Modeling Competition and Investment
in Liberalized Electricity Markets

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Abstract

In this thesis current questions regarding the functionality of liberalized electricity markets are studied addressing different topics of interest in two main directions: market power and competition policy on electricity wholesale markets, and network investments and incentive regulation. The former is studied based on the case of the German electricity market with respect to ex-post market power analysis and ex-ante remedy development. First an optimization model is designed to obtain the competitive benchmark which can be compared to the observed market outcomes between 2004 and 2006. In a second step the horizontal breaking up of dominant firms (divestiture) is simulated applying equilibrium techniques (the classical Cournot approach and the Supply Function Equilibrium approach). The later issue of transmission capacity investment is addressed by highlighting the complexity of network investments in electricity markets and by analyzing a regulatory mechanism with a two part tariff approach. The technical characteristics of power flows are combined with economic criteria and tested for different network settings.

JEL-code: L94, L51, D61

Key words: electricity, liberalization, modeling, market power, Germany, Cournot, SFE, divestiture, network investment, incentive regulation

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Table of contents

Figures

Tables

Abbreviations

AC	Alternating Current
AEEG	Regulatory Authority for Electricity and Gas (Italy)
APX	Amsterdam Power Exchange
ARA	Amsterdam-Rotterdam-Antwerp
Bafa	Federal Office of Economics and Export Control (Germany)
Belpex	Belgian Power Exchange
Benelux	Belgium, Netherlands, Luxemburg
BETTA	British Electricity Trading and Transmission Arrangements
BMWi	Federal Ministry of Economics and Technology
bn.	Billion
CAISO	California Independent System Operator
CalPX	California Power Exchange
CCGT	Combined Cycle Gas Turbine
CEER	Council of European Energy Regulators
CEGB	Central Electricity Generation Board (UK)
CGE	Computable General Equilibrium
CHP	Combined Heat and Power
CNSE	Comisión Nacional del Sistema Eléctrico (Spain)
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
CRE	Commission de Régulation de l'Energie (France)
DC	Direct Current
DCLF	DC load flow model
DENA	German Energy Agency
DEWI	German Wind Energy Institute
DG	Directorate-General (EU)
DGTREN	Directorate-General for Energy and Transport
DOE	Department of Energy (US)
DOJ	Department of Justice (US)
DTe	Office of Energy Regulation (Netherlands)
DWD	Deutscher Wetterdienst
EC	European Commission
EDF	Electricité de France
EEX	European Energy Exchange (Germany)
EFET	European Federation of Energy Traders
ENEL	Ente Nazionale per l'Energia Elettrica (Italy)
EPEC	Eequilibrium Problem with Equilibrium Constraints
ERCOT	Electric Reliability Council of Texas
ERGEG	European Regulators' Group for Electricity and Gas
ESB	Electricity Supply Board (Ireland)
ETSO	European Transmission System Operators
EU	Europan Union
EUA	EU emission Allowances
EWI	Institute of Energy Economics at the University of Cologne
FCA	Finnish Competition Authority
FERC	Federal Energy Regulatory Commission (US)
FTR	Financial Transmission Right
GAMS	General Algebraic Modeling System
GDF	Gaz de France
GJ	Giga Joule
GRTN	Gestore della Rete di Trasmissione Nazionale (Italy)

GSE	Gestore dei Servizi Elettrici (Italy)
GW	Giga Watt
HHI	Herfindahl-Hirschman Index
IEEE	Institute of Electrical and Electronics Engineers
IEM	Internal Electricity Market
IFIEC	International Federation of Industrial Energy Consumers
IPP	Independent Power Producer
ISO	Independent System Operator
KKT	Karush–Kuhn–Tucker
kW	Kilo Watt
kWh	Kilo Watt-hour
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LOSEN	Ley de Ordenación del Sistema Electrico Nacional (Spain)
LP	Linear Program
Magnox	Magnesium Alloy Graphite Moderated Gas Cooled Uranium Oxide Reactor
MCP	Mixed Complementarity Problem
Mibel	Iberian Electricity Market
MILP	Mixed Integer Linear Program
Mn.	Million
MPEC	Maximization Program with Equilibrium Constraints
MW	Mega Watt
MWh	Mega Watt-hour
NERC	North American Electric Reliability Council
NETA	New Electricity Trading Arrangements
NJPBU	New Jersey Board of Public Utilities
NMa	Netherlands Competition Authority
NO_x	Nitrogen Oxide
OASIS	Open Access Sametime Information System (US)
OCGT	Open Cycle Gas Turbine
OFFER	Office of Electricity Regulation (UK)
OFGEM	Office of the Gas and Electricity Markets (UK)
OMEL	Compañía Operadora del Mercado de Electricidad (Spain)
OMI	Iberian Market Operator
OMIP	Operador do Mercado Ibérico de Energia (Portugal)
OTC	Over-The-Counter
PAPUC	Pennsylvania Public Utility Commission
PG&E	Pacific Gas & Electric
PJM	Pennsylvania - New Jersey - Maryland
PNP	Proactive Network Planning
PPA	Power Purchase Agreement
PSP	Pump Storage Plant
PURPA	Public Utility Regulatory Policy Act (US)
REC	Regional Electricity Company (UK)
RES	Renewable Energy Sources
RTE	Réseau de Transport d'Electricité (France)
RTO	Regional Transmission Organizations (US)
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SDM	Standard Market Design (US)
SEP	Electricity Generation Board (Netherlands)
SFE	Supply Function Equilibrium
SoCalGas	Southern California Gas
SSNIP	Small but Significant and Non-transitory Increase in Price
TPA	Third-Party Access
	nTPA negotiated TPA
	rTPA regulated TPA
TEN-E	Trans-European Energy Networks Program
Transco	Transmission Company

TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	Tera Watt-hour
UCTE	Union for the Coordination of Transmission of Electricity
US	United States
VGE	Verlag Glückauf
VDN	Association of German Network Operators
VIPP	Virtual Independent Power Producers
VPP	Virtual Power Plant

Nomenclature

Chapter 3:

Indices:

H	height	*ref*	reference
max	upper boundary	*t*	time period (hours)
min	lower boundary	τ	subset of hours
p	plant		

Variables and Parameters:

c	(marginal) costs [€/MWh]	PSP_{up}	energy demanded to fill a PSP [MWh]
CO_2 *price*	EUA price [€/t]		
d	demand [MWh]	PSP_{down}	energy produced by a PSP [MWh]
emissions	CO_2 emissions [t/MWh]	$PSP_{storage}$	filling level of a PSP [MWh]
fuelprice	fuel price [€/MWh]	*sc*	startup fuel costs [€/MWh]
g	generation [MWh]	*startup*	startup costs [€]
l	start-up time [h]	z_o	surface roughness [.]
on	binary plant condition variable {0,1}	η	efficiency [.]
		v	wind speed [m/s]
operationcosts	operation costs excluding fuel [€/MWh]		

Chapter 4:

Indices:

F	fringe	*n*	neighboring countries
G	Germany	*O*	oligopolistic
i,j	firm	*obs*	observed
I	import	*t*	time period (hours)
k	shock	*z*	dummy set
mod	modeled		

Variables and Parameters:*

c	marginal costs [€/MWh]	γ	slope of demand function [GW/€]
comp	dummy for competitiveness {0,1}	δ	vector of time dummies
D	demand level [GW]	ε	error term
f	fixed-capacity contract [GW]	μ	time dummy coefficient
q	output [GW]	λ	marginal cost function coefficient
α	highest demand intercept [GW]	Δ	demand shock [GW]
β	slope of supply function [GW/€]		

Chapter 5:

Indices:

i,j	nodes	*T*	last period
max	upper boundary	*w*	weight
t	time period	*0*	starting condition

Variables and Parameters:*

a	extension cost function parameter [€]	q_i	net injection at a node [MW]
		q_{ij}	FTR between i and j [MW]
B_{ij}	line series susceptance	Q_{ij}	Set of all q_{ij}
b	extension cost function parameter [€/MW]	*p*	nodal price [€/MWh]
		p(.)	demand function
c(.)	transmission costs function [€]	*pf*	power flow [MW]
d	demand [MWh]	*r*	interest rate [.]
ecf	extension cost factor	*RPI*	inflation [.]
F	fixed fee [€]	*W*	welfare [€]
f(.)	extension cost function [€]	*X*	efficiency factor [.]
g	generation [MWh]	X_{ij}	line reactance
k	line capacity [MW]	Θ	voltage angel difference
mc	marginal generation costs [€/MWh]	π	Transco profit [€]
		τ	FTR auction price [€/MW]
N	number of consumers [.]		

* Note that the calculation are carried out for hourly time steps. Thus MW(GW) and MWh(GWh) are used interchangeable.

1 Introduction

“We will make electricity so cheap that only the rich will burn candles…”

credited to Thomas Edison

In the early days of electricity markets in the late 19^{th} century of America’s fledgling electricity industry, entrepreneurs Thomas Edison, Samuel Insull and George Westinghouse competed to electrify homes and businesses. The price of electricity was set by the number of light bulbs or rooms, not actual usage. Standards had yet to be established for alternating or direct current transmission (Nikola Tesla – alternating – vs. Edison – direct – is known as the “war of currents”), and existing technology limited distribution to short distances. The history of the industry shows that many small utilities with overlapping distribution lines and inefficiencies lead to high costs (Stoft, 2002, p. 6), and while it took years, the industry gradually transformed. Those early competitive markets were replaced by monopolized and regulated markets in the course of the 20^{th} century based on the natural monopoly character of electricity transmission and distribution as well as economies of scale in generation via large steam turbine systems. In the late 1980s and during the 1990s the monopoly status quo in the US was disrupted by growing interest in the new, liberalized models of major electricity markets in the UK, Australia, New Zealand, Chile, and Europe.

The changeover instigated much debate over the best methods to design, operate, regulate, and analyze the new markets. The dominance of engineering analysis during the regulated era soon broadened to incorporate economics and engineering-economics studies. In reviewing a multitude of issues, this thesis has chosen to focus upon three topics of great interest to researchers and policy-makers alike: market power, competition policy, and incentive regulation. The topics are analyzed using mathematical modeling techniques to obtain insights that in turn may contribute to future discussion.

The remainder of this thesis is structured as follows. *Chapter 2* reviews the restructuring processes in electricity markets around the world in the last decades. It sets out the general framework of the thesis and the modeling approaches used for analysis. *Chapter 3* examines the first topic, market power, using Germany’s electricity market as the base case. Given the present structure of two dominant firms and four oligopolists owning about 80% of generation capacity, the issue is whether the price increases observed in the last years are based solely on increasing fuel prices. The price setting is simulated using an optimization model to obtain a competitive benchmark that can be compared to the observed market outcomes. The results for 2004 until 2006 suggest that a large percentage of the prices lie above the modeled competitive level. A robustness test indicates that this divergence cannot be explained only by the simplifying model assumptions.

Chapter 4 presents the second topic, competition policy. Can a truly competitive environment emerge without proper, pro-active regulatory policy? Breaking up Germany’s vertically-integrated dominant firms is one possible solution. Applying equilibrium techniques (the classical Cournot approach and the Supply Function Equilibrium approach), divestiture scenarios for the market are simulated. The results indicate that although Germany's is among the "less" concentrated markets in Europe, requiring divestiture of the two dominant incumbents can produce significant welfare gains and price reductions.

Chapter 5 focuses on incentive regulation, specifically the development of incentives to foster investment in transmission. Most liberalized electricity markets face increasing network congestion due to changes in the generation structure, increased demand and increasing trade. Since electricity networks are natural monopolies, market mechanisms are unsuited to provide investment incentives and thus a proper regulatory framework is required. Based on the technical characteristics of power flows, the chapter highlights the problems when deriving cost estimates in transmission. A two-part tariff approach to incentivize transmission companies is tested within a meshed network environment. The problem is formulated as a mathematical program with equilibrium constraints. The results indicate that the mechanism is suited for electricity networks, leads to welfare enhancing investments, and holds promise for real-world application. The thesis concludes with a summary and suggestions for further research in *Chapter 6*.

2 Review of Liberalization and Modeling in Electricity Markets

2.1 Introduction

In the old days of vertically integrated, monopolistic supply, most modeling focused on technical processes and network calculations. However, this changed drastically in the last two decades as markets were opened for competition and economic modeling methods became applicable. In addition the reform process induced the need for tools to analyze the new markets from different perspectives. Governments, policy-makers, and regulators all need robust analyses to judge the implementation and effectiveness of new market rules. Competition authorities have to analyze the impact of mergers and acquisitions. Market operators need dependable software to run the systems. Companies need forecasts and investment analysis. And last but not least scientist rely on modeling techniques to analyze the market performance ex-post, understand market processes, and further develop the market given the future challenges of electricity markets world wide.

The literature that examines various aspects of electricity markets has expanded significantly to address research questions throughout electricity's value chain. The focus of this review lies on aspects of competitiveness and regulation in generation and transmission markets and market design whereas distribution and retail are not pursued in detail.

In Section 2.2 a review on the liberalization process of electricity markets around the world including the main motivation, the actual processes, and lessons learned is provided highlighting the current framework of competitive electricity markets to be assessed. In section 2.3 an overview about current modeling trends regarding liberalized electricity markets is provided. A particular focus is on market design and market performance. The review does not go into detail on related issues including the growing debate about environmental aspects, or aspects on the retail side, i.e. smart metering and demand response, nor does it discuss the issue of actual operations from a technical point of view. The modeling techniques are first structured according to the underlying mathematical principles. Afterwards, a taxonomy of research topics analyzed with modeling approaches is presented including market power, investment analysis, price forecasts, network modeling, and market design. I do not discuss the mathematical formulation of the different methods in detail, but rather intend to provide an overview of the applied techniques.

A comprehensive literature survey on the specific topics of each Chapter is provided in Chapter 3 (market power), Chapter 4 (competition policy and strategic company behavior), and Chapter 5 (network investments) respectively.

2.2 Liberalization of Electricity Markets

Electricity markets around the world were for a long time either formed by vertically-integrated, state-owned companies, or private firms subject to governmental regulation that were often monopolies within their supply area. Following Shioshansi (2006a) the prime justifications for regulatory intervention are:

- Significant economies of scale and scope that favor large integrated utilities
- The natural monopoly character of electricity transport
- Segments of the electricity value chain that are regarded as indivisible
- The belief that private investment will not occur without long-term hedging.

Despite the assumed advantages, this market paradigm had many shortcomings, including: classical regulatory problems, e.g., the risk of over-investments and regulatory capture; little or no customer choice; price disparities; and an absence of incentives and technological innovation. It was not until the 1990s that this paradigm was rejected in favor of market-based approaches.[1] By the end of the century liberalization processes had been initiated in about 50 countries (Pollitt, 1999) although the process slowed after the dramatic failure of the California market in 2000-2001.

The change to free markets is based on several economic and policy motivations that differ strongly from country to country (Shioshansi, 2006a). Whereas developed countries hope to overcome the inefficiencies inherent in large, regulated companies, developing countries often initialize liberalization because governments lack money for necessary investments.[2] In addition the technological advancement of gas-fired turbines, in particular highly efficient combined cycle turbines, have broken the dominance of coal and nuclear plants and significantly lowered barriers to entry for private investors in generation.

The process of restructuring and liberalization is not a synonym for the same set of policies and measurements throughout the world. Several approaches and measurements have been taken. Sioshansi and Pfaffenberger (2006) distinguish:

- *Restructuring:* reorganizing the roles of market participants (including regulators and institutions), not necessarily a "deregulation" of the market,
- *Liberalization:* synonym of restructuring with the aim to obtain competitive (sub)markets,
- *Corporatization:* make state-owned institutions act like private ones,
- *Privatization:* selling state-owned assets to private stakeholders,
- *Deregulation:* removing or reducing of sector specific regulation, however, a misnomer as competitive markets still need some regulation.

According to Jamasb and Politt (2005) successful liberalization generally requires: sector restructuring, implementation of competitive wholesale markets and retail supply, incentive regulation of the grid, independent regulation, and privatization. A successful liberalization thus requires a proper initial restructuring, a large share of government initiative, and political and regulatory endurance to overcome the drawbacks.

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[1] Sioshansi (2006b) also defines four phases of liberalization: 1; problems in existing system; 2; what is broke and how to fix it; 3. implementation of new market rules; 4. ongoing adjustment of reforms.

[2] Further motivations include political campaigns (Newbery, 2000), public debt (e.g., in Victoria, Australia), the growing complexity of regulation, and a need for more decentralized decision-making processes.

2.2.1 UK and Norway: First Movers

2.2.1.1 UK[3]

The British electricity market has been state-owned since its nationalization in 1947. The Central Electricity Generation Board (CEGB) possessed the monopoly on generation and transmission, distribution was divided into twelve Area Boards, and the Scottish market consisted of two vertically integrated companies. The sector was subject to governmental cost-plus regulation. The coal industry was also state-owned and sold 75% of its output to national generators. Thus the UK power plant fleet was largely focused on coal (Newbery, 2005a).

With the third election victory of the Thatcher government in 1987 the privatization of the industry appeared on the political agenda. The end results were an ambitious privatization process and the breakup of the CEGB (see Green, 2006). With the passage of the Electricity Act of 1989 a fundamental step was taken to transform the nationalized industry into a competitive market. The CEGB was split into four companies of which three were sold to private stakeholders: one grid company (National Grid) and two generators (National Power und PowerGen). The larger share of generation (about 60%, 40 plants with 30 GW capacity) went to National Power, leaving the remainder for PowerGen (40%, 23 plants with 20 GW capacity). Initially it was planned that the twelve British nuclear plants would be privatized with National Power hoping that the resulting company structure would be economically viable. However, this idea was abolished and the nuclear power plants remain state-controlled as Nuclear Electric.

The twelve Area Boards were reorganized into twelve Regional Electricity Companies (RECs) that jointly owned National Grid. The market was opened stepwise with the aim of full supplier choice for all consumers in 1998. The price-cap regulation of network tariffs as well as price regulation of non-eligible customers was transferred to the Office of Electricity Regulation (OFFER, later OFGEM). Competition in the wholesale market was expected to be spurred by the mandatory pool that defined clearing prices via supply bids and demand forecasts by National Grid.

In the first years prices increased slightly and there was a significant entry of new market participants into gas-fired power plants (aka Dash for Gas) (Figure 2.1). This entry was supported via long-term contracts for gas and electricity. RECs were allowed to offer Power Purchase Agreements (PPAs) to Independent Power Producers (IPPs) and in return could obtain property rights. This allowed the RECs to reduce their dependence on the two large suppliers. The PPAs in turn allowed the IPPs to sign long-term take-or-pay natural gas contracts. The entry support led to a significant capacity increase in natural gas-fired plants: within a few months 5 GW of new capacity had been contracted by IPPs and another 5 GW by the two incumbents.

In 1993 OFFER decided that the latest price developments meant a decoupling of fuel and electricity prices and consequently introduced a price monitoring as well as a divestiture of generation capacities

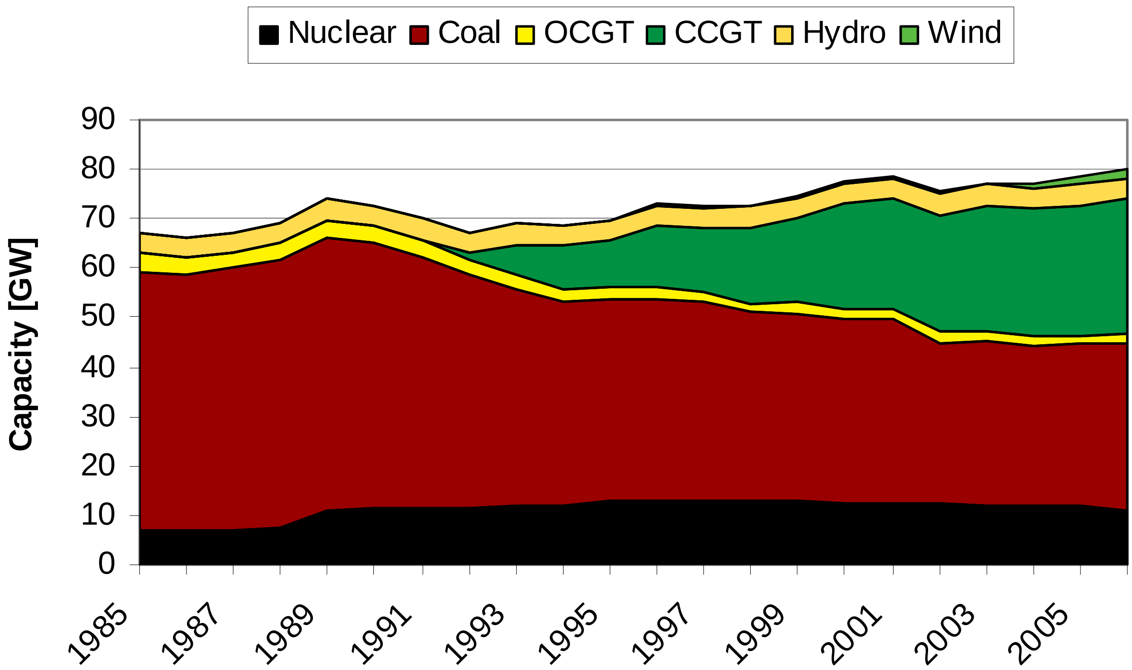
[3] This case study is based on Newbery (2005a), Stubbs and Macatangay (2002), Thomas (2004).

to increase competition (see Section 4.2.2.1 for details). In 1996 the state-owned nuclear plants were partly privatized (the older Magnox-reactors remained state-owned).

With the phase-out of the take-over protection for the RECs in 1995 a number of mergers and acquisitions took place that led to a rearrangement of the initially introduced separation between generation and supply.[4] Until 2002 all regional suppliers were acquired by other companies, and today the supply market is controlled by six vertically integrated suppliers while the generation segment is relatively competitive (Figure 2.2).

Another step in the reform process was the abolishment of the old pool model which was replaced by New Electricity Trading Arrangements (NETA) in 2001. Within NETA four voluntary, overlapping market segments exist: a bilateral market for long-term transactions, a forward market for standardized products, a spot market, and a reserve market. The main difference to the pool lies in the responsibilities of the system operators that have been reduced to network security leaving unit commitment and dispatch to the market participants. In 2005 the trading arrangements were extended to include the Scottish market. Thus with the „British Electricity Trading and Transmission Arrangements“ (BETTA) the whole British island is coordinated by one wholesale market.

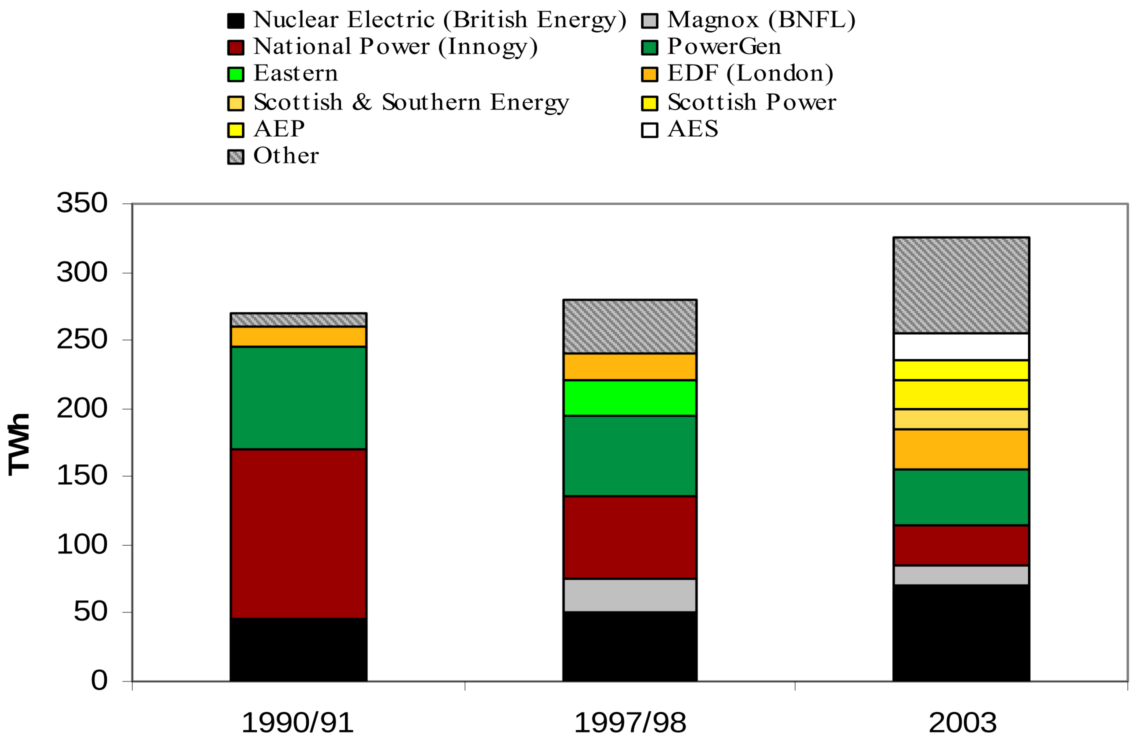
Figure 2.1: Generation capacities in Great Britain



Source: Eurostat

[4] From 2000 on all suppliers had to fully unbundle their network operations.

Figure 2.2: Generation in Great Britain



Source: Based on Green (2006, p. 2537 and p. 2538)

2.2.1.2 Norway and the Nordic Market[5]

The Norwegian market was the second to be fully liberalized in Europe. In 1990 the Norwegian Parliament approved the reform of the electricity market which was implemented in January 1991. The main motivations for the new energy market legislation were the need for cost savings and efficiency, price discrimination across consumer groups, regional price differences, and overinvestment. The core element of the reform was a decentralized free trade approach. The restructuring included a separation of the transmission system from the state-owned Statkraft into a new state-owned company, Statnett, while the remaining generation facilities were reorganized but remained with Statkraft. Other reforms included the introduction of a common carrier approach and grid access for third parties, retail opening, and the establishment of voluntary wholesale markets. Contrary to the UK, Norway had a spot market before liberalization in order to allow better management of the country's large hydro generation capacities (market for occasional power). The liberalized spot market Nordpool (operated by a subsidiary of Statnett) was, more or less, just the market for occasional power opened for market participants. Finally, markets for long-term transactions were also established.

Unlike the UK, public ownership of Statkraft was maintained and thus a large share of generation facilities, about 30% of total production. The Norwegian approach aimed at introducing competition via structural competition and ownership concerns were considered a minor issue. Generation and

[5] This case study is based on Amundsen and Bergman (2006), Amundsen and Bergman (2007), Friedholfsson and Tangeras (2008), Johnson (2003), and Midttun and Thomas (1998).

supply were not split. The first phase of the market, 1991-1993, was characterized by low prices, a competitive market, and surplus supply. Similar to the British experience after liberalization, however, market power concerns gained ground as prices increased (Johnsen et al., 1999).

The other Nordic countries integrated their electricity sectors into the common Nordic market: Sweden joined in 1996, Finland in 1998, Western Denmark in 1999, and Eastern Denmark in 2000. All countries established state-owned system operators to manage the grid and balance supply and demand. The voluntary wholesale market Nordpool is jointly owned by the Transmission System Operators (TSOs) of the participating countries. Due to the coupling of several national markets no company has a dominant position although most of the large players are dominant in their home market (Table 2.1). The Nordic market was the first to introduce a combination of energy and transmission capacity auctioning. In case of a cross-border congestion signal by a TSO the bids in the market are allocated to several congestion areas pre-defined by country borders (in the case of Norway, up to four congestion areas). A different price is defined for each area. Transmission from one area to any other is priced with the difference of the area prices. Congestion within one area is managed via counter trading and re-dispatching of power plants. The resulting congestion rent is split between the TSOs.

The first major test of the Nordic market took place in 2002-2003 when unexpectedly dry weather reduced the available hydro generation, the major energy source in Scandinavia. Producers started to restrict supply in fall 2002 due to low reservoir levels and prices soon rose to three times the normal level. They remained high during 2003 before gradually normalizing. Although consumer prices also increased, politicians did not abolish liberalization or intervene in market processes. The high wholesale prices translated into higher retail prices and thus also to a slight demand reduction (particularly in Norway, less so in Sweden) that eventually helped to control the crisis. Post-crisis some researchers consider the event as proof of flawed markets, but others see it as a sign of market maturity (Newbery, 2005b).

Table 2.1: Generation structure in the Nordic countries (2004)

Company	Production [TWh]	Production share [%]	Home country
Vattenfall	70.5	18.6	Sweden
Fortum	50.7	13.4	Finland
Statkraft	34.3	9.1	Norway
Sydkraft (now E.ON Sverige)	34.0	9.0	Sweden
Pohjolan Voima	17.7	4.7	Finland
Teollisuuden Voima	15.9	4.2	Finland
Elsam (now DONG Energy)	14.6	3.9	Denmark
E2 (now DONG Energy)	10.8	2.8	Denmark
Others	130.5	34.4	
Total	**379.0**	**100**	

Source: Amundsen and Bergman (2007)

2.2.2 Continental Europe

Spurred by the liberalization in the UK and Scandinavia the European Commission (EC) undertook a reorganization of its electricity policy that resulted in the proposal of a liberalized, market-based, Europe-wide electricity market (Internal Electricity Market, or IEM). However, "Europe" is not a single entity with a central government to establish and administer new market arrangements. Therefore, the liberalization of continental Europe's markets can be summarized as a top-down approach in which the EC develops a road map for liberalization and monitors the process (Section 2.2.2.1), and the national governments choose how to implement its directives (Section 2.2.2.2). This political arrangement frequently obstructs the outcomes desired by the EC which is then forced to pursue new proposals.

2.2.2.1 The European Directives[6]

In the pre-liberalized world the EC regarded electricity not as a good but a service of economic interest. Thus it was not subject to the EU Treaties of Rome (1957) and Maastrich (1993) requiring open markets within the European Union. With the liberalization in UK and Scandinavia this view changed, especially after the European Court of Justice ruled that electricity is indeed a good (Meeus et al., 2005).

The process of liberalization began with the Electricity Directive 96/92/EC which was implemented in 1996 and had to be adopted by each country by February 1999.[7] This first directive, aimed at a gradual market opening, included:

- The introduction of "eligible customers" which could freely choose their supplier (at least 1/3 of the market in 2003)
- Three possible third-party access (TPA) models:
  - negotiated TPA
  - regulated TPA
  - single-buyer model
- Administrative unbundling of network activities, generation, and supply.

The EC did not address privatization, which was left to the national governments to resolve, since the utility sector in member states ranged from state-owned monopolies to regulated private firms.

The outcome of Electricity Directive 96/92/EC was unsatisfactory and a second directive was proposed at the European Council in Stockholm in 2001, which was later formalized as Directive 2003/54/EC. It reduced freedom of choice and shortened the deadlines to encourage convergence among the member states:

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[6] This case study is based on Green (2006), Jamasb and Politt (2005), Meuss et al. (2005), Moselle (2008), Newbery (2002), and Percebois (2008).

[7] A large body of institutions also became involved: Directorate-General of the EC developing and implementing European policies (DGTREN, DG Competition, DG Environment), the Florence forum, the Council of European Energy Regulators (CEER), the European Regulators' Group for electricity and gas (ERGEG), voluntary European associations (generators: Eurelectric, consumers: IFIEC, traders: EFET), and TSOs and their boards (UCTE, Nordel, ETSO).

- Eligible customers: all non-household customers free to chose from July 1, 2004; and all consumers free from July 1, 2007,
- Grid access: only regulated TPA permitted and a regulator required
- Unbundling: requiring legal unbundling for transmission after July 1, 2004, and for distribution after July 1, 2007.

The second directive ruled out the single buyer model and negotiated TPA, and required full market opening till July 2007 which aimed at largely increasing competition on electricity markets. However, declared market opening does not by definition mean effective competition. A particular focus was also put on the role of the regulator as a key market institution. The EC's second directive required the establishment of a regulator (if not already in place) and regulatory independence (see Larsen et al., 2006, on that issue). The second directive, only partially fulfilled in 2007, remains incomplete in 2009.
A particular concern of the IEM development is the insufficient cross border capacity and the partly inefficient allocation mechanism. Starting with the liberalization process the Trans-European Energy Networks Program (TEN-E) was initiated. Since the first directive did not address the issue of cross border trade, to provide a framework and to establish more consistent trading, Regulation 1228/2003 was issued together with Directive 2003/54/EC. The regulation included a compensation mechanism for cross border electricity flows and harmonized cross border transmission charges and capacity allocation.
TEN-E together with Regulation 1228/2003 builds a framework for the cross border development. TEN-E, lists bottlenecks in need of upgrading, provides co-financing of feasibility studies, and to a small extent, co-financing of the actual grid investment. Following Regulation 1228/2003, revenues from capacity allocations are to be used for: (1) guaranteeing the availability of capacity; (2) network investments; or (3) reducing network tariffs. Regulators are often biased to take the latter option and reduce short-term tariffs (Meuss et al., 2005). The market-based allocation of interconnection capacity required by the regulation is now gradually being implemented which should lead to a full or partial coupling of national markets via implicit energy auctions (e.g., 2006, with France, Belgium and the Netherlands).
The EC issues yearly benchmark reports on the status of liberalization. The fourth report in 2005 concluded that although states were moving in the right direction, some were rather slow in doing so, and eight received a warning from the EC. The 2005 report also found that the market-based allocation of cross-border capacities should have been in place in 2004 but that 13 of the 25 most-congested connections had none (Meuss et al., 2005).
The EC's 2007 benchmarking report concluded that despite encouraging improvements, particularly in cross-border coordination, major barriers to achieving a single IEM still existed. EC legislation was insufficiently implemented; regulators were not empowered enough to encourage implementation of legal requirements; the industry needed to implement without compromise; and regulated energy

prices were not resolved. The EC addressed the shortcomings in a third legislative package issued in September 2007:

- Unbundling:
  - ownership unbundling: the preferred option by the Commission (Torrit, 2008),
  - Independent System Operator (ISO): this option is included after France, Germany, and seven other member states have opposed the full unbundling in July 2007.
- Regulators:
  - harmonizing and strengthening the powers and duties of regulators,
  - ensuring independence,
  - mandating a co-operation between regulators.
- Creation of an European agency for the coordination of energy regulators (with limited powers, focused on cross-border issues),
- Establishment of an European Network for TSOs:
  - to develop harmonized standards regarding grid access,
  - to ensure coordination of operation,
  - to coordinate and plan network investments.

The third package fosters the integration and coordination between TSOs and regulators that has so far been voluntary. The slow progress of those voluntary approaches (e.g. the development of an Inter-TSO compensation mechanism for transit flows) and the slow regional integration of national markets were one reason for the formal adoption of the issue in the package. Only time will tell whether these problems can be resolved. Additionally, the relationship between the EU's ambitious environmental goals and the EC's market goals is of concern. Table 2.2 shows that Europe's desire for a single competitive market with many players, lower prices, and appropriate regulation is unfulfilled.

Table 2.2: Major electricity companies in continental Europe

Company	EDF France	SUEZ Belgium	EON Germany	RWE Germany	ENEL Italy	ENDESA Spain	IBERDROLA Spain
Sales in 2006 [bn €]	59	45	69	42	39	21	12
Capacity [GW]	131	48	54	43	46	39	38
Market share Origin	84%	75%	38%	30%	43%	44%	31%
Market share EU	24%	5%	14%	11%	10%	6%	4%
Main subsidiaries	- London Electricity - EnBW - Edison	- GDF	- PowerGen - Ruhrgas	- NPower - Thyssengas	- Endesa		- Scottish Power

Source: Percebois (2008)

2.2.2.2 *The National Implementation*

As discussed above, the EC's first directive failed to define a consistent program of implementation and subsequent legislative proposals and directives did not produce convergence among member states and a single IEM. Although the Commission has set guidelines in which way liberalization of the national markets shall proceed, it left a lot of issues open for the national governments to define. The directives make no recommendation or requirement regarding the actual wholesale market design. Thus either the national governments set up a market architecture (e.g. the mandatory pool in Spain) or left it to the industry to develop proper markets. Consequently, most of the trade transactions in the EU take place bilaterally and in over-the-counter (OTC) markets. Due to the intransparancy of those trades and the associated high transactions costs power exchanges were created due to private and partly public initiatives in most member states that provide reference prices and a standardized and anonymous trading platform. Furthermore, the topic of horizontal concentration has not been addressed and due to pre-liberalization structures the market concentration remained high in most member states. In addition, cross border mergers and acquisitions lead to a concentration process within Europe (Table 2.2).

Following, a brief review of the restructuring process in the important member states highlights the approaches national governments have taken to implement the directives.[8] Table 2.3 at the end of this section lists the key indicators for all member states.

Germany[9]

According to Germany's energy law of 1935 the country's electricity market was a private sector under state supervision. The federal Energy Industry Act of 1998 implemented the EC's first directive by requiring a non-discriminatory TPA and separate accounting sheets for companies but no real unbundling. German consumers were free to choose a supplier right from the start. Germany chose not to implement a regulator, basically allowing the market to self-regulate with an option of ex-post control by the government. This unsuccessful attempt to implement a TPA was abolished after the EC's second directive. Germany had to established an independent regulator via the federal Energy Act of 2005 which created the "Bundesnetzagentur" and transformed the negotiated TPA to a regulated TPA.[10] The 2005 law also required vertically integrated firms to unbundle.

The liberalization approach of the first phase increased the likelihood of cross-subsidies between the monopoly service and the competitive segments. Brunekreeft (2002) argues that the very low price level at the start of liberalization can be caused by vertical integrated firms keeping competitors out of the market via cross-subsidies. This may also explain why most of the new independent suppliers that entered the market in the first liberalization phase have vanished rapidly. The low prices together with

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[8] The EC's benchmarking report of 2006 gives an in-depth country analysis of the implementation of its second directive (see EC, 2007a).

[9] This case study is based on Heck (2006).

[10] Companies with fewer than 100,000 customers can still be regulated by state agencies.

excess capacity also contribute to the low market entry of new generation beside subsidized renewable energies in the post-liberalization years. In 2000 exchange trading started in Leipzig and Frankfurt and was finally merged 2002 in the European Energy Exchange (EEX) in Leipzig which now provides the reference price for the German market. However, a large fraction of trades still takes place in bilateral and OTC transactions.

The German authorities' lack of concern about market power culminated in the allowance for the EON-Ruhrgas merger that combined the largest vertically integrated electricity and natural gas companies in Germany. Furthermore, Germany has four control areas which leads to inefficient doubling of network services particularly in the balancing markets (see Brunekreeft and Twelemann, 2005; and Riedel and Weigt, 2007). The balkanization within the country hampers efficient cross-border trade since there is no single platform for transaction to and from Germany. The EC considers Germany's high vertical and horizontal concentration and the prevailing cross-border congestion as the major barriers to new entry (EC, 2007a).

France[11]

Europe's second-largest electricity market is characterized by the dominant position of Electricité de France (EDF) of which the state holds a 90% share. EDF was a vertically integrated state-owned monopoly prior to the onset of market liberalization, and has never been privatized or split into several companies to foster competition. With the liberalization process in 2000 the regulator (CRE) was established which controls prices and investments. Network operation was transferred to RTE but the ownership remained with EDF. Legal unbundling took place under the EDF holding.

New generators tend to emerge slowly in a scenario with low-priced nuclear capacity and a dominant utility. To increase market competition a group of traders, generators, and grid companies formed the French energy exchange Powernext which associated in 2006 with the Belgian and Dutch exchanges in a trilateral market coupling.

The EC has criticized France. EDF's dominance combined with a retail policy to provide low, regulated tariffs in addition to competitive tariffs, make entry for new participants very difficult. In fact, the EC does not expect France to become competitive in the near future (EC, 2007a).

Benelux[12]

Until 1998 the *Dutch* electricity market was characterized by four large suppliers and 23 local distributers. The suppliers coordinated via the jointly operated company SEP to provide 80% of generation. All companies were regulated on a regional level. The liberalization process already underway before the first directive anticipated most of the changes demanded by the EC (Osterhuis, 2001). The federal Electricity Act of 1998 transformed the first directive into national law including

[11] This case study is based on Glachant (2004), and IEA (2004).

[12] This case study is based on London Economics (2004), Moselle et al. (2006), Osterhuis (2001), van Damme (2005), and Van Roy (2001).

legal unbundling, a regulated TPA, gradual opening of retail markets until 2004, and a regulator (DTe) which applied price cap regulation of network tariffs.

The initial plan was to merge the four suppliers and SEP into one supplier that could compete in the European electricity market. However, due to different expectations of the four suppliers the merger idea was abandoned. Transmission assets remained with SEP and system operation was transferred to TenneT which is a state-owned company. Wholesale trade takes place in bilateral transactions and after 1999 on the energy exchange APX which TenneT purchased in 2001. On the generation side several mergers and acquisitions characterize the post-liberalization phase. The EC regards the Dutch market as one of the most liberalized in the EU.

The *Belgian* market was and is dominated by the private, vertically integrated company, Electrabel (now owned by GDF Suez), which controlled about 90% of generation and 80% of supply in the pre-liberalized market. In 1999 the first directed was transformed to national law that opted for a regulated market system without splitting the generation segment. Retail competition was introduced slowly, i.e. since 2003 consumers in Flanders were free to choose their supplier whereas Wallonia and Brussels opened up in 2007. Transmission service is tendered by the government for 20 years and is currently controlled by Elia. Due to the dominance of Electrabel and the resulting low liquidity of the Belgian wholesale market most transactions took place in bilateral trades.

The Benelux markets initialized a coupling to increase the efficiency of international trades: in November 2006 the Belgian energy exchange Belpex was established that is coupled with the Dutch APX and the French Powernext. Similar to Nordpool the three markets are cleared as a single entity in cases of unhindered cross-border flows, but are split up in cases of congestion. With the introduction of this trilateral market coupling price convergence sharply increased (De Jonghe et al., 2008).

Italy[13]

The Italian electricity sector, like the UK and France, was virtually controlled by one state-owned company (ENEL) since 1963. Starting with the Bersanie decree of 1999 that codified the first directive into national law ENEL was broken but not completely transferred to private hands, since the government retained a 60% share. Nevertheless, the Bersanie decree introduced competition in generation and (partially) retail, and separation of network activities by transferring all segments of the value chain to separate companies under ENEL SpA as the financial holding company.

In the generation segment ENEL was restricted to a maximum share of 50% and thus had to divest 15 GW: three of its generation companies had to be sold by 2003. The market was first split into a market for eligible customers and a market for all other customers. This market splitting was transitional, due to the deadlines mandated in the second directive. In 2001 a pool wholesale market opened which was “semi-compulsory” and supported by bilateral transactions. The new wholesale market included day-

[13] This case study is based on Ferrari and Giulietti (2005).

ahead, congestion, reserve, and balancing segments. A zonal system was used to address congestion problems.
The network ownership was with ENEL Terna and network operation was transferred to GRTN (now GSE) in 1999 which guaranteed open access to the network according to the regulatory specifications of AEEG. Insufficient cross-border capacities limit the competitiveness of the Italian market which depends heavily on imports to meet demand. Congestion has increased significantly in recent years. The Marzano decree of 2002 simplified administrative barriers for new generation investments which indeed are taking place, but it will take some time to show the effects on the tight supply/demand situation. The Marzano decree also made GRTN the owner of the transmission grid to foster network investment incentives. The failure of Italy's grid in 2003 is partly a result of problems that have not been properly addressed during liberalization (Ferrari and Giulietti, 2005).
The Italian government's large share of ENEL hinders the development of competition since political interference too often constrains market developments. Despite such problems, the EC regards the Italian market as an attractive one, with the incumbent's dominant position and network congestion as the major issues needing resolution (EC, 2007a).

Spain[14]

In 1994 Spain passed the Spanish Electricity Sector Act (LOSEN) to reform the regulatory framework of its market and thus initiated at least some restructuring prior to the EC's first directive. However, actual implementation was delayed and in 1997 the Spanish Electricity Power Act implemented the first directive which opened the generation and retail markets to competition (with a gradual opening of the consumer market), guaranteed grid access, and legal unbundling. The Comisión Nacional del Sistema Eléctrico (CNSE) which had already been created with LOSEN was delegated as sector regulator.
The wholesale market was re-organized as a sequence including a uniform-priced day-ahead, several intra-day, and an ancillary market operated by Compañía Operadora del Mercado de Electricidad (OMEL). Participation is voluntary. However, consumers pay a capacity charge in addition to the energy price which is only re-assigned to market participants. This mechanism has discouraged extensive bilateral trading.
The pre-liberalized electricity sector consisted of a mixture of public and private companies. After several mergers the fragmented structure was replaced by two dominant companies (Endesa and Iberdrola) controlling about 80% of generation and retail. This high concentration bears a risk of market power abuse. However, via "Competition Transition Costs" payments[15] stranded costs were supposed to be recovered during a transition period and on the other hand market power mitigation was ensured (Newbery, 2005b) that kept prices down even during the shortage in winter 2000/2001.

[14] This case study is based on Crampes and Fabra (2004).
[15] A variant of contracts for differences (CfD).

The Spanish market provides an attractive environment for independent generators because the limited interconnection capacity to the lower-priced French grid restrains the high electricity prices. Furthermore natural gas is available via LNG imports. During the last several years new CCGT plants came online. Gas Natural, benefiting from its activity in the gas market, has been an active new entrant in the generation market.

Accompanying the Spanish liberalization the international electricity exchange was opened for market participants. However, the limited available capacities restrict the competitive potential of cross-border trade. Several projects to increase capacity between France and Spain have been delayed or abandoned. In 2001 the Portuguese and Spanish governments agreed to create a single Iberian Electricity Market (Mibel). It actually started in July 2007 with two divisions managing the derivate market (OMIP, Portuguese division) and the day-ahead and intraday market (OMEL, Spanish division). Both divisions are expected to merge into one Iberian Market Operator (OMI). The markets are managed with respect to transmission constraints. Thus in cases of congestions the single market is split into submarkets after Nordpool or the trilateral coupling of France, Belgium and the Netherlands (Capelo at al., 2008).

Table 2.3: Indicators of the liberalization of the IEM, 2005

Country	Unbundling		Market Model	Balancing	Capacity Top 3	Retail Top 3
	Trans.	Dist.				
Austria	leg.	leg.	Bilateral	market	75%	67%
Belgium	leg.	leg.	Bilateral	regulated	95%	90%
France	leg.	man.	Bilateral	market	95%	88%
Germany	leg.	acc.	Bilateral	market	70%	50%
Italy	own.	leg.	Bilateral	reg/TSO	75%	35%
Netherlands	own.	leg.	Bilateral	market	80%	88%
Portugal	own.	acc.	Bilateral	regulated	80%	99%
Spain	own.	leg.	Pool	market	80%	85%
UK	own.	leg.	Bilateral	market	40%	60%
Denmark	leg.	leg.	Hybrid	market	40%	67%
Finland	own.	acc.	Hybrid	market		30%
Norway	own.	leg./acc.	Hybrid	market		70%
Sweden	own.	leg.	Hybrid	market		44%

Source: Green et al. (2006)

2.2.3 United States[16]

The liberalization in the US has a major similarity with the European one: due to the absence of a centrally planned restructuring process liberalization in the US is characterized by diverging national

[16] This case study is based on Joskow (2005, 2006), Newbery (2005b).

processes.[17] Today the US is a mixture of liberalized states, states under traditional regulation, and states in delayed transition (see Figure 2.3).

The pre-liberalized US electricity market was characterized by a large number of private vertically integrated utilities which were primarily state-regulated. The large number of small utilities and operating control areas as well as state regulation limited investment in transmission capacity across regions. The US relied largely on state initiatives supported by the Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE) to promote national liberalization. In essence restructuring consisted of a transmission policy defined by FERC and DOE that opened networks to competition and state-level restructuring of wholesale and retail markets.

The US has three synchronized AC network areas which are divided into ten Regional Reliability Councils. These are further divided into 24 sub-regional reliability organizations. Following the northeast blackout in 1965 the reliability organizations and the North American Electric Reliability Council (NERC) were created to develop voluntary operating reliability criteria and coordination of long-term planning. However, NERC lacked the authority to set investment incentives. The roles of the councils, NERC and the reliability rules have not been adopted within the liberalization process which is one reason why there is an increase in transmission congestion in the US. The blackout of 2003, however, forced the federal government to prioritize grid planning.

Pre-liberalization, transmission pricing was state-regulated and most utilities provided “voluntary” transmission service for neighboring utilities which were regulated by FERC but the commission had no authority to require utilities to allow grid access to third parties.[18] The federal Energy Policy Act of 1992 removed legal barriers with respect to ownership restrictions (discussed below) and expanded FERC’s authority to demand that utilities provide transmission service. With the state restructuring initiative in California FERC realized that transmission access needed to adapt to a completely new market setting and thus ordered two major rules in 1996. Order 888 requires transmission owners to provide third parties grid access at cost-based prices. FERC also issued a weak form of separation by restricting contracts between TSOs and affiliated companies. Order 889 required utilities that are involved in interstate transactions to participate in an Open Access Sametime Information System (OASIS) which provides necessary information for transmission customers. It also requires utilities to functionally separate transmission and unregulated wholesale functions.

