity at the AT↔SK border (500 MW)

Increased capacity SK↔HU (500 MW)

The results for a 500 MW increase of the transfer capacity between Hungary and Slovakia are illustrated in Figure 55. This project effectively removes the former network constraint between those two countries. At the same time, we observe slightly increased flows from the Czech Republic and Poland to Slovakia.

Our market simulations show total savings of 29.5 M€/a in production costs and 46 M€/a in market payments.

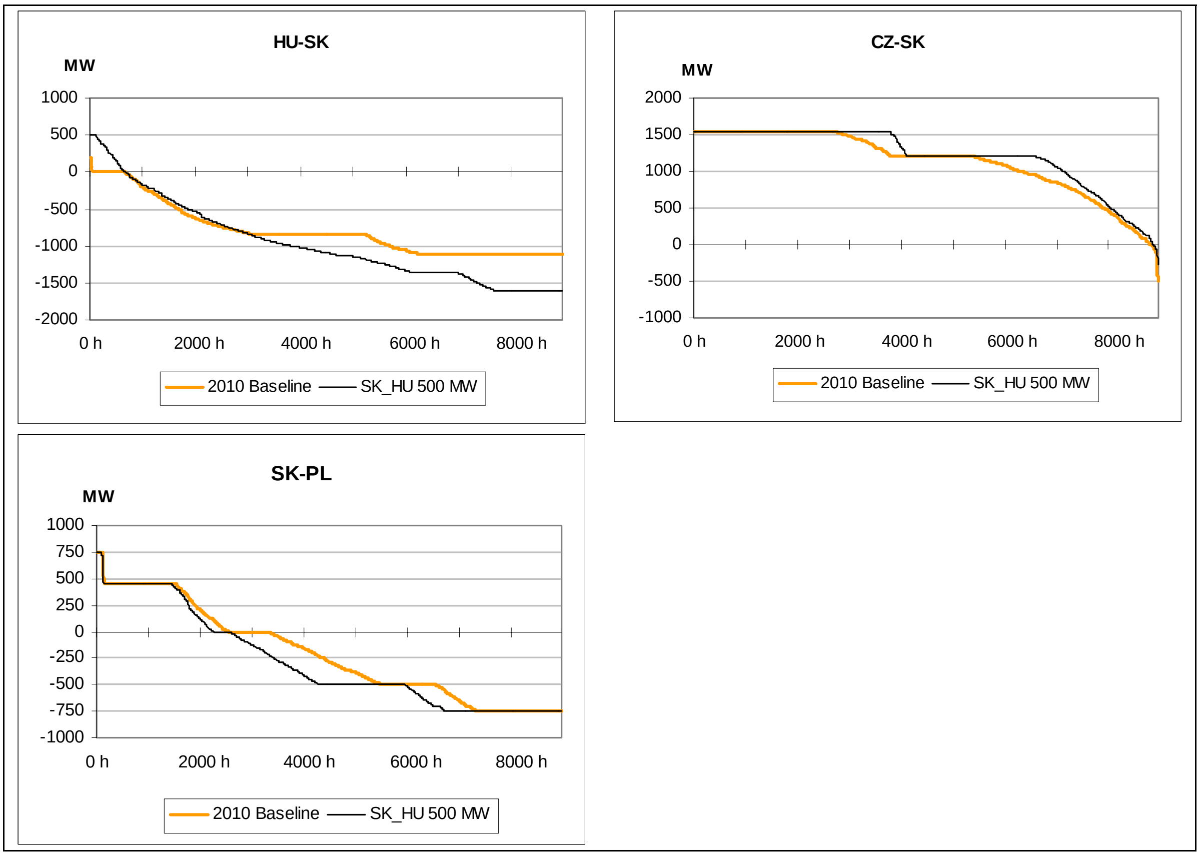


Figure 55: Changing flow patterns for increased capacities SK↔HU (500 MW)

Increased capacity SK↔HU (1000 MW)

Figure 56 shows the results of a further increase of the transfer capacity between Hungary and Slovakia by an additional 500 MW, i.e. by a total of 1000 MW compared to the base case. This modification completely removes congestion at this border. However, when comparing the outcome to the previous case, it is obvious that the benefits are marginal. Furthermore, a further increase of the flows from the Czech Republic and Poland to Slovakia results in serious congestion at both borders.

Our market simulations show total savings of 33.1 M€/a in production costs and 36.5 M€/a in market payments. Compared to the 500 MW project, savings increase by 3.6 M€/a and 9.5 M€/a for production and market payments, respectively.

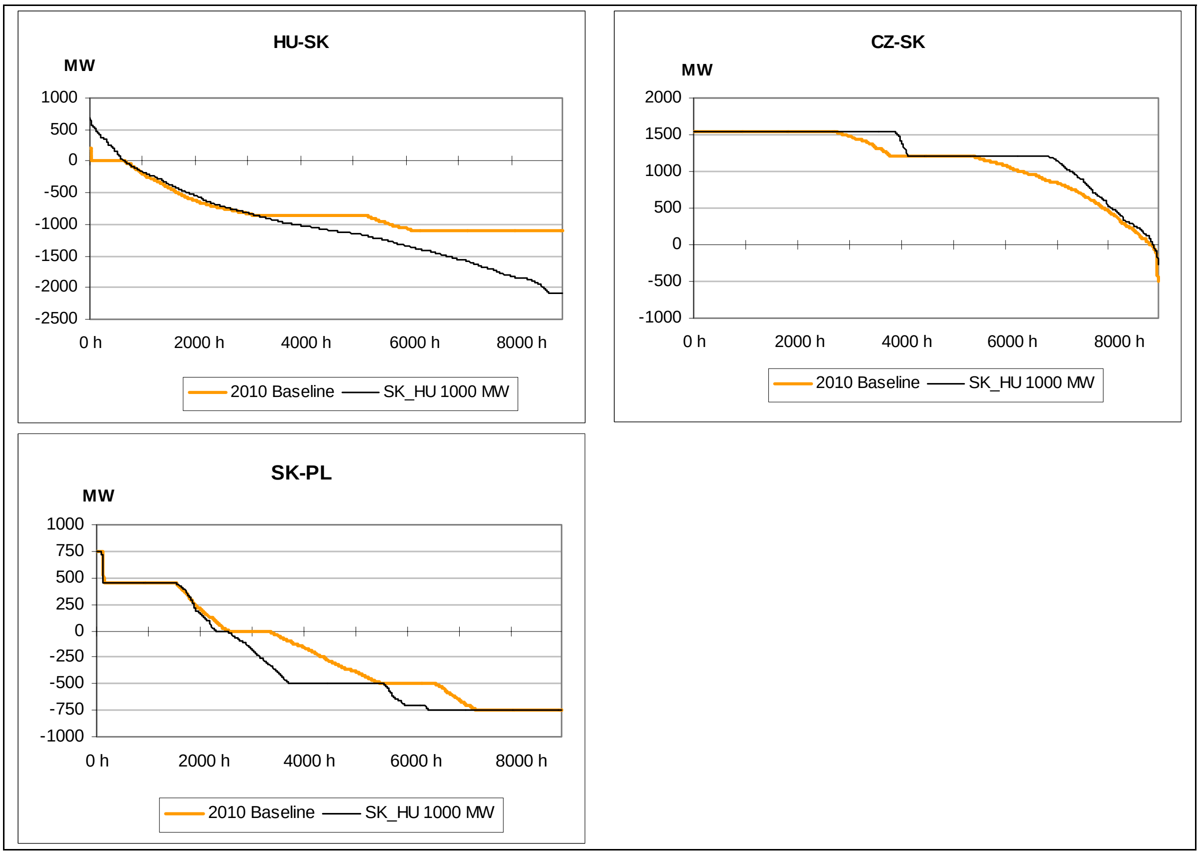
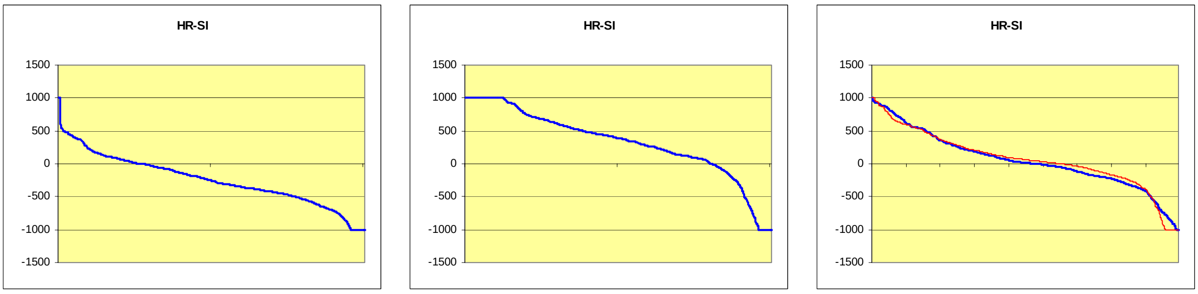


Figure 56: Changing flow patterns for increased capacities SK↔HU (1000 MW)

Increased capacities CZ/AT↔AT, AT↔SI and SI ↔IT (500 MW)

Next, we have considered a case with an increase of transfer capacities by 500 MW at three different borders, namely CZ/AT↔AT, AT↔SI, and SI↔IT. This scenario effectively combines the impact of the previous case d-(i) and the case a-(i) from section 6.3.5 below. Hence, the new flow patterns at all four Austrian borders (CZ, DE, HU, SI) as well as between Hungary and Slovakia are largely equivalent to the case of increased transfer capacities at the Austrian borders only (without Germany). Conversely, the flows between Italy and Slovenia as well as between Hungary and Croatia are similar to the separate addition of new capacity between Slovenia and Italy. As illustrated by Figure 57, there is only one main difference, namely the exchange between Croatia and Slovenia. Obviously, the electricity exported from Slovenia to Italy now comes from Austria, whereas the additional flows from Hungary to Croatia now serve the benefits of countries in the South-Eastern part of Europe.

The market simulations show total savings of 140.7 M€/a in production costs and 32.3 M€/a in market payments.



a) Increased capacities CZ/AT↔AT, AT↔SI | *b) Increased capacities SI↔IT* | *Combination of a) and b) compare to baseline scenario*

Figure 57: Changing flows at the SI↔HR under different scenarios

Increased capacities CZ/AT↔AT, AT↔SI and SI ↔IT (1000 MW)

Finally, we have increased the changes in transfer capacities from the previous scenario by another 500 MW, i.e. using an overall increase of 1000 MW for the 3 relevant borders. The results show however a largely similar characteristic, once again with the exception of the Croatian-Slovenian border, which now shows a pattern more similar to the separate increase of transfer capacity at the Slovenian-Italian border (see below). One of the reasons likely is a new network constraint since the NTC-value for exports from Hungary to Croatia has now become binding for almost half of the year.

The market simulations show total savings of 195.7 M€/a in production costs and an increase of 22 M€/a in market payments. Compared to the 500 MW case, savings in production costs increase by 50 M€/a, and savings to consumers (market payments) by some 54 M€/a.

6.3.5 South Central Europe: Italy, Slovenia, Croatia, Bosnia & Hercegovina and Hungary

For this area, we have considered a total of 7 different scenarios, including three cases where we have studied the increase of transfer capacities between Croatia, Bosnia & Hercegovina, and Serbia & Montenegro. None of these countries is either a member of the European Union or currently an official candidate country. However, we have studied these cases to check for the impact of corresponding projects on the EU Member states and Accession Countries. Table 14 provides a summary of the changes in NTC under each scenario.

Table 14: Estimated change in transfer capacities by projects studied for South Central Europe

Project / Border	NTC (MW) *(New and/or change)*		
	(i)	**(ii)**	**(iii)**
a) Increased capacity SI↔IT	+500	+1000	
b) Increased capacity SI↔HU	+600		
c) Increased capacity HR↔BA	+200		
d) Increased capacity HR↔CS	+300		
e) Increased capacity BA↔CS	+500		
f) Increased capacity HU↔CS	+500		

Increased capacity SI↔IT (500 MW)

In the first simulation, we have increased cross-border capacities between Slovenia and Italy by 500 MW. The added capacity shows a good utilisation, mainly for exports from Slovenia to Italy. As illustrated by (see Figure 58), this exported power is obviously not produced in Slovenia, but originates in Hungary and is then transported through Croatia to Slovenia. While not removing congestion between Slovenia and Italy, this investment causes a limited amount of congestion at both the Hungarian-Croatian and Croatian-Slovenian borders.

The market simulations show total savings of 31.6 M€/a in production costs but an increase of 28.6 M€/a in market payments. The increase in market payments is due to increased transmission capacity, which increases the market prices on the Slovenian side of the Slovenian-Italian border.

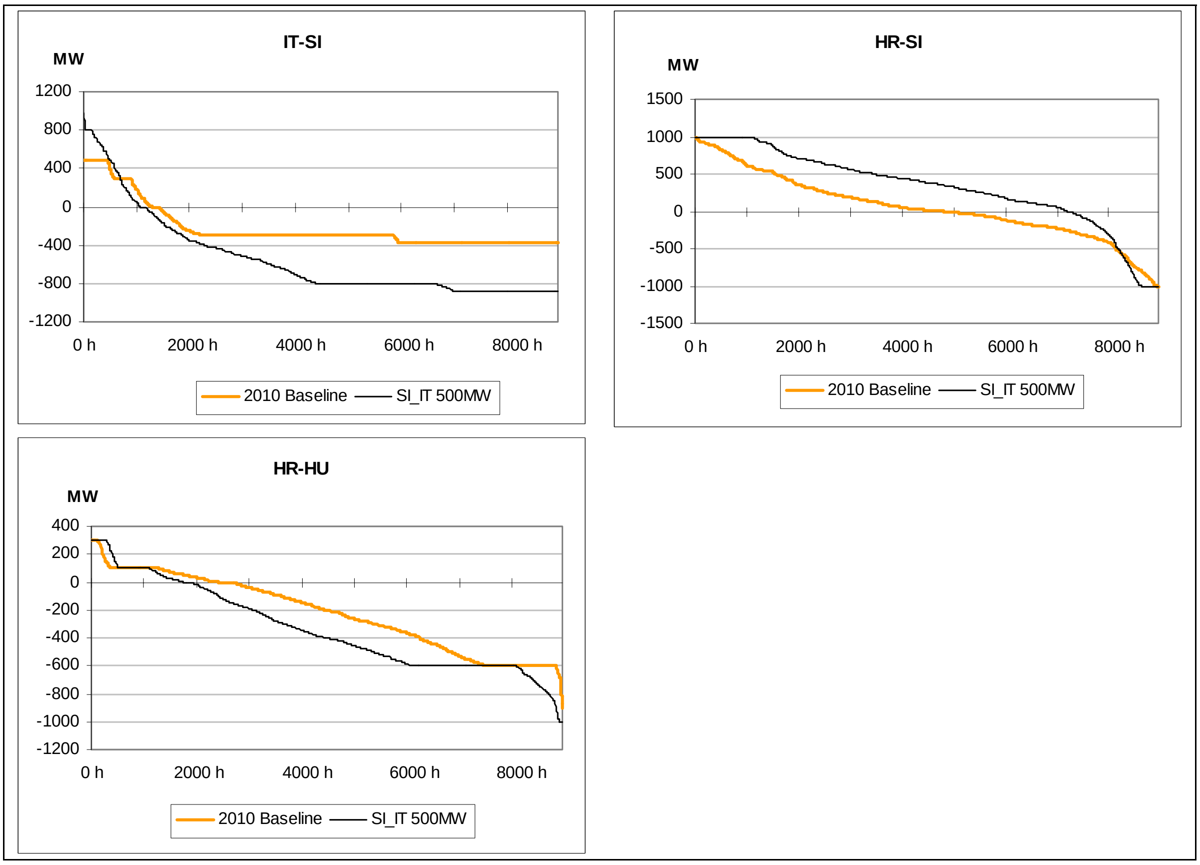


Figure 58: Changing flow patterns for increased capacities SI↔IT (500 MW)

Increased capacity SI↔IT (1000 MW)

Next, we have added an additional 500 MW, increasing the total addition of NTC at the Slovenian-Italian border to 1000 MW. Basically, the effects of this change are similar to the previous one, even if at a larger scale. However, a comparison of Figure 58 and Figure 59 shows that the network constraint at the Slovenian-Italian has now been effectively removed. Conversely, the previously uncongested borders between Hungary, Croatia and Slovenia have now each become a bottleneck for some 2000 – 3000 hours.

The market simulations show total savings of 38.8 M€/a in production costs but an increase of 43.3 M€/a in market payments. Similar to the previous case, increased market prices in Slovenia cause increasing market payments. The savings in production costs are around 7 M€/a compared to the 500 MW transmission project. Likewise, there is an increase of around 15 M€/a for savings in market payments compared to the 500 MW case.

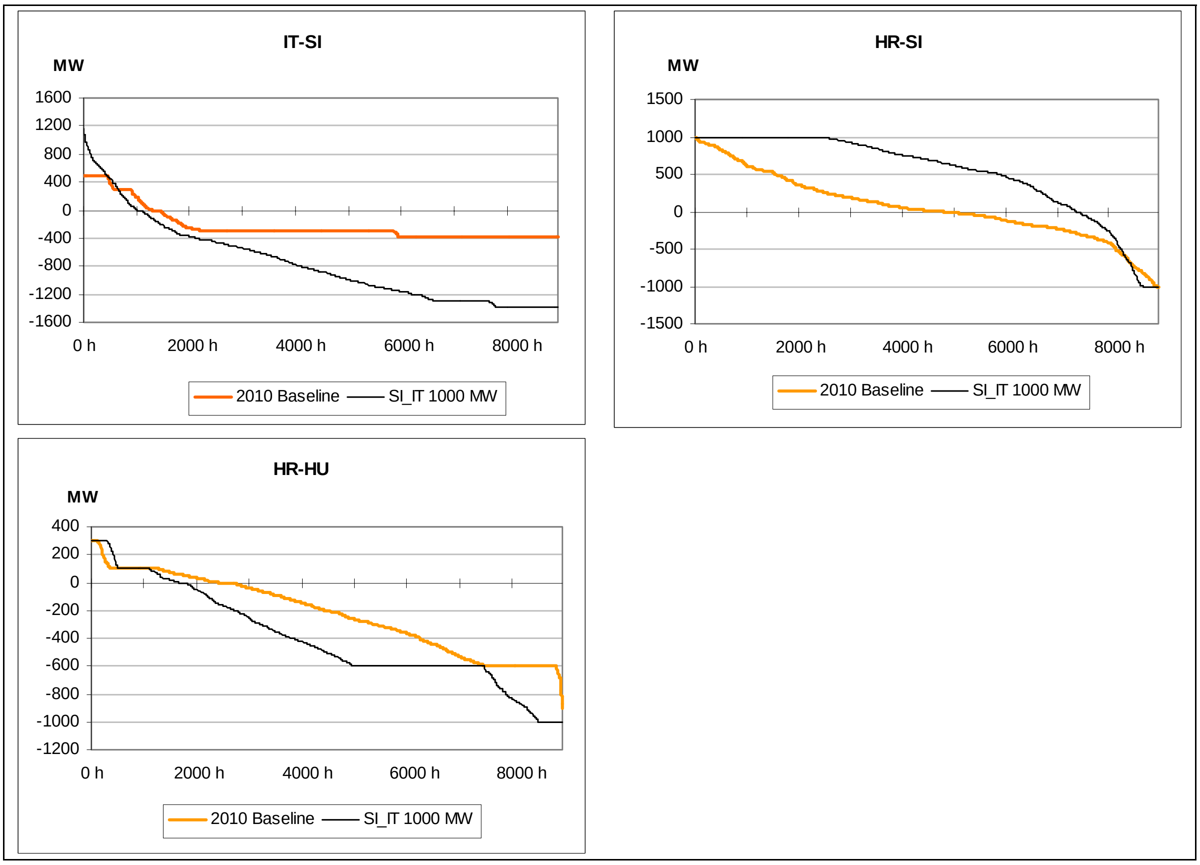


Figure 59: Changing flow patterns for increased capacities SI↔IT (1000 MW)

Increased capacity SI↔HU

Following the analysis of the Slovenian-Italian border, we have studied the case of a new line between Slovenia and Hungary, with a resulting NTC of 600 MW. As illustrated by Figure 60, this new link is utilised for most of the year, but hardly ever congested. In addition, this new link also influences the exchanges between Slovenia and Croatia, as well as between Croatia and Hungary. Combined with the fact that the flow is somewhat evenly distributed to exports and imports, these observations imply that this new link simply creates a new, direct link, even in the absence of prior congestion.

The market simulations show total savings of 12.7 M€/a in production costs and 21.1 M€/a in market payments.

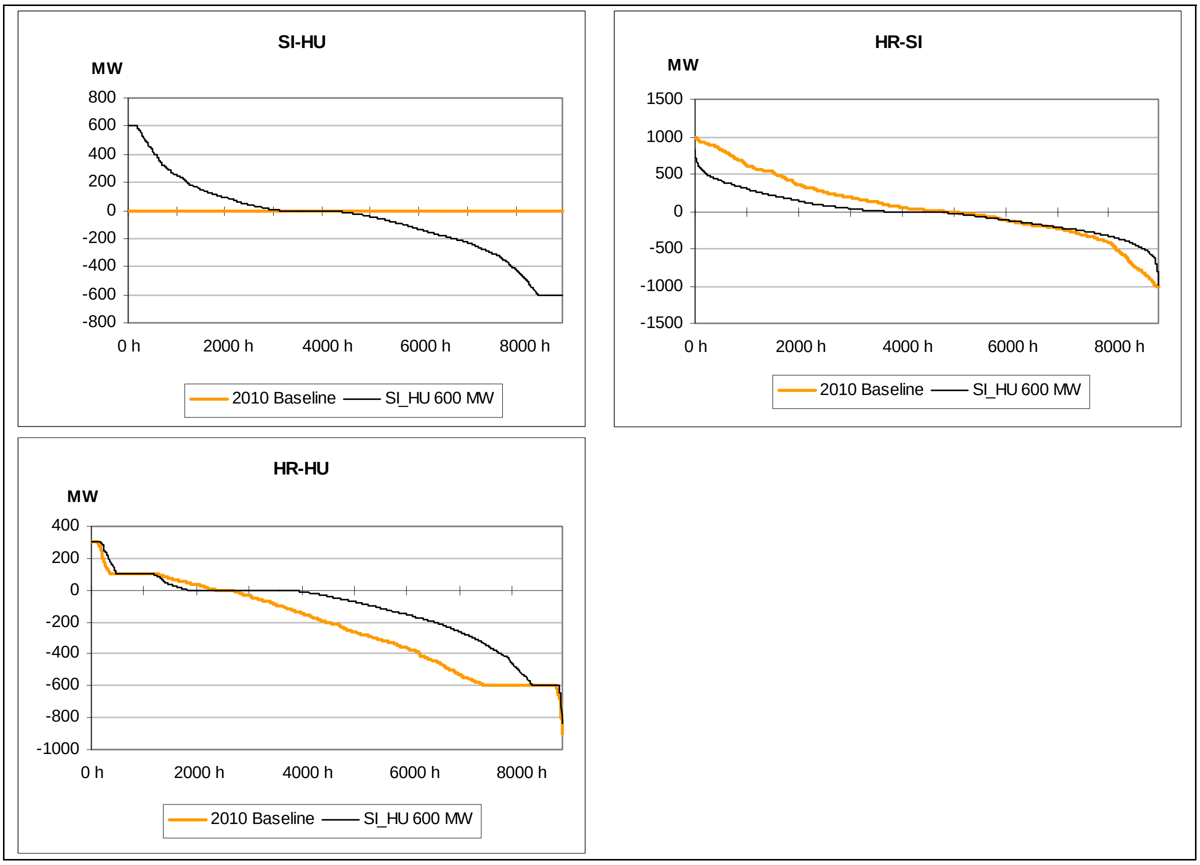


Figure 60: Changing flow patterns for increased capacities SI↔HU (600 MW) Increased capacity HR↔BA

When increasing the transfer capacity between Croatia and Bosnia & Hercegovina, the new capacity shows a high utilisation as illustrated by Figure 61, without however removing the existing congestion at this border. At the same time, these flows partially replace Croatian imports from Hungary and exports from Bosnia & Hercegovina to Serbia & Montenegro. Although there are some minor changes on other borders as well (e.g. BG↔CS, HU↔SK), this investment obviously has a largely local impact, without any significant influence on the EU Member States and Accession Countries.

The market simulations show total savings of 16.7 M€/a in production costs and 89.3 M€/a in market payments.

