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Abstract

This dissertation focuses on selected aspects of network congestion arising in liberalized electricity markets and their management methods with a special weight placed on the integration of increased renewable generation in Europe and Germany. In a first step, the theoretical concepts of congestion management are introduced complemented by a review of current management regimes in selected countries. In the second step, the European approach of managing congestion on international as well as national transmission links is analyzed and the benefits of an integrated congestion management regime are quantified. It is concluded that benefits can be achieved by a closer cooperation of national transmission system operators (TSOs). Thirdly, the German congestion management regime is investigated and the impact of higher renewable generation up to 2020 on congestion management cost is determined. It is shown that a homogeneous and jointly development of generation and transmission infrastructure is a prerequisite for the application of congestion alleviation methods and once they diverge congestion management cost tend to increase substantially. Lastly, the impact of intermittent and uncertain wind generation on electricity markets is analyzed. A stochastic electricity market model is described, which replicates the daily subsequent clearing of reserve, dayahead, and intraday market typical for European countries, and numerical results are presented.

Das Leben ist wert, gelebt zu werden,
sagt die Kunst, die schönste Verführerin;
das Leben ist wert, erkannt zu werden,
sagt die Wissenschaft.
Friedrich Nietzsche (1844-1900)

Contents

List of Tables

List of Figures

List of Abbreviations and Nomenclature

Abbreviations

$\Delta E, \Delta E^{max}$	Maximum additional exchange between two countries
AAC	Already Allocated Capacity
AEP	American Electric Power
ARMA	Auto regressive moving average
ATC	Available Transmission Capacity
AusglMechV	Ausgleichsmechanismusverordnung
BCE	Base case exchange
BDEW	Bundesverband der Energie- und Wasserwirtschaft
BETTA	British Electricity Trading and Transmission Arrangements
BNetzA	Bundesnetzagentur
CB	Congestion benefit
CC	Congestion cost
CCGT	Combined cycle gas turbine
CCOT	Combined cycle oil turbine
CEE	Central East Europe (Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia)
ComEd	Commonwealth Edison
CR	Congestion rent or surplus
CWE	Central West Europe (Belgium, France, Germany, Luxembourg, Netherlands)
D	Day
DC	Demand or consumer cost
DCLF	Direct current load flow
DSO	Distribution System Operator
EC	European Commission
EEG	Erneuerbare Energien Gesetz
EEX	European Energy Exchange
ELMOD	Electricity market model

EMCC	European Market Coupling
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz
EPEX	European Power Exchange
ERCOT	Electric Reliability Council of Texas
ERGEG	European Energy Regulators
ETSO	European Transmission System Operators
EU	European Union
EUR	Euro
EWEA	European Wind Energy Association
EWIS	European Wind Integration Study
FACTS	Flexible Alternating Current Systems
FERC	Federal Energy Regulatory Commission
FPN	Final Physical Notification
FTR	Financial Transmission Right
GB	Generation benefit
GBP	British Pound
GC	Generation cost
GDP	Gross domestic product
GS	Generation surplus
GW	Gigawatt(s)
GWh	Gigawatt Hour(s)
HVDC	High voltage direct current
ISO	Independent System Operator
km	Kilometer(s)
LMP	Locational marginal price
MW	Megawatt(s)
MWh	Megawatt Hour(s)
NETA	New Electricity Trading Arrangement
NGET	National Grid Electricity Transmission
NTC	Net Transfer Capacity
NUTS	Nomenclature of Territorial Units for Statistics
OCGT	Open cycle gas turbine
OCOT	Open cycle oil turbine
OFGEM	Office of Gas and Electricity Markets
OTC	Over the counter
PJM	Pennsylvania-New Jersey-Maryland Interconnection

PR	Primary Reserve
PTDF	Power Transfer Distribution Factor
RB	Re-dispatching benefit for generators
RC	Re-dispatching cost for generators
RES-E	Renewable energy sources for electricity generation
RT	Real time
RTO	Regional Transmission Organization
SEK	Swedish Krona
SR	Secondary Reserve
stELMOD	Stochastic electricity market model
StromNZV	Stromnetzzugangsverordnung
TR	Tertiary Reserve
TRM	Transmission Reliability Margin
TS	Total surplus
TSO	Transmission System Operator
TTC	Total Transfer Capacity
UCTE	Union for the Co-ordination of Transmission of Electricity
UCTE-STUM	UCTE Study Model
UK	United Kingdom
USD	U.S. Dollar
VDN	Verband deutscher Netzbetreiber
VGE	Verlag Glückauf Essen
WILMAR	Wind Power Integration in Liberalised Electricity Market research project

Indices

$\Gamma(k)$	All predecessors of node k
$\gamma(k)$	Direct predecessor of node k
Ψ	Mapping from plants to nodes
A	Set of plants allowed to contribute to reserve r
c, cc, co, cco	Country
J, j	Set of pump storage facilities
K, k	Set of nodes in the stochastic tree
L, l, ll	Set of transmission lines
N, n, nn	Set of nodes in electricity network
$O_{p,t}^{off}, O_{p,t}^{on}$	Minimum off/ontime periods
P, p, pp	Set of power plants

R, r	Set of reserve markets
T, t	Set of time periods
W, w	Set of renewable sources

Parameters

$\Delta netexport_{co}^{co \rightarrow cco}$	Additional export in country co for border co to cco [MW]
η_j	Pump storage efficiency [%]
$\hat{g}_A, \hat{g}_B$	Generation in Region A or B with limited interconnection [MWh]
$\hat{p}_A, \hat{p}_B$	Price in Region A or B with limited interconnection [EUR/MWh]
$\overline{s_{w,t}}$	Expected renewable supply [MW]
ϕ_k	Probability of occurrence of scenario tree node k [%]
$b_{n,nn}$	Node susceptance matrix [1/Ω]
c_w^c	Curtailment cost of renewable source w [EUR/MWh]
c_p^s, c_p^d	Startup and shutdown cost [EUR/startup]
cap_l	Thermal transmission limit of transmission line l [MW]
g_p^{DA}	Contracted day-ahead generation of plant p [MW]
$g_n^{maxwind}$	Maximum wind generation at node n [MW]
g_p^{max}	Maximum generation of plant p [MW]
g_p^{min}	Minimum generation of plant p [MW]
g_n^{solar}	Solar generation at node n [MW]
g_n^{wind}	Wind generation at node n [MW]
G_A, G_B	Merit-order cost curve of Region A or B, respectively [EUR/MWh]
g_A, g_B	Demand in Region A or B without interconnection [MWh]
g_A^*, g_B^*	Generation in Region A or B with unlimited interconnection [MWh]
$h_{l,n}$	Branch susceptance matrix [1/Ω]
$HVDC_{n,nn}^{max}$	Maximum possible HVDC transfer between node n and nn [MW]
$i_{l,n}$	Incidence matrix
l_j^{max}	Maximum storage level [MWh]
m	Big scalar value
mc_p	Marginal costs of power plant p [EUR/MWh]
$neighbor_{co,cco}$	Neighbor relationship of country co and cco
$netexport_{co}^{BCE}$	Net export of country co in BCE case [MW]

$ntc_{co,cco}$	Net transfer capacity between country *co* and *cco* [MW]
p_l^{max}	Thermal transmission limit of transmission line l [MW]
p_A, p_B	Price in Region A or B without interconnection [EUR/MWh]
p_A^*, p_B^*	Price in Region A or B with unlimited interconnection [EUR/MWh]
$price_n^{DA}$	Day-ahead market price [EUR/MWh]
$ptdf_{l,n}$	Power transfer distribution factor
Q_A, Q_B	Demand in Region A or B [MWh]
$q_n, q_{n,t}$	Load at node n [MW]
$qr_{n,t}^+, qr_{n,t}^-$	Reserve demand [MW]
r_l	Series reactance [Ω]
t_p^{on}, t_p^{off}	Required online and offline times [h]
TC	Transmission Capacity [MW]
$ttc_{co,cco}$	Total transfer capacity between country *co* and *cco* [MW]
v_j^{max}	Maximum pump storage release [MW]
w_j^{max}	Maximum pump storage pumping [MW]
x_l	Series resistance [Ω]

Variables

Δ_n	Voltage angle at node n [rad]
$C_{w,t}$	Renewable curtailments [MW]
$CS_{p,t}, CD_{p,t}$	Startup and shut down cost [EUR]
G_p^{DOWN}	Decreased generation of plant p [MW]
G_p^{UP}	Increased generation of plant p [MW]
G_n^{wind}	Wind generation at node n [MW]
$G_p, G_{p,t}$	Generation of plant p [MW]
$HVDC_{n,nn}$	HVDC transfer between node n and nn [MW]
$L_{j,t}$	Storage level [MWh]
LF_l	Flow on line l [MW]
NI_n	Netinput at node n [MW]
$ONLINE_l$	Binary status variable of line l
R_{pt}^+, R_{pt}^-	Provided upward and downward [MW]
$R_{p,t}^{H+}, R_{p,t}^{H-}$	Provided upward and downward reserve by pump storage [MW]
$S_{w,t}$	Renewable supply [MW]
$TF_{n,nn}$	Transactional transfer between nodes n and nn [MW]
$U_p, U_{p,t}$	Binary status variable of plant p

$V_{j,t}$	Pump storage release [MW]
$W_{j,t}$	Pump storage pumping [MW]
$Y_{n,t}$	Netinput from the transmission grid at node n [MW]

1. Introduction

Fooling around with alternating current is just a waste of time.
Nobody will use it, ever.
Thomas A. Edison

In the late 19th century researchers like Nikola Tesla, George Westinghouse, and Thomas A. Edison contributed to the understanding of the principles of generating, transmitting, and transforming electrical power. So far the phenomena of electricity was rather a curiosity, but turned to be an essential element of modern life through the pioneering work on electrical power. In 1882 Thomas A. Edison built up the first electrical distribution system in order to light his Pearl Street laboratory in Manhattan. The distribution system was based on direct current (DC). At the same time Nikola Tesla started to work on alternating current (AC) distribution network which allows the transmission of electrical power over long distances without serious power losses through a transformation of voltages. In 1886 George Westinghouse and William Stanley applied the AC transmission concept and installed the first AC power system in Great Barrington (Massachusetts) using multiple voltages to transmit electrical power. In the following years the AC concept became the preferred transmission technology due to higher transmission efficiency. The progress in generation technologies towards larger power generators additionally fostered the development of AC distribution networks transmitting electrical power to consumers. In the following decades, power networks evolved into a widespread and meshed infrastructure to link large centralized generation units with load centers and to ensure a reliable power supply. Integrated utilities dealt with all parts of the value chain namely generation, transmission, and distribution and enabled an integrated optimization of operation, maintenance, and expansion of the entire power system.

In the 1990s, the unbundling of vertically integrated utilities came up in various countries all over the world and the power supply industry moved from monopolistic towards liberalized market structures. Vertically integrated utilities were unbundled into distinct generation, transmission, and distribution services. In the following, liberalized electricity markets evolved which enabled the market entrance of new players beside the formerly integrated utilities. However, the transmission and distribution networks remained a natural monopoly. An industry is a national monopoly when the total industry output is produced by a single firm at lower total production costs than by two or more firms (Bobzin, 2006, p. 254). Therefore, the regulation of the transmission and distribution networks by public authorities and a guaranteed non-discriminatory access to network capacities has become a crucial element in liberalized electricity markets. In general, the unbundling of integrated utilities has broken up the formerly integrated optimization of the power system into distinct optimization problems for generation and transmission operation.

In the last years, the discussions on climate change and the associated promotion of renewable energy sources have added further challenges to current power systems. The integration of decentralized and fluctuating renewable generation has required structural changes of parts of the value chain and the liberalized market design of power systems. Due to decentralization of renewable generation, distribution and transmission networks[1] are of special importance to allow an efficient integration of newly built generation capacities.[2]

However, technical and economic characteristics of electricity transmission limit the access to network capacities. Firstly, power flows in transmission networks follow Kirchhoff's laws[3]. Kirchhoff's laws cause power flows mainly on the direct link but also on parallel links, so called loop flows. In general, the distribution of power flows within the transmission network depends on the network topology and the electro-technical characteristics of transmission lines.[4]

1 In the following, the focus is laid on analyzing the aspects arising in transmission networks thus abstracting from distribution networks.

2 At the time of writing this thesis, especially physical congestion problems in the existing network became increasingly important in Germany due to the transformation of the energy system and the associated increase in renewable generation capacities (e.g. Flauger and Stratmann, 2012). In 2011, the nuclear disaster in Fukushima (Japan) initiated the transformation for the German energy system especially the successive shut-down of nuclear power plants. In combination with ambitious targets for renewable generation, this presented a structural change of the existing energy system. In particular wind generation impacts the transmission network and causes network congestion (e.g. Uken, 2011b).

3 Kirchhoff's laws are two rules that describe the conservation of charges (Kirchhoff current or point law) and energy (Kirchhoff voltage or mesh law) in electrical networks. Further information can be found in standard electrotechnical textbooks e.g. (Claussnitzer, 1965, p. 40ff).

4 For instance, the German wind generation and the impact on the transmission network is not restricted solely to Germany due to physical loop flows. In particular, the Polish and Czech network operators claimed that renewable wind generation in Germany overloads their transmission networks more frequently. Due to physical characteristics of power flows in transmission networks, the security of the network is jeopardized due to overloading of transmission lines through unscheduled loop flows especially on windy days (Uken, 2011a; Ponikelska, 2012).

Secondly, transmission capacity is scarce. Transmission lines are limited by thermal or stability limits and if these limits are binding a transmission line becomes congested. Furthermore, building up a congestion-free network is not economical and thus inefficient due to the economic characteristics of transmission investments (Stoft, 2006). The economic characteristics of transmission networks and their investments are long lifetimes of transmission assets and capital-intensive, lumpy, and irreversible investments in transmission capacities (e.g. Brunekreeft, 2004; Kirschen and Strbac, 2004; Lévêque, 2006). The physical and economic characteristics of transmission networks in combination with the liberalized market structure require an efficient operation of the network in the short-run and adequate expansion in the long-run perspective. Efficient operation includes a market-based allocation of scarce transmission capacity taking physical characteristics of power flows into account in order to avoid network congestion. To allocate transmission capacity, congestion management methods have been developed and are diversely applied in liberalized electricity markets.

It is the objective of this thesis to analyze selected aspects of network congestion arising in liberalized electricity markets and their management methods with respect to the identified existing and future challenges, especially the integration of increased renewable generation. The provided economic analyses focus on transmission networks due to their relevance in providing inter-regional trade and transmission opportunities. The main contribution of this thesis is that theoretical concepts of managing congestion problems in transmission networks are applied to realistic representations of existing electricity markets. Furthermore, model approaches are developed to reflect the mentioned technical and economic characteristics of electricity markets and thus to provide quantitative insights.

The remainder of the thesis is as follows. In Chapter 2 the principles of congestion management and available methods to manage arising congestion in transmission networks are introduced. The theoretical introduction to congestion management methods is complemented by a review of selected countries and their congestion management strategies. The chapter provides the theoretical background for the analysis performed in the subsequent chapters of the thesis.

Chapter 3 deals with the European congestion management regime and asks whether a change in the current European congestion management and thus pricing regime towards a more integrated transmission and energy market achieves benefits with respect to costs and surpluses of market participants. An European electricity market model is applied to determine the optimal operation of generation and transmission infrastructure under different congestion management regimes. It is concluded that the integration of transmission and energy markets achieves lower generation costs which accrue from a closer cooperation among European countries in the congestion management.

Chapter 4 seizes the research question of the previous chapter for the German electricity system. As the significant share of renewable generation and the phase-out of nuclear power plants after the disaster of Fukushima poses a challenge for the existing transmission infrastructure, the amount of future congestion management costs are quantified which would occur under the current congestion management regime based on congestion alleviation methods. Within the developed model economic as well as technical methods to manage network congestion are explicitly taken into account. It is shown that the application of technical methods can reduce the need for redispatching power plants but are limited by the requirements on security and stability of the transmission network. It is concluded that a homogeneous and jointly development of generation and transmission infrastructure is a prerequisite for the application of congestion alleviation methods and once they diverge congestion management cost tend to increase. Through the application of an integrated congestion management regime, market participants are informed about the network situation and thus receive economic signals which may support a homogeneous development.

Given the challenge of renewable integration in current power systems, a unique electricity market model is presented in Chapter 5, which explicitly takes the characteristics of variable and stochastic wind generation into account. The German electricity market serves as a basis for the mathematical formulation of the dayahead and intraday market as well as the sequential clearing procedure of both markets. The dayahead market model sets out to minimize total generation cost and determines the commitment and the generation dispatch of individual power plants. Given these commitments of generators, the intraday market provides the opportunity to firstly reoptimize the dayahead commitments, and secondly to balance uncertainty about wind generation. As the forecast of wind supply improves over time due to shorter forecast lengths the adjustments of generation commitments are required in the intraday. It is shown that the adjustment of generation and thus the development of a flexible generation portfolio depends on the way uncertainty is introduced in the models. If uncertain wind generation is explicitly considered during the market procedure, less flexible generation units are used by decreasing their utilization and increasing the number of operating units to balance resulting forecast errors.

Chapter 6 concludes the thesis with a summary of the analyses carried out. Topics for future research are identified.

2. Review of Congestion Management Methods in Liberalized Electricity Markets

2.1. Introduction

Congestion has become an issue in the liberalization process of national electricity markets. In the past, national electricity markets were characterized by vertically integrated monopolistic companies managing both generation and transmission systems. Through the liberalization the integrated management of production and transmission was broken up into two distinct processes. Firstly, generators optimize and determine their power plant scheduling and dispatch[5] with respect to market prices of the different sub-markets (future and spot markets)[6] available in a liberalized electricity market. Secondly, transmission operators have to manage the transmission system with respect to technical and economic criteria given the previously determined dispatch of power plants. Thus, the dispatch of power plants is preset to the transmission system operator and he can make use of congestion management methods to achieve a technically and economically feasible operating status of the transmission system. However, as congestion is an immanent part of a liberalized power system due to the technical and economic nature of transmission networks, the efficient use of the existing infrastructure and thus management of transmission congestion has become increasingly important.

Congestion is the restriction of transfers between different system nodes or regions in an electricity system. Congestion (or a bottleneck) arises when scheduled or planned transactions exceed available transmission capacity and thus the

[5] Power plant scheduling (or unit commitment) and dispatch describes the determination of the operating status of power plants (offline or online) and their generation quantities for a given time period.

[6] The term spot market describes the dayahead market, which is characterized by a physical trading of the commodity with a delivery at the next day. Additionally, short-term physical trading close to delivery is possible within the intraday market. In contrast, future and forward markets enable a financial (future) or physical (forward) trading with a delivery at a future date (e.g. year-ahead, month-ahead). See e.g. Stoft (2002) or Kirschen and Strbac (2004) for further information.

physical transmission grid is not capable of transmitting scheduled power. Congestion occurs as a consequence of too little available generation capacity in conjunction with limited import capacities, or as a consequence of a generation surplus in conjunction with limited export capacities.

Congestion can be distinguished by their cause in either physical or economic congestion (Knops et al., 2001). Physical congestion describes the situation the electricity system is not able to technically serve electrical load. Thus, available generation and transmission capacities cannot serve regional loads leading to black-outs in the short-term. In the long-run, investments in generation and transmission facilities are required to overcome physical congestion. Economic congestion arises when market transactions (e.g. dispatch of power plants) lead to overloadings in the transmission system. Thus, the transmission system is technically capable[7] to meet electricity demand, but available transmission capacity is insufficient to implement pre-determined market transactions. Thus, the market solution is infeasible for the transmission network, but a feasible status can be achieved through adjustments of the market transactions. Congestion management methods are used to relieve economic congestion. Congestion management aims to optimally allocate the scarce transmission capacity either before, during and/or after clearing of the electricity market (Wangensteen, 2007; Kirschen and Strbac, 2004).

The remainder of this Chapter is structured as follows. Section 2.2 provides an overview on congestion management methods including preventive capacity allocation methods and curative congestion alleviation methods. Capacity allocation methods comprise the explicit and implicit auction of transmission capacity in order to price scarce transmission capacity. Congestion alleviation methods include the description of market-based (e.g. redispatch) and technical congestion management methods. Congestion management methods have different economic implications with respect to short- and long-run efficiency. Therefore, an economic evaluation of congestion management methods is presented Section 2.3. In Section 2.4 the electricity markets of Germany, Norway, Sweden, Great Britain, and Pennsylvania-New Jersey-Maryland (PJM) are described. A particular focus is on national congestion management approaches. Section 2.5 provides the conclusions.

[7] Available transmission capacity is firstly determined by their technical capacity (e.g. maximum thermal current). However, security and stability aspects (e.g. N-1 criterion) further reduce technical capacity of transmission lines (Kawann and Sakulin, 2000; Ilic et al., 2011).

2.2. Congestion Management Methods

Congestion management methods aim to "handle network access in the presence of congestion" (Frontier Economics and Consentec, 2004, p. 4). They can be generally classified into preventive or curative methods[8] (Table 2.1). Preventive congestion management methods aim at managing congestion prior or during the market procedure and can be further classified into administrative and capacity allocation methods. Through capacity allocation methods, market participants[9] are directly informed about the existence of congestion and thus receive economic signals (e.g. price information) which are considered in their market decision (e.g. generation dispatch of power plants). On the other hand, expected congestion in the real-time operation of the power system as a result of the market procedure are managed by curative congestion management methods. Redispatch of power generation as well as technical methods are used to ease congestion in the transmission network. A bibliographical survey of congestion management, applied methods, and other related issues is given in Kumar et al. (2005).

Preventive Methods		**Curative Methods**
Administrative	**Capacity Allocation**	**Congestion Alleviation**
Access Limitation	Explicit Auctioning	Redispatch
Priority List	Implicit Auctioning	Counter-trade
Pro rata rationing		Technical methods

Table 2.1.: Congestion management methods. Source: Own illustration

Following Frontier Economics and Consentec (2004), the management of congestion in electricity systems can be classified into four characteristic phases during the regular market clearing procedure (Figure 2.1). First, available transmission capacity is determined by the transmission system operator and is afterwards allocated in the second phase to market participants through capacity allocation methods. After the clearing of the transmission capacity market and spot market, the transmission system operator is able to perform a congestion forecast in the third phase. Based on market results, physical flows in the transmission network can be forecasted and, if required, congestion alleviation is performed to ease remaining congestion. The use of congestion alleviation

[8] Other classifications of congestion management methods exist (see e.g. Androcec and Wangensteen, 2006; Dieckmann, 2009).

[9] Generators, consumers, and network operators are considered as characteristic market participants in this analysis. The terms demand or load are used for consumers interchangeable.

may not be required and depends on the applied capacity allocation methods and the transmission constraints considered in this phase.

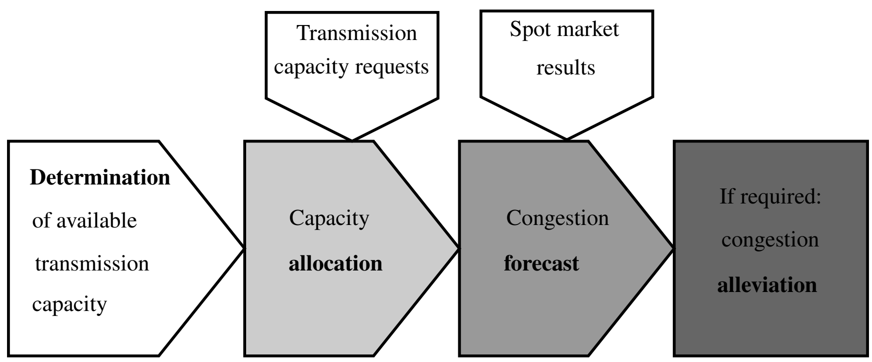


Figure 2.1.: Phases of congestion management. Source: Own illustration based on Frontier Economics and Consentec (2004)

2.2.1. Administrative Methods

Administrative methods describe preventive congestion management regimes which are applied prior to regular market clearing procedure. They are characterized by the fact that the transmission system operator decides about the allocation of scarce transmission capacity administratively without considering the economic efficiency. Thus, the methods are neither market-based nor do they give economic signals to market participants (ETSO, 2006).

Retention or Access Limitation

Available transmission capacity is not available for market participants and reserved for specified participants (Wangensteen, 2007).

Priority List

Transmission capacity is allocated to market participants in a specified priority order until available capacity is reached. Priority criteria are e.g. chronological order (first-come, first-served) or past use of capacity (ETSO, 2006).

Pro rata rationing

Transmission capacity is allocated to all market participants without any priority. If requested capacity exceeds available transmission capacity, available transmission capacity is allocated relative to capacity requests of market participants (ETSO, 2006). As transmission capacity is allocated to all requests, the method is non-discriminatory, but is neither market-based nor does it provide economic signals to market participants.

2.2.2. Capacity Allocation Methods

Another category of congestion management methods is the allocation of transmission capacity prior or within the clearing of the spot market. Market participants therefore anticipate the congestion problem in their market transactions and finally generation and demand patterns are efficiently adjusted. Capacity allocation methods can be generally distinguished into explicit and implicit auctions. Explicit auctioning requires a separate market for transmission capacity (beside the spot market) where this capacity is explicitly allocated to market participants according to certain market rules. In an implicit auction, transmission capacity is allocated implicitly during the spot market clearing procedure to market participants and a separate market for transmission capacity is not required.

2.2.2.1. Explicit Auctioning

In explicit auctions, market participants offer a price along with the requested capacity for the use of the transmission. Afterwards, the bids are ordered by price and allocated to market participants until available transmission capacity is reached. Market participants with the highest willingness to pay are considered first in the allocation procedure. Thus, the auction is economically efficient as the transmission capacity is allocated to market participants according to their willingness to pay (Wawer, 2007). Pricing of transmission capacity can be done in a uniform or discriminatory way based on the bids of the market participants. Uniform or marginal bid pricing means that the price of transmission capacity is determined by the last accepted or marginal bid if requested capacity exceeds available transmission capacity. Otherwise, the price is zero. Thus, all accepted bids pay the same price for transmission capacity. On the other hand, in a discriminatory pricing (pay-as-bid) market participants pay the price notified in their bid if accepted. A discussion of different pricing methods is given in de Vries and Hakvoort (2002). They conclude that uniform pricing provides better bidding incentives and pay-as-bid pricing is rather interesting from a theoretical point of view as it results in higher auction revenues due to the individual pricing of market participants' bids.

In explicit auctions the transmission capacity is allocated in a separate market and thus timely separated from the spot market. In a competitive environment and under the assumption of complete information the price of transmission capacity determined in explicit auctions equals the price differential of the regional wholesale markets (Wawer, 2007). However, the separation of the energy and transmission capacity market increases the complexity of the entire market as market participants have to value transmission services prior to clearing of the spot energy market (Ehrenmann and Smeers, 2005). The increased complexity can lead to a misjudgment of market outcome and thus market inefficiency as available transmission capacity is not optimally used.

The advantage of an explicit auction is its 'simple' implementation as it can function between quite different market regimes (Knops et al., 2001). Therefore it was a popular and widely used option for international congestion management thus the allocation of interconnector capacities between European countries in the last years (e.g. ETSO, 2006). To overcome the aforementioned higher complexity of the market, the explicit auctioning is mostly replaced by an implicit auctioning of international capacity.

In the context of national congestion management and thus the management of congestion within a market region, the use of explicit auctions as a tool for managing congestion is possible only for bilateral trades and incompatible with anonymous trading at power exchanges (Wawer, 2007). The knowledge about the location of the counterpart is essential to explicitly contract the required transmission rights for network usage.

2.2.2.2. Implicit Auctioning

The implicit auction describes a congestion management method in which the network restrictions are reflected in the spot market price. Market participants submit "bids for energy in the geographical zone they wish to generate or consume, and the market clearing procedure [of the spot market] determines the [...] efficient amount and direction of physical power exchanges between the market zones" (Frontier Economics et al., 2006, p. 7). Hence, transmission capacity is implicitly auctioned within the spot energy market procedure and a separate transmission capacity market is not required as in an explicit auction. The implicit auctioning procedure can be in the form of market splitting or market coupling.

The main difference between market splitting and coupling is the number of electricity market places considered in the procedure. In case of *market splitting*, a single electricity market is divided into market zones or bidding areas according to the network congestion. A cooperation of multiple independent electricity markets and the implicit auctioning of transmission capacity between those markets is known as (decentralised) *market coupling*. Ehrenmann and Smeers

(2005) analyze both approaches and resume that market splitting and coupling are equivalent if the definition of (possible) market zones and the representation of network constraints are identical.

The advantage of an implicit auction is the integration of the transmission market in the energy market. Thus, market participants do not have to value transmission prior to the clearing of the energy market as in an explicit auctioning.

Market Splitting Procedure

Market splitting aims to split a single market into different market zones according to congestion within the network. If congestion occurs, market prices of different market zones will differ. The utilization of limited transmission capacity is implicitly done by the responsible market operator using the bids of market participants in the energy market. The procedure of market splitting is explained in the following using a stylized example (Figure 2.2).

Region A is characterized by high demand and generation capacities with high marginal costs, whereas in Region B demand and generation with low marginal costs are located. Bid curves of generation and demand for each Region are denoted by G_A, G_B, Q_A, and Q_B. Transmission between both regions is possible up to the maximum capacity TC. Due to cost structure of generation and regional demand, Region B always exports some amounts to Region A where generation shows higher marginal generation costs.

The market splitting procedure starts with the clearing of the two market areas (Region A and B) as if there is infinite transmission capacity TC connecting both zones. Hence, a single market price $p_A^* = p_B^*$ can be determined based on a combined generation curve and total demand (see Figure 2.2, right graph). The regional generation is g_A^* and g_B^* and the difference between regional demand and generation represents transfer between both regions. In general, if the determined transfer between both regions exceeds the available transmission capacity TC, the single market will be split into different market zones as congestion occurs. Otherwise, if the transfer is lower than the available transmission capacity (unconstrained case), a splitting of the market is not necessary and market prices are equal. In this unconstrained case, Region B exports the difference between g_B^* and Q_B to Region A. This export is considered as additional generation in Region A shifting the generation curve to the right (G_A^*)[10].

[10] The generation cost curve of Region A (G_A) and the exporting part of the generation cost curve of Region B are combined to a new generation cost curve for Region A (G_A^*).

In case of congestion, the exchange between both market zones is restricted to the maximum transmission capacity TC. Thus, previously determined generation in Region B g_B^* is decreased to available transmission TC leading to final generation $\hat{g}_B$. Consequently, the export TC from Region B is considered in Region A as additional generation resulting in the new generation curve $\hat{G}_A$. The transmission capacity between both regions is now fully utilized. The final market prices ($\hat{p}_A > \hat{p}_B$) are different from the market prices in the unconstrained case ($p_A^* = p_B^*$) as transmission capacity is limited (see Figure 2.2).

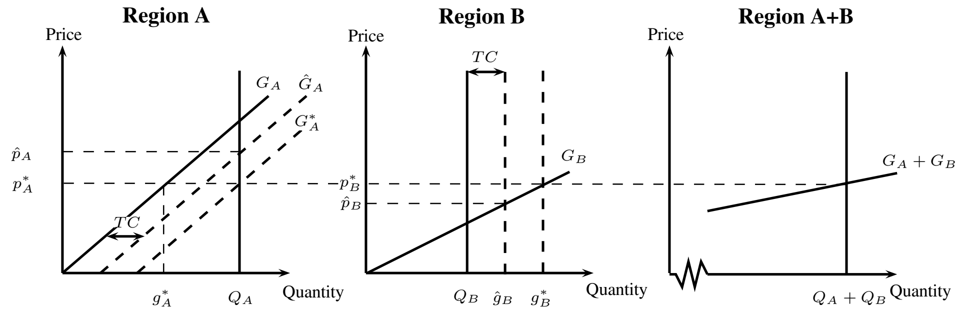


Figure 2.2.: Market splitting procedure. Source: Own illustration based on Krause (2007)

Market splitting requires an organized electricity exchange to determine the unconstrained market results and the zonal decomposition in case of congestion. The approach of market splitting is currently applied in the Italian[11] and Nordic power market (Nord Pool[12], see Section 2.4.2) to manage internal network congestion. Furthermore, Spain and Portugal allocate their cross-border capacities through a market splitting procedure.[13]

Market Coupling Procedure

The market coupling follows a comparable procedure as market splitting. However, the main difference is that "market coupling does not have an integrated market to start with, but only a set of independent market that it wants to link" (Ehrenmann and Smeers, 2005, p. 145).

The market coupling procedure starts an independent clearing of the separate regional markets. Thus, no transmission capacity is considered. The clearing results in the regional market prices p_A and p_B (see Figure 2.3). In a second step, the net import/export curves are computed and import/export quantities up to

[11] Compare: `http://www.mercatoelettrico.org/En/Mercati/MercatoElettrico/MC_Modello.aspx`

[12] Compare: `http://www.nordpoolspot.com/`

[13] Compare: `http://www.omip.pt/OMIP/MIBEL/tabid/72/language/en-GB/Default.aspx`

the available transmission capacity TC are determined (see Figure 2.3, middle graph). Due to transmission possibility between both regions, costly generation in Region A can be replaced by cheaper generation in Region B, thus leading to a reduction in market prices to $\hat{p}_A$ and $\hat{p}_B$. If the transmission capacity TC is lower than the quantity at the intersection of net import/export curves (Figure 2.3, mid graph) regional price differences occur ($\hat{p}_A > \hat{p}_B$). Otherwise, regional prices converge to an identical price for both regions ($p^*_A = p^*_B$) as the transmission capacity is not limiting.

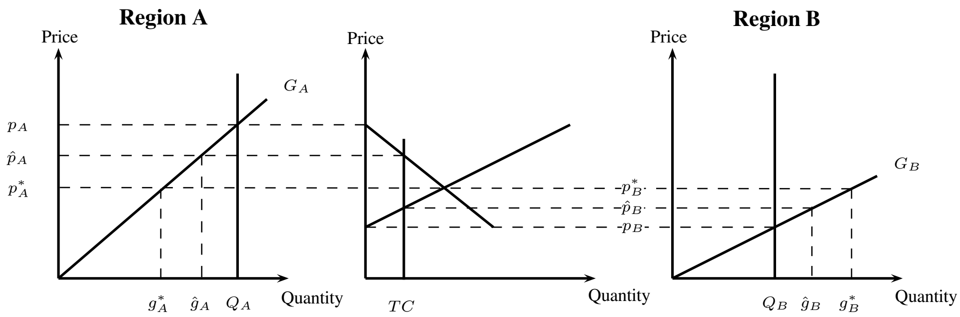


Figure 2.3.: Market coupling procedure. Source: Own illustration based on Schwarz and Lang (2006)

The market coupling requires organized power exchanges on both sides of the congested connection. Market coupling is currently applied in the central western European (CWE) market region (covering Belgium, the Netherlands, France, and Germany) to efficiently allocate cross-border capacities between these countries during the EPEX dayahead spot market procedure.[14] Additionally, the Nordic power market is coupled with the central western European market (European Market Coupling (EMCC)[15]).

Definition of Market Zones

The application of implicit auctions and the market splitting or coupling procedure requires the definition of (possible) market zones or bidding areas.[16] Following the described procedures, only transmission capacities between specified market zones can be considered in the capacity allocation procedure. The definition of (possible) market zones or bidding areas can be done in different

[14] Compare: `http://www.epexspot.com/en/market-coupling`

[15] Compare: `http://www.marketcoupling.com/`

[16] A market zone can be described as a aggregation of substations (or system nodes) within a power network. System nodes or substations are points in power systems where electricity can be feed-in or withdrawn from the power network. Within a market zone congestion in the transmission network is not explicitly considered and thus a market zone is characterized by a single zonal price.

ways, either flexible or a priori fixed (Ehrenmann and Smeers, 2005).

Flexible zoning implies the separation of a single market area into a specified number of market zones according to resulting congestion. Hence, the definition is variable and changes with congestion situation. In case of infinitesimal small market zones so that each substation forms a market zone, the method is called nodal pricing or locational marginal pricing. On the other hand, the definition of market zones can be determined a priori and is thus fixed. In contrast to flexible zoning, market zones are the same in all load situations and is therefore not necessarily efficient (Bjørndal and Jørnsten, 2001). The definition of fixed market zones is applied for example in Italy, Sweden, and Norway, where the zone definition is made by the transmission system operator. However, the Nordic market started with flexible zoning before changing to fixed zones (Ehrenmann and Smeers, 2005). In central western Europe, pricing zones used in the market coupling procedure on interconnectors correspond to national borders.

The zonal pricing or market splitting regime and the definition of market zones is discussed in Bjørndal (2000) and Bjørndal and Jørnsten (2001). Bjørndal and Jørnsten (2001) describe a mathematical model in order to determine the optimal zonal decomposition with respect to economic welfare. They conclude that zonal pricing and the definition of optimal flexible market zones is difficult and affects the surplus of market participants. Especially if fixed (a priori determined) market zones are considered, the definition requires a detailed analysis of welfare implications and redistribution effects on market participants. Ehrenmann and Smeers (2005) among others confirm the concerns of Bjørndal and Jørnsten (2001) about the definition of market zones. Using a simple six-node network, Ehrenmann and Smeers (2005) analyze different zonal configurations under various congestion management approaches. Bjørndal and Jørnsten (2007) provides a comparable analysis for the Nordic power market. Imran and Bialek (2007) investigate the zonal decomposition within the European electricity market based on locational marginal prices. Different methods for zonal clustering are conceptually described and applied to a detailed representation of the European electricity market. Imran and Bialek (2007) confirm the previous studies as they conclude that zonal clustering is difficult due to significant variations in nodal prices and resulting zones are rather small. Hence, forming zones is nearly impossible and market inefficiencies may be created if zones are formed. To conclude, forming market and thus price zones is a complicated task, especially in case of fixed zones comprising more than one substation. Therefore, it is often emphasized that a zonal aggregation is not appropriate and locational marginal pricing or nodal pricing is more efficient and consistent (e.g. Hogan, 1999).

2.2.3. Congestion Alleviation Methods

Congestion alleviation methods aim to manage congestion resulting from market transactions, without influencing spot market results (Knops et al., 2001). In contrast to capacity allocation methods, generation and load patterns are not adjusted to the congestion situation during the spot market clearing accordingly and the transmission system operator is in charge to manage network congestion using corrective measures after clearing of the spot markets. Congestion alleviation methods can be classified into technical and economic methods in order to adjust physical flows in the transmission network.

Technical methods make use of technical devices in order to control physical flows and to mitigate congestion. The involvement of market participants is not necessary. Optimization of network topology or phase shifting transformers are exemplary options. On the other hand, economic methods include the participation of selected market participants and the change of their market transactions. Through rescheduling of generation or demand, physical flows can be managed.

2.2.3.1. Technical Methods

Flexible Alternating Current Transmission Systems (FACTS)

'Flexible alternating current systems' (FACTS) are defined as "alternating current transmission systems incorporating power electronic-based system and other static equipment to enhance controllability and increase power transfer capability" (Edris et al., 1997, p. 1849). FACTS controllers provide control of one or more transmission system parameters (e.g. transmission voltage, phase angle) which determine the load flow in the power systems. Therefore, FACTS controllers attempt to increase actual line capacity and direct load flows, thus diminishing problems caused by loop flows and make optimum use of existing network structures. FACTS controllers can be connected either in series or in shunt with the power system, or even in a combined pattern to provide compensation for the power system. Variable series capacitors, phase shifters and unified power flow controllers can be utilized to control load flows in the power system and thus manage congestion. Edris et al. (1997) gives a detailed definition of the general concepts as well as the different FACTS controllers.

Taranto et al. (1992) present a methodology for the representation of FACTS controllers in an economic dispatch power flow model. Phase shifters and series compensations are considered as FACTS controllers and applied to the Brazilian power system. Lu et al. (2005) analyze diverse concepts for mitigating congestion in power systems. Among various alternatives, the impact of phase shifting devices on locational market prices is analyzed and discussed. The authors conclude that phase shifting transformers can help to mitigate congestion and to reduce the need for transmission expansion. Verboomen et al. (2006, 2008) further analyze the grid operation with phase shifting transformers and conclude that the use of multiple phase shifting transformers in power systems requires a careful coordination to achieve an efficient use of transmission infrastructure. The optimal placing of FACTS controllers esp. thyristor controlled phase shifter transformers is studied by Zeraatzade et al. (2007). The authors formulate a mixed integer economics dispatch model in order to determine the placing of FACTS controllers and to minimize redispatching costs. They show that the application of FACTS devices can reduce costs for redispatching generation facilities.

Network Topology Optimization

In a meshed system such as the transmission grid, energy flows are distributed across the transmission lines depending on their technical characteristics following Kirchhoff's laws. Furthermore, meshed networks increase the security of the system, but the resulting loop flows can limit the optimal use of low cost generation capacities and congestion may arise. The introduction of flexible or dispatchable transmission can reduce loop flows as load flows are directed by switching on or off of transmission elements. In general, transmission topology can be determined by the transmission system operator and further optimized by specified switching actions with respect to dispatch costs or power system security.

The basic concept of network topology optimization (or transmission switching) can be applied as a control action to either technical or economic problems. A review of several technical publications on the use of switching control methods is presented in Rolim and Machado (1999). Most of the applications concentrate on aspects such as overloads (Granelli et al., 2006; Arya et al., 2000), loss reduction (Schnyder and Glavitsch, 1990) or enhancing power system security (Schnyder and Glavitsch, 1988). In a technical context, transmission switching has been explored as a powerful control option and is used in real-world applications to improve technical parameters (e.g. voltage) by transmission system operators (Fisher et al., 2008).

Regarding economic problems, O'Neill et al. (2005a) introduce the concept of a dispatchable network in a market context. The passive behavior of transmission operators is replaced by an active participation of transmission owners on power markets and market-based transmission pricing is introduced. They show that the implementation of bidable, dispatchable transmission can provide firstly the market with greater efficiency and competition, and secondly incentives to increase transmission capacities. Another application of transmission switching is described in Fisher et al. (2008). This paper focuses on the application of switching actions within the DC optimal dispatch procedure to a test network. It is shown that dispatchable transmission lines can significantly improve the dispatch costs by changing the status of only a few lines. The concept is extended in Hedman et al. (2008a) and Hedman et al. (2008b) by a sensitivity analysis and a congestion analysis. Dispatch cost savings found in Fisher et al. (2008) can be confirmed while satisfying N-1 security standards. However, switching concepts are only applied to test networks and have to be confirmed with real networks. Görner et al. (2008) apply the switching concept to a welfare maximization with an underlying network of Belgium, the Netherlands and Luxembourg. It is shown that generation costs can be reduced in off-peak periods through changing grid topology towards a more radial structure. Kamga (2009) analyzes network topology optimization with respect to congestion management and develops a model for optimizing network topology subject to technical and economic constraints. He concludes that the optimization of network topology significantly reduces costs of congestion management in the short-term and the need for network expansion in the long-term.

2.2.3.2. Redispatch

Redispatching aims to adjust generation (or load) patterns in order to change the physical flows in the network and to mitigate congestion. Generally two forms of redispatching can be distinguished, which differ in the determination of the generation capacity available for the redispatch. In cost-based redispatch, the determination of available generation capacity is based on the generation costs, whereas in the market-based redispatch (or counter-trading) a separate merit order curve is used to determine the available generation capacity. Both congestion management methods are described in the following. Redispatch is used in many electricity markets as preventive congestion management option. E.g. in Germany cost-based redispatch is applied, whereas in Nord Pool and Great Britain market-based redispatch is used.

