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SUPWIND Deliverable D 6.1

Analysis of strategic grid investment and management issues

Report on Findings of Working Package 6

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Content

Preface

This deliverable is part of a series of working documents within the project *Decision Support for Large Scale Integration of Wind Power SUPWIND*, supported by the European Commission within the 6^{th} FP under Contract No. TREN/05/FP6EN/S07.61830/020158 SUPWIND. It describes the outcomes of Working Package 6.

Motivated by high targets for renewable energy sources, the installed wind power capacities are increasing. Due to the volatile nature of wind, this will cause residual load gradients (load minus wind power injection) to increase. As a consequence, flexibility requirements for the conventional part of the power system increase, too. Additionally, the sites of wind power plants are located away from demand centers in most cases. This leads to longer transmission distances of the generated power. The power system has to cope with these challenges. Possible mitigation measures are storages or transmission extension measures. The focus of this work package is on the analysis of transmission extension measures as mitigation measure for wind integration and the socioeconomic effects that come along with transmission extension. The expansion of the transmission system has impacts on the system operation and the development of the power plant park. However, network extension measures are associated with costs.

The effects of transmission system extensions are analyzed with the tools "European Electricity Market Model" (E2M2s) and "Joint Market Model" (JMM) and it is shown how these tools can be used to estimate the socioeconomic costs and benefits of wind integration measures with a focus on line extension. The tools are applied for the determination of optimal power plant investments and system operation cost. The evaluation of network investments is performed via comparing the model results for the topology of the transmission grid without expansion to the topology of the transmission grid with expansion. Savings in total system operation and power plant investment costs are used as measure for the socioeconomic evaluation of transmission investments. Besides technical reasons, socioeconomic analysis of transmission investment is important due to the European domestic electricity market.

The application of the tools was performed in two case studies. A country specific case study of Greece applies the tools on national level and shows how a single TSO can benefit from the tools for evaluation of extension projects. An European case study applies the tools to the European system and shows how the tools can be used for the support of energy policy decisions on international projects. So, the main difference of the two applications is the geographical scope. The two cases determine the structure of this report. Each case is represented by a chapter describing the outcomes of the case.

Chapter 1[1] describes the usefulness of stochastic planning tools for individual TSOs in order to cope with large amounts of wind power. In this chapter an analysis of the Greek power system is demonstrated. The transmission system operator of Greece, HTSO, supported this case study with several essential contributions on network parameters and other system specific data like information on investment costs in Greece.

The electrical power system of Greece is characterized by relatively little interconnection with its neighbours compared to Western European countries. As a consequence, trade and parallel flows do not play an equally important role as for other countries. Another key characteristic of the Greek power system is the expected growth of wind power. The geographical and meteorological conditions of Greece favor wind power installations due to relatively high average wind speeds in many regions of Greece. The Greece government has set financial incentives for investors to exploit this potential.

In this study, a projection of the future power system of Greece is analyzed under user-defined hypothetical assumptions on determined boundary conditions, which are responsible for the future energy mix. A system including reinforcements - mainly between the 400 kV main grid and the 150 kV subsystems of Evia and Thrace - is compared to a system with the status quo of the grid infrastructure.

Chapter 2[2] provides an analysis of socioeconomic costs and benefits of wind integration measures on European level. The liberalization of electricity markets in Europe has led to more trading of electricity and to increasing integration of formerly separated national markets. Limited cross-border-capacities, however, hamper the domestic market, and interconnector investments are considered as important options to improve the merging of European markets. Additionally, interconnectors are expected to improve the integration of newly developed wind power capacities into the electricity market. Interconnectors help to cope with intermittency of wind power in-feed and also reduce the need for generation reserves in case of low wind speeds. The European case study covers 30 European countries. The model E2M2s is used to evaluate the benefits of further line extensions between UCTE and NORDEL countries. Efficiency gains and the distribution of these gains within a business as usual scenario up to 2030 are computed.

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[1] This part of the report was presented at the 8th International Workshop on Large-scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Windfarms in Bremen, 2009.
[2] This part of the report was presented at the 8th International Workshop on Large-scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Windfarms in Bremen, 2009.

1 Network and power plant investments – country case study with high wind power penetration

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1.1 Introduction

The European Union has defined targets for renewable energy sources. Directive 2001/77/EC sets the legal framework and provides national objectives. Greece, the country that is considered in this paper, has the target to increase the share of renewable energy sources in the electricity generation mix from 8.6% (1997) to 20.1% until 2010. In order to meet its target, Greece is promoting renewable energy sources. Tariff rules for renewable energy sources can be found in laws 2771/1999 and 3468/2006. Financial support for investors in renewable energy sources is regulated via law 3299/2004 [1].

Studies on the potentials of wind energy in Greece indicate that the wind regime in several parts of Greece is of high significance. According to [2], average wind speeds on the Cyclades and on the region of the Aegean Sea exceed the value of 8 m/s at 40 m height. The current status of wind farms and a prediction of future allocation of wind power capacities in Greece can be found in [3]. It is a prevailing opinion that the growth of installed wind power capacities will accelerate in the near future.

The increase of wind power generation leads to challenges for the interconnected Greek power system in a long term perspective. One reason is the volatility of injection by wind turbines. The volatility of injections by wind turbines leads to higher gradients of residual load (load minus wind power). The higher gradients of residual load increase the flexibility requirements for the conventional power plant park.

Another aspect is the distance between high demand centers like Athens and Thessaloniki and the regions with high wind potentials. This is an issue, because transmission capacities to regions with high wind potential are relatively small as their implementation took place before the expansion of wind energy exploitation for electricity. As a consequence, it can be expected that with increasing wind capacities, the links to the windy regions will evolve as bottlenecks. According to [3], this will be a problem for the region of Evia, Southeast Peloponnese and Thrace.

As wind power penetration increases, the necessity for wind integration measures increases as well. As a consequence, methods and tools to evaluate integration measures gain importance on the expansion of the transmission system. The objective of this work is to present a methodology how to estimate the economic impact of investment decisions for wind integration. The analysis is mainly based on a power plant investment model (E2M2) and an enhanced unit commitment and dispatch model (JMM). The models in their current versions were developed within the SUPWIND project. Both models are able to consider the transmission network performance under a DC Load Flow procedure. A DC Load flow scheme does not represent all parameters of a transmission system. However, it is a fast and flexible tool for large interconnected transmission systems and it may be considered as a safe approximation. Taking into account the large wind potential and the geographical distance between windy regions and the high load centers, the case of Greece shows great interest for the study.

This paper is structured as follows. 1.2 describes in brief the applied models E2M2 and JMM and explains how these models were used for the investigation of wind integration cost. The next section introduces the data assumptions on the Greek power system in 2030 (a milestone set within the SUPWIND project). In 1.4 the results are presented. The conclusions about future wind power integration in the Greek power system are given in the last section.

1.2 Models and methodology

In this section the applied models and the methodology are presented. After a short introduction of the models, their application is explained.

A. The applied models E2M2 and JMM

In order to describe the future power system in 2030 (a milestone set within the SUPWIND project) it is necessary to evaluate the development of the generation mix in Greece. Due to the fact that the JMM optimizes dispatch and scheduling of flows very detailed, another less complex, but still sufficient detailed model was needed to evaluate future investments in power plants. For this reason, the same data as used for the JMM modeling was fed into a load flow extended version of the E2M2 model. Annualized investments are decision variables which are part of the models' objective function. Due to calculation limitations, the model optimizes 144 typical load segments, based on seasonal and daily load patterns. With E2M2, the development of the power plant park until 2030 could be calculated. The development of wind generation is an exogenous parameter to the model, only conventional power plant capacity investments are determined. The maximum age allowed for units is depended on the technology. Units going out of service have to be replaced adequately and new capacities have to cover demand growth. The model E2M2 has the option to invest in lignite and coal fueled power plants, as well as in natural gas fired combined cycle gas turbines (CCGT) and gas turbines.

In addition to the model E2M2, the model JMM is used. The JMM is a unit commitment model which works on an hourly resolution. The JMM covers both, the day ahead market and the intraday market. For both time intervals (day ahead and intraday), there is the option to include specified reserve categories (automatic reserves for the day ahead and manual reserves for the intraday market) as additional electricity products. The demand for reserves is exogenous data to the JMM. The objective function of the JMM is minimizing total system cost. The market restriction for supply and demand is included for both day ahead and intraday market. This restriction ensures that for every hour, the amount of generated electricity corresponds to demand. The same applies to the reserve markets. Additional power plant characteristics like capacity constraints, reduced part load efficiency and start up costs are included. The optimization in the model is done consecutively, which is called rolling planning. Rolling planning approximates very well, how market structures work in reality. It also represents that rescheduling may occur when new information becomes available. According to this, the daily planning cycle of the model starts at noon, since at this point in time the day-ahead scheduling is optimized taking into account forecasts of the wind power production 12 – 36 hours ahead. In the following planning periods, rescheduling is done. Details can be found in [4-6].

B. Application of the models

The Greek power system has to adapt to the changing requirements of future, which means the integration of large wind power capacities. The methodology, how the models were applied, in order to investigate the economic impact of wind integration measures is shown in Fig. 1.1.

In a first step, data on the Greek power system was collected. During the data collection process, the development of demand and the development of installed wind power capacities until 2030 were investigated. Afterwards, the model E2M2 (see A in Fig. 1.1) with all European countries was running. In this model run, Greece was treated as a single node. As a result, the exchanges with the neighboring countries could be fixed. Greece is relatively isolated and has relatively little exchange capacities with neighboring countries.