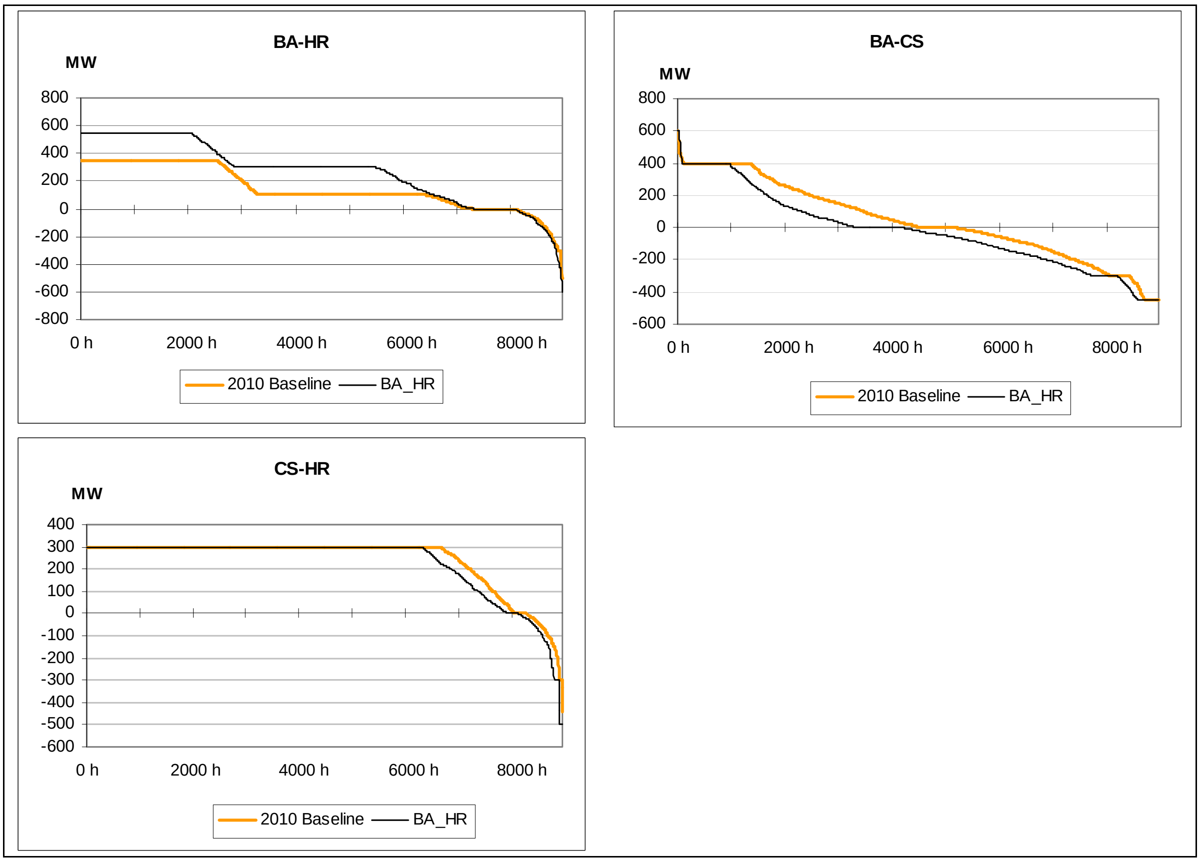


Figure 61: Changing flow patterns for increased capacities BA↔HR (200 MW)

Increased capacity HR↔CS

Our next scenario simulates an increased transfer capacity between Croatia and Serbia & Montenegro. Not surprisingly, this capacity shows a high utilisation since this link was heavily congested before. As illustrated by Figure 62, these flows obviously largely replace previous Croatian imports from Hungary, which in turn imports slightly less from Slovakia.

The market simulations show total savings of 17.7 M€/a in production costs and 102.2 M€/a in market payments.

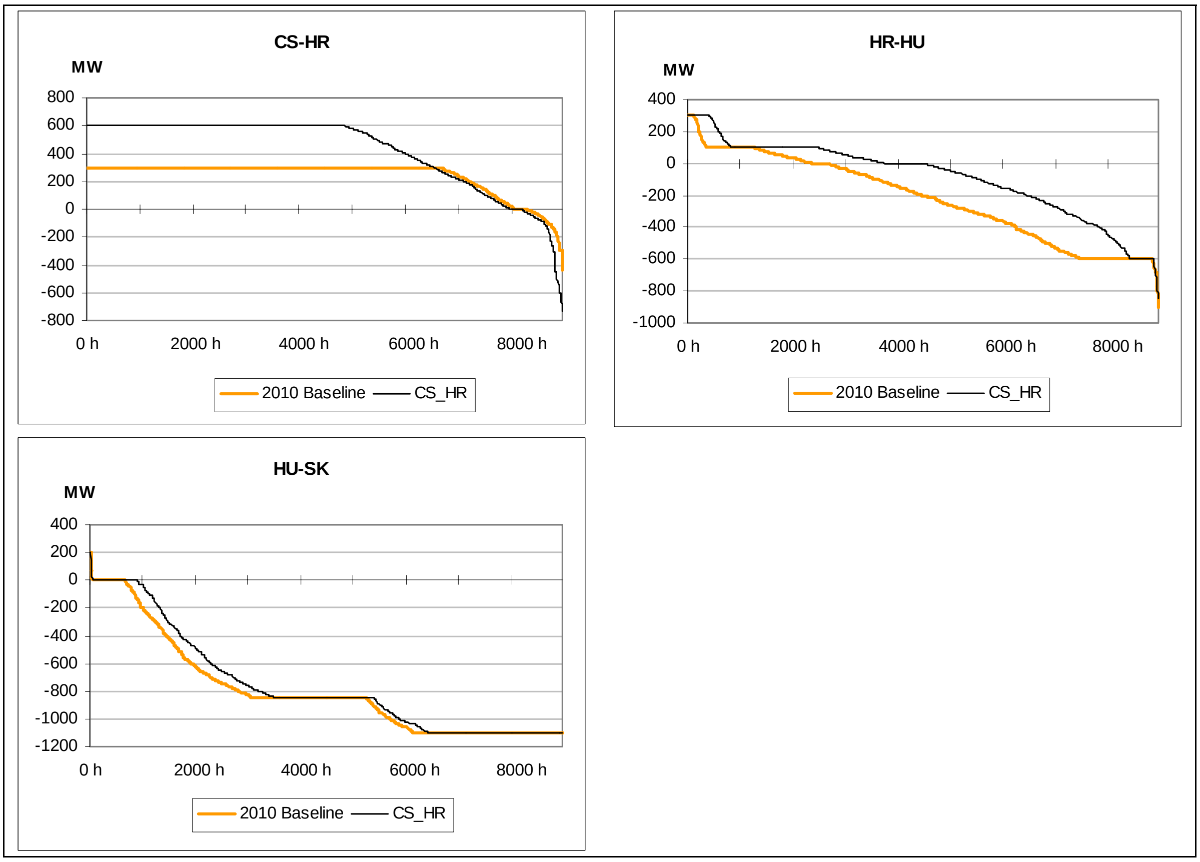


Figure 62: Changing flow patterns for increased capacities HR↔CS (300 MW)

Increased capacity BA↔CS

As a third project outside the core study countries, we have also considered an increased transfer capacity between Bosnia & Hercegovina and Serbia & Montenegro (Figure 63). However, the only real change relates to this border itself where the congestion disappears. Although this allows increased exports by Bosnia & Hercegovina, the additional exchange of electricity is minimal and corresponds to a small fraction of the added capacity only.

The market simulations show total savings of 11.7 M€/a in production costs and 43.3 M€/a in market payments.

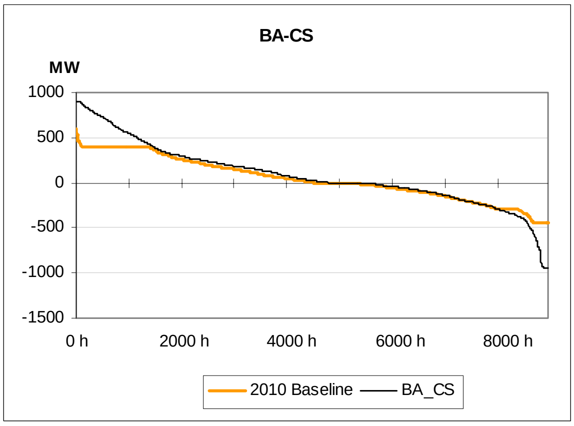


Figure 63: Changing flow patterns for increased capacities BA↔CS (500 MW)

Increased capacity HU↔CS

As final scenario within this group, we have analysed an increased exchange capacity between Hungary and Serbia & Montenegro. As illustrated by Figure 64, the additional capacity is utilised for about 50% of the time but does not remove the congestion from Serbia & Montenegro to Hungary. This increase is compensated for by increased imports of Serbia & Montenegro from Bulgaria and Romania, as well as reduced Hungarian imports from Slovakia.

The market simulations show total savings of 23.9 M€/a in production costs and 73.0 M€/a in market payments.

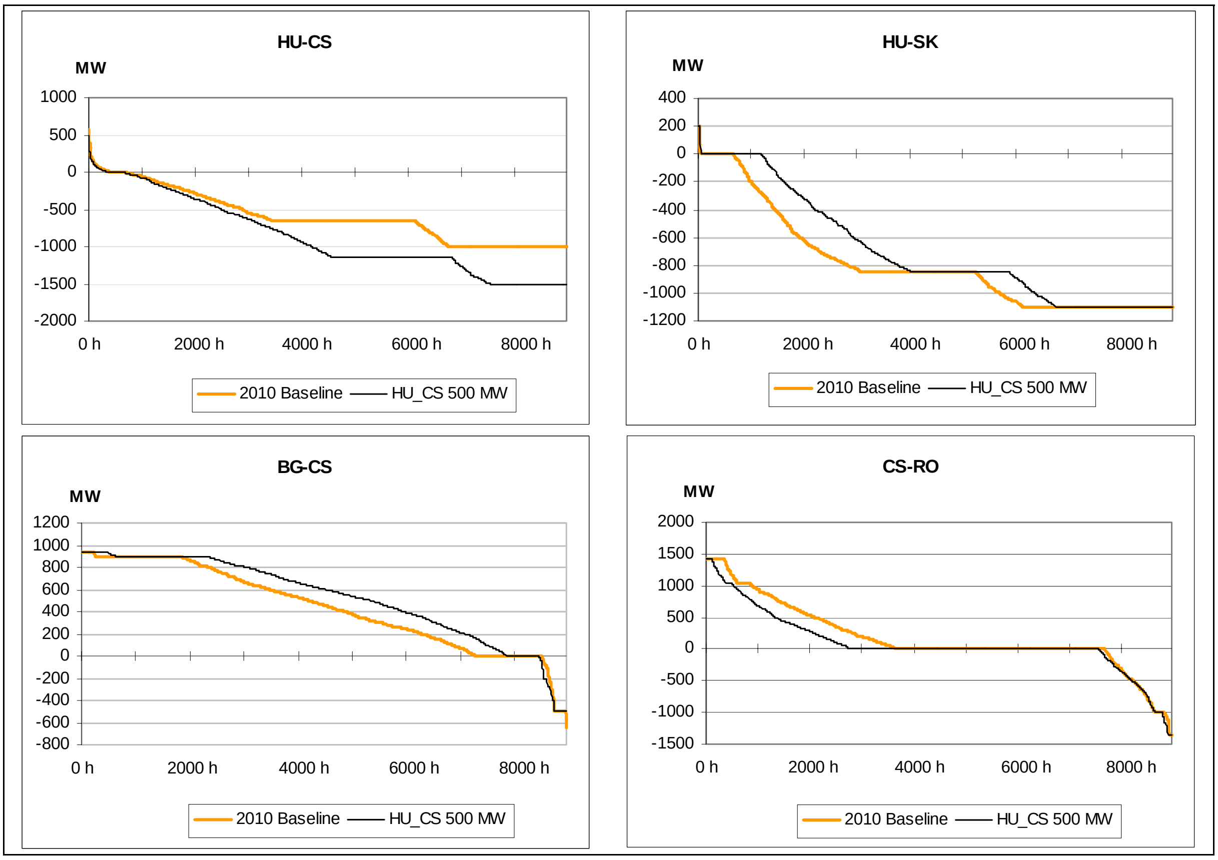


Figure 64: Changing flow patterns for increased capacities HU↔CS (500 MW)

6.3.6 South-Eastern Europe: Serbia & Montenegro, Albania, Macedonia, Romania, Bulgaria, Turkey and Greece

For South-Eastern Europe, we have analysed a total of 9 different variations as summarised in Table 15. Besides exchanges between the Member States and Accession Countries Hungary, Romania, Bulgaria, Greece and Turkey, we have also studied the impact of increased transfer capacities between Serbia & Montenegro, Albania and Macedonia. Since we have been told that there is a major bottleneck for flows from Serbia & Montenegro and Bulgaria to Greece, it seems reasonable to assume that any changes in this area may also be to the benefit of Greece.

Table 15: Estimated change in transfer capacities by projects studied for South-Eastern Europe

Project / Border	NTC (MW) *(New and/or change)* (i)	(ii)	(iii)
a) Increased capacity HU↔RO	+850		
b) Increased capacity CS↔AL	+250		
c) Increased capacity CS↔MK / MK↔GR	+500 / +100		
d) Increased capacity CS↔MK (i), CS↔AL (ii) and MK↔GR (iii)	+500	+250	+300
e) Increased capacity MK↔BG	+500		
f) Increased capacity BG↔GR	+500		
g) Combination of d and f			
h) Increased capacity BG↔TR	+850		
i) Increased capacity GR↔TR	+800		

Increased capacity HU↔RO

The first project for this group of borders considers the construction of a new link between Hungary and Romania, adding an estimated 850 MW in NTC. As illustrated by Figure 65, this additional capacity is only utilised during those times where the existing link was congested before. The average utilisation thus remains relatively low, and the border still remains congested for about 2000 hours a year. The additional imports from Romania are largely compensated for by a corresponding reduction of Hungarian imports from Slovakia. Similarly, a part of the additional Romanian exports to Hungary comes from increased Romanian imports from Bulgaria. At all other borders, this new project has a very minor impact only.

The market simulations show total savings of 55.1 M€/a in production costs and 65.6 M€/a in market payments.

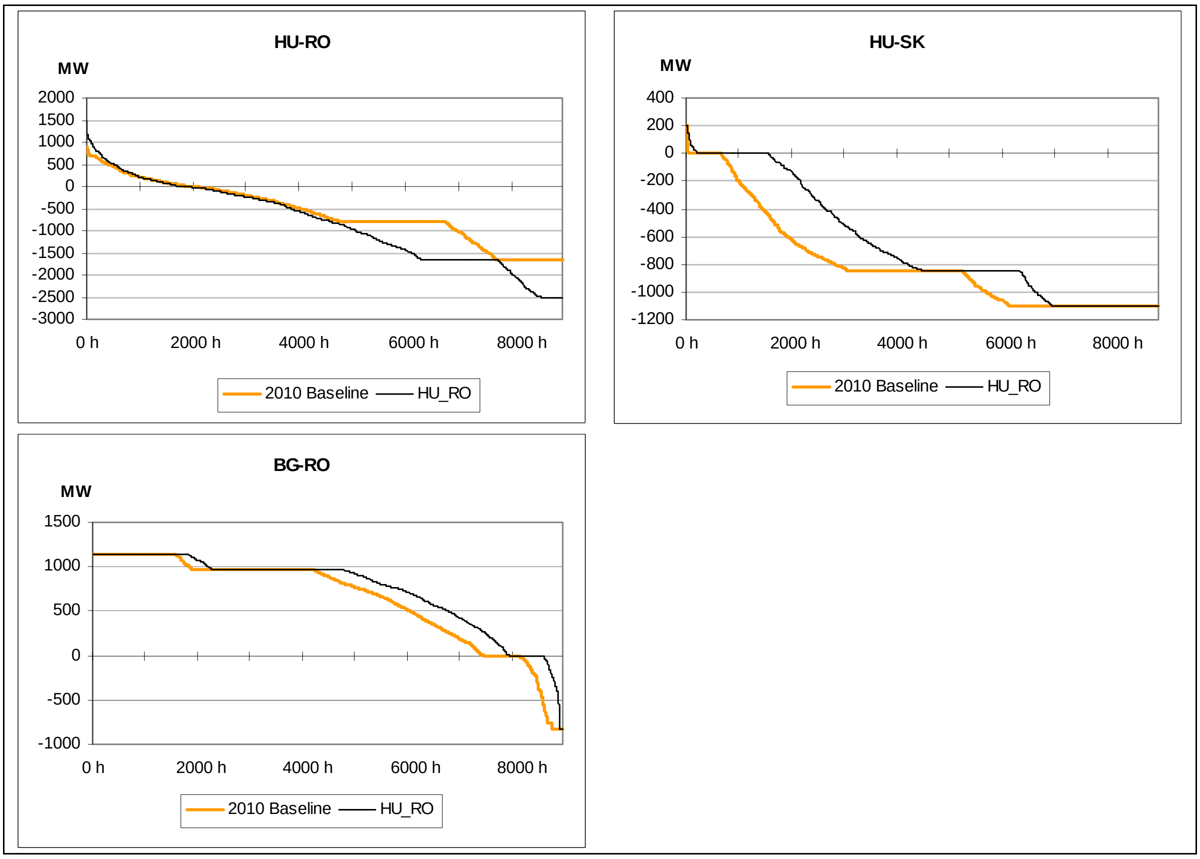


Figure 65: Changing flow patterns for increased capacities HU↔RO (850 MW)

Increased capacity CS↔AL

Secondly, we have studied a 250 MW increase in NTC from Serbia & Montenegro to Albania. As Figure 66 shows, this additional capacity is almost fully utilised but still leaves this border congested for most of the year. A considerable amount of this increased flow is obviously used for increased exports from Albania to Greece. Similarly, part of the additional exports from Serbia & Montenegro are covered by imports from Bulgaria. Besides these major changes, our results also show some minor modifications of the flows between Serbia & Montenegro and its other neighbours, as well as a slight reduction of Macedonian exports to Greece.

The market simulations show total savings of 11 M€/a in production costs and 74.3 M€/a in market payments.

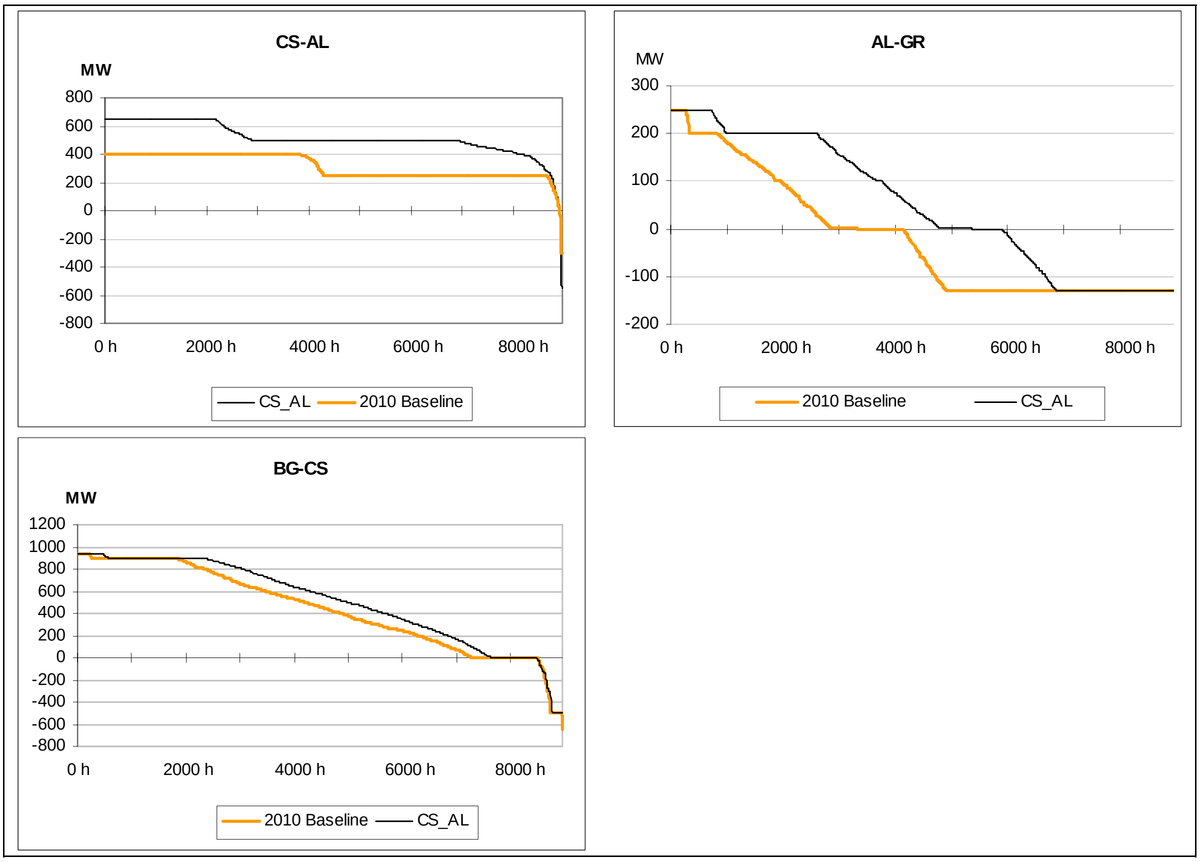


Figure 66: Changing flow patterns for increased capacities CS↔AL (250 MW)

Increased capacity CS↔MK and MK↔GR

Instead of changing the capacity at the border between Serbia & Montenegro and Albania, our next scenario considers the impact of additional transfer capacity between Serbia & Montenegro and Macedonia. Since we have been informed that exports from this area to Greece are largely constrained by insufficient capacities at this border, we simultaneously assume a minor increase in export capacities to Greece. Not surprisingly, Figure 67 shows that the added capacity is utilised to a considerable degree, without however removing the existing congestion. Simultaneously, Albanian exports to Greece are reduced. Similar to the previous case, the additional exports from Serbia & Montenegro are partially covered by imports from neighbouring countries, primarily Bulgaria.

The market simulations show total savings of 51.4 M€/a in production costs and 29.7 M€/a in market payments.

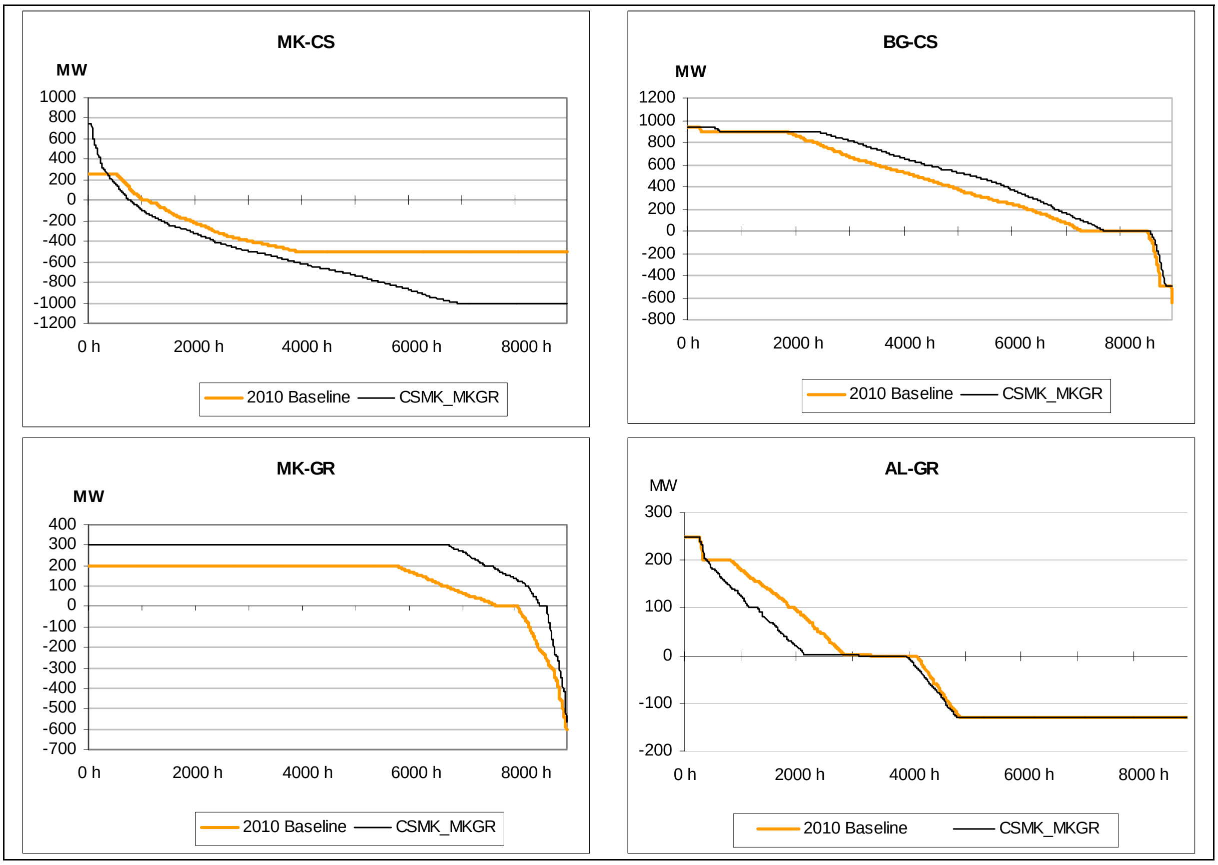


Figure 67: Changing flow patterns for increased capacities CS↔MK (500) and MK↔GR (100 MW)

Increased capacity CS↔MK, CS↔AL and MK↔GR

Next, we have simulated the combined impact of increasing transfer capacities from Serbia & Montenegro to both Albania and Macedonia, i.e. a combination of the two previous cases. Under the assumption that exports to Greece are primarily restricted by congestion within former Yugoslavia, we simultaneously increase our estimate of additional export capacity from Macedonia to Greece to a total of 100 MW. The resulting flow patterns are largely similar to those of the individual cases: The exchange between Serbia & Montenegro, Albania and Greece is comparable to that under case b, whereas the flows between Serbia & Montenegro, Macedonia and Greece show a pattern similar to case c. Despite more than doubling the NTC value between Macedonia and Greece, this border still remains congested for more than 5000 hours a year. Conversely, the added export potential towards Greece ‘restores’ congestion at the border between Serbia & Montenegro and Macedonia if compared to the previous case.[97] Figure 68 furthermore illustrates that

[97] As a matter of fact, it is questionable whether realisation of new transmission investments between CS and AL, and between CS and MK would result in an increased NTC value from Macedonia to Greece

Serbia & Montenegro is no longer able to support these additional southbound flows itself and through imports from Bulgaria. In addition, we also observe increasing imports, respectively decreasing exports, from or to all other neighbouring countries.