Cost-Based Redispatch

Given the stylized power system of two regions and a transmission capacity of TC between both regions, the cost-based redispatch works as follows (see Figure 2.4). First, the spot market is cleared and a market price $p_A^* = p_B^*$ is determined for the single market. The transmission capacity is not considered in this clearing procedure. Resulting generation in Region A and B are g_A^* and g_B^*, respectively. Given the market result of the spot market, it is obvious that the exchange between both regions exceeds the available transmission capacity TC. The amount $g_B^* - Q_B$ represents excess generation in Region B and thus the planned export to Region A. However, as $g_B^* - Q_B$ exceeds the available transmission capacity TC the export is operationally not feasible. Henceforth, the generation dispatch has to be adjusted to ensure feasibility. Therefore, the responsible transmission system operator reduced generation in Region B from g_B^* to $\hat{g}_B$ so that the export equals available transmission capacity TC. On the other hand, generation has to be increased in the deficit Region A to ensure equality of demand and generation. Generation is increased from g_A^* to $\hat{g}_A$ and the final import in Region A equals the export in Region B.

In order to implement the redispatch, generators expect compensation payments for reducing and increasing their generation. Generators in Region B pay their avoided costs to the transmission operator as their generation is reduced (grey area in Region B, Figure 2.4). Increased generation in Region A receive their additionally incurred marginal costs (grey area in Region A, Figure 2.4). For the transmission system operator, the redispatch results in additional costs, as payments to generators in Region A are higher than avoided marginal costs of generators in Region B.

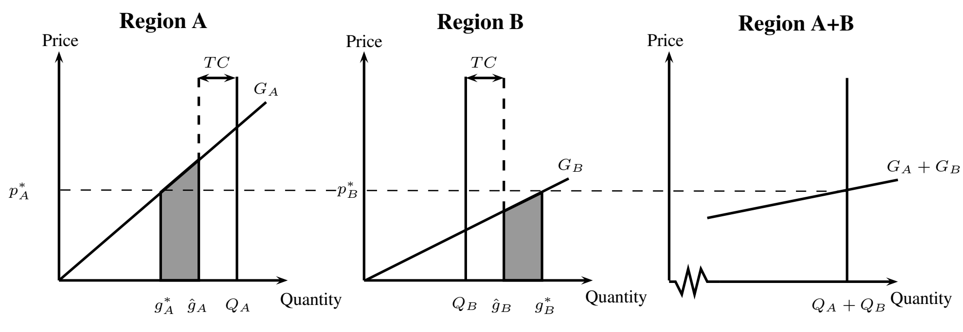


Figure 2.4.: Cost-based redispatch. Source: Own illustration based on de Vries and Hakvoort (2002)

Efficiency is guaranteed in the short-run as the cheapest available power plants are producing (Wawer, 2007). However, market participants do not internalize the congestion and only power plants involved in the redispatch procedure are informed about congestion and receive signals on congestion (de Vries, 2001). Therefore, the congestion management approach does not give appropriate long-term signals to all market participants for efficient siting of power plants or demand. de Vries (2001) points out that redispatching provides efficient signals to the transmission system operator. As redispatching results in costs for the transmission system operator, he can balance the redispatching costs against the costs of a capacity expansion.[17]

Market-Based Redispatch / Counter-Trading

As in the cost-based redispatch congestion management method, the spot market is characterized by a uniform price for electricity if a market-based redispatch is used as congestion management method. Contrary to the cost-based redispatch, available redispatch capacities are now determined in a market procedure using bids of market participants at which they are willing to increase or decrease generation. In this case two additional markets are created in addition to the dayahead spot market: the redispatch market for the provision of additional capacity and the redispatch market for the shutdown of capacity (Inderst and Wambach, 2007). This can also be seen as positive and negative redispatch capacity. In case of congestion, the transmission system operator will counter-trade against the flow of congestion by using available redispatching capacities until congestion is eliminated (Dijk and Willems, 2011). Thus, the market-based redispatching is also known as counter-trading.

The general procedure of the market-based redispatch is comparable to the cost-based redispatch (see Figure 2.5). Given the market result of the unconstrained energy market, the exchange between both regions exceeds the available transmission capacity TC. Again, the amount $g_B^* - Q_B$ represents the planned export from Region B to A and exceeds the available transmission capacity TC. Therefore, the responsible transmission system operator reduced generation in Region B from g_B^* to $\hat{g}_B$ so that the export equals available transmission capacity TC. On the other hand, generation has to be increased in the deficit Region A to ensure equality of demand and generation. Generation is increased from g_A^* to $\hat{g}_A$ and the final import in Region A equals the export in Region B.

In order to implement the redispatch, generators receive compensation payments for reducing and increasing their generation. Generators in B should not be willing to pay more than their avoided marginal costs (grey area in Region B,

[17] The theoretical incentive to balance redispatching costs against the costs of network expansion may be limited as it depends on the characteristics of the regulatory regime.

Figure 2.5), whereas generators in A should not receive more than their incurred marginal costs (grey area in Region A, Figure 2.5). For decreasing generation, the transmission system operator accepts the highest offers and the lowest bids for increasing generation. Also in a market-based redispatch, the payments to generators in Region A are higher than avoided marginal costs of generators in Region B. Comparing Figure 2.4 and 2.5 indicates that resulting payments are at least as much as in the cost-based redispatch, but most likely to be more (de Vries and Hakvoort, 2002).

The determination and pricing of available redispatch capacities in a separate market can be designed either as discriminatory (pay-as-bid) or uniform-price (marginal bid) auction. Alternatively, the bids placed on the spot market or the reserve market may be used for the determination and provision of redispatch capacities (Inderst and Wambach, 2007; Wawer, 2007).

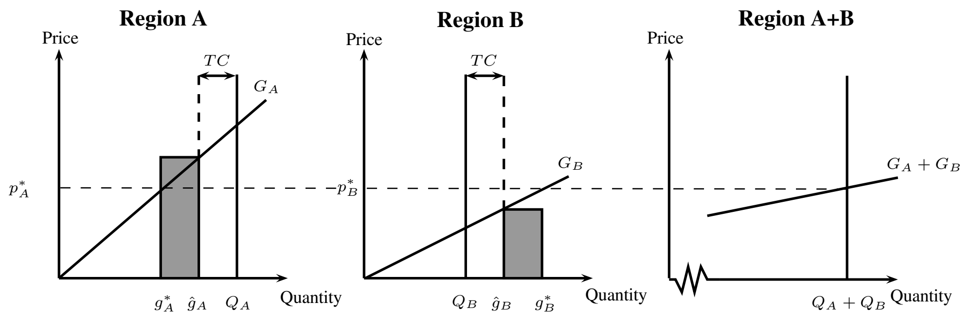


Figure 2.5.: Market-based redispatch. Source: Own illustration based on de Vries and Hakvoort (2002)

Similar to cost-based redispatch, efficiency is guaranteed in the short-run as the cheapest available power plants are producing (Wawer, 2007). As a transparent and market-based market procedure is applied, the prices in the redispatch market give generators long-run incentives to place new power plants in the deficit region (Inderst and Wambach, 2007). As in cost-based redispatch, the transmission operator faces the costs of congestion management and can balance the costs against the costs of a capacity expansion. Hence, efficient signals are provided to the transmission system operator to invest in transmission infrastructure.[18]

However, the simultaneous optimization of the bidding in the various markets will also present a more complex decision problem for power plant operators, which opens the possibility for an adverse behavior and resulting inefficiencies in the short-run as well as long-run perspective (Inderst and Wambach, 2007;

[18] Again, the theoretical incentives provided to the transmission system operator may be limited by the characteristics of the regulatory regime.

Wawer, 2007; Perekhodtsev and Cervigni, 2010; Dijk and Willems, 2011). The price on the redispatch market in the deficit region can be higher than the uniform price on the spot market, as power plants that are not in-merit have to increase their generation. This could be anticipated by power plants in the deficit region, including those who would operate at the spot market price due to their low marginal generation costs. In order to maximize their profits, they could withhold their capacity from the spot market in order to offer this capacity in the redispatch market. However, this assumes that the congestion can be predicted by the power plant operators. Due to the reduction of the generation capacity in the deficit region, the deficit appears even greater. In particular, this means that in comparison to the cost-based redispatch the spot price increases (Inderst and Wambach, 2007). Due to the anticipation of the congestion in the bidding behavior of the power plant operator and the resulting impact on the spot price, inefficient long-run incentives for generation investments are created (Perekhodtsev and Cervigni, 2010).

2.3. Economic Evaluation of Congestion Management Methods

Congestion management methods can be compared with respect to different criteria. In economic theory, the concept of economic efficiency is introduced to evaluate and compare e.g. different economic mechanisms based on resulting outcomes. The concept of economic efficiency[19] can be further differentiated into a short-term and long-term perspective. Short-term economic efficiency means that an efficient (least-cost) dispatch of generators is used to serve a given level of loads in the power system. In a power system, generators with lowest generation costs should be used to serve loads with highest willingness to pay. In a power system with transmission congestion, congestion management methods should aim to achieve economic efficiency. Beside the short-term perspective, long-term economic efficiency refers additionally to investing in generation and transmission facilities. Long-term economic efficiency is achieved if market participants receive efficient economic incentives firstly to invest in required amounts of new facilities (e.g. power plants, transmission lines) and secondly to place them where they are needed.

Various studies investigate the economic aspects of congestion management methods (see e.g. de Vries, 2001; de Vries and Hakvoort, 2002; Frontier Eco-

[19] A system is economically efficient if a given yield is achieved with lowest effort or if highest yield is reached with a specified level of effort (Feess, 2004).

nomics and Consentec, 2004; Brunekreeft et al., 2005; Ehrenmann and Smeers, 2005; Androcec and Wangensteen, 2006; Krause, 2007). The studies point out that congestion management methods mainly match short-term economic efficiency. Differences between congestion management methods are in the distribution of costs and their long-term impacts. In the following section, the economic implications of different congestion management regimes are analyzed using the introduced two region example. Beside economic efficiency, further criteria — for instance institutional or regulatory aspects — are available but are neglected in this analysis as they depend on the specific characteristics of the investigated market. The interested reader is referred to e.g. Knops et al. (2001).

2.3.1. Short-Term Efficiency

Based on the previously introduced two region example, the following characteristics can be observed given a fixed price-inelastic demand. Firstly, generation quantities and thus system generation costs are the same independently of the applied congestion management method. As can be seen in Figure 2.6 and Table 2.2, the final generation and thus generation costs are identical among different congestion management regimes and amounts to $\hat{g}_A + \hat{g}_B$. The initial generation represents the generation of the spot market. If congestion alleviation methods either cost- or market-based redispatch are used, the upcoming scarcity of transmission capacity is considered after clearing of the spot market. Hence, market transactions are not affected by congestion management and the realized spot market generation is identical to the case with full or unlimited transmission capacity $(g^*_A + g^*_B)$. Afterwards, arising congestion is managed by redispatching power plants in both regions. In Region A generation is increased by $\hat{g}_A - g^*_A$ whereas in Region B generation is decreased to the same extent $g^*_B - \hat{g}_B$ to ensure the balance of load and generation. In case of an explicit or implicit auctioning of capacity, scarcity of transmission capacity is explicitly taken into account prior or during the spot market clearing and the generation dispatch is accordingly adjusted $(\hat{g}_A + \hat{g}_B)$ to optimally utilize transmission capacity.

To sum up, applying congestion alleviation methods require the redispatch of generation in case of congestion to achieve a feasible generation dispatch, whereas using capacity allocation methods the final generation dispatch is already achieved in the spot market. However, all methods achieve the same final generation dispatch of $\hat{g}_A + \hat{g}_B$ independently of the applied management regime. Interpreting generation costs as an efficiency measure the considered methods are thus equally efficient in the short-run under the assumption of perfect competition and perfect foresight.

	Spot market generation	**Constrained-off generation**	**Constrained-on generation**	**Final generation**
No interconnector capacity	$g_A + g_B$	–	–	$g_A + g_B$
Full interconnector capacity	$g_A^* + g_B^*$	–	–	$g_A^* + g_B^*$
Explicit auction	$\hat{g}_A + \hat{g}_B$	–	–	$\hat{g}_A + \hat{g}_B$
Implicit auction	$\hat{g}_A + \hat{g}_B$	–	–	$\hat{g}_A + \hat{g}_B$
Cost-based redispatch	$g_A^* + g_B^*$	$g_B^* - \hat{g}_B$	$\hat{g}_A - g_A^*$	$\hat{g}_A + \hat{g}_B$
Market-based redispatch	$g_A^* + g_B^*$	$g_B^* - \hat{g}_B$	$\hat{g}_A - g_A^*$	$\hat{g}_A + \hat{g}_B$

Table 2.2.: Generation under different congestion management regimes. Source: Own illustration

However, different congestion management regimes result in different distributions of costs and thus economic surpluses[20] to the different market participants. Table 2.3 depicts the economic surpluses of different market participants shown in Figure 2.6 under different congestion management regimes assuming perfect competition and foresight.

In the case without an interconnection, the demand in both regions is satisfied by their available generation capacities and each region shows its own price determined by the intersection of regional merit-order curve and demand. Due to more costly generation sources in Region A, the final price in Region A p_A is higher than in Region B p_B. This leaves consumers in Region A with a surplus of the area A and consumers in Region B with a surplus area of E+F_1+G_1. Generators receive a surplus amounting to the difference of the regional price and marginal costs accounted with generation quantities (Region A: B_1+(C_1+C_2)+D; Region B: H). If an interconnector links both regions and the transmission capacity is considered to be sufficiently high[21], available generation in Region B can be used to satisfy demand in Region A. Thus, generation in Region A is replaced due to lower generation costs of Region B generation. As transmission capacity is sufficiently high, regional prices are equalized and amount to $p_A^* = p_B^*$. In terms of surplus, consumers (generators) in Region A

20 The term economic surplus is a synonym for welfare and both terms are used interchangeably.

21 'Sufficiently high' means that transmission capacity does not represent a restriction on optimal trade between both regions.

(B) profit whereas consumers (generators) in Region B (A) loose through the introduction of an interconnection and the impact on prices. However, the overall welfare of the entire system is increased by the area $B_2+(C_3+C_4)+(F_2+F_3)+G_2$ through the linking of both regions. The increase of welfare presents the general economic rationale for connecting regional markets.

However, if an interconnection exists and transmission capacity is not sufficiently high to allow an unrestricted regional exchange, congestion management methods are applied to ease arising congestion through scarce transmission capacity. If transmission capacity is allocated during the spot market clearing through explicit or implicit auctioning, the difference of final regional market prices reflect the degree of transmission capacity scarcity. If transmission capacity is sufficiently high, the price difference equals zero, otherwise it is greater than zero. Based on this, the surplus of market participants varies between the previously explained 'no interconnection capacity' and 'full interconnection capacity' cases. However, the transmission system operator faces congestion rents in the amount of transmission capacity times regional price difference[22] through the allocation of scarce transmission capacity. With respect to the example, the transmission system operator buys generation in the amount of the transmission capacity in Region B at the the price $\hat{p}_B$ in order to sell it in Region A at the price $\hat{p}_A$ resulting in a congestion rent of the area C_4+F_2. This outcome is valid if an implicit or marginal-bid based explicit auction is applied for allocating capacity. In case of a pay-as-bid based explicit auction, the transmission system operator can achieve additional congestion rent in the amount of G_2 as he buys generation in Region B at their marginal costs.

If congestion is managed by alleviation methods, the scarce transmission capacity is neglected in the clearing process of the spot market and arising congestion is managed by adjusting the determined generation dispatch through redispatch. Thus, it is obvious that generators and consumers achieve the same surplus as in the 'full interconnector capacity' case. However, if transmission capacity is scarce, the transmission system operator is in charge of redispatching generation and financially compensate them. This leaves the transmission system operator with congestion costs in the amount of C_3+F_3 in case of a cost-based redispatch. These congestion cost accrue from the decrease of generation in Region B in the amount of $g_B^* - \hat{g}_B$ and according increase in Region A $\hat{g}_A - g_A^*$ (see Table 2.2). In case of market-based redispatch these congestion costs

[22] In the 'no interconnector capacity' case, the transmission system operator does not receive congestion rent as the transmission capacity is zero. In case of 'full interconnector capacity', the transmission capacity is greater than zero, but the price difference between both regions is zero resulting in no congestion rents.

are expected to be higher as the last accepted bid for increasing and decreasing generation determines the financial compensation of redispatched generation. In the example, the amount of C_2+F_4 represents the additional congestion costs for the transmission system operator, but also profits for generation in Region A and B, respectively.

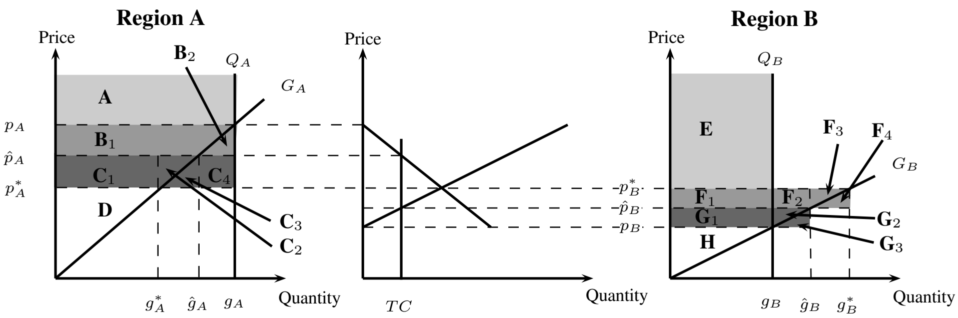


Figure 2.6.: Distribution of surplus. Source: Own illustration

	Consumer		**Generator**		**Trans-mission operator**
	Region A	Region B	Region A	Region B	
No inter-connector capacity	A	$E+F_1+G_1$	B_1 $+(C_1+C_2)$ $+D$	H	–
Full inter-connector capacity	A $+(B_1+B_2)$ $+(C_1+C_2$ $+C_3+C_4)$	E	D	$(F_1+F_2+F_3)$ $+(G_1+G_2)$ $+H$	–
Explicit auction (pay-as bid)	A $+(B_1+B_2)$	$E+F_1$	(C_1+C_2) $+D$	G_1+H	$C_4+F_2+G_2$
Implicit auction[23]	A $+(B_1+B_2)$	$E+F_1$	(C_1+C_2) $+D$	(G_1+G_2) $+H$	C_4+F_2
Cost-based redispatch	A $+(B_1+B_2)$ $+(C_1+C_2$ $+C_3+C_4)$	E	D	$(F_1+F_2+F_3)$ $+(G_1+G_2)$ $+H$	$-(C_3+F_3)$
Market-based redispatch	A $+(B_1+B_2)$ $+(C_1+C_2$ $+C_3+C_4)$	E	$D+C_2$	$(F_1+F_2$ $+F_3+F_4)$ $+(G_1+G_2)$ $+H$	$-(C_2+C_3)$ $-(F_3+F_4)$

Table 2.3.: Distribution of surpluses of different market participants under different congestion management regimes. Source: Own illustration

[23] The distribution of surplus in case of an uniform-priced explicit auction is equivalent to

Based on these considerations the following conclusions on distribution effects can be drawn.[24] First, consumers profit from congestion alleviation methods as a limitation of transmission capacity is neglected in the spot market. This leaves consumers with the high surplus as in the 'full interconnector capacity' case. Using capacity allocation methods, consumer surplus is reduced in Region A by $C_1+C_2+C_3+C_4$ but only slightly increased in Region B by F_1 compared to the 'full interconnector capacity' case.

Second, the transmission operator profits from capacity allocation methods as he faces congestion profits rather than congestion costs for redispatching power plants. In particular, in a cost-based redispatch congestion costs are in the amount of C_3+F_3 which represent the costs for increasing generation in Region A and decreased generation in Region B. Using implicit auctioning, market participants adjust their generation pattern and the transmission operator is not in charge of redispatching power plants. Thus, he receives profits from allocating transmission capacity in the amount of C_4+F_2. Resulting congestion profits or costs may vary slightly between different implementations of congestion alleviation and capacity allocation methods.

Third, generators are affected by different regimes. However, the general effect depends on the characteristics of the regional cost curves. Comparing implicit auctioning with cost-based redispatch shows that generators in Region A gain surplus (C_1+C_2), but generators in Region B loose surplus ($F_1+F_2+F_3$). As can be seen in Figure 2.6, the resulting overall impact on generators depends on the slope of regional merit-order curves. Thus, the distributional impact depends on the characteristics in particular the merit-order curve of the considered regions and a general conclusion cannot be drawn.

To summarize, the considered congestion management regimes achieve short-term efficiency as fixed load is always served by a least-cost dispatch of available generation assuming perfect market conditions. Differences between different regimes are in the distribution of costs and surplus. Consumers profit from the application of congestion alleviation methods, whereas the transmission system operator achieves highest profits when capacity is allocated during market procedure. The impact on generation is ambiguous and depends on the regional characteristics of the merit-order curve.

an implicit auction.

[24] The quantified effects are limited to a price-inelastic demand and may change if a price-elastic demand is assumed. Furthermore, the analysis abstracts from a regulatory regime which may redistribute surplus or costs from the transmission operator to generators and/or consumers.

2.3.2. Long-Term Efficiency

In the long-run perspective, adequate incentives for transmission and generation investments should be provided to market participants to promote investments in the required amount of transmission and generation capacity, and their location. In an idealized world neglecting lumpiness of investments and economics of scale in generation and transmission, one would invest to equalize short-run and long-run marginal cost (Rious et al., 2008). However, the real-world characteristics of transmission and generation investments cause a difference between short-run and long-run marginal cost. Furthermore, as an efficient use of capacities is achieved by prices at short-run marginal costs this results in the problem that investments may not be able to cover their long-run marginal cost (Lévêque, 2006). Thus, spot market prices as a result of applied congestion management methods which ensure an efficient usage of existing capacity are usually extended by additional components (e.g. network tariffs) to recover investment expenditures.

With respect to the expansion of the transmission network, the transmission network operator faces costs if congestion alleviation methods are applied. Hence, incentives exist to expand transmission infrastructure in order to reduce costs associated with the redispatch of power plants. In an idealized world neglecting lumpiness of investments and economics of scale, the transmission system operator would invest as long as marginal cost of transmission capacity equals the marginal benefit of a reduction in congestion cost. Considering realistic characteristics of transmission investments, the network operator would expand the network as long as the (expected) reduction in congestion costs justifies the lumpy investment expenditures. However, due to e.g. uncertainty about the development of generation capacities and thus resulting congestion costs the transmission operator may not be willing to adequately invest in transmission expansion solely on the basis of congestion costs. Hence, regulated network tariffs are important beside congestion costs to ensure the covering of investment expenditures.

In case of capacity allocation methods, congestion rents accrue to the transmission system operator, thus eliminating incentives for an adequate expansion of the transmission network. Hence, regulatory mechanisms are required to incentivize the transmission operator to adequately extend existing infrastructure or to build up new infrastructure and to recover investment expenditures as the achievable congestion rents may not be necessarily sufficient (Pérez-Arriaga and Olmos, 2006). For instance, Hogan et al. (2010) develop an appropriate incentive mechanism to induce network expansion in case of network congestion which is profitable for the transmission system operator. Rosellón and Weigt (2011) apply the theoretical concept to a realistic electricity system and prove the functioning of the incentive mechanism. Alternatively, merchant investors may be attracted by achievable congestion rents to reinforce the transmission network. However, as merchant investors would require a certain extent of congestion rent to recover their investment expenditures a tendency to underinvestment would result (Joskow and Tirole, 2005; Stoft, 2006).

On the other hand, generators and consumers receive economic signals on congestion in capacity allocation regimes as prices may vary in case of congestion. Under the assumption that incentives exist to invest in generation capacity in general[25], the received regional price differences thus give these market participants incentives to place new generation or consumption in regions where it is adequate. In the considered two region example, the price in Region A is higher than in Region B. Hence, it may be profitable for generators to place new facilities in the high priced region, whereas consumption may prefer Region B due to lower prices. Both developments would reduce congestion between both regions and are thus efficient in the long-run perspective.

If congestion alleviation methods are analyzed, the spot market price does not reflect the congestion situation of the physical network. Thus, incentives to place generation or consumption in specific regions are not provided. Also if alleviation methods are applied, long-term incentives are ambiguous. In case of cost-based redispatch only power plants used for redispatch are informed about congestion. Remaining generation do not receive information on congestion situation. In case of market-based redispatch, all market participants are informed about congestion through resulting prices of the redispatching market. However, as Perekhodtsev and Cervigni (2010) analyzed the separation of energy and redispatching market may induce adverse bidding incentives for market participants leading to wrong investment signals in the long-run. Furthermore, Ding and Fuller (2005) show that congestion alleviation methods are not able to provide appropriate investment signals and can even result in contrary investment incentives. Based on the evaluation of achievable surpluses (Table 2.3), generators in Region A receive less surplus when congestion alleviation is used compared to capacity allocation. The difference in surplus in Region A amounts to C_1. Furthermore, generators in Region B achieve additional surplus in the amount of F_1+F_2+F_3 than in case of implicit auctioning of capacity. In the end, generators would be incentivized to invest rather in Region B than in Region A.

[25] This implies that electricity markets allow market participants to recover their investment costs either through scarcity rents in the 'energy-only' spot market or an explicit capacity market (e.g. Green, 2006).

This outcome would aggravate the congestion situation and is thus not efficient in the long-run perspective.

To summarize, congestion alleviation methods provide correct long-term incentives to extend network infrastructure, whereas capacity allocation induces efficient generation and consumption investments. This raises the question which market participant should receive adequate investment signals. de Vries and Hakvoort (2002) argue that giving competitive market segments should be preferred and economic signals on congestion should be provided through locationally differentiated prices. Generation and consumption would be incentivized to locate their facilities in regions where it is required and relaxes the congestion situation.[26] As the transmission of electricity is a natural monopoly and therefore a regulated market segment, adequate investment incentives should be provided through regulatory mechanisms by national regulatory authorities independently of the applied congestion management regime. From a practical point of view, building up new transmission infrastructure probably requires longer lead times due to administrative procedures than expansions in consumption or generation. In particular, renewable generation capacity is significantly increased during the last years. Therefore, giving economic signals to generation and consumption could to some extent steer the location of additional capacities. However, capacity allocation would not entirely reduce the need for transmission expansion as locating generation expansions are additionally influenced by other factors (e.g. availability of fuel and/or fuel transportation costs, meteorological conditions in case of renewable generation).

2.4. Application of Congestion Management Methods

2.4.1. Germany

The liberalization process in the German electricity market started in 1998 with the Energy Act (EnWG), which implemented the EU Energy Directive 96/92/EC. Key elements of the law are the free choice of electricity supplier by end users and the regulation of network access. In the initial phase of the liberalization the long-term and short-term electricity trade are rather bilateral (so-called Over-The-Counter or OTC transactions). However, exchanges have been implemented as central power markets and trading started in 2000. In 2001, the German power exchanges in Leipzig (LPX) and Frankfurt (EEX) merged in the European Energy Exchange (EEX)[27] in Leipzig.

[26] Pérez-Arriaga and Olmos (2006) point out that the efficient siting of generation and consumption can be further improved by locational network charges.

[27] Compare: `http://www.eex.com/`

The commercial area of the EEX expanded over the past few years to Austria and Switzerland. In 2008 a cooperation with the French power exchange Powernext started. This cooperation led to the creation of EPEX Spot SE[28], which performs the spot market settlement for Germany / Austria, Switzerland and France. The EEX operates the futures market since 2008 for the mentioned market areas. The focus of the daily dayahead auction is the clearing of demand bids and generation offers for the following day separately for the different market areas. Market participants are not required to attend to the exchange trading and still have the option to trade bilaterally. The pricing on the EPEX is uniform for the entire German market area. An explicit consideration of national network constraints is not applied.

Transmission congestion arising from any dayahead generation schedules of market participants will be managed by the responsible transmission system operator, which receives the respective generation schedules of power plants in advance to real-time operation. Based on the generation schedules network congestion management is performed by the relevant transmission system operators and emerging network congestion is eased by using network-related and market-related methods (§ 13 (1) EnWG, § 15 (1) StromNZV). Network-related methods include inter alia the adjustment of network topology through switching actions (VDN, 2007, Appendix A). As a market-based method cost-based redispatch of power plants and counter-trading are applied in the German electricity market (VDN, 2007; Inderst and Wambach, 2007; Ockenfels et al., 2008). If those methods are not sufficient, the transmission system operator can make use of further short-term options (§ 13 (2) EnWG). Furthermore, if the occurrence of network congestion cannot be prevented by using network- and market-related methods, the transmission system operators are obliged to manage the available transmission capacity non-discriminatory according to market-oriented and transparent procedures (§ 15 (2) StromNZV).

The congestion management costs of the past years are displayed in Table 2.4. As can be seen, redispatching costs are rather low; up to 45 million EUR in 2008 or 0.09 EUR/MWh. Hence, congestion occurs rarely in the German transmission network and thus management costs to relieve congestion are rather low. According to Deutscher Bundestag (2010), wind generation impacts congestion management costs and caused the increase in 2008 due to high wind generation. In 2009, wind generation is lower due to meteorological conditions and thus costs for redispatching power plants are reduced. Therefore, generation of renewable energy sources (esp. wind) is an determining factor for transmission

[28] Compare: `http://www.epexspot.com/`

	Congestion costs	**Consumption**	**Congestion costs /consumption**
	million EUR	GWh	EUR/MWh
2007	30	527,351	0.06
2008	45	525,549	0.09
2009	26*	495,572	0.05
2010	48*	528,958	0.09

* Including national and international counter-trading

Table 2.4.: Congestion management costs in Germany. Source: Own illustration based on Deutscher Bundestag (2010),BNetzA (2011b), and Eurostat (2012)

congestion and similarly congestion management costs.

Furthermore, according to (Monopolkommission, 2011, p. 24) the phase-out of nuclear power plants is expected to affect congestion management costs. Hence, the application of the current uniform pricing regime including congestion management by alleviation methods is not uncritical as market participants do not receive market information (e.g. price) about network congestion. However, market information are required to give price signals for efficient placing of production or consumption within the power system. Hence, Monopolkommission (2011) points out, that the implementation of at least two pricing zones with an implicit allocation of transmission capacity should be discussed in order to achieve an efficient management of national congestion. Frontier Economics and Consentec (2011) study the economic and administrative implications of the introduction of price zones and thus a market splitting in the German-Austrian market area. It is concluded that potentially negative impacts (e.g. potential of lower market liquidity, higher market concentration in price zones) outweigh the positive economic implication of efficient congestion signals to market participants.

2.4.2. Nord Pool

2.4.2.1. Norway

Norway was the first country in northern Europe, which promoted the liberalization of the electricity market significantly. The production structure is characterized especially by a very high proportion of hydro (99 %), which is spread over a large number of small companies (Hjalmarsson, 2000; Woo et al., 2003). The four largest generating companies account for 44 % of installed generation capacity (Woo et al., 2003). At that time, the Norwegian electricity market was characterized by significant regional price differences and a high share of hydro storage generation and their seasonal availability (Skytte, 1999). These reasons increased the need of a coordination of production, thus offsetting regional price fluctuations. In 1991, Norway passed a law to liberalize the production and distribution sector in the electricity market. However, the Norwegian electricity market was not fully privatized and the national transmission system operator Statnett is still owned by the Norwegian state and municipalities.

In 1993 the first power exchange (Statnett Marked) was implemented. In 1996 the exchange was extended by the Swedish electricity market and renamed in Nord Pool. The power exchange was further expanded to include Finland (1998), West-Denmark (1999) and Eastern Denmark (2000). The Nord Pool is currently designed as a voluntary power exchange, which comprises the central clearing of auctions as well as bilateral contracts. The markets of the Nord Pool are divided into the physical dayahead market Elspot[29] and the physical intraday market Elbas[30]. There is also the possibility to trade financial products. The latter are however not handled by Nord Pool but by NASDAQ OMX Commodities[31].

The optimization of power plant operation remains in the responsibility of producers and is not made by the Nord Pool. The price determination is based on the bids and offers of market participants and corresponds to the intersection between supply and demand bid function for the entire market area. The prices are determined taking into account the available transmission capacities between the national market areas. This represents an implicit auctioning of transmission capacity (market splitting) between the various defined market areas.

Within the Norwegian market area the implicit auctioning of transmission capacity (market splitting) is also used as internal congestion management method. Based on the bids and offers of market participants the transmission capacities of national bottlenecks are allocated within the market clearing procedure of the Nord Pool. In case of congestion, regionally differentiated prices are determined for the market zones. The definition of the potential market or bidding zones including the determination of the transmission capacity between zones is performed by the Norwegian network operator Stattnett. The zone definition is not variable in the short term but will be adjusted according to the load flow and congestion situation. Currently the Norwegian electricity market is divided into 5 possible market zones (see Figure 2.7; east Norway NO1, south-western Norway NO2, central Norway NO3, northern Norway NO4, and western Norway NO5).

[29] Compare: `http://www.nordpoolspot.com/`
[30] Compare: `http://www.nordpoolspot.com/`
[31] Compare: `http://www.nasdaqomxcommodities.com/`

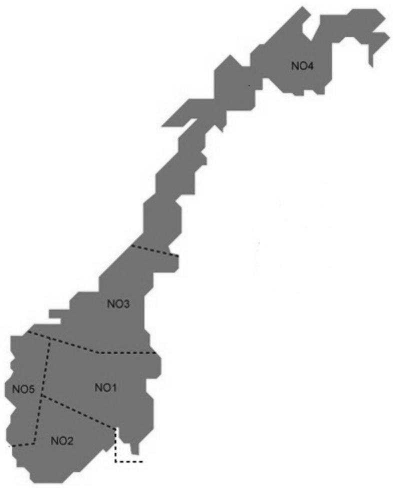


Figure 2.7.: Price zones in Norway. Source: `http://www.statnett.no`

Due to the implicit consideration of network constraints within the wholesale electricity market, producers receive direct information about network congestion through regionally differentiated prices. This leads to a more efficient allocation of resources and creates regionally differentiated investment incentives in the long-term perspective.

2.4.2.2. Sweden

In 1992, the Swedish state company Vattenfall was divided into the state-owned network operator Svenska Kraftnät and the state-owned generator Vattenfall. Svenska Kraftnät has been responsible for the maintenance and operation of the national transmission network. This was the first step towards the liberalization of the national electricity market, which was completed in 1996 through the liberalization of the electricity market. Due to the Swedish legislation, the national companies were more open to private investors compared to Norway. Nevertheless, the large companies remained mostly owned by the Swedish government or the municipalities (Skytte, 1999). In 1996 the Swedish electricity market joined the Nord Pool and trade rules between both countries were harmonized.

In contrast to the Norwegian electricity market, the Swedish electricity market is characterized by a uniform wholesale electricity price. Implicit auctioning of transmission capacity takes only place on the interconnectors to the neighboring countries. Congestion within the Swedish market area is managed through the national transmission system operators using the market-based redispatch (counter-trading) within the operational phase (Svenska Kraftnät, 2007, p. 6). Available capacities necessary for the counter-trading are procured within the

	Congestion costs	**Consumption**	**Congestion costs /consumption**
	million SEK*	GWh	SEK/MWh*
2007	213	131,082	1.62
2008	113	128,649	0.88
2009	300	123,374	2.43
2010	186	131,217	1.42

* Exchange rate (2010) EUR/SEK: 9.5373 (ECB, 2012)

Table 2.5.: Congestion management costs in Sweden. Source: Own illustration based on Svenska Kraftnät (2008, 2009, 2010) and Eurostat (2012)

balancing market and a separate market for redispatching capacity does not exist. The congestion management costs are depicted in Table 2.5. Due to the uniform market price in Sweden, regionally differentiated investment incentives are not provided to market participants. However, in order to pass the short-term and long-term costs of network use to market participants, regionally differentiated network usage charges are currently applied.

However, the Swedish congestion management regime needs to be changed as required by the European Commission in their investigation (Case COMP/39.351 - Swedish Interconnectors). In 2009 the European Commission opened the formal proceedings with respect to the Swedish transmission system operator Svenska Kraftnät for possible abuse of their dominant market position. The European Commission investigated the reduction of international capacities by Svenska Kraftnät in order to ease national congestion. Following Svenska Kraftnät (2007), the Swedish power system is characterized by a significant transfer from the Northern to Southern Sweden. Low-cost generation units are located in the Northern part of Sweden, whereas main load centers are in the South. Additionally, electricity from Norway is imported in the North and exports to Denmark take place in the South. Both effects results in a main flow of electricity from the North to the South. Due to this characteristics of the Swedish power system, Svenska Kraftnät denied the export of electricity to Denmark, but allowed the import from Denmark in order to relieve congestion in the national transmission network. Thus, Svenska Kraftnät discriminated between different market participants and abused their dominating market position.

Following a decision of the European Commission (European Commission, 2010) Svenska Kraftnät divided the Swedish market area into four market zones and started to operate the transmission system on this basis on 1 November 2011. Thus, congestion management through counter-trading is replaced by an implicit auctioning (market splitting) of transmission capacity. Hence, market

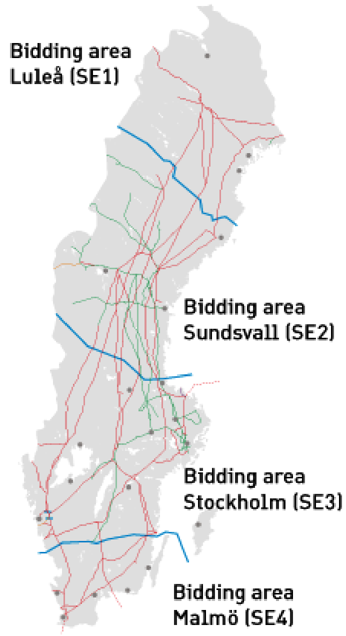


Figure 2.8.: Price zones in Sweden. Source: `http://www.svk.se/`

participants now receive market information about congestion situation through regional differentiated market prices in case of congestion. Furthermore, the definition of market zones is fixed in the short term, but flexible in the long-run in order to anticipate changes in congestion situation. The applied price zones are displayed in Figure 2.8.

2.4.3. Great Britain

The British government privatized and liberalized the British electricity industry in 1990 as the first country in Europe. Furthermore, a mandatory power pool was implemented, which required the participation of all market participants. The producers had to submit their bids to the National Grid Company, which determined the least cost dispatch of power plants.

In 2001, the New Electricity Trading Arrangements (NETA) were introduced and replaced the mandatory power pool by an electricity exchange with voluntary participation and bilateral trade opportunities. National Grid Company was responsible for operating the transmission grid.

In 2005, the existing NETA has been extended to the Scottish market area (British Electricity Trading and Transmission Arrangements, BETTA). A single electricity market for Great Britain with system operator (National Grid Electricity Transmission, NGET) independent from production and distribution has been established. The ownership of the transmission grid remained with the

	Congestion costs	**Consumption**	**Congestion costs /consumption**
	million GBP*	GWh	GBP/MWh*
2005/06	152	348,676	0.44
2006/07	188	345,229	0.54
2007/08	112	342,644	0.33
2008/09	448**	341,853	1.31
2009/10	474**	322,417	1.47

* Exchange rate (2010) EUR/GBP: 0.85784 (ECB, 2012)
** Forecasted values

Table 2.6.: Congestion management costs in Great Britain. Source: Own illustration based on OFGEM (2009) and Eurostat (2012)

three owners (the National Grid, Scottish Power, and Scottish & Southern Energy). The operation of the transmission network is performed by the independent transmission system operator NGET.

Two elements of the BETTA are of particular importance with respect to congestion management: the forward bilateral market and the balancing mechanism (Perekhodtsev and Cervigni, 2010). Market participants perform bilateral trades in the forward markets till the gate closure of the markets (1 hour before real time). The trades are geographically unlimited and physical network constraints are considered neither explicitly nor implicitly. At the gate closure the transmission system operator receives the final physical positions (Final Physical Notification, FPN). In the remaining hours between gate closure and real-time, the balancing mechanism takes place and the transmission system operator collects the bids and offers on a change in the physical position of the market participants. Based on the bids and offers of the balancing mechanism the transmission system operators performs a market-based redispatch by adjusting the physical position in order to ease network congestion. Other technical measures to increase network capacity and availability are also used by the transmission system operators in the operational phase to relieve network congestion (Paravalos et al., 2005).

Currently, significant congestion and high congestion management costs are observed and expected in particular at the border between England and Scotland (see Table 2.6). Perekhodtsev and Cervigni (2010) analyzed the reasons for the increased congestion management costs. They point out that it is unclear whether this increase in congestion management costs is caused by anti-competitive behavior of certain producers and/or resulting from the overall design of congestion management. However, the application of market-based redispatch as congestion management methods turns out to result in negative effects regarding wholesale prices and congestion costs especially if network congestion can be well predicted by market participants (Perekhodtsev and Cervigni, 2010).

2.4.4. Pennsylvania-New Jersey-Maryland (PJM)

The electricity market was established in 1927 through the merger of three electricity distribution companies and in 1956 renamed in Pennsylvania-New Jersey-Maryland Interconnection (PJM)[32] through the integration of other electricity distribution companies. The aim of the merger was to coordinate and optimize the dispatch of power plants. In 1998 an independent system operator (ISO) was implemented in the PJM electricity market and in 2001 expanded to a regional transmission organization (RTO). Thus, the deregulation of the electricity industry according to the Federal Energy Regulatory Commission (FERC) Order 880 was established and an independent system operator was implemented.

Currently, the PJM market area comprises a large part of north-eastern states in the United States with an installed capacity of more than 167 GW (PJM, 2011). Hence, PJM is the largest centralized electricity market in North America, serving more than 54 million people with a peak load of approximately 145 GW (PJM, 2011).

The PJM electricity market is characterized by a centralized market structure comprising a financial dayahead and a physical real-time market. Both markets are interrelated by a two-settlement system in order to enable the various market participants to participate in the markets (Ott, 2003; Fan et al., 2008). Furthermore, PJM operates a capacity market to ensure the necessary generation capacity in the market area. The dayahead market is designed as a voluntary bid-based market, which includes the determination of hourly market prices for the following day. Generating plants, which entered an Installed Capacity Contract, or have sold capacity in the PJM capacity market, are obliged to participate (e.g. place bids) in the dayahead market (Ott, 2003). Even in case of bilateral agreements or power plant failures, the placing of bids in the dayahead market is required in order to consider power plants in the subsequent optimization procedure. The possible bids in dayahead market include generation and demand bids as well as the inclusion of bilateral transactions (Fan et al., 2010).

The dayahead market is a financial market, which can be used to hedge against price uncertainty in the real-time market. Additionally, congestion costs for bilateral transactions are determined in the dayahead market. The bids of market

[32] Compare: `http://www.pjm.com`

participants which are taken into account in the dayahead market are automatically considered in the subsequent physical real-time market. Market participants also have the option to adjust their bids between both markets, or to act only in one of the markets. Based on the detailed bids of market participants, all operational decisions regarding generation and transmission are simultaneously optimized by PJM system operator and the least-cost dispatch of power plants is determined taking power plant, network and security restrictions in the dayahead and real-time market into account (Ott, 2003). The central coordination of generation and transmission, however, requires a detailed representation of the cost structures of market participants including economic costs and technical restrictions. The optimized power plant schedules are sent to the power plant operators. Deviations from these optimized schedules and new or revised bids will be considered in subsequent real-time market and included in the real-time market optimization. The real-time market is optimized every 5 minutes, taking into account the current system status and real-time market prices are determined. Through the pricing and the application of two-settlement system market participants are encouraged to follow the optimized real-time generation schedules (Ott, 2003).

Due to the simultaneous optimization of power plant operation and the network usage, the so-called 'Locational Marginal Pricing' or 'Nodal Pricing' can be applied. Herewith, locationally differentiated prices can be determined for each system node reflecting generation cost structures as well as network congestion in the system. Market participants will receive or pay the price of the system node they are connected to. The price difference between different system nodes reflects the congestion costs. The simultaneous optimization of power plants and power usage represents an implicit auctioning of transmission capacity as the capacity is allocated within the market procedure. Due to application of nodal pricing, market participants receive information (or price signals) about the network utilization and congestion within the system. If congestion occurs within the market area, regionally differentiated prices are determined which reflect the degree of the congestion. Thus, information on congestion through the locationally differentiated prices are directly passed to market participants resulting in locationally differentiated investment incentives. The congestion costs[33] are displayed in Table 2.7.

