THE ECONOMICS OF RENEWABLE ELECTRICITY MARKET INTEGRATION

AN EMPIRICAL AND MODEL-BASED ANALYSIS OF REGULATORY FRAMEWORKS AND THEIR IMPACTS ON THE POWER MARKET

Inauguraldissertation
zur Erlangung des Doktorgrades
der Wirtschafts- und Sozialwissenschaftlichen Fakultät
der Universität zu Köln
2011

vorgelegt von
Dipl.-Kfm. Marco Nicolosi, MBA
aus Braunschweig

Referent: Prof. Dr. Marc Oliver Bettzüge

Korreferent: Prof. Dr. Dominik Möst

Tag der Promotion: 8.7.2011

Yes, We Can.
Barack Obama (2008)

To my godchildren Giona and Thea

Acknowledgement

The way towards finishing this thesis was defined by support in ways that make me feel profoundly grateful. More than I could ever express. Nevertheless, I would like to start with this list, which is by no means complete.

- I thank my friends and colleagues Barbara Burstedde, Jochen Schwill and Michael Bartels as well as my other colleagues from the Institute of Energy Economics at the University of Cologne for the valuable time we spent together.
- My particular gratitude goes to my close friend Ingo Kucz and to my former judo coach and dear friend Gottfried Burucker, who taught me to add the word 'yet' to the sentence 'I cannot do it'.
- My family, who supported me, and in particular my grandparents Gertrud and Alfons Adamski, who believed in me.
- During my research visit, I benefited from the great atmosphere at the Lawrence Berkeley National Laboratory. I thank the renewables team, in particular Ryan Wiser, Andrew Mills and Naïm Darghouth, who gave me an intellectual and friendly place for my research, and Michael Stadler and Chris Marnay, for granting me access to their modeling server.
- Finally, I would like to thank Prof. Dr. Bettzüge for refereeing and Prof. Dr. Möst for co-refereeing my thesis.

In addition, I would like to thank everyone I met along the way who either helped me with fruitful discussions or had a valuable impact on me in any other way.

Contents

List of Figures

List of Tables

Nomenclature

Abbreviations

Alps	Austria and Switzerland
BDEW	Federal Association for Electricity and Water
BMU	Federal Ministry of Environmental Affairs
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CO_2	Carbon dioxide
EEG	Renewable Energy Sources Law
EEX	European Energy Exchange
EIA	Energy Information Administration
ENTSO-E	European Network Transmission System Operators for Electricity
Epex	European Power Exchange
ERCOT	Electricity Reliability Council of Texas
FIT	Feed-in tariff
HPC	High performance computing
IEA	International Energy Agency
KWh	Kilowatt hour
LB	Lower bound
MP	Master problem
MWh	Megawatt hour
North	Finland, Norway and Sweden
NREAP	National renewable energy action plants
NTC	Net transfer capacities
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
OTC	Over-the-counter
PLCZ	Poland and Czech Republic
PR	Producer rent
PTC	Production tax credit
PTDF	Power transfer distribution factor
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources

RPS	Renewable portfolio standard
SP	Subproblem
THEA	The high temporal resolution electricity market analysis model
TSOs	Transmission system operators
TWh	Terrawatt hour
UB	Upper bound
UKIE	United Kingdom and Ireland
VOLL	Value of lost load

Parameters

$anmat$	Annuity matrix
$avail$	Availabilities of conventional plants
$capaddex$	Exogenous capacity commissioning
$capsubex$	Exogenous capacity decommissioning
$contractcap$	Reserve requirement
$co2fac$	CO_2 content
$curtailpenalty$	Curtailment penalty
$demand$	Demand
$deptime$	Depreciation time
$dfac$	Discount factor
ϵ	Convergence criterion
η	Efficiency
η_loss	Part-load losses
η_pump	Compressing efficiency
$existcap$	Incumbent capacity
fc	Fixed costs
$feascom$	Feasibility matrix
$fuelc$	Fuel costs including CO_2
$fuelup$	Fuel upper bound
$hydsinflow$	Hydro inflow
ic	Investment costs
$idletime$	Idle time
$installedcap$	Installed Capacities
$instcap$	Installed capacities
$loadmin$	Minimum load per technology
$loadminpump$	Minimum load of storage
$lspenalty$	Penalty for load shedding
$maxload$	Maximal load
$maxresload$	Maximal residual load
$minhyds$	Minimum water run-off
ny	Number of years
$ovar$	Other variable costs

$ovarcpump$	Other variable costs for compressing energy
$rampup$	Ramp gradient
$resgen$	Generation from RES
$resload$	Residual load
$spinningreserve$	Demand for spinning reserve
$standingreserve$	Demand for additional back-up reserve
$startattr$	Attrition costs
$startdur$	Start-up time
$startt$	Linearized cool-down function
$startupcostpump$	Ramp-up costs
$storecapturbratio$	Storage plant size
$subcosts$	Parameter of SP objective function in MP
τ	Cooling rate
$tcap$	Transmission capacity
$tertiaryreserve$	Demand for tertiary reserve
$tloss$	Transmission losses
$validreservepump$	Reserve ability of storage
$validreservespinning$	Spinning reserve possibility
vc	Variable costs

Variables

α	Variable in Benders Cut
$AVAILCAP$	Available capacities
$AVAILPUMP$	Available pump storage capacities
CAP	Capacity
CAP_ADD	Endogenous capacity commissioning
CAP_SUB	Endogenous capacity decommissioning
$CAPDOWN$	Ramping down capacity
$CAPRTO$	Ramped-up capacity
$CAPUP$	Ramping-up capacity
$CO2TOT$	CO_2 emissions
$CURTAIL$	Curtailment
FC	Fixed costs
FOM	Fixed operation and maintenance costs
$FUELUSE$	Used fuel
GEN	Generation
$HYDPSVOL$	Stored energy volume of pumped storage plants
$HYDSBYPASS$	Hydro curtailment
$HYDSVOL$	Stored energy volume of storage plants
λ	Capacity dual
LB	Lower bound
LS	Load shedding
PT	Power transfer between regions
$PUMP$	Compressing variable

$PUMPDOWN$	Ramping down storage
$PUMPRTO$	Ramped-up storage
$PUMPUP$	Storage ramp-up variable
$SUBCOSTS$	Objective scalar of the SP
TC	Total costs
UB	Upper bound
$VARCOSTS$	Variable costs
$VCCURTAIL$	Curtailment costs
$VCPARTLOAD$	Partload costs
$VCRTO$	Ramp-up costs

Indices

h	Hour
Hyd_S	Hydro storage
I	Iteration
m	Month
$negSpinning$	Negative spinning reserve
$negTR$	Negative tertiary reserve
$posSpinning$	Positive spinning
$posTR$	Positive tertiary reserve
r	Region
$restech$	Renewable technology
$stortech$	Storage technology
t	Technology
y	Year

Summary

As power systems increase in complexity due to higher shares of intermitting RES-E, so increase the requirements for power system modeling. This thesis shows empirically, with examples from Germany and Texas, that the increasing RES-E share strongly affects current power market operation. The markets further create price signals, which lead to system adaptations in the long-run.

To get an estimate of the adaptation effects, 'The High Temporal Resolution Electricity Market Analysis Model' (THEA) has been developed. In a first application for the ERCOT market in Texas, particular model attributes are tested and compared to some complexity reducing approaches, i.e. the reduction of temporal resolution and the reduction of operational constraints. In both cases, the results show significant differences compared to the results when the full spectrum of THEA's capabilities is utilized. The ERCOT case study additionally shows that the adaptation to RES-E in an isolated, mainly thermal-based power system is quite severe. Market signals which underline this conclusion are the severely reduced value of wind energy, the increasing curtailment and the strong shift towards peak-oriented generating capacities.

The second application of THEA models the German power market with its interconnected markets. This analysis increases the complexity significantly by modeling a well interconnected system, increasing the amount of different RES-E technologies and adding CAES investment options. In order to assess the impact on the different system component's supply, demand and grid infrastructure, specific measures are applied to compare several scenarios. Each scenario represents a policy option, which either reduces or increases the flexibility of the power system. The scenario comparisons capture the effects of a lower RES-E share, a larger baseload capacity fleet, higher interconnector capacities, various RES-E support scheme designs and the capability of RES-E to participate in the reserve power market. In general, the results show that if the flexibility of one system component is reduced, the flexibility values of other system components increase, which suggests a careful, integrated and long-term oriented policy setting.

Zusammenfassung

Der stark wachsende Anteil dargebotsabhängiger erneuerbarer Energien (EE) im Strommarkt erhöht die Komplexität des Elektrizitätssystems und die Anforderungen an die Strommarktmodellierung. Die vorliegende Arbeit zeigt anhand empirischer Beispiele aus Deutschland und Texas, dass der steigende EE Anteil die Marktabläufe stark beeinflusst. Die daraus resultierenden Preissignale ziehen in der langen Frist Systemanpassungen nach sich.

Um eine Abschätzung der Anpassungseffekte zu erhalten, wurde das Strommarktmodell 'The High Temporal Resolution Electricity Market Analysis Model' (THEA) entwickelt. In einer ersten Anwendung wird das ERCOT Marktgebiet in Texas modelliert um die spezifischen Modelleigenschaften zu testen und mit komplexitätsreduzierenden Methoden hinsichtlich der zeitlichen Auflösung und der betrieblichen Detailschärfe zu vergleichen. In beiden Fällen zeigen die Ergebnisse deutliche Unterschiede im Vergleich zu den Resultaten der vollen Modellnutzung. Der ERCOT Anwendungsfall zeigt darüber hinaus, dass die EE induzierten Anpassungseffekte in einem isolierten, hauptsächlich thermischen Strommarkt sehr deutlich sind. Marktergebnisse, welche das Fazit unterstreichen, sind der starke Wertverlust des Windstroms, das zunehmende Einspeisemanagement und die deutliche Verschiebung zu spitzenlastorientierter Erzeugungskapazität.

Die zweite Anwendung von THEA modelliert den deutschen Markt unter Berücksichtigung der verbundenen Nachbarmärkte. Die Komplexität der Analyse steigt deutlich durch die Modellierung eines stark vermaschten Systems, die Berücksichtigung verschiedener EE-Technologien und die Zubaumöglichkeit von CAES Speichern. Um die Rückwirkungen auf die Systemkomponenten Angebot, Nachfrage und Netz zu untersuchen werden verschiedene Szenarienanpassungen vorgenommen. Jedes Szenario untersucht eine Politikoption hinsichtlich der Flexibilitätsteigerung oder -reduzierung des Stromsystems. Die Szenarienvergleiche beinhalten die Effekte eines geringeren EE Anteils, einer größeren Grundlastkapazität, höherer Interkonnektorkapazitäten, verschiedener EE Fördersystemdesigns und der Möglichkeit der EE Teilnahme am Regelenergiemarkt. Zusammenfassend lässt sich feststellen, dass die Einschränkung der Flexibilität einer Systemkomponente den Wert der Flexibilität anderer Systembestandteile erhöht, woraus eine behutsame, integrierte und langfristorientierte Energiepolitikempfehlung abgeleitet werden kann.

1 Introduction

The promotion of electricity from renewable energy sources (RES-E) in Germany began in the early 1990s. Since 2000, the deployment of RES-E capacities has grown considerably due to the Renewable Energy Sources Act (EEG). In 2009, 16.1% of the gross electricity production stemmed from renewable energy sources (RES), of which 6.5% came from wind power alone (BMU, 2010a). With a total installed capacity of 25.8 GW at the end of 2009, Germany is the largest wind power market in Europe, in absolute terms.

Since most RES-E are not able to compete in the power market, additional financial support is required to trigger investments. The EEG is a feed-in tariff system (FIT) which remunerates each renewable generated energy unit fed into the grid. The rapid increase of the RES-E share can be attributed to this low risk investment scheme. One crucial support scheme design element is the obligation for the transmission system operators (TSOs) to integrate each generated RES-E unit independent of the actual demand.

The remaining power market faces increasing challenges toward integrating the growing RES-E share due to the intermitting nature of wind and solar irradiation. Since each RES-E unit must be integrated, the conventional side of the power market has to provide the flexibility to adjust itself to the fluctuating residual demand. Throughout the entire thesis, the residual demand perspective is applied, since the later analysis focuses on the optimization of the conventional supply side. Consequently, the RES-E are seen as a part of the demand side, which also bears the support costs. The integration challenges for the supply side can be translated into requirements for the long-run development of the electricity market. Besides the technical challenges of following the fluctuations, the economics of the power market are also challenged. Since an increasing share of the demand is met by out-of-market supported RES-E, the remaining power market faces different requirements, which in the long-run lead to adaptations of the generating capacity. Therefore, the main research question is how different policy decisions affect interdependent system components in high RES-E scenarios.

In order to enable the analysis of the new challenges for the power market, the requirements in electricity market modeling also mirror the additional complexity. Therefore, 'The High Temporal Resolution Electricity Market Analysis Model' (THEA) has been developed, which takes these additional requirements, in particular the increased temporal resolution, into account. This model is tested against other approaches found in the literature and applied to two case studies. The first case study represents the ERCOT power market in Texas. The primary purpose of this case study is to test particular model attributes in a medium-sized, isolated power system. The second case study represents the primary analysis of this thesis and focuses on the German power market, however taking into account the surrounding interconnected markets as well. Here, the analysis focuses on the impact of various policy options on the ability to integrate RES-E, the flexibility of the market and its corresponding economic impacts. The particular scenario specifications are defined on the basis of previously identified design options.

The thesis is structured as follows. The next chapter provides the motivation and an overview of the literature. The evolution of the research questions is provided on the basis of the literature and further research potential is identified. Chapter 3 is partially based on Nicolosi (2010) and explains in greater detail the particular RES-E integration challenges. Empirical data are analyzed to provide an intuition on market reactions in times of high RES-E infeed. In addition, alternative integration approaches are discussed and long-term adaptation effects explained. Chapter 4 explains the utilized methodology, which enables the detailed analysis. Chapter 5 is partially based on Nicolosi et al. (2010) and provides the first model application on the Texas case study, compares different model attributes found in the literature and thereby shows how the detail provided by THEA impacts the results. In chapter 6 the German power market is analyzed under consideration of the interconnected neighboring markets. Particular scenarios and their impact on the power market are compared in order to identify solutions for further increasing the RES-E share efficiently. Finally, chapter 7 discusses the results, identifies further research potential and concludes the analysis.

2 Motivation and Literature Review

This chapter provides an overview of the literature on RES-E market integration and identifies gaps which are filled by the research presented in this thesis. First, literature on short-term market effects and their economic interpretation is discussed. Second, the literature on market adaptation which projects the short-term effects into the longer term, is reviewed. Finally, literature on market design is presented, which intends to solve the previously identified market challenges.

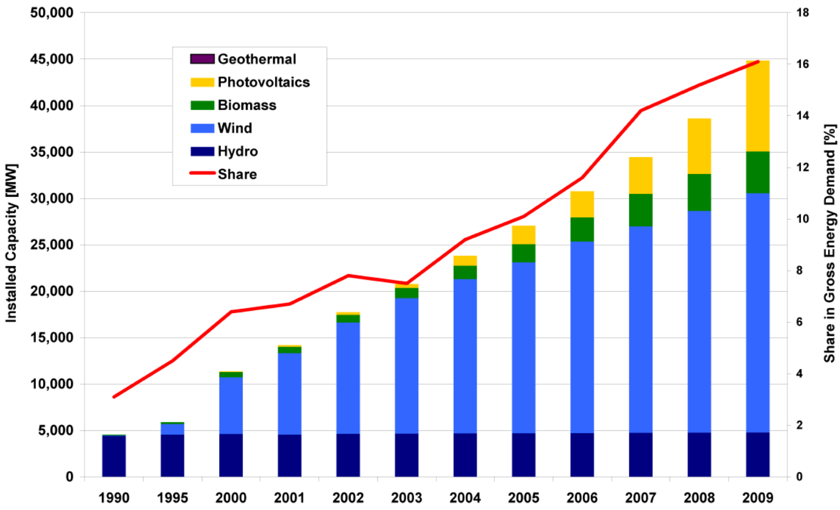
2.1 Short-Term Effects

Adding a high share of intermitting RES-E to an existing power system changes the optimal operation of the remaining power plants. With low, near-zero variable costs, intermitting RES-E technologies are usually the first generating units that are dispatched in the power system. Additionally, FIT support schemes usually have a RES-E infeed obligation for TSOs. It is therefore common to subtract the RES-E generation from total demand to form the time-varying residual demand according to which the remaining generation units must be dispatched. This perspective is followed throughout the entire thesis. Due to these dynamics, wholesale power prices tend to be lower in hours with high RES-E infeed because the lower residual demand can be met by cheaper marginal units (see e.g. Neubarth et al. (2006) or Bode and Groscurth (2006) for a discussion on these wholesale power price-reducing effects in Germany; Munksgaard and Morthorst (2008) for Denmark; and Miera et al. (2008) for Spain).

Since Germany has a significant RES-E growth (see Figure 2.1 for an overview of the capacity development), the discussion on this wholesale price-reducing effect and on its economic interpretation is still ongoing.

The German Federal Ministry of Environmental Affairs (BMU) published a report already in 2007 which discussed the so-called 'merit-order effect' and its economic interpretation (see BMU (2007)) and was used to inform the EEG amendment. To calculate the merit-order effect, a power market model simulated the power prices of one particular year with and without RES-E. The resulting average power price difference amounted to 7.73 EUR/MWh. The aggregated hourly price differences were denoted as the volume of 'cost reduction', which was compared to the EEG remuneration volume. The total amount of the merit-order effect was thus reported to be 4.98

Figure 2.1: Historic RES-E capacity development in Germany



Source: own illustration, based on BMU (2010a).

bn. EUR, while the total RES-E support was 3.3 bn. EUR in 2006 (BMU (2010a)). Wissen and Nicolosi (2008) initiated a critical discussion on this approach. First, the conventional capacity adaptation since the introduction of the EEG in 2000 was not considered. It is questionable if a power system without any RES-E would have had exactly the same installed capacity mix as the reference case. Second, international exchange was assumed to be identical in both model runs, since neighboring markets were not included in the modeling approach. Thus, the considerable export volumes that especially result in hours of very high RES-E infeed were assumed to occur indifferently in the second model run without RES-E. As a consequence, the national capacity portfolio had not only to serve the national demand, but also the assumed export amount. Consequently, in the first run, the power price was very low in these hours while in the second model run, they were very high due to the exponential shape of the supply curve. Sensitivities concerning capacity adaptation and a discussion on cost savings versus rent redistribution was provided in Sensfuss et al. (2008) and confirmed the power price-reducing effect of RES-E. Even though the economic interpretation of the RES-E-induced power price reductions has been questioned, important research questions can be derived from these early research results:

- How does the power price evolve with a dynamically increasing RES-E share over time?

- How does this influence the value of RES-E and consequently the support costs for consumers?
- How does the power market adapt to the increasing RES-E share?
- Which market design options enable further integration of increasing RES-E shares?

Eventually, the discussion on the 'merit-order effect' inspired the research that is presented in this thesis.

However, before an economic interpretation of the RES-E-induced effects can be derived, a better understanding of the underlying fundamental effects is required. In the course of the discussion, different studies have applied diverse approaches to assess the price-reducing effects. Since observations of changes in the market prices initiated the debate, Neubarth et al. (2006), Munksgaard and Morthorst (2008) and Jónsson et al. (2010) analyzed empirical data and compared hours with high RES-E infeed to hours with low RES-E infeed. A different approach has been applied by Bode and Groscurth (2006) and Sensfuss et al. (2008), who use computer models to further assess the observed effects. Another dimension in the form of a market power perspective was first introduced by Vasilakos and Green (2009), who show that the level of price reduction depends on the number of participants in the market and their market power exploitation. Nonetheless, the research presented in this thesis follows the aforementioned approaches in assuming a competitive power market in order to isolate the fundamental drivers of the price effects without stipulating additional assumptions on market power behavior.

Wissen and Nicolosi (2008) and Miera et al. (2008) started discussions on capacity adaptation within this context, though mainly on a qualitative level. However, in order to assess the economic implications of the RES-E market value, a long-run perspective is required which takes system adaptations into account. Understanding the short term effects is nevertheless of fundamental importance for the analysis. Hence, the fundamental dispatch structure and the resulting market prices are of particular interest. Therefore, in this thesis, the short-term effects are contextualized by analyzing dispatch and prices on the basis of a capacity portfolio optimized over time. Consequently, the following provides an overview on research concerning long-run capacity development.

2.2 Long-Term Effects

Deriving an economic value of RES-E for a power system based solely on the static perspective of a dispatch model or empirical data is not sufficient, since the evolution of RES-E includes by definition the long-term perspective of investment decisions. Consequently, capacity adaptations of the remaining system must be included in the analysis as well. The dynamic process in which new power plant investment decisions are considered is critical in modeling the impact of RES-E on the power system. A valid way to accurately capture the value of RES-E is therefore to compare a power system without RES-E, and consequently without the adaptation effects due to RES-E, to a system that adapts to the RES-E penetration through appropriate investment decisions. Both optimized capacity mixes have a different quantity and a different quality. The particular context defines the required attributes of the capacity mix. In any case, the generating capacity must be sufficient to guarantee a reliable operation of the system. The terminology of the reliability problem follows roughly Batlle et al. (2007), who distinguish between security, firmness and adequacy:

- Security is understood to be the readiness of existing generating capacity to respond, when needed, to meet the actual load. This means that the capacity is capable of following the load pattern.
- Firmness is defined as the short-term generating availability resulting from the operational scheduling of installed capacity. This definition is modified to incorporate the ability to provide sufficient reserve capacity and energy at the same time. If the market is firm at a certain point, opportunity costs influence the pricing mechanism. In the context of this thesis, this is especially important in low demand situations, which will be discussed in more detail in section 3.1.
- Adequacy means the existence of sufficient available installed capacity to meet demand at any time (the long-term effects will be discussed in section 3.2).

Despite the interrelation between short-term dispatch results and longer-term investment decisions, modeling the combined impact of both effects has proven challenging. Two general research streams exist in the literature: The first one is discussed above and uses high-temporal resolution dispatch models (usually 8760 hours) to capture the short-term price effects due to the variability of RES-E, whereas the second approach uses capacity-expansion investment models to illustrate the longer-term adaptation processes of the remaining power system. In order to capture longer-term investment effects, dispatch models sometimes use power plant portfolios that are generated from an investment model (see e.g. Vasilakos and Green (2009)), but in other cases, impacts on investment decisions are ignored (e.g. NREL (2010a)) because the focus of the research lies on operational challenges. The altered dispatch patterns and wholesale power prices, however, also impact the investment calculus of new power plants as demand rises or existing plants retire, and those new investments further influence dispatch and pricing results (Dena, 2005). It is therefore crucial to implement the capacity adaptation into the analysis.

Some studies have sought to explicitly combine dispatch and investment optimization into a single modeling framework in order to more accurately capture the benefits and impacts of wind power on the power system. Due to the high computational demands of accurately modeling the combined dispatch and investment optimization problem in great detail, however, a reduction in model complexity is usually required. One typical way to do this is to reduce the temporal resolution of the modeling framework. For example, rather than dispatching the system on an hourly basis over entire years, a smaller number of broader time slices is selected instead. NREL (2008) investigates the effects of a 25 % wind power penetration in the U.S. and applies 16 time slices that are primarily based on seasonal and daily load patterns. The electricity market module of the U.S. Energy Information Administration, which is used for the 'Annual Energy Outlook', uses nine representative time slices per year for the dispatch decisions (EIA (2010b)). Pehnt et al. (2008) analyze the impact of adding offshore wind power to the German power system and use 144 hours (6 typical months, 2 typical days and 12 typical hours). However, in order to take the variability of wind infeed into account, they use a stochastic approach with three different wind levels per modeled hour. Dena (2010) models the system adaptation to a considerable rise in wind power in the German power market until 2020 on the basis of typedays (4 seasons, 3 typical days and 24 hours), which in total represent 288 typical hours per year. Neuhoff et al. (2008) go further and consider 1040 hours in their analysis. They also integrate wind power investments into their research, but reduce the amount of potential conventional investment options to combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs). Möst and Fichtner (2010) choose an alternative approach by manually iterating a long-term energy system model and a heuristic model. In this way, the long-term development is taken into account on the basis of a higher resolution dispatch model. The intermediate results are checked after each iteration and manually stopped, in general after two iterations.

With the exceptions of Neuhoff et al. (2008) and Möst and Fichtner (2010), who capture a significant amount of load and wind power levels, the temporal resolution is quite low in the discussed approaches for modeling a high-level RES-E system. Reducing temporal resolution in this manner may be appropriate in systems without high penetrations of variable generation because, for example, every workday evening within a season may have a relatively typical demand pattern that does not deviate inordinately from one day to the next. Adding significant quantities of intermitting generation, however, can change the residual load substantially on an hourly basis. Since e.g. wind power fluctuates between close to zero infeed on calm days and very high infeed on windy days, this additional volatility should be considered by the methodology. Capturing these effects requires either a model with a higher temporal resolution is required or the addition of correction factors to try to approximate the correct result. Until now, however, little research has been published on the impact of model-based temporal resolution on modeling results in systems with high RES-E penetration.

The impact of intertemporal constraints on system operation and power prices on the other hand is well documented. Since these constraints increase the computational complexity, Neuhoff et al. (2008) ignore them to be able to benefit from the higher temporal resolution. In order to be able to model power block specific start-up decisions, the implementation of a mixed integer problem is required. This approach, however, is computationally quite expensive, as e.g. described in Wood and Wollenberg (1996). The linearization of intertemporal operational constraints is discussed by Kuntz and Müsgens (2007). Abrell et al. (2008) compare different approaches to model start-up costs and find that most approaches are unable to simultaneously obtain price-spikes in hours of start-up as well as prices below marginal costs when plants are kept online in demand valleys. The only exception found is the application of the linearized approach. Also Kreutzberg (2001) reports a good match of observed prices and modeled prices for the German power market in a linear setup. Even though this discussion is particularly important for the operation of the power system and therefore belongs to the short-run effect discussion, the example of Neuhoff et al. (2008) shows that trade-offs are often required to keep the problem solvable. As mentioned above, by now most dispatch models take intertemporal constraints into account. The effects of adding intertemporal constraints to a high resolution investment and dispatch models on the other hand, has not yet been well documented.

2.3 Corresponding Market Design Discussion

The focus of the analysis in this thesis is to increase the understanding of fundamental market interrelations. Therefore an approach is used which assumes a competitive power market. In this way, the price setting is based on short-term marginal costs in combination with an optimized capacity mix such that the resulting short-term effects can be correctly captured.[1]

However, as a consequence of this approach, the resulting price levels are not necessarily sufficient to recover investment costs. Joskow (2007) explains that competitive power markets produce prices which are not sufficient to cover investment costs and therefore cause the 'missing money' problem. Usually price caps at the wholesale markets are referred to as one of the main reasons for the lack of fixed cost recovery. Although, due to fundamental differences in market structures and market design, the 'missing money' problem in the U.S. is not directly transferable to the situation in Europe, Traber and Kemfert (2010) confirm this phenomenon for Germany, especially with increasing wind power penetration. A further issue which prevents sufficient price signals is the lack of demand response. In order to provide incentives to recover investments, demand signals based on the 'value of lost load' (VOLL) are required, which trigger price spikes in a sufficient number of hours and therefore finance the investment costs of the last required unit (Joskow (2007)). However, the assumed

1 For a discussion on long-run versus short-run marginal costs, see section 4.2.

VOLL, in combination with the annualized investment costs of a peaking plant, determine the amount of hours that are required to cover the investment costs.[2] Since the analysis focuses on the resulting price patterns induced by RES-E infeed, using an approach which determines the number of price spikes would interfere with the analysis. Price-setting based on short-term marginal costs in combination with an optimized power plant portfolio is the only way to capture the fundamental effects, which requires fundamentally determined power prices. The resulting prices in this central planner approach reflect the market results under perfect competition with sufficient generation capacity. Therefore, this approach reflects a situation with a capacity adequacy measure exogenous to the energy market, e.g. a capacity market. In reality, hardly any energy-only markets exist. Most markets have some kind of capacity market either in the form of reserve markets or bilateral contracts due to system adequacy and security reasons.

Solutions for the 'missing money' problem are discussed amongst others by Joskow (2008); Cramton and Stoft (2008); Batlle and Pérez-Arriaga (2008); De Vries and Heijnen (2008); Finon and Pignon (2008); and Roques (2008). In general, either energy-only markets with particular design characteristics are proposed or capacity markets are requested to support capacity investments. A further discussion on the particular designs and requirements exceeds the scope of the present research.

Further market design discussions which touch the present research, but cannot be included, are concerned with, e.g. the geographical scope and size of the market areas (e.g. Green (2008); Leuthold et al. (2008); Neuhoff et al. (2008); and Brunekreeft et al. (2005)), the temporal scope in terms of gate-closure and corresponding forecast issues (e.g. Holttinen (2005a); Müsgens and Neuhoff (2006); and Weber (2009)) as well as RES-E support scheme designs which intend to trigger investments in an efficient way by setting either prices or quantities and are primarily based on Weitzman (1974) (e.g. Hiroux and Saguan (2010); Klessmann et al. (2008); and Menanteau et al. (2003)). Since the focus of the present analysis is on the market integration of RES-E rather than on the financial incentives to invest into RES-E technologies, only the effects of different support schemes on the power market are analyzed (see 3.1.4).

2 See e.g. Stoft (2002) for a more detailed explanation.

3 Fundamentals of RES-E Market Integration

This chapter explains some fundamental interdependencies that motivate the particular modeling approach explained in chapter 4. Since wind is an intermitting energy source, the power markets react strongly to the stochastic wind power infeed. In times of high wind power infeed, the spot price at the wholesale market tends to be lower then when compared to times without wind power in the system. This phenomenon became popular under the term merit-order effect (see the literature discussion in 2.1). Since wind and solar power already covers a certain share of the load, the conventional power market only needs to cover the residual load. This leads to a lower interception of the merit-order curve with the demand function, and thus, to lower power prices.

An increase of intermitting generation capacity from wind and solar energy sources changes the requirements for the conventional energy market. In the long-run, investment decisions take this factor into account, leading to investments in generating capacities that are better equipped to efficiently cover the stronger fluctuating residual demand. This chapter is partially based on Nicolosi (2010) and is divided into two sections. First, the short-term integration effects are discussed. A general framework on firm market situations is provided on the basis of a fundamental market structure explanation and ensuing empirical examples of the German market illustrate the effects. Second, the long-term investment effects are explained in more detail.

3.1 Short-Term Effects and Empirical Evidence

The supply curve in the power market represents the marginal generation costs of the power plant fleet in an adjacent order and is therefore called merit-order. In a competitive power market, the power price is set by the marginal costs of the last generator that is required to cover the demand. In more extreme situations at both ends of the merit-order, in times of either very high or very low demand, the pricing structure deviates from this pattern. In times of low demand and high wind power infeed, the market reacts with bids below variable costs to avoid ramping-down base load power plants, which would require a costly ramp-up later. Up until September 2008 in Germany, the consequences included situations with a potential oversupply that needed to be cut on an inefficient pro-rata basis. The European Energy Exchange (EEX) in Leipzig (now EPEX [3]) reacted to this inefficiency by allowing for the possibility of negative price bids. In October 2008, the EEX closed with a negative power price for the first time. By December 2009, 86 hours with negative prices had been observed at the EEX. Among those, 19 hours had significantly negative prices below -100 EUR/MWh. The occurrence of negative prices is not problematic per se. However, they are an indicator of a firm market situation that could lead to situations in which the market does not clear at all if a proper market design is missing. Therefore, in this section, these 19 hours are examined in detail by analyzing the factors limiting market flexibility. Since the oversupply is currently the main issue, this section focuses on the flexibility at the low demand side. The flexibility at the high demand side is discussed in the long-run perspective in section 3.2. Before the empirical effects are shown, some institutional market fundamentals are explained in sections 3.1.1 and 3.1.2.

Figure 3.1 shows one random week in 2009. The load is shown as the blue line, the load negative wind power infeed is the green line and the red line represents the power price at the EEX. At first sight, one can see that the load follows roughly the same pattern every day of the week with the exception of the weekend days. The difference between the blue and the green line shows the wind power infeed, which varies strongly during this week. On the first Thursday, there is hardly any wind in the system, while on Sunday, Monday and the last Thursday there is a significant amount present. Consequently, the conventional power market has to supply a different amount of energy every day to serve the residual load.

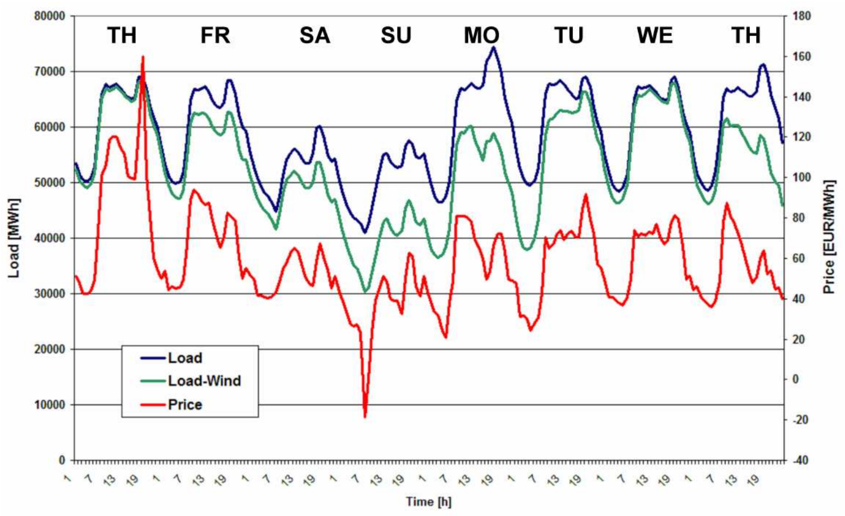
The power price reflects this pattern. On the first Thursday, with almost no wind in the system, the power price is the highest during this week. The next Thursday has a higher absolute load, but the power price is roughly 100 EUR below the previous week, due to a high wind power infeed during that day. Also, the Monday has only an average power price even though it shows the highest load during that time-frame. This relationship shows an even more interesting market result on Sunday morning. The wind power infeed is significant, while the load is at the lowest point of this week. Even though the residual load is still at 30 GW, the resulting market price is -20 EUR/MWh. The next section explains the market fundamental behind this phenomenon.

3.1.1 Power System Flexibility and Negative Power Prices

The flexibility of power markets is characterized by their ability to efficiently cover fluctuating demand. This flexibility is influenced by various factors, such as the installed

3 The exchange recently merged with other exchanges and is now called Epex. The explanation and empirical information is based on the earlier market data and market rules. Therefore, here it is still referred as the EEX.

Figure 3.1: Load and price curves



Source: own illustration, data provided by ENTSO-E (2010b), BDEW (2010) and EPEX Spot (2010).

power plant mix and the interaction with other markets. A power system, consisting of supply, grid infrastructure and demand, is adequately designed if it is able to cope with its challenges. Furthermore, the reserve power markets are responsible for system security in the real-time period. Since they require additional capacity, they also influence the flexibility of the power market. Flexibility becomes an issue in times with either very high or very low demand. In both cases, the market shows wholesale power prices which deviate from the usual variable cost based pattern (Cramton (2004), Ockenfels et al. (2008)). In times with very high demand, the market occasionally shows prices above variable cost, while in hours with very low demand, the market shows prices below the variable costs of the power plants. This section analyzes the flexibility restrictions concerning low demand cases by showing how different markets and market participants behave during these hours.

The system components supply, grid and demand have their own flexibility restrictions. This section abstracts from the grid infrastructure, since the price settlement at the market under consideration (the German power market) does not take grid bottlenecks into account. When internal grid bottlenecks occur within a price zone, the transmission system operators (TSOs) redispatch power plants on both sides of the bottlenecks after the market settlement of the wholesale market. In this case, the operation of power plants is not only based on economic principles, but also on post-market system security measures.

The Demand Side

The most obvious flexibility requiring factor on the demand side is the fluctuating, but almost inflexible, load itself (Strbac (2008)). Depending on the load structure throughout the day and the year, either a flexible power supply system is required if the load structure is very volatile, or a rather inflexible supply system is sufficient in the case of low volatility. The second factor is the amount of must-run generation, which is subtracted from the total load. Since must-run generation is independent from the level of demand, the offset of both factors defines the residual demand, which needs to be covered by the conventional supply system. In general, the more must-run installations, the more flexibility is required by the remaining power system. Furthermore, the must-run generation can be subdivided: The most important differentiation is between the renewable and the conventional side, such as combined heat and power (CHP). The focus of this thesis is the intermitting RES-E infeed, which is also placed on the demand side. The more load that is covered by RES-E, the less it needs to be covered by the conventional power market. The fluctuation of the demand, in addition to the fluctuation of the RES-E, forms an increasingly challenging requirement for the supply side of the system (Nicolosi and Fürsch, 2009).

The Supply Side

The flexibility of the supply side is determined by the mix of its installed capacities and the design of its interrelated markets. Base load power plants have high investment costs and low variable costs. Therefore, they require a high utilization throughout the year to cover investment costs. In addition, these plants are not designed for ramping-up and -down regularly since this reduces the lifetime of the parts that are exposed to high levels of pressure and heat. Consequently, a high share of baseload plants limits the flexibility of the power system. Furthermore, all thermal power plants have a minimum load. Due to the steam stream, they are not able to produce electricity below a particular share (see e.g. Strauß (2006)). If they are willing to lower the generation below this threshold, they need to shut-off the plant. This minimum-load restriction limits the flexibility considerably, especially when big power blocks are required to stay online.

The integrated design of the interrelated markets can limit market flexibility in several ways. First, the national market for reserve power strongly influences the power system since it reduces the flexibility by the amount of reserve power which needs to be held back for system security. If the auctions for the reserve power markets are not efficiently aligned with the wholesale power market, inefficient capacity commitment could be a result. Second, the interaction with international markets through interconnectors influences the power market. Again, if the auction of interconnector capacities is not well aligned with the gate-closure of the spot markets, the auctioned flow direction of the interconnector could deviate from the direction suggested by the price delta between the two power markets. This reduces the efficiency of the market results, and therefore market flexibility (for a more detailed analysis of market coupling and market splitting see, e.g. Brunekreeft et al. (2005), Wawer (2009)).

Firm Market Situation

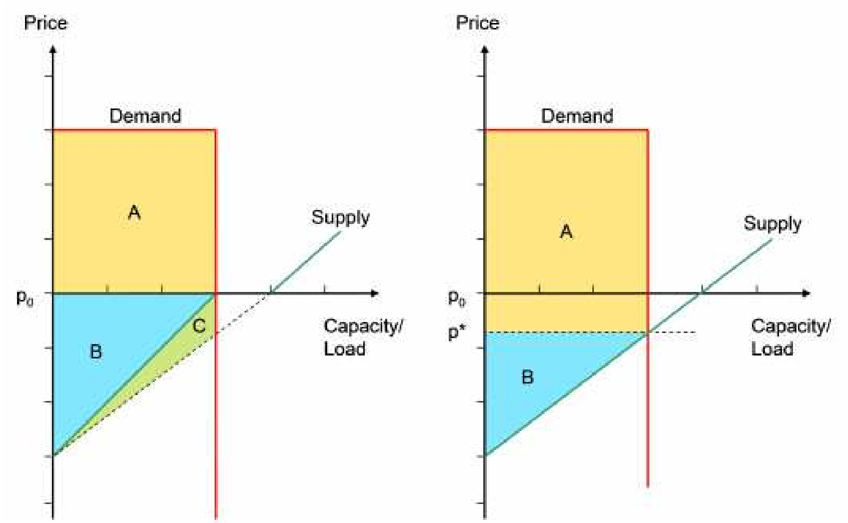
As explained previously, a market situation sometimes becomes critical due to a lack of flexibility. Since this section focuses on negative prices, the situations under consideration are characterized by potential oversupply. In the case of low load and e.g. high wind power infeed, the residual load is consequently quite low, as illustrated in Figure 3.1. The supply system needs to react to this situation by ramping down, or shutting off, power plants. Up to a certain threshold, this is not uncommon. However, at a certain point, this 'negative flexibility' becomes firm. This means that there is a lack of opportunities to further reduce conventional generation or to increase export.

A firm market situation occurs when plants that are online are not allowed to reduce their generation because they are obligated to supply system services, e.g. through commitments on the reserve power market. In reality, base load plants are also likely to generate because they are unwilling to shut-off the plant due to very high start-up and opportunity costs, arising when prices above variable costs occur in the following hours and the plants cannot start up in time. The base load induced market firmness varies by season. Since power plants need to be in revision once a year, they usually choose to revise during the season with the lowest demand. During this season, a lower base load share is available, meaning that the market becomes more flexible.

Negative Wholesale Power Prices

Although the possibility of negative prices seems to be counter-intuitive for an 'ordinary' good, the particular attributes of electricity, primarily the non-economic storage possibilities of large amounts, in combination with the limited flexibility of demand, leads to the occurrence of bids below variable costs, even negative ones. Before negative price bids were allowed in Germany, oversupply was cut on a pro-rata basis, which led to inefficiency (see the left side of Figure 3.2). This oversupply was due to the fact that opportunity costs are marginal-cost relevant (Cramton (2004)), e.g. if a power plant needs to ramp-down, additional costs occur for the later ramp-up (e.g. Hofer (2008) quantifies a ramp-up of a combined cycle gas turbine with 2.500 - 5.000 EUR). Therefore, it is efficient to integrate these opportunity costs into the bid to avoid the ramp-down and generate, even though prices do not cover the short term variable costs. As a result of these dynamics, the supply curve does not begin at zero, but has a slope leading into the negative area until the negative price cap is reached (see the right side of Figure 3.2).

Figure 3.2: Pro-rata distribution versus negative price possibility



Source: Nicolosi (2010), adapted from Viehmann and Sämisch (2009).

With the occurrence of negative prices, as illustrated on the right side of Figure 3.2, the new price is settled at p^* instead of p_0. The result of the negative price mechanism increases the overall welfare, since an efficient dispatch is possible and the welfare loss in area C on the left side of Figure 3.2 is avoided. Allowing negative price bids consequently leads to an efficient market result which takes opportunity costs into account. Negative prices also have effects on the distribution between producer and consumer rents. A brief explanation is provided according to Viehmann and Sämisch (2009). In Figure 3.2, A is the consumer rent and B the producer rent. As illustrated on the left side, the price limit of zero reduces the producer rent by C, since producers would have been willing to bid differently into the market and are forced to deviate from their optimal strategy and to run the power plants inefficiently. With the occurrence of negative prices (right side of Figure 3.2), the consumer rent is increased and the producer rent is decreased. The producers gain from changing to their efficient operation strategy. Since they are allowed to bid their opportunity costs, the overall efficient dispatch of the power plants increases welfare, while the negative price is also a market signal of the demand for flexibility. The consequences for the investment behavior are discussed in section 3.2

3.1.2 The German Power Market

The German power market is the biggest market in Europe when it comes to consumption. The four largest power producers are RWE, E.ON, Vattenfall and EnBW. They account for a market share of between 70 and 85% (Lise et al. (2008); Weigt and von Hirschhausen (2008)). The four TSOs have either been legally unbundled from the four main power producers or have even been sold by now. When it comes to bottlenecks within the grid infrastructure, the TSOs are obligated to redispatch the power plant operation after the market settlement of a single price zone. This is common for most power markets in Europe. Other market designs, such as zonal or nodal pricing are widely applied (e.g. Nordpool or PJM). However, the benefits of one single, liquid and transparent market are presently valued higher than the more efficient price-settling mechanisms which take grid constraints into account (for a more detailed discussion on market designs in carbon constrained power systems, see Green (2008)).

