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Fundamental modeling approaches and case studies assuming perfect competition

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Preface

This book is the final result of many years of intensive learning, hard work and many walks into dead ends. It is the tip of an iceberg that has been built during the last years. I struggled through periods of constant frustration, accompanied by endless mulling over different ideas and exhausting discussions. Despite all that, I consider the work on this thesis as an invaluable experience. A researcher never stops thinking. And he or she needs to embrace this state of mind. Otherwise, the work most probably does not deliver any significant added value. Research for me turned out to be a constantly ongoing process, rather than a task that can be finished at some point. This process is fired by two important ingredients; curiosity and criticality. My guiding motivation has always been to reveal truths. Truths that are not simply opinions and that can be verified by means of real observations. It is one of the most valuable insights of this work that such truths, first, in nearly all cases are linked to a certain perspective and, second, that the level of understanding that is required to unveil them is far from what many people are willing to achieve. A very useful skill that I acquired through this work is to utilize modern algorithms and computational power in order to derive quantitative insights into problems that otherwise cannot be satisfactorily answered. However, probably the most valuable skill is that I learned to ask the right questions. Pablo Picasso once stated, “Computers are useless. They can only give you answers”.

In the course of my research activities many people guided, motivated and supported me. Every idea grows in a certain environment and has multiple parents. In the following, I want to thank with deep gratitude my faithful companions for their support.

First, I want to thank Christoph Graf and Daniel Huppmann, who intensively supported my research activities via content-wise input, their professional experience and feedback whenever they had a free minute. I greatly thank Gerhard Totschnig, from whom I learned a lot and who inspired me in many ways. He lent an ear to me whenever I needed his advice and passionately worked together with me also during tough times. Big thanks go to my boss Gustav Resch who trusted in me from the very beginning, supported me wherever he could and who gave me with great indulgence the freedom I needed in order to finish this thesis. I am also very thankful for the support of Sebastian Busch and Michael Hartner that accompanied me on my path from the very beginning and who enriched my thinking in many different ways. Also I would like to thank my other colleagues from the EEG and e-think who created an incredible well working environment that is characterized by intense cooperation, collaborative working, mutual motivation and friendships. In particular, I want to thank my good friend Raphael Bointner, who was an exceptional person that showed me how to live with passion and pride. Six years ago, he was the one who smiled at me, knocked me on the shoulder and said: “You can and you should do it!”, with regard to my question whether I should start writing a thesis. I also thank our senior researchers Hans Auer, Lukas Kranzl and Reinhard Haas for their great support throughout my work. A very important source of inspiration and substantial content-wise input for my work was Christian von Hirschhausen and his team at Technical University of Berlin and the German Institute of Economic Research. I am very thankful for their guidance and support. A big thanks goes to my examiners Audun Botterud and David Wozabal, who took the effort to review this thesis. Last, but surely not least, I would like to express my deepest thanks to my family that actually provided me the opportunity to be in a position to write a thesis at all. In particular, my beloved Sara was there for me in every second and supported my work wherever she could.

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Abstract

In the European context the term electricity balancing market refers in its general form to all activities of transmission system operators related to their obligation to ensure an efficient and reliable real-time settlement of active power imbalances in their networks. In many countries, the concrete implementation of these activities historically evolved around the specific characteristics of system imbalances and the type of available generation facilities in their national power systems. Therefore, a great variety in the design and organization of balancing mechanisms and markets across Europe exists today. For that reason, there are no standard methods available for the quantitative analysis of this particular market segment. On the basis of three case studies it is shown how suitable optimization models can be designed, parametrized and evaluated in order to enable the fundamental economic analysis of electricity balancing markets across Europe. Each of the case studies serves to answer a distinct set of specific research questions that together lead to an overall understanding of the fundamentals of these markets. In that way this thesis contributes to the existing literature in several ways. First, a novel modeling approach is presented that is able to determine competitive equilibrium prices and quantities for the simultaneous clearing of electricity spot markets and auctions for reserve capacity. The main innovation of this approach lies in the fact that it is able to incorporate non-convex features of electricity generation, e.g. minimum stable output or start-up costs. Second, based on the findings of the previous chapter, a large-scale optimization model is applied to the case of Austria with the objective to explore to which extent historical market prices in the Austrian balancing market can be explained by means of perfect competition. A considerable gap between modeled and actual prices supports the conclusion that among other factors collusive behavior of market participants might have played an important role. Third, synthetic high frequency forecast error time series are developed and fitted into a European electricity market model to assess how relevant electricity balancing markets might get in the 2030 time frame. It is argued that although these markets might remain niche markets, revenue streams from electricity balancing could gain importance for certain technologies. The presented modeling approaches in this thesis can be applied to wide range of questions related to the functioning of short-term electricity markets under the assumption of perfect competition.