The initiative for these two rules took place before many states began to consider major restructuring. The development of competitive wholesale markets and the consequent need for transparent system operations impelled FERC to issue Order 2000, in December 1999. The goal is a regional transmission platform that supports competitive wholesale markets and:

- Transfers system operation to independent operating entities (Regional Transmission Organizations, RTOs)

[17] Furthermore, the US and EU15 electricity market are also of similar extend with about 600-700 GW and both markets are split into three synchronized areas (Newbery, 2005b).
[18] The Federal Power Act of 1935 gave FERC jurisdiction over prices and terms of interstate transmission services.

- Increases the regional scope of network operations
- Assigns responsibilities for maintaining short-term reliability to the independent entities
- Defines RTOs' minimum functions.

All TSOs within the jurisdiction of the FERC had to join one RTO which in principal meant to expand the ISO models established in the northeast (New England, New York, PJM) to the rest of the US. It also reflected FERC's missing authority to demand ownership restructuring since the transmission assets would remain with the TSOs.

The timing of Order 2000 shortly before the meltdown of the California wholesale electricity market was crucial given the demanding requirements. The general slowdown of the liberalization process also slowed reforming the transmission system. Thus Order 2000 did not lead to a complete transformation to RTOs. Frustrated with the implementation FERC issued a proposal for a Standard Market Design (SMD) in 2002. SMD required that ISOs would operate locationally priced wholesale markets; complete unbundling of transmission service; regional transmission planning; market monitoring; and resource requirements. SMD immediately faced strong opposition particularly in southern and western states and FERC soon retreated to focus instead on improving Order 2000.

The second aspect of liberalization in the US is the restructuring of wholesale and retail markets, mostly upon state initiative. It was initiated in 1978 with the Public Utility Regulatory Policy Act (PURPA) that allowed independent generation investments and until the mid 1990s 60 GW of new capacity (about 10% of the US generation capacity) joined the market (mainly in the Northeast, California, and Texas). FERC also issued regulations to ease the administrative barriers for IPPs. Beginning in 1998 with New Hampshire, Massachusetts, Rhode Island and California state restructuring began to foster wholesale and retail competition which enabled new generators to enter the market.

After 1996 about 100 GW of generation capacity had been divested, another 100 GW transferred to unregulated companies (see also Ishii and Yan, 2007; and Bushnell et al., 2005), and between 1999 and 2004, 200 GW of new capacity had been constructed of which 80% was unregulated. However, many merchant investors have encountered financial difficulties and the quantity of new capacity is declining. The restructured markets face a gap between what generators earn and what they need to recover their fixed costs. This is partly due to the inadequate wholesale market design including very low price caps[19] and out-of-market actions by the RTOs for reliability reasons. There is an ongoing debate about developing adequate wholesale markets for capacity investment (e.g., see Cramton and Stoft, 2005).

Retail competition was introduced in some states, mostly those with the highest regulated retail prices in 1996. The monthly utility bill shows a regulated component (network services) and a competitive component (generation and supply). Incumbents were generally required to continue to offer a regulated "default service". Overall the switching numbers of household consumers have been low,

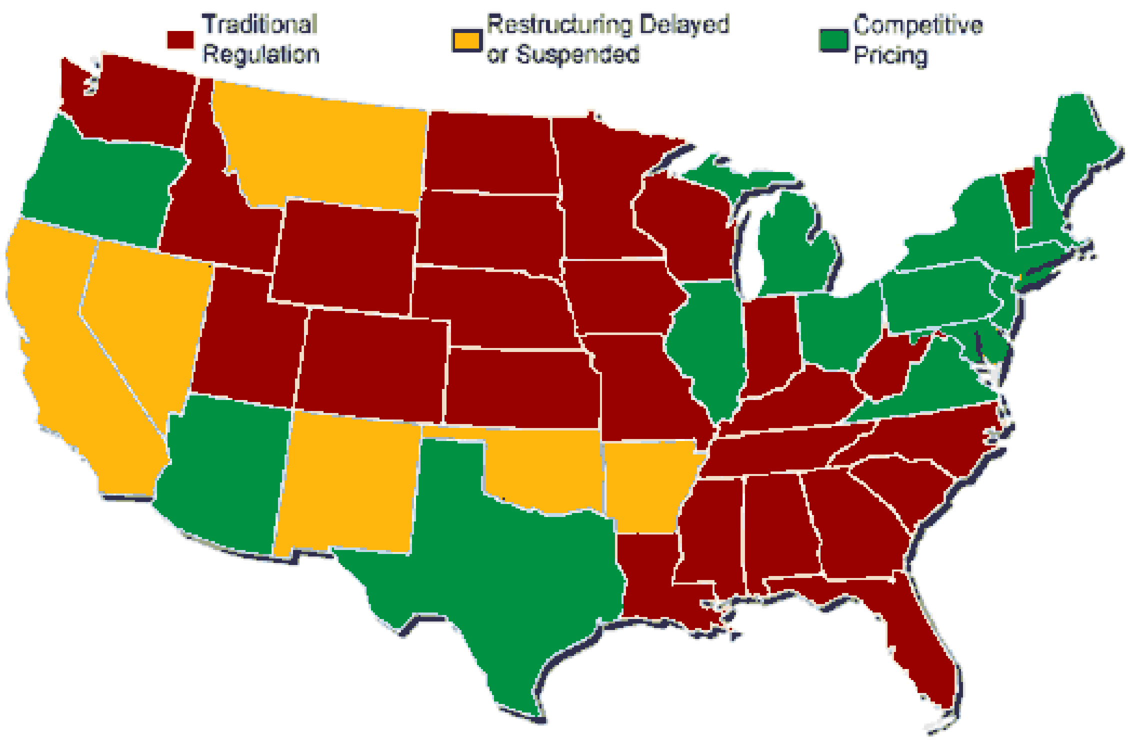
[19] And similar measurements taken to mitigate market power.

with the exception of Texas and New York (Sioshansi, 2008). Only large industrial consumers have really exploited to the opportunities to switch suppliers. Some market critics fault state regulators for complicated rules that the average consumer finds difficult to understand, and failing to penalize marketers who neglect to inform consumers of the costs of switching.

Absent national guidelines, the states took different paths. California adopted a pool-based system, divested incumbent generation, and introduced an ISO. However, the market design was so flawed that it finally broke down in 2000-2001 (e.g., see Blumstein et al., 2002; Joskow and Kahn, 2002; and Kumkar, 2002). In the northeast ISO-based markets with locational prices gradually developed. PJM started operating in 1998 and New England opened in 1999. In PJM vertical integration between retailers and generators remained (see Mansur, 2003) while in New England divestiture of generation assets from vertical integrated utilities occurred. However, many retailers then signed long-term supply contracts with the firms to which they divested. Texas adopted a system like NETA in the UK that relied heavily on bilateral transactions; only part of the state is ISO-adminstered (Adib and Zarnikau, 2006).

Following the California crisis and the eastern blackout in 2003, restructuring efforts in many states were suspended or cancelled even as the northeast and Texas continued to move forward. In summary, the US is a patchwork of fully liberalized markets, hybrids, and no liberalization at all (Figure 2.3).

Figure 2.3: Status of restructuring in the US



Source: Sioshansi (2008)

2.2.4 Other Countries

The first country to introduce a market reform was Chile in 1982. However, the motivation for reforms in developing countries is often the need to increase capital for infrastructure maintenance and expansion. Between 1990 and 1999 private investments occurred in about 75 developing countries, amounting to 160 bn €, with the majority in the generation segment (Jamasb, 2006).

The restructuring processes generally followed the sequence of regulation, restructuring, and privatization. Beside those key elements many developing countries have specific structural issues. Often developing countries have small electricity systems[20] that may favor approaches like the single buyer model. Often, political and institutional settings are unstable, enforcement of property rights and judicial independence is scarce or non-existent, and corruption, nepotism and opportunism make effective restructuring more complicated than in developed countries. Resources for specialized regulators and agencies may also be scare given the limited budgets. International development organization can play an important role in supporting the institutional settings and in promoting renewable energies.[21] Table 2.4 summarizes the restructuring processes in several developing countries. Victor and Heller (2007), Jamasb (2006), and Jamasb et al. (2005) provide an overview about the restructuring process in developing countries.

The restructuring process also did not stop before former centrally planned economies like Russia or still more or less centrally organized ones like China. The later emerged from a totally state-owned monopoly towards a more competitive setting but is still within the process (Xu and Chen, 2006). The Chinese electricity sector was until 1985 a state monopoly combining government and business function. In 1985 the government encouraged entry of new investors into the market but did not change the management system or the vertical integration. In 1997 structural problems in the industry led to a separation of government and business functions and some pilot competition projects. Finally in 2002 an electricity reform was initiated to break the monopoly structure and introduce competition to improve efficiency and lower costs. The State Power Corporation is split into two grid operators and five generators and a regulator supervises the market. Nevertheless, up to now only the generation segment is partly restructured. The establishment of wholesale markets, retail competition and open grid access are still in process (Xu and Chen, 2006).

Russia, as the fourth largest electricity producer in the world (behind the US, China, and Japan), had a transformation process underway in the 1990s when the Soviet Union fell apart and the centralized industry was opened for privatization. However, the electricity sector faced serious problems, including needed investments into infrastructure, cross-subsidies, and too-low, regulated tariffs. Although the implementation of a reform in 2001 retained strong regional elements, the goal was to attract foreign investment by introducing competition upstream and downstream, regulated grid access, and a stable regulatory environment (Engoian, 2006). In the first phase (2001-2005) a system

[20] About 60 developing countries have a system with less than 150 MW peak (Jamasb, 2006).

[21] Many developing countries have a high potential for renewable energy sources, but are still depending on energy imports.

operator and a dispatch center were established. However, much remains to be accomplished, such as the independence of the regulator which appears unlikely within the country's political framework.

The potential benefits of improved performance of liberalized electricity markets has also motivated other developed countries. Soon after the liberalizations in England and Norway, the Australian states Victoria (in 1994) and New South Wales (in 1996) set up pools, and New Zealand began its wholesale electricity market in 1996 (Al-Sunaidy and Green, 2006). Japan opened its electricity market to independent producers in 1995 due to high electricity prices and is slowly approaching restructuring (Asano, 2006). In Canada, Alberta and Ontario introduced competition. However, Ontario rescinded some of its liberalization due to public pressure following price increases.

With the extension of the European Union East and South-East Europe are on the way to liberalized electricity markets (Pollitt, 2009). Finally, Turkey has initiated restructuring (in 2001) and although the market structure has not changed dramatically, the process is still ongoing (Erdogan et al., 2008; Bagdadiohlu and Odyakmaz, 2009). Israel is proceeding with restructuring program in the years ahead (Tishler et al., 2008).

Table 2.4: Electricity liberalization in developing countries

Country	Liberalization	Capacity Top 3	Network arrangements	
			Trans	Dist
Argentina	1992: restructuring, wholesale competition and IPPs 1992/93: privatization	30%	rTPA	rTPA
Brazil	1995: partial restructuring 1999: wholesale competition and IPPs	40%	rTPA	rTPA
Chile	1982: restructuring 1985: privatization 1997: IPPs	67%	nTPA	nTPA
Colombia	1995: restructuring and wholesale competition 1996/97: privatization and IPPs	50%	rTPA	rTPA
Peru	1994: restructuring 1995-99: privatization, wholesale competition, and IPPs	100%	rTPA	rTPA
Bolivia	1995: restructuring 1996: wholesale competition 2000: IPPs	70%	rTPA	rTPA
El Salvador	1994/95: IPPs (pre-reform) 1998: restructuring 1998/99: privatization, wholesale competition	83%	rTPA	rTPA
Panama	1998: restructuring and privatization 2002: wholesale competition	82%	rTPA	rTPA
Pakistan	1996/97: IPPs 2000: restructuring	95%	SB	SB
Thailand	1995: privatization 1996: IPPs	100%	SB	SB
Malaysia	1995: IPPs 1997: restructuring	62%	SB	SB
Indonesia	1996/97: IPPs 2003: restructuring	100%	SB	SB

Source: Jamasb (2006)

Table 2.5: Electricity liberalization in developed countries

Country	Liberalization	Unbundling	Regulation	Retail opening Started	Retail opening Full
Australia	1994: Electricity Industry Act of Victoria	own.	price cap	1994	n.a.
Canada	1998: Ontario, Energy Competition Act	own.	cost-based	1996	n.a.
Czech Republic	2000: Energy Act	leg.	price cap	2002	2006
Greece	1999: Electricity Law	leg.	cost-based	2001	2007
Hungary	2001: Electric Power Act	leg.	price cap	2003	2007
Ireland	1999: Electric Regulation Act	leg.	price cap	2000	2005
Japan	1995: Amendments to Electric Utility Law	acc.	cost-based	2000	-
Korea	2000: Act on Promotion of Restructuring of the Electric Power Industry	leg.	cost-based	-	-
Mexico	IPPs allowed	none	n/a	-	-
New Zealand	1992: Energy Ac and Companies Act	own.	ex post	1993	1994
Poland	1997: Energy Act	man.	cost-based	1998	2005
Slovakia	1998: Law on Energy	leg.	price cap	2002	2005
Turkey	2001: Energy Market Law	leg.	revenue cap	2002	2011

Source: Al-Sunaidy and Green (2006)

2.2.5 Lessons Learned

As is evident from the review above, electricity markets around the world are in various stages of liberalization. In general, reforms to create a new institutional arrangement that is able to provide long-term benefits have not been achieved everywhere. The question for policy-makers is whether liberalization was (and is) worth the effort. Peerbocus (2007) reviews empirical studies that assess the reforms in electricity markets. One problem of estimating the potential benefits is the design of a proper counterfactual benchmark that represents the state of the world if restructuring would not have occurred. The cost-benefit studies undertaken show that there are significant potential benefits to market liberalization. However, if the reforms are not properly implemented there is great risk of significant potential costs from market failures as evidenced by the California crisis. A further concern is who benefits from the efficiency gains: Newbery and Pollit (1997) show that the restructuring of the British electricity market leads to significant benefits of which the majority is allocated to producers. By contrast Littlechild (2007) estimates that the gains are shared about equally between producers and consumers.

Given the experiences of the last two decades it is clear that there is no standard formula to ensure a successful outcome, and that in the end variations of well-functioning market designs are possible. Joskow (2008) lists desirable features which he calls the “textbook model”. The textbook model shows that restructuring is indeed a demanding task for governments to implement:

- Privatization of state-owned monopolies
- Vertical separation of competitive and regulated segments

- Horizontal restructuring of the generation segment
- Implementation of a single independent system operator for the network
- Creation of voluntary public wholesale markets
- Active demand side institutions
- Efficient grid access and capacity allocation
- Unbundling of retail tariffs
- Creation of independent regulatory agencies and establishment of market monitoring
- Transition mechanisms.

Not all markets have implemented these key elements, yet they are functioning quite well, e.g., the Nordic market has no full privatization. Every set of reforms must fit the underlying market characteristics (see Woo et al., 2003) and different approaches must also reflect the political understanding of the reform process. Thus Newbery (2002) sees deregulation in the US as a relaxation of regulatory price control recognizing a high probability of market power whereas the EU approach introduces wholesale markets assuming that they will be naturally competitive.

Percebois (2008) shows that liberalization does not go hand in hand with price reduction and that some consumers may bear a net loss of surplus due to price convergence. Joskow (2008) also summarizes further lessons learned from international experiences and hints at ongoing discussions and unresolved problems:

- The textbook model provides a sound guideline for reforms and a departure is likely to lead to performance problems
- Energy markets should be integrated with allocation of transmission capacity (locational pricing approach)
- Market power should be dealt with by ex-ante structural methods
- Network regulation of transmission and distribution is important but often neglected
- Well-functioning transmission investment framework remains a challenge
- Resource adequacy is an ongoing issue
- Retail market design and default service conditions are important for successful retail programs
- Vertical (re)integration of generation and supply is likely to be efficient, but has inherent market power problems
- Demand response in spot markets needs more attention
- Deregulation is an ongoing process ("reform of reforms")
- Strong political commitment is necessary for a successful transformation.

Sioshansi (2006a, b) and Sioshansi (2008) summarize the points to be clarified in future research. They emphasize the resource adequacy problem and whether capacity markets are needed for generators to recover their fixed costs and provide adequate signals for investments (e.g., see Cramton and Stoft, 2005; and Adib et al., 2008). Still unresolved is the question of vertical integration of generation and supply. On the one hand it provides a hedge for generators to manage price volatilities (Chao et al., 2008), but it reduces market liquidity and may increase market power abuse. The problem of resource adequacy also translates into transmission and distribution although in this case a proper incentive regulatory approach is needed (see Chapter 5).

Sioshansi (2006b) sees diverging developments in the role of the regulator: the purpose can either be to provide a level playing field for market participants and monitor the market (an approach most markets have taken), or as a central agency to set concrete rules and steps to follow (an approach in some countries that has produced disappointing liberalization results). Other topics of future development include the progress of market integration, ways to promote and integrate demand response in the wholesale markets, promotion of renewables and the question of centralized versus decentralized markets, and finally the ongoing climate change debate and its impact on electricity markets.

What will the future structure of electricity markets look like? Will there be full liberalization, limiting regulation to networks and monitoring tasks, or will it swing back to integration and strong regulation of all segments? Following Correlje and de Vries (2008) the end result may be hybridized structures.[22] Hybrid markets generally fall into three categories:

- Liberalized markets that are not fully privatized
- Privatized markets that are not fully liberalized
- Markets where the regulator intervenes in the key decisions of market players.

Although these types of markets were initially considered to represent transition stages it appears that they may become permanent in some countries, due to slowing progress, lack of political will, more pressing economic problems within a country, and so on. Whether this is a serious problem is still a matter of debate.

2.3 Modeling of Electricity Markets

Modeling electricity markets has accelerated in recent years because of the growing need for more sophisticated methodologies. Higher computational speeds now allow quicker and more complex simulations to be performed. Prior to liberalization operational models were applied for cost-based or pure technical analyses, but they were inadequate for understanding the emerging market structures. As the former centralized planning approach shifted to a more decentralized focus, cost-based approaches were replaced by profit maximization, and ex-post regulation was transformed to ex-ante benchmarking. A growing number of interest groups and stakeholders, including former monopolized or regulated firms, new entrants, new system and market operators, regulators and governmental agencies, and researchers and academics welcomed the new analytical tools.

[22] Following Sioshansi (2008) the word „hybrid“ may be a bad choice as the worst instead of the best elements of regulation and competition may be combined.

In the context of market economics, research can draw upon a large body of economic modeling theory and application. However, the specific characteristics of electricity (e.g., non-storability, inelastic demand) present a challenge to apply those principals and derive robust model results. Furthermore, market outcomes are influenced by electro-technical, thermodynamic, and mechanical restrictions that require a combination of economic and technical modeling.

The wide array of interest groups and the underlying characteristics are reasons for the large variety of model techniques applied to different aspects of electricity markets. Several studies that provide an overview of the modeling approaches used for electricity markets (see Nanduri and Das, 2009; Ventosa et al., 2005; Day et al., 2002; Kahn, 1998; and Smeers, 1997) attempt to classify them according to some arbitrary criteria based on mathematical characteristics or on application orientation. The sections below classify the market models according to model structure and discuss their applications. This review of electricity market models is intended to provide a rough guideline of the recent developments that have been addressed by modeling approaches.

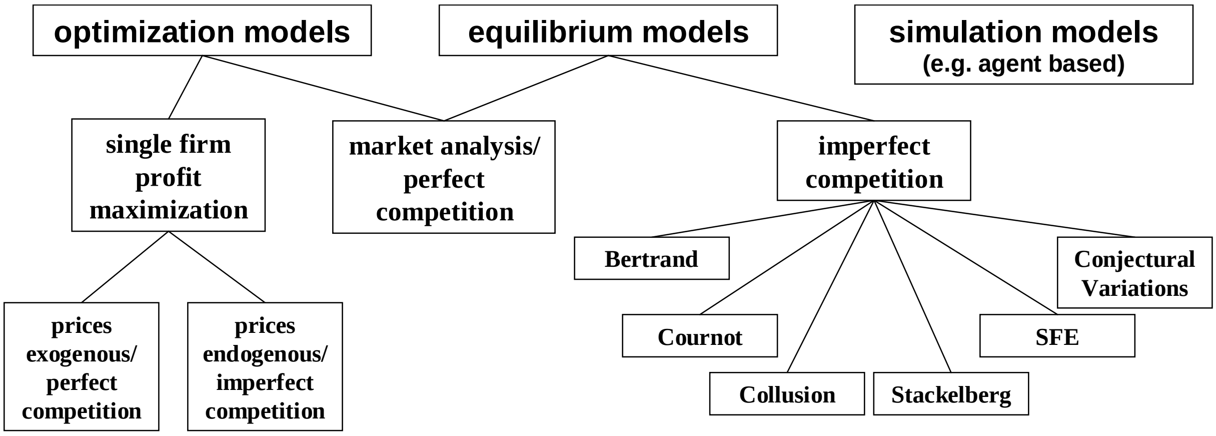
2.3.1 Classification of Model Types

Following Ventosa et al. (2005) electricity market models can be classified according to their structure into three types: optimization, equilibrium, and simulation models. These can be further categorized according to the market environment assumed: perfect or imperfect competition. Figure 2.4 is a schematic of this classification.

Optimization models maximize or minimize a specific objective which is typically a single firm's profit subject to technical or economic constraints. If one assumes perfect competition the market price is an exogenous variable while under imperfect competition the firm can influence market prices. One can also examine the entire market via welfare maximization or cost-minimizing approaches. To analyze a market with several players, particularly an imperfect market setting, an equilibrium model is best since it can combine different players' market behaviors. Strategic behavior can be defined ranging from classic Betrand and Cournot competition to the mathematically more demanding Supply Function Equilibrium (SFE) model.

Simulation models can be applied if the considered problem becomes too complex to apply a formal equilibrium model. They typically represent market agents via specific assumptions and rules and thus allow a wide array of strategic behaviors and market representations.

Figure 2.4: Classification of model types



Source: Following Ventosa et al. (2005), Day et al. (2002), and Smeers (1997)

2.3.1.1 Optimization Models

The main advantage of optimization models is the availability of optimization algorithms that allow large-scale models with a multitude of technical or economic restrictions. However, the focus on a single objective value reduces the complexity these models can obtain with respect to market behavior. The simplest form of an optimization model is profit maximization under fixed deterministic market prices which resembles perfect competition. This problem can generally be expressed as a linear program (LP) or mixed integer linear program (MILP). The model type can be improved by introducing uncertainty of the price e.g., via a distribution function. This method bears similarities to risk management methods and thus allows analyses of risk hedging methods. On a single-firm level the next family of model types includes the possibilities to influence the market price assuming the supply of its competitors as given (leader-in-price model). Again, the model type can be differentiated in deterministic and stochastic models depending on the representation of the demand function (Ventosa et al., 2005).

Another branch of optimization models addresses whole markets by maximizing the total welfare given the supply and demand functions, or by cost minimization given a fixed demand level. The obtained price and quantity results are numerically identical to a competitive equilibrium setting. However, the formulation via a welfare maximizing or cost-minimizing social planer does not include the single firm's profit decisions or trader activities. Hence it represents a completely different type of market representation in economic terms. The advantage of an optimization formulation lies in the simplicity of adding additional constraints (power flow calculations, network constraints, etc.) which would otherwise need a complete reformulation of an equilibrium model. Furthermore, mixed integer formulation can be addressed in an optimization framework but presents a large obstacle in equilibrium analyses.

2.3.1.2 Equilibrium Models

Equilibrium models simultaneously satisfy each of the considered market participants' first order conditions of their profit maximization (Karush–Kuhn–Tucker/KKT conditions) and the market clearing condition equaling supply and demand. The KKTs and market clearing define a mixed complementarity problem (MCP) or can be formulated as variational inequalities. The solution to an equilibrium problem (if it exists) satisfies the Nash equilibrium condition that no market participant wants to alter its decision unilaterally (see Day et al., 2002).

The advantage of equilibrium models compared to optimization models is the capability to address several market participants' profit maximization simultaneously. Thus insights can be gained about the impact of strategic behaviors on market outcomes. The main drawback is that they require convex optimization problems for the players to guarantee that the KKT conditions define an optimal solution and the existence of a market equilibrium. The convexity assumption is incorrect for many specific problems in electricity markets, e.g., the unit commitment process (requiring binary decisions), or AC power flow dispatch. Therefore equilibrium models generally make strong assumption to keep their problems convex. Similar to optimization models the solver algorithms for equilibrium models are capable of handling large datasets and thus allow the application of strategic market models to large-scale approximations of real markets.

The strategic interactions of competitors within the market can take several forms following the concepts of game theory and industrial organization. Day et al. (2002) differentiate six types (see Figure 2.4):

- Betrand Strategy (gaming in prices): the decision variable is the price offered by the firm
- Cournot Strategy (gaming in quantities): the decision variable is the supply by the firm given a demand function
- Collusion: the principal idea is a maximization of joint profits of the colluding firms; the concrete collusion design with possible side payments and penalties can vary
- Stackelberg: a "leader" is defined that correctly accounts for the reaction of "followers" that do not consider how their reactions affect the leader's decisions,
- Conjectural Variations: the reaction of competing firms to a firm's own decisions is anticipated via functional relations,[23]
- SFE: firms compete by bidding complete supply functions instead of a single supply.

In addition to imperfect markets, equilibrium problems can also be applied to analyze a perfect competitive market by assuming that prices are fixed and the firms are profit maximizers.

[23] General Conjectural Variations assume that the output of other firms depends on one's own output decision and include Cournot, Collusion, and Competition as special cases. Conjectured Supply Functions assume that the output of rivals is anticipated to respond to the price. They can be seen as a generalization of the Stackelberg setting and superficially resemble the SFE (see Day et al., 2002, p. 599).

2.3.1.3 Simulation Models

The complexity of electricity markets often requires simplifications to obtain a solution within a equilibrium framework. Simulation models provide a flexible setting for market analysis when formal equilibrium approaches are no longer feasible. Agent-based models have emerged as a preferred tool for dynamic market analyses. Static equilibrium approaches typically neglect the fact that market participants base their decisions on historic information which accumulates over the market processes. Agent-based approaches can overcome these drawbacks and provide a compromise between fully flexible linguistic models and restrictive analytical models (Richiardi, 2003).

The main feature of agent-based modeling is that market participants are modeled as computational agents that are goal-oriented and adaptive. Following Tesfatsion (2002) the procedure is as follows: (i) define a research question to resolve, (ii) construct an economy with an initial agent population, (iii) define the agents' attributes and the structural and institutional framework, (iv) let the economy evolve over time, and (v) analyze and evaluate the simulation results.

Tesfatsion (2006) divides four strands of agent-based research: 1. the empirical or descriptive strand analyzing why and how global regularities result from agents' interactions; 2. the normative strand using agent-based models for market design analyses; 3. the theory generation; and 4. improving the models. The majority of electricity-related papers are focused on the market design analysis.

Weidlich and Veit (2008) provide a review and critical assessment of agent-based electricity market models. Their comparison shows these similarities and differences of applied agent-based approaches:

- Majority of models neglect transmission constraints
- Majority of models assumes demand side as fixed
- Agents' learning task is mostly set to profit-maximizing bids
- The learning representation and modeling of behavior follow no trend
- Majority of studies focus on market power and market mechanisms.

Weidlich and Veit (2008) also note that agents' learning behavior differs in most models; usage of one specific learning algorithm is seldom clearly justified; and most papers miss an empirical model validation. Another open question is the interpretation of results. Generally the simulation is run for a specific number of iterations and the last ones are aggregated as model outcome. The flexibility of agent-based approaches is a large drawback since the heterogeneity limits the comparability. Nevertheless, they represent an interesting opportunity for modeling complex market structures which make them well suited for electricity markets.

2.3.1.4 Other Model Types

In addition to these classifications combinations of several types are possible. A maximization program with equilibrium constraints (MPEC) requires a single objective to be optimized (e.g., a single firm profit) that is subject to some form of equilibrium (e.g., the locational price formulation of an ISO). This approach can be used to obtain a Stackelberg game solution. However, the computational ability to solve those models is still limited (see Chapter 5 for an application).

If the single objective is replaced by more objective functions that are maximized simultaneously, one has an equilibrium problem with equilibrium constraints (EPEC). This model type is, in principle, fitted to represent the complex nature of market interactions without the limiting restrictions of Stackelberg games to define a leader. However, the computational capacities for EPECs are very restricted and further progress on the algorithm side is necessary to enable applications to electricity markets.

Additional mathematical methods are applied to transform the demanding MPEC and EPEC approaches into "simpler" problems that can be solved with the existing algorithms. Gabriel and Leuthold (2009) present an approach to solve two-stage Stackelberg games based on disjunctive constraints and linearization which in the end leads to a replacement of the MPEC by a MILP, thus allowing the inclusion of binary problem types like unit commitment. Other methods include Lagrangian relaxation to decompose large-scale problems into smaller sub-problems.

With the increasing attention on environmental and cross-sectoral issues, general equilibrium (CGE) models can be used to analyze electricity markets and simultaneously assess the impact on the economy as a whole (e.g., see Wing, 2006, and Böhringer, 1998).

2.3.2 Application of Models in Electricity Markets

Although most research questions can be analyzed with each of the types described above, several modeling techniques are more suited for one topic than another which is largely defined by the necessary technical detail level required (which often makes equilibrium approaches obsolete) and the desired degree of market competition and company behavior (which favors equilibrium approaches).

Following a structuring of research topics analyzed with modeling techniques as well as a snapshot on applied studies is presented. Further topics not mentioned in detail include the improvement of modeling approaches, comparison of models, and technically oriented models. The structuring of these research fields is arbitrary. Researchers have invented a variety of structural taxonomies, for example, Ventosa et al. (2005) present structuring models according to the degree of competition, time scope of the model, uncertainty modeling, interperiod links, transmission constraints, generation system representation, and market modeling. Hobbs (2007) distinguishes large-scale models for grid operation and planning that apply numerical solutions; very small models for gaining insights within policy debates by applying easily-tracked structures; and "in-between" models for forecasting and impact analyses of policies. Based on an evaluation of energy model research in 2006, Hobbs (2007) also reviews the need to develop modeling capabilities that are presently unavailable.

2.3.2.1 Market Power in Wholesale Markets

Unfortunately, most liberalized electricity market are dominated by a few large suppliers and market power remains a permanent concern (see Chapter 3). Since static approaches like the Herfindahl-

Hirschman Index (HHI) or other concentration measures are insufficient to capture the dynamic nature of electricity markets, modeling approaches have been widely used to assess market power and all model types have been applied in this critical area of research. Optimization models are typically limited to reproduce the perfect competitive prices and quantities; nevertheless the definition of a competitive benchmark via these models provides an estimation of price markups if compared to observed market outcomes (e.g., see Joskow and Kahn, 2002, for California; Wolfram, 1999, for the UK; and Weigt and Hirschhausen, 2008, for Germany). Many studies applying more complex methods also employ the marginal cost benchmark to classify their results.

Equilibrium models make it possible to model strategic company behaviors and thus reproduce observed market outcomes as well as estimate future outcomes. Cournot-type models are commonly used to model strategic competition in electricity markets (e.g., see Kahn, 1998; Bushnell et al., 1999; and Ellersdorfer, 2005). Due to the short-term inelastic demand the obtained prices are typically too high. Therefore, further restrictions, i.e. forward contracts, are introduced to bring prices down (see Bushnell et al., 2008). Other types of strategic interactions that overcome the price shortcoming of Cournot models are also used (e.g., SFE in Green and Newbery, 1992).

Simulation models also allow different strategic behaviors and furthermore present a framework to test consequence of market power along several market segments. Weidlich and Veit (2008) conclude in their survey that a large share of agent-based models deals with market power issues under different market structures and mechanisms e.g. the comparison of pay-as-bid and uniform priced auctions.

2.3.2.2 Investments in Generation Capacities

Pre-liberalization, markets were typically subject to cost-plus regulatory schemes, investment decisions bore low risk, and cost coverage was of little concern. The post-liberalization environment requires far more complex investment analyses to account for the uncertainties and price impacts of each investment. Investment research can be divided into two streams: the actual investment decision from the firm or market viewpoint, given uncertain future returns and changing market environments, and the interaction of investments and market prices under strategic company behaviors.

The simplest way to determine the profitability of investment decisions is to conduct a net present value analysis taking into account several future scenarios. Here, the model focuses more on the actual future price forecast (discussion follows in the next section), whereas the investment decision can be handled with an optimization approach. The so-called real options approach (Dixit and Pindyck, 1994) uses techniques applied in finance, such as tree approaches (e.g., Tseng, 2001) and Monte-Carlo simulation techniques (e.g., Roques, 2006); Ronn (2002) provides examples and case studies for real options approaches in electricity. Other research examines specific investment questions (e.g., Auerswald and Leuthold, 2009, commodity price uncertainty; Ishii and Yan, 2004, regulatory uncertainty; Bøckman et al., 2008, hydro generation). Also deriving from the financial sector are analyses based on the mean-variance portfolio theory that account for the revenue-risk distribution of different generation assets (e.g., Roques et al., 2008).

The question of investment and strategic behavior can be addressed, e.g., with two-stage equilibrium approaches. Kreps and Scheinkman (1983) show that assuming Cournot competition of the first stage (investment) and Betrand competition on the second (wholesale) leads to an overall Cournot outcome. Murphy and Smeers (2005) provide an in-depth discussion of algorithmic issues arising from different market structure assumptions on this issue. Zoettl (2008) studies the types of generation capacities in which strategic firms invest. He concludes that under imperfect competition firms have strong incentives to invest in capacities with low marginal costs, while at the same time the total capacities chosen are too low from a welfare point of view. Uncertainty of future developments generally leads to a slowing down of investment decision while strategic behaviors may increase investments due to entry deterrence. However, a full theoretical treatment is not yet available (Smeers, 1997).

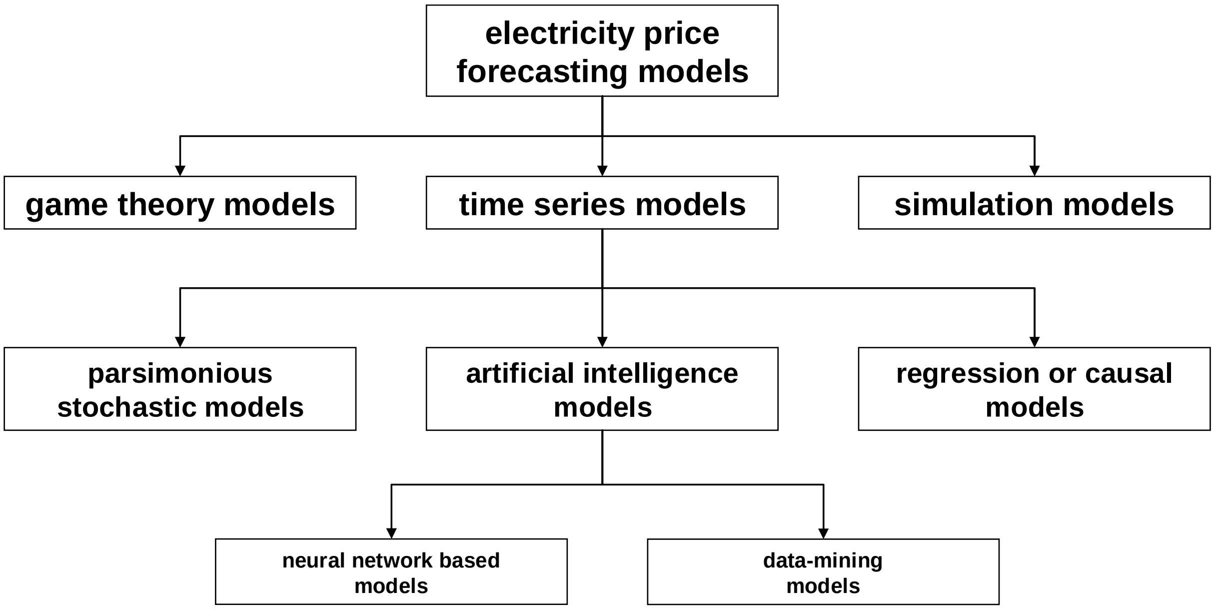
2.3.2.3 Price Forecasting

Price forecasting plays a major role in decision processes like trading and investments and is crucial to the performance of profit-oriented firms. Future prices are influenced by factors including basic market characteristics, uncertainties, strategic behaviors (both the firm's and its competitors), and temporal effects. Consequently, an equally wide array of modeling techniques and empirical approaches can be applied. Aggarwal et al. (2009) review price forecasting in deregulated electricity markets, and distinguish three trends of price forecasting models: game theory, time series, and simulation models (Figure 2.5).

Game theory models are based on the equilibrium concept and thus are applied if strategic interactions are explicitly modeled. Simulation models can reproduce the complex nature of markets, but require detailed system operation data to produce robust forecasts. Thus, time series models are an alternative since they focus on past behavior and do not require detailed market structure data. Aggarwal et al. (2009) further classify time series models into parsimonious stochastic models which are inspired by financial literature and include methods like autoregressive and moving average models; regression or causal models where the future price is modeled as a function of some exogenous variables; and artificial intelligence models that map input-output relations without exploring the underlying prices. The latter can further be divided into artificial neural network-based models and data-mining models.

Price forecasting is normally aimed at either determining the average price, peak prices, or the price profile for a specific period for the day-ahead market in the relatively short term. Other market segments are still largely neglected (Aggarwal et al., 2009).

Figure 2.5: Classification of price forecasting models



Source: Following Aggarwal et al. (2009)

2.3.2.4 Network Modeling

Modeling networks and power flows is in itself a purely technical task. Sophisticated engineering tools and commercial programs exist to derive specific operational figures, but in an economic context these models are generally too detailed because their focus is the actual power delivered. Therefore, for economic modeling purposes power flow calculation is often approximated, or for a large part of research, neglected.

When network constraints must be considered, the most common model approach is the DC load flow model (DCLF) that approximates the full AC load flow by neglecting reactive parts (Stigler and Todem, 2005). Overbye et al. (2004) compare the DCLF approach with a full AC-model to determine the impact of neglecting reactive power issues. They conclude that the results are close to the full AC formulation. However, the difference can become significant in cases of high reactive and low real power flows. The main advantage of DCLF is its applicability to large-scale problems with many capacity constraints and agents (Day et al., 2002).

Including the network can be seen as an (sometimes necessary) add-on to electricity market modeling that increases the scope of the model, but not necessarily the research focus. For example, a plant investment decision can be analyzed within a network framework if significant congestion may alter prices in regions (e.g., Smeers, 2006), price forecasts need to account for network constraints if resembling a locationally priced market, or market power can be analyzed with and without an underlying network formulation depending on the market clearing process to be simulated. Hobbs (2001) analyzes the impact of arbitrageurs in a Cournot market setting with network constraints. Neuhoff et al. (2007) show the complexity of deriving robust results of strategic models with an underlying network calculation. Bautista et al. (2007) show that the introduction of reactive power increases the strategic space for market participants, and thus the results differ from a simple DC approximation. However, they are unable to classify the extent to which simplified assumptions provide misleading market results.

Purely network-related research topics center upon market design questions (see next section) or oftentimes have a large technical focus, e.g., voltage support. Of particular concern are the necessary grid extensions most electricity markets require due to increased demand, an increase or change in generation capacities, or existing bottlenecks (e.g., at cross-borders). Leuthold et al. (2009) address the possible costs of a welfare optimal extension of the European network with respect to wind integration. Other studies look at national extension plans (e.g., DENA, 2005, for Germany; Hondebrink et al., 2004, for the Netherlands; or Haidvogel, 2002, for Austria). A special issue of the IEEE Transactions on Power Systems (2007) addresses the research problems pertaining to "Transmission Investment, Pricing, and Construction." Latorre et al. (2003) provide a review and classification of models on transmission expansion planning.

2.3.2.5 Market Architecture

Optimal market design and the comparison of outcomes from different designs is another research concern. As is evident from the liberalization processes presented in Section 2.2 there is no perfect decentralized market architecture, and as a result, all model types are utilized. Research on market design can be divided into three streams: the design of a specific market segment; the interaction of company behavior on different market segments; and the institutional setting and regulatory impacts.

Regarding market segment analysis discussions are ongoing about the revenue adequacy of wholesale markets and the question of capacity markets (e.g., Gribik et al., 2007); the design of ancillary services and reserve markets (e.g., Glachant and Saguan, 2007); network operation and congestion management (Christie et al., 2000); cross-border auction design (e.g., Leuthold and Todem, 2007); pricing mechanisms (Bin et al., 2004); and demand side response (e.g., Holland and Mansur, 2006).

Since firms tend to be involved in more than one segment of the electricity value chain, the concern about strategic interactions across market segments is also subject to modeling analyses. Focusing on strategic interactions, equilibrium approaches are applicable. Possible interactions include the relationship between forward and spot markets (basic concept for Cournot competition developed by Allaz and Villa, 1993); interactions between markets for reserve capacities and spot markets (Wieschhaus and Weigt, 2008); transmission allocation and market power (Gilbert et al., 2004); and investment in generation and network facilities (Rious et al., 2008).

The complexity of the interactions between several market segments require flexible simulation models. Following Weidlich and Veit (2008) a large share of agent-based models focuses on market power and market mechanisms analyses, including vertical integration and market power (Rupérez Micola et al., 2006) and dynamics between forward and spot markets (Veit et al., 2006).

The more general question is how best to design the institutional setting and analyze the potential impacts of the regulatory framework on market participants. There is an ongoing debate about the welfare optimal way to enhance transmission investment either by regulation or merchant approaches (see Chapter 5). Chao and Peck (1998) analyze the possibilities to design an incentive scheme for system operators to obtain welfare optimal reliability. A consistent inter-TSO compensation is still unsolved in the EU (Dietrich et al, 2008). Environmental aspects and their implementation within the market architecture have gained attention, including the interaction of emissions trading and electricity prices (Rathmann, 2007); interaction of renewable support and wholesale prices (Weigt, 2009); the design of the European Emission Trading scheme (Böhringer et al, 2005); and the interactions of emissions trading and renewable support mechanisms (Abrell and Weigt, 2008).

2.4 Conclusion

This chapter has reviewed electricity market liberalization and the application of various modeling techniques. Starting in the 1990s with the UK, electricity markets around the world have been (and still are) restructured, transforming the former monopolized sector into partially decentralized competitive market segments. International experiences show that this process is neither straightforward nor riskless. Nevertheless, the lessons learned to date from successful and even less successful liberalization attempts can be used to shape future markets as well as to provide guidelines for countries that are at the beginning stages.

In the wake of liberalization a large and differentiated body of modeling techniques and approaches has developed that aims to understand the process, help market participants to cope with the new market environment, and in the end to improve the market architecture that ensures a stable, competitive, and sustainable electricity market.

The complexity of the commodity electricity and the different market structures and architectures around the world are reflected in the modeling approaches applied, ranging from “simple” optimization approaches over equilibrium concepts to simulation models and the large range of analyzed topics.

3 Competition in Liberalized Electricity Markets: The Case of Germany

3.1 Introduction

As most liberalized electricity markets around the world are successors of former monopolistic markets market power is a significant issue to be addressed in research and policy. Germany is no exception: The German electricity market has undergone significant changes in the last decade, yet the scientific discussion about the appropriate market design is still in its infancy. Since the first EU liberalization directive 96/92/EC was promulgated, Germany has taken almost a decade to address critical issues such as network tariff regulation and market monitoring. Since 2006, the newly established regulator ("Bundesnetzagentur") has published cost-based revisions of transmission and distribution network tariffs, and is considering alternative instruments of congestion management, cross-border trading, and incentive regulation.

The political discussion has begun to focus on the generation sector, especially since average spot prices at the EEX rose by almost 150% from 2002 to 2006; prices declined again in early 2007 but rose once more in winter 2007/2008. A price increase is no proof of malfunctioning markets or market power abuse; during the same period fuel prices rose significantly and the European emissions allowance trading scheme was implemented. On the other hand, the oligopolistic structure of Germany's generation market particularly lends itself to abuse, with a duopoly controlling over 55% of market share, and the largest four firms owning almost 85% (Bundeskartellamt, 2006).

In this Chapter the level of competition in Germany's wholesale electricity market is analyzed, by comparing the observed prices with estimated market clearing prices under the hypothesis of perfect competition. Subsequent a brief theoretical introduction to the issue of market power in electricity markets is provided followed by a survey of international experiences with market power analysis (Section 3.2). Afterwards the German electricity market and the most recent studies on market power and competition are presented (section 3.3). In order to test the competitiveness of the German market two different test cases are analyzed in Section 3.4: First, the period from 2004 to 2005 is examined using a benchmark supply curve; second, the complete price formation in 2006 is analyzed applying a extensive welfare optimizing model. I conclude that market power is an influential feature of Germany's electricity markets, and should be addressed by more competition-oriented market design.[24]

3.2 Theory of Market Power in Electricity Markets

Market power is usually defined as "the ability to alter profitably prices away from competitive levels" (Mass-Collell, et al., 1995, p. 383). Contrary to "normal" markets such as mineral water, today's

[24] The Chapter draws on Hirschhausen, Weigt, and Zachmann (2007).

electricity markets are prone to market power issues because electricity cannot be stored; its demand is inelastic; and vertical integration exists between generation and transmission (for a survey, see Twomey et al. 2004). Empirical evidence shows that market power concerns are present in almost all electricity markets around the world.

Economic theory suggests that market prices depend on (i) the form of competition (quantity competition, price competition, strategic behavior, etc.) and (ii) the number of competitors in a given market. The reference benchmark case (competitive equilibrium) corresponds to the equilibrium between demand and supply, given by the "real" marginal cost curves of the producers.

In this context, the question about short- vs. long-term marginal costs is important. Short-term marginal costs are the relevant benchmark as long as the capacities are fixed; thus, only fuel costs, costs of CO_2-emission allowances, and variable operation expenditures represent marginal costs. In that situation, the competitive price will be determined by the *short-run* marginal costs of the last producer dispatched.[25] On the other hand, long-run marginal costs include investment costs as the capacity decision is assumed to be a variable in the long run, too.

According to Stoft (2002, p. 321) market power in electricity markets can be analyzed in three levels:

1. Strategic exercising of market power,
2. Effects on quantities and prices, and
3. Implications of market power on the distribution of rents, allocation, and social welfare.

1. In principle, two possibilities exist to exercise market power: *physical* withholding of generation (voluntary non-availability of specific generation assets) or *financial* withholding (bidding above marginal costs). Both strategies can be considered as equivalent; ex-post, it is difficult to determine whether the withholding was physical or financial. Physical withholding is more difficult to detect as a variety of technical restrictions can lead to a decreased generation capacity. Either type of withholding leads to a new equilibrium between demand and supply at a higher price level and lower quantities. Figure 3.1 shows the case of physical withholding in which a fraction of the available power plants is taken out of the market thus leading to a shift of the supply curve to the left. In case of financial withholding the "production" supply curve remains stable, however the "bidden" supply curve moves upwards leading to similar price/quantity distortions as in the quantity withheld case.

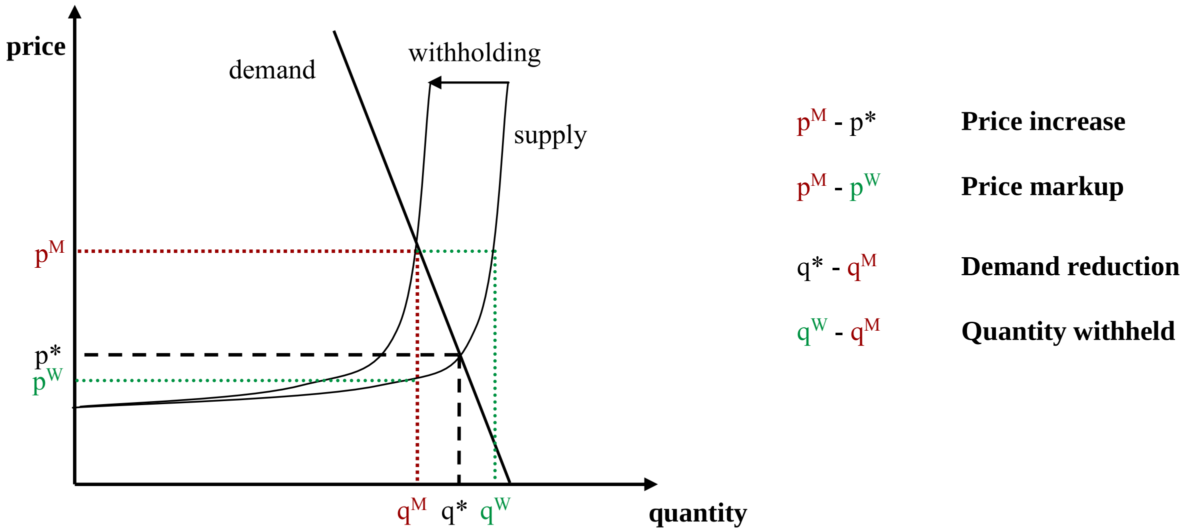
2. The exercise of market power leads to four price/quantity – effects (Figure 3.1). The first is the *quantity withheld* ($q^W - q^M$) which represents the amount of plant capacity taken out of the market (physical withholding) or priced excessively (financial withholding) by strategic players, thus shifting the supply curve to the left and upward, respectively. A new intersection between supply and demand occurs, leading to a higher price level. The difference between these two is the *price distortion*

[25] Stoft (2002, p. 129) shows that short-run marginal cost, including opportunity cost of capacity constraints, are sufficient to cover variable and fixed costs; he also provides an overview of the issue.