The German Wholesale Market

The German wholesale market is fragmented into an virtual over-the-counter (OTC) market and the European Energy Exchange (EEX) in Leipzig. While the OTC market has a continuous trade, the EEX has a single auction with a gate closure for the day-ahead market at 12 p.m. on the day before physical delivery. Although three fourths of the trading volume are settled via bilateral OTC contracts, the EEX spot price is of fundamental importance as a benchmark and reference point for other markets, such as OTC or forward markets. Since buyers and sellers always have an arbitrage option at the EEX, the price expectations on both sides cannot systematically deviate from the expected outcome of the other markets. Nobody would accept an offer at the OTC market if the expected outcome at the EEX was more beneficial. However, it is still possible that forward prices deviate from the day-ahead EEX price, due to different information or risk perceptions (see Ockenfels et al. (2008) for a discussion on different auction designs). The price settling mechanism at the EEX is a uniform price auction.

After the day-ahead market closure, trade is still possible at the intraday market. However, the main share of the trades is settled with the gate closure of the EEX (Viehmann (2011)). The intraday market still lacks liquidity and the resulting market price is therefore not a valid benchmark. The hour before physical delivery falls into the responsibility of the reserve power market, which is operated by the TSOs. Within this short time frame, they are obligated to balance the deviations between supply and demand, which arise due to load and wind infeed forecast errors, as well as unplanned power plant outages (Just and Weber (2008)). Since September 2008, the EEX has allowed negative price bids, with the first negative market result occurring in October 2008.

Market Interaction

The interaction with other markets influences the ability of the entire system to react efficiently to new information and to adapt its generation accordingly. In this section, international interactions through interconnectors will be discussed first, followed by a description of the German reserve power market.

The German wholesale power market is influenced by its surrounding markets since it has interconnectors to most of them with total net transfer capacities of 17 GW import and 14.8 GW export capacities (ENTSO-E (2009a)). Transmission rights are required to manage the international exchange between the power markets. Depending on the individual interconnector, either implicit or explicit auctions settle the transmission rights. The current trend is to integrate the markets as closely as possible to increase the economic utilization of the interconnector capacities. In general, the individual interconnectors serve as either additional supply in the merit-order in the case of imports or as flexible demand options in case of exports. Since many interconnector capacities are explicitly auctioned before the gate closures of the individual power markets, the auction results do not reflect the market results and are therefore not included in this analysis. However, the general trend is to implicitly integrate the auctions into the settlement of the market results (market splitting). This is supported by the increasing demand for the efficient utilization of the interconnector capacities.

Not only is the interaction of international markets of great relevance but the interdependencies between intra-national markets is as well. The reserve power market interacts with the wholesale power market, since generation capacities are required for assuring security of supply (see Table 3.1 for an overview of the reserve products).

In the reserve power market, 5.7 to 7.2 GW of positive reserve and 4.3 to 6.2 GW of negative reserve were auctioned within the time frame under consideration and were therefore not available for the economic settlement of the wholesale power market. These capacities were required for primary, secondary and tertiary reserve.

Primary reserve is required to react instantly in the case of frequency imbalances. This product is responsible for the first five minute time frame and is substituted by secondary reserve afterwards for the following 10 minutes. These two products are

Table 3.1: Overview of auctioned reserve power products (10/2008-12/2009 in MW)

Reserve products	direction	Min	Max
Primary	negative/positive	656	664
Secondary	negative	2,064	2,340
	positive	2,678	3,013
Tertiary	negative	1,559	3,238
	positive	2,285	3,508
Total	negative	4,279	6,242
	positive	5,619	7,185

Source: Nicolosi (2010), based on Regelleistung.net (2010).

automatically controlled by the TSOs. Since primary and secondary reserve power are spinning reserves, these plants need to generate power to supply positive and negative reserve. One exception is the provision of secondary reserve by non-spinning hydro power plants with sufficiently quick start-up times. Tertiary reserve needs to be online within 15 minutes and can therefore also be met by non-spinning reserves, e.g. by open cycle gas turbines (OCGTs) with short start-up times. While tertiary reserve is auctioned every workday for the following workday and weekend, primary and secondary reserves are auctioned every month. In other words, the power plants that win the auctions for primary and secondary reserve are obliged to stay online for the entire month, independent of spot market results. The power plants that supply negative reserve are required to generate according to the contracted margin above their minimal load restriction in order to reduce the infeed when required. In consequence, the flexibility of the German power generation was significantly lowered by the negative reserve power requirements of 4,279 to 6,242 MW in the considered time frame, of which 2,720 to 3,004 MW were auctioned monthly and 1,559 to 3,238 MW were auctioned daily. Because the tertiary reserve is auctioned every workday, the auction results serve as an indicator for market tightness, since the additional opportunity costs result in higher reserve power prices in tight market situations. Therefore, these market results are analyzed in the hours of extremely negative prices of below -100 EUR/MWh in section 3.1.3.

Due to its broad technology mix, the German power market is a good example for an investigation of the flexibility of power systems. A substantial base load plant fleet (see Table 3.2) satisfies the base demand throughout the year. Load following is mostly conducted by hard coal plants and gas-fired power plants. Table 3.2 shows the available conventional capacity according to the voluntary declaration of market participants on the EEX transparency website between October 2008 and December 2009 as well as the installed RES-E capacity at the end of 2008 and 2009 respectively.

Table 3.2: Available capacities in Germany (MW)

Technology	Min	Max
Nuclear	10,914	18,266
Lignite	11,703	18,766
Hardcoal	8,986	16,675
Natural Gas	6,868	13,925
Oil	1,159	2,409
Hydro	3,463	4,574
Others	356	451
Wind	23,897	25,777
Photovoltaics	5,877	8,877
Biomass	3,973	4,429

Source: Nicolosi (2010).

The RES-E market growth has been substantial in the last 10 years. Germany started in 1990 with a feed-in tariff system. The so-called 'Stromeinspeisegesetz' was technology neutral and linked to the end consumer price. In 2000, the Renewable Energy Sources Act (EEG) came into force and implemented a technology-specific, highly diversified feed-in tariff structure to allow for deployment in less efficient locations on the one hand and to lower the producer rents at favourable locations on the other.

The TSOs are obliged to purchase any amount of RES-E from the plants and integrate them into the market (EEG (2008)). Beginning in 2010, the TSOs directly sell RES-E to the EEX (before 2010, distributors were forced to integrate a fixed RES-E share into their portfolio). This rule had to be followed at all times without consideration of the demand. On the one hand, the fixed feed-in tariff, in combination with the guaranteed purchase, has increased the investment security and thereby led to a significant growth of installed capacities and market share. On the other hand, the forced RES-E market integration, independent of the level of demand, covers an increasingly high share of the demand and even leads to potential 'oversupply' situations. Consequently, the market clearance is threatened due to this flawed market design. This leads to challenging situations in low demand hours, which can easily be identified via the resulting market prices.

3.1.3 Empirical Investigation

The data for this investigation stem from a variety of sources which, in combination, help to explain the market situation of supply, demand and market results. The market result comprises spot power prices as well as the actual generation, and the available capacity on the supply side has been provided by EEX. The time frame starts with the first occurrence of negative prices at the EEX and ends in December 2009. From 2010 on, the German regulator installed out-of-market curtailment rules, which made negative prices very rare.

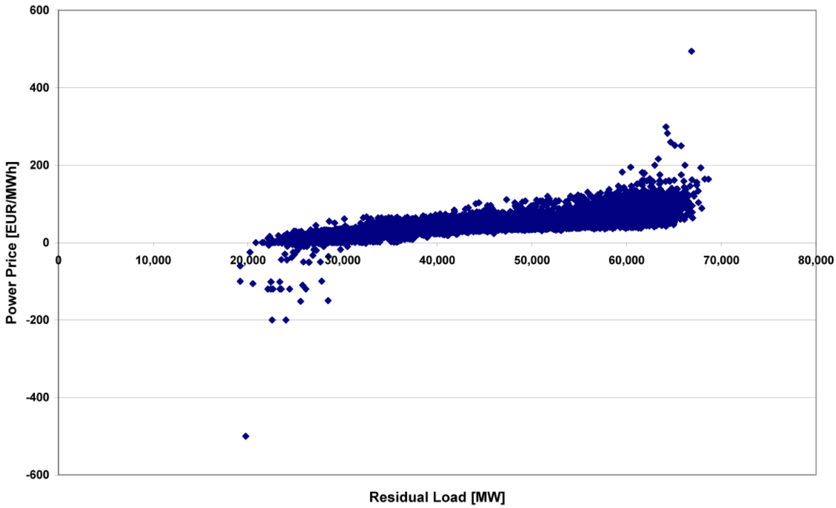
The actual wind power infeed has been provided by the German Energy and Hydro Association (BDEW). The day-ahead wind power forecast would have provided a better explanation of the market results, since the actual wind power infeed is the value every market participant tries to predict. There are numerous wind forecasts available and every market participant uses a different one or a combination of several. Since, in this section, the actual market situation is analyzed, the realized values are used. The fact that the spot price is settled day-ahead, and is therefore based on slightly different information, is of minor importance for the investigation of tight market situations. The same is true for the realized load which has been provided by the European Network of Transmission System Operators for Electricity (ENTSO-E). BDEW also supplied monthly data on the total RES-E generation. Reduced by the hourly wind power infeed, the RES-E data have been calculated as a monthly band in order to take the must-run generation of other RES into account. Thus, load and wind power infeed, in combination with a band of the remaining RES-E, form the residual load. The reserve power market provides an additional hint of the market tightness. The data of the auction results stem from the shared website of the German TSOs (regelleistung.net). In the following subsections, the data are aligned in a way in which the relative tightness of the market becomes apparent.

Overview of the Market Behavior in the Entire Time Frame

For a first impression, Figure 3.3 provides an overview of the data for the time frame between October 2008 and December 2009. In Figure 3.3, the residual load is expressed on the x-axis and the power price on the y-axis. The scatterplots' shape resembles the merit-order curve. It can be seen that in tight market situations, on both ends of the curve, the market reaction has deviated from the usual pattern.

All hours with negative prices have been found to have a residual load below 30 GW. The reason why these dots are not aligned more smoothly is that the flexibility shortage of the power market depends on power plants that are online, which strongly depends on the season. When a significant number of base load plants is in revision, the residual load can become much lower before a negative price occurs. Conversely,

Figure 3.3: Spot prices and residual load



Source: Nicolosi (2010), data provided by ENTSO-E (2010b), BDEW (2010) and EPEX Spot (2010).

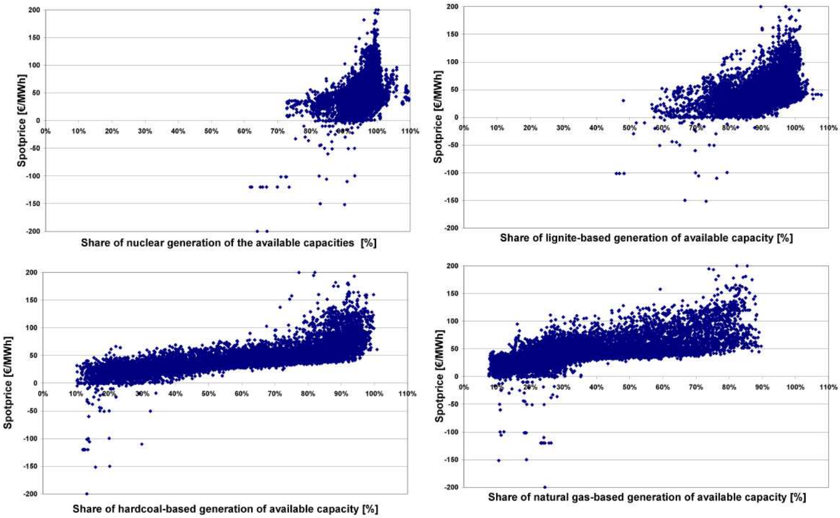
if all plants are online, the system will be under pressure much earlier.

Next, the market behavior in the time frame is evaluated from the supply side. Figure 3.4 provides an overview of the utilization of the conventional generation from nuclear, lignite, hard coal and gas.[4] The y-axis denotes the spot price and the x-axis, the share of generation from a given energy source in the respective registered available capacity for each day. Through this approach, one can analyze how the relative utilization has been without the previously explained seasonality effects.

Power generation from nuclear power plants (upper-left corner) shows very little fluctuation. The total generation is never below 60% of the available capacity, with a strong concentration above 90%. The generation from lignite (upper-right corner) shows a little more flexibility. However, the share is never below 45% of the available lignite-fired capacity, whereas the concentration is above 80% utilization. The distribution of hard coal-based generation (lower-left corner) and natural gas-based generation (lower-right corner) is quite different from the two base load technologies. While no energy source ever falls below a 10% share, the generation from hard coal

4 Due to data errors in December 2009 for lignite, this month is not included in the illustration.

Figure 3.4: Utilization of capacity by energy source



Source: Nicolosi (2010), data provided by EEX Transparency (2010) and EPEX Spot (2010).

fluctuates between 10% and 100%. In contrast, generation from natural gas is never above 90% utilization, which is probably due to system security requirements. If the entire power plant mix is highly utilized, natural gas-fired power plants are most likely used to provide positive reserve power.

The Significant Negative Prices

Between October 2008 and December 2009, 19 hours exhibited extremely negative prices (below -100 EUR/MWh). An overview of the conventional supply side in these hours is provided in Table 3.3.

Generation from nuclear and lignite power plants were found to account for much higher percentages of available capacity than hard coal and gas fired power stations. Even at the lowest spot price of -500 EUR/MWh on October 4th, the total capacity had an utilization of 46% (generation as share of available capacity), which corresponds to a thermal generation of 26 GW in this hour. Nuclear power plants were utilized to 83% and lignite power plants to 71%. The relative utilization on December 26th was

Table 3.3: Supply-side data of 19 hours with substantially negative prices

Index	Day	Date	Hour	Price	Nuclear		Lignite		Hardcoal		Gas		Total	
					[MW]	[%]	[MW]	[%]	[MW]	[%]	[MW]	[%]	[MW]	[%]
	Mo	22.12.2008		Avail. Cap.	17,814		18,050		15,683		13,872		47,605	
1			3	-101.5	12,938	72.6	8,462	46.9	2,085	13.3	2,523	18.2	29,102	40.4
2			4	-101.5	12,646	71.0	8,300	46.0	2,074	13.2	2,575	18.6	28,686	39.9
3			5	-101.5	12,904	72.4	8,713	48.3	2,121	13.5	2,606	18.8	29,424	40.9
	Su	08.03.2009		Avail. Cap.	14,989		17,201		13,103		11,502		62,821	
4			7	-110.0	13,629	90.9	13,112	76.2	3,907	29.8	2,771	24.1	36,239	57.7
	Mo	04.05.2009		Avail. Cap.	14,453		16,819		14,000		10,660		63,123	
5			2	-151.7	13,034	90.2	12.284	73.0	2,218	15.8	1,119	10.5	32,181	51.0
6			5	-99.7	13,478	93.3	13,344	79.3	2,789	20.0	1,285	12.1	34,275	54.3
	Su	04.10.2009		Avail. Cap.	13,138		15,666		12,911		9,475		56,928	
7			2	-105.8	11,136	84.8	11,089	70.8	1,809	14.0	1,061	11.2	26,690	46.9
8			3	-500.0	10,913	83.1	11,042	70.5	1,765	13.7	1,035	10.9	26,361	46.3
9			4	-100.1	10,842	82.5	10,942	69.8	1,763	13.7	1,034	10.9	26,175	46.0
	Su	24.11.2009		Avail. Cap.	17,013		17,420		15,416		12,156		68,379	
10			4	-149.9	14,098	82.9	11,608	66.6	3,103	20.1	2,292	18.9	32,703	47.8
	Tu	26.12.2009		Avail. Cap.	17,213		17,137		13,979		10,363		65,347	
11			1	-119.9	12,033	69.9	10,215	59.6	1,728	12.4	2,724	26.3	29,054	44.5
12			2	-120.0	11,470	66.6	10,005	58.4	1,684	12.0	2,531	24.4	27,990	42.8
13			3	-120.0	10,627	61.7	9,908	57.8	1,678	12.0	2,422	23.4	26,886	41.1
14			4	-120.0	10,705	62.2	10,151	59.2	1,702	12.2	2,401	23.2	27,207	41.6
15			5	-120.0	11,149	64.8	10,153	59.2	1,742	12.5	2,434	23.5	27,745	42.5
16			6	-120.0	11,256	65.4	10,152	59.2	1,780	12.7	2,484	24.0	27,968	42.8
17			7	-200.0	10,990	63.8	10,008	58.4	1,844	13.2	2,528	24.4	27,711	42.4
18			8	-199.9	11,469	66.8	10,288	60.0	1,852	13.2	2,531	24.4	28,678	43.9
19			9	-120.0	12,646	73.5	11,105	64.8	1,894	13.5	2,657	25.6	31,067	47.5

Source: Nicolosi (2010), data provided by EEX Transparency (2010) and EPEX Spot (2010).

lower due to the longer duration of the negative price period.

A look on the demand side in Table 3.4 illustrates how the mix of load and wind infeed leads to the residual load, which the conventional market needs to cover. The hour with the most extreme negative price of -500 EUR/MWh occurred on October 4th, 2009. The average wind power infeed was 4.5 GW within the considered time frame. The wind power infeed on May 4th, 2009 was not considerably above that average. However, the low load in these hours, in combination with the modest wind power infeed, resulted in one of the most negative prices so far. In contrast, on October 4th, the wind infeed was quite significant, while the load was not uncommonly low.

Table 3.4: Demand-side data of 19 hours with substantially negative prices

Index	Day	Date	Hour	Price EUR/MWh	Wind MWh	Demand MWh	Res. Demand MWh
1	Mo	22.12.2008	3	-102	15,787	41,763	25,976
2	Mo	22.12.2008	4	-102	15,897	41,845	25,948
3	Mo	22.12.2008	5	-102	16,022	42,919	26,897
4	Su	08.03.2009	7	-110	8,722	38,488	29,766
5	Mo	04.05.2009	2	-152	4,965	34,922	29,957
6	Mo	04.05.2009	5	-100	4,786	36,973	32,187
7	Su	04.10.2009	2	-106	17,607	42,051	24,444
8	Su	04.10.2009	3	-500	17,188	40,874	23,686
9	Su	04.10.2009	4	-100	17,072	40,176	23,104
10	Tu	24.11.2009	4	-150	17,614	50,041	32,427
11	Sa	26.12.2009	1	-120	19,809	48,107	28,298
12	Sa	26.12.2009	2	-120	19,263	45,566	26,303
13	Sa	26.12.2009	3	-120	18,262	44,250	25,988
14	Sa	26.12.2009	4	-120	17,259	43,799	26,540
15	Sa	26.12.2009	5	-120	16,264	43,666	27,402
16	Sa	26.12.2009	6	-120	15,704	42,982	27,278
17	Sa	26.12.2009	7	-200	14,464	40,903	26,439
18	Sa	26.12.2009	8	-200	13,929	41,835	27,906
19	Sa	26.12.2009	9	-120	13,579	43,588	30,009

Source: Nicolosi (2010), based on EPEX Spot (2010), BDEW (2010) and ENTSO-E (2010b).

Nonetheless, this combination led to the lowest price observed in Europe so far. In comparison, the residual load on November 24th was almost 9 GW above the level of October 4th. On November 24th, a significant negative price occurred independently from a weekend or a holiday for the first time. At that time, more plants were online, such that the market became less flexible in terms of the possibility of further reducing the generation, e.g. due to minimal load restrictions. These fundamental flexibility reducing factors can also be observed as high capacity prices on the market for negative tertiary reserve. Table 3.5 provides an overview of the market results in times of the extreme events.

Although the market for tertiary reserve has gate-closure at the last workday for the next workday, the overall expectation of the market tightness is well illustrated in the market results. It strikes the eye that the market was very tight on December 26th. Together, the information from Tables 3.3, 3.4 and 3.5 provide an overview of the main market characteristics which triggered the extreme negative price events. Low demand with an eventually high wind power infeed in combination with an inflexible power mix, observable as high negative reserve power prices, leads to highly negative spot market power prices.

Table 3.5: Tertiary reserve prices of 19 hours with substantially negative prices

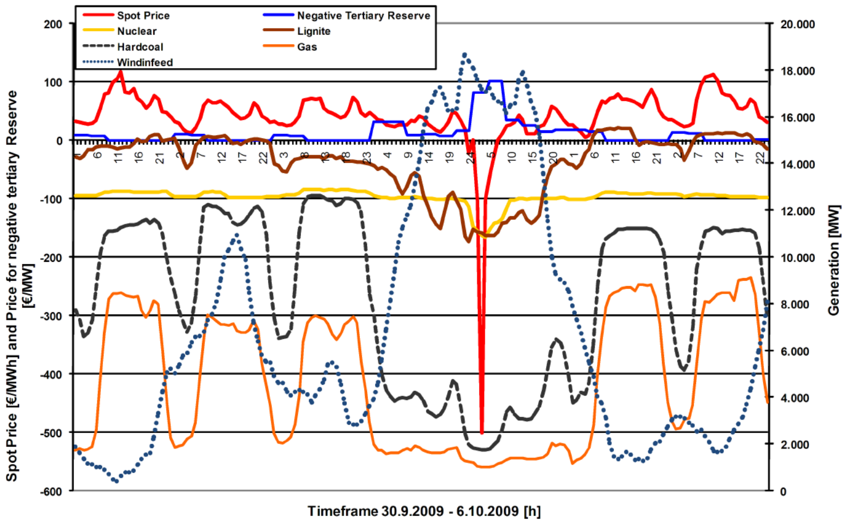
Index	Day	Date	Hour	Price EUR/MWh	Positive EUR/MWh	Negative EUR/MWh
1	Mo	22.12.2008	3	-102	0	31
2	Mo	22.12.2008	4	-102	0	31
3	Mo	22.12.2008	5	-102	0	29
4	Su	08.03.2009	7	-110	2	75
5	Mo	04.05.2009	2	-152	1	13
6	Mo	04.05.2009	5	-100	5	14
7	Su	04.10.2009	2	-106	0	81
8	Su	04.10.2009	3	-500	0	81
9	Su	04.10.2009	4	-100	0	81
10	Tu	24.11.2009	4	-150	1	68
11	Sa	26.12.2009	1	-120	1	100
12	Sa	26.12.2009	2	-120	1	100
13	Sa	26.12.2009	3	-120	1	100
14	Sa	26.12.2009	4	-120	1	100
15	Sa	26.12.2009	5	-120	1	185
16	Sa	26.12.2009	6	-120	1	185
17	Sa	26.12.2009	7	-200	1	185
18	Sa	26.12.2009	8	-200	1	185
19	Sa	26.12.2009	9	-120	1	16

Source: Nicolosi (2010), data provided by Regelleistung.net (2010) and EPEX Spot (2010).

Since the market showed the lowest price on October 4th, in order to get a better idea of the market dynamics, Figure 3.5 shows the corresponding generation of the main energy sources on the right axis as well as the spot price and the price for negative tertiary reserve on the left axis.

The first observation in Figure 3.5 is that the spot prices and the price for negative tertiary reserve are negatively correlated. This led to the highest price for negative tertiary reserve when the spot price had its negative peak at -500 EUR/MWh. The second observation is that no energy source reduced its generation to zero. Natural gas- and hard coal-based generation were strongly reduced in the hours with negative prices. Lignite-based generation was reduced quite significantly for a base load technology. In contrast, the generation from nuclear plants was hardly reduced. These observations confirm the lessons learned from Figure 3.4, illustrating, more or less, the fluctuating generation of the different energy sources. In summary, one can say that the flexibility of the aggregated supply side is probably lower than expected, since all technologies show limited bandwidths of flexibility and altogether were not able to reduce the generation below 46% of the available capacity. Especially base load technologies showed thresholds which seem to be at relatively high levels.

Figure 3.5: Dispatch on October 4th, 2009



Source: Nicolosi (2010), data provided by EEX Transparency (2010) and EPEX Spot (2010).

3.1.4 Impact of Support Schemes and Curtailment Regulation on Market Prices

With the two predominant power system attributes of inflexible demand and forced RES-E infeed, the conventional power capacity is the only flexibility option of the current German power system. If this was a static system, one would probably argue that the limitation of wind power infeed in low demand hours would be the solution. However, having the dynamics of the power system evolution in mind, it becomes apparent that this approach is short-sighted, as it reduces the market signals that reward flexibility and facilitates the necessary structural changes. Due to its climate policy, Germany has ambitious targets for its renewable energy deployment.[5] Therefore, a more balanced approach is required to enable an increasing RES-E infeed on the one hand and to provide market signals that trigger the right investments on the other hand.

One step in facing this challenge has been the implementation of a market based option in the EEG, which allows RES-E plant operators to sell their electricity directly to the market. By now, the option has not been used to a great extent due to the lack of a premium system as a profitable alternative to the FIT. In this support system, RES-E operators would receive a premium on top of the market price for every sold energy unit. As soon as a premium is available that is high enough to motivate plant operators to switch to this EEG option, the amount of the premium would become the lowest possible negative price these operators would bid into the market before curtailing their generation. Without the premium option, TSOs would have to place an open bid (which means at the negative cap of -3000 EUR) into the market, if it was not for a last minute regulation change of the German regulator Bundesnetzagentur (BNetzA). On February 22nd, 2010, an interim rule (valid until the end of 2010) was published, which allowed some flexibility in the RES-E market integration (BNetzA (2010b)). If 60% of the installed wind power capacity were utilized and the national load was at the same time below 60% of the peak load of 2009, the TSOs were then allowed to place restricted bids. The height of these bids needed to change randomly, so that other market participants were not able to guess at which price wind power was integrated into the market. If not all the wind power was sold, bilateral arrangements with RES-E plant operators were possible to curtail their generation.

This interim rule increased insecurities about the actual amount of wind power in the market. Therefore, in the medium-term, the premium system is strongly preferable compared to the interim rule, since the placing of bids in the market would depend on fundamental and publicly available data, which increases the transparency of the market. The question about the optimal bid for wind power remains. From a static economic perspective, the value of wind power is zero as soon as the wholesale price is zero. However, RES-E has additional attributes, such as environmental benefits, which are politically supported. Therefore, the value seems to be above the wholesale power price. This would explain negative bids, but does not justify the risk of lacking market clearance. Finding the exact value for a premium or an out-of-market curtailment rule is nevertheless challenging, due to the interdependence with the conventional part of the power market. According to various market participants,

5 The detailed technology-specific targets will be discussed in greater detail in section 6.1.

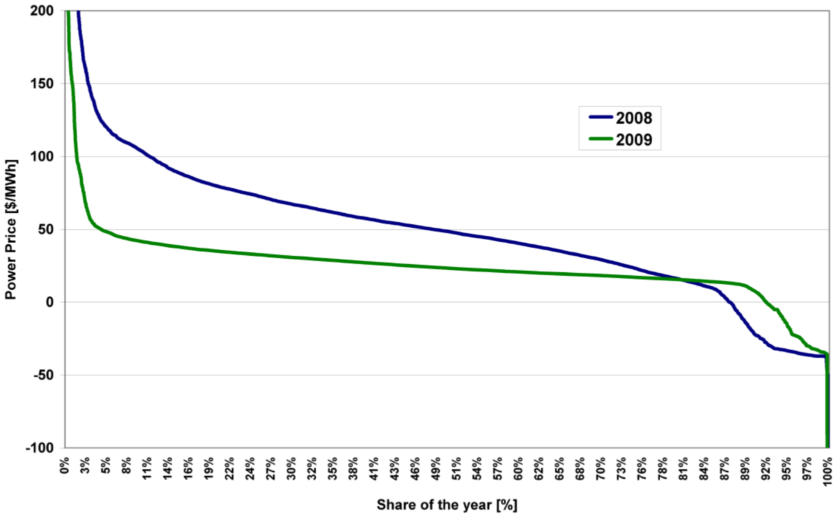
negative prices below -100 EUR are fundamentally not explainable from the perspective of a conventional generator (BNetzA (2010a)). To answer this question requires a complex analysis of detailed technical restrictions and market developments in the consecutive hours in which the opportunity costs arise.

The empirical examples of the German power market show that the market design in the considered time frame had a flaw, which could lead to a non-clearing market. As already mentioned, due to this reason, the BNetzA implemented an out-of market curtailment rule in Germany. As a result, in 2010 there were hardly any negative prices observable. However, market participants strongly argued against this particular approach because it reduces the transparency of the market. Traders who rely on wind forecasts do not know how much wind power is actually bid into the market. This causes unnecessary friction in the market in addition to forecast deviations. However, the flaw of the market design needed to be fixed in order to avoid a market failure. The BNetzA has revisited this rule, such that from 2011 on, limited RES-E bids of the TSOs are only allowed if a second auction is required due to a resulting market price below -150 EUR/MWh. These bids must to be between the bandwidth of -150 EUR and -350 EUR. Each TSO is obligated to split the bids into ten equal pieces and bid randomly within the bandwidth. This leads to 40 random negative bids for RES-E from the four TSOs in total.

With the next amendment of the EEG in 2012, a premium system is likely to replace the curtailment rule, since the premium level determines the amount of the negative bid. If, e.g. the premium for one MWh of wind power is 50 EUR, the operator would sell the wind energy until the spot market reaches -50 EUR because the sell is profitable until this level. If the power price is below -50 EUR, the operator curtails the wind power infeed due to economic consideration. No out-of market rule would be required to reach market clearance. Curtailment rules would only be required if grid bottlenecks occur independently of the market results within one price zone. In Germany, the TSOs redispatch conventional generators in this case. For RES-E, additional rules are usually required.

The effects of a premium system can be observed in the ERCOT market in Texas. Texas has a renewable portfolio standard (RPS) which sets minimum targets for RES-E. However, the actual RES-E share is much higher than the current target. Consequently, the RPS tradable certificate price is close to 0 USD/MWh. The majority of the wind generation is deployed in the western Texas price zone, due to very favorable wind conditions. This price area however has a very low demand, which makes it ideal for this analysis. In addition to the RPS, a federal RES-E support scheme is in place. The production tax credit (PTC) provides tax cuts for generated and sold RES-E. As a consequence, the PTC has the same effect as a fix premium system, since it is paid on top of the market price. The resulting bidding behavior can best be observed for the year 2008 in Figure 3.6. The price duration curves are market results of one year in an anticlimactic order. Initially, one can see that a significant share of the power prices in 2008 is negative. In addition, the negative power prices converge to a certain level. This level is the previously-explained level of the PTC or premium payment.

Figure 3.6: Price duration curves of the ERCOT market



Source: own illustration, data provided by ERCOT (2010a).

The price duration curve of 2009 shows a different pattern. Especially in the higher priced hours, the price level is much lower than the price level of the previous year. For this change, economic reasons such as a lower natural gas price are responsible. The focus of this section however lies on the lower priced region of the price duration curve. During the year 2009, 850 MW of wind power capacity was added to the portfolio. However, the price duration curve of 2009 shows significantly less negative prices compared to the previous year. What first seems counter intuitive can be explained by the previously-discussed regulatory changes. A significant share of the wind power capacity is installed in McCamey county. Since this deployment happened at a very fast pace, the grid infrastructure could not carry all wind energy at times of high infeed. Due to this reason, at the beginning of 2009, an out-of-market curtailment rule was implemented. Since the wind power curtailment notice reduces the amount of wind power bid into the market, the market-based curtailment was dramatically reduced compared to 2008.

This section showed that as long as the grid infrastructure is sufficient to distribute wind energy, a market-based curtailment rule can lead to market clearance and is therefore favorable compared to other methods currently implemented in Germany. However, if the grid infrastructure is insufficient, out-of-market curtailment rules are required to ensure system security. In the Texan example, one can easily observe that the presence of these rules can change market results and consequently market signals significantly. However, correct market signals are necessary to trigger the right investments. In the case of Texas, a transmission investment plan has been established to enable the system to carry the high wind power share. Infrastructure investments are the result of a planning process within a regulated component of most power markets. This thesis focuses on the competitive part of the power market, which covers the wholesale market and also the investments in generating capacities. Efficient power plant investments as a consequence of market signals that are triggered by a high RES-E share are discussed in the next section.

3.2 Long-Term Effects

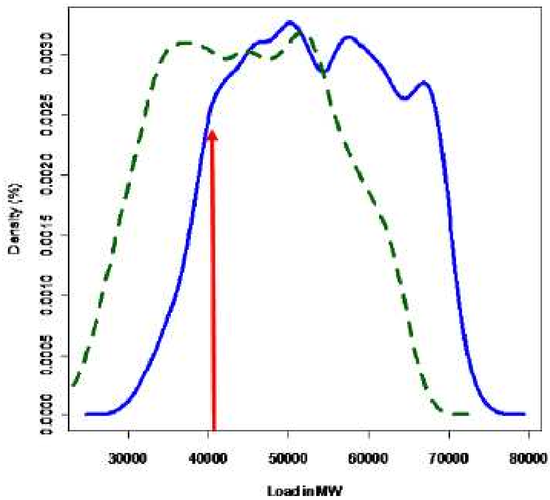
This section covers two different effects that explain a shift in the optimal power plant portfolio: the utilization and the flexibility effect. The increasing RES-E share in a non-growing system necessarily leads to a reduction in the utilization of the conventional power plant capacity. In the long-run, under consideration of investment decisions, this leads to a shift towards a lower base load capacity share since base load plants require a high utilization due to their high fixed costs. If the system has an increasing demand, it simply reduces the investment needs for base load plants.

Figure 3.7 shows probability distributions of the load and the residual load in Germany for the above discussed time frame. Although both distributions represent the same time frame, one can see how the requirements for the conventional part of the system change due to the high RES-E share of 16.1% in 2009 (BMU (2010a)). As a reference point, the red arrow indicates the load level at which the -500 EUR price occurred.

The peak load is reduced and the overall distribution is moved to lower load regions. The lower slope of the residual load in the peak area indicates that the highest residual load level materializes less often, while the high load levels have a higher probability of occurring. This effect can also be shown by annual load duration curves, as done in the lower right corner of Figure 3.8[6]. Load duration curves show all load levels of one year in an adjacent order. One can see that the peak load is hardly reduced, while the lowest load changes substantially.

6 The data are from an ERCOT case with a high wind energy share, which will be discussed in Chapter 5.

Figure 3.7: Change of load structure (solid line: load; dashed line: residual load)



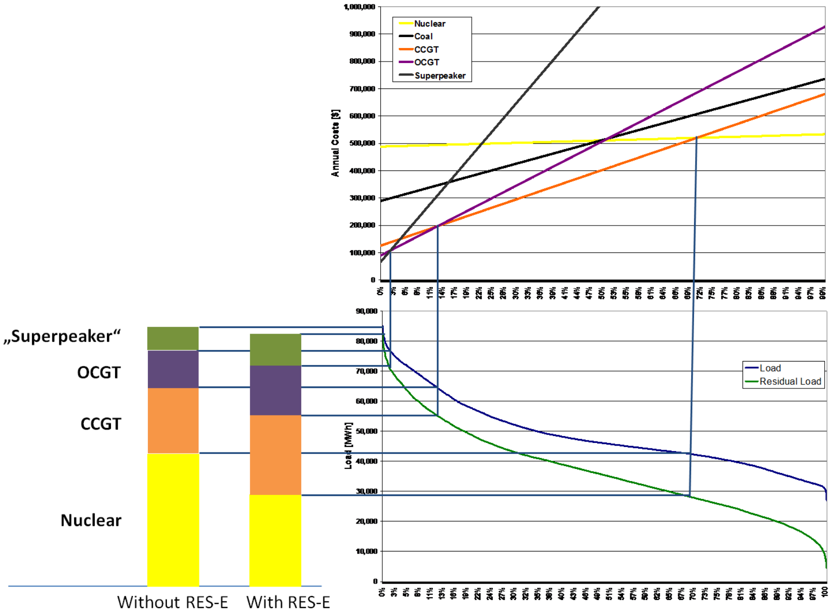
Source: Nicolosi (2010), based on BDEW (2010) and ENTSO-E (2010b).

The Utilization Effect

Based on the load duration curves, one can derive a rough estimate on the optimal structure of the optimal power plant portfolio for a given demand structure. Since the load duration curves have no information on the structural requirements of the chronological order of the load levels, the results are based purely on the utilization of a generating technology.

The upper right corner illustrates streaming curves with annuity capacity costs as a starting point at the ordinate. It can be seen that base load plants have relatively high investment costs and low variable costs (i.e. fuel and CO_2 costs). Peak load plants have low investment costs and relatively high variable costs. The abscissa shows the annual utilization time at which the plant types become efficient. Base load plants are economically viable when a high utilization time can be reached. Peak load plants are the efficient choice when the utilization remains at a low level (see, e.g. Stoft (2002) and Nabe (2006)). In the lower right graph, the two annual load duration curves are depicted. The shift of the shares of the different power plant types can be seen in the lower left graph. This shift stems from the relationship between the relatively high RES-E infeed, compared to its relatively low share of secured capacity of the total

Figure 3.8: Capacity adaptation to RES-E increase



Source: own illustration, data provided by ERCOT (2010a).

RES-E capacity, since the RES-E generation is not guaranteed in the hours of peak demand. However, because of regional distribution, it is also unlikely that there is simultaneously no wind whatsoever in all regions. That means that a certain amount of wind capacity can be accounted as guaranteed nonetheless. This guaranteed capacity, which is called capacity credit, is able to substitute a certain amount of conventional capacity in the power plant mix. Compared to the RES-E infeed however, the share of substitutable capacity is relatively low. Dena (2005) has calculated that a wind capacity of 14.5 MW in Germany in 2003 had a capacity credit of between 7% and 9%, meaning that between 1.0 and 1.3 GW of conventional capacity could have been substituted. One important implication is that an increasing penetration reduces the relative capacity credit. The above-mentioned study also calculated that the considered 35.9 GW wind capacity in 2015 would be associated with a capacity credit of only 5% to 6%. The result of a high intermitting RES-E share with a relatively low capacity credit is an increase in peak load capacity and a decrease in base load capacity.

The Flexibility Effect

In addition to the utilization-based shift of the capacity mix, the previously-discussed negative power prices catalyze this trend by penalizing less flexible generation capacity. Since base load plants avoid unnecessary ramping, negative bids are one sign of limited flexibility. Due to the inflexible demand, negative prices are a tool for finding an efficient market result. However, if negative prices occur very often and are very high, it can be interpreted as a sign of too little flexibility in the market. In addition to the utilization requirements of particular plants, this additional sign of required flexibility in the long-run leads to more investments in more flexible generating technologies which are better equipped to follow the load.

With the increase of intermitting RES-E the gradient of the residual load can frequently be steeper than in a system without RES-E. Especially in the morning hours, when load increases and the wind power infeed decreases, more conventional power plants are required to ramp-up within a short time frame to compensate both effects. To cover these situations, sufficient quick starting capacity is required to serve the load pattern which is eventually substituted by later ramp-ups of baseload plants. Both effects, the steep load gradient and the penalty for running through load valleys by accepting negative prices, lead to more demand for flexible units and penalize base load units.

The utilization effect and the flexibility effect are separated in chapter 5, where attributes of the optimization model and the effects of high RES-E penetration are explained.

4 The High Temporal Resolution Electricity Market Analysis Model

This chapter explains the 'The High Temporal Resolution Electricity Market Analysis Model' (THEA). As indicated in the motivation chapter, the aspired computation is too complex to solve it in a global investment and dispatch model. Therefore, this chapter explains the basic methodology which enables THEA to calculate the impact of RES-E on the capacity mix in high temporal resolution.

The chapter is structured as follows: First, the general structure of Benders Decomposition is explained in a simplified manner with a limited equation set to illustrate the basic principles of the process. Second, the modeling framework of THEA is explained in a qualitative way to provide an intuitive understanding of the methodology. Third, the technical model description provides insight into the equation sets of the investment and the dispatch part of the model, which supplements the initial explanation of Benders Algorithm.

4.1 Benders Decomposition Algorithm

To allow efficient solutions to the dispatch and capacity expansion problem in such a high temporal resolution, an approach that was first presented by Benders (1962), and is known as 'Benders Decomposition', is implemented. Based on the duality theory, large mathematical problems can be decomposed into smaller problems by fixing the complicating variable in the subproblem (SP) and optimizing it in the master problem (MP) through an iterative algorithm that converges when an optimal solution is reached. Cote and Laughton (1979) presented an initial application of Benders Decomposition to power system optimization and proved its advantages for a simple investment and operation problem in terms of memory requirements and solution times.

In addition to Benders (1962) and Cote and Laughton (1979), a recent mathematical proof is provided by Conejo et al. (2006), who show that

> *'if a linear programming problem has a decomposable structure with complicating constraints, its dual linear programming problem has a decomposable structure with complicating variables. And*

> *conversely, if a linear programming problem has a decomposable structure with complicating variables its dual linear programming problem has a decomposable structure with complicating constraints'* (p. 109).

This is the foundation of the Benders Decomposition approach. The information transfer from the SP to the MP is possible due to the introduction of the function α, which iteratively reduces the solution space of the MP by adding so called 'Benders Cuts'. It is important to note that α is convex. Since the original linear problem has the structure of a convex polytope, the structure of α is also convex, as it is restricted by the fixed values of the previous capacity investment decisions, which are all solutions of the constrained MP. This will be further explained in the following explanation of the algorithm (for a more detailed discussion on the mathematical proofs, see Conejo et al. (2006)).

The Benders Decomposition approach has been further applied for stochastic and integer programming applications, while the challenge of utilizing the approach for 'real world' power systems has been summarized by Wang (1996):

> *'Methods of Benders Decomposition are somewhat complicated, and their application may be computationally impossible for large power systems'* (p. 50).

Fortunately, the latter concerns have subsequently been addressed by the recent developments of the IT industry, thereby overcoming computational challenges. To the knowledge of the author, THEA is the first application of Benders Decomposition that utilizes a dynamic approach by computing investment decisions in five-year steps rather than one single investment decision for the year under observation, while also making those decisions on the basis of full dispatch years with 8760 hours each and for multiple zones. The actual time saving due to the utilization of Benders Decomposition is not easy to assess since large problems, as the one used in this research, would not be solvable at all within a global model due to the limits of working memory and acceptable computation time (less than a few weeks).[7] Therefore, one way of enabling the complex optimization needs to be applied. As an example of a small case study, Baíllo et al. (2002) compare two decomposition approaches for day-ahead bidding in the electricity market, 'Lagrangian Relaxation' and 'Benders Decomposition'. Solving the case study with Lagrangian Relaxation required 614 seconds and with Benders Decomposition, 41 seconds. However, each model structure consists of its individual challenges, which makes a generalization of these findings not recommendable. However, a general rule seems to be that in smaller problems, Benders Decomposition is slower due to higher communication requirements and the time sav-

7 This research was enabled by utilizing the modeling server of the Berkeley Lab, which at that time had 16 cores and a working memory of 72 GB. Depending on the actual problem size, the scenarios in this thesis required three to four days to solve.

ing increases with the model size.

In the following, the principle of the algorithm is described step by step for a reduced power market model before it is embedded in the entire technical model description in section 4.3.[8]

The algorithm starts with the initialization of the iteration counter I, before the investment model starts, which is the master problem (MP) of this approach. The initial MP is a reduced form of the later MP since no information on the capacity value from the dispatch part is available yet. The objective function of the MP minimizes the investment costs,

$$Min \sum_{t} fc_t * CAP_t \tag{4.1}$$

with fc_t as annualized investment costs per technology and CAP_t as capacity per technology, subject to the minimum capacity restriction,

$$\sum_{t} CAP_t \geq maxload \tag{4.2}$$

in order to provide sufficient capacity to cover the maximal load $maxload$ for the following first dispatch model run. Since no information on the structural requirements of an optimal capacity mix is available in the initial MP, the least cost capacity is deployed to fulfill the peak load requirement. At this point, the capacity mixed is passed on to the dispatch model or sub problem (SP) via the following equation:

$$installedcap_t = CAP_t^I. \tag{4.3}$$

The term $installedcap_t$ is written in lower cases, since the variable CAP_t becomes a parameter in the dispatch problem.