[33] Congestion costs in the PJM are defined as the difference of total load and generator payments.

	Congestion costs	**Consumption**	**Congestion costs /consumption**
	million USD*	GWh	USD/MWh*
2003	464	674,471	0.69
2004	750	689,008	1.09
2005	2,092	682,441	3.07
2006	1,603	694,989	2.31
2007	1,845	724,541	2.55
2008	2,117	713,910	2.97
2009	719	680,767	1.06
2010	1,428	808,977	1.77

* Exchange rate (2010) EUR/USD: 1.3257 (ECB, 2012)

Table 2.7.: Congestion management costs in PJM electricity market. Source: Own illustration based on Monitoring Analytics (2008, 2009, 2010, 2011), PJM (2010), and PJM (2012)

2.5. Conclusions

Different approaches to manage congestion in transmission networks are available ranging from congestion alleviation to capacity allocation methods. Congestion alleviation methods aim to manage congestion without changing trades at the spot market. Hence, market participants (generation and consumers) are not informed about the existence of congestion. On the other hand, capacity allocation methods aim to allocate scarce transmission capacity to market participants in an market-oriented approach. Market participants receive information about the congestion situation and therefore internalize congestion in their market bidding procedure. Both congestion management regimes achieve short-term economic efficiency as generators with lowest generation costs are producing. However, differences between both regimes are existent in the long-run perspective. In a capacity allocation regime, market participants receive information about congestion situation and hence internalize these information in the long-term planning (e.g. generation investment planning). Thus, capacity allocation methods provide efficient long-term economic incentives to market participants (generation and consumers). On the other hand, congestion alleviation methods provides economic signals to transmission operator whereas market participants are left uninformed about congestion.

The application of congestion management methods depends on characteristics of power systems. In Germany, congestion within the national transmission system was rather rare and therefore congestion management is mainly performed using congestion alleviation methods. As market participants do not internalize congestion, the transmission system operator faces the problem of congestion management. As long as congestion remains rather limited in space and time, congestion alleviation methods are preferred as they do not require complex market organizations.

If congestion becomes persistent in power systems, congestion alleviation methods can result in high congestion management costs as market participants do not internalize congestion. For instance in Great Britain, congestion management costs are expected to increase significantly due to congestion on the Scottish-British border as market participants anticipate the congestion situation in their bidding strategy. Additionally, adverse bidding incentives are provided through the application of a market-based redispatching regime which further increases congestion management costs. Furthermore, as experienced in the Swedish power system, limitation of international trades was required to relieve national congestion by congestion alleviation methods. Hence, management of congestion is required to be changed to give market participants relevant market information about the congestion situation. In Sweden, the implementation of a zonal pricing approach including an implicit auctioning of transmission capacity was required by the European Commission.

Nodal pricing as the implicit allocation of (all) transmission capacities is seen in the academic literature as the optimal approach with respect to short-term economic efficiency abstracting from any costs for system change and implementation. In a nodal pricing regime, the dispatch of power plants and the utilization of the transmission network are optimized simultaneously and an optimal usage of scarce transmission capacity is ensured. Hence, market participants receive efficient short-term signals on network congestion in the spot market. The nodal pricing regime is successfully implemented and applied in the PJM electricity market.

3. Quantifying Economic Implications of Congestion Management Regimes in Europe

3.1. Introduction

The creation of an Internal Electricity Market (IEM) is one of the main targets of the energy policy of the European Commission (EC). The underlying motivation is to increase efficiency by promoting competition between market participants and finally to achieve transparent and market-based electricity prices for final consumers. To achieve the objective, the liberalization process was initiated in 1996 by implementing the Directive 96/92/EC and the subsequent adoption into national legislation in the following years. In 2001, the second Directive 2003/54/EC was introduced with the aim to further improve competition. The directive replaced the earlier Directive 96/92/EC. The third Directive 2009/72/EC introduced in 2009 repealed the earlier directives and provides revisions on regulations on unbundling of production/supply and network activities, implementation of regulatory authorities including the establishment of an European Agency for the Cooperation of Energy Regulators (ACER) and the introduction of intelligent metering to promote energy efficiency.

Beside the re-organization of market structures within countries, the promotion of cross-border trade is a key prerequisite for a functioning of an European electricity market. As the first directive did not address cross-border trade among European countries, Regulation 1228/2003/EC was issued in combination with the second directive to intensify the cross-border trade of electricity. Through the Regulation 1228/2003/EC in combination with the Annex 2006/770/EC an important step towards enhancement of capacity allocation and congestion management on cross-border lines (interconnectors) has been achieved (ERGEG, 2010b). The regulation defines rules for cross-border trade including an compensation mechanism, harmonized transmission charges, and the allocation of available cross-border transmission capacity. The focus of the regulation is explicitly on cross-border trade between European countries and the regulation and management of national transmission networks is left to national authorities. However, the integration of national markets did not proceed as expected (ERGEG, 2010b). Therefore, the new Regulation 714/2009/EC was introduced together with the third directive and replaced the former Regulation 1228/2003/EC. A main shortcoming of the previous regulation was the lack of coordination of congestion management between transmission system operators. To promote the coordination and transparency, an European Network of Transmission System Operators for Electricity (ENTSO-E) is established by the new regulation.

With respect to congestion management methods as introduced in Chapter 2, the Regulation 1228/2003/EC and 714/2009/EC define that arising congestion on cross-border connections shall be addressed by non-discriminatory and market-based methods which provide efficient economic signals to market participants (Article 16(1) of Regulation 714/2009/EC). As the requested congestion management methods are required to allocate cross-border capacities prior or during the regular market procedure, explicit and implicit auctioning are the preferred options. Furthermore, explicit auctions are widely implemented in the beginning of re-organization of the European electricity system as they are easy to implement and compatible with different market organizations (Section 2.2.2). In contrast, an implicit auction requires the establishment of a standardized market for electricity (power exchange) in both regions connected by the cross-border link.

Historically, electricity system were planned and organized on a national level. Cross-border links are designed to ensure security of supply rather than promoting trade between connected regions. Thus, access to capacity of interconnectors is mainly organized by corresponding transmission system operators using administrative methods (ETSO, 2004) which are not market-based (Section 2.2.1). Due to Regulation 1228/2003/EC, the establishment of market-based and non-discriminatory capacity allocation methods is required and accordingly adopted by transmission system operators. ETSO (2004) and ETSO (2006) provide an overview of applied congestion management methods across European countries for the years 2004 and 2006, respectively. The explicit auctioning of capacity became the preferred option to allocate capacity in the long- and short-term. An exemption is the Nordic power market where implicit auctions are used to allocate cross-border capacity (Section 2.4.2). In the following years, the advancement of power exchanges enables the introduction of coordinated explicit auctions between different transmission system operators and even implicit auctioning in some European regions (e.g. CWE Market Coupling). Figure 3.1

depicts the currently applied short-term congestion management regimes. Especially the expansion of implicit auctions and thus the market coupling of national electricity markets across European countries has been opted by European energy regulators (ERGEG, 2011).

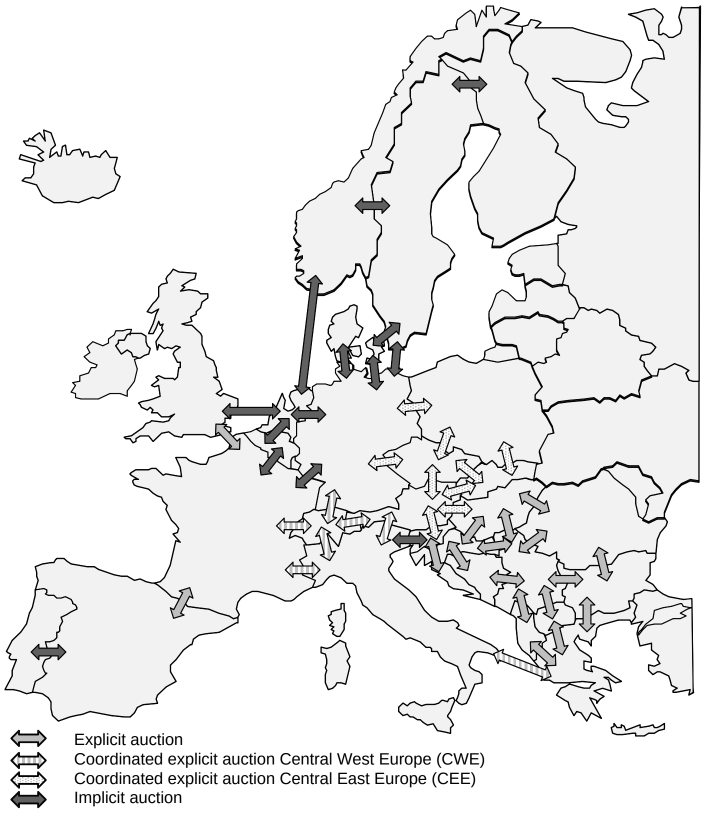


Figure 3.1.: Short-term (dayahead) capacity allocation methods in Europe. Source: Own illustration

Another issue addressed by Regulation 714/2006/EC and the former regulation is the definition of the transmission capacity available for market participants. According to Article 16(3) of Regulation 714/2009/EC, the maximum available capacity of the interconnections complying with operational security standard of the network shall be made available to market participants. International capacity allocations distinguish between commercial transfer which are used by market participants to plan their cross-border trades and physical flows as used by transmission system operators in real-time operation (ETSO, 2001b). Physical flows represent the flows on transmission lines which realize from injections and withdrawals from the transmission network according to physical characteristics of the transmission lines. This is formalized in Kirchhoff's current and voltage law (Claussnitzer, 1965). The main characteristic of physical flows is that they do not entirely flow on the direct transmission line between the point of injection (generation) and withdrawal (demand) but also impact adjacent transmission lines. The effect is known as loop flow. On the other hand, commercial or transactional transfers describe the transfer between two points neglecting the characteristics physical laws. The advantage of using commercial transfers for capacity allocation is that market participants do not have to take into account the physical characteristics of the flows when trading electricity between different regions. However, the maximum capacity available for market participants has to be determined by transmission system operators with respect to physical flows in order to ensure a secure network operation.[34]

Within the European electricity system, the concept of commercial transfers is currently applied for capacity allocations on each cross-border link between neighboring countries. Following (ETSO, 2001a, p. 6f) the subsequent transfer capacity definitions are used:[35]

TTC The Total Transfer Capacity (TTC) "is the maximum exchange program between two areas compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance" (ETSO, 2001a, p. 6).

TRM The Transmission Reliability Margin (TRM), is imposed to account for uncertainties arising from the functioning of frequency regulation, emergency exchanges, and inaccuracies in data and measurements (ETSO, 2001a).

NTC The Net Transfer Capacity (NTC) "is the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions" (ETSO, 2001a, p. 7). It is defined as:

$$NTC = TTC - TRM \tag{3.1}$$

Capacities are defined for each cross-border link and direction individually by

[34] To point out the difference between physical and commercial values, one may consider the German-Swiss border. In total 12 high-voltage transmission lines connect both countries which results in a total physical transmission capacity of approximately 15000 MVA. The commercial capacity (NTC) for the Winter 2011/12 amounts 1500 MW from Germany to Switzerland and 3500 MW in the reversed direction. Thus, commercial capacity represents a share of 10% or 23% on total physical capacity depending on considered direction.

[35] Beside the listed capacity definitions, the Already Allocated Capacity (ATC) and the Available Transmission Capacity are distinguished (ETSO, 2001a, p. 7). Both capacities are the results of each stage (long-term or short-term) of the applied capacity allocation procedure. The ATC describes the capacity allocated in previous stages of the capacity allocation procedure and the ATC the capacity available for the current stage of capacity allocation. Thus, the ATC can be defined as $ATC = NTC - AAC$.

the responsible transmission system operators. ENTSO-E publishes a table of 'Indicative values for NTCs in Europe' on its website twice a year.[36] The main complexity with commercial transfers is in the determination procedure of the maximum available capacity as physical characteristics of electricity transmission have to be taken into account. The issue of the determination of available commercial capacity is considered in Section 3.2.

However, the current commercial capacity definitions may not be able to efficiently utilize cross-border capacities as mentioned capacity definitions abstract from physical realities of electricity transmission. One particular reason is the integration of large-scale renewable electricity generation and the efficient utilization into the electricity network. According to ERGEG (2010b) current congestion management regimes are not able to sufficiently support the integration. Therefore, closer cooperation of national transmission system operators is required. Additionally, the improvement of the existing commercial- or transaction-based procedure towards a flow-based procedure which incorporates the characteristics of physical flows is considered by European Energy Regulators (ERGEG) and transmission system operators (ERGEG, 2010b). For instance, Amprion et al. (2011) investigate the feasibility of a flow-based capacity allocation regime within the existing market coupling in the CWE region. A comparison of different congestion management regimes is performed in Section 3.3.

As shown in Chapter 2, an efficient use of the existing network can provide flexibility utilizing the network more fully, can offer a transparent price signal to inform transmission system operators and regulators of the location of transmission congestion and hence needed network expansion projects. European countries and some US states have adopted two contrasting approaches to address congestion in their market designs: European countries have opted for an expansion of market coupling linking price zones (zonal pricing) as proposed by ACER (2011) and ERGEG (2011), and curative congestion management within price zones, while five regional markets in the US have adopted the implicit auctioning of all transmission constraints which is known as nodal pricing or locational marginal pricing (LMP) (O'Neill et al., 2005b).

As zonal pricing captures only the actual state of physical flows and congestion on transmission lines connecting price zones, it does not provide sufficient information that is necessary to inform regulators, transmission system operators, and market participants about the congestion situation within price zones and hence the need for transmission reinforcement and investment. To account

[36] Compare: `https://www.entsoe.eu/resources/ntc-values/`

for the congestion situation within price zones, ACER (2011) requires in its Framework Guidelines that zones shall be defined with respect to the congestion situation.[37] Currently, price zones are fixed and defined with respect to national borders within the European system.

From a theoretical perspective, Schweppe (1988) and Hogan (1992) have shown that nodal pricing leads to higher social welfare than zonal pricing. Other papers argue that a system using nodal pricing accommodates renewable energy sources more efficiently (Leuthold et al., 2008; Neuhoff, 2011). Leuthold et al. (2008) have shown the superiority of nodal pricing for the integration of wind into the German network. Other analysis of benefits from using full network models and nodal pricing rather than zonal pricing and aggregate international transfer capacity are provided by Barth et al. (2009) and Weijde and Hobbs (2011).

While Chapter 2 has discussed the theoretical benefits of different congestion management regimes, the purpose of this Chapter is to quantify whether improving system design makes better use of the network capacities in the European electricity system (ENTSO-E, formerly called UCTE). Therefore, the benefits in costs and surpluses of a nodal pricing regime compared to the current zonal or national pricing regime are quantified for the European electricity system in this Chapter. In a first step the achievable savings in generation costs are determined given different shares of renewable wind generation and mentioned pricing regimes (Section 3.2). This Section is based on Neuhoff et al. (2011). However, as highlighted in Chapter 2 congestion management regimes theoretically achieve short-term efficiency, but differ in their distribution of surplus among market participants. Therefore, distributional effects on costs and surpluses of market participants are evaluated in Section 3.3. Again, a zonal pricing regime is compared with the nodal pricing regime and surplus as well as price results are presented and discussed. Section 3.4 draws on Neuhoff et al. (2011) and provides the conclusions of the provided analysis.

3.2. Quantifying Cost Benefits of Congestion Management Regimes

As shown in Chapter 2 different methods to manage network congestion exist ranging from congestion alleviation to capacity allocation methods. The application of congestion management methods varies across countries. Whereas in

[37] The issue of the optimal definition of price (or market or bidding) zones is discussed in Section 2.2.2.2.

PJM market all network constraints are implicitly accounted in the spot market using an nodal pricing regime, European countries mainly use congestion alleviation methods to manage physical congestion in the national transmission network and do not incorporate network constraints in spot markets. Capacity allocation methods are used in Europe to allocate international transmission capacity through explicit and implicit auctions. The transmission capacity available for capacity allocation (net transfer capacity, NTC) is determined by national transmission system operators for each cross-border connection.

The current practice with respect to international as well as national congestion management in Europe raises the question whether an implicit allocation and thus a nodal pricing regime achieves benefits with respect to generation costs and international flows. To answer the question two models are developed. The first model applies the theory of nodal pricing to electricity systems. Based on an approximation of physical flows in an electricity network, generation and network usage can be optimized simultaneously. In a second model, only international transfers are limited which refers to a zonal pricing regime. Physical flows and associated congestion are managed subsequently in a separate model. To define the available capacity for international transfers, current approaches are firstly reviewed and afterwards used to determine the maximum transmission capacity between two neighboring countries.

A dataset covering the European power market is utilized in this analysis and used to calculate the differences between nodal pricing and zonal pricing regimes resulting from the traditional net transfer capacity (NTC) approach. To determine the difference between a nodal pricing regime and the current European electricity system, the results of the nodal pricing regime are then compared to a calculation representing implicit auctions with joint allocation of transmission capacity (NTC) across all international links, i.e., the optimization of the current paradigm pursued by European Regulators (ERGEG, 2010a). For this purpose, the model presented in this Section first calculates the volume of total transmission capacity (TTC) based on the calculation methodology presented in ENTSO-E documents (UCTE, 2009). This provided TTC values that are consistent with the model network and are used as a base for the calculation of market results from the dayahead market with subsequent redispatch where necessary. Afterwards, the differences between the nodal and zonal approaches as determined in the models are evaluated.

3.2.1. Model[38]

To quantify the impact of different congestion management regimes on market results, two mathematical models are developed. First, a nodal pricing model applies the theory of locational marginal prices, thus it determines a cost minimal generation dispatch of power plants considering the physical characteristics of the transmission network. Thus, the model assumes an implicit allocation of all transmission capacity during the spot market. The model is described in Section 3.2.1.1. Second, a zonal pricing model is introduced in Section 3.2.1.2 which replicates the described current market regime in Europe. Thus, the model optimizes the dispatch of generation units subject to restrictions on transactional cross-border trade. Afterwards, the physical network characteristics are included and the new generation dispatch is determined by applying congestion alleviation methods. Additionally, the zonal pricing model requires the definition of available capacities for cross-border trade. Therefore, the general calculation procedures are firstly reviewed and the applied methodology is described in Section 3.2.1.3.

3.2.1.1. Nodal Pricing Model

The nodal pricing model determines the cost minimizing unit commitment U_p and dispatch G_p of power plants p (Equation (3.2)) respecting economic and technical restrictions, namely the energy balance (Equation (3.3)), minimum and maximum generation capacity limits (Equations (3.4) and (3.5)), and line capacity limitations (Equation (3.9)). Generally, an electricity system can be described by transmission lines l connecting nodes or substations n. At nodes generation G_p as well as demand q_n are located and through the transmission lines electrical energy can be transfered between nodes.

The energy balance (Equation (3.3)) ensures the balance of demand q_n, generation of thermal power plants G_p located at node n, renewable wind generation G_n^{wind}, and nodal injections or withdrawals from the network NI_n. The energy balance has to be valid in equality in order to ensure the stable and secure operation of the electricity system. Thermal power generation is restricted by their minimum generation requirement g_p^{min} (Equation (3.5)) and the maximum available capacity g_p^{max} (Equation (3.4)). To incorporate minimum generation constraints, a binary status variable U_p is introduced, indicating the operating

[38] The following notation is used throughout the thesis. Capital letters are variables and small letters describe parameters and sets. Subscripts indicate the set(s) the variable or parameter depends on, whereas superscripts provide additional information on the variable or parameter. The nomenclature of the used mathematical notation is given in the beginning of the thesis.

status of a power plant p. In a unit commitment model, U_p is a decision variable; in a dispatch model, it is predetermined. To allow for the possibility of wind spillage, wind generation G_n^{wind} is variable and bounded by the available wind generation $g_n^{maxwind}$ (Equation (3.6)). The power flow LF_l on transmission line l and resulting nodal injection or withdrawal NI_n are based on DC load flow equations (Equations (3.7) and (3.8)) and restricted by maximum thermal transmission capacity p_l^{max} (Equation (3.9)). The parameters $h_{l,n}$ and $b_{n,nn}$ describe the physical characteristics of the underlying transmission network and are defined by the topology of the network and the resistance and reactance of transmission lines. The DC load flow equations are derived from the AC power flow equations for active and reactive power. Through the assumptions of (i) small voltage angle differences ($\Delta_n - \Delta_{nn}$), (ii) constant voltages, and (iii) absence of reactive power flows the AC power flow equations can be simplified to the so called DC load flow (DCLF) equations (Schweppe, 1988; Wood and Wollenberg, 1996; Stigler and Todem, 2005; Leuthold et al., 2012). The approximation of AC power flows reduces the mathematical complexity of the optimization problem and are therefore widely used for techno-economic purposes. Transmission losses are neglected in this approach as well as intertemporal aspects. Locational marginal prices are defined as the dual variable of the energy balance (Equation (3.3)).

$$\min_{U_p, G_p, G_n^{wind}} \sum_p mc_p G_p \tag{3.2}$$

$$q_n = \sum_p G_p + G_n^{wind} - NI_n \qquad \forall n \tag{3.3}$$

$$G_p \leq g_p^{max} U_p \qquad \forall p \tag{3.4}$$

$$G_p \geq g_p^{min} U_p \qquad \forall p \tag{3.5}$$

$$G_n^{wind} \leq g_n^{maxwind} \qquad \forall n \tag{3.6}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \qquad \forall n \tag{3.7}$$

$$LF_l = \sum_n h_{l,n} \Delta_n \qquad \forall l \tag{3.8}$$

$$|LF_l| \leq p_l^{max} \qquad \forall l \tag{3.9}$$

$$G_p, G_n^{wind} \geq 0$$

$$U_p = \{0, 1\}$$

3.2.1.2. Zonal Pricing Model

As mentioned previously, the zonal pricing model abstracts in the first step from physical realities of transmitting electricity as it is designed to replicate the current spot market design of European electricity systems. In a second step, physical network constraints are introduced and the generation dispatch is optimized given the previous decision on the spot market. The second step therefore represents the optimization problem of national transmission system operators who have to ease national congestion.

Firstly, the unit commitment of power plants U_p is optimized (Equation (3.10)) subject to the energy balance (Equation (3.11)), technical restriction on thermal generation (Equations (3.12) and (3.13)), renewable generation (Equation (3.14)), and limitations on international trade $ttc_{co,cco}$ (Equation (3.15)). In contrast to the nodal pricing model physical international and national network constraints are neglected, as transfers $TF_{n,nn}$ refer to transactional exchanges between nodes n and nn. Transfers between nodes within one country co are unrestricted, whereas transfers between nodes of different countries co and cco are limited (Equation (3.15)). The total transfer capacity $ttc_{co,cco}$ represents the upper limit on international trades between neighboring countries co and cco. The determination procedure of the total transfer capacity $ttc_{co,cco}$ is described in Section 3.2.1.3.

This step represents the stylized dayahead market procedure in most European countries. The mixed integer linear program is as follows:

$$\min_{U_p,G_p,G_n^{wind}} \sum_p mc_p G_p \tag{3.10}$$

$$q_n - g_n^{wind} = \sum_p G_p + \sum_{nn} TF_{nn,n} - \sum_{nn} TF_{n,nn} \qquad \forall n \tag{3.11}$$

$$G_p \leq g_p^{max} U_p \qquad \forall p \tag{3.12}$$

$$G_p \geq g_p^{min} U_p \qquad \forall p \tag{3.13}$$

$$G_n^{wind} \leq g_n^{maxwind} \qquad \forall n \tag{3.14}$$

$$\sum_{n \in co} \sum_{nn \in cco} TF_{n,nn} \leq ttc_{co,cco} \qquad \forall co, cco \tag{3.15}$$

$$G_p, TF_{n,nn} \geq 0$$

$$U_p = \{0,1\}$$

Once the unit commitment of power plants U_p is optimized in the first step subject to transactional exchange limitations, the power plant dispatch G_p is optimized in the second step using the nodal pricing model (Section 3.2.1.1) subject to physical network constraints (power flow limitations and DC load flow constraints). Hence physical network congestion is introduced and has to be managed using short-term congestion alleviation methods in the form of redispatching of power plants. However, the flexibility of power plants is limited as the unit commitment U_p is fixed to the values of the first optimization step. The exception is that the unit commitment of fast starting gas-turbine power plants is not fixed due to their technical flexibility. Beside the power plant dispatch, wind spilling and load shedding are introduced as additional short-term congestion alleviation options.

3.2.1.3. Calculation of Total Transfer Capacity

As mentioned in the introduction of this Chapter, international capacity allocations distinguish between commercial transfer which are used by market participants to plan their cross-border trades and physical flows as used by transmission system operators in real-time operation (ETSO, 2001b). The abstraction from physical characteristics of transmitting electricity in the definition of commercial transfers requires a specified calculation procedures which are described in UCTE (2009). The available calculation methods are subsequently presented followed by the description the applied methodology.

The computation of TTC starts with establishing a Base Case Exchange (BCE), based on the best available information on network conditions, generation and load patterns, and planned cross-border transactions. To compute the TTC from area A to area B, generation is increased stepwise in area A and decreased in area B, maintaining loads the same, until security limits in either system A or B are reached:

$$TTC = BCE + \Delta E = NTC + TRM \tag{3.16}$$

where ΔE is the maximum increase in transfer before security limits are breached.

Operationally, there are three available methods for determining the maximum transfer of generation between two areas in TTC calculations (UCTE, 2009):

- **Method A**: Each chosen injection is scaled in proportion to the remaining available capacity at the relevant generator node. The value of ΔE^{max} (i.e., $TTC - BCE$) is determined when either all generators reach their maximum outputs, or if a network operational limit is reached. This method brings the key advantage that physical generator output limits are respected. UCTE (2009) states that it should therefore be used under normal circumstances.

- **Method B**: If the necessary data on generation limits for the first method are not available, the generator outputs may be scaled without consideration of output limits.
- **Method C**: The generator outputs are modified according to merit order, with limits on output being respected.

Hence detailed information are available on methods for TTC calculation. However, NTC determination is more difficult, as the public information on methods used for determining the transmission reliability margins (TRM) is limited. ETSO (2001b) suggests that the margin required for load-frequency control can be determined by statistical analysis of historical time series, and that the margins required for reserve sharing and emergency transfers should be agreed upon between transmission system operators. It also discusses how these components of the TRM should be combined. However, the precise calculations are not described in that source, and cannot be duplicated based on that information.

Operational experience from three control areas illustrates the differences in the methods that different transmission system operators use to determine transmission reliability margins.

- For Nordpool, ENTSO-E (2010a) states that in practice, the TRMs between areas in Nordpool are based on transfers due to frequency regulation only. It gives the current TRM values used as 100 MW between Sweden and Finland, 150 MW between Sweden and southeastern Norway, and 50 MW for most of the remaining connections. A further description for the specific case of Finland is given in Fingrid (2009).
- To determine the TRM, a number of the German transmission system operators (EnBW Transportnetze AG, 2010; Vattenfall Europe Transmission GmbH, 2010; RWE Transportnetz Strom GmbH, 2010) use a heuristic formula. They multiply the square root of the number of connection circuits between control zones with 100 MW to obtain the TRM. Some examples of the numbers of cross-border circuits are 4 (Germany to France), 6 (Germany to Netherlands), 15 (Germany to Switzerland), and 12 (Germany to Austria).
- Information supplied by the Polish System Operator (PSE Operator S.A.) confirms that there are no universal regulations defining the TRM deter-

mination process (Neuhoff et al., 2011). The TRM is said to be lower for shorter time horizons, when uncertainty is reduced.

This diversity of methods prevents a comparison of modeled and actually announced values by the transmission system operators, as discussed in Section 3.2.3.

The applied TTC calculation approach follows 'Method C' using an economic dispatch model with DC load flow constraints which specifies the generation of power plants following the merit order principle. In order to calculate the TTC between neighboring countries, the nodal pricing model (Section 3.2.1.1) is extended by Equations (3.17) and (3.18). Each country co is characterized by a specified net export position $netexport^{BCE}$, which corresponds to an agreed base case (BCE) and defined international transactional exchanges. To allow an adjustment of the net export position and henceforth the calculation of the total transmission capacity TTC, the parameter $netexport$ is introduced and successively increased in country co and decreased in country cco during the calculation procedure. The change in the net export position of a country has to be counterbalanced by the generation dispatch which is determined by the economic dispatch model (Equation (3.17)).

$$\sum_{p \in co} G_p - \sum_{n \in co} q_n = netexport_{co}^{BCE} + \Delta netexport_{co}^{co \to cco} \qquad \forall co \tag{3.17}$$

$$\Delta netexport_{cco}^{co \to cco} = -\Delta netexport_{co}^{co \to cco} \tag{3.18}$$

The calculation procedure works as follows (see Figure 3.2). In the first step the generation dispatch and power plant status is optimized for the defined base case (BCE). In order to determine the additional bilateral exchanges, the net export position of two neighboring countries (co and cco) is changed (a stepwise increase of $\Delta netexport_{co}^{co \to cco}$ in one country and vice versa).

The unit commitment U_p and the dispatch of power plants G_p in both countries (co and cco) is optimized using the economic dispatch model. The unit commitment in the remaining countries is fixed to the base case commitment whereas redispatching of power plants within these countries is allowed. The demand is fixed at the initial demand q and not changed during the optimization procedure. If a feasible commitment and dispatch is found, the calculation procedure continues and the net export position $\Delta netexport_{co}^{co \to cco}$ is further increased in country co and decreased in country cco, respectively. Otherwise if the economic dispatch is infeasible meaning that a transmission limit is violated the procedure stops and the total increase of bilateral exchanges ($\Delta netexport_{co}^{co \to cco}$)

reflects the maximum additional exchange (ΔE) between country *co* and *cco* according to the TTC definition (Equation (3.16)). In the following, the procedure continues for the next combination of neighboring countries.

```
Initialization
        Set netexport_co^BCE
        Solve the economic dispatch model
        Save the generation quantities G_p and power plant status U_p
LOOP co
  LOOP cco
    IF neighbor_co,cco = YES THEN
        Set iter = 1
        Set Δnetexport = 0
        Solve the economic dispatch model
      WHILE economic dispatch is feasible
        Save COSTS and Δnetexport_co^(co→cco)
        Set Δnetexport_co^(co→cco) = Δnetexport_co^(co→cco) + iter * 50
        Solve the economic dispatch model
        Set iter = iter + 1
      END WHILE
    END IF
  END LOOP
END LOOP
```

Figure 3.2.: Pseudo code of the TTC calculation procedure. Source: Own illustration

The calculation procedure is performed for each combination of neighboring countries. Finally, the total transfer capacity (TTC) is calculated as the initial transfer of the base case plus the maximum possible additional transfer $\Delta netexport$ following the definition in Equation (3.16). The calculated total transfer capacity $ttc_{co,cco}$ reflects the maximum exchange, which can be technically managed by the national power systems through adjustments of generation commitment and dispatch. Corresponding generation costs can be considered as an additional economic criterion for the determination of the maximum allowable additional exchanges.

3.2.2. Data and Scenarios

The UCTE-Study Model (UCTE-STUM) dataset is used for the network study, which was provided by ENTSO-E for research purposes. The UCTE-STUM is a limited version of the UCTE reference data set for each seasonal period produced for third-party analysis. The dataset comprises a forecast for the static operation of the UCTE control area for the 3rd Wednesdays in January for the year 2008 and includes a detailed representation of the former UCTE network of approximately 4,300 buses, 6,300 lines and 1,100 transformers together with their loads and generation in-feeds. The dataset allows the calculation of the AC load flow for the respective snapshot of the system operation. To perform network studies, the UCTE-STUM dataset was enhanced to allow dispatch optimization (Neuhoff et al., 2011).

In Figure 4.1, the network topology is presented, where different line colours are used for the different voltage levels and equivalent elements are represented with dotted lines. The capacity of transmission lines is de-rated to 80% of their nominal capacity to approximate the N-1 security constraints in the network (Leuthold et al., 2012).

A European generation database was matched to the nodes including power plants with capacities exceeding 100 MW. The matching was performed on the basis of geographic proximity and according to information provided at the ENTSO-E network map (ENTSO-E, 2011b). The total installed capacity amounts to approximately 430 GW, comprising 10 generation technologies[39]. To counterbalance the impact of distributed generation, nodal loads were decreased pro-rata on a country basis based on the load values published by ENTSO-E (ENTSO-E, 2011a). The derived total system load for the obtained snapshot amounts to approximately 300 GW.

In order to investigate the impact of renewable generation on the power system, a single load scenario and three wind scenarios are specified and analyzed. Beside a scenario without wind production, two wind production snapshots (high: 38 GW and medium: 13 GW) were selected as representative scenarios of the total wind feed-in in the system corresponding to a total installed wind capacity of approximately 63 GW (EWEA, 2009). Wind feed-in scenarios were calculated and matched to the network nodes based on the 'high scenario 2008' of the TradeWind study (Van Hulle et al., 2009, p. 21).

[39] Combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), gas-fired steam turbine, coal power plant, lignite power plant, oil-fired power plant, nuclear power plant, wind power, hydro power plant (reservoir), and pumped hydro power plant.

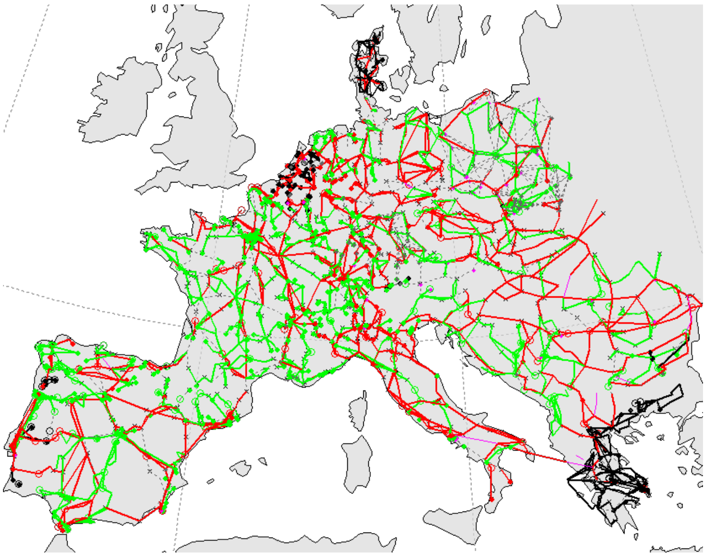


Figure 3.3.: Geographic representation of the network model (Red: 380 kV, Green: 220 kV, Black: 150 kV, and dotted lines correspond to equivalent elements). Source: Neuhoff et al. (2011)

3.2.3. Results

3.2.3.1. Nodal Pricing Results

In this section the results from the nodal pricing model (Section 3.2.1.1) are compared considering different wind generation scenarios across the observed region of continental Europe. Table 3.1 illustrates the operating costs as well as volume weighted nodal price for the considered European countries. As expected, operating costs decrease with higher wind generation as marginal costs are zero. This is additionally reflected in the volume weighted nodal prices.

	No Wind	**Mean Wind**	**Max Wind**
Operating costs million EUR/h	7.80	6.99	5.59
Avg. price EUR/MWh	72.87	68.05	62.84

Table 3.1.: Operating costs and prices of nodal pricing regime. Source: Own illustration

Figure 3.4 depicts the volume weighted nodal price by country as an indicator of the prices that would be experienced under nodal pricing. For the depicted countries, data on dayahead market prices as well as average hourly prices was available for comparison for the hour of the reference case (10 a.m.–11 a.m., Wednesday 16 January 2008). The dayahead spot price for that hour is closest

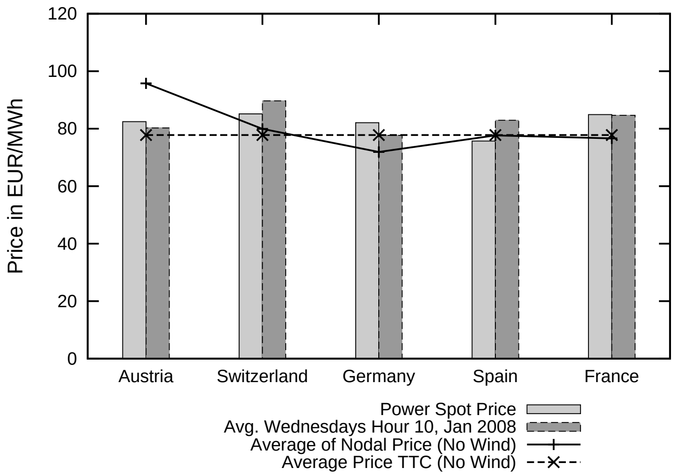
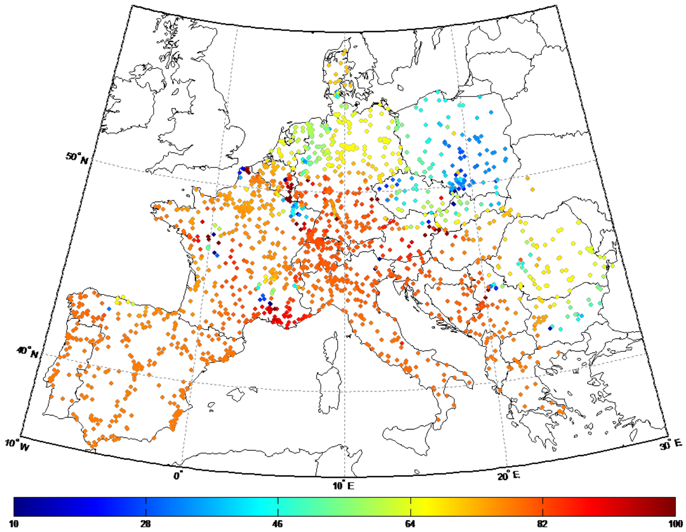


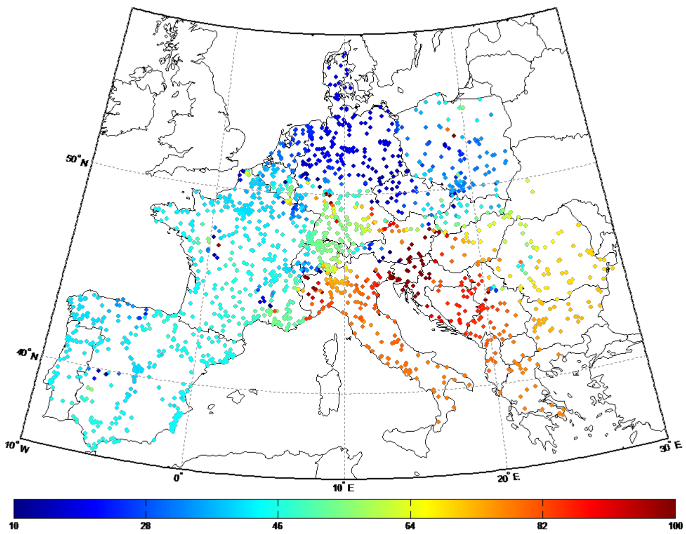
Figure 3.4.: Comparison of selected actual market prices for power products for Wednesday 16 January 2008 (bars) and simulated prices (lines). Source: Own illustration

to the specific situation of network and generation assets, but additional factors (contract positions, intraday changes to dispatch) might have impacted the price or network configuration. Hence, the average price for this hour across all Wednesdays in the month is additionally depicted to abstract from specific aspects of the day. The overall price levels are similar between simulated and observed prices, with the largest discrepancy occurring in Austria. This can be attributed to the complex congestion structure combined with the impact of international flow patterns in Austria (see Figure 3.5).

In Figure 3.5, the nodal price distribution within Europe for two operational snapshots, the no wind case and the maximum wind case, are presented. The impact of wind integration in Northern and South West Europe can be seen by the reduction in nodal prices. Differences between nodal prices indicate congestion, either across borders (e.g. between France and Italy) or internally (e.g. North - South Germany). The calculations show the existence of areas in Europe with comparable prices that firstly do not necessarily match the national borders and secondly vary with different wind in-feeds.



(a) No wind scenario



(b) Max wind scenario

Figure 3.5.: Geographic representation of nodal prices for selected wind scenarios (Bar represents energy prices at nodal level: from 10 EUR/MWh in blue to 100 EUR/MWh in red). Source: Neuhoff et al. (2011)

Regarding the utilization of transmission capacity, about 50 out of about the 6,000 lines are loaded up to their thermal transmission limit, the majority of which correspond to branches within national zones (internal congestion). In particular, only two branches are cross-border lines while six are transformers.

In Figure 3.6, the line loadings for the European network for the maximum wind scenario are presented, where the geographic extent of congestion can be seen. High line loadings can be observed on single transmission lines in nearly each country, whereas the majority of transmission lines shows a low loading. Thus, a general pattern of congested transmission lines restricted to specific countries or regions cannot be noticed.

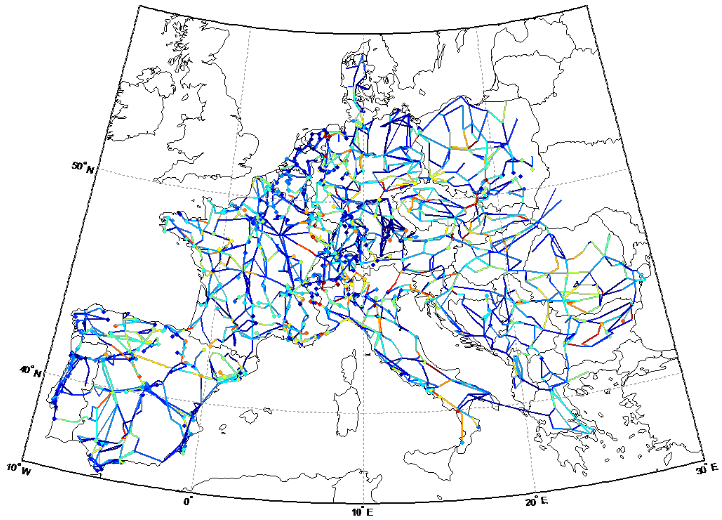


Figure 3.6.: Line loading representation for the maximum wind scenario (Line loading is depicted with a respective colour: from blue colour (low loading) to red (high loading)). Source: Neuhoff et al. (2011)

3.2.3.2. Zonal Pricing Results

Based on the parameterization of the network representation, and after confirming that nodal prices provide consistent results, the implicit allocation of international transmission capacity within a zonal pricing regime is analyzed. Therefore, the optimal dispatch model described in Section 3.2.1.3 is used to calculate the TTC values for available transmission capacity between countries. Using these TTC values a TTC-constrained optimization (Section 3.2.1.2) then allows a consistent comparison with model results under the nodal pricing regime. As described in Section 3.2.1.3, the NTC (published by ENTSO-E) is calculated by the difference between TTC and TRM. The TRM is however not available for all transmission lines, thus preventing a direct comparison of calculated TTC values and NTC values actually announced by the TSOs. The calculated TTC values are listed in Table A.1 in Appendix A.

Next, the model described in Section 3.2.1.2 is used to optimize the dispatch of power plants using implicit auctions allocating transmission capacity (TTCs) between European countries. Therefore a two step approach is chosen: first, initial trading is carried out among generators and demand, respecting international transmission constraints as defined by the TTC values, but not transmission constraints within countries. This trading is based on a transshipment (path-based) model. Second, national TSOs then resolve congestion on lines within their respective country by redispatching national generation, which is online. National TSOs are restricted to national generation and cannot make use of international generation to relieve congestion (e.g. international redispatch). The second step allowed the introduction of load shedding and/or wind spilling for balancing purposes with marginal costs of this procedure arbitrarily set at 500 EUR/MWh (greatly exceeding the marginal costs of other generation). This two step approach likely yields higher operating costs than the nodal pricing model because the nodal model does not impose the limitation on international transfers, and only imposes the line constraints without restricting the international transfers to possibly suboptimal values found in the first TTC run.