(p^M - p^*). As demand for electricity is inelastic, the quantity difference between the competitive and the distorted market equilibrium (q^* - q^M) is generally lower than the quantity withheld, the *quantity distortion*. In the case of a completely inelastic demand the market quantity does not reduce at all due to market power abuse. The difference between the distorted price and the marginal generation costs at the reduced quantity (p^M - p^W) corresponds to the *price markup* on competitive supply. This measure is also applied to obtain the Lerner Index by setting it into relation with the market price. [26]

3. Beside the price and quantity changes the exercise of market power also has two effects on welfare allocation and distribution. In quantitative terms, the redistribution of consumer rent to producer rent plays the most important role. Due to the higher market price a larger fraction of the welfare is allocated to producers at the expense of consumers. In addition to the welfare transfer there also is a deadweight welfare loss: because of the reduced availability of plants, demand is not satisfied although the marginal willingness to pay is above marginal generation costs under competitive conditions. Producers also loose a portion of their welfare from the less efficient generation employed in their withholding strategies. The transfer of rent from consumers to producers over compensates this loss, making strategic bidding profitable. Figure 3.2.1 depicts the physical withholding case in which the bidden supply curve is altered by changing the available power plants. Beside the transfer and loss of consumer rent this strategy also inherits a significant loss of producer rent as the altered plant dispatch leads to an inefficient utilization of the power plant fleet. In case of a financial withholding (Figure 3.2.2) the welfare deadweight loss reduces to a triangle as the supply curve is altered by bidding above marginal costs whereas the producing power plants are not changed and consequently the loss of producer rent is only driven by the demand reduction.

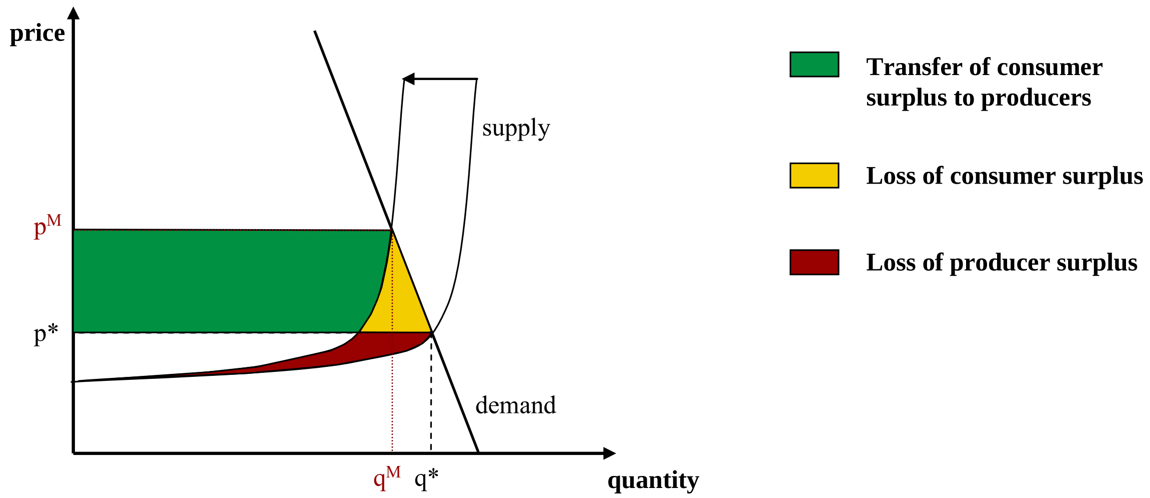
Figure 3.1: Strategy of physical withholding



Source: Following Stoft (2002, p.320)

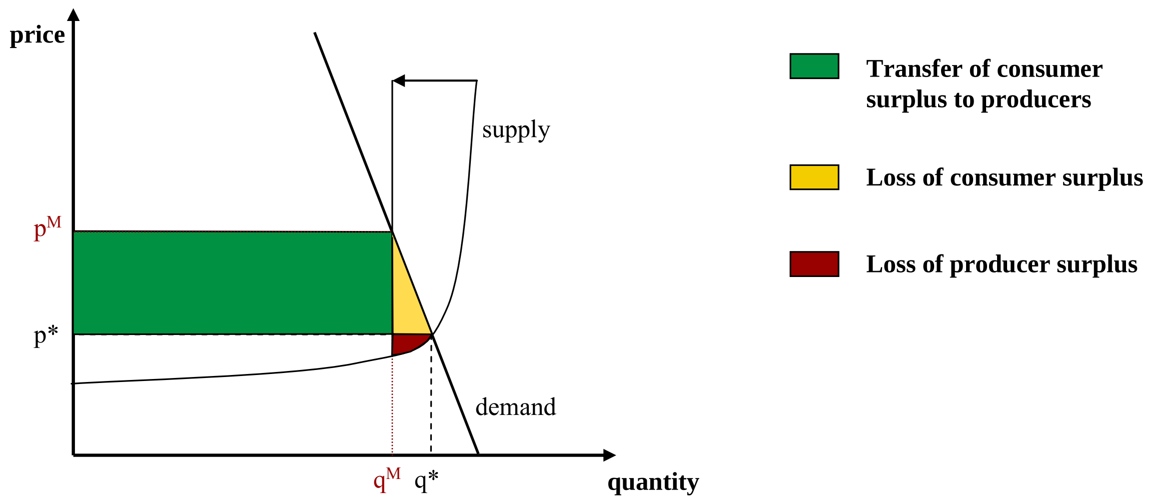
[26] The Lerner Index (L) is defined as the mark-up on marginal cost (MC) given a market price (P): L = (P-MC)/P (Stoft, 2002, p.339)

Figure 3.2.1: Welfare transfer due to market power, physical withholding



Source: Following Stoft (2002, p.333)

Figure 3.2.2: Welfare transfer due to market power, financial withholding



Source: Following Stoft (2002, p.333)

3.3 International Experiences with Market Power in Electricity Markets

At the time of monopolistic, oftentimes vertically integrated electricity companies, there was neither room nor need for any market power analysis. The restructuring of the US and the British market have opened the way to rigorous market power analysis. Thus Wolfram (1999) was among the first to apply a competitive benchmark analysis to the electricity market of England and Wales. Wolfram finds significant markups during the observed period covering 18 months in 1992, 1993 and 1994, although the generators were not taking full advantage of the inelastic demand as oligopoly models predict. Borenstein at al. (2002) and Joskow and Kahn (2002) use the competitive benchmark approach to analyze the Californian market. Both find that in summer 2000 observed prices differ from the competitive benchmark price levels which can not be explained by load, imports, gas prices or

NO_x-allowance prices. Mansur (2001) undertakes an analysis of the PJM market calculating a demand-weighted Lerner index of 0.293, which indicates significant market power abuse.

Beside the benchmarking approach a wide variety of studies have been conducted to analyze market power concerns. Green and Newbery (1992) applied a SFE model to simulate the British electricity market after the first liberalization period. They show that the dominant duopoly has significant market power possibilities which could be greatly reduced if five equally large firms would compete within the wholesale market. Sweeting (2007) analyzes the bidding behavior in the British market for long term periods. He shows that in the beginning of the liberalized market the participants did not utilize their large market power potentials whereas at the end of the 1990s due to structural changes the much lesser potential was fully utilized. Furthermore, the companies may even have applied collusive strategies. Side payments by the Pool were also subject to criticism. Newbery (1995) shows that capacity payments provide high incentives for large firms to withhold generation units. However, Green (2004) does not find evidence that this strategy was applied by the companies.

The market crisis in California was also subject to several market power analyses. Wolak (2003b) investigates the residual demand companies were facing between 1998 and 2000 and shows that in 2000 incentives for market power abuse were significantly higher than in the former years. Thus a coordinated behavior of the market participants was not necessary to explain the observed price spikes. Kim and Knittel (2006) analyze the price-cost margins by estimating the first order conditions within a conjectural variations framework. They show that in the specific setting of the California electricity market the results of this method are not reliable. Kolstad and Wolak (2003) analyze the interaction between the NO_x emission market and electricity prices. They show that NO_x-allowance prices were used by suppliers during 2000 to enhance their ability to exercise market power in the California electricity market.

Market power analyses have also been conducted for various other countries: e.g. Zhou et al. (2009) analyzes capacity withholding in China, Lise et al. (2008) analyze the impact of dry weather and transmission capacity in Europe, Lise et al. (2006) develop a game theoretic model of Northwest Europe, Hu et al. (2005) analyze bidding pattern in Australia, and Ahn and Niemeyer (2007) model market power in the Korean electricity market.

A drawback of competitive benchmark analysis is the necessary simplification when estimating the supply curve. As electricity markets are highly complex while available information is generally spare, models have to make assumptions that may influence the outcome. Typically the simulation is static neglecting start up and shut down costs or minimum load constraints. Missing information about plant outages may add to the error. Also, in general, the grid is not considered as part of the market. Thus network congestion which can lead to market prices above marginal costs is not considered. The simplifications can lead to a general underestimation of marginal costs. Harvey and Hogan (2002) undertake a sensitivity test of competitive benchmark analysis, by reproducing the results and estimating the impact of varying assumptions. They conclude that the differences obtained by the simulation can come from the real-world constraints omitted from the model.

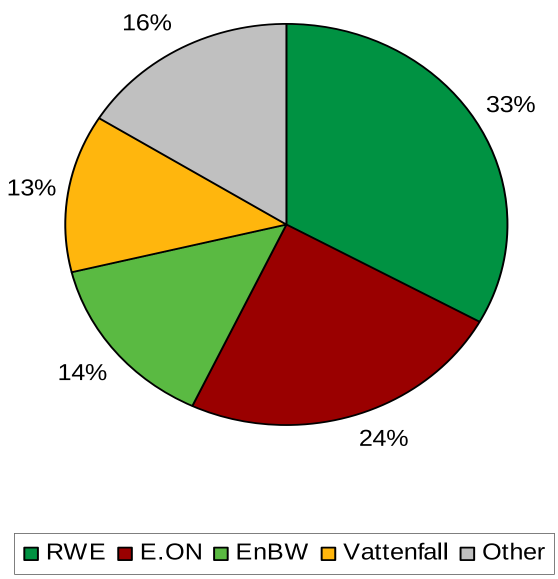
3.4 Market Power Concerns in the German Electricity Market

3.4.1 Market Structure

As described in Section 2.2.2.2 the German electricity market was liberalized relatively late and key elements like a robust network regulation were missing for a long period. The wholesale electricity market of Germany was and still is dominated by four companies owning about 85% of conventional power plant capacity (Figure 3.3). The German Cartel Office assumed a dominant duopoly consisting of E.ON and RWE owning about 60% of generation (Bundeskartellamt, 2006). The generation park is characterized by large percentages of nuclear, lignite and hard coal capacities, significant capacities for natural gas-fired plants and an increasing share of wind capacities. In 2007 the total available generation capacity reached about 140 GW for a total production of 640 TWh (Table 3.1). Inland consumption was about 540 TWh and exports about 60 TWh (BMWI, 2008a).

The structure of the German generation portfolio bears incentives for the four large suppliers to abuse their market shares. Nuclear plants are solely owned by the four oligopolist which obtain – together with large scale lignite and coal fired base load plants – a high profit margin due to their low fuel costs. As the oligopolists also own more expensive mid and peak load units gaming during high price times can become profitable: reducing the output of more expensive plants to drive market prices and in return obtain a large revenue via base load units.

Figure 3.2: Market share by generator excluding renewable energy sources beside hydro, 2005/06



Source: RWE (2006), E.ON (2005, 2006), Vattenfall (2005), EnBW (2005)

Table 3.1: German power plant capacities and gross generation, 2007

Plant type	Capacity [GW] / [%]	Generation [TWh] / [%]
Nuclear	21.3 / 16%	141 / 22%
Lignite	22.5 / 16%	156 / 24%
Coal	29.3 / 21%	145 / 23%
Natural Gas	21.3 / 16%	74.5 / 12%
Oil	5.4 / 4%	8 / 1%
Hydro	10.1 / 7%	27.5 / 4%
Wind	22.2 / 16%	39.5 / 6%
Other	5.3 / 4%	45.5 / 7%
Total	**137.5 GW**	**636 TWh**

Source: BMWI (2008b)

3.4.2 Market Architecture and Development

The market architecture of the German electricity market includes:

- *a long-term market:* electricity producers sell their production up to several years in advance, and consumers can secure their supplies; there is active trading with financial products (options, futures) and physical contracts (forwards),
- *a spot market:* physical and financial trading occurs in a classical day ahead market,
- *an intraday market:* since fall 2006 electricity can also be traded shortly before actual delivery,
- *a balancing market for physical supplies:* producers can bid positive or negative balancing capacity.

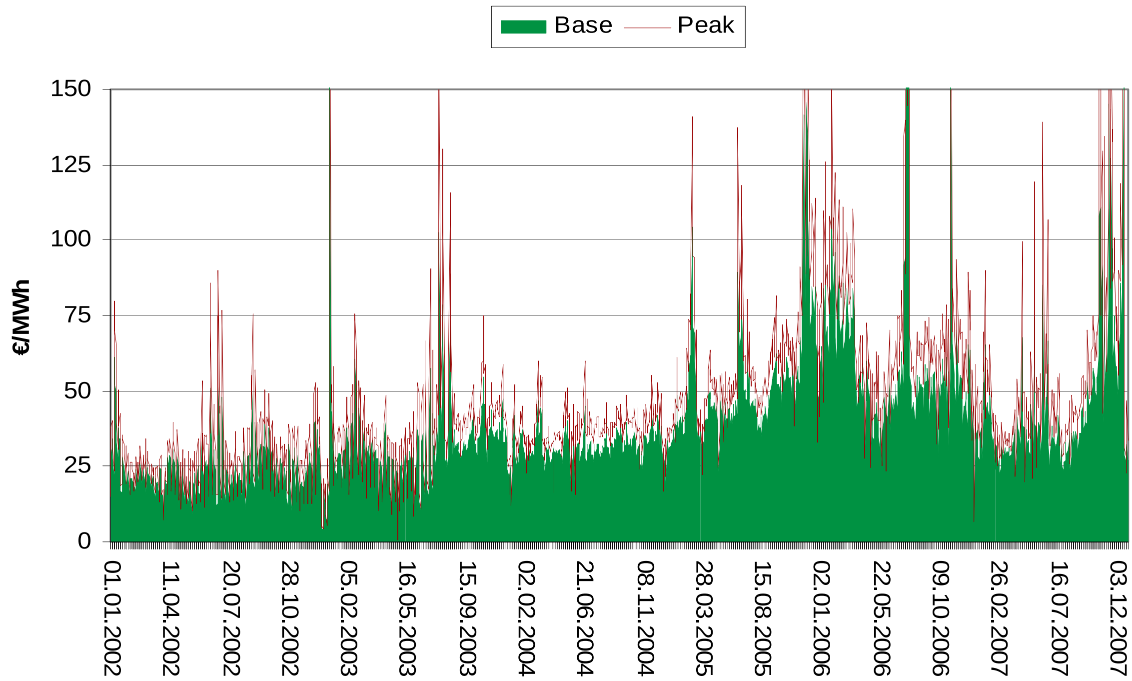
These market segments are embedded in a so called "common carrier" system in which all market participants (generators, suppliers, consumers, and traders) are allowed to trade with one another and only network access is regulated. Thus contrary to a pool system like in the first liberalization stage in the UK or most US markets bilateral transactions and power exchanges coexist in Germany. The EEX trades supplies for specific time periods, such as four-hour blocks or single hours. Trading takes place in so-called one-shot auctions: suppliers and consumers bid individual supply and demand functions which are then aggregated. At present, there is no mechanism to determine whether supply functions correspond to real-time prices or whether the bidding is affected by market power.[27] In addition to electricity generators, traders are also active. Therefore the supply curve does not necessarily correspond to the marginal cost curve of electricity generators; it may also represent rents from trading activities. However, if one assumes a competitive trading market, the supply curve is only marginally different from the cost curves bid by the generators.

[27] Such mechanisms are now in place in the California electricity market (Market Surveillance Committee). In the aftermath of the Western Market Crisis of 2000-2001, the US Congress expanded the Federal Energy Regulatory Commission's market monitoring functions and enforcement; in January 2007, FERC dedicated a Webpage to the subject: http://ferc.gov/market-oversight/market-oversight.asp

Besides trading at the EEX there exists a large fraction of OTC transactions. These can take e.g. the form of bilateral contracts and agreements or independent trading platforms. In 2007 more than 1,100 TWh were traded forward at the EEX and about 125 TWh electricity were traded via the spot market (23% of consumption). Although only a quarter of energy is actually traded in the EEX spot market it represents the only available indicator for price developments and thus has an impact on all other transactions.

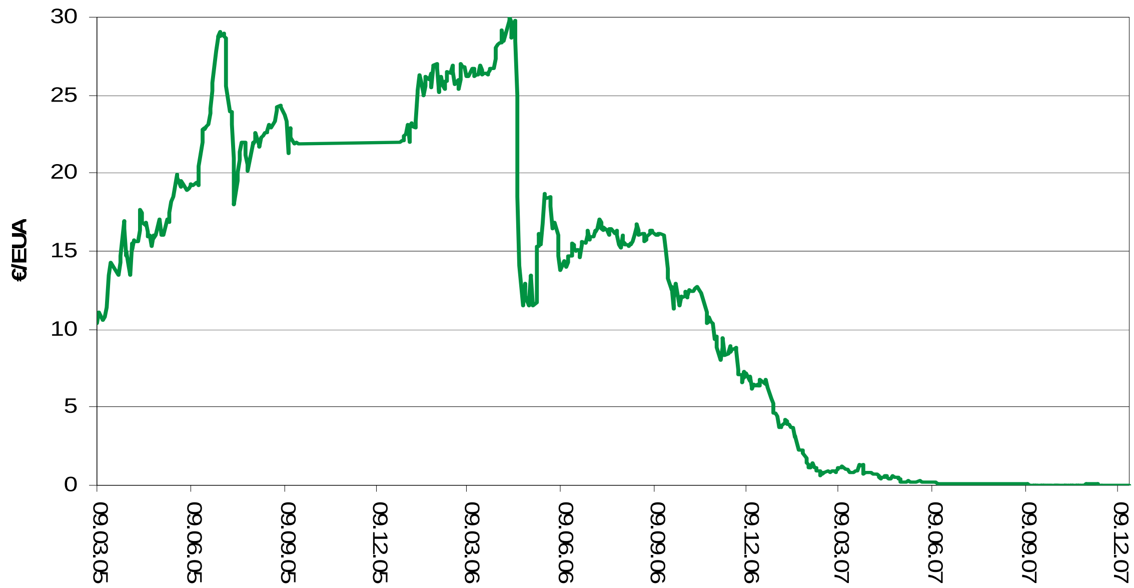
Figure 3.4 shows the price developments of base (0am-12pm) and peak (8am-8pm) prices during the last years. Since the onset of trading on the EEX, prices have continuously increased till 2006. During 2006 a more volatile price development emerged and prices declined again in early 2007. However, during the fall and winter of 2007 the price level rose again to values above 50 €/MWh. The average price in 2006 was with 57 €/MWh about 150% higher than in 2002. Figure 3.5 shows the price development for EU emission allowances (EUA) since the beginning of trading. After reaching a level between 20 and 30 €/EUA in the first year, the over allocation of allowances lead to a sharp price decrease in spring 2006 continuing to a steady decline of prices towards 0 € until the end of the first trading period.

Figure 3.3: Price development at the EEX, 2002-2007



Source: EEX

Figure 3.4: EUA price development, 2005-2007



Source: EEX

3.4.3 Market Power Concerns

Given the oligopolistic market structure and the price developments over the last years, the question arises whether the observed market outcomes represent competitive behavior or whether market power is applied. Müsgens (2006) is the first to simulate a comprehensive marginal cost model of the German market for the period of June 2000 to June 2003. He uses a linear optimization model to estimate the competitive market prices. Starting in 2000 the observed and modeled market prices coincided until fall 2001, followed by a break leading to a divergence between them that lasted until the end of the observation period. He assumes that strategic company behavior and learning effects were the main reasons for the observed differences. Next, Ellersdorfer (2005) uses a two-period Cournot model to study the impact of long-term contracts on the oligopolistic model. A competitive benchmark used as well also shows that a significant difference between modeled and observed market prices existed.

Schwarz and Lang (2006) analyze German electricity prices by estimating the impact of fundamental price components such as fuel price development and allowance prices. They find that from 2000 until 2005, rising fuel prices and in 2005, allowance prices were the major price influencers. However, starting in 2003, the impact of market power increased and therefore influenced prices.

The Sector Inquiry issued by the EC (2007b) adds a political view to the market power debate. Most of its conclusions are applicable to Germany: wholesale markets show a high degree of supplier concentration, vertical integration is a dominant factor in many markets, international trade is insufficient to provide pressure on domestic producers, there is a high degree of intransparency, price formation on electricity markets is complex, and consumers have little confidence in the competitiveness of these markets. Based on the Sector Inquiry, London Economics carried out an in-depth analysis using real-world data and confirmed that the German wholesale electricity market faced mark-ups of up to 50% in the past few years (London Economics, 2007). Furthermore an analysis of earned revenues revealed that the two largest German companies would have earned 7 bn. € from 2003 till 2005 which is considered sufficient for covering investment and start-up costs.

Other studies of Germany's competitiveness employe strategic or econometric approaches. Zachmann (2007) compares the German and British electricity markets using Markov Switching, concluding that the British market had a closer relation to marginal costs . Zachmann and Hirschhausen (2008) test the impact of emission allowance pricing on electricity wholesale prices in Germany. Based on an error correction model and an autoregressive distributed lag model they find that the price for emission allowances is passed through asymmetrically: allowance price increases are translated into electricity price increases more rapidly than decreases.

However, the impact of market power on price formation is not unilaterally accepted. General electricity market analyses of Germany with respect to market power are presented by Weber and Vogel (2007) and Ockenfels (2007a). These and other authors agree that the lack of full information in the empirical model approaches is viewed as a source of unreliability. Due to a steep merit order close to peak capacity, the impacts of incorrect availability or price assumptions can produce large, absolute errors. In addition the non-linear complexity of electricity markets with many external impact factors (wind speed, temperature, and technical restrictions) contribute to the difficulty of designing a fully realistic model. Swider et al. (2007) show these issues exemplary for existing model approaches and specific time periods. Like Harvey and Hogan (2002) they show that every model has some level of uncertainty and thus will produce a range of possible outcomes.

Melzian and Ehlers (2007) study the pricing mechanism at the EEX, and conclude that the structure of the German market makes EEX prices an improper benchmark. They argue that since price formation at the EEX is mainly driven by missing or excess capacity of forward contracts, the price cannot be considered as system marginal price. Ehlers and Erdmann (2007) also analyze the EEX pricing formation and concluded that the traded volumes and supply and demand curves do not allow a significant price manipulation. However, assuming that EEX prices act as the benchmark for most bilateral and long-term trades in Germany's electricity market as it is the only transparent price available, the EEX still represent a form of equilibrium market clearing price.

The problem of fixed cost covering and short-term marginal costs has been addressed by Müller (2007) and Ockenfels (2007b). Müller simulates a simplified electricity market with base, mid and peak load units to estimate the revenues each plant type earns in a competitive market based on short-term marginal costs. He concludes that in an optimal market segmentation with respect to installed capacity, even base load plants will not cover their fixed costs. Ockenfels (2007b) argues that under competitive conditions, market prices above marginal costs are possible and necessary to cover fixed costs. Whenever demand exceeds available capacities, the market price is set according to consumers' willingness to pay. Due to the low elasticity in electricity markets this can lead to significant mark-ups on marginal costs. As the German electricity market was subject to overcapacities this situation did not prevail in 2006.

3.5 A Competitive Benchmark Model of German Electricity Prices

One of the main questions of estimating market power abuse is the “right” approximation of competitive levels. The model approach to define this level is referred as competitive benchmark. Technically more complex approaches like Cournot or SFE often use the competitive benchmark as a starting point or additional information to classify the model results.[28] The main aim of the benchmarking approach is to estimate a competitive supply function in terms of marginal costs. In a fully competitive market no player can influence the clearing price; thus the simulated supply function in combination with a given demand level yields the competitive benchmark. This is mainly done by collecting data on the generation facilities and calculating marginal costs for each plant. Arranging the plants according to increasing marginal costs yields the competitive supply curve. The difference between simulated and observed market prices allows to quantify the extent of market power.

Stoft (2002, p. 129) shows that marginal cost pricing suffices to cover the capital cost of investment, because price spikes will occur in case of shortages. An in-depth discussion of the issue is provided by Hogan (2007) and Cramton and Stoft (2006). Marginal costs should set the competitive prices when the market is characterized by overcapacity. The current German electricity market was subject to overcapacities in the hour of peak load in 2006. In addition capacites are reserved for balancing purposes and a large fraction of renewable capacities is not available on demand due to the stochastic nature of wind and sun.[29] Given this framework a short-run marginal cost approach based on fuel and operation cost is used to estimate the competitive benchmark for the German market.

In a first approach a “simple” cost benchmark for reference days is estimated and compared to the observed prices at the EEX between 2004 and 2005. The limited nature of this model is based on the non-availability of hourly demand data for the Germany before 2006. The study is a continuation of the analysis carried out by Müsgens (2006) until 2003 and follows the paper by Schwarz and Lang (2006) who also cover the observation period. The analysis is based on Hirschhausen and Weigt (2007a). This first approach is extended in a second step and a comprehensive welfare maximizing model is used for the whole year 2006 on hourly basis (Weigt and Hirschhausen, 2008).

[28] For a comprehensive overview about different approaches of measuring and modeling market power see Twomey et al. (2004).

[29] In 2006, overall public available conventional capacity was 103 GW, with a system peak load of 86.2 GW. At this peak, the market had surplus capacities of 8.4 GW in addition to 7.9 GW system reserves and an export surplus of 2.1 GW (VDN, 2006).

3.5.1 A Stylized Analysis of 2004-2005

3.5.1.1 Methodology and Data

In order to derive a market price for electricity in Germany a single wholesale market is assumed in which demand and supply are traded. OTC transactions as well as the impact of forward contracts are neglected. I assume that trading is a competitive activity, so that market power is exercised by the generators only, and neglect markups by traders and arbitrageurs. The competitive price level is defined by the intersection of the supply and the demand curve. The latter is assumed to be price inelastic (Figure 3.6) and shifting over time. Publicly available demand information for the period from 2004 till 2005 on hourly basis is only provided for selected days (3^{rd} Wednesdays of a month) by the UCTE. Thus the analysis is limited to those days. Further impacts on the actual demand level are not considered in the model. Particularly the missing impact of exports and imports may bias the obtained results. If Germany is exporting electricity the price level may be higher than modeled as a fraction of local generation is supplying foreign demand shifting the merit order to the left. On the other hand in the case of imports the merit order may be shifted to the right due to additional generation capacities from foreign suppliers. As Germany is on average an exporter the estimated price level is likely to be underestimated.

The competitive supply curve ("merit order") is derived by estimating the available generation capacities and the corresponding marginal costs based on the underlying fuel prices. The total generation capacity in Germany during the observation period is about 120 GW (VDN, 2005). The basic plant list is obtained from VGE (2005, 2006) and adjusted to account for seasonal availability according to Hoster (1996) with the highest level of availability in winter months.[30] Since the analysis is based on single hours the generalization can lead to divergences in specific cases, such as a plant outage of a large coal block.

Renewable energies play an increasing role in Germany's energy supply. As they are not dispatch-able like conventional generation units they are included into the demand estimation (Figure 3.6). Demand is reduced by calculating the hourly wind input for the analyzed days. Other renewable sources like solar and bio mass are neglected due to the relatively small installed capacities. Wind capacities range from about 15 GW in 2004 to 18 GW in 2005. As the energy input of wind plants is determined by wind speed the actual output varies accordingly. Thus, historic wind speed information from the German Weather Agency (Deutsche Wetterdienst, DWD) is used to estimate the wind energy input. Therefore Germany is split up in seven zones (North Sea coast line, Baltic Sea coast line, western Germany, eastern Germany, low mountain range, southern Germany). Using the logarithmic height correlation (Hau, 2003) the wind speeds in an average turbine height of 60m can be calculated:

[30] December, January and February are considered as winter months; June, July and August as summer months; the remaining months as transition period.

$$v_H = v_{ref} \frac{\ln \frac{H}{z_0}}{\ln \frac{H_{ref}}{z_o}} \tag{3.1}$$

with	v_H	*wind speed in H (60m)*
	v_{ref}	*wind speed in reference height H_{ref} (10m)*
	z_o	*surface roughness (0,2)*

Using an average wind turbine characteristic the calculated wind speeds can be transformed into an energy output. The actual wind capacities on regional basis are obtained from the German Wind Energy Institute (DEWI, 2004a, 2004b, 2004c, 2004d, 2005a, 2005b).

Marginal costs for electricity generation are mainly based on fuel prices. Therefore fuel type and plant efficiency are estimated. To derive the efficiency of each plant, the age is used as a proxy: for coal, lignite, oil/gas fired steam plants, CCGT plants and gas turbines, the link between age and efficiency is taken from Schröter (2004). Nuclear plants are assumed to have an average efficiency of 33% (Müller, 2001) and hydro plants have 100% efficiency. Pump storage plants have a chronologically staggered efficiency according to Müller (2001).[31]

Fuel prices for imported oil and gas on a monthly basis and quarterly plant coal prices are obtained from Bafa (2006). For nuclear plants fuel costs of 3 €/MWh are assumed leading to generation costs of 9 €/MWh.[32] As there exists no global market for lignite extraction costs of 1.76 €/GJ are used as presented in the high price scenario in Schneider (1998); this figure over- rather than underestimates the real costs. Hydro plants are assumed to have no fuel costs. Pump storage plants are assumed to store water during off peak hours and are available during peak hours. Thus the off peak price at the EEX is considered as "fuel price" and the generation costs are calculated using the plants efficiency. Hydro and pump storage plants act as price takers like every other plant. In addition to fuel costs an uplift payment for variable operating expenses is used for each plant type (EWI, 2005). Coal plants have addition expenses of 2 €/MWh, nuclear plants 3 €/MWh and gas fired plants 0.5 €/MWh. Hydro plants are assumed to have operating expenses of 1 €/MWh. Start up costs as well as ramping costs are not considered.

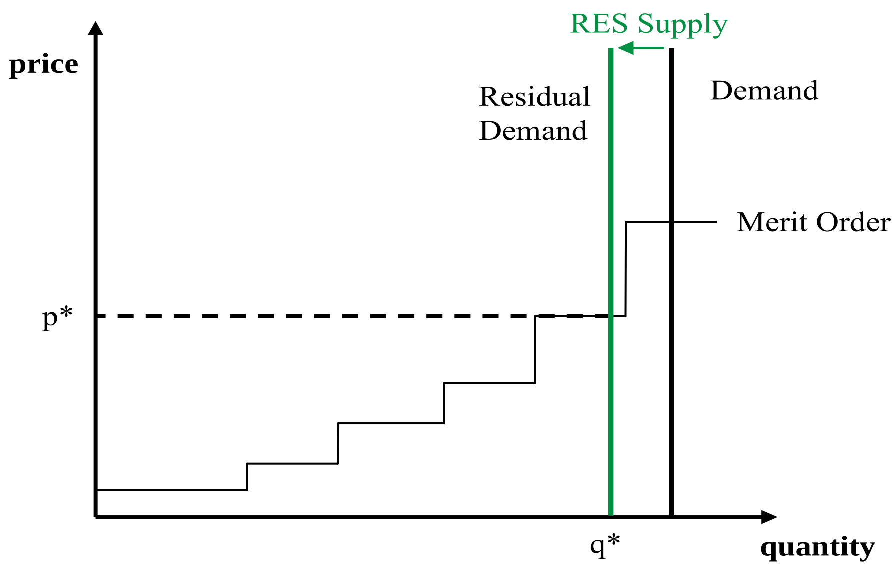
With the introduction of the emission allowance trading scheme in 2005 an additional cost element has to be considered: allowance prices can be taken into account as opportunity costs of production. Therefore the plant specific CO_2-emissions are calculated based on efficiency and plant type

[31] Pump storage plants build before 1950 have 60% efficiency, before 1960 65%, before 1970 70%, before 1975 75% and plants built afterwards have 82% efficiency. If there was no information about the year of construction, 1980 is assumed to be the relevant date.

[32] Nuclear is not the marginal supplier in the relevant periods, so that the estimate of its marginal costs does not change the results.

according to Gampe (2004). These emissions are valued with the average allowance price of the analyzed month and added to the fuel and operation costs.

Figure 3.5: Estimating the competitive price level in electricity markets



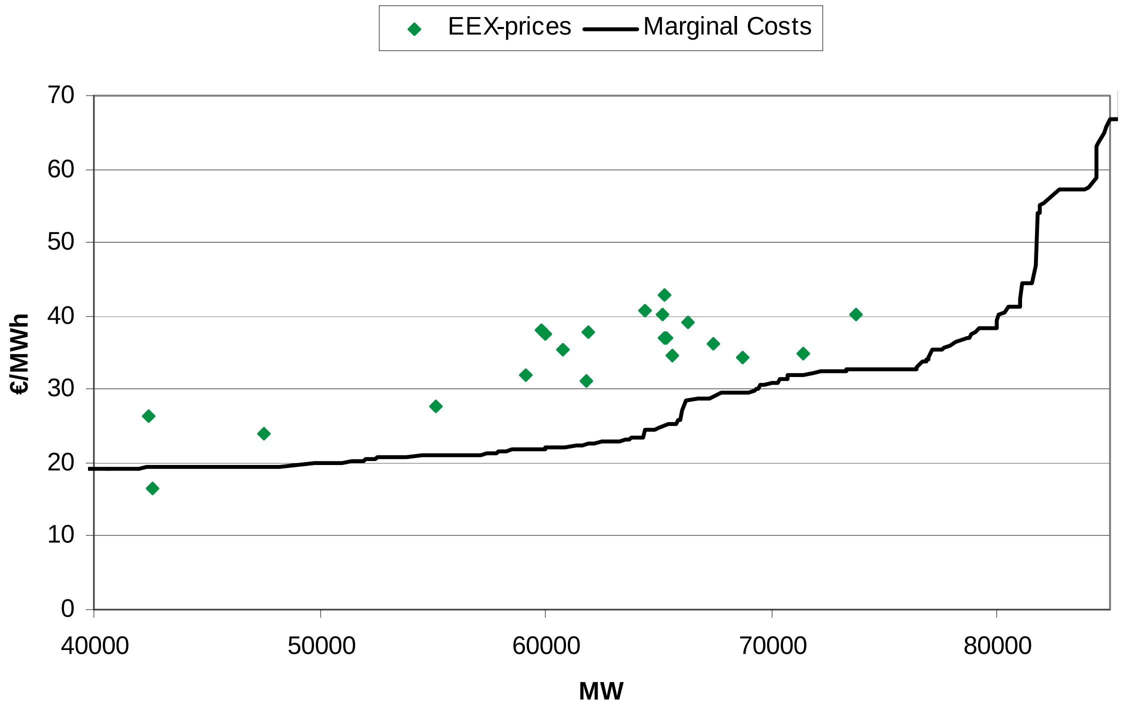
Source: Own representation

3.5.1.2 Results

Comparing the marginal cost estimates with the market prices for the period from 2004 till 2005 (a total of 24 days) shows that the prices exceed the cost estimates consistently. In particular, mark-ups occur during peak hours, whereas in off-peak the prices more or less correspond to the cost estimates. Hence the further analysis is focused on the mid and peak load periods (8am-8pm).

For the year 2004, the average Lerner index is 0.21. The analyzed days show the highest margin in a range between 80 to 90% of daily peak load with Lerner indices of more than 0.4. This corresponds to the results of Schwarz und Lang (2006). The September day is an example of the unexpected price development (Figure 3.7): the highest mark-ups are observable during mid term while they drop slightly near the days peak load. The results also show that startup costs seem to have a significant impact on market decision for base load plants. Especially in the summer days market prices during off peak hours are below the modeled competitive prices. This seems to hold true whenever the load level drops below 50 GW. This effect can be explained by the necessary time and costs of shutting down a base load plant during the night and restarting it the next morning. Plant owners seem to prevent this procedure by bidding below marginal costs and therefore secure that their plant is running all the time. Thus the modeled supply curve may have to be shifted to the right reducing the simulated market clearing prices.

Figure 3.6: Results for September 15, 2004



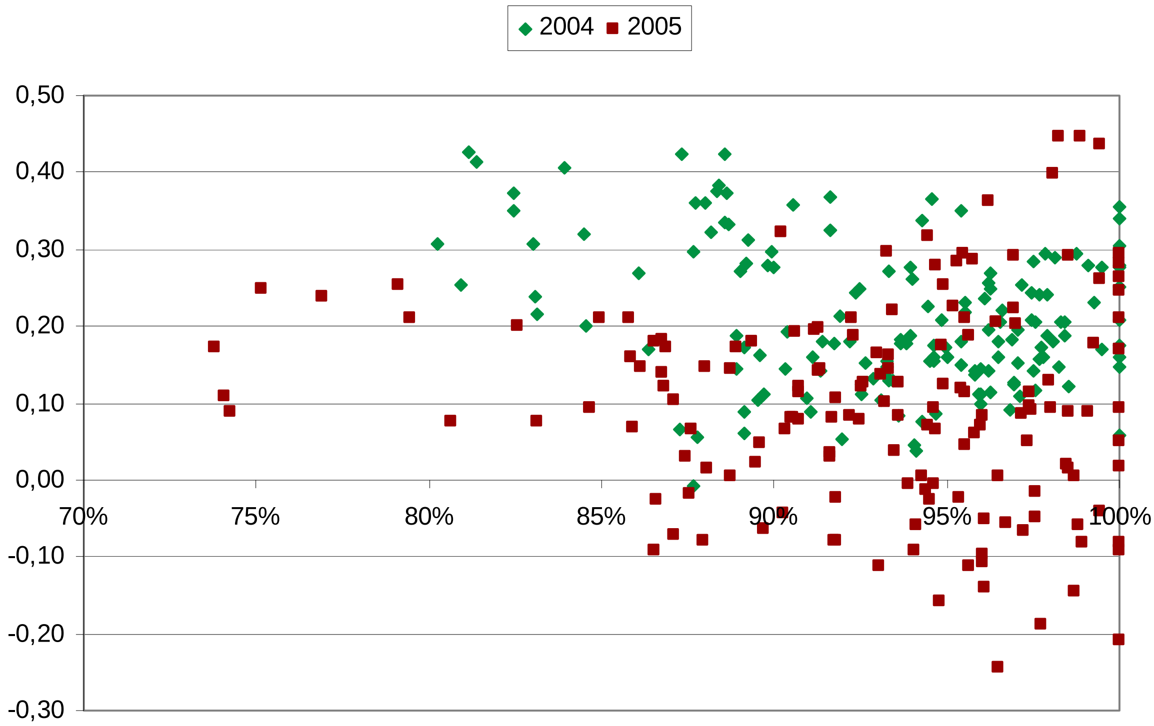
Source: Hirschhausen and Weigt (2007a).

With the introduction of emission allowances in 2005 the situation changed. The clear situation of 2004 with a general positive mark-up during peak times is replaced by unsteady results with positive and negative mark-ups.[33] The situation in 2005 can be separated into three different segments: In the first half of 2005 (January till May) the analysis shows a similar pattern as in 2004 with negative Lerner Indices during off peak and positive indices during peak hours. The main difference is the increased price level of the supply curve due to the opportunity costs of CO_2-emissions. Thus the calculated Lerner indices are smaller compared to the same period in 2004.

The situation changes noticeable during the following months (June to October). The average Lerner index drops to -0.13 and even during peak hours negative mark-ups can be observed. Neglecting the opportunity costs for emission allowances yields that the observed market prices are still above the fuel and operation expenses. Thus the market participants seemed to be uncertain whether to fully include the allowance prices or not. In November and December 2005 the Lerner indices are throughout positive during peak hours and the average values indicate a significant mark-up comparable to the situation in 2004. Figure 3.8 summarizes the obtained Lerner indices for 2004 and 2005 during mid- and peak-load hours.

[33] A full presentation of all obtained price curves is presented in Appendix I.

Figure 3.7: Lerner indices, 2004 and 2005, mid and peak load period (8am-8pm)



Source: Own calculation, based on Hirschhausen and Weigt (2007a).

3.5.1.3 Discussion

As Harvey and Hogan (2002) have shown, benchmarking analyses are sensitive to the underlying dataset as well as simplifications and assumptions. Thus a sensitivity analysis is needed to verify the obtained results. As the presented model is based on publicly available data, some key information may be missing to explain the observed differences. In the presented case the absence of reliable data on the imports and exports is a major drawback of the model. Therefore, a sensitivity analysis is conducted to examine the shifts in demand or in plant availability that would be required to obtain a fully competitive solution. The obtained values show how far the supply curve has to be shifted to intersect with demand in order to obtain the observed market results at the EEX. Thus if these values are relatively high, the basic conclusion is valid while only little differences would suggest missing information as explanation. As the main focus lies on market power abuse again only peak hours have been considered.

For 2004 the sensitive analysis yields an average gap of about 9 GW. Thus the simulated supply curve would have to be shifted to the left by 9 GW or the demand level was 9 GW higher than assumed.[34] Only July shows relatively low differences of 3 GW that are most likely due to the model assumptions. However, other months (e.g. May and September) show average difference of about 15 GW with maximum divergences of more than 19 GW (Figure 3.9). These errors are most likely not solely

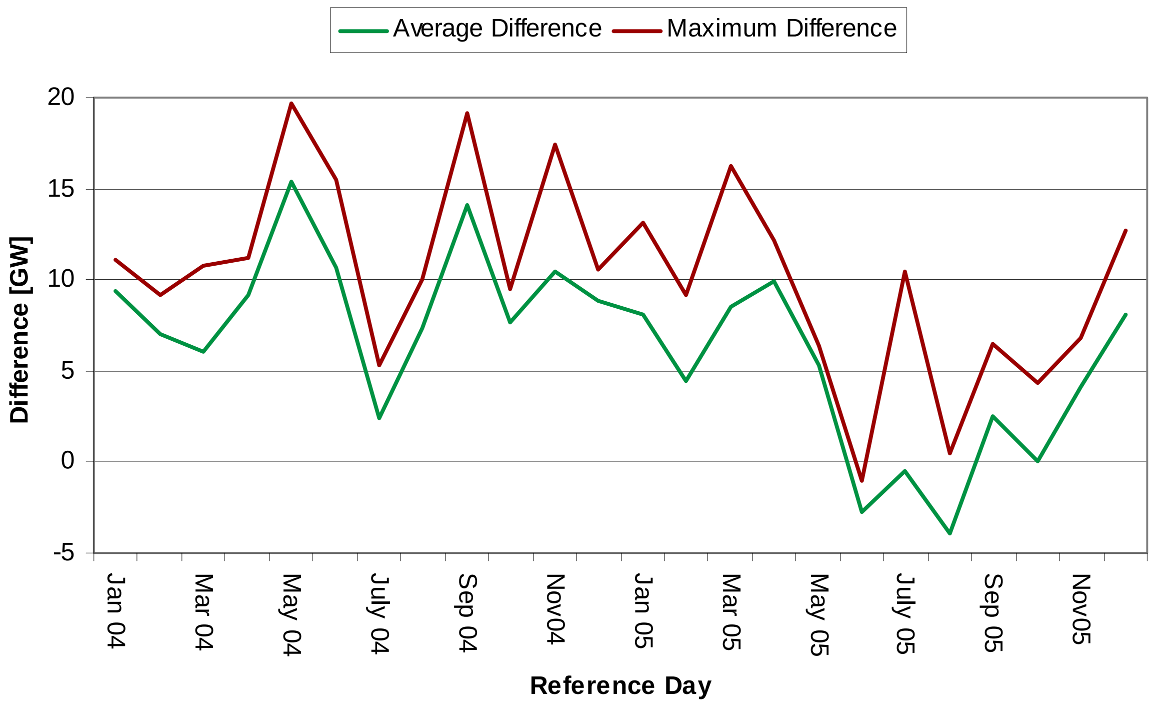
[34] Given that the demand values are more likely to be smaller than assumed as imported energy and smaller renewable energy sources have not been considered the value indicates a possible overestimation of available plants.

explainable by data issues and suggest that strategic behavior by market participants might have played a role.

In 2005 the situation follows the same three patterns as the Lerner indices described above. In the first half the capacity gap is comparable to the situation in 2004 with average values of about 10 GW. However, in the summer months this situation reverses completely and the gap becomes negative. This indicates that either the plant availability is overestimated (e.g. due to a heat wave) or the actual demand level is below the modeled one. The situation returns to the old trend in November and December.

Figure 3.9 shows the average and maximum differences between the real supply and the (hypothetical) market-clearing supply. Except for the summer of 2005 these differences are significantly high, with values of more than 10 GW on average. This shows the general robustness test to be valid: underestimation of load and overestimation of generation capacity in a height of more than 10 to 15 GW is relatively unlikely for a large fraction of observations.

Figure 3.8: Sensitivity analysis, withheld capacity in 2004 and 2005



Source: Hirschhausen and Weigt (2007a).

3.5.2 Price Formation in 2006

3.5.2.1 Methodology

Similar to the previous analysis the aim of the 2006 model is to derive estimates for the "real" marginal costs which are then compared with the prices at Germany's wholesale electricity market

EEX. However, starting with 2006 hourly demand data for Germany is provided by the UCTE as well as hourly wind input values by the four German TSOs. This dataset allows a more sophisticated approach to estimate the competitive price level by applying a costs minimizing model to satisfy the German demand subject to technical characteristics of electricity generation:

$$\min_{g} \text{ costs } = \sum_{t,p} \left(c_p^t \, g_p^t \right) + \sum_{t,p} startup_p^t \qquad \text{objective} \qquad (3.2)$$

where c^t_p are the marginal generation costs of plant *p* in hour *t*, g^t_p is the actual output of that plant in hour *t*, and $startup^t_p$ are the occurring start-up costs in case the plant has to go online. The considered overall timeframe is 2006 divided into 12 model runs, one for each one month. The output of a plant is restricted by lower and upper boundaries due to the thermal capabilities of the generation process:

$$on_p^t \, g_p^{\min} \leq g_p^t \leq on_p^t \, g_p^{\max} \qquad \text{capacity constraint} \qquad (3.3)$$

with g_p^{max} as maximal available power output, g_p^{min} as minimal necessary generation output to operate a plant, and on^t_p as the binary condition variable stating if a plant is online (1) or offline (0). The resulting start-up costs are calculated as a cost block in the hour the plant goes online:

$$startup_p^t = sc_p^t g_p^t (on_p^t - on_p^{t-1}) \qquad \text{start-up costs} \qquad (3.4)$$

where sc^t_p are the start-up fuel cost necessary to heat up the power plant *p*. These are mainly driven by fuel prices which vary for the time *t*. If a plant remains on- or offline the condition difference $(on_p^t - on_p^{t-1})$ is zero and thus there are no costs. In case of a shut-down the difference becomes -1 but the actual output g^t_p of the plant *p* in *t* is zero. Only in case of a start-up the condition difference is 1 and the output is positive resulting in a positive start-up cost block. According to the type of plant, start-up can take a few minutes (small gas turbines) up to several days (nuclear) thus a constraint on the plants condition variables is introduced following Takriti et al. (1998):

$$on_p^{t-1} - on_p^t \leq 1 - on_p^{\tau}, \quad \tau = t+1,...,t+l_p \qquad \text{start-up constraint} \qquad (3.5)$$

with l_p as the required start-up time of a plant *p.* In case a plant goes offline in *t* the left hand side of equation 3.5 becomes 1. In order to fulfill the inequality the condition variables of the following τ hours have to remain 0 thus restricting the start-up possibilities of the plant.

As the model is an ex-post analysis, demand *d* in hour *t* is known and has to be satisfied:

$$PSP_{up}^t + d^t = \sum_p g_p^t + PSP_{down}^t \qquad \text{energy balance} \qquad (3.6)$$

with PSP^t_{up} as stored energy in pump storage facilities in *t* and PSP^t_{down} withdrawn energy from that facilities in *t*. In order to satisfy the demand in electricity markets the only possibility beside power generation is to use pump storage facilities. The storage process is considered as additional demand, increasing the necessary power generation, whereas the withdrawal is equal to conventional generation increasing the energy output. Typically pump storage facilities use cheap generation during nighttimes

to fill their storage and use the stored water during peak times to allow for a better control of the transmission grid. Network constraints are not considered and thus losses are not taken into account.
The pump storage process is an inter-temporal condition:

$$PSP_{storage}^{t+1} = 0{,}75 * PSP_{up}^{t} - PSP_{down}^{t} + PSP_{storage}^{t} \qquad \text{storage equation} \qquad (3.7)$$

where $PSP^{t}_{storage}$ is the stored amount of energy in hour t. If it runs in pump mode (PSP_{up}), 75%[35] of the consumed energy will be added to the storage for the next period and if it runs in generation mode (PSP_{down}), the appropriate amount of energy is taken from the storage. The initial storage level for each model run is assumed to be zero. The storage and withdrawal processes are furthermore subject to capacity restrictions:

$$PSP_{up}^{t} + PSP_{down}^{t} \leq PSP^{\max} \qquad 1^{st} \text{ PSP capacity constraint} \quad (3.8)$$

with PSP^{max} as the maximum capacity of pump storage plants in Germany. The total sum of storage and withdrawal can not exceed the installed pump capacity. The withdrawal is further limited by the amount of energy stored, which may be lower than the installed pump capacity:

$$PSP_{down}^{t} \leq P_{storage}^{t} \qquad 2^{nd} \text{ PSP capacity constraint} \quad (3.9)$$

The model is implemented in GAMS as a combination of a mixed integer problem for the unit commitment and an optimization problem with fixed binary plant condition variables for the actual dispatch.[36] The dual variable on the energy balance constraint is considered to represent the hourly market price.