The market simulations show total savings of 61.3 M€/a in production costs and 74.7 M€/a in market payments.

only, without influencing the individual transfer capacities at both ‘Northern’ borders. This particular has therefore been chosen to analyse the benefits of parallel investments on the most likely transit route, even if some of the additional transfer capacity might also become available between Albania and Greece.

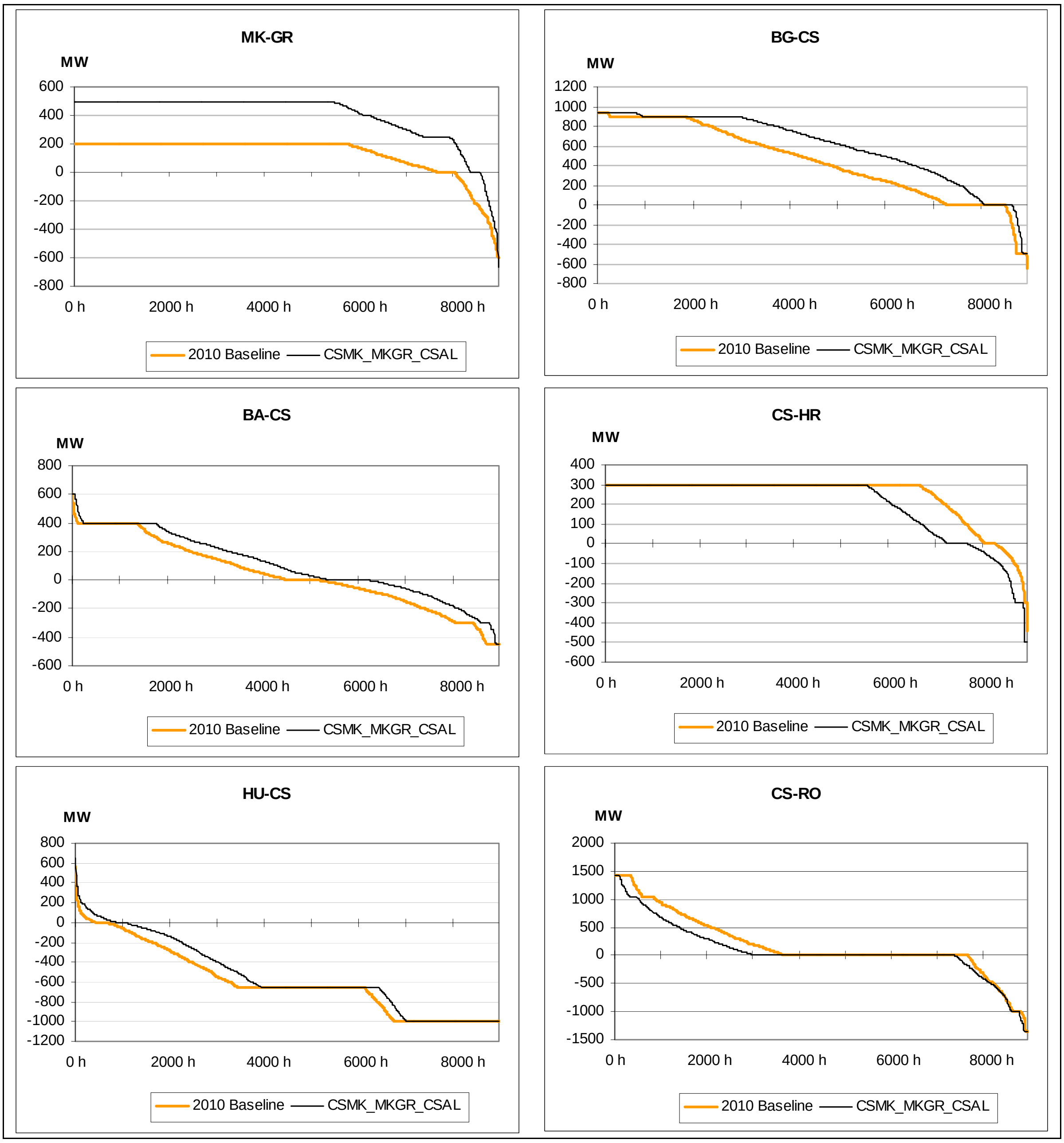


Figure 68: Changing flow patterns for increased capacities CS↔MK, CS↔AL and MK↔GR (500/250/300 MW)

Increased capacity MK↔BG

Figure 69 illustrates some selected results for the case of a new link between Bulgaria and Macedonia (500 MW). The new interconnection has a high utilisation (approx. 75% of the theoretical potential) and is congested for almost half of the time. But only a part of these flows can be considered as truly additional since we simultaneously observe a considerable reduction in power flows from Bulgaria to Serbia & Montenegro and then into Macedonia. Yet, a slight increase in Macedonian exports to Greece indicates that this link helps to make use of the economic export potential to Greece, which had obviously been partially constrained by limited transfer capacities between Serbia & Montenegro and Macedonia.

The market simulations show total savings of 48.9 M€/a in production costs and 23.2 M€/a in market payments.

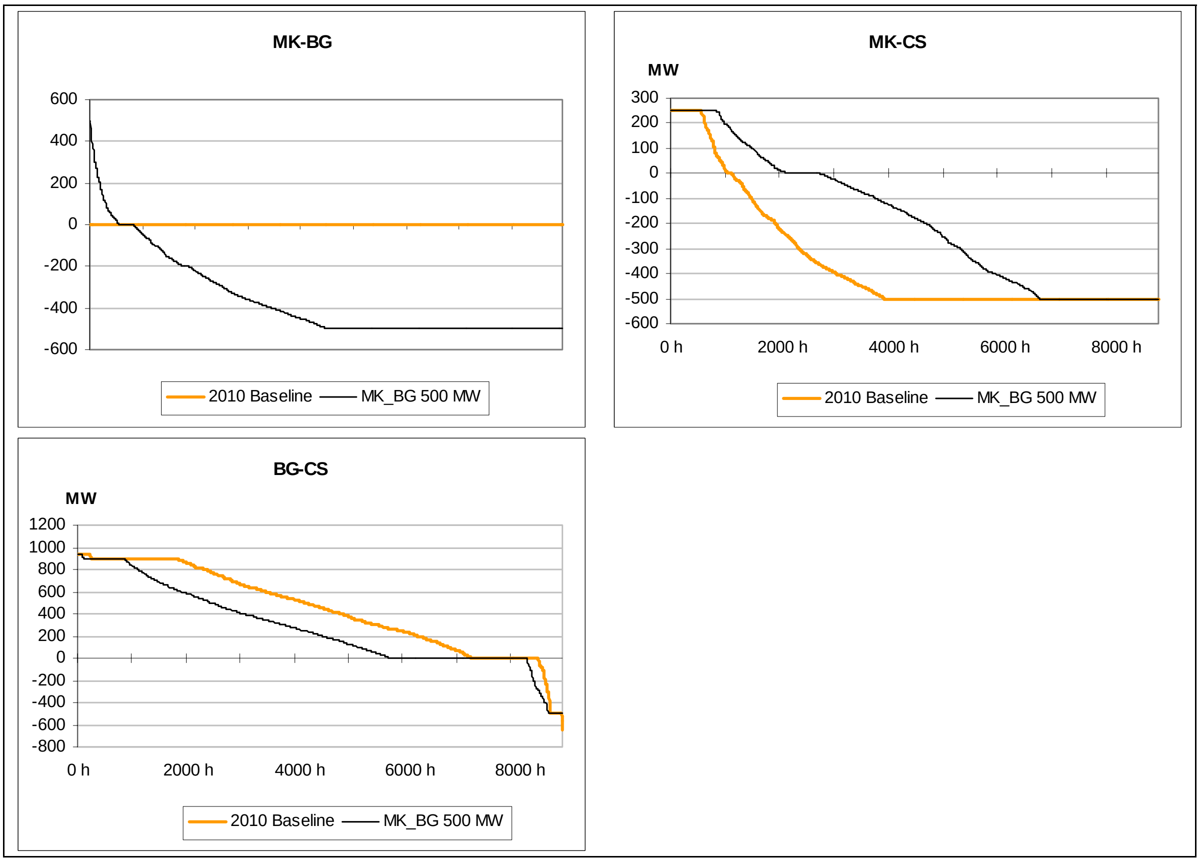


Figure 69: Changing flow patterns for increased capacities MK↔BG (500 MW)

Increased capacity BG↔GR

In Figure 70, we present four selected results of the changes in flow patterns after increasing the NTC between Bulgaria and Greece by 500 MW. Apparently, the new capacity is almost fully utilised, without however really reducing the degree of congestion as the border still remains congested for almost all hours of the year. The huge increase of Bulgarian exports to Greece comes partially at the expense of exports to Serbia & Montenegro as well as to Romania. Simultaneously, we see a slight increase in flows from

Bosnia & Hercegovina to Serbia & Montenegro, and a small reduction in power flows from Albania to Greece.

The market simulations show total savings of 77 M€/a in production costs but an increase of 68.4 M€/a in market payments.

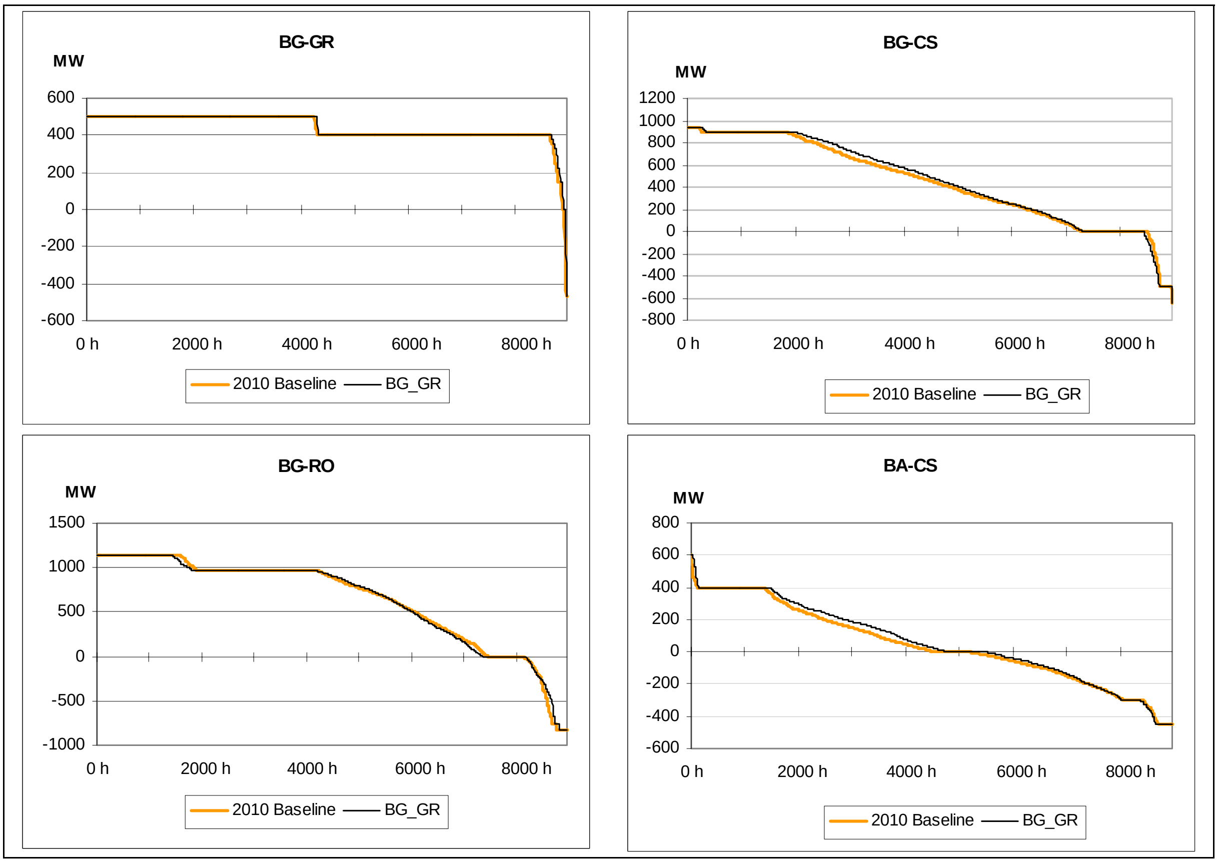


Figure 70: Changing flow patterns for increased capacities BG↔GR (500 MW)

Increased capacity CS↔MK, CS↔AL, MK↔GR and BG↔GR

When combining the previous case with the scenario d (increased capacity for CS↔MK, CS↔AL, MK↔GR), the results can again largely be understood as a simple addition of both cases. Hence, while the flow between Greece and Bulgaria corresponds to the previous case, several other exchanges show a pattern similar to case d (AL↔GR, CS↔AL, CS↔MK, MK↔GR, CS↔RO). In contrast, we observe a major reduction in flows from Bulgaria to Serbia & Montenegro (Figure 71). Similarly, Serbian imports and exports with other countries show a significant increase respectively decrease, with a marked influence even on the Croatian-Hungarian border. Thus, this scenario has a substantial impact also on a regional level.

The market simulations show total savings of 93.2 M€/a in production costs and 115 M€/a in market payments.

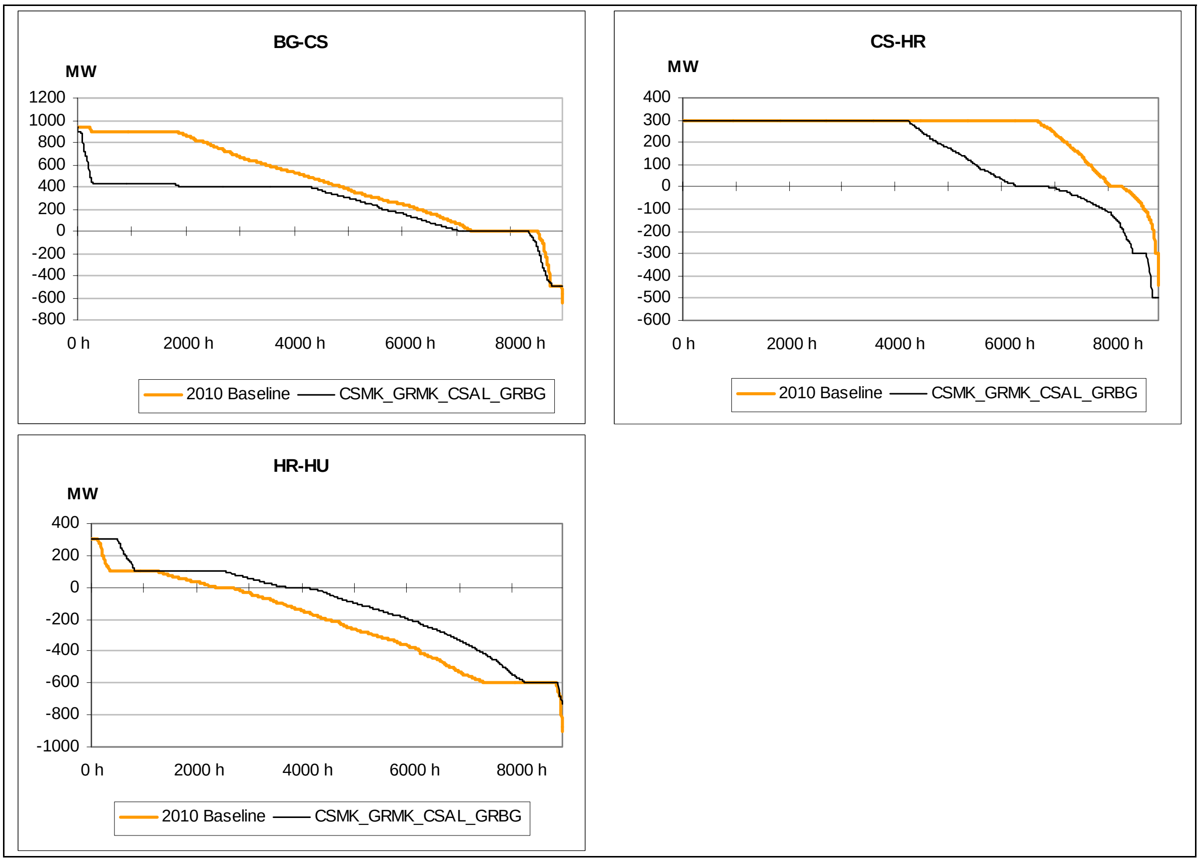


Figure 71: Changing flow patterns for increased capacities CS↔MK, CS↔AL, MK↔GR and BG↔GR (500/250/300/500 MW)

Increased capacity BG↔TR

The last two scenarios in this group consider power exchanges with Turkey. First, we simulated the free use of the existing link between Bulgaria and Turkey. As illustrated by Figure 72, the interconnector capacity is almost fully utilised, largely for exports to Turkey (approx. 6000 h/a) and for imports to Bulgaria in the remaining time. The massive flows come at the expense of reduced Bulgarian exports to other countries, notably to Romania and Serbia & Montenegro. This again influences the exchange between Serbia & Montenegro and 3 of its neighbouring countries, namely Bosnia & Hercegovina, Croatia and Macedonia. At the same time, we note reduced exports from Hungary to Croatia, which can be interpreted as a reduced exchange potential due to generally rising prices throughout the region.

The market simulations show total savings of 6.9 M€/a in production costs and an increase of 99.7 M€/a in market payments.

Figure 72: Changing flow patterns for increased capacities BG↔TR

Increased capacity GR↔TR

Finally, we also studied the impact of a new line between Greece and Turkey. Our simulations show that this link is also used up to its maximum capacity for more than 50% of time, but with approx. even flows in both directions (see Figure 73). All other cross-border exchanges remain virtually unchanged. This implies that this new interconnection can be considered to be of a primarily bilateral nature, i.e. without influence on the wider regional market.

The market simulations show total savings of 86.6 M€/a in production costs and 171.8 M€/a in market payments.

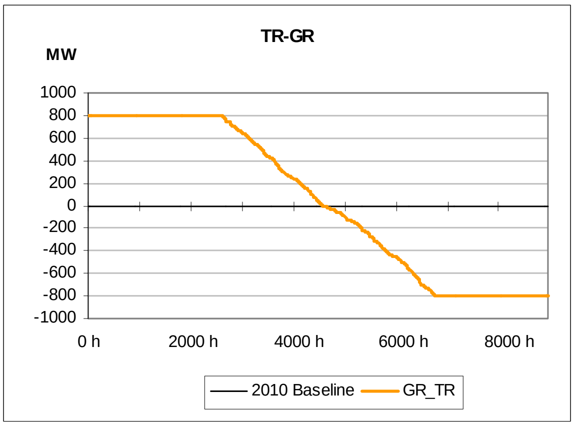


Figure 73: Changing flow patterns for increased capacities GR↔TR

6.3.7 Additional Simulations and Combinations

Finally, we have simulated three additional scenarios for the year 2010 that study the combined impact of different investments, and a potential interconnection of the UPS/IPS system with the UCTE. The corresponding simulations are summarised in Table 16.

Table 16: Additional simulations performed under the study (2010)

Description	
a)	Combined realisation of planned investments
b)	Interconnection of UPS/IPS with Central Europe
c)	Combined realisation of planned investments + Interconnection of UPS/IPS with Central Europe and Baltics

Combined realisation of planned investments (2010)

First, we consider the combined realisation of most planned investments for the 2010 scenario. Naturally, this change results in a multitude of variations, such that we limit ourselves to those cross-border connections that exhibit the most important change in export/import patterns and/or duration of congestion. Generally, we observe substantially increased flows at the borders from Austria to Hungary and Slovenia, from Slovenia to Italy, from Bulgaria to Macedonia, from Bulgaria and Macedonia to Greece, from Slovakia to Hungary, from Estonia to Latvia, and from Latvia to Lithuania. Also, the new interconnections between Finland and Estonia, Slovenia and Hungary, Slovakia and Austria, Turkey and Greece, Turkey and Bulgaria, and Bulgaria to Macedonia all show a high utilisation. At the same time, we also see substantial decreases in congestion at the following borders: Czech Republic and Poland, Hungary to Croatia, Serbia & Montenegro and Romania, and Bulgaria to Romania and Serbia & Montenegro.

Interconnection of UPS/IPS with Central Europe

Then, we consider the interconnection of Russia, Ukraine and Belarus with the UCTE. Generally, we observe that there are reductions in the flows from Croatia to Hungary, Czech Republic to Slovakia, and from Bulgaria to Romania compared to the 2010 base case At the same time, we also see notable decreases in congestion at the border Bulgaria to Romania. Conversely, there are increases in congestion at Croatia to Hungary border.