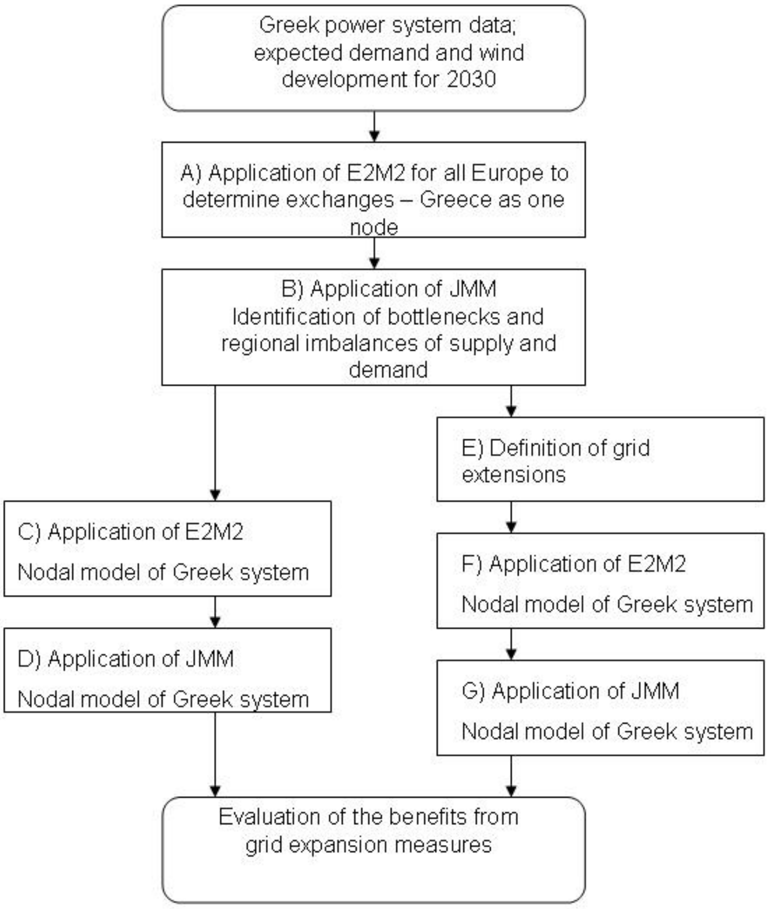

Fig. 1.1. Sequence of model runs performed

The next series of model runs included a geographical resolution that takes into account the different nodes of Greece. These model runs include the physical network properties and transportation limits of the high voltage und the ultra high voltage grid via DC Load Flow and capacity limits. A model run with the JMM (see B in Fig. 1.1) served as base case which helped to identify congested network areas and to develop the grid extension scenario.

In scenario 1, (left path as shown in Fig. 1.1) the development of the power plant park under the status quo of the transmission network was computed with a regionalized version of E2M2 (see C in Fig. 1.1). A model run with the JMM (see D in Fig. 1.1) that takes into account the additional power plant capacities of this E2M2 run followed. As a final result, detailed cost figures for the case that no network extension takes place are obtained.

In scenario 2, the model run with E2M2 (see F in Fig. 1.1) takes into account network reinforcements, as defined with the help of the first JMM (see B in Fig. 1.1) run. Due to the changed network infrastructure, one obtains an alternative power plant investment package. The economic impact of this power plant package is also analyzed in detail with the JMM (see G in Fig. 1.1).

In the next section, a simplified version of the Greek power system is introduced and important system data are explained.

1.3 The Greek power system and system data

The most important parameters for this study are the characteristics of network elements, power plant data, load demand records and wind speed data. Fig. 1.2 shows the considered network.

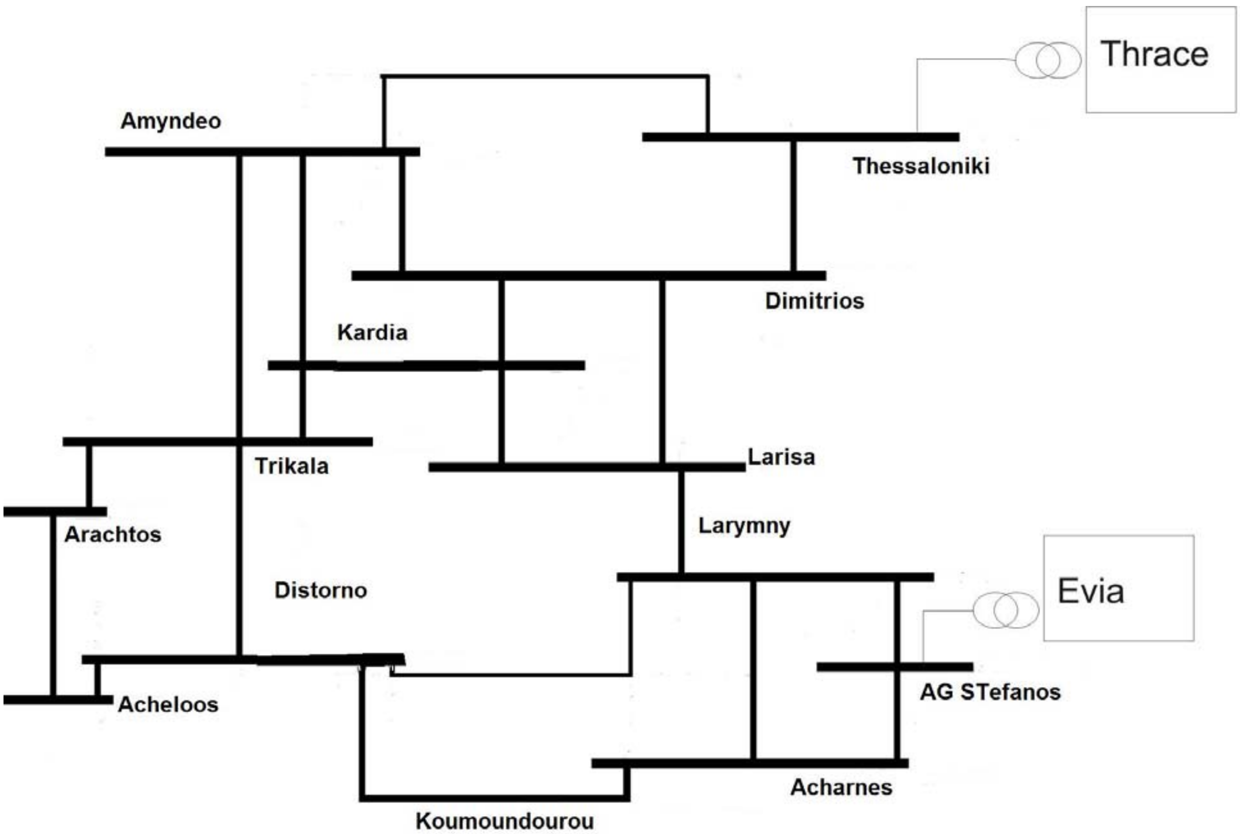

Fig. 1.2. Simplified network topology of considered Greek power system.

In addition to the 400 kV network of central Greece the earlier mentioned regions of Evia and Thrace are considered within this work. In this study, the subsystem of Evia is defined as the nodes Aliberi, Arguros, Myrtia, Polypota, Heliolousti, Karustos, Leibadi and Andros. The subsystem Thrace is defined as the nodes Kavala, Keramoti, Magiko, Epva, Xanthi, Zarkadia, Iasmos, Komotini, Komot_TH, Alexandropouli, Pravaton, Didimote, Orestiad, Kechros, Patriar, Sapka, and Kerversos. From the point of view of the transmission system, the system of Evia can be seen as a radial branch of the 150 kV network that is linked with the 400 kV network at Stefanos. The Thrace loop geographically covers the Northeastern regions of

Greece. This part of the Hellenic Transmission System currently is based on 150 kV. There are upgrade measures on the way that will integrate the bus K_NSANTA which is on 400 kV level.

We assume that nowadays existing concentration of wind generators is persisting in the future, too. It is assumed that future wind farm deployment will be significantly focused on the parts of Greece, where wind turbines are expected to have the largest full load hours. Based on hypothetical boundary conditions, it was assumed that in Greece, there will be 6553 MW of wind power generation capacity installed.

Yearly electricity consumption data can be obtained on the website of UCTE, now ENTSO-E. In order to derive regionalized data, it was assumed that the consumption profiles are the same for all Greek regions. The cumulated electricity consumption was allocated to the regions according to population shares.

The future CO2 price is assumed to rise linearly from nowadays level of 25 €/t CO2 to 60 €/t CO2 in 2030.

The assumptions on fuel prices are shown in Fig. 1.3. The prices for coal and lignite remain stable, whereas the prices for natural gas and oil are increasing. These boundary conditions were defined within the framework of the SUPWIND project [7]. Furthermore, the same parameters were used for the model run with E2M2 for all Europe.

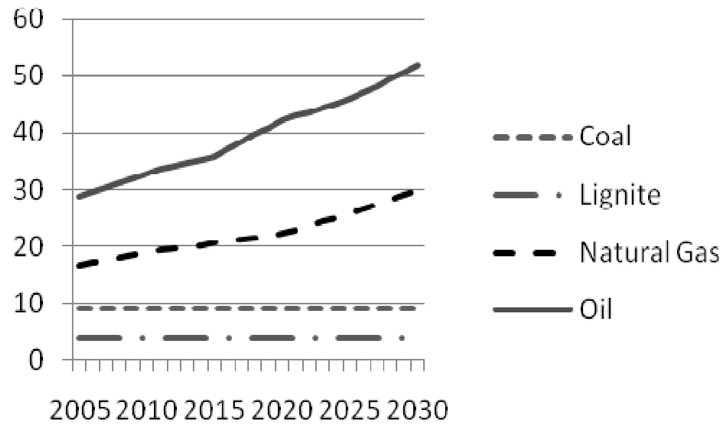

Fig. 1.3. Assumptions on fuel prices in Euro/MWh

Based on a power plant database, the allocation of large units (>20 MW) to network nodes was performed by specific research for each unit. Small units were aggregated by fuel and allocated proportionally to the fuel specific installed generation capacities. As far as available, information on future power plant projects was included as exogenous information in the power plant database. Due to the fact, that public information is only available for projects in the near future and due to the fact, that the information on power plant projects is incomplete, further power plant investment is needed in the future which is calculated by E2M2.