3.5.2.2 Data

The underlying generation dataset draws on the same information utilized in the previous analysis (see Section 3.5.1.1). The power plant database is extended to account for start-up restrictions. The minimum capacity requirements as well as the necessary start-up fuel consumption are differentiated according to plant type and taken from DENA (2005, p. 280). Within the model nuclear plants are assumed to supply base load. Therefore, they are must-run plants that cannot be shut down, thus their condition variable on^{t}_{p} is fixed to one. Lignite, coal, steam and CCGT plants are modeled with specific start-up times l_p according to Schröter (2004, p. 39). Gas turbines and hydro plants are assumed to be able to go online in less than an hour thus equation 3.5 is not binding for them.
Germany has a large fraction of combined heat and power producing plants (CHP) particularly in the industry sector. These plants are treated as must run plants with a specific minimum output level. As additional restrictions representing the heat consumption CHP plants must run at least 50% of their maximum electrical capacity in winter, 30% in spring and fall, and 20% in summer. A detailed hourly heat profile is not used.

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[35] Following Müller (2001), modern PSPs have an average efficiency between 70 and 80%.
[36] The GAMS code is presented in Appendix II.

Fuel prices for coal, oil and natural gas are based on wholesale price levels of reference markets, thus transportation costs or transmission fees are not considered.[37] The price for steam coal is based on prices for internationally traded coal at ARA, daily natural gas prices are taken from the Dutch market TTF, and oil prices are daily Brent prices. Fuel costs of nuclear, hydro, and lignite plants are modeled similar to the previous analysis. PSPs are modelled as either demand or generators and thus have no external marginal costs. The resulting impact on the price level is obtained by optimizing pumped storage usage and accounting for the generation costs needed to replenish the storage.

In addition to fuel costs again an uplift payment for variable operating expenses is used for each plant type following EWI (2005) and an emission factor is determined following Gampe (2004). The emissions are valued with the allowance price taken from EEX and added to the fuel and operation costs. Thus the marginal generation costs c^t_p of a plant p in any considered hour t consist of the fuel costs based on plant efficiency η and fuel price, operating costs, and opportunity costs for emissions based on plant-specific CO_2 emissions and the allowance price at the EEX:

$$c_p^t = \frac{1}{\eta_p} fuelprice^t + operation\ costs_p + emissions_p\ CO_2 price^t \quad \text{marginal costs of generation (3.10)}$$

On the demand side the hourly demand level for Germany is provided by the UCTE (2007). Total demand ranges between 75 GW at peak and 35 GW at off-peak times. Imports and exports are considered on an hourly basis by reducing or increasing the demand level. The total trading balance of Germany based on actual cross-border power flows is obtained from ETSOVista (2007).[38] The resulting net flow into or out of Germany is considered in the total demand level d^t. Thus when energy is imported, a portion of Germany's demand is covered by foreign plants, reducing the necessary amount of domestic generation and vice versa. However, the modeled prices represent the upper bound in cases of net exports, since plants above market price can be used for exports, and a lower bound in cases of net imports since a foreign generator can set the market price in Germany. Wind energy input is again subtracted from the demand level and other renewable energy sources are neglected. The approximation of hourly wind input via wind speeds could be replaced by the actual energy input published by the four German TSOs increasing the accuracy of the estimation.

3.5.2.3 Basic Results

The basic model approach uses twelve runs (one for each month) to simulate the wholesale market in 2006 and find the competitive market outcomes. Figure 3.10 shows the model prices and the observed prices ordered from highest to lowest EEX price. The simulated prices and the EEX prices behave similarly with a clear segmentation between off- peak and peak prices. However, in off-peak periods, EEX prices often drop below marginal generation costs and sometimes even reach zero, whereas the

[37] Due to the volatility of wholesale prices particularly for oil and natural gas, generators are expected to sign contracts for their fuel supply. The pricing details of these contracts are not publicly available. The wholesale prices are assumed to be sufficient to reflect the average price level. However, this can lead to divergences for specific plants.

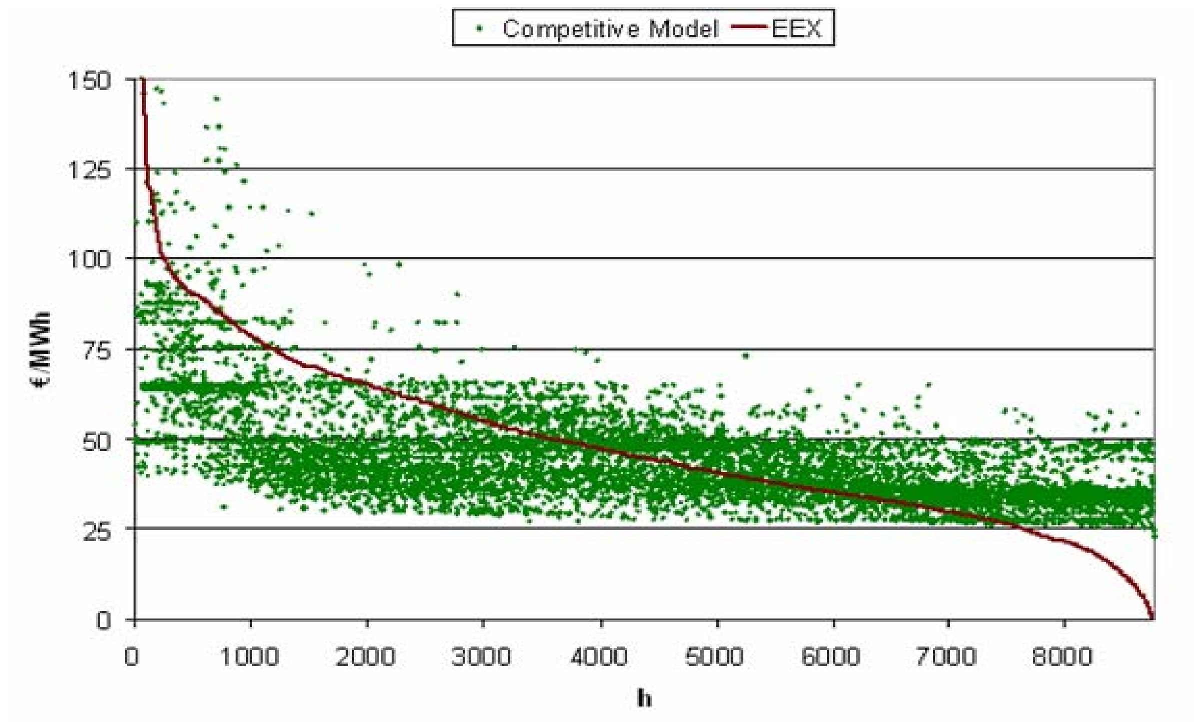
[38] The values for cross-border flows have been completed using publicly available information from the four TSOs and Nordel.

model prices reach a level, representing coal and lignite fired base load plants between 30 and 40 €/MWh. In general, prices below marginal costs are explained by start-up conditions since the temporary shut-down of a base load plant can become more expensive than maintaining operations without revenues. Because the model is based on perfect knowledge, the price difference may be due to asymmetric information (e.g., bidders' "wrong" expectations about market conditions). Furthermore the model includes emission allowance prices as opportunity costs whereas bidders may vary between full, partial and no cost past through.

In the mid-price segment the EEX prices increase from 40 to about 60 €/MWh while the model prices exhibit volatility ranging from 28 to 65 €/MWh with a high number of price combinations that diverge strongly from each other. This trend continues in the peak price segments. The results clearly show that high EEX prices generally do not have an equivalent high competitive price counterpart. EEX prices increase towards their yearly peak of more than 2000 €/MWh while model prices remain between 40 and 95 €/MWh.

The average price in 2006 at the EEX is 50.79 €/MWh whereas the model average is about 11% lower with 45.28 €/MWh. For the peak segment (weekdays 8am-8 pm), the difference is more striking with a model average price of 52.31 €/MWh (about 30% below the observed average of 74.48 €/MWh). For off-peak hours including holidays and weekends, the observed prices are lower with an average of 38.23 €/MWh compared to 41.54 €/MWh in the model. Focusing only on weekdays, this divergence is reduced to 1.4 €/MWh or 3%. Using the underlying demand, the total expenses at the EEX price level are 3.6 bn € higher than in the model.

Figure 3.9: Price comparison, model results and EEX, 2006

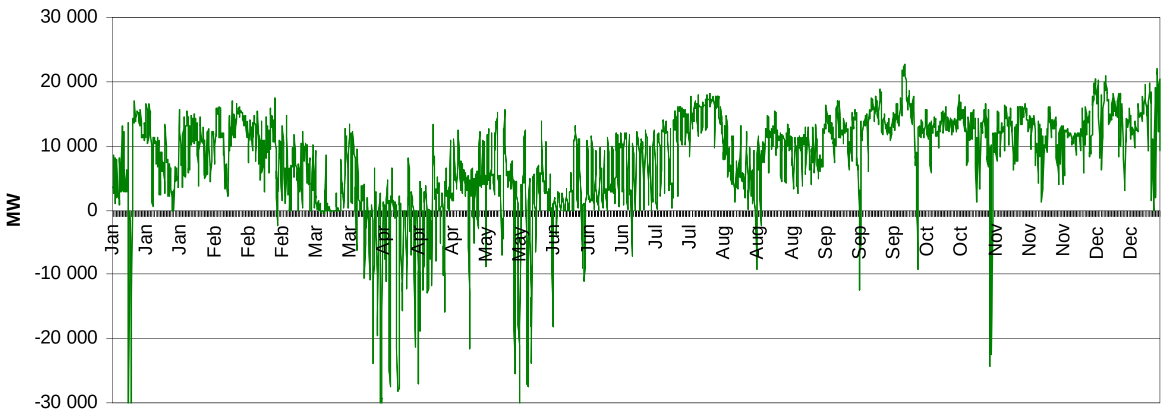


Source: Weigt and Hirschhausen (2008)

Similar to the analysis for 2004 and 2005 the underlying model is subject to simplifications and assumptions. To test the robustness of the results first the capacity difference is estimated and afterwards two sensitivities are tested.

To estimate the difference in quantities between the model and the EEX, withheld capacity is calculated for weekday hours 8am- 8pm as market power abuse is expected to occur mainly when demand is close to the capacity limit. Furthermore, off-peak and weekend hours show a high degree of prices below marginal generation costs. To obtain the withheld capacity all available plant capacities with marginal costs below the EEX price but not operating in the corresponding modeled solution for each hour are summed up. In 2006, the average amount of capacity withheld during peak hours is about 8 GW and thus similar to the values obtained for 2004 and the first half of 2005, but it varies throughout the year. Figure 3.11 shows that the average values in the first two months of around 9 GW, the gap then narrows significantly from March until June, even reaching an average of -2 GW in April. After July, the capacity withheld again increases, with average values between 8.5 and 14 GW. The low capacity values for April and May could be a result of the sharp drop in emission allowance prices in spring 2006 due to an over allocation of allowances. The situation normalized during the summer although allowance prices remained significant lower (Figure 3.11).

Figure 3.10: Capacity withheld during workday peak hours (8am–8pm)



Source: Weigt and Hirschhausen (2008)

3.5.2.4 Sensitivity Analysis

In addition to the capacity analysis two sensitivities are tested to estimate the robustness of the obtained results. First, the fuel price level is varied by increasing prices for gas and oil by 10%. This should lead to an increase in peak prices when CCGT, gas turbines and oil- or gas-fired steam plants set the market price, while off-peak prices are unaffected. Second, varied power plant availabilities are incorporated. Due to a lack of hourly availability values only seasonal factors are used, which may misinterpret the real availability due to high temperatures, low water levels or plant outages.[39] The basic availability values from Hoster (1996) are altered by reducing the winter availability by 2%, the intermediate values by 3% and summer values by 4%. Table 3.2 shows the available capacities in each season compared to the corresponding values at monthly peak load of 2004 (VDN, 2005).

The impact of the changed fuel prices is only evident during peak load situations when the according plant capacities are needed. During these times the price level slightly increases. The average market price increases to 46.54 €/MWh (about 8% below EEX prices); average peak prices are 2.5 € above the base case and thus still 26% below the observed ones. The impact of reduced plant availability is more distinctive. During off-peak and mid-load periods, the difference is rather small because the remaining capacity is still sufficient to keep a moderate price level. During peak situations the prices are above the basic model results, particularly in winter and summer months. This effect can be explained by the steep slope of the merit order close to maximum capacity in combination with start-up conditions that lead to prices above marginal costs. On average a market price of 48.74 €/MWh (4% below EEX prices) can be observed. Average peak prices increase to 59.55 €/MWh (20% below observed prices). In both sensitivities the off-peak prices are little affected.

However, even the reduced capacity is still sufficient to satisfy demand, thus no capacity rent for peak units can be expected. The average quantity gap in peak hours is reduced to 6.7 GW in the fuel price variation scenario and to 5.8 GW in the availability variation scenario. The monthly pattern remains similar to the base case with average values above 10 GW in the second half of 2006 for both sensitivities.

Comparing the basic model with the sensitivity analyses and EEX prices shows that the observed price duration curve has higher prices in about 4500 h in 2006 (Figure 3.12). On the other hand, EEX prices are lower than the modeled prices in 3000 h.[40] All model variations have price spikes of more than 200 €/MWh (in cases of the availability analysis also 500 €/MWh), which are comparable but generally still lower than the maximum prices at the EEX. In the mid to peak price region (between 50 and 100 €/MWh) an interesting results is observable: a general price divergence of about 10 €/WMh is obtained for more than 2000 h. This difference is only slightly affected by the changed parameters of the sensitivity analyses. Since these differences are observed in price regions that do not indicate capacity shortages, the question to raise is whether missing information and model simplification are solely responsible for the divergence.

[39] Ockenfels (2007a, b) discusses this topic in detail. Other potential model limitations like stochasticity, asymmetric information, and opportunity pricing of cross-border transactions and hydro plants are not considered in the sensitivity analysis.

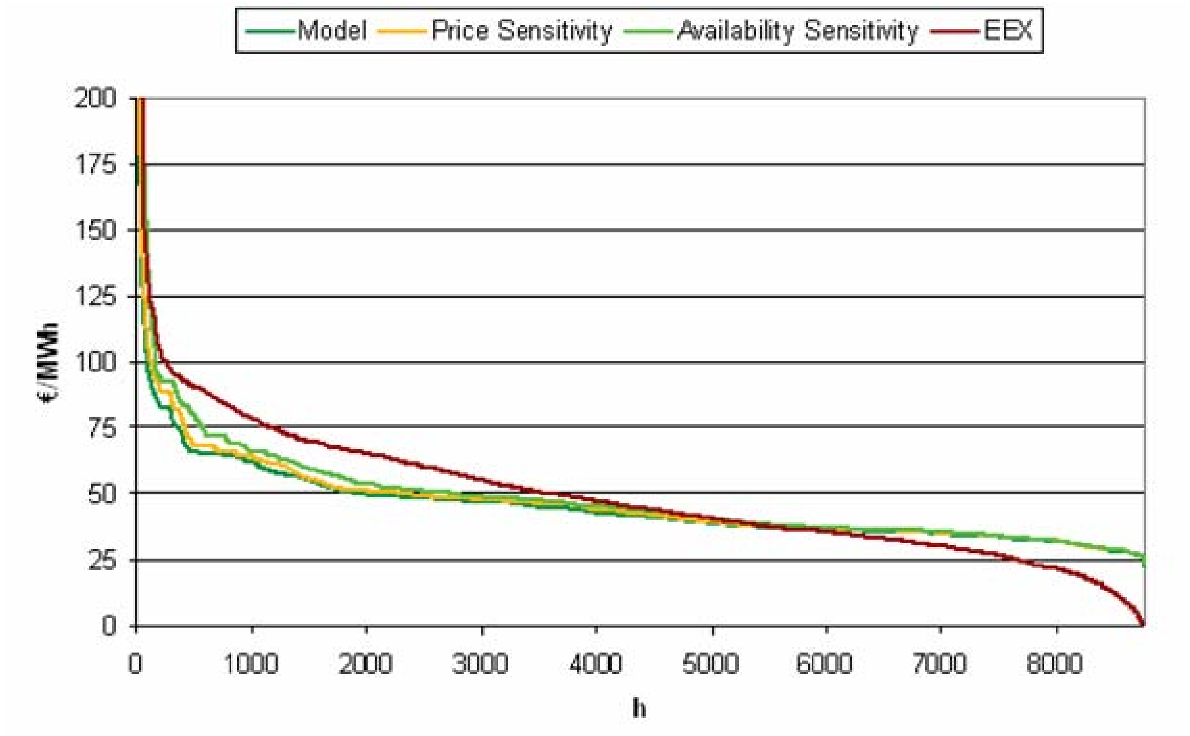
[40] These values correspond to the price duration curves and not to actual model/EEX price combinations.

Table 3.2: Available capacities, 2006 model

		Winter	Intermediate	Summer
Basic model	Fossil plants	83 350 MW	77 850 MW	74 170 MW
	Pump storage	3 900 MW	3 650 MW	4 150 MW
Reduced capacity	Fossil plants	81 430 MW	74 960 MW	70 320 MW
	Pump storage	3 770 MW	3 460 MW	3 900 MW
Values at peak load (VDN, 2005)	Reliably available capacity	83 130 MW	79 500 MW	74 370 MW

Source: Weigt and Hirschhausen (2008), based on VDN (2005), VGE (2005, 2006), and Hoster (1996)

Figure 3.11: Price duration curves, 2006



Source: Weigt and Hirschhausen (2008)

3.5.2.5 Fixed Cost Coverage

One further point of interest is how competitive market outcomes translate into revenues for fixed cost covering. Pricing is based on short-term marginal costs; therefore, companies are expected to cover their investment costs when generators with higher costs set the market price or capacity is lower than demand, and both situations can result in price spikes that allow companies to "earn" rents above their generation costs. As mentioned, the German market is frequently subject to overcapacities. Thus, the price level is expected to give no signal for new investments.

In order to analyze the investment signals provided by the spot market the annual revenues for each fossil fuel plant type are obtained by summing the difference between market price and generation costs. Each plant type is considered to be running according to the model outcome thus off-peak units have significantly more hours to recover there costs than peak units. The earned revenues do not take into account forward trading or other market segments like reserve markets. Thus, the values represent spot market based results. As benchmark average investment are calculated assuming average overnight costs per MW, an interest rate of 7%, and 40 years' duration for base and 25 years for peak units.

Table 3.3 shows the calculated rents generators earned according to the model. As the European-wide emission allowance trading scheme includes a grandfathering mechanism the revenues from opportunity pricing of allowances are windfall profits for the generators. These can also be used to cover fixed costs and are supposed to set incentives for investment into cleaner technologies. The analysis is made for two revenues for each plant type: one that includes allowance prices as marginal generation costs and one that excludes them. Only the values including allowance costs are relevant for estimating market competitiveness as firstly opportunity pricing is not an aspect of market power and secondly the same price outcome is supposed to occur under full auctioning of allowances.

The results reveal that under modeled competitive conditions, only nuclear plants can cover their fixed costs, under EEX price calculations, both nuclear and coal plants can cover their costs, and in both scenarios, peak load plants cannot cover their costs. [41] The results indicate that no additional capacities are needed in the postulated overcapacity of the German market. Another issue is the impact of the allowance trading mechanism on investment signals. The political intent is to foster investment in emission reduction mechanisms or power plants with low emission values like CCGT. However, the results to date point to an absence of investment activity. Due to the base load character of most coal plants and the grandfathering mechanism giving the largest bulk of allowances for free, the current market prices set a high incentive to invest in coal technology rather than gas-fired units. Based on the values for 2006, the current system fails to fulfill the expected political objectives.

However, the results do not permit us to conclude empirical which mechanism (competitive system or the EEX market) is adequate for fixed costs covering. Due to the long term investment character of power plants, importance of forward contracts, fuel price variations, existence of optional markets like reserve markets, and the uncertain further development of the emission allowance system in Europe, consistent results regarding the issue of capacity financing can only be answered with long term analyses.

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[41] The possible rents for peak units may increase since other market segments (e.g., reserve markets) are not considered.

Table 3.3: Annually earned revenues for fixed cost covering per installed MW in 2006

Plant Type	Competitive Model		EEX price based		Annuity of Investment cost[42]
	Including allowance costs	Excluding allowance cost	Including allowance costs	Excluding allowance cost	
Nuclear (surplus)	234 100 € (+46 600 €)	234 100 € (+46 600 €)	271 800 € (+84 300 €)	271 800 € (+84 300 €)	187 500 €
Lignite (surplus)	64 900 € (-47 600 €)	167 100 € (+54 600 €)	114 500 € (+2 000 €)	216 600 € (+104 100 €)	112 500 €
Hard coal (surplus)	60 300 € (-29 700 €)	147 700 € (+57 700 €)	110 200 € (+20 200 €)	197 600 € (+107 600 €)	90 000 €
Steam (surplus)	600 € (-85 200 €)	2 200 € (-83 600 €)	1 700 € (-84 100 €)	3 300 € (-82 500 €)	85 800 €
CCGT (surplus)	5 000 € (42 200 €)	11 000 € (-36 200 €)	14 400 € (-32 800 €)	20 400 € (-26 800 €)	47 200 €
Gas turbine (surplus)	160 € (21 300 €)	320 € (-21 100 €)	70 € (-21 400 €)	230 € (21 200 €)	21 450 €

Source: Weigt and Hirschhausen (2008)

3.6 Conclusion

In this Chapter the competition on liberalized electricity wholesale markets is analyzed using Germany as a reference case. By conduction marginal costs calculations the competitive market prices are estimated and compared to the observed wholesale prices. For the period from 2004 to 2005 significant price markups can be observed. Although, the model for this period is rather limited (only 24 reference days) the obtained results seem to be robust as the estimated capacity error is about 10 GW on average. For 2006 a full analysis of all 8760 hours is made showing that the competitive price level in Germany is about 11% below the EEX prices with significant higher price mark ups during peak hours. The results are also robust towards changes in price and availability assumptions of the model. The analysis shows that Germany is no exception with respect to market power concerns in liberalized electricity markets following the UK and California examples. Possible measurements to improve the competitiveness of electricity markets are analyzed in the next Chapter.

Beside the “pure” competitiveness of the market also the revenue adequacy is addressed. For 2006 only base load plants are able to recover their investment costs whereas mid and peak units can not. This result is in line with the postulated overcapacity of the German electricity market which should not provide incentives for further capacity extension. In this context also the misleading impact of grandfathering emission allowances is shown. Whereas coal plants are able to improve their investment recovery, gas fired plants remain unprofitable and thus contradict the postulated political aims to foster clean generation technologies.

[42] Nuclear plants are assumed to have overnight cots of 2500 €/kW, lignite 1500 €/kW, coal 1200 €/kW, steam 1000 €/kW, CCGT 550 €/kW, and gas turbines 250 €/kW.

4 Competition Policy and Strategic Company Behavior: Will Divestiture Solve the Problem?

4.1 Introduction

As shown in Chapter 3 most liberalized electricity markets are subject to market power concerns due to their oligopolistic market structure, possible flaws in the market architecture, and the specific characteristics of electricity generation and demand. Around the world several methods have been applied to increase the competitiveness of the new electricity markets, and thus to reap the benefits from liberalization. These methods range from strict market monitoring to structural measurements. What is actually required to obtain a sufficient level of competition in restructured electricity markets largely depends on the historical heritage defining the market structure, the technical characteristics of the national generation mix, and the interconnections to neighboring markets. Measures successfully applied in some markets may not produce the same benefits for other markets.

In this Chapter pro-active policy measurements to improve the competiveness of electricity wholesale markets are presented and the outcome of one measurement – divestiture – is tested using the German market as reference case. The next section reviews competition policy in electricity markets (Section 4.2). A particular focus is on divestitures including a review of international experiences. To test the effect of a divestiture measurement in an electricity market a fundamental competitive benchmark model as in Chapter 3 is insufficient. To examine the price reducing effect of changing the supply structure of a market, the strategic behaviors of market participants must be considered. Thus, in Section 4.3 a review and a comparison of two oligopoly model approaches – the classical Cournot approach and the SFE approach – are given. Afterwards both methods are applied to test different divestiture scenarios for the German market and to assess the potential welfare increasing effect given the current market structure (Section 4.4). Section 4.5 concludes.

4.2 Pro-Active Competition Policy: Methods and Experiences

The objective of competition policy is to increase the competitiveness of markets through price and/or structural instruments or – in the case of natural monopoly industries – through sector-specific regulation. Efficient competition is a fundamental aim of a free, market-based economic policy. However, the word "competition" is often interpreted by politicians, industrials, and economists according to their aims and thus can differ largely. In addition, following Hayek (1945) competition is not an end in itself but can be understood as a discovery procedure. The classification of competition largely depends on the prevailing circumstances and according to Schmidt (2005) can be defined as the pursuit towards a goal of two or more groups where a higher gain for one group normally means a lower one for the other(s). In economic terms competition is characterized by:

- The existence of markets

- At least two suppliers or consumers
- Market participants behave antagonistically.

In a dynamic context, competition leads to a gradual adaption of companies and consumers which increases the welfare of most participants. Schmidtchen (2005) differentiates four possibilities for suppliers to obtain a specific value added potential:

- Cost reduction on the production side (generation, transport)
- Cost reduction on the supply side (transaction costs)
- Improved quality and/or price alteration for complementary goods or substitutes
- Development of new products.

Competition can generally be considered the welfare optimal market solution to economic problems. Nevertheless, competition may not be the "natural" state an unregulated market will obtain. Regulatory intervention is often necessary when market failures occur (e.g., external effects, public goods, or natural monopolies). This is true for electricity transmission where only one supplier will emerge, due to the sub-additive cost function which must be regulated to avoid market power abuse.

The generation segment on the other hand is generally considered to be competitive, but due to the pre-liberalization structures many of the world's liberalized electricity markets initially showed an unsatisfactory degree of competition. To accelerate the transformation to full competition, a pro-active competition policy is necessary in many cases. Pro-active competition policy refers to sector- and company- specific measurements, unlike a passive competition policy that relies on market design and control elements common to anti-trust law. A short overview on competition policy measurements applicable for electricity markets is discussed below. The instrument of horizontal divestiture is presented in detail in Section 4.2.2, including a theoretical overview and a review on international experiences. In addition the topic of virtual divestitures is discussed as an electricity market specific instrument.

4.2.1 Competition Policy Measurements

Several policy measurements can be applied to overcome exiting obstacles and hasten the development of a competitive environment.[43] However, the most suitable measurements depend on the underlying market structures and regulatory setting; thus no general roadmap of efficient competition policy can be designed.[44] The following possible measurements are in common use.

Unbundling

Most electricity markets were characterized by a vertical integration of generation, transmission, distribution, and supply during the pre-liberalization period. In a competitive market setting the shared ownership of generation and network assets provides incentives to discriminate against competing

[43] This Section is based on Hirschhausen and Weigt (2007b).

[44] Joskow (2008) presents international experiences with liberalization in electricity markets and designs a blueprint for an efficient liberalization including elements of a pro-active competition policy (see Section 2.2.5).

generators and thus maintain higher wholesale prices. To avoid this conflict a separation of generation and transport by either ownership or legal unbundling is advisable. There is an ongoing discussion whether legal unbundling is sufficient to reduce the potential for discrimination (e.g., see van Koten and Ortmann, 2008; and Pollitt, 2008). If the negative effect of a vertically integrated company on competitiveness can be offset by the positive effect of integrated generation-transmission extension planning is also debatable (e.g., see Cremer et al., 2006).

Release

Due to the vertical structure of the pre-liberalized electricity markets a large share of transaction was accomplished with long-term contracts binding generators and consumers. The contracts can refer to energy deliveries and/or network access. The release of long-term contracts can increase the number of competing generators, increase the market demand for energy, and reduce network barriers. However, fair compensation of the contracted parties must be reached. In case of energy deliveries the revenue from an auctioning can be utilized. In case of network access the compensation depends on the underlying market design, e.g., in a locationally priced market like PJM compensation in the form of financial transmission rights is a feasible option.

Market Entry

Supporting new entry to the market and to construct new generation is another possibility for increasing competition in the medium- and long-terms. However, support requires designing an appropriate wholesale market. Non-market-based measurements like investment subsidies, tax deductions, and price guarantees can foster entry but can also lead to overinvestment and market distortion (e.g., see Stoft, 2002, p. 334ff; and Burns and Riechmann, 2004).

The increasing importance of environmental issues in electricity markets has led to several instances of politically induced interference that increased the uncertainty regarding future returns and reduced incentives to invest in specific technologies. The design of emissions trading will have a major impact on generation investment decision, (e.g., the question of grandfathering versus auctions). Reliable political guidelines therefore are important to reduce barriers to entry.

Additional issues are the available network access for new generation units and pricing network congestion. The most efficient solution would be a locational pricing mechanism that includes generation and transmission restrictions as well as losses. This would ensure that new market participants obtain a transparent price signal where new generation is valued highest.

Network Management and Extension

A simple yet effective measurement to increase competitiveness is to increase the available exchange capacity to adjoining markets. This is particularly true for Europ;e since the existing cross-border capacities were never designed to be the backbone of an integrated European market. Increasing the exchange capacities enlarges the relevant market and may increase the number of competitors and reduce market power (e.g., see Küpper et al., 2009). However, to obtain a positive price-reducing effect firms on both sides of the interconnection must actually compete (In the early years of liberalization in Europe most firms remained active within their regional or national borders.) Beside the physical extension of capacity the economic distribution of the available capacity is important if competitiveness is the goal.

Supporting Measurements

A wide array of other policy options is also available. *Privatization* is often the first option if an electricity market is liberalized. Privatization allows a clear separation between private competitive and regulated company activities, and leads to efficiency gains compared to the former state- owned or controlled activity (see Saal and Parker, 2001; Ng and Seabright, 2001; and Newbery and Pollit, 1997). Bushnell and Wolfram (2005) show for the US electricity market that the accompanying incentive change is a main contributor to the efficiency gain. Whether companies or consumers benefit from the increased efficiency is not entirely clear, e.g., Newbery und Pollit (1997) show that firms are the main benefactor of the efficiency gain in the British electricity market whereas Littlechild (2006) assumes an equal distribution between consumers and companies.

The overarching *market architecture* that combines competition policy instruments is another option. The main criterion of a functioning wholesale market is its transparency which is necessary for new market entrants to reduce entrance barriers and associated risks and additionally enables market monitors to detect market power. The wholesale market links to the reserve markets and to the transmission sector. In other words, the design of reserve requirements has a direct impact on wholesale prices since they reduce the available generation capacities for energy deliveries (e.g., see Riedel and Weigt, 2007; and Wieschhaus and Weigt, 2008). In the US most markets rely on real-time markets to allow customers to balance supply and demand as long as possible, thus reducing the need for reserve capacities.

The interaction of several competition policy measurement, regulation, and market segments becomes very important when the market is liberalized in several steps. Particularly if the consumer segment remains regulated, the interactions between a fixed priced supply and a variable wholesale market price can lead to problems (see Section 4.2.2.2).

To reduce the possibility of market power abuse and to detect possible anti-competitive structures a *market monitor* can be established. The threat of detection helps to discipline market participants while simultaneously the obtained information helps contributes to improvements in market design. Clearly the market monitor must remain independent from all market participants, including the system operator. Although the system operator has an information advantage regarding reserve markets and network related issues.

Related to the task of the market monitor is the necessary *merger control* to avoid market concentration. This can be accomplished by either prohibiting large firms to merge or acquire further companies and by requiring specific merger remedies to counteract the competition-reducing effects of a merger, e.g., divestiture of specific generation units. A supporting instrument of merger analysis is the SSNIP-test[45] which specifies the relevant market and enables appropriate modelling approaches to test the impact of a merger. Static approaches like simple concentration indices or the HHI-index are typically insufficient for electricity markets (see Twomey et al., 2004, for a discussion on market power analysis).

4.2.2 Divestiture

As discussed divestiture means splitting certain parts of an enterprise or a holding company to increase competition in a specific market.[46] Divestiture is generally considered a “hard” instrument of competition policy, because it directly impacts the management and ownership structure of firms. The focus of this section is on horizontal divestiture within the generation segment.[47] Horizontal divestiture of dominant firms is supposed to lead to a larger number of competing producers and therefore to enhance the intensity of competition within a market. The “marginal” effect of divesting assets of market-dominant firms is larger for an initial high concentration; the effect diminishes as more independent firms operate in the market. There is potential interrelation between horizontal and vertical divestiture: horizontal unbundling can remain ineffective if one of the firms remains vertically integrated. Vertical separation may therefore be a necessary condition for horizontal unbundling to be effective.

Divestiture improves the allocative efficiency of a market keeping the remaining market characteristics constant.[48] The larger number of firms leads to price decreases, quantity increases, and thus a welfare increase. Divestiture also improves the dynamic efficiency of a sector, i.e. its ability to innovate and invest. Increased competition forces companies to more innovation, to modernize products and production structures, and to develop other strategies to survive in the market place. The decline in investment of the incumbent will be partly offset by investment by new market entrants trying to increase their market share and may further reduce the typical overcapacities that cost-regulated markets face (e.g., see Borrmann and Finsinger, 1999, p 356ff).

The effect of divestiture on productive efficiency is complex: on one hand, the increased level of competition reduces the inefficiency inherent in the management of the former monopolistic firm (so-called X-inefficiencies, Leibenstein, 1966); on the other, , divestitures may reduce economies of scale if the resulting firm size is such that the costs of production are higher than in the previous situation. In

[45] Small but Significant and Non-transitory Increase in Price.

[46] This section is based on Weigt et al. (2009).

[47] The vertical separation of electricity companies (unbundling) can have quite different effects than horizontal divestiture. Further analyses regarding unbundling are provided by Cremer et al., 2006, Pollitt, 2008, and van Koten and Ortmann, 2008.

[48] Allocative efficiency characterizes a situation where the allocation of factors of production and the allocation of goods to consumers is structured such that the prices approach marginal costs, and social welfare is maximized (for details see Mas-Colell et al., 1995).

this case, the advantages of a divestiture should be weighed against the potentially adverse effects (Viscusi et al., 2005).

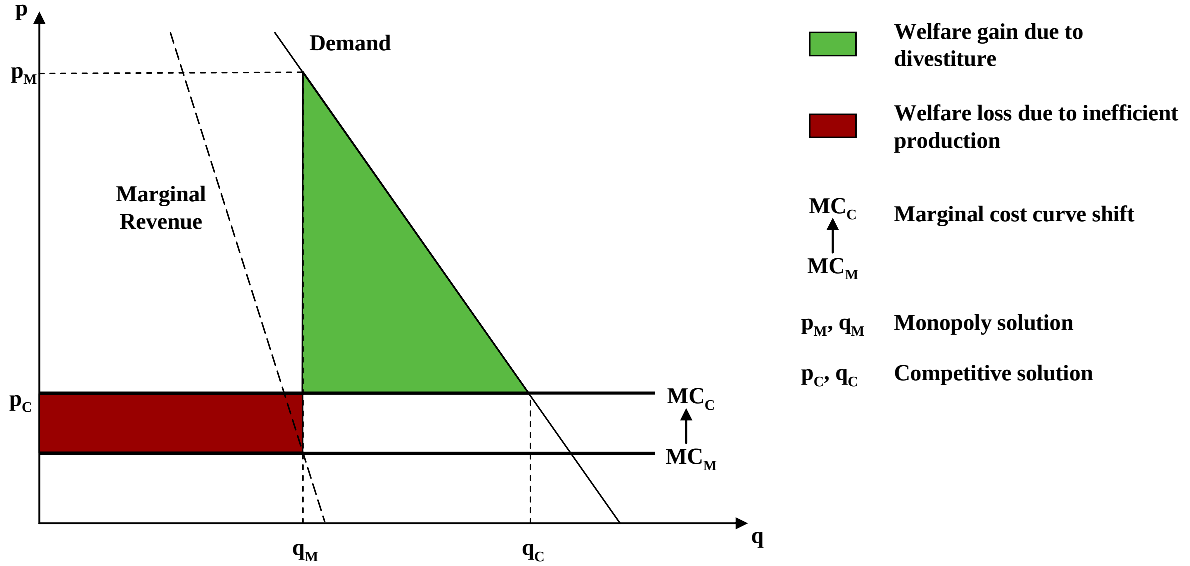
In more detail, a divestiture leads to an increase in the number of firms, which drives up the produced quantity and reduces prices. However, the marginal production costs may also be affected: (i) marginal costs can remain the same, e.g., due to strong technical restrictions which remain unaffected by the size of a firm; (ii) marginal costs can decrease, e.g., due to the pressure of competition; and (iii) marginal cost can increase due to lost economies of scale leading to a lower output level of firms at higher marginal costs, or lost incentives to increase efficiency or effort levels as the producer surplus decreases with competition leading to an upward shift of the production cost curve, or lost bargaining power on the input side leading to higher input prices and consequently to an upward shift of the production cost curve. In the first two cases (i, ii) the welfare impact is clear. In the third case (iii) the situation may be more complex since higher production costs can offset possible welfare gains. Figure 4.1 highlights this situation with a simple example. Assuming a monopolistic pre-divestiture market with constant marginal costs, the market outcome is defined by the monopolist's marginal revenue function. If via a divestiture the monopolistic market is transformed into a competitive market setting the market outcome is defined by the intersection of the marginal cost curve and the demand function. If the marginal costs increase due to the divestiture[49] the change in welfare consists of a producer rent loss due to the higher generation costs and a consumer rent increase due to the higher demand and lower price level.

Whether a divestiture is profitable under these circumstances depends on the underlying market characteristics. Given the strong technical restrictions on electricity generation the impact of divestitures on marginal generation costs and thus the loss of producer rent may be neglectable. However, divestitures may not be an appropriate tool to increase the efficiency of lightly concentrated markets, given the greater legislative burden of divestitures and the possibility of other competition measurements with similar effects.

The following sections review some of the divestitute experiences in the electricity and energy sectors. Regularly, the timing of these divestiture decisions coincides with market restructuring.

[49] One can assume a market with identical power plants that are each divested to a different company. Due to the monopolist's dominant position and bargaining power it could obtain a discount on fuel input prices which is offset by the divestiture.

Figure 4.1: Impacts on consumer and producer surplus due to divestiture



Source: Weigt et al. (2009), based on Viscusi et al. (2005)

4.2.2.1 Experiences in the Liberalized British Market[50]

The horizontal divestiture of electricity generation capacities in the UK in the mid-1990s is generally considered successful. With a certain time lag, the more competitive structure of the wholesale market led to decreasing prices. This structural measure laid the foundation for a competitive wholesale market.

Starting with the liberalization process in 1989 the state-owned monopolized electricity sector was privatized (see Section 2.2.1.1 for details). The CEGB owning generation and transmission was split into three generation companies (National Power, PowerGen, and Nuclear Electric) and one transmission company. Due to the state ownership of the monopolized British electricity market this process did not require interference by private ownership structures and the initial divestiture of generation and network assets can be seen as standard restructuring process. Competition on the wholesale market was supposed to be fostered by a mandatory pool where the price was defined via supply schedules and forecasted demand. The first years of the liberalized market were marked by slightly increasing prices and the construction of new natural gas power plants, the so-called Dash for Gas which resulted in several new entrants.

In 1993, the regulator (OFFER) suspected the dominant companies of manipulating prices, since price-cost margins appeared to reflect a decoupling of electricity and fuel prices. OFFER threatened to refer the two dominant generators National Power and PowerGen to the Monopolies and Merger Commission. To avoid this step both agreed to divest 15% of their capacity and to be subject to a two-year price regulation. In 1995, 6 GW of coal capacity was sold to the Eastern Group, one of the

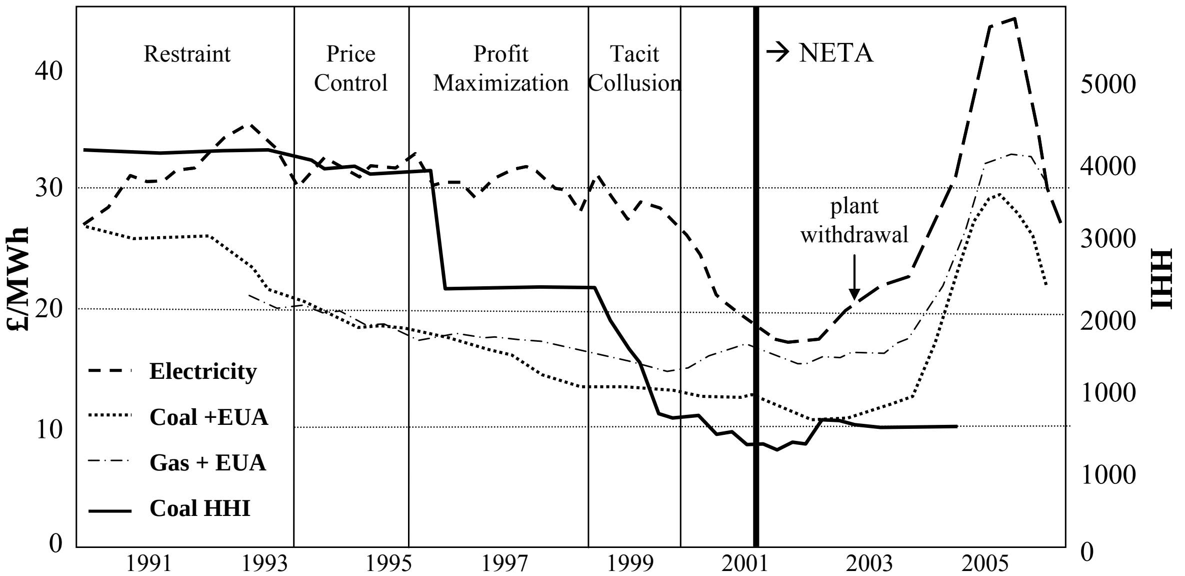
[50] This case study is based on Newbery (1995, 2000, 2005a, 2007), Evans and Green (2005), Newbery and Pollitt (1997).

regional companies. With the privatization of the modern nuclear plants as a separate company, an oligopolistic market with four larger and several smaller companies emerged. However, the effects of this first divestiture were limited. Prices remained approximately stable, despite a significant drop in coal prices and a modest reduction in natural gas prices. The new market structure (a dominant oligopoly) was able to keep prices high, despite the newly emerging competition by the Eastern Group. Also, one has to acknowledge that the plants that had been divested were mainly base-load, the mid-load plants and the peakers remained even less competitive.

Starting in 1995 a number of mergers and acquisitions took place, among them mergers between generating companies and supply companies. Until 2002 the market structure was transformed leaving five integrated suppliers.[51] In the course of the merger process, National Power and PowerGen had to divest another 4 GW of capacity in exchange for the takeover of a REC. For the two incumbents, the divestiture can thus be seen as trading horizontal against vertical integration.

The effects of this second divestiture were significant, as shown by Figure 4.2 (see Newbery, 2007): after a brief period of a tacit collusion (1999), electricity prices fell significantly, albeit fuel prices stayed constant or rose slightly. By late 2001, market concentration had declined significantly, the HHI-Index for coal plants was almost 1000; parallel to this, electricity wholesale prices hit an all-time low (~15£/MWh). Prices later increased, primarily due to increased fuel prices. In 2004, no market participant owned more than 17% of capacity. But even with re-increasing concentration the market has remained competitive since (Zachmann, 2007).[52]

Figure 4.2: Price development and market concentration in the British electricity market



Source: Newbery (2007)

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[51] Network activities are fully unbundled.

[52] Since 2004 the shares have slightly increased. Most of the market participants are integrated companies owning generation and supply. From the initial 14 suppliers at the beginning of liberalization (in England and Scotland) five regional suppliers remain.

4.2.2.2 The California Crisis[53]

The liberalization of the Californian electricity market produced of the largest market crises in recent history. The divestiture approach which was applied to increase market competitiveness followed the standard recipe of a pro-active competition policy and was principally well-founded. However, divestiture was followed by other incoherent measures which led to a collapse of the entire market design.

Before restructuring the California market was characterized by three vertically integrated companies securing generation and supply: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Electricity prices were among the highest in the US. A legislative reform package was approved in 1996 and implementation began in 1998. Network operations were transferred to a state-owned, non-profit independent system operator (California Independent System Operator, CAISO). Incumbents were obliged to cover their supply completely via the California Power Exchange (CalPX), to guarantee high liquidity on the spot market. Consumers were free to choose suppliers although a price cap regulation was in place until 2002.

Vertical separation between electricity generation and transmission assured non-discriminatory access to the network. As an independent system operator CAISO was able to establish itself as a nonpartisan player in the market. Further upstream, reforms sought to reduce the oligopolistic market situation: the three incumbents had to divest 50% of their fossil power plants to competing companies. Thus, 18 GW of capacity – about 30% of the whole market – was sold to five independent suppliers.[54] By the summer of 1999 all incumbents sold more than the requested 50% and five new suppliers – AES, Duke, Dynergy, Reliant, Southern (later Mirant) – held nearly equal shares of the divested capacities.

The divestiture of electricity generation in California achieved the objective of a more competitive market structure. The HHI-Index fell from about 2,700 in 1995 to only 960 in 1999. The two dominant firms (PG&E, SCE) found themselves with reduced market shares of only 21% and 17% respectively (Table 4.1). Market entry of companies from other US states was favored, as well as greenfield investments. In addition to reduced concentration, the CalPX was classified as a central pool, thus increasing price transparency, forming a benchmark for OTC transactions, and facilitating market entry.

However, the potentially positive effects of divestiture on market prices and consumer benefits could not emerge due to the inconsistencies in the reform package, such as a ban of long-term contracts, and the price caps for regulated electricity supplies. PG&E and SCE lost the support of Wall Street and went into bankruptcy. Trading at CalPX collapsed and the system operator had to impose rolling blackouts to avoid the collapse of the entire electricity system. Restructuring was brought to a standstill.

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[53] This case study is based on Blumstein et al. (2002), Bushnell (2005), Joskow and Kahn (2002), Kumkar (2001, 2002), and Wolak (2003a).

[54] SCE sold most of its capacity in one and a half months after market opening. PG&E sold part of its plants in July 1998 and the remaining ones in April 1999. SDG&E sold its plants in spring 1999.

The breakdown makes it impossible to assess the impact of the divestiture on market competiveness. The divestiture of electricity generation capacities of the dominant firms followed clear rules, a reasonable objective, and can be considered a success. However, the potentially positive effects of this policy could not translate into lower prices and consumer benefits due to inconsistencies in the overall market design and poor crisis management by the government. Therefore, the objective of divestiture was not attained, and it is difficult to single out the effects of divestiture from the other implemented policy measures.

Table 4.1: Structure of the California electricity market (1995 and 1999)

1995		1999	
Company	**Capacity [GW] (market share)**	**Company**	**Capacity [GW] (market share)**
PG&E	20,2 (37%)	PG&E	11,6 (21%)
SCE	20,1 (36%)	SCE	9,5 (17%)
SDG&E	3,1 (5%)	SDG&E	0,7 (1%)
Other	13,3 (23%)	AES	4,7 (8%)
		Duke	2,9 (5%)
		Dynergy	2,9 (5%)
		Reliant	4,0 (7%)
		Mirant	3,2 (6%)
		Other	16,2 (29%)
Sum:	**56,7**	**Sum:**	**55,7**
HHI	~ 2.700	HHI	~ 960

Source: Blumstein et al. (2002), Marnay et al. (1998)

4.2.2.3 Other International Experiences

Beside the two above mentioned cases divestiture has been used both as an instrument to improve competitiveness and as merger remedy to avoid dominant market positions. In Europe a direct divestiture was applied in the *Italian* electricity market dominated by the state utility ENEL which owned generation, transmission and distribution assets. After the vertical unbundling the newly formed generation-only company ENEL was partially privatized (the state still holds a 60% majority). Due to its dominant market position no real competition could emerge in the short term, and in 1999 ENEL was required to divest part of its capacity to reduce its market share below 50%. The divested capacity was split among three independent companies which were sold in 2003 (Ferraria and Giuliettib, 2005).

In the US, *TXU Corporation in Texas* was subject to divestiture proposals to curb market power and establish more competitive electricity markets. The assessment of TXU's market power potential by Potomac Economics Ltd. (2007) examined the deregulated wholesale market during the summer of 2005 using a pivotal analysis. The analysis concluded that TXU's offer prices of its on-line capacities were not competitive. A simulation was carried out to estimate the impact of its bidding strategy on the balancing market based on the system operator's scheduling, pricing and dispatch model, TXU's estimated marginal costs, and the actual inputs used to clear the balancing energy market. Based on the identification of market power abuse TXU was fined $210 mn including $70 mn in proposed market refunds to wholesale power buyers and $140 mn in penalties. The other action proposed was divestiture of some generation to limit future potential for market power abuse (*Wall Street Journal,* 2007).