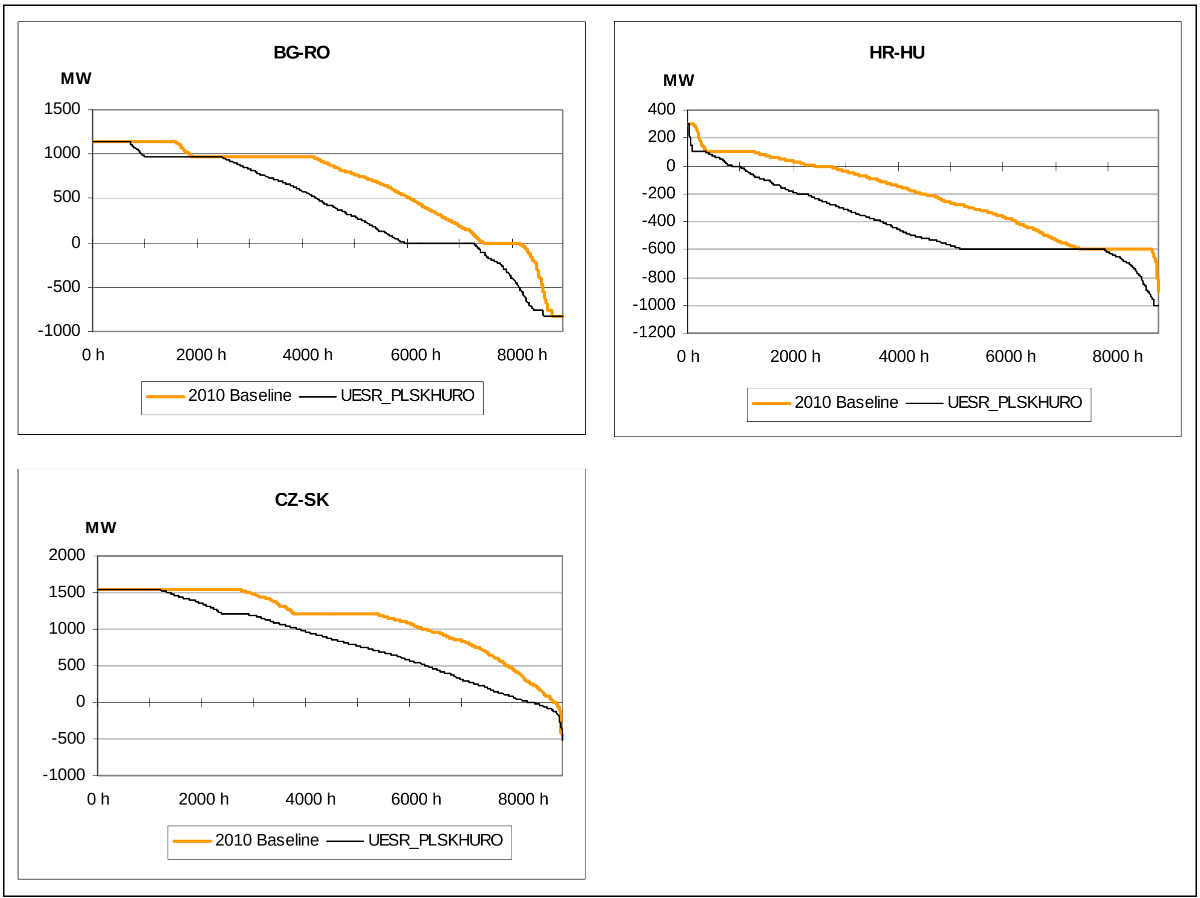


Figure 74: Interconnection of UPS/IPS with Central Europe

Combined realisation of planned investments and Interconnection of UPS/IPS with Central Europe and Baltics

Finally, we consider the interconnection of UPS/IPS in combination with most planned investments for the 2010 scenario. Generally, these market simulations show that many countries change from either being an exporter to being an importer and vice versa. The most notable changes are the flows from Austria to Slovenia (now importer) and from Czech Republic to Germany (importer). Conversely, Hungary is exporting to Romania and Slovakia to Poland. There are substantial increases in flows at the borders from Slovenia to Austria, from Bosnia to Croatia, from Croatia to Slovenia, from Germany to Czech Republic, Slovakia to Poland, from Romania to Serbia & Montenegro, and from Hungary to Slovakia and Serbia & Montenegro. Conversely, there are decreases in flows from Latvia to Estonia. Also, the new interconnections between Finland and Estonia, Slovenia and Hungary, Turkey and Bulgaria, and Bulgaria to Macedonia all show a high utilisation. At the same time, we also see substantial decreases in congestion at the following borders: Czech Republic and Austria, Italy and Austria, Austria and Hungary, Austria and Slovenia, Bulgaria and Greece, Bulgaria and Romania, Croatia and Hungary, Croatia and Slovenia, Germany and Poland, Italy and Slovenia, Macedonia and Serbia & Montenegro, Czech Republic and Poland, Hungary and Romania, Hungary and Slovakia, Serbia & Montenegro and Croatia and Hungary and Serbia & Montenegro.

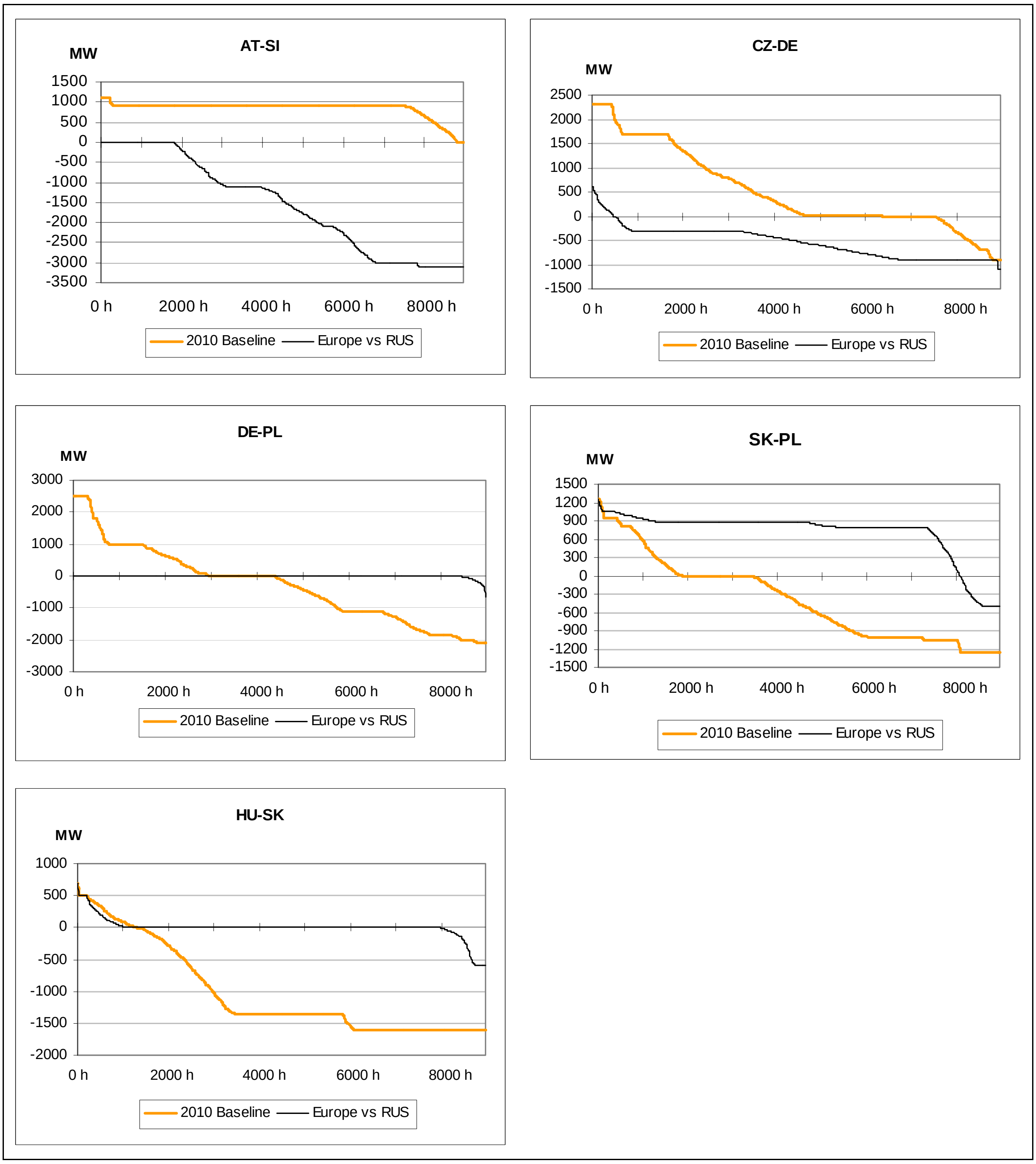


Figure 75: Combined realisation of planned investments and Interconnection of UPS/IPS with Central Europe and Baltics

6.4 Cost-Benefit Analysis

6.4.1 *Summary of Project Benefits*

In this section 6.4, we combine the results of sections 6.2 and 6.3 and compare the estimated benefits of interconnections with their costs. For the assessment of benefits, we utilise both measures that have been in section 6.3.1 above: First, the savings in annual production costs, and secondly, the savings in market payments, i.e. those savings enjoyed by consumers. Both of these measures are compared against the annualised costs determined in section 6.5.

6.4.2 *Baltic States*

Figure 39 shows the difference between benefits and costs for those projects in the Baltic States that have been investigated in this study. Starting with the connection from Finland to Estonia, the results of our study do not really support the business case for this new 350 MW DC cable, which is already in its tendering phase. More precisely, the annual costs of this connection, estimated at 17 million Euro/year (± 40%) will not be covered by 6.7 million Euro/year (± 10%) in annual benefits based on production costs. One could argue that, based on the comparison with benefits based on market payments, there is a sound business case for the Estlink 350 MW cable. However, in our opinion any project should preferably at least be paid back from its savings in production costs. Therefore, we consider these results as inconclusive and do not see a strong business case for this new connection.

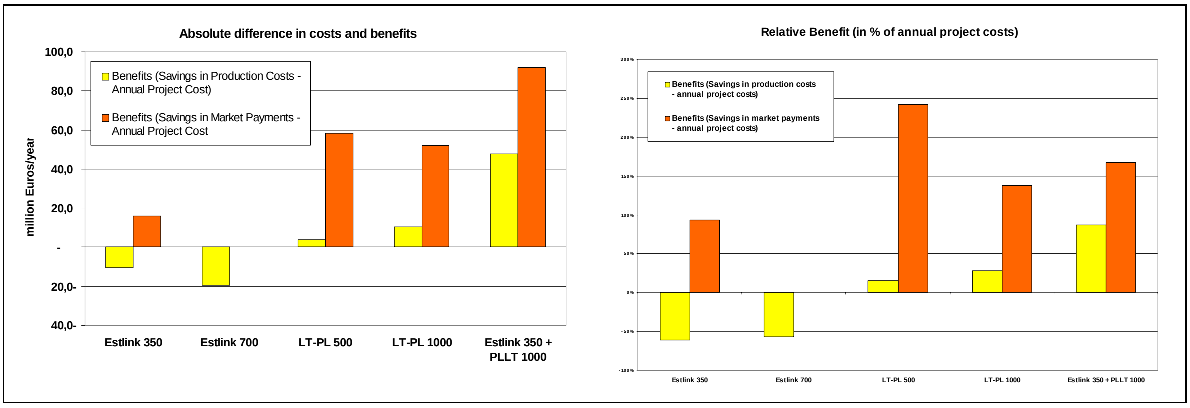


Figure 76: Cost-benefit assessment for selected projects in the Baltic States

Based on this assessment, it follows that the profitability of a second 350 MW connection between Finland and Estonia may be equally questionable. This judgement is confirmed by Figure 39, which shows overall benefits to be further reduced. These results do certainly not support the case for investing into a second 350 MW link between Finland and Estonia.

In contrast, the planned connection between Poland and Lithuania appears rather positive on first sight. While the costs of this investment are just about covered by the savings in production costs, the market-based assessment shows substantial overall benefits. Moreover, when built in combination with the (first) 350 MW link from Finland to Estonia, the overall savings in production costs increase to some 102.5 million Euro/year. Hence, there seems to be a case for realising both investments in combination. However, there is one important caveat: Our cost calculations do not include additional reinforcements that will be necessary especially in the Polish network if this investment is realised. It is however clear to us that, in order to transport 1000 MW from the Northeast to the South and West of Poland, major investments in the Polish network are required. These extra costs could easily amount to several hundred million Euros, a corresponding increase in annual costs. Considering the substantial uncertainty related to the net benefit between the relatively high costs of the project (estimated at 54.9 million Euro/year, ± 40%) and the savings in production costs (103 million Euro/year, ± 30%), the remaining margins are getting rather small. As a result, we are not fully convinced of the economic feasibility of this project and suggest that the Poland-Lithuania connection should not be of the highest priority.

6.4.3 North Central Europe: Czech Republic, Slovakia, Poland and Germany

As discussed in the first part of this chapter, flows in North Central Europe are heavily influenced by the production of wind power plants in Germany and the required shifts in generation to compensate the unavoidable fluctuations in the output of wind power plants. Future NTC values will thus largely depend on further development of wind power plants in Germany as well as Poland in the coming years. It is therefore difficult to provide for an accurate estimation of the increase in NTC due to investments in cross-border capacity. However, based on some assumptions, we have studied trends, which could logically be the result of possible investments in this region.

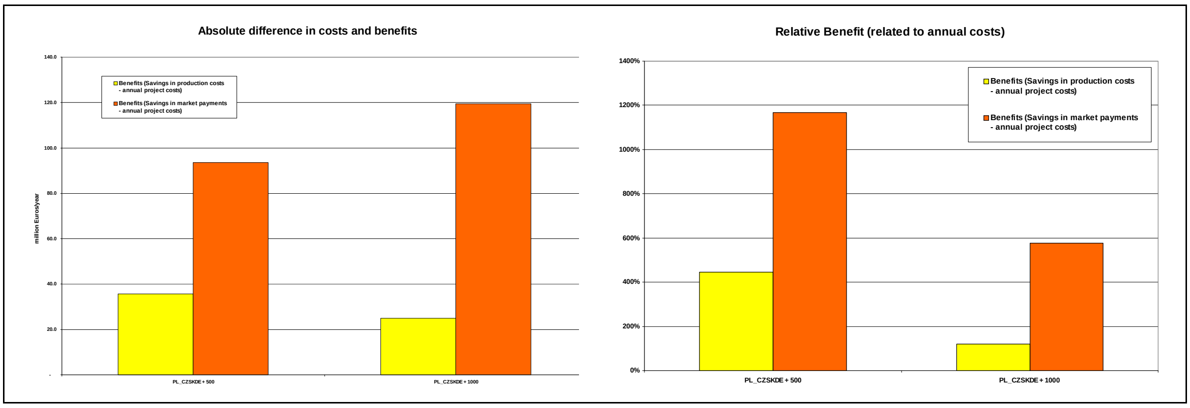


Figure 77: Cost-benefit assessment for selected projects in North Central Europe

We have studied the impact of two investments in this region. As the most likely investment in this region, we have considered the reinforcement of the cross-border connection between Poland and Slovakia by building a new double circuit 400 kV-line from Byczyna (Poland) to Varin (Slovakia), with annual costs of some 8 million Euro (± 30%). We assumed conservatively that this new connection would add 500 MW to the NTC between Poland on one side, and Slovakia, the Czech Republic and Germany on the other side.[98]

The left part of Figure 77 compares the costs and benefits for this connection. Clearly, the benefits of 44 million Euro/year (± 30%, based on production costs) are far higher than the costs of this connection, namely, 8 million Euro/year (± 30%). Taking into account the conservative estimation of 500 MW, we believe that this reinforcement would generate savings for both generators and customers. Therefore, we recommend starting detailed (scenario) studies on this cross-border reinforcement, in order to obtain a more accurate estimate for the resulting increase in NTC.

The right part of Figure 77 shows the costs and benefits after a second investment is added to the new double circuit 400 kV-line from Byczyna (Poland) to Varin (Slovakia). In this case, we have chosen the upgrading of the existing 220 kV-line Neuenhagen (Germany)-Vierraden (Germany) - Krajnik (Poland) to a 400 kV-line. We assume, for the same reasons as before, an NTC increase of 500 MW. This NTC increase only leads to an increase in savings (based on production costs) of around 1.8 million Euro/year, compared to the case where only Byczyna (Poland) to Varin (Slovakia) is built. Total costs however increase by 20.7 million Euro/year (± 30%), such that the incremental benefit of this

[98] Depending on internal reinforcements in both the Polish and Slovakian transmission networks and the developoments regarding wind in mainly Germany could easily lead to higher increases of NTCs by this investments. As we suggest additional more detailed feasibility studies before investing in this connection, we consider the chance low that the connection will be constructed when the NTC increase will be lower than 500 MW.

additional investment becomes negative. These observations clearly do not support realisation of this project.

6.4.4 Central Europe: Austria, Czech Republic, Slovakia and Hungary

As discussed before, the insufficient capacity between Northern and Southern Austria has a major influence on the entire region. Based on an conservative estimate, the planned internal connection between Kainachtal and Südburgenland in Austria will add at least 500 MW in NTC between Austria and Slovenia, as well as between Austria and the Czech Rupublic/Hungary. The savings in production costs alone of this planned link thus amount to 112 million Euro/year (± 30%). If we take less conservative assumption of 1000 MW for both borders, overall savings increase to 139 million Euro/year (± 30%). Although this connection represents a purely internal reinforcement, it should thus be considered of the highest priority for the IEM.

Depending on the realisation of the Kainachtal – Südburgenland and St. Peter – Tauern lines, our simulations result in entirely different results for different projects. In the following, we always describe both situations. At the same time, it should be considered that the planned lines between Kainachtal - Südburgenland and St. Peter - Tauern are also essential for mitigating internal congestion between the Northern and Southern parts of Austria.

Before realisation of Kainachtal - Südburgenland and St. Peter - Tauern

Figure 78 shows three different situations, in which the savings in production costs are higher than the investments into the network. The left bar reflects the results of adding a second circuit to the existing connection from Slavetice (Czech Republic) to Dürnrohr (Austria). Since the towers of this connection are already prepared for a second circuit, this reinforcement is rather cheap, annual costs amount to 1.8 million Euro/year (± 30%). Although the NTC will only be increased in summer by 200 - 300 MW, the annual benefits of 40 million Euro/year (± 30%) are far higher. Consequently, we suggest prioritising this investment, irrespective of the progress on the Kainachtal - Südburgenland and St. Peter - Tauern lines.

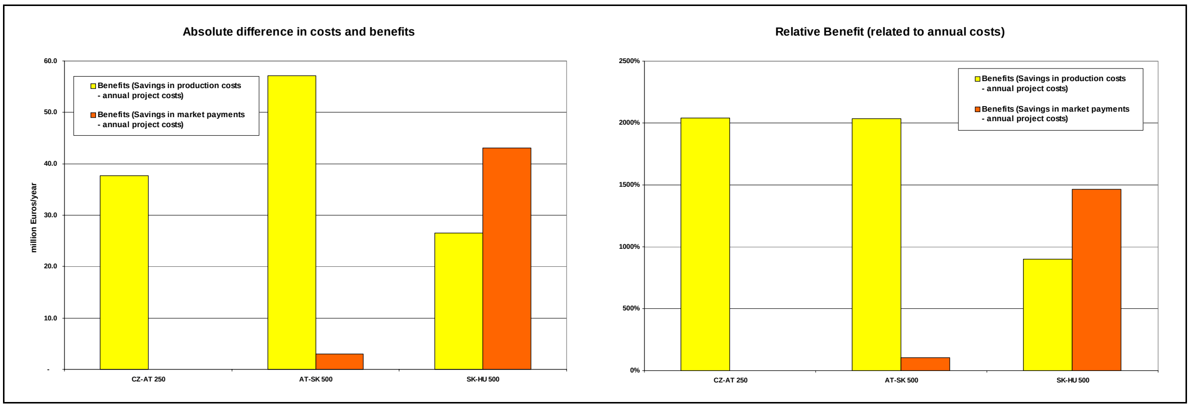


Figure 78: Cost-benefit assessment for selected projects in Central Europe, without the connections Kainachtal - Südburgenland and St. Peter - Tauern (Austria)

The second situation we studied was an increase of 500 MW, achieved through a new connection between Austria and Slovakia. Due to the congestion within Austria, it is rather questionable whether a direct connection between Austria and Slovakia would really add any capacity to the NTC. Therefore, our assumptions for studying this option are likely too optimistic. Furthermore, even if the assumption are assumed to be realistic, our simulations show that the link is used mainly for exports from the Czech Republic to Slovakia, via Austria. However, we are not aware of any current congestion at this border (and in this direction). Moreover, we believe that there may be more efficient means of realising the corresponding benefits. Therefore, we do not support a direct connection between Austria and Slovakia without a connection between Kainachtal and Südburgenland.

A connection between Slovakia and Hungary has been studied based on a conservative estimation of an increase in NTC by 500 MW. The savings in production costs of 29.5 million Euro/year (± 30%) are far higher than the annual costs of the investment for a connection from Moldava (Slovakia) to Sajoivanka (Hungary), estimated at 2.9 million Euro/year (± 30%). Therefore, we suggest that an investment in a new link between Slovakia and Hungary should be prioritised, even before the connection between Kainachtal and Südburgenland is realised.

After realisation of Kainachtal - Südburgenland and St. Peter - Tauern

As discussed, adding a second circuit to the existing connection from Slavetice (Czech Republic) to Dürnrohr (Austria) is resulting in benefits before realisation of Kainachtal and Südburgenland. After realisation, this connection will contribute to a larger NTC between Austria and the Czech Republic/Hungary. We have discussed above that an increase in NTC by 500 - 1000 MW between these countries and Slovenia and Austria will increase the benefits from 112 million Euro/year (± 30%) to 139 million Euro/year (± 30%). Taking into accounts its low costs, i.e. 1.8 million Euro/year (± 30%), the second circuit of the line Slavetice (Czech Republic) to Dürnrohr (Austria) will still have a positive influence.

When a 500 MW NTC increase between Austria and Slovakia is realised after the construction of the Kainachtal - Südburgenland and St. Peter - Tauern lines, the extra benefits are 19 million Euros/year. If this NTC increase could be realised by the described project, costing about 2.8 million Euros/year, it should become feasible in economic terms.

6.4.5 South Central Europe: Italy, Slovenia, Croatia, Bosnia & Hercegovina and Hungary

In South Central Europe, we have considered some projects that seem to be quite attractive in economic terms. First, we have studied two versions of the new connection between Udine (Italy) and Okroglo (Slovenia): One double circuit, leading to a 1000 MW increase of the NTC between Italy and Slovenia, and a second solution with only one circuit, resulting in a 500 MW NTC increase. As illustrated by Figure 79, the savings in production costs of 31.6 million Euro/year (± 30%) are significantly higher than the investments costs of 6.3 million Euro/year (± 30%). Although the incremental benefits of the second 500 MW are less, a 1000 MW increase would still result in higher benefits (7.2 million Euro/year) than costs (3.4 million Euro/year). This makes both scenarios beneficial. However, we would like to make two comments here.

First, we have performed this study for the situation without the Austrian connection between Kainachtal and Südburgenland. Afterwards we re-run the simulations for the Slovenia-Italy connections in combination with the Kainachtal-Südburgenland link. In this case, we find that the additional benefits of a 500 MW connection from Slovenia to Italy are decreasing to around 9.7 million Euro. Since this value is close to the costs, we believe that a more detailed analysis is necessary. Secondly, we have to emphasise that Italy is on the border of our study network and that we have not modelled the remaining Italian borders. This means that changes on this border could influence the results.

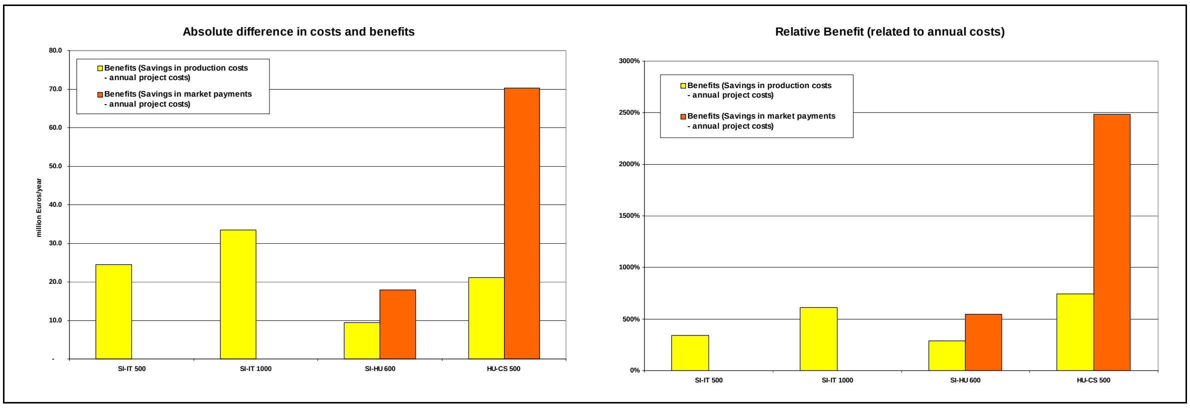


Figure 79: Cost-benefit assessment for selected projects in South Central Europe

Currently, no direct connection between Slovenia and Hungary exists. However, in Figure 79 shows that a connection will be feasible, with costs of 3.3 million Euro/year (± 30%) and benefits of 12.7 million Euro/year (± 30%).

A third project in South Central Europe that has been investigated is the connection between Pécs (Hungary) to Sombor (Serbia). Although the 500 MW is a (conservative) estimation, the difference between the benefits of 23.9 million Euro/year (± 30%) and the costs of 2.8 million Euro/year (± 30%) is really large. Realisation of this link between Pécs (Hungary) to Sombor (Serbia) should thus receive a high priority. Although we have not studied this variant, we believe that the (alternative) connection between Pécs (Hungary) and Ernestinovo (Croatia) would result in similar benefits.

Our studies conclude that investments in former Yugoslavia and Albania are resulting in cost-savings, however mainly within these countries. The influence of these investments on EU countries (including Bulgaria and Romania) is limited. They are thus not critical for the Internal Electricity Market, such that we have refrained from a more detailed analysis.

6.4.6 South Eastern Europe: Romania, Bulgaria, Turkey and Greece

The intended investment in the connection between Romania and Hungary result in savings in production costs of 55.1 million Euro/year (± 30%) but costs only 7.2 million Euro/year (± 30%). It is clear that this investment is feasible and should receive a high priority.