Fig. 1.4 shows installed generation capacities in 2030 as obtained by the run with E2M2 covering Europe and with Greece as one node (see A in Fig 1.1):

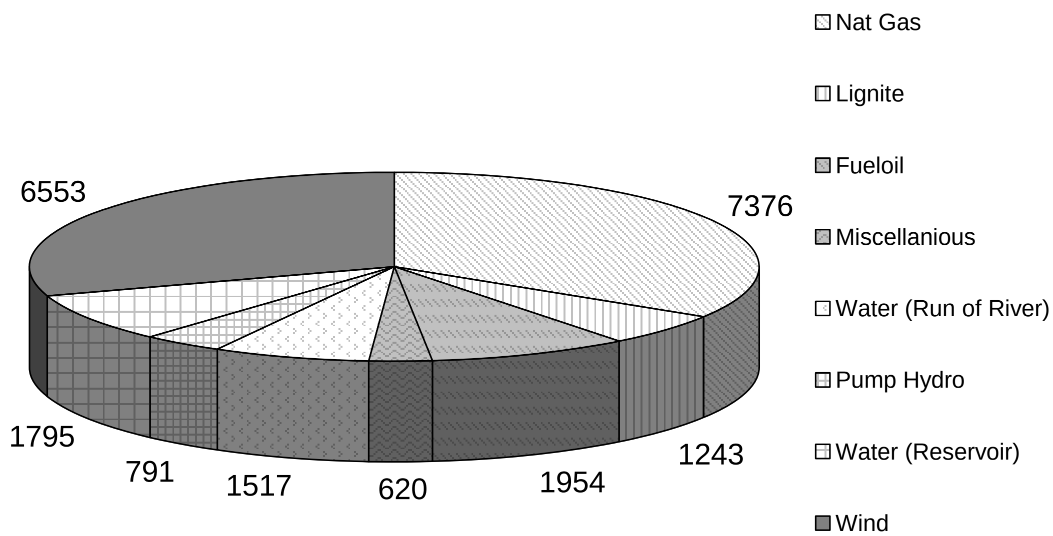

Fig. 1.4. Installed power plant capacities base case in 2030

According to the results from the investment model for 2030, there is a strong shift from lignite to natural gas. Installed lignite capacities will decrease from over 5000 MW to around 1250 MW in 2030. According to the applied power plant database, most lignite fired blocks get out of service between 2015 and 2030. The key driver for the strong shift from lignite to natural gas is the price for emission permits which is assumed to increase up to 60 Euro per ton carbon dioxide in 2030.

1.4 Results

After having performed the final model runs with the JMM, the results were analyzed with a focus on the electricity generation fuel mix and system cost. Based on these results the economic advantages and disadvantages of the different approaches can be assessed when investment cost is taken into account, too.

A. Base Case

The first JMM (see B in Fig. 1.1) run that is based on regions has the main objective to identify critical network elements and to define the network expansion measures.

Table 1.1. Critical network elements

Description	**Node 1**	**Node 2**
Line	Iasmos	Komotini
Line	Kavala	Thessaloniki
Line	Arachtos	Trikala
Line	Aliberi	Stefanos
Line	Aliberi	Arguros

Table 1.1 shows the list of critical network elements. The number of hours, when the network elements were operated at their power limit served as measure. Without power plant or network investment, the system has problems to cope with the increased demand and the large amount of wind power generation. The line between Arachtos and Trikala is the only part of the 400 kV main grid that faces congestion during some hours at its current situation. The majority of problems can be observed at the connections of the 400 kV central network with Evia and the Thrace loop as it was expected due to high wind power penetration.

B. Scenario 1: Wind integration with status quo of transmission network

The investment model E2M2 provided additional power plant capacities for the case that a nodal resolution was applied. Within the defined scenario, the model endogenously invested solely into gas turbines and gas fueled combined cycle units. With the given load structure and the defined parameters on CO2 and fuel development, lignite and coal fired technologies were less efficient than gas fueled power plants. Although gas fired power plants have higher fuel costs, their capital costs are lower and their emissions are lower, a factor which gains importance with increasing prices for emission certificates. Most of the investments took place in Arachtos and Stefanos. The additional power plant capacities are shown in Fig. 1.5. One observes a increase in total investment and a decrease of CCGT. The investment patterns show coherence with lignite power plants going out of service. The increasing share of gas turbines compared to CCGT in the future can be explained with a decreasing number of full load hours of gas units due to high wind penetration.

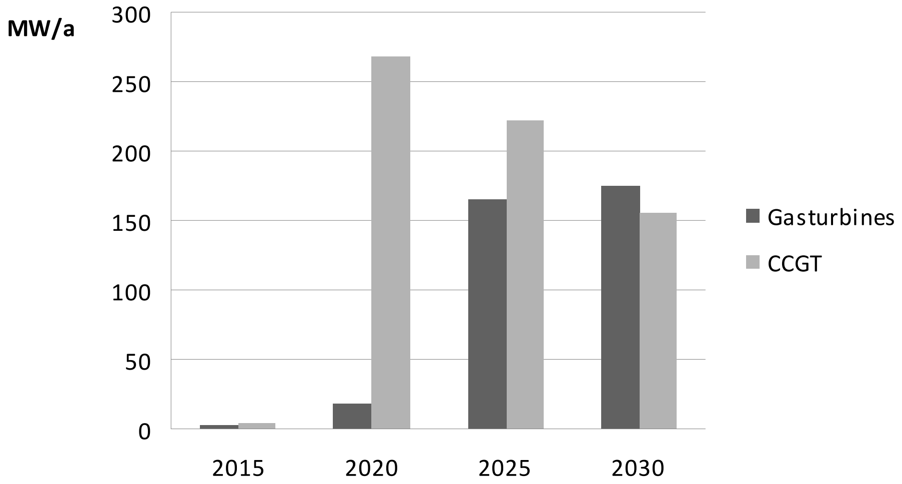

Fig. 1.5. Additional power plant capacities – scenario 1

After the final model runs with the JMM, information on the electricity generation mix by fuel and the system operation costs were obtained. The yearly electricity generation by fuel of selected regions is shown in Fig. 1.6. Only the regions with the highest electricity generation are shown. One can see that the largest part of the conventional electricity generation is covered by natural gas fired power plants. This can be explained with the high competitiveness of natural gas technologies in this scenario due to high emission certificate prices. Another explanatory reason is increased flexibility requirements due to the high wind penetration.

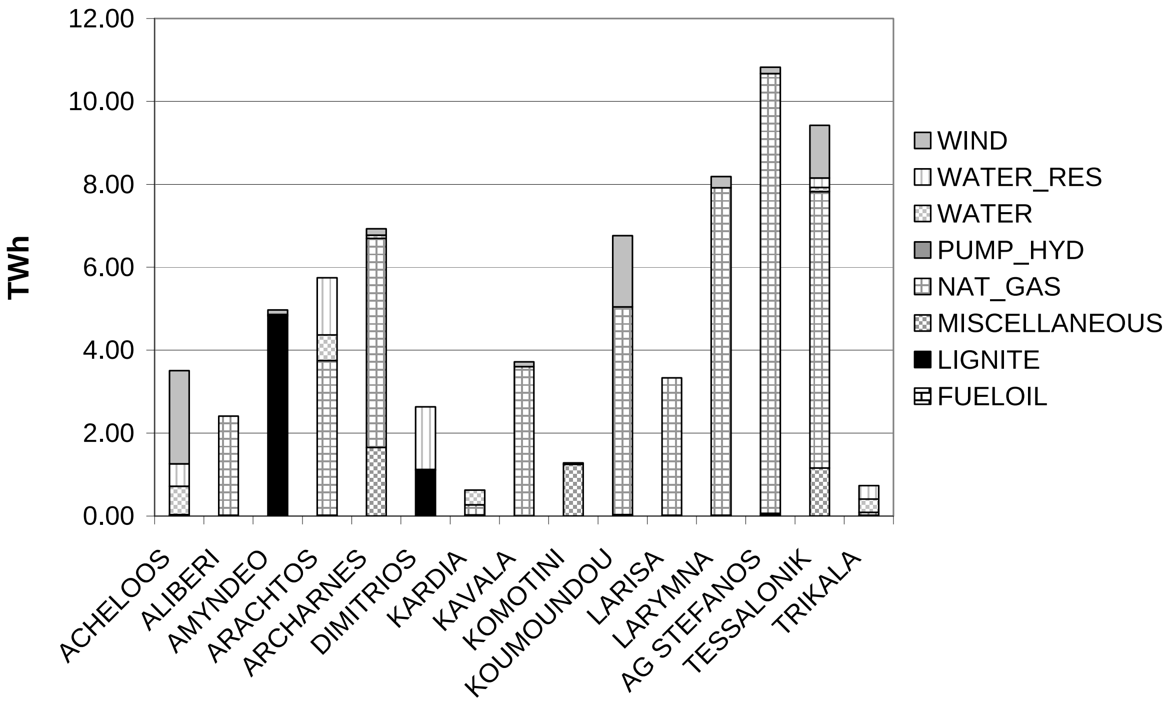

Fig. 1.6. Yearly electricity generation by fuel of selected regions in TWh – scenario 1

Table 1.2 shows the system operation costs in million Euro/year. The value fuel cost describes the price weighted fuel consumption for electricity generation. The emission cost (CO2) include all cost components that are due to emissions of greenhouse gas. For this purpose, the emissions of each power plant were calculated based on fuel consumption and the resulting emissions were transformed into cost via the price for emission allowances as defined in 1.3. The variable operation and maintenance cost (OMV) include all cost components that are related to the operation of the plant, but not emission or fuel costs. The fuel start cost describes the fuel consumption due to starting up and shutting down power plants. OMV cost and fuel start cost only play a minor role compared to the fuel cost and the cost for emission certificates.