Every time the MP solved, the lower bound (LB) of the algorithm is computed:

8 In the following, variables are expressed in capital and parameters in lower case letters.

$$LB = \sum_t fc_t * CAP_t + \alpha. \tag{4.4}$$

The term α is explained below. It originates from an equation that does not show up in the initial MP. Therefore, the LB from the initial MP is simply the aggregated investment cost.

Next, the SP is initialized. The objective function of the SP minimizes the dispatch costs,

$$Min \sum_h \sum_t vc_t * GEN_{t,h} \tag{4.5}$$

with vc_t as variable costs per technology, which incorporates fuel and CO_2 costs per technology and $GEN_{t,h}$ as generation per technology and hour, subject to the energy market constraint

$$\sum_t GEN_{t,h} = demand_h \tag{4.6}$$

which requires that the demand $demand_h$ has to be met at every point in time. In order to meet the demand, only the available capacity $installedcap$ can be used. Therefore, the capacity constraint, which originated from the MP, limits the amount of available generating capacity, as follows:

$$GEN_{t,h} \leq installedcap_t. \tag{4.7}$$

The dual of this equation provides the intrinsic value of the available capacity for the next MP. For now, further dispatch constraints are dropped for this initial explanation of Benders Algorithm.

After the SP, an upper bound for the convergence of the algorithm is computed:

$$UB = \sum_{t} vc_t * GEN_t + \sum_{t} fc_t * CAP_t. \tag{4.8}$$

The algorithm proceeds with a convergence check after the first iteration:

$$\frac{UB - LB}{UB} < \epsilon \tag{4.9}$$

Since the initial MP had no information on the dispatch costs and α was zero, the algorithm will not converge after the initial iteration, as the fraction is larger than the predefined tolerance ϵ. In the second iteration, the Benders Cut is added to the MP equation set in the form of an additional constraint:

$$\alpha \geq subcosts^I + \sum_{t} \lambda_t^I * (CAP_t - installedcap_t^I). \tag{4.10}$$

The Benders Cut computes the optimality of the capacity mix which was available in the SP. Thereby, $subcosts$ is the total dispatch cost of the SP and λ_t is the capacity constraints' dual, which contains information on the value of the particular technology. α is then added to the objective function,

$$Min \sum_{t} fc_t * CAP_t + \alpha \tag{4.11}$$

in order to enable a cost minimizing investment decision which incorporates the information from the SP. After a new capacity mix is calculated, it is passed on to the dispatch problem once again to start the next iteration. The algorithm adds one Benders Cut per iteration and reduces the solution space until convergence is reached.

4.2 Qualitative Model Description

THEA is a linear optimization dispatch and investment model. The hourly dispatch is made possible by the implementation of the previously-explained decomposition technique. Investment decisions are computed in 5-year steps up to 2070, which enables an economic interpretation until 2030 due to long investment lifetimes. THEA's main advantage is a high resolution investment decision based on a full dispatch year. Not only does the investment decision consider all extreme situations of one year, but the dispatch part of the model provides information on part-load and start-up costs based on a full year allowing for a detailed analysis of typical as well as extreme contiguous time frames.

Again, the capacity mix is determined by investment decisions in the MP. The investment decisions are optimized according to the results from the dispatch part of the model, which provides information on efficient capacity adaptations in the form of duals of the capacity restriction. This investment decision is updated in every iteration according to the SP results until the predefined convergence criterion is fulfilled.

The hourly dispatch considers fuel-type and vintage fleet capacities in order to keep the problem linear (i.e., the model considers all CCGTs within one vintage class as a single unit, and therefore does not evaluate distinct individual plants). This approach follows e.g. Müsgens (2005) and Gatzen (2008) for applications in dispatch models and Bartels (2009) for an application in a global typeday investment and dispatch model.

All considered technologies in THEA are distinguished between endogenous and exogenous investment possibilities according to Table 4.1. For endogenous investments, the investment costs are annualized according to a predefined depreciation time and interest rate. The age structure of the existing fleet is mirrored by vintage classes, which take technology developments into account (e.g. increasing efficiency). The coal fleet has six different vintage classes, the lignite fleet five, the CCGT fleet four, the OCGT fleet three and the nuclear fleet two. Superpeaker, hydro storage, pumped storage and CAES are aggregated in one fleet each. The total amount of vintage classes is similar to Gatzen (2008), where a pure dispatch model was applied. Considering that the same temporal resolution is used and that the complexity has been increased by an investment problem, it becomes apparent that HPC tools in terms of Benders Decomposition and parallel computing (on the aforementioned 16 cores of the Berkeley Lab server) are necessary.

Existing hydro power capacities and exogenous investments are also included, but new endogenous investments are not possible due to natural resource restrictions. Each modeled year, the gap between incumbent generation and the peak load requirement has to be met by endogenous investments.

Table 4.1: Considered technologies

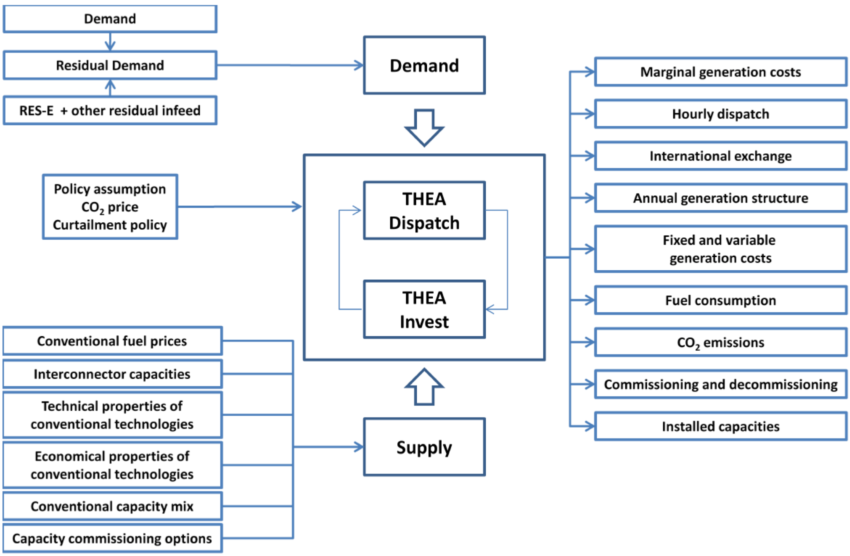
Technology	Endogenous Investment	Exogenous Investment
Nuclear	yes	yes
Lignite	yes	yes
Hardcoal	yes	yes
CCGT	yes	yes
OCGT	yes	yes
Superpeaker	yes	yes
Hydro Storage	no	yes
Pumped-Storage	no	yes
CAES	yes	yes
Wind Onshore	no	yes
Wind Offshore	no	yes
Biomass	no	yes
Biogas	no	yes
Bioliquid	no	yes
Running Hydro	no	yes
Photovoltaics	no	yes
Concentrating Solar	no	yes
Geothermal	no	yes
Ocean	no	yes
Others	no	yes

In the dispatch problem, THEA optimizes the dispatch of the installed conventional capacities according to the residual load. Hereby, start-up costs and part-load losses are considered. Additionally, technical ramping constraints are taken into account limiting extreme ramp-ups for individual technologies. In accordance with section 3.1, the ramping is further limited by minimum load restrictions. Spinning and non-spinning reserve requirements constitute further requirements to the dispatch problem. In times of high RES-E infeed and low load, the minimum load limitations in combination with reserve requirements force the dispatch solution into extreme situations. To enable the match of supply and demand, RES-E curtailment options are implemented. Since RES-E receive market independent support, the curtailment option is only chosen if no cheaper way is feasible. In the case of oversupply, the typical 'first choice' flexibility is the international exchange between market zones. This exchange is limited by exogenously-provided net transfer capacities (NTC) and causes transmission losses. Further flexibilities on the demand and supply side are storage technologies. In situations of oversupply, storage technologies increase the demand and store energy for high demand hours. In these high demand hours, the storage technologies are part of the supply side and reduce the demand for expensive peaking units. While the capacities of pumped-hydro storage are exogenously provided, compressed air energy storage (CAES) can also be commissioned endogenously.

Since OCGT is the only technology that is able to start-up within 15 minutes, it is also able to provide tertiary reserve without being ramped-up. While the 'superpeaker' technology can be interpreted as long-term system security investment or a capacity adequacy solution, OCGT investments can be interpreted as a requirement for the quality of the capacity.

The load and the RES-E structure are provided exogenously and are based on historic data. Combined with annual load and RES-E targets for each year, the residual load is computed as well as the required installed RES-E capacities. Since the curtailment per technology is limited by the total infeed of this particular technology, the individual RES-E infeed needs to be implemented in the dispatch problem as well. Other exogenous parameters are the availability of plants and the hydro inflow into the reservoirs. Figure 4.1 shows the overall structure of THEA.

Figure 4.1: THEA input-output structure



Source: own illustration.

To enable the computation of this complex problem in an iterative manner, THEA adds one additional tool from recent high-performance-computing (HPC) developments: the dispatch is calculated in a monthly decomposed parallel mode (see Figure 4.2

for a visualization of this approach within the Benders Algorithm). The advantage of this latter approach is that while a global model utilizes only one processor core, THEA uses all available cores of the modeling server in the SP. In this way, the IT infrastructure can be utilized more efficiently and the overall solution time is reduced substantially.

The main outputs of THEA are the technology choices of the investment decision in the MP and the generation mix of the SP. These outcomes show on an aggregated level how the market reacts to the increasing penetration of RES-E. These results come with the underlying investment and generation costs. A further dispatch outcome is the international exchange and the price level. Thereby, the main advantage of THEA is the greater temporal detail of these outcomes which are available for every hour of the year. Especially the extreme hours can be analyzed in detail in this way.

Brief Discussion on the Implemented Methodology

One potential way to model RES-E integration is to optimize the entire generating capacity, consisting of the conventional and the renewable part. The drawbacks are summarized by Neuhoff et al. (2008), who show that the optimal renewable capacity expansion is quite sensitive to various exogenous assumptions. In particular, predefined maximal growth rates in terms of available resource potential and maximal capacity expansion limits per time period determine the deployment. In turn, the model generates extreme results if these restrictions are not set correctly within realistic boundaries. One additional crucial assumption is the cost development of RES-E technologies. While conventional technologies are in general mature and assumptions on cost developments are relatively robust, the development of RES-E investment costs is usually determined by the uncertain learning curve approach and has therefore a much higher uncertainty. Since RES-E developments are primarily driven by political decisions, the technology mix is a result of technology specific support schemes and not of economic considerations. Therefore, the present approach takes the political deployment plans as exogenous assumptions into account and not as an option for the optimization.

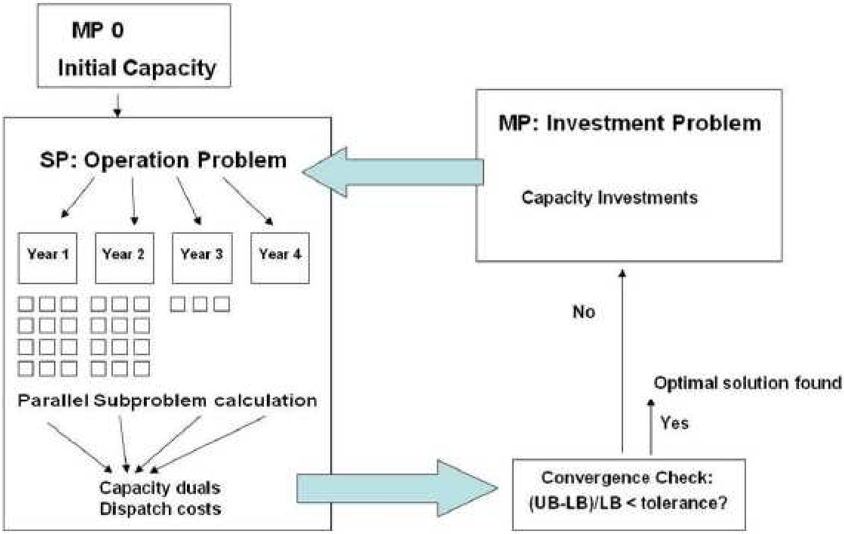
One way to reduce complexity and at the same time capture extreme residual load situations is the usage of a stochastic approach. However, modeling extreme situations which have a probability of less than $\frac{1}{8760}$ as applied by the high resolution in THEA is not very efficient. Nevertheless, when it comes to the calculation of an absolute minimal capacity requirement for i.e. detailed system security studies, it is also reasonable to take into account extreme situations that have a lower probability is reasonable. This approach is not utilized here, since it would simply affect the absolute capacity requirement, which is set in the case of THEA by the required reserve amounts in addition to the maximal residual load. Adding further capacity requirements equally in all scenarios would simply increase the amount of superpeaker capacity but would not affect the remaining results in any way. Modeling stochastic trees increases the absolute amount of modeled time periods significantly. Therefore, a stochastic approach would also require subdividing the modeling period in order to keep the problem solvable, e.g. into days wthat are then multiplied by their predefined probability, which affects the intertemporal constraints. This is avoided here, since the interpretation of the pricing behavior is of particular importance for the present research. Additionally, the interpretation of stochastic results is quite challenging. Since the effects of particular sensitivities, i.e. policy option, are the focus of this research, the results should not primarily reflect a stochastically set path.

One particular strength of THEA is the high resolution price information. Assuming perfect competition and foresight of a well-informed benevolent planner, the investment and dispatch costs are minimized. In contrast, global investment and dispatch models follow a different logic when it comes to interpreting the marginals of the energy market constraint (see, e.g Bartels (2009) for an example of a complex global investment and dispatch model). In a global model, the marginal also reflects the investment costs that are required to fulfill the demand constraint, since all constraints are optimized simultaneously. Therefore, the marginals can only be interpreted as long-run marginal costs, which by definition increase as soon as investments are required. Thereby, long-run marginal costs follow the logic of the peak-load pricing model, but are not necessarily the market results of a market under perfect competition (see discussion in section 2.3). This is due to the fact that once investments are undertaken, the bidding process does not take sunk costs into account. In an oligopolistic market structure, companies could influence the market results to cover the investment costs. This however deviates from the assumption of perfect competition which is chosen here to address the fundamental effects of high RES-E penetration independent from ownership assumptions. One additional weakness of the peak-load pricing approach is the arbitrary starting-point. All investments that are undertaken previously to the starting year are not reflected by the marginals of the energy market constraint; future investments however are taken into account. If one would interpret the long-run marginal costs of global investment and dispatch models, one could understand those as the price level required to cover the required investments, but not as competitive market prices. THEA treats all investment decisions as sunk costs since capacities are passed as parameters from the MP to the SP. This approach ensures that the marginals of the energy market constraint can be interpreted as short-run marginal costs or as market prices in a competitive market.

The Implementation of Benders Decomposition

The basic steps in the dispatch and capacity expansion problem solved by THEA are presented in Figure 4.2.

Figure 4.2: Benders structure with parallelization

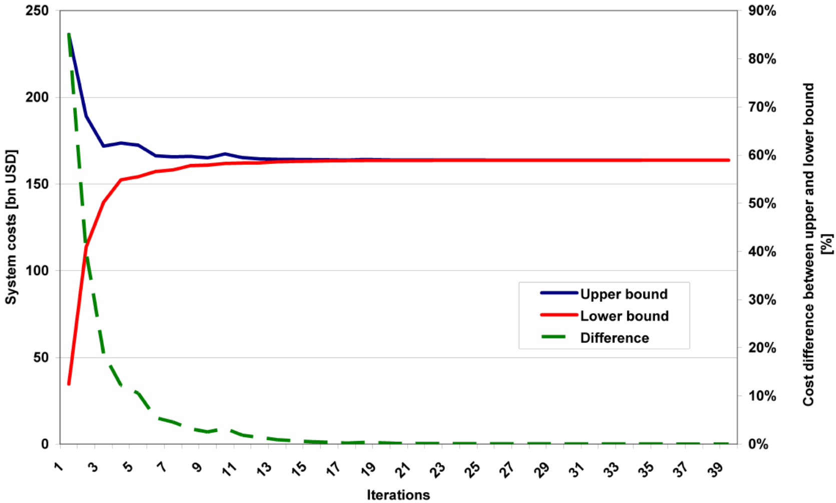


Source: own illustration.

First, the initial capacity of the power system is calculated in the master problem (MP), representing a mix of existing incumbent generation capacity as well as any new installations that are required to fulfill the power system's overall capacity requirements. Any new installations required to meet overall capacity obligations under these initial conditions are chosen based on a least cost algorithm in the first iteration without considering the dispatch problem. Second, this initial generation capacity mix is passed on to the dispatch part of THEA, the subproblem (SP). Here, THEA solves the linear dispatch problem considering all of the above explained constraints, such as start-up, partload costs, ramp-up constraints as well as reserve requirements. The total dispatch costs that come from the SP as well as the capacity duals are then passed on to the convergence check in the third step. Here, the algorithm measures the relative cost difference between the lower bound (LB) and the upper bound (UB). Figure 4.3 shows an example of the model convergence throughout the iterations.

The lower bound is the target function of the master problem whereas the upper bound is derived from the dispatch cost of the SP and additional cost factors from the MP. Since the initial MP only has information on investment costs, and not on the inefficiency of the dispatch problem that comes from fuel, start-up and part-load costs as well as reserve requirements, there is no possibility that the algorithm can

Figure 4.3: Example of convergence



Source: own illustration.

converge after only one dispatch run. Since the algorithm does not converge in the third step, in the fourth step, the full MP receives the dispatch costs as well as the capacity duals. The so called Benders Cut then calculates the change in the capacity mix that leads to a lower cost solution on the basis of the capacity duals, which are calculated in the SP and passed on to the MP. In every iteration, one additional Benders' Cut is added to further constrain the solution space. This new capacity mix is then again passed on to the SP and the algorithm continues. It is observable in Figure 4.3 that after only 13 iterations, the cost difference between the upper and lower bound is already less than 1%. If the solution is within the predefined cost tolerance (in this thesis 0.0001), the algorithm converges with the optimal solution.

4.3 Technical Model Description

This section explains the actual analytical THEA equation sets. The code is written in GAMS and embedded in the Benders Algorithm explained in section 4.1. Due to the decomposed structure of THEA, this section is divided in the investment and the dispatch part of the model.

4.3.1 Investment Problem

The objective function in the master problem (MP) minimizes the discounted fixed costs FC_y, the fixed operation and maintenance costs FOM_y as well as the term alpha α_y:

$$TC = \sum_y (FC_y + FOM_y + \alpha_y). \tag{4.12}$$

The fixed costs are the annualized investment costs of the commissioned power plants discounted by the parameter $dfac_y$ and multiplied by the number of year ny_y, which are represented by the modeled year. Therefore, the investment costs $ic_{r,t}$ are multiplied with the annuity matrix $anmat_{r,t,y,y1}$. The $CAP\_ADD_{r,t}$ variable is computed endogenously according to the optimization calculus and the capacity requirements. The $capaddex_{r,t}$ parameters are provided exogenously and represent projects that are already under construction or have a high probability of being build. The fixed costs are calculated by

$$\begin{aligned} FC_y = dfac_y * \sum_r \sum_t \sum_{y1} ic_{r,t} * anmat_{r,t,y,y1} \\ *(CAP\_ADD_{r,t} + capaddex_{r,t}) * \frac{ny_y}{10^3} \end{aligned} \tag{4.13}$$

with

$$anmat_{r,t,y,y1} = \frac{i * (1+1)^{deptime_{r,t}}}{(1+i)^{deptime_{r,t}} - 1} \tag{4.14}$$

as annuity matrix and with a depreciation time $deptime_{r,t}$ per technology and region. Fixed operation and maintenance costs apply to all existing power plants $CAP_{r,t}$ according to the technology-specific cost factor $FOMC_{r,t}$ in every considered year:

$$FOM_y = dfac_y * \sum_r \sum_t CAP_{r,t,y} * fomc_{r,t} * \frac{ny_y}{10^3}. \tag{4.15}$$

The Benders Cut calculates the change in the investment decision according to the capacity dual $\lambda_{r,t,y}$. Thereby, $subcosts_y^I$ is the objective value of the subproblem. The cut shows the optimization potential of the current iteration and chooses a new investment mix according to this information:

$$\alpha_y \geq subcosts_y^I + \sum_r \sum_t \lambda_{r,t,y}^I * (CAP_{r,t,y} - installedcap_{r,t,y}^I). \tag{4.16}$$

Capacities are fixed for the first year of the optimization according to the parameters $existcap_{r,t,y}$. These parameters are based on data of all existing power plants for the region under consideration,

$$CAP_{r,t,2010} = existcap_{r,t}. \tag{4.17}$$

In the subsequent periods, capacities are commissioned and decommissioned according to the optimization calculus with two exemptions. First, capacities that are either under construction or have a high probability of being built are added exogenously by the parameter $capaddex_{r,t}$. Second, existing capacities are forced out as soon as they reach their lifetime limit:

$$\begin{aligned} &CAP_{r,t,y} = CAP_{r,t,y-1} + capaddex_{r,t} \\ &+CAP\_ADD_{r,t,y} * feascom_{r,t,y} - CAP\_SUB_{r,t,y}. \end{aligned} \tag{4.18}$$

Investment options can further be limited by the parameter $feascom_{r,t,y}$, which sets commissioning possibilities. The variable $CAP\_SUB_{r,t,y}$ is responsible for decommissioning the capacity. Thereby, $capsubex_{r,t,y}$ serves as a minimal decommissioning parameter. Power plants can also be decommissioned before they reach the end of their lifetime if there are cheaper options to produce energy and fulfill the peak requirement:

$$\sum_{y1 \leq year} CAP\_SUB_{r,t,y1} \geq capsubex_{r,t,y}. \tag{4.19}$$

Installed capacities need to be able to cover the peak demand of each year. Thereby, the peak demand which the conventional power market needs to cover is the actual demand for electricity reduced by the exogenous generation from RES-E. Therefore, the peak reserve requirement needs to fulfill only the peak residual demand $maxresload_{r,y}$. Furthermore, power plants have different seasonal availabilities $avail_{r,t}$ since revision cycles are usually organized in times with lower demand to ensure that the plants are available during the season with the highest demand. In addition to the maximal residual demand, reserve capacity requirements for spinning reserve $spinningreserve_r$ and tertiary reserve $tertiaryreserve_r$ increase the minimal capacity requirements since even in the hour of peak demand, sufficient positive reserve needs to be installed to ensure system security. The parameter $standingreserve_r$ can be used to define further back-up capacity requirements in addition to the auctioned reserve requirements for spinning and tertiary reserve:

$$\sum_t CAP_{r,t,y} * avail_{r,t} \geq maxresload_{r,y} + spinningreserve_r$$
$$+ tertiaryreserve_r + standingreserve_r. \qquad (4.20)$$

The peak requirement leads to feasible dispatch problems, since sufficient generating capacity is ensured. However, the installed capacity may not be optimal from an economic or technical point of view. Through the iterative approach of Benders Algorithm the capacity mix is optimized stepwise on the basis of the evaluation in the dispatch problem.

4.3.2 Dispatch Problem

The dispatch part of the model is the subproblem within the Benders Algorithm. The value of the investment decision is evaluated in this part of the model. Besides the capacity duals, the variable $SUBCOSTS$ is a crucial component which is passed on to the MP. As explained above, the SP is further decomposed into monthly dispatch problems which are computed in a parallel manner. After the last SP has been solved, the relevant terms are grouped and passed on to the convergence criterion and, if no convergence is reached, again to the MP.

Objective and Cost Equations

The SP minimizes the $SUBCOSTS_{y,m}$ in the objective function:

$$Min \sum_{y} \sum_{m} SUBCOSTS_{y,m} \tag{4.21}$$

with

$$\begin{aligned} &SUBCOSTS_{y,m} = VARCOSTS_{y,m} + VCRTO_{y,m} \\ &+VCPARTLOAD_{y,m} + VCCURTAIL_{y,m}. \end{aligned} \tag{4.22}$$

The objective function sums up the costs of the subproblem SP, which are the variable costs $VARCOSTS_{y,m}$, the start-up costs $VCRTO_{y,m}$, the partload costs $VCPARTLOAD_{y,m}$ and the curtailment costs $VCCURTAIL_{y,m}$. The variable costs consist of the discounted generation costs $GEN_{r,t,y,m,h}$, load-shedding costs $LS_{r,y,m,h}$ and the pumping costs of storage technologies $PUMP_{r,stortech,y,m,h}$. First, the variable generation block comprises the fuel costs $fuelc_{r,t,y,m}$ and other variable generation costs $ovar_{r,t}$ per region and technology in each hour. Second, the load-shedding costs are summed up over the regions and all hours, which will be zero in the final iteration. By allowing load reduction to be penalized through the parameter $lspenalty$, the SP iteration solves even if insufficient capacity is installed. In this case, insufficient does not mean too little capacity, since the absolute amount is ensured by the peak requirement in the MP. Instead, insufficient means that the capacity is not able to follow the load in every situation when taking into account start-up costs and ramping constraints. Third, the variable pumping costs $ovarcpump_{,r}$ for storage technologies are summed up over all regions, technologies and hours:

$$\begin{aligned} &VARCOSTS_{y,m} \\ &= dfac_y * (\sum_{r} \sum_{t} \sum_{h} (fuelc_{r,t,y,m} + ovar_{r,t}) * GEN_{r,t,y,m,h} \\ &+ \sum_{r} \sum_{h} LS_{r,y,m,h} * lspenalty \\ &+ \sum_{r} \sum_{stortech} \sum_{h} ovarcpump_{,r} * PUMP_{r,stortech,y,m,h}) * \frac{numy_y}{10^6}. \end{aligned} \tag{4.23}$$

Start-up costs include the variable costs as well as the attrition costs of the equipment per start-up. Thereby, the variable $CAPUP_{r,t,y,m,h}$ is calculated endogenously and takes into account attrition costs $startattr_{r,t}$ in addition to the other variable costs. Furthermore, the $startt$ parameter is the linearized cool-down function. It is calculated exogenously to keep the model linear on the basis of the idle time of each technology, which is derived from the the residual load structure. The start-up costs of storage plants is the last term in the start-up cost calculation and takes the amount of starts $PUMPUP_{r,stortech,y,m,h}$ and the variable cost parameter $startupcostpump_{stortech,r}$ into account:

$$
\begin{aligned}
&VCRTO_{y,m} \\
&= dfac_y * (\sum_r \sum_t \sum_h CAPUP_{r,t,y,m,h} * \\
&(fuelc_{r,t,y,m} + ovar_{r,t} + startattr_{r,t}) * startt_{r,t,y,m,h} \\
&+ \sum_r \sum_{stortech} \sum_h PUMPUP_{r,stortech,y,m,h} * startupcostpump_{stortech,r}) \\
&* \frac{numy_y}{10^6},
\end{aligned}
\tag{4.24}
$$

with

$$
startt_{r,t,y,m,h} = startdur_{r,t} * \left(1 - e^{\frac{idletime_{r,y,m,h}+0.01}{\tau_{r,t}}}\right) \tag{4.25}
$$

where $startdur_{r,t}$ is the required time per technology to start-up, $idletime_{r,y,m,h}$ is the time in which the capacity was idle and $\tau_{r,t}$ is the cooling time per technology. Partload costs arise when the generation is below its fully ramped-up capacity. When the load is only lower for a short amount of time, partload generation can reduce the amount of start-ups and therefore be the more efficient solution. Additionally, partload costs are especially relevant for the reserve requirements. Partload costs are derived from the difference between the ramped-up capacity and the level of generation within this hour and are penalized by the reduced efficiency in partload mode,

$$
\begin{aligned}
&VCPARTLOAD_{y,m} \\
&= dfac_y * \sum_r \sum_t \sum_h (CAPRTO_{r,t,y,m,h} - GEN_{r,t,y,m,h}) * \\
&\frac{fuelc_{r,t,y,m} * \eta\_loss_{r,t}}{\eta_{r,t} - \eta\_loss_{r,t}} * \frac{numy_y}{10^6}
\end{aligned} \tag{4.26}
$$

with $\eta_{r,t}$ as efficiency per technology and $\eta\_loss_{r,t}$ as partload efficiency loss. In case of oversupply and no further export possibilities, THEA has the option to curtail the RES-E infeed by technology. Without political subsidies for RES-E, the curtailment penalty would be close to zero due to the very low variable costs of most renewable technologies. However, since a premium is usually paid on top of the market value, the operator will only curtail its generation when the power price is below its premium $curtailpenalty_{r,t,y}$ (see section 3.1.4). Due to this behavior, the premium determines the curtailment behavior of a particular technology,

$$
\begin{aligned}
&VCCURTAIL_{y,m} \\
&= dfac_y * \sum_r \sum_t \sum_h CURTAIL_{r,t,y,m,h} * curtailpenalty_{r,t,y} * \frac{numy_y}{10^6}
\end{aligned} \tag{4.27}
$$

with $curtailpenalty_{r,t,y}$ as premium level per region, technology and year.

Energy Market Constraints

The energy market constraints are the core of the dispatch problem since supply must meet demand at all times. Additionally, some flexibilities are implemented to enable efficiency gains throughout regions and technologies. The energy balance constraint provides the marginal value which can be interpreted as power price. Basically, in every region, the total generation $GEN_{r,t,y,m,h}$ from all technologies must meet the residual demand $resload_{r,y,m,h}$ at every point in time. In addition to the regional generation, the demand can also be served by import through international exchange $PT_{y,m,h,r,r1}$ between the regions or increased by export. Further flexibilities on the demand side are the compressing of storage technologies $PUMP_{r,stortech,y,m,h}$ and curtailment options $CURTAIL_{r,restech,y,m,h}$ if the residual demand needs to be increased for technical or economic reasons:

$$\sum_t GEN_{r,t,y,m,h} + LS_{r,y,m,h} + \sum_r PT_{y,m,h,r,r1} - \sum_{r1} \frac{PT_{y,m,h,r1,r}}{tloss_{r1,r}}$$
$$= resload_{r,y,m,h} + \sum_{stortech} PUMP_{r,stortech,y,m,h}$$
$$+ \sum_{restech} CURTAIL_{r,restech,y,m,h}. \tag{4.28}$$

The international exchange is limited by the amount of net transfer capacities $tcap_{r,r1,y}$ and transmission losses $tloss_{r,r1}$. Over time, the capacity can be increased exogenously:

$$\frac{PT_{y,m,h,r,r1}}{tloss_{r,r1}} \leq tcap_{r,r1,y}. \tag{4.29}$$

The curtailment flexibility is limited by the actual generation from the particular renewable technology $resgen_{y,m,h}$ which is curtailed. If the cheapest curtailment option is exhausted, the next technology must be curtailed. Due to this reason, THEA carries all technology-specific RES-E infeeds and not only the residual load:

$$CURTAIL_{r,restech,y,m,h} \leq resgen_{r,restech,y,m,h}. \tag{4.30}$$

Availability Constraints

The generation from one particular technology is limited by its installed capacity $instcap_{r,t,y,m}$, which is passed on from the MP in every iteration in the form of the parameter $installedcap_{r,t,y}$. The capacity constraint's dual provides the information on the value of each technology and is therefore a crucial element of the algorithm:

$$instcap_{r,t,y,m} = installedcap_{r,t,y}. \tag{4.31}$$

The generation is further restricted by the availability of the technology at a certain point of time $AVAILCAP_{r,t,y,m,h}$. This applies for thermal technologies as well as for hydro and storage technologies:

$$AVAILCAP_{r,t,y,m,h} = instcap_{r,t,y,m} * avail_{r,t,m,h}. \tag{4.32}$$

Operational Constraints

The maximal generation is constrained by the ramped-up capacity, which is 'ready-to-operate', $CAPRTO_{r,t,y,m,h}$. Storage plants are also restricted in a respective way. $PUMP_{r,stortech,y,m,h}$ is the amount of storable energy in one hour:

$$GEN_{r,t,y,m,h} \leq CAPRTO_{r,t,y,m,h}, \tag{4.33}$$

$$PUMP_{r,stortech,y,m,h} \leq PUMPRTO_{r,stortech,y,m,h}. \tag{4.34}$$

As explained in the partload cost equation reference, it is inefficient to have too much capacity ready-to-operate. The calculation of the ramp-up costs depends on the previous hour $CAPRTO_{r,t,y,m,h-1}$,

$$\begin{aligned} &CAPRTO_{r,t,y,m,h} \\ &= CAPRTO_{r,t,y,m,h-1} + CAPUP_{r,t,y,m,h} - CAPDOWN_{r,t,y,m,h} \end{aligned} \tag{4.35}$$

with $CAPUP_{r,t,y,m,h}$ as the ramp-up variable and $CAPDOWN_{r,t,y,m,h}$ as the ramp-down variable. The same approach is applied for storage ramping,

$$\begin{aligned}&PUMPRTO_{r,stortech,y,m,h}\\&=PUMPRTO_{r,stortech,y,m,h-1}+PUMPUP_{r,stortech,y,m,h}\\&-PUMPDOWN_{r,stortech,y,m,h}\end{aligned} \tag{4.36}$$

with $PUMPRTO_{r,stortech,y,m,h-1}$ as the initial value, $PUMPUP_{r,stortech,y,m,h}$ as the ramp-up variable and $PUMPDOWN_{r,stortech,y,m,h}$ as the ramp-down variable. Furthermore, the ramping of conventional and storage capacities is constrained by an upper bound which is provided by the currently available capacity:

$$CAPRTO_{r,t,y,m,h} \leq AVAILCAP_{r,t,y,m,h}, \tag{4.37}$$

$$PUMPRTO_{r,stortech,y,m,h} \leq AVAILPUMP_{r,stortech,y,m,h}. \tag{4.38}$$

In case of low residual demand, the generation can only be reduced to the technology specific minimum load parameter $loadmin_{r,t}$ of the ramped-up capacity for conventional and $loadminpump_{stortech,r}$ for storage technologies. If the generation needs to be reduced further, more capacity has to ramp-down and will be required to ramp-up in future periods. Also storage plants have a minimum constraint for the energy amount of storage per hour:

$$GEN_{r,t,y,m,h} \geq loadmin_{r,t} * CAPRTO_{r,t,y,m,h}, \tag{4.39}$$

$$\begin{aligned}&PUMP_{r,stortech,y,m,h}\\&\geq loadminpump_{stortech,r} * PUMPRTO_{r,stortech,y,m,h}.\end{aligned} \tag{4.40}$$

In addition to the economic ramping costs, technical limitations apply for thermal capacities. Since thermal capacities are not able to increase output instantaneously a maximal ramp rate per hour $rampup_{r,t}$ is implemented to capture the complexity of high load gradients. Especially in systems with a high share of intermitting RES-E high load gradients are possible and the capacity mix needs to follow the residual load pattern:

$$GEN_{r,t,y,m,h} - GEN_{r,t,y,m,h-1} \leq AVAILCAP_{r,t,y,m} * rampup_{r,t}. \quad (4.41)$$

If very high load gradients are present, this constraint forces quick starting units to start-up and later to be substituted by 'slower' technologies as soon as these started up in the subsequent hours. In the worst case, the installed capacities cannot follow the load and load therefore needs to be shed.

Storage Plant Constraints

Two different types of storage are utilized in THEA. First, hydro storage plants have a natural inflow, a storage reservoir and generating capabilities. Second, storage plants such as pumped hydro storage or CAES storage plants do not have a natural inflow but a pumping capability, which fills the storage. The stored energy volume of a hydro storage plants $HYDSVOL_{r,y,m,h}$ is based on the stored volume of the previous hour $HYDSVOL_{r,y,m,h-1}$ plus the additional inflow of the current hour $hydsinflow_{r,y,m,h}$. Energy is extracted either through generation or, in the unlikely case of a full basin and oversupply through the spilling of water, through the $HYDSBYPASS_{r,y,m,h}$ variable:

$$\begin{aligned} &HYDSVOL_{r,y,m,h} = \\ &HYDSVOL_{r,y,m,h-1} + hydsinflow_{r,y,m,h} \\ &-HYDSBYPASS_{r,y,m,h} - \frac{GEN_{r,Hyd_S,y,m,h}}{\eta_{r,Hyd_S}}. \end{aligned} \quad (4.42)$$

A minimum water run-off $minhyds$ into rivers is required due to environmental reasons. This run-off can either be spilled or used for electricity generation:

$$GEN_{r,Hyd_S,y,m,h} + HYDSBYPASS_{r,y,m,h} \geq minhyds * instcap_{r,Hyd_S,y,m} * avail_{r,Hyd_S,m,h}. \tag{4.43}$$

The availability of storage plants is determined by a ratio of storage capacity and generation capacity, $storecapturbratio_{stortech,r}$, to enable CAES investments with a specific storage capacity:

$$AVAILPUMP_{r,stortech,y,m,h} \leq instcap_{r,stortech,y,m} * avail_{r,stortech,m,h} * storecapturbratio_{stortech,r}. \tag{4.44}$$

To fill the storage of a storage plant $HYDPSVOL_{r,y,m,h}$, energy must be pumped into the reservoir or the cavern with the variable $PUMP_{r,stortech,y,m,h}$. Only if the storage has a certain amount of energy stored, either on the basis of the storage volume of the previous hour $HYDPSVOL_{r,y,m,h-1}$ or due to compressed energy, can energy be generated according to

$$HYDPSVOL_{r,y,m,h} = HYDPSVOL_{r,y,m,h-1} + PUMP_{r,stortech,y,m,h} * \eta\_pump_{stortech,r} - \frac{GEN_{r,stortech,y,m,h}}{\eta_{r,stortech}} \tag{4.45}$$

with $\eta\_pump_{stortech,r}$ as compressing loss and $\eta_{r,stortech}$ as the efficiency of the generation technology.

Fuel and CO_2 Constraints

The amount of primary fuel consumed is calculated before a limitation on particular fuel consumption can be implemented. Additionally, the CO_2 emissions are also calculated on the basis of primary fuel consumption,

$$FUELUSE_{r,y,m,fuel} = \sum_{t} \sum_{h} \left(\frac{GEN_{r,t,y,m,h}}{eta_{r,t}} + \frac{CAPRTO_{r,t,y,m,h} - GEN_{r,t,y,m,h}}{\eta_{r,t} - \eta\_loss_{r,t}} \right). \quad (4.46)$$

The parameter $fuelup_{r,y,m,fuel}$ serves as the upper bound for the primary fuel consumption,

$$FUELUSE_{r,y,m,fuel} \leq fuelup_{r,y,m,fuel}. \quad (4.47)$$

The CO_2 emissions are then derived from the primary fuel consumption and its CO_2 content $co2facfuel$:

$$CO2TOT_{r,y,m} = \sum_{fuel} co2facfuel * FUELUSE_{r,y,m,fuel}. \quad (4.48)$$

Reserve Capacity Constraints

As discussed in section 3.1, reserve capacity requirements restrict the dispatch of the energy market. Sufficient spinning and non-spinning reserve needs to be able to increase or decrease the generation to make up for load, RES-E forecast errors and disturbances of the conventional plants. This capacity cannot be used for an economic dispatch because system security measures are binding. Especially in firm market situations of either very high or very low residual load, the reserve constraints are binding.

The positive spinning reserve requirement can be fulfilled by quick starting technologies, according to the parameter $validreservespinning_{t,posSpinning}$, which are able to provide energy within a very short time frame, such as spinning units which operate in part-load mode or storage technologies which are in storing mode and could reduce the storing process:

$$\sum_t ((AVAILCAP_{r,t,y,m,h} - CAPRTO_{r,t,y,m,h})$$
$$*validreservespinning_{t,posSpinning}$$
$$+(CAPRTO_{r,t,y,m,h} - GEN_{r,t,y,m,h}))$$
$$+ \sum_{stortech} (PUMP_{r,stortech,y,m,h} - PUMPRTO_{r,stortech,y,m,h}$$
$$*loadminpump_{stortech,r})$$
$$\geq contractcap_{posSpinning,r}. \tag{4.49}$$

The tertiary reserve follows the same logic. The main difference is the quality of the requirements, since units have more time to start-up when providing tertiary reserve:

$$\sum_t ((AVAILCAP_{r,t,y,m,h} - CAPRTO_{r,t,y,m,h})$$
$$*validreservespinning_{t,posTR}+$$
$$(CAPRTO_{r,t,y,m,h} - GEN_{r,t,y,m,h}))$$
$$+ \sum_{stortech} (PUMP_{r,stortech,y,m,h} - PUMPRTO_{r,stortech,y,m,h}$$
$$*loadminpump_{stortech,r})$$
$$\geq contractcap_{posTR,r} + contractcap_{posSpinning,r}. \tag{4.50}$$

Technologies which fulfill the negative reserve constraints are required to be able to reduce the generation in case of potential oversupply. Consequently, power plants need to be in operation in order to reduce generation. The binding restriction in this case is the minimum load requirement $loadmin_{r,t}$ for ramped-up capacity. To reduce the absolute level of this requirement for a specific fleet, capacity needs to ramp-down, which induces later ramp-up costs. At a certain point, however, this restriction is binding and no technologies are able to further reduce the generation. Storage plants can provide negative reserve through the possibility of starting the storing process according to the parameter $validreservepump_{stortech,negSpinning}$ until the available storing capacity is reached, or through the increase of an active part-load storing process and consequently an increase in demand:

$$\sum_t (GEN_{r,t,y,m,h} - CAPRTO_{r,t,y,m,h} * loadmin_{r,t})$$
$$+ \sum_{stortech} ((AVAILPUMP_{r,stortech,y,m,h} - PUMPRTO_{r,stortech,y,m,h})$$
$$*validreservepump_{stortech,negSpinning}$$
$$+PUMPRTO_{r,stortech,y,m,h} - PUMP_{r,stortech,y,m,h})$$
$$\geq contractcap_{negSpinning,r}. \tag{4.51}$$

Again, the same logic is applied for the negative tertiary reserve, which might differentiate from the spinning reserve requirement through the quality of the technologies' storing ramps.

$$\sum_t (GEN_{r,t,y,m,h} - CAPRTO_{r,t,y,m,h} * loadmin_{r,t})$$
$$+ \sum_{stortech} ((AVAILPUMP_{r,stortech,y,m,h} - PUMPRTO_{r,stortech,y,m,h})$$
$$*validreservepump_{stortech,negTR}$$
$$+PUMPRTO_{r,stortech,y,m,h} - PUMP_{r,stortech,y,m,h})$$
$$\geq contractcap_{negTR,r} + contractcap_{negSpinning,r}. \tag{4.52}$$

5 First Application of THEA - The Texas Case

This chapter shows the particular model attributes of THEA and compares the results to cases in which some constraints are dropped. Particular focus is laid on the capability of high temporal resolution. The aim of this comparison is to evaluate the influence of temporal resolution in modeling the impacts of high penetrations of RES-E on the power system, and not to specifically evaluate any individual pre-existing models. By learning more about how temporal resolution impacts results, it is hoped that models might be improved, either by increasing temporal resolution, or where modeling complexity does not allow increased resolution, by adding correction factors in order to approximate the true impacts of wind energy on power systems. A better understanding of the impacts of RES-E on the power market might also assist climate modelers taking these factors into account when evaluating alternative approaches to reducing global carbon emissions and using models that, because of their geographic and sectoral scope, are unable to apply high time resolutions. Even where model changes are not possible, the results that follow may at least provide an indication of how 'inaccurate' low-temporal-resolution models might be in simulating the impacts of high wind energy penetrations.[9]

In order to capture the temporal resolution effects, two specific scenarios (with three temporal resolution cases of 8760 h, 288 h, and 16 time slices) are presented in the following. The first scenario contains no additional wind power deployment after 2008 and the model is run under all three temporal resolutions. The second scenario adds a substantial quantity of additional wind generation to demonstrate how that expanded penetration of wind energy impacts investment decisions and dispatch results relative to the first scenario, again under all three temporal resolutions. By this approach, the temporal resolution effects can first be analyzed and then the particular wind energy integration challenges can be analyzed under different temporal resolutions.