The same applies for a connection between Bulgaria and Greece. According to our simulation results, this connection will be highly beneficial as well. However, when the reinforcements between Serbia and FYROM, Serbia and Albania, Macedonia and Greece are taken into account, the savings in production costs will reduce by more than 50% to 31.9 million Euro/year (± 30%). This is however still significantly more than the costs of around 5 million Euro/year (± 30%). This makes the investment in the connection from Maritsa East3 (Bulgaria) to Filippi (Greece) very recommendable.

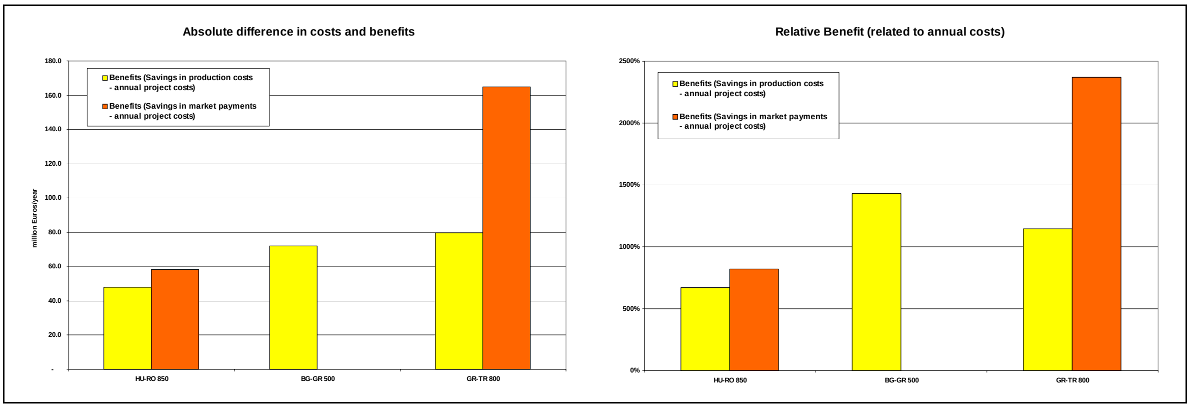


Figure 80: Cost-benefit assessment for selected projects in South Eastern Europe

The same conclusion applies to the case of a connection between Greece and Turkey. However, while our simulations show that the connection will generate significant benefits, we should mention that over 90% of the benefits of 87 million Euro/year (± 30%) will likely occur in Turkey. Given that we have studied the Turkish market in less detail, we recommend that this link to be pursued with limited priority.

6.5 Overall Assessment of Proposed Network Extensions

Based on the detailed assessment of the costs and benefits of individual projects in the previous chapter, this section starts out by summarising our main conclusions for the overall net benefits of each project under study. Thereafter, we use this information to establish an indicative list of priorities for these projects.

In summary, our cost-benefit analysis allows to draw the following conclusions:

- Baltic States:
    - There does not seem to be a strong business case for building a subsea cable between Finland and Estonia. However, the link would serve a wider purpose as it would connect two regions of the IEM, namely the Baltic States and Scandinavia, and could therefore provide additional security of supply to the Baltic States. Moreover, this project is already in its tendering phase such that we assume it to proceed.

- Even after realisation of the first connection between Finland and Estonia, construction of a second 350 MW link is unlikely to be beneficial. We do thus not currently see a business case for this project.
- The investment in a 1000 MW connection between Poland and Lithuania could generate benefits, especially when considering the expected realisation of the Estlink cable. However, it may only be possible to fully exploit these benefits after substantial investments in the Polish transmission grid have been made, such that we would not foresee realisation of this project until after 2010. Moreover, when taking account of the additional reinforcements in Poland, the remaining net benefits are within the accuracy of our results. At the same time, though, the planned link would enable the coupling of two parts of the IEM that are so far without any physical connection. Amongst others, this might also be to the benefit of security of supply in the Baltic region. This project may therefore require further analysis but should only be given medium priority.

- Czech Republic, Slovakia, Poland and Germany
  - An increase in NTC between Poland and its neighbours Germany, the Czech Republic and Slovakia can generate substantial benefits. A considerable share of these benefits can possibly already be realised with limited costs. In practice, we recommend studying the detailed consequences of a connection between Byczyna (Poland) and Varin (Slovakia), in order to obtain a better estimate of the resulting increase in NTC. If, in line with our assumptions, the results are positive, we suggest that this reinforcement should be prioritised.
  - The addition of a second reinforcement will likely be less beneficial than the first one. We therefore believe that additional reinforcements, e.g. the upgrading of the existing 220 kV-line Neuenhagen (Germany) - Vierraden (Germany) - Krajnik (Poland) to 400 kV-line should not be considered before the planned reinforcements in the Polish network have been realised.
- Central Europe: Austria, Czech Republic, Slovakia and Hungary
  - The internal Austrian connection between Kainachtal - Südburgenland and St. Peter - Tauern (North-South) are crucial for Central Europe. The first connection already results in savings in production costs of at least 112 million Euro/year (± 30%) and should be realised with priority.
  - Adding a second circuit to the existing connection from Slavetice (Czech Republic) to Dürnrohr (Austria) is most probably beneficial, before as well as after realisation of the Kainachtal - Südburgenland and St. Peter – Tauern connections. We thus suggest supporting the realisation of this investment.

  - Reinforcements in cross-border capacity between Hungary and Slovakia are likely to result in substantial benefits. Therefore investments in this capacity should be prioritised.
  - Investing into a new connection between Austria and Slovakia is unlikely to result in real benefits before realisation of the Kainachtal - Südburgenland and St. Peter - Tauern connections. We therefore suggest pursuing this project with only a low priority for the time being.
- South Central Europe: Slovenia, Italy, Hungary, Serbia
  - Our study only provides inconclusive support for a connection between Slovenia and Italy. We thus suggest that this link should not receive the highest priority but be subject to further study.
  - Both the connections between Slovenia and Hungary, and between Hungary and Serbia are likely to be beneficial and should receive a high priority.
- South Eastern Europe: Romania, Bulgaria, Turkey and Greece
  - The reinforcement between Hungary and Romania brings significant benefits and should receive a high priority.
  - Similarly, the connection from Maritsa East3 (Bulgaria) to Filippi (Greece) appears as highly recommendable.
  - Although a connection between Greece and Turkey may generate significant benefits, these can be largely attributed to savings within Turkey. Given that this line does not have a wider impact on other countries within the IEM, we believe that this project should only receive a medium priority.

Based on these results, we define three different groups of projects:

- *Highly beneficial projects:* The probability that these projects are bringing more benefits than costs is very high. Realisation of these projects should be considered a priority.
- *Projects with potentially high benefits:* For some projects, our simulations show considerable benefits under certain assumptions, but less under different assumptions. Some of these projects may also render additional benefits, such as the connection between previously isolated parts of the IEM, or may require a more detailed analysis. In our opinion, these projects should be pursued with a medium priority.
- *Projects with minor or questionable benefits:* For some of the projects under study, our simulations have led to inconclusive results. For others, it seems questionable whether these provide any benefits at all. The corresponding projects should thus

only be realised if further analysis confirmed the business case for these investments.

The allocation of different investments to each of these groups is summarised in Table 17. For the projects in the first group, we have additionally compared the total absolute net benefits (savings – costs) and the relative benefits, expressed as the ratio between the total savings in production costs and the annualised costs of the project. Figure 81 summarises the results of this comparison.

Table 17: Prioritisation of Projects under Study

High Priority	
Byczyna (Poland) to Varin (Slovakia)	*Increases the trade possibilities between Poland, Slovakia, the Czech Republic and Germany. Study results show benefits, which are far higher than the costs.*
Slavetice (Czech Republic) to Dürnrohr (Austria)	*Since towers are prepared for a second circuit, this reinforcement is rather cheap. According to our studies, the additional NTC will be used intensively and lead to major cost reductions.*
Moldava (Slovakia) to Sajoivanka (Hungary)	*The market study shows that costs of this project are far lower than the benefits.*
Hevic (Hungary) to Cirkovce (Slovenia)	*Because this project makes us of existing infrastructure, the costs of this project are limited. The market study shows that costs of this project are far lower than the benefits.*
Pécs (Hungary) to Sombor (Serbia)	*The market study shows that costs of this project are far lower than the benefits.*
Nadab (Romania)-Bekescaba (Hungaria)	*The market study shows that costs of this project are far lower than the benefits.*
Maritsa East3 (Bulgaria) to Filippi (Greece)	*The market study shows that costs of this project are far lower than the benefits.*
Requiring further analysis	
1000 MW connection between Poland and Lituania	*The project on it own can be considered as feasible. However, including the major investments required in the Polish Transmission, the feasibility is doubtful. Nevertheless, the wider impact on connecting two parts of the IEM and the potential gains in security of supply for the Baltic States should be considered.*
Udine (Italy) and Okroglo (Slovenia)	*Our study shows benefits, which are in the same order of magnitude as the costs. Secondly, Italy is on the border of our study network, which influences the accuracy of the results. Therefore, we believe that more detailed analysis is needed to confirm the feasibility of this project.*
Filippi (Greece) to Babaeski and Hamitabat (Turkey)	*The study shows that 90% of the benefits will likely occur in Turkey. Moreover, Turkey is on the border of our study network, which influences the accuracy of the results.*
Not leading to cost savings	
Second 350 MW connection between Finland and Estonia (Estlink)	*The results of our simulations do not support a second 350 MW connection between Finland and Estonia; i.e. The costs will be larger than benefits. Assuming previous construction of the first Estlink cable, the incremental gains in security of supply for the Baltic States can be considered minor.*
Upgrading of existing 220 kV-line Neuenhagen – Vierraden - Krajnik (Germany - Poland) to 400 kV	*This project will only lead to increasing NTC after major reinforcements in the Polish Network have been realised. After this, reinforcements on the German-Polish border could be considered.*
Connection between Austria and Slovakia	*Our simulations show that this line will be used for exports from the Czech Republic, via Austria to Slovakia. However, we are not aware of any congestions on the Czech Republic and Slovakia border. Moreover, we believe that there may be more efficient means of realising the corresponding benefits.*

As illustrated by Figure 81, the absolute net benefits are highest in case of the planned link between Maritsa East3 (Bulgaria) and Filippi (Greece). However, it should be noted this value is reduced to 27 million Euro/year, when taking into account the benefits that will already be obtained after realisation of ongoing network reinforcements in former Yugoslavia. If we correct for this, the project Nadab (Romania)-Bekescaba (Hungary) becomes the most beneficial. When comparing the relative net benefits, it is easily visible that the addition of the second circuit on the Slavetice (Czech Republic) - Dürnrohr (Austria) line provides the highest benefits per Euro invested. Conversely, the project Cirkovce (Slovenia) to Hevic (Hungary) appears as the least attractive in both absolute and relative terms.

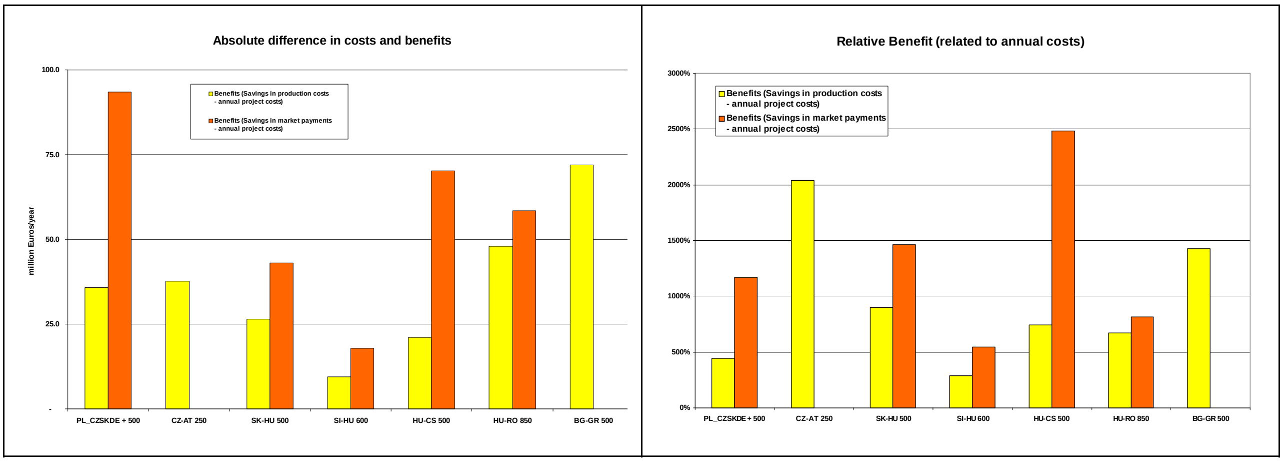


Figure 81: Comparison of the absolute and relative benefits for 'high priority' projects

7 Conclusions and Recommendations

In this chapter, we summarise the main conclusions of this study, separately for each of the three main parts of our analysis. In section 7.1, we present some of the main findings from the market simulations for the years 2010 and 2020, focusing on the consequences for the future development of regional trading patterns and the economic export and import potential. The following section 7.2 deals with the determination and allocation of transfer capacities, i.e. possible 'soft measures' for increasing the cross-border capacities that can be made available to the market. Finally, section 7.3 summarises the results of our analysis of individual projects that have been proposed to mitigate network constraints. As far as possible, we also provide an indicative assessment of possible priorities for different projects, which would endeavour to focus on those investments that may render the largest net benefits to the Internal Electricity Market.

7.1 Future Export and Import Potential

The simulation of the power markets in the Accession Countries, selected Member States and the remaining countries in Central and Eastern Europe has revealed a number of important observations. First, our simulations show a significant room for efficient use of existing transfer capacities. Today, a large part of trading transactions in the study area is still based on base load exchanges on a monthly or even yearly basis. Consequently, the commercial exchanges across many borders still show a 'uniform' pattern, with a somewhat constant use of interconnection capacities in one direction. In contrast, the results of our market model show that there would be substantial scope for a regional and inter-temporal optimisation. Especially for countries with limited peak load capacities, it might be beneficial to rely on the import of relatively cheaper peak load from other countries, possibly in exchange for increased exports during off-peak periods. Consequently, we believe that regulators, market operators and, last but not least, transmission system operators should endeavour to facilitate the exchange of electricity for shorter time intervals, such as on an hourly basis.

Secondly, our simulations have confirmed the general belief that there are typical export and import countries. For instance, it seems reasonable to expect that Italy will remain a potential importer of huge amounts of electricity in the medium term. Conversely, it appears that e.g. the Czech Republic or Estonia will maintain their status as major exporting countries of electricity for the foreseeable future. Furthermore, it appears that the theoretical export and import potential is, in many cases, far higher than the transport capacities currently available. Simulations with an unconstrained network, i.e. with all transfer capacities set an infinite value, sometimes show exchanges of many thousand MW that would be economically desirable. It would certainly be wrong to assume that such extreme potentials could ever be fully realised. However, this observation does show that the existing import and export potential, based on differences in production costs, is currently used to a limited degree only. At least in theory, there is thus economic scope for considerably higher commercial exchanges of electricity.

Another important conclusion from our market simulations is that these export and import potentials, and the resulting regional flow patterns, are generally quite robust to changes in important variables, such as the future generation structure, price developments, or the speed of general economic development. For most of the scenarios that we have used for sensitivity analysis, which we believe to represent a rather large range of possibilities, regional flow patterns show only minor variations. This indicates that the future development of efficient cross-border flows is subject to limited uncertainty at least for the next decade. This conclusion is however subject to the assumption that electricity production and trading will generally approach towards the most economic, i.e. the least cost dispatch if the entire system.

Moreover, we have to emphasise two important caveats. First, our ‘nuclear scenario’ has revealed a considerable sensitivity of our results to the future development of nuclear power. Although the specific cost and size of nuclear power plants, and their uneven distribution throughout the Accession Countries, provide for a reasonable explanation, this result nevertheless indicates that unexpected changes in the future for example the use of nuclear power for electricity production may have a significant impact not only on individual countries, but also on the regional exchange patterns in the IEM. Similarly, all our scenarios have been based on the same type of variation in all countries under study. In contrast, we have not studied cases where e.g. the share of production from hard coal would be significantly increased in country A but decreased in country B, or vice versa. Although such an analysis may provide further insights into the sensitivity of our simulations to corresponding changes, the sheer number of countries to be studied makes it impossible to do so in a consistent and comprehensive manner. We recommend that corresponding changes should be assessed when studying individual projects in more detail.

7.2 Determination and Allocation of Transfer Capacities

Regarding the use the existing transmission infrastructure, we recommend analysing the potential application of special protection system within the UCTE network. This may allow accepting higher line loads, which would otherwise violate the (n-1) criterion. If properly installed, this may result in a significant increase of NTC, especially in otherwise weak and less densely meshed parts of the transmission system. While such schemes are widely used in the former Soviet Union, they are also sometimes applied in some of the countries studied in the report, as well as in Scandinavia or in England and Wales. Hence, we see no fundamental technical problems in using corresponding systems at certain places, especially as a precaution against potential incidents that will only happen with a very low probability. One major advantage is that corresponding solutions do not require any significant investments and will thus almost always be significantly cheaper, and quicker to implement, than any reinforcements of the network. Nevertheless, it needs to be emphasised that the introduction of special protection systems requires a high degree of coordination between all parties involved. Thus, in a meshed transmission network like the UCTE system, the implementation of a corresponding system will thus usually require prior analysis and agreement by all TSOs concerned. Furthermore, it has to be considered that generating units play an important role in special protection schemes, which may be different from their current role as participants in the markets for wholesale energy, reserves and ancillary services. EU and national legislation and procedures should thus support 'special protection system' contracts to be concluded with the generators.

Secondly, we believe that consideration of different thermal limits may provide for another means of making additional, even if limited amounts of transfer capacity available to the market. While most TSOs use constant values throughout the year, lower ambient temperatures may allow for slightly increased thermal limits, and thus TTC/NTC, during the winter months, i.e. at a time when demand for electricity is the highest. We emphasise that transmission line maintenance, which is mainly scheduled in summer months, can hardly be used as reason for not applying higher TTCs in the winter period. Similarly, we believe that double circuit and busbar failures should not generally be taken into account in the TTC/NTC assessment, in order to avoid excessively conservative TTC/NTC values. While this may be justified in certain cases, we recommend that those TSOs who currently consider corresponding failures should check their assumptions accordingly.

Our analysis of the current mechanisms for the allocation of cross-border capacities has revealed considerable scope for improved coordination and transparency. Since the fundamental advantages and drawbacks of different allocation has been the subject of various other reports, we simply emphasise two areas where we see the potential of quickly improving efficiency at no tangible costs. First, we consider the recent example of the new capacity allocation scheme for the borders between Poland, Germany and the Czech Republic as a definitive improvement as it allows for a flexible, market-based allocation of cross-border capacities not only to individual market participants, but also to different borders. This solution has two main benefits: First, one may generally believe that the market will help to determine a more efficient solution than the subjective decision of a single actor, namely the TSO. Furthermore, this approach potentially allows for a higher amount of NTC to be allocated to the market. While a definition of two or more separate capacity products may entail the risk of uneven usage, the simultaneous determination and allocation of the final limits for each of these products avoids this uncertainty. Especially in case of daily auctions, and in this case particularly if combined with an obligation to use, this approach may thus even increase the overall amount of TTC effectively be made available to the market.

Finally, we note that the introduction of this new allocation regime has only been made feasible through a common agreement between all participating TSOs, and the transfer of the exclusive responsibility to a single TSO. Besides, a single allocation procedure reduces the problems associated to the difference in market knowledge that is inevitable in case of different auctions over an extended period of time. We therefore recommend that the TSOs and regulators increase their efforts in developing of one or more truly coordinated regional schemes, with a single, centralised point of allocation.

7.3 Measures to Increase Transmission Capacities

Besides investments into new lines and cables, phase shifters represent another means of mitigating network constraints and increasing the NTC values. The use of phase shifters allows network operators to influence power flows, thus helping to avoid overload on critical connections. Besides the general use of phase shifters, a particular application might be the switching of phase shifters as part of a special protection system. Despite these possible advantages, it needs to be considered that the use of phase shifters usually results in higher (thermal) network losses. Secondly, and similar to the potential application of special protection systems, the use of phase shifters requires close coordination between different TSOs, in order to avoid situations where problems are simply shifted from one part of the network to another.

Investing into network reinforcements, i.e. the upgrading of existing and the construction of new transmission lines and substations, clearly represents the most obvious way of increasing transmission capacities. Most TSOs have therefore nominated specific projects within the framework of the Trans-European Networks. In this study, we have assessed the costs and potential benefits of individual projects, or combinations thereof. As part of the benefit analysis, we have both evaluated the general impact of each project on the regional exchange patterns, i.e. whether a particular investment helped to reduce congestion, and calculated the potential financial savings.

Based on our cost benefit analysis, we have established an indicative ranking of these projects into three different groups, in the order of decreasing priority. Our recommendations for the assignment of different projects to each of these groups are summarised below. Please note that this list does not consider those investments that are already under construction, of where the start of construction is imminent.

7.3.1 Recommended Priority Projects

The projects in the first group represent those investments, which we believe to provide the largest benefits to the Internal Electricity Market. Moreover, it should be feasible to realise most of these projects within a few years. In detail, we suggest to focus on pursuing the following reinforcements:

- Insufficient network capacity especially in the Southern and Western part of the **Polish transmission grid** represents a major source of congestion. In a first step, priority should be given to removing the existing constraints in the Polish grid, namely to complete the planned reinforcements from Dobrzeń to Wielopole, and further on Rogowiec via Trebaczew and Ostrow to Plewiska.
- Our analysis shows that transfer capacities in the region can be increased at limited costs by investing into a new link between **Poland and Slovakia**. Specifically, we recommend to realise the planned link from Byczyna (Poland) to Varin (Slovakia).
- Internal network constraints in the **Austrian transmission grid** in the North-South do not only restrict internal exchanges, but simultaneously are the decisive factor for limited cross-border capacities between Austria, on the one side, and Slovenia, Hungary and the Czech Republic, on the other side. Moreover, continued growth of wind power in the North-East of Austria and the decommissioning of several power plants in Southern Austria are likely to result in further reduced NTC values in the future.
- Irrespective of the internal reinforcement of the Austrian grid, the addition of a second circuit to an existing line between **Austria and the Czech Republic** will result in increased cross-border capacity at limited costs.
- The **Slovakian-Hungarian** border is notoriously congested. Similarly, our simulations show a considerable potential for increased cross-border exchanges.
- Similarly, our analysis shows that a new link between **Slovenia and Hungary** could not only be constructed at limited costs, but would also render substantial benefits to the IEM.
- The borders between **Hungary and Serbia**, and between **Hungary and Romania** both represent links between the former first and second synchronous zones of the UCTE. Our simulations shows that new interconnections between Hungary and the two other countries may result in substantial benefits to the IEM at limited costs.
- Greece imports of electric power are highly congested. Construction of the planned link between **Bulgaria and Greece** would thus render significant savings to the European economy. Furthermore, these benefits are likely to be

further increased by the parallel construction of a new link between Serbia and Macedonia, which is already under progress.

7.3.2 Medium Priority Projects

In this group, we have combined those projects that are likely to provide less significant benefits to the IEM than those from the first group, that are dependent on the prior completion of other investments, or which may still require further study:

- Our cost-benefit analysis provides inconclusive results on the profitability of the planned interconnection between **Lithuania and Poland**, especially when taking into account further reinforcements in the Polish transmission grid that may be required over and above the construction of the interconnection and the new 400 kV line from Matki via Elk to Narew. On the other hand, the combined realisation of this link and the planned cable between Finland and Estonia is likely to provide significant benefits to the IEM. The recent decision for construction of the latter link may thus positively influence this project. However, we do not believe that this new line could be fully exploited before 2010.
- Our analysis shows that the new link between **Slovenia and Italy**, which has been under study for a long time already, would potentially result in considerable benefits especially for the Italian market. However, the real potential will strongly depend on the development at the remaining Italian borders. While we are generally convinced of the advantages of this project, we recommend that this investment be evaluated in combination with other projects at the Italian border.
- Our market simulations show a potentially significant benefit of a new connection between **Greece and Turkey**. However, it should be considered that this link might be primarily used for bilateral exchanges and thus remain without any significant impact on the IEM. Moreover, it appears that the potential savings can largely be attributed to Turkey. We thus recommend that a final decision should be subject to further study.

7.3.3 Other Projects

Finally, we have grouped certain projects that, while being profitable, may still require further study, or that can realistically only be expected after 2010:

- While the reinforcement of the cross-border connection between **Germany and Poland** would enable potential savings for the IEM, these benefits will only become available after completion of some basic internal reinforcements of the Polish power grid.
- Our market simulations show considerable benefits for additional transfer capacities between **Austria and Slovakia**. However, there currently seems to be limited demand as there obviously are sufficient transfer capacities between Slovakia and the Czech Republic. Moreover, we doubt whether a new line between these countries could be fully used without the prior completion of the planned North-South connection in Austria. Conversely, we believe that it should first be studied whether this link would really provide a substantial increase in NTC, especially after a potential upgrading of the Austrian grid, and the interconnection between the Czech Republic and Austria.