Table 1.2. Scenario 1, system operation costs in mio. €/year

Region	**CO_2**	**Fuel costs**	**Fuel start**	**OMV**	**Total**
Acheloos	0.94	1.79	0.02	1.40	4.14
Aliberi	51.73	124.16	1.08	2.90	179.86
Amyndeo	288.26	54.21	0.33	9.70	352.50
Andros	5.04	11.61	0.03	0.29	16.97
Arachtos	80.53	192.82	2.74	7.95	284.04
Archarnes	142.99	280.21	1.89	8.58	433.67
Arguros	1.21	2.48	0.00	0.06	3.75
Dimitrios	73.17	13.18	0.64	6.01	92.99
Heliolousti	1.22	2.49	0.00	0.06	3.77
Kardia	9.24	21.76	0.40	0.33	31.72
Karustos	1.22	2.49	0.00	0.06	3.76
Kavala	77.51	186.24	2.50	4.32	270.58
Komotini	22.36	3.21	0.02	1.96	27.54
Koumound..	108.70	262.89	1.08	6.06	378.73
Larisa	71.62	172.41	1.14	4.01	249.17
Larymna	169.60	408.12	3.91	9.51	591.14
Leibadi	1.15	2.54	0.00	0.06	3.75
Myrtia	1.21	2.48	0.00	0.06	3.76
Polypota	1.21	2.49	0.00	0.06	3.76
AG Stefanos	234.55	565.37	4.70	12.82	817.43
Tessalonik	166.39	357.03	1.90	10.73	536.05
Trikala	2.68	5.84	0.12	0.92	9.56
Greece	1512.51	2675.81	22.50	87.83	4298.66

The evaluation of cost data is completed by evaluating power plant investment cost. Table 1.3 shows the annualized investment costs up to 2030. The total investment cost is transformed into annual rates, which are called annuities in the following. It was assumed that the interest rate was 10.2 % and the rates of 40 years, which approximately corresponds to the lifetime of gas fired power plants, had to cover the investment sum. In scenario 1, the total annuity for all power plant investments is 69.5 million Euro, which reflects a undiscounted investment sum of 670 million Euro.

Table 1.3. Scenario 1, Annualized investment costs in mio. €/year

Year	Annuity of investments in gas turbines	Annuity of investments in combined cycle gas turbines
2020	0.812	22.316
2025	7.203	18.507
2030	7.674	12.969

C. Scenario 2: Wind integration with grid extension

The second scenario included network extensions of critical network elements as found in the base case. The analysis starts with a further run of E2M2 (see F in Fig. 1.1). As reinforcements additional transmission capacity at Stefanos, an extension of the lines Iasmos - Komotini, Kavala – Thessaloniki, Arachtos – Trikala, Aliberi – Stefanos and Aliberi- Arguros were implemented. For lines an additional circuit was added which had the same parameters than the existing circuit. The transformation capacity at Stefanos was doubled.

The power plant investment decisions in scenario 2 by the model E2M2 (see F in Fig. 1.1) show strong coherence with the power plant investment decisions made by the run for scenario 1 (see C in Fig. 1.1), but are a little lower. The additional plant capacities are shown in Fig. 1.7. In the investigated case, network expansion could reduce the need for new gas turbines in 2030. This result is in line with expectations, as through the network expansion measures, some regional bottlenecks could be alleviated and so the power plant capacity on one side of the previous bottleneck becomes available for the rest of the system.

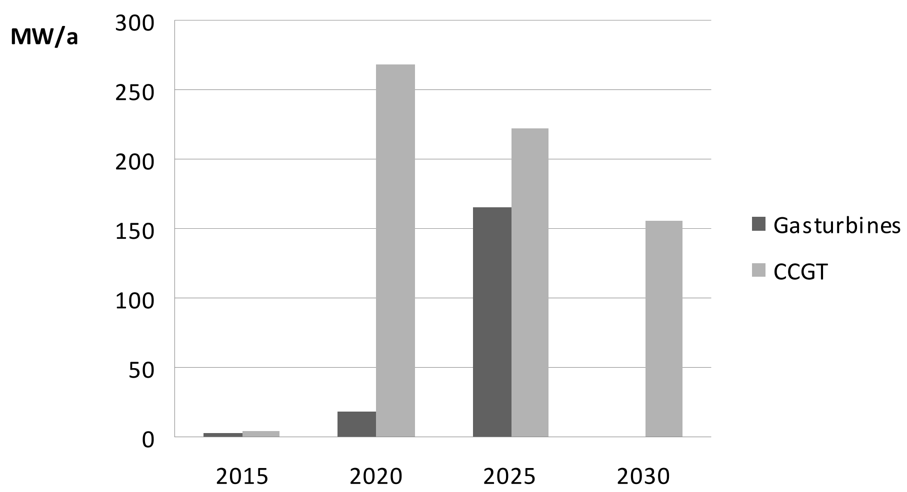

Fig. 1.7. Additional power plant capacities – scenario 2

Scenario 2 was analyzed in detail with the JMM, too. The electricity generation mix by fuel of selected regions is depicted in Fig. 1.8. The overall picture is similar to scenario 1. The dominant fuel is natural gas. Table 1.4 shows the system operation costs.

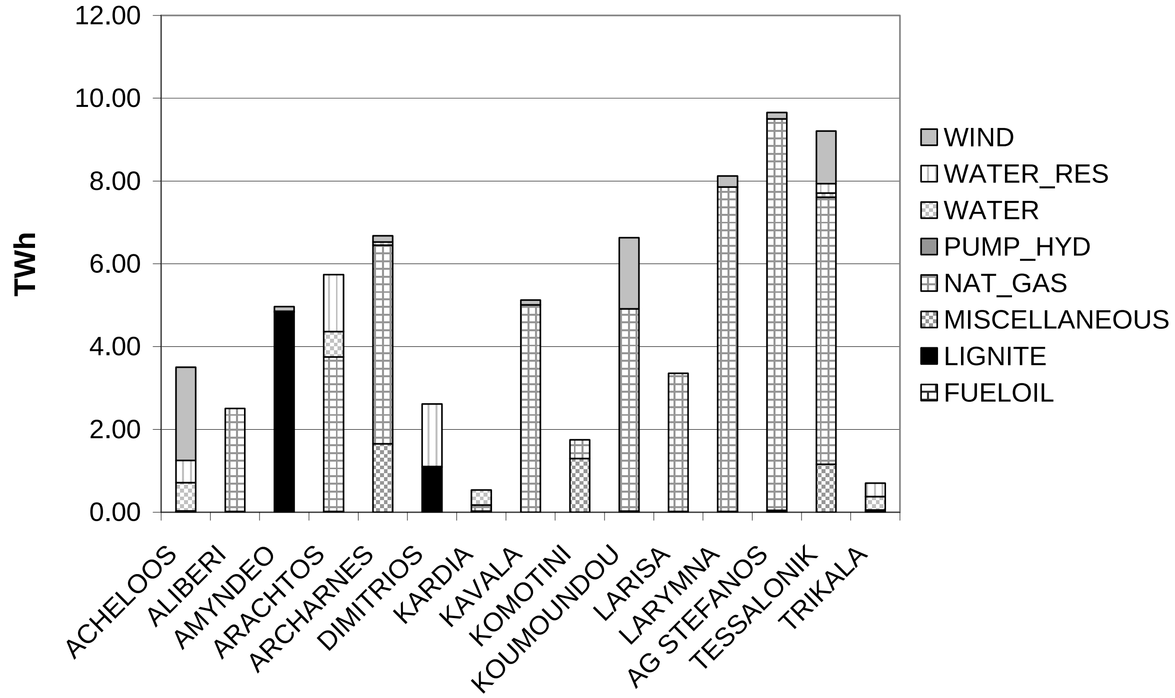

Fig. 1.8. Yearly electricity generation by fuel of selected regions – scenario 2

Table 1.4. Scenario 2, system operation costs in mio. €/year

Region	CO_2	Fuel Costs	Fuel start	OMV	Total
Acheloos	0.78	1.38	0.01	1.39	3.56
Aliberi	53.73	129.09	0.98	3.01	186.82
Amyndeo	288.03	53.39	0.30	9.69	351.42
Andros	5.08	11.73	0.02	0.30	17.13
Arachtos	80.51	192.68	2.81	7.95	283.95
Archarnes	136.94	265.44	2.00	8.28	412.66
Arguros	1.18	2.41	0.00	0.06	3.65
Dimitrios	72.04	12.90	0.64	5.98	91.55
Heliolousti	1.20	2.44	0.00	0.06	3.70
Kardia	5.91	13.76	0.24	0.22	20.12
Karustos	1.20	2.44	0.00	0.06	3.70
Kavala	107.72	258.79	3.49	6.01	376.01
Komotini	37.46	38.11	0.63	2.68	78.89
Koumound..	105.74	255.37	1.15	5.90	368.16
Larisa	72.01	173.37	1.10	4.03	250.50
Larymna	168.25	404.91	3.82	9.43	586.41
Leibadi	1.15	2.54	0.00	0.06	3.75
Myrtia	1.20	2.44	0.00	0.06	3.70
Polypota	1.20	2.44	0.00	0.06	3.70
AG Stefanos	208.71	503.22	3.49	11.41	726.84
Tessalonik	159.33	340.05	1.58	10.40	511.36
Trikala	1.58	3.20	0.06	0.88	5.72
Greece	1510.95	2672.11	22.34	87.91	4293.31

Again, the evaluation of cost data is completed by evaluating power plant investment cost. Table 1.5 shows the annualized yearly investment costs up to 2030. The same assumptions as for scenario 1 apply. In scenario 2, the annuity for power plant investments is 60.9 million Euro.

Table 1.5. Annualized investment costs in mio. €/year

Year	Annuity of investments in gas turbines	Annuity of investments in combined cycle gas turbines
2020	0.813	21.192
2025	7.251	17.917
2030	0.000	13.696

For the scenario with network investment, also the cost of network investment has to be taken into account. For line investments in 400 kV lines, we have assumed 300000 Euro/km for line upgrades. Investment cost on high voltage level (150 kV) were calculated with data by HTSO. In order to make the annualized investment cost of the networks comparable to the annualized power plant investment cost, the same interest rate and the same number of yearly rates was applied. However, normally the interest rate for transmission equipment is lower, because the grid is generally considered as a natural monopoly and thus risk premiums are lower. Further, the real lifetime of electricity network equipment is generally longer than 40 years. Under consideration of these assumptions, one obtains annualized investment cost of 9.39 million Euro. This corresponds to an overnight investment cost of 90.160 million Euro.