Divestiture also plays an important role in merger and acquisition cases as part of anti-trust instruments. In the US two cases highlight the problems when analyzing mergers and defining proper remedies.[55]

The proposed merger between *Exelon and PSEG* shows that merger remedy analysis and results can vary among regulatory institutions (Madsen et al. 2005). In February 2005 Exelon and PSEG filed four major cases relating to their planned merger at FERC, the US Department of Justice (DOJ), the New Jersey Board of Public Utilities (NJBPU), and the Pennsylvania Public Utility Commission (PAPUC). FERC approved the merger subject to the divestiture of 2,500 MW in sales of virtual capacities ("long-term contracts") and another 1,500 MW in actual sales of capacity (FERC, 2005). This decision was based upon a company-wide modeling of the market effects. The Antitrust Division of the DOJ also investigated and required a divestiture of 5,600 MW (DOJ, 2006). The NJBPU investigation looked at the potential impacts for the state of New Jersey, especially the effects on reliability, customer service, and assistance for low-income ratepayers. NJBPU requested the divestiture of 10,000 MW of generating capacity, and a "rate relief" payment of $600-1,500 per customer. Even though the merging parties reached an agreement on divestiture with FERC and the DOJ, this final requirement imposed by New Jersey broke the deal. Exelon and PSEG withdrew the merger in September 2006.

San Diego Gas & Electric (part of the ENOVA Group) and *Southern California Gas* (SoCalGas, part of Pacific Enterprises) is an example where market power was constrained in a vertical merger case (Bailey, 1999). Both FERC and the California PUC considered the Pacific-Enova merger as a "convergence" merger resulting in an integrated energy company capable of supplying both fuel (natural gas) and electricity. With market power in natural gas storage and transportation segments the new company could drive up wholesale electricity prices for competitors, whereas SDG&E would benefit from internal transfer pricing within the merged firm. Both regulators found that the proposed merger indeed created the potential for market manipulation. The imposed divestiture measures were based upon a detailed market power analysis carried out by FERC. In addition to the mitigation measures recommended by FERC, California required SDG&E to divest its generation assets to mitigate the potential vertical market power abuse during high demand periods.

In Europe, to prevent dominant market structures, divestitures have been used to cope with anti-competitive outcomes of merger cases. Lévêque and Monturus (2007) provide a comprehensive

[55] See Hirschhausen, Neumann, and Weigt (2007) for details.

overview of 241 merger and acquisition deals between European electricity and natural gas companies from January 1998 to July 2007. The deals include: the Nordic markets in the case of the Norwegian state-owned electricity company Statkraft (Statkraft, 2005a, b), the Finnish Fortum company (FCA, 2006a, b), and the Danish oil and natural gas incumbent DONG (EC, 2006; EU 2006a), that all included divestiture proposals; GdF and Suez (EU, 2006b); proposed divestitures in the Spanish merger case of Endesa and Iberdrola (Crampes and Fabra, 2004); and the prohibition of the acquisition of Gás de Portugal by Electricidade de Portugal (EC, 2004).

4.2.2.4 Virtual Divestitures

Virtual divestitures are becoming increasingly popular as policy instruments. The term refers to a spin-off of an incumbent's generation capacities without changing the property rights structure of these facilities. Thus, the divestiture is a financial transaction, not a physical one: an owner of virtual power plants basically has a contract allowing it to trade a given capacity without actually managing a specific power plant. Willems (2006) shows that virtual divestitures represent a bundle of call options where the virtual production cost is equal to the strike price of the option. The buyer of the option has the right to consume the electricity of its Virtual Power Plants (VPPs).[56] Regulatory authorities see an advantage of virtual over real divestitures in the possibility to withdraw the measure after a specified time, or continue if the desired outcome has not been accomplished.

Willems (2006) concludes for oligopolistic electricity markets that virtual power plant divestitures either increase competition or the contracted volume of incumbents depending on their design: financial VPPs (an insurance contract against upward jumps in the spot price) lead to more aggressive bidding in the spot market similar to forward sales;[57] physical VPPs (an option contract for physical delivery of energy) lead to flattening of the slope of the residual demand function of competitors. To improve the effect of virtual divestitures the regulatory authority must ensure that divested facilities increase competitiveness within the market; that incumbents cannot buy back their sold capacities; and that large market participants cannot increase market share beyond certain limits.[58]

In the ongoing liberalization process of Europe's electricity markets, several cases of virtual divestitures, the VPPs have substituted for real divestitures to curb market power and increase market competitiveness. In the *Netherlands,* VPPs were proposed in the Nuon merger case. The Dutch competition authority NMa opted to prevent the merger if no counteractions were taken to increase market competitiveness (van Damme, 2005). It demanded a virtual divestiture of 900 MW plant capacities in 90 contracts with duration of five years. After legal actions capacity was reduced to 200 MW and auctioned in September 2004 in 10 MW blocks.

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[56] Retailers might buy VPP peaking capacity to counter the effect of market power during those periods.

[57] Following Allaz and Vila (1993) a higher contracted volume also leads to reduced prices on the spot market; see Section 4.3.1.1.

[58] Further competition policy measurements that fall short of the given segmentation can still be defined as virtual divestiture, e.g., if a transmission company is requested to keep a certain amount of its transmission capacity free for other market participants.

In *Belgium*, the electricity market is dominated by Electrabel which owns about 90% of the generation assets. In 2003 the Belgian Competition Council mandated that Electrabel was allowed to become the default supplier for customers of several inter-municipal distribution companies. As part of this decision Electrabel had to virtually divest some generation assets. The auctions were supposed to occur on a quarterly basis (Electrabel, 2006). No single buyer was allowed to obtain more than 40% of the capacity for sale. Although this threshold appears reasonable in general to prevent the emergence of dominant firms, the limited capacity offered in total implies that none of the buyers can achieve more than 4% of available capacity in the market. Thus, Electrabel never faced significant competition.[59]

The *French* electricity market is dominated by a single firm, EdF. Virtual divestiture of generation capacities was required in a recent merger case: the European competition authority required EdF to divest part of its generation capacity to acquire a share in Germany's supplier EnBW (Case COMP/M.1853 - EdF/ENBW). Starting in 2001, EdF was required to auction about 6 GW on an annual basis for five years. However, even after the divestiture EdF remains dominant with about 85 to 90% of available capacity. A further concern is that part of the VPP capacity is sold back to EdF instead of domestic customers. In 2004, this re-selling reached about 30% of the issued VPP capacity (Glachant, 2004).

Spain is a particularly interesting case, because virtual divestitures are not directly linked to a merger case, but rather are an instrument to establish a forward market. In 2006, the Spanish government required Endesa and Iberdrola to hold five auctions offering virtual capacity to members of the Spanish electricity market (Royal Decree 1634/2006) starting in summer 2007. At the time, Endesa owned about 37% of the installed capacity and Iberdola owned about 42%; thus the market was dominated by the duopoly. Whether the auctions have a pro-competitive effect on the development of a futures market remains to be determined.

Further virtual divestiture cases have taken place in several European countries, showing that this instrument has become a serious option of active competition policy in electricity market liberalization:

- In the *Czech Republic* the dominant company CEZ held a VPP auction in line with an antitrust authority ruling related to the SCE acquisition in 2006 (CEZ, 2006)
- in 2005 the *Italian* Authority for Electricity and Gas aimed to promote competition in the wholesale power market via virtual divestiture of 3850 MW of Enel (Authority for Electricity and Gas, 2006)
- in *Ireland* the regulatory authorities agreed to introduce a Virtual Independent Power Producers (VIPP) to reduce the dominance of ESB via an auction process to provide independent suppliers with contracted capacity in 2005 (CER, 2005).

[59] A study for the Competition Council suggests that the divested capacity should be between 2 and 5.6 GW to obtain sufficient mitigation effects (Platts, 2003).

4.3 Modeling of Strategic Company Behavior: Cournot vs. SFE

As noted, classical economic tools, such as the HHI, are largely unsuitable for electricity markets(Borenstein, et al. 1999). Therefore, for oligopolistic wholesale electricity markets mainly two approaches are used: the Cournot model and the SFE model. While standard Cournot models are simple to calculate, the results often do not represent reasonable market outcomes. For realistic values of demand elasticities, prices are too high and output too low. SFE models (e.g., Klemperer and Meyer, 1989) on the other hand are deemed to represent electricity markets more realistically because they assume that generators, instead of one single quantity, compete by bidding complete supply functions in an oligopolistic market with demand uncertainty. The SFE approach has been used to analyze electricity markets since its first application by Green and Newbery (1992) for England and Wales. The major drawbacks are that the models are difficult to calculate, often have multiple equilibria, often give unstable solutions, and require simplifications with respect to market and cost structures.

The following overview discusses the strengths and weaknesses of both approaches in market analyses and a comparison of both models based on Willems et al. (2009) is presented. The two approaches are calibrated with an identical dataset taken from the German electricity market, and the results are compared with the observed market clearing prices.

4.3.1 Review on Cournot and SFE Models in Electricity Markets

To obtain market results that represent strategic behavior the welfare maximizing approach presented in Chapter 3 must be replaced by a profit-maximizing assumption. However, beside the same objective function Cournot and SFE models differ in their assumption regarding the free choice variables and the behavior of the remaining market participants.

In a Cournot equilibrium the demand function is known by the firm before bidding in every time period. Each firm maximizes profits by setting production quantities and sales, knowing that the market price is a result of its own output and the output of its competitors. The Cournot approach yields a direct outcome in terms of price and quantities for a given demand realization. Cournot models generally provide a unique Nash equilibrium.

In SFE models firms cannot condition their bids on the demand realization since it is assumed that demand follows a certain stochastic behavior. Nor are firms allowed to submit different bids for different time periods. Thus, each maximizes its (expected) profits by bidding a supply curve, assuming that the supply curves of its competitors remain fixed. Hence, the quantity produced by the competitors depends on the market price, and indirectly on the output decision of the firm itself. To solve the SFE model, it is assumed that the stochastic demand shock and the time period shift the demand function horizontally. Under these assumptions the (stochastic) optimization problem that each firm must solve can be rewritten as a differential equation. Typically, a range of feasible equilibrium supply functions is found when solving one set of differential equationsfor each firm. It can be shown that every SFE supply function lies between the Cournot and the Bertrand solutions for any realized demand shock. Delgado and Moreno (2004) show, however, that only the least-competitive equilibrium is coalition-proof when the number of firms is sufficiently large. A serious drawback of SFE models is that they require simplified assumptions of the markets' supply structure to obtain feasible solutions.

4.3.1.1 Cournot Models in Electricity

Although Cournot models are ubiquitous, they often overestimate observed market prices and underestimate market quantities. Since the model outcome is based only on quantity competition, the results are highly sensitive to assumptions about demand elasticity. Given that most electricity markets have few oligopolistic firms and low, short-term demand elasticities, markups are accordingly very high. Following Allaz and Villa (1993), forward contracts can be used to predict more realistic outcomes. Firms can both sell energy in a spot market and a certain amount of their supply in the forward market. In a two-stage game, the oligopolists first determine the quantity to be sold in the forward market before entering the spot market and playing a Cournot game. Assuming two companies *(1,2)* with a given forward position (*g, h*) the profit function *u(.)* on the production stage (spot market) is given by:

$$u_1 = p(q_1 + q_2)(q_1 - g) - c_1(q_1)$$
$$u_2 = p(q_1 + q_2)(q_2 - h) - c_2(q_2)$$

with *q* representing the total sales on the spot and forward market, and *c(.)* as production cost function. Assuming a linear demand function *(p=a-q1-q2)* and linear cost function *(c=b*q)* the resulting reaction function $q_1(q_2)$ is given by (see Allaz and Villa, 1993, p. 4):

$$q_1(q_2) = \frac{a - b + g - q_2}{2}$$

The reaction function is increasing with the amount of forward sales. The marginal revenue in this setting for the first firm is given by $p'(q_1 + q_2)(q_1 - g) + p(q_1 + q_1)$. Thus the obtained marginal revenue is smaller with a forward coverage *(g>0)* than without. The equilibrium conditions are given by:

$$q_1 = \frac{a - b + 2g - h}{3} \quad q_2 = \frac{a - b + 2h - g}{3} \quad p = \frac{a + 2b - f - g}{3}$$

Thus, forward sales *(g and h >0)* increase the oligopolists' output given the other company's decision and reduce the spot market price (p), resulting in a more competitive market. Varying the contracting factor of a firm generates a "bundle" of feasible Cournot solutions that resemble SFE outcomes.

The role of forward contracts, when comparing Cournot results with real market outcomes, is demonstrated by Bushnell et al. (2008). They look at California, PJM and New England markets, comparing price data of the power exchanges with competitive model outcomes, a standard Cournot model, and a Cournot model using contract cover as an approximation for vertical arrangements. They conclude that neglecting the contract cover yields results that vastly exceed observed market prices.

Ellersdorfer (2005) analyzes the competitiveness of the German market using a multi-regional two-stage Cournot model. He shows the extent to which cross-border network extensions and increased forward capacities enhance competition and decrease market power.

Cournot approaches are often preferred when technical characteristics such as network constraints (voltage stability, loop flows) or generation characteristics (start-up costs, ramping constraints, unit commitment) must be considered. The impact of congestion on market prices and market power has been analyzed in several studies. Smeers and Wei (1997) use variational inequalities to describe the Cournot model. Willems (2002) discusses the assumptions necessary to include transmission constraints in Cournot models. Neuhoff et al. (2005) summarize different characteristics of Cournot network models, and show that although all models predict the same outcomes, they vary with respect to assumptions about market design and expectations of generators in cases of competitive markets.

A more general overview of Cournot models used to analyze market power issues appears in Bushnell et al. (1999). Other reviews of electricity market models with respect to network issues are Day et al. (2002) and Ventosa et al. (2005) (see also Section 2.3).

4.3.1.2 SFE Models in Electricity

In general, SFE models are frequently used in determining market power issues. Bolle (1992) makes a theoretical application to electricity markets by analyzing the possibility of tacit collusion when bidding in supply functions. He concludes that if firms coordinate on bidding the highest feasible supply function, a decrease in market concentration does not necessarily result in convergence of aggregated profits to zero. Green and Newbery (1992) present an empirical analysis for England and Wales using symmetric players. They compare the duopoly of National Power and PowerGen with a hypothetical five-firm oligopoly, concluding that the latter results in a range of supply functions closer to marginal costs.

Baldick and Hogan (2002) design a model of the England and Wales markets that incorporates price caps, capacity constraints, and varies the time horizon by which supply functions must remain fixed. They show that the latter characteristic has a large impact on market competitiveness. Evans and Green (2005) simulate the same market for the period of April 1997 to March 2004 and calculate the SFE taking into account the firms' asymmetricity. They approximate the competitive pressure in the market with 'an equivalent number of symmetric firms' based on HHI and conclude that the change to a decentralized market has no impact on short-term prices while reductions in concentration do have impacts. Sioshansi and Oren (2007) study the Texas balancing market using SFE with capacity constraints. They find that the larger firms more or less behave according to the SFE for incremental bids. They argue that SFE models with capacity constraints are an interesting tool to study balancing markets since demand is very inelastic, and hence the supply elasticity of competitors is a major component in determining the elasticity of the residual demand of the firms. These SFE models with capacity constraints are also useful because they reflect the actual bidding behavior of the firms, i.e.

"hockey stick bidding": firms bid (too) low for low levels of supply and have a steep supply function for greater levels of supply.
Several theoretical contributions have extended Klemperer and Meyer (1989) by incorporating typical market characteristics. Holmberg (2007) considers the problem of asymmetric companies by simplifying the supply structure to constant marginal costs. He shows that under this setup there is a unique SFE that is piece-wise symmetric. Anderson and Hu (2008) propose a numerical approach using piece-wise linear supply functions and a discretization of the demand distribution. They show that the approach also has good convergence behavior in models with capacity constraints. Holmberg (2008) studies capacity constraints on generation units and shows that a unique, symmetric SFE exists with symmetric producers, inelastic demand, a price cap, and capacity constraints. Green (1996), Rudkevich (2005) and Baldick et al. (2004) develop the theory of linear supply functions. These functions are easier to solve, can be used in asymmetric games, and generally give stable and unique equilibria, but do not account for capacity constraints. Boisseleau et al. (2004) use a piece-wise linear supply function and describe a solution algorithm that obtains an equilibrium even when capacity constraints exist.

4.3.1.3 Comparison of Cournot and SFE Models

Only a few authors have compared the equilibria in both models. Vives (2007) studies the properties of two auction mechanisms: one where firms bid supply functions and one where they bid à la Cournot. Firms are assumed to have private information about their costs. Solving for a Bayesian equilibrium in linear supply functions, Vives (2007) shows that supply functions aggregate the dispersed information of the players, while the Cournot model does not. Hence, Cournot games might be socially less efficient, since the dispersed information is not used effectively. Hu et al. (2004) use a bi-level game to model markets for delivery of electrical power on looped transmission networks with the focus on the function of the ISO. Within this analysis they compare supply function and Cournot equilibria and show that in case of transmission congestion, SFE need not be bounded from above by Cournot equilibria as is the case for unconstrained networks. They conclude that when congestion is present, Cournot games may be more efficient than supply function bidding.
Ciarreta and Gutiérrez-Hita (2006) undertake a theoretical analysis of collusion in repeated oligopoly games using a supergame model that is designed both for supply function and quantity competition. They show that depending on the number of rivals and the slope of the market demand, collusion is easier to sustain under supply function rather than under quantity competition. An experimental approach by Brandts et al. (2008) includes the impact of forward contracts on electricity market outcomes. They show that the theoretical outcomes of SFE models (mainly their feasibility range between Cournot and marginal costs) can be reproduced by experimental economics. Further, they find that introducing a forward market significantly lowers prices for both types of competition.

4.3.2 Methodology of the Cournot and SFE Approaches

To establish the suitability of both approaches to resemble exiting electricity markets a consistent model framework is developed by Willems et al. (2009) to compare the model outcomes with observed market prices in Germany.

The Cournot and SFE supply models are found by simultaneously solving a set of equations describing the market equilibrium for different demand realizations *k*. Market demand D_k is assumed to be linear and depends on a demand shock Δ_k and the price p_k:[60]

$$D_k = \alpha - \gamma p_k - \Delta_k \qquad \text{demand equation} \qquad (4.1)$$

with *k* the index of the aggregate demand shock, both due to the stochastic demand component and the deterministic time component. For all demand realizations the energy balance must hold, thus demand should equal total supply.

The marginal cost equation relates the output of firm *i* to the marginal cost given by a continuous cubic function:[61]

$$c_{ik} = \lambda_{i0} + \lambda_{i1} q_{ik} + \lambda_{i2} q_{ik}^{2} + \lambda_{i3} q_{ik}^{3} \qquad \text{marginal cost function} \qquad (4.2)$$

Following Anderson and Hu (2008), the continuity of the bid supply function is imposed specifying a piece-wise linear supply function, with $0 < \xi_{ik} < 1$:

$$q_{ik+1} - q_{ik} = (p_{k+1} - p_k)\left[(1-\xi_{ik})\beta_{ik} + \xi_{ik}\beta_{ik+1}\right] \qquad \text{supply slope restriction} \qquad (4.3)$$

The pricing equation describes the first order conditions of each player *i* for each demand shock *k* requiring that each player's marginal revenue and marginal cost be equal, with F_{ik} as the amount of contracts signed in equilibrium by firm i in realization k, and $\frac{dp_{ik}^R}{dq_{ik}}$ as the slope of its inverse residual demand function:

$$(q_{ik} - F_{ik})\frac{dp_{ik}^R}{dq_{ik}} = p_k - c_{ik} \qquad \text{pricing equation} \qquad (4.4)$$

Firms are allowed to sign fixed-capacity contracts f_i specified as a quantity (in MW) which is independent of the demand shock *k*. The pricing equation differs for the two models. In the Cournot equilibrium, each player assumes the production of the other players as given, and therefore the slope of the residual inverse demand function depends only on the slope of the demand function (γ):

$$q_{ik} - f_i = \left(p_k - c_{ik}\right)\gamma \qquad \text{Cournot equilibrium condition} \qquad (4.5)$$

[60] The demand levels are derived by taking the German demand reduced by wind output as price inelastic (see Section 3.5.2.2 for the underlying dataset) and obtaining a demand elasticity via imports and fringe production. The fringe elasticity is derived via a weighted least squares regression of the fringes production costs. The import elasticity is obtained by a two-stage least squares estimator to address the endogeneity of the German price with respect to imports (see Willems et al., 2009)

[61] The marginal cost functions parameters are obtained by minimizing the weighted squared difference of the parameterized function and the true cost function subject to the condition that marginal cost should be upward sloping. The stepwise true marginal cost curve is based on the dataset described in Section 3.5.2.2.

For the SFE model, the slope of the residual demand function depends on the slope of the demand function and the slope of the supply functions of the competitors (β_j):

$$q_{ik} - f_i = (p_k - c_{ik})\left(\sum_{j \neq i} \beta_{jk} + \gamma\right) \qquad \text{SFE equilibrium condition} \qquad (4.6)$$

The Cournot equilibrium is a solution of equations (4.1), (4.2), (4.5) and a market clearing condition,and the SFE is a solution of equations (4.1), (4.2), (4.3), (4.6) and a market clearing condition.

Both models are tested using the same sample dataset based on the German electricity market. E.ON, RWE, Vattenfall, and EnBW are assumed to be strategic firms i, and the remaining generators act as competitive "fringe". Generation capacities and costs are based on the same data as the fundamental model presented in Chapter 3. The stepwise marginal cost functions of the generators are simplified to the cubic function 4.2 without a capacity constraint.

The dataset is the winter period of 2006 since strategic behavior is more likely to occur when capacity is scarce. The four periods considered are: January peak and off-peak hours, and February peak and off-peak hours.[62] For each period the observed demand, wind production, net import amounts, and prices are used to estimate the corresponding demand function for Germany. The day ahead price at the EEX is the reference price index. [63]

4.3.3 Comparison

Given the observed price-quantity pairs during the sample period both models are calibrated to reproduce them as closely as possible by changing the contract coverage f_i. The Cournot model produces a single equilibrium given the demand realization and the contract cover. The SFE model produces a bundle of equilibria for a given contract cover. Which equilibrium firms choose depends on how the firms coordinate. A common assumption is that firms coordinate on the least-competitive SFE equilibrium, i.e. the equilibrium where prices are highest (e.g., see Green and Newbery, 1992, and Delgado and Moreno, 2004). A non-linear least squares regression is conducted to compare the models' prices with the observed market prices..

Figure 4.3 shows the Cournot solution and the "bundle" of SFE solutions for the optimal contract positions found in the regression compared to the observed hourly price-quantity outcomes at the EEX spot market and the LOWESS regression of those observations.[64] The demand function represents the highest possible peak demand level. Cournot firms sign contracts for 49.8% of their installed generation capacity, and SFE firms contract for 27.4% (based on the SFE solution with the highest price neglecting the remainder of the bundle). In the mid-load range both models produce the same outcome. However, during peak and off-peak load, the SFE solution is above the Cournot outcome. In

[62] Hours between 8am and 8pm are considered peak hours; the others are off-peak.
[63] A more detailed representation of the model formulations and dataset is provided in Willems et al. (2009).
[64] LOWESS stands for locally weighted scatterplot smoothing and represents one possible method to obtain a regression if no function behaviour is to be specified.

general the Cournot solution follows a more linear trend whereas the SFE solution is convex. Both supply curves are above the competitive supply function representing the marginal cost curve of generation which emphasizes the impact of firms' strategic behaviors on price mark-ups.

To test which approach performs better under varying assumptions a series of robustness tests checks whether the relative performance of the Cournot and the SFE model depend on the particular assumptions taken. Tested are different contract coverages during peak and off-peak periods, varying marginal generation costs on a monthly basis, different import elasticities for the four peak and off-peak periods, an elastic and a fixed fringe output, and load-following contracts in the Cournot simulations.

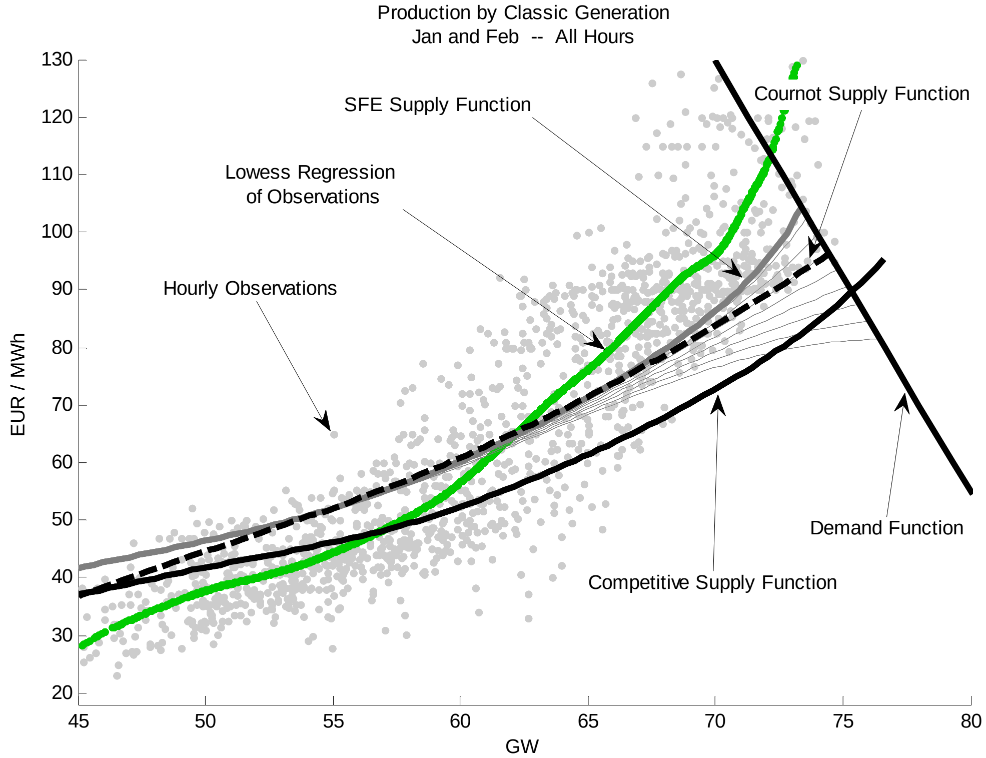
Applying the models to each of the four periods respectively, Willems et al. (2009) observe that the contract coverage is higher during off-peak periods. However, the Cournot model still yields a higher optimal contract cover. Furthermore, the off-peak outcome of the oligopolistic models is only slightly better than the marginal cost curve. However, during peak hours, the marginal cost curve is a bad predictor of market results, indicating that during peak hours it is more important to consider firms' strategic behaviors.

Comparing both fringe assumptions, the optimal model is probably one where the inelastic fringe is used during peak hours – the production capacity is binding – and the elastic fringe is used during off-peak hours – the production capacity is not binding. In that case a similar amount of contracts will be signed during peak and off-peak periods, implying that during off-peak hours, a larger fraction of total demand is covered by contracts, because the contracted amount is defined via the installed capacity.

The regression analysis of the impact of load-following contracts for the Cournot approach shows that the optimal amount of these contracts is equal to 0%, an indication that the model can be finely calibrated during both peak and off-peak by relying only on fixed contracts. [65]

[65] Load-following contracts can be understood as a representation of vertically integrated generators that aim to satisfy the demand of their customers.

Figure 4.3: Unique Cournot outcome and bundle of SFE outcomes at the calibrated optimal contract cover



Source: Willems et al. (2009)

4.3.4 Suitability of Cournot and SFE for Divestiture Analyses

The results indicate that both approaches can be adjusted to represent oligopolistic electricity markets. The Cournot approach can be fine-tuned to the observed market outcomes by assuming a relatively high level of fixed-capacity contracts. For the SFE model, the best fit is found when firms sign fewer contracts. The SFE model does not significantly outperform the Cournot model and both models are suitable for analyzing competition policy.

Both models produce a slightly different supply curve shape and thus the price results for specific demand quantities can vary. An assessment of divestiture's benefits based on price differences and welfare effects consequently will vary accordingly. Furthermore, a change in the underlying market structure (i.e. number of firms) may have a different impact on the model outcome for both approaches. The following section describes the use of *both* approaches to assess the impact of divestiture scenarios for Germany and provide a plausible range of expected post-divestiture market outcomes.

4.4 Impact of Reduced Market Concentration on Electricity Prices in Germany

As shown in Section 0 divestiture is an appropriate tool of a pro-active competition policy and has been applied several times to improve the competiveness of electricity markets or to compensate possible dominant market positions in merger cases. Nevertheless, from a political and legal point of view divestitures are considered a “hard” instrument compared to other possible measurements, i.e. market monitoring or fostering of market entry. In Germany the possibility of divestiture due to market power concerns is not in the competition law but has been proposed by the Hessian Ministry of Economics (2007). Schwarz and Lang (2007) study this proposal and compare a regulatory solution, introduction of market coupling, cross-border capacity extensions, and divestiture to mitigate market power in the German market. Regarding the divestiture option they conclude that the British experiences show the potential of divestiture in fostering competition but in light of the expected market coupling they assume that divestiture of German suppliers is unnecessary.

Given this setting it is important to obtain a robust forecast of the impact of a divestiture to analyze the potential benefits. As highlighted in Section 4.3 the possibility to adjust strategic market models to observed market outcomes via contract coverage provides a decent bottom-up approach to obtain a reasonable forecast. Following, this methodology is applied to assess the possible price and welfare effects of divestiture within the German market framework. The model structure presented in Section 4.3.2 is applied to obtain a contract cover calibration for the market outcome in 2006. Subsequently, different divestiture cases are modeled assuming that the contract coverage remains fixed. The outcomes allow a classification of the possible benefits from a divestiture and in addition provide a comparison of different divestiture methodologies.

4.4.1 Modeling Divesture

Modeling approaches to assess the impact of divestitures ex-ante are relatively scare. Green and Newbery (1992) are among the first to use SFE for electricity market analysis. They compare the duopoly of National Power and PowerGen in the British market with a hypothetical five-firm oligopoly, concluding that the latter results in a range of supply functions closer to marginal costs. Day and Bunn (2001) apply a computational modeling approach to the second round of capacity divestiture in the liberalized electricity market of England and Wales in 1999. They conclude that although the divestiture was substantial it may still be insufficient to pave the way to a fully competitive market. Ishii and Yan (2006) analyze the impact of divestitures on new power plant investments in US electricity markets. Based on empirical data on the investment decisions of 20 major IPPs between 1996 and 2000 they develop a net present value model to calculate the incentives for plant investment in the absence of divestiture. They conclude that the new capacity “crowded out” by divestitures is on average only 177 MW. However, the divested assets encouraged participation of new market entrants that may not have occurred otherwise.

Since divestitures are often requirements in merger cases Vasconcelos (2007), among others has examined the connection between efficiency gains due to mergers and structural remedies by the antitrust authority in a Cournot setting. They find that divestiture creates new merger possibilities, the authority tends to over-fix the amount of divestiture (which discourages further mergers), and that divestitures have a positive impact on consumer surplus. Moselle et al. (2006) analyze the Dutch electricity market using a Cournot model that includes a competitive fringe and forward contracts to test the divestiture requirement in the Nuon-Essent merger case. They results show that although the commissions guidelines are already fulfilled with a divestiture of 1,900 MW, a total of 4,200 MW is necessary the merged firm is to remain pivotal. London Economics (2004) analyze the Belgian electricity market and the role of Electrabel as the dominant incumbent. Depending on the underlying assumptions on interconnection capacities they find that four players are needed to provide a competitive market. They also analyze the virtual divestiture of Electrabel and conclude that four to seven times the current divested capacities would be needed to achieve a more competitive market.

Lévêque (2007) analyzes a study by the EC (2005) evaluating 96 merger cases between 1996 and 2000, and emphasizes that:strategic behavior of the merged firms and insufficient trustees can hinder the effectiveness of remedies; the merging firm can sell assets of inadequate scope due to asymmetric information; and a close observation of the development of the market's competitiveness after a merger is important. Christiansen (2005) analyses the interaction between regulation and merger control in the liberalized European electricity sector, in particular the effectiveness of divestiture remedies. Based on two case studies he shows that a stricter merger control is necessary.

4.4.2 Methodology and Calibration

A pre-divestiture benchmark is needed prior to testing the impact of divestitures on the German electricity market. Therefore, the model structure presented in Willems et al. (2009) is extended beyond the first two months of 2006 to cover the complete year. The analysis looks at peak hours only, because strategic company behavior is more likely to occur in hours with high demand and tighter capacity situations, and secondly, the model structure with approximated cost functions and simplified market interactions is not well-suited to capture the unit commitment process determining pricing in off-peak periods.[66]

The residual German demand D during peak hours is assumed to be price inelastic, varying through time t, and with a random component ε:

$$D_t = \alpha_t - \varepsilon_t \qquad \text{German peak demand in t} \qquad (4.7)$$

Oligopolists face an elastic residual demand due to the fringe supply and imports from neighboring countries. Imports Q_I are determined by the difference of the price p_G in Germany and the neighboring regions p_j by regressing:[67]

$$Q_{It} = \gamma_I p_{Gt} - \sum_n \gamma_n p_{nt} + \sum_z \mu_z \delta_{zt} + \varepsilon_{It} \qquad \text{Import regression} \qquad (4.8)$$

[66] Due to ramping constraints, start-up restrictions, and start-up costs market prices during off-peak periods can fall below marginal generation costs (see Abrell et al., 2008).

[67] δ_z is a vector of time dummies (day of week) for all hours t in the peak period. A two-stage least squares estimator is used to address the endogeneity of the German price p_G with respect to imports. As instruments the total demand level in Germany and German wind production is used.

Hourly price data is taken from energy exchanges in the Netherlands, France, Austria, Poland, Sweden, East Denmark and West Denmark. Imports Q_I are obtained from ETSOVista (2007). One import elasticity γ_I for the entire peak period in 2006 is calculated.

The fringe supply is assumed to be price taking based on the underlying marginal cost structure. Following Willems et al. (2009), during peak periods a fixed fringe output may present a better approximation since a cost function approach neglects the capacity constraints of fringe suppliers. Therefore, the available fringe generation capacity α_F (based on VGE, 2006 and decreased by seasonal availability factors) is subtracted from the residual German demand. The residual demand function for the oligopolists D^O rewrites to:

$$D_t^O = \alpha_t - \alpha_{Ft} - \gamma_I p_{Gt} - \varepsilon_t \qquad \text{Oligopoly demand} \qquad (4.9)$$

Equation (4.7) is transformed into a demand function with a specified set of demand realizations k (equation (4.1), for details see Willems et al., 2009). The intercept of the demand level is chosen such that when the shock is zero, either 95% of the observations in the German market are below the demand function, or a maximum price of 200 €/MWh is obtained.[68]

The marginal generation costs of each oligopolist are based on each player's generation portfolio VGE (2006). Plant capacities are decreased by seasonal availability factors following Hoster (1996). Marginal costs are estimated for each month respectively based on the plants' efficiency and fuel prices resembling average monthly cross-border prices for gas, oil and coal from Bafa (2006). The step-wise marginal cost functions of the generators are simplified to a cubic function (equation (4.2)) where the parameters of the function are found by minimizing the weighted squared difference of the parameterized function and the true cost function subject to the condition that the marginal cost should be upward sloping (see Willems et al., 2009, section 4.2).

Given the underlying dataset the Cournot and SFE models are simulated varying the contract coverage f_i from 0% up to 100%.[69] The resulting supply curves are then analyzed to obtain the optimal contract cover f using the observed price-demand results at the EEX spot market as a benchmark:

$$\min_f \left(P_t^{obs} - P_t^{\text{mod}}(f)\right)^2 \qquad \text{Squared error mimization} \qquad (4.10)$$

with P^{obs} the observed prices at the EEX and P^{mod}(f) the modeled prices given the contract cover f.

Given this setting the optimal contract cover for each month and the year can be obtained (Table 4.2). The Cournot model has on average about 20 percentage points of higher coverage than the SFE model. The values in the second half of 2006 are lower for both models which may be a result of the slightly lower electricity prices (see Figure 3.2) at the same time that fuel prices remained relatively stable. For the remainder of the divestiture analyses only the yearly values are used.

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[68] The second condition became necessary because in July 2006 a large amount of peak hours were exceptionally high, resulting in unrealistic imports as the import estimation neglects transmission capacities.

[69] The models are solved in GAMS with a MATLAB interface to call up the GAMS code for different months and different contract covers f. The GAMS code appearsin Appendix III.

Table 4.2: Optimal contract covers, pre-divestiture calibration, 2006

	Cournot	SFE
January	39%	18%
February	36%	15%
March	46%	32%
April	48%	44%
May	40%	24%
June	46%	35%
July	27%	0%
August	37%	20%
September	32%	10%
October	33%	9%
November	32%	10%
December	31%	5%
2006	37%	18%

Source: Own calculation

4.4.3 Scenarios and Results

4.4.3.1 Divestiture Scenarios

Given the pre-divesture results of 2006 two divestiture cases are modeled to obtain theoretical reference values for the year given the changed market structure. The first divestiture case (*6 Firm Case*) resembles breaking the dominant duopoly of EON and RWE into four separate companies which each own one half of the pre-divested company respectively. This divestiture could either be realized by forcing EON and RWE to split their assets into separate companies (similar to unbundling), or to sell the separated companies to investors (i.e. foreign companies or financial investors). The resulting market structure would be a six-firm oligopoly in which each firm owns about 10 GW of generation capacity and thus no one has more than 15% market share.

For the second divestiture case (*4 Firm Case*) the duopoly of EON and RWE is also broken by forcing them to divest half of their capacities. However, the divested assets are sold to several companies and interested parties such that no buyer can obtain significant market share. Thus, the divested plants become part of the competitive fringe and are no longer strategic companies. The resulting market structure would be a four-firm oligopoly as in the pre-divestiture case but the concentration ratio would decrease from about 80% to about 50% with no firm having a capacity share above 15%.

The *6 Firm Case* does not require a change in the modeling methodology since only the underlying dataset is adjusted and the number of strategic firms is increased. For the *4 Firm Case* the two new companies resulting from the divestiture of EON and RWE need to be modeled as price takers. This is accomplished by introducing a binary dummy variable *comp* that takes the value 0 if the firm acts as a price taker and 1 otherwise. The equilibrium conditions are reformulated accordingly. In the case of a competitive firm the conditions guarantee that marginal costs are equal to the market clearing price:

$$comp \cdot \frac{q_{ik} - f_i}{\gamma} = \left(p_k - c_{ik}\right)$$

Adjusted Cournot equilibrium condition(4.11)

$$comp \cdot \frac{q_{ik} - f_i}{\left(\sum_{j \neq i} \beta_{jk} + \gamma\right)} = \left(p_k - c_{ik}\right) \qquad \text{Adjusted SFE equilibrium condition} \qquad (4.12)$$

The supply curves of the divested firms are obtained by splitting the plant portfolio of EON and RWE into two identical subsets which are then transformed into cubic cost functions following the methodology described in Section 4.4.2. This symmetric divestiture guarantees that the resulting firm cost curves add up to the pre-divestiture oligopoly cost curve.

For both cases the monthly bidding curves are estimated using the calibrated contract cover to obtain monthly prices, welfare, and profit estimates.

4.4.3.2 Price and Welfare Results

Since the divestitures will increase the number of firms and reduce the market share of the strategic companies prices will decrease and welfare will increase. Thus the interesting question is the extent of the changes. With four oligopolists the German electricity market has a relatively "low" market concentration given the European context. A further concentration reduction may only result in few price effects, particularly if the divested assets end up with other strategic firms. The simulated results do not confirm this hypothesis. For both models the divestiture of EON and RWE significantly reduces the bidden supply curves (Figure 4.4). In particular the highest bidding range is lower while the changes are less pronounced for lower demand levels. In the *4 Firm Case* the divestiture even brings the bid curve close to the market's marginal costs curve.

Overall the average peak prices can be reduced by 8 to 10 €/MWh in the *6 Firm Case* and by more than 16 €/MWh in the *4 Firm Case* (Table 4.3). This price reduction provides consumers with a significant larger surplus ranging from and additional 3 bn € per year in the *6 Firm Case* and more than 5 bn € per year in the *4 Firm Case.* On the other hand producer rent significantly decreases by more than 1 and 2 bn € respectively (Table 4.3). Thus the overall welfare balance of the divestiture cases is positive.[70]

Table 4.3: Price and welfare results for peak hours compared to pre-divestiture, 2006, excluding fringe

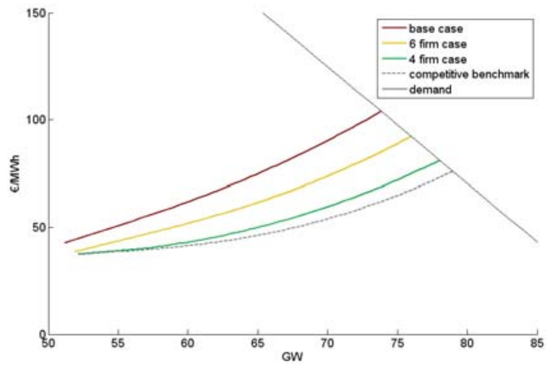
	Pre-Divestiture		6 Firm Case		4 Firm Case	
	Cournot	SFE	Cournot	SFE	Cournot	SFE
Average peak price [€/MWh]	63.6	62.9	-8.3	-9.8	-16.1	-16.9
Welfare [bn €/a]	44.67	44.75	+1.51	+1.80	+2.87	+2.96
Consumer surplus [bn €/a]	37.79	37.98	+2.78	+3.29	+5.45	+5.55
Producer surplus [bn €/a]	6.88	6.77	-1.26	-1.49	-2.57	-2.60

Source: Own calculation

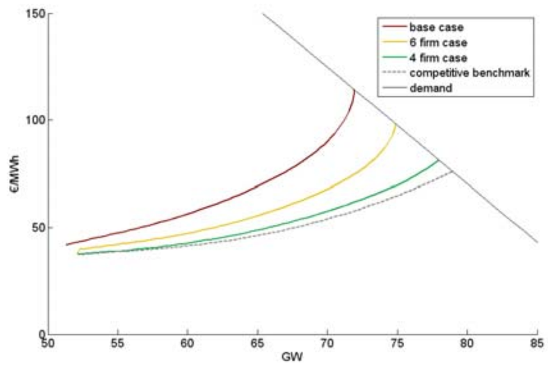
[70] A detailed overview of the price and welfare results appears in Appendix IV.

Figure 4.4: Cournot and SFE supply curves, January 2006

Cournot



SFE



Source: Own calculation

4.4.3.3 Discussion

A comparison of the pre- and post-divestiture market results shows clear price and welfare effects of the proposed divestiture cases. With more than 3% welfare increase the impact of a changed market structure is not negligible. As the initial set of divested power plants is equal in both divestiture cases the differences are solely contributed to the ownership assumptions taken. Thus an enforcement of strict buying rules that prevent large players from increasing market shares via the divested assets significantly increases the benefits reaped from the divestiture.

Examining firms' profits shows that in the pre-divestiture situation the oligopolists earn about 70-90% more than under pure competitive conditions (see Appendix IV). This excess revenue can be greatly reduced via the divestitures. In the *6 Firm Case* revenues drop by 15-30% and thus reduce the markup on competitive levels. The two non-divested firms face slightly higher reductions than the two large incumbents, showing that the two smaller oligopolists profit from the strategic behavior of the two large dominant incumbents in the pre-divestiture market. They are able to benefit from the higher price level without withholding too much capacity. In the *4 Firm Case* the profit of the divested assets from EON and RWE that are sold to fringe companies are slightly lower than the remaining assets that are modeled as strategic companies. This is in line with the expectations. However, the overall price level is close to the competitive benchmark and thus the effect is rather small. The profit markups are between 10-15% for all four remaining oligopolists and 7-10% for the divested fringe assets.

Comparing the two applied models shows that they both produce similar results and thus do not provide a large range of possible outcomes. The SFE approach has a slightly higher price reducing and welfare enhancing effect due to the steeper slope of the bidding curve close to the capacity/demand limit of the market. Thus, although the obtainable peak-price level is higher in the SFE model the average price is lower.

The obtained results are subject to assumptions that may bias the conclusions drawn. First, the contract coverage obtained during the calibration may not be the one applied in the post-divestiture market. A reduced market share may motivate firms to sign fewer contracts to increase gaming in the spot market. The higher competitive pressure may also motivate firms to sign more contracts to secure their revenues. Second, the continues cost function assumption neglects capacity constraints that may lead to higher prices. This is also true for imports because the constant import elasticity may overestimate competition from abroad. Finally, the characteristics of real world electricity markets can lead to situations that a model cannot capture, e.g., strategic behavior by small firms at peak times with scarce capacity reserves.

4.5 Conclusion

This chapter has analyzed competition policy and divestiture in electricity markets. Following an overview of competition policy divestiture was considered as a possible remedy to overcome market power problems. Based on the case of Germany it was shown that a reduced market concentration can provide significant welfare benefits. Applying Cournot and SFE models two divestiture cases were analyzed that both led to a large peak-price reduction and welfare gains. The results show that in the case of Germany divested assets should be sold to independent and small firms to prevent the emergence of further strategic players. An increase of consumer surplus of more than 5 bn € per year, and a peak price reduction of more than 16 €/MWh could be achieved in this setting.

Even though the chapter emphasizes that divesture can increase the competitiveness of oligopolistic electricity markets the question remains whether it is the most suitable instrument. Divestiture is generally considered a “hard” instrument of competition policy and thus significant opposition may arise from concerned companies that delay implementation. An acceptable alternative may be provided by virtual divestures with a limited duration. Whether other measurements such as the increase in cross-border transmission capacity and the further integration of congestion management schemes can provide a similar or higher benefit requires further research. In addition a translation of the result for the German case to other markets is not advisable given the large structural divergence among European electricity markets.

5 Network Investments, Regulation and Incentives

5.1 Introduction

Electricity generation is generally considered a competitive activity. Thus beside market power surveillance, no further regulatory activities are necessary; the transmission and distribution of electricity remains regulated even in liberalized markets. This is due to the natural monopoly character of these activities. Two directions are of particular concern and need to be addressed with different regulatory methods. The fist is the short run operation of electricity networks including network access for generators and consumers, congestion management, and auxiliary service markets. In recent years locational marginal pricing (LMP) in an ISO setting has emerged as common solution in US markets. In Europe a common trend has not yet emerged.

The second direction is the long run market development with a particular focus on the problem of sufficient network investments to secure supply and avoid inefficient congestion. The question whether investments in transmission capacities can be a competitive activity or need a regulated planning approach is still subject to discussion. Recent years have not shown a satisfactory solution to this problem. In U.S. networks congestion costs have increased considerably, particularly in the Midwest (Dyer, 2003) and in the PJM, Southern Connecticut, and New England markets. In 2006 the US Department of Energy identified two critical congestion areas (Atlantic coastal area and Southern California) and four congestion areas of concern (New England, the Phoenix – Tucson area, the Seattle - Portland area, and the San Francisco Bay area). In addition transmission investment in the US has declined in recent years (Joskow, 2005b). The US regulator, FERC, has suggested policies based on the use of merchant mechanisms, but little effort has been exerted to apply performance-based regulatory mechanisms. Implementation of regulatory measures is further complicated by the duality of attributions at the federal and state levels (see Section 2.2.3).

In Europe, due to the liberalization processes initiated in the late 1990s, existing national electricity networks with limited cross-border capacities now form the backbone of the emerging European-wide internal market. However, the grid remains segmented into several regional and national sub-networks, with the result that little or no competition exists between countries. Diverging policy approaches complicate the development of a functioning market and harmonization of congestion management has been one central focus for the EU in recent years (EC, 2007c). Furthermore, Europe's expected capacity increase in renewables (primarily offshore and onshore wind) will require significant transmission investment. Although several studies have proposed ambitious extension schedules for the existing grid (e.g. DENA, 2005), an economical-technical approach that can cope with the need for expansion while simultaneously accounting for welfare effects has not yet been designed and implemented neither in the US nor in Europe.

In this Chapter the question how to incentivize the transmission company to invest into the network and reduce congestion and increase welfare addressed. I start with a literature overview on network investment in electricity markets with a focus on merchant and regulatory approaches (Section 5.2). Afterwards the characteristics of network expansion in meshed electricity networks is presented by conducting a simulation of the impact of loop flows on extension costs (Section 5.3). Finally, a price-cap mechanism is introduced which is based upon the redefinition of the output of transmission in terms of point-to-point transactions or financial transmission rights (FTRs), and the rebalancing of the variable and fixed parts of two-part tariffs (Section 5.4). I show that this mechanism is suitable for actual transmission expansion projects in real-world grids.