5.1 Input Overview

The model application presented here loosely simulates the power system in Texas (ERCOT, in particular), home to the largest wind power market in the United States. Except for the quantity of wind power deployed (which is exogenous input, and varies

9 Since the focus of this chapter is to explain and compare particular attributes of THEA, a reduced model version is used, which only integrates wind power as a single renewable source and does not allow CAES investments.

between the two scenarios), all other inputs remain the same throughout the calculations.

Fuel prices and generation investment costs are based on EIA (2010a), whereas CO_2 price assumptions are based on Synapse (2008) (see table A.1 and table A.2). Because it impacts wholesale power prices and wind energy curtailment decisions, an assumption for the level of policy support per kWh offered to wind power plants is required.[10] Based on the current production tax credit (PTC) for wind energy in the United States and on renewable energy certificate prices necessary to meet a potential future renewable portfolio standard (RPS), an incremental wind support payment of 30 USD/MWh is assumed now and RPS certificate prices of up to 18.2 USD/MWh in future years according to EIA (2007).

Assumed investment costs for the five alternative generation unit types considered by THEA are presented in table A.2. The 'superpeaker' unit type is intended to reflect generation units that are only utilized in very few hours per year. In the model setup presented here, this unit is assumed to have the attributes of an oil turbine, though in practice, the services provided by these plants could be met with load shedding, demand-response programs, diesel generating sets, gas combustion turbines, or other options. Other generation options considered in THEA are nuclear, hydro storage, pumped storage, coal, combined-cycle gas turbines (CCGT), and open-cycle gas turbines (OCGT).

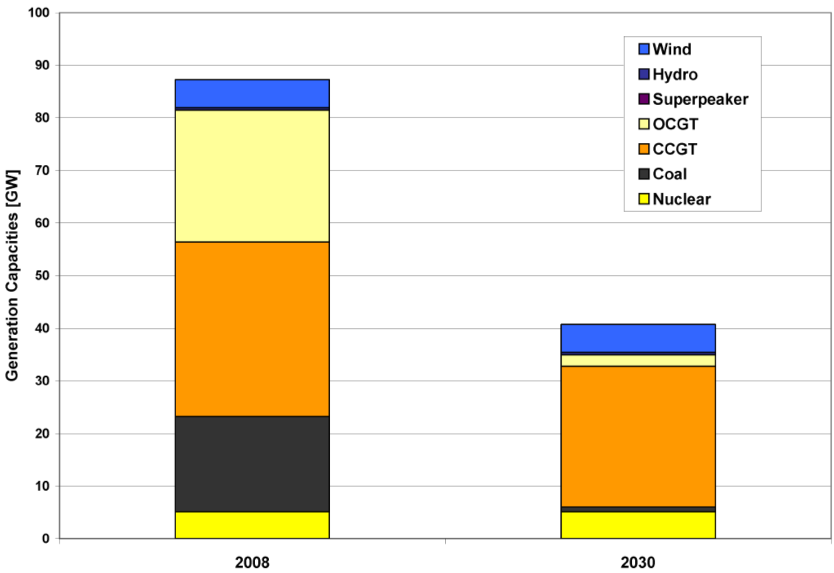
Figure 5.1 shows the amount of incumbent generation capacity that is still available in 2030. With the exception of wind and hydro, the generating capacities that are required to meet the residual demand are added endogenously. The underlying lifetime assumptions for existing technologies are 50 years for nuclear plants, 40 to 50 years for coal plants, 30 to 40 years for CCGTs, 25 to 40 years for OCGTs and 40 years for the superpeakers.

Overall annual electricity demand is assumed to increase from 312 TWh in 2008 to 427 TWh in 2030, which is derived from the estimated increase in peak load provided in ERCOT (2010a). The overall temporal load pattern is assumed to remain constant throughout the modeling period and is derived from ERCOT (2010b).

In the high-wind scenario, the wind share is assumed to increase from 4.8% in 2008 to 25% in 2030, while in the reference scenario wind generation is kept constant at 4.8%. Since much of the new wind power deployment in the high-wind scenario is

10 The effects of this support scheme on dispatch and market based curtailment decisions has already been discussed in section 3.1.4.

Figure 5.1: Incumbent capacity mix in Texas



Source: Nicolosi et al. (2010), based on EIA (2010d) and ERCOT (2010a).

likely to occur in the western zone of the ERCOT market, away from major load centers, additional transmission capacity would be needed to serve load. Though THEA does not directly address transmission issues, it is assumed in the present analysis that new transmission is built such that for 98% of the time all wind generation is able to serve load, while during the remaining 2% curtailment is applied based on transmission limitations. This approach is consistent with ERCOT (2006), and follows the reasoning that optimal (least-cost) transmission expansion for wind will not necessarily seek to deliver each and every unit of wind electricity to load.

The high-resolution case has 8760 h per year, allowing for hourly dispatch decisions to be considered when determining optimal capacity expansion and other results. The medium-resolution case evaluates 288 h during the year, reflecting typical days by season as has been used in Dena (2010). The low resolution case has just 16 broad time slices, which follows the approach used by NRELs ReEDS model as used to evaluate a high penetration wind scenario for the U.S. (NREL (2008)), but without the correction terms utilized by ReEDS.[11] The analyzed cases represent the approaches used in the identified literature. Different approaches can consequently lead to different results. An overview on stochastic scenario generation and reduction approaches is provided by Möst and Keles (2010).

The initial difference in temporal resolution can be observed in Figure 5.2 for the year 2030, which shows the load duration curves for the two wind penetration scenarios under the different time slice approaches. The original load duration curves for the low-wind reference case and high-wind base case are equivalent, such that the only variation in the load duration curves comes in their temporal resolution (upper three curves); the residual load duration curves of the low-wind and high-wind cases do differ, and Figure 5.2 only presents the latter (lower three curves). At first sight, even the load duration curve under the very low resolution case with only 16 time slices matches the 8760 h case surprisingly well. The differences between the three temporal resolutions are most obvious at both ends of the curves, but overall are not substantial for load duration curves.

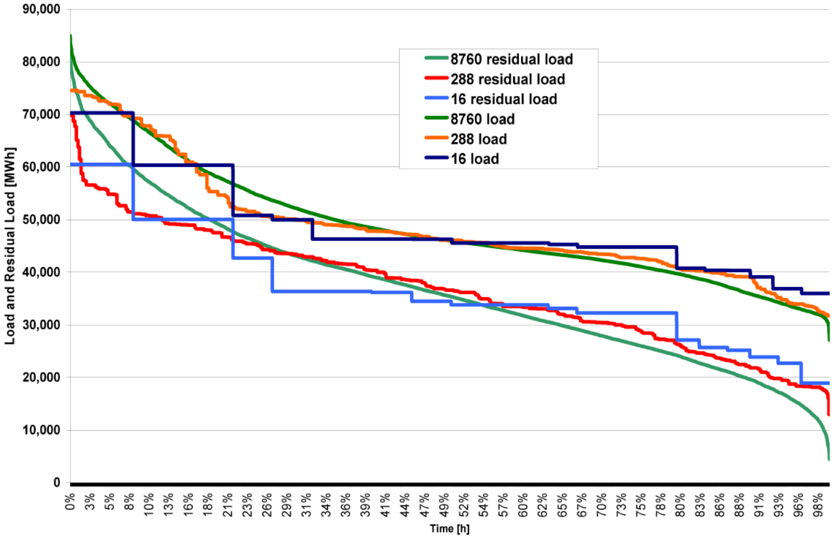
Since the conventional power system does not have to meet the full load, but only the residual load, Figure 5.2 also highlights the three different residual load duration curves for the high wind scenario. As shown, the deviations between the three temporal-resolution cases increase in comparison with the total load cases. In addition to the stronger deviations, which are especially observable at both ends of the curves, the slope of the duration curves differs also to a higher degree compared to the overall load duration curves. In summary, reducing temporal resolution does not - visually - have a significant impact on the load (or residual load) curve when variable wind generation is low. At a 25 % wind energy penetration level, however, the residual load curve varies substantially among the three temporal resolution cases presented in Figure 5.2.

5.2 Results

In the following, the modeling results for capacity and generation mixes are discussed, followed by RES-E specific results, such as the market value of wind energy and the development of required curtailment.

11 The 288 h resolution case assumes typical patterns for workdays, Saturdays and Sundays within each season and therefore averages, e.g. the third Wednesday per month each season to create a 'typical' workday. The 16 time slice approach averages similar load situations per season in a broader approach, e.g. all night hours within one season.

Figure 5.2: Comparison of different time slicing approaches

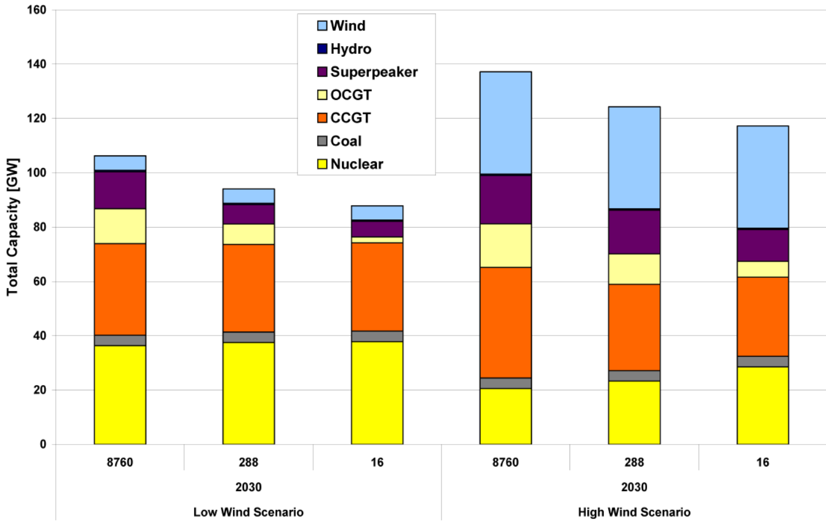


Source: Nicolosi et al. (2010), data provided by ERCOT (2010b).

5.2.1 Optimal Capacity Expansion

Model results for total generation capacity in 2030 by unit type, under both scenarios and all three temporal resolutions are presented in Figure 5.3. In the low wind scenario, the main difference in generation capacity among the different temporal resolutions comes from different deterministically calculated peak loads. This is a direct result of the observed difference in the left-hand-side of the load duration curves shown in Figure 5.2, where one can see substantial differences in peak loads depending on the temporal resolution used. The higher the temporal resolution, the more effective the model is in capturing real peak load requirements, leading to greater quantities of peaking unit capacity (i.e., the capacities of 'superpeakers' and OCGTs increase as temporal resolution increases). When it comes to the remaining capacities, however, there are only slight differences among the three resolution cases in terms of nuclear, coal, and CCGT capacity. Even the 16 time-slice low resolution case shows more or less the same capacity development as the high resolution case apart from the need for peaking capacity. Adding a 'superpeak' time slice, as applied in the ReEDS model (NREL (2008)), is likely a sufficient solution to close this gap, under the low wind scenario.

Figure 5.3: Capacity comparison of high and low wind penetration under different time slicing approaches in 2030



Source: Nicolosi et al. (2010).

Optimal capacity expansion is substantially different in the high-wind penetration scenario, and also varies significantly depending on the temporal resolution. Under all three temporal resolutions, the peak capacity need in the high-wind scenario is substantially greater than in the low-penetration scenario. This requirement is met by substantially greater quantities of superpeakers and OCGTs, but correspondingly lower amounts of nuclear generation capacity. This shift towards greater quantities of peaking generation and lower quantities of baseload generation is consistent with other analyses of high-penetration wind energy scenarios (Dena (2005)).

In comparison to the low-wind scenario, the remaining capacity mix in the high-wind scenario also varies substantially depending on the degree of temporal resolution. In addition to the greater investments in OCGTs, the higher temporal-resolution cases with high wind also result in greater investments in combined cycle gas turbines (CCGTs). When it comes to general baseload investments, even though the low resolution case has, in absolute terms, lower peak capacity requirements, the base-load investments are found to be higher, even in absolute terms, than in the high resolution cases. In effect, as temporal resolution increases under a high-wind penetration scenario, the remaining conventional generation mix tends to shift towards intermediate and peaking plants that can cost-effectively meet the decreased capacity factor and flexiblity needs of a high-wind scenario, while shifting away from conventional base load units.

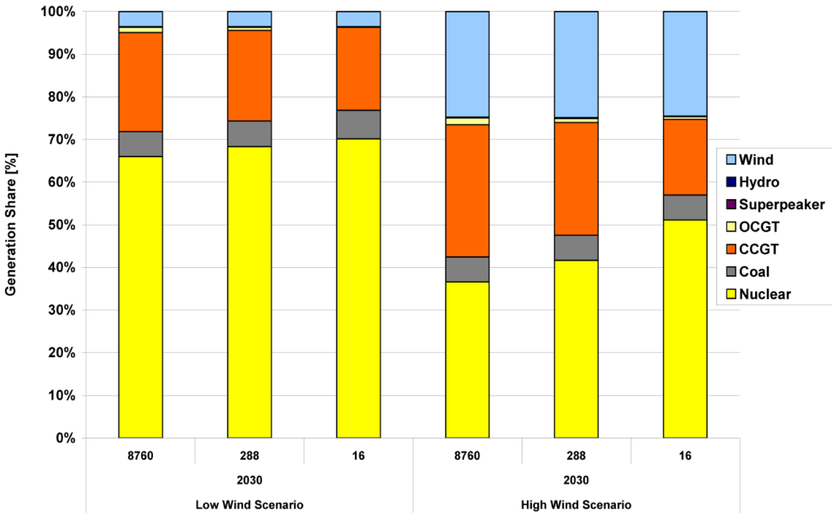
One additional outcome of this scenario comparison is the implicit capacity credit for the additional wind capacity. In 2030, the wind capacity difference between the low- and the high-wind scenarios is 32 GW. The difference in conventional capacity between the scenarios in the low resolution case is 3 GW, in the medium resolution case 2 GW, and in the high resolution case 1.4 GW, which equals a capacity credit of 9.3% in the low, 6.4% in the medium and 4.3% in the high resolution case. Using lower temporal resolutions is therefore found to overstate the capacity value of wind energy. In summary, these results demonstrate that higher temporal resolution plays a significantly more important role in high wind energy penetration scenarios than in traditional energy sector modeling. Scenarios with a relatively low amount of wind energy, on the other hand, may be modeled with lower temporal resolutions without sacrificing the accuracy of the results substantially, especially if peak load requirements are accurately modeled.

5.2.2 Generation Dispatch

Model results are presented in Figure 5.4 for generation utilization in 2030 by unit type, under both scenarios and all three temporal-resolution cases. The generation mix in the low wind scenario follows the observations above covering investment decisions: only relatively modest differences result among the temporal resolution cases. Some differences, however, are observable. Specifically, generation from nuclear plants is somewhat higher in the low resolution case, while generation from CCGTs is higher in the high resolution case. In addition, there is a small amount of generation from OCGTs in the higher resolution cases and virtually none in the low resolution case. Even with low levels of wind generation, it is clear that lower temporal resolution models are unable to fully capture the need for peaking and intermediate generation in the power sector.

As with the optimal capacity mix, these differences become much more striking under the high-penetration wind energy scenario. Regardless of the degree of temporal resolution, high penetrations of wind energy are found to increase the supply of peaking and intermediate generation, and reduce the need for baseload generation. Perhaps more importantly from a modeling perspective, however, is that temporal resolution has a dramatic impact on model results in high wind penetration scenarios. In particular, the generation mix becomes much more peak oriented in the high resolution cases: there is more generation from OCGTs, CCGTs and even the 'superpeaker'

Figure 5.4: Generation comparison of high and low wind penetration under different time slicing approaches in 2030



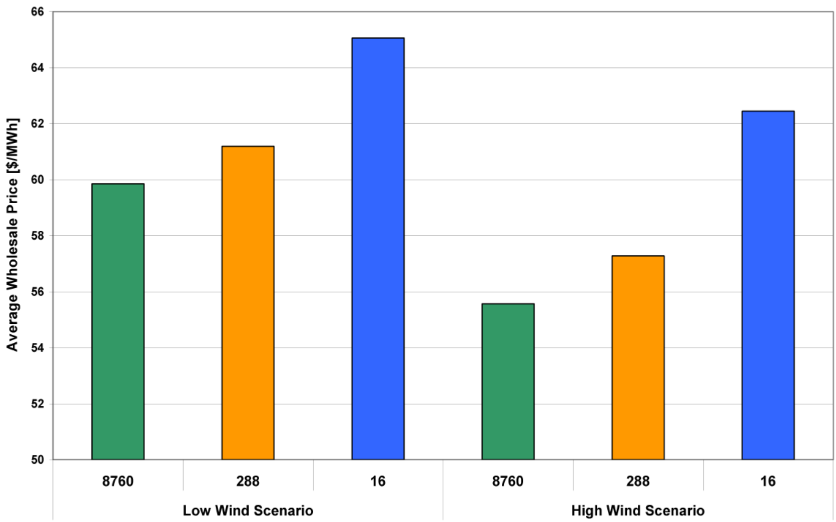
Source: Nicolosi et al. (2010).

category has up to 21 generation hours, whereas baseload nuclear generation decreases substantially. As with capacity expansion, these results demonstrate that higher temporal resolution plays a significantly more important role in high wind energy penetration scenarios than in traditional energy sector modeling. These differences are, in part, simply an outcome of the different investment patterns but, as can be seen in the cases of OCGTs, differences are also due to dispatch decisions.

5.2.3 Wholesale Power Prices

Differences in capacity expansion and generation mix are also reflected in estimated annual average wholesale power market prices, as shown in Figure 5.5. The wholesale market power prices are assumed to be equal to the marginal values of the energy market constraint as explained in section 4.3. The high wind scenarios tend to have lower average wholesale prices than the low wind scenarios, while higher temporal resolutions also tend to result in lower average wholesale prices.

Figure 5.5: Price comparison of high and low wind penetration under different time slicing approaches in 2030

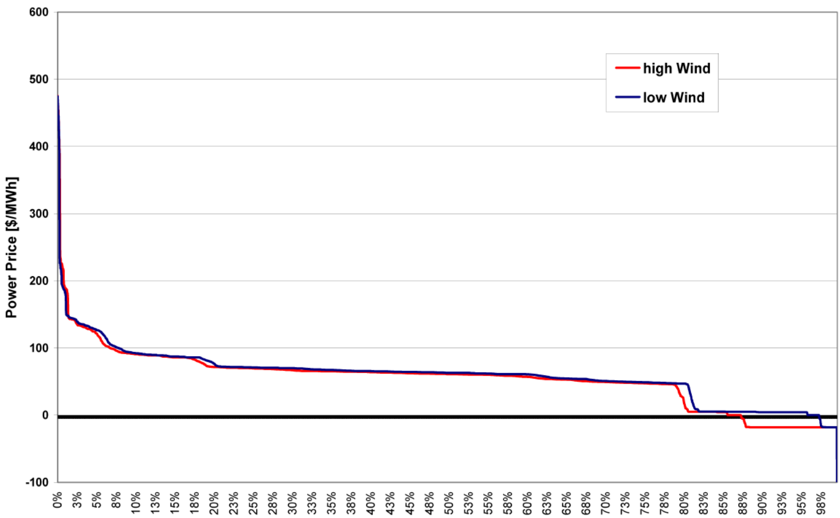


Source: Nicolosi et al. (2010).

The different price levels between the time slicing approaches in the low wind scenarios represent the differences in load volatility. Since in the 8760 h case, a base load technology sets the price every once in a while, the prices are lower compared to the lower resolution cases, where the price is most often set by medium load technologies. The effects of higher wind penetration are observable by the comparison of both wind levels. During hours of high wind power generation, wholesale power prices are driven below the average price level, resulting in an overall reduction in average wholesale power prices under the high-wind penetration scenario, as shown in Figure 5.5. Nevertheless, a second trend operates in the opposite direction: under the high-wind scenario, a greater amount of intermediate and peaking generation is used, generation that requires higher wholesale prices to support the variable costs of those units relative to base load plants. Since the prices shown in Figure 5.5 present only the average effects, thereby masking these influences, Figure 5.6 depicts the wholesale price behavior in form of price duration curves, where both of the above-mentioned trends are observable. To explain the price effects of high wind penetration, only the highest temporal-resolution (8760 h) cases are compared in Figure 5.6.

As shown, the price duration curve of the low wind scenario is, most of the time, above

Figure 5.6: Comparison of price duration curves in 2030

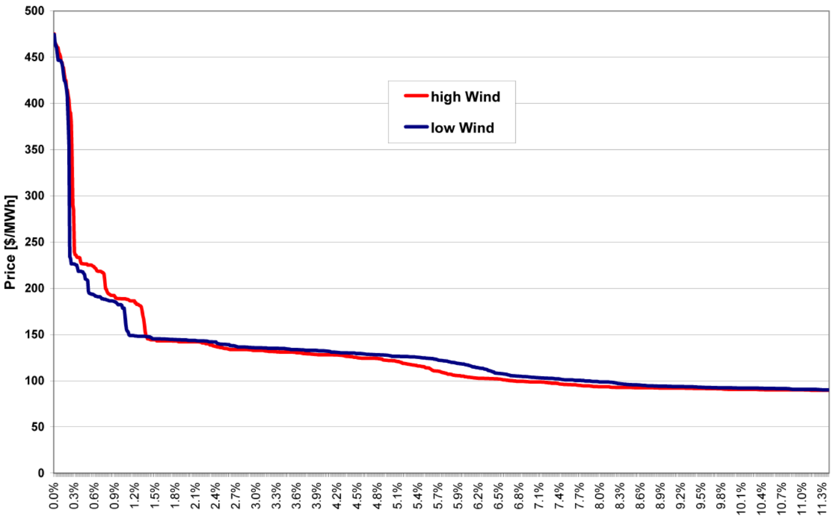


Source: Nicolosi et al. (2010).

the one from the high wind scenario, especially in the lower price segment. During very high-priced periods, however, the opposite trend is observable. Both effects are more-readily seen in Figure 5.7 and Figure 5.8, which focus on the particularly high- and low- price sections of the price duration curve.

During the periods of high wholesale power prices, the price duration curve of the high wind scenario is above the one from the low wind scenario, consistent with the higher generation share of peaking and intermediate units in this scenario and the lower use of base load units. Though these difference in the high-price periods are relatively modest, the difference in the lowest price sections are more apparent. In particular, the price duration curve in the high wind scenario drops to low and even negative prices far earlier than in the low wind scenario. Thereby, the low but positive plateaus represent the hours in which nuclear generation is the marginal unit, whereas negative prices are capped by the assumed support payment of 18.2 USD/MWh for wind infeed. The support motivates wind operators to generate at wholesale prices at or above -18.2 USD/MWh. As soon as the power price drops below this 18.2 USD/MWh level, wind generation is curtailed; this negative threshold therefore indicates curtailment, which of course occurs more often in the high wind scenario.

Figure 5.7: Comparison of price duration curves with particular focus on high prices in 2030



Source: Nicolosi et al. (2010).

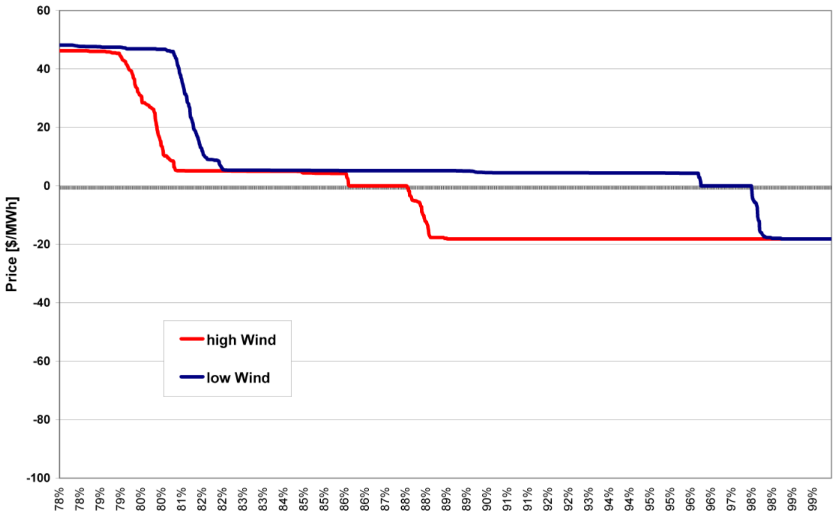
5.2.4 Market Value of Wind Energy and Curtailment Results

One additional metric that shows the advantage of high temporal resolution modeling and that naturally follows the price discussion is the wholesale market value of wind energy, relative to average annual wholesale prices (Figure 5.9). The market value of wind energy is determined by the spot market price in each hour. This implies that the value of the wind energy reflects the value of the alternative energy source that is crowded out.

The general pattern over time shows that, after the transmission restriction is assumed to be somewhat relaxed from 2015 onwards (as explained in the section 5.1), the wholesale market value of wind energy increases until higher wind penetration levels are reached, at which point the market value of wind drops due to the price-depressing effects discussed in section 3.1. This pattern is observable in all cases, regardless of the degree of temporal resolution, and can also be seen when comparing the low- and high-wind cases in Figure 5.9.

In addition, the higher the temporal resolution, the lower the estimated wholesale value of wind energy, since more extreme events, which are only present in the high

Figure 5.8: Comparison of price duration curves with particular focus on low prices in 2030

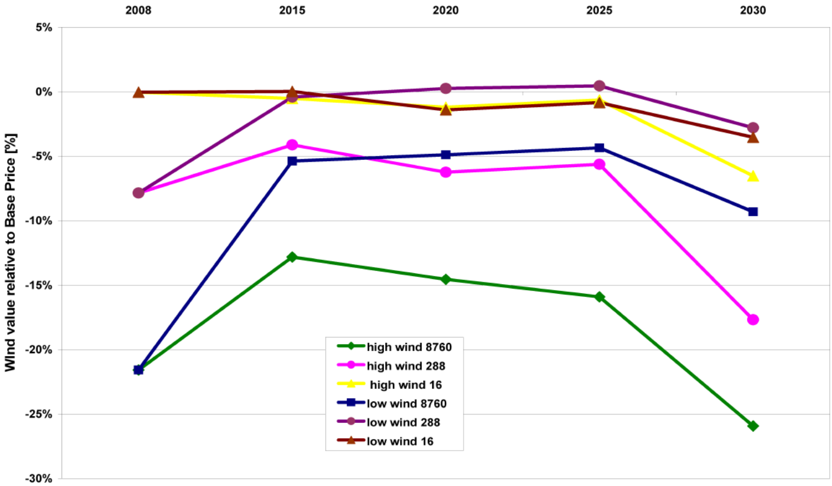


Source: Nicolosi et al. (2010).

resolution cases, have particularly strong price effects. As a result, in the low resolution case, the wholesale market value of wind is only slightly below the average wholesale price, whereas the higher resolution cases show a stronger deviation between the wholesale value of wind and average wholesale prices.

The wind energy value is partially determined by curtailment, since if curtailment is required, the power price reflects the negative premium price. Figure 5.10 presents model results for wind energy curtailment which illustrate the interdependence with the power price. Naturally, the higher wind penetration scenario also shows higher relative curtailment levels. In addition, since the extreme events only show up in the higher resolution cases, curtailment is found to increase with temporal resolution. This finding, along with the previous finding on the wholesale market value of wind energy, underline the conclusion that dispatch behavior is best matched with high temporal resolution. The extreme events are not representative enough to show up in typical days. Capturing these events therefore requires a higher temporal resolution or at least the consideration of more days.

Figure 5.9: Comparison of wind values



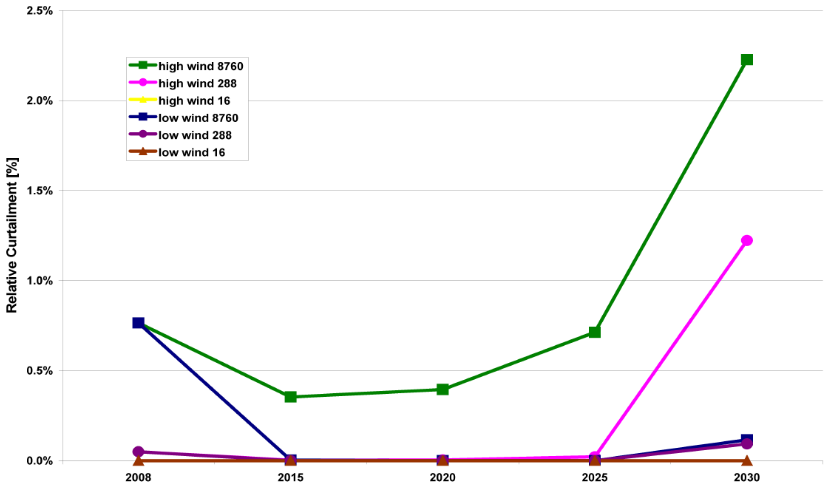
Source: Nicolosi et al. (2010).

5.2.5 The Separation of the Adaptation Effects

In section 3.2, the explanation of the long-run adaptation effect of high RES-E penetration is divided into the utilization effect and the flexibility effect. To capture these effects individually, three scenario comparisons are required. The overall adaptation effect is already captured by the comparison between the high and the low wind scenarios. One scenario, which can purely follow the utilization effect, is required to separate both effects. In this scenario, all ramping related constraints are ignored. Therefore, the optimization purely follows the static merit-order approach without any costs for ramping and without part-load costs. As soon as an additional technology is required, the variable costs of this marginal unit sets the price. By this approach, only the times when a particular technology is utilized purely on the basis of its position in the merit-order count for the optimization of the capacity mix. Consequently, the results of this scenario can only be compared to the high-wind scenario in order to represent the difference between the pure utilization effect and the additional flexibility effect.

The difference between the 'no ramping scenario' and the full high wind energy scenario in Figure 5.11 is the difference with additional ramping requirements. Due to the utilization effect, a shift towards less base load and more mid-merit as well as

Figure 5.10: Comparison of wind energy curtailment



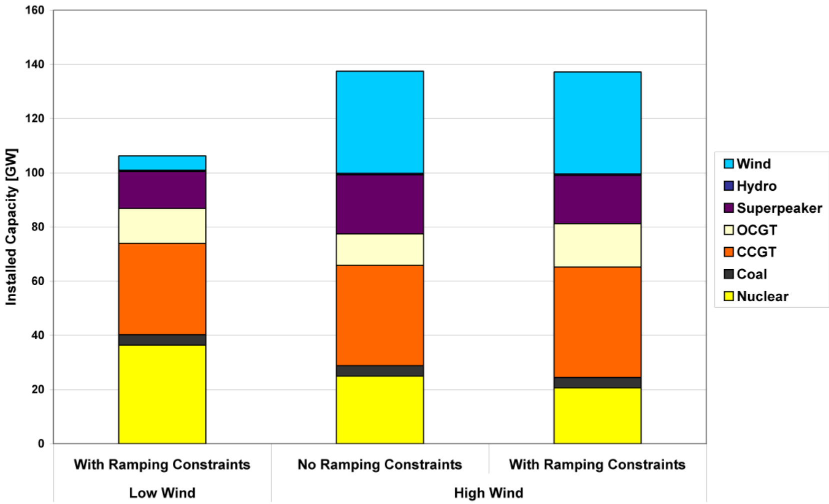
Source: Nicolosi et al. (2010).

peak load capacity is observable. In addition, the flexibility effect further reduces the amount of base load capacity and increases the demand for peaking units. The reason behind the higher demand for OCGT capacity in the full ramping scenario is that they are more often required when ramping constraints are present, while the superpeaker units are reduced because they are mainly deployed to fulfill the peak requirement, and due to the high costs are only very rarely utilized.

The generation mix in Figure 5.12 reflects the capacity adaptation process. The main effect can clearly be identified as the utilization effect. The flexibility effect adds complexity to the dispatch problem, which causes more investments in peak-oriented capacities. Clearly, CCGTs and OCGT are more strongly utilized compared to the merit-order based scenario without ramping constraints.

The comparison of the price duration curves in Figure 5.13 focuses only on both high wind scenarios. The highest price in the scenario without start-up costs represents the highest variable fuel costs of the superpeaker, while the peak prices in the base scenario also reflect start-up costs. One can easily see that the price duration curve of the base scenario is above the other in times when ramping costs or part-load costs are added to the pure variable costs of the marginal capacity. By the comparison of the medium plateaus, it is observable that the price duration curve with intertemporal constraints reflects the benefits of avoided shut-down and subsequent start-up

Figure 5.11: Comparison of flexibility effect

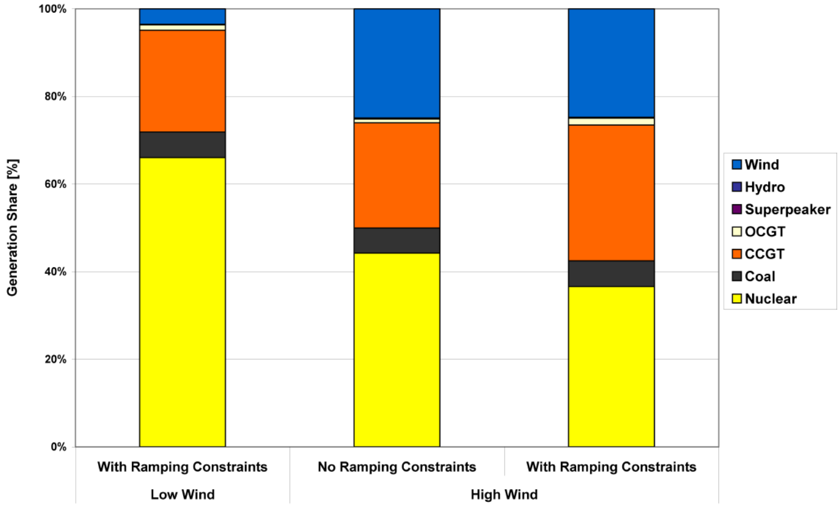


Source: own illustration.

decision and thereby confirms the findings of Müsgens and Neuhoff (2006). On the low price side, one can see by the long plateau that without ramping constraints, the prices are often set by nuclear capacity. Only a few curtailment hours are responsible for the negative prices. In the ramping scenario, curtailment happens more often to avoid the start-up costs of the conventional capacity. In addition, it is important to note that the comparison between the two price duration curves reveals not only different dispatch constraints, but also a slightly different capacity mix, as shown in Figure 5.11.

Finally, the comparison of the wind energy values shows that if ramping constraints are not accurately modeled, the wind energy value is overestimated. Although the base load capacity in the 'no ramping constrains' scenario is higher, the wind energy value is higher in this scenario too. Adding the complexity of consecutive hours with intertemporal ramping constraints changes not only dispatch results, but also capacity investment decisions.

Figure 5.12: Comparison of flexibility effect in generation



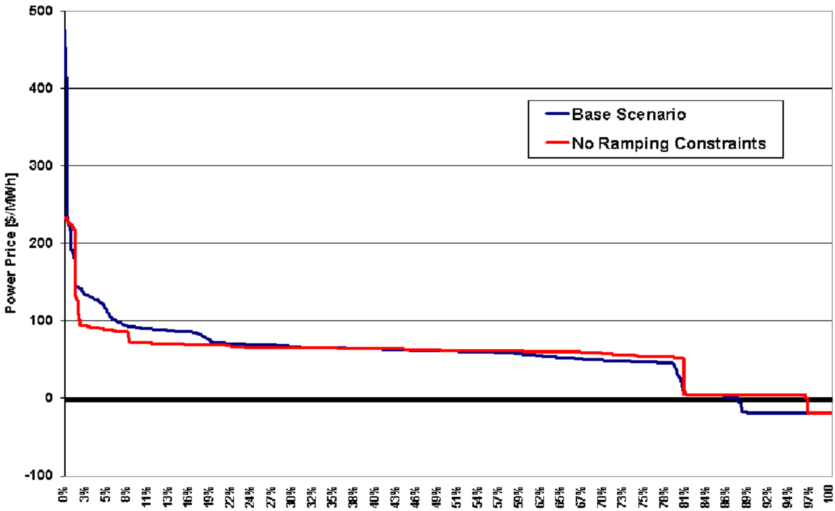
Source: own illustration.

5.3 Intermediate Conclusion

The modeling results presented in this chapter demonstrate the importance of temporal resolution in evaluating high wind penetrations. The low wind scenarios show relatively small capacity investment deviations when moving from high to low temporal resolution. The corresponding results for the high wind scenarios, on the other hand, differ significantly with temporal resolution. More specifically, under high wind scenarios, lower temporal resolutions are found to result in far-higher levels of base load capacity (e.g. nuclear) than are found to be optimal with more accurate modeling. The higher the temporal resolution, the lower the base load capacity. Consequently, models with low temporal resolution may substantially overstate the amount of base load generation that would be economically efficient in a high-penetration wind energy scenario, while understating the need for peaking and intermediate generation units. The same is true for modeling capacity expansion without ramping constraints, as done by Neuhoff et al. (2008). Their intuition that adding ramping constraints would lead to less base load and more peak load capacity investments can be confirmed by the presented results.

When it comes to the dispatch part of the model, temporal resolution is also found

Figure 5.13: Comparison of price curves with and without ramping constraints

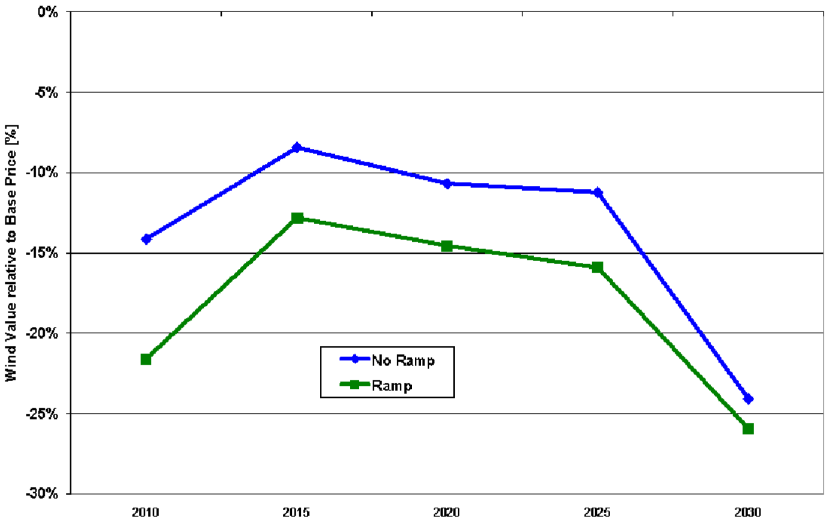


Source: own illustration.

to play an important role, especially under high penetration wind energy scenarios. Again, the higher the temporal resolution, the greater the reliance on peaking and intermediate generation supply and the lower the contribution of baseload generation. Moreover, lower-probability power system events are only captured when temporal resolution is high, so notable differences in the market value of wind and wind energy curtailment are observed when temporal resolution changes. The market value of wind as well as the curtailment behavior is best captured by high temporal resolution; models with low temporal resolution will tend to overstate the market value of wind and understate the prevalence of wind curtailment.

An important implication of these results is the need to model high-wind scenarios with capacity expansion and dispatch models with high temporal resolutions. Where high temporal resolution is not possible due to computing constraints, correction factors might be applied instead. Based on the results presented here, those corrections would ideally have the effect of reducing base load (and increasing peaking and intermediate) capacity and generation with an increasing level of wind energy supply, while also increasing the aggregate level of conventional capacity to meet peak system loads. In addition, in the modeling presented in this thesis, wind power development was established exogenously, and the value of that wind generation was found to decrease with penetration. Though the degree of that decrease in value will depend

Figure 5.14: Comparison of wind values with and without ramping constraints



Source: own illustration.

to a large degree on the composition and flexibility of the conventional generation mix and will be highly system specific, correction factors to account for the decrease in market value of wind with penetration are needed if low temporal resolution models are used.

In conclusion, the additional requirements imposed on conventional power markets with high wind penetration are also reflected in additional requirements for detailed power sector dispatch and capacity expansion modeling. In general, the higher the wind penetration, the more important the temporal resolution is in simultaneous dispatch and investment decision. Fortunately, progress in computational power enables modelers to increase the degree of accuracy and to increase temporal resolution. Although modeling at an hourly time step is not possible for all applications, stepwise progress seems appropriate, with correction factors applied where necessary.

6 The German RES-E Targets in High Resolution

In previous sections, the attributes of THEA were explained and compared to other approaches. Now the German power market will be analyzed under consideration of the surrounding markets. The impact of the RES-E targets on the German power marked up to 2030 is modeled. The ambitious RES-E targets have strong effects on the system component's supply, grid and demand. To gain better insight into the dynamics of the power market with increasingly high RES-E shares, the focus is laid on the effects on the RES-E value and on the conventional supply side consisting of different technology types. The impact on the grid is represented by the analysis of the cross-border interconnector capacities, since individual power markets are modeled as copperplates without internal grid bottlenecks. Even though this represents only a small fraction of the grid infrastructure, the development over time as well as the scenario comparisons provide an indication for the challenges of the grid infrastructure. Finally, the demand side is considered by taking into account the financial burden which stems from energy and reserve markets as well as from exogenously applied RES-E support payments.

The next section provides an overview of the input assumptions. The remaining sections discuss model results, which provide insight into the market adaptation and behavior due to the German RES-E targets, and analyze how the integration challenges affect different system components. A more detailed analysis of various changes in particular system attributes shows how RES-E integration can be eased or restrained.

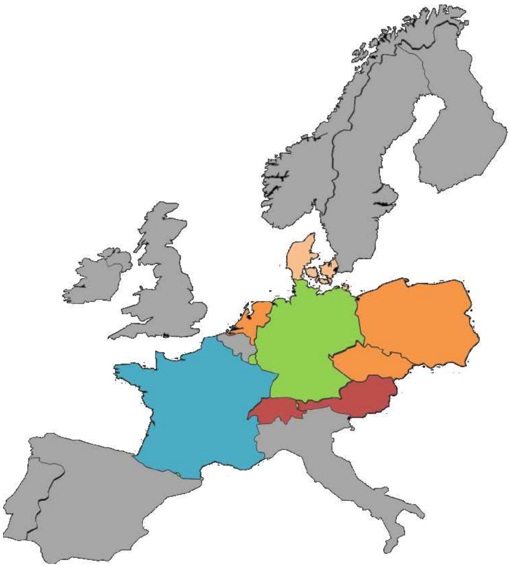
6.1 Input Overview

This section provides an overview of the input assumptions for the German case study. This overview consists of the applied model system boundaries and assumptions on the supply side, demand side and the interconnector infrastructure. Finally, the individual scenario assumptions are explained.

Model Boundaries and Market Connections

In order to enable a feasible computation time and at the same time to capture important market interaction features, the modeled power system is limited to 11 zones as can be seen in Figure 6.1. The markets that have a direct interconnection with Germany (Denmark, Poland, Czech Republic, Austria, Switzerland, France and the Netherlands) are modeled with all model attributes explained in Section 4.3.

Figure 6.1: Model regions (colored: full model regions; gray: remote zones)



Source: own illustration.

In order to reduce computation complexity, interconnector restrictions between Poland and Czech Republic (PLCZ), as well as between Austria and Switzerland (Alps), are neglected. Therefore, these country pairs form one power market each as can be seen by the color coding in Figure 6.1. The same applies for the Nordpool area (North), consisting of Finland, Norway and Sweden, the Iberian peninsula and the UK and Ireland (UKIE). The latter pooled countries (North and UKIE), as well as Italy and Belgium, are treated differently in the model. Since they are important for the interregional exchange decision of the neighboring countries of Germany, they are also modeled in full temporal resolution, but with a limited equation set (e.g. ramping constraints are removed). In this way, the exchange decisions of the surrounding markets of Germany are taken into account, but instead of the full complexity, a pure merit-order perspective is implemented in these remote zones.

As already mentioned above, the individual power markets are able to exchange en-

Table 6.1: Net electricity consumption excluding own consumption and consumption of pumped-storage plants [TWh_{el}]

Zone	2010	2015	2020	2025	2030
Germany	557	547	525	525	525
France	494	503	513	513	513
Netherlands	116	123	130	130	130
Denmark	34	36	36	36	36
PLCZ	191	197	203	203	203
Alps	105	109	116	116	116
Italy	332	343	355	355	355
Iberia	319	357	403	403	403
Belgium	84	85	86	86	86
UKIE	373	382	391	391	391
North	373	382	391	391	391

Source: own assumptions, based on EU Commission (2010).