Based on our market simulations, there is reason to believe that the proposed new links between Croatia and Serbia, Croatia and Bosnia & Herzegovina, and between Bosnia & Herzegovina and Serbia would have a positive influence on the IEM. However, it seems that these projects are still at a very premature stage. Moreover, they would likely have a limited impact on the Accession Countries only.

8 Appendices

8.1 Appendix A: Market Modelling

8.1.1 Production Simulation Tool PROSYM

The production simulation tool PROSYM is a probabilistic, hourly chronological power market simulation model. The hour-by-hour model allows for the simulation of chronological events, such as start-up times, thermal plant ramp rates, thermal plant up and down times, and hourly spinning reserve constraints. In addition, it allows us to define the available transmission capacities between different market areas, thus making it possible to simulate a constrained generation dispatch. Within PROYSM, the power system configuration is a representation of a scheme of available power units and distribution capacity. In addition, specific modules allow to simulate a multi-area model with given transmission constraints. Most of these characteristics may change every hour of the year.

PROSYM offer different modes of operation to take account of random effects, such as outages. For our simulations, we have used the preferred calculating method for the model, the convergent Monte Carlo method. This method causes carefully distributed outages throughout each period. A unit with an outage rate of *x* % is then available exactly 1-*x* of the time. This allows fast simulations of long periods of time, as considerably less iterations are necessary. This method is tuned to help accounting for the effect of outages at different times of day and seasons of the year.

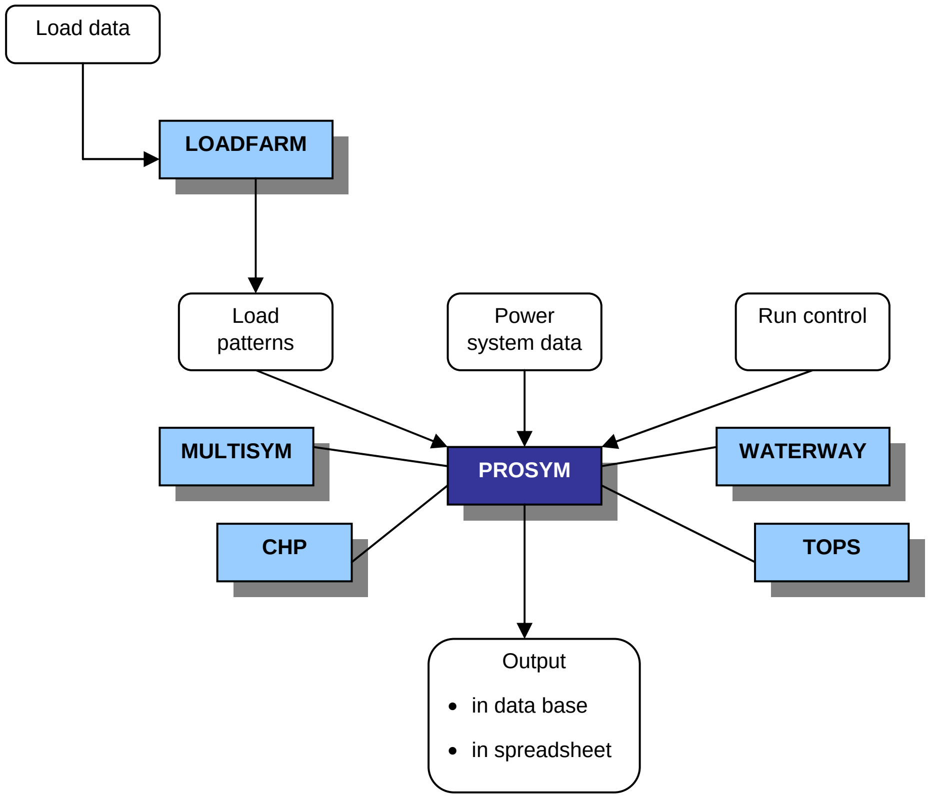


Figure 82: PROSYM tool and its modules.

As illustrated by Figure 82, PROSYM consists of a suite of different modules, which can be combined with the core PROSYM tool. For our study we have added the modules LOADFARM and MULTISYM, whereas we have not used the CHP module, WATERWAY and TOPS.

LOADFARM is the load forecast and record management module, which requires a hourly load file. Moreover, it allows to automatically create future forecasts, based on absolute or relative volume and peak growth. For the purpose of this study, we have however not used this feature. Instead, we have created additional input files for the years 2010 and 2020, which has allowed us to better take account of the different country-specific developments across the region.

MULTISYM is a superset of PROSYM that is able to convert PROSYM into a multi-area model by taking transmission constraints into account. MULTISYM can handle mode independent and connected transmission areas with different topologies. In principle, this module can be combined with the TOPS (Transmission-Oriented Production Simulation) module that gives the full optimal power flow solution. This would however replicate a fully integrated production and transmission market, but does not represent the commercial transmission capacities that are faced by traders in the European power market. We have therefore used a DC load flow model to simulate power flows, based on the (published) NTC values.[99]

Finally, the modules WATERWAY and CHP allow a more accurate representation of hydropower and combined heating plants. Waterway is a short-term hydroelectric simulation and optimization model designed to represent the hourly operation of a network of hydroelectric and non-hydroelectric "stations". The CHP module is designed to optimize heat and power production in one step, while observing the constraints of the conventional system as well as those constraints specific to CHP stations. The use of both models does however result in a drastic increase of modelling complexity, both in terms of input data and with respect to calculation time. We have therefore decided against the use of the two modules for this study, but modelled CHP and hydro differently, as further described in section 3.4.2.

8.1.2 Strategic Bidding Model SYMBAD

SYMBAD is a proprietary model of KEMA Consulting that has been developed to allow for the simulation of strategic bidding in power markets. The model incorporates the game-theoretical background of the Nash equilibrium and is based on the concept of the supply function equilibrium (SFE). The SFE approach suggested by Klemperer and Meyer (1989) lies between Bertrand and Cournot concepts of competition in an oligopolistic market.[100] The SFE approach assumes that, facing uncertain demand, players will compete in both price and quantity (i.e. defining a supply function) rather than competing only on price or quantity. The idea is that, when firms have to decide on their strategy before knowing what the demand will be, they will define an entire supply curve with different prices for different quantities. Klemperer and Meyer showed that, for every point of a given demand function, there exists a so-called Nash equilibrium with a price above the competitive price. The advantage of the SFE approach is its capacity to handle random shocks in demand. Moreover, the SFE concept appears more realistic than “single variable” approaches because it fits well into the bidding rules used in most organized power markets (e.g. pools or power exchanges). It thus allows for a better understanding of bidding behaviour, in particular in markets where market participants bid repeatedly.

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[99] The model also reports losses, but these are only used for reporting and in deciding, from which transmission area it is best to obtain power. The losses are not reflected in actual power produced.

[100] Cournot’s models assume that each firm choose a level of output with respect to the rival’s production decisions (Cournot, 1838). In such a model players compete on quantity. By contrast, Bertrand´s models use the opposite rivalry notions using prices rather than quantity (Bertrand, 1883).

SYMBAD expands the original approach from Baldick et al (2000). Besides introducing piecewise affine marginal cost functions, thus allowing for a more precise approximation of marginal costs, SYMBAD also has the option of defining several demand segments with different demand slopes and non-availability of generation. Based on the marginal costs of different generation units and their allocation to different players, the model creates linear supply functions for each player. This use of affine or piecewise affine supply functions is a precondition for using the linear SFE concept. Compared to the general form of the SFE concept, the major advantage of the SFE model with linear marginal costs is its ability to handle asymmetric companies when there are more than two strategic companies.

Within SYMBAD, the demand function is defined as a linear curve with slope (price elasticity) and characteristic demand. Demand segments are defined in order to recognise the differences in power market characteristics for different periods of the year, such as in demand elasticity and or generation availability. The demand curve is essential for determining the system market price both in the marginal cost case and in the SFE case. An important feature of the demand curve used by SYMBAD is the use of a constant slope for each demand segment. However, by defining several demand segments, it is possible to create an overall demand curve consisting of different line segments, each with a different price elasticity.

The equilibrium quantity and price in a perfectly competitive market are generally defined as the intersection between the demand curve and the marginal cost curve. Similarly, the equilibrium quantity and price under strategic behaviour are defined as the intersection between the demand curve and supply function curve in the case of strategic behaviour. As an output, SYMBAD therefore derives a set of mark-ups for each demand segment and for each value of demand within the separate demand segments. As illustrated by Figure 83, these mark-ups are defined as the difference between the competitive price and the price resulting from strategic bidding and can be interpreted as indicators of strategic bidding.

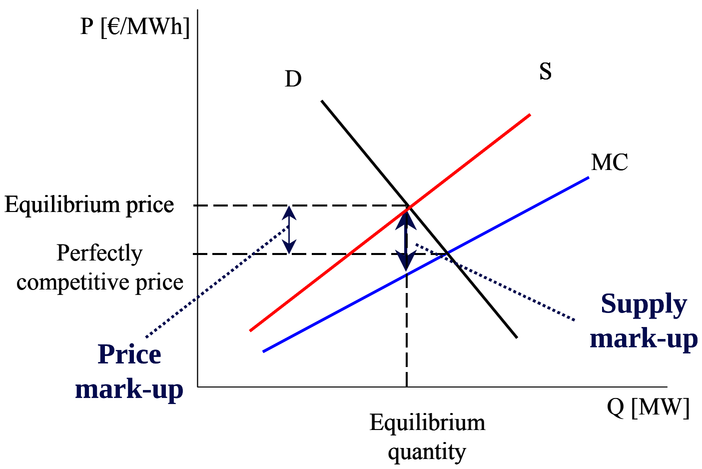


Figure 83: Graphical representation of price and supply mark-ups in SYMBAD

8.1.3 Main technical parameters for generation in PROSYM

The following is a list of the main technical parameters and constraints considered within the production simulation tool PROSYM:

- Number of units and average generation capacity;
- Fuel type and source (differentiated by country);
- Minimum and maximum generation capacities:These values define the minimum and maximum output of a unit when being synchronised to the system; we have generally set these limits to 25% and 100% (except for CHP, see section 3.4.2) of the average generation capacity, respectively;
- Run-up and ramp rates (up/down):
  These values (in MW/hr) characterize the permitted change in generation when a unit is first committed, respectively in unit generation, either up or down, during continued operation; all three values may be differentiated by age, technologies and fuels;
- Minimum down and up times:
  This constraint is enforced by not allowing a unit to shut down if it is needed again before the expiration of its specified minimum down time; once started, a unit is not shut down until expiration of its minimum up time; both values may be differentiated by age, technologies and fuels;
- Plant efficiencies and heat rates (in kJ/kWh)
  The efficiency is defined for the 40%, 70%, 85% and 100% load levels;
- Time of instalment and time of shut down:
  Since some of the previous parameters may vary by the age of a unit, information on the time of construction is important; we have used the average age profile for each plant category and country based on the average age of all plants within that category; information on the shut down of a plant defines the time when a unit is replaced by a new one; this value is determined by adding a standard lifetime (differentiated by generation technology) to the time of installment;
- Planned maintenance and forced outage rates:
  Power plants may not be available either due to planned maintenance or because of (unplanned) outages; given the lack of information on future maintenance plans, we have standardised values for both values, differentiated by technologies and fuels;
- Must-run generation:
  While production units are generally turned on as needed in PROSYM, other plants may follow a different pattern, be it for technical reasons or as a result of administrated/ regulated interference; we have used must-run patterns for wind power, run-of-river plants, and CHP plants (see section 3.4.2).

The above characteristics apply to all power plants, except hydro and wind power. Special attention must be given to the modelling of hydropower and wind power plants that exhibit seasonal and regional variations. For instance, the amount of hydro and wind energy will have an impact on the electricity prices because it may replace or be replaced (in a dry year) by more expensive generation.

8.1.4 Heat rate modelling

As illustrated by Table 18, we have differentiated the average efficiency of different technologies and fuels and as a function of age (i.e. years in operation). All information has been taken from KEMA Consulting's database on generation technologies. In accordance with the major types of plants simulated in this study, we differentiate the following technologies and fuels

1. Gas and/or oil-fired steam turbine (ST):
2. Coal-fired steam turbine:
   This includes all types of coal such as anthracite coal, bituminous coal, lignite coal (brown coal) or a mix of these.
3. Steam turbine as part of a nuclear power plant;
4. Gas-fired combined cycle turbine (CCGT):
   This category may also include gas turbines;
5. Gas and/or oil-fired gas or combustion turbine (GT).

Table 18 shows the estimated efficiency of different power plants built in different years, also indicating the development towards improved efficiency between 1960 and 2040 (estimate).[101] For years between those specified by Table 18, we have interpolated the efficiency curve. Combined cycle turbines and gas/combustion technologies were not available before the 1980s and are therefore only shown starting in 1980 and 1990, respectively. Conversely, oil- and gas-fired steam turbines were phased out around 2000.

[101] Since PROSYM can only handle the years starting in 1970, we have used the efficiencies and heat rates from 1970 for all power plants that were built before that time.

Table 18: Average plant efficiency differentiated by technology and fuel as function of age

	Efficiency (%)				
	Gas/Oil ST	Coal ST	Nuclear ST	CCGT Gas	Gas/Oil GT
1960	37.0	35.0	25.0		
1970	39.0	37.0	27.0		
1980	41.0	39.0	29.0		30.0
1990	43.0	41.0	31.0	50.0	34.0
2000	45.0	43.0	33.0	55.0	36.0
2010		46.0	36.0	58.0	38.0
2020		49.0	39.0	60.0	40.0
2030		52.0	42.0	62.0	41.0
2040		55.0	45.0	64.0	42.0

As mentioned above, the heat rate of a unit varies as a function of its current production. For the purpose of this study, we have relied on two standardised relationships as illustrated by Table 19. More precisely, the efficiency and heat rate are defined for four load levels, namely 40%, 70%, 85% and 100% of installed production capacity. While we have applied the heat rate curve for ST to steam turbines fired by oil, gas, coal and uranium, the CCGT curves are used for gas-fired combined cycle turbines and gas- or oil-fired gas/combustion turbines. It is worth noting that the CCGT technology suffers from relatively low efficiency at low load levels compared to the average efficiency.

Table 19: Calculation of heat rate curves for two different technologies

	Load	**40%**	**70%**	**85%**	**100%**	**Average**
ST	Efficiency	38.00%	40.80%	41.50%	42.00%	41.0%
	Heat Rate	9,474	8,824	8,675	8,571	
CCGT	Efficiency	39.48%	48.34%	50.46%	51.00%	50.0%
	Heat Rate	9,119	7,447	7,135	7,059	

8.1.5 Fuel price forecasts

Unless otherwise stated, all price forecasts are based on the following sources:

- Oil price forecast from Annual Energy Outlook 2004 (AEO2004), including forecasts from other agencies (EIA, 2004).
- Natural gas price forecasts from AEO2004;
- Coal price forecasts from AEO2004 and from various agencies and from interviews with the system operators.

The price forecasts are in 2002 USD per barrel for oil, per thousand cubic feet for natural gas, per million short tons,[102] and per million Btu for coal.

In accordance with our definition of different price scenarios, we have used two different scenarios for future oil price development: a reference price forecast for e.g. the base case scenario, and a high price forecast for the 'high gas price scenario' and the gas-to-gas competition scenario. These price scenarios and the relevant AEO price forecasts are shown in Table 20. We assume that the use of high sulphur fuel oil will no longer be allowed in the EU in 2010. For low sulphur heavy fuel oil, prices are already similar in the reviewed countries, with the exceptions of Greece and Italy (20% higher), the Czech Republic and Slovakia (20% lower). After harmonisation of levies, prices are expected to be similar in all countries. Light fuel oil prices are quite different in the various countries but are of minor importance since there is very little capacity based on light fuel price. Therefore we have used average price for all countries.

Table 20: Oil price forecasts in 2003 USD per barrel (source: AEO2004).

Forecast	2005	2010	2015	2020
AEO2003	23.57	24.28	25.01	25.77
AE2004 reference	23.3	24.17	25.07	26.02
AE2004 high	31.16	33.27	34.23	34.63
AE2004 low	16.98	16.98	16.98	16.98
KEMA assumptions:				
Base case				
Crude oil	N/A	30	30	30
Low sulpur heavy fuel oil	N/A	25	25	25
Light fuel oil	N/A	50	50	50
High price case				
Crude oil	N/A	40	40	40
Low sulpur heavy fuel oil	N/A	33.4	33.4	33.4
Light fuel oil	N/A	66.8	66.8	66.8

Gas prices were rather similar in most countries in 2003. Prices were different in Germany (+20%), Austria (+10%), Czech Republic (-20%), Hungary (-10%) and Slovakia (-10%). Generally speaking, prices seem to be lower on the Eastern side of the power system. This may be due to levies and transport costs. Gas sources are both in the west (North Sea, Netherlands and Norway) and east side (mainly Russia) of our system. It is however expected that the influence of the Russian gas will become dominant. It therefore seems

[102] One short ton is 907.10 kg and is a measure used in the oil industry.

reasonable to assume that prices at the eastern side will remain lower due to lower transportation cost, even if levies are harmonised within the EU. We use three different levels of gas prices for 2010 and 2020:

- Gas prices based on oil prices in Poland, Czech Republic, Slovakia and Romania;
- 5% lower prices in the Baltic countries (Estonia, Latvia and Lithuania); and
- 5% higher prices in all other countries

For the high fuel price scenario (crude oil prices of 40 USD/bbl), we have made sensitivity calculations based on gas-to-gas competition. We have assumed that gas prices in this case are related to a crude oil level of 35 USD/bbl rather then to a level of 40 USD/bbl. Based on these assumptions, Table 21 summarised all gas price estimates used for this study.

Table 21: Natural gas price forecasts for 2010 and 2020 in 2003 USD per thousand cubic feet.

Gas prices (USD/ per thousand cubic feet)	Base	High	High gas-to-gas
PL, CZ, SK, RO	4.49	5.93	5.21
LT, LV, EE	4.26	5.63	4.95
Others	4.71	6.22	5.47

International hard coal prices excluding freight are assumed to be equal for all countries. The same applies for levies due to expected EU harmonisation and tax reforms. Transport costs might be different but are difficult to quantify. We have used 1.75 USD per million Btu for all years until 2020 and for all scenarios except the high coal price scenarios.

Prices of domestic coal are sometimes higher and sometimes lower than prices of international hard coal. Due to increasing wages, cheap domestic fuels will become more expensive and due to harmonisation, expensive domestic fuels will become cheaper in order to be able to compete with world market prices of alternative fuels like coal. We assume convergence of all prices of domestic fuel towards a general level of domestic fuel prices. We used 90% of the international hard coal prices in 2025 for this level. Based on this, coal prices are average prices of domestic and international coal. It is assumed that domestic coal prices converge to 90% of the international coal price of 1.76 USD per million Btu in 2025.

The following Table 22, Table 23 and Table 24 summarise all prices for fossil fuels used in this study.

Table 22: 2003 fuel prices (€/GJ) used for the study

Fuel prices 2003	Coal	Lignite	Natural gas	BCGFG	HFO	LFO	Oil shale
Albania	-	-	533	483	-	-	-
Austria	139	153	588	538	481	802	-
Bulgaria	143	153	533	483	-	-	-
Bosnia	187	153	533	483	-	-	-
Croatia	187	-	533	-	410	802	-
Czech	70	89	452	-	338	647	-
Estonia	-	-	533	-	-	-	40
Macedonia	294	153	533	-	410	-	-
Germany	165	110	657	607	442	817	-
Greece	-	153	533	-	462	1,084	-
Hungary	312	172	496	-	408		-
Italy	187	153	522	472	459	1,943	-
Lithuania	-	153	533	483	410	-	-
Latvia	-	-	533	483	410	-	-
Poland	146	161	533	483	404	730	-
Romania	290	153	533	483	410	-	-
Serbia Montenegro	294	153	533	-	410	-	-
Slovakia	187	233	504	454	362	733	-
Slovenia	187	153	533	-	410	802	-
Turkey	195	153	510	460	560	802	-

Note: BCGFG contains all types of gases like blast furnace gas, refinery gas etc.

Table 23: 2010 fuel prices (€cent/GJ) used for the study

Fuel prices 2010	Coal	Lignite	Ngas	BCGFG	HFO	LFO	Oil shale
Albania	-	-	525	475	-	-	-
Austria	158	162	525	475	450	900	-
Bulgaria	161	162	525	475	-	-	-
Bosnia	190	162	525	475	-	-	-
Croatia	191	-	525	-	450	900	-
Czech	111	118	500	-	450	900	-
Estonia	-	-	475	-	-	-	85
Macedonia	264	162	525	-	450	-	-
Germany	176	132	525	475	450	900	-
Greece	-	162	525	-	450	900	-
Hungary	276	175	525	-	450		-
Italy	191	162	525	475	450	900	-
Lithuania	-	162	475	425	450	-	-
Latvia	-	-	475	425	450	-	-
Poland	163	167	500	450	450	900	-
Romania	255	162	500	450	450	-	-
Serbia Montenegro	263	162	525	-	450	-	-
Slovakia	191	216	500	450	450	900	-
Slovenia	191	162	525	-	450	900	-
Turkey	-		525	475	450	900	-

Table 24: 2020 fuel prices (€cent/GJ) used for the study.

Fuel prices 2020	Coal	Lignite	Ngas	BCGFG	HFO	LFO	Oil shale
Albania	-	-	525	475	-	-	-
Austria	186	174	525	475	450	900	-
Bulgaria	187	174	525	475	-	-	-
Bosnia	196	174	525	475	-	-	-
Croatia	197	-	525	-	450	900	-
Czech	170	159	500	-	450	900	-
Estonia	-	-	475	-	-	-	148
Macedonia	221	174	525	-	450	-	-
Germany	192	164	525	475	450	900	-
Greece	-	174	525	-	450	900	-
Hungary	225	178	525	-	450		-
Italy	197	174	525	475	450	900	-
Lithuania	-	174	475	425	450	-	-
Latvia	-	-	475	425			
Poland	188	176	500	450			
Romania	206	174	500	450			
Serbia Montenegro	221	174	525	-			
Slovakia	197	192	500	450			
Slovenia	197	174	525	-			
Turkey	-		525	475			

For Uranium we only have historic prices for 2003. Based on these prices, we estimate the Uranium price to be 0.7 €/GJ for 2003. We have used the same price for 2010 and 2020.

Table 25: 2003 uranium prices (US-$/lb of U_3O_8) used for the study

UxU_3O_8 Price	RUU_3O_8 Disc.	NA Conv Price	EU Conv Price	NA UF_6	EU UF_6	SWU Price	RU SWU Price
$11.55	$0.20	$4.99	$6.48	$35.16	$36.65	$108.00	$88.83

Note: Prices shown in US-$/lb for U_3O_8, $/kgU for conversion and UF_6 , and $/SWU for SWU.

US-$/lb of U_3O_8

8.1.6 Conversion factors

The fuel prices in the PROSYM model are in Euro cents per GJ. To convert the energy units into GJ we use the following conversion factors (British Petroleum, 2004):

Table 26: Conversion Factors and Calorific equivalents

1 metric ton = 1.1023 short tons = 2204.62 lb
1 kilolitre = 6.2898 barrels = 1 cubic metre
1 barrel = 0.1364 tons (metric)
1 kilocalorie (kcal) = 4.187 kJ = 3.968 Btu
1 kilojoule (kJ) = 0.239 kcal = 0.948 Btu
1 British thermal unit (Btu) = 0.252 kcal = 1.055 kJ
1 kilowatt-hour (kWh) = 860 kcal = 3600 kJ = 3412 Btu
One ton of oil equivalent equals approximately:
Heat units: 10 million kilocalories = 42 gigajoules = 40 million Btu
Solid fuels: 1.5 tons of hard coal = 3 tons of lignite
Electricity 12 megawatt-hours
One million tons of oil produces about 4500 gigawatt-hours (=4.5 terawatt hours) of electricity in a modern power station

Gaseous fuels such as natural gas (NG) and LNG can be converted by using the Table 27.