	No Wind	**Mean Wind**	**Max Wind**
Operating costs (1st step) million EUR per h	7.47	6.53	5.33
Operating costs (2nd step) million EUR per h	8.03	7.29	5.88
Load shedding and wind spillage costs (2nd step)* million EUR per h	1.18	0.85	0.46
Redispatching costs** million EUR per h	0.57–0.74	0.76–1.00	0.56–0.77
Avg. price (1st stage) EUR/MWh	75.94	52.65	44.05

* Load shedding and wind spillage are accounted with marginal costs of 500 EUR/MWh.
** The lower limit of the cost range corresponds to cost-based redispatch and the upper limit represents market-based redispatching cost.

Table 3.2.: Operating costs and prices of zonal pricing regime. Source: Own illustration

Table 3.2 provides the cost and price results for different wind scenarios. The average price reflects the volume weighted price across EU countries. Operating costs are depicted for both steps of the optimization procedure. Again, operating costs decline with higher wind generation comparable to the nodal pricing results. The difference between both cost values represents the management costs to relieve congestion in national physical transmission network. Hence, costs of the second step are likely to be higher than the first case as physical network constraints become relevant.

Two options to translate the redispatch of power plants through the introduction of physical network constraints into redispatch costs are listed as a cost range in Table 3.2. First, it is assumed that each country's TSO can price discriminate when redispatching, and thus limit redispatch costs. Hence, all upward response (constrained-on generation) is paid their marginal generation costs and all downward responses (constrained-off generation) pay their generation costs to the TSO. This corresponds to a cost-based congestion alleviation regime (Section 2.2.3.2) and results in the lower value of the redispatching cost range depicted in Table 3.2. Second, it is assumed that constrained-on generation is paid the maximum price which corresponds to the highest marginal cost of constrained-on generation within the country. Similarly all constrained-off production pays the lowest price for such buy-back within the country. The lowest prices represents the lowest marginal costs of constrained-off generation. This congestion alleviation approach corresponds to market-based redispatch procedure (Section 2.2.3.2) and causes higher redispatching costs than the cost-based method (Table 3.2).

Typically the TSO has to pay the market price rather than remunerating generators at cost. The market-based redispatch thus corresponds to a competitive market outcome. With market power, where generators submit bids for upward or downward response that diverge from their variable cost, the prices could further increase. In fact, if generators anticipate payments that are available in the redispatch market, then they are likely to bid in this manner, raising prices and congestion management costs above those depicted in Table 3.2.

3.2.3.3. Comparison of Results

Firstly operating costs reflecting total variable costs incurred for power generation are analyzed. Variable costs of generating power plants are summed (reflecting both fuel and carbon costs of generators), but ignored fixed start-up and minimum run costs. As not all demand is met by available generation capacity across the scenarios in the zonal pricing case, additional costs for load shedding and wind spillage occur.

Figure 3.7 depicts the operational costs of considered congestion management regimes. Based on operational costs, cost savings that are achievable through the system wide optimization possible with nodal pricing relative to zonal pricing market designs vary between 0.14 and 0.3 million EUR per hour excluding

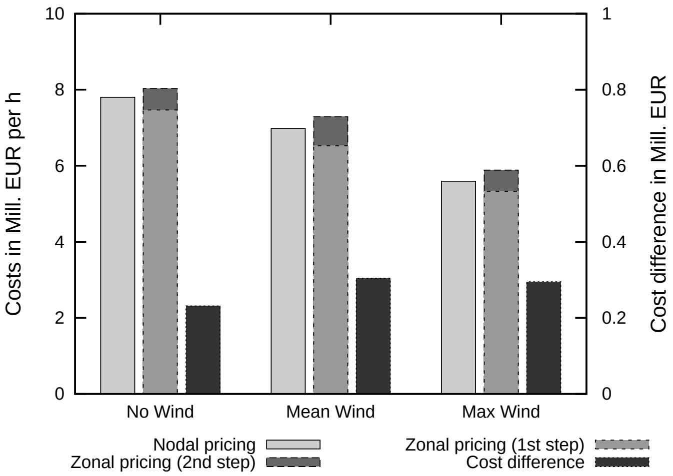


Figure 3.7.: Operational costs of congestion management regimes. Source: Own illustration

costs of load shedding and wind spillage. Relative to operational costs of zonal pricing regime, cost saving represent 1.7%–3.6% depending on the wind scenario. According to Neuhoff et al. (2011), this yields estimates of annual savings that range from 0.8–2.0 billion EUR.

Subsequently, the level of network utilization under both congestion management regimes is considered. Table 3.3 depicts the total volume of international transfers that is observed in each of scenarios. International transfers in the zonal pricing regime represent absolute flows of the second step. The nodal pricing approach leads to an increase in international transfers that take place between countries, up to 32% more in the mean wind scenario. Neuhoff et al. (2011) calculates an increase in international transfers up to 34%. Thus, existing network capacity is better utilized to accommodate increasingly large volumes of intermittent energy sources. The results indicate that this difference is greatest in the scenario with high wind penetrations.

	No Wind	**Mean Wind**	**Max Wind**
Zonal Pricing GW per h	31.4	31.9	33.5
Nodal Pricing GW per h	35.9	41.9	41.2

Table 3.3.: International transfers of pricing regimes. Source: Own illustration

The calculated increase of the volume of flows resulting from nodal pricing is likely to provide a lower bound to the benefits of nodal pricing for two reasons. Firstly, the maximum possible TTC values are calculated for each pair of neighboring countries. It is assumed that the values for all pairs are simultaneously possible, but in practice the TTC values have to be reduced to ensure that they are jointly viable. Secondly, the redispatch volume as determined in the model causes congestion management costs for TSOs and would ample opportunities for gaming if these are high. Therefore in practice the TSO could issue lower TTC values to constrain international transfers in order to limit the level of domestic transmission constraints as experienced in the Swedish power market (Section 2.4.2.2).

3.2.4. Discussion

Models have to abstract from many details of reality because of the lack of adequate data or computational limitations. Thus, trade-offs are necessary when deciding upon the level of detail of the physical representation of the grid, generation and demand. In addition, the temporal dimension can be captured to different levels of detail or accuracy ranging from long-term investment choices to daily unit-commitment requirements or short-term representation of system flows and stability. As interconnected power systems are no longer operated according to one system-wide optimization algorithm, models could also aim to represent market design and strategic behavior of market participants. The focus of this Chapter is on the role of congestion management in the European network. Hence a detailed representation of the transmission grid and spatial distribution of generation and load was necessary. To allow for a comparison of different power market designs, the main characteristics of both nodal pricing and of the implicit and joint allocation of international transmission capacity had to be captured in the model.

The simplifications inherent in a model thus raise the question, to what extent do the qualitative and quantitative model results provide evidence for the impacts of nodal pricing on real power systems. As many of the detailed characteristics of power stations, as well as system requirements like reserve requirements, are not explicitly modeled, the interpretation is focused on the model results concerning overall congestion and pricing patterns rather than locational prices or constraint volumes of a specific line, and the comparison between power market designs based on the same system and demand configuration. Those aggregations are likely to be more reliably projected than, for instance, prices at individual buses or flows through individual lines. For these comparisons the results of the different models are broadly consistent with each other and with observed market prices.

3.2.4.1. Results from Other Studies

The achieved model results confirm observations from existing nodal pricing-based systems in the US. Mansur and White (2009) studied PJM and AEP / Dayton / ComEd operations before and after their merger. Their studies show that the volume of commercial transaction between the geographical regions increased by approximately 42% after the integration of both markets. The increase is consistent without optimization results that showed up to a 34% increase in international flows. The incremental benefit of extending nodal pricing to the AEP / Dayton / ComEd areas to PJM was 180 million USD annually, which multiplied by the size ratios (50 GW for the three states, 820 GW EU) translates to a gain of 2.95 billion USD. As US fuel prices in 2009 measured in USD roughly correspond to EU fuel prices in Euro, the results can be interpreted as system savings of 2.95 billion EUR. PJM estimates that the overall benefits of integrated operation of their system are 2.2 billion USD (approximately 1.8 billion EUR) annually (Ott, 2010). Analysis from nodal pricing-based operations in Texas (Watson, 2011) revealed that the ERCOT system could have helped avoid potentially "millions, or hundreds of millions [USD]" if it had been implemented before a 2008 spike in power price. The system, which went fully operation December 2010, has reportedly already reduced prices by 25%–33% compared to December 2009 because the increased granularity of the power market design allows for more precise operations.

In addition to this experience, other simulations have quantified the benefits of nodal pricing for international coordination of dispatch. For instance, Weijde and Hobbs (2011) simulate both nodal and zonal power market designs on a four-node model and find that coordinated international redispatch can save up to 10% of system unit commitment and dispatch costs relative to a TTC-type market outcome. As the coordinated international redispatch reinstates a configuration of power production that is similar to nodal pricing, the 10% savings can be interpreted as the savings of nodal pricing relative to TTC-type approach. Most of these savings are due to the ability to adjust international flows in balancing markets. If international rebalancing is allowed in a TTC system, then the cost savings of instead using nodal pricing are an order of magnitude smaller, but still significant. The high value of these savings, compared to results presented in Section 3.2.3, relates to the higher level of congestion in the network, and the additional constraints imposed by the small number of generators in the model that can contribute to resolving the constraint.

In another study, Barth et al. (2009) obtain an estimated LMP benefit (compared to an NTC system) of 0.1% of system variable cost for the EU in the year 2015 under more than 125 GW of wind capacity. These benefits are a combination of improved efficiency of international transactions, within-country dispatch, and dayahead unit commitment that considers all international network constraints instead of NTCs. However, they treat each country as a single zone with no consideration of individual circuits between countries or congestion within countries, therefore, this estimate should be viewed as a lower bound. Oggioni and Smeers (2009) use a simple six-node network to examine the benefit of coordinated international balancing markets. Market coupling based upon nodal pricing is found to be more efficient than using NTCs. Meanwhile, Vandezande et al. (2009) provide an estimated benefit of coordinated balancing between Belgium and the Netherlands (compared to no international redispatch) to be approximately 40% of total balancing costs. Other studies have examined the benefits of LMP, but not specifically relative to NTC-based management of international constraints. Green (2007) estimates that LMP would provide efficiency benefits equal to about 1.5% of generator revenues in the UK due to better dispatch and demand response to prices. Leuthold et al. (2005) estimate that LMP would provide a 0.6–1.3% increase in economic surplus in the German power markets. A further 1% gain would result if more wind capacity is built because of increased congestion. Weigt (2006) extends that model to include unit commitment of aggregations of power plants and international transmission. He obtains a benefit equal to 0.06% of the market surplus for all of Europe, including a net 0.79% increase in consumer surplus which is partially offset by decreases in profits. Thus, results from other modeling confirm that significant cost savings would likely result from a shift to nodal pricing-based congestion management on a European scale.

To the extent that initial implementation of a nodal market design will be limited to part of the EU region, only parts of these savings will be generated. However, improvements to the power market design can also offer additional savings where system-wide intraday optimization (as possible in nodal pricing related power market designs) allows for effective use of the better wind forecasts that appear during the day. Also, the benefits of transparent information on congested lines for network expansion decisions and public engagement during the planning process have not been quantified.

3.2.4.2. EU Transition to Nodal Pricing Market Design

Shifting to a nodal power market design would require considerable changes in the institutional settings in Europe towards a more centralized market structure. The current separation of power exchanges and grid operation would have to be abandoned in favor of an integrated ISO (Independent System Operator) or closely coordinated ISOs, at least for the dayahead and intraday market. Future and other derivative markets can be handled by one or several institutions distinct from the system and spot market operator. Nevertheless, such institutional changes raise several objections even beyond the evident self-interests of some of the current players in the markets. According to Neuhoff et al. (2011) four major concerns may be identified:

- *Feasibility.* The entire European system is larger (600+ GW) than the PJM area (160+ GW), therefore the algorithms for optimal commitment and dispatch will require more computation time. This clearly has to be checked carefully, but the improvements in computer and algorithm performance have been tremendous over the last decade, and further improvements are expected to come. Thus, the importance of this constraint is likely to fade away over time; even if it is possibly relevant today at a full European scale, it is certainly not relevant for an implementation in a limited number of European states in the next years.

- *Security.* Today accountability for system security in Europe rests on the shoulders of the control zone operators (TSOs) at a decentralized level. Shifting this responsibility to a more central level is feared by some to reduce system security. The PJM experience shows that centralized operation does not mean increased unreliability, e.g., the territory covered by PJM was saved from the large scale August 2003 blackout across the northeast USA and some Canadian provinces because an integrated real time dispatch algorithm provided timely and accurate information that allowed for quick responses. A coordination of real-time responses to disturbance may hence even contribute to increased system security. Alternatively, it is possible to maintain the real-time operation and security responsibility at a decentralized level even with centralized dayahead and intraday dispatch. The shift in responsibility would then occur at gate closure (e.g., 1–2 hours from real time). This would obviously raise several coordination issues, but these would be of a technical nature and could be solved, see Baldick et al. (1999) and Aguado and Quintana (2001).

- *Market Liquidity.* The argument here is that large areas with uniform prices encompass multiple agents, thus inducing more liquid markets. In turn, this creates more hedging possibilities, helping in particular smaller power plant operators. This issue certainly requires further investigation, yet the financial hedging using derivatives may still be concentrated on one reference product (like Brent or WTI in the oil market). This reference product may correspond to some particular node in the system (like Henry Hub for US gas contracts), or it may be a virtual system point or system average (like the Nordpool system marginal price). Locational deviations from this reference price, as far as they are temporary and stochastic, will largely level out over a month or year and thus do not constitute a major risk for the individual plant operator. If the deviations by contrast are systematic, then they provide a clear locational signal for power plant investors. Moreover, Financial Transmission Rights (FTR) may be used to hedge locational spreads (O'Neill et al., 2006).

- *Lack of institutional competition.* Ockenfels et al. (2008) argue that the centralization of operation decisions eliminates the competition between different trading institutions (e.g., power exchanges vs. OTC trading). Also the competition between different power plant operation strategies — typical for today's bilateral and voluntary trading arrangements — is at first sight replaced by one centralized dispatch algorithm. However, in the US, organized markets, independent power exchanges coexist with the formal ISO markets, and there are multiple trading institutions that deal in forward products. Obviously in this dispatch algorithm, power plant owners still may influence the operation of their power plants through the bids which they submit to the system operator, or they can self-schedule, accepting whatever prices the market offers. An important issue is to what extent cost-based bids will be required by the ISO: PJM and the California ISO, for instance, require them as a back-up to be used in the case congestion creates opportunities for exercising local market power (O'Neill et al., 2006).

These and other issues have to be discussed in detail when it comes to implementing nodal pricing in practice. Yet the analysis presented here at least provides an economic rationale for introducing an implicit allocation of transmission capacity and thus nodal prices.

3.3. Quantifying Distributional Effects of Congestion Management Regimes

Section 3.2 analyzes the impact of different pricing regimes only on system operating costs. However, Chapter 2 pointed out that all market-based congestion management regimes achieve a least-cost generation dispatch and are thus efficient in short-run perspective. Furthermore, it is stated that distributional effects are dominating and market participants (consumer, generators, transmission system operator) face different costs and benefits. As the previous analysis in Section 3.2 concentrates on cost saving in generation achieved through better allocation of transmission capacity, the subsequent Section aims to quantify distributional effects of costs, benefits, and surpluses among market participants. A model is described which reflects the currently applied congestion management procedure based on transaction-based allocation of international capacity and national redispatch to ease congestion. The current procedure is compared to a flow-based allocation of international transmission capacity and to a complete allocation of all transmission capacity within the spot market. The last procedure is known as a nodal pricing regime, whereas other approaches represent zonal pricing regimes.

The structure of the section is as follows. The nodal and the zonal pricing model are described in Section 3.3.1 including a description of the transaction and flow-based allocation methods. Underlying data for the European electricity market is described in Section 3.3.2. Section 3.3.3 presents and discusses the achieved results.

3.3.1. Model

To quantify the distributional implications of a change in the European congestion management regime a nodal and a zonal pricing model are applied. The general model specifications are already known from Section 3.2. However, the exact model formulations differ to Section 3.2 as the high voltage direct current transmission (HVDC) is introduced mainly due to the inclusion of neighboring Scandinavian countries, the binary status variable of power plants including minimum generation requirements is omitted, and a separate congestion management model is formulated to optimize the least cost redispatch of power plants. Therefore the description of the models is subsequently repeated to maintain readability.

Within this analysis, a nodal pricing model serves as a benchmark as it ensures the optimal usage of generation and transmission infrastructure. Second, a zonal pricing model is described comprising the allocation of international capacities and the alleviation of national congestion by responsible transmission system operators. Within the zonal pricing model, a spot market model considers the allocation of international transmission capacities while determining the dispatch of generation units. Afterwards, the redispatch of generation is optimized on a national basis in a congestion management model.

3.3.1.1. Nodal Pricing Model

The nodal pricing model optimizes the power dispatch G_p of individual power plants p by minimizing total generation cost $\sum_p mc_pG_p$ (Equation (3.19)) subject to physical network restrictions. Physical load flows of the entire transmission network and occurring congestion are considered while optimizing the generation dispatch of individual power plants. The objective function is constrained by the energy balance (Equation (3.20)), maximum generation capacity of thermal power plants (Equation (3.21)), and the restrictions on power transmission (Equations (3.24) and (3.25)). In contrast to Section 3.2 HVDC transmission is added to the model beside the alternating current (AC) transmission.

The nodal energy balance (Equation (3.20)) ensures the equality of thermal generation G_p located at node n, renewable wind generation g_n^{wind}, nodal demand q_n, and net input or withdrawal from the AC transmission grid NI_n and HVDC lines $HVDC_{n,nn}$. As the transmission of electricity within the AC transmission grid is characterized by the physical characteristics, a direct current load flow (DCLF) approach is used to determine the load flows LF_l on individual transmission lines l. Based on the technical network characteristics $b_{n,nn}$ and $h_{l,n}$, the power flow on physical transmission lines LF_l (Equation (3.23)) as well as the physical netinput at each system node NI_n (Equation (3.22)) are determined by the load angle Δ_n. In contrast to the AC network, the flow on HVDC lines can be directly controlled and thus does not depend on physical characteristics of the AC network. Therefore the HVDC transmission $HVDC_{n,nn}$ from node n to nn is directly considered in the energy balance depending on their direction. The maximum capacity of AC and HVDC transmission lines limits the absolute physical exchanges between system nodes (Equations (3.24) and (3.25)).

$$\min_{G_p} \sum_p mc_pG_p \tag{3.19}$$

$$\begin{aligned} q_n - g_n^{wind} = &\sum_p G_p - NI_n \\ &- \sum_{nn} HVDC_{n,nn} + \sum_{nn} HVDC_{nn,n} \qquad \forall n \end{aligned} \tag{3.20}$$

$$G_p \leq g_p^{max} \qquad \forall p \tag{3.21}$$

$$NI_n = \sum_{nn} b_{n,nn}\Delta_{nn} \qquad \forall n \tag{3.22}$$

$$LF_l = \sum_n h_{l,n}\Delta_n \qquad \forall l \qquad (3.23)$$

$$|LF_l| \leq p_l^{max} \qquad \forall l \qquad (3.24)$$

$$HVDC_{n,nn} \leq HVDC_{n,nn}^{max} \qquad \forall n, nn \qquad (3.25)$$

$$G_p \geq 0$$

3.3.1.2. Zonal Pricing Model

The zonal pricing model follows a two step approach consisting of a spot market and a congestion management model. Given the results of the spot market and the generation dispatch determined considering international trade limitations, the congestion management applies cost-based redispatch of generation units to ease arising congestion in national transmission networks.

Spot Market Model

Comparable to the nodal pricing model, the spot market model also minimizes the total generation costs of the entire system $\sum_p mc_p G_p$ for a predefined level of load q_n. Again, the minimization of total generation costs (Equation (3.26)) is subject to the energy balance (Equation (3.27)), the capacity restrictions of power plants (Equation (3.28)), and the restriction of international trade from country c to cc (Equation (3.29)). The dual variable on the energy balance condition is interpreted as the marginal spot market price $price_n^{DA}$. Renewable wind generation is introduced as a parameter g_n^{wind} and thus reduces the load at each node. Generation of thermal power plants is restricted by the installed capacity g_p^{max} of power plant p (Equation (3.28)).

In contrast to the nodal pricing model, the transactional trade $TF_{n,nn}$ between system nodes n and nn is introduced rather than physical exchanges. The trade between nodes n belonging to countries c depends on the direction and is restricted by the net transfer capacity $ntc_{c,cc}$ between country c and country cc (Equation (3.29)). Thus, international transfer between nodes in different countries is limited whereas transfers between national nodes is unlimited. The allocation regime of international capacity refers to an implicit auction (see Section 2.2.2.2) as the usage of capacity is optimized simultaneously with the generation dispatch.

$$\min_{G_p} \sum_p mc_p G_p \qquad (3.26)$$

$$q_n - g_n^{wind} = \sum_p G_p - \sum_{nn} TF_{n,nn} + \sum_{nn} TF_{nn,n} \qquad \forall n \qquad (3.27)$$

$$G_p \leq g_p^{max} \qquad \forall p \qquad (3.28)$$

$$\sum_{n \in c} \sum_{nn \in cc} TF_{n,nn} \leq ntc_{c,cc} \qquad \forall c, cc \qquad (3.29)$$

$$TF_{n,nn}, G_p \geq 0$$

Congestion Management Model

As the spot market model takes only restrictions on international transfers into account, a separate congestion management model has to be specified to manage physical congestion within the countries. Thus, congestion alleviation methods are applied given the results of the spot market model. Cost-based redispatching of power plants is therefore considered as market-based congestion management methods.

Given the spot market dispatch of individual power plants g_p^{DA}, the congestion management model optimizes redispatch of generation units by minimizing total redispatching costs (Equation (3.30)). The spot market generation g_p^{DA} can be adjusted by increasing (G_p^{UP}) or decreasing (G_p^{DOWN}) the generation of power plants. Power plants which increase their generation are accounted with their marginal cost mc_p. The decrease of generation saves the marginal costs mc_p. Again, the energy balance condition (Equation (3.31)) and the generation capacity restriction (Equation (3.32)) have to be ensured. Furthermore, the redispatch of power plants is restricted to national power plants meaning that the increase of generation G_p^{UP} equals the decrease of generation G_p^{DOWN} for each country c (Equation (3.37)). Thus, international redispatch of power plants to ease national network congestion is not allowed.

As the congestion management model determines redispatching costs resulting from physical network constraints, a DC load flow approach is introduced to reflect the physical specifics of transmitting electrical energy. Based on the technical characteristics of the transmission network ($b_{n,nn}$ and $h_{l,n}$), the AC power flow LF_l (Equation (3.34)) as well as the physical netinput at each system node NI_n (Equation (3.33)) are determined by the load angle Δ_n. The AC power flow is limited by the available transmission capacity p_l^{max} (Equation (3.35)). Physical flow on high voltage direct current (HVDC) lines is considered separately and restricted by corresponding capacity (Equation (3.36)). To ensure the feasibility of the congestion management model, options to reduce nodal load and wind generation are introduced. Marginal costs for these options are arbitrarily set to 500 EUR/MWh significantly higher than marginal generation costs.

$$\min_{G_p^{UP}, G_p^{DOWN}} \sum_p mc_p G_p^{UP} - mc_p G_p^{DOWN} \tag{3.30}$$

$$q_n - g_n^{wind} = \sum_p (g_p^{DA} + G_p^{UP} - G_p^{DOWN}) - NI_n - \sum_{nn} HVDC_{n,nn} + \sum_{nn} HVDC_{nn,n} \quad \forall n \tag{3.31}$$

$$G_p^{UP} - G_p^{DOWN} \leq g_p^{max} - g_p^{DA} \quad \forall p \tag{3.32}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \quad \forall n \tag{3.33}$$

$$LF_l = \sum_n h_{l,n} \Delta_n \quad \forall l \tag{3.34}$$

$$|LF_l| \leq p_l^{max} \quad \forall l \tag{3.35}$$

$$HVDC_{n,nn} \leq HVDC_{n,nn}^{max} \quad \forall n, nn \tag{3.36}$$

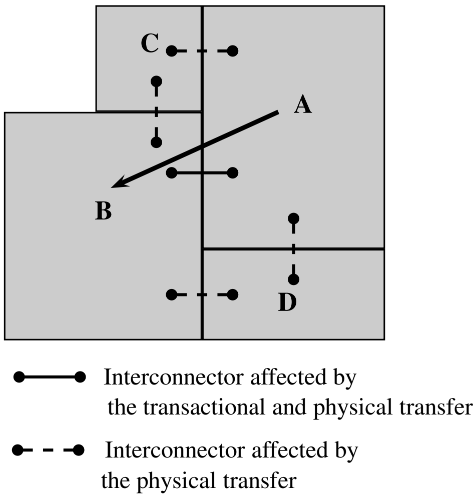
$$\sum_{p \in c} (G_p^{UP} - G_p^{DOWN}) = 0 \quad \forall c \tag{3.37}$$

$$G_p^{UP}, G_p^{DOWN} \geq 0$$

Assignment and Allocation of International Transmission Capacity

The assignment and allocation of international transmission capacity within the spot market can be designed in different ways as highlighted in Section 3.1. The assignment can be distinguished into transaction based and flow based. Both differ in the inclusion of physical characteristics of transporting electrical energy.

The first approach is based on transactional transfers between countries abstracting from resulting physical flows. If a transfer between two countries A and B is settled (see Figure 3.8), the according transmission capacity between both countries has to be procured by market participants up to the available transfer capacity $NTC_{A,B}$. However, this approach abstracts from physical characteristics of transporting electricity energy in a meshed network as a transfer between two countries affects other national as well as international transmission lines beside the direct transmission lines between both countries. E.g. transmission lines connecting country A and C, A and D, B and C, and B and D are physically impacted to a certain extent by the transaction. This impact is known as loop flow and is caused physical characteristics as described by Kirchhoff's electrical laws (Claussnitzer, 1965). To account for this characteristics, the available transmission capacity is determined with respect to impacts on physical flows by transmission system operators. In this analysis, published values on net transfer capacity for the Winter 2007/08 are used (ENTSO-E, 2011c).

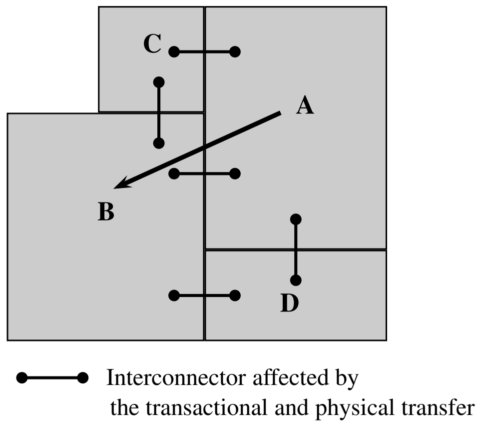


Example
1. Transaction
   $A \rightarrow B = 100\text{MW}$
2. Required transactional capacity
   $A \rightarrow B = 100\text{MW}$
3. Resulting physical flow
   $A \rightarrow B = 60\text{MW}$
   $A \rightarrow C = C \rightarrow B = 30\text{MW}$
   $A \rightarrow D = D \rightarrow B = 10\text{MW}$

Figure 3.8.: Transaction based allocation of transmission capacity. Source: Own illustration

The second approach takes the characteristics of the transmission network and physical flows into account. The approach is known as flow-based allocation of transmission capacity. If the same transaction between country A and B is considered, market participants have to procure transmission capacity not only on the direct interconnection between countries A and B but also on other interconnections affected by the transaction (see Figure 3.9). The amount of capacity that has to be contracted on the affected interconnections depends on the physical characteristics of the transmission network. Based on this, a Power Transfer Distribution Factor (PTDF) matrix can be calculated expressing the relation between transactional flows and resulting physical flows in the defined network. As available transmission capacity, the physical transmission capacity of international links is used instead of an aggregated capacity value as considered in the first approach.

Once the assignment regime is specified, the allocation of transmission capacity takes place prior or during the spot market clearing (see Section 2.2.2). Explicit auctioning of available transmission capacity requires a separation of the energy spot market and the market for transmission capacity as described in Section 2.2.2.1. Hence, market participants procure transmission capacity prior to the clearing of the energy market. On the other hand, both markets are integrated when using an implicit allocation of transmission capacity (see Section 2.2.2.2). Within this approach, transmission capacity is automatically or implicitly allocated during the energy spot market clearing and a separate transmission capacity market is not required. Market coupling and market split-



Example

1. Transaction
   $A \rightarrow B = 100\text{MW}$
2. Required flow based capacity
   $A \rightarrow B = 60\text{MW}$
   $A \rightarrow C = C \rightarrow B = 30\text{MW}$
   $A \rightarrow D = D \rightarrow B = 10\text{MW}$
3. Resulting physical flow
   $A \rightarrow B = 60\text{MW}$
   $A \rightarrow C = C \rightarrow B = 30\text{MW}$
   $A \rightarrow D = D \rightarrow B = 10\text{MW}$

Figure 3.9.: Flow based allocation of transmission capacity. Source: Own illustration

ting are possible implementations of an implicit auctioning procedure. In this analysis, transmission capacity is implicitly allocated within the spot market model.

3.3.2. Data and Scenarios

The model data is based on the ENTSO-E high voltage network (ENTSO-E, 2011b) including continental European countries and electrically connected neighboring countries (United Kingdom, Norway, Sweden, and Denmark East). The topology of the underlying physical network for the considered region is depicted in Figure 3.10. The physical network is characterized by substations and transmission lines, connecting two substations. Electrical parameters required for the determination of physical flows on transmission lines are based on Fischer and KieSSling (1989). A detailed description is given in Leuthold et al. (2012).

Beside network data, data on demand as well as generation needs to be specified. Used average demand, generation capacities, as well as renewable wind capacities are depicted in Table 3.4 for each considered country. In order to retrieve a load value for each substation of the physical network, regional data on population and gross domestic product are used to distribute national demand to individual nodes (Leuthold et al., 2012). On the other hand, power plants are considered individually based on VGE (2008) and are assigned to the nearest location of the physical network. However, as only power plants with a capacity above 100 MW are considered for this procedure, the remaining decentralized generation capacity is approximated for each country and national demand is accordingly adjusted. Data on total net generation capacities as listed in ENTSO-E (2008) and ENTSO-E (2009) are used to determine capacities of

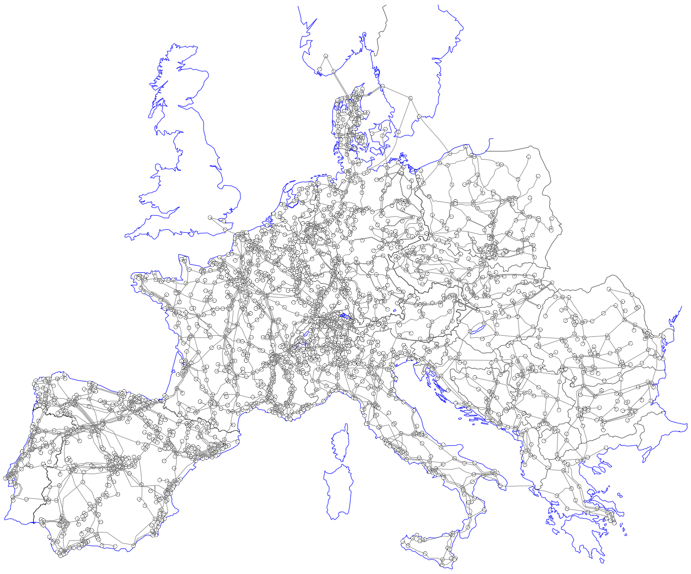


Figure 3.10.: European high voltage transmission network. Source: Own illustration based on ENTSO-E (2011b)

decentralized generation for considered countries by subtracting the power plant capacities as listed in VGE (2008) from the total net generation capacities. Renewable wind generation capacities are based on EWEA (2010). Generation is characterized by different generation technologies which differ in their main fuel and generation efficiency. The considered conventional generation technologies and their assumed marginal generation costs for 2008 are displayed in Table 3.5. In this analysis regional differences in marginal generation costs are neglected.

In order to capture the changes in demand and wind generation during a year, different hourly scenarios are specified. Changes in demand and wind are captured in three scenarios (Low, Mean, and High) resulting in nine final scenarios. To cumulate results of each scenario to annual results, probabilities are determined based on experienced demand and wind generation for Germany for the year 2008. The defined scenarios and probabilities are displayed in Table 3.6. Percentage values in Table 3.6 refer to average demand and wind generation capacity, respectively. However, the chosen scenario definition allows only an approximation of annual results and further analysis should aim to use experienced hourly values instead of characteristic scenarios. Additionally, characteristics of individual countries are neglected as German load curves and wind generation in-feeds are used. Interregional smoothing effects which are expected to be relevant on an European scale especially for wind generation are not taken into account due to missing publicly available data and to reduce computational effort.

Country	Average Demand	Wind Capacity	Conventional Generation Capacity
	MW	MW	MW
AL	468	0	1,399
AT	7,784	995	16,871
BA	1,318	0	3,547
BE	10,185	384	15,011
BG	3,922	158	11,409
CH	7,335	14	14,947
CZ	7,416	150	15,014
DE	63,429	23,903	89,663
DK-E	4,126	1,590	3,676
DK-W	2,472	1,590	3,530
ES	30,842	16,740	77,744
FR	56,295	3,404	107,038
GR	6,411	985	12,468
HR	2,033	18	3,087
HU	4,700	127	12,053
IT	38,648	3,736	69,930
LU	760	35	1,450
ME	522	0	855
MK	984	0	1,664
NL	13,683	2,225	16,093
NO	14,665	428	29,557
PL	16,263	472	32,915
PT	5,940	2,862	8,833
RO	6,286	10	18,627
RS	4,438	0	8,342
SE	16,389	1,021	29,912
SI	1,444	0	1,843
SK	3,146	3	7,870
UA	473	0	0
UK	38,101	3,241	77,719
Total	370,477	64,091	693,067

Table 3.4.: Average demand, wind generation capacity, and conventional generation capacity in Europe. Source: Own illustration based on VGE (2008); ENTSO-E (2008, 2009); EWEA (2010)

Technology	**Marginal Costs** EUR/MWh
Nuclear	9.71
Lignite	26.61
Hard Coal	50.36
CCGT	65.04
Gas Steam	90.38
OCGT	103.68
CCOT	69.58
Oil Steam	89.20
OCOT	102.32
PSP	42.30

Table 3.5.: Marginal generation costs for 2008. Source: Own calculations based on Nitsch (2008)

Demand	**Wind**	**Probability**
Low (85%)	Low (20%)	19%
	Mean (40%)	4%
	High (60%)	1%
Mean (100%)	Low (20%)	34%
	Mean (40%)	16%
	High (60%)	2%
High (115%)	Low (20%)	13%
	Mean (40%)	9%
	High (60%)	2%

Table 3.6.: Definition of considered demand and wind scenarios. Source: Own calculations

3.3.3. Results and Discussion

The analysis of the achieved results concentrates on the presentation and discussion of firstly cost and surplus results and secondly price results. The results of the nodal pricing model are compared to zonal pricing results considering a transaction- and flow-based allocation of international transmission capacity within the spot market model. To formalize the presentation and the discussion general remarks are provided in the beginning of each section.

3.3.3.1. Surplus and Cost Results

Within this analysis, consumer or demand cost DC is defined as the sum of the product of nodal demand q_n and nodal or zonal spot market price $price_n^{DA}$, respectively (Equation (3.38)). The dual variable on the respective energy balance (Nodal Pricing: Equation (3.20); Zonal Pricing: Equation (3.27)) is interpreted as the spot market price $price_n^{DA}$. Generation cost GC refer to the costs of the final generation dispatch thus including generation costs of redispatched power plants used for congestion management RC. Generation profits or benefits GB describe the profits earned in the spot market plus profits from redispatching power plants if required during the congestion management procedure RB. Subtracting generation costs from generation profits results in respective surplus of generation (Equation (3.39)). Finally, the transmission system operator faces firstly costs CC for resolving national congestion through compensation of constrained-on generation reduced by payments of constrained-off generation $-(RB - RC)$ and secondly rents or profits from congestion CR. In zonal pricing regime, profits for the transmission system operator result from allocation of international transmission capacity during the spot market clearing. In a nodal pricing regime, additionally congestion in national electricity networks results in nodal price differences and thus profits for the transmission system operator. Hence, congestion rent or profits can alternatively be describes as the difference of spot market payments received from consumers DC and spot market payments to generators GB (Equation (3.40)).

$$DC = \sum_n price_n^{DA} q_n \tag{3.38}$$

$$\begin{aligned} GS &= GB - GC + RB - RC \\ &= \sum_n \left(price_n^{DA} \sum_{p \in n} g_p^{DA} \right) - \sum_p mc_p (g_p^{DA} - g_p^{DOWN} + g_p^{UP}) \end{aligned} \tag{3.39}$$

$$+\sum_p mc_p g_p^{UP} - \sum_p mc_p g_p^{DOWN}$$

$$\begin{aligned} CS &= CR - CC = (DC - GB) - (RB - RC) \\ &= \sum_n price_n^{DA} q_n - \sum_n (p_n^{DA} \sum_{p \in n} g_p^{DA}) \\ &- \left(\sum_p mc_p g_p^{UP} - \sum_p mc_p g_p^{DOWN} \right) \end{aligned} \tag{3.40}$$

The overall surplus and cost results are depicted in Table 3.7. Regional surplus and cost results of considered pricing regimes are listed in Appendix B. The analysis is restricted to short-term cost and surplus values and abstracts from long-term aspects. As can be seen in Table 3.7, total generation cost is the lowest in the case of nodal pricing as generation and transmission utilization is simultaneously determined and thus optimally utilized (e.g. Schweppe, 1988; Hogan, 1992). Hence, the nodal pricing regime can be seen as a benchmark with respect to generation costs. Zonal pricing regimes show comparable but higher overall generation cost results. Total generation costs increase by 1.3 billion EUR per year or 2.0% if international transmission capacity is allocated transaction based during the spot market. In the flow based zonal pricing case, generation costs rise even more by 1.6 billion EUR or 2.5%.

Following de Vries and Hakvoort (2002) and Ding and Fuller (2005), economic efficiency — meaning that a least cost dispatch of power plants is achieved — is ensured with all congestion management methods independent of their exact procedure under the assumption of a fixed (inelastic) demand. The presented cost picture shows contrary results. Differences in generation cost among the investigated congestion management regimes are obvious and amount to 2.5% in the maximum. However, these differences to nodal pricing can be explained by the restriction on national congestion management. As only national power plants can be used to alleviate national congestion in the zonal pricing regime, generation costs are higher than in nodal pricing. Thus, through a closer cooperation of national transmission system operators and the application of international redispatch the difference in generation costs is reduced to the level of the nodal pricing regime. Introducing the opportunity for international redispatch in the transaction based pricing regime and thus relaxing the restriction to national redispatching capacities (Equation 3.37) results in generation costs of 61.5 billion EUR per year. Hence, generation costs are reduced to the level of the nodal pricing regime if a close cooperation of national transmission system operators in managing national congestion is assumed. Thus, short-term economic efficiency is achievable in this investigated setup independently of the applied congestion management methods, but depends on the level of international cooperation of national transmission system operators in managing network restrictions.

	Nodal Pricing	Zonal Pricing	
		Transaction based	Flow based
	billion EUR per year	billion EUR per year	billion EUR per year
Consumer costs (DC)	**148.1**	**140.1**	**144.3**
Generation benefits (GB)	136.9	138.2	144.9
Generation costs (GC)	61.5	62.8	63.1
Generation surplus (GS)	**75.4**	**75.4**	**81.8**
Congestion rent (CB)	11.1	3.6	2.7
Congestion costs (CC)	0	1.8	3.4
Congestion surplus (CS)	**11.1**	**1.8**	**-0.7**

Table 3.7.: Surplus and cost results of considered pricing regimes in billion EUR per year. Source: Own illustration

Beside the absolute differences, pricing regimes vary in the distribution of surplus among market participants. As described in Section 2.3, consumers and in some cases also generators profit from the application of congestion alleviation methods thus neglecting transmission constraints within the spot market. The transmission operator profits from capacity allocation methods as he is not in charge to manage congestion through congestion alleviation methods. Looking at the achieved results, gives comparable findings. Consumers profit most in the zonal pricing regime as spot market prices do not reflect national congestion. If a nodal pricing regime is applied, consumer cost increase by 8 billion EUR per year (5.7% of consumer cost) through locationally differentiated prices. As demand is assumed to be price-inelastic throughout all considered cases, the change in consumer cost is caused by spot market prices (see Table 3.8).

Beside consumers, generators should be similarly affected by different pricing regimes. However, generation benefits decline by 1% in the nodal pricing regime compared to the transaction based regime, but generation costs are similarly reduced in a comparable amount of generation surplus in the nodal pricing regime. The reduction of generation cost is one reason for the similar level of generation surplus. However, the introduction of national transmission constraints in the nodal pricing case causes price increases in countries with significant national congestion (esp. in Italy, see Table 3.8) leading to only slightly decreased generation profits as prices reflect national congestion. With respect to the flow based zonal pricing regime, generation surplus shows a significant increase to 82 billion EUR per year caused by highest generation benefits among pricing regimes. As the allocation regime of international capacity is changed towards a flow based regime, spot market prices are affected in various countries (esp. in France and South East Europe) resulting in higher generation benefits. Furthermore, significant amounts of redispatching costs occur further increasing the benefits of generators. However, it has to be noted that the results are sensitive to available transmission capacity allocated in the spot market. If the international transmission capacity is specified more conservatively, a decrease in generation benefits is expected.

Finally, the nodal pricing regime results in the highest surplus for the transmission system operator of 11 billion EUR per year. As the entire transmission network is considered during the spot market optimization, the transmission system operator does not face costs for redispatching power plants. Whereas in the zonal pricing regimes, the transmission system operator faces both congestion profits from international capacity allocation within the spot market as well as congestion costs due to required redispatch and the corresponding payments to generation. In the transaction based zonal pricing regime, congestion costs are overcompensated by congestion rents leaving a surplus of 1.8 billion EUR per year to the transmission system operator. However, if flow based allocation is considered, congestion management costs are greater than congestion rents. This is caused by the available transmission capacity assumed in the flow based approach which refers to the physically available transmission capacity of international lines. The transmission system operator faces negative overall surplus as costs for redispatching power plants exceed congestion rents. In reality, transmission system operators would define a more conservative capacity value to ensure stability of the system and to reduce congestion management costs. However, this would not change the overall picture, but the distribution of costs is expected to change increasing congestion surplus on the one hand and probably decreasing consumer as well as generation surplus on the other hand. The assumption of rather high available transmission capacity additionally impacts zonal prices as well as generation profit and consumer costs which are raised significantly especially in France and in South East Europe (see Table 3.8).

To subsume, the transmission operator profits most from an implicit allocation of network constraints within the spot market especially if all network constraints are considered. However, the results are sensitive to the definition of available transmission capacity. Comparing different pricing regimes, the gain of surplus for the transmissions system operator results from a distribution of surplus from consumers and partly generators to the transmission system operator. Especially consumers face a significant increase in consumer costs due to locationally differentiated prices in the nodal pricing regime. The impact on generators however is twofold and depends on the level of physical congestion within countries. Some countries show lower generation surplus, whereas other countries generators profit from higher spot market prices in the nodal pricing regime if national congestion is significant. However further analysis is required to underline these impacts for the European network as achieved results depend on the quality of underlying data.

3.3.3.2. Price Results

As discussed previously, demand is assumed to be fixed (or price-inelastic) and thus changes in surpluses depend mainly on the spot market prices. Achieved regional prices are depicted in Table 3.8 on an aggregated level and in Figure 3.11(a) and 3.11(b) on a detailed nodal level. In general, nodal prices reflect marginal generation costs of the corresponding spot market. In the zonal pricing regimes, the dual variable on Equation (3.27) is interpreted as price of the spot market. The dual variable on Equation (3.20) is considered as nodal price in the nodal pricing regime. According to spot pricing theory (Schweppe, 1988), spot prices are viewed as the sum of different components:

- *Marginal value of generation*: The marginal value of generation includes marginal fuel and maintenance costs as well as a quality of supply component. Under normal operational conditions, the fuel and maintenance cost dominate the spot price component and the quality component is very small, but in critical situations (e.g. limitation of generation capacity) the quality component may dominate the price component.