5.2 Natural Monopolies and Network Extension in Electricity Markets

Léautier and Thelen (2007) provide a review on the question of optimal network expansion in liberalized electricity markets. Beside the issue of transmission costs and vertical unbundling the applied methods can be differentiated into the market based approaches and regulatory approaches. For the market based approach the investor has to be incentivized to undertake investments by profit opportunities. This approach is also known as a "merchant mechanism" or "merchant transmission" investment because the participation of economic agents is voluntary and solely driven by revenue opportunities. The main problem is that line extensions or upgrades result in network externalities that affect other market participants and thus have to be taken into account. For the regulatory approach investments are considered to be planned centrally by a welfare maximizing regulator or a regulatory approach incentivizing the transmission company (Transco) to extend the network accordingly.

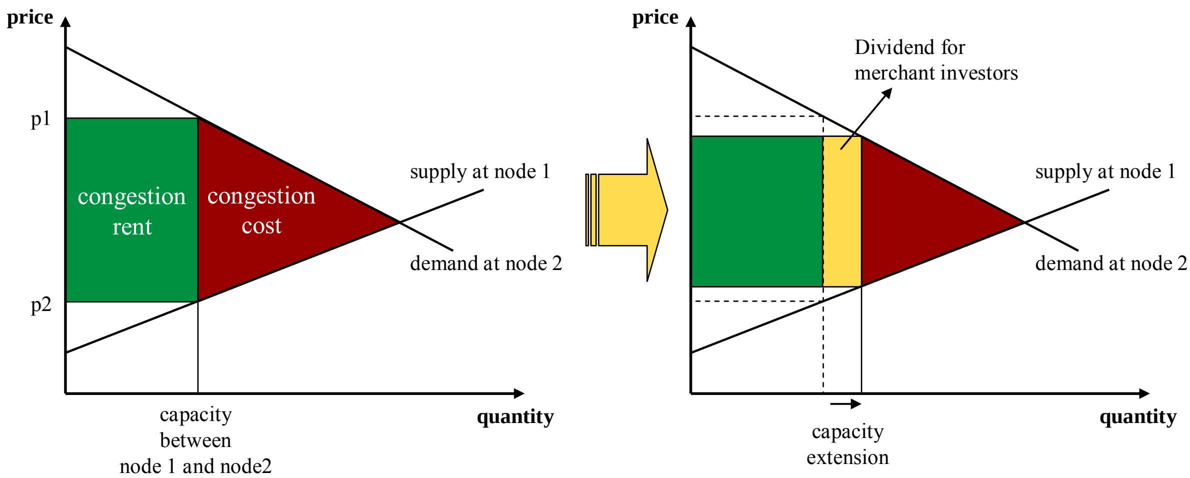
Beside the question how to handle network investments the interaction between generation and transmission extensions is a further concern. Pérez-Arriaga and Olmos (2006) look at the compatibility of investment signals in transmission and generation, Rious et al. (2008) analyze whether a two-part tariff is able to incorporate short- and long-run issues in order to manage electricity networks efficiently, and Sauma and Oren (2006) compare a three-period proactive network planning (PNP) model to a combined generation-transmission operation and investment planning as well as to a transmission only planning, they conclude that PNP can correct some of the shortcomings of the transmission only approach.

5.2.1 Merchant Transmission Investment

Joskow and Tirole (2005) conduct an in depth analysis of merchant investment under different market imperfections. They differentiate two types of network extension: deepening investments and expansion investments. The former are considered to be only possible by the incumbents due to incentive problems with decentralized ownership and information asymmetries. Thus only independent network extension (construction of separate new lines) can be subject to merchant approaches. Given a congested two node network the marginal increase of capacity will provide the investor with a dividend equal to the shadow price of the transmission constraint if he is rewarded by a financial transmission right (Figure 5.1). Extension will take place until the costs for new capacity equals the shadow price of congestion. In contracts an incumbent will weight the investment costs with the reduction of congestion rent from its inframarginal units (see Joskow and Tirole, 2005, p. 241ff). Hogan (1992) and Bushnell and Stoft (1996) show that under simplifying assumptions all profitable transmission investments are also efficient. Joskow and Tirole (2005) state that this optimality of market mechanisms is based on strong assumptions which if relaxed can contradict the outcome. They show that market power, lumpy investments, FTR allocation, and the actual definition of transmission capacity all impact the outcome and conclude that the merchant model ignores important restrictions of electricity markets which a regulatory approach can cope with and thus a sole reliance on merchant investment seems unlikely.

Brunekreeft and Newbery (2006) analyze the regulatory issues connected to merchant investments in the European legal framework. Although the EU regulation on cross-border exchange (No. 1228/2003) allows merchant investment to be exempt from regulated third party access it still requires a must-offer provision of capacity for the owner of the new connection and a use-it-or-lose-it provision for the holders of capacity rights. They conclude that the regulatory instrument of must-offer provision has positive short-term welfare effects but may lead to underinvestment in network assets. Hence, the authors do not recommend applying must-offer provisions. Baldick (2007) proposes a property rights model based on so called border flow rights to support financial hedging of merchant investment. The rights resolve the property-rights issues for existing and new transmission capacity arising from new investments. Further studies (e.g. Salazar et al., 2007; Saphores et al., 2004) address the issue of decisions under uncertainty in a merchant investment setting.

Figure 5.1: Congestion and merchant investment



Source: Following Joskow and Tirole (2005, p. 241)

5.2.2 Regulatory Transmission Investment

The objective of the regulatory approach is to maximize the social welfare within the electricity system. The regulatory approach involves a commercial transmission company (Transco) that is regulated through price or revenue regulation to provide long-term investment incentives while avoiding congestion. Léautier and Thelen (2007) distinguish two families of regulatory contracts: Bayesian and Non-Bayesian contracts.

Bayesian regulatory approaches aim to reduce the transmission costs and simultaneously obtain optimal expansion quantities while the regulator knows a correct distribution of the monopolists cost function. Laffont and Tirole (1993) show that the regulatory task in this setting can be split up into two separate ones dealing with the above mentioned aims, respectively. Léautier (2000) analyzes a Bayesian approach under the congestion management scheme in England and Wales. He shows that the "uplift" measure does in fact measure the social cost of congestion and thus a network company exposed to pay the uplift will extend the grid in a socially optimal way.[71] Since its implementation in 1996 congestion in the British transmission grid has reduced considerably.

Non-Bayesian contracts assume that the regulator does not know the cost function details of the regulated firm (Vogelsang, 2005). Therefore, most approaches rely on a price cap formulation that either produces the optimal outcome by applying optimal weights or shows a gradually convergence towards the social optimum by applying Laspeyres weights (Léautier and Thelen, 2007). Nasser (1997) designs a transfer mechanism providing the firm with the current congestion rent reduced by a rent constructed from current price levels and previous periods capacities. Another Non-Bayesian regulatory variation is the two-part tariff cap proposed by Vogelsang (2001). The first tariff part consists of the congestion rent in the system and the second part is a fixed component. By rebalancing the fixed and variable portions of the tariff the Transco can be incentivized to invest as reduced congestion revenues can be offset by increased fixed revenues. Vogelsang shows that under well-behaved cost and demand functions, and appropriate weights (such as Laspeyres weights) the mechanisms grants convergence to equilibrium conditions. However, Vogelsang's assumed cost and demand properties may actually not hold in a real network context with loop-flows. Furthermore, a conventional linear definition of the transmission output is in fact difficult to maintain.

An extension of the Vogeslang (2001) mechanism is proposed by Hogan et al. (2007) who apply the approach in an environment of price-taking generators and loads taking into account meshed networks. Transmission output is redefined in terms of incremental long term FTRs in order to apply the incentive mechanism to a meshed network. The Transco maximizes profits intertemporally subject to a price cap constraint on its two-part tariff, and the choice variables are the fixed and the variable fees. The fixed part of the tariff can be considered as a complementary charge. The variable part of the tariff is the price of the FTR output, and is then based on nodal prices. Fixed costs are allocated so that the variable charges are able to reflect nodal prices. Thus, variations in fixed charges over time partially counteract the variability of nodal prices, giving some price insurance to the market participants. However, they do not consider an alteration of the loop flow characteristics by the network extensions

[71] The uplift is defined as the sum of the difference between generation costs and the unconstrained market price for all units that are re-dispatched due to network restrictions (see Léautier, 2000).

which is only valid for small scale extensions. In this Chapter the approach by Vogeslang (2001) and Hogan et al. (2007) is extended to include a full representation of extensions in meshed electricity networks.

5.3 Meshed Networks and Non-Well-Behaved Cost Functions

Electricity markets differ from most other commodity markets as electricity can not be stored and thus generation and demand always have to equal one another. Furthermore, as all nodes in a system are connected via a network following physical laws, a local change in demand or generation impacts the whole system. This interconnection yields problems when assessing the cost of additional transmission capacity. As shown in Section 5.2.1 an additional unit of capacity in a two node setting reduces the price difference and increases the traded quantity between both nodes. The additional benefit from new capacity steadily decreases with each marginal increase of capacity. However, when the network is extended beyond two nodes this general conclusion may not hold.

In this Section network extension costs are estimated using two simplified network topologies including loop flows. The global extension costs function is derived by obtaining the least costs network extension for a given transmission demand. Three different assumptions on the behavior of extension costs on a single line are tested (constant, increasing, or decreasing returns to scale) to examine whether they also translate in a similar global cost behavior. This section draws on Rosellón and Weigt (2008).

5.3.1 Model

To analyze the cost behavior of extending meshed networks the output of electricity transmission is defined as point-to-point transactions. In directed networks like natural gas, oil, or logistic problem sets, an additional unit of output normally can be associated with a well defined cost parameter or function. By contrast in electricity networks additional output heavily depends on the grid conditions and can not be considered separately from the general output setting.

To derive a cost function for electricity transmission the properties of power flows in meshed networks have to be examined. Therefore the DCLF as proposed by Schweppe et al. (1988) is used. The DCLF focuses on real power flows and neglects reactive power flows within a network. Although a simplification, the approach still yields reasonable results with respect to locational price signals and grid utilization. Overbye et al. (2004) compare the DCLF with a full AC model and conclude that significant differences only occur on lines with high reactive and low real power flows.

The complete approximation of the DCLF from the physical fundamentals of transmission lines is presented e.g. in Stigler and Todem (2005). The principal of a DCLF is that flows *pf* on a line depend on the voltage angle difference Θ_{ij} and the line series susceptance B_{ij} between the two nodes *i* and *j*:[72]

$$pf_{ij} = B_{ij} \cdot \Theta_{ij} \qquad \text{power flow between } i \text{ and } j \qquad (5.1)$$

The power flow on one line furthermore has an impact on the energy balance of its connected nodes. For each node *i* in a system the net injection q_i has to equal the sum of power flows on connected lines:

$$q_i = \sum_j pf_{ij} \qquad \text{energy balance at } i \qquad (5.2)$$

If more energy is to be delivered to or from node *i* all power flows on lines connected to that node are affected and in turn all nodes connected to those lines are affected as well, continuing throughout the network. Therefore, the resulting power flow pattern in an electricity network is always depending on all system conditions.

To asses the costs related to electricity transmission, transactions q_{ij} between two nodes *i* and *j* are defined as the relevant output.[73] These point to point transactions or financial transmission rights (FTRs) are determined as a specific load value e.g. in 'MW' that has to be transmitted between two nodes. There is no fixed line utilization associated to a FTR. Market participants can bid for specific FTRs and the system operator allocates those accordingly, maximizing the revenue from the FTRs given the available transmission capacity of the network. FTRs are assumed to be obligations thus the associated energy transfer can be taken for granted.

The transmission costs function *c(.)* of network extension is defined as the least costs combination of line capacities *k* necessary to satisfy Q_{ij} (the matrix consisting of a specific set of FTR combinations q_{ij}):

$$c(Q_{ij}) = \min_{k_i} \sum_{i,j} f_{ij}(k_{ij}) \qquad \text{transmission cost function} \qquad (5.3)$$

Each line capacity k_{ij} is associated to a specific cost value via an extension function *f(.)*.

The minimization is subject to technical restrictions representing the power flow characteristics of electricity networks:

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[72] The reactance X represents the opposition of a line towards alternating current, based on the inductance and/or capacitance of the line. Together with the resistance R, they define the impedance of a line and thus determine the amount of power flowing over this line given the net injections. The line series susceptance B_{ij} is then derived via: $B_{ij} = \frac{X_{ij}}{X_{ij}^2 + R_{ij}^2}$

Generally, the resistance is assumed to be significantly smaller than the reactance (X >> R), and thus we do not consider it further in this analysis simplifying the susceptance to: $B_{ij} = \frac{1}{X_{ij}}$

The voltage angle difference Θ_{ij} is a relative measure. By fixing one voltage angle at one node (the slack bus) to 0 a reference is obtained against which all angles of all other nodes are computed.

[73] q_i and q_{ij} are connected via: $\sum_j q_{ij} - \sum_j q_{ji} = q_i = \sum_j pf_{ij}$

$$\left|pf_{ij}\right| \leq k_{ij} \quad \forall ij$$ line capacity constraint (5.4)

$$\sum_j q_{ij} - \sum_j q_{ji} = \sum_j pf_{ij} \quad \forall i$$ energy balance constraint (5.5)

First, power flows pf_{ij} on the lines have to remain within the capacity limits k_{ij} defined by the system operator by designing the grid (equation 5.4). And second, at each node i the sum of outgoing FTRs (q_{ij}) and ingoing FTRs (q_{ji}) has to equal the sum of power flows on connected lines pf_{ij} (equation 5.5). In other words the model defines for a given set of injections and withdrawals (Q_{ij}) the cost minimal line capacities k_{ij} (a green field approach) which in turn define the line characteristics B_{ij} and thus the power flows pf_{ij} in the whole system. The models is incorporate into GAMS as a non-linear minimization problem, with the overall grid extension costs as an objective function and looped over a specific set of FTRs.

5.3.2 Data

The model is tested using a numeric dataset representing idealized market characteristics. The initial grid topology comprises a three-node network with two generation nodes and one demand node representing the simplest loop flowed network structure, and an extended six node network again with two generation and one demand node (Figure 5.2). FTRs are defined from the generation to the demand node respectively and are varied between 1 MW and 10 MW, respectively, to estimate the resulting global cost function.

With respect to the network extension behavior two cases are analyzed:

- First, only the capacity of a line can be changed whereas the lines reactance remains unchanged. Thus, an extension only impacts the transmission capacity of the system but does not alter the power flow pattern. This approach is a theoretical one, as in reality pure capacity increases are only possible for small scale extensions. The purpose of this method is to asses the impact of loop flows on transmission costs without the interfering influence of power flow changes.
- Second, line extensions are combined with a change of the lines reactance and thus added capacity changes the power flow pattern of the whole system. This approach resembles the real world problem that a new or upgraded line impacts the whole electricity system and leads to externalities for other market participants.

Three different forms of line extension costs $f_{ij}(k_{ij})$ are tested corresponding to constant, decreasing and increasing returns to scale:[74]

Linear function: $f_{ij} = b_{ij}\, k_{ij}$

Logarithmic function: $f_{ij} = \ln\left(a_{ij} + b_{ij}\, k_{ij}\right)$

[74] Although increasing returns to scale are rather unlikely in electricity networks (see e.g. Richert and Brakelmann, 2004; and DENA, 2005) they are included for the sake of completeness.

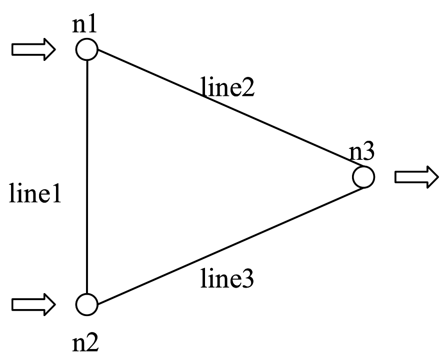
Quadratic function: $$f_{ij} = b_{ij}\, k_{ij}^2$$

The values of *a* and *b* are varied for different cases. All three extension functions represent a continuous approach which is an approximation of the lumpy investment pattern of electricity networks. For all scenarios the topology of the network is fixed thus neither new connections can be built nor can exiting connections be abolished.

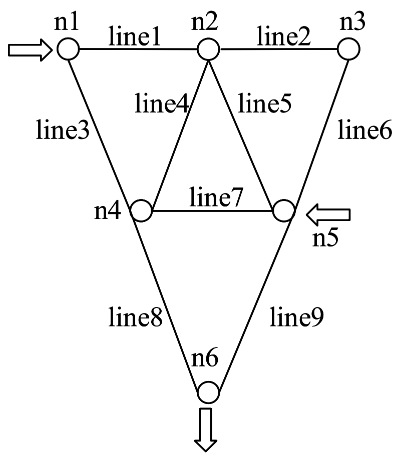
When only the line capacities are extended the presented extension cost functions are sufficient to derive numerical solution. In case of a connection between extensions and line reactances the law of parallel circuits[75] is applied to derive a functional connection between capacity extensions and line characteristics $B_{ij}(k_{ij})$. Thus, doubling of capacity results in a bisection of a line reactance. Whereas the first approach does not need specific start values for line capacities the latter approach needs initial network characteristics to obtain result. The scenarios are tested using a series of numerical analyses varying the underlying parameter. An overview about the basic dataset is provided in Table 5.1.

Figure 5.2: Network topologies

Three-node network



Six-node network



Source: Own representation

[75] In a parallel circuit the total resistance of the system is defined by $R_{total} = 1 \Big/ \sum_i \frac{1}{R_i}$.

Table 5.1: Scenario overview for cost function calculation

	Fixed line reactances	Variable line reactances
Three-node network		
FTR range [MW]	FTR 1 to 3: 1 to 5 FTR 2 to 3: 1 to 10	
Line extension functional parameters	Base values: $a_{ij} = b_{ij} = 1$	Base values: $a_{ij} = b_{ij} = 1$
Starting capacity values [MW]	$k_{ij} = 0$	Base values: $k_{ij} = 2$
Six node network		
FTR range [MW]	FTR 1 to 6: 1 to 5 FTR 5 to 6: 1 to 10	
Line extension functional parameters	Base values: $a_{ij} = b_{ij} = 1$	Base values: $a_{ij} = b_{ij} = 1$
Starting capacity values [MW]	$k_{ij} = 0$	Base values: $k_{ij} = 2$

Source: Own calculation

5.3.3 Scenarios and Results

5.3.3.1 Fixed Line Reactances

The first part of the cost function analysis only considers the capacity extension while the grid's topology is fixed in terms of line reactances and available connections. Varying the FTRs has an exogenously determined impact on the power flow pattern. Hence, the model only calculates the minimum capacity amount needed to exactly fulfill this pattern.

In the three node system line 1 (between nodes 1 and 2) is subject to power flows in opposite directions depending on the value of the two FTRs. Given a fixed level of one FTR, an increase in the second FTR will first lead to a decrease in the flow on line 1 towards zero until both FTRs have the same value. Afterwards, the flow will again increase, although in the opposite direction. The resulting capacity cost for increasing the FTR value will show a "kink" at the level of the fixed FTR. The left hand side of Figure 5.2 shows this for all three analyzed cases: At a level of 2.5 MW the flows on line 1 will cancel out and the slope of the cost functions will not be continuous at that point. The effect is less pronounced in the quadratic case as the slope of the line extension function around zero is almost horizontal with gradual changes contrary to the linear or logarithmic case. Furthermore, the resulting global cost function for increasing two FTRs simultaneously shows that the costs when moving from one FTR combination to another can even slightly decrease and the kink of line 1 moves gradually with the increasing FTRs, which is best visualized in the logarithmic (Figure 5.3, right side).[76] This result is specific to the decreasing-returns extension function, since the cost always increases with increasing FTR values for both the linear and quadratic functions. When the line extension costs parameters *a* and *b* are altered such that the loop flowed line 1 is more expensive to update than the other lines, the effect becomes more distinct.

[76] Linear and quadratic cases are presented in Appendix V.

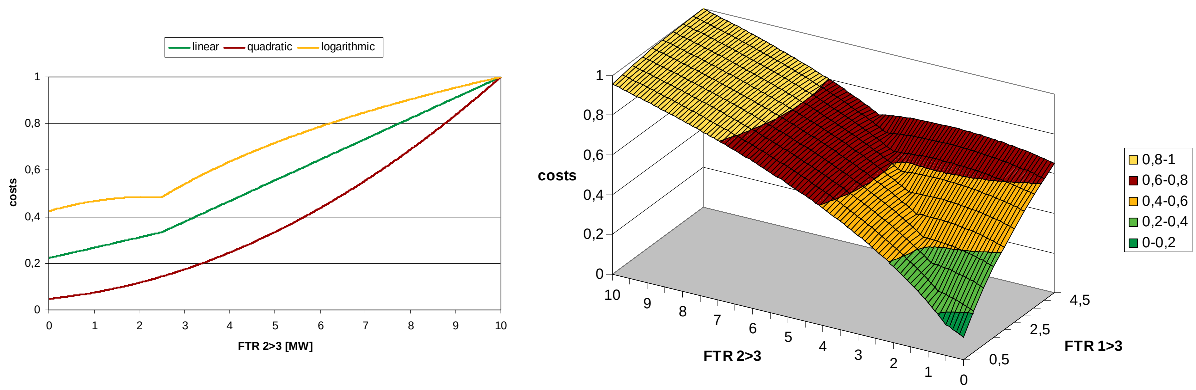
Extending the model to the six nodes setting subjects five lines to counter-flows according to the FTR combinations. Since lines 2, 5 and 6 are symmetric, their counter-flows will "kink" at the same level. The resulting cost function can have up to three kinks. For the 2.5 MW case we only observe two kinks (Figure 5.4, left side), one at 1.25 MW (canceling out the flows on line 7) and the second at 5 MW (canceling out the flows on lines 2, 5, and 6). The last kink occurs at a FTR value of 20 MW, which is outside the observation range. The resulting global cost function shows all three kinks, which again are best visualized in the logarithmic case (Figure 5.4, right side).Comparing the six- and the three-node networks, the quadratic extension function still results in an always-increasing feasibility range while the logarithmic function can have decreasing global cost ranges according to the FTR combination. Even the linear extension function can have decreasing elements in the global costs function if the loop flowed lines are more expensive to extend than the other lines.

In other words, by extending a specific FTR, the simultaneous increase of further FTRs can reduce the overall costs in meshed networks. However, this will not always be achieved because the necessary counter-flow generating FTRs may not be needed and the positive effect of the additional net injections will not be obtained. The results for the simple networks show that even under the restriction that line reactances remain unchanged the costs for a marginal unit of transmission capacity are subject to the overall grid conditions making general revenue conclusions infeasible.

Figure 5.3: Global cost function, three-node network, base case

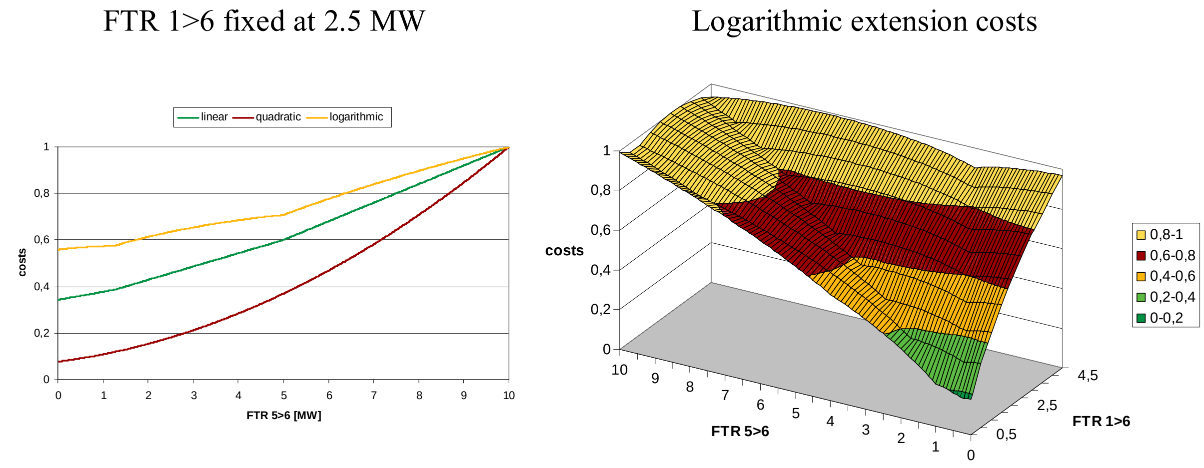
FTR 1>3 fixed at 2.5 MW

Logarithmic extension costs



Source: Own calculation, based on Rosellón and Weigt (2008)

Figure 5.4: Global cost function, six-node network, base case



Source: Own calculation, based on Rosellón and Weigt (2008)

5.3.3.2 Variable Line Reactances

In reality, there are limitations to extending a line capacity without altering its technical characteristics. Normally, a capacity extension is linked to a change in the reactance of the line.[77] Therefore, for the second scenario, capacity extensions are coupled to line reactances via the law of parallel circuits. As starting values of the lines' capacities are necessary, a direct comparison to the first scenario that uses fixed-line reactances is not possible.

Using the three-node case and a starting capacity of 2 MW on each line, the resulting cost functions do not necessarily have a kink when one FTR is fixed. In addition, all lines start with zero extension costs since the first portion of the FTR increase can be accomplished with the existing grid. In the 2.5 MW case (Figure 5.5, left side) no kinks can be observed because line 1 is not extended for the three-node case. Increasing the capacity of line 3 will lead to a larger power-flow on that line relative to the path over node 1 utilizing line 1 and 2. This allows the full utilization of the starting capacity values of those lines (2 MW). Therefore, the cost function only resembles the extension cost of increasing capacity on line 3 which consequently is a continuous function.

The resulting cost function can still have kinks but these do not necessarily relate to a specific loop-flowed line. Discontinuities can now also be caused by changing grid conditions as the same FTR combination can be obtained by several different extension measures e.g. increasing two line capacities by modest amounts or increasing only one line significantly. This impact is particularly important for the logarithmic case.

[77] The reactance represents the opposition of a line towards alternating current, based on the inductance and/or capacitance of the line. Together with the resistance they define the impedance of a line and thus determine the amount of power flow over this line given the net injections. Generally the resistance is assumed to be significantly smaller than the reactance and thus is not further regarded in this analysis.

The global cost function for extending both FTRs no longer shows a clear correlation with the number of loop-flowed lines as in the first scenario. Moreover, all line extension functions show decreasing elements for certain FTR combinations like the logarithmic function (Figure 5.5, right side).[78] However, this range has no resemblance to the kink observed in the fixed reactance case which was solely attributable to the unavoidable counter-flow on line 1. In this case the decreasing cost range is attributed to the absence of a counter-flow in the very first case (FTR from 1 to 3 is "0"). The power-flow within the system therefore is only defined by the FTR from 2 to 3 and consequently the flow on line 1 is higher than in all other cases, making an extension of this line necessary (or a much larger extension of line 3). Increasing the FTR from 1 to 3 produces a counter-flow on line 1 and allows better utilization of the existing capacity. This effect makes the overall extension less costly (negative marginal costs). As the simulation needs starting values for line capacities, an alternative approach with reduced capacities has been calculated. However, when decreasing the starting capacity from 2 MW to 1 MW the resulting cost functions show a similar behavior. The functions slightly shift to the left and the outcomes of higher FTR levels vary accordingly.

Increasing the parameters of the cost function of the loop-flowed line does not alter the results. Thus, in the optimal solution of the three-node network an extension of line 1 is avoided entirely. But when the cost parameter of another line is altered, the outcome changes, although the general functional form remains similar. The logarithmic extension function yields different results as the trade-off between extensions of one or two lines becomes more evident (i.e. large extensions are relatively less expensive).

Next, the model is extended to six nodes and nine lines to estimate the impact of more loop-flowed lines on the cost functions. Similar to the 3-node setting by extending the most-utilized lines the power-flow share on these lines increases, which avoids further extension of other lines. However, contrary to the 3-node case more than one line needs to be extended along the FTR range. Thus, kinks can occur when the extension includes more lines or when it switches the extended line. For the logarithmic case also more capacity is added on a line than is actually utilized, due to the decreasing marginal extension cost. Since the marginal extension cost in the logarithmic case is the highest for initial extension and decreases with capacity, it is less costly to extend a line that may not be fully utilized if other initial capacity extension can be avoided. This is the case in the first kink at 3.55 MW (Figure 5.6, left side). This situation may also switch back – making another line the less costly alternative to be extended – if the costs for excess capacity are no longer counteracted by a beneficial power-flow distribution. This is the case for the second kink at 5.2 MW where the former extended line 8 is no longer extended, and the full additional capacity shifts to line 9, which alters the power-flow pattern.

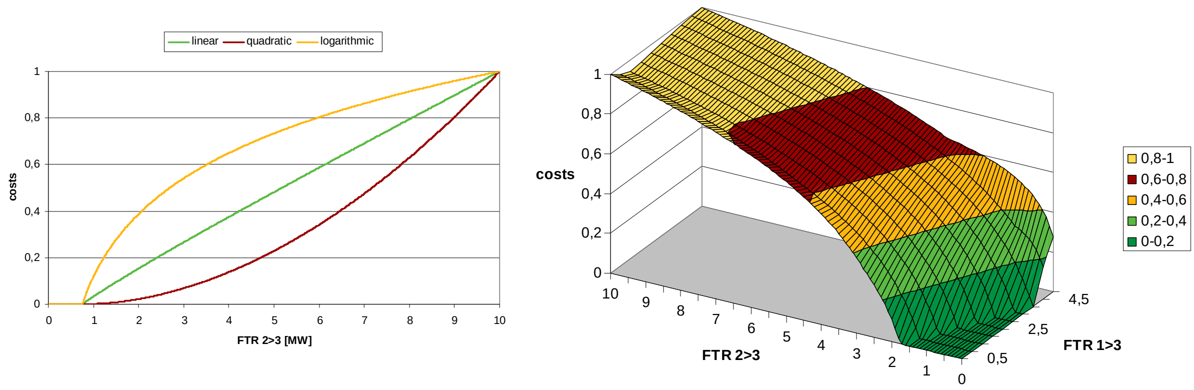
As in the three-node simulations, the obtained global cost functions do not reveal an obvious correlation to the number of loop-flowed lines. The results for linear and quadratic extension functions

[78] Linear and quadratic cases are presented in Appendix V.

show generally increasing cost function with a relatively smooth outline; however the logarithmic extension function results in a global cost function with significant slope changes (Figure 5.6, right side). Furthermore, a consistent solution in the logarithmic case could not be obtained in all model runs, resulting in cost spikes which occurred in three scenario runs. Reducing the starting capacity of the lines to 1 MW does not significantly change the results of the linear and quadratic extension functions. The global cost function in the logarithmic case also resembles the same form but the slope changes are less pronounced. Likewise, a shifting of the line parameters for loop-flowed and non loop-flowed lines does not alter the general results although the absolute values differ.

Figure 5.5: Global cost function, three-node network, base case, variable line reactances

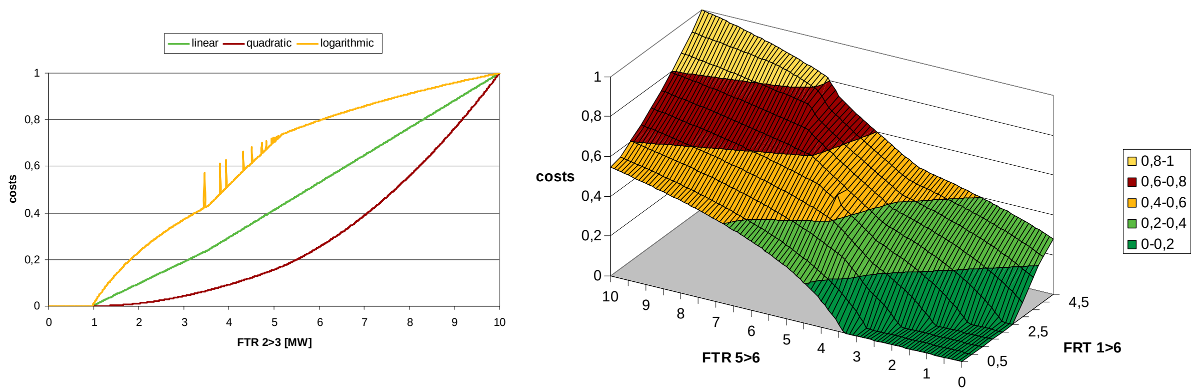
FTR 1>3 fixed at 2.5 MW | Logarithmic extension costs



Source: Own calculation, based on Rosellón and Weigt (2008)

Figure 5.6: Global cost function, six-node network, base case, variable line reactances

FTR 1>6 fixed at 2.5 MW | Logarithmic extension costs



Source: Own calculation, based on Rosellón and Weigt (2008)

5.3.3.3 *Discussion*

Comparing the results with the fixed network case shows that the introduction of variable line reactances significantly changes the possible outcomes. In particular, for linear or quadratic extension functions, the introduction of a link between capacity and reactance appears to reduce the impact of loop-flows in terms of significant kinks.

The results of the cost function analyses reveal the difficulties that electricity networks present when applying standard approaches. Even for a simple extension, loop-flows within the system can lead to mathematically problematic global cost function behaviors and thus make an estimation of the revenue possibilities for merchant or regulated network investors infeasible in a general setting. The link between capacity extension and line reactances (and thus the flow patterns) produces complex results that are highly sensitive to the underlying grid structure. None of the three tested extension functions can fully reproduce realistic extension structures since these are subject to lumpiness and external influences (e.g. geographical conditions) that can cause dysfunctional behaviors with sudden slope changes. The assumption of linear extension costs is acceptable when considering line length; however with respect to capacity increase, a lumpy function with constant costs for corresponding voltage levels and circuit number is required.

For modeling purposes, the logarithmic behavior produces a high degree of nonlinearities with non-smooth behavior, and demands more intense calculations and solver capabilities. Quadratic functions show a generally continuous behavior that makes them suitable for modeling purposes but are the most unrealistic assumption. Linear extension functions fall between the logarithmic and quadratic cases. However, the piecewise, linear nature of the resulting global costs function makes the derivation of global optima feasible. In combination with the advantages of retaining linear functions, this is preferred for modeling purposes. It is also compatible with the realistic extension costs neglecting lumpiness. Nevertheless, an analysis of investment incentives in electricity transmission has to rely on numerical analysis trying to capture the physical nature of the network. Otherwise the conclusions may be infeasible for specific systems and cases.

5.4 An Incentivized Two Part Tariff Applied to Transmission Companies

As general theoretical approaches can not be derived without taking the underlying network into account following a numerical model approach is presented that implements an investment incentive mechanism for Transcos. Building on Vogelsang (2001) and Hogan et al. (2007) the incentive regulatory logic is implemented via a profit maximizing Transco subject to a regulatory price cap. The Transco’s profit consist of a variable component representing the congestion rent in the system and a fixed component to recover investment costs. Both components are subject to a price cap. By rebalancing the two parts the Transco has the possibility to recover extension costs when decreasing the congestion rent due to newly built transmission capacity.

The problem is implemented as a MPEC. It is decomposed into upper-level and lower-level programs that are solved simultaneously. The upper-level problem is the Transco´s profit maximization subject to a price-cap regulatory constraint; the lower-level problem consists of an ISO that finds optimal loads and nodal prices through a power-flow welfare-maximizing model within a network-constrained wholesale electricity market. The approach presented in Hogan et al. (2007) is designed to solve the cost minimizing network capacity approach and derive an extension cost function that depends on the price for transmission. The Transco thus chooses the FTR price (variable part), and the fixed part of its two-part tariff. As shown in Section 5.3 the global costs function of network extension shows a high degree of non-convexities that may lead to problems when deriving numerical results. Therefore, the choice variables in this mechanism are the line capacities and the fixed fee which avoids the derivation of the global cost function. This approach is theoretically equivalent, since the network capacity is a function of the FTR prices.

The incentive mechanism is applied to simple transmission structures based on a three-node network to determine the impact of loop flows on transmission investment decisions. Through the use of chained-Laspeyres weights the regulatory mechanism inter-temporally promotes an investment pattern that relieves congestion, increases consumer surplus, augments the Transco´s profits, and induces convergence of nodal prices to marginal costs. A series of robustness tests is conducted to assess the impact of varying assumptions on the results. Afterwards the incentive mechanism is applied to a more realistic representation of an existing network to test whether the theoretical conclusions obtained are appropriate using a simplified grid with 15 nodes and 28 lines in North West Europe that connects Germany, the Benelux countries, and France.

5.4.1 Model Formulation

For the model the output of a Transco is defined in terms of FTRs which makes it applicable in most LMP based markets in the US. Accordingly, the mechanism has the following sequence of actions:

1. Given an existing grid with historic market price information the regulator sets up the two-part pricing constraint.
2. Based on the available market information (demand, generation, network topology, etc.) the Transco identifies the lines to expand.
3. The Transco auctions the available transmission capacity as point-to-point FTRs to market participants.
4. The ISO manages actual dispatch. According to locational marginal prices it collects the payoffs from loads and pays the generators. The difference of both values represents the congestion rent of the system that is redistributed to the FTR holders.
5. The Transco sets the fixed fee according to the regulatory price cap.

The upper-level problem of the MPEC consists of the profit maximization of the Transco subject to the regulatory constraint. The objective function of the Transco is its profit and its choice variables the lines capacities k and the fixed fee F:

$$\max_{k,F} \quad \pi = \sum_{t}^{T} \left[\sum_{ij} \tau_{ij}^{t}(k) q_{ij}^{t}(k) + F^{t} N^{t} - \sum_{i,j} c\left(k_{ij}^{t}\right) \right] \text{Transco profit function} \tag{5.6}$$

The first term of this function represents the collected congestion rent defined as point-to-point FTRs q_{ij} between two nodes i and j multiplied by the FTR auction price τ_{ij}.[79] The second term represents the transmission revenue from the fixed fee F collected by the Transco from N consumers. The Transco is free to choose the fixed fee as long as the regulatory price constraint (see equation 5.7 below) is met. The second term represents the costs the Transco bears when extending the capacity k_{ij} between two nodes according to the extension cost function $c(.)$. A total time framework of T periods is considered and perfect information is assumed neglecting uncertainty about demand and generation. If a positive interest rate $r > 0$ were to be considered, each monetary part of the profit function would be multiplied by $(1+r)^{-t}$.

The FTR prices and the demand for FTRs are a function of the available capacity of the network. Thus, the Transco's choice variables are the line capacities k_{ij} and the fixed fee F. Hogan et al. (2007) assume that the network capacity and the FTR demand are functions of the FTR price τ, and thus their choice variables are the two parts of the Transco's tariff.[80]

In each period, the Transco is subject to a regulatory price cap:

$$\frac{\sum_{ij} \tau_{ij}^{t}(k) q_{ij}^{w}(k) + F^{t} N^{t}}{\sum_{ij} \tau_{ij}^{t-1}(k) q_{ij}^{w}(k) + F^{t-1} N^{t}} \leq 1 + RPI + X \qquad \text{regulatory cap} \tag{5.7}$$

The prices and quantities of each period are linked with a weight mechanism w (e.g., Paasche or Laspeyres weights), and subject to a cap defined by the regulator and considering inflation RPI and efficiency factors X. A grid expansion would generally be aimed at reducing the congestion rent of the system, and would then decrease the Transco's profit from the FTR auction. Given the regulatory mechanism, the Transco can counter the decrease of auction revenues by increasing its fixed fee. By this mechanism, the Transco is incentivized to expand the grid even if the collected congestion rent decreases. As long as the rebalancing of the variable and the fixed fee compensates possible revenue losses from reduced congestion the Transco will extend the grid, up to a point where the per-unit marginal cost of new transportation capacity equals the expected congestion cost of not adding an additional unit of capacity (Crew et al., 1995, and Vogelsang, 2001).

If the demand and optimized cost functions are differentiable, and ignoring the inflation and efficiency factors, the first-order optimality conditions of maximizing (5.6) subject to (5.7) are the following:

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[79] Following Vogelsang (2001) who employs total transmission output, the total available FTRs in each period t is auctioned. Hogan et al. (2007) use incremental FTRs following the practice in actual markets that hold FTR auctions (such as PJM). Hence, their output Δq_{ij} refers to the additional or *incremental* FTRs between i and j sold between periods t and $t-1$.

[80] In such a model, the minimum cost for each possible FTR price (and consequently for each possible FTR quantity) is obtained in a lower-level power-flow problem and, as a consequence the optimal grid size k is derived. This minimum cost function is later plugged into an upper-level problem where the Transco maximizes its profits subject to a regulatory constraint similar to the constraint in Vogelsang (2001), see section 5.3.

$$(\nabla q_{ij}^{t}+\nabla q_{ij}^{w})\tau_{ij}^{t}(k)-\nabla c^{*}=(q_{ij}^{w}-q_{ij}^{t}(k))\nabla\tau_{ij}^{t} \qquad \text{first-order conditions} \qquad (5.8)$$

Vogelsang (2001) and Hogan et al. (2007) analyze this key relationship to explore the incentive properties of the regulatory price cap constraint. Hogan et al. (2007) point out the limited information that can be derived. Due to the looped-flow nature of power flows in meshed networks, FTR-based demand and cost functions are only piecewise differentiable, and in general not separable. However, the local properties may in many circumstances be those of well-behaved functions.

One problem in deriving an MPEC mathematical formulation for the mechanism is the uncertainty about the FTR auction outcome. Thus, the FTR auction income is redefined as the congestion rent collected by the ISO given the market-clearing prices. If the considered set of FTRs is simultaneously feasible and the system constraints are convex, the FTRs satisfy the revenue adequacy condition.[81] That is, equilibrium payments collected by the ISO through economic dispatch will be greater than or equal to payments required under the FTR obligations. Given the assumption of perfect information, this approach allows to abstract from the explicit modeling of an auction mechanism. Therefore the distribution of FTRs to specific market participants is not an output of the model. The profit objective function of the Transco is then rewritten as:

$$\max_{k,F} \quad \pi=\sum_{t}^{T}\left[\sum_{i}(p_i^t d_i^t - p_i^t g_i^t)+F^t N^t-\sum_{i,j}c\left(k_{ij}^{t}\right)\right] \quad \text{adjusted profit function} \qquad (5.9)$$

The first part of the Transco's profit rewrites the outcomes of the lower-level problem i.e. payoffs from loads d and payments to generators g. The prices p_i are the resulting market-clearing prices at each node i. FTR prices and locational prices are related via $\tau_{ij} = p_j - p_i$. In choosing the line capacities k_{ij} the Transco will determine resulting market prices and quantities and thus the collected congestion rent. The price cap is rewritten accordingly, replacing the FTR auction revenue with the collected congestion rent:

$$\frac{\sum_{i}(p_i^t d_i^w - p_i^t g_i^w)+F^t N^t}{\sum_{i}(p_i^{t-1} d_i^w - p_i^{t-1} g_i^w)+F^{t-1} N^t}\leq 1+RPI+X \quad \text{adjusted regulatory cap} \qquad (5.10)$$

The lower level problem defines the wholesale market outcome taking into account power flows, line restrictions, and generation capacity limits:

$$\max_{d,g} \quad W=\sum_{i}\left(\int_{0}^{d_i^{t*}} p(d_i^t)\,\mathrm{d}d_i^t\right)-\sum_{i} mc_i g_i^t \quad \forall t \qquad \text{ISO objective function} \qquad (5.11)$$

s.t.

$$g_i^t \leq g_i^{t,\max} \quad \forall i,t \qquad \text{generation constraint at node } i \qquad (5.12)$$

[81] This has been shown for lossless networks by Hogan (1992), analyzed for quadratic losses by Bushnell and Stoft (1996), and generalized to smooth nonlinear constraints by Hogan (2000) and Hogan (2002a,b).

$$\left| pf_{ij}^t \right| \le k_{ij}^t \quad \forall ij$$ line flow constraint between i and j (5.13)

$$g_i^t + q_i^t = d_i^t \quad \forall i,t$$ energy balance constraint at node i (5.14)

The wholesale market is managed by an myopic ISO maximizing social welfare W for each period, respectively. Demand d and generation g are located at specific nodes i within a meshed network. Welfare is derived by obtaining the gross consumer surplus and subtracting the total generation costs. The demand behavior $p(.)$ is approximated via a linear demand function specific for each node i and marginal generation costs mc_i are taken as constant.

The welfare maximization is subject to technical constraints: First, actual generation g_i cannot exceed the available generation capacities g_i^{max} (equation 5.12); second, the power flow pf_{ij} on a line connecting i and j cannot exceed the available transmission capacity k_{ij} defined by the Transco (equation 5.13); third, the energy balance constraint ensures that demand at each node is satisfied by either local generation or net injections q_i (equation 5.14).

Again the DC-Load-Flow approach is used to derive power flows following Schweppe et al. (1988) and Stigler and Todem (2005). When the capacity k_{ij} of a line is increased, the reactance X_{ij} of that line will change as well and therefore the overall power flow pattern in the network is affected (see Section 5.3). According to the law of parallel circuits adding a second line on a connection and thus doubling the capacity will halve the lines' reactance. Assuming that the lines have a starting capacity and reactance the functional connection can be expressed as:

$$X_{ij}^t = \frac{k_{ij}^0}{k_{ij}^t} X_{ij}^0$$ line reactance and capacity (5.15)

Starting values k^0 and X^0 are given by the existing grid's topology.

In order to include the wholesale market in the profit maximization of the Transco, the power flow calculation and equation 5.15 are incorporated in the lower-level problem (equations 5.11 to 5.14). The derivation of the Karush–Kuhn–Tucker conditions of the expanded lower level problem is reformulated as a mixed complementarity problem. These first-order conditions are in turn included as constraints into the Transco's maximization besides the price-cap constraint. The problem is incorporated as MPEC into GAMS. The Transco's choice of available capacity k_{ij} has therefore a direct impact on the resulting market prices and thus on its variable income component. The locational prices p_i are derived as duals of the energy balance constraint.[82]

5.4.2 Three-node case

First the incentive approach is tested using a three-node network. Beside a base case representation several robustness test are undertaken to figure out the impact of different market characteristics on the

[82] The GAMS code is presented in Appendix VI.

Transco's investment behavior. Finally the welfare properties of the approach are compared to a benevolent planer scenario.

5.4.2.1 Basic Model Outcome

The underlying three-node network topology is the same as in section 5.3 (Figure 5.2). The topology is assumed to be given and fixed, thus only existing lines can be upgraded. Generation at nodes 1 and 2 is assumed to be unrestricted and no generation capacity is available at node 3. For simplicity the marginal costs of generation are fixed to zero. Each node i has a linear demand function $p(d_i)$. The locational price at nodes 1 and 2 will be at marginal cost level and the price at node 3 will include possible congestion charges because no local generation capacities are available.

The initial line characteristics represent a congested system. The available transmission capacity is such that node 3 faces a higher price than nodes 1 and 2. The system is assumed to be symmetric with respect to capacities and line reactances. According to its objective function (equation 5.9) the Transco is free to choose the line capacities k_{ij}. Extension costs are specified via a linear cost function $c(.)$ using a constant extension cost factor ecf:

$$c_{ij}^{t} = ecf \cdot \left(k_{ij}^{t} - k_{ij}^{t-1}\right) \qquad \text{extension cost function} \qquad (5.16)$$

As the Transco can only extend line capacity it follows that $k_{ij}^{t} \geq k_{ij}^{t-1}$.[83]

Table 5.2 summarizes the initial network characteristics (these are later relaxed to analyze the impact on the Transco's extension behavior). The time framework is 10 periods. Regarding the price cap a classic chained Laspeyres approach is assumed, weighing the current period's prices with the previous period's quantities ignoring inflation or efficiency targets:

$$\frac{\sum_{i} (p_i^t d_i^{t-1} - p_i^t g_i^{t-1}) + F^t}{\sum_{i} (p_i^{t-1} d_i^{t-1} - p_i^{t-1} g_i^{t-1}) + F^{t-1}} \leq 1 \qquad \text{Laspeyres cap} \qquad (5.17)$$

The number of consumers N is considered to be constant over all periods and normalized to 1, and the initial fixed fee is equal to 0.