Table 27: Conversion factors for natural gas and LNG

From	billion cubic metres NG	billion cubicfeet NG	Million tons oil equivalent	Million tons LNG	trillion British thermal units	million barrels oil equivalent
Billion cubic metres NG	1	35.3	0.90	0.73	36	6.29
Billion cubic feet NG	0.028	1	0.026	0.021	1.03	0.18
Million tons oil equivalent	1.111	39.2	1	0.805	40.4	7.33
Million tons LNG	1.38	48.7	1.23	1	52.0	8.68
Trillion British Thermal units	0.028	0.98	0.025	0.2	1	0.17
Million barrelsoil equivalent	0.16	5.61	0.14	0.12	5.8	1

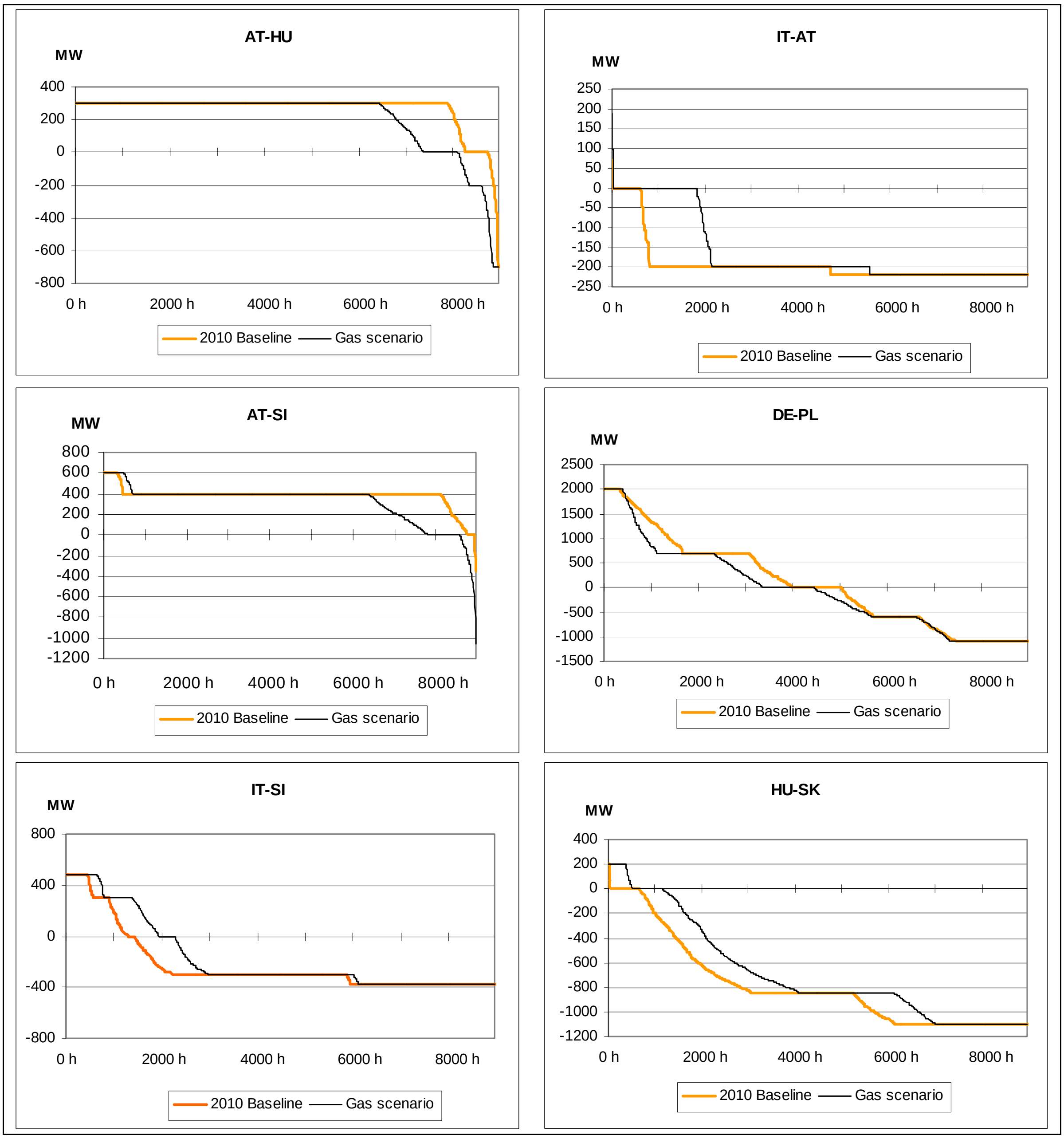
8.2 Appendix B: Results of Sensitivity Analysis

8.2.1 Generation Scenarios

8.2.1.1 Gas Scenarios

Under the gas scenario, we had assumed an even higher growth of gas-fired generation than under the baseline scenario. Since the PRIMES dataset generally assumes a strong growth of gas-fired plants throughout the study period, this scenario (for 2010) can partially be considered as similar to the 2020 baseline scenario. Amongst others, one might thus expect the price levels in the many countries to converge. In turn, this might result in decreasing congestion. To some extent, these expectations are confirmed by our modelling results.

Generally, the differences under the gas scenario remain moderate. None of the flow patterns show drastic changes, in many cases, there are hardly any variations at all. As illustrated by Figure 84 there is a reduction of the prevailing flows, and thus also congestion, at several borders, including e.g. exports from Austria to Hungary, Italy and Slovenia, from Estonia to Latvia, from Germany to Poland, from Slovenia to Italy, and from Slovakia to Hungary. Conversely, flows and congestion from the Czech Republic to Germany and from Latvia to Lithuania show an increase. Finally, it is interesting to note that this scenario also shows more times with flows from Italy to Slovenia, i.e. opposite to the prevailing direction.



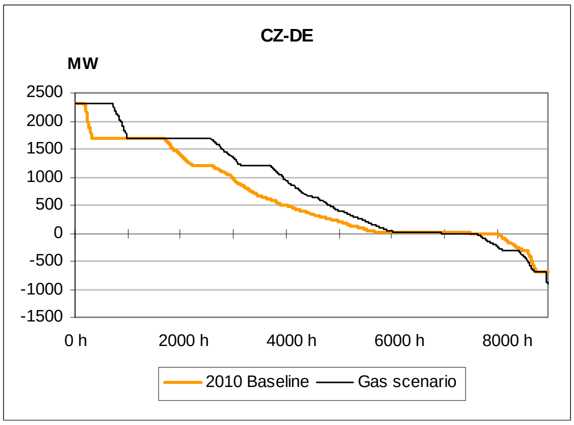


Figure 84: Changing flow patterns under the ‘gas scenario’

8.2.1.2 Hard Coal Scenario

In contrast to the gas scenario, the hard coal scenario assumes a slower growth of gas-fired generation, being replaced by a correspondingly larger share of coal-fired generation. Once again, this scenario shows minor changes to the baseline situation only. The main variations can be observed for Italy, which further imports from Austria and Slovenia but reduced exports to Greece. Similarly, the selection of flow duration charts in Figure 85 shows exports from Bulgaria to Serbia & Montenegro as well from Serbia & Montenegro to Macedonia. Similarly, there also is a slight general shift in cross-border flows from Austria to the direction of Germany.

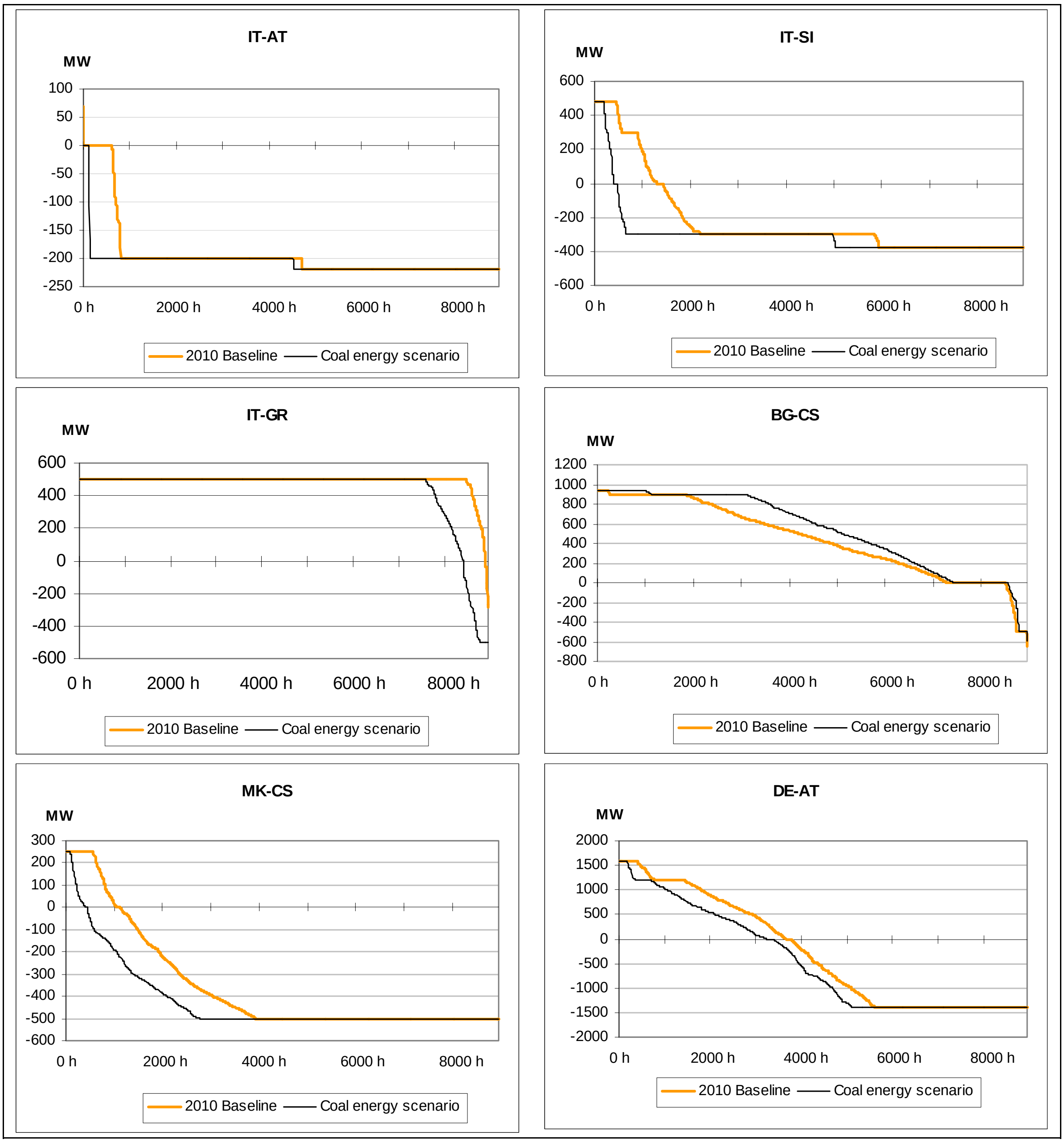
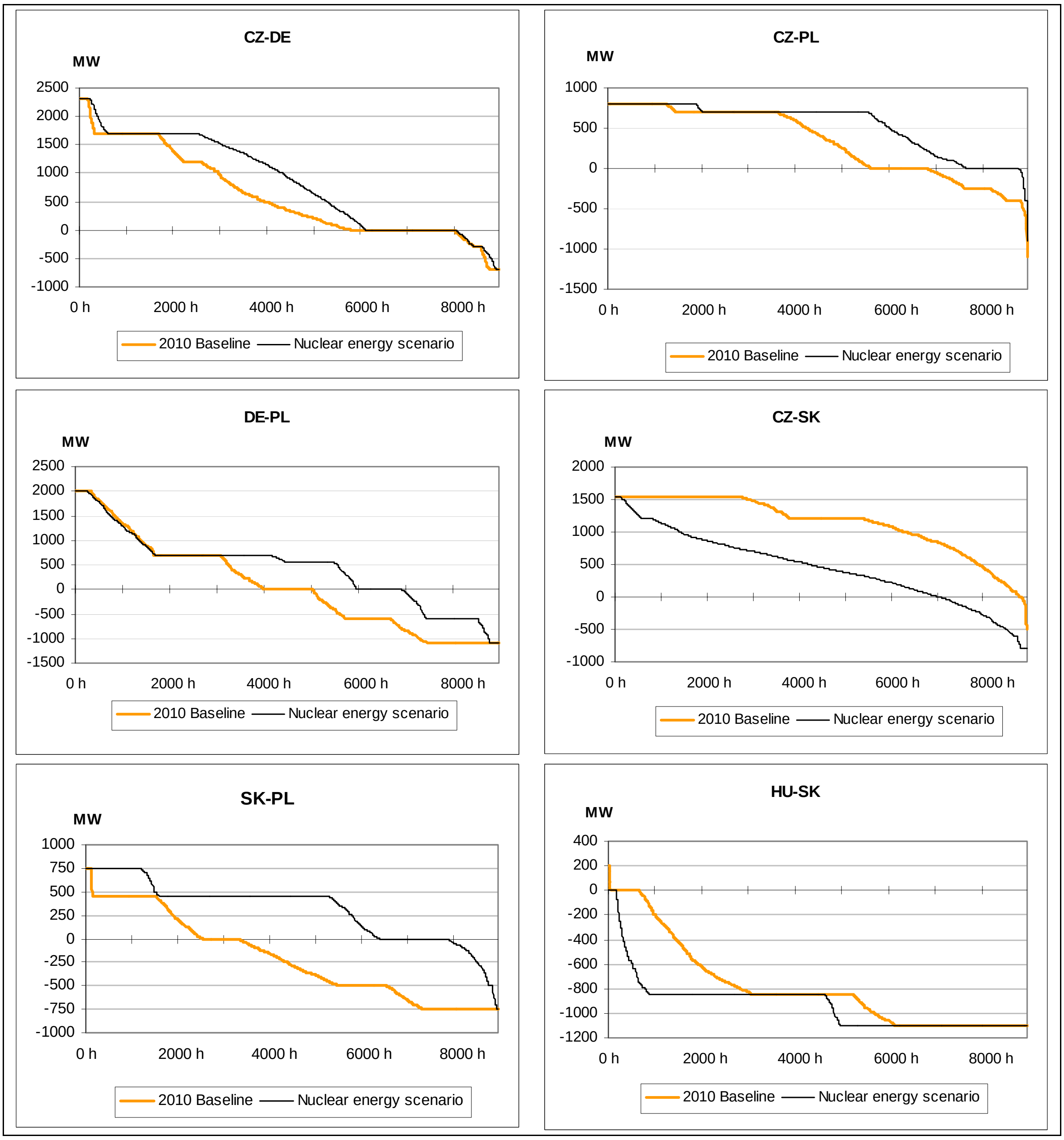


Figure 85: Changing flow patterns under the 'hard coal scenario'

8.2.1.3 Nuclear scenario

Contrary to the first two cases, the nuclear scenario results in substantial changes at many borders. As illustrated by Figure 86, these changes are most marked for the Baltic States, the Czech Republic, Hungary, Poland and Slovakia. While the Czech Republic increases its exports to Germany and Poland (same applies for Germany), the imports of Slovakia from Poland and the Czech Republic are drastically reduced; in fact the relation between Poland

and Slovakia turns from a net export into a net import situation. In addition, Slovakia increases its exports to Hungary, which in turn increases its exports to Croatia while reducing its imports from Serbia & Montenegro. The biggest change can be observed in the Baltic States where Lithuania turns from a big net importer into a major exporter, whilst Estonia changes from a major export into a limited import position. Although not shown in Figure 86, we finally note increasing exports from the Czech Republic and Germany to Austria, but reduced exports from Bulgaria and Hungary to Romania.



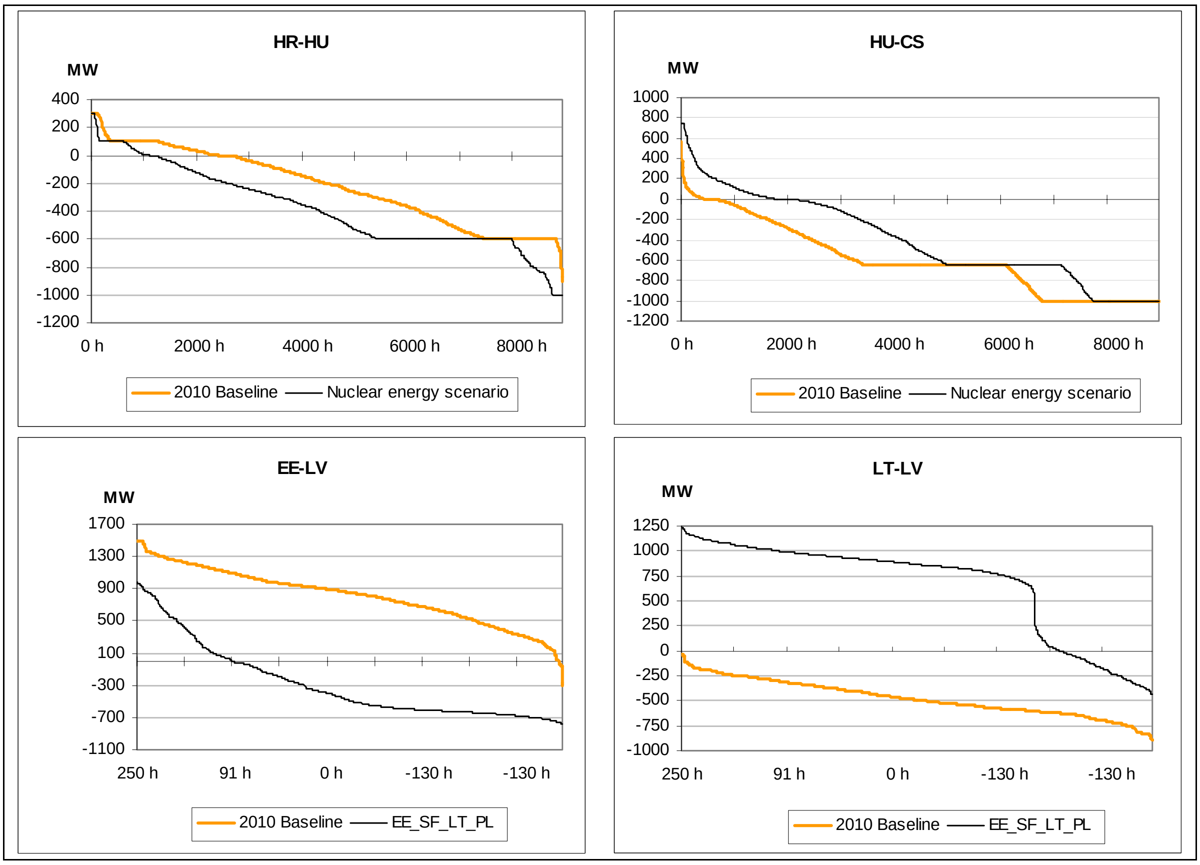


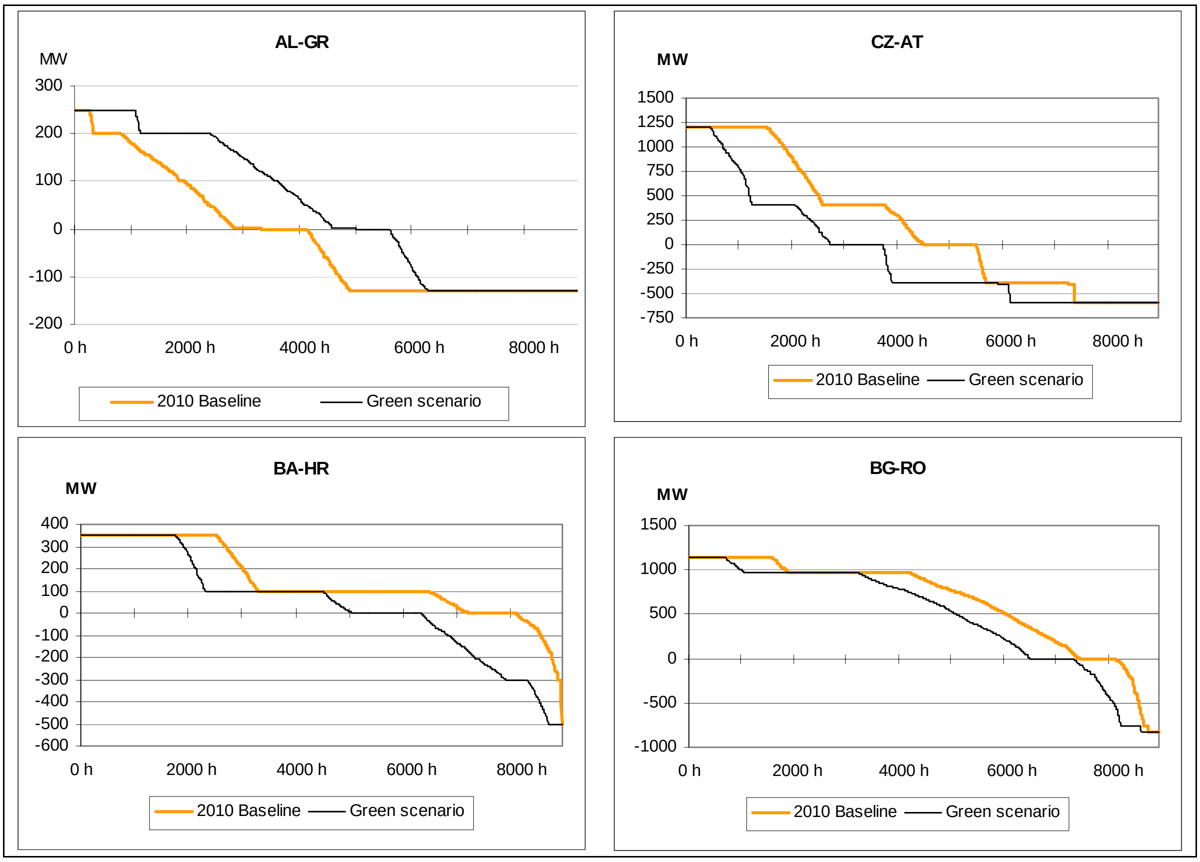
Figure 86: Changing flow patterns under the 'nuclear scenario'

Overall, this scenario increases existing congestion mainly at the borders from Hungary to Croatia, the Czech Republic to Poland, Hungary to Slovakia, but relieves the constraints between the Czech Republic and Slovakia, from Serbia & Montenegro to Hungary and from Estonia to Latvia. The prevailing flows reverse their direction between Slovakia and Poland as well as Latvia to Lithuania. Finally, some of the most congested borders, such as for imports to Italy and Greece, are hardly affected at all. This can also be explained by the fact that nuclear generation is unevenly distributed through the region, with a major share of nuclear power in some countries but none in others. Given the large size of nuclear units to the generally smaller systems in the region, and the fact that the baseline scenarios considers a considerable decommissioning of nuclear plants between 2003 and 2010, it also seems reasonable that this scenario has a substantial impact on the cross-border trade and flow patterns.

8.2.1.4 Green scenario

The last generation scenario finally assumes an even faster growth of renewable energies than under the base case. Not surprisingly, our results show increased exports, respectively reduced imports, for those countries with a large share (and growth) of either wind or hydro power. For instance, those countries with a substantial increase, their exports (e.g. AL →GR, AT→DE) and/or reduce their imports (CZ→AT, BA/CS→HR, CS→HU, BG/CS→RO, EE→LV). In addition, we observe a changing pattern on the border between Italy and Slovenia, with a reduced net import by Italy.

Generally, these developments lead to reduce congestion, with the exception of the Albania-Greek, Austrian-Czech and Austrian-German borders. Furthermore, most other exchanges again show minor variations only, such that the impact of this scenario can again be considered as moderate.