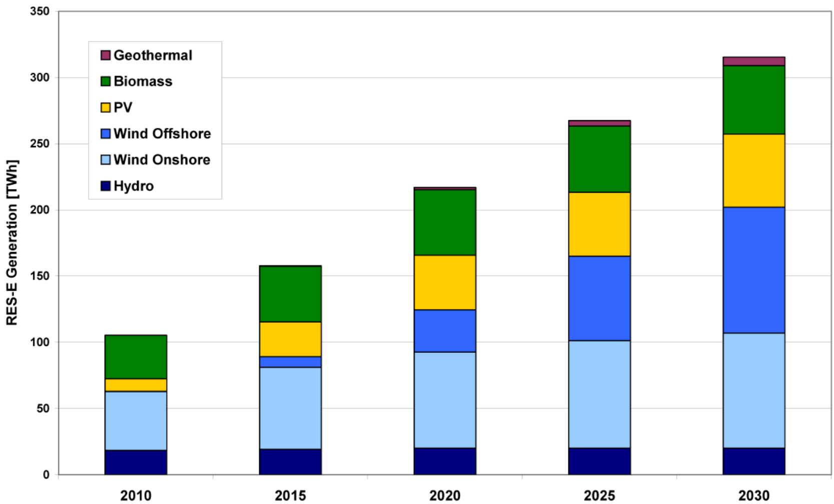
ergy to reduce costs. Although the western European power markets are closely connected, the exchange is limited by net transfer capacities (NTC) (see Table A.3). NTCs are an approximation of actual transfers possibilities, which are best reflected by physical power flow analysis. These are usually conducted for a particular point in time (i.e. one load situation) and cannot capture dynamic developments, such as intertemporal dispatch. One simplification is the utilization of power transfer distribution factor (PTDF) matrices, which capture the distribution of the power flows per node. According to Duthaler (2007), the advantages of PTDF matrices are negligible when they are applied in a zonal model instead of a nodal approach. Since the border capacities in a zonal model have to be defined before the actual market situation, they follow the same assumptions as NTCs. Therefore, the NTC approach is sufficient for the present analysis. The initial NTC values are based on ENTSO-E (2010c) and the development is derived from (EWI (2010)). Grid losses further limit the physical and economic utilization of the NTCs. On average, 10% energy loss is assumed for 1000 km transport distance.

Demand Side Assumptions

The net electricity consumption excluding plant consumption and consumption of pumped storage plants is derived from the 'National Renewable Energy Action Plans' (NREAP), which each country submitted to the EU Commission (2010). These plans show the expected development by 2020. Since energy efficiency is one of the main goals of the European energy strategy, it is assumed that the electricity demand will remain on the 2020 level until 2030 (see Table 6.1).

One important information of the NREAP is a detailed plan of how each country intends to reach its renewable energy targets, whereas the 'EU Renewable Directive' (European Union (2009)) only states overall targets for the renewable energy share of the total energy consumption. The NREAP intend to show in detail how each country plans to reach its target, by sector and even by energy source. After 2020, the German technology specific RES-E targets are derived from the 'Leitszenario 2010' of the German Federal Ministry of Environmental Affairs (BMU (2010b)). The corresponding technology specific RES-E targets are shown in Figure 6.2. The RES-E development for the other countries for the time frame after 2020 is assumed to increase further, but by a reduced growth pace of 50% compared to the development from 2010 to 2020. Additional exogenous generation is supplied by e.g. waste combustion and inflexible chp plants. The total values are shown in Table A.4.

Figure 6.2: German RES-E generation targets



Source: own assumptions, based on EU Commission (2010) and BMU (2010b).

The RES-E infeed structures are based on historic weather data. For wind power infeed, the same data source is used as for EWI (2010), where wind speeds from various weather stations across Europe have been collected. Since the wind speeds are collected at relatively low measuring points, they are first adjusted by applying a power law adjustment to estimate wind speeds at hub heights. The wind speeds are then converted into electricity by applying a modified wind farm power curve as done in Holttinen (2005b) to estimate the power production across larger geographical areas (for comparisons of actual versus modeled power generation from wind speeds, see Fripp and Wiser (2008)). For the PV infeed structure, NRELs 'Solar Advisor Model' (NREL (2010b)) has been utilized. It converges measured solar irradiation data into PV generation. The weather data are provided by the U.S. Department of Energy's 'Energy Efficiency & Renewable Energy Program' (DoE (2010)).

If an oversupply situation requires curtailment, a novel approach is applied. Most RES-E integration studies (e.g. BMWi (2010b)) allow curtailment at a price of zero. However, the analysis in sections 3.1.3 and 3.1.4 shows that the price level at which RES-E is curtailed depends on the support scheme. In the case of Germany without an out-of-market curtailment rule, the power price dropped to -500 EUR/MWh without any curtailment. In theory, it could even have dropped to -3000 EUR/MWh. In the case of Texas on the other hand, market-driven curtailment is observable at negative power prices, which reflect the PTC price for RES-E support. In the present analysis, a premium system for Germany is assumed. Since the currently implemented rule would result in an extreme scenario, it is modeled separately as a sensitivity case. It is likely that Germany will implement a premium system in the next EEG amendment in 2012. The assumed premiums do not reflect the required support level, but serve as a proxy for the market-driven curtailment. These premiums are derived from the difference between levelized generation costs of the technologies and an average power price level. Wind onshore receives a premium of 34 EUR/MWh; wind offshore 96 EUR/MWh; solid biomass 46 EUR/MWh; gaseous biomass 116 EUR/MWh; liquid biomass 118 EUR/MWh; geothermal 96 EUR/MWh; and PV 414 EUR/MWh. These premiums apply for all scenarios except the sensitivity scenarios for the curtailment rule and remain constant throughout the modeling period to ease the interpretation over time.

Supply Side Assumptions

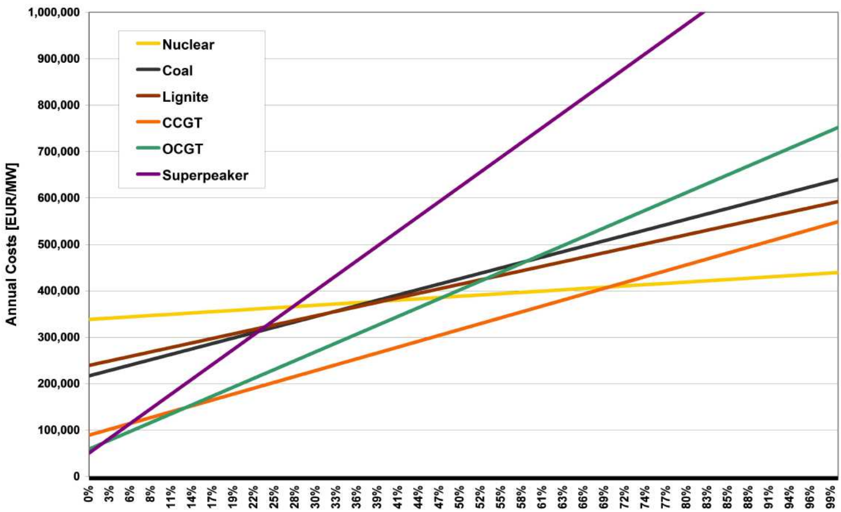
The economics of individual conventional technologies are determined by various technological and economic properties. Investment cost assumptions and efficiency development follow IEA (2010). Table A.5 provides an overview of properties of current technology design as well as assumptions for future investment options from 2020 on. The assumptions about storage technologies follow Dena (2010). Pumped hydro storage can only be commissioned exogenously and has a round trip efficiency of 76%. CAES[12] on the other hand can be commissioned endogenously with a six full load hours storage and a round trip efficiency of 70%. The required reserve for system services follows ENTSO-E (2009b) and is assumed to be 8.2 GW for positive and negative reserve, of which 50% are spinning and 50% non-spinning, respectively. Even though this level is slightly higher than today's levels, it is still a moderate

12 CAES in this case is an advanced adiabatic compressed air energy storage, which does not require the co-firing gas and has a higher efficiency than diabatic compressed air energy storage. See, e.g. Gatzen (2008) for an analysis of various storage technologies.

assumption since the power system requires a certain amount of conventional generation online to supply grid stabilizing services, such as inertia, frequency control and reactive power in addition to the pure reserve requirements. For the annualization, an interest rate of 10% is assumed for the conventional power plant investments. Furthermore, all costs in this analysis reflect 2009 values.

The assumptions about the lifetime and the depreciation time frame of the conventional technologies are summarized in Table A.6. The fuel costs in 2010 are primarily based on the 2009 values of IEA (2010) as well as the coal price assumptions in subsequent years. Natural gas price assumptions after 2010 follow BMWi (2010a). CO_2 price assumptions are based on the impact assessment of the European RES-E directive (Capros et al. (2008)). Table A.7 shows the fuel and CO_2 price assumptions. As explained in section 3.2, these inputs can be converted into screening curves, which initially provide a rough intuition on the system adaptation, purely based on the input assumptions. Figure 6.3 shows this approach for the year 2020.

Figure 6.3: Screening curves for the year 2020



Source: own assumptions, based on data from IEA (2010).

Due to the economic assumptions, it can already be seen that coal and lignite are unlikely to be commissioned. Since new investments in nuclear plants are not allowed in Germany, the cheapest alternative energy technology above a certain utilization is

CCGT.

6.2 Scenario Definitions

The scenarios are selected in a way that the effects on various system components can be compared and directly attributed to particular assumptions. The particular scenario designs are derived from findings in section 3.1, which indicate that particular system component designs have an impact on the flexibility of the power system. Therefore, modifications of these system components are analyzed to see how the remaining system is affected in the long run.

- **Base Scenario:** The 'Base' scenario serves as the main reference point. The results of the other scenarios are always compared to the results of the 'Base' scenario. This scenario is characterized by a premium system assumption, which allows marked-driven curtailment as explained in section 3.1.4. Due to current RES-E integration challenges, it is highly likely that the next amendment of the EEG will provide a premium system which internalizes the curtailment decision. The conventional part of the market is characterized by the nuclear phase-out according to a political agreement in 2002.[13]
- **Low RES-E Scenario:** The 'Low RES-E' scenario assumes no further RES-E deployment after 2010 and remains at this level for the considered period. The comparison between the 'Base' and the 'Low RES-E' scenarios allows for the identification of the market adaptation according to the additional RES-E penetration in the base scenario.
- **Lifetime and Friction Scenarios:** Since an extension of the lifetime of nuclear plants in Germany is currently under discussion, two nuclear lifetime extension scenarios are calculated. The first simply assumes an average lifetime extension of 12 years, as targeted by the currently reigning coalition. The second scenario adds an additional constraint to the equation set. Since the analysis in section 3.1.3 showed that base load technologies stay at a certain generation level even if power prices are significantly negative, this scenario takes this additional friction into account. It is assumed that the nuclear fleet cannot reduce its generation below 60% of its available capacity and the lignite fleet is required to generate above 40% of its available capacity according to the findings in section 3.1.3. Since base load plant flexibility is an important factor in the analysis of RES-E market integration, the 'what if' question is raised. This scenario does not intend to state that these plants are not flexible. But for some reason, the plants have been operated in this way. Even though it is likely that

13 In fall 2010, when the scenario assumptions were set, the political discussion on nuclear lifetime extensions was still ongoing. Therefore, the nuclear phase-out still serves as a business-as-usual assumption.

the plants will be operated more flexibly in the future, this scenario is motivated by the previous findings.

- **Grid Extension Scenario:** To increase the flexibility of the power market, in the 'Grid Extension' scenario NTC capacities are extended by 50% in 2015 and doubled from 2020 onwards. This scenario allows for an analysis of the effects of an increase in the grid infrastructure especially in firm market situations.

- **Curtail0, Curtail150 and Curtail3000 Scenarios:** It has been shown in section 3.1.4 that the RES-E support scheme plays an important role in the RES-E curtailment decision and therefore in the price setting in firm market situations. To capture the extreme ends in addition to the premium system assumption of the base scenario, three additional regimes are assumed. First, the 'Curtail0' scenario does not allow negative bids for RES-E and therefore curtails the infeed as soon as the price is below zero, as assumed in most RES-E integration studies. The 'Curtail3000' scenario simulates a pure feed-in tariff system with a TSO infeed obligation as it is defined in most FIT systems. The curtailment level of -3000 EUR is defined by the floor of the Epex Spot. This design provides a strong investment security for RES-E, but has obvious weaknesses in the system integration at high penetration levels. This is also the reason why this current FIT design in Germany does not qualify as base scenario. One additional scenario is designed, which represents the current German out-of-market curtailment rule. The 'Curtail150' scenario starts curtailing at -150 EUR/MWh. It is motivated by the rule of the German regulator BNetzA, which states that when the spot price reaches -150 EUR/MWh, a second auction is allowed with limited RES-E bids from the TSOs.

- **RES-E Reserve Scenario:** As shown in 3.1.3, tight market situations are also influenced by reserve capacity requirements. Therefore, in this scenario, RES-E are enabled to provide positive and negative reserve. In the case of negative reserve requirements, the RES-E infeed can be reduced and, for positive reserve, only the previously curtailed amount can be used to provide positive reserve. In this way, it can be analyzed whether this design option facilitates the RES-E market integration in firm market situations.

6.3 Modeling Results

This section provides an overview of the scenario results on an aggregated level. The results of particular system components are compared between all scenarios.

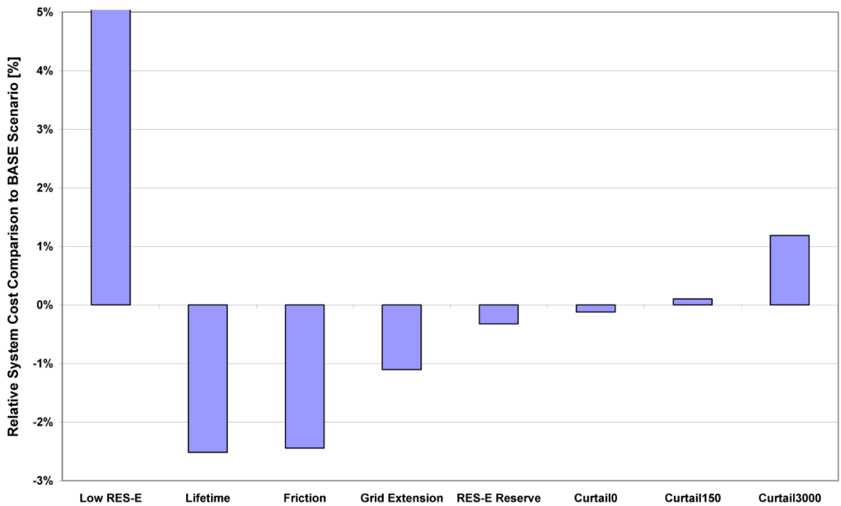
6.3.1 Overview of Scenario Comparisons

First, the total costs of conventional generation (which represent primarily the supply side) of all scenarios are compared with the 'Base' scenario in Figure 6.4. The costs include all considered markets and all model endogenous cost components (i.e. investment and generation costs). Initially, it strikes the eye that the costs of the 'Low RES-E' scenario are much higher than in all the remaining scenarios. This is simply due to the fact that in each scenario RES-E are added exogenously, which means they are not considered as costs in the model and substitute conventional generation. Consequently, the 'Low RES-E' scenario has to provide much more conventional energy compared to the other scenarios, since the RES-E share stays at the 2010 level. This leads to higher investment requirements and more variable costs. The biggest cost-saving in the total system costs are observable in the 'Lifetime' and the 'Friction' scenarios. This result is also quite intuitive since additional base load capacity is granted to the model for free, which on the one hand reduces the demand for investments, and on the other hand provides very low cost energy. The 'Grid Extension' scenario also shows cost reductions compared to the 'Base' scenario. Since the system has more flexibility to optimize the dispatch between the different markets, the power plants can be utilized more efficiently, which also has consequences for the investment decisions. The 'RES-E Reserve' scenario is also cheaper compared to the 'Base' scenario, since the whole system is more flexible due to the reduction of firm market situations. If RES-E can be curtailed as soon as their market value is zero, as assumed in the 'Curtail0' scenario, system costs are also slightly lower than with the assumed premium system in the 'Base' scenario. In the 'Curtail3000' scenario on the other hand, the market is much more firm due to the extremely high curtailment costs. This additional firmness is reflected by the higher total costs compared to the 'Base' scenario.

The comparison of the total conventional generation costs shows, already in an aggregated form, the direction of the individual scenario effects. How the costs develop over time for the German market can be seen in Figure 6.5. The calculations include investment costs, operation and maintenance (O&M) costs, variable generation costs, import costs, partload costs and start-up costs. The comparison between the scenarios follows the same logic as for the total system costs. One can see that the scenario differences increase over time as the system adapts in the individual scenarios. For instance, the 'Curtail3000' scenario is much more expensive with a higher RES-E share in later years. The costs in the 'Lifetime' and 'Friction' scenarios decline compared to the 'Base' scenario until the decommissioning takes place in later years.

Overall, one can see that the total costs in the energy market change according to either direct political decisions concerning the conventional power market, such as the nuclear lifetime extension, or due to market design decision, such as RES-E integration rules or the RES-E participation in the reserve power market. Changing the

Figure 6.4: Cost comparison of conventional generation



Source: own illustration.

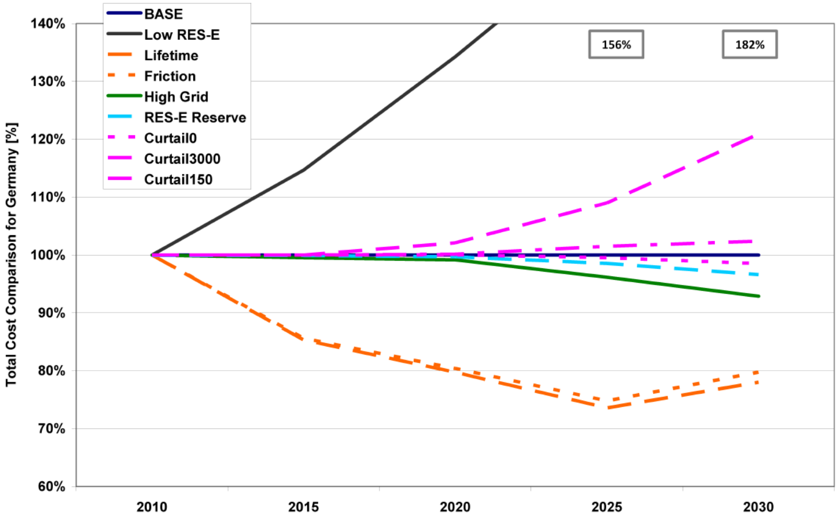
RES-E integration rule, from market bids based on the variable cost of zero to an infeed obligation with a forced market clearing at -3000 EUR, increases the costs by more than 20% in 2030. The following subsections discuss the effects on the individual market components in order to identify the changes in these segments before the individual scenario differences are discussed in more detail.

The Supply Side

THEA optimizes the capacity mix and the dispatch according to the scenario attributes. Therefore, Figure 6.6 shows the capacity mix development for each scenario for the years 2020 and 2030 in addition to the starting point in 2010.

Overall, it is observable that the total capacity increases over time and that the demand for conventional technologies is only slightly reduced due to reliability reasons. However, since the superpeaker technology serves as an option to fulfill the capacity requirements but is hardly utilized, differences in the quality of the capacity mix can be observed. This is actually the main advantage of the usage of the superpeaker technology. Without this option, the amount of OCGTs would have been used to provide sufficient capacity as, e.g. observed by Decarolis and Keith (2006). With the usage

Figure 6.5: Total cost comparison for Germany

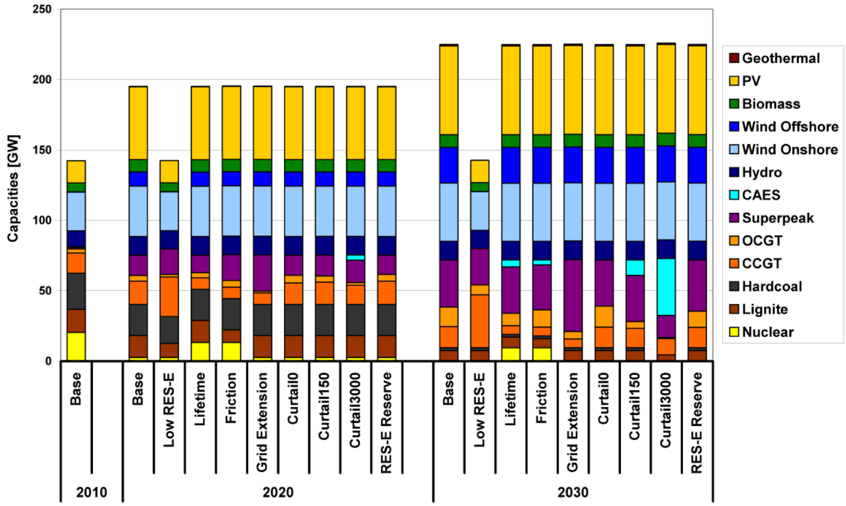


Source: own illustration.

of the superpeaker technology, the quality of the required peak capacity can additionally be assessed. As soon as the utilization of the superpeaker technology reaches a certain share, OCGTs are the more economic choice due to a more favorable ratio of investment and variable costs. In other words, if the utilization of a peaker technology is required and therefore does not primarily serve the capacity requirement, OCGTS are installed. OCGTs are therefore required to a certain degree to cover the hours of peak demand. Additionally, OCGTs are able to provide tertiary reserve since they are quick-starting units. The superpeaker technology does not provide this quality. It can be seen that the 'Low RES-E' scenario requires fewer OCGT capacities.[14] Also, the 'Grid Extension' scenario has less OCGTs since the peak hours can be more efficiently met by international exchange, which is more flexible in this scenario. In comparison, the 'Curtail3000' scenario has almost no installed OCGTs. The peak demand hours can be met by the enormous amount of CAES storage. This investment is triggered by the assumption that RES-E can only be curtailed at a power price of -3000 EUR. Consequently, it is cheaper to build CAES and store the RES-E than to curtail it. CAES also serves the peak requirement to a certain degree.

14 Due to the assumed fuel and CO_2 prices, the construction and operation of CCGT is the most economic choice in the 'Low RES-E' scenario to fill the gap which arises from plant decommissioning and lower RES-E shares. With different assumptions, this gap could also be filled with other technologies, such as hardcoal or lignite.

Figure 6.6: Capacity mix comparison

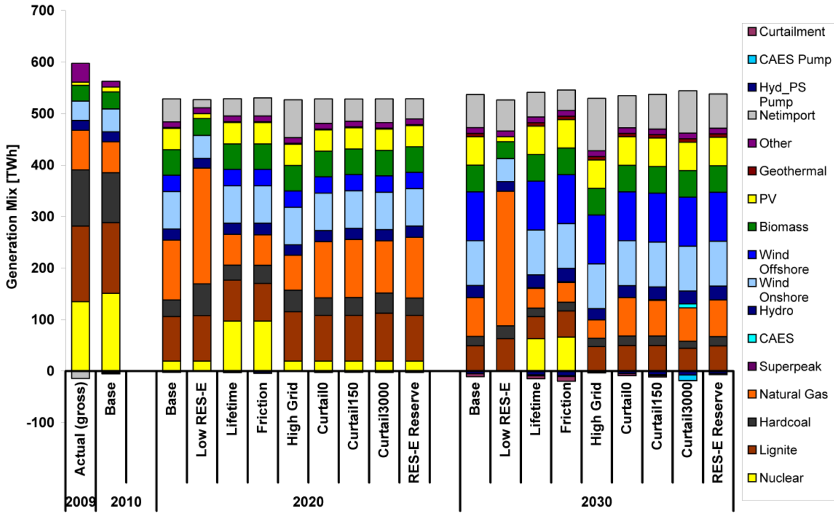


Source: own illustration.

The 'Lifetime' and the 'Friction' scenarios also require CAES to provide additional flexibility to the system. At first, it seems surprising that the 'Lifetime' scenario has a slightly higher CAES amount compared to the 'Friction' scenario. The reason behind this observation lies in the initial decommissioning of almost 7 GW lignite capacity in the 'Friction' scenario, which reduces the 'inflexibility' of the market. As explained in section 4.3.1, capacities can be decommissioned if it serves the overall efficiency. The additional peak capacity requirement is then met by a higher amount of OCGTs. Additional lignite and hardcoal decommissioning can also be seen in the 'Curtail3000' scenario in 2030. The forced RES-E infeed strongly penalizes base load capacity and requires the installation of flexible CAES capacity. The total utilized capacity is the lowest in the 'Grid Extension' scenario since higher import options are often available and can be used to avoid expensive peak load generation. The high amount of superpeaker capacity is a sign that a higher share of the energy demand can be met by cheaper imports from at least one of the surrounding markets most of the time.

As a consequence of the diverging capacity developments, the generation mix varies significantly as well between most of the scenarios as shown in Figure 6.7. Without further RES-E deployment after 2010, the 'Low RES-E' scenario covers most of the additional demand with natural gas based generation. Another prominent result is the higher nuclear based generation in the 'Lifetime' and the 'Friction' scenarios. As a consequence, the market shows an increase in curtailment as well as in energy storage. Since a source of low cost energy is available, the netimport is reduced compared to the 'Base' scenario.

Figure 6.7: Generation mix comparison

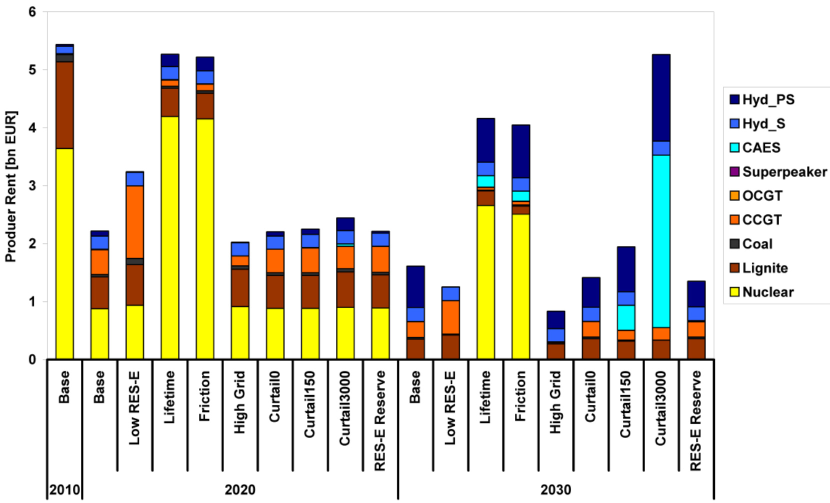


Source: own illustration and AGEB (2010).

Even more firm market situations are present in the 'Curtail3000' scenario. The significant amounts of CAES storage and generation are a clear sign of flexibility demand if RES-E is forced into the market. The higher netimport in the 'Grid Extension' scenario shows that most of the time at least one of the surrounding markets has less costly generation options. Consequently, the total conventional generation is the lowest in this scenario. Overall, Germany becomes a netimporting country throughout the scenarios, which confirms the findings of other recent studies such as BMWi (2010a), BMWi (2010b) and BMWi (2010c). The effects in the remaining scenarios are not dominant enough to show significant differences in this aggregated result overview but will further be discussed in the context of their individual set-ups.

The shift in the generation structure has consequences for the profitability of the particular technologies. Therefore, the pure cost perspective is extended by an analysis of the producer rent. Dependent on their economic and technical attributes, technologies have different values in the scenarios. Storage technologies have a better economic situation if the overall system is less flexible. In this case, the provided flexibility of the storage technologies is very valuable for the system. Existing nuclear capacities on the other hand have such a strong economic position due to their low variable costs that they are quite robust to scenario assumptions. However, due to their prominent position in the market, they affect the economics of the remaining system. Figure 6.8 shows the producer rents (PR) per technology in all scenarios.

Figure 6.8: Producer rent comparison



Source: own illustration.

The calculation mirrors the short-term perspective, meaning that the energy and reserve market income per technology is reduced by the variable costs according to the following equation:

$$PR_{t,y} = \sum_h (\lambda_{y,h}^{spot} - vc_{t,y,h}^{spot}) * Q_{t,y,h}^{spot} + \sum_h \sum_{rp} (\lambda_{rp,y,h}^{reserve} - vc_{rp,t,y,h}^{reserve}) * Q_{rp,t,y,h}^{reserve} \quad (6.1)$$

with λ as marginal values for the spot and reserve market per reserve product rp and Q as respective quantities supplied per technology t. The variable costs vc are given per technology t, year y and hour h. Consequently, this analysis represents the profitability of existing units and fixed costs are treated as sunk. Since each technology receives the marginal cost based power price for their produced energy, which is set by the last dispatched unit, the PR are highest for base load technologies.

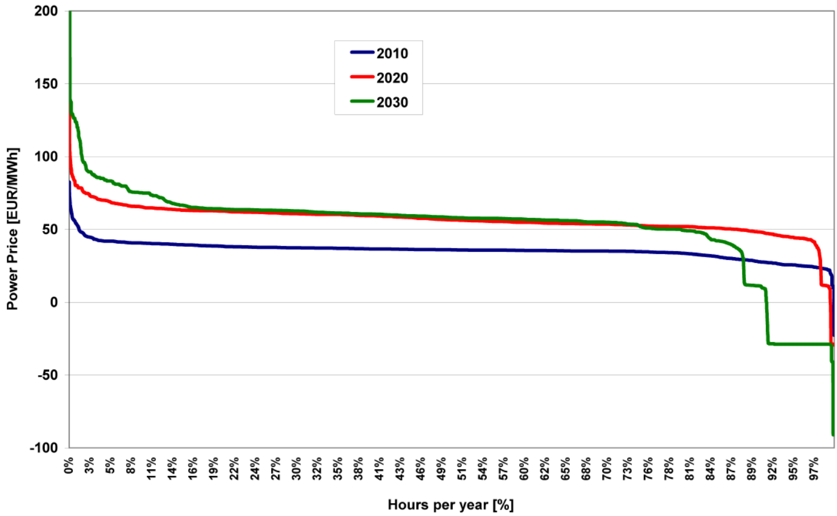
It is initially observable that the nuclear fleet generates high PR, especially under both lifetime extension scenarios. In the 'Friction' scenario, the PR is slightly lower for the nuclear fleet, since the generation cannot be reduced below a certain level, even if power prices are negative. As a consequence, lignite capacity is decommissioned and generates a lower PR. CCGT profitability suffers under the lifetime extension while the profitability of storage technologies increases. Pumped hydro storage is more profitable under the nuclear lifetime extension scenarios because it provides flexibility to a firmer system. The system comes under even more pressure in the 'Curtail3000' scenario, where the flexibility of curtailment is penalized with 3,000 EUR. Consequently, the profitability of pumped hydro storage increases. In four scenarios, additional flexibility is required for economic operation, which leads to investments in CAES capacities. CAES profitability gains from the firm market situation in both nuclear lifetime extension scenarios. The demand and therefore the profitability for CAES is even higher in the expensive curtailment scenarios. Here, CAES profits from compressing energy at negative prices and generating at positive prices. This is a clear sign that flexibility becomes highly valuable if other system components are less flexible and therefore benefits from the higher price volatility. In order to provide an overview of the future marginal cost based price volatility, Figure 6.9 shows the price duration curves of the 'Base' scenario for the years 2010, 2020 and 2030.

The different levels of the price duration curves stem from different fuel price assumptions in the different years. Especially in 2010, the fuel prices were relatively low. Nonetheless, the main focus lies on the differences in the structures between the years. The development towards higher RES-E shares leads to a steeper slope of the price duration curve. This development has strong effects on all system components and will be discussed in more detail in the subsequent sections.

The Demand Side

While certain technologies are more profitable depending on the scenario setting, the consumer has to pay the corresponding market price. Therefore, the term consumer cost is based on the resulting market prices. This analysis takes into account the energy market price, the reserve market price as well as the RES-E support value. Other consumer cost components, such as other grid fees and taxes, are not included in the analysis. The energy market costs for the consumer is the demand in each hour valued by the power price. The reserve market costs are part of the grid fees in Germany and consist of the price of the reserve products multiplied by the reserve requirements. The RES-E support costs are calculated as the difference between the levelized generation costs of each technology, which mirrors the required support

Figure 6.9: Price duration curves of the 'Base' scenario



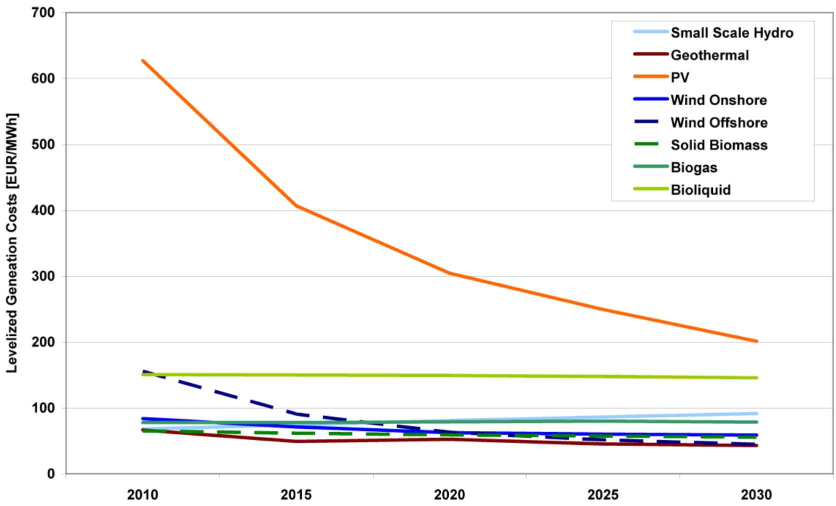
Source: own illustration.

payment, and the market price in each hour. To calculate the levelized generation costs (see Figure 6.10) which are used to estimate the required support costs for the scenario comparison, future investment cost assessments are taken from IEA (2010) and variable biomass costs from BMU (2010b).

The costs do not entirely reflect the current cost structure. Especially the assumed PV investment costs do not reflect the rapid cost decrease in the recent years. Nevertheless, since the analysis focuses on the differences between the scenario comparison and not the absolute values, the deviations from current cost levels can be ignored. To annualize the investment costs, a depreciation time of 20 years and an interest rate of 8% is assumed.

It is assumed that in this support scheme design, the regulator knows how much curtailment occurs each year and the levelized generation costs take the actual full load hours into account. This means that the support payment is higher if a technology is curtailed more often in order to enable the recovery of the fixed costs. This approach avoids that the support scheme costs are lower if more curtailment occurs. The total support scheme costs therefore depend directly on the value of the individual RES-

Figure 6.10: German RES-E levelized generation costs



Source: own assumptions, based on IEA (2010) and BMU (2010b).

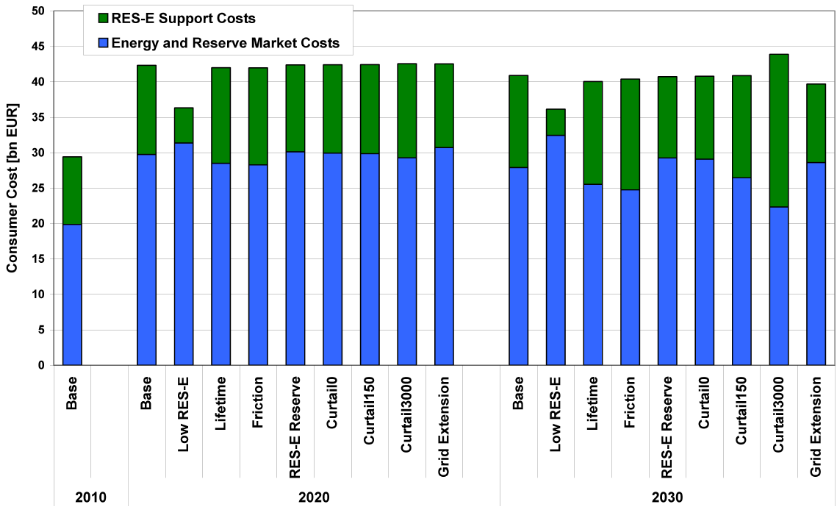
E in each hour.[15] In reality, the FIT is locked in at the year of commissioning and is valid for 20 years. In the present approach, the level is calculated for each year individually in order to ease the interpretation without carrying costs resulting from previous years, which cannot directly be attributed to particular effects. The support costs which the consumer has to pay are the aggregated differences between the FIT (here levelized generation costs) and the market value of RES-E. Figure 6.11 shows the consumer costs, divided into market relevant costs (energy and reserve market) and RES-E support costs according to the following equation:

$$CC_y = \sum_h (\lambda_{y,h}^{spot} * q_{y,h}^{spot} + \sum_{rp} \lambda_{rp,y,h}^{reserve} * q_{rp,y,h}^{reserve}) + \sum_{rt} \sum_h (lc_{rt,y} - \lambda_{y,h}^{spot}) * q_{rt,y,h} \tag{6.2}$$

The first term indicates the energy and reserve market costs with λ as marginal values for the spot and reserve market per reserve product rp and q as respective demand per year y and hour h. The second term indicates the RES-E support costs with lc as levelized generation costs per renewable technology rt per year y and hour h.

15 The previously defined curtailment penalties would in reality mirror the height of the particular premium. In this modeling framework, this would require additional iterations to specify the height of the premium, since the amount of curtailment has repercussions on the required support level. Therefore, the applied curtailment penalty and the support costs can deviate in this approach.

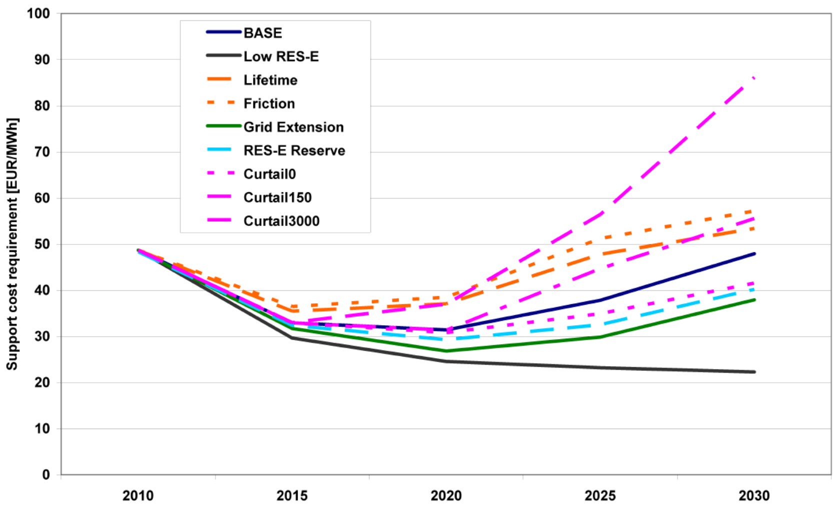
Figure 6.11: Consumer cost comparison



Source: own illustration.

Following the merit-order discussion in section 2.1, it is observable in the comparison of the 'Base' and the 'Low RES-E' scenarios that the energy and reserve market costs are indeed lower in the 'Base' scenario. However, the RES-E support costs overcompensate these savings even with this direct support cost approach. If support costs from previous years had been included, the cost burden would even increase, since earlier FIT levels tend to be higher. Besides this scenario comparison, the overall consumer cost burden remains relatively stable between the different curtailment cases with the exception of the 'Curtail3000' scenario. The nuclear lifetime extension scenarios reduce the energy market costs for the consumer. Since this automatically increases the RES-E support volume, the overall cost burden is only slightly reduced. If RES-E participate in the reserve market, the overall market costs for the consumer increase and the RES-E support volume decreases. This effect will be discussed in more detail in section 6.3.6. Furthermore, The RES-E integration policy strongly affects the cost distribution. RES-E support costs are the lowest in the 'Curtail0' scenario, followed by the premium system assumption in the 'Base' scenario. The out-of-market curtailment level of at least -150 EUR in the 'Curtail150' scenario strongly increases the support costs, but at the same time reduces the energy market costs almost to the same extent. In summary it is slightly more expensive than the 'Base' scenario. The 'pure' FIT system assumption with the infeed obligation in the 'Curtail3000' scenario not only increases the RES-E support costs, but also increases the total consumer costs. It becomes apparent that the forced RES-E integration strongly affects the entire system, which consequently leads to a higher cost burden for the consumer. As explained above, the effects are compared to each other on the basis of the required support costs based on levelized generation costs for each year. In order to provide a better understanding of the effects, Figure 6.12 shows the support cost differences between the scenarios per MWh for a wind power plant, which was installed in 2010 and receives the same absolute FIT until 2030.

Figure 6.12: Support cost difference per MWh for a wind power plant installed in 2010



Source: own illustration.

The levelized generation cost, which represent the required FIT level, is 83.9 EUR/MWh based on the previously discussed assumptions. The difference between the FIT and the market value of the wind energy is the required support costs, which is passed on to the consumers (as seen in Figure 6.11). Due to the increase of the fuel costs after 2010, the required support costs are reduced in all scenarios. Since no further wind power deployment is assumed in the 'Low RES-E' scenario, this effect further reduces the required support costs until 2030. All other scenarios assume a further penetration of wind power. Therefore at a certain point in time, the value of wind power is reduced due to its price depressing effect. This leads to an increase of the required support costs. The particular value of wind energy depends on the scenario assumptions. Overall, the support costs depend on the flexibility of the entire system and its ability to absorb the wind energy. The wind value in the 'Grid Extension' scenario is higher compared to the other scenarios due to the higher export possibilities in firm market situations, and the required support costs are the lowest. The 'Curtail3000' and 'Curtail150' scenarios reduce the flexibility of the market compared to the 'Base' scenario and therefore require higher support costs. The same is true for the lifetime extension scenarios, where the lower power price compared to the 'Base' scenario leads to higher support costs for wind energy. The reduced flexibility in the 'Friction' scenario also results in higher support costs.

Impact on the Grid Infrastructure

The last system component in this overview, which is strongly affected by the increasing RES-E penetration, is the grid infrastructure. The individual power markets are modeled as copperplates without internal grid bottlenecks. In order to get an idea of the effects on the grid infrastructure, the interconnector capacities can be evaluated. The sum of all marginal values of the interconnector constraint within one year can be interpreted as the grid value. In order to reduce the complexity of the analysis and to avoid the interpretation for each connection individually, all interconnections' values are accumulated.

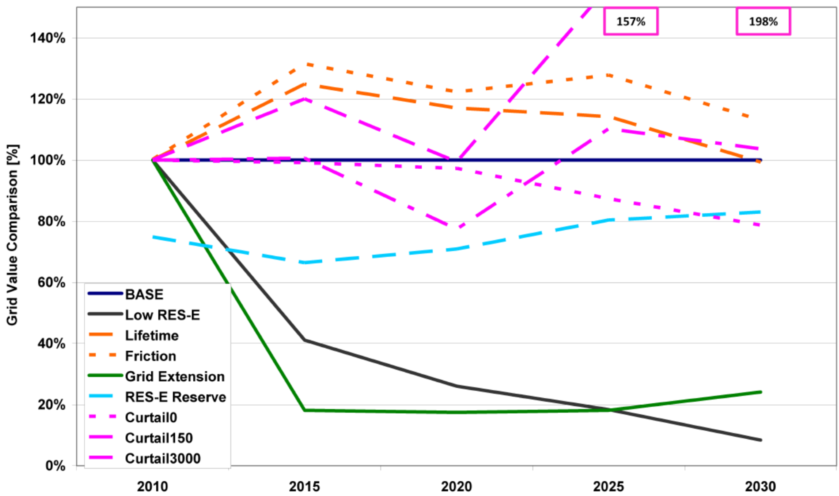
$$Gridvalue_y = \frac{\sum_h \sum_i \lambda_{y,h,i} * Q_{y,h,i}}{\sum_i NTC_{y,i}} \tag{6.3}$$

with $\lambda_{y,h,i}$ as the marginal value of the interconnector i in hour h and year y. $Q_{y,h,i}$ is the corresponding transferred energy and $NTC_{y,i}$ is the total capacity of each interconnector per year.