Given these conditions the approach shows an investment pattern that reduces the price at node 3 over time close to the marginal costs of generation (Figure 5.7). The obtained final price pattern represents the point where the per-unit marginal cost of new transportation capacity equals the expected congestion cost of not adding an additional unit of capacity. Given the initial grid conditions, providing an additional MW unit at node 3 decreases the nodal congestion price difference by 1 €. Thus, after the capacity expansion there will be an increased demand satisfied (in one MW) but at a reduced price (in one 1 €). To this new income the Transco still subtracts the extension costs (of 1 €

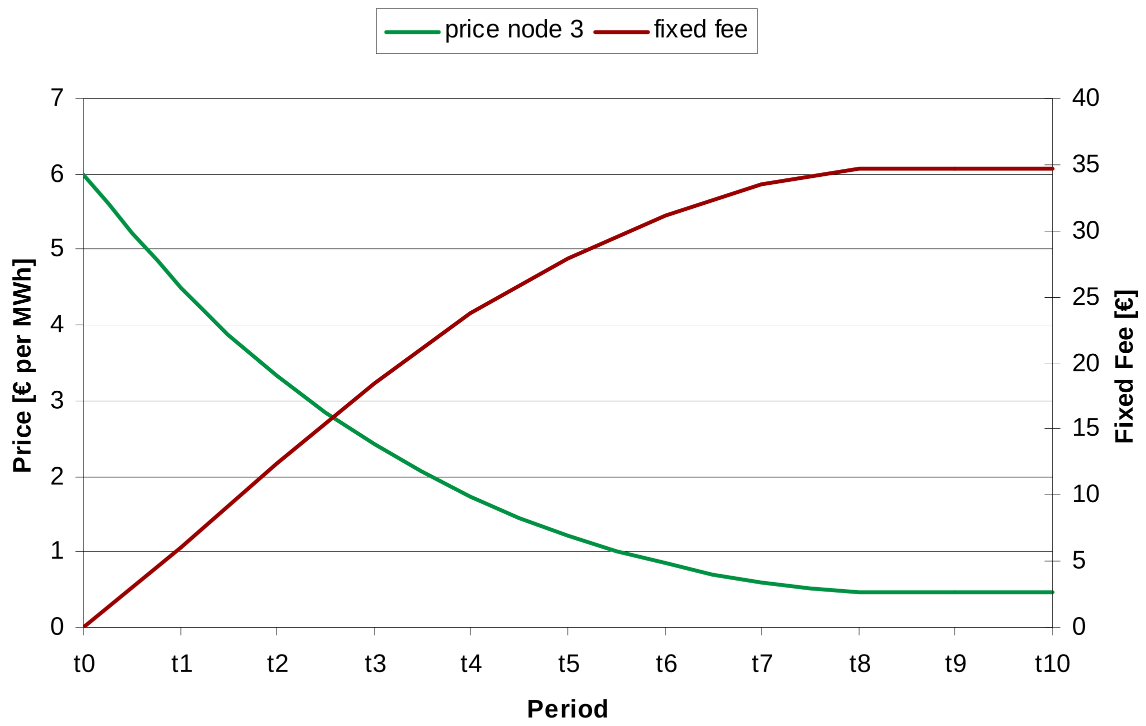
[83] The possibility of reducing capacity with the given formulation presents two problems. First, reduction of capacity would also be costly; thus at 0 the function would have a kink. Second, following equation 5.15 the line's reactance increases with each reduction converging to infinity if the line is completely taken out (capacity k_{ij} set to 0). This may result in infeasible solutions due to numerical limitations of the modelling software.

per MW). The new profit is however further positively counterbalanced by the Transco via the fixed fee *F*. This rebalancing behavior is precisely the one that promotes successive grid extensions through time.

Compared to the initial congested grid conditions the consumer rent increases by about 35% in period 10 due to the reduced prices and increased demand. Likewise, the Transco's profit increases due to the balancing of congestion revenues and the fixed fee. If the Transco does not expand the grid, its profits would be 30% lower.

Due to the symmetry of the network characteristics the extension pattern is not a fully unique solution. The loop-flowed line 1 is never subject to expansions[84] and the Transco increases the capacities of line 2 and 3 each period by decreasing amounts. Although the total amount of expanded capacity in each period is unique, its distribution to either line 2 or 3 is not unique and can vary with each model run. This occurs because the cost factors and initial line parameters are similar for both lines, and have symmetric generation structures at nodes 1 and 2.

Figure 5.7: Price and fixed fee development for the base case



Source: Own calculation, based on Rosellón and Weigt (2008)

[84] Rebalancing the injections at nodes 1 and 2 produces counter flows that keep the power flow on line 1 stable, this implies that there is no need to expand.

Table 5.2: Initial network characteristics

	line1	line2	line3
Extension cost	*ecf = 1*		
Initial capacity	2 MW		
Initial reactance	1		

	n1	n2	n3
Demand	$p(d_i) = 10 - d_i$		
Generation costs	$mc_i = 0$		n.a.

Source: Own calculation

5.4.2.2 *Tests for Robustness*

To analyze the impact of the underlying assumptions on the model outcome the base case parameters are adjusted sequentially:

Initial line capacities: In the base case a congested system with 2 MW of capacity on each line is assumed. If the initial capacity is decreased or increased by the same amount on each line the general results do not change. The price and extension patterns resemble the base case, although with different absolute levels. If the symmetry assumption is relaxed and the initial capacity of either line 2 or 3 compared to the other lines is increased, the obtained price pattern resembles the base case outcome although the absolute values are lower as the initial congestion is reduced. The largest expansion occurs on the line with the lower initial capacity.

Initial line reactance: The reactances define how the power flow “splits” on each line. Increasing the reactance of one line compared to the rest of the grid reduces the power flow share on that line and increases the flow on the others. However, changing individual line reactances does not alter the basic results compared to the base case with respect to prices.

Line extension costs: In the base case all lines have similar expansion cost factors *ecf*, also meaning that line lengths are equal. Increasing the *ecf* for either line 2 or 3 does not alter the price pattern compared to the base case, because the entire grid expansion is focused on the cheaper line. Increasing the reactance of the more expensive line to resemble the length increase has no impact on the observed outcome.

These results suggest that altering the network assumptions under the given simplified grid topology has no major impact. The observed gradual grid expansion remains stable reducing congestion within the system and thus the price at node 3 leading to an increase in consumer rents and the Transco’s profit.

In addition to the initial value of line parameters, changes in the assumptions about generation, demand, and the length of the observation period may have an impact on the model outcome:

Generation costs: Given that most electricity markets face a variety of generation technologies, the Transco must consider the price structure since it has a large impact on the resulting power flows. Increasing the generation costs at node 2 in the model leads to a new price pattern (now node 2 faces a price different from zero). The possibility to satisfy the demand at node 2 with cheaper generation from node 1 by increasing the grid’s capacity means a higher transmission volume. A large fraction of local generation at node 2 will be replaced by injections from the grid which in turn increases the Transco's profits. The results confirm these assumptions. A significantly larger capacity extension amount and higher profits for the Transco are observed. Prices at nodes 2 and 3 gradually decrease whereas prices at node 3 behave identically to the base case.

Generation capacities: Plant availability also plays an important role. If cheaper generation is already at its maximum capacity limit, additional transmission capacity may not increase the transmission volume. To model this scenario the capacity of the cheap generation at node 1 is reduced to 15 MW while keeping the more expensive generation at node 2 unrestricted. Although the initial market outcome is the same as in the upper-level case it is not expected that the Transco will increase the network capacity significantly since only a limited amount of additional transmission will occur, thus resulting in a lower profit. The results confirm the assumptions; the prices at nodes 2 and 3 drop but remain higher than in the cases without generation capacity restrictions, and the profit is lower as the transported energy decreases. The price at node 1 increases as the network is extended, bringing all prices together.

Demand behavior: The initial demand function represents a relatively elastic consumer behavior. In the short term the demand for electricity is inelastic, and thus congestion can lead to significantly higher prices without altering the transported energy in large amounts. Therefore the demand function is changed to $p(d_i) = 1000 - 10d_i$, while the remaining parameters are kept as in the base case. The results show that although the absolute values are significantly higher, consumers still have an equivalent price decrease. Thus the increased congestion rent due to the more inelastic demand does not change the incentives for the Transco to relieve congestion.

Number of periods: The limited time frame of the model as well as missing depreciation of future payments can bias the outcome. Extending the time frame to 100 periods shows a much slower price decrease than in the 10-period case. However, this result is caused by the missing depreciation as current and future payments are weighted equally by the Transco. Introducing depreciation into the model reduces the impact of the considered number of periods. The higher the depreciation the more rapid the investment since future earnings are weighted less by the Transco.

5.4.2.3 Welfare Properties

To determine whether the results produced by the model also imply desirable welfare increases it is compared to a model where a benevolent welfare-maximizing ISO administers the line capacities as choice variables. In this model, the Transco is omitted from the formulation and the basic market clearing equations are extended. Thus network extensions become part of the welfare objective function:

$$\max_{d,g,k} \quad W = \sum_{i,t} \left(\int_0^{d_i^t} p(d_i^t) \mathrm{d}d_i^t \right) - \sum_{i,t} mc_i g_i^t - \sum_{i,j} c\left(k_{ij}^t\right) \text{ ISO objective function} \qquad (5.18)$$

s.t. equations (5.12) to (5.15)

Two robustness tests are presented in detail: asymmetric generation costs with limited generation capacities and asymmetric generation costs with unlimited generation capacities. The remaining results show a similar general behavior although with different absolute values.[85] Table 5.3 summarizes the outcomes comparing the base case of no grid extension, the case of capacity extension under the regulatory approach, and the case of a benevolent ISO. The non-extension case represents the initial network conditions; thus congestion and prices are the highest. In the case of the regulatory mechanism, an increase in consumer surplus and in the Transco's profit, and a decrease of the congestion rents and nodal prices is observed. The results of the regulatory approach are relatively close to a pure welfare-maximizing outcome and suggest a convergence over time towards the welfare optimum. Furthermore, the case with limited generation capacities shows a common outcome in the case of congested markets: if congestion is relieved, prices converge to a common level and thus areas with initially low prices may afterwards face higher prices due to increased export. This may be of particular concern when implementing the approach in existing markets.

Given the simplified topology of a three-node network the approach has robust welfare-enhancing properties. Although the absolute values of prices, rents, and capacities change by varying the assumptions, the Transco is incentivized to expand the grid in a way that market prices converge towards the welfare optimum.

Table 5.3: Comparison of regulatory approach with welfare maximization (values refer to the last period: t10)

	Asymmetric generation costs, limited generation capacities			Asymmetric generation costs, unlimited generation capacities		
	No grid extension	Regulatory Approach	Welfare maximization	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	98.50 €	142.93 €	148.01 €	98.50 €	118.85 €	120.61 €
Producer rent	0.00 €	0.00 €	0.00 €	4.35 €	13.46 €	15.00 €
Congestion rent	22.00 €	6.93 €	1.98 €	22.00 €	4.10 €	1.98 €
Total welfare	120.5 €	149.9 €	150.0 €	124.9 €	136.4 €	137.6 €
Extension sum	-	4.59 €	4.90 €	-	15.28 €	15.80 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	9.75 MW	9.90 MW
Capacity: line 2	2.00 MW	5.90 MW	6.00 MW	2.00 MW	9.53 MW	9.90 MW
Capacity: line 3	2.00 MW	2.70 MW	2.90 MW	2.00 MW	2.00 MW	2.00 MW
Price: node 1	0.00 €	0.90 €	1.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	1.00 €	1.00 €	1.00 €	1.00 €	0.25 €	0.10 €
Price: node 3	6.00 €	1.41 €	1.10 €	6.00 €	0.47 €	0.10 €

Source: Own calculation

[85] A list of results is presented in Appendix VII.

5.4.3 Application to a Real-world Network

5.4.3.1 Model and Data

Following the insights obtained in the previous sections are tested by applying the approach to a more realistic representation of an existing electricity network with a diversified generation park. Figure 5.8 illustrates the simplified grid of North West Europe connecting Germany (D), the Benelux, and France (F) based on Neuhoff et al. (2005). The model consists of 15 nodes and 28 lines. The nodes connecting France and Germany with their neighbors are auxiliary nodes without associated demand or generation. The lines connecting the German and French nodes with these auxiliary nodes are assumed to have unlimited capacities. Thus intra-country congestion in those two countries is not considered in detail. Each country node has given generation capacities (VGE, 2006) and a reference demand (UCTE, 2007). There are eight generation technologies, with identical cost structures in all countries for each type. With the exception of hydro power, renewable generation is not considered within the model. Table 5.4 gives an overview of the types, installed capacities, and marginal generation costs. A linear demand behavior at the nodes is derived from the average load level for the node, a reference price of 30 €/MWh, and an assumed price elasticity of 0.25 at that reference point.

The model formulation used for the application to the European network is similar to the previous three-node approach. The time frame is extended to 20 periods and includes a depreciation factor with an interest rate of 8%.[86] Inflation or an efficiency factor within the Transco's price cap are not included. The derived market results for one time period represent one hour; thus the Transco's revenue is multiplied by 8,760 for each period to resemble yearly incomes. Due to the average nature of both the load level and the generation structure, this approach omits the variable nature of real-world electricity systems. Line expansion costs are assumed to behave linearly. Following Richert and Brakelmann (2004) and DENA (2005), the extension value is around 100 € per km per MW.[87] The Transco can only expand already existing lines.

The starting conditions in the market are classified by a high price level in the Netherlands (Krim, Maas, Zwol), a divided price structure in Belgium (Gram, Merc), modest prices in Germany, and low prices in France. Thus, congestion occurs between Belgium and France as well as between Germany and the Netherlands.

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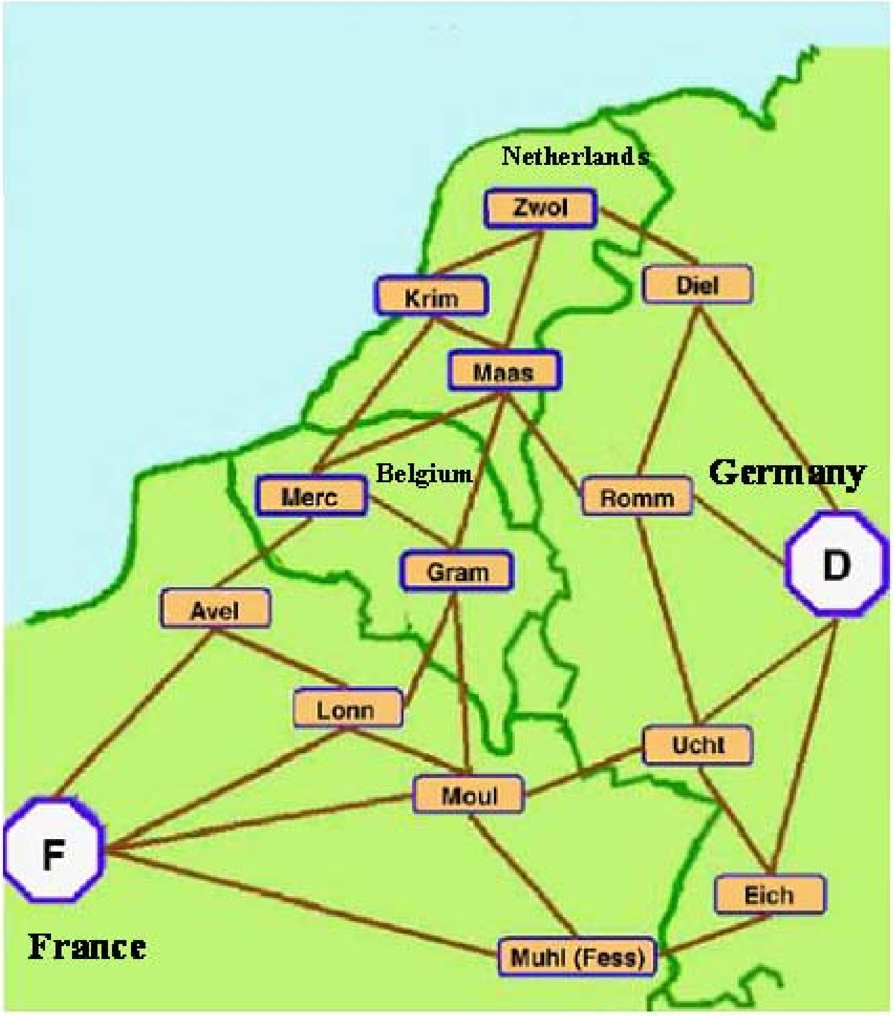
[86] 20 years are supposed to represent the depreciation time of assets in electricity markets and 8% represent an investment with rather low risk.

[87] This value is derived from upgrade costs for additional lines of the same voltage level, and upgrades from 220 kV to 380 kV. The lumpy character of network investments is omitted.

Figure 5.8: Simplified grid of North West Europe



Source: Neuhoff et al. (2005)

Table 5.4: Plant characteristics

Plant type	Installed capacity	Marginal generation cost	Plant type	Installed capacity	Marginal generation cost
Nuclear	83 500 GW	10 €/MWh	**Steam**	28 000 GW	45 €/MWh
Lignite	21 000 GW	15 €/MWh	**Gas turbine**	5 500 GW	60 €/MWh
Coal	51 250 GW	18 €/MWh	**Hydro**	17 000 GW	0 €/MWh
CCGT	18 500 GW	35 €/MWh	**Pumped storage**	13 000 GW	28 €/MWh

Source: VGE (2006), own calculations

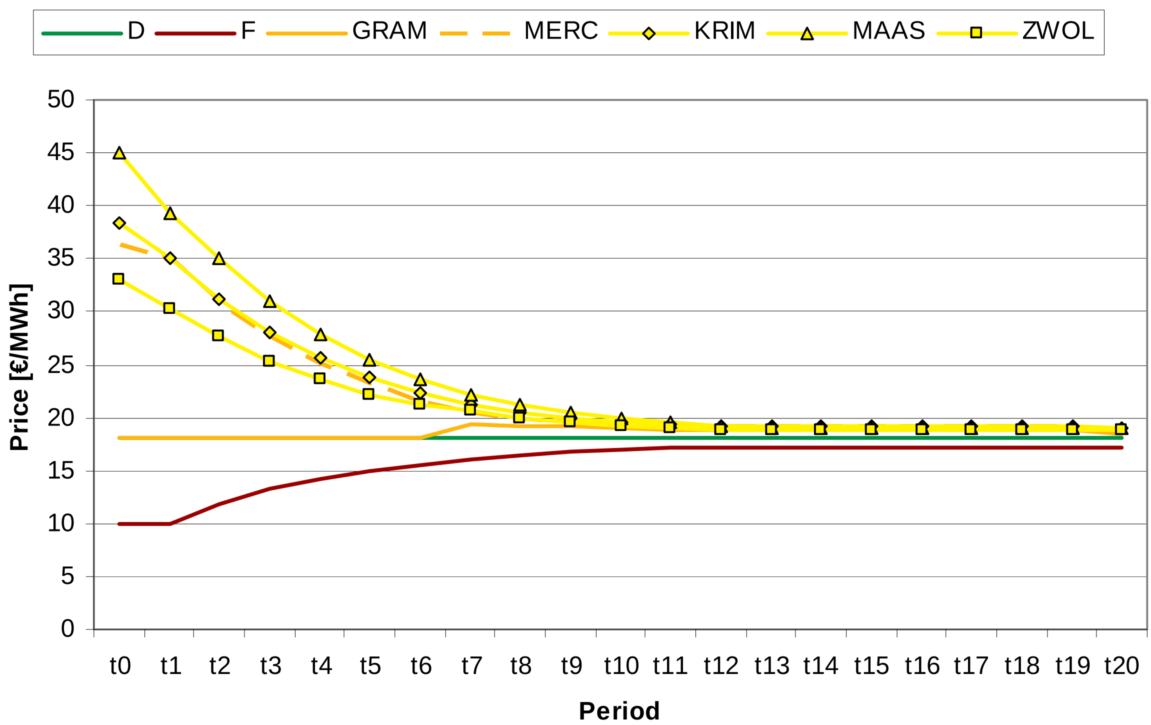
5.4.3.2 Results

To classify the obtained results they are compared to a case without grid extension (the starting conditions) and a benevolent ISO. Figure 5.9 shows the price developments at the country nodes over the considered periods. Given an initially high price divergence in the market they gradually converge to a common price level resembling the marginal cost of the last running unit. However, the price convergence already occurs within the first 10 periods. In the second half of the considered time frame the prices change only marginally, and additional expansions are relatively small.

Comparing the welfare components shows a convergence of the regulatory approach towards the welfare optimum (Table 5.5). However, even though the overall welfare increases, consumer surplus decreases, due to the increased prices that French consumers must pay. In the initial grid case, congestion separates the French market from the remainder of the grid. Thus, the prices go down to marginal costs of local nuclear units resulting in the lowest price in the market. If the grid is expanded, more of the available French nuclear power is utilized to satisfy demand at other nodes, and the price in France increases, thus reducing consumer surplus. This reduction cannot be offset by the lower prices in the Benelux because the demand in France is higher than the total demand in the Benelux. However, the decrease in consumer rent is compensated by a significant increase in producer rent. The largest fraction of the additional company profit will benefit France since the nuclear generation is now priced above their marginal costs.

The grid expansion totals about 300 mn € within the 20 periods (Table 5.5), a relatively small amount given the market's total welfare of 10 bn € per year. This is mainly due to the assumption that the grid upgrades that do occur will be less expensive than entirely new connections. However, the total new installed capacity increases significantly, doubling the initial available grid capacity. The Transco's profit over all 20 periods is about 25% higher under the regulatory approach than if it would not have extended the grid at all and just collected the initial congestion rent in all periods.

Figure 5.9: Price development in the European model



Source: own calculations

Table 5.5: Comparison of regulatory approach with welfare maximization (values refer to the last period: t20)

	No grid extension	Regulatory Approach	Welfare Maximization
Consumer rent [Mio€/h]	10.37	10.31	10.30
Producer rent [Mio€/h]	0.65	0.99	1.02
Congestion rent [T€/h]	107.8	20.20	7.13
Total welfare [Mio€/h]	11.13	11.32	11.33
Total extension sum [Mio€]	-	285.27	305.26
Total grid capacity [GW]	33.4	60.9	62.64
Average price [€/MWh]	28,4	18,5	18,1

Source: own calculations

5.5 Conclusion

In this chapter the problem of securing investment into transmission capacity is investigated applying numerical modelling techniques to cope with the loop flow characteristic of meshed electricity networks. Whereas optimal regulatory or market based approaches for investment are common knowledge in economic theory the main problem of electricity markets is their combination of negative and positive external effect in transmission and the physical nature of electricity transport which complicates a clear cost allocation. The specific nature of transmission investments is analyzed by applying a cost minimizing approach given an external transport demand. The results show that electricity markets are subject to non-linear correlations between investment costs and transmission capacity. In particular even in simple network setting it is possible that an increasing transport demand can be satisfied more cheaply than a smaller demand. However, this correlation is not stable and depends on the specific network characteristics.

A possible solution to the investment problem is presented by implementing a regulatory mechanism as an MPEC problem with a profit-maximizing Transco subject to a price cap and a competitive wholesale market based on nodal pricing and FTRs. The results show that the Transco expands the network and that prices converge towards marginal costs over the periods. The mechanism holds promise for real-world practice. Implementation could be carried out relatively easily and at low cost, providing considerable increases in social welfare, congestion relief, and profits for firms. Electricity markets with different institutional settings would only need reliable information on nodal prices. Additional research should demonstrate the robustness of the obtained results including the extension of the model structure to consider myopic behavior, varying weights in the price-cap constraint, employing variable pricing mechanisms (particularly zonal pricing), and examining the impacts of additional Transcos within a single network.

6 Summary, Conclusion, and Further Research

"Essentially, all models are wrong, but some are useful"

credited to George E. P. Box

This thesis focuses on modeling competition and investment in liberalized electricity markets. In this concluding Chapter I summarize the main finding, discuss some policy implications and sketch out topics for further research.

6.1 Summary and Conclusion

In this thesis three model approaches have been developed to analyze specific issues in liberalized electricity markets. As every scientist relying on models I can indeed claim that all the presented models are “wrong”. Of course, they are formulated correctly, and also the solving process is (in the limits of numerical modeling) correct. However, the aim to represent real electricity markets can never be reached as simplifications are necessary to remain a solvable model structure.

In Chapter 3 an optimization model is developed to obtain a competitive price benchmark for the German electricity wholesale market between 2004 and 2006 to estimate markups due to market power abuse. The 2004 and 2005 analysis is subject to simplifications due to the limited available data. The analysis is based on 24 days and neglects important market features like unit commitment restrictions. For the 2006 analysis the applied model captures unit commitment processes and the underlying dataset allows a detailed representation of the generation and demand side for each of the 8760 hours during the year. Nevertheless, important features like uncertainty and daily variations of fuel prices and plant availabilities are not included. Thus the obtained benchmark prices are only a “good” estimate of what one could expect in a perfect competitive market environment on average and may provide misleading conclusions when looking at a specific hour.

So is the carried out analysis useful? Several robustness test highlight that the observed and simulated market outcomes diverge by large degrees in quantity terms. On average the capacity gap is larger than 10 GW which represents about 15% of the peak demand levels. Furthermore, the analyses show that high price levels above marginal generation costs often occur during mid-load levels (a general price divergence of about 10 €/WMh is obtained for more than 2000 h). Thus, although the underlying models are not capable to fully reproduce a competitive market environment, the obtained price patterns hint on divergences during market periods that are not primarily considered to be subject of market power abuse and may require further investigation from regulatory side. In addition the analysis also highlights the current market situation with significant overcapacities making further investments into generation unprofitable.

The two strategic models applied in Chapter 4 to investigate divestiture scenarios in the German market are also "wrong" by definition. Due to the restrictive nature of the SFE approach the applied costs structure via a cubic cost function can not capture the complexity of real world electricity markets. In addition, the assumed linear demand behavior, unrestricted import availability and stylized competitive fringe behavior adds to the error. And consequently the Cournot approach suffers the same drawbacks as it applies the same simplifications for the sake of comparability. So again, are the simulations at least useful? The are several important insights gained. First, the impact of a divestiture in the German electricity market seems to be quite large with an estimated welfare increase up to 3 bn € per year. Although this number is subject to the before mentioned restrictions it shows a high potential of this pro-active competition policy tool which justifies its principal threat of application even in the German market setting. Second, the comparison of a divestiture to establish a wider six firm oligopoly with a pure sell out to small competitive companies hints at the potential gains a well founded divestiture policy can provide. Given that in both cases the same assets are divested the divergence of price and welfare results is significant favoring the sales to smaller firms. And finally, the analysis also shows that both strategic model approaches perform equally once calibrated to the underlying dataset.

And last but not least also the model approach presented in Chapter 5 to analyze the regulatory incentive scheme for transmission companies is no more than a stylized representation of the real world. The application of a regulated two part tariff system to allow for a rescheduling of congestion rent and fixed cost recovery represents a complicated class of mathematical models (a MPEC) and thus is not yet applicable for large datasets. Therefore, the analysis is restricted to highly simplified market structures. In addition, the three-node example and the cost function simulations are not designed to represent a real market environment but to highlight the complexities of electricity transmission and resulting problems. So finally, how useful can such a simplified simulation prove? The effort shown in this thesis was the first necessary step to allow further research regarding practical implementation and interaction in a more flexible environment. Up to now, the regulatory approach initiated by Vogelsang (2001) has only been analyzed theoretically or without the full underlying complexity of electric power flows (Hogan et al. 2007). The results of my simulation show that the approach can prove welfare improvements given the characteristics of electricity networks and thus a major obstacle has been overcome. Whether the approach still represents a proper solution once additional real world market complexities like different ownership structures and interfering generation investments are included is subject to further research. But if these first stylized test would have shown the incapability of the approach any further analyses would be obsolete.

6.2 Further Research

There are a couple of related issues that have not been covered in this thesis. As is evident from Chapter 2 liberalized electricity markets provide a wide array of research questions that can be assessed by modeling techniques ranging from ex-post market analyzes to theoretic market design questions. Regarding the competitiveness of wholesale electricity markets and possible policy measurements the basic research framework is well developed. The main point to pursuit is the development and implementation of a proper market design and a consequent market monitoring to prevent possible market power abuse. Thus future research will focus on governmental and regulatory support to enhance the exiting market frameworks. Regarding network investments and regulation the debate about a proper mechanism is still ongoing (see Chapter 5). The US markets are discussing about potential beneficiary-pay approaches whereas the European markets are still strolling with a proper cross-border coordination.

Beside those two directions related to the work presented in this thesis following two further topics are shortly discussed in more detail: the integration of wind energy in electricity networks and the interaction of generation and network investments.

6.2.1 Wind Integration

Within the last years wind energy has become one of the fastest growing renewable energy technologies. However, the intermitted nature of the wind output is a challenge for electricity market design, system operation, and network extension. The Chair of Energy Economics and Public Sector Management (EE^2) has developed a model of the European electricity market(s) based on a DCLF, called ELMOD to address these topic and conduct a series of research papers.[88]

Leuthold et al. (2005) analyze the implication of additional wind supply into the German high-voltage grid showing that a nodal pricing scheme provides a welfare increases between 0.6% and 1.3% or about 350 Mio € per year compared to the reference uniform prices German market system. Weigt et al. (2006) extends this analysis and models the effects of nodal pricing in combination with increased wind energy on the North-Western European grid. They point out that even under status quo conditions, the price situation in Benelux is affected by high wind input in Germany.

The need for grid investments due to wind extension and cross-border bottlenecks is not only a German problem but the whole UCTE grid will have to be extended if the European Union wants to fulfill its aim of firstly obtaining a single integrated market and secondly integrate a large share of distributed renewable energy sources. Leuthold et al. (2009) focus on large-scale wind integration in a European context with a particular focus on efficient grid extension measurements. They develop a grid-extension algorithm to extend the grid incrementally until an economically optimal grid status is identified that is capable of carrying the additional wind. They show that extending the network at existing bottlenecks – mainly cross-border connections – should be encouraged by regulatory authorities. With a more moderate wind expansion of 114.5 GW till 2020, the optimal grid investments are even smaller due to resulting counter flows. However, if the additional wind capacity

[88] A detailed description of ELMOD is provided in Leuthold et al. (2008).

becomes too great (181 GW), the needed grid extensions will increase compared to the actual situation.

The nest research steps are to analyze the interaction of fossil back-up and wind generation on the market side (prices and volatility) and on the investment side, as well as the coordination of large scale intermitted energy sources across Europe and beyond (e.g. solar energy from Africa) with demand centers and pump storage facilities via a high voltage direct current system.

6.2.2 Substitutability between Generation and Transmission Investment

Another research topic to be addressed is the interaction between generation and network investments and the necessary market design to avoid double investments. Whereas in the pre-liberalization years this process was carried out by vertical integrated companies the liberalized markets will yet have to proof that they can handle this task. This topic combines several research areas including the concern of generation investment planning, network modeling, and network investments and regulation.

A first step has been made by Dietrich et al. (2009). They model investment behavior of power plants in the German market up to the year 2012 based on realistic data of planned generation investments and analyze where in the current scheme new investment in generation is most likely to take place and compare these results to an optimal investment pattern taking into account network capacities. The analysis is carried out for different assumptions regarding market representation including a national focus on Germany, a market coupling setting, and a fully integrated European market. The results indicate that new generation capacities are not needed in Germany but in the Benelux area. Their paper demonstrates that great benefits for consumers and producers can be created when physical network restriction are taken into account within a real integrated market. The approach takes the network as given. The next step would be to combine network and generation investment within a market framework. The crucial issue is the timing of investments as additional power plants may render a new line unprofitable and vice versa.

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Appendix

Appendix I: Price Curves 2004-2005 (Chapter 3)

Figure X: Observed and modeled prices January – April 2004

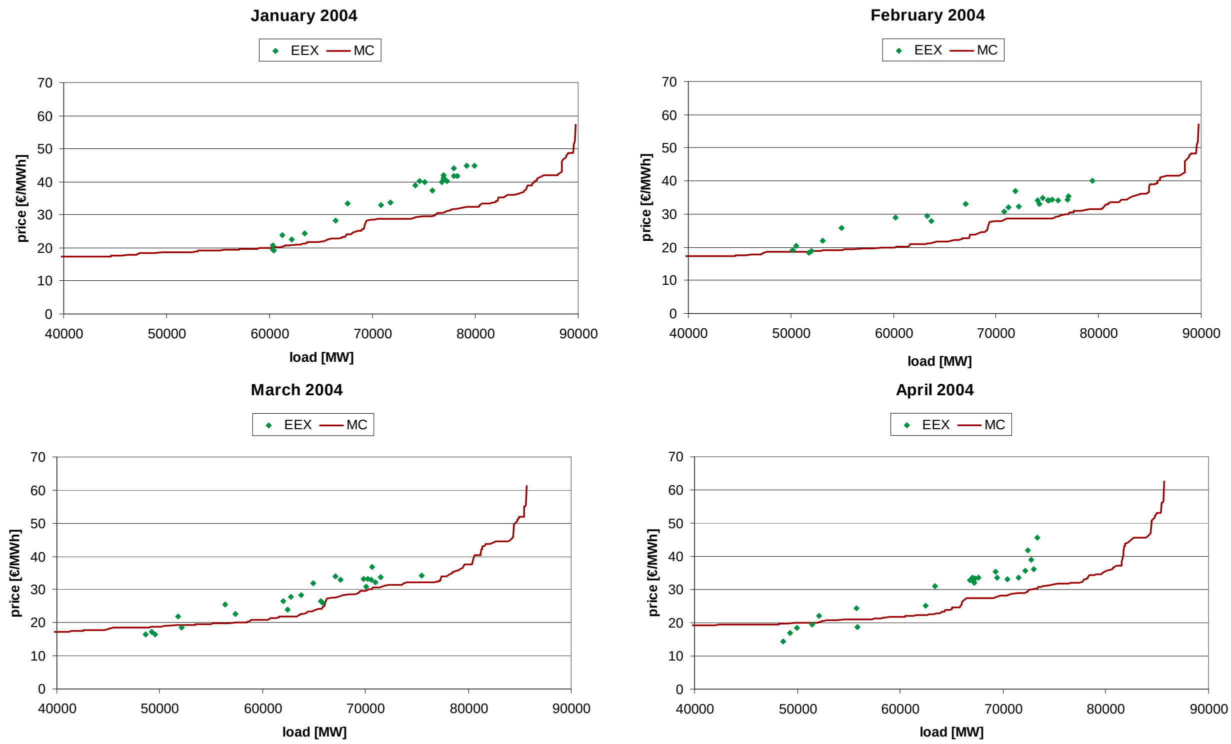


Figure XI: Observed and modeled prices May– August 2004

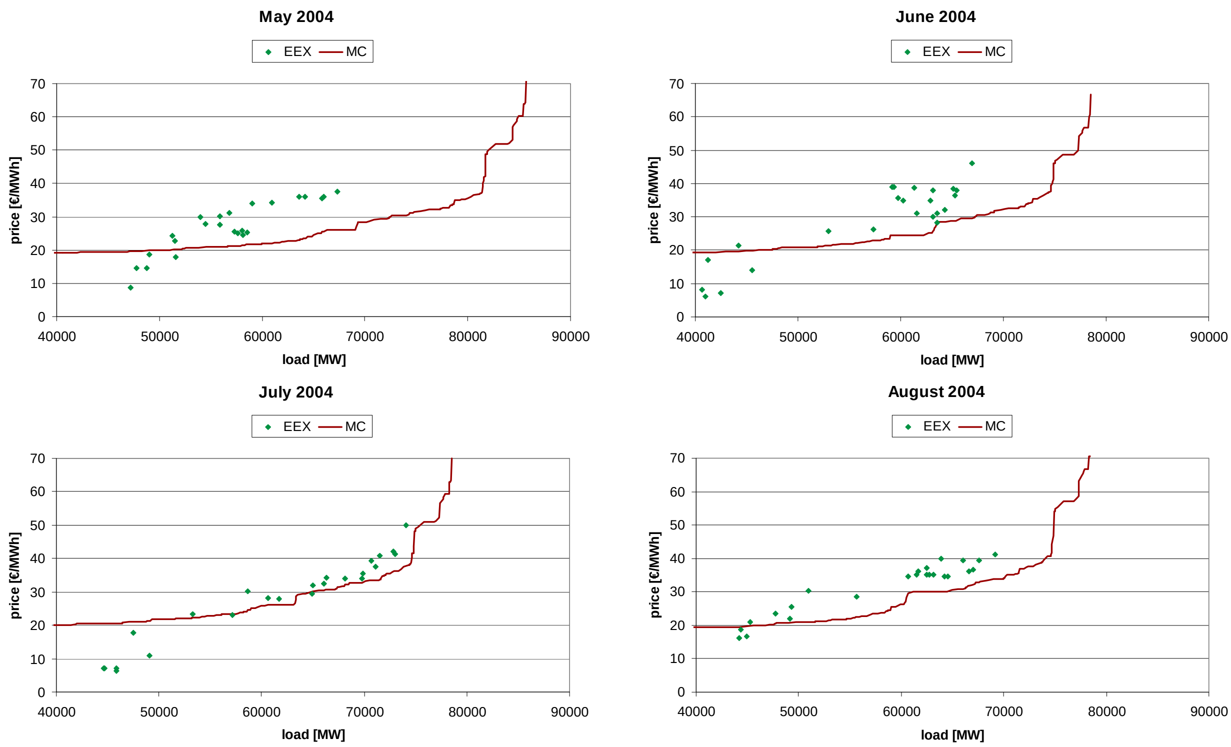


Figure XII: Observed and modeled prices September– December 2004

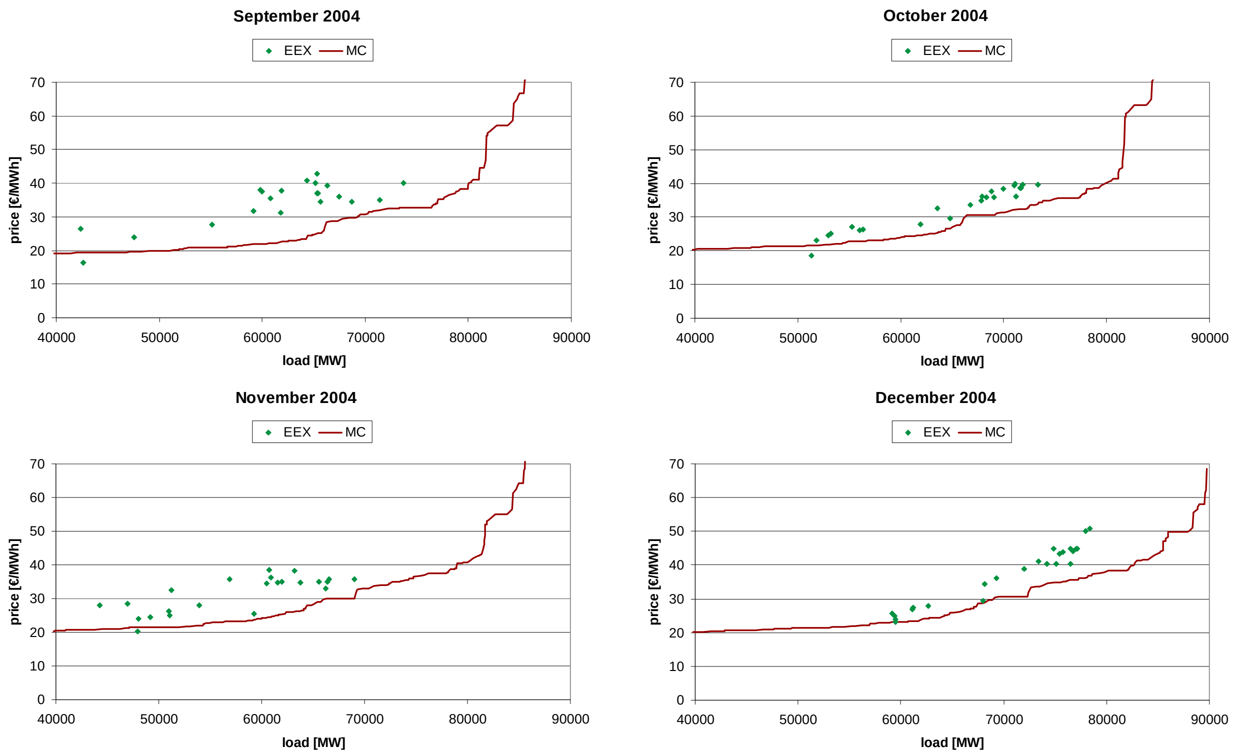


Figure XIII: Observed and modeled prices January – April 2005

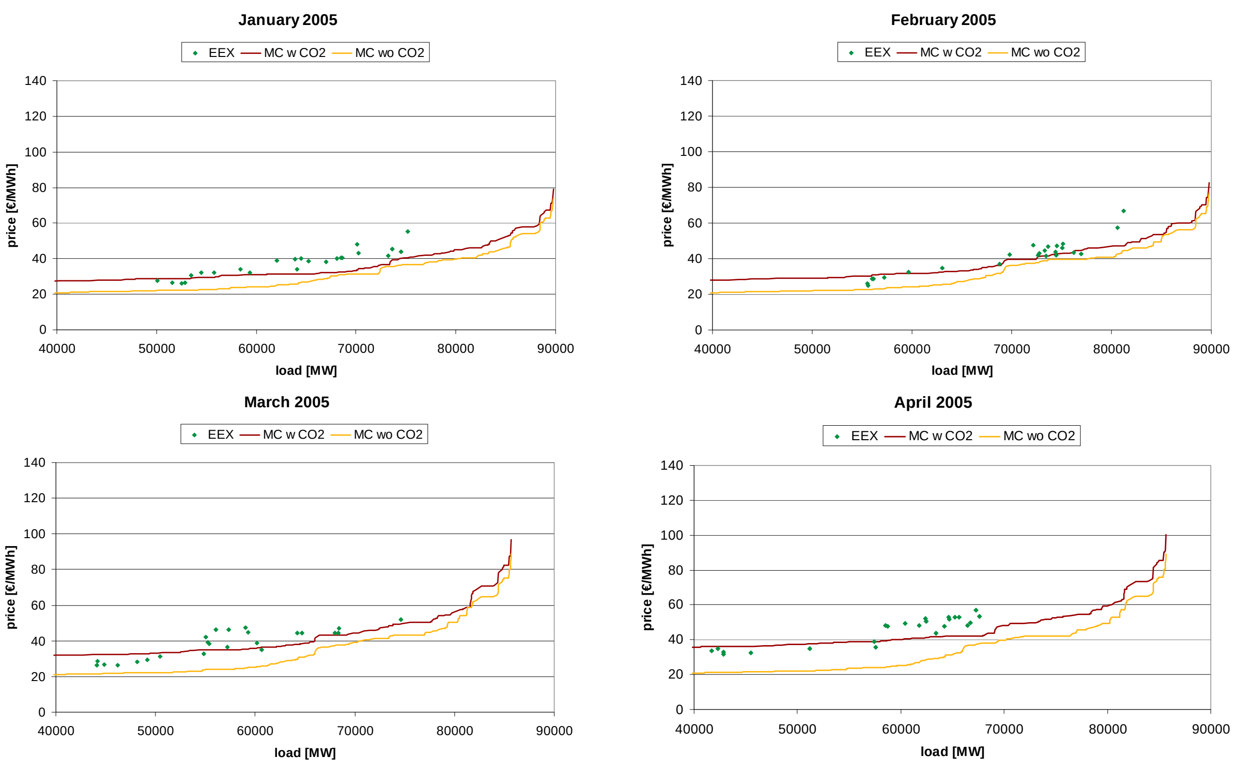


Figure XIV: Observed and modeled prices May– August 2004

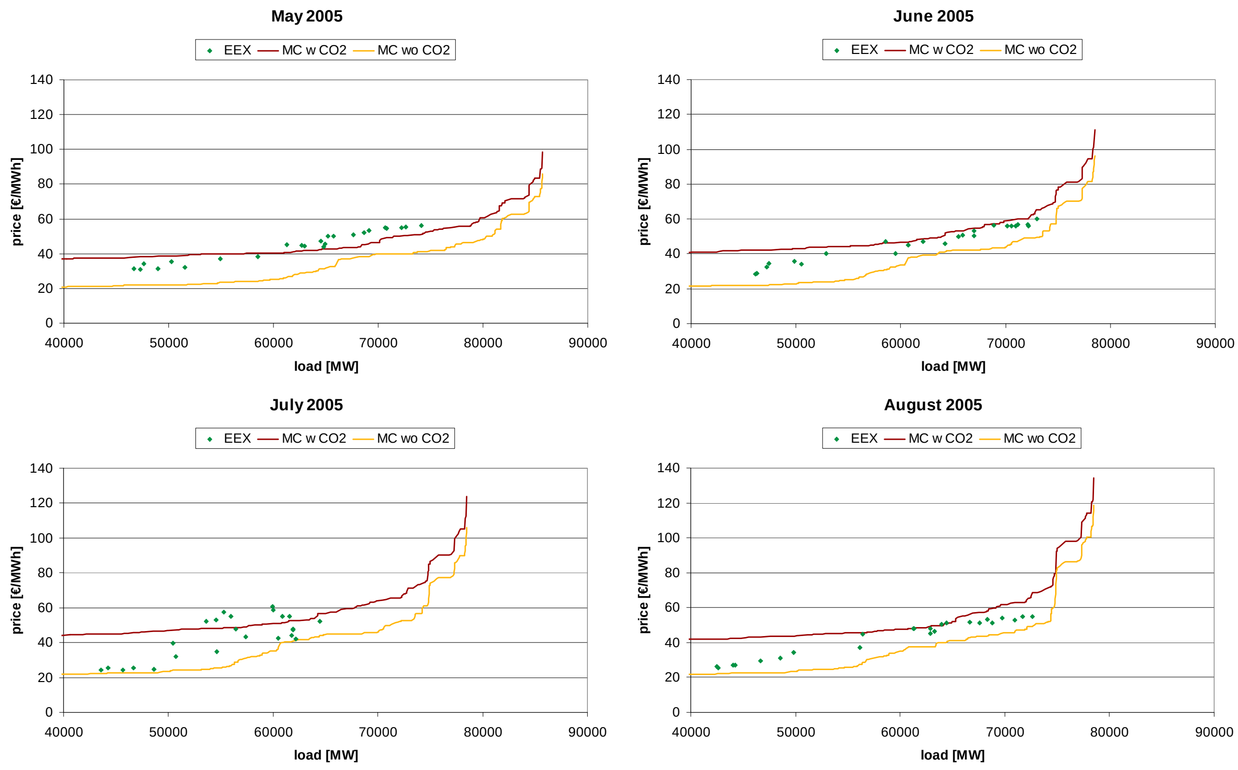
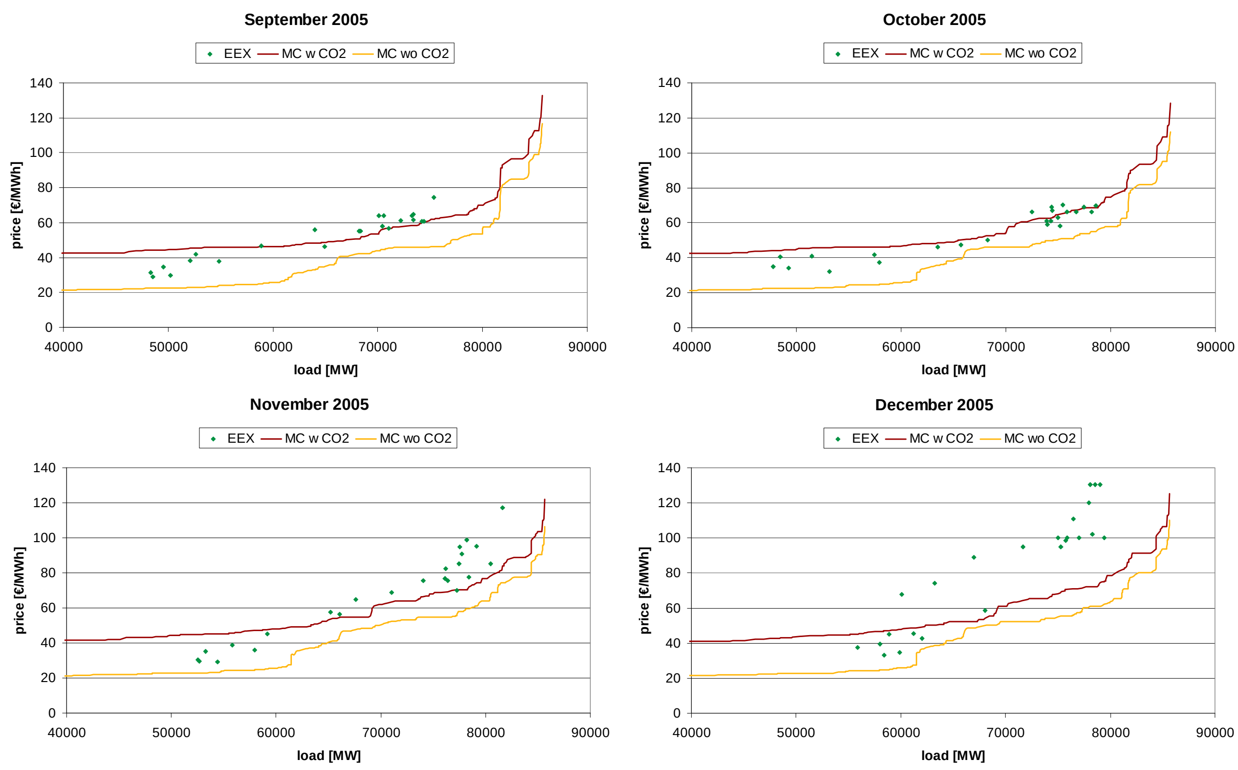