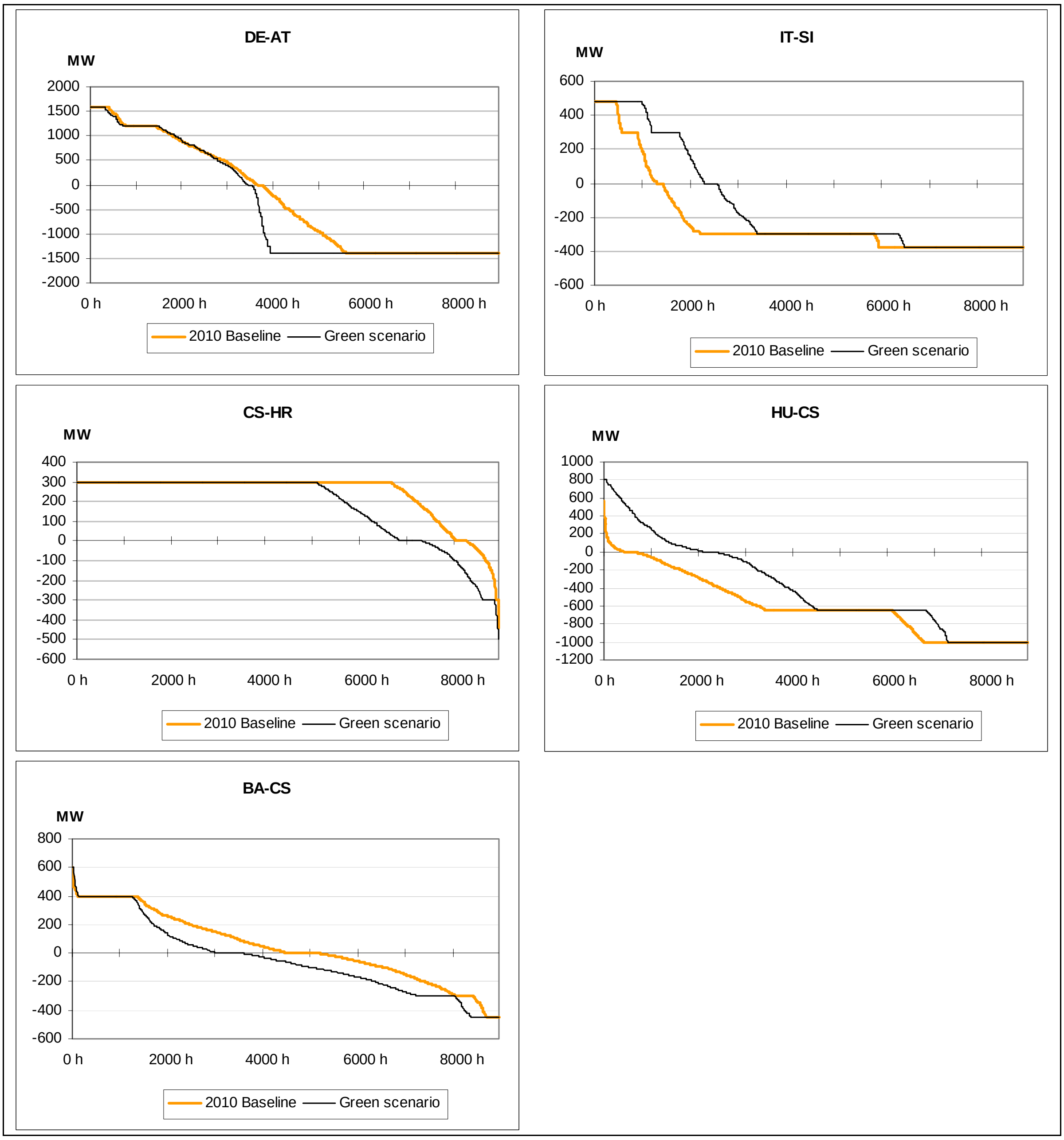


Figure 87: Changing flow patterns under the 'green scenario'

8.2.2 Price Scenarios

8.2.2.1 High gas price

This scenario simulates the impact of continuously high oil and gas prices. Given the increasing share of gas-fired generation, this variation might potentially have a significant impact on prices and the resulting cross-border flows. On the one hand, high gas prices may result in increasing electricity imports by those countries that are highly dependent on gas. On the other hand, an increased use of gas in most countries under study, in combination with a comparable level of gas prices throughout the region, could also result in a levelling of wholesale electricity prices, thus potentially reducing the economic scope for cross-border exchanges.

Our results however show a limited sensitivity to this modification only. As illustrated by Figure 88, the main change occurs at the Hungarian-Slovakian border, with significant reduced imports by Hungary. This development obviously results in a parallel reduction of the power flows from the Czech Republic to Slovakia, again reducing congestion. Finally, we also observe a further increase of Italian imports from Austria and Slovenia, resulting in an almost complete utilisation of these links. All other exchanges remain almost unchanged. In summary, these observations again suggest an only moderate impact of this particular scenario.

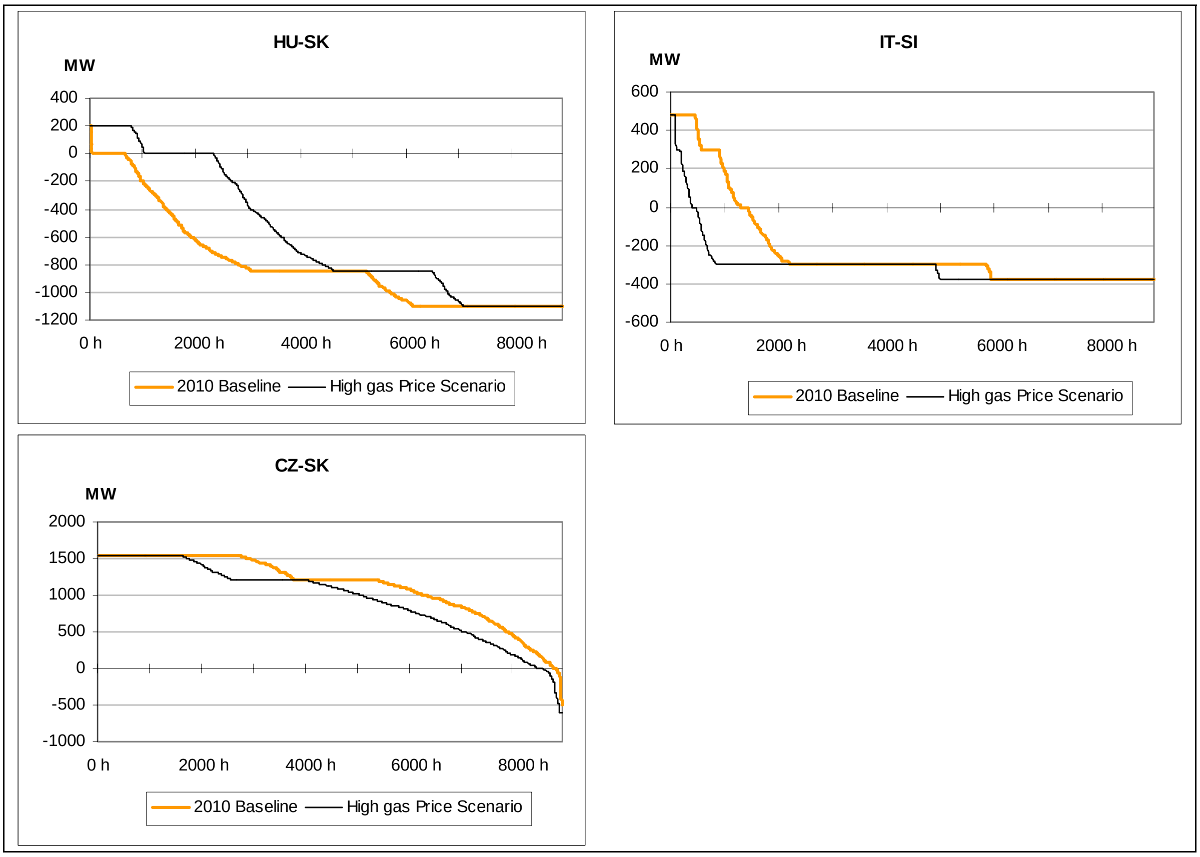


Figure 88: Changing flow patterns under the 'High gas price scenario'

8.2.2.2 High hard coal price

The coal price scenario somewhat reflects the opposite to the gas price scenario, since higher coal prices could also be interpreted as a situation with low gas and oil prices.[103] Again, we observe largely minor variations of the cross-border flows, with the main exception of Macedonia. As illustrated by Figure 89, Macedonia not only further increases its imports from Serbia & Montenegro. In addition, the previous exports to Greece are reduced by some 50%, with Macedonia even starting to import from Greece for about a third of the year. This drastic impact is obviously caused by the particular combination of already constrained imports from Serbia and the fact that Macedonia only has coal-fired and hydro-power plants. Hence, it is not possible to use alternative fuels.

Further changes, but a much lower level, can be observed for exports from Serbia & Montenegro to Croatia (see Figure 89), for imports to Hungary from Croatia and Slovakia. With the mentioned exception of Macedonia, however, the market model and the resulting cross-border flows again appear as quite robust against these changes.

[103] This understanding is based on the assumption that coal and gas are the main marginal/price-setting fuels, in contrast to nuclear and hydropower, which are believed to provide cheap base load plus, in the case of hydropower, cheap peak load capacity.

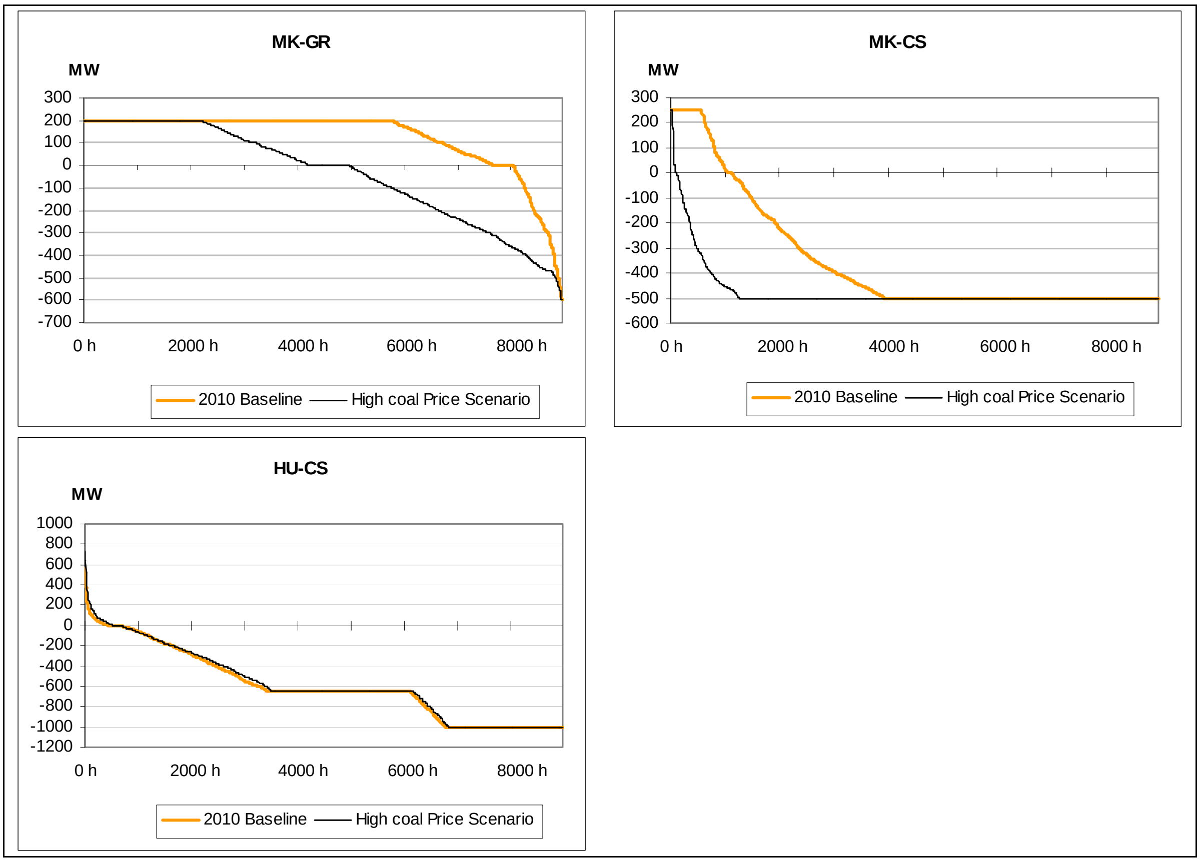


Figure 89: Changing flow patterns under the 'High hard coal price scenario'

8.2.2.3 Decoupled gas prices

Most of our simulations assume gas prices to be coupled to the oil price. Under this particular scenario, we have therefore modelled a situation where only oil prices increase, whereas we have kept gas prices stable. When comparing the results to the base case, the variations to the base case are practically negligible. It thus appears that divergent oil and gas prices will not have any tangible impact on cross-border flows. This result also seems reasonable, given the decreasing share of oil-fired generation, and generally the higher efficiency of gas-fired plants. A variation of gas relative to oil prices can thus be considered as being insignificant for the outcome of our market simulations.

8.2.3 *Development Scenarios*

8.2.3.1 Fast development

The fast development scenario is based on the assumption of considerably faster economic growth than under the baseline scenario. As such, it represents a situation that is already closer to the 2020 than the 2010 base case; in practice, we have used the (interpolated) 2017 scenario. Not surprisingly, Figure 90 and Figure 91 thus show a number of variations to the 2010 baseline scenario. Although these affect a large number of different borders, it is not generally possible to identify a clear trend for either increasing or decreasing congestion. Moreover, most of these changes remain in nature and do not result in any new network constraints, or major changes of existing areas of congestion.

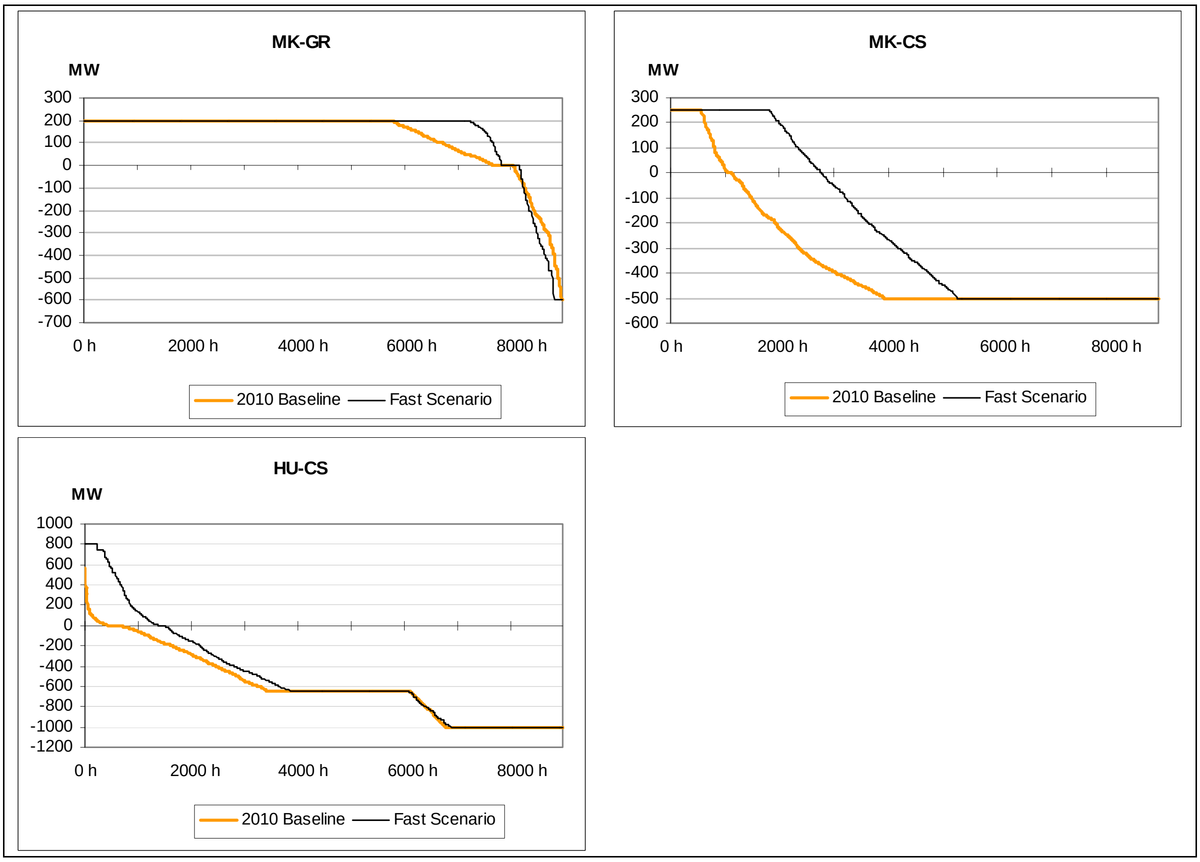


Figure 90: Changing network constraints under the 'Fast scenario'

As illustrated by Figure 90, we observe a number of different borders with either increasing (DE→AT/PL, BG→RO, MK→CS) or decreasing (CZ→AT/DE, HU/BG→RO, CS→HR) congestion. Simultaneously, Figure 91 shows various cases, where the prevailing flows are changing, without however causing or removing congestion to a significant degree. Only in two cases (CZ↔PL, BA↔HR), the prevailing flows change their direction, at least partially removing the existing congestion. Despite their number, these changes do not result in fundamentally changing flow patterns in the region and can thus be considered to confirm the robustness of the baseline scenario. Nevertheless, they are a clear indication of potential changes to the prevailing flows over time.

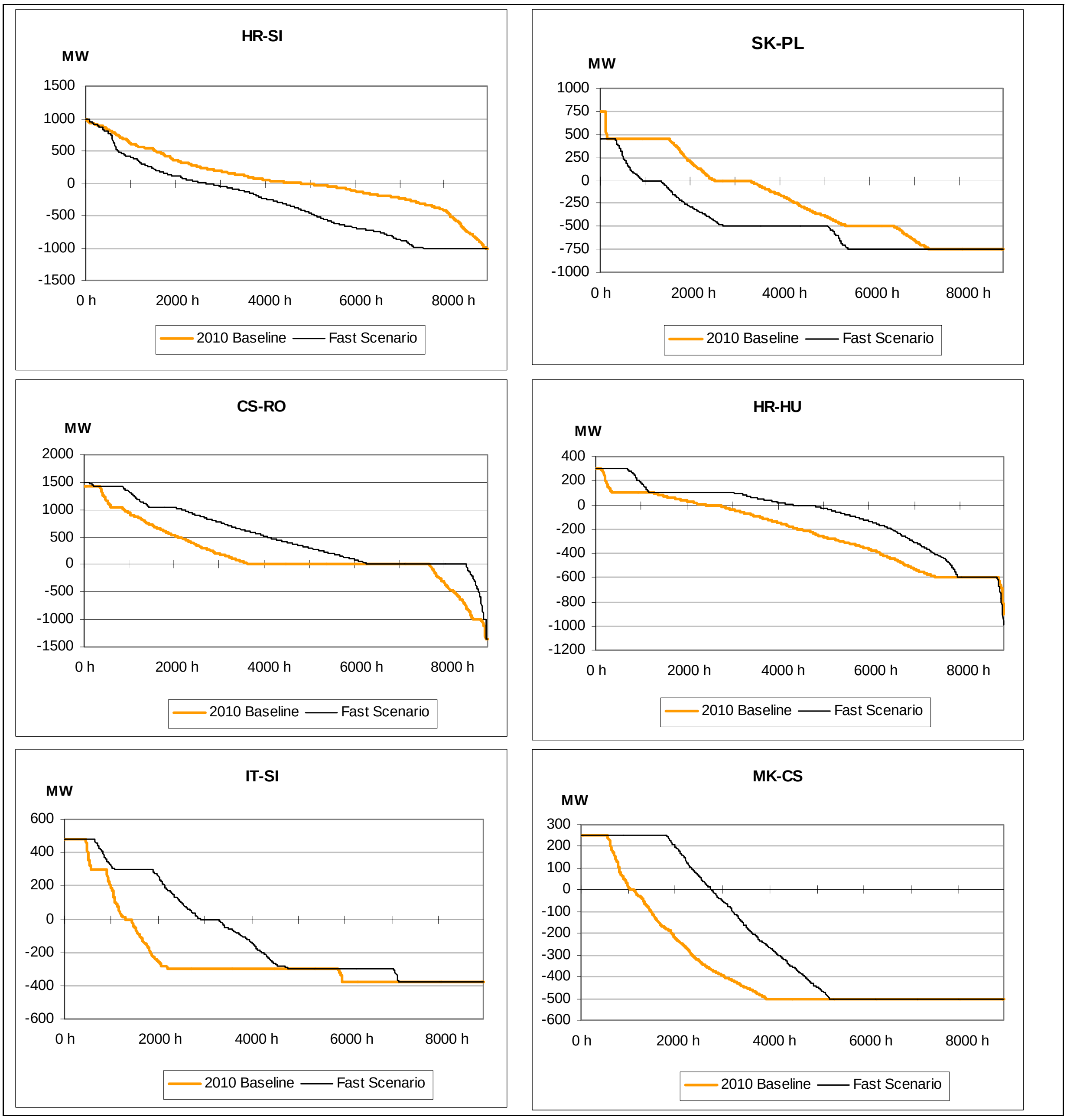


Figure 91: Reduced flows and congestion under the 'Fast scenario'

8.2.3.2 Lagging development

In contrast to the previous situation, this scenario reflects a case where both generation and demand grow at a much slower rate than anticipated within the PRIMES dataset. Once again, it is possible to observe different flows at many borders. However, in contrast to the fast development scenario, most of these changes remain marginal. One of the main effects can be observed for the Czech republic, with reduced exports to all neighbouring countries (compare Figure 92). Similarly, reduced exports from Bulgaria to Romania also result in less congestion. In contrast, there are increasing flows from Slovakia to Hungary and further on to Croatia, without however any major reduction of congestion. Overall, these changes are less marked than for the case of the fast development scenario. Due to their largely marginal nature, they do not really impact the prevailing flow patterns in the region. Hence, we do not consider this scenario to put into question the results of our baseline scenario.

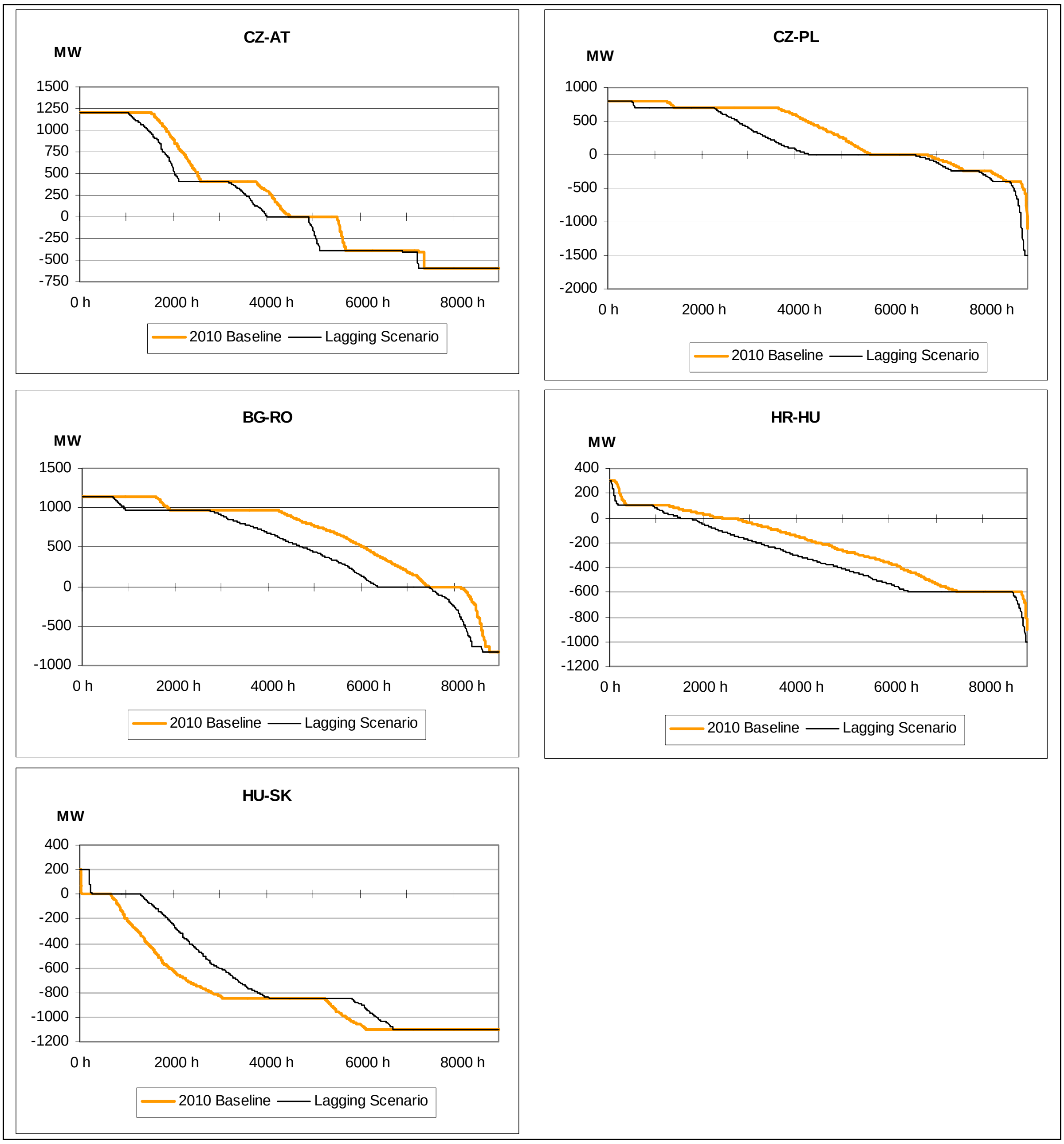


Figure 92: Changing flow patterns under the 'Lagging scenario'

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