In this way, the basic effect becomes clear and comparable between the scenarios. Even though this approach does not lead to an assessment of absolute grid requirements within the power system, the comparison of the relative values is nevertheless an indicator for the development between the scenarios. In this case, the value reflects the differences between individual power markets with individual prices. Figure 6.13 shows the development of the grid values in all scenarios relative to the 'Base' scenario.

With the 'Base' scenario as a reference point, the grid value of the 'Low RES-E' scenario drops significantly over time. This means that the increasing RES-E amount leads to higher values for interconnector capacities. The grid values further increase

Figure 6.13: Comparison of grid values



Source: own illustration.

in the nuclear lifetime extension scenarios. The generation capacity in these scenarios is less flexible compared to the 'Base' scenario, which increases the value of the flexible grid infrastructure. The grid value in the 'Grid Extension' scenario is also much lower than in the 'Base' scenario. Since the overall interconnector capacities are much higher, the constraint is much weaker, which decreases the relative value. If RES-E can be utilized more flexibly, as in the 'RES-E Reserve' scenario for the reserve requirements, the firmness of the market is also reduced, leading to lower grid values as well. The RES-E infeed is also more flexible in the 'Curtail0' scenario compared to the 'Base' scenario since RES-E infeed can be curtailed for free. Consequently, the grid values are higher in the 'Curtail150' and the 'Curtail3000' scenario, where the RES-E is forced into the system with higher curtailment penalties. Overall, it can be seen that the grid values are an indicator for market firmness. On the one hand, if the conventional capacities or the RES-E infeed are flexible, the value of the grid infrastructure is lower than in the context of a firm market environment. On the other hand, if the grid infrastructure is increased, the firmness of the market is reduced.

6.3.2 Impact of RES-E Increase

As already discussed on a highly aggregated level in the previous section and for the ERCOT case study in section 6.3, the increase of RES-E has strong effects on the remaining system. Within this section, a closer look at the individual system components is provided by comparing selected model outputs between the 'Base' and the 'Low RES-E' scenarios for the German power market. Additionally, the analysis approach for the different system components is introduced, and will be used again in the subsequent sections to estimate the effects of the other scenario modifications.

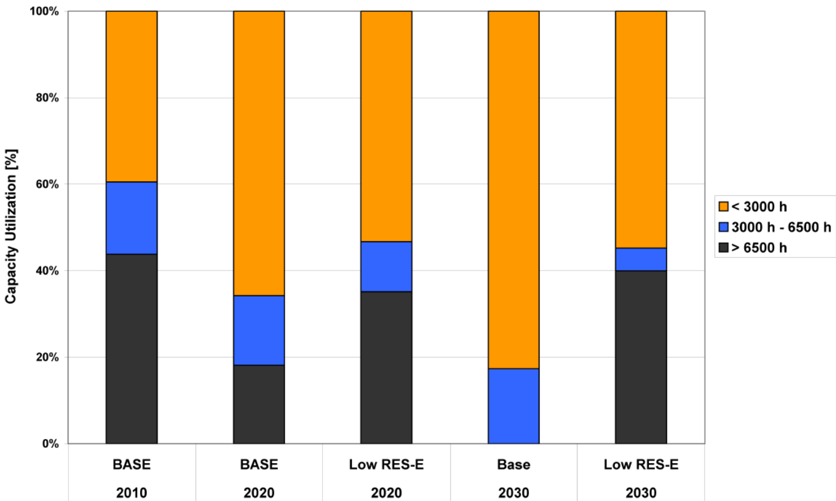
RES-E Impact on the Supply Side

The intermittent RES-E infeed covers a changing share of the demand in each hour. Whenever RES-E is available, it is forced into the market, either by infeed obligations or simply due to its low variable costs. Nevertheless, sufficient conventional capacity is required for the times with low RES-E infeed. The capacity mix in Figure 6.6 shows that the total conventional capacity in the 'Low RES-E scenario' is not substantially higher, even though much more energy must be generated. Therefore, the amount of CCGTs is higher, while the amount of OCGTS and superpeakers is lower compared to the 'Base' scenario. Consequently, when the RES-E share increases over time, the total conventional capacity is decreasingly utilized, as shown in Figure 6.14.

The capacity in both model runs is evaluated according to their utilization. While the share of installed capacity with a utilization above 6,500 hours remains at roughly 40% throughout the entire period in the 'Low RES-E' scenario, the share drops to 18% in 2020, and in 2030 no capacity is utilized above this share in the 'Base' scenario. The capacity with a utilization below 3,000 hours increases from roughly 40% in 2010 to roughly 55% in 2020 and 2030 in the 'Low RES-E' scenario. In the 'Base' scenario, the share of low utilized capacity increases to 66% in 2020 and to 83% in 2030. In other words, significant shares of the capacity mix only serve as back-up capacities for times with low RES-E infeed. This applies also for former base load technologies, such as old lignite and old coal capacities. Therefore, the high share of low utilized generation adds a different dimension to the peak load definition. In addition to the requirement for flexible capacities, which usually serve as peak capacities, back-up capacities are also required, which also generate a few days in a row in times of low RES-E infeed.

The higher share of peak oriented generation can also be interpreted as demand for flexibility. An additional sign of flexibility requirement is the short-run profit of storage technologies. The value of both storage technologies per installed MW can be seen in Figure 6.15.

Figure 6.14: Capacity utilization ('Base' vs. 'Low RES-E')

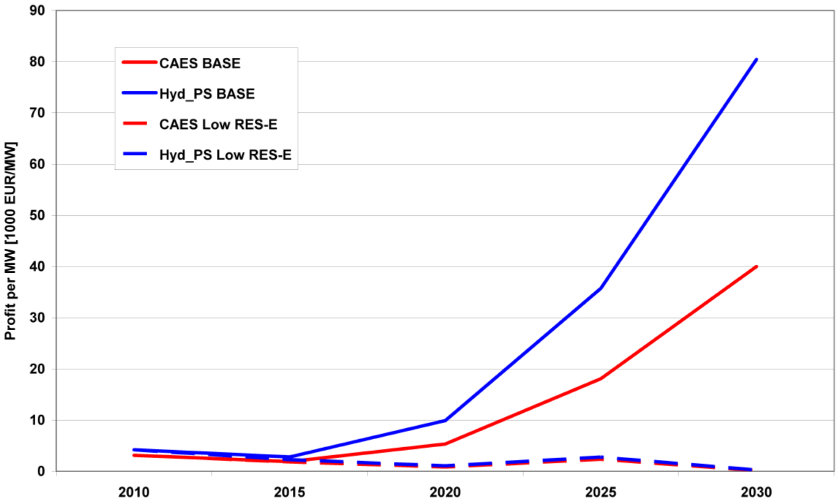


Source: own illustration.

Over time, as the conventional capacity mix adapts to the RES-E level in the 'Low RES-E' scenario, the value of storage as a means of flexibility decreases. Then, the higher peak generation share in Figure 6.14 provides sufficient flexibility. In contrast, the value of both storage technologies increases over time with the increasing RES-E share in the 'Base' scenario. Thereby, the value of CAES remains below the pumped hydro value due to the lower overall efficiency. Even though the value increases, it is still not sufficient to trigger significant CAES investments. The relative development of the storage value compared between both scenarios nevertheless shows a clear trend. As shown in section 3.1.2, the demand for flexibility in the system can also be seen in the reserve power market. In THEA, as soon as a firm market situation occurs and opportunity costs arise due to part-load or start-up costs, a positive marginal value occurs in the reserve requirement restriction. Therefore, the aggregated reserve market volume is an indicator of the firmness of the market and can be seen in Figure 6.16.

While the capacity optimization in the 'Low RES-E' scenario leads to less firm market situations over time, the rising RES-E share in the 'Base' scenario leads to more than a doubling of the reserve market volume from 2010 to 2020 and is even more than 17 times higher in 2030 compared to 2010.

Figure 6.15: Profit of storage technologies ('Base' vs. 'Low RES-E')



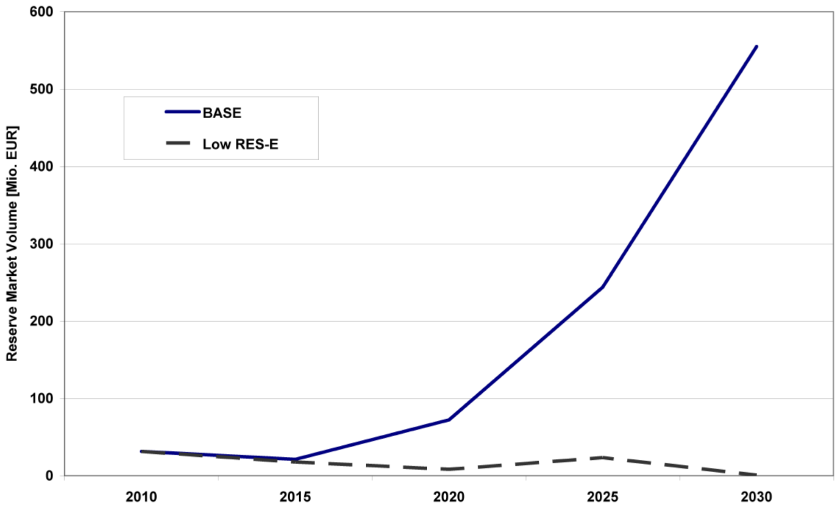
Source: own illustration.

RES-E Impact on the Demand Side

Since RES-E are relevant for the consumer costs, a further analysis is also attributed to the demand side. The development of the overall RES-E support volume has already been show in Figure 6.11. Now, a more detailed analysis is conducted to better understand the value development of individual RES-E, evaluated according to the hourly power price. This means that the RES-E value in a particular hour is equal to the wholesale power price which reflects the avoided costs. This is done for every hour per year and then aggregated to receive the RES-E value of this year. The remaining gap to cover the required support costs has to be paid by the consumers via their electricity bill. The focus of the analysis lies on intermittent RES-E since the value of the more base load-oriented generation reflects basically the base price level. Figure 6.17 shows the relative RES-E value per MWh for wind onshore, wind offshore and PV compared to the base price of the 'Base' and the 'Low RES-E' scenarios, respectively.

The relative PV value in the 'Low RES-E' scenario remains above the base price level over the entire period. Since PV generation is the highest around noon when energy consumption peaks, the positive value reflects the correlation of load and sun irradiation. The typical evening peak, however, cannot be covered by PV generation.

Figure 6.16: Reserve market volume ('Base' vs. 'Low RES-E')

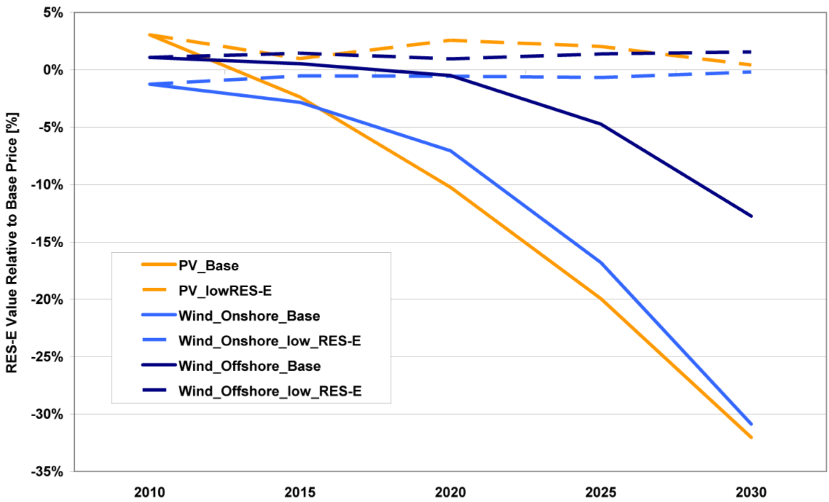


Source: own illustration.

The PV value in the 'Base' scenario falls below the base price already by 2015. At a certain tipping point in the PV deployment, the PV infeed is high enough to basically reduce the noon peak to an off-peak level on sunny days and thus the energy value. Since the evening peak is more dominant and the former noon peak is now below average load, the PV value further shrinks with each installed MW. The wind onshore value starts below the base price, since the installed capacity in 2010 is already high enough to have a significant impact on the power prices as previously discussed in section 3.1. This trend continues with further deployment. The relative value in the 'Low RES-E' scenario increases slightly with the optimization of the capacity mix until it reaches almost the base price level. Figure 6.18 shows the season market income per MW for all three technologies.

Figure 6.18 summarizes the market value per MW and season, which incorporates the infeed structure and the total utilization (explaining the relatively low income of PV compared to both wind technologies). Overall, the wind pattern has a seasonality similar to the load pattern, which lowers the price-depressing effect slightly. PV on the other hand has the strongest seasonal effect in the summer when demand is relatively low in Germany, and a lower effect in the winter with high demand. In addition to this seasonal effect, wind does not follow as strict a pattern as PV, with generation only during the day. Wind generation is more stochastic and has, by trend, a higher capacity factor compared to PV. This is also the reason why the wind offshore value

Figure 6.17: RES-E value relative to base price ('Base' vs. 'Low RES-E')



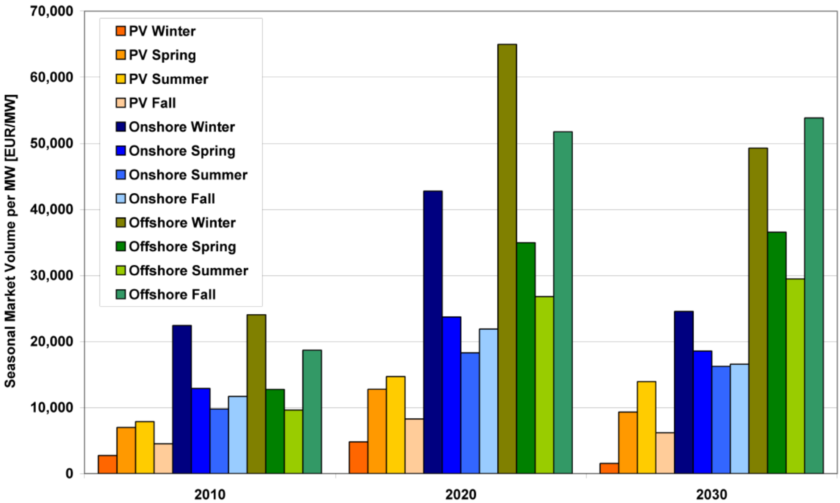
Source: own illustration.

remains above the base price in the 'Low RES-E' scenario. First, the installed capacity is too little to have an impact on the price. Second, the seasonal wind and demand pattern is favorable for wind offshore. The wind offshore value nevertheless drops in the 'Base' scenario with higher deployment. However, since the capacity factor is higher for wind offshore, the relative price-depressing effect per hour is lower, since it affects the average base price in general. The relative value compared to the base price does not necessarily explain the shift in consumer costs between energy market and RES-E support costs in Figure 6.11. Thus, the absolute values are relevant for the further analysis. Therefore, Figure 6.19 compares the absolute RES-E value per MWh for wind onshore, wind offshore and PV as well as the base price in both scenarios.

The values of all RES-E in both scenarios increase after 2010. The reason for the value increase is the low base price of 35.6 EUR/MWh in 2010.[16] Overall, it can be seen that the base price in the 'Low RES-E' scenario is higher than in the 'Base' scenario. The relative comparison in Figure 6.17 therefore underestimates the price-depressing effect, since the relative values in the the 'Base' scenario have a lower

16 The reason for the low price level is the low fuel costs in 2009, which are assumed to be the same in 2010. At the EPEX, the average base price was 38.6 EUR/MWh in 2009. The model results are slightly lower due to the assumption of a well informed benevolent planner.

Figure 6.18: RES-E market volume per season and MW ('Base' scenario)



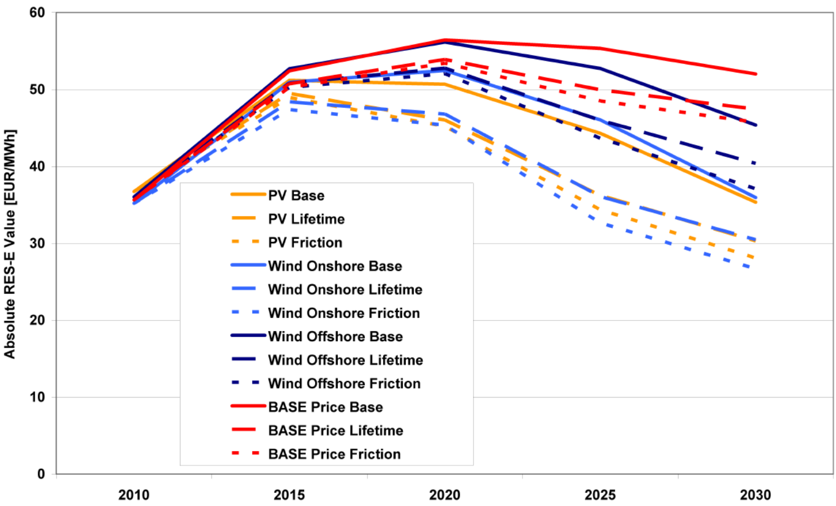
Source: own illustration.

reference value. For example, in 2030 the absolute PV value in the 'Low RES-E' scenario is 75% higher than the PV value in the 'Base' scenario. Taking into account that the levelized generation costs are the same in both scenarios, the RES-E support costs per MWh in the 'Base' scenario are significantly higher. The average base price comparison already shows that the further RES-E deployment suppresses power prices. The structure of the prices, however gives a better indication of the development in the market, especially when price signals are interpreted as market signals which indicate conventional capacity requirements of the market. Figure 6.20 shows the price duration curves of both scenarios in 2030.

It is directly observable that the price duration curve of the 'Base' scenario is much steeper compared to the 'Low RES-E' scenario. For the positive prices, more peak oriented generation and more start-ups in the 'Base' scenario lead to higher prices. On the low price side, the 'typical' merit-order effect first leads to lower marginal values in the 'Base' scenario. Later, the prices are set by curtailment decisions as discussed in section 3.1.4. The price differences between both scenarios also explain the previously discussed increasing values of the storage technologies which benefit from the higher price volatility.

RES-E Impact on the Grid Infrastructure

Figure 6.19: Absolute RES-E value ('Base' vs. 'Low RES-E')

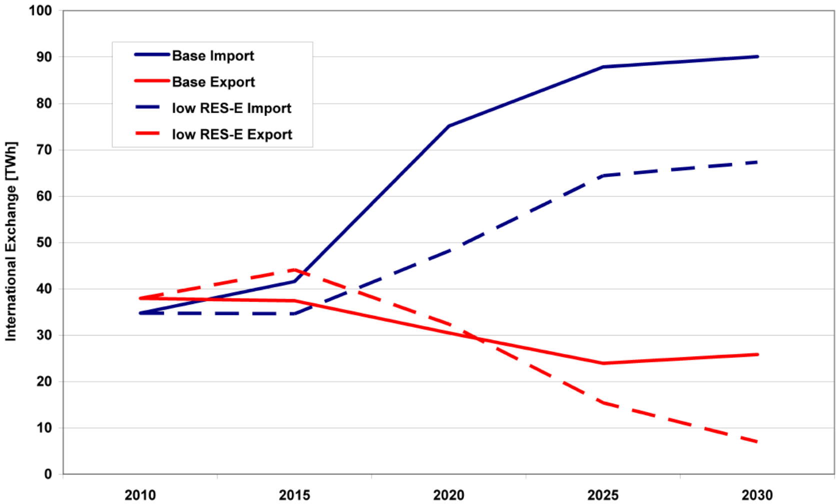


Source: own illustration.

The interconnections between the power markets remains the most efficient flexibility option. If the exchange possibilities were unrestricted, power prices would be the same in all price zones and the steep price duration curve would be avoided by imports from and exports to neighboring markets. To understand how the RES-E increase affects the exchange behavior, Figure 6.21 shows the development of import and export amounts for the 'Base' and the 'Low RES-E' scenarios.

The import amount increases with the increasing RES-E share and is consequently higher in the 'Base' scenario than in the 'Low RES-E' scenario. As discussed above, the generation is increasingly peak-oriented, which means that the low RES-E peak hours are quite expensive due to the high cost marginal units. Whenever one of the surrounding power markets is able to export energy at a lower price, this option is used. In the 'Low RES-E' scenario, this trend is weaker, since the developments in all markets follow the same economic pattern, with the exception that some markets are allowed to invest in nuclear capacity, which is partially responsible for the moderate import increase. Because of the stronger peak orientation in the 'Base' scenario, the export amount drops slightly. It remains above the 'Low RES-E' scenario in later years due to the high RES-E infeed which needs to be exported to an increasing extent. The export amount in the 'Low RES-E' scenario drops, since in future years

Figure 6.20: Price duration curves in 2030 ('Base' vs. 'Low RES-E')



Source: own illustration.

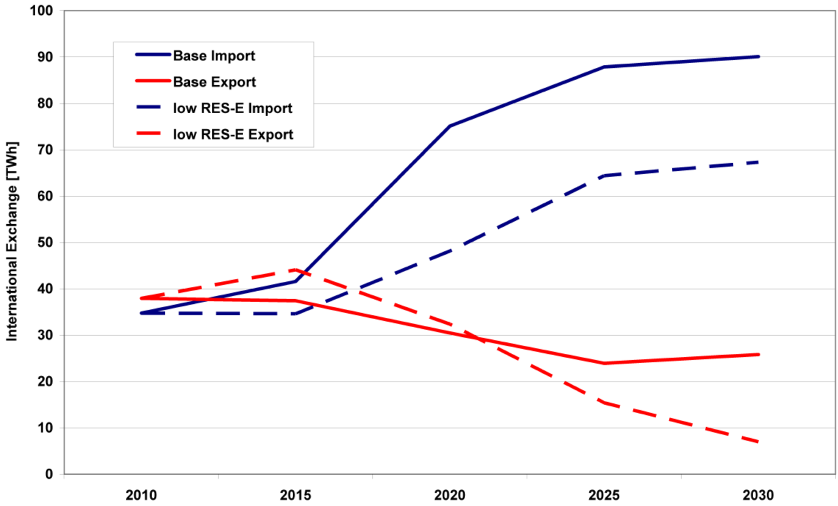
Germany only has a small amount of low cost generation which can efficiently be exported.

The value of the grid infrastructure reflects this pattern. As the utilization of the grid infrastructure increases, the value increases as well. Figure 6.13 already showed the scenario comparison for the overall grid values. In order to examine the import and export capacities separately, Figure 6.22 shows the marginal NTC values for the import and export NTCs.

The marginal NTC values are the aggregated marginals of all interconnectors, divided by the amount of interconnectors to neighboring countries. In this way, one average MW of NTC import and export capacity can be compared between the scenarios. The overall effect can be captured and discussed without requiring too detailed an analysis of individual interconnectors, which are strongly affected by individual RES-E and conventional deployment of all involved countries.

As a consequence of the absolute exchange amounts depicted in Figure 6.21, the import NTC values in the 'Base' scenario rise over time due to the increasing value of

Figure 6.21: International exchange ('Base' vs. 'Low RES-E')



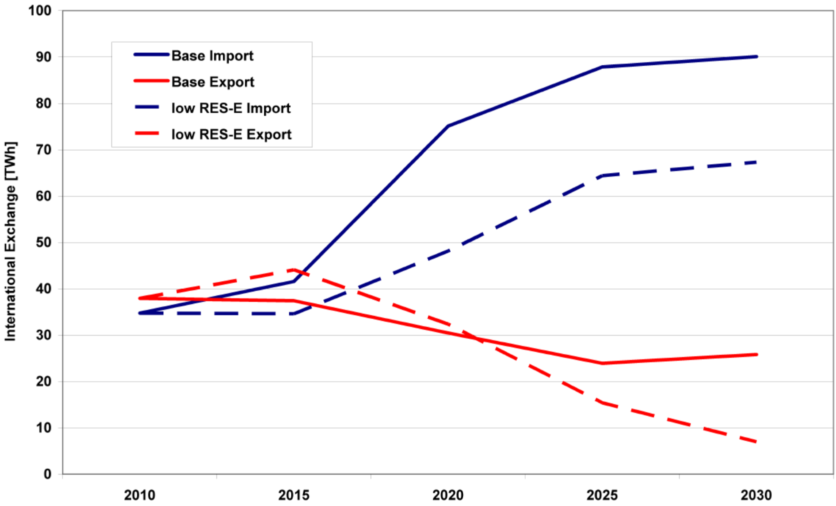
Source: own illustration.

the imported energy. The increase depends also on the deployed capacity in the surrounding markets. If, for any reason, the other markets do not invest in low variable cost generation capacity, the value of the import capacity only rises to a lower level. The NTC value of the import capacity remains more or less at the same level. The value of the export capacity drops in the 'Low RES-E' scenario due to the absence of low cost generation in Germany. In the 'Base' scenario, the value increases since the occasional oversupply from intermitting RES-E relies on export capacities to avoid curtailment or investments in storage technologies.

Conclusion on the RES-E System Impact

In this section, it has been shown that all system components are affected by an increasing RES-E share. The supply side is characterized by a less utilized capacity mix with a higher valuation of flexible technologies. The reason is that the appearance of firm market situations increases, which has been shown by the strong rising reserve market volume. The consumer benefits on the one hand from a reduced power market price, but on the other hand pays higher reserve power costs and higher RES-E support payments due to the strongly decreasing value of intermitting RES-E. In summary, the merit-order effect, which reduces the power market price, is not sufficient

Figure 6.22: Marginal NTC value ('Base' vs. 'Low RES-E')



Source: own illustration.

to have a cost reducing effect for the consumer. The market interconnections gain increasing importance, since they provide a flexible option to share national market imbalances. The following subsections take these findings into account and analyze the individual system components by changing either their absolute amounts or particular rules concerning their treatment.

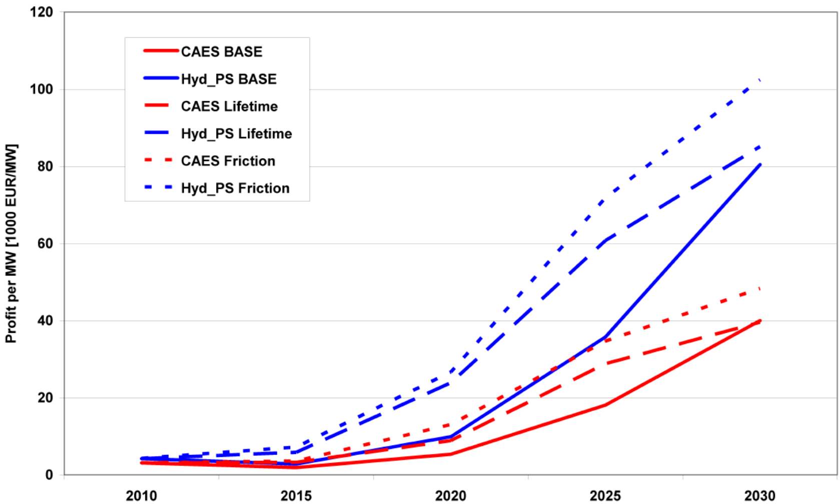
6.3.3 Nuclear Lifetime Extension and More Friction

In this section, the 'Lifetime' scenario and the 'Friction' scenario are compared to the 'Base' scenario. The aim of this section is twofold. First, the lifetime extension of the German nuclear fleet is a likely scenario in the current political debate, which consequently should also be discussed in an analysis that covers the German market. Second, the lifetime extension allows for an analysis of how the remaining system reacts to a higher share of low cost base load capacity. In addition to the lifetime extension, the 'Friction' scenario follows the findings in section 3.1.3, where limited flexibility of the nuclear and the lignite fleet in hours with extreme negative prices was observed. It is likely that these restrictions were simply company internal rules or unfamiliarities with the required market flexibility and have therefore been resolved over time. However, if additional restrictions exist, this scenario can be interpreted as a worst case scenario.

Effects of the Nuclear Lifetime Extension on the Supply Side

As already discussed in the previous section, the value of storage technologies can be used as an indicator of flexibility requirements. The capacity overview in Figure 6.6 showed that CAES is commissioned in both lifetime extension scenarios, 5 GW in the 'Lifetime' scenario and 3.5 GW in the 'Friction' scenario. This is already a clear sign that the market is firm enough to justify investment in this flexibility option due to the higher price volatility. Figure 6.23 shows the short-run profits per MW of the storage technologies for all three scenarios.

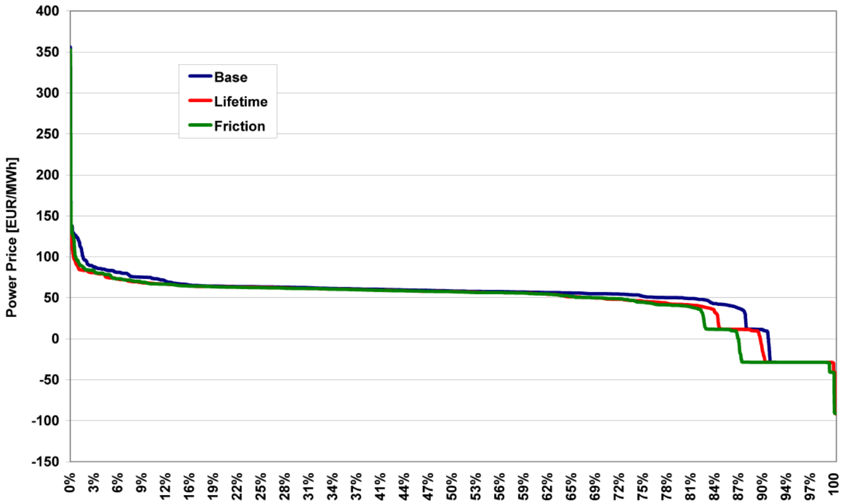
Figure 6.23: Profit of storage technologies ('Base' vs. nuclear lifetime extension scenarios)



Source: own illustration.

The values of both storage technologies increase in all scenarios. The extension of the nuclear lifetime leads to higher profits for storage technologies compared to the 'Base' scenario. This is not surprising since the low cost nuclear generation provides additional cheap energy which can be stored and released at higher prices. In addition, if prices are negative, storage technologies also benefit from compressing energy. The average value of CAES storage can only rise within a certain bandwidth since higher values would lead to additional investments, which would consequently reduce the value again. Of course, this also affects the value of pumped storage. If investments in CAES were not allowed, the value of pumped hydro storage would have been much higher. The storage value in the 'Friction' scenario is the highest, since the base load fleets have minimum generation levels, which enforce generation even at negative prices. The CAES capacity is nevertheless lower in the 'Friction' scenario since the cheapest option proves to be the early decommissioning of lignite capacity and investments in peak generating capacity to increase flexibility, before CAES investments occurs in later years. An additional indicator of market firmness, which has also been introduced in the last section, is the reserve market volume. Figure 6.24 shows a comparison of the reserve market volumes of all three scenarios.

Figure 6.24: Reserve market volume ('Base' vs. nuclear lifetime extension scenarios)



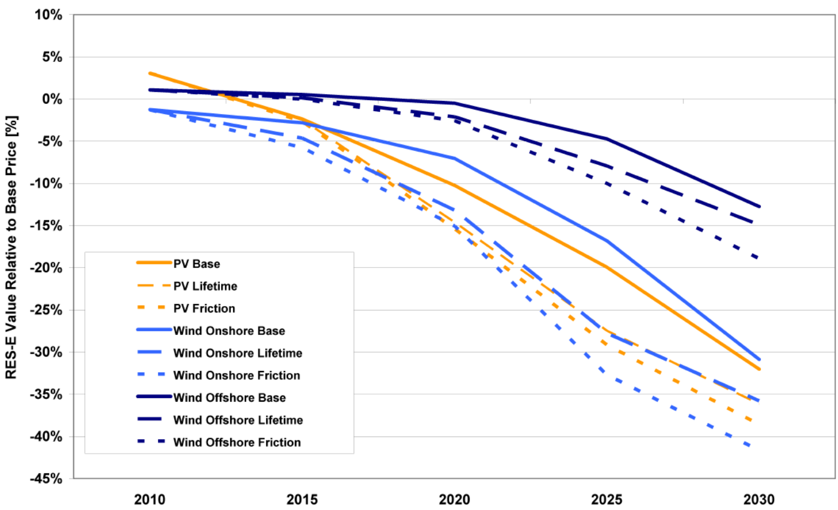
Source: own illustration.

As already indicated by the storage commissioning and the storage values, the market is firm more often in both lifetime extension scenarios. In 2020, the reserve market volume of the 'Lifetime' scenario is 2.4 times higher than in the 'Base' scenario and in the 'Friction' scenario even more than 2.6 times. The differences are lower in 2030, since by then parts of the nuclear fleet are decommissioned and the overall capacity mix is further optimized. While the market volume of the 'Lifetime' scenario is 9% above the 'Base' scenario in 2030, the volume in the 'Friction' scenario is still 30% higher. Since all components in the system are interconnected, the interpretation of the individual values needs to take the reaction of other system components into account as well. One additional reason for the lower difference of the market volume is that CAES is able to provide negative reserve and therefore reduces the firmness of the market by providing the ability to store additional energy. As already mentioned, without the ability to invest in CAES as a flexibility option, the power market would show significantly higher signs of firmness.

Effects of the Nuclear Lifetime Extension on the Demand Side

The higher share of nuclear capacity also has effects on the consumer costs as shown in Figure 6.11. It is observable that while the energy market costs decrease, the RES-E support costs increase. Figure 6.25 shows the relative RES-E value compared to the base price for all three scenarios.

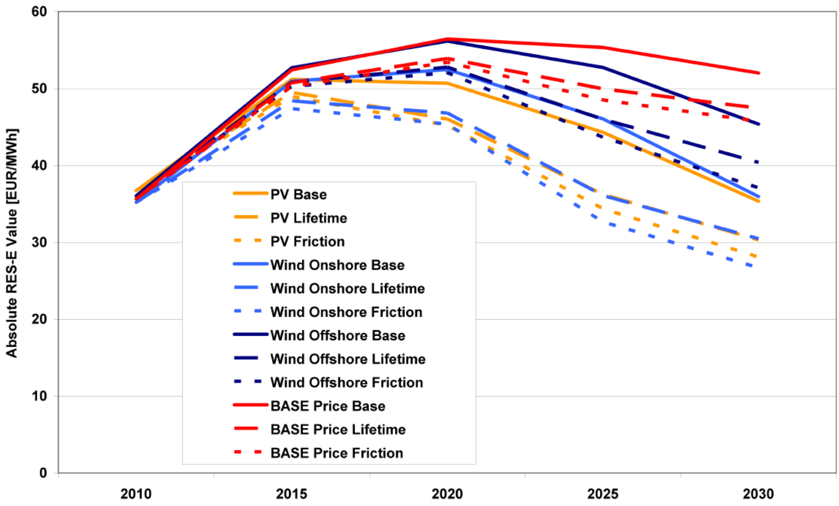
Figure 6.25: Relative RES-E value ('Base' vs. nuclear lifetime extension scenarios)



Source: own illustration.

The relative RES-E value decrease is stronger in both lifetime extension scenarios for all RES-E in comparison to the 'Base' scenario. It is also observable that with the deployment of CAES in 2030, the decreasing trend is reduced in both lifetime scenarios since the oversupply can be stored, which reduces the price-depressing effect. Without this additional storage possibility, the RES-E value would have been much lower. Benitez et al. (2008) show that hydro storage increases the value of wind power in a constrained power market. The same effect can be seen for the absolute RES-E values in Figure 6.26.

Figure 6.26: Absolute RES-E value ('Base' vs. nuclear lifetime extension scenarios)

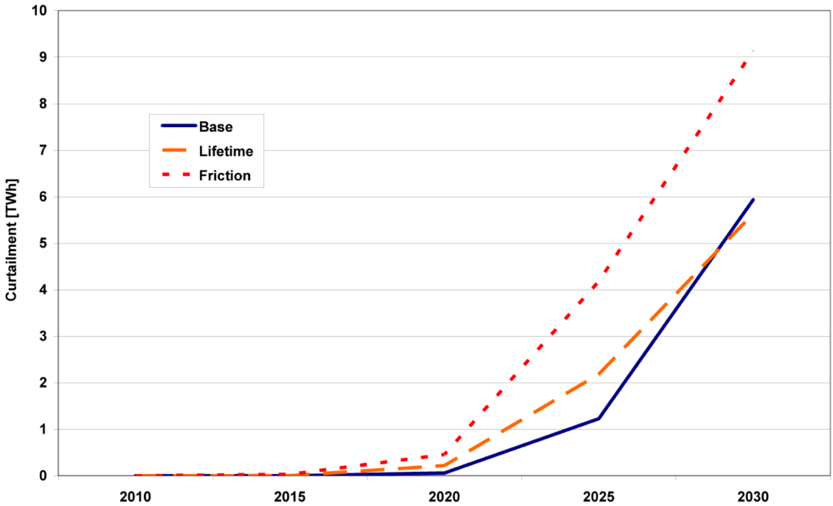


Source: own illustration.

All absolute RES-E values in both lifetime extension scenarios are below their corresponding value of the 'Base' scenario. For example, the value of wind onshore in the 'Lifetime' scenario amounts to only 85% of the value in the 'Base' scenario and only 74% in the 'Friction' scenario. Also the base prices in the lifetime extension scenarios are lower than in the 'Base' scenario, which explains the lower consumer costs on behalf of the energy market. The reason is the higher share of nuclear or lignite generation as a marginal unit, which sets the price more often. In addition, the power price is also influenced by the curtailment penalty. Figure 6.27 shows the development of the absolute curtailment amount of all RES-E technologies for all three scenarios.

The curtailment in all three scenarios starts in 2020 and rises strongly until 2030. Approximately 6 GW are curtailed in the 'Base' scenario, and in the 'Friction' scenario, more than 9 GW are curtailed. In the 'Lifetime' scenario, the curtailment amounts to a little less than in the 'Base' scenario because of the additional CAES storage possibility. Since the curtailment sets the price in these hours, the price becomes

Figure 6.27: Total curtailment comparison ('Base' vs. nuclear lifetime extension scenarios)



Source: own illustration.

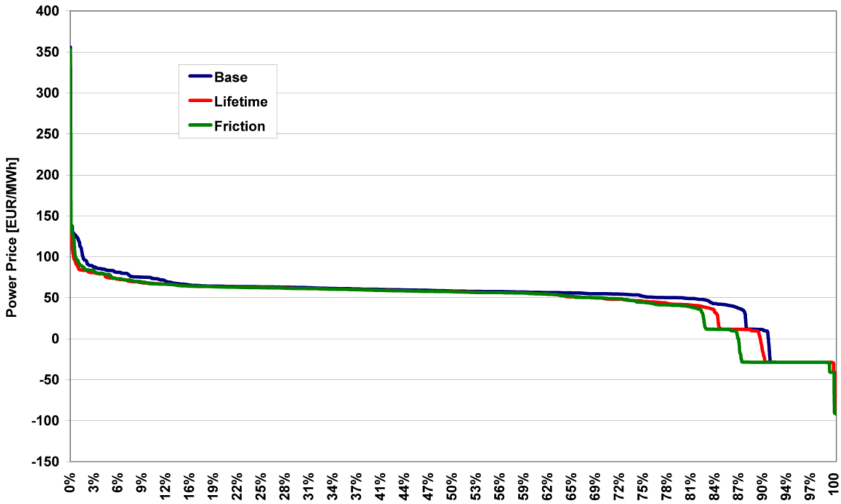
more volatile with an increasing curtailment share. To illustrate this effect, Figure 6.28 shows a comparison of the three price duration curves for 2030.

The price duration curve of the 'Base' scenario shows higher prices in the high price area than both lifetime extension scenarios. At the low price end, all scenarios show significant amounts of negative prices. In the 'Base' scenario, the power price is negative in 9% of all hours. This number rises to 10% in the 'Lifetime' scenario and even to 13% in the 'Friction' scenario. Overall, it can be seen that the nuclear lifetime extension increases the challenges to integrating a high share of RES-E. Without CAES investments, the resulting market firmness signs would have been more severe. Since the market flexibility is highly valued in the lifetime extension scenarios, the grid infrastructure is likely to gain importance.

Effects of the Nuclear Lifetime Extension on the Grid Infrastructure

In both lifetime extension scenarios, the total low variable cost generation from RES-E and nuclear is higher compared to the 'Base' scenario. The share of peak oriented generation is lower in both lifetime extension scenarios, with the exception of CAES. This shift in capacity and generation has consequences for the utilization of the grid

Figure 6.28: Price duration curves in 2030 ('Base' vs. nuclear lifetime extension scenarios)



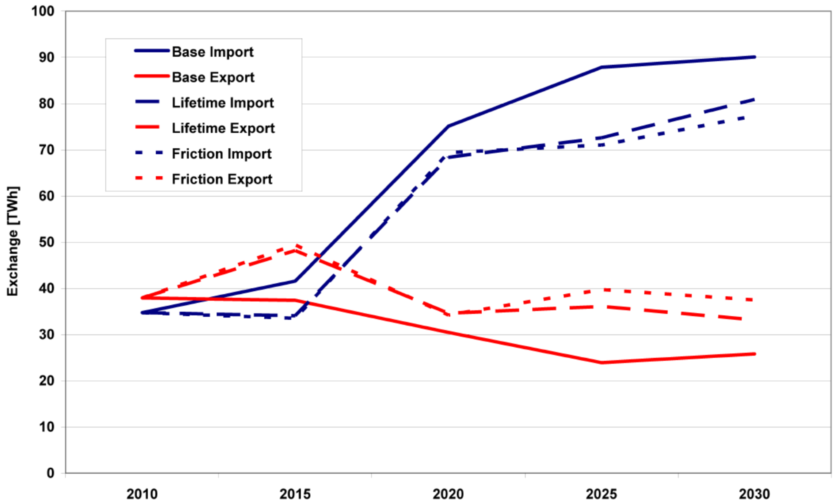
Source: own illustration.

infrastructure as can be seen in Figure 6.29, which shows the development of the international exchange amounts in all three scenarios.

The import amount is reduced in both lifetime extension scenarios due to the higher share of low cost generation. At the same time, the low cost generation increases the export amount, since RES-E in combination with nuclear generation forms a base load energy band, which either needs to be consumed or exported to avoid costly curtailment. In summary, this means that due to the lifetime extension, Germany does not become a netimporting country until after 2015, and in 2030 the netimport is reduced by 26% in the 'Lifetime' scenario and by 38% in the 'Friction' scenario. In the case of both lifetime extension scenarios, the possibility to store additional energy via CAES relaxes the constraint on the export NTC since an additional option is available. Why the investment in the CAES is necessary can be understood with the help of the analysis of the average NTC values. Figure 6.30 shows the average marginal NTC values of all three scenarios.

Compared to the average export NTC value of the 'Base' scenario, the values from both lifetime extensions scenarios are significantly higher. This reflects the firm market situations, shown above in the discussion of the reserve market volumes. If one

Figure 6.29: Development of international exchange ('Base' vs. nuclear lifetime extension scenarios)



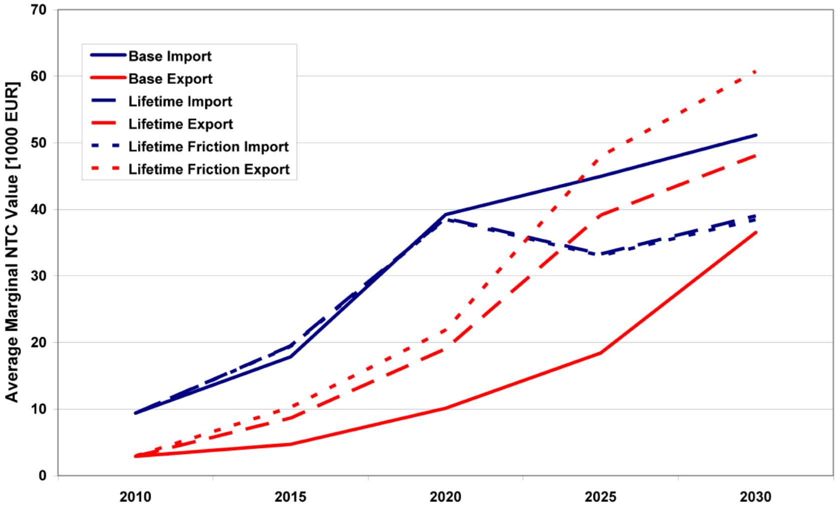
Source: own illustration.