Figure XV: Observed and modeled prices May– August 2004



Appendix II: GAMS Code Market Power Model for 2006 (Chapter 3)

```
*------------------------------------------------------------------------------*
*                             declaration of sets                              *
*------------------------------------------------------------------------------*

Sets
p                plant number
nuc(p)           nuclear plants
lig(p)           lignite plants
coal(p)          coal plants
steam(p)         oil and gas steam plants
ccgt(p)          ccgt plants
gt(p)            gas turbines
hydro(p)         hydro plants
pump(p)          pump storage plants
kwk(p)           combined heat and power plants
oil(p)           oil fired plants (regardless if ccgt or steam or gt)
gas(p)           gas fired plants (regardless if ccgt or steam or gt)
t                time
tfirst(t)        first time period
;

*------------------------------------------------------------------------------*
*                             declaration of scalars                           *
*------------------------------------------------------------------------------*

Scalars
kwkfactor        load factor of chp plants
;

*------------------------------------------------------------------------------*
*                             declaration of parameters                        *
*------------------------------------------------------------------------------*

Parameters
marginalcosts(p,t)      generation costs of plants
fuelcosts(p,t)          generation costs without emissions
gmax(p)                 maximum capacity
gmin(p)                 minimum capacity
eff(p)                  efficiency of a plant
price(p,t)              price of the fuel used by p in t
co2(p)                  co2 emissions of a plant
co2price(t)             co2 emission allowance price in t
pumpmax                 sum of all pump storage plants
demand(t)               demand in Germany
season                  seasonality
startup(p,t)            start up costs per MWh depending on fuel price in t
opcosts                 operation costs
eex(t)                  EEX prices in t
;

*------------------------------------------------------------------------------*
*                             Variables                                        *
*------------------------------------------------------------------------------*

Variables
costs           overall generation expanses
;

Positive Variables
startupcosts
gen(p,t)        generation of plant p at time t
PSPdown(t)      Pump storage generation
PSPup(t)        Pump storage "pump it up"
PSP             Pump Storage level
;

Binary Variable
status(p,t)     plant condition (1=on 0=off)
;
```

```
*---------------------------------------------------------------------------*
*                                Equations                                  *
*---------------------------------------------------------------------------*

EQUATIONS

objective                total cost function
linobjective             total costs excluding startup costs
energybalance            demand = generation
genmax                   upper limit for generation
genmin                   lower limit for generation
startupc                 calculation of startup costs
PSPcapacity              pump storage level
PSPcapacitystart         pump storage starts with an empty storage
PSPupdown                1st capacity constraint for PSP
PSPupdown2               2nd capacity constraint for PSP
shutdown_li_1h           startup constraints for lignite
shutdown_li_2h
shutdown_li_3h
shutdown_li_4h
shutdown_li_5h
shutdown_li_6h
shutdown_li_7h
shutdown_co_1h           startup constraints for coal
shutdown_co_2h
shutdown_co_3h
shutdown_steam_1h        startup constraints for steam
shutdown_steam_2h
shutdown_cc_1h           startup constraints for ccgt
;


objective..            costs =e=
                       sum((p,t)$gmax(p), marginalcosts(p,t)*gen(p,t))/1000000
                       + sum((p,t)$startup(p,t), startupcosts(p,t))/1000000
;
linobjective..         costs =e= sum((p,t)$gmax(p), marginalcosts(p,t)*gen(p,t))/1000000
;
energybalance(t)..     demand(t) + PSPup(t) =e= sum(p,gen(p,t)) + PSPdown(t)
;
genmax(p,t)..          gen(p,t) =l= status(p,t)*gmax(p)
;
genmin(p,t)$gmin(p).. gen(p,t) =g= status(p,t)*gmin(p)
;

startupc(p,t+1)$startup(p,t)..   startupcosts(p,t+1) =e=
                                  sqr(status(p,t)- status(p,t+1))* startup(p,t+1) * gen(p,t+1)
;

*PSP system
PSPcapacity(t+1)..               PSP(t+1) =e= PSP(t) + 0.75*PSPup(t) - PSPdown(t)
;
PSPcapacitystart(tfirst)..       PSP(tfirst) =e= 0
;
PSPupdown(t)..                   PSPup(t) + PSPdown(t) =l= pumpmax
;
PSPupdown2(t)..                  PSPdown(t) =l= PSP(t)
;

*Startups
shutdown_li_1h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+1);
shutdown_li_2h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+2);
shutdown_li_3h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+3);
shutdown_li_4h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+4);
shutdown_li_5h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+5);
shutdown_li_6h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+6);
shutdown_li_7h(lig,t)..      status(lig,t-1)- status(lig,t) =l= 1-status(lig,t+7);

shutdown_co_1h(coal,t)..     status(coal,t-1)- status(coal,t) =l= 1-status(coal,t+1);
shutdown_co_2h(coal,t)..     status(coal,t-1)- status(coal,t) =l= 1-status(coal,t+2);
shutdown_co_3h(coal,t)..     status(coal,t-1)- status(coal,t) =l= 1-status(coal,t+3);

shutdown_steam_1h(steam,t).. status(steam,t-1)- status(steam,t) =l= 1-status(steam,t+1);
shutdown_steam_2h(steam,t).. status(steam,t-1)- status(steam,t) =l= 1-status(steam,t+2);

shutdown_cc_1h(ccgt,t)..      status(ccgt,t-1)- status(ccgt,t) =l= 1-status(ccgt,t+1);
```

```
*------------------------ MIP run ------------------------------------------*
Model Plantfixer
/
linobjective
energybalance
genmax
genmin
PSPcapacity
PSPcapacitystart
PSPupdown
PSPupdown2
shutdown_li_1h
shutdown_li_2h
shutdown_li_3h
shutdown_li_4h
shutdown_li_5h
shutdown_li_6h
shutdown_li_7h
shutdown_co_1h
shutdown_co_2h
shutdown_co_3h
shutdown_steam_1h
shutdown_steam_2h
shutdown_cc_1h
/;

solve Plantfixer using mip minimizing costs;


*------------------------ NLP run ------------------------------------------*
parameter
statfix(p,t)   fixing the status of a plant after mip solve
;

statfix(p,t)=status.l(p,t);
status.fx(p,t)=statfix(p,t);

Model NLP_run
/
objective
energybalance
genmax
genmin
startupc
PSPcapacity
PSPcapacitystart
PSPupdown
PSPupdown2
shutdown_li_1h
shutdown_li_2h
shutdown_li_3h
shutdown_li_4h
shutdown_li_5h
shutdown_li_6h
shutdown_li_7h
shutdown_co_1h
shutdown_co_2h
shutdown_co_3h
shutdown_steam_1h
shutdown_steam_2h
shutdown_cc_1h
/;

solve NLP_run using rminlp minimizing costs;
```

Appendix III: GAMS Code Cournot and SFE Model (Chapter 4)

```
*-----------------------------------------------------------------------------*
*                              declaration of sets                            *
*-----------------------------------------------------------------------------*

sets

i                     max number of firms
j(i)                  considered firms in this run
k                     demand shock steps
kfirst(k)             first step
klast (k)             last step
coef                  Coefficient for polynomials
otherfirms(i,ii)      all firms excluding firm i
;
alias (ii,i);
alias (j,jj);

*-----------------------------------------------------------------------------*
*                              declaration of scalars                         *
*-----------------------------------------------------------------------------*

Scalar

gamma                 slope of demand function
alpha_high            highest intercept of demand function
epsilon               distance between demand shocks on one axis
;

*-----------------------------------------------------------------------------*
*                              declaration of parameters                      *
*-----------------------------------------------------------------------------*

Parameters

gbeta(i,coef)         cost Parameters of the firms (cubic coest function)
fgrade(coef)          cost function polynomials
dummy(i)              competitive firm dummy [1 competitive 0 strategic]
fixed_contract(i)     contract coverage in terms of max capacity
eps_flex(k)           variable epsilon for each shock k
;

*-----------------------------------------------------------------------------*
*                              Variables                                      *
*-----------------------------------------------------------------------------*

variable

f                     objective dummy
p(k)                  price with shock k
D(k)                  total demand with shock k
c(i,k)                marginal costs at the quantity q
ksi(i,k)              slope difference variable
;

positive variables

beta(i,k)             slope of supply curve at shock k
q(i,k)                quantity by firm i at shock k
;
```

```
*----------------------------------------------------------------------------*
*                                 Equations                                  *
*----------------------------------------------------------------------------*

EQUATIONS

objective                 objective dummy minimizing slope and epsilon differences
MarketClearing            sum of supply equals demand
Demand                    demand level for shock k
MC                        marginal costs at the quantity q(i k)
Supply                    Anderson approach for continuity
FOC_SFE                   Equilibrium condition for SFE model
FOC_COMP                  Equilibrium condition for competitive benchmark
FOC_COUR                  Equilibrium condition for Cournot model
;


objective..            f =e= 100*sum(kfirst(k),D(k))- 100*sum(klast(k),D(k))
                            + sum((j,k),sqr(ksi(j,k)-.5))
                            + sum(k,sqr(eps_flex(k)-epsilon * (ord(k)-1)))/(epsilon*epsilon);

Demand(k)..            D(k) =e= alpha_high - gamma*p(k) - eps_flex(k);

MarketClearing(k)..    sum(j,q(j,k)) =e= D(k);

MC(j,k)..              c(j,k) =e= sum(coef, gbeta(j,coef)*power (q(j,k),fgrade(coef)));

Supply(j,k+1)..        q(j,k+1)-q(j,k) =e=
                       (p(k+1) - p(k))*((1-ksi(j,k))*beta(j,k)+ksi(j,k)*beta(j,k+1));

FOC_SFE(j,k)..         (q(j,k)- fixed_contract(j))*dummy(j)
                       - (p(k)-c(j,k))*(sum(otherfirms(j,jj),beta(jj,k)) + gamma )=e= 0 ;

FOC_COMP(j,k)..       (p(k)-c(j,k))=e= 0 ;

FOC_COUR(j,k)..       (q(j,k)- fixed_contract(j))*dummy(j) - (p(k)-c(j,k))* gamma  =e= 0 ;



*------------------------- model defintions ----------------------------------*

model anderson     / objective,MarketClearing,Demand,MC,Supply,FOC_SFE /;
model competition  / objective,MarketClearing,Demand,MC,Supply,FOC_COMP/;
model cournot      / objective,MarketClearing,Demand,MC,Supply,FOC_COUR/;
```

Appendix IV: Price Curves and Welfare Results, Divestiture (Chapter 4)

Table VI: Base case and asymmetric capacities

	Competitive Benchmark	Pre-Divestiture		6 Firm Case		4 Firm Case	
		Cournot	SFE	Cournot	SFE	Cournot	SFE
Average peak price [€/MWh]	44.6	63.6	62.9	55.3	53.1	47.5	46.7
Welfare [mn €/h]	12.94	12.02	12.04	12.42	12.53	12.79	12.84
Consumer surplus [mn €/h]	11.92	10.17	10.22	10.91	11.10	1.08	1.09
Profit EON [T€/h]	342	586	579	246	232	193	187
Profit RWE [T€/h]	298	560	536	232	216	174	167
Profit Vattenfall [T€/h]	199	378	381	293	277	229	220
Profit EnBW [T€/h]	187	327	326	262	248	209	203
Profit EON divested [T€/h]	-	-	-	246	232	188	184
Profit RWE divested [T€/h]	-	-	-	232	216	165	162

Figure XVI: Cournot and SFE supply curves, January 2006

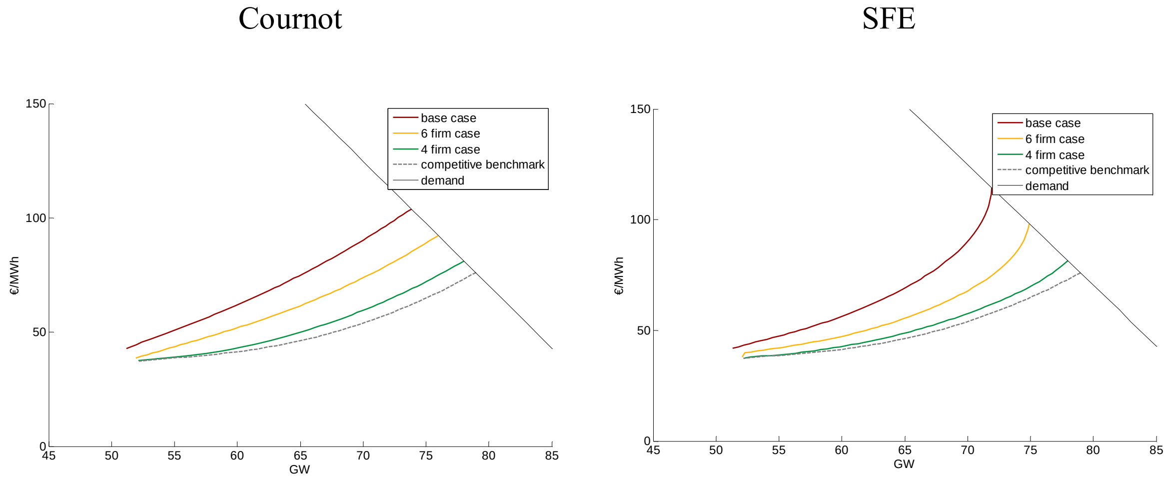


Figure XVII: Cournot and SFE supply curves, February 2006

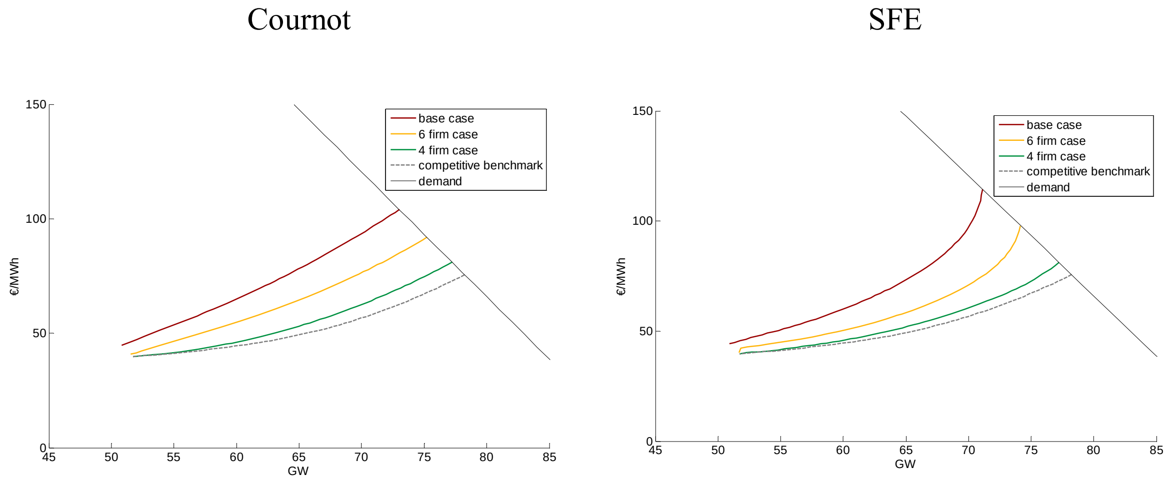


Figure XVIII: Cournot and SFE supply curves, March 2006

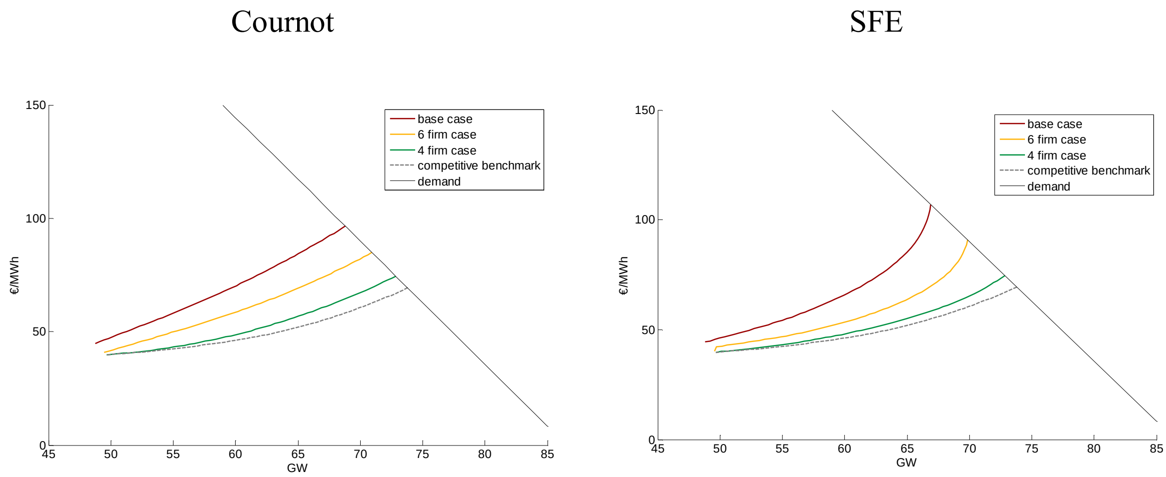


Figure XIX: Cournot and SFE supply curves, April 2006

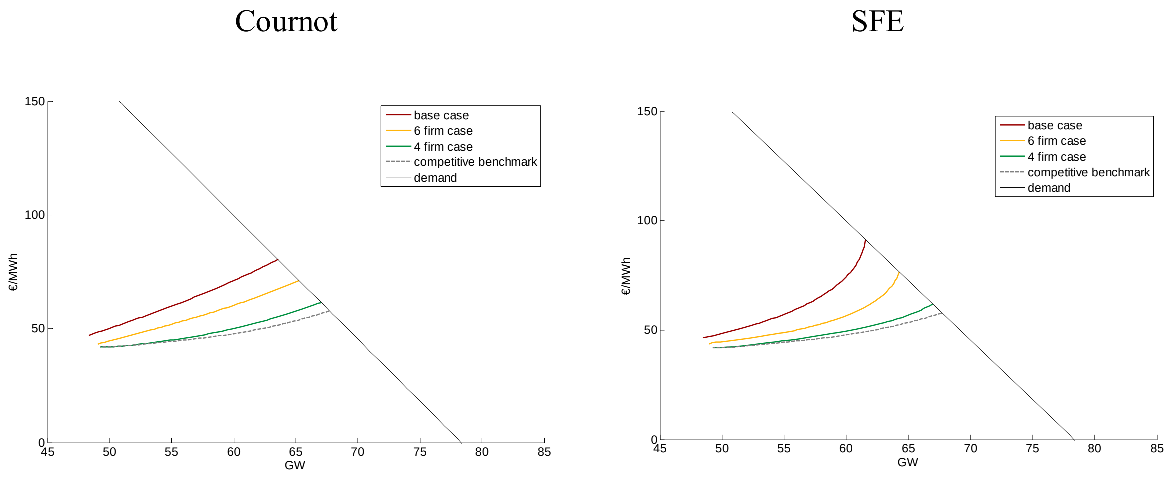


Figure XX: Cournot and SFE supply curves, May 2006

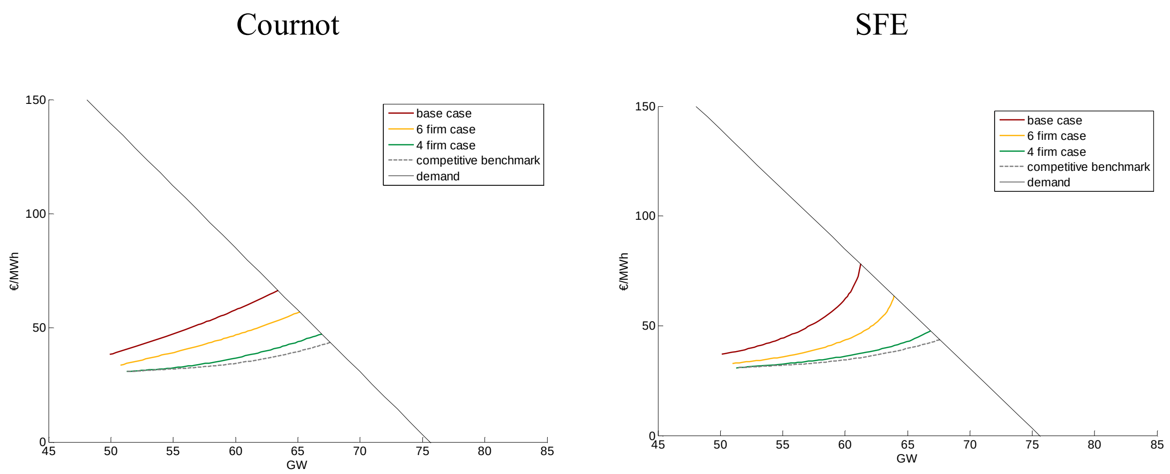


Figure XXI: Cournot and SFE supply curves, June 2006

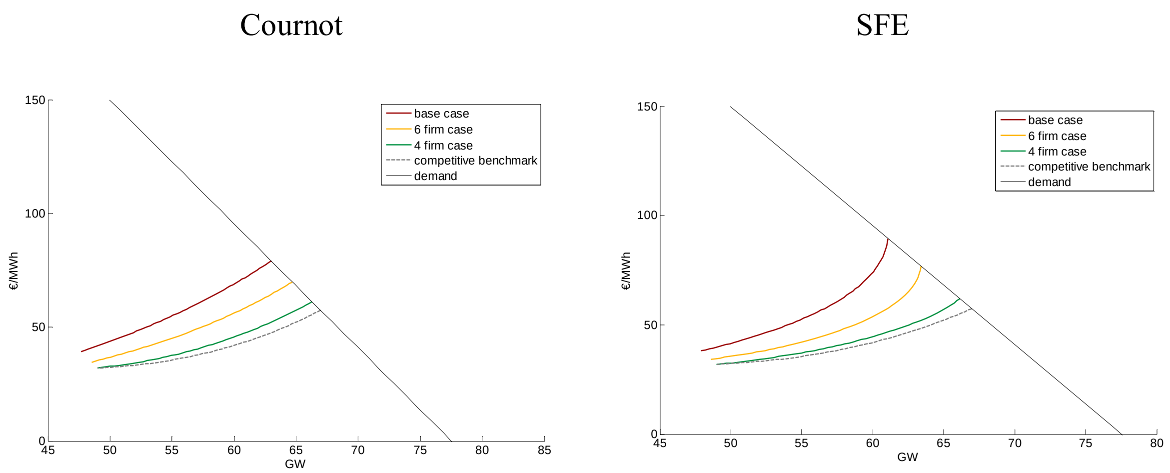


Figure XXII: Cournot and SFE supply curves, July 2006

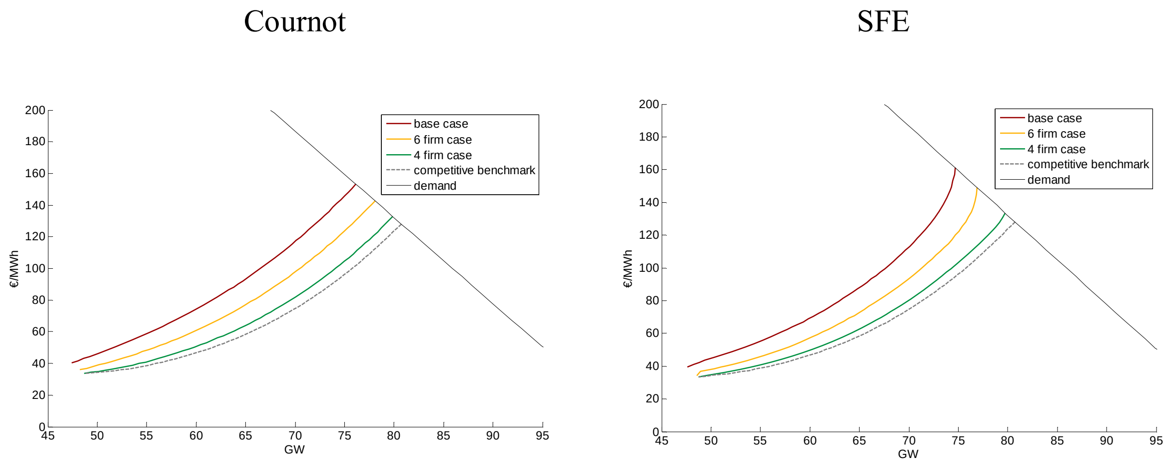


Figure XXIII: Cournot and SFE supply curves, August 2006

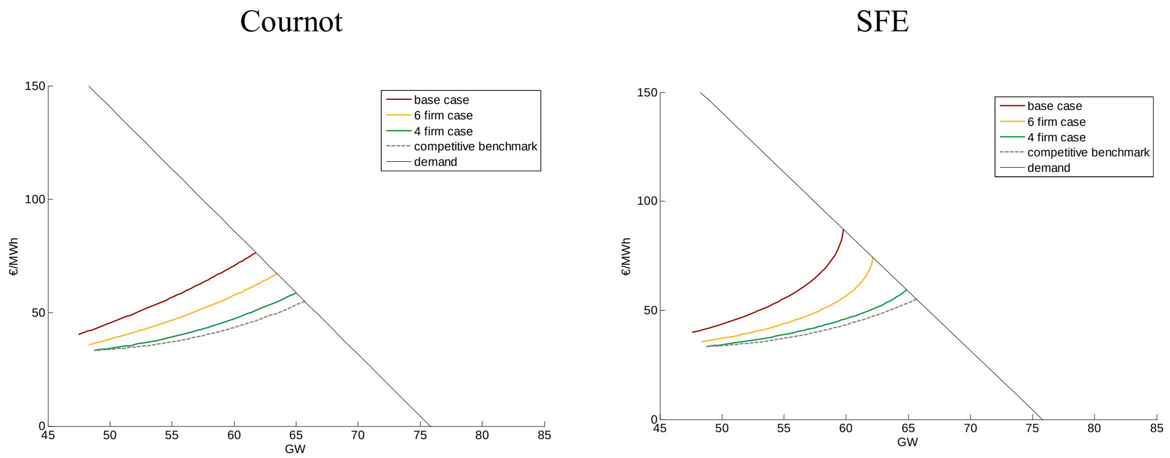


Figure XXIV: Cournot and SFE supply curves, September 2006

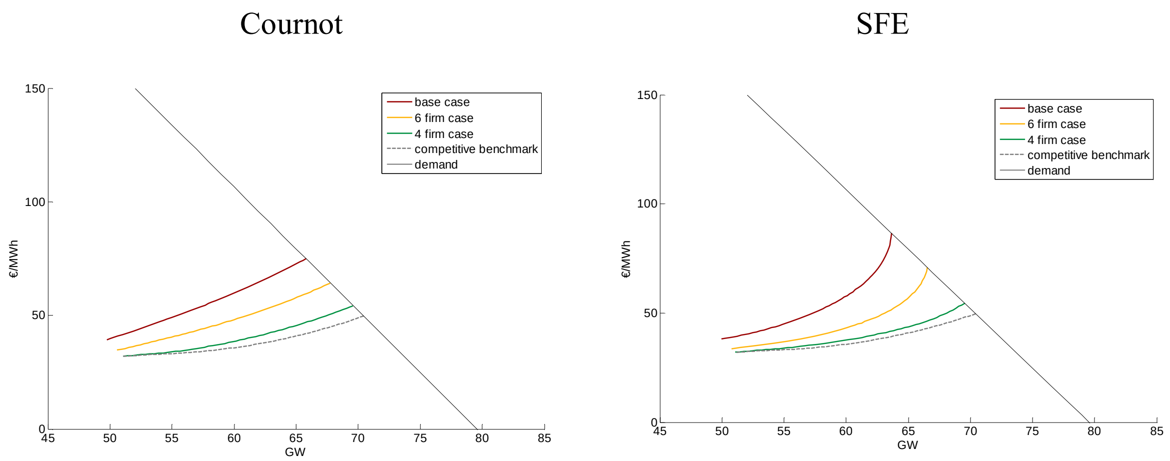


Figure XXV: Cournot and SFE supply curves, October 2006

Cournot SFE

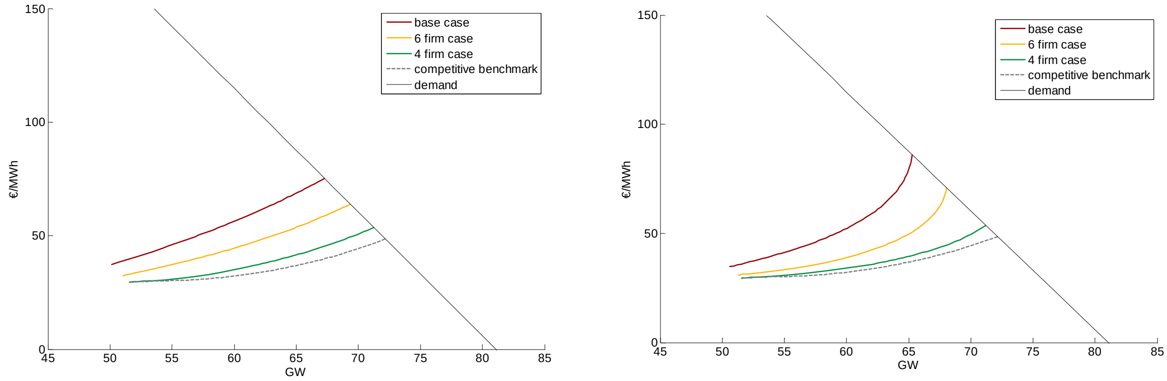


Figure XXVI: Cournot and SFE supply curves, November 2006

Cournot SFE

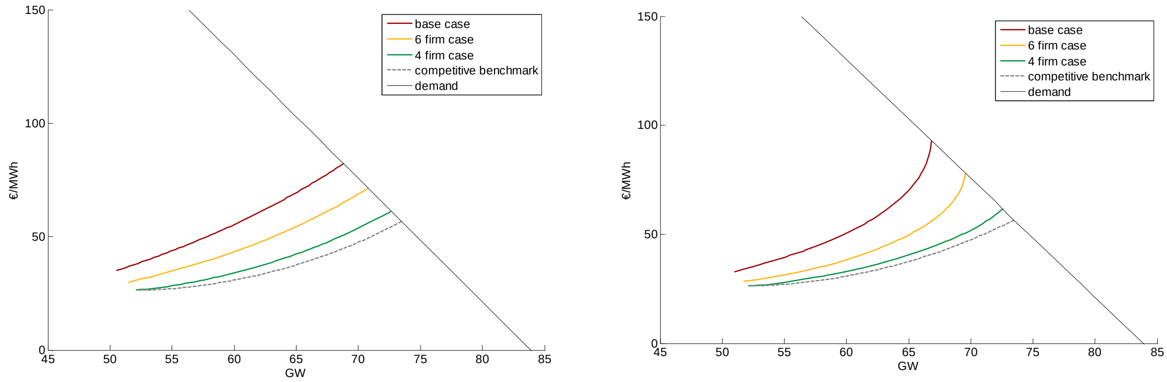
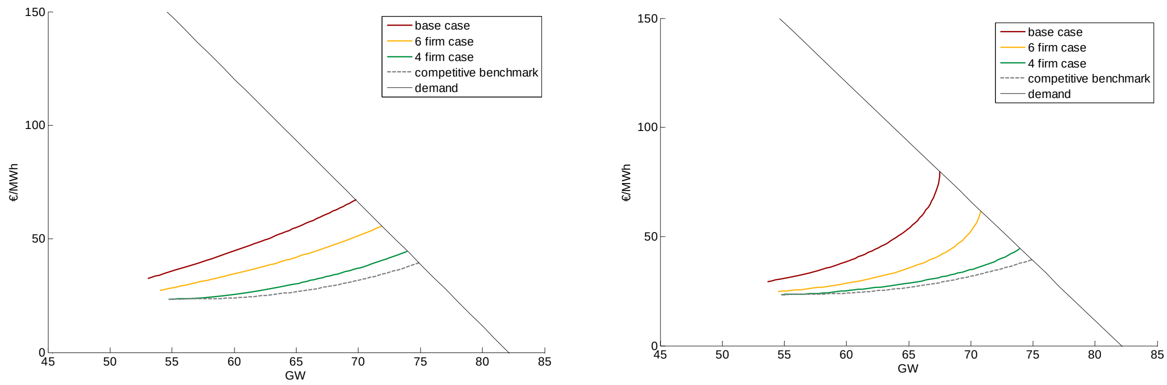


Figure XXVII: Cournot and SFE supply curves, December 2006

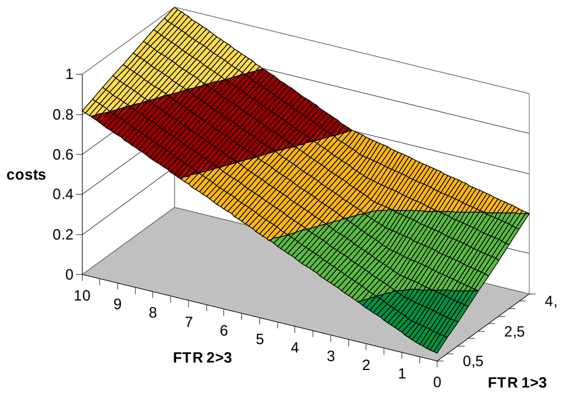
Cournot SFE



Appendix V: Numerical Results of Cost Function Analysis (Chapter 5)

Figure XXVIII: Global cost function, three-node network, base case, fixed line reactances

Linear extension costs



Quadratic extension costs

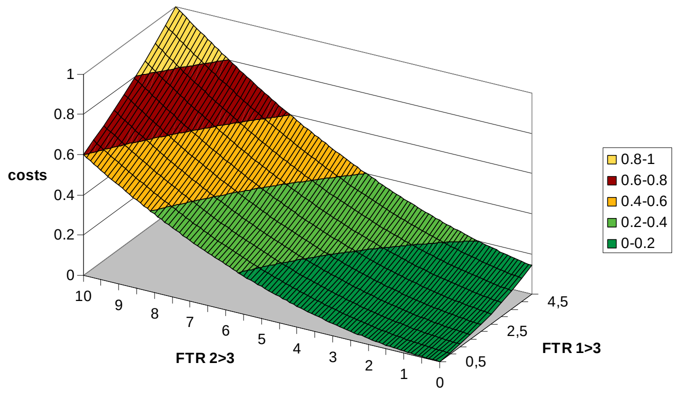
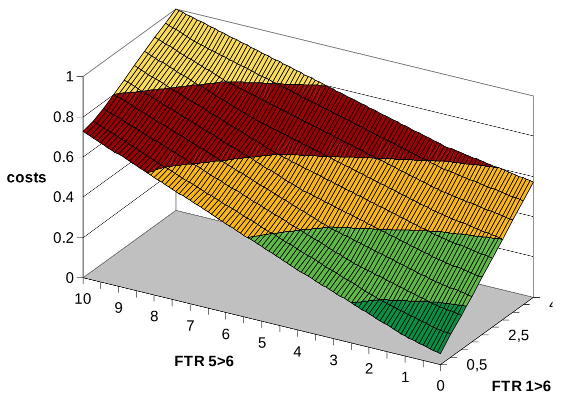


Figure XXIX: Global cost function, six-node network, base case, fixed line reactances

Linear extension costs



Quadratic extension costs

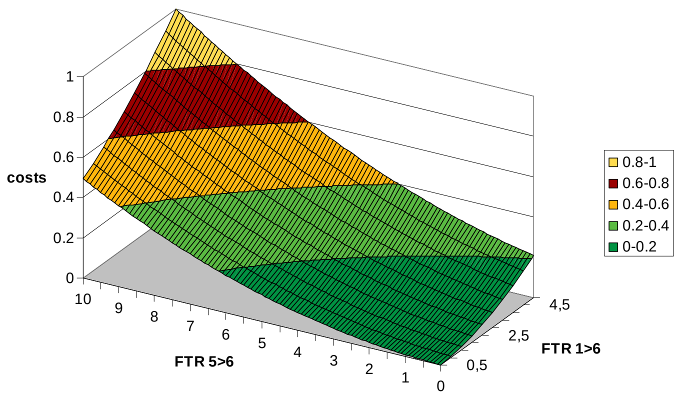


Figure XXX: Global cost function, three-node network, base case, variable line reactances

Linear extension costs   Quadratic extension costs

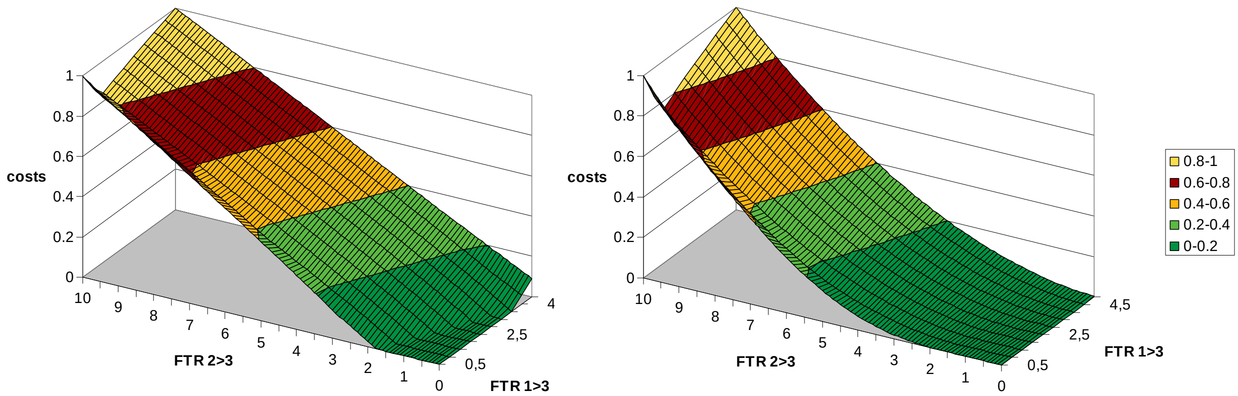
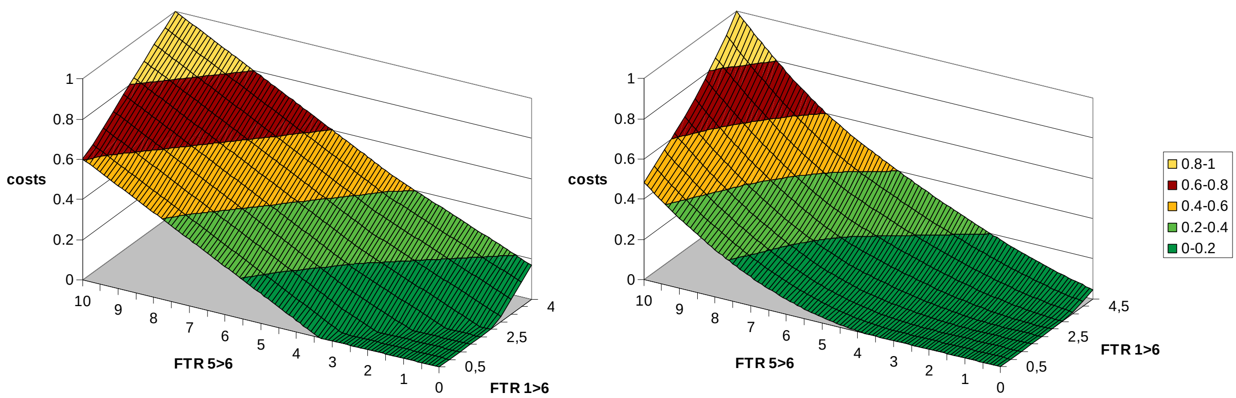


Figure XXXI: Global cost function, six-node network, base case, variable line reactances

Linear extension costs   Quadratic extension costs



Appendix VI: GAMS Code MPEC Approach (Chapter 5)

```
*----------------------------------------------------------------------------*
*                        declaration of sets                                 *
*----------------------------------------------------------------------------*

Sets
l                lines
n                nodes
t                period
tfirst(t)        first time period
;
Alias (n,nn);

*----------------------------------------------------------------------------*
*                        declaration of parameters                           *
*----------------------------------------------------------------------------*

Parameter
Incidence(l,n)              indicating starting- and end-node of a line l
slack(n)                    slack bus (voltage angel fixed at 0 for this node)
cap_0(l)                    starting capacity on line l
ecf(l)                      cost function: extension cost factor
marginalcosts(n,t)          marginal generation costs
max_gen(n)                  maximum generation capacity at n
intercept(n)                demand function: highest price at y-axis
slope(n)                    demand function: slope
;
* note that for this code the lines reactance X is assumed to be 1 for each line


*----------------------------------------------------------------------------*
*                        Variables                                           *
*----------------------------------------------------------------------------*

Variables
return           Tranco profit
delta            voltage angle difference
price            price at a node n
lambdadelta      dual variable on the slack bus constraint
;

Positive Variables
extension(l,t)        extension in period t in times of original capacity (e.g. 2 times cap0)
cap(l,t)              existing capacity in t (original capacity + all further extensions)
generation(n,t)       generation at a node
demand(n,t)           demand at a node
capacityrent(n,t)     shadow price of generation capacity
flowpos(l,t)          shadow price of line capacity positive flow direction
flowneg(l,t)          shadow price of line capacity negative flow direction
fix_part              fixed part of Trancos transmission tariff
;

*----------------------------------------------------------------------------*
*                        Equations                                           *
*----------------------------------------------------------------------------*

EQUATIONS

profit           objective of the Transco (congestion rent + fixed part - extension costs)
price_cap        regulatory constraint on variable and fixed part
line_caps        actual line capacity in a period based on previous capacity and extension
line_caps_one    starting line capacities

* MCP market clearing (welfare maximizing ISO)
* note that in order to obtain starting values a welfare maximizing network extending Transco
* run is modelled in addition in which "extension(l,t)" is a variable within the welfare
* maximization

FOC_g                 First-Order-Condition of variable generation
FOC_ext               First-Order-Condition of variable ext for a welfare maximizing Transco
                      for pre-run
FOC_delta             First-Order-Condition of variable delta for a welfare maximizing Transco
                      for pre-run
FOC_delta_MPEC        First-Order-Condition of variable delta
FOC_q                 First-Order-Condition of variable demand
```

```
Slackbus              setting voltage angel difference at slack bus to 0
gen_capacity          upper limit for generation
Energybalance         demand = generation for a welfare maximizing Transco for pre-run
Energybalance_MPEC    demand = generation
Lineflow_pos          upper limit for line flows for a welfare maximizing Transco for pre-run
Lineflow_neg          lower limit for line flows for a welfare maximizing Transco for pre-run
Lineflow_pos_MPEC     upper limit for line flows
Lineflow_neg_MPEC     lower limit for line flows
;


*TRANSCO profit maximization under regulatory cap
profit..       return =e= sum(t,
                      sum(n, price(n,t)*demand(n,t)) - sum(n, price(n,t)*generation(n,t)))
                      + sum(t,fix_part(t))
                      - sum((l,t), ecf(l)* cap_0(l)*extension(l,t))
;

price_cap(t+1)..      sum(n, price(n,t+1)*demand(n,t)) - sum(n, price(n,t+1)*generation(n,t))
                      + fix_part(t+1)
                      =l=
                      sum(n, price(n,t)*demand(n,t)) - sum(n, price(n,t)*generation(n,t))
                      + fix_part(t)
;


*Calculation of line capacities in each period t
line_caps(l,t+1)..         cap(l,t+1) =e= cap_0(l)*extension(l,t) + cap(l,t)
;

line_caps_one(l,tfirst)..  cap(l,tfirst) =e= cap_0(l)
;


*MCP formulation of the market clearing for the MPEC run

FOC_g(n,t)..                 marginalcosts(n,t) + capacityrent(n,t) - price(n,t) =g= 0
;

FOC_q(n,t)..                 -(intercept(n) + slope(n)*demand(n,t)) + price(n,t) =g= 0
;

FOC_delta_MPEC(n,t)..
               SUM(l, 1/( cap_0(l)/(cap(l,t) +
               cap_0(l)*extension(l,t))) * Incidence(l,n)*(-flowpos(l,t)+flowneg(l,t)))
               - sum(nn, price(nn,t)*SUM(l, Incidence(l,nn) *
               (1/( cap_0(l)/(cap(l,t) + cap_0(l)*extension(l,t)))  * Incidence(l,n) )))
               + lambdadelta(n,t)*slack(n)
               =g= 0
;

Slackbus(n,t)..              slack(n)*delta(n,t) =e= 0
;

gen_capacity(n,t)..          max_gen(n)- generation(n,t) =g= 0
;

Energybalance_MPEC(n,t)..    generation(n,t) - demand(n,t)
                             -  SUM(l, Incidence(l,n) * SUM((nn), 1/( cap_0(l)/(cap(l,t)
                             + cap_0(l)*extension(l,t))) * Incidence(l,nn) * Delta(nn,t)))
                             =e= 0
;
Lineflow_pos_MPEC(l,t)..
               (cap(l,t) + cap_0(l)*extension(l,t))
               - SUM(n, 1/( cap_0(l)/(cap(l,t) + cap_0(l)*extension(l,t)))
               * Incidence(l,n) * Delta(n,t)) =g= 0
;
Lineflow_neg_MPEC(l,t)..
               (cap(l,t) + cap_0(l)*extension(l,t))
               + SUM(n, 1/( cap_0(l)/(cap(l,t) + cap_0(l)*extension(l,t)))
               * Incidence(l,n) * Delta(n,t)) =g= 0
;
```

```
*MCP formulation of a welfare maximizing pre-solve to obtain starting values for each period
FOC_ext(l,t)..
               ecf(l)* cap_0(l)
               - flowpos(l,t)*(cap_0(l)- SUM(n, -sqr(cap_0(l))*1/sqr(cap_0(l)
               + cap_0(l)*extension(l,t)) * Incidence(l,n) * Delta(n,t)))
               - flowneg(l,t)*(cap_0(l)+ SUM(n, -sqr(cap_0(l))*1/sqr(cap_0(l)
               + cap_0(l)*extension(l,t))  * Incidence(l,n) * Delta(n,t)))
               =e= 0
;

FOC_delta(n,t)..
               SUM(l, 1/( cap_0(l)/(cap_0(l) + cap_0(l)*extension(l,t)))
               * Incidence(l,n)*(-flowpos(l,t)+flowneg(l,t)))
               sum(nn, price(nn,t)*SUM(l, Incidence(l,nn)
               * (1/( cap_0(l)/(cap_0(l) + cap_0(l)*extension(l,t)))
               * Incidence(l,n) ))) + lambdadelta(n,t)*slack(n)
               =g= 0
;

Energybalance(n,t)..
               generation(n,t) - demand(n,t)
               -  SUM(l, Incidence(l,n) * SUM((nn),(1/( cap_0(l)/(cap_0(l)
               + cap_0(l)*extension(l,t))) * Incidence(l,nn)) * Delta(nn,t)))
               =e= 0
;

Lineflow_pos(l,t)..
               (cap_0(l)+cap_0(l)*extension(l,t)) -   SUM(n, 1/( cap_0(l)/(cap_0(l)
               + cap_0(l)*extension(l,t))) * Incidence(l,n) * Delta(n,t)) =g= 0
;

Lineflow_neg(l,t)..
               (cap_0(l)+cap_0(l)*extension(l,t)) +   SUM(n, 1/( cap_0(l)/(cap_0(l)
               + cap_0(l)*extension(l,t))) * Incidence(l,n) * Delta(n,t)) =g= 0
;

*------------------------- MCP pre-run ---------------------------------------*

model MCP
/
FOC_g.generation
FOC_ext.extension
FOC_delta.delta
FOC_q.demand
Slackbus.lambdadelta
gen_capacity.capacityrent
Energybalance.price
Lineflow_pos.flowpos
Lineflow_neg.flowneg
/
;

solve MCP using mcp;

*------------------------- MPEC main run --------------------------------------*

model MPEC
/
profit
price_cap
line_caps
line_caps_one
FOC_g.generation
FOC_delta_MPEC.delta
FOC_q.demand
Slackbus.lambdadelta
gen_capacity.capacityrent
Energybalance_MPEC.price
Lineflow_pos_MPEC.flowpos
Lineflow_neg_MPEC.flowneg
/
;

solve MPEC maximizing return using mpec;
```

Appendix VII: Numerical Results of Robustness Tests (Chapter 5)

Table VII: Base case and asymmetric capacities

	Base case			Asymmetric transmission capacities (line2)		
	No grid extension	Regulatory approach	Welfare maximization	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	108.00 €	145.44 €	149.01 €	118.00 €	146.21	149.01 €
Producer rent	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Congestion rent	24.00 €	4.45 €	0.99 €	24.00 €	3.71 €	0.99 €
Total welfare	132.00 €	149.89 €	150.00 €	142.00 €	149.92 €	150.00 €
Extension sum	-	5.53 €	5.90 €	-	3.61	3.90 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW
Capacity: line 2	2.00 MW	6.56 MW	2.00 MW	4.00 MW	5.58 MW	4.00 MW
Capacity: line 3	2.00 MW	2.98 MW	7.90 MW	2.00 MW	4.03 MW	5.90 MW
Price: node 1	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 3	6.00 €	0.47 €	0.10 €	4.00 €	0.39 €	0.10 €

Table VIII: Asymmetric reactances and asymmetric line extension costs

	Asymmetric lien reactances (line2)			Asymmetric extension costs and reactances (line2)		
	No grid extension	No grid extension	No grid extension	No grid extension	Regulatory approach	Welfare maximization
Consumer rent	108.00 €	108.00 €	108.00 €	108.00 €	146.21	149.01 €
Producer rent	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Congestion rent	24.00 €	24.00 €	24.00 €	24.00 €	3.71 €	0.99 €
Total welfare	132.00 €	132.00 €	132.00 €	132.00 €	149.92 €	150.00 €
Extension sum	-	-	-	-	3.61	3.90 €
Capacity: line 1	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW	2.00 MW
Capacity: line 2	2.00 MW	2.00 MW	2.00 MW	2.00 MW	5.58 MW	4.00 MW
Capacity: line 3	2.00 MW	2.00 MW	2.00 MW	2.00 MW	4.03 MW	5.90 MW
Price: node 1	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 2	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
Price: node 3	6.00 €	6.00 €	6.00 €	6.00 €	0.39 €	0.10 €