1.5 Conclusions

The case study demonstrated how the model package of E2M2 and JMM can be used to evaluate the economic impacts of network expansion measures for wind integration. The results are specific for the hypothetical assumptions of the scenarios and are likely to vary for different boundary conditions and/or of other countries.

In the case study, expansion measures had small economic impact, but lead to lower costs. In scenario 1, the power plant investment cost annuities are 8.6 million Euros higher. However, if one considers the annualized transmission investment cost of 9.4 million Euro, the overall investment cost in its annualized version is 0.8 million Euro higher in scenario 2.

The impact on operation cost was about 5 million Euro cost savings for 2030. This impact might be higher on systems with overcapacities, but for Greece in 2030, the generation capacities were tight in all scenarios. The investment cost are nearly equally high in both cases.

For transmission system operators, the tools can be used for evaluating the effects of different investment packages on total system cost. As a consequence, apart from grid reliability and other technical aspects, the economic benefits can be assessed and evaluated for a more thorough planning of future transmission system works.

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2 Investment planning of Interconnectors under consideration of wind power extensions in Europe

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2.1 Introduction

During the last decade, power markets in Europe have been liberalized and competition has been introduced into the wholesale markets. Making use of existing interconnectors, the trade of electricity has led to an increased integration of single countries' markets [1]. Within a functioning, integrated European market, dispatch and exchanges are organized in a cost minimizing way. As long as there are price differences between interconnected zones, there are potential welfare gains in increasing the grid capacities that connect neighboring zones. Hence increasing interconnector capacities is a policy option that helps to reduce overall electricity generation cost [2]. Unfortunately, the increase of interconnectors is rather expensive and therefore it has to be investigated whether the benefits of the investment are higher than cost. Herewith it should also be investigated whether investing into cheaper generation technologies instead of grid capacities is more economic.

In order to do so, system planning models can be used to estimate the value of additional interconnectors and power plants in a fundamental system perspective (as described by [3] or [4]). Another trend that can be observed in recent years is the fact that in many European countries large amounts of intermittent generation capacities, most notably wind turbines, have been installed. Wind turbines make system planning more difficult, because their capacity contribution is limited compared to conventional generation technologies and their stochastic behavior impacts the dispatch of plants and also the long run investment planning in power systems [5], [6]. In order to consider the impact of wind stochastics, it is not sufficient to use deterministic planning tools as they were established previously, because they do not properly consider volatile generation [6]. Within this chapter we present a stochastic power system market model that takes the intermittent characteristics of wind into account and is capable of modeling the whole European power market in order to analyze investment decisions. We use the model to assess a potential increase in European interconnector capacities, mostly between the northern European countries and the European mainland. The results of the model can also be used to determine the distributional effects on transmission system operators (TSOs), producers and consumers of electricity in the affected countries.

This chapter starts with the economic valuation of interconnector capacities and the impact of wind power onto these considerations in section 2.2. Afterwards a description of the applied model and the investigated scenarios are presented in section 2.3. Consecutively we present model results and discuss their implications (section 2.4). The chapter ends with brief conclusions on the achieved results.

2.2 Economic considerations

In the following we summarize the economic considerations and concepts on which the envisaged results are based.

2.2.1 Interconnector economics

Interconnection between countries has several positive effects, of which the most important are [2]:

- Decrease in generation cost
- Decrease in generation investment
- Increase of system security
- Reduction of potential market power

Within this analysis we only investigate the first three issues, whereby system security can only roughly be approximated, because the physical representation of the model is rather low. Mostly reserve issues are considered with help of a convolution approach and some restrictions on capacities being online. The last issue cannot be analyzed because fundamental system models always assume perfect competition in the electricity markets. As higher interconnection is mostly useful for increasing competition we tend to underestimate the benefit of increased interconnection capacities. In the following a stylized two country model is used (cf. Fig. 2.1) to highlight the general benefits of increased interconnection and how these benefits are distributed among the relevant stakeholders. For further details we refer to [15].

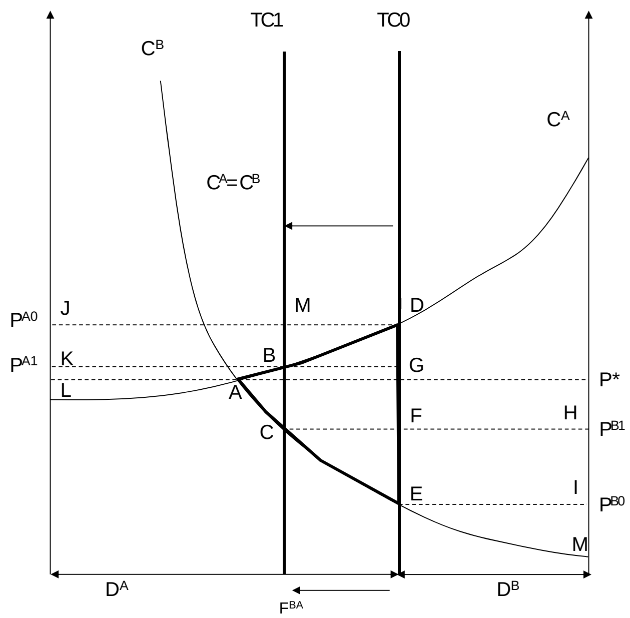

Fig. 2.1. Welfare implications of interconnection

On the abscissa we draw the total demand of two countries in one particular situation. Supply is represented in form of merit order curves C^A and C^B that are different in shape. Actual demand levels D^A and D^B deviate from each other as well. If both countries are to serve their own load, significant differences in (marginal) generation cost arise. If the two countries could exchange electricity with no limitation, they would do so and as a result a homogenous price in both zones P* would be established. Of course this can only occur when there is sufficient transport capacity for transmitting electricity, so that one single price level is reached. In the described situation above we firstly presume no transmission capacity (TC0) just defining the demand level in both countries. Here potential beneficial exchanges of electricity are impossible. Herewith we have different prices in height of $P^{A0} > P^{B0}$ and the optimal situation with a uniform price level is not reached. This situation leads to a theoretical welfare loss in height of the area ADE, because overall generation costs are higher than they theoretically could be. If the interconnector capacity is increased to the level TC1 the optimal price level is still not met, but the welfare loss is significantly reduced to the Area ABC, resulting in a welfare gain in height of CBDE. When looking onto these results, one has to keep in mind that the increase of interconnection is rather expensive. As the marginal welfare gain decreases with increased capacity the optimal transmission capacity is not the one that avoids all welfare losses of congestion, but the one where avoided welfare losses equal the investment cost of newly built transmission lines. This means that there is an optimal level of congestion on interconnectors, because it is too expensive to avoid all congestion.

Furthermore, the interconnection of countries has also distributional effects which are of great relevance in grid planning, because not all welfare benefits of grid upgrades are given to the investors of interconnectors, so that there might be not the right incentives for welfare optimal grid planning as described above. In principle three different groups are affected by grid planning: Firstly the network operator who is auctioning the available network capacity, secondly the generators of electricity and lastly the consumers of electricity.

Whilst the last two can easily be distinguished on a country level, it is not easy to allocate the grid income to the involved countries. Here it often depends on given contracts and made investments which country is benefiting from grid investments. Therefore, we assume within this study that the congestion rent obtained by the TSOs is split in half for both involved countries TSOs. The following table summarizes how the increased interconnection is affecting the rents of the involved stakeholders in the following table:

Table 2.1. Welfare implications of interconnection

Stakeholder	Situation 0	Situation 1	Δ
consumers A	∞	∞	KJBD >0
consumers B	∞	∞	FHEI <0
producers A	LJD	LKB	KBJD <0
producers B	MEI	MCH	ECHI >0
TSO A	0	½*BCGF	½*BCGF>0
TSO B	0	½*BCGF	½*BCGF>0

The table shows that consumers in A benefit from interconnection whilst consumers in B suffer from higher prices. Due to inelastic demand in the figure the consumer surplus is infinite. Nevertheless there is a change in surplus in both countries. The situation of producers is vice versa, because the last unit serving system needs becomes more expensive in B and cheaper in A. The TSOs have to split the congestion rent BCGF, which is smaller than the total welfare benefits in height of CBDE. Due to this, it is very important to consider not only the gains in welfare but also its distribution, because it might be necessary to compensate the TSOs if overall welfare gains of an optimal line extension are higher than the investment costs but at the same time the congestion rent is not sufficient to cover these investment cost.

2.2.2 Impact of wind power

Besides the arguments derived from economic theory, the impact of wind has to be considered in future grid planning, too. The impact of stochastic wind in-feed onto power system planning is mostly given in two ways. Firstly, wind generation is influencing the merit order curves in both countries and is affecting the generation cost differences, which can be seen as most important drivers for welfare increase of interconnection. In the following graph this impact is stylized:

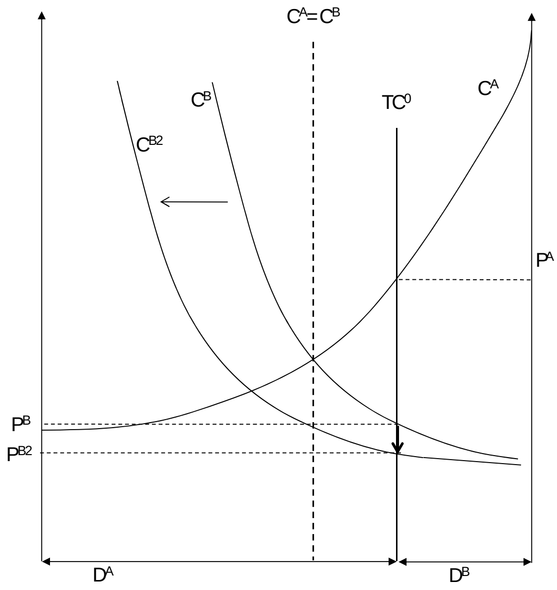

Fig. 2.2. Static welfare impact of wind on interconnection

If in country B the wind is blowing, the merit order curve is shifted from C^B towards C^{B2}. This leads to a price drop from P^B to P^{B2} and hence the price difference between the two countries increases. As a result the value of interconnection between both countries increases. One has to be aware of the fact, that in the reverse case, if wind is blowing in country A, the value of interconnection is decreasing.