- *Marginal value of network operation*: The marginal value of network operation comprises a part associated with operating costs and a second quality of supply part. The operating costs with in the network result from network losses and the costs associated with balancing it. The quality component is analogous to the marginal value of generation, but with respect to network capacity. Thus, if network capacity is limited and the congestion occurs, the quality component may dominate the marginal value of network operation.

Thus, the spot market price firstly depends on the generation technology and corresponding marginal costs which is used to meet the additional unit of demand. As transportation is essential in an electricity system, network congestion may hinder the use of the cheapest available generation technology as this would exceed available transmission capacity. Hence, a second component of the spot market price reflects costs due to congestion. An operational network cost part may arise from network losses, but are neglected in this analysis. A mathematical derivation of the different price components is given in Schweppe (1988) and Stigler and Todem (2005).

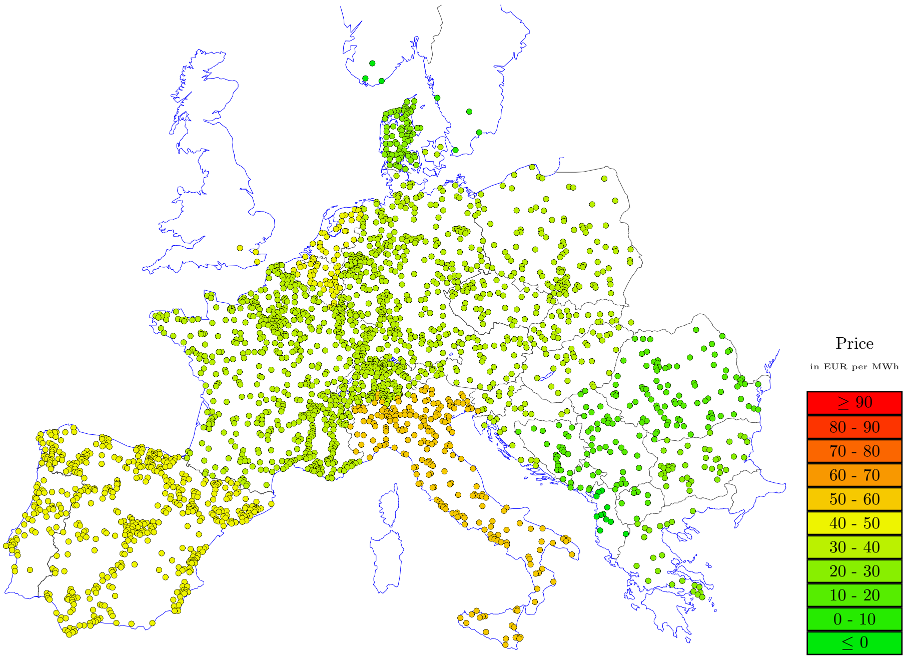
With respect to the analysis, the network price component reflects only congestion on international transmission links within the zonal pricing calculations. Thus, spot market prices vary between countries, but within a country similar prices occur as innernational transmission is not restricted. On the other hand, all network constraints (international and national) are considered in the nodal pricing regime leading to prices varying between system nodes of the same country due to national congestion. These general effects are displayed in Figure 3.11(a) and 3.11(b).

	Zonal Pricing		**Nodal Pricing**
	Transaction based EUR/MWh	Flow based EUR/MWh	EUR/MWh
BE, NL, LU	53.63	55.49	53.50
AT, CH	47.85	44.30	43.01
DE	47.85	48.34	48.13
FR	47.68	51.16	52.70
IT	67.23	67.77	77.90
South West*	52.39	52.84	54.75
Central East**	46.82	45.44	48.91
South East***	32.74	41.37	41.11
UK	53.88	53.88	55.02
North****	9.29	11.53	10.17
Average	**46.35**	**47.97**	**49.46**

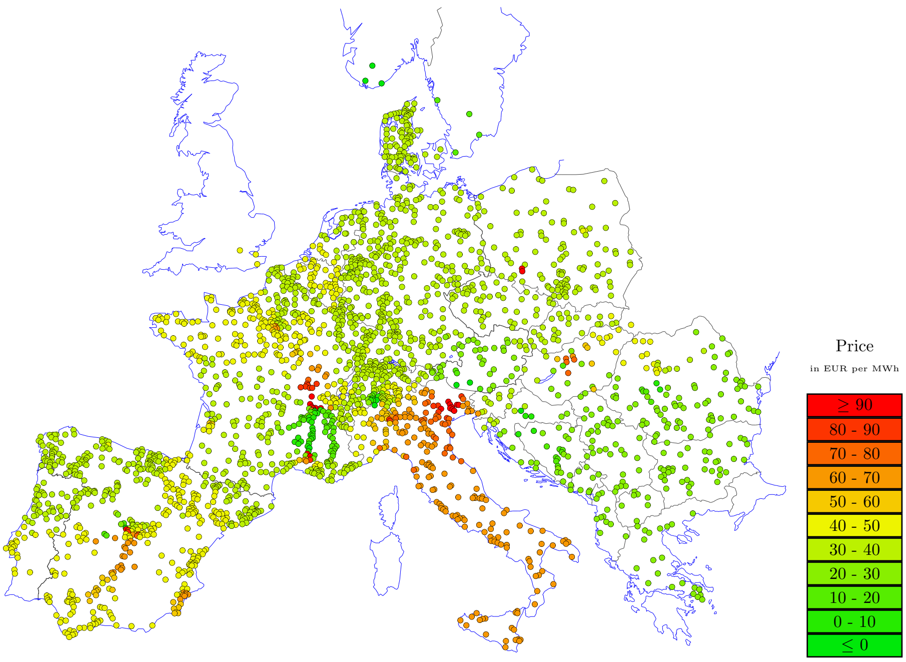
* ES, PT
** PL, CZ, SK
*** SI, HR, HU, RO, BA, RS, ME, MK, AL, BG, GR
**** DK, NO, SE

Table 3.8.: Average consumption weighted price of considered pricing regimes in EUR per MWh. Source: Own illustration

As can be seen in Table 3.8, prices increase with the introduction of additional transmission constraints from 46.35 EUR per MWh to 49.46 EUR per MWh representing an increase of 6.7%. The price level is the lowest in the transaction based zonal pricing regime. Highest prices occur in the nodal pricing regime as all network constraints are taken into account. If prices of the transaction based zonal pricing regime and the nodal pricing regime are compared, the impact on average prices in twofold. Some regions show lower prices (e.g. BE, NL, LU), whereas in other regions e.g. Italy the average price is raised significantly up to ca. 10 EUR per MWh. On the one hand, through introduction of flow based capacity allocation in both nodal and zonal pricing available transmission capacity is increased between countries on an international level. This leads to a reductive impact on spot market prices. On the other hand, prices increase due to incorporation of national congestion. Especially in countries with high congestion management costs (e.g. France and Italy) a significant price increase can be observed. However, as mentioned previously prices — especially if flow based zonal pricing is considered — strongly depend on the available transmission capacity. If transmission capacities are more conservatively specified, prices would change in both directions depending the characteristics of the country.



(a) Zonal pricing (transaction based)



(b) Nodal pricing

Figure 3.11.: Geographic representation of average nodal prices. Source: Own illustration

3.4. Conclusions

An important issue for the implementation of an Internal Electricity Market across Europe is the more efficient use of and development of additional network capacities, and managing congestion problems. This Chapter sets out to explore whether the choice of the design of European spot power markets makes a difference and quantifies the distributional effects associated with it. Two market designs are compared across Europe. Firstly, an optimized approach of implicit auctions of transmission capacity between nationally defined price zones, and secondly a nodal pricing approach. The national or zonal pricing is additionally separated into transaction and flow-based allocation of international transmission capacity.

A model is described to calculate TTC values for limits to commercial transfers between countries. As no formal standardized method exists for TTC calculations, and national transmission system operators do not report on their specific methodology, a range of methodologies is explored that capture some of the variations that might be inherent in current TTC calculations. These TTC values are then used as a basis for modeling the single price zones according to national boundaries with one implicit auction for all international transmission capacity.

The analysis has some limitations. In particular, the quality of the available data is insufficient to allow for the evaluation of individual lines or investment projects. However, for the aggregated analysis presented here, the data is adequate. Additionally, specific operation constraints, e.g. intertemporal generation constraints or system security aspects, are omitted since generally these are not formally implemented or published by European transmission system operators but instead are carried out informally by the operators based on established practices.

Applying a nodal pricing regime to the European system with the used data set provides a set of insights that confirms previous studies. Most of the transmission constraints are not associated with lines between countries, but with lines within countries. The current European power market design (outside of Scandinavia and Italy) does not make this explicit within the spot market. This creates incentives for system operators to limit international flows to avoid domestic congestion that requires redispatching of power stations within their boundaries to resolve remaining constraints. Furthermore, the nodal pricing results illustrate that the congestion — and price — patterns vary considerably between wind scenarios. This suggests that approaches that aim to define price zones within countries are not suitable to address internal congestion as the zones would either have to vary depending on system conditions or be small and thus be essentially equivalent to nodal pricing.

The comparison with the nodal pricing results suggests that generation cost savings are achievable with nodal pricing. The costs savings accrue from a coordinated generation scheduling across European countries taking all network constraints into account. However, cost savings refer only to generation costs and ignore the distributional effects of different pricing regimes. In particular consumers will loose due to locationally differentiated prices and face higher costs. On the other hand, transmission system operators will profit from international as well as national congestion. Based on these results, further research should address the issue whether the resulting improvements in generation costs and increased transparency justifies the cost of implementing new systems, and whether the political effort necessary to change the current design is achievable. For instance, Poland is already anticipating the need for a change of the current system towards nodal pricing (Newbery, 2012). Additionally, Baldick et al. (2011), Bell et al. (2011) and Newbery (2011) recommend a nodal pricing regime for the British electricity system to ensure an efficient operation of the existing system.

4. Improving Congestion Management in Germany - How to Facilitate the Integration of Renewable Generation in Germany

4.1. Introduction

Several European countries have implemented special support schemes for renewable energy sources in electricity generation in order to achieve the RES-E targets set by the European commission and to reduce domestic emissions of carbon dioxide in the energy sector. Especially in northern Europe, wind energy became the dominating renewable energy source due to the geographical conditions. Renewable electricity generation especially wind generation is characterized by high capital and low operational costs. Hence, wind generation is placed in the beginning of the merit order and should be dispatched first in the short run. Furthermore, the location of wind turbines strongly depends on regional wind conditions. In Germany significant wind capacities are located in the northern part of the country. On the other hand, electricity load is mainly located in the mid-western and southern part of Germany. Both aspects will result in an increasing flow of electricity from northern to southern Germany. Especially in years with high wind generation, network congestion increases and congestion management costs are affected (Deutscher Bundestag, 2010).

As described in Section 2.4.1, the German electricity market is characterized by a decentralized market structure and market participants are responsible for planning their unit commitment without considering physical transmission restrictions. Given the commitment decisions of the market participants determined in the markets (futures, dayahead, intraday market or bilateral trading) the transmission system operators are in charge of managing physical transmission restrictions and of maintaining the balance between generation and demand.

To manage transmission limitations the transmission system operators have two general control options to ease network congestion, namely technical and market based methods (§ 13 (1) EnWG). Active power flow management can be done technically through adjustments of network topology (e.g. switching actions) or network characteristics (e.g. changes of transformer taps). On the other, hand market-based congestion management methods comprise the adjustment of nodal generation or load through market-based methods. In Germany cost-based redispatching of power plants is applied (Section 2.4.1). As described in Section 2.2.3.2, power plants in regions with excess generation have to decrease their output to reduce congestion in the transmission network. On the other hand, the reduced generation output in the surplus region has to be compensated by an increase of generation output in the deficit region to ensure equality of demand and supply. The increase and decrease of generation is associated with costs which are interpreted as congestion management costs.

The current level of congestion management costs in Germany is rather low as described in Section 2.4.1. However, in the future an increase of congestion management costs is expected firstly due to higher wind generation and significant fossil generation investments in northern Germany. Therefore, recent studies emphasize the need for significant investments in transmission capacity to reduce future network congestion (50Hertz Transmission et al., 2010). On the other hand, the option to adjust or extend the current congestion management regime could reduce the need for transmission investments through a better utilization of the transmission network. Furthermore, price signals resulting from congestion management could give market participants adequate incentives to locate generation or demand.

This Chapter investigates the impact of physical network constraints on spot market results in Germany and quantifies the development of congestion management costs given higher shares of renewable generation. Therefore, a model is described which replicates the current market regime in Germany consisting of a spot market and a congestion management model. After clearing of the uniform pricing spot market the final power plant dispatch is determined by the system operator given the physical network constraints. Redispatching of power plants and optimization of network topology are considered as congestion alleviation methods and interpreted as lower and upper bound on congestion management costs. The results of the uniform pricing model are compared to an implicit allocation of national transmission within the spot market known as nodal or locational pricing.

The Chapter draws on Kunz (2011) and is structured as follows. The models and the underlying dataset are described in Section 4.2. The results are presented and discussed in Section 4.4. Section 4.5 provides the conclusions.

4.2. Model

The general setting of the uniform and nodal pricing model follows Section 3.2 and 3.3. In contrast to the previous applications, technical congestion alleviation methods are introduced as congestion management methods in the uniform pricing model beside the already known cost-based redispatch of power plants. Therefore, the uniform pricing model and the nodal pricing model are subsequently described in Section 4.2.1 and 4.2.2, respectively. Again, the uniform pricing model comprises a spot market and a congestion management to reflect the German market regime.

The general assumptions of the model are that firstly a competitive behavior of market participants is assumed and secondly an independent system operator optimizes the system variables for the entire regional scope of the model. The model optimizes a representative hour, thus intertemporal aspects are neglected.

4.2.1. Uniform Pricing Model

4.2.1.1. The Spot Market Model

The spot market model minimizes the total generation costs $\sum_p mc_p G_p$ for a given level of load q_n. The load is defined for each system node n representing substations of the physical transmission network. The minimization of total generation costs (Equation (4.1)) is subject to the market clearing constraint, the individual power plant capacity restrictions, and the restriction of international trade. The market clearing constraint (Equation (4.2)) ensures the equality of load q_n, renewable generation $g_n^{wind} + g_n^{solar}$, generation of thermal power plants G_p, and international exchanges $TF_{n,nn}$. The dual or marginal on the market clearing condition is the marginal price $price_n^{DA}$. Renewable generation is defined as a parameter and reduces the load at each node. This assumption is founded in the priority feed-in of renewable generation according to the German renewable energy sources act (Erneuerbare-Energien-Gesetz, EEG). On the other hand, generation of thermal power plants is an optimization variable of the model and restricted by the installed capacity g_p^{max} of power plant p (Equation (4.3)). As the model aims to optimize the spot market, trade $TF_{n,nn}$ between system nodes refers to transactional volumes rather than physical exchanges. The trade between countries depends on the direction and is restricted by the net transfer capacity $ntc_{c,cc}$ between country c and country cc (Equation (4.4)).

Thus, international transfer is limited whereas transfers between national nodes is unlimited.
The final linear problem is optimized for one hour.

$$\min_{G_p} \sum_p mc_p G_p \tag{4.1}$$

$$q_n - g_n^{wind} - g_n^{solar} = \sum_p G_p - \sum_{nn} TF_{n,nn} + \sum_{nn} TF_{nn,n} \qquad \forall n \tag{4.2}$$

$$G_p \leq g_p^{max} \qquad \forall p \tag{4.3}$$

$$\sum_{n \in c} \sum_{nn \in cc} TF_{n,nn} \leq ntc_{c,cc} \qquad \forall c, cc \tag{4.4}$$

$$TF_{n,nn}, G_p \geq 0$$

4.2.1.2. The Congestion Management Model

Given the results of the spot market model, the different congestion management methods are evaluated using a congestion management model. Cost-based redispatching of power plants and network topology optimization methods are considered as options for market-based and technical congestion management methods.
The congestion management model optimizes the total redispatching costs (Equation (4.5)) based on the results of the spot market model, namely the contracted generation of power plants g_p^{DA}. Contracted spot market generation can be adjusted by increasing (G_p^{UP}) or decreasing (G_p^{DOWN}) the generation of power plants. Power plants which increase their generation are paid their marginal cost mc_p whereas the decreased generation pays their saved fuel costs mc_p to the TSO. Similar to the spot market model, the market clearing condition (Equation (4.6)) and the generation capacity restriction (Equation (4.7)) are considered as constraints of the optimization problem. Furthermore, as the congestion management model aims to determine redispatching costs resulting from physical network constraints, a DC power flow approach is used to reflect technical restrictions of the transmission network. Given the technical network characteristics ($b_{n,nn}$ and $h_{l,n}$), the power flow on physical transmission lines LF_l (Equations (4.9) and (4.10)) as well as the physical netinput at each system node NI_n (Equation (4.8)) are determined by the load angle Δ_n. Physical transmission limits are represented by p_l^{max} (Equation (4.11)).

In contrast to the model formulations in Section 3.2 and 3.3, flexibility of the network topology is considered as a congestion management method and reflected by the binary variable $ONLINE_l$ in the model (Fisher et al., 2008).

The scalar m used in Equations (4.9) and (4.10) is a large number. If a line is switched off ($ONLINE_l = 0$) the transmission capacity is set to zero according to Equation (4.11). Additionally, Equations (4.9) and (4.10) result in a large positive and negative number representing the upper and lower limitation on load angle differences $\sum_n h_{l,n}\Delta_n$. Otherwise if a transmission line is online ($ONLINE_l = 1$), Equations (4.9) and (4.10) collapse to an equality constraint $LF_l = \sum_n h_{l,n}\Delta_n$ and determine the power flow on transmission lines. The introduction of two separate equations for the power flow is necessary to put no restriction on load angle differences.[40] Optimization of network topology goes in hand with reliability issues as switching lines may reduce the N-1 security meaning that the system may not be able to withstand the outage of single transmission equipment. Hedman et al. (2008b) present an approach to incorporate reliability constraints in a network topology optimization problem. However, the solution time of the network topology problem increases substantially, if security constraints according to Hedman et al. (2008b) are introduced. To approximate reliability requirements in the presented model transmission capacity of lines is downgraded by 20% (Leuthold et al., 2012).

The presented congestion management model is solved in a two-step procedure to differentiate between congestion costs resulting from congestion on international and national transmission lines. Firstly, only international transmission lines are considered and congestion management costs are determined. Afterwards, national transmission lines are added and redispatching costs for relieving national congestion are determined. As the net transfer capacities used in the spot market model are assumed to be fixed and thus do not necessarily reflect resulting congestion situation, the separation is useful. National congestion can be managed by redispatching power plants and optimizing network topology. If only redispatching of power plants is considered[41], congestion management costs are interpreted as an upper bound. The lower bound on congestion management costs is achieved if both methods (redispatching and network topology optimization) are incorporated as topology optimization is available at no direct costs. In this case the mixed integer problem is solved in the relaxed version to reduce computation time.[42] The final linear problem is optimized for one hour

40 If Equations (4.9) and (4.10) are replaced by the equality constraint for the power flow $LF_l = \sum_n h_{l,n}\Delta_n$ the power flow on line l will be zero if a line is switched off due to the reduction of transmission capacity. More importantly the load angle difference between nodes connected by line l will be zero, too. This would result in zero exchanges between both nodes, which is not necessarily the case as power flows are just rerouted with in the transmission network if a line is switched off.

41 In this case the binary variable $ONLINE_l$ is fixed to one for all transmission lines.

42 Solving the network topology optimization to an optimal integer solution increases computation time substantially (e.g. Fisher et al., 2008). As the analysis focuses on general

given the results of the spot market model.

$$\min_{G_p^{UP}, G_p^{DOWN}} \sum_p mc_p G_p^{UP} - mc_p G_p^{DOWN} \tag{4.5}$$

$$q_n - g_n^{wind} - g_n^{solar} = \sum_p (g_p^{DA} + G_p^{UP} - G_p^{DOWN}) - NI_n \qquad \forall n \tag{4.6}$$

$$G_p^{UP} - G_p^{DOWN} \leq g_p^{max} - g_p^{DA} \qquad \forall p \tag{4.7}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \qquad \forall n \tag{4.8}$$

$$LF_l \leq \sum_n h_{l,n} \Delta_n + (1 - ONLINE_l) * m \qquad \forall l \tag{4.9}$$

$$LF_l \geq \sum_n h_{l,n} \Delta_n - (1 - ONLINE_l) * m \qquad \forall l \tag{4.10}$$

$$|LF_l| \leq p_l^{max} ONLINE_l \qquad \forall l \tag{4.11}$$

$$G_p^{UP}, G_p^{DOWN} \geq 0$$

$$ONLINE_l = \{0, 1\}$$

4.2.2. Nodal Pricing Model

The nodal pricing model now includes physical network characteristics and optimizes the power dispatch G_p by minimizing total generation cost $\sum_p mc_p G_p$ (Equation (4.12)) subject to physical network restrictions. The previously described uniform pricing spot market model takes only transfer limitations on international exchanges into account and congestion in the physical national transmission network is solved afterwards using the congestion management model. In the nodal pricing model, physical load flows of the entire transmission network and occurring congestion are considered while optimizing the generation dispatch of individual power plants. Thus, the generation dispatch of power plants does not necessarily follow the national merit-order curve (compared to the uniform pricing model) as physical load flows and their restrictions may require more costly plants to be online in case of congestion. Again, the nodal energy balance (Equation (4.13)) has to ensure the equality of nodal generation including renewable generation from solar and wind capacities (g_n^{wind} and g_n^{solar}), nodal load q_n, and net input or withdrawal from the transmission grid NI_n. To account for physical characteristics of transmitting electricity, a DCLF approach is used to determine the load flows LF_l on individual transmission lines l (Equation (4.16)). The maximum capacity of transmission lines

results rather than detailed impacts on network topology, the relaxed solution of the integer problem provides sufficient information.

limits the absolute physical exchanges between system nodes (Equation (4.17)). The final linear problem is optimized for one hour assuming an independent system operator.

$$\min_{G_p} \sum_p mc_p G_p \tag{4.12}$$

$$q_n - g_n^{wind} - g_n^{solar} = \sum_p G_p - NI_n \qquad \forall n \tag{4.13}$$

$$G_p \leq g_p^{max} \qquad \forall p \tag{4.14}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \qquad \forall n \tag{4.15}$$

$$LF_l = \sum_n h_{l,n} \Delta_n \qquad \forall l \tag{4.16}$$

$$|LF_l| \leq p_l^{max} \qquad \forall l \tag{4.17}$$

$$G_p \geq 0$$

4.3. Data and Scenarios

The model comprises the region of Germany on a detailed level and the neighboring countries Denmark (West), the Netherlands, Belgium, France, Switzerland, Austria, the Czech Republic, and Poland on an aggregated level. Data for the year 2008 is used as input.

Generation is divided into twelve plant types: hydro (run-of-river and reservoir), nuclear, lignite, coal, gas and oil steam, combined cycle gas and oil turbine, open cycle gas and oil turbine, and pump storage plants. National power plant capacities are based on VGE (2008) and include existing power plants with a capacity above 100 MW. The development of the German power plant fleet until 2020 assumes decommissioning of existing power plants based on technical lifetimes (50Hertz Transmission et al., 2010) and proposed power plant investments till 2018 (BDEW, 2011). The phase-out of 12.3 GW out of 20.5 GW nuclear generation capacities in Germany till 2022 is taken into account. The shutdown of eight nuclear plants in 2011 as well as the stepwise phase-out of remaining nuclear capacities till 2022 is based on Deutscher Bundestag (2011). Marginal costs of power plants are based on fuel and CO_2 certificate price for 2008 (Table 3.5).

Renewable electricity generation comprises wind as well as solar generation and is accounted with marginal costs of zero. Thus, the node-specific load will be lowered by corresponding nodal renewable generation. In 2008, generation capacities of installed wind turbines sum to 27 GW and are expected to increase to 37 GW onshore and 14 GW offshore in 2020 (50Hertz Transmission et al., 2010). However, only 4.3 GW offshore wind capacity are currently planned to be commissioned until 2020 (BDEW, 2011). On the other hand, solar electricity generation capacities increased substantially during the last years. Installed solar generation capacity in 2008 is 5.3 GW. Following Nitsch et al. (2010), installed capacity raises to 38.4 GW in 2015 and 51.8 GW in 2020. Renewable generation capacities in Germany are distributed among all system nodes according to data on regional renewable capacities published by national transmission system operators. Renewable generation capacity of neighboring countries is aggregated.

Demand values for 2008 represent the average hourly demand of 63.4 GW as published by ENTSO-E. In 2020, demand is expected to decrease by 8% in Germany (50Hertz Transmission et al., 2010). Within Germany, nodal demand is determined by taking the regional population and gross domestic product into account. Further information can be found in Leuthold et al. (2012).

The underlying physical grid for Germany is based on the European high-voltage grid ENTSO-E. The neighboring countries of Germany are represented on an aggregated level. Hence, national congestion in those countries is neglected. The transmission network is depicted in Figure 4.1. The development of the physical transmission grid until 2020 is based on ENTSO-E (2010b). Transactional restrictions used in the spot market model between countries are based on the net transfer capacity (NTC) published by the European Network of Transmission System Operator for Electricity (ENTSO-E) (ENTSO-E, 2011c). The indicative NTC values for summer 2008 are used and considered constant until 2020. The development of the physical transmission grid until 2020 is based on the Ten-Year Network Development Plan published by the ENTSO-E (ENTSO-E, 2010b). Based on this report, network extensions of a total length of 1,946 km are added to the existing transmission grid until 2020, of which 504 km are upgrades of existing transmission lines and remaining 1,442 km are new overhead lines. 974 km of network extensions are considered to be realized before 2015. The network extensions comprise both regional network extension projects with only a few kilometers length as well as interregional ones mainly from Northern to Southern Germany. Main purpose of planned network extensions is the integration of renewable energy sources in the Northern part of the country in the existing transmission network. Additionally, ensuring security of supply, reduction of redispatching costs, as well as connection of thermal generation capacities are listed as expected benefits of planned network extensions.

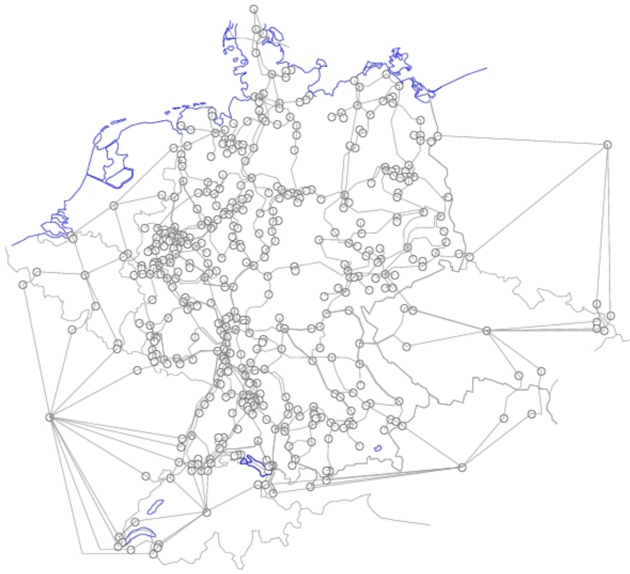


Figure 4.1.: German high voltage transmission network. Source: Own illustration

To analyze the impact of different load, wind, and solar levels on congestion management costs 27 representative hours are specified as scenarios based on data for 2008. Load is defined relative to average hourly load and classified into three scenarios representing low (85%), medium (100%), and high (115%) load levels. Wind generation is defined by three different scenarios and varied between low (20% of installed capacity), medium (40% of installed capacity), and high (60% of installed capacity) wind generation. Solar generation is divided into a low (0% of installed capacity), medium (10% of installed capacity), and high (20% of installed capacity) generation scenario.[43] Models are optimized for each hourly scenario separately, thus representing a static optimization neglecting intertemporal aspects. Defined scenarios are weighted to achieve annual results. Scenario weights are based on hourly load and renewable generation data for 2008 published by ENTSO-E and national transmission system operators.

4.4. Results and Discussion

In total 27 different scenarios are considered which are simulated for the years 2008, 2015, and 2020. Proposed power plant investments, expected wind and

[43] The utilization values of solar generation capacities are defined to meet the yearly average of solar generation.

solar generation capacities, electrical load, and proposed network extensions for Germany are adjusted for the 2015 and 2020 optimizations. Data related to neighboring countries as well as generation costs are not changed. Yearly or total costs represent the costs for consumers[44] and are the weighted costs of the presented scenarios. The following analysis firstly presents cost and price results of the uniform and nodal pricing regime using the models described previously. Afterwards, results of both pricing regimes are compared and discussed.

4.4.1. Uniform Pricing

Total yearly costs for consumer in Germany are 25.0 billion EUR in 2008 (Figure 4.2) representing the product of market price and national load of the spot market model. In 2015 and 2020 total yearly costs decrease to 22.3 and 21.3 billion EUR. The decrease of the total costs is caused firstly by the increase of renewable generation capacity. Wind capacity is expected to rise from 23.9 GW in 2008 to 37 GW onshore and 4.3 GW offshore in 2020. Additionally, solar generation capacity changes from 5.3 GW in 2008 to 51.8 GW in 2020. As renewable generation is accounted with marginal costs of zero, load is reduced and thus cost for consumers decrease. Secondly, load decreases by 8% and thirdly, significant generation investments in relatively cheap hard coal power plants are planned. All three factors impact the total costs and lead to a decrease of spot market costs by roughly 17%. Among the impacting factors, renewable generation has the strongest impact causing a reduction of consumer costs of ca. 9%. Comparing renewable generation, wind generation accounts for a reduction of 37 million EUR per 1000 MW installed capacity, whereas solar generation reduces consumer costs for 11 million EUR per 1000 MW installed capacity. The difference between both technologies results from the utilization of installed renewable generation. As wind generation shows on average higher utilization factors, generation and thus cost reduction potential is higher compared to solar generation in Germany. As spot market model does not take physical transmission constraints into account and the dispatch is characterized by the national merit order cost curve of available fossil and renewable generation. Thus, the impacts of renewable generation on costs represent the merit order effect of additional renewable generation as market prices decline by increased generation from renewable sources (e.g. SensfuSS et al., 2008).

However, the spot market model does not take physical transmission con-

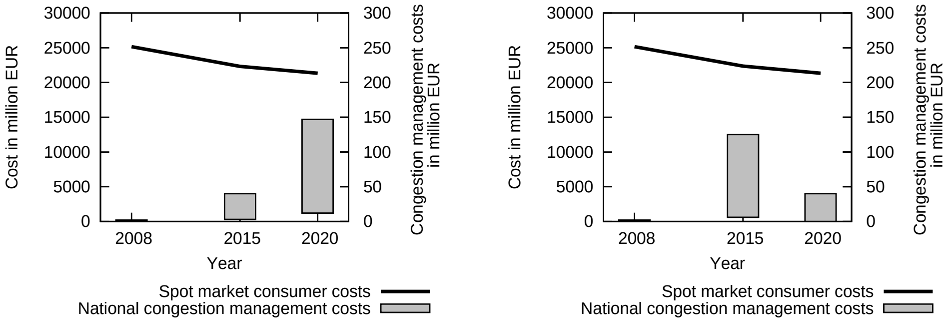
[44] Costs for consumers represent short-run marginal costs and are defined as the product of load and market price (dual variable on Equation (4.2)). Additional costs resulting from the promotion of renewable sources, capital costs of transmission and generation equipment as well as taxes are not considered in this analysis.

straints into account as only international transfers are limited by the net transfer capacity. In order to match the dispatch determined in the spot market model with transmission limitations of the physical transmission network, additional actions have to be undertaken by national TSOs to ensure secure operation of the transmission network. In the described modeling approach two different congestion management methods are implemented.

Firstly, redispatching of power plants in order to ease national physical network congestion is considered. Power plants in regions with excess generation have to decrease their output to reduce congestion in the transmission network. On the other hand, the reduced generation output in the surplus region has to be compensated by an increase of generation output in the deficit region to ensure equality of load and supply. In this modeling approach all power plants are allowed to be redispatched in order to retrieve limits on congestion management costs. Technical or administrative restrictions which may limit the adjustment of generation output are not taken into account.

Secondly, the redispatching of power plants is extended by the option to optimize network topology in order to manage power flows. The physical transmission network is characterized by substations and transmission lines connecting different substations. Within substations, transformers and switches are the main components and enable the TSO to optimize power flows in the network through switching actions. In order to reflect the technical flexibility of the TSO, switching of transmission lines is considered as a congestion management option. The mathematical representation is rather simplified as transmission lines can only be switched on or off and further switching options within a substation are neglected.

In both congestion management methods the increase and decrease of generation is associated with costs which are interpreted as congestion management costs. As network topology optimization does not cause direct costs to the TSO, the second congestion management method (network topology optimization and redispatching of power plants) can be interpreted as a lower bound on congestion management costs. On the other hand, the management of congestion using only redispatching of power plants is interpreted as an upper bound on congestion management costs. Additionally, international and national congestion management costs are differentiated. The national costs of considered congestion management methods are displayed in Figure 4.2 and listed in Table 4.1 for the considered years and for the different network expansion cases. The line represents consumer cost and the bars reflect the range between the lower and the upper bound of national congestion costs.



(a) Without network extension **(b)** With network extension

Figure 4.2.: Total spot market (line, left axis) and congestion management (CM) costs[45] (bars, right axis). Source: Own illustration

It can be seen in Figure 4.2 that the option to redispatch power plants results in additional dispatch costs as power plants which are dispatched in the spot market model have to be redispatched due to national network congestion. On the other hand, network topology optimization reduces the need for power plant dispatch adjustments as network topology optimization does not cause direct costs to the TSO.

For 2008, national congestion management costs within the model range between 0 and 1.7 million EUR per year. Comparing calculated costs with experienced costs of 45 million EUR (see Table 2.4) the calculations confirm the relatively low need for congestion management. Differences between experienced and calculated redispatching costs can be explained by the approximations inherent in the modeling approach in particular the abstraction from intertemporal aspects and the scenario definition. Furthermore, at the moment the TSOs cannot decide over all available generation units and are limited to pre-contracted redispatching capacities which may increase congestion management cost.

In 2020, congestion management costs increase to 147 million EUR per year (ca. 0.7% of total spot market costs) in the maximum if no network expansion is considered (Figure 4.2(a)). The significant increase in congestion management costs can be explained by the location of new renewable and fossil generation in northern Germany. In combination with the regional distribution of load this leads to a significant physical flow from northern to southern Germany and thus increases the need for congestion management. Among renewable sources, wind generation shows the strongest impact on redispatching costs resulting in 1.7 million EUR per 1000 MW installed capacity (Table 4.1). On the other hand,

[45] The upper (lower) end of the bar represents the upper (lower) bound on yearly congestion management costs.

additional solar generation decreases redispatching costs by -0.3 million EUR per 1000 MW installed capacity. As solar generation is mainly located in southern Germany and closer to load centers, the specific impact on redispatching costs is negative. Through optimization of network topology congestion management costs are reduced to 12.0 million EUR per year in 2020 (ca. 0.1% of total spot market costs). Hence, switching of transmission lines leads to a reduction of congestion management costs but cannot ease all network congestion as it is the case in 2008 and (costly) redispatching of power plants is still needed to ensure secure network operation. Costs for international congestion management are 178 million EUR in 2008 and decline to only 2.4 million EUR in 2020. The costs for international congestion management strongly depend on the definition of the net transfer capacity which limits international transfers. Whereas in 2008, the net transfer capacity used in the spot market model allows more international transactions as physically possible. Thus, additional redispatch is required to ease network congestion. In future years, the opposite occurs and more trades are possible from a physical perspective and hence international redispatch is beneficial as costly generation is replaced by cheaper ones. This effect accrues mainly from the assumption that the values for the net transfer capacity are left unchanged during the investigated years. In reality, TSOs would adjust the net transfer capacity between countries during the hours and years taking impacts on international congestion management costs into account.

The overall picture does change if network extension is introduced in the model (Figure 4.2(b)). Costs of the spot market remain unchanged as physical network constraints are not considered. However, national congestion management costs are reduced through planned network extension stated in ENTSO-E (2010b). In 2020, yearly congestion management costs are reduced and range between 0 million EUR and 39.6 million EUR (ca. 0.2% of total spot market costs). Compared to the case without network extension (Figure 4.2(a)), the need for redispatching power plants decreases significantly as the physical network from northern to southern Germany is strengthen. This is especially true in 2020 as interregional transmission lines are expected to come online. However in 2015, congestion management costs show a steep increase which is mainly caused by a heterogeneous development of generation and transmission capacity. At selected locations within the transmission network, generation capacity is expected to come online, but existing transmission capacity is not sufficient to transport the additional generation resulting in higher redispatching costs for these plants. In 2020, additional transmission capacity is available at these locations and hence congestion management costs decrease. It is likely that both developments are coordinated to some extent especially if a new power plant is commissioned. Regarding the impact of renewable sources on congestion management costs, additional wind as well as solar generation show a specific impact of 1.7 and -0.04 million EUR per 1000 MW installed capacity, respectively. The impact is comparable to the case without network extension. Costs for international congestion management decrease to 4 million EUR in 2020 considering network extensions.

	2008	**2020 No Network extension**	**2020 Network extension**
Spot market costs million EUR per year	24,983	21,322	21,322
International congestion management costs million EUR per year	178	2	4
National congestion management costs million EUR per year	0–1.7	12–147	0–40
Max spot market and congestion management costs[46] million EUR per year	**25,162**	**21,471**	**21,366**
Avg. spot market price EUR/MWh	47.90	44.70	44.70

Table 4.1.: Results of the uniform pricing regime. Source: Own illustration

4.4.2. Nodal Pricing

In a second step, it is assumed that the German market implements a nodal pricing regime meaning that national as well as international transmission lines are taken into account in the optimization of the power plant dispatch. In the nodal pricing regime, an independent system operator is assumed which optimizes the entire electricity system subject to physical network constraints. Physical characteristics of transporting electrical energy is reflected by a DC power flow approach. In contrast to the uniform pricing, only a spot market is considered and a separate congestion management regime is not required as those are already accounted in the spot market.

Comparing the spot market costs defined as product of nodal price and nodal load, the results are generally comparable to the uniform pricing. In 2008, spot market costs amount 25.6 billion EUR and decrease 15% to 21.8 billion EUR

[46] Cost of the current market regime represent spot market cost, international and the upper bound of national congestion management cost.

per year in 2020 neglecting transmission expansion (Table 4.2). If network expansion is taken into account, spot market costs are affected as congestion situation and hence the dispatch of power plants changes. Therefore, costs decrease to 21.8 billion EUR per year compared to 2008.

Comparing both network extension cases indicates that spot market costs slightly increase by 0.2% with additional transmission capacity. This is surprising, but a result of regional differentiated prices. In the case without network extension, nodes in the northern part of the country benefit from low cost wind generation. Due to network congestion, nodal prices reflect the low generation costs of wind. In case of network expansion local network congestion is relieved and prices in the northern part of Germany increase. Hence, additional transmission lines increase the transmission capacity between nodes especially in the northern part, but do not lead to a significant reduction of spot market costs.

	2008	**2020 No Network extension**	**2020 Network extension**
Spot market costs million EUR per year	25,626	21,751	21,805
Avg. nodal price EUR/MWh	49.14	45.60	45.71

Table 4.2.: Results of the nodal pricing regime. Source: Own illustration

4.4.3. Comparison and Discussion

Comparing the spot market and congestion management cost results between the considered years with the nodal pricing results indicates the impact of internal congestion management given higher shares of wind generation and the development of the thermal power plant fleet. Table 4.3 depicts the cost and surplus results of both pricing regimes for 2008 and 2020. The results comprise all countries considered in the modeling approach in contrast to the previous focus on Germany. The consumer cost are equivalent to spot market costs and reflect the product of price and demand of the corresponding spot market. Generation cost comprise the cost of the final generation dispatch valued with marginal costs. The benefit of congestion describes the congestion rent of implicit auctioning of net transfer capacity in the uniform pricing and of transmission capacity in the nodal pricing, respectively. Congestion costs are the previously described international and national congestion management costs occurring in the uniform pricing model neglecting network topology optimization. In the following short-term as well as long-term economic implications of both pricing regimes are discussed.[47]

	Uniform Pricing		**Nodal Pricing**	
	2008	**2020 Network extension**	**2008**	**2020 Network extension**
	million EUR	million EUR	million EUR	million EUR
Consumer cost	77,928	72,281	77,193	71,419
Generation benefit	45,374	41,532	44,937	41,163
Generation cost	30,677	28,603	30,676	28,573
Congestion rent	2,056	2,191	1,581	1,683
Congestion cost	180	44	–	–

Table 4.3.: Comparison of cost and benefit results for uniform and nodal pricing regime. Source: Own illustration

In the short-term perspective, pricing regimes are expected to show comparable overall cost results, but the distribution of costs among the market players may vary. Using a stylized two-node electricity system, de Vries and Hakvoort (2002) and Frontier Economics and Consentec (2004) analyze various congestion management regimes and their impact on cost and revenues of market participants. They conclude that in the short-run all congestion methods achieve an efficient dispatch, but the distribution of costs and benefits differs. Consumers and generators profit when using congestion alleviation methods (e.g. redispatch or counter-trading) as the TSO rather pays congestion costs than receives congestion revenues. If capacity allocation methods (e.g. implicit auctioning) are applied, de Vries and Hakvoort (2002) found opposite effects as prices are regionally differentiated depending on congestion situation. Thus, overall consumer costs increase while generation benefits decrease. The TSO benefits as he faces congestion revenues rather than congestion costs. Ding and Fuller (2005) analyze distributional effects using a realistic dataset for the Italian transmission system. However, the provided analysis concentrates on a comparison of individual congestion management regimes and does not take into account the interaction of different congestion methods. Contrasting to the existing academic literature, the uniform pricing regime applied in this analysis comprises the capacity allocation of international capacities as well as the congestion alleviation of national congestion in a second step. As can be seen in Table 4.3

47 Beside the economic implication additional aspects exist which may reduce economic advantages. See (e.g. Knops et al., 2001) for an evaluation of congestion management regimes with respect to institutional and legal aspects. Concerning the implementation of nodal pricing in Europe, Neuhoff et al. (2011) lists additional aspects which are relevant when changing the current market design towards nodal pricing.

the previously mentioned aspects on overall efficiency and distributional effects are comparable, but not identical. Due to the interaction of two congestion management regimes deteriorating effects can be observed. Interpreting generation cost as an efficiency measure, the uniform pricing shows higher generation cost as only national generation in Germany is allowed to be redispatched to ease national congestion. In 2008, the effect is rather marginal whereas in 2020 generation costs increase to 30 million EUR per year reflecting 0.1% of generation costs. Thus, the limitation of available capacities for redispatch causes a loss of efficiency. On the other hand, consumers do not necessarily profit from the application of congestion alleviation methods. Due to characteristics of the uniform pricing spot market model, prices and thus consumer costs are higher than in nodal pricing. Hence, consumer rent[48] is distributed to the TSO who profits from higher prices and receives congestion rents through the allocation of international transfer capacity. A participation of demand within the redispatch procedure would redistribute rent from the TSO to consumer. However, the effect on consumers as well as other market participants varies between considered countries. E.g. consumer in Germany profit from the uniform pricing regime as costs are lower compared to nodal pricing.