MWh cannot be exported, it needs to be either curtailed or stored. This means additional costs for the system. The value of import NTC is relaxed by the lifetime extension, since high residual load situations in which imports are necessary to avoid start-ups of expensive peakload capacity are reduced. By now, it has been shown that the grid infrastructure plays an important role in RES-E integration and that changes in the power market have direct consequences for the exchange amounts and the value of the NTC.

6.3.4 Grid Extension

While the market in the last scenario became more firm, the market in this section is relaxed due to the higher exchange possibilities between the markets. The results overview shows that the non-utilized peak share of the capacity mix is strongly increased and that the overall generation in Germany is reduced, which consequentially increases the netimport share. This is in line with the overview of the producer rent, which shows less profits in the 'Grid Extension' scenario. Overall, the conventional generation in Germany suffers from low cost imports from the surrounding markets due to the increased peak oriented generation capacity compared to the 'Base' scenario. The more flexible market environment also makes investments in storage

Figure 6.30: Average marginal NTC values ('Base' vs. nuclear lifetime extension scenarios)



Source: own illustration.

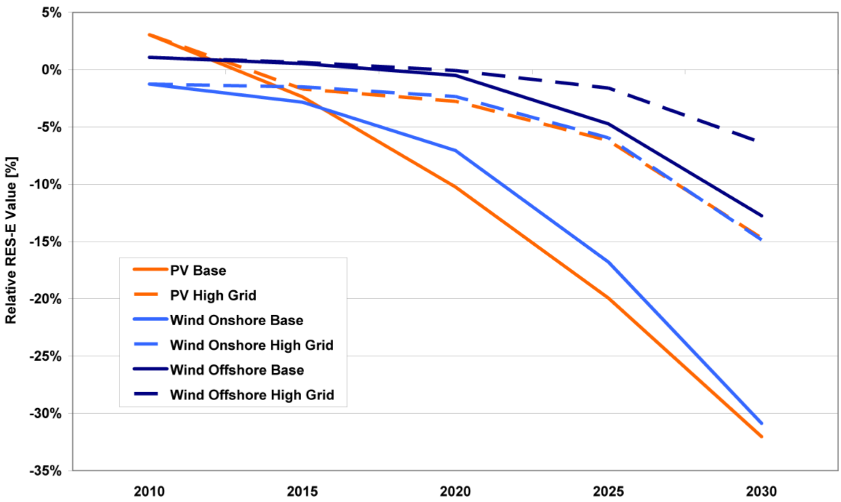
technologies dispensable. Since these findings can already be derived from the discussion in in the results overview in section 6.3.1, the analysis in this section starts with the impact on the RES-E value, which directly impacts the overall consumer costs.

Effects of an Extended Grid Infrastructure on the Demand Side

It is observable in Figure 6.11 that the consumer has to bear lower costs in the 'Grid Extension' scenario compared to the 'Base' scenario. The costs related to the energy markets in the 'Grid Extension' scenario are higher, while the reduced RES-E support costs overcompensate this cost increase. To understand the effect on the RES-E support, Figure 6.31 shows the relative RES-E value compared to the base price.

The relative RES-E values of all technologies remain at much higher levels throughout the entire time period compared to the 'Base' scenario. This already indicates that firm market situations in which the RES-E value drops occur much less in the 'Grid Extension' scenario. This assumption is confirmed by the reserve market volume which is 70% lower in 2020 and still 57% lower in 2030 compared to the 'Base' scenario. To understand what these effects mean for the consumer costs, Figure

Figure 6.31: Relative RES-E value comparison ('Base' vs. 'Grid Extension')



Source: own illustration.

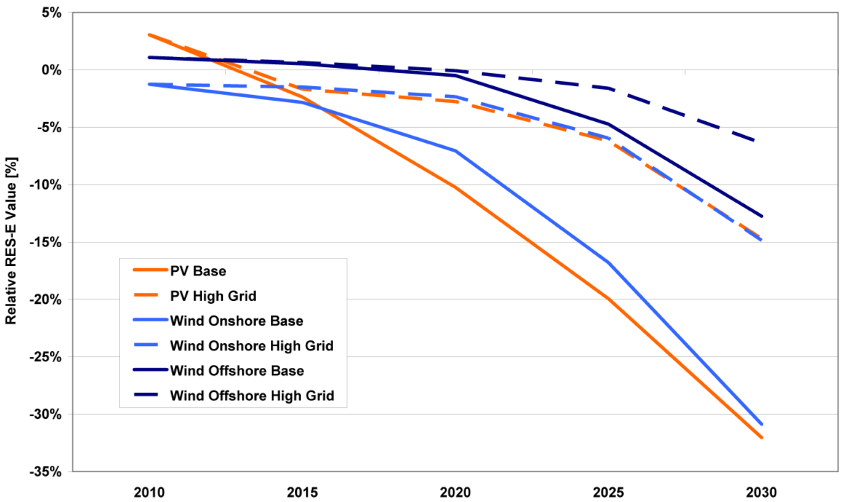
6.32 shows the absolute results.

The comparison of the absolute RES-E values explains why the RES-E support costs are much lower in the 'Grid Extension' scenario. The value of PV is 12% higher in 2020 and 30% higher in 2030. Consequently, the support costs decrease substantially. The same pattern is observable for wind onshore, for which the value is 9% higher in 2020 and 28% higher in 2030, whereas the corresponding numbers for wind offshore are 4% and 11% respectively. As already mentioned, the markets' firmness is dramatically reduced by the higher grid infrastructure. As a consequence, the curtailment is strongly reduced to less than 900 GWh in 2030 compared to almost 6 TWh in the 'Base' scenario. Since this also has strong effects on the prices, the base price in the 'Grid Extension' scenario remains 4% above the price of the 'Base' scenario. This higher price has to be paid by the consumer, who on the other hand benefits from the reduced RES-E support costs.

Effects of an Increased Grid Infrastructure on the Grid

The extension of the grid infrastructure allows international exchange to a much greater degree. Figure 6.33 shows the import and export amounts of Germany.

Figure 6.32: Absolute RES-E value comparison ('Base' vs. 'Grid Extension')

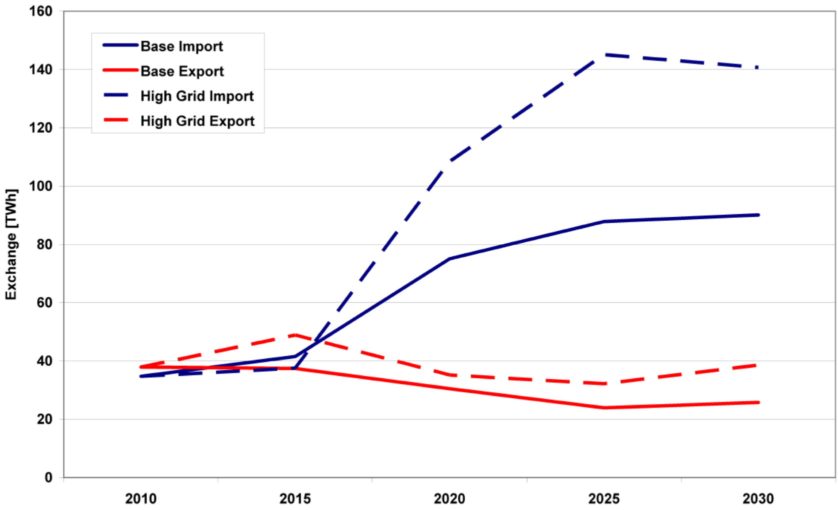


Source: own illustration.

As the scenario overview has shown, the netimport is increased compared to the 'Base' scenario. The import is much higher, which is a result of the higher peak orientation of the generation capacity. Most of the time, expensive generation can be avoided by imports, which also leads to a higher share of base load generation in some of the surrounding power markets. The export is also increased, but to a much lesser extent than the import. As discussed above, most of the time, the RES-E oversupply can be exported and curtailment strongly reduced.

To summarize, the increased grid infrastructure reduced the RES-E induced firmness of the market significantly. All market signs indicate that this approach is able to provide significant additional flexibility to the market. The reserve market volume is reduced substantially due to the higher flexibility. The export possibility in times of RES-E oversupply times increases the RES-E value while decreasing the required curtailment. The direction of the effects is clear. Assessing the efficient amount of grid extension in the interconnected system with various investment decision in renewable and conventional generation remains a challenging task.

Figure 6.33: International exchange comparison ('Base' vs. 'Grid Extension')



Source: own illustration.

6.3.5 Effects of Support Schemes and Curtailment Regulation

The design of the RES-E support scheme and thus the applied curtailment rules are an important element of power systems with a higher RES-E share as discussed in section 3.1.4. The design has strong effects on the dispatch and on the power prices. Therefore, the market adapts to the support scheme design when RES-E play a significant role in the power market.

Effects of Support Scheme Design on the Supply Side

Power prices are directly influenced by the curtailment behavior, which sets the equilibrium power price in firm oversupply situations. Consequently, investment decisions concerning conventional capacities are directly influenced as well, as has been shown in Figure 6.6 in the results overview. Overall, the generation capacity becomes more peak oriented with higher curtailment costs. Therefore, to avoid high generation costs, the netimport increases with higher curtailment costs as well. In the assumed premium system of the 'Base' scenario as well as in the free curtailment scenario 'Curtail0', investments in OCGTs are required to provide flexibility in the energy and the reserve market. If higher curtailment costs are assumed, as in the out-of-market assumption in the 'Curtail150' case, the commissioning of 11 GW CAES crowds out parts of the OCGT fleet and provides the required flexibility instead. If no curtailment rule is applied and the market reaches its limit at -3000 EUR, as in the 'Curtail3000' scenario, the effects are much more extreme. However, market rules would quickly change if oversupply situations resulted in prices of -3000 EUR without market clearance. Therefore, this scenario should not be interpreted as realistic. It simply shows that forced RES-E infeed has its limits. In order to avoid the extremely high curtailment costs, investments in 40 GW CAES can be observed that store the RES-E oversupply and avoid curtailment costs that are too high. The immense CAES fleet provides the entire flexibility requirement and replaces almost the entire OCGT fleet, significantly reducing the required superpeaker capacity. Since the storage technologies benefit from storing energy at extremely negative prices and releasing it to the market at positive prices, their profits increase as shown in Figure 6.8. Storage technologies benefit from market firmness, since they are able to provide flexibility on both sides of the market, during the peak hours and the oversupply hours.

Figure 6.34 shows the reserve market volume as an indicator of market firmness. Compared to the 'Base' scenario, the 'Curtail0' scenario shows less firmness due to the ability to curtail the RES-E oversupply without any costs. This possibility is treated as additional flexibility in the market.

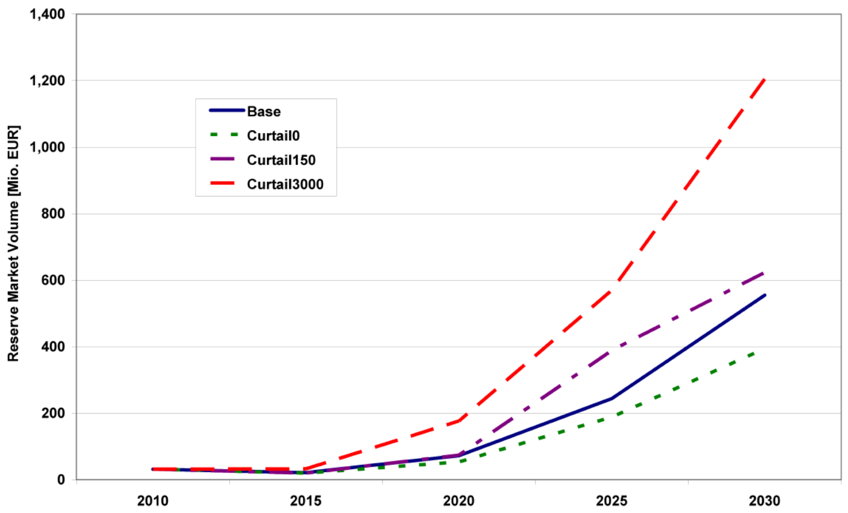
This flexibility is reduced as soon as the curtailment penalty increases. As discussed above, the market firmness increases in the 'Curtail150' scenario to a level that requires CAES to reduce the firmness. The reserve market volume increases nevertheless to 112% of the 'Base' scenario in 2030. The forced RES-E infeed in the 'Curtail3000' scenario increases the firmness further, which has been seen in the high CAES investments as well as in the reserve market volume, which rises to 217% of the volume of the 'Base' scenario.

Effects of Support Scheme Design on the Demand Side

It is intuitive that the support scheme design affects the consumer costs, which can be seen in Figure 6.11. While the RES-E support costs increase with the curtailment penalty, the overall costs remain more or less the same, with the exception of the extreme penalty assumption in the 'Curtail3000' scenario in which the overall costs for the consumer increase. The more RES-E is forced into the market, the lower the energy market costs. Therefore, the value of RES-E, and consequently the total RES-E support costs, strongly depend on the support scheme design. Figure 6.35 shows the scenario comparison of the relative RES-E value.

The increase of the curtailment penalties reduces the value of the individual RES-E. In the 'Curtail0' scenario, the individual RES-E value is the highest, since curtailment

Figure 6.34: Reserve market volume ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000')

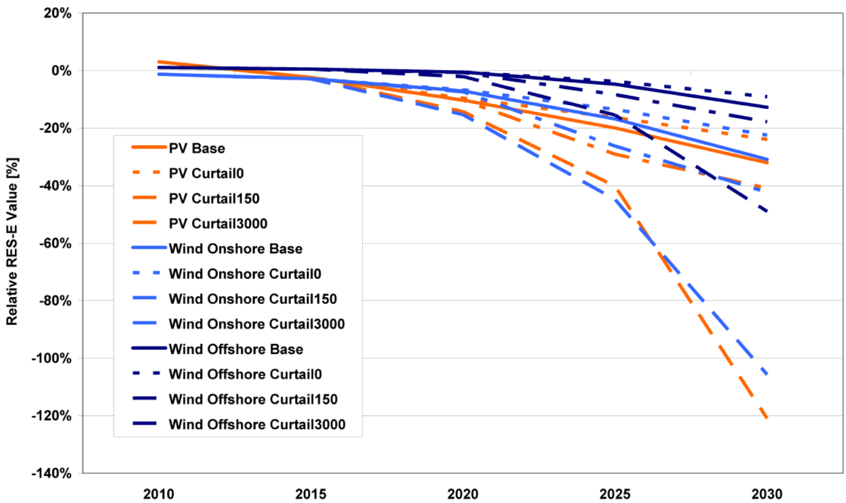


Source: own illustration.

is free of cost and the value reducing effect is primarily the merit-order effect. The results of the premium assumptions in the 'Base' scenario are primarily curtailment decisions at slightly negative prices below -100 EUR/MWh. The RES-E value is therefore slightly lower than the one from the 'Curtail0' scenario. The out-of-market curtailment level of -150 EUR/MWh in the 'Curtail150' scenario already shows stronger value reducing effects. These effects are the highest in the 'Curtail3000' scenario. Even though the majority of curtailment is avoided by the CAES storage, the RES-E values decrease dramatically. Figure 6.36 shows the absolute values, which directly determine the total RES-E support costs for consumers.

The high curtailment penalty in the 'Curtail3000' scenario leads to negative RES-E values for PV and wind onshore. Even though the total RES-E curtailment is reduced to 2.6% of the amount of the 'Base' scenario in 2030, the impact on the value is high enough to result in a RES-E value below zero. While in the 'Curtail150' scenario the total curtailment amount is reduced to 40% of the 'Base' scenario in 2030, the value of PV is reduced to 82% of the value of the 'Base' scenario and the value of wind onshore to 79%. The same logic applies in the 'Curtail0' scenario, where the RES-E values are above the ones from the 'Base' scenario. Also the base prices reflect the impact of the curtailment penalties. While the price in the 'Curtail0' scenario is 5% above the one from the 'Base' scenario, the prices for the 'Curtail150' and 'Cur-

Figure 6.35: Relative RES-E value ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000')

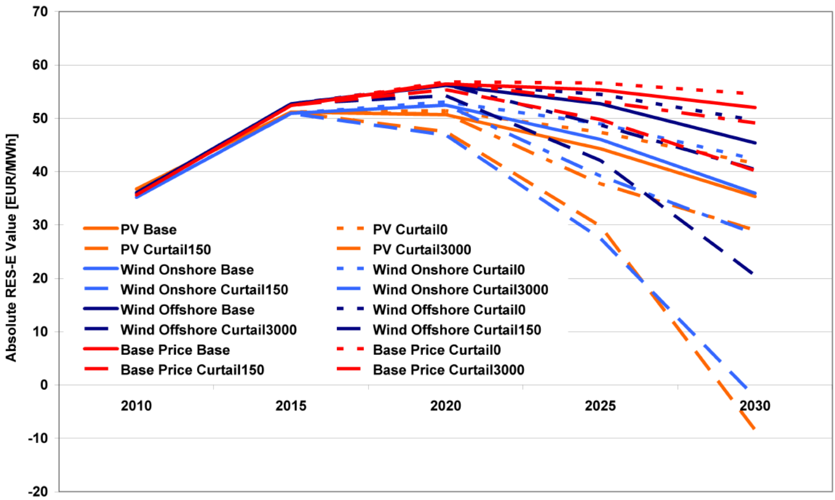


Source: own illustration.

tail3000' scenarios are 6% and 23% lower, respectively. The scenario comparison of the price behavior can be seen in Figure 6.37 by the price duration curves.

The overview of the price duration curves illustrates the impact of the RES-E support scheme designs and their corresponding curtailment rules. While the 'Base' and the 'Curtail0' scenarios show similar price patterns, apart from the lowest price levels which are set by the different curtailment penalties, the patterns in the other two scenarios deviate stronger. The 'Base' scenario curtails at the individual RES-E premium levels and shows overall negative prices 8.8% of the time. The 'Curtail0' scenario curtails at a power price of zero, which is the market result 9.1% of the time. Both scenarios show the same pattern at the positive side. The 'Curtail150' scenario starts curtailing at -150 EUR/MWh. However, the price also drops to lower values as compared later to the 'Base' scenario. This pattern has already been seen in section 3.1.4, where an out-of-market curtailment rule has been applied at the ERCOT market in Texas. The reason for the delayed drop in the 'Curtail150' scenario is the added storage capacity, which reduces the market firmness in these hours. Even though the effects look similar, two different flexibility options are responsible, namely out-of-market curtailment in the ERCOT case and storage in the 'Curtail150' case. Due to the utilization of the additional CAES storage in the 'Curtail150' scenario, negative price results can be reduced to 4.8% of the time. This effect is strongly increased

Figure 6.36: Absolute RES-E value comparison ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000')



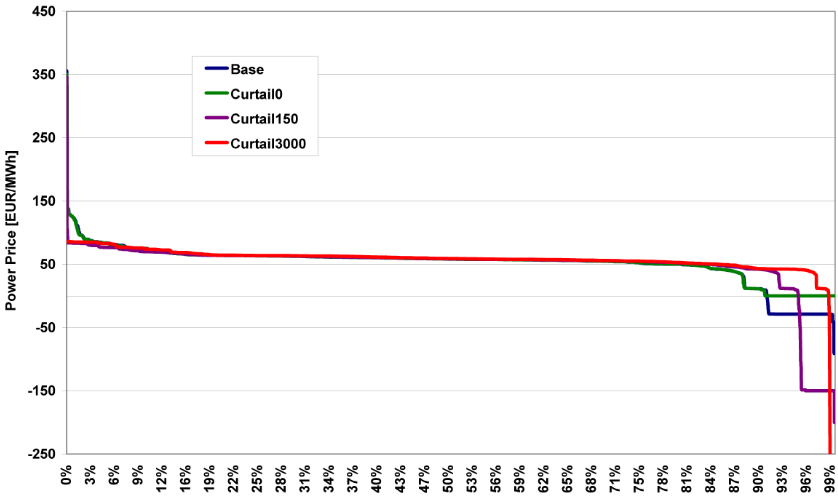
Source: own illustration.

in the 'Curtail3000' scenario, since the high curtailment penalty leads to much higher CAES investments, delaying the price drop and leading to negative prices in less than 0.8% of the time. On the positive price side, the two lower curtailment cost scenarios deviate in a few hours to higher prices. This pattern is avoided in the other two scenarios due to the utilization of the additionally stored energy.

A detailed analysis of the support scheme effects on the grid infrastructure is dispensed at this point due to the repetition of the pattern. In short, the market firmness increases with the curtailment penalties and leads to higher valuations of the grid infrastructure. Also the exchange is increased, leading to the previously mentioned increase of the netimport due to the higher peak orientation of the generation capacity when higher curtailment penalties are applied.

In summary, the RES-E support scheme design strongly influences market behavior as soon as critical penetration levels are reached which lead to firm market situations. The generation capacity becomes more peak oriented with higher curtailment penalties, requiring higher netimport amounts. At a certain point, even CAES investments are required to provide flexibility to enable efficient market clearance. The consumer has to bear higher RES-E support costs when RES-E are forced into the market, but this requires benefits from reduced energy market costs until the distortions of

Figure 6.37: Comparison of price duration curves ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000')



Source: own illustration.

the market become too extreme and costly flexibility options. On the one hand, the market benefits from price signals, which reflect the requirement for flexibility, as discussed in chapter 3. On the other hand, too many market distortions through overly ambitious RES-E integration forces result in higher costs and penalize the RES-E value substantially.

6.3.6 RES-E Reserve Market Participation

In the previous section, the reserve market volume served as an indicator of market firmness, since the market volume increases when firm market situations generate opportunity costs due to reserve requirement constraints. It has been shown that this volume decreases when additional flexibilities are available. As already discussed in section 3.1.1, the reserve market requirements are also one of the drivers of firm market situations. Positive reserve requires sufficient capacity in the market which is able to increase the generation in a certain time frame. Negative reserve requires a minimum generation level, which allows for a reduction. In situations with potential oversupply, this restriction forces conventional capacities to generate above their minimum load level and therefore to increase the firmness of the market. A fundamental assumption in this scenario is that RES-E are able to provide reserve power.

In order to do this, an IT infrastructure needs to be installed that enables the control of the RES-E capacity.[17] According to Dena (2010), only pitch controlled wind mills are able to control the output and are therefore able to participate in the reserve market. However, the majority of installed wind capacity and almost all new installed wind mills are pitch controlled, so it is assumed that no further limitations are required for the scenario assumptions. For a detailed analysis of the technical capabilities of wind power to provide system services, see Ummels (2008).

Effects of RES-E Reserve Market Participation on the Supply Side

The 'RES-E Reserve' scenario allows RES-E to participate in the reserve market. In order to provide positive reserve, the particular infeed needs to be curtailed to increase it again. Negative reserve can be provided as soon as a particular technology generates electricity that can be reduced. If the reserve market would actually require negative reserve to be triggered, the price for the actual reserve energy would be the foregone alternative value on the energy market and the premium payment. While in theory the opportunity costs can simply be attributed and calculated, in reality a complex game theoretic approach is required, which may also take potential oligopolistic market structures into account. The approach of this scenario is therefore in line with the general orientation of this entire analysis, which focuses on fundamental interrelationships and not on behavioral aspects of the markets. Furthermore, this scenario is not intended to actually model a particular reserve market with its corresponding design features in detail, but simply to analyze the effects on the energy market if RES-E are allowed to participate in the reserve market. One can interpret the set-up as a reserve market design with two separate auctions. The first auction, which is reflected by this scenario approach, is for the reserve capacity requirement. The second auction is for the energy price if the reserve needs to be triggered. This reflects roughly the current German reserve market design.

Before the results are discussed, a brief explanation is provided for the fundamental interdependencies of the reserve market. First, the negative reserve market is discussed. Whenever RES-E is fed into the market, it can be curtailed. This possibility fulfills the negative reserve requirement and can be provided without any additional costs. If the energy reduction was actually required, opportunity costs would be the energy market value plus the premium. In normal market situations in reality, the opportunity costs for conventional generators are the avoided fuel costs. Therefore, the conventional generator actually saves money if he has to reduce generation. In

17 Since the availibility of RES-E is a crucial assumption for this scenario, forecast errors are also important in order to enable that only the guaranteed RES-E amounts participate in the reserve market. To take this probability into account, a sensitivity case has been computed. In this case, only 50% of the curtailed amount is allowed to provide positive reserve and only 50% of the RES-E infeed is allowed to provide negative reserve. The results differ only to a negligible degree and therefore only one scenario discussion is sufficient.

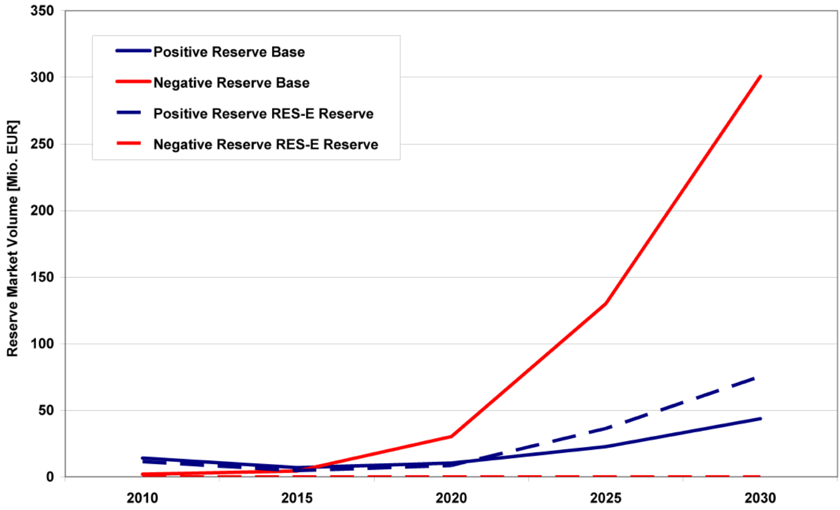
the case of RES-E, the energy would be lost if the primary energy source were non-storable.[18] Therefore, intermitting RES-E would be quite an expensive choice in the 'merit-order' of 'negative energy' and would not be efficient under normal market conditions. In the model, opportunity costs show only up in the extreme situations when the conventional generation reaches certain limits, i.e. in cases of oversupply. Then, it is efficient if RES-E provide negative reserve and, since the price at the energy market isfrequently negative in oversupply situations, to reduce the energy infeed. In this way, conventional capacities are allowed to ramp down and to avoid burning fuel and paying the negative price at the energy market in order to generate above their minimum load level. Additionally, the provision on negative reserve by RES-E reduces the amount of curtailment and therefore also additional RES-E support costs. In summary, the situations in which it would be inefficient to ramp down RES-E do not in reality show up in the model results, since in this case no opportunity costs are present, the reserve price is equal to zero and THEA chooses a conventional generator to provide negative reserve. Only firm market situations provide negative reserve prices. In these situations, it might very well be efficient if RES-E, especially with storable primary energy sources, provided negative reserve. Especially if their premium is lower than the opportunity costs of the conventional generator.

The explanation of the positive reserve market follows a different logic, since actual curtailment is required before RES-E can provide the possibility to increase the energy output. In all normal and high energy price situations this would not be efficient, since RES-E is valuable at the energy market. However, in firm oversupply situations it might be different. In this case, the model does not show positive reserve prices, since the reserve requirement restriction is not binding because all ramped-up capacities in part-load mode can increase generation. If RES-E is curtailed in these oversupply situations anyway, it can easily provide positive reserve. In combination with the possibility to also provide negative reserve, this allows conventional capacities to ramp-down, leading to less curtailment, higher RES-E values and consequently to lower support costs. If the energy were required in the market, it would not generate any fuel costs. The 'merit-order' of the positive reserve would start at the negative premium level, since as soon as RES-E is fed into the grid, the premium is earned. Figure 6.38 shows the effects on the reserve market volume with RES-E participation compared to the 'Base' scenario.

The main market firmness in the 'Base' scenario is represented by the market volume for negative reserve. This observation confirms the previous explanation since higher RES-E shares lead to potential oversupply situations more often. Since these oversupply situations occur due to high RES-E infeed, providing negative reserve omits any opportunity costs, which reduces the market volume to zero in the 'RES-E Reserve' case. The positive reserve volume in the 'RES-E Reserve' scenario is even higher compared to the 'Base' scenario in 2025 and 2030. This might be surprising,

18 Only biomass uses storable primary fuels, wind and solar energy are non-storable and would be lost.

Figure 6.38: Reserve market volume comparison ('Base' vs. 'RES-E Reserve')



Source: own illustration.

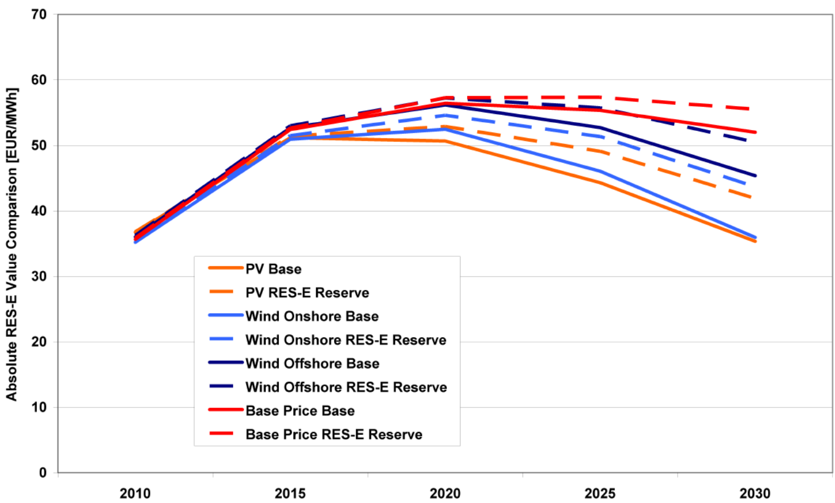
since the reserve requirement constraint has more options and should therefore be more flexible. In addition to the reasons provided in the following, the adapted capacity mix is also partially responsible for this difference, as will be explained later. However, as previously explained, due to the reduced firmness in the negative reserve market, less capacity is required to stay online. Now, the only reason to generate in part-load, and this even when negative prices occur, is to provide positive reserve. This is only observable if insufficient curtailment is available to provide positive reserve. In comparison to the negative reserve, actual curtailment is required in the positive reserve market when RES-E are used. The firmness-reducing effect is therefore much lower compared to the negative reserve and the overall costs are even higher, since the positive reserve is now the only constraint which provides friction in the energy market. An additional indicator for the overall lower market firmness is the reduced producer rent of pumped hydro storage, which can be seen in Figure 6.8. This is partially due to the lower amount of negative prices, which in turn explains why pumped hydro storage might also be partially responsible for the higher positive reserve prices. Since less energy can be compressed at negative prices, the opportunity costs increase, which partially set the positive reserve prices.

As mentioned before, the change in the reserve market requirements also affects the capacity mix (Figure 6.6). Since additional flexibility is provided by RES-E, the conventional market requires less flexibility. For the year 2030, this leads to a reduction of almost 2.3 GW OCGT and roughly 0.6 GW CCGT. In order to fulfill the peak requirement, this leads to an increase of almost 2.9 GW superpeaker capacity. Superpeakers are not able to provide standing reserve as opposed to OCGTs and are too expensive to provide spinning reserve. It has been noted above that OCGT investments are a sign of required quality in the capacity mix, since they are cheaper as superpeakers already at very low utilizations and are able to provide tertiary reserve even when they are not ramped up. Therefore, these results directly show that the additional RES-E possibility in the reserve markets leads to lower quality requirements on the conventional capacity side.

Effects of RES-E Reserve Market Participation on the Demand Side

The consumer cost comparison in Figure 6.11 shows that the RES-E support costs are reduced in the 'RES-E Reserve' scenario compared to the 'Base' scenario, while the market costs increase. Figure 6.39 shows the absolute RES-E values of both scenarios.

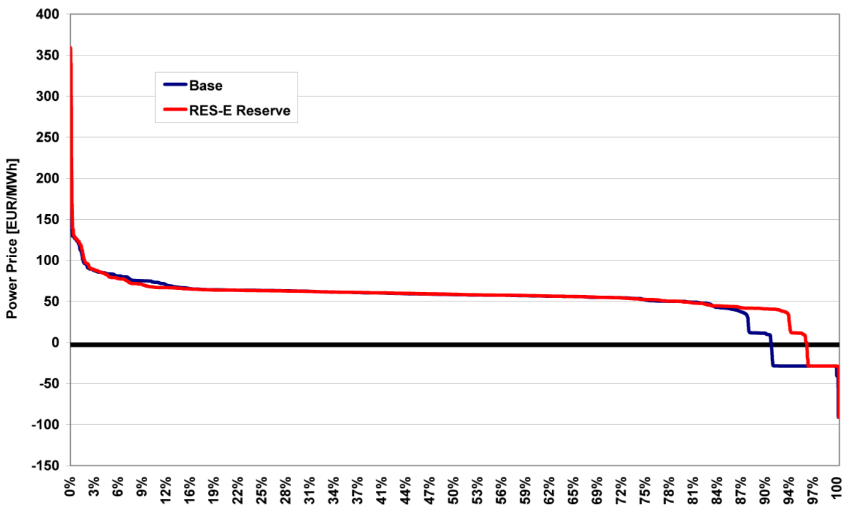
Figure 6.39: Absolute RES-E value comparison ('Base' vs. 'RES-E Reserve')



Source: own illustration.

The previously discussed reduction of market firmness leads to overall higher RES-E values compared to the 'Base' scenario. In 2030, the PV value is 19% higher than the one in the 'Base' scenario, the wind onshore value 22% and the wind offshore value 11% higher. Due to the higher flexibility, the total amount of curtailment is reduced by 65% compared to the 'Base' scenario. This clearly shows that the reserve requirement is one of the fundamental factors which limit further RES-E integration. Since in the 'Base' scenario conventional capacity is forced to stay online, RES-E has to be curtailed more often. This leads to higher power prices in the 'RES-E Reserve' scenario compared to the 'Base' scenario of almost 7% in 2030. Figure 6.40 shows a price duration curve comparison of both scenarios for 2030.

Figure 6.40: Price duration curves in 2030 ('Base' vs. 'RES-E Reserve')



Source: own illustration.

As discussed in the previous scenario comparisons, the additional market flexibility leads to a delayed price drop in the 'RES-E Reserve' scenario. While the price is negative 8.8% of the time in the 'Base' scenario, it is only negative 4.2% of the time in the 'RES-E Reserve' scenario. This in turn is in line with the reduced curtailment as discussed above.

Under the assumption that RES-E are able and allowed to participate in the reserve market, the market firmness is substantially reduced. Conventional capacity is allowed to reduce its minimum generation level, which leads to higher RES-E infeeds in firm market situations and thus to reduced curtailment. In addition, the conventional capacity has to provide less quality in terms of flexibility, which further reduces the total costs.

6.4 Critical Discussion of Modeling Results

The modeled scenarios provide an overview on adaptation effects under different policy scenarios in high temporal resolution. The advantages of high temporal resolution, especially for high RES-E penetration cases, are already discussed in chapter 5 for the Texas case study. From the comparison between the 'Base' and the 'Low RES-E' scenarios it can be seen to which degree the capacity mix and in particular its utilization is affected by the increasing RES-E penetration. This finding confirms the results of previous studies such as Dena (2005), Lamont (2008) and EWI (2010) who show that less base load capacity is required in high RES-E power systems. However, since a deterministic approach is applied, the results can still be considered as conservative. By trend a stochastic approach which incorporates uncertainty, e.g. in terms of forecast errors, would lead to an even higher peak load share. The present analysis extends the previous research by applying various curtailment rules. The effects are noteworthy. Depending on the level of the curtailment penalty, the power market adapts to the degree of flexibility the curtailment rule implies. Under high curtailment penalties, substantial investments in CAES can be observed. Decarolis and Keith (2006) showed that diabatic CAES is not competitive in a carbon constrained system with a wind energy share of 70% of the load. Without knowing how curtailment is treated in their analysis, this finding cannot be confirmed for advanced adiabatic CAES. Gatzen (2008) concludes that adiabatic CAES could be a successful storage application. Nevertheless, he underestimates the increasing price volatility due to intermitting RES-E and neglects curtailment penalties. Therefore, he assumes a future flattening of the merit-order which cannot be confirmed by the present research.

However, as seen in the comparison to the other scenarios, these findings depend strongly on the settings of various system components. Even in a quite flexible premium system, which applies only modest curtailment penalties and which are comparable with current market observation in Texas (see section 3.1.4), investments in CAES are the efficient solution if nuclear capacities are rewarded a lifetime extension. Therefore, this approach extends the findings of other studies, such as BMWi (2010a) and BMWi (2010b), who also combine high RES-E penetration with nuclear lifetime extensions in the German power market, but who apply curtailment at power prices of 0 EUR/MWh as applied in the 'Curtail0' scenario. These previous findings substantially underestimate the integration challenges due to the assumed flexibility of RES-E curtailment. One common finding is the price reducing effect of a nuclear lifetime extension. As long as the the power price drops to at most 0 EUR/MWh, this price-depressing effect seems beneficial. If the price frequently drops to -150 EUR/MWh (as currently defined by the BNetzA), integration challenges are recognized and seem much more alarming than a frequent price of 0 EUR/MWh.

Besides the findings for CAES and nuclear lifetime extensions, the curtailment rule also provides significant insight into RES-E support costs. In fact, a trade-off is observable between high curtailment penalties on the one hand, which lead to system adaptations, and lower RES-E support costs on the other hand, which are present with relaxed curtailment penalties. A similar trade-off also applies to the nuclear lifetime extension, which leads to lower power prices but reduces the value of RES-E and increases the firmness of the market. Overall, a balance between sufficient market signals for triggering system adaptation and reasonable support costs must be found. Both extremes, the 'Curtail0' and the 'Curtail3000', lead to politically unsustainable results. A market-driven rule, which allows curtailment in extreme situations and at the same time signals the demand for flexibility, is thus preferable to the current support scheme and curtailment regulation. The fundamental challenge is already observable in present firm market situations as discussed in the empirical investigation in section 3.1.3. The firmness of the power market would even be increased if additional must-run generation restrictions, which are required for system services in addition to reserve requirements, would be applied.

In addition to the discussed free curtailment option, other flexibility increasing measures can be implemented. If the grid infrastructure is extended, oversupply market situations can be relaxed by additional export possibilities. This in turn leads to lower RES-E support costs, since the power price does not fall below 0 EUR/MWh very often. Market firmness can also be reduced via the participation of RES-E in the reserve market. Ummels (2008) shows that wind power is able to provide certain system services. The possibility to reduce RES-E infeed decreases the required ramped-up conventional generation, which leads to higher tolerance levels until curtailment is required. A similar effect can be reached if the total amount of required reserve capacity can be reduced due to better forecast or a gate closure closer to physical delivery as shown by Müsgens and Neuhoff (2006) and Weber (2009).

7 Conclusion

The integration of large amounts of RES-E challenges the operation of the power system and leads to long-run adaptations. In the short-run, the interactions of the energy and the reserve market indicate that the German power market is already firm today when low demand meets high RES-E infeed. The market firmness is observable in negative power prices and high prices for negative reserve products. These market results signal additional demand for flexibility in the market and therefore already indicate requirements for system adaptation.

The negative correlation of RES-E infeed and power prices has already been discussed in the literature but still calls for additional modeling applications in real-scale power systems with international exchange. Open research questions are further found to concern long-run system adaptations, especially in set-ups which reflect the complexity of intermitting RES-E infeed and operational power market requirements. The present work adds various details to the discussion on power system modeling in general and RES-E integration in particular:

- First, the long-run system adaptation of real-scale power systems with 8760 hours in a multi-year, multi-zonal set-up is modeled for the first time.
- Second, the discussion on the value of RES-E is enriched by a dynamic approach, which takes system development into account and further adds complexity by international exchange options.
- Third, for the first time in capacity expansion power system modeling, particular curtailment policies of RES-E support schemes are taken into account.
- Finally, several scenario settings, which either reduce or increase system flexibility, are analyzed to inform the current debate on various flexibility increasing options.

Compared to the latest literature, the applied approach captures a significant part of the complexity which RES-E infeed places on the power system. Nevertheless, further research is required to fill open spaces, which were not addressed in detail in the present analysis. It has been shown in this research that the grid infrastructure plays a crucial role in the long-run system adaptation to increasing RES-E penetrations. Future research is required on the optimal grid development and how it relates to changes of other system components. Additionally, the distribution grid perspective, which mirrors the flexibility of the demand side, can be captured in greater detail by gathering data and analyzing in which ways a smart grid connected to flexible industries and households could provide flexibility to the system.

The research has been conducted from the perspective of a well informed benevolent planner to capture the fundamental system adaptations. Nevertheless, the real world is usually characterized by more friction than a purely linear optimal world. Therefore, a magnitude of different approaches can be applied to the analysis of RES-E integration challenges. Besides game theoretic assumptions about the behavior of more or less dominant market participants, more detail can also be applied in the operation of the system. While the present research captures fleet-wide operational constraints, specific power blocks can be modeled for a more detailed analysis. While block specific dispatch models are used for short time periods (e.g. the day-ahead market), long-run system adaptations are not yet analyzed with such detail. From an IT technical point of view this is currently quite challenging; future IT solutions however might enable this degree of detail.

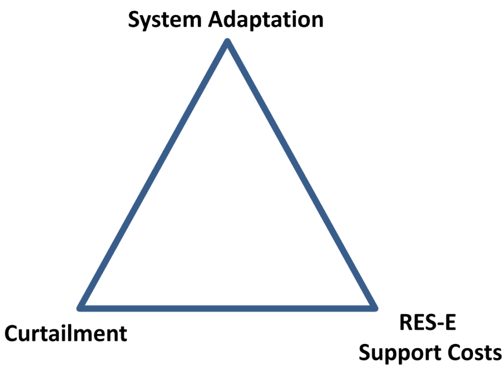
The research provided in this thesis utilizes a state of the art IT infrastructure to analyze the economic developments in a large-scale power system. Therefore, the findings provide deeper insight into the economics of RES-E market integration. These findings are summarized in the following:

By the utilization of THEA, it has been shown that the reduced temporal resolution approaches used in the current literature lead to different results and tend to underestimate the impact of large-scale RES-E penetration. Overall, the capacity mix tends to be more base load-oriented when lower temporal resolutions are applied. Since the variability increases with temporal resolution, more extreme situations are captured. This leads to an optimized capacity mix which is characterized by a higher share of peak oriented generating capacity. A reduced temporal resolution also leads to an overestimation of the value of RES-E and an underestimation of the required curtailment.

Additionally, modeling operational constraints such as start-up and part-load costs, adds further complexity to the optimization, which also leads to adjustments in the results. It has been found that modeling with a pure 'merit-order perspective' which ignores the intertemporal complexity of start-up and ramping decisions, also tends to overestimate the demand for base load capacity. Furthermore, the value of RES-E and the required curtailment is incorrectly assessed without operational constraints, since the intermitting nature of wind and solar irradiation is one of the drivers for increasing integration challenges, which must be reflected by the modeling set-up.