But just assuming one wind power scenario and its impact onto prices is not sufficient for the evaluation of interconnectors, because the volatile characteristics are not properly included. Due to this, not only cost savings, but also the impact on system flexibility has to be addressed. Here interconnection between systems with high and low flexibility becomes more attractive in such a stochastic setting, because without congestion the interconnectors can be used to avoid cost intensive redispatch due to drops in wind in-feed.

Meanwhile, not only short run generation cost but also investments into power plants can be saved with increased interconnection. Due to the fact that it is rather expensive to store electricity to a large extent it is necessary to have sufficient capacities to handle peaks in wind production and to serve peak demand needs. If the wind production as well as load of neighboring countries is not perfectly correlated, interconnection helps to reduce backup capacities, because the capacities of the neighbor could partly be used in peak situations. Respectively, if capacities have to be held available in terms of security the cost-efficient power plants of the whole system and not of each region can be used.

2.3 Methodology

2.3.1 The E2M2s model

For quantification of economical effects of limited transmission capacities and their extension the stochastic European electricity market model (E2M2s) is used. It was developed within the GreenNet project [7] and further sophisticated within the SUPWIND project [8]. The E2M2s model starts from the well-established result in economics that a functioning competitive market will lead to the same results as system optimization by an omniscient central planner– the market manages and coordinates supply and demand optimally like an invisible hand. As a result cost efficient power plants are used to cover demand. Considering an inelastic demand in the short run it is possible to use a cost minimizing optimization approach. This approach is formulated as a linear, stochastic programming model that contains different time steps (typical days and typical hours), different regions and all relevant actors. It is implemented in the General Algebraic Modeling System (GAMS) and for the current study it deals with 14.4 Mio parameters and 1.5 Mio variables.

The key variables of the model are generation, transmission and pumping quantities. The model simultaneously determines the yearly vector of variables that minimizes total cost subject to demand satisfaction and detailed technical limitations of power system components. A detailed description of the restrictions can be found in [5], in [8] and in the appendix.

An entire year is covered in order to represent adequately yearly reservoirs whose dispatch cannot be optimized in shorter periods, because the use of the reservoir filling is usually allocated in a yearly perspective. In order to capture seasonal effects on electricity demand, power supply and demand are analyzed at twelve typical days within one year. Thereby a working day and a non working day are chosen for every second month. These weekdays are again divided into two-hour-steps in order to represent temporary fluctuations in demand and in production of RES. Altogether there are twelve typical days with twelve typical hours each.

Concerning electricity demand all model nodes have to have sufficient capacities to match demand needs on an aggregated level. Due to the fact that parts of electricity generation is produced by CHP units, which also have to serve heat at a local level, we also define local heat grids which are regional subsets of a corresponding zone. The CHP units located in certain subareas can only be used to produce heat in this specific location, but its electricity can also be used to match overall electricity demand in the aggregate of all sub regions in one country node.

The objective function of the model includes all operational cost of the existing conventional power plants. In case the inelastic electricity demand cannot be covered with given generation capacities the model endogenously decides in which new technology to invest. For newly built capacities therefore also annualized investment cost beside variable cost are considered in the objective function in line with the Peak load Pricing approach as developed by [9] and [10]. For investment decisions the yearly full load hours are a key driver for technology selection. In case that there is only need for new plant capacities during short periods in time, less capital intensive technologies like gas turbines are preferred, in case that there is a capacity need for long periods in a year, base load technologies with low variable cost become more attractive.

The innovative features of the model are the depiction of wind and hydro stochastic. The challenge in the design of a large scale stochastic system model is the representation of stochastic and an extremely large system at the very same time. For this reason the model optimizes typical days with typical wind generation scenarios based on weekly and seasonal characteristics in electricity demand. Wind power and hydro inflow are approximately incurred via a so called recombining decision tree as shown in the following graph.

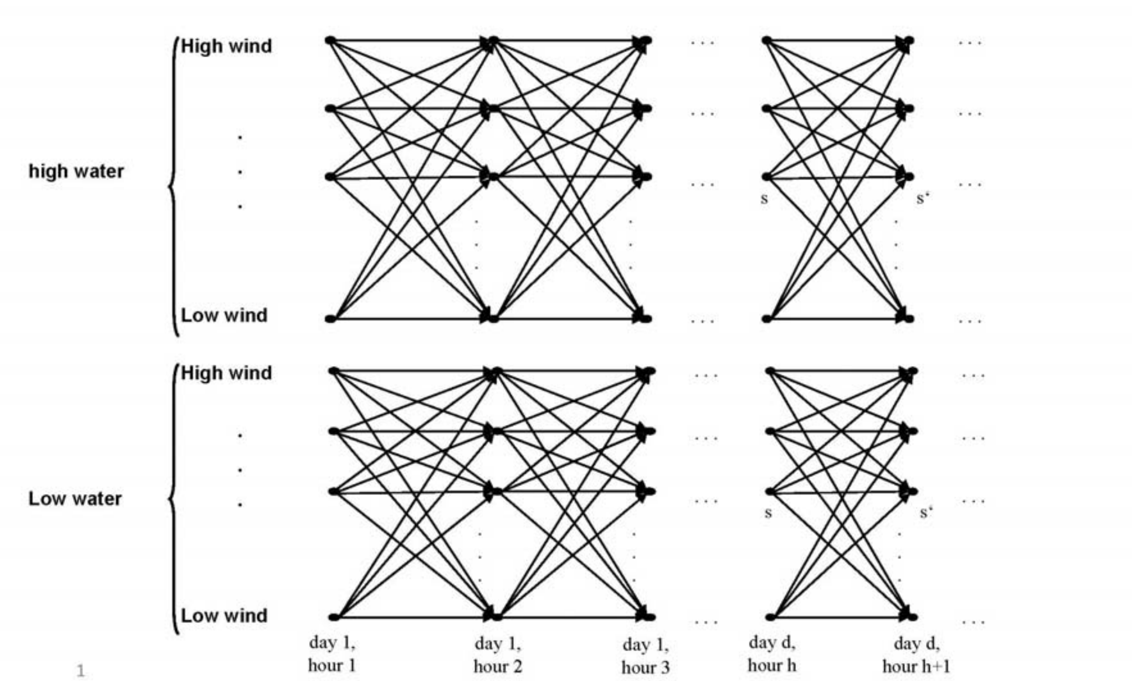

Fig. 2.3. Concept of recombining decision tree

In stochastic programming the size of a problem is exponentially increasing with the numbers of variables [11]. Due to this we use an approximation which limits the number of stochastic nodes in any stage of the decision process to three wind scenarios and two hydro scenarios. Thereby the tree is defined as a recombining tree, reducing considerably the number of nodes and avoiding the curse of dimensionality.

The probabilities of the typical nodes and the corresponding transition probabilities between the nodes are derived by cluster analysis applied on historical wind production and hydro inflow data. This approach is not covering the total range of meteorological driven insecurity, but it is able to approximate system variability to a large extent and is still feasible for application in large scale modeling, which is much better than a deterministic planning approach, which is not at all taking the stochastic of meteorological driven technologies into account.

The reason why a proper representation of stochastic in long run investment planning is so important is straightforward: The incorporation of increasing amounts of intermittent technologies gives need for sufficient system flexibility. Deterministic planning tools do not fully reflect the need for system flexibility and hence there is the danger that they optimize a power system in a way that too little flexibility is given for the dealing with intermittent generation. The stochastic of the E2M2s model is also helpful in evaluation of interconnector capacities as done in this study, because increased interconnection of regions with higher flexibility and regions with little flexibility might reduce system cost related to wind integration insecurities. Further the variability and related uncertainty introduced by wind power is also determined by interconnection capacities as the wind power generation in interconnected regions is typically not perfectly correlated.

With the inclusion of several realistic wind scenarios which approximate the range of wind generation scenarios the evaluation of interconnectors and also power plants becomes more realistic. The power plants have to cope with the insecurity of realized wind and hence within the dispatch the risk of rapid drops or increases of wind generation has to be incorporated. The stochastic model will not only choose the cost efficient dispatch for one wind scenario, but also a dispatch that is capable in dealing with potential large changes of wind in-feed at least cost. Hereby the fact that efficiency is reduced under part load operation and that increased start ups of units are expensive is explicitly considered within the model by linear approximation as done by [16].

2.3.2 Geographical scope and data

The model can be run at different levels of regional aggregation. Level of detail and the number of considered zones can be handled flexibly. Within this study the EU-27 region is modeled, excluding Cyprus and Malta. Additionally, the Balkan countries, Switzerland and Norway are considered. Every country is considered as one single node in the model – taking into account the zonal separation of markets in Europe. For trading net transmission capacities (NTC) are assumed, which can be used by traders but leave an emergency margin for loop flows and n-1 security. Due to the fact that the market is in the focus of the modeling it is assumed that physical constraints, as they are considered by TSOs but not by generators are of lower priority. Generators and traders only consider the limits as given to the markets and do not consider physical boundaries. In order to model realistic market outcomes it is necessary to neglect physical restrictions.

The data for the model has been collected within the SUPWIND project. For details we refer to [8]. The scenario for the future deployment of renewables has been derived using the Green-X tool, which models investment decisions based on future potentials and costs of several renewable technologies for electricity production and country specific framework conditions. For the specific scenario it was assumed that currently implemented support policies and existing barriers to penetration are persisting in the future. (e.g. [12]).