In the long-run perspective, investment incentives provided by pricing regimes become relevant. Following de Vries and Hakvoort (2002) congestion alleviation gives the TSO economic incentives to extend the network in order to reduce costs for alleviating congestion. Comparing the savings of congestion management costs in Germany through network extension of 107 million EUR per year with annualized investment costs of 183 million EUR per year[49], show that both are in a comparable range. However, transmission extensions provide additional benefits such as increased security of supply which are not explicitly considered in this approach. Hence, annualized investment costs are higher than direct savings in congestion management costs. On the other hand, Consumers and generators do not receive economic signals about congestion when using congestion alleviation methods. Furthermore, Ding and Fuller (2005) show that a uniform pricing regime with congestion alleviation gives even perverse incentives for generation expansion. Contrary to congestion alleviation methods, capacity allocation methods provide generators as well as consumers with economic signals on network congestion through regionally differentiated prices while the TSO receives no or negative incentives. Thus, it is impossi-

[48] Assuming an arbitrary demand function, consumer rent can be determined by subtracting consumer costs from the integral of the specified demand function.

[49] Annualized investment costs are based on investment costs of 800,000 EUR/km (L'Abbate and Migliavacca, 2011) and an annuity factor of 11.75% (Leuthold et al., 2009).

ble to give all market participants economically efficient signals in a long-run perspective. This raises the question which market participant should receive congestion signals. de Vries and Hakvoort (2002) conclude that giving economic signals to consumers and generators should be preferred as it may be easier to control the network planning process of regulated TSOs. As the results have shown, congestion management costs depend on a homogeneous development of generation and transmission infrastructure and tend to increase significantly if both developments diverge. Economic signals on congestion given to generators and consumers can at least to some extent achieve a homogeneous development, but investment in generation may also depend on other locational specific factors (e.g. fuel costs). On the other hand, if no economic signals are provided through differentiated prices, extension of transmission infrastructure is of special importance and has to anticipate the development of thermal and renewable generation, and demand. With respect to Germany, the Federal Network Agency (Bundesnetzagentur, BNetzA) stated in their network monitoring report (BNetzA, 2011a) that 49 out of 151 transmission expansion projects are delayed caused by missing administrative approvals due to diverse reasons (e.g. public resistance, uncertainty about renewable capacity extension). Especially in the context of renewable generation and the expected capacity development (17 GW wind and 46 GW solar capacities till 2020) the relevance of an appropriate development of both transmission as well as conventional generation infrastructure is important to achieve a secure, economically efficient, and environmentally friendly electricity system.

The modeling approach bears shortcomings with respect to consideration of security constraints of the physical transmission network as the N-1 security criterion is considered in an approximated way. Furthermore, transmission switching is roughly modeled as only complete transmission lines can be switched on or off. Technical flexibility resulting from switching of individual circuits esp. in substations, as well as other technical options are not considered. Regarding the input data, only data for Germany is adjusted between considered years. Therefore, the impact of adjusted generation and load in neighboring countries is not taken into account. The spot market and the congestion management model are rather simple as only one hour is optimized. A better representation of the current market regime and intertemporal optimization aspects can be achieved by a 24h spot market model including unit commitment of power plants.

4.5. Conclusions

This Chapter firstly investigates the impact of physical network constraints on spot market and congestion management costs. Therefore, an approach is described which replicates the current uniform pricing market regime in Germany consisting of a spot market and a congestion management model. Re-dispatching of power plants and optimization of network topology are considered as congestion alleviation methods. Secondly, uniform pricing results are compared to a nodal or locational pricing regime as an integrated congestion management regime. The results indicate that both investigated pricing regimes achieve comparable overall results in the short-term perspective, but both regimes differ in the distribution of costs. However, as international capacity is allocated within the spot market and national congestion is eased through congestion alleviation in the uniform pricing model, differences to theoretical analyzes occur. More importantly, pricing regimes provide different incentives to market participants to adjust their long-term investment behavior. The uniform pricing regime provides incentives to the TSO to appropriately extend network infrastructure, whereas generators and consumers receive economic signals through locational differentiated prices in the nodal pricing regime. This raises the question, which market participant should receive long-term signals, either the TSO or generators/consumers. The analysis for the German electricity system shows that a homogeneous development of transmission as well as generation infrastructure is required to reduce congestion management costs otherwise management costs increase significantly. However, German TSOs are currently in charge to appropriately extend the network to expected generation and consumption developments. Given the expected capacity expansion of renewable energy sources and the current delays of transmission expansion projects, it is concluded that long-term economic signals should be given to market participants rather than TSOs to achieve a homogeneous development. Based on the presented analysis, the need for improving the current congestion management regime arises in order to manage expected congestion and resulting congestion management costs in Germany given higher shares of renewable generation and the development of the conventional power plant fleet.

5. Integrating Intermittent Renewable Wind Generation - Insights from the Stochastic Electricity Market Model stELMOD

5.1. Introduction

Electricity markets across Europe are experiencing a major restructuring process towards a competitive market environment in which power generators face the fundamental task to optimally dispatch their power plants. In contrast to former monopolistic times generators now have to recover their generation costs and investments solely through market based prices. Furthermore, the concerns on climate change initiated the de-carbonization of the electric power industry through the promotion of renewable energy sources. Therefore, support schemes for renewable energy sources have been implemented in several European countries to reduce domestic emissions of carbon dioxide and import dependency on fossil fuels in the energy sector. In particular wind energy has become a dominating renewable energy source due to natural conditions, technological progress, and political support. However, the characteristics of wind energy limit the response to market signals and thus affect electricity markets.

Firstly, wind generation is characterized by low operational costs and is thus dispatched first in the short run.[50] Secondly, wind generation depends on meteorological conditions and hence cannot be dispatched in a controlled manner like conventional power plants. This results in variability of wind generation and uncertainty about realized wind generation, which can be partly reduced through appropriate wind forecasts. However, uncertainty has always been present in electrical power systems, in the form of possible unit outages or errors in load prediction. In the last years, electricity production from wind has increased

[50] In some European countries (e.g. Germany) the feed-in of renewable energies is prioritized independently of their marginal generation costs.

significantly and thus uncertainty about wind output and its variability. Thus, wind energy and its characteristics have to be taken into account when planning and operating power systems.

Unit commitment and economic dispatch are used in power systems to achieve a secure and economic generation scheduling as well as grid management. As most power systems are dominated by thermal generation capacities, the aim of the short-term planning is to determine the least-cost generation mix of different power plants required to meet electrical load taking operational limitations of thermal generation into account (e.g. minimum on-time, minimum off-time, ramping constraints). In Baldick (1995) a generalized formulation of the unit commitment is presented. A review of various contributions to the unit commitment problem is given in Padhy (2004). However, the variability and uncertainty associated with renewable wind generation imposes new challenges to the short-term planning. To capture the characteristics of renewable wind generation, the unit commitment and economic dispatch problem is extended by introducing stochastic optimization. However, stochastic optimization has been introduced in unit commitment problems before to reflect uncertainty about other relevant factors e.g. demand (Takriti et al., 1996, 2000). In general, stochastic models are characterized by uncertainty of at least one input parameter, whereas in deterministic optimization models all input parameters are assumed to be certain. Fundamentals of stochastic optimization can be found in e.g. Birge and Louveaux (1997) and Kall and Wallace (1994). With respect to the energy sector, Wallace and Fleten (2003) provide a survey of different stochastic programming models and their application to the energy sector. Herein, stochastic versions of the unit commitment, generation dispatch, as well as optimal power flow are presented and solution methods are discussed. Additionally, an overview of different applications of stochastic programming with focus on power systems is given in Weber (2005), Kallrath et al. (2009), Möst and Keles (2010), and Conejo et al. (2010).

Recent contributions focus on the large-scale integration of wind generation in power systems as installed wind generation capacities increased substantially, e.g. an amount of 75 GW wind capacity are installed between 2000 and 2010 in Europe resulting in a share of 10% on European power capacity mix (EWEA, 2011). This leads to various challenges in short-term operation as well as long-term planning of power systems. In the long-term, the appropriate development of transmission as well as generation infrastructure has to ensure a secure and efficient integration of renewable energy sources. In the short-term operation, the variability and uncertainty inherent in wind generation is a dominating aspect affecting the unit commitment of thermal generation units (e.g. Bouffard and Galiana, 2008; Wang et al., 2008; Delarue and D'haeseleer, 2008). However, most studies do not consider the subsequent clearing of daily dayahead and hourly intraday electricity markets, and focus on optimal unit commitment strategies within the dayahead market considering stochastic wind generation.

Weber et al. (2009) describe a stochastic programming model to assess the impact of large-scale wind power generation on electricity systems and the different electricity markets using a rolling planning procedure. The described model was developed during the Wind Power Integration in Liberalised Electricity Markets (WILMAR) research project[51]. The stochastic behavior of wind generation as well as forecast errors on wind generation are explicitly taken into account and the model thus allows to assess the impact of increased wind generation on reserve needs and usage, power plant operation and system cost. Tuohy et al. (2009) present an updated version including a mixed-integer unit commitment model. However, physical characteristics of electricity transmission are neglected in Weber et al. (2009) and Tuohy et al. (2009) as only transactional transfers between regions are taken into account. In other words, congestion in the physical transmission network which may influence utilization of thermal as well as renewable capacities is not considered. Leuthold et al. (2012) describe a deterministic techno-economic electricity market model with a detailed representation of the European high voltage network. Physical characteristics of power transmission are represented by a DC-loadflow approach. In various applications, the impact of wind power generation on the power system in particular on the physical transmission network are analyzed (e.g. Leuthold et al., 2009; Weigt et al., 2010). The approach presented in this Chapter combines the characteristics of the different electricity markets with the technical specifics of thermal generation as well as the transmission of electricity. In addition, the uncertainty of wind generation is explicitly taken into account by employing stochastic programming techniques.

Thus, in this Chapter a stochastic ELectriticty Market MODel (stELMOD) is described. The model is used to investigate the impact of stochastic wind generation on the unit commitment and dispatch of power plants taking limitations through physical network congestion into account. To do so, a mathematical model is presented which rebuilds the successive clearing process of the dayahead and intraday market given the arrival of improved information on wind generation forecasts. After clearing of the daily dayahead and the subsequent hourly intraday market the final power plant dispatch is determined

51 `http://www.wilmar.risoe.dk`

by the system operator given the unit commitment decisions of the generators. Uncertainty about wind generation is represented by a two-stage multi-period scenario tree and updated for each optimization step within the intraday model. A DC-loadflow approach is used to determine electricity transmission within the interconnected system based on technical characteristics of physical transmission network. An implicit auctioning of transmission constraints corresponding to a nodal pricing regime is assumed due to their characteristics in providing an optimal usage of transmission generation facilities as indicated in Section 2. The model is applied to evaluate the impacts of stochastic wind power availability in the German electricity market.

This Chapter is based on Abrell and Kunz (2012) and the remainder is structured as follows. Section 5.2 describes the current market setup and the daily market procedure in Germany. Based on the German market procedure two distinct models, a dayahead and intraday market model, are developed and coupled by a rolling planning procedure to reflect the subsequent clearing of both models. The mathematical model and the coupling procedure are described in Section 5.3. Section 5.4 presents the data used including the derivation of wind generation forecasts. In Section 5.5 indicative results are shown and analyzed given different degrees of uncertainty about wind generation. Section 5.6 provides the conclusions.

5.2. The German Electricity Market

5.2.1. The Structure of the German Electricity Market

The German electricity market is characterized by a decentralized market structure as market participants are responsible for planning their unit commitment and dispatch without considering physical restrictions of the power system. Given the commitment decisions of the market participants the system operator is in charge of managing physical transmission restrictions and of maintaining the balance between generation and demand.

The German electricity market comprises four sub-markets namely the futures or forward market, dayahead or spot market, the intraday market, and the reserve market. Whereas futures market, dayahead and intraday market are organized by the EPEX, the reserve market is organized by the system operators. Beside the organized (standardized) markets, market participants can trade on a bilateral basis except for reserve capacities. An overview of the different sub-markets is given in Table 5.1.

	Futures market		Dayahead market		Intraday market		Reserve market
Trading	Standardized	Bilateral	Auction	Bilateral	Standardized	Bilateral	Tendering
Type	financial	physical	physical	physical	physical	physical	physical
Products	Futures Options	Forwards	Hour contracts Baseload contracts Peakload contracts		Hour contracts Baseload contracts Peakload contracts		PR: no time slices SR: 3 time slices[*] TR: 6 time slices[**]
Contractual partner	EEX	others	EPEX	others	EPEX	others	TSOs[***]
Participation	Voluntary	Voluntary	Voluntary	Voluntary	Voluntary	Voluntary	Voluntary, but pre-qualification required
Clearing interval	Continuous	Continuous	Daily	Continuous	Continuous	Continuous	Weekly (PR, SR) Daily (TR)
Gate closure			12.00 a.m. D-1				10.00 a.m. D-1 (TR)
Pricing	Forward pricing	Bargaining	Uniform pricing	Bargaining	Spot pricing	Bargaining	Capacity price (PR) Capacity/Energy price (SR, TR)

[*] Monday– Friday: peak/offpeak period; Weekend and general holiday: base period.
[**] 0.00– 3.59; 4.00– 7.59; 8.00– 11.59; 12.00– 15.59; 16.00– 19.59; 20.00– 23.59.
[***] `www.regelleistung.net`

Table 5.1.: Characteristics of electricity markets in Germany. Source: Own illustration

5.2.2. The Daily Market Procedure

The daily market procedure is displayed in Figure 5.1 and described in this section.

The *dayahead market* is organized as a power exchange and operated by the EPEX Spot SE in Paris. The standardized dayahead market comprises a central daily auction which is cleared at 12.00 a.m. for all hours of the following day. Market participants are not obliged to trade at the power exchange and can also trade bilaterally 'over the counter'. Based on the contractual obligations of the dayahead market and bilateral trading power plant generators have to inform the responsible transmission system operator of their proposed dispatch timetable at 2.30 p.m. dayahead (§ 5 (1) StromNZV).

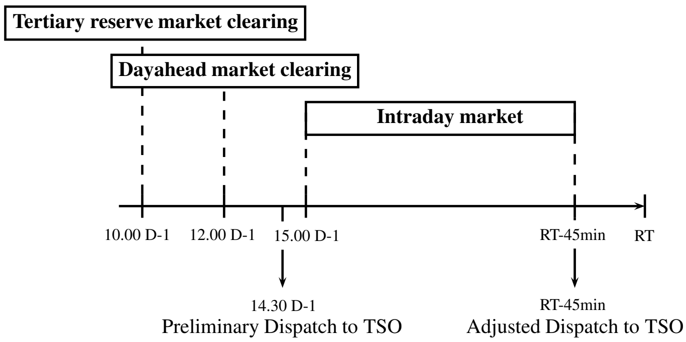


Figure 5.1.: Daily market procedure of the German electricity market. Source: Own illustration

The *intraday market* starts at 3.00 p.m.. Market participants can trade electricity either standardized through the market platform provided by the EPEX or on a bilateral basis. Standardized trading at the intraday market is possible till 45 minutes before physical delivery. Furthermore, generators are obliged to inform the transmission system operator of their adjusted power plant dispatch 45 minutes prior to real time for each 15 minute interval (§ 5 (2) StromNZV). Contrary to the initial dispatch timetable, transmission system operators can reject dispatch adjustments caused by intraday trades (§ 5 (2) StromNZV). Given the initial and final dispatch timetables the transmission system operators are in charge of managing physical network limitations. To do so the transmission system operators have two general options to ease network congestion, namely technical or market-based methods (§ 13 (1) EnWG). As described in Section 2.4.1, active loadflow management can be done technically through adjustments of network topology (e.g. switching actions) and network characteristics (e.g. changes of transformer taps). On the other hand, market-based congestion management methods comprise the adjustment of nodal generation or load (redispatch or counter-trading).

5.2.3. Real Time Balancing of Load and Generation

After clearing of the markets, physical delivery based on contractual obligations takes place at real time. Due to the technical characteristics of the electricity system electricity has to be generated and consumed in real time. Hence, the balance between demand and generation is immanent for the operation of the electricity systems, but cannot be completely ensured through trading activities. An imbalance between generation and demand is caused by two factors namely forecast errors and unexpected events (Jarass et al., 2009, p. 256). Examples are unexpected outages of power plants or deviations of forecasted demand or generation. Small disturbances are balanced by the self-regulating effect of the system.

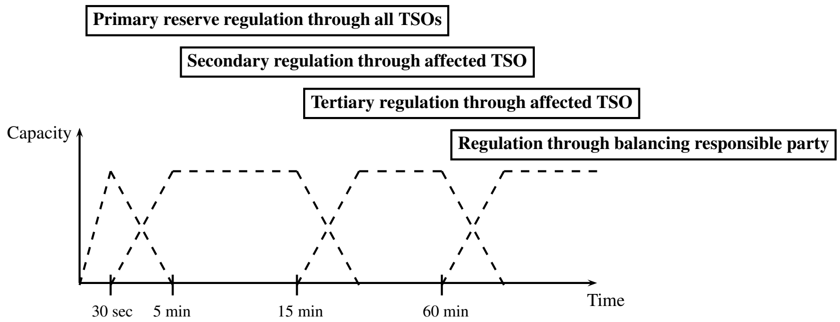


Figure 5.2.: Scheduling of reserve energy. Source: Own illustration based on (UCTE, 2009, Policy 1)

In order to settle large and long-lasting imbalances, reserve capacities have to be contracted through monthly and daily tendering by the transmission system operator. Following UCTE (2009), reserve capacities are classified according to their technical characteristics and their application in three groups (primary, secondary, and tertiary reserve, see Figure 5.2). Primary reserve (PR) is called first and comprises operating and fast adjustable power units, mainly thermal power plants producing in part load. If frequency of the system drops significantly, primary reserve allows a balance to be reestablished at a system frequency other than the frequency reference value of 50 Hz (UCTE, 2009, Policy 1). After a time period of normally five minutes secondary reserve (SR) replaces primary capacities and restores the system to the reference frequency value. Technically, secondary reserve capacity has to be started within 5 minutes and is called for 15 minutes. Tertiary reserve (TR) capacity is called 15 minutes after the frequency drop and has to set free secondary reserve. Finally, tertiary reserve capacity is replaced by adjusted generation of the responsible balancing party after 60 minutes. Further information on technical specifications can be found in (UCTE, 2009, Policy 1 and Appendix 1). In Germany, the transmission system operator is responsible for the secure operation of the electricity system (§ 12 EnWG) and the commitment of contracted reserve capacity. The application of reserve energy lasts at least one hour after the event. For deviations longer than one hour the balancing responsible party is in charge of compansating the deviation (see Figure 5.2).

5.2.4. Market Integration of Wind Generation

Regarding market integration of wind generation in Germany, wind generators are neither responsible for balancing deviations nor responsible for bringing generated energy to market. Until 2009, wind generation had to be taken by distribution system operator (DSO) to whose grid the wind generator was physically connected and by the transmission system operator (TSO) the DSO was connected to. Based on a monthly basis, the TSO was obliged to transform the forecasted wind generation into a regular baseload band for the corresponding month (EEG-Veredelung). Deviations between wind forecast and desired baseload product had to be managed by the TSO. The final baseload product was delivered to suppliers and finally to consumers. Financially, the tariffs for renewable generation were paid by the DSO the wind generator was connected to. Additional costs of transformation to baseload product and feed-in tariffs were finally passed through to consumers.

However, since 2010 the physical process has been changed (§ 64 (3) EEG). Instead of transforming the wind generation to a baseload product, TSOs are now obliged to bring renewable generation to the market, either dayahead or intraday market (§ 2 (2) AusglMechV). Received revenues from renewable generation are offset with costs for paid feed-in tariffs. Deficits between both positions are finally paid by consumers.

5.3. Model

In order to represent the German electricity market two different models are used: In the dayahead model, the system operator decides about the quantities of electricity and reserve delivered on the next day based on the expected renewable generation supply. In the intraday model, the operator takes these quantities as given. Based on new informations about the renewable supply he has the possibility to correct the pre-contracted electricity quantities by trading in the intraday market. The models are combined in a rolling planning procedure which passes the pre-contracted quantities as well as the plant status between the models. The two single model are described in Section 5.3.1 and 5.3.2. Afterwards the rolling planning approach is explained in detail in Section 5.3.3.

5.3.1. Dayahead Market Model

In the dayahead model, the system operator decides about the generation and contribution to reserve requirements of the different plants in order to minimize the total cost. Power plants, denoted by $p \in P$, are characterized by their marginal generation cost c_p and costs that occur if the plant is started or shut down, c_p^s and c_p^d, respectively. The installed capacity is given by g_p^{max} and the required minimum generation if the plant is online by g_p^{min}. Furthermore, power plants have to fulfill technical requirements in the form of minimum offline and online time requirements: After a plant has been started it has to be online for t_p^{on}. Similarly, t_p^{off} denoted the periods the plant has to be offline if it has been shut down. Generation in period $t \in T$ is denoted by G_{pt}, the contribution to reserve market $r \in R$ by $R^+_{p,r,t}$ and $R^-_{p,r,t}$ depending on whether it is upward or downward reserve, and the plant status by $U_{p,t}$ which becomes one if the is plant online and zero else.

Beside power plants, the model also includes pump storage facilities $j \in J$. The release or generation of these facilities is denoted by $V_{j,t}$ and pumping or withdrawal from the market by W_{jt}. Both, generation and pumping of the storage facilities are upper bounded by v_j^{max} and w_j^{max} [MW], respectively, and the pumping process causes losses expressed by $\eta_j \in]0,1]$. Furthermore, the storage capacity puts a natural bound l_j^{max} on the level of the storage facility $L_{j,t}$. The reserve contribution of storage facilities is denoted by $R^{H+}_{j,t}$ and $R^{H-}_{j,t}$, respectively.

Renewable sources are denoted by $w \in W$. In the dayahead model, there exists a unique forecast for the supply from these sources $\overline{s_{w,t}}$. The generation of renewable sources $S_{w,t}$ [MWh] is equal to this forecast reduced by the amount of renewable supply curtailed $C_{w,t}$. The curtailment of renewable sources causes a penalty payment c_w^C.

The electricity grid is represented by a set of nodes $n \in N$ and lines $l \in L \subset N \times N$ connecting these nodes. Lines are characterized by their thermal capacity cap_l. The power transmission distribution factors $ptdf_{l,n}$ determine the flow on line l caused by net injection $Y_{n,t}$ at node n. The locational information of plants, storage facilities, and renewable sources is expressed using the two-dimensional set $\Psi \subset (P \cup J \cup W) \times N$, e.g. if plant p is located at node n $(p, n) \in \Psi$.

The load at node n in period t is given by $q_{n,t}$. The possibility of different reserve markets is included into the model. The reserve markets are denoted by $r \in R$ and are characterized by their positive and negative reserve demand $qr^+_{r,t}$ and $qr^-_{r,t}$. Depending on the technical pre-qualification requirement of the reserve market, plants and storage facilities are allowed to contribute to these markets. These pre-qualification requirements are expressed via the two-dimensional set $A \subset (P \cup J) \times R$.

$$\min \sum_{t,p} [c_p G_{p,t} + CS_{p,t} + CD_{p,t}] + \sum_{t,w} c^C_w C_{w,t} \tag{5.1}$$

$$CS_{p,t} \geq c^s_p \left(U_{p,t} - U_{p,(t-1)}\right) \quad \forall p,t \tag{5.2}$$

$$CD_{p,t} \geq c^d_p \left(U_{p,(t-1)} - U_{p,t}\right) \quad \forall p,t \tag{5.3}$$

$$\sum_n q_{n,t} = \sum_p G_{p,t} + \sum_j (V_{j,t} - W_{j,t}) + \sum_w S_{w,t} \quad \forall t \tag{5.4}$$

$$q_{n,t} + Y_{n,t} = \sum_{p \in \Psi(n)} G_{p,t} + \sum_{j \in \Psi(n)} (V_{j,t} - W_{j,t}) + \sum_{w \in \Psi(n)} S_{w,t} \quad \forall n,t \tag{5.5}$$

$$qr^+_{r,t} = \sum_{p \in A(r)} R^+_{p,r,t} + \sum_{j \in A(r)} R^{H+}_{j,r,t} \quad \forall r,t \tag{5.6}$$

$$qr^-_{r,t} = \sum_{p \in A(r)} R^-_{p,r,t} + \sum_{j \in A(r)} R^{H-}_{j,r,t} \quad \forall r,t \tag{5.7}$$

$$U_{p,t} g^{max}_p \geq G_{p,t} + \sum_r R^+_{p,r,t} \quad \forall p,t \tag{5.8}$$

$$G_{p,t} - \sum_r R^-_{p,r,t} \geq U_{p,t} g^{min}_p \quad \forall p,t \tag{5.9}$$

$$U_{p,\tilde{t}} \geq U_{p,t} - U_{p,(t-1)} \quad \forall p,t,\tilde{t} \in O^{on}_{p,t} \tag{5.10}$$

$$1 - U_{p,\tilde{t}} \geq U_{p,(t-1)} - U_{p,t} \quad \forall p,t,\tilde{t} \in O^{off}_{pt} \tag{5.11}$$

$$L_{j,t} = L_{j,(t-1)} + \eta_j W_{j,t} - V_{j,t} \quad \forall j,t \tag{5.12}$$

$$w^{max}_j \geq W_{j,t} + \sum_r R^{H-}_{j,r,t} \quad \forall j,t \tag{5.13}$$

$$v_j^{max} \geq V_{j,t} + \sum_r R_{j,r,t}^{H+} \qquad \forall j,t \quad (5.14)$$

$$l_j^{max} \geq L_{j,t} + \sum_r R_{j,r,t}^{H-} \qquad \forall j,t \quad (5.15)$$

$$S_{w,t} = \overline{s_{w,t}} - C_{w,t} \qquad \forall w,t \quad (5.16)$$

$$cap_l \geq \sum_n ptdf_{l,n} Y_{n,t} \qquad \forall l,t \quad (5.17)$$

$$\sum_n ptdf_{l,n} Y_{n,t} \geq -cap_l \qquad \forall l,t \quad (5.18)$$

$$G_{p,t}, V_{j,t}, W_{j,t}, L_{j,t}, C_{w,t}, CS_{p,t}, CD_{p,t}, R_{p,r,t}^{+}, R_{p,r,t}^{-}, R_{j,r,t}^{H+}, R_{j,r,t}^{H-} \geq 0$$

$$Y_{n,t} \text{ free}$$

$$U_{p,t} \in \{0,1\}$$

The objective function (5.1) of the dayahead model minimizes the sum of the marginal, startup $CS_{p,t}$, and shutdown $CD_{p,t}$ costs as well as the renewable curtailment penalty payment. The startup and shutdown cost are defined in Equations (5.2) and (5.3) in terms of a change of the plant status variable. The market clearing Equation (5.4) equates the total demand and supply in the market. In contrast, the node based market clearing Equation (5.5) equates demand and supply at each node. This equation is necessary to define the net-injection variable $Y_{n,t}$. Equations (5.6) and (5.7) ensure the provision of the reserve requirements. Equations (5.8) and (5.9) implement the minimum and maximum generation constraints. Equations (5.10) and (5.11) are the minimum online and offline time requirements. For the ease of notation the sets $O_{p,t}^{on} := \{t+1, \cdots, min[t+t_p^{on}, T]\}$ and $O_{p,t}^{off} := \{t+1, \cdots, min[t+t_p^{off}, T]\}$ are introduced which define the periods in which the plant has to be online and offline. Equation (5.12) is the law of motion for the reservoir level of storage facilities. The restrictions on the pumping and release processes as well as the reservoir levels are given in Equations (5.13) to (5.15). The supply of renewable energy sources $S_{w,t}$ is defined in Equation (5.16) in terms of the exogenously given supply and the curtailed amount. Equations (5.17) and (5.18) restrict the flows on the lines of the electricity network to stay within the thermal limit.

5.3.2. Intraday Market Model

The intraday model is similar to the dayahead model in terms of technical restrictions for thermal plants and storage facilities. However, in this model the pre-contracted generation quantities and reserve contributions are given from the dayahead model. In order to express the pre-determined character of the given variables they are denoted by upper bars, i.e.: $\overline{G_{p,t}}$, $\overline{V_{j,t}}$, $\overline{W_{j,t}}$, and $\overline{C_{w,t}}$ are the fixed generation, pumping, release and curtailment variables determined in the dayahead market. The reserve quantities are denoted in the same manner, i.e. $\overline{R^{+}_{p,r,t}}$, $\overline{R^{-}_{p,r,t}}$, $\overline{R^{H+}_{j,r,t}}$, and $\overline{R^{H-}_{j,r,t}}$ are the reserve contribution contractes in the dayahead market and fixed in subsequent intraday markets. In the intraday market, the system operator has the possibility to correct these quantities by additional trading actions. Due to the corrective character of these variables, they are free in sign. The notation is maintained, but the intraday variable are denoted by a tilde sign. Given these notations, the total generation in the intraday market is defined as the sum of the pre-determined dayahead quantity and the corrective intraday action.

As the second major difference between the dayahead and intraday market model, the stochasticity of the renewable sources supply is explicitly incorporated by introducing a scenario tree. This tree represents the underlying stochastic process by a set of nodes $k \in K$ which belong to a certain period. The subset of nodes that belong to period t is denoted by $\Omega_t \subset K$. The probability of reaching node k is given by π_k. Except the root node, each node has a unique predecessor node which is denoted by $\gamma(k)$. Furthermore, the set of all nodes in the route from the root node to node k is denoted by $\Gamma(k) \subset K$. With this notation at hand, the intraday model becomes:[52]

$$\begin{aligned} \min \sum_{k,t,p} & \pi_k \left[c_p G_{p,k,t} + CS_{p,k,t} + CD_{p,k,t}\right] \\ & + \sum_{k,t,w} \pi_k c_w^C C_{w,k,t} \end{aligned} \tag{5.19}$$

$$G_{p,k,t} = \overline{G_{p,t}} + \tilde{G}_{p,k,t} \qquad \forall p,t,k \in \Omega_t \tag{5.20}$$

$$V_{j,k,t} = \overline{V_{j,t}} + \tilde{V}_{j,k,t} \qquad \forall j,t,k \in \Omega_t \tag{5.21}$$

$$W_{p,k,t} = \overline{W_{p,t}} + \tilde{W}_{j,k,t} \qquad \forall j,t,k \in \Omega_t \tag{5.22}$$

$$C_{w,k,t} = \overline{C_{w,t}} + \tilde{C}_{w,k,t} \qquad \forall w,t,k \in \Omega_t \tag{5.23}$$

$$CS_{p,k,t} \geq c_p^s \left(U_{p,k,t} - U_{p,\gamma(k),(t-1)}\right) \qquad \forall p,t,k \in \Omega_t \tag{5.24}$$

$$CD_{p,k,t} \geq c_p^d \left(U_{p,\gamma(k),(t-1)} - U_{p,k,t}\right) \qquad \forall p,t,k \in \Omega_t \tag{5.25}$$

$$\sum_n q_{n,k,t} = \sum_p G_{p,k,t} + \sum_w S_{w,k,t}$$

[52] In general the notation given above is continued. However, due to stochastic programming approach, the variables are additionally indexed by the set of nodes in the scenario tree.

$$+ \sum_j (V_{j,k,t} - W_{j,k,t}) \qquad \forall t, k \in \Omega_t \quad (5.26)$$

$$q_{n,k,t} + Y_{n,k,t} = \sum_{p \in \Psi(n)} G_{p,k,t} + \sum_{w \in \Psi(n)} S_{w,k,t}$$

$$+ \sum_{j \in \Psi(n)} (V_{j,k,t} - W_{j,k,t}) \qquad \forall n, t, k \in \Omega_t \quad (5.27)$$

$$U_{p,k,t} g_p^{max} \geq G_{p,k,t} + \sum_r \overline{R^+_{p,r,t}} \qquad \forall p, t, k \in \Omega_t \quad (5.28)$$

$$G_{p,k,t} - \sum_r \overline{R^-_{p,r,t}} \geq U_{p,k,t} g_p^{min} \qquad \forall p, t, k \in \Omega_t \quad (5.29)$$

$$U_{p,\tilde{k},\tilde{t}} \geq U_{p,k,t} - U_{p,\gamma(k),(t-1)} \qquad \forall p, t, \tilde{t} \in O^{on}_{p,t}$$

$$\forall k \in \Gamma_{\tilde{k}}, \tilde{k} \in \Omega_{\tilde{\tau}} \quad (5.30)$$

$$1 - U_{p,\tilde{k},\tilde{t}} \geq U_{p,\gamma(k),(t-1)} - U_{p,k,t} \qquad \forall p, t, \tilde{t} \in O^{off}_{p,t}$$

$$\forall k \in \Gamma_{\tilde{k}}, \tilde{k} \in \Omega_{\tilde{\tau}} \quad (5.31)$$

$$L_{j,k,t} = L_{j,\gamma(k),(t-1)} + \eta_j W_{j,k,t} - V_{j,k,t} \qquad \forall j, t, k \in \Omega_t \quad (5.32)$$

$$w_j^{max} \geq W_{j,k,t} + \sum_r \overline{R^{H-}_{j,r,t}} \qquad \forall j, t, k \in \Omega_t \quad (5.33)$$

$$v_j^{max} \geq V_{j,k,t} + \sum_r \overline{R^{H+}_{j,r,t}} \qquad \forall j, t, k \in \Omega_t \quad (5.34)$$

$$l_j^{max} \geq L_{j,k,t} + \sum_r \overline{R^{H-}_{j,r,t}} \qquad \forall j, t, k \in \Omega_t \quad (5.35)$$

$$S_{w,k,t} = \overline{s_{w,k,t}} - C_{w,k,t} \qquad \forall w, t, k \in \Omega_t \quad (5.36)$$

$$cap_l \geq \sum_n ptdf_{l,n} Y_{n,k,t} \qquad \forall l, t, k \in \Omega_t \quad (5.37)$$

$$\sum_n ptdf_{l,n} Y_{n,k,t} \geq -cap_l \qquad \forall l, t, k \in \Omega_t \quad (5.38)$$

$$\begin{aligned} G_{p,k,t}, V_{j,k,t}, W_{j,k,t}, L_{j,k,t}, C_{w,k,t}, CS_{p,k,t}, CD_{p,k,t} &\geq 0 \\ \tilde{G}_{p,k,t}, \tilde{V}_{j,k,t}, \tilde{W}_{j,k,t}, \tilde{C}_{w,k,t}, Y_{n,k,t} &\text{ free} \\ U_{p,k,t} &\in \{0,1\} \end{aligned} \quad (5.39)$$

Equations (5.20) to (5.23) define the total quantities as the sum of the predetermined dayahead quantities and the intraday corrective trading actions. Hereby $\tilde{G}_{p,k,t}$ is the intraday electricity trading amount which is free in sign and $G_{p,k,t}$ is the total generation of plant p at the node k in the scenario tree in period t. The notation generally follows this reasoning. The remaining Equations (5.24) to (5.38) are similar to the corresponding ones in the dayahead model and explained above. Due to the use of the different sets for the expression of the scenario tree further non-anticipativity constraints are not required. In equations directly related to the previous period the direct predecessor $\gamma(k)$ are used. Furthermore, in the online and offline time requirements, Equation (5.30) and (5.31), the set of all predecessors in the path to the root node are used. The periods before the actual period t are denoted by $\tilde{t}$ and the predecessor notes by $\tilde{k}$.

5.3.3. Rolling Planning Procedure

As described in Section 5.2 and depicted in Figure 5.1 the German electricity market is characterized by a sequential clearing of different markets. In the reserve and dayahead markets the commitments regarding reserve contribution and generation quantities are determined for all hour of the next day. After the clearing of the dayahead market, intraday trading is possible for each individual hour of the next day starting at 3.00 p.m. the day before and ending 45 minutes before realtime. During this time frame market participants can trade continuously for a specific hour as for instance new information on uncertain parameters (e.g. demand, renewable generation, unplanned outages of generation units) become available.

The described models are designed to reflect these characteristics, in particular the sequential clearing of markets and the improvement of forecasts on uncertain parameters over time. First, the dayahead market model optimizes the generation and reserve commitments for all hours of the next day given the current information on uncertain parameters. The time horizon of the model covers 36 hours comprising 24 hours of the next day and additional 12 hours to account for terminal conditions. Second, the intraday model reoptimizes the dayahead commitments as the information on uncertain parameters improve. The optimized time frame of the intraday model covers 36 hours. However, the intraday model specification abstracts from the market procedure in two ways: First, the intraday model for a specific hour t is optimized subject to the final realization of uncertain parameters. Thus, the time gap of 45 minutes between the final clearing of the intraday and realtime is neglected. Second, the intraday model abstracts from the continuous trading as the final adjustments of the dayahead commitments for hour t are determined in the intraday optimization of the specific hour t given the improved information on uncertain parameters compared to the dayahead clearing. Furthermore, the future development of uncertain parameters beyond hour t is taken into account by employing a stochastic programming approach. Thus, the continuous trading is substituted by a centralized intraday clearing.

The sequential clearing of the dayahead and intraday market is achieved by applying a rolling planning procedure. The procedure is initialized by running the dayahead model determining the contracted quantities and reserve contribution for the first 24 hours. Given these values, the intraday model is optimized for hour one resulting in the realized generation, storage facility actions, and plant status for hour one. Moving one hour forward, the intraday model is solved again. In this second run the plant status as well as the level of the storage facilities are used as initial values. Furthermore, status variables are fixed if a startup or shutdown occurred within the previous periods depending on the minimum offline and online times. Having solved the model for hour two, the necessary information to solve the intraday model are available for hour three. This procedure rolls until hour 12. At hour 12, the intraday model is solved first. From this model run the expected value for the plant status, generation, and storage values for the next day hour one are obtained. Given these expected values as initial conditions, the dayahead model is solved subsequently to determine the pre-contracted generation quantities and the reserve contribution for day two hour one to 24. This procedure is repeated until the end of the considered time horizon is reached.

5.4. Data

In order to apply the described model a realistic electricity system is chosen comprising Germany as well as its neighboring countries. The underlying data concerning conventional and renewable generation, electrical load, and the transmission network are described in this section. In addition, the applied wind forecast approach is presented. Wind generation is considered as solely source of uncertainty, thus uncertainty resulting from other renewable generation (e.g. solar), electrical load, and unplanned outages of generation units are neglected. The time horizon used for the application covers the time frame from 9th November till 15th November 2010. The week has been chosen due to the a high amount of wind generation and unexpected deviations between expected and final wind generation.

5.4.1. Conventional Generation

Generation and storage facilities are divided into 12 different technology types reflecting different generation technologies as well as fuel types: run-of-river hydro, nuclear, lignite, coal, gas and oil steam, combined cycle gas (CCGT) and oil turbines plants (CCOT), open cycle gas (OCGT) and oil turbines plants

(OCOT), hydro reservoirs and pump storage plants. Installed generation capacities are based on VGE (2008) and include power plants with a capacity above 100 MW. The technical characteristics of each technology are given in Table 5.2. These include the heat efficiency, the minimum generation as percentage of the installed capacity, the emission factors, and the obliged online and offline time restrictions.

	Average efficiency in %	**Minimum generation** in %	**Emission factor** in t per MWh_{el}	**Ontime** in h	**Offtime** in h
Nuclear	30	45	0	12	8
Lignite	37	40	0.98	8	8
Hard Coal	42	38	0.85	8	8
CCGT	54	33	0.37	4	2
OCGT	34	20	0.59	1	0
Gas Steam	39	38	0.52	4	2
CCOT	50	33	0.56	4	2
OCOT	34	20	0.82	1	0
Oil Steam	39	38	0.71	4	2

Table 5.2.: Technical characteristics of thermal generation types. Source: Bagemihl (2003), IPCC (2006), Hundt et al. (2009), and own assumptions.

The marginal cost are derived from the fuel cost which are given in Table 5.3 and the carbon cost based on a CO_2 price of 14.89 EUR/t, both accounted with the technology-specific heat efficiency. Market prices of fuels and CO_2 certificates for the considered time horizon are used for the calculation of the technology-specific marginal costs. Beside the marginal costs, fixed startup cost incurring for each startup of generation unit are considered for each technology type based on DEWI et al. (2005). Shutdown cost are assumed to be zero.

	Fuel cost in EUR/MWh	**Marginal cost** in EUR/MWh	**Startup cost** in EUR/startup and MW
Nuclear	3	9.71	164
Lignite	4.39	26.50	77
Hard Coal	11	39.02	168
CCGT	19.63	41.77	137
OCGT	19.63	66.58	74
Gas Steam	19.63	58.04	317
CCOT	37.72	83.74	274
OCOT	37.72	123.14	132
Oil Steam	37.72	107.35	604

Table 5.3.: Economic characteristics of thermal generation types. Source: DEWI et al. (2005) and own assumptions

5.4.2. Wind Generation

The model uses three different inputs for wind generation: First, the realization of wind output per hour; second, the dayahead forecast of wind output which enters the dayahead model; finally, the distribution of wind output in the scenario tree is used in the intraday model. The realized wind power generation as well as dayahead wind power forecast is taken from the EEX Transparency Platform[53] and depicted in Figure 5.3. The figure reveals that the forecast has a high quality, i.e. low forecast error, for hours zero up to 120. However, afterwards predicted and realized wind generation show a high deviation.

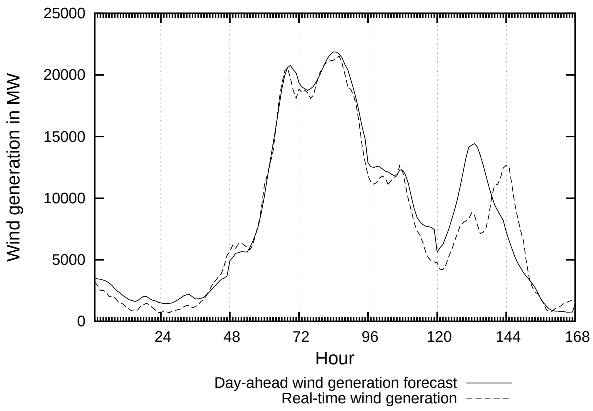


Figure 5.3.: Expected and realized wind generation in Germany from 9th November till 15th November 2010. Source: EEX Transparency Platform

Uncertainty about wind power generation, considered in the intraday model, is represented by different wind speed scenarios reflecting the increasing wind speed forecast error for future time periods. The simulation approach for wind forecast errors is based on Barth et al. (2006) using an auto regressive moving average (ARMA) approach. The ARMA-series is characterized as follows:

$$W^{err}_{ft} \quad = \alpha W^{err}_{ft-1} + Z_{ft} + \beta Z_{ft-1} \tag{5.40}$$

where W^{err}_{ft} is the wind speed forecast error for forecast time period ft and Z_{ft} is a random Gaussian variable with a standard deviation of σ. The parameters of the ARMA-series α and β are assumed to be 0.95 and 0.02, respectively (Barth et al., 2006). The standard deviation σ is set to 0.5. For $ft = 0$ the forecast error $W^{err}_{ft=0}$ and the random variable $Z_{ft=0}$ are zero as the final realization is already known. If one looks into the future ($ft > 0$) forecast error depends firstly on the forecast error in the previous period and secondly on a stochastic

[53] `http://www.transparency.eex.com/en`

component. An exemplary set of simulated forecast errors is displayed in Figure 5.4. As can be seen, the forecast error increases with forecasting length.

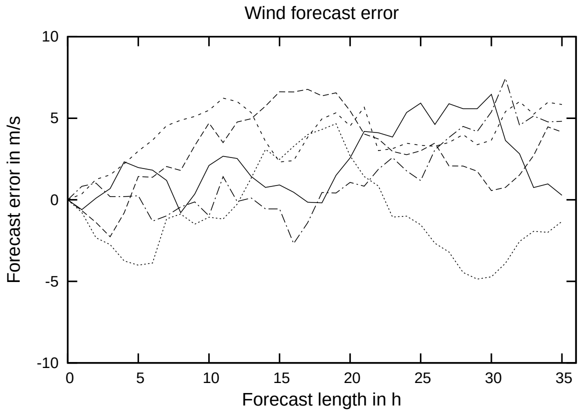


Figure 5.4.: Exemplary set of simulated wind speed forecast errors. Source: Own illustration

Once wind speed errors are simulated, they are added to the realized wind speeds and converted to wind power utilization using mean wind power curves of different wind turbines. In order to incorporate the large amount of simulated wind power series in the stochastic modeling approach a one-stage scenario tree is implemented comprising a reduced number of three representative scenarios or branches. In the literature different algorithms are described to achieve a representative scenario reduction (e.g. Dupačová et al., 2003; Heitsch and Römisch, 2003). However, the applied method to reduce the simulated wind power series to scenarios is rather simple as scenarios represent the 35%, 50%, and 65% quantiles of the simulated wind power series. Further research therefore aims to improve the approach to reduce wind scenarios.