The value of RES-E has been shown to be strongly affected by the particular scenario setting. If, e.g. more international exchange is possible due to an increased grid infrastructure, the RES-E value increases and curtailment can often be avoided due to higher exports. These findings underline the importance of international exchange for RES-E integration. Additionally, the literature showed high price differences in the merit-order effect discussion with and without RES-E in modeling set-ups without international exchange, whereas the present analysis shows that these price spikes can often be avoided due to higher imports. Overall, the consumer costs induced by the power market are reduced due to a higher RES-E share. However, the required RES-E support costs lead to higher total costs for the consumers compared to a low RES-E scenario. Figure 7.1 shows the dimensions which should be considered by policy makers for the long-term development of the power system.

Figure 7.1: Renewable integration triangle



Source: own illustration.

One finding which has not yet been discussed in the literature is the importance of the RES-E support scheme, and in particular its corresponding RES-E integration policy for the long-run system adaptation. The RES-E integration policy is one major flexibility design criterion in power systems with a high RES-E penetration. It has been found that if RES-E is forced into the market by heavily penalizing curtailment, substantial flexibility requirements are forced upon the remaining system, which even results in substantial investments in CAES. This finding is not only important from a market design perspective, but also for modeling RES-E integration in general.

Furthermore, the value of the grid infrastructure increases due to the higher value of diverging system imbalances. If RES-E can be curtailed without much additional costs, e.g. based on a premium payment, the integration challenges are relaxed since RES-E provides additional flexibility to the system. This on the other hand leads to lower market signals which could trigger system adaptation.

If the lifetime of the nuclear fleet in Germany is increased, the overall costs in Germany are reduced due to the 'free' additional low variable cost generating capacity. The firmness of the market, however is increased. This can be seen in higher market volumes of the reserve market and higher RES-E curtailment. Also the value of the RES-E is reduced, which in turn leads to higher support costs for the consumers. To increase the flexibility of the system, significant CAES capacity is required.

One set-up which showed reduced firmness of the market is the participation of RES-E in the reserve power market. Since the reserve requirements are one source of market firmness in high RES-E infeed situations, the market participation of RES-E allows conventional generation to ramp-down and therefore leads to more efficient solutions. As a result, less curtailment is required and the RES-E value is higher, which consequently leads to lower support costs and reduced quality requirements for the conventional generation capacity.

In conclusion, it is shown by this research that high temporal resolution plays an important role in modeling high RES-E penetration scenarios, and that the design of all system components which affect the flexibility of the market requires careful consideration in order to enable a system adaptation which allows for higher RES-E shares.

A Appendix

Table A.1: Variable cost input assumptions

Technology	Unit	2008	2015	2020	2025	2030
Nuclear	$\frac{USD}{mmBtu}$	0.4	0.4	0.4	0.4	0.4
Coal	$\frac{USD}{mmBtu}$	2.2	2.1	2.1	2.1	2.1
Natural Gas	$\frac{USD}{mmBtu}$	8.9	6.3	6.6	7.0	8.0
CO_2	$\frac{USD}{tCO_2}$	0.0	19.5	30.8	42.1	53.4
Wind Support	$\frac{USD}{MWh}$	30	3.9	18.2	18.2	18.2

Source: own assumptions, based on EIA (2010a), EIA (2007) and Synapse (2008).

Table A.2: Power plant investment cost assumptions

Technology	$\frac{USD}{kW}$
Nuclear	3,820
Coal	2,223
CCGT	968
OCGT	648
Superpeaker	500

Source: own assumptions, based on based onEIA (2010c).

Table A.3: Overview of NTC capacities

Direction	Import			Export		
Country	2010	2020	2030	2010	2020	2030
Germany	18,650	21,266	21,266	13,825	16,267	16,267
France	10,130	14,501	17,191	15,350	18,662	22,267
Netherlands	7,100	8,909	8,909	7,000	8,784	8,784
Denmark	2,530	3,173	3,173	4,750	5,419	5,419
Poland/Czech Rep.	3,200	3,661	3,661	5,500	5,981	5,981
Alps	10,555	11,984	11,984	14,360	15,813	15,813
Italy	7,110	9,300	10,505	3,090	5,812	5,812
North	4,400	5,000	5,000	1,700	2,300	2,300
Iberia	1,300	2,566	3,966	500	2,310	4,000
UK/IE	2,000	2,102	3,102	2,000	2,102	3,102
Belgium	5,800	6,359	6,359	4,700	5,372	5,372

Source: own assumptions, based on ENTSO-E (2010a) and EWI (2010).

Table A.4: Total exogenous generation $[TWh_{el}]$

Zone	2010	2015	2020	2025	2030
Germany	189	230	282	332	380
France	66	94	132	152	171
Netherlands	71	88	111	122	134
Denmark	40	45	49	50	52
PLCZ	58	63	65	66	67
Alps	56	59	61	63	64
Italy	139	155	173	182	191
Iberia	127	160	203	224	245
Belgium	15	24	34	39	44
UKIE	76	109	169	199	230
North	113	122	136	143	150

Source: own assumptions, based on EU Commission (2010) and AGEB (2010).

Table A.5: Conventional technology endogenous investement input assumptions

Technology	Parameter	Unit	2015	from 2020 on
Nuclear	Investment Cost	$\frac{EUR}{kW}$	2,735	2,735
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	54.7	54.7
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	0.6	0.6
	Efficiency	%	33	33
Lignite	Investment Cost	$\frac{EUR}{kW}$	1,368	1,576
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	49.8	54.2
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	1	1
	Efficiency	%	43	48
Coal	Investment Cost	$\frac{EUR}{kW}$	1,368	1,576
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	27.4	31.7
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	1	1
	Efficiency	%	46	50
CCGT	Investment Cost	$\frac{EUR}{kW}$	648	648
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	13	13
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	0.7	0.7
	Efficiency	%	57.8	61
OCGT	Investment Cost	$\frac{EUR}{kW}$	389	389
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	7.9	7.9
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	0.1	0.1
	Efficiency	%	35	40
Superpeaker	Investment Cost	$\frac{EUR}{kW}$	370	370
	Fixed O&M Cost	$\frac{EUR}{kW*a}$	7.9	7.9
	Variable O&M Cost	$\frac{EUR}{MWh_{el}}$	0.1	0.1
	Efficiency	%	35.4	35.4

Source: own assumptions, based on information from electric utilities and IEA (2010).

Table A.6: Life time and depreciation time assumptions

Technology	Life Time	Depreciation Time
Nuclear	40	35
Lignite	40	20
Coal	40	20
CCGT	30	20
OCGT	25	15
CAES	40	20
Superpeaker	25	20

Source: own assumptions.

Table A.7: Fuel price assumptions

Fuel	Unit	2010	2015	2020	2025	2030
Nuclear	$\frac{EUR}{MWh_{th}}$	3.6	3.6	3.6	3.6	3.6
Lignite	$\frac{EUR}{MWh_{th}}$	1.5	1.5	1.5	1.5	1.5
Coal	$\frac{EUR}{MWh_{th}}$	8.6	8.6	9.4	9.7	9.9
Natural Gas	$\frac{EUR}{MWh_{th}}$	18.2	25	23	24.5	26
CO_2	$\frac{EUR}{tCO_2}$	15	33.8	42.7	45.6	48.5

Source: own assumptions, based on BMWi (2010a), IEA (2010) and Capros et al. (2008).

Table A.8: Capacity mix of scenarios in 2020 (GW)

Technology	Base	Low RES-E	Lifetime	Friction	Grid Extension	Curtail0	Curtail150	Curtail3000	RES-E Reserve
Nuclear	2.6	2.6	13.3	13.3	2.6	2.6	2.6	2.6	2.6
Lignite	15.5	10.0	15.5	8.9	15.5	15.5	15.5	15.5	15.5
Hardcoal	22.1	19.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
CCGT	16.6	28.2	8.3	8.3	8.3	15.2	15.8	13.6	16.5
OCGT	4.1	1.8	3.7	4.7	1.1	5.6	4.4	1.9	4.8
Superpeaker	14.5	18.2	12.4	18.2	25.8	14.3	14.8	15.9	13.7
CAES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0
Hydro	13.2	12.8	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Wind Onshore	35.7	27.5	35.7	35.7	35.7	35.7	35.7	35.7	35.7
Wind Offshore	10.0	0.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Biomass	8.8	6.3	8.8	8.8	8.8	8.8	8.8	8.8	8.8
PV	51.8	15.8	51.8	51.8	51.8	51.8	51.8	51.8	51.8
Geothermal	0.3	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Source: own calculations

Table A.9: Capacity mix of scenarios in 2030 (GW)

Technology	Base	Low RES-E	Lifetime	Friction	Grid Extension	Curtail0	Curtail150	Curtail3000	RES-E Reserve
Nuclear	0.0	9.5 9.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lignite	7.6	7.6	7.6	6.5	7.6	7.6	7.6	4.5	7.6
Hardcoal	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.0
CCGT	15.1	37.5	6.2	6.2	6.2	14.7	13.8	11.6	14.5
OCGT	13.7	7.1	8.8	12.2	5.3	14.9	4.8	0.7	11.5
Superpeaker	33.6	25.8	32.9	32	51.1	32.9	32.8	15.7	36.4
CAES	0.0	0.1	5.0	3.5	0.0	0.0	11.1	40.4	0.1
Hydro	13.2	12.8	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Wind Onshore	41.2	27.5	41.2	41.2	41.2	41.2	41.2	41.2	41.2
Wind Offshore	25.5	0.2	25.5	25.5	25.5	25.5	25.5	25.5	25.5
Biomass	9.0	6.3	9.0	9.0	9.0	9.0	9.0	9.0	9.0
PV	63.0	15.8	63.0	63.0	63.0	63.0	63.0	63.0	63.0
Geothermal	1.0	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Source: own calculations

Table A.10: Capacity mix of scenarios in 2020 (TWh)

Technology	Base	Low RES-E	Lifetime	Friction	Grid Extension	Curtail0	Curtail150	Curtail3000	RES-E Reserve
Nuclear	19.4	19.5	97.0	97.2	19.5	19.4	19.4	19.4	19.5
Lignite	86.4	88.4	79.6	73.0	95.7	88.5	88.7	88.7	92.9
Hardcoal	32.2	61.5	29.0	35.2	42.0	34.2	34.5	39	33.8
Natural Gas	116.3	224.6	59.8	59.2	67.9	108.9	113.1	101.4	117.6
CAES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Hydro	21.6	18.9	21.8	22.6	20.3	21.8	21.6	21.7	22.0
Wind Onshore	72.7	44.4	72.7	72.7	72.7	72.7	72.7	72.7	72.7
Wind Offshore	31.8	0.3	31.8	31.8	31.8	31.8	31.8	31.8	31.8
Biomass	49.5	32.8	49.5	49.5	49.5	49.5	49.5	49.5	49.5
PV	41.4	9.5	41.4	41.4	41.4	41.4	41.4	41.4	41.4
Geothermal	1.7	0.1	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Other	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Netimport	44.6	15.8	33.7	35.2	73.3	47.8	43.1	46.1	39.4
Hyd PS Pump	-2.4	-0.8	-2.6	-3.8	-0.4	-2.6	-2.3	-2.5	-2.6
CAES Pump	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	0.0
Curtailment	-0.1	0.0	-0.2	-0.5	0.0	-0.1	0.0	0.0	0.0

Source: own calculations

Table A.11: Capacity mix of scenarios in 2030 (TWh)

Technology	Base	Low RES-E	Lifetime	Friction	Grid Extension	Curtail0	Curtail150	Curtail3000	RES-E Reserve
Nuclear	0.0	0.0	62.8	66.0	0.0	0.0	0.0	0.0	0.0
Lignite	49.1	62.8	42.8	50.8	47.5	49.7	49.8	44.2	49.0
Hardcoal	18.2	25.2	16.7	16.9	16.4	18.3	18.1	13.5	18.0
Natural Gas	75.4	261.1	38.0	38.5	35.3	74.5	69.4	64.9	71.2
CAES	0.0	0.0	1.3	1.1	0.0	0.0	1.5	7.6	0.0
Hydro	23.4	18.9	25.1	26.1	21.8	23.4	24.7	25.2	26.9
Wind Onshore	87.0	44.4	87.0	87.0	87.0	87.0	87.0	87.0	87.0
Wind Offshore	95.0	0.3	95.0	95.0	95.0	95.0	95.0	95.0	95.0
Biomass	51.6	32.8	51.6	51.6	51.6	51.6	51.6	51.6	51.6
PV	55.2	9.5	55.2	55.2	55.2	55.2	55.2	55.2	55.2
Geothermal	6.6	0.1	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Other	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Netimport	64.3	60.3	47.7	39.9	102.1	62.4	67.3	82.4	66.5
Hyd PS Pump	-5.0	-0.7	-7.4	-8.9	-2.6	-5.0	6.9	-7.6	-5.0
CAES Pump	0.0	0.0	-1.8	-1.5	0.0	0.0	-2.1	-10.9	0.0
Curtailment	-5.9	0.0	-5.6	-9.1	-0.9	-4.0	-2.4	-0.2	-2.1

Source: own calculations

Table A.12: Base prices in all scenarios (EUR/MWh)

Scenario	2010	2015	2020	2025	2030
Base	35.6	52.4	56.4	55.3	52.0
Low RES-E	35.6	54.5	59.7	61.1	61.7
Lifetime	35.6	50.7	53.9	50.0	47.5
Friction	35.6	50.3	53.4	48.5	45.7
Grid Extension	35.6	53.0	58.4	57.5	54.0
Curtail0	35.6	52.4	56.8	56.6	54.6
Curtail150	35.6	52.4	56.6	52.6	48.2
Curtail3000	35.6	52.4	55.4	49.8	40.2
RES-E Reserve	35.9	52.7	57.3	57.3	55.5

Source: own calculations

Bibliography

J. Abrell, F. Kunz, and H. Weigt. Start Me Up Modeling of Power Plant Start-Up Conditions and Their Impact on Prices. *papers.ssrn.com*, (July), 2008.

AGEB. Energieverbrauch in Deutschland im Jahr 2009. Technical report, Arbeitsgemeinsachaft Energiebilanzen e.V., Berlin, 2010.

A. Baíllo, M. Ventosa, M. Rivier, A. Ramos, and G. Relaño. Bidding In A Day-Ahead Electricity Market: A Comparison Of Decomposition Techniques. In *14th Power Systems Computation Conference, Sevilla*, number June, Sevilla, 2002.

M. Bartels. *Cost Efficient Expansion of District Heat Networks in Germany*. PhD thesis, University of Cologne, 2009.

C. Batlle and I. Pérez-Arriaga. Design criteria for implementing a capacity mechanism in deregulated electricity markets. *Utilities Policy*, 16(3):184–193, Sept. 2008. ISSN 09571787.

C. Batlle, C. Vázquez, M. Rivier, and I. J. Pérez-Arriaga. Enhancing power supply adequacy in Spain: Migrating from capacity payments to reliability options. *Energy Policy*, 35(9):4545–4554, 2007. ISSN 03014215.

BDEW. Bundesverband der Energie- und Wasserwirtschaft, www.bdew.de, 2010.

J. F. Benders. Partitioning procedures for solving mixed-variables programming problems. *Numerische Mathematik*, 38(1):3–252, Dec. 1962.

L. E. Benitez, P. C. Benitez, and G. C. van Kooten. The economics of wind power with energy storage. *Energy Economics*, 30(4):1973–1989, July 2008. ISSN 01409883.

BMU. Analyse des Preiseffektes der Stromerzeugung aus erneuerbaren Energien auf die Börsenpreise im deutschen Stromhandel -Analyse für das Jahr 2006-. Technical report, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, Berlin, 2007.

BMU. Erneuerbare Energien in Zahlen. Nationale und internationale Entwicklung. Technical report, Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, Berlin, 2010a.

BMU. Langfristszenarien und Strategien für den Ausbau der Erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global. Technical report, Berlin, 2010b.

BMWi. Energieszenarien für ein Energiekonzept der Bundesregierung. Technical Report 12, German Federal Ministry of Economics and Technology, Berlin, 2010a.

BMWi. Voraussetzungen einer optimalen Integration erneuerbarer Energien in das Stromversorgungssystem. Technical report, Bundesministerium für Wirtschaft und Technologie, Berlin, 2010b.

BMWi. Analyse und Bewertung der Versorgungssicherheit in der Elektrizitätsversorgung. Technical report, Bundesministerium für Wirtschaft und Technologie, Berlin, 2010c.

BNetzA. Vermarktung der EEG- Energiemengen nach AusglMechV und AusglMechAV. Technical report, Bundesnetzagentur, Bonn, 2010a.

BNetzA. Verordnung zur Ausführung der Verordnung zur Weiterentwicklung des bundesweiten Ausgleichsmechanismus (Ausgleichsmechanismus- Ausführungsverordnung - AusglMechAV), 2010b.

S. Bode and H. Groscurth. The Effect of the German Renewable Energy Act (EEG) on the Electricity Price. Technical report, Hamburg Institute of International Economics, Hamburg, 2006.

G. Brunekreeft, K. Neuhoff, and D. Newbery. Electricity transmission: An overview of the current debate. *Utilities Policy*, 13(2):73–93, 2005. ISSN 09571787.

P. Capros, L. Mantzos, V. Papandreou, and N. Tasios. Model-based Analysis of the 2008 EU Policy Package on Climate Change and Renewables. Technical report, EU Commission, Brussels, 2008.

G. Cote and M. Laughton. Decomposition techniques in power system planning: the Benders partitioning method. *International Journal of Electrical Power & Energy Systems*, 1(1):57–64, Apr. 1979. ISSN 01420615.

P. Cramton. Competitive Bidding Behavior in Uniform-Price Auction Markets. In *Proceedings of the Hawaii International Conference on System Science*, number January, 2004.

P. Cramton and S. Stoft. Forward reliability markets: Less risk, less market power, more efficiency. *Utilities Policy*, 16(3):194–201, 2008. ISSN 09571787.

L. De Vries and P. Heijnen. The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms. *Utilities Policy*, 16 (3):215–227, Sept. 2008. ISSN 09571787.

J. Decarolis and D. Keith. The economics of large-scale wind power in a carbon constrained world. *Energy Policy*, 34(4):395–410, 2006. ISSN 03014215.

Dena. Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020. Technical report, Berlin, 2005.

Dena. Integration erneuerbarer Energien in die deutsche Stromversorgung im Zeitraum 2015 bis 2020 mit Ausblick auf 2025. Technical Report November, Deutsche Energie Agentur, Berlin, 2010.

DoE. Energy Efficiency & Renewable Energy Program, http://www.doe.gov, 2010.

C. L. Duthaler. Power Transfer Distribution Factors : Analyse der Anwendung im UCTE-Netz, Masterarbeit. 2007.

EEG. Gesetz zur Neuregelung des Rechts der Erneuerbaren Energien im Strombereich, 2008.

EEX Transparency. EEX Transparency, http://www.transparency.eex.com, 2010.

EIA. Impacts of a 15-Percent Renewable Portfolio Standard, http://www.eia.doe.gov. Technical Report June, U.S. Energy Information Administration, Washington D.C., 2007.

EIA. Annual Energy Outlook 2010, http://www.eia.doe.gov/. Technical report, U.S. Energy Information Administration, Washington D.C., 2010a.

EIA. Assumptions to the Annual Energy Outlook 2010, http://www.eia.doe.gov. Technical Report 2010, U.S. Energy Information Administration, Washington D.C., 2010b.

EIA. Assumptions to the Annual Energy Outlook 2010, http://www.eia.doe.gov/. Technical Report March, U.S. Energy Information Administration, Washington D.C., 2010c.

EIA. Electricity Generating Capacity, Independent Statistics & Analysis, http://www.eia.doe.gov, 2010d.

ENTSO-E. Indicative values for Net Transfer Capacities (NTC) in Europe Winter 2009/2010, https://www.entsoe.eu. Technical Report 3, European Network of Transmission System operators for Electricity, Brussels, 2009a.

ENTSO-E. System Adequacy Forecast 2009 until 2020, https://www.entsoe.eu. Technical report, Union for the co-ordination of transmission of electricity, Brussels, 2009b.

ENTSO-E. Indicative values for Net Transfer Capacities (NTC) in Europe Summer 2010, https://www.entsoe.eu. Technical Report 10, European Network of Transmission System Operators for Electricity, Brussels, 2010a.

ENTSO-E. Consumption Data, https://www.entsoe.eu, 2010b.

ENTSO-E. NTC Matrix 2010, https://www.entsoe.eu, 2010c.

EPEX Spot. EPEX Spot, http://www.epexspot.com/en, 2010.

ERCOT. Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas, www.ercot.com. Technical report, Electric Reliability Council of Texas, Austin, 2006.

ERCOT. Report on the capacity, demand and reserves in the ERCOT region, www.ercot.com. Technical report, Electric Reliability Council of Texas, Austin, 2010a.

ERCOT. Wind generation and load in 2008, www.ercot.com. Technical report, Electric Reliability Council of Texas, Austin, 2010b.

EU Commission. Renewable Energy Action Plans, URL: http://ec.europa.eu/energy/renewables/transparency_platform /action_plan_en.htm, 2010.

European Union. EU Directive 2009/28/EC, 2009.

EWI. European RES-E Analysis - A model-based analysis of RES-E deployment and its impact on the conventional power market. Technical report, Institute of Energy Economics, Cologne, 2010.

D. Finon and V. Pignon. Electricity and long-term capacity adequacy: The quest for regulatory mechanism compatible with electricity market. *Utilities Policy*, 16: 143–258, 2008.

M. Fripp and R. H. Wiser. Effects of Temporal Wind Patterns on the Value of Wind-Generated Electricity in California and the Northwest. *IEEE Transactions on Power Systems*, 23(2):477–485, May 2008. ISSN 0885-8950.

C. Gatzen. *The Economics of Power Storage*. PhD thesis, University of Cologne, 2008.

R. Green. Electricity wholesale markets: designs now and in a low-carbon future. *The Energy Journal*, 29(Special Issue\# 2):95–124, 2008.

C. Hiroux and M. Saguan. Large-scale wind power in European electricity markets: Time for revisiting support schemes and market designs? *Energy Policy*, 38(7): 3135–3145, July 2010. ISSN 03014215.

R. Hofer. Wirtschaftliche Grundlagen der Stromerzeugung. In M. Bartsch, A. Röhling, P. Salje, and U. Scholz, editors, *Stromwirtschaft - Ein Praxishandbuch*, pages 410–417. 2 edition, 2008.

H. Holttinen. Optimal electricity market for wind power. *Energy Policy*, 33(16):2052–2063, 2005a. ISSN 03014215.

H. Holttinen. Hourly wind power variations in the Nordic countries. *Wind Energy*, 8 (2):173–195, 2005b.

IEA. World Energy Outlook 2010, http://www.iea.org. Technical Report 4, International Energy Agency, Paris, 2010.

T. Jónsson, P. Pinson, and H. Madsen. On the market impact of wind energy forecasts. *Energy Economics*, 32(2):313–320, 2010. ISSN 01409883.

P. Joskow. Competitive electricity markets and investment in new generating capacity. In D. Helm, editor, *The New Energy Paradigm*. Oxford University Press, 2007.

P. Joskow. Capacity payments in imperfect electricity markets: Need and design. *Utilities Policy*, 16(3):159–170, 2008. ISSN 09571787.

S. Just and C. Weber. Pricing of reserves: Valuing system reserve capacity against spot prices in electricity markets. *Energy Economics*, 30(6):3198–3221, 2008. ISSN 01409883.

C. Klessmann, C. Nabe, and K. Burges. Pros and cons of exposing renewables to electricity market risks: A comparison of the market integration approaches in Germany, Spain, and the UK. *Energy Policy*, 36(10):3646–3661, 2008. ISSN 03014215.

M. Kreutzberg. *Spot Prices of Electricity in Germany and other European Countries*. PhD thesis, University of Cologne, München, 2001.

L. Kuntz and F. Müsgens. Modeling start-up costs of multilpe technologies in electricity markets. *Mathematical Methods of Operations Research*, 66(1):21–32, 2007.

A. D. Lamont. Assessing the long-term system value of intermittent electric generation technologies. *Energy Economics*, 30(3):1208–1231, May 2008. ISSN 01409883.

F. Leuthold, H. Weigt, and C. von Hirschhausen. Efficient pricing for European electricity networks: The theory of nodal pricing applied to feeding-in wind in Germany. *Utilities Policy*, 16(4):284–291, Dec. 2008. ISSN 09571787.

W. Lise, B. F. Hobbs, and S. Hers. Market power in the European electricity market: The impacts of dry weather and additional transmission capacity. *Energy Policy*, 36(4):1331–1343, Apr. 2008. ISSN 03014215.

P. Menanteau, D. Finon, and M. Lamy. Prices versus quantities: choosing policies for promoting the development of renewable energy. *Energy policy*, 31(8):799–812, June 2003. ISSN 0301-4215.

G. S. Miera, P. Gonzales, and I. Vizcaino. Analysing the impact of renewable electricity support schmes on power prices: The case of wind electricity in Spain. *Energy Policy*, 36(9):3345–3359, 2008.

D. Möst and W. Fichtner. Renewable energy sources in European energy supply and interactions with emission trading. *Energy Policy*, 38:2898–2910, 2010.

D. Möst and D. Keles. A survey of stochastic modelling approaches for liberalised electricity markets. *European Journal of Operational Research*, 207(2):543–556, Dec. 2010. ISSN 03772217.

J. Munksgaard and E. P. Morthorst. Wind power in the Danish liberalised power market: Policy measures , price impact and investor incentives. *Energy Policy*, 36: 3940–3947, 2008.

F. Müsgens. *The Economics of Wholesale Electricity Markets*. PhD thesis, University of Cologne, 2005.

F. Müsgens and K. Neuhoff. Modelling dynamic constraints in electricity markets and the costs of uncertain wind output, Cambridge Working Papers in Economics. 2006.

C. Nabe. *Effiziente Integration erneuerbarer Energien in den deutschen Elektrizitätsmarkt*. PhD thesis, TU Berlin, 2006.

J. Neubarth, O. Woll, C. Weber, and M. Gerecht. Beeinflussung der Spotmarktpreise durch Windstromerzeugung. *Energiewirtschaftliche Tagesfragen*, 56(7):42, 2006.

K. Neuhoff, A. Ehrenmann, L. Butler, J. Cust, H. Hoexter, K. Keats, A. Kreczko, and G. Sinden. Space and time: Wind in an investment planning model. *Energy Economics*, 30(4):1990–2008, 2008. ISSN 01409883.

M. Nicolosi. Wind power integration and power system flexibility: An empirical analysis of extreme events in Germany under the new negative price regime. *Energy Policy*, 38(11):7257–7268, Nov. 2010. ISSN 03014215.

M. Nicolosi and M. Fürsch. The Impact of an increasing share of RES-E on the Conventional Power Market: The Example of Germany. *Zeitschrift für Energiewirtschaft*, (3), 2009.

M. Nicolosi, A. Mills, and R. Wiser. The Importance of High Temporal Resolution in Modeling Renewable Energy Penetration Scenarios. In *Infraday Conference Proceedings 2010*, number 0, Berlin, 2010.

NREL. 20% Wind Energy by 2030, http://www.nrel.gov. Technical report, Golden, Colorado, 2008.

NREL. Western wind and solar integration study, http://www.nrel.gov. Technical Report May, National Renewable Energy Laboratory, Golden, Colorado, 2010a.

NREL. Solar Advisor Model (SAM), www.nrel.gov/analysis/sam, 2010b.

A. Ockenfels, V. Grimm, and G. Zoettl. Strommarktdesign: Preisbildungsmechanismus im Auktionsverfahren für Stromstundenkontrakte an der EEX. Technical Report March, 2008.

M. Pehnt, M. Oeser, and D. Swider. Consequential environmental system analysis of expected offshore wind electricity production in Germany. *Energy*, 33(5):747–759, May 2008. ISSN 03605442.

Regelleistung.net. Internetplattform zur Vergabe von Regelleistung, www.regelleistung.net, 2010.

F. Roques. Market design for generation adequacy: Healing causes rather than symptoms. *Utilities Policy*, 16(3):171–183, 2008. ISSN 09571787.

F. Sensfuss, M. Ragwitz, and M. Genoese. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. *Energy Policy*, 36(8):3086–3094, 2008. ISSN 03014215.

S. Stoft. *Power System Economics - Designing Markets for Electricity*. IEEE Press, Piscataway, 2002.

K. Strauß. *Kraftwerkstechnik zur Nutzung fossiler, nuklearer und regenerativer Energiequellen*. Springer, Berlin Heidelberg, 5 edition, 2006.

G. Strbac. Demand side management: Benefits and challenges. *Energy Policy*, 36 (12):4419–4426, 2008. ISSN 03014215.

Synapse. Synapse 2008 CO2 Price Forecasts, http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf. Technical Report July, Synapse Energy Economics, Inc., Cambridge, 2008.

T. Traber and C. Kemfert. Gone with the wind? Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics*, July 2010. ISSN 01409883.

B. Ummels. *Power System Operation with Large-Scale Wind Power in Liberalised Environments*. PhD thesis, Technische Universiteit Delft, 2008.

N. Vasilakos and R. Green. Market behaviour with large amounts of intermittent generation. *Energy Policy*, 38(7):1–10, 2009. ISSN 0301-4215.

J. Viehmann. Risk premiums in the German day-ahead Electricity Market. *Energy Policy*, (June), 2011.

J. Viehmann and H. Sämisch. Windenergieintegration bei negativen Strompreisen. *Energiewirtschaftliche Tagesfragen*, 59(11):49–51, 2009.

E. Wang. Modelling long-run cost minimization and environmental provisions for utility expansion. *Energy Economics*, 18(1-2):49–68, Apr. 1996. ISSN 01409883.

T. Wawer. Effizientes Engpassmanagement zur Schaffung eines europäischen Strombinnenmarktes: Die Rolle von finanziellen Übertragungsrechten. pages 91–97, 2009.

C. Weber. Adequate intraday market design to enable the integration of wind energy into the European power systems. *Energy Policy*, (2002):1–9, 2009. ISSN 03014215.

H. Weigt and C. von Hirschhausen. Price formation and market power in the German wholesale electricity market in 2006. *Energy Policy*, 36(11):4227–4234, Nov. 2008. ISSN 03014215.

M. L. Weitzman. Prices vs. Quantities. *Review of Economic Studies*, 41(4):477–91, 1974.

R. Wissen and M. Nicolosi. Ist der Merit-Order-Effekt der erneuerbaren Energien richtig bewertet? *Energiewirtschaftliche Tagesfragen*, 58(1-2):110–115, 2008.

J. Wood and B. F. Wollenberg. *Power generation, operation and control*. Wiley-Interscience, 1996.

SCHRIFTEN DES ENERGIEWIRTSCHAFTLICHEN INSTITUTS

FRÜHERE VERÖFFENTLICHUNGEN

Band 67 Nicolosi, Marco: The Economics of Renewable Electricity Market Integration. An Empirical and Model-Based Analysis of Regulatory Frameworks and their Impact on the Power Market. 2012.

Band 66 Wissen, Ralf: Die Ökonomik unterschiedlicher Ausbaudynamiken erneuerbarer Energien im europäischen Kontext. Eine modellbasierte Analyse. 2012.

Band 65 Endress, Martin: The Development of Emissions Trading in Germany. A Political Economy Analysis of Stakeholders, Interests and Power Resources. 276 Seiten, 2010.
ISBN: 978-3-8356-3227-1.

Band 64 Bartels, Michael: Cost Efficient Expansion of District Heat Networks in Germany. 170 Seiten, 2009.
ISBN: 978-3-8356-3184-7.

Band 63 Gatzen, Christoph: The Economics of Power Storage. Theory and Empirical Analysis for Central Europe. 230 Seiten, 2008.
ISBN: 978-3-8356-3138-0.

Band 62 Kühn, Christian: Yardstick Regulierung für Elektrizitätsverteilungsnetzbetreiber. 560 Seiten, 2006.
ISBN 978-3-8356-3108-3.

Band 61 Seeliger, Andreas: Entwicklung des weltweiten Erdgasangebots bis 2030. Eine modellgestützte Prognose der globalen Produktion, des Transports und des internationalen Handels sowie eine Analyse der Bezugskostensituation ausgwählter Importnationen. 236 Seiten, 2006.
ISBN: 978-3-8356-3100-7.

Band 60 Perner, Jens: Die langfristige Erdgasversorgung Europas. Analysen und Simulationen mit dem Angebotsmodell EUGAS. 371 Seiten, 2002.
ISBN: 3-486-26536-9.

Band 59 Kreuzberg, Martin: Spot Prices of Electricity in Germany and Other European Countries. 139 Seiten, 2001.
ISBN: 3-486-26522-9.

Band 58 Drasdo, Peter: Kosten der Endlagerung radioaktiver Abfälle. 405 Seiten, 2001.
ISBN: 3-486-26523-7.

Band 57 Drillisch, Jens: Quotenmodell für regenerative Stromerzeugung. Ein umweltpolitisches Instrument auf liberalisierten Elektrizitätsmärkten. 417 Seiten, 2001.
ISBN: 3-486-26516-4.

Band 56 Starrmann, Frank: Entwicklung der Kraft-Wärme-Kopplung in liberalisierten Elektrizitätsmärkten. 230 Seiten, 2001.
ISBN: 3-486-26513-X.

Band 55 Drillisch, Jens: Quotenregelung für regenerative Stromerzeugung. 110 Seiten, 2000.
ISBN: 3-486-26482-6.

Band 54 Drasdo, Peter: Endlagerung radioaktiver Abfälle. Ein europäischer Organisations- und Kostenvergleich. 280 Seiten, 2000.
ISBN: 3-486-26477-X.

Band 53 Riechmann, Christoph: Wettbewerb im Endverbrauchermarkt für Strom. Das Beispiel von England und Wales. 450 Seiten, 1999.
ISBN: 3-486-26454-0.

Band 52 Drasdo, Peter et al.: Konzentration und Wettbewerb in der deutschen Energiewirtschaft. 600 Seiten, 1998.
ISBN: 3-486-26427-3.

Band 51 Perner, Jens, Riechmann, Christoph, Schulz, Walter: Durchleitungsbedingungen für Strom und Gas. 358 Seiten, 1997.
ISBN: 3-486-26410-9.

Band 50 Hensing, Ingo: Ansätze einer internationalen Entsorgung hochradioaktiver Abfälle. Eine ökonomische Analyse aus deutscher Sicht. 166 Seiten, 1996.
ISBN: 3-486-26209-2.

Band 49 Hoster, Frank: Auswirkungen des europäischen Binnenmarktes für Energie auf die deutsche Elektrizitätswirtschaft. Ein Ansatz zur Analyse ordnungs- und umweltpolitischer Instrumente in der Elektrizitätswirtschaft. 180 Seiten, 1996.
ISBN: 3-486-26350-1.

Band 48 Welsch, Heinz: Klimaschutz, Energieolitik und Gesamtwirtschaft. Eine allgemeine Gleichgewichtsanalyse für die europäische Union. 290 Seiten, 1996.
ISBN: 3-486-26315-3.

Band 47 Kreuzberg, Peter: Energieeinsparungen als Versicherung gegen Marktrisiken. Eine kapitalmarkttheoretisch fundierte Wirtschaftlichkeitsrechnung. 220 Seiten, 1996.
ISBN: 3-486-26325-0.

Band 46 Schwarz-Schilling, Cara: Wettbewerb auf dem Erdgasmarkt. Hub-System und alternative Konzepte. 260 Seiten, 1995.
ISBN: 3-486-26249-1.

Band 45 Hensing, Ingo, Schulz, Walter: Wirtschaftlichkeitsvergleich verschiedener Entsorgungspfade von Kernkraftwerken. Eine Kostensimulation alternativer Strategien aus deutscher Sicht. 150 Seiten, 1995.
ISBN: 3-486-26249-1.

Band 44 Funk, Cara, Millgramm, Carola, Schulz, Walter: Wettbewerbsfragen in der deutschen Gaswirtschaft. 290 Seiten, 1995.
ISBN: 3-486-26278-5.

Band 43 Güntensperger, Heinz: Die Nachfrage nach PKW und Kraftstoffen im Individualstraßenverkehr. Eine ökonomische Analyse für die Bundesrepublik Deutschland. 250 Seiten, 1993.
ISBN: 3-486-26342-0.

Band 42 Klopfer, Thomas, Schulz, Walter: Märkte für Strom. Internationale Erfahrungen und Übertragbarkeit auf Deutschland. 350 Seiten, 1993.
ISBN: 3-486-26338-2.

Band 41 Schulz, Walter, Willers, Yves-Pierre: Internationale Industriestrompreise. 382 Seiten, 1993.
ISBN: 3-486-26267-X.

Band 40 Hoven, Ingolf: Ausschreibungswettbewerb um regionale Strommärkte. 220 Seiten, 1992.
ISBN: 3-486-26275-0.

Band 39 Bolle, Friedel: Wettbewerb und Kooperation in der Elektrizitätswirtschaft. Neuere Entwicklungen in den USA. 200 Seiten, 1990.
ISBN: 3-486- 26242-4.

Band 38 von Weizsäcker, C. Christian, Schneider, Hans K., Schulz, Walter, Schmitt, Dieter (Hrsg.): Erdgas im Europäischen Binnenmarkt. 269 Seiten, 1990.
ISBN: 3-486-26232-7.

Band 37 Eiß, Harald, Lukes, Rudolf, Pick, Hartmut, Schulz, Walter: Die Ordnung des Elektrizitätsmarktes in der Europäischen Gemeinschaft. 688 Seiten, 1990.
ISBN: 3-486-26317-X.

Band 36 Herppich, Wolfram, Schulz, Walter, Zuchtriegel, Walter: Least-Cost Planning in den USA. 232 Seiten, 1989.
ISBN: 3-486-26117-7.

Band 35 Schulz, Walter, Wilhelm, Martin: Die Regulierung der stromwirtschaftlichen Zusammenarbeit nach der PURPA in den USA. 183 Seiten, 1988.
ISBN: 3-486-26170-3.

Band 34 Bergschneider, C., Schmitt, D., mit Beiträgen von Seifert, B., Suding, P.H.: Dezentrale Kraft-Wärme-Kopplung. 255 Seiten, 1988.
ISBN: 3-486-26150-9.

Band 33 Breuer, Barbara: Die Energiewirtschaft der Bundesrepublik und der DDR im Vergleich. 240 Seiten, 1987.

Band 32 Ciesiolka, Josef F.: Der Einsatz von Wärmepumpen im Haushaltsbereich. 389 Seiten, 1986.
ISBN: 3-486-26391-9.

Band 31 Bozem, Karlheinz: Controlling in Versorgungsunternehmen. 463 Seiten, 1986.
ISBN: 3-486-26236-X.

Band 30 Siebert, Horst (Hrsg.): Angebotsentwicklung und Preisbildung natürlicher Ressourcen. 148 Seiten, 1986.
ISBN: 3-486-26171-1.

Band 29 Junk, Herbert: Die Rolle von Versorgungskonzepten auf dem Wärmemarkt. 613 Seiten, 1985.
ISBN: 3-486-26311-0.

Band 28 Görgen, Rainer: Zur Problematik verstaatlichter Unternehmen in der Energiewirtschaft. Nationalized Industries in Großbritannien. 223 Seiten, 1982.
ISBN: 3-486-27871-1.

Band 27 Suding, Paul H.: Ökonomische Ansätze zur Analyse des Energieverbrauchs der Haushalte für Raumwärmezwecke. 252 Seiten, 1984.
ISBN: 3-486-28661-7.

Band 26 Bohnen, Ulrich: Regressionsanalytische Untersuchung der Entwicklung des Primärenergieverbrauchs in Abhängigkeit von Wirtschaftswachstum, Energiepreisniveau und Temperatur. 180 Seiten, 1982.
ISBN: 3-486-27401-5.

Band 25 Schulz, Walter: Ordnungsprobleme der Elektrizitätswirtschaft. 420 Seiten, 1979.
ISBN: 3-486-23801-9.

Band 24 Schürmann, Heinz-Jürgen: Ökonomische Ansätz zu einer rationalen Umweltpolitik und wirtschaftliche Konsequenzen.
2. überarbeitete Auflage.

Band 23 Schiffer, Hans-Wilhelm: Kostenfunktionen der Energieträger als Grundlage für Wirtschaftlichkeitsvergleiche auf dem Haushaltswärmemarkt. 416 Seiten, 1978.
ISBN: 3-486-21871-9.

Band 22 Pluge, Wolf: Die Höchstpreisregulierung der Erdgasproduktion in den USA. Ursache und ökonomische Konsequenzen. 335 Seiten, 1978.
ISBN: 3-486-21861-1.

Band 21 Modemann, Gerhard: Einsatzoptimierung von Wärmekraftwerksblöcken mit beschränkter Leistungsänderungsgeschwindigkeit. 108 Seiten, 1977.
ISBN: 3-486-21541-8.

Band 20 Struckmeier, Paul, Schulz, Walter: Möglichkeiten zur Verbesserung der Wasserpreisstruktur in der Bundesrepublik Deutschland. 130 Seiten, 1976.
ISBN: 3-486-20601-X.

Band 19 Wohlgemuth, Rolf: Die volkswirtschaftliche Beurteilung des Recycling am Beispiel der Abwärmenutzung für die Fernwärmeversorgung. 325 Seiten, 1975.
ISBN: 3-486-20151-4.

Band 18 Mönig, Walter: Determinanten des Elektrizitätsangebots und volkswirtschaftliche Kriterien zu seiner Beurteilung. 297 Seiten, 1975.
ISBN: 3-486-20141-7.

Band 17 Schulz, Walter: Ökonomische Probleme der Politik der Erdölkonservierung in den USA. 389 Seiten, 1972.
ISBN: 3-486-39081-3.

Band 16 Wallmann, Karl-Gerhard: Wirtschaftliche Methoden der Investitionsplanung einschließlich Standortplanung in der mineralölverarbeitenden Industrie. 279 Seiten, 1969.

Band 15 Derichs, Hans: Die Problematik der Produktivitätsmessung von Wirtschaftssektoren. 140 Seiten, 1969.

Band 14 Lindenlaub, Jürgen: Energieimpulse und regionale Wachstumsdifferenzierung. 231 Seiten, 1968.

Band 13 Michaelis, Hans: Atomenergie heute. 74 Seiten, 1966.

Band 12 Marcus, Peter: Der ökonomische Inhalt der linearen Planungsrechnung, dargestellt an Beispielen aus der Energiewirtschaft. 195 Seiten, 1966.

Band 11 Wessels, Theodor: Die volkswirtschaftliche Bedeutung der Energiekosten. 78 Seiten, 1966.

Band 10 Gilsbach, Albert: Die Konzeption der französischen Energiepolitik. 234 Seiten, 1965.

Band 9 Fischer, Klaus-Dieter: Struktur und Beeinflussungsfaktoren der Stromerzeugungskosten in Kernkraftwerken. 168 Seiten, 1964.

Band 8 Weber, Egon: Die Gaserzeugung aus Mineralölprodukten als Entwicklungsproblem der deutschen Ortsgaswirtschaft. 200 Seiten, 1964.

Band 7 Böke, Ernst: Die fiskalische Belastung der Energieträger. 203 Seiten, 1963.

Band 6 Otto, Gerhard: Die Abschreibung in der Elektrizitätswirtschaft. 186 Seiten, 1963.

Band 5 Rumler, Franz-Josef: Wirtschaftliche Probleme bei der Aufstellung von Energiebilanzen bei der Vorausschätzung des künftigen Energiebedarfs. 159 Seiten, 1960.

Band 4 Bergmann, Kurt: Unternehmensformen in der kommunalen Energieversorgung. 185 Seiten, 1957.

Band 3 Plett, Hans: Ökonomische Nachfrageuntersuchung in der Energiewirtschaft. Möglichkeiten und Grenzen. Mit Beispielen und Anwendungen. 206 Seiten, 1954.

Band 2 Schmitz, Wilfried: Das Recht der Energiewirtschaft im Ausland (Westeuropa). 277 Seiten, 1953.

Band 1 Didden, Rolf: Konzessionsabgaben der Energie- und Wasserversorgungsunternehmen. 425 Seiten, 1952.