The collected data is stored within a database that can be used to flexibly transfer desired parameters into a format suitable for optimization.

2.3.3 Scenarios

For the calculations within this study we assumed a business as usual scenario where we presume a continuation of ongoing trends in energy markets. The parameters refer to the “Conflict” scenario of the SUPWIND project as described in detail in [8]. The following graph describes the fuel price developments in euro/MWh, which are a key for the planning of future power plants and interconnectors.

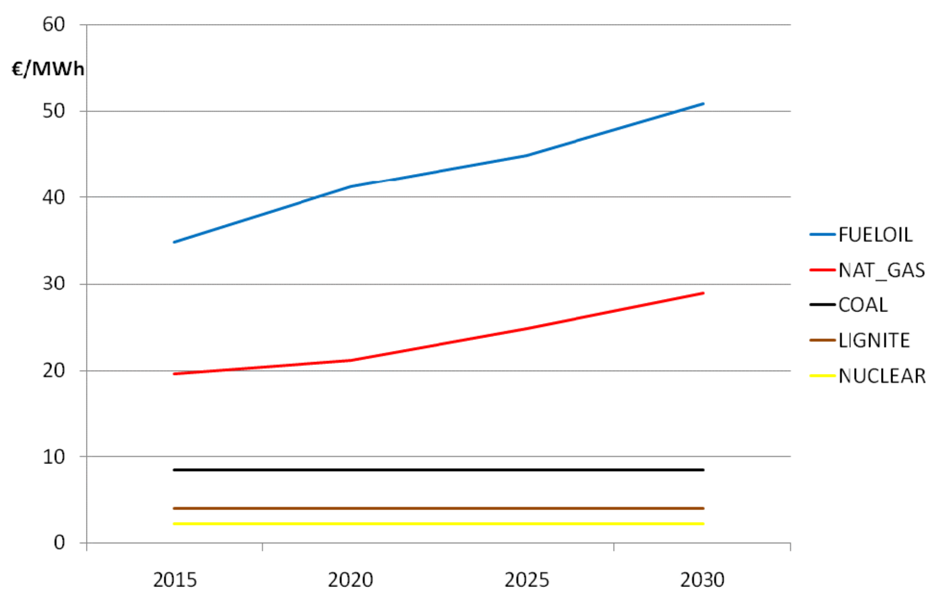

Fig. 2.4. Assumptions on fuel price development in euro/MWh

The CO_2 price is assumed to start from nowadays 25€/t level up to a level of 60€/t in 2030. The interest rate for investments is assumed to be 7% in real terms and is based on the weighted average cost of capital. Another key issue for the scenarios is the further deployment of wind power capacities. We assume a significant increase in wind power installations, which makes an evaluation of the stochastic more important than nowadays.

Since the value of interconnectors is of particular interest in the present study, we perform two model runs. One run with the existing grid – taking into account already announced interconnection projects and another model run with increased interconnector capacities beyond the existing planning, starting from 2020. We focus on a stronger connection of Northern Europe to the mainland, because this interconnection is under discussion for a better integration of wind power. In principle this analysis can be seen as a starting point for the investigation of a *supergrid* which is often discussed for integration of wind power (cf. [13]). We only investigate the market value and the benefits of wind market integration of increased interconnection, but neglect the fact that there might be synergies in combined planning of offshore wind farms and oversea DC-Links [14]. The focus of the calculation is on welfare effects and their distribution. The presumed enforcements and extensions are shown in the following picture:

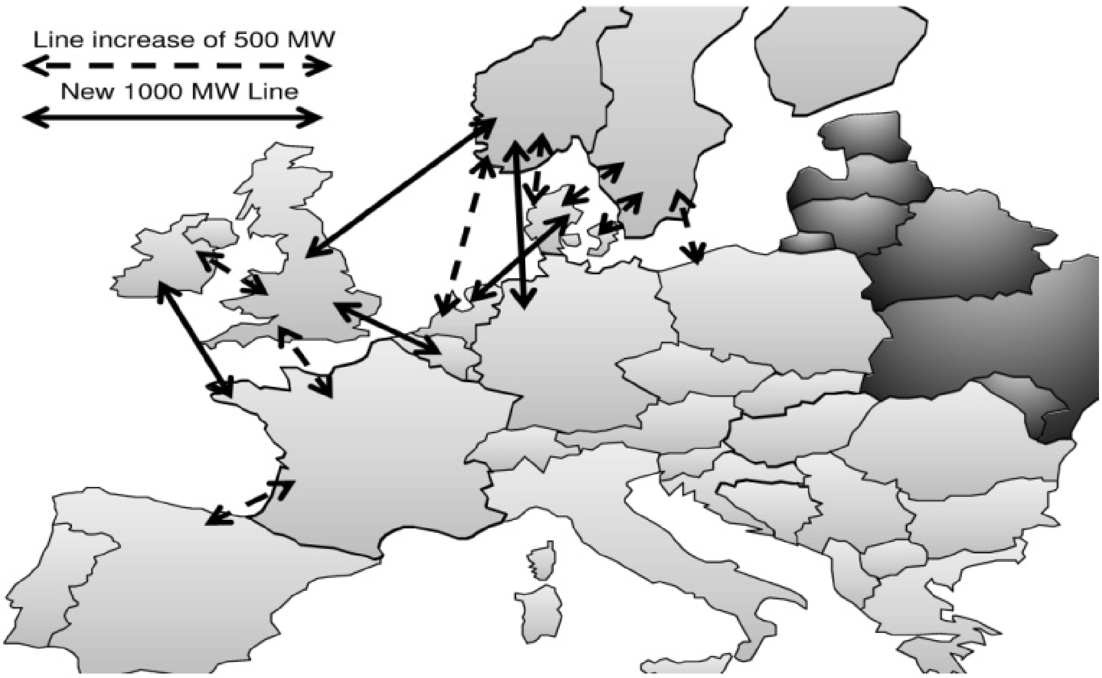

Fig. 2.5. Changes in European interconnection

We assume that on 8 existing interconnections additional capacities of 500 MW are installed and that 5 new connections with 1 GW capacity are introduced. Due to calculation time we model in time steps of 5 years and interpolate the remaining years up to 2030. It is assumed that the newly build lines would become operative in 2020.

2.4 Results and discussion

In the following we will summarize the core results of the modeled scenarios. Analyzing interconnector utility a high utility on most lines can be observed and as a result bottle necks often occur. Only the interconnector between Belgium and the United Kingdom has a utility under 30% over the whole period. Notably, even with additional transmission capacities bottle necks are hardly reduced referred to the utilization. Also new lines have mostly a high utilization in the beginning. This shows that utilization alone is not an appropriate indicator for line investment. More significant is the marginal value of transmission capacities, which means the average price difference between two regions over the year. This is shown in Fig. 2.8 and equates to the price difference between P^{A0} and P^{B0} in Fig. 2.1. It shows the welfare effect of marginal line investment. Depending on the merit order curves of both countries this is not the average welfare effect of a discrete line investment. Further on you can see in Fig. 2.8 that with additional transport capacities simultaneously on different borders welfare may even increase instead of decreasing with additional investment. This can be observed on the border between France and United Kingdom in 2030. Here additional transport possibilities for France in other neighboring countries indicate that beside occurred transmission investment additional transport capacities gets a higher value.

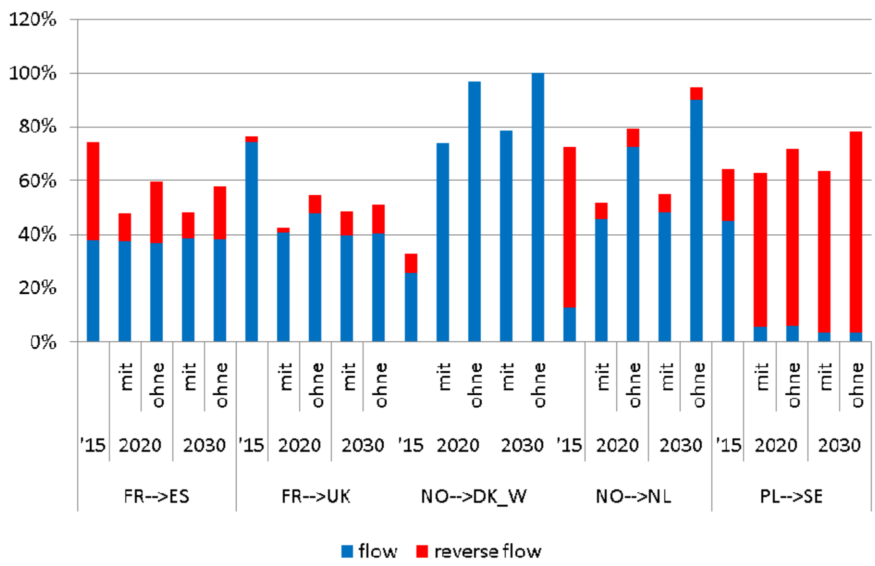

Fig. 2.6. Utilization of selected transmission capacities - with and without extension