In order to derive node-specific wind power supply regional data on wind power installations is taken from 50Hertz Transmission et al. (2011). Node-specific wind power capacities are multiplied with a time-dependent utilization factor to retrieve the wind generation.

5.4.3. Load

Electrical load is assumed as a parameter and elasticity of consumption as well as uncertainty is not considered. Total electrical load and the hourly load profile of the considered countries is based on values derived from ENTSO-E (2011a) for 9th November till 15th November 2010. In order to distribute national load to specific nodes in the transmission network, regional characteristics on gross domestic product (GDP) and population are taken into account. The regional

GDP serves as a distribution key for electrical load of industry and services, and regional population for households, respectively. The regional GDP and population are taken from Eurostat (2011) on a NUTS 3 level[54] corresponding to districts in Germany. The derivation of node-specific load is based on Leuthold et al. (2012).

5.4.4. Transmission Network

The underlying transmission network of Germany is based on the European high voltage transmission grid (ENTSO-E, 2011b) comprising transmission lines and substations at the 220 kV and 380 kV voltage level. The network topology of the high voltage transmission grid is depicted in Figure 5.5. Neighboring countries of Germany (Denmark (West), Poland, Czech Republic, Austria, Switzerland, France, Belgium, and the Netherlands) are additionally considered. In order to reduce computational effort associated with a detailed representation of the transmission network, a zonal transmission model of the German high voltage transmission system is applied. Based on 50Hertz Transmission et al. (2010), existing substations in Germany are assigned to 18 zones and interzonal transmission lines are considered during the optimization. The zonal aggregation of physical transmission system results in 26 nodes consisting of 18 zones within Germany and 8 neighboring countries, and 159 transmission lines crossing zonal boundaries.

The determination of technical characteristics for the zonal transmission network is based on the detailed physical transmission network and afterwards aggregated to zonal characteristics. Technical characteristics of transmission lines are based on KieSSling et al. (2001). For representative voltages of 380 kV and 220 kV specific values for series reactance and resistance are derived and multiplied with the line length to derive line-specific characteristics (reactance x_l, resistance r_l). The derivation of the *ptdf* coefficients entering the model is described in the Appendix C.

5.5. Results

In the following application of the model, the impact of different kinds of incorporating stochastic wind generation is analyzed. Three different cases are compared reflecting different degrees of wind uncertainty considered in the dayahead and intraday markets subject to transmission restrictions of the physical

[54] NUTS (Nomenclature of Territorial Units for Statistics) is a hierarchical system for geographic division of the European territory. `http://epp.eurostat.ec.europa.eu/portal/page/portal/nuts_nomenclature/introduction`

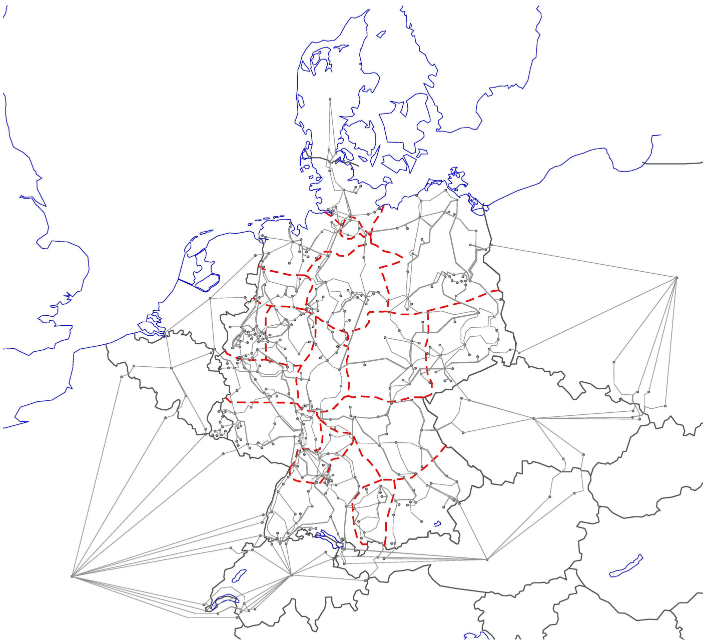


Figure 5.5.: Topology of the high voltage transmission grid and zone definition. Source: Own illustration

network[55]. Afterwards, the impact on system operating costs, the generation dispatch of power plants, and finally prices of the dayahead and intraday market are described and discussed.

5.5.1. Cases of Wind Uncertainty

The three considered cases of wind uncertainty are as follows. In the *deterministic* case, wind generation is set to the realized values in both the dayahead and intraday market, and thus uncertainty about wind generation is not considered.

In the second case, the impact of a *changing forecast* of wind generation is regarded. Changing forecast means, that in each market clearing, both dayahead and intraday, a single wind generation forecast is considered representing the current status of information on wind generation. As the information about wind generation improves with decreasing forecast lengths, the forecast error for a specific hour decreases during the rolling planning procedure. In the final intraday clearing for a specific hour, the wind generation equals the final wind realization.

[55] The incorporation of network constraints within the dayahead and intraday market, in particular network constraints within a country, abstracts from the current market design of the German and most European countries where congestion in the national transmission grid are managed after the clearing of the markets (see e.g. Section 2.4.1). Hence, an implicit auctioning of all considered transmission constraints is assumed as it ensures an optimal utilization of transmission and generation.

The third case takes into account the *stochastic* aspects of wind generation. In the intraday market, a scenario tree is introduced and the power plant dispatch is optimized with respect to different possible wind scenarios of the scenario tree. Again, a single wind generation forecast is considered in the dayahead market based on published data and thus stochasticity of wind generation is incorporated solely in the intraday market.

It is important to note that the three different approaches are distinguished by the treatment of the uncertainty of wind supply. For instance wind supply is known with certainty in the *deterministic* case in both markets, the dayahead and intraday market, respectively. Whereas, in the *changing forecast* case, the system operator has given a unique value of renewable supply in the dayahead market, the dayahead wind generation forecast. In the intraday market this value changes over time as the quality of the forecast is improved with decreasing forecast lengths. In the *stochastic* approach the same unique value is given in the dayahead market. However, in the intraday market, the system operator has given a distribution of possible wind realizations represented by a scenario tree.

While the approaches differ in the treatment of wind uncertainty, they have an important feature in common: Due to the rolling planning approach each of the employed approaches receives new information on the wind generation and demand in each iteration as the time horizon is extended by one hour. As the rolling planning approach moves hourly wise forward, in each iteration a new value for the final model hour for demand and wind is given. Consequently, the intraday market serves two functions: First, it enables the system operator to reoptimize the generation portfolio based the additional information about demand and wind supply which was not available in the dayahead market. Second, in the cases that incorporate forecast errors on wind generation, the intraday market balances the deviation from the dayahead forecast.

5.5.2. Cost Results

The model is optimized for a total time frame of nine days where the first and the last day are introduced to account for initial and terminal model conditions. In turn, the reported time horizon covers one week of seven days from Tuesday to Monday. The costs analyzed in this section reflect the operating cost of the generation dispatch determined in the final clearing of the intraday model for each hour of the time horizon.

Taking into account the system operating cost for the entire time frame of all nine days, the *deterministic* case produces with system operating cost of

735.89 million EUR, the *changing forecast* case causes 736.2 million EUR, and the *stochastic case* results in 735.95 million EUR. Thus, these system operating cost indicate that the *deterministic* case results in the lowest overall operating cost, whereas the *changing forecast* case causes the highest system operating cost. However, in particular the first day is characterized by high system operating costs as the entire system has to be initialized and therefore the first and the last day are neglected in the following analysis due to their specifics.

The aggregated cost as well as the different cost components for the time frame of seven days are given in Table 5.4. For the *determinstic* case the total system cost amount to 590.82 million EUR. The main part of the system cost are the fuel cost, 433.65 million EUR, followed by the carbon cost, 150.55 million EUR. With 6.62 million EUR, the startup cost account only for around 1% of the total system cost. For the *changing forecast* case the total cost become 590.45 million EUR consisting of 433.93 million EUR fuel, 150.43 million EUR carbon, and 6.09 million EUR startup cost. Finally, the *stochastic* approach shows 433.55 million EUR fuel, 150.86 million EUR carbon, and 5.55 million EUR startup cost, which sums up to the total system cost of 589.96 million EUR.

Comparing the cases which incorporate uncertainty about the supply of wind with the *determinstic* case shows lower total system cost. In particular, the sum of marginal cost, defined as the sum of fuel and carbon cost, in the uncertainty cases always exceeds the total marginal cost of the *deterministic* case. However, this cost increase is counterbalanced by a decrease of startup cost. Overall, the *determinstic* case shows the highest cost followed by the *changing forecast*, and finally the *stochastic* approach. However, the differences of the system operating cost between the cases are marginal up to 0.86 million EUR (0.2%) mainly due to the analyzed time frame of seven days.

Except for the startup cost, which follow the cost ranking of the system cost, the ranking on the cost component level is not uniform. Concerning the fuel cost, the *stochastic* approach shows the lowest cost followed by the *determinstic* case. The *changing forecast* approach shows the highest fuel but the lowest carbon cost. The carbon cost of *determinstic* case are lower than for the *stochastic* programming approach.

in million EUR	**Deterministic**	**Changing forecast**	**Stochastic**
Fuel costs	433.65	433.93	433.55
Carbon costs	150.55	150.43	150.86
Start-up costs	6.62	6.09	5.55
System operating costs	590.82	590.45	589.96

Table 5.4.: System operating costs of the considered cases. Source: Own illustration

Comparing the system operating cost with and without the first and last day shows that the ranking of the three approaches varies. One reason for this effect is that for instance pumped-hydro storage is charged less during the first day in the deterministic case than in the changing forecast or stochastic one. Hence, the system operating costs of the deterministic case are higher in the following days than in other cases if these days are analyzed independently of the first day. To that end, particularly the influence of the first day on system operating costs prevents a final conclusion on the ranking of the considered approaches regarding their system operating cost. Future analysis will extend the analyzed time horizon to diminish the influence of initial and terminal conditions on model results.

5.5.3. Dispatch Results

The characteristics of the cost results concerning their cost components can be explained by analyzing the aggregated generation and average number of operating plants which are depicted in Table 5.5 at the technology level.[56] Comparing the different cases, it is observe that the generation and the number of plants online are remarkably invariant. Beside a slight change in the use of storage, the approaches differ in the use of lignite, coal, and CCGT plants. Concerning these technologies it is important to emphasize that the marginal cost of a coal plant are higher than lignite plants, whereas they have the same operational flexibility in terms of minimum online and offline times (see Table 5.2 and 5.3). Furthermore, lignite generation more carbon cost intensive than coal and the same is true for the comparison of coal to CCGT generation.

Comparing the *changing forecast* approach with the *determinstic* case, it is observed that the introduction of the wind forecast error leads to a decrease of lignite production. However, the average number of operating lignite plants remains constant implying a decrease of average utilization[57] by 0.15%. Furthermore, coal-fired generation also decreases slightly but is accompanied by a decrease of the average number of operating plants. Average utilization is falling by 0.17%. In contrast, generation of CCGT plants as well as the average number of plants online is increasing and thus utilization is increasing by 0.93%. As coal and lignite generation are partly replaced by more costly but less carbon intensive CCGT generation, the fuel cost rise and the carbon cost

[56] The high share of nuclear generation is explained by the fact, that neighbouring countries are included with their demand and generation capacities. Incorporating loop flows in the electricity grid it is required to close the model accounting for cross-border transmission which is done by including these countries.

[57] Average utilization is defined as the ratio of production to available installed capacity.

decline, respectively (see Table 5.4).

Comparing the *stochastic* case to the *determinstic* case, lignite generation is falling but by a larger amount as in the *changing forecast* case. However, the average number of operating plants is increasing. Thus, utilization of lignite plants is decreasing by 0.55%. For coal it is observed an increase in electricity generation and additionally in the number of committed plants. However, coal plants are used more intensively on average, resulting in an increase of average utilization by 1.48%. This is also true compared to the *changing forecast* approach. Concerning CCGT plants, generation and average plants operating are decreasing. Average utilization declines by 2.84%. Hence, by applying the *stochastic* approach the system operator reacts to the uncertainty of wind availability mainly by decreasing CCGT generation and substituting it by coal-fired generation. Although lignite power plants decrease their generation, the results show that the effect of switching away from gas-fired generation dominates and thus total fuel cost decrease but total carbon cost increase (see Table 5.4).

Summing up, in both cases with forecast error included, lignite generation is decreased. This decrease is necessary to increase the flexibility of the generation portfolio, in particular increasing the ability to react on changes in the wind forecast in a least cost manner. However, the flexibility is realized in different ways. The *changing forecast* approach enhances the flexibility by using more flexible generation technologies, i.e. CCGT plants. In contrast, the *stochastic* approach introduces flexibility by committing more coal plants. As coal plants are not running at their capacities bounds, using more coal-fired plants enables reacting to changes in the forecast by varying the generation level instead of starting more expensive gas-fired plants. This more cost efficient behavior of the system operator is caused by the stochastic programming approach: As he takes into account possible deviations of the forecast he dispatches coal plants at a level which allows balancing the forecast error in cases of negative and positive deviation.

In addition to the overall generation results, Figure 5.6 shows the generation of the different plant technologies in the different markets as well as total generation for each hour. Looking at the dayahead and total generation figures, the dispatch is as expected and follows marginal generation costs. Hydro and nuclear power plants operate in nearly all hours at their capacity bound. Lignite power plants provide base load generation during the days with high demand, but decrease their generation during day with lower demand levels. Hard coal and partly gas-fired generation represents mid load generation which is dispatched during peak hours and reduced to minimum generation levels dur-

	Deterministic		Changing forecast		Stochastic	
	Generation in GWh	Online	Generation in GWh	Online	Generation in GWh	Online
Nuclear	13553	21	13553	21	13553	21
Coal	5145	55	5136	52	5221	58
Lignite	4693	59	4686	59	4667	60
CCGT	1744	23	1760	24	1694	21
OCGT	85	6	85	6	85	6
Gas Steam	811	10	812	10	811	10
OCOT	7	1	7	1	7	1
Oil Steam	10	1	10	1	10	1
Reservoir	1465	4	1465	4	1465	4
RoR	2180	56	2180	56	2180	56
PSP	-147	–	-148	–	-147	–
Wind	1338	–	1338	–	1338	–

Table 5.5.: Aggregated generation and average number of plants online. Source: Own illustration

ing off-peak hours. The relative constant production of natural gas fired plants is caused by incorporating combined heat and power plants using must-run conditions. Finally, pump storage facilities are charged at night and released during the day. Notable differences are observed in the intraday market.

In the *deterministic* case the intraday is used to reoptimize the generation portfolio given new information about demand and wind generation.[58] As the wind supply realization is already known in the dayahead market, intraday trades in each hour sum up to zero. Reoptimizing mainly occurs to avoid startups and shutdowns of thermal generation by using storage facilities as new information on load and wind generation are provided during the rolling planning procedure. As the first 100 hours show, storages are mainly charged by CCGT plants. From around hour 120 onwards the figure changes and lignite plants are kept running by charging storages. This is caused by the fact that wind generation in these hours is relatively low. Furthermore, the future demand increases, which is accompanied by a decrease in wind supply, which becomes known in these hours. During these hours with high demand and low wind supply CCGT plants are used charging the storage. As lignite and coal plants are operating at maximum capacity these plants are needed to satisfy demand. Therefore the CCGT plants are needed anyway and generation is increased above the level

[58] As described in Section 5.3.3 the intraday model is optimized for a time frame of 36 hours. Within the rolling planning procedure the intraday model is solved for each hour and thus new information on load and wind generation are given compared to the dayahead market model due to the optimized time frame of 36 hours. To that end, the reoptimization of decision variables occurs due to intertemporal constraints such as ontime/offtime or pump storage restrictions.

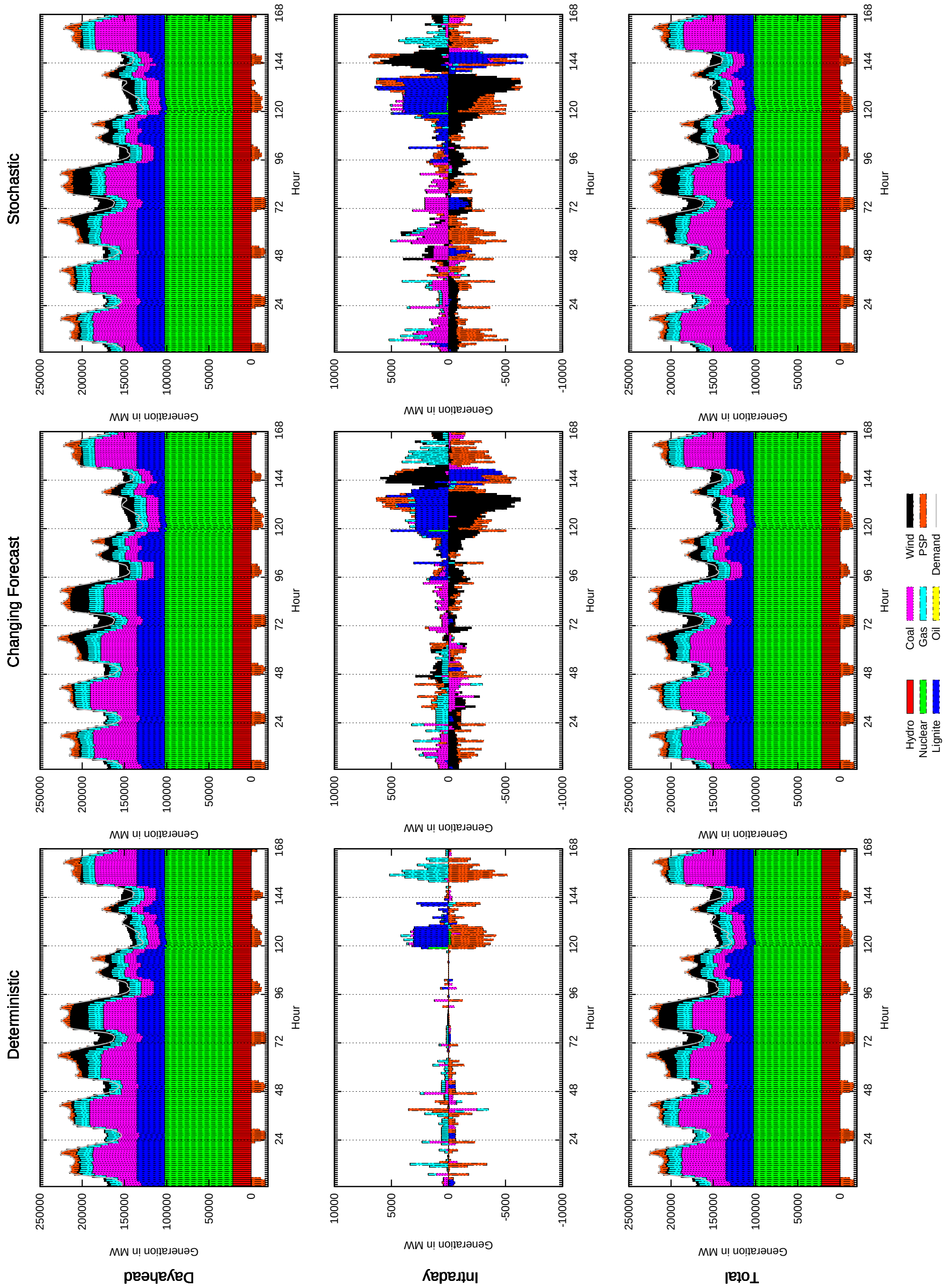


Figure 5.6.: Dispatch results for considered cases and markets by fuel types. Source: Own illustration

needed and storages are filled.

In the *changing forecast* approach the reoptimization of the generation dispatch takes place in the intraday market, but more importantly errors of the wind forecast need to be balanced. The reoptimization of the dispatch becomes obvious by noting that positive and negative trades occur at the same time. Regarding the balancing of wind forecast errors, it is observed that coal plants are used for balancing purposes during the first hours. Additionally they are also used to charge storage facilities. In the following hours, a switch to CCGT plants occurs. The CCGT trades are always higher than in the *deterministic* case indicating that more plants are running and consequently startup cost are saved. In the hours with large forecast errors and low load lignite plants are used for balancing the forecast error. However in contrast to the *deterministic* storages are also used to balance the forecast error indicated by positive production of pump storages.

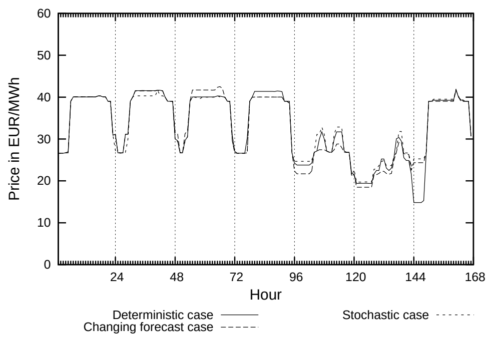
Comparable to the *changing forecast*, the reoptimization and the balancing of forecast errors is done in the intraday market in the *stochastic* case. However, coal-fired generation is used especially in the first hours for intraday adjustments instead of flexible CCGT generation. Furthermore, an increased use of storage facilities is observed as more plants are running with lower utilization which charge storage facilities. This allows balancing wind forecast error with storage facilities instead of starting up new plants. As in the other cases in hours with low demand lignite plants are used to balance mispredictions of wind generation. However, the *stochastic* case uses more lignite than these cases.

To sum up, the general generation dispatch follows the marginal cost structure of the generation technologies and the considered wind uncertainty cases differ mainly in their adjustment of the generation dispatch in the intraday. The intraday market itself provides two opportunities: First, the generation dispatch can be reoptimized given new information on demand and wind generation; second, mispredictions in wind generation are balanced within the intraday as the information on wind generation improves over time. Regarding the considered cases, the generation technologies used especially to balance the wind error differ. The *stochastic* case makes use of available generation capacities, whereas the *changing forecast* case compensates forecast errors by utilizing flexible generation units. The difference in balancing forecast errors is based on the application of stochastic programming in the *stochastic* case. Taking into account possible deviations of the forecasted wind supply, this case adjusts the generation portfolio in a more cost optimal manner than the *changing forecast* approach which is based on the expected value only.

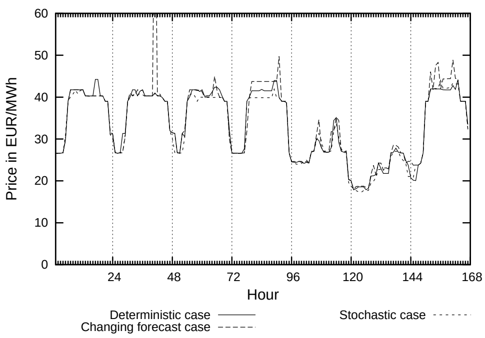
5.5.4. Price Results

The described characteristics of the generation dispatch between the different uncertainty cases determine the prices in the considered markets. The achieved prices of the different markets and cases are shown in Figure 5.7. The depicted prices represent the hourly dayahead and intraday nodal prices weighted by the nodal consumption.

For the dayahead market (Figure 5.7(a)), the general price pattern is comparable in all cases with high prices during peak and low prices during off-peak hours. Differences in the price pattern between the cases occur firstly during peak hours and secondly during hours with low demand and high wind generation (e.g. hour 96-144). In particular, the prices between the *deterministic* and the uncertainty cases differ in hours with high wind forecast errors as the *deterministic* case does not consider uncertainty about wind generation. This becomes obvious in hour 144 where the difference between the dayahead forecast and the final realization of wind generation is significant. Thus, the *deterministic* case shows lower prices as the other cases. Regarding the cases with uncertainty about wind generation, differences in dayahead prices occur in particular during peak hours and in periods with high wind generation mainly caused by the incorporation of wind uncertainty and hence the different use of coal and CCGT power plants as described previously. Thus, dayahead prices are nearly identical during the first day due to low wind supply. During the following days the wind supply increases, henceforth the generation dispatch is affected, and finally the dayahead prices differ between the *stochastic* and *changing forecast* case.



(a) Dayahead market



(b) Intraday market

Figure 5.7.: Prices results of the dayahead and intraday market. Source: Own illustration

With respect to the intraday market (Figure 5.7(b)), the general price pattern does not change significantly and all considered cases show comparable price patterns. Again, differences in the price pattern are caused by the different generation patterns. In particular, the *stochastic* case utilizes more coal units to balance the wind generation forecasts. Henceforth, intraday prices (esp. in peak hours) represent the marginal cost of coal generation and are thus the lowest among the cases. On the other hand, the *changing forecast* case compensates the forecast error of wind generation by increasing generation from flexible CCGT rather than coal generation. Hence, intraday prices reflect the marginal cost of the CCGT power plants and are the highest especially during peak hours. Additionally, the *changing forecast* case shows a remarkable price peak of roughly 100 EUR/MWh in the intraday market in hour 42. Due to high demand in combination with the unexpected increase of wind generation network congestion arises in the western part of the electricity network causing an increase of the intraday market price for this specific hour in the import-constrained part of the network. To avoid an overloading of transmission lines base load generation in the export-constrained region has to be reduced and replaced by more expensive generation in the import-constrained region. This replacement effect causes costs for increasing as well as decreasing generation, and is thus responsible for the significant height of the price peak. This effect occurs solely in the *changing forecast* case as a single wind generation forecast is considered within the dayahead and the intraday market. In the other cases wind generation is either known with certainty (*deterministic* case) or different possible wind realizations are considered (*stochastic* case) which limits the occurrence of comparable price spikes.

To summarize, the general pattern of market prices is comparable among the considered cases especially in time periods with low uncertainty about wind generation. Most remarkably, the different use of the intraday market either for reoptimization of balancing of wind forecast errors determines the price pattern in this market. As the changing forecast case utilizes flexible plants with higher marginal cost rather than inflexible generation at lower utilization rates as in the stochastic case, intraday market prices of the changing forecast case tend to higher than in other cases. In addition, the occurrence of network congestion depends on the considered case of integrating wind generation.

5.6. Conclusions

In this Chapter a stochastic electricity market model (stELMOD) is described which captures the economic and technical characteristics of liberalized electricity markets. First the unit commitment and generation dispatch for the following day is determined in a dayahead market model. Simultaneously capacities providing reserves for system stability are optimized. Afterwards an hourly intraday market model enables to adjust dayahead generation quantities as well as the unit commitment if required. Uncertainty of wind generation can be incorporated and successively updated to reflect the improvement of wind generation forecast over time. Finally network constraints are reflected using a DC-loadflow approach which captures the physical characteristics of transporting electrical energy. Possible applications of the model are to analyze the impact of stochastic renewable generation or the impact of different markets regimes within the rolling planning procedure (e.g. incorporation of network constraints) on electricity market results. Future analysis could also address the issue of the optimal timing of electricity markets within a daily market procedure.

Within this Chapter, stELMOD is applied to the electricity system of Germany including their neighboring countries. Uncertainty about wind generation is considered in two distinct ways. First, the improving information on wind generation are incorporated by a single wind forecast changing over time, and secondly by a set of possible future wind realizations in a stochastic approach. Both cases are compared to a deterministic case which neglects the uncertain characteristics of wind supply. The consideration of uncertainty induces an adjustment of the generation portfolio towards a more flexible one in order to deal with the forecast errors of wind generation. The changing forecast case achieves the flexibility of the generation portfolio by the increased use of flexible generation units, whereas the stochastic case balances the forecast error by flexibilizing the generation pattern of rather inflexible generation units. These characteristics of the generation dispatch impact the system operating cost as well as the prices of the different dayahead and intraday market. As the presented application covers only a time frame of an exemplary week, the achieved results have to be confirmed by analyzing longer time horizons.

6. Summary, Conclusions, and Further Research

Get the prices right, and it is much easier to rely on the market.
Hogan (1999, p.3)

In this thesis selected aspects of network congestion arising in liberalized electricity markets and their management methods with a special weight placed on the integration of increased renewable generation in Europe and Germany. In this Chapter the thesis is summarized, the main finding are presented and topics for future research are identified based on the presented work.

6.1. Summary and Conclusions

Chapter 2 provides an introduction to the topic of network congestion and their management methods aimed to ease network congestion in liberalized electricity markets. Congestion management methods are classified into preventive capacity allocation and curative congestion alleviation concepts. Preventive methods allocate scarce transmission capacity within the regular market clearing process and thus market participants adjust their generation or load pattern accordingly. On the other hand, congestion alleviation methods are applied subsequently to spot market clearing. Thus market participants do not internalize limitations of transmission capacity and network operator is in charge to solve the congestion problem using economic or technical methods. Based on the various management concepts, it is shown that the way how congestion is handled results in diverse economic implications for market participants. After the review of theoretical concepts, the electricity markets of Germany, Norway, Sweden, Great Britain, and Pennsylvania-New Jersey-Maryland (PJM) are reviewed with a focus on national congestion management strategies. The review shows that various market-based options are available to handle congestion in transmission networks. In particular the implicit allocation of scarce capacity during spot market clearing is seen as superior congestion management concept as it provides correct economic signals on physical network congestion to market participants. This concept is currently applied in various electricity markets (e.g. Norway, Pennsylvania-New Jersey-Maryland). However, most European countries currently introduced this concept to allocate only international transmission capacities, whereas national congestion is eased by curative methods.

In Chapter 3 the current European concept to handle scarce transmission capacity is analyzed and it is questioned whether a change in the congestion management regime is beneficial especially in the light of the integration of renewable energy sources. In a first step savings in generation costs are quantified in Section 3.2 if the current regime of national price zones including an allocation of commercial transmission capacity is replaced by a nodal pricing regime. An European network model is utilized and modified to gain quantitative insights given different levels of renewable wind generation. However, this analysis is restricted to the analysis of generation costs and neglects distributional effects of congestion management and implied spot market pricing regimes. Therefore impacts on distribution of surpluses of generation, demand, and network operators are addressed in Section 3.3. The results indicate that savings in generation costs can be achieved by the establishment of a nodal pricing regime through a coordinated generation scheduling across European countries taking all network constraints into account. However, cost savings refer only to generation costs and ignore the distributional effects of different pricing regimes. In particular consumers will loose due to locationally differentiated prices as they face higher costs for electricity. On the other hand, transmission system operators will profit from international as well as national congestion. However, it is questionable whether the lower generation costs and increased transparency justifies the cost of implementing a nodal pricing regime across European countries.

Chapter 4 draws on the previous congestion analysis and focuses on the future development of congestion management costs till 2020 in Germany. Given higher shares of renewable generation, both wind and solar generation, the extent of network congestion is quantified and selected congestion management methods to ease these congestion are evaluated. The expected evolution of the high voltage transmission network and conventional generation capacities are explicitly taken into account. Comparably to Chapter 3, the results indicate that both investigated pricing regimes (uniform and nodal pricing) achieve comparable overall results in the short-term perspective, but both regimes differ in the distribution of costs. More importantly, pricing regimes provide different incentives to market participants to adjust their long-term investment behavior. The uniform pricing regime provides incentives to the transmission system operator to appropriately extend network infrastructure, whereas generators and consumers receive economic signals through locational differentiated prices in the nodal pricing regime. The analysis for the German electricity system further shows that a homogeneous development of transmission as well as generation infrastructure is a prerequisite to reduce congestion management costs. If both developments diverge congestion management costs tend to increase significantly. However, German transmission system operators are currently in charge to appropriately extend the network taking into account the expected generation and consumption developments. Given the expected capacity expansion of renewable energy sources and the current delays of transmission expansion projects, it is concluded that economic signals should be given to market participants rather than regulated transmission system operators to achieve a homogeneous development of the power system. Therefore, the need for improving the current congestion management regime arises in order to manage expected congestion and resulting congestion management costs in Germany given higher shares of renewable generation and the development of the conventional power plant fleet.

Chapter 5 focuses on the integration of intermittent generation from renewable sources in the existing market procedure consisting of a sequential clearing of electricity markets. As forecasting intermittent renewable electricity generation is subject to errors which reduce with shorter forecast lengths, the required balancing of these forecast errors has to be performed by adjustments of the generation commitment and dispatch. To reflect the market clearing procedure as well as the characteristics of wind generation a stochastic electricity market model is described consisting of two models (dayahead and intraday market model) coupled by a rolling planning procedure. Stochastic programming techniques are applied to reflect uncertainty about wind generation. The optimization is subject to economical as well as technical constraints arising from thermal generation units and the transmission of electricity. It is shown that the adjustment of generation and thus the development of a flexible generation portfolio depends on the way uncertainty is introduced in the models. If uncertain wind generation is explicitly considered during the market procedure, less flexible generation units are used by decreasing their utilization and increasing their number of operating units to balance resulting forecast errors. As the generation from intermittent renewable sources is expected to further increase in Germany as well as in other countries, the quantification of their impacts on electricity systems is of particular importance and therefore the presented stochastic electricity market model can contribute to this.

6.2. Future Research

There are several directions for further research. The existing analysis in Chapter 3 and 4 on congestion management regimes could be extended to quantify long-term implications of different pricing regimes. The investment in adequate generation and transmission infrastructure is currently a relevant issue especially in the light of higher renewable generation. Nodal pricing is seen as an efficient way to use existing generation as well as transmission infrastructure in the short-run operational perspective. However, in the long-run investment incentives should be provided to market participants in order to achieve an efficient and homogeneous development of the power system. A quantitative analysis of long-term economic implications of different congestion management approaches and thus pricing regimes could contribute to the understanding of investments in liberalized electricity markets and provides insights on relevant market design and regulatory aspects especially in the context of increased renewable generation.

Furthermore, the energy transformation towards a renewable oriented electricity generation in particular in Germany represents a structural change for the existing power system. Especially the uncertainty associated with renewable generation has to managed in the operation of the power system. In Chapter 5 a model is described which is able to quantify the impacts of intermittent generation. As the presented application covers only a time frame of an exemplary week, the achieved results have to be confirmed by analyzing longer time horizons. Therefore, a possible application of this model is to extend the model horizon to e.g. a year in order to analyze the impacts of stochastic renewable generation on the power system. Furthermore, the model could be extended to quantify the influence of different market regimes on market results. For instance, it could be worthwhile to analyze the different ways of managing congestion as addressed in Chapter 4. Future analysis could also address the issue of optimal timing of subsequently cleared electricity markets within a daily market procedure.

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Appendix

A. Total Transfer Capacity (Chapter 3)

MW		From																									
		AL	AT	BA	BE	BG	CH	CZ	DE	DK	ES	FR	GR	HR	HU	IT	MA	ME	MK	NL	PL	PT	RO	RS	SI	SK	UA
To	AL	0	0	0	0	0	0	0	0	0	0	0	173	0	0	0	0	0	0	0	0	0	0	109	0	0	0
	AT	0	0	0	0	0	1054	709	939	0	0	0	0	0	1017	763	0	0	0	0	0	0	0	0	73	0	0
	BA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	375	0	0	0	0	0	114	0	0	0
	BE	0	0	0	0	0	0	0	0	0	0	763	0	0	0	0	0	0	0	2972	0	0	0	0	0	0	0
	BG	0	0	0	0	0	0	0	0	0	0	0	854	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3096	0	0	0	0	0	0	0	0	0	0	0
	CZ	0	1241	0	0	0	0	0	1446	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	480	0
	DE	0	911	0	0	0	2673	204	0	1591	0	2308	0	0	0	0	0	0	0	7395	3439	0	0	0	0	0	0
	DK	0	0	0	0	0	0	0	459	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ES	0	0	0	0	0	0	0	0	0	0	2830	0	0	0	0	400	0	0	0	0	0	0	0	0	0	0
	FR	0	0	0	4287	0	2645	0	5592	0	2870	0	0	0	0	2799	0	0	0	0	0	0	0	0	0	0	0
	GR	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	HR	0	0	387	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	728	0	0
	HU	0	183	0	0	0	0	0	0	0	0	0	0	972	0	0	0	0	0	0	0	0	627	1153	0	0	0
	IT	0	387	0	0	0	704	0	0	0	0	3951	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ME	154	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	243	0	0	0
	MK	0	0	0	0	0	0	0	0	0	0	0	974	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	NL	0	0	0	1128	0	0	0	2055	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PL	0	0	0	0	0	0	1999	1211	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1210	100
	PT	0	0	0	0	0	0	0	0	0	1054	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	RO	0	0	0	0	2131	0	0	0	0	0	0	0	0	323	0	0	0	0	0	0	0	0	942	0	0	0
	RS	0	0	0	0	119	0	0	0	0	0	0	0	228	0	0	0	0	981	0	0	0	0	0	0	0	0
	SI	0	227	0	0	0	0	0	0	0	0	0	0	0	0	814	0	0	0	0	0	0	0	0	0	0	0
	SK	0	0	0	0	0	0	120	0	0	0	0	0	0	2415	0	0	0	0	0	40	0	0	0	0	0	865
	UA	0	0	0	0	0	0	0	0	0	0	0	0	0	684	0	0	0	0	0	1300	0	701	0	0	0	0

Table A.1.: Total transfer capacities in MW. Source: Own illustration

B. Regional Cost and Surplus Results (Chapter 3)

	Consumer Cost million EUR	Generation Profit million EUR	Generation Cost million EUR	Congestion Rent million EUR	Congestion Cost million EUR
BE, NL, LU	9,880	6,663	3,955	–	-1
AT, CH	5,448	6,893	997	–	83
DE	24,116	22,830	10,951	–	69
FR	23,710	28,836	7,544	–	762
IT	20,253	16,074	9,323	–	316
South West*	16,420	16,416	5,252	–	196
Central East**	108,23	11,378	7,003	–	40
South East***	9,087	9,192	5,004	–	299
UK	18,159	17,215	12,062	–	0
North****	2,172	2,696	675	–	0
Total	**140,068**	**138,193**	**62,766**	**3,595**	**1,764**

* ES, PT
** PL, CZ, SK
*** SI, HR, HU, RO, BA, RS, ME, MK, AL, BG, GR
**** DK, NO, SE

Table B.1.: Regional cost and surplus results of transaction based zonal pricing regime in million EUR per year

	Consumer	Generation		Congestion	
	Cost	Profit	Cost	Rent	Cost
	million EUR	million EUR	million EUR	million EUR	million EUR
BE, NL, LU	9,914	6,791	3,840	–	10
AT, CH	5,010	6,280	654	–	82
DE	24,329	22,440	10,064	–	103
FR	25,563	32,275	8,760	–	732
IT	20,099	15,189	8,807	–	374
South West*	16,512	16,356	5,089	–	291
Central East**	10,505	9,413	5,197	–	120
South East***	11,549	15,295	7,673	–	1,715
UK	18,160	17,524	12,370	–	0
North****	2,690	3,307	632	–	0
Total	**144,331**	**144,870**	**63,086**	**2,686**	**3,427**

* ES, PT
** PL, CZ, SK
*** SI, HR, HU, RO, BA, RS, ME, MK, AL, BG, GR
**** DK, NO, SE

Table B.2.: Regional cost and surplus results of flow based zonal pricing regime in million EUR per year

	Consumer	Generation		Congestion	
	Cost	Profit	Cost	Rent	Cost
	million EUR	million EUR	million EUR	million EUR	million EUR
BE, NL, LU	9,752	6,575	3,811	–	0
AT, CH	4,859	5,843	596	–	0
DE	24,068	21,169	9,795	–	0
FR	25,987	26,992	8,352	–	0
IT	22,968	17,217	9,188	–	0
South West*	16,944	15,271	4,437	–	0
Central East**	11,228	10,275	5,941	–	0
South East***	11,274	12,482	6,308	–	0
UK	18,364	17,847	12,490	–	0
North****	2,689	3,264	608	–	0
Total	**148,133**	**136,935**	**61,526**	**11,078**	**0**

* ES, PT
** PL, CZ, SK
*** SI, HR, HU, RO, BA, RS, ME, MK, AL, BG, GR
**** DK, NO, SE

Table B.3.: Regional cost and surplus results of nodal pricing regime in million EUR per year

C. Derivation of the PTDF Coefficients (Chapter 5)

Technical parameters are required to calculate power transfer distribution factors (PTDF, $\mathbf{PTDF}_{l,n}$) which describe the impact of an incremental power injection at node n on transmission line l. Incremental power is withdrawn at the reference or slack bus. In order to determine the power transfer distribution factors, branch and nodal susceptance matrices are calculated using Equations (C.1) and (C.2), respectively. $\mathbf{I}_{l,n}$ is the incidence matrix of the transmission network and contains zeros except at the start (end) node n of transmission line l where it is 1 (-1).

$$\mathbf{H}_{l,n} = \mathbf{b}_l \mathbf{I}_{l,n} \tag{C.1}$$

$$\mathbf{B}_{n,nn} = \mathbf{I}'_{l,n} \mathbf{H}_{l,nn} \tag{C.2}$$

The power transfer distribution matrix $\mathbf{PTDF}_{l,n}$ is then calculated using Equation (C.3)

$$\mathbf{PTDF}_{l,n} = \mathbf{H}_{l,n} [\mathbf{B}^*_{n,nn}]^{-1} \tag{C.3}$$

where $\mathbf{B}^*_{n,nn}$ is the nodal susceptance matrix without the slack bus. Given the PTDF matrix of the detailed transmission network, zonal distribution characteristics of power flows on interzonal transmission lines are achieved through aggregation of the nodal power transfer distribution matrix belonging to the considered zone. Power flows on transmission lines are then calculated as the sum of all nodal injections $Y_{n,t}$ weighted with the power transfer distribution matrix $ptdf_{l,n}$ (see Equations (5.17) and (5.18), (5.37) and (5.38)).