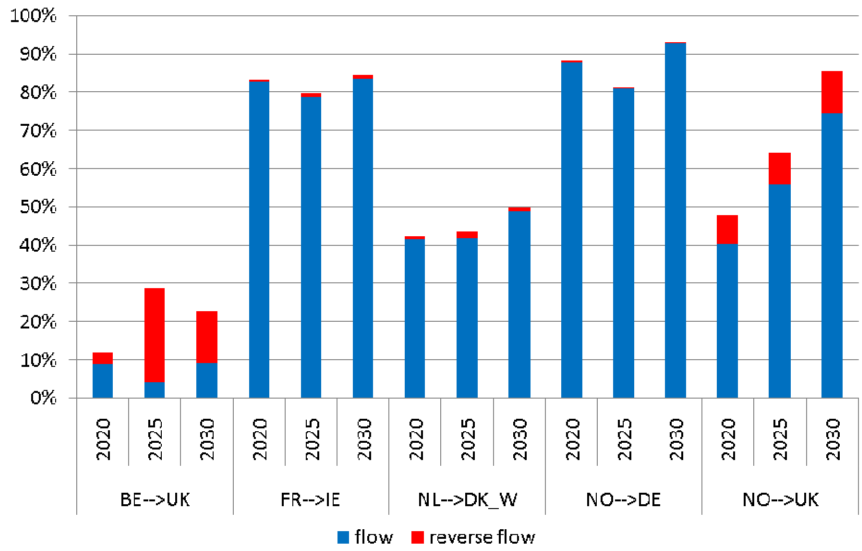

Fig. 2.7. Utilization of selected new transmission capacities

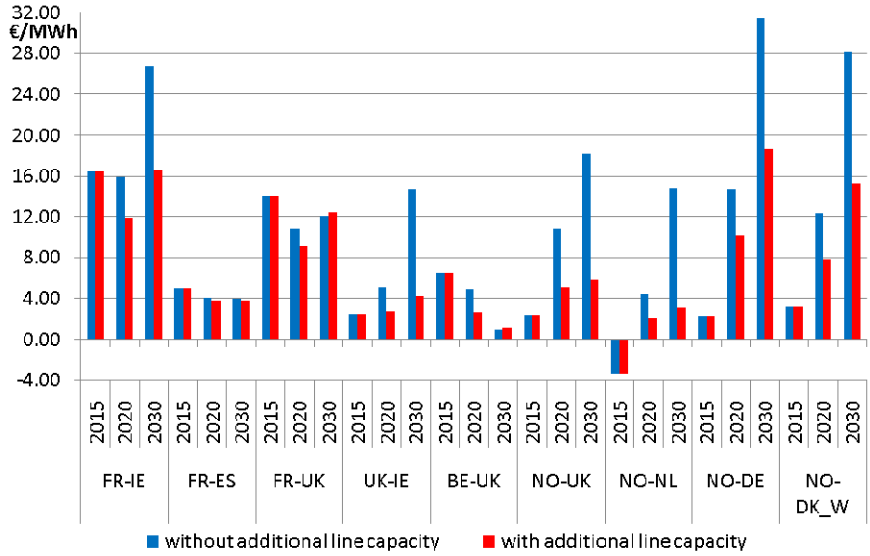

Fig. 2.8. Opportunity costs of selected transmission capacities

For an integral evaluation it is necessary to analyze total welfare gain by additional transmission capacities. Therefore total reduction in system cost can be calculated, which is equal to welfare gain of increased interconnector capacities. The welfare gains can separately be shown for the modeled countries. The following graph reveals the welfare gains discounted to the year 2020 on a selected country level:

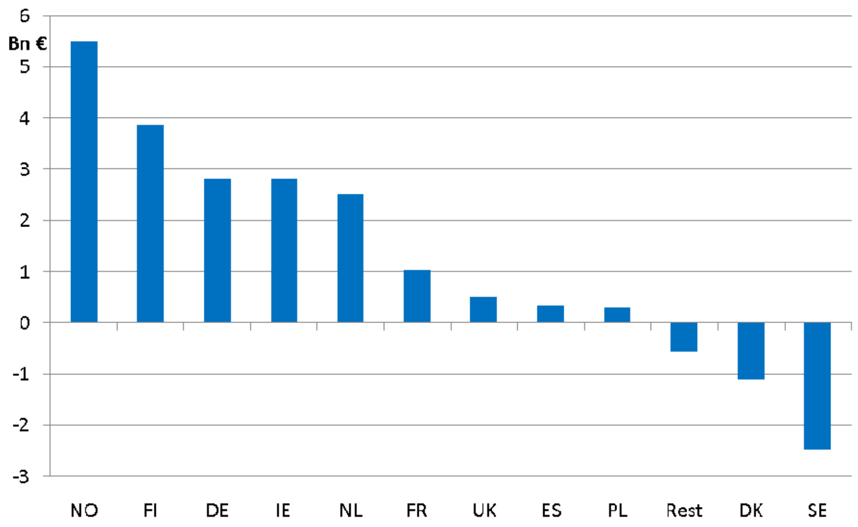

Fig. 2.9. Discounted national welfare gains of interconnection in 2020

When discounting the yearly outcomes it was assumed that not explicitly modeled years had the same cost savings as the preceding ones. For the years beyond 2030 the perpetuity concept was used.

Not surprisingly the additional interconnection is increasing the total welfare. Within this scenario the discounted benefits amount up to 15.5 billion euros in 2020. In general this means that interconnection as presumed in our scenario is legitimized whether the investment cost for the new lines and upgrades are below this level. Using a deterministic approach, benefits of 7.5 billion euros occur. The difference of 8.0 billion euros can be interpreted as a value of flexibility connected to fluctuating power and wind production that comes along with a particular investment.

Looking into the details, one can observe that the overall welfare gain is concentrated on two countries: Norway and Finland. Here especially the producers take advantages of increased national electricty prices due to larger interconnection and they start to export more. It is a little bit surprising, that the Netherlands are gaining so much from interconnection. The reason for this gain is the fact that with the assumptions on CO_2 and gas prices, combined cycle units become more attractive than coal units. Due to the fact that the Netherlands have a lot CCGT units they can use the new built lines to export towards other countries. Within scenarios without high CO_2 prices this might not be the case. It can also be observed that the welfare of selected countries is negativley affected by interconnection. Here in total the countries stakeholders loose more parts of there rents and the interconnection is reducing the regional welfare. Especially Denmark and Sweden are loosers within our setting. Both are suffering from higher prices in Norway due to interconnection. This results from the fact, that

Norway is exporting more to other countries than Sweden, which now has to use more expensive home based units or imports from more expensive regions.

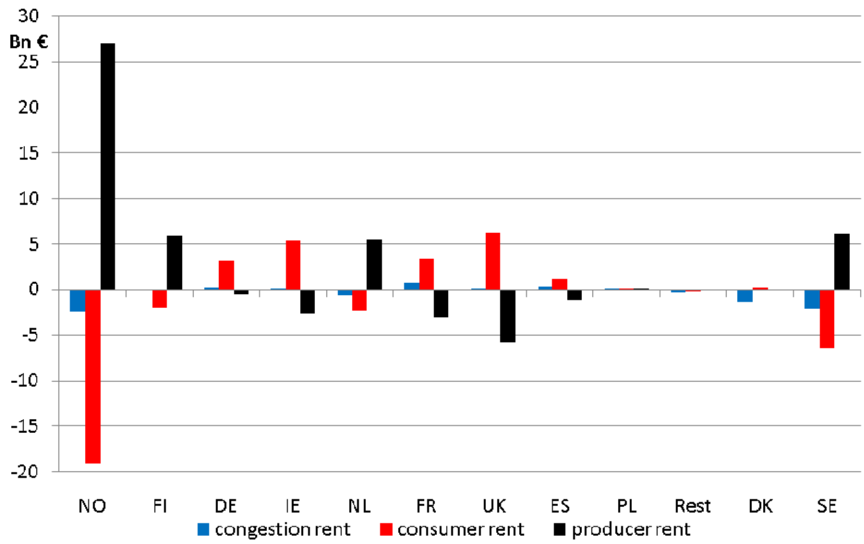

Fig. 2.10. Discounted welfare gains' distribution in the year 2020

It is also interesting to investigate how the different stakeholders in the electricity market are affected by the interconnection. In Fig. 2.10 the effect on consumer and producer surplus as well as on the congestion rent is highlighted for the discounted values in 2020. Here it can be seen that there are severe impacts on the distribution of welfare. Compared to the welfare changes the impact on single stakeholders has a much larger magnitude. E.g. in Norway the consumers have to cope with very high losses due to the fact that increased interconnection is increasing national electricity prices. These losses are more than outweighted by the increases in producers gains so that an overall positive welfare effect is given. Besides this it is also very interesting to observe that enhanced interconnection is mostly reducing the congestion rents of the involved TSOs. Even though there is an overall welfare gain from interconnection, most TSOs lose revenues when financing interconnector increases. Notable exemptions is the case of France, here congestion revenues are increased. The reason why congestion rents are reduced is a decrease in price differences between the involved countries. This effect is reducing the revenues from auctioning interconnectors despite the fact that more electricity is traded. This result emphasises that if welfare optimal investments are to be undertaken, TSOs need revenues from other sources for paying the overall beneficial investments. An obvious solution for this problem would be an increase in network tariffs, which would have to be allowed by the regulatory institutions which are supervising the Transmission system operators.

Another important issue when looking onto the results of this analysis is the question of investment timing. Due to both changes in the European generation mix, notably the phasing out of old plants and the commissioning of new plants and in fundamental parameters like fuel and CO_2 certificate prices, the impact of interconnection might change over the years.

When looking on these results it has to be emphasised that it is useful to time new interconnection in a way so that the related benefits arise around the time of investment. The reason for this is the discounting of future payments. Herewith, also the interest rate chosen for analysis is of importance. Benefits which occur far ahead in the future are less valuable than more promptly benefits. In order to find the best point in time for investment it is useful to model several scenarios of investment planning with different starting points. An optimal solution could also contain different starting dates for several envisaged lines, which of course makes an investigation very cumbersome. All in all for a decision under uncertainity it is useful to investigate a set of scenarios that reflect the future development of parameters like fuel and CO_2 certificate prices and electricity demand under different framework conditions. because these are key drivers for investment planning. Hence, for a real world decision not simply one but several scenarios with different assumptions on future circumstances and different network enhancements should be investigated.

2.5 Summary

Within this study we present a stochastic market model for the evaluation of grid extensions. The introduction of wind makes a proper representation of wind stochastic necessary, because interconnectors might help to increase system flexibility for wind integration.

We distinguished overall welfare effects of interconnectors incorporating potential flexibility gains. Additionally we derived the distribution of these effects, because the distribution of benefits can make it necessary to compensate those who are investing into new interconnectors. We have shown within an example how to evaluate the welfare impacts of transmission investments. For real world decision making is recommended to model several scenarios of interconnector increases, where fuel and CO_2 costs and the timing and magnitude of investment are varied.

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