D. GAMS Codes

D.1. GAMS Codes for Chapter 3

D.1.1. Nodal and Zonal Pricing Regime (Section 3.2.1.1 and 3.2.1.2)

```
*------------------------------------------------------------------------*
* Scalars
*------------------------------------------------------------------------*
SCALARS

        MVABase         for p.u. calculation [MVA]                / 100 /
        VoltageBase1    for p.u. calculation [kV]                 / 750 /
        VoltageBase2    for p.u. calculation [kV]                 / 380 /
        VoltageBase3    for p.u. calculation [kV]                 / 220 /
        VoltageBase4    for p.u. calculation [kV]                 / 150 /
        VoltageBase5    for p.u. calculation [kV]                 / 110 /
        ReferenzBus     swing bus for calculation                 / 1   /
        TRM             transmission reliability margin [%]       / 0.2 /
;


*------------------------------------------------------------------------*
* Sets
*------------------------------------------------------------------------*

SETS
        c               colums in excel-data-sheets        / c1 * c30        /
        t               timeframe                          / t1*t1           /
        l               lines in the network               /
                                                           Line1*Line7191
                                                           /
        n               nodes in the network
        s               plants in the market               / s1 * s1381      /
        reg             Country                            / 1*27 /

        region(reg,n)
        neighbor(reg,reg)

        nuc(s)          nuclear plants
        lig(s)          lignite plants
        coal(s)         coal plants
        steam(s)        oil and gas steam plants
        ccgt(s)         ccgt plants
        gt(s)           gas turbines
        hydro(s)        hydro plants
        pump(s)         pump storage plants
        kwk(s)          combined heat and power plants

        tfirst(t)       first time periode
        tlast(t)        last time periode


ALIAS (L,LL), (N, NN), (reg,rreg,rrreg);

tfirst(t) = YES$(ORD(t) eq 1);
tlast(t)  = YES$(ORD(t) eq CARD(t));
```

```
*------------------------------------------------------------------------------*
* Parameters
*------------------------------------------------------------------------------*

PARAMETERS
         LineData(l,*)                   data table lines
         NodeData(n,*)                   data table nodes
         PowerPlantData(s,*)             data table power plants
         d_ref(n,t)                      reference demand
         p_ref(n,t)                      reference price table
         WindGen(n,t)                    wind energy table
         available(c,t)                  plant availablilies
         country(n,c)
         FromBus(l)                      starting node of line L
         ToBus(l)                        end node of line L
         LineVoltage(l)                  voltage level of line L (150 220 380)
         Resistance(l)                   Resistance of line L
         Reactance(l)                    Reactance of line L
         ThermalLimit(l)                 Max. current of line L[A]
         PowerFlowLimit(l)               power flow limit of line L[MW]
         Incidence(l,n)                  incidence matrix of the system
         IncidenceTest(l)                checking the incidence matrix
         H(l,n)                          flow sensivity matrix
         B(n,nn)                         network susceptance matrix
         BVector(l)
         GVector(l)
         TRM(l)                          transmission reliability margin [%]
         gmax(n,s)                       max generation capacity
         gmin(n,s)                       min output to run a plant
         pumpmax(n)                      max pump capacity
         marginalcosts(n,s)              reference marginal costs at max output
         season(n,s,t)                   plant availability
         slack(n)
         par_exchange
         exchange_BCE
         g_TTC
         on_TTC
         delta_exchange
         TTC
;
*------------------------------------------------------------------------------*
* Variables
*------------------------------------------------------------------------------*

VARIABLES
         costs                   generation costs of the system
         startupcosts(n,s,t)     cost due to starting of a plant
         netinput(n,t)           net input at n in t
         lineflow(l,t)           line flow on l in t
         delta(n,t)              voltage angle differenc at n in t
         on(n,s,t)               plant condition variable
         delta_BCE
;

POSITIVE VARIABLES
         g(n,s,t)                generation at n of plant s in t
         q(n,t)                  demand at n in t
         exchange
         loadshed_up
         loadshed_down
         linescaling
         gen
         transfer
;

BINARY VARIABLES
         on(n,s,t)               plant condition variable
;
*------------------------------------------------------------------------------*
* Equations
*------------------------------------------------------------------------------*

EQUATIONS
```

```
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
energybalance_TTC
constraint_TTC
;

gencosts..
                costs =e= (SUM ((n,s,t), marginalcosts(n,s)*g(n,s,t))
                               + 100000 * SUM(l, linescaling(l))
                               + 500 * SUM((n,t),
                                       loadshed_up(n,t)
                                       + loadshed_down(n,t))
                          )/1000000;
generationcapacity1(n,s,t)$gmax(n,s)..
                g(n,s,t) =l= on(n,s,t)*season(n,s,t)*gmax(n,s);
generationcapacity2(n,s,t)$gmax(n,s)..
                g(n,s,t) =g= on(n,s,t)*gmin(n,s);
linearinput(n,t)..
                NetInput(n,t)
                - SUM((nn),  B(n,nn)*Delta(nn,t)) * MVABase
                =E= 0;
flow(l,t)..
                LineFlow(l,t) - SUM(N$H(l,n), H(l,n) * Delta(n,t) ) =E= 0;
linecap_pos(l,t)..
                LineFlow(l,t) * MVABase
                =L=
                + (1+linescaling(l))*PowerFlowLimit(l);
linecap_neg(l,t)..
                LineFlow(l,t) * MVABase
                =G=
                - (1+linescaling(l))*PowerFlowLimit(l);
slackfunct(n,t)$Slack(N)..
                Slack(N) * Delta(N,T) =E= 0;
energybalance(n,t)..
                SUM(s$gmax(n,s),g(n,s,t)) + gen(n,t) + windgen(n,t)
                - q(n,t) - NetInput(n,t)
                + loadshed_up(n,t) - loadshed_down(n,t)
                =e= 0;
energybalance_TTC(n,t)..
                SUM(s$gmax(n,s),g(n,s,t)) + gen(n,t) + windgen(n,t)
                - q(n,t)
                + loadshed_up(n,t) - loadshed_down(n,t)
                + SUM(nn$B(nn,n), transfer(nn,n,t))
                - SUM(nn$B(n,nn), transfer(n,nn,t))
                =e= 0;
constraint_TTC(reg,rreg,t)..
                SUM(n$region(reg,n),
                        SUM(nn$region(rreg,nn), transfer(n,nn,t)$B(n,nn)))
                =l= TTC(reg,rreg);


*----------------------------------------------------------------------------*
* Solution procedure
*----------------------------------------------------------------------------*
*                               Optimal power flow                           *
*----------------------------------------------------------------------------*

delta_exchange(reg) = 0;

pumpdown.fx(n,t)=0;
pumpup.fx(n,t)=0;

gen.fx(n,t) = -nodedata(n,'P bus (MW)')$(nodedata(n,'P bus (MW)') < 0);
q.fx(n,t)=1*d_ref(n,t);

*windgen(n,t) = NodeData(n,'Wind infeed max (MW)');
*windgen(n,t) = NodeData(n,'Wind infeed mean (MW)');
```

```
windgen(n,t) = 0;

PowerFlowLimit(l) = 1 * PowerFlowLimit(l);

g.l(n,s,t)$gmax(n,s)=1*gmax(n,s);
g.fx(n,s,t)$(gmax(n,s) AND PowerPlantData(s,'Type') eq 3) = 1*gmax(n,s);

loadshed_up.fx(n,t) = 0;
loadshed_down.fx(n,t) = 0;

** define some generation for Ukraine and Marocco in order to make the BCE feasible
loadshed_up.up('4073',t)$region('26','4073') = 0.01;
loadshed_down.up('4073',t)$region('26','4073') = 0.01;

linescaling.fx(l) = 0;
par_exchange(reg) = 0;

MODEL UCTE_OPF/
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
/;

UCTE_OPF.reslim =         1000000000;
UCTE_OPF.iterlim =        1000000000;
UCTE_OPF.holdfixed =      1;
UCTE_OPF.optcr =          0;
UCTE_OPF.optfile =        1;

SOLVE UCTE_OPF min costs use mip;

*----------------------------------------------------------------------------*
*                              UC with TTC constraint                        *
*----------------------------------------------------------------------------*

TTC(reg,rreg)$neighbor(reg,rreg) = 0;

PARAMETER exchange_BCE(reg,rreg), additional_tc(reg,rreg);
EXECUTE_LOAD '[Datafile].gdx' additional_tc;

exchange_BCE(reg,rreg)$neighbor(reg,rreg) =
        - SUM((l,t), lineflow.l(l,t) * mvabase
                * SUM(n$(incidence(l,n) eq 1), Incidence(l,n)$region(reg,n))
                * SUM(nn$(incidence(l,nn) eq -1), Incidence(l,nn)$region(rreg,nn))
          )
        + SUM((l,t), lineflow.l(l,t) * mvabase
                * SUM(n$(incidence(l,n) eq -1), Incidence(l,n)$region(reg,n))
                * SUM(nn$(incidence(l,nn) eq 1), Incidence(l,nn)$region(rreg,nn))
          );

TTC(reg,rreg)$neighbor(reg,rreg) = max(exchange_BCE(reg,rreg) + additional_tc(reg,rreg),0);

TTC(reg,rreg)$(TTC(reg,rreg) AND TTC(rreg,reg)) = min(TTC(reg,rreg), TTC(rreg,reg));
TTC(reg,rreg) = max(TTC(reg,rreg), TTC(rreg,reg));


TTC(reg,reg) = INF;

*BA --> XX
TTC('3','27') = 60;
TTC('27','3') = 60;

*IT --> XX
TTC('15','27') = 20;
TTC('27','15') = 20;

*GR --> XX
TTC('12','27') = 20;
```

```
TTC('27','12') = 20;

*PL --> XX
TTC('20','27') = 220;
TTC('27','20') = 220;

*windgen(n,t) = NodeData(n,'Wind infeed max (MW)');
*windgen(n,t) = NodeData(n,'Wind infeed mean (MW)');
windgen(n,t) = 0;

MODEL UCTE_UC_TTC /
gencosts
generationcapacity1
generationcapacity2
energybalance_TTC
constraint_TTC
/  ;

UCTE_UC_TTC.reslim =         1000000000;
UCTE_UC_TTC.iterlim =        1000000000;
UCTE_UC_TTC.holdfixed =      1;
UCTE_UC_TTC.optcr =          0;
UCTE_UC_TTC.optfile =        1;

SOLVE UCTE_UC_TTC using mip minimizing costs;

PARAMETER nodalprice(n,t);
nodalprice(n,t) = energybalance_TTC.m(n,t) * 1e6;

PARAMETER generation(s,t), costs_TTC;
generation(s,t) = SUM(n, g.l(n,s,t));

g_TTC(n,s,t) = g.l(n,s,t);
on_TTC(n,s,t) = on.l(n,s,t);

costs_TTC = costs.l;

*------------------------------------------------------------------------------*
*                              Optimal re-dispatch                             *
*------------------------------------------------------------------------------*
loadshed_up.up(n,t) = INF;
*loadshed_down.up(n,t) = INF;

on.fx(n,s,t)$(gmin(n,s) AND marginalcosts(n,s) le 114) = on_TTC(n,s,t);

MODEL UCTE_Dispatch_TTC /
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
/  ;

UCTE_Dispatch_TTC.reslim =         1000000000;
UCTE_Dispatch_TTC.iterlim =        1000000000;
UCTE_Dispatch_TTC.holdfixed =      1;
UCTE_Dispatch_TTC.optcr =          0;
UCTE_Dispatch_TTC.optfile =        1;

SOLVE UCTE_Dispatch_TTC using mip minimizing costs;
```

D.1.2. Total Transfer Capacity Calculation (Section 3.2.1.3)

```
*------------------------------------------------------------------------------*
* Scalars
*------------------------------------------------------------------------------*
```

```
SCALARS

        MVABase         for p.u. calculation [MVA]               / 100 /
        VoltageBase1    for p.u. calculation [kV]                / 750 /
        VoltageBase2    for p.u. calculation [kV]                / 380 /
        VoltageBase3    for p.u. calculation [kV]                / 220 /
        VoltageBase4    for p.u. calculation [kV]                / 150 /
        VoltageBase5    for p.u. calculation [kV]                / 110 /
        ReferenzBus     swing bus for calculation                / 1   /
        TRM             transmission reliability margin [%]      / 0.2 /
;

*--------------------------------------------------------------------------------*
* Sets
*--------------------------------------------------------------------------------*

SETS
        c               colums in excel-data-sheets         / c1 * c30        /
        t               timeframe                           / t1*t1           /
        l               lines in the network                /
                                                            Line1*Line7191
                                                            /
        n               nodes in the network
        s               plants in the market                / s1 * s1381      /
        reg             Country                             / 1*27 /

        region(reg,n)
        neighbor(reg,reg)

        nuc(s)          nuclear plants
        lig(s)          lignite plants
        coal(s)         coal plants
        steam(s)        oil and gas steam plants
        ccgt(s)         ccgt plants
        gt(s)           gas turbines
        hydro(s)        hydro plants
        pump(s)         pump storage plants
        kwk(s)          combined heat and power plants

        tfirst(t)       first time periode
        tlast(t)        last time periode


ALIAS (L,LL), (N, NN), (reg,rreg,rrreg);

tfirst(t) = YES$(ORD(t) eq 1);
tlast(t)  = YES$(ORD(t) eq CARD(t));

*--------------------------------------------------------------------------------*
* Parameters
*--------------------------------------------------------------------------------*
PARAMETERS
        LineData(l,*)                   data table lines
        NodeData(n,*)                   data table nodes
        PowerPlantData(s,*)             data table power plants

        d_ref(n,t)                      reference demand
        p_ref(n,t)                      reference price table
        WindGen(n,t)                    wind energy table
        available(c,t)                  plant availablilies
        country(n,c)
        FromBus(l)                      starting node of line L
        ToBus(l)                        end node of line L
        LineVoltage(l)                  voltage level of line L (150 220 380)
        Resistance(l)                   Resistance of line L
        Reactance(l)                    Reactance of line L
        ThermalLimit(l)                 Max. current of line L[A]
        PowerFlowLimit(l)               power flow limit of line L[MW]
        Incidence(l,n)                  incidence matrix of the system
        IncidenceTest(l)                checking the incidence matrix for errors
        H(l,n)                          flow sensivity matrix
        B(n,nn)                         network susceptance matrix
```

```
        BVector(l)
        GVector(l)
        TRM(l)                          transmission reliability margin [%]
        gmax(n,s)                       max generation capacity
        gmin(n,s)                       min output to run a plant
        pumpmax(n)                      max pump capacity
        marginalcosts(n,s)              reference marginal costs at max output
        season(n,s,t)                   plant availability
        slack(n)
        par_exchange
        exchange_BCE
        g_BCE
        on_BCE
        delta_exchange
;
*------------------------------------------------------------------------------*
* Variables
*------------------------------------------------------------------------------*

VARIABLES
        costs                   generation costs of the system
        startupcosts(n,s,t)     cost due to starting of a plant
        netinput(n,t)           net input at n in t
        lineflow(l,t)           line flow on l in t
        delta(n,t)              voltage angle differenc at n in t
        on(n,s,t)               plant condition variable

        delta_BCE
;

POSITIVE VARIABLES
        g(n,s,t)                generation at n of plant s in t
        q(n,t)                  demand at n in t
        exchange
        loadshed_up
        loadshed_down
        linescaling
        gen
;

BINARY VARIABLES
        on(n,s,t)               plant condition variable
;
*------------------------------------------------------------------------------*
* Equations
*------------------------------------------------------------------------------*

EQUATIONS
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
constraint_BCE_exchange
constraint_exchange
;

gencosts..
                costs =e= (SUM((n,s,t), marginalcosts(n,s)*g(n,s,t))
                                + 100000 * SUM(l, linescaling(l))
                                + 100000 * SUM((n,t), loadshed_up(n,t)
                                        + 10000*loadshed_down(n,t))
                          )/1000000;
generationcapacity1(n,s,t)$gmax(n,s)..
                g(n,s,t) =l= on(n,s,t)*season(n,s,t)*gmax(n,s);
generationcapacity2(n,s,t)$gmax(n,s)..
                g(n,s,t) =g= on(n,s,t)*gmin(n,s);
linearinput(n,t)..
                NetInput(n,t)
                - SUM((nn),  B(n,nn)*Delta(nn,t)) * MVABase
```

```
                =E= 0;
flow(l,t)..
                LineFlow(l,t) - SUM(N$H(l,n), H(l,n) * Delta(n,t) ) =E= 0;
linecap_pos(l,t)..
                LineFlow(l,t) * MVABase
                =L=
                + (1+linescaling(l))*PowerFlowLimit(l);
linecap_neg(l,t)..
                LineFlow(l,t) * MVABase
                =G=
                - (1+linescaling(l))*PowerFlowLimit(l);
slackfunct(n,t)$Slack(N)..
                Slack(N) * Delta(N,T) =E= 0;
energybalance(n,t)..
                SUM(s$gmax(n,s),g(n,s,t)) + gen(n,t) + windgen(n,t)
                - q(n,t) - NetInput(n,t)
                + loadshed_up(n,t) - loadshed_down(n,t)
                =e= 0;
constraint_BCE_exchange(reg,t)$exchange_BCE(reg)..
                SUM((n,s)$(region(reg,n) AND gmax(n,s)), g(n,s,t) + loadshed_up(n,t))
                - SUM((n)$(region(reg,n)), q(n,t) - loadshed_down(n,t) - windgen(n,t) - gen(n,t))
                =e= exchange_BCE(reg) + delta_exchange(reg);
constraint_exchange(reg,t)..
                SUM((n,s)$(region(reg,n) AND gmax(n,s)), g(n,s,t) - g_BCE(n,s,t))
                =e= -par_exchange(reg);

*------------------------------------------------------------------------------*
* Solution procedure
*------------------------------------------------------------------------------*

delta_exchange(reg) = 0;

pumpdown.fx(n,t)=0;
pumpup.fx(n,t)=0;

gen.fx(n,t) = -nodedata(n,'P bus (MW)')$(nodedata(n,'P bus (MW)') < 0);
q.fx(n,t)=1*d_ref(n,t);

*windgen(n,t) = NodeData(n,'Wind infeed max (MW)');
*windgen(n,t) = NodeData(n,'Wind infeed mean (MW)');
windgen(n,t) = 0;

PowerFlowLimit(l) = 1 * PowerFlowLimit(l);

g.l(n,s,t)=1*gmax(n,s);
g.fx(n,s,t)$(PowerPlantData(s,'Type') eq 3) = 1*gmax(n,s);

loadshed_up.up(n,t) = 0;
loadshed_down.fx(n,t) = 0;

** define some generation for Ukraine and Marocco in order to make the BCE feasible
loadshed_up.up('4073',t)$region('26','4073') = 0.01;
loadshed_down.up('4073',t)$region('26','4073') = 0.01;

linescaling.fx(l) = 0;
par_exchange(reg) = 0;


MODEL UCTE_LMP /
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
/  ;

UCTE_LMP.reslim =         1000000000;
UCTE_LMP.iterlim =        1000000000;
UCTE_LMP.holdfixed =      1;
UCTE_LMP.optcr =          0;
```

```
UCTE_LMP.optfile =        1;


SOLVE UCTE_LMP using mip minimizing costs;

PARAMETER nodalprice(n,t);
nodalprice(n,t) = energybalance.m(n,t) * 1e6;

PARAMETER generation(s,t);
generation(s,t) = SUM(n, g.l(n,s,t));


exchange_BCE(reg) = SUM((n,s)$region(reg,n), g.l(n,s,'t1'))
                        - SUM((n)$region(reg,n), q.l(n,'t1') - gen.l(n,'t1'));

DISPLAY exchange_BCE;

exchange_BCE('16') = 0;
exchange_BCE('21') = 0;
exchange_BCE('26') = 0;
exchange_BCE('27') = 0;

g_BCE(n,s,t) = g.l(n,s,t);
on_BCE(n,s,t) = on.l(n,s,t);

*-------------------------------------------------------------------------------*
* Determination of TTC-Capacity
*-------------------------------------------------------------------------------*
MODEL UCTE_TTC /
gencosts
generationcapacity1
generationcapacity2
linearinput
flow
linecap_pos
linecap_neg
slackfunct
energybalance
constraint_BCE_exchange
/  ;

UCTE_TTC.reslim =         1000000000;
UCTE_TTC.iterlim =        1000000000;
UCTE_TTC.holdfixed =      1;
UCTE_TTC.optfile =        1;
UCTE_TTC.optcr =          0.01;
UCTE_TTC.solvelink =      2;

OPTION Limrow=0;
OPTION Limcol=0;

*loadshed_up.up(n,t) = INF;
loadshed_down.up(n,t) = INF;


PARAMETER results_costs(reg,reg,*);
PARAMETER additional_tc(reg,rreg), ntc(reg,rreg);
SET  count   /1*500/
SCALAR end_looping       /0/;


LOOP(neighbor(rreg,rrreg),
*        par_exchange(reg) = 0;
        delta_exchange(reg) = 0;
        end_looping = 0;
        loadshed_up.l(n,t) = 0;
        loadshed_down.l(n,t) = 0;

        g.lo(n,s,t) = 0;
        g.up(n,s,t) = INF;
        g.l(n,s,t) = g_BCE(n,s,t);

        on.lo(n,s,t) = 0;
        on.up(n,s,t) = 1;
```

```
        on.l(n,s,t) = on_BCE(n,s,t);

        execerror = 0;

                LOOP(count$(end_looping eq 0),

                        on.fx(n,s,t)$(NOT (region(rreg,n) OR region(rrreg,n))) = on_BCE(n,s,t);

                        delta_exchange(rreg) = delta_exchange(rreg) + 50;
                        delta_exchange(rrreg) = - delta_exchange(rreg);

                        SOLVE UCTE_TTC using mip minimzing costs;

                        end_looping = 1$(SUM((n,t), loadshed_down.l(n,t)) gt 0.02 or UCTE_TTC.modelstat
                             = 10);
                        execerror = 0;
                        additional_tc(rreg,rrreg)$(end_looping eq 0) = delta_exchange(rreg);

                        results_costs(rreg,rrreg,count) = costs.l;
                );
);
```

D.1.3. Nodal Pricing Regime (Section 3.3.1.1)

```
$include [Datafile]

*------------------------------------------------------------------------------
*                                 VARIABLES
*------------------------------------------------------------------------------

VARIABLE
         COST            objective value: total cost
         LINEFLOW        line flow
         NETINPUT        net injection
         DELTA           voltage angle
;

POSITIVE VARIABLE
         G               conventional generation
         LOADSHED
         WINDSHED
         HVDCFLOW
         LINESCALE
;

*------------------------------------------------------------------------------
*                                 EQUATIONS
*------------------------------------------------------------------------------

EQUATIONS
*        Objective functions
         OBJ_cost        objective function: total generation cost

*        Market clearing equations
         MKT_lp          market clearing equation wo network losses (linear)

*        Thermal generation restrictions
         RES_gmax        maximum generation restriction

*        Network defintions and restrictions
         DEF_LINEFLOW    lineflow definition
         DEF_NETINPUT    netinput definition
         RES_pmax        maximum transmission restriction
         RES_pmin        minimum transmission restriction
         RES_HVDC        maximum transmission restriction for HVDC
         DEF_slack       slack bus definition

*        Other Restrictions
         RES_WINDSHED    maximum amount of windshedding
;
```

```
*        Objective functions
OBJ_cost..
                 COST =E= SUM(sc,
*                         weight(sc) * (
                          SUM(p, c(p) * G(p,sc))
                          + 500 * SUM(n, LOADSHED(n,sc))
                          + 500 * SUM(n, WINDSHED(n,sc))
*                          )
                          + SUM(l, 500*LINESCALE(l,sc))
                          )
;

*        Market clearing equations
MKT_lp(n,sc)..
                 0 =E= q(n,sc) + NETINPUT(n,sc)
                         - SUM(p$mappn(p,n), G(p,sc))
                         - g_wind(n,sc)
                         - g_solar(n,sc)
                         - LOADSHED(n,sc) + WINDSHED(n,sc)
                         + SUM(nn$P_HVDC_max(n,nn), HVDCFLOW(n,nn,sc))
                         - SUM(nn$P_HVDC_max(nn,n), HVDCFLOW(nn,n,sc))
;


*        Thermal generation restrictions
RES_gmax(p,sc)..
                 G(p,sc) =L= g_max(p)
;


*        Network defintions and restrictions
DEF_LINEFLOW(l,sc)..
                 LINEFLOW(l,sc) =E= SUM(n$h(l,n), h(l,n) * DELTA(n,sc))
;

DEF_NETINPUT(n,sc)..
                 NETINPUT(n,sc) =E= SUM(nn, b(n,nn) * DELTA(nn,sc)) * MVABase
;

RES_pmax(l,sc)..
                 LINEFLOW(l,sc) * MVABase =L= P_max(l) + LINESCALE(l,sc)
;

RES_pmin(l,sc)..
                 LINEFLOW(l,sc) * MVABase =G= - P_max(l) - LINESCALE(l,sc)
;

RES_HVDC(n,nn,sc)$P_HVDC_max(n,nn)..
                 HVDCFLOW(n,nn,sc) =l= P_HVDC_max(n,nn)
;

DEF_slack(n,sc)..
                 DELTA(n,sc) * slack(n) =E= 0
;

*        Other Restrictions
RES_WINDSHED(n,sc)..
                 WINDSHED(n,sc) =L= g_wind(n,sc)
;

MODEL Europe_OPF /all/;

Europe_OPF.optfile       = 1;

LOADSHED.up(n,sc) = q(n,sc);
LINESCALE.up(l,sc) = 0.0*P_max(l);

SOLVE Europe_OPF min COST use lp;
```

D.1.4. Zonal Pricing Regime (Section 3.3.1.2)

```
$include [Datafile]

*------------------------------------------------------------------------------
*                               PARAMETERS (additional)
*------------------------------------------------------------------------------
PARAMETERS
        p_ntc           price of ntc optimization
;
*------------------------------------------------------------------------------
*                               VARIABLES
*------------------------------------------------------------------------------

VARIABLE
        COST            objective value: total cost
        RE_COST         objective value: total redispatch cost
        LINEFLOW        line flow
        NETINPUT        net injection
        DELTA           voltage angle
;

POSITIVE VARIABLE
        G               conventional generation
        G_UP            additional re-dispatch generation
        G_DOWN          reduced re-dispatch generation
        LOADSHED
        WINDSHED
        TRANSFER
        HVDCFLOW
        LINESCALE
;

*------------------------------------------------------------------------------
*                               EQUATIONS
*------------------------------------------------------------------------------

EQUATIONS
*       Objective functions
        OBJ_cost        objective function: total generation cost
        OBJ_redispatch  objective function: total redispatch cost

*       Market clearing equations
        MKT_lp          market clearing equation wo network losses (linear)
        MKT_lp_ntc      NTC market clearing equation wo network losses (linear)

*       Thermal generation restrictions
        RES_gmax        maximum generation restriction
        RES_gmin        minimum generation restriction

*       Network defintions and restrictions
        RES_ntc         ntc restriction
        DEF_LINEFLOW    lineflow definition
        DEF_NETINPUT    netinput definition
        RES_pmax        maximum transmission restriction
        RES_pmin        minimum transmission restriction
        DEF_slack       slack bus definition
        RES_HVDC

*       Other Restrictions
        RES_WINDSHED    maximum amount of windshedding
        RES_National_Redispatch
;

*       Objective functions
OBJ_cost..
                 COST =E= SUM(sc,
                         (
                          SUM(p, c(p) * G(p,sc))
                          + 500 * SUM(n, LOADSHED(n,sc))
                          + 500 * SUM(n, WINDSHED(n,sc))
                          )
                          + SUM(l, 500*LINESCALE(l,sc))
                          )
```

```
;

OBJ_redispatch..
                 RE_COST =E= SUM(sc,
                         (
                          SUM(p, c(p) * G_UP(p,sc)
                          + ( - c(p)) * G_DOWN(p,sc))
                          + 500 * SUM(n, LOADSHED(n,sc))
                          + 500 * SUM(n, WINDSHED(n,sc))
                          )
                          + SUM(l, 500*LINESCALE(l,sc))
                          )
;

*        Market clearing equations
MKT_lp(n,sc)..
                 0 =E= q(n,sc) + NETINPUT(n,sc)
                         - SUM(p$mappn(p,n), G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc))
                         - g_wind(n,sc) - g_solar(n,sc)
                         - LOADSHED(n,sc) + WINDSHED(n,sc)
                         + SUM(nn$P_HVDC_max(n,nn), HVDCFLOW(n,nn,sc))
                         - SUM(nn$P_HVDC_max(nn,n), HVDCFLOW(nn,n,sc))
;

MKT_lp_ntc(n,sc)..
                 0 =E= q(n,sc)
                         - SUM(p$mappn(p,n), G(p,sc))
                         - g_wind(n,sc) - g_solar(n,sc)
                         + SUM(nn$(b(n,nn) or P_HVDC_max(n,nn)), TRANSFER(n,nn,sc))
                         - SUM(nn$(b(n,nn) or P_HVDC_max(n,nn)), TRANSFER(nn,n,sc))
                         - LOADSHED(n,sc) + WINDSHED(n,sc)
;


*        Thermal generation restrictions
RES_gmax(p,sc)..
                 G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc) =L= g_max(p)
;

RES_gmin(p,sc)..
                 G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc) =g= 0
;


*        Network defintions and restrictions
RES_ntc(co,cco,sc)$ntc(co,cco)..
                 SUM(n$mapnc(n,co), SUM(nn$(mapnc(nn,cco) AND (b(n,nn) OR P_HVDC_max(n,nn))),
                         TRANSFER(n,nn,sc)))
                         =L= ntc(co,cco)
;

DEF_LINEFLOW(l,sc)..
                 LINEFLOW(l,sc) =E= SUM(n$h(l,n), h(l,n) * DELTA(n,sc))
;
*$SUM(co$mapnc(n,co), region(co))
DEF_NETINPUT(n,sc)..
                 NETINPUT(n,sc) =E= SUM(nn, b(n,nn) * DELTA(nn,sc)) * MVABase
;

RES_pmax(l,sc)..
                 LINEFLOW(l,sc) * MVABase =L= P_max(l)+LINESCALE(l,sc)
;

RES_pmin(l,sc)..
                 LINEFLOW(l,sc) * MVABase =G= - P_max(l)-LINESCALE(l,sc)
;

RES_HVDC(n,nn,sc)$P_HVDC_max(n,nn)..
                 HVDCFLOW(n,nn,sc) =l= P_HVDC_max(n,nn)
;

DEF_slack(n,sc)..
                 DELTA(n,sc) * slack(n) =E= 0
;
```

```
*        Other Restrictions
RES_WINDSHED(n,sc)..
                 WINDSHED(n,sc) =L= g_wind(n,sc)
;
*$region(co)
RES_National_Redispatch(co,sc)..
                 SUM(n$mapnc(n,co), SUM(p$mappn(p,n),
                         G_UP(p,sc) - G_DOWN(p,sc)) + LOADSHED(n,sc) - WINDSHED(n,sc))
                 =E= 0
;

TRANSFER.fx(n,nn,sc)$(SUM(co$mapnc(n,co), SUM(cco$mapnc(nn,cco), NTC(co,cco))) eq 0) = 0;
G_UP.fx(p,sc) = 0;
G_DOWN.fx(p,sc) = 0;
LOADSHED.up(n,sc) = q(n,sc);

* If transaction based allocation of international capacity
      MODEL Europe_NTC
      /
                   OBJ_cost
                   MKT_lp_ntc
                   RES_gmax
                   RES_ntc
                   RES_WINDSHED

      /;

* If flow based allocation of international capacity
      MODEL Europe_NTC
      /
                   OBJ_cost
                   MKT_lp
                   RES_gmax
                   RES_WINDSHED
                   DEF_LINEFLOW
                   DEF_NETINPUT
                   RES_pmax
                   RES_pmin
                   RES_HVDC
                   DEF_slack

      /;
      *Europe_NTC.optfile  = 1;
      SET countrylines(l);
      countrylines(l)=YES$lineup(l,'Countrylines');
      DISPLAY countrylines;

      PARAMETER P_max2;
      P_max2(l) = P_max(l);
      P_max(l)$countrylines(l) = 1e6;

*Europe_NTC.optfile  = 1;

SOLVE Europe_NTC min COST use lp;

p_ntc(n,sc)          = MKT_lp_ntc.m(n,sc);
G.fx(p,sc)           = G.l(p,sc);

PARAMETER price_ntc(co);
price_ntc(co) = SUM(sc, weight(sc) * SUM(n$mapnc(n,co), p_ntc(n,sc))/SUM(n, 1$mapnc(n,co)));

display price_ntc;
*------- Re-dispatch due to national restricitions

MODEL Europe_Nat_Redispatch
/
         OBJ_redispatch
         MKT_lp
         RES_gmax
         RES_gmin
         DEF_LINEFLOW
         DEF_NETINPUT
         RES_pmax
```

```
        RES_pmin
        RES_HVDC
        DEF_slack
        RES_WINDSHED
        RES_National_Redispatch

/;


LOADSHED.up(n,sc) = INF;
WINDSHED.up(n,sc) = INF;

LINESCALE.up(l,sc) = 0.0*P_max(l);

SOLVE Europe_Nat_Redispatch min RE_COST use lp;
```

D.2. GAMS Code for Chapter 4

D.2.1. Uniform Pricing Regime (Section 4.2.1)

```
$ontext
Model for congestion management analysis in Germany
$offtext

$include dataload_scenario_22092011

*-----------------------------------------------------------------------------*
* Optimal Dispatch Calculation
*-----------------------------------------------------------------------------*
*-----------------------------------------------------------------------------
*                                 PARAMETERS (additional)
*-----------------------------------------------------------------------------
Parameters
        p_ntc           price of ntc optimization
        n1              n-1 matrix
;
*-----------------------------------------------------------------------------
*                                 VARIABLES
*-----------------------------------------------------------------------------

Variable
        COST            objective value: total cost
        RE_COST         objective value: total redispatch cost
        LINEFLOW        line flow
        NETINPUT        net injection
        DELTA           voltage angle
;

Positive Variable
        G               conventional generation
        G_UP            additional re-dispatch generation
        G_DOWN          reduced re-dispatch generation
        LOADSHED
        WINDSHED
        TRANSFER
;

Binary Variable
        ONLINE          line status variable
;

*-----------------------------------------------------------------------------
*                                 EQUATIONS
*-----------------------------------------------------------------------------

Equations
*       Objective functions
        OBJ_cost        objective function: total generation cost
```

```
        OBJ_redispatch  objective function: total redispatch cost

*       Market clearing equations
        MKT_lp          market clearing equation wo network losses (linear)
        MKT_lp_ntc      NTC market clearing equation wo network losses (linear)

*       Thermal generation restrictions
        RES_gmax        maximum generation restriction
        RES_gmin        minimum generation restriction

*       Network defintions and restrictions
        RES_ntc         ntc restriction
        DEF_LINEFLOW_up lineflow upper definition
        DEF_LINEFLOW_lo lineflow lower definition
        DEF_NETINPUT    netinput definition
        RES_pmax        maximum transmission restriction
        RES_pmin        minimum transmission restriction
        DEF_slack       slack bus definition

*       Other Restrictions
        RES_WINDSHED    maximum amount of windshedding
;

*       Objective functions
OBJ_cost..
                COST =E=
                        SUM(sc,
*                        weight(sc) * (
                        SUM(p, c(p) * G(p,sc))
                        + 500 * SUM(n, LOADSHED(n,sc))
                        + 500 * SUM(n, WINDSHED(n,sc))
*                        )
                        )
;

OBJ_redispatch..
                RE_COST =E=
                        SUM(sc,
*                        weight(sc) * (
                        SUM(p, c(p) * G_UP(p,sc)
                        + (- c(p)) * G_DOWN(p,sc))
                        + 500 * SUM(n, LOADSHED(n,sc))
                        + 500 * SUM(n, WINDSHED(n,sc))
*                        )
                        )
;

*       Market clearing equations
MKT_lp(n,sc)..
                0 =E= q(n,sc) + NETINPUT(n,sc)
                       - SUM(p$mappn(p,n), G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc))
                       - g_wind(n,sc)
                       - g_solar(n,sc)
                       - LOADSHED(n,sc) + WINDSHED(n,sc)
;

MKT_lp_ntc(n,sc)..
                0 =E= q(n,sc)
                       - SUM(p$mappn(p,n), G(p,sc))
                       - g_wind(n,sc) - g_solar(n,sc)
                       + SUM(nn$b(n,nn), TRANSFER(n,nn,sc))
                       - SUM(nn$b(n,nn), TRANSFER(nn,n,sc))
                       - LOADSHED(n,sc) + WINDSHED(n,sc)
;


*       Thermal generation restrictions
RES_gmax(p,sc)..
                G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc) =L= g_max(p)
;

RES_gmin(p,sc)..
                G(p,sc) + G_UP(p,sc) - G_DOWN(p,sc) =g= 0
;
```

```
*        Network defintions and restrictions
RES_ntc(co,cco,sc)..
                 SUM(n$mapnc(n,co), SUM(nn$mapnc(nn,cco), TRANSFER(n,nn,sc)))
                         =L= ntc(co,cco)
;

DEF_LINEFLOW_up(l,sc)..
                 LINEFLOW(l,sc) =l= SUM(n$h(l,n), h(l,n) * DELTA(n,sc))
                                 + (1 - ONLINE(l,sc)) * 10000
;

DEF_LINEFLOW_lo(l,sc)..
                 LINEFLOW(l,sc) =g= SUM(n$h(l,n), h(l,n) * DELTA(n,sc))
                                 - (1 - ONLINE(l,sc)) * 10000
;

DEF_NETINPUT(n,sc)..
                 NETINPUT(n,sc) =E= SUM(l, Incidence(l,n) * LINEFLOW(l,sc)) * MVABase
;

RES_pmax(l,sc)..
                 LINEFLOW(l,sc) * MVABase =L= P_max(l) * ONLINE(l,sc)
;

RES_pmin(l,sc)..
                 LINEFLOW(l,sc) * MVABase =G= - P_max(l) * ONLINE(l,sc)
;

DEF_slack(n,sc)..
                 DELTA(n,sc) * slack(n) =E= 0
;

*        Other Restrictions
RES_WINDSHED(n,sc)..
                 WINDSHED(n,sc) =L= g_wind(n,sc)
;

G_UP.fx(p,sc) = 0;
G_DOWN.fx(p,sc) = 0;
LOADSHED.up(n,sc) = q(n,sc);

model OPF_Germany_NTC
/
         OBJ_cost
         MKT_lp_ntc
         RES_gmax
         RES_ntc
         RES_WINDSHED

/;
solve OPF_Germany_NTC min COST use lp;

p_ntc(n,sc)         = MKT_lp_ntc.m(n,sc);
G.fx(p,sc)          = G.l(p,sc);

model OPF_Germany_Redispatch
/
         OBJ_redispatch
         MKT_lp
         RES_gmax
         RES_gmin
         DEF_LINEFLOW_up
         DEF_LINEFLOW_lo
         DEF_NETINPUT
         RES_pmax
         RES_pmin
         DEF_slack
         RES_WINDSHED
/;

*------- Re-dispatch due to international restrictions
set countrylines(l);
```

```
loop((l,n,nn),
        if(Incidence(l,n) eq 1 and Incidence(l,nn) eq -1,
                countrylines(l) = YES$(mapnc(n,'DE') and mapnc(nn,'DE'));
        );
);
display countrylines;

parameter P_max2;
P_max2(l) = P_max(l);
P_max(l)$countrylines(l) = 1e6;

G_UP.up(p,sc)               = g_max(p) - G.l(p,sc);
G_DOWN.up(p,sc)             = G.l(p,sc);
G_UP.lo(p,sc)               = 0;
G_DOWN.lo(p,sc)             = 0;

ONLINE.fx(l,sc)     = 1;

solve OPF_Germany_Redispatch min RE_COST use rmip;

*------- Re-dispatch due to national restricitions
P_max(l) = P_max2(l);
parameter g_up_int, g_down_int, g_int;
g_up_int(p,sc) = G_UP.l(p,sc);
g_down_int(p,sc) = G_DOWN.l(p,sc);
g_int(p,sc) = G.l(p,sc);

G.fx(p,sc)          = G.l(p,sc) + G_UP.l(p,sc) - G_DOWN.l(p,sc);

G_UP.fx(p,sc) = 0;
G_DOWN.fx(p,sc) = 0;

G_UP.up(p,sc)$SUM(n$mappn(p,n), mapnc(n,"DE"))       = g_max(p) - (G.l(p,sc))$((g_max(p) - G.l(p,sc)) ge
      0);
G_DOWN.up(p,sc)$SUM(n$mappn(p,n), mapnc(n,"DE"))     = G.l(p,sc);
G_UP.lo(p,sc)$SUM(n$mappn(p,n), mapnc(n,"DE"))       = 0;
G_DOWN.lo(p,sc)$SUM(n$mappn(p,n), mapnc(n,"DE"))     = 0;

ONLINE.fx(l,sc)     = 1;
ONLINE.lo(l,sc)$(SUM(n$mapnc(n,"DE"), abs(incidence(l,n))) eq 2)    = 0;

solve OPF_Germany_Redispatch min RE_COST use rmip;
```

D.2.2. Nodal Pricing Regime (Section 4.2.2)

```
$ontext
Model for congestion management analysis in Germany
$offtext

$include dataload_scenario_22092011

*------------------------------------------------------------------------------*
* Optimal Dispatch Calculation
*------------------------------------------------------------------------------*
*------------------------------------------------------------------------------
*                                 VARIABLES
*------------------------------------------------------------------------------

Variable
        COST            objective value: total cost
        LINEFLOW        line flow
        NETINPUT        net injection
        DELTA           voltage angle
;

Positive Variable
        G               conventional generation
        LOADSHED
        WINDSHED
;
```

```
*------------------------------------------------------------------------------
*                                EQUATIONS
*------------------------------------------------------------------------------

Equations
*        Objective functions
         OBJ_cost         objective function: total generation cost

*        Market clearing equations
         MKT_lp           market clearing equation wo network losses (linear)

*        Thermal generation restrictions
         RES_gmax         maximum generation restriction

*        Network defintions and restrictions
         DEF_LINEFLOW     lineflow definition
         DEF_NETINPUT     netinput definition
         RES_pmax         maximum transmission restriction
         RES_pmin         minimum transmission restriction
         DEF_slack        slack bus definition

*        Other Restrictions
         RES_WINDSHED     maximum amount of windshedding
;

*        Objective functions
OBJ_cost..
                 COST =E= SUM(sc,
*                         weight(sc) * (
                          SUM(p, c(p) * G(p,sc))
                          + 500 * SUM(n, LOADSHED(n,sc))
                          + 500 * SUM(n, WINDSHED(n,sc))
*                          )
                          )
;

*        Market clearing equations
MKT_lp(n,sc)..
                 0 =E= q(n,sc) + NETINPUT(n,sc)
                         - SUM(p$mappn(p,n), G(p,sc))
                         - g_wind(n,sc)
                         - g_solar(n,sc)
                         - LOADSHED(n,sc) + WINDSHED(n,sc)
;


*        Thermal generation restrictions
RES_gmax(p,sc)..
                 G(p,sc) =L= g_max(p)
;


*        Network defintions and restrictions
DEF_LINEFLOW(l,sc)..
                 LINEFLOW(l,sc) =E= SUM(n$h(l,n), h(l,n) * DELTA(n,sc))
;

DEF_NETINPUT(n,sc)..
                 NETINPUT(n,sc) =E= SUM(nn, b(n,nn) * DELTA(nn,sc)) * MVABase
;

RES_pmax(l,sc)..
                 LINEFLOW(l,sc) * MVABase =L= P_max(l)
;

RES_pmin(l,sc)..
                 LINEFLOW(l,sc) * MVABase =G= - P_max(l)
;

DEF_slack(n,sc)..
                 DELTA(n,sc) * slack(n) =E= 0
;
```

```
*        Other Restrictions
RES_WINDSHED(n,sc)..
                 WINDSHED(n,sc) =L= g_wind(n,sc)
;

model OPF_Germany /all/;
solve OPF_Germany min COST use lp;
```

TECHNISCHE UNIVERSITÄT DRESDEN

Abstract

This dissertation focuses on selected aspects of network congestion arising in liberalized electricity markets and their management methods with a special weight placed on the integration of increased renewable generation in Europe and Germany. In a first step, the theoretical concepts of congestion management are introduced complemented by a review of current management regimes in selected countries. In the second step, the European approach of managing congestion on international as well as national transmission links is analyzed and the benefits of an integrated congestion management regime are quantified. It is concluded that benefits can be achieved by a closer cooperation of national transmission system operators (TSOs). Thirdly, the German congestion management regime is investigated and the impact of higher renewable generation up to 2020 on congestion management cost is determined. It is shown that a homogeneous and jointly development of generation and transmission infrastructure is a prerequisite for the application of congestion alleviation methods and once they diverge congestion management cost tend to increase substantially. Lastly, the impact of intermittent and uncertain wind generation on electricity markets is analyzed. A stochastic electricity market model is described, which replicates the daily subsequent clearing of reserve, dayahead, and intraday market typical for European countries, and numerical results are presented.

Author

Friedrich Kunz was born in Bad Saarow in 1983. He studied at Technische Universität Dresden from which he received a diploma in industrial engineering in 2009. Afterwards he continued with postgraduate studies at the Chair of Energy Economics (EE^2) at Technische Universität Dresden and received a PhD in 2013. From 2009 till 2012, he was holder of a RWE scholarship (RWE Studienförderung). His research focus is on electricity market modeling, especially transmission networks and congestion management.

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