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Chapter 1

Introduction

1.1. Evolvement of electricity markets in Europe

In the 19th century the electricity industry was created in the United States and the United Kingdom in the form of the provision of public street lighting. From the very beginning local authorities played a crucial role for the provision of such services. Several central power station companies emerged, each striving to get their share in the promising new business field. After a period of fierce competition, overlapping distribution lines and thus extensive costs it became the general opinion that due to the infrastructure involved, this business had to be considered as a *natural monopoly*. Consequently, regional licenses were issued that guaranteed a certain vertically integrated utility the exclusive right to supply electricity to residential, industrial and commercial costumers in a defined geographic region. Over the course of the 20th century electricity emerged as one of the most important energy sources across the world. It is therefore not surprising that the electricity industry became of great strategic and economic importance for many governments. These interests manifested itself in the form of intense regulations and/or government ownership of the industry. Since generation technologies used at that time showed great economics of scale, large generators were placed at strategic locations — e.g. large-scale hydro reservoirs, or coal plants near big mines — and a high-voltage transmission grid had been developed in order to transport electricity to the load centers. Soon it became clear that such connections were also useful in order to increase supply security, because the transmission grid served as *safety grid* that counterbalanced unplanned generator outages. In order to benefit even more from increased supply security through larger grids the *Union for the Coordination of Production and Transmission of Electricity* (UCPTE) was established in Europe in 1951. Initially, founded by a small number of interconnected firms at the interface of Germany, Switzerland and France this cooperation was rapidly enlarged to ensure the synchronous operation of the Continental European power grid. In the same period electric utilities were already well established across Europe. However, decisions in these companies were merely driven by a "engineering-perspective" and political interests. The results were high operating costs motivated by an exaggerated focus on security of supply, cost overruns of new facilities and costly programs enforced by political pressure. Altogether, these developments led to high retail prices, which in turn gave rise to increasing public pressure for an industry change. At this time, the size and volume of international cross-border flows were comparatively small. However, the sheer existence of a strong transmission grid across Europe made a deintegration and thus the introduction of trade across countries in principle a possibility. This together with the emergence of competitive small-scale technologies like the combined cycle gas turbines (CCGT) plants laid the ground for the intension to restructure the whole electricity industry by means of introducing competition on the basis of an EU-wide internal electricity market. The most prominent and radical electricity sector reforms in Europe took place in the UK (1989) and in Norway (1992).

Reforms in Chile and Argentina that had already been carried out in the 1980s proved that competition in the electricity sector was possible in principle. Other reforms of infrastructure-bound industries like Telecom reforms in the UK serve as an example for how to introduce competition. In 1988 the European Commission announced their strategic aim of reaching the *The Internal Energy Market* in gas and electricity for the first time[1]. These considerations led to the enactment of the European Commissions Directive 96/92/EC "Directive for a common electricity market". In this directive the Commission claimed a separation of ownership of the transmission grid and the generation and supply part of before vertically integrated utilities. This directive was part of the so-called "First-Energy-Package" that was followed by a "Second-Energy-Package" in the year 2007. Therein, it was stated that National Energy Regulators should be established, whose main tasks were to open the supply side as well as the retail sector for competition, to guarantee third party access to the market and grids and to regulate national Transmission System Operators (TSOs) on the basis of a cost-plus approach. Finally, in the framework of the "Third-Energy-Package"[2] containing a number of additional directives concerning the electricity and the gas sector were published in the year 2007.

The Third Energy package were the first common European policy framework forming the basis to reach the strategic goals of the European Union. The directives in this package stimulated the creation of truly European institutions, e.g. the further development of UCTE into ENTSO-E, the cooperation of transmission system operators with the clear objective to help enabling the EU internal electricity market and ACER the umbrella association containing all national energy regulatory authorities. The overarching goal was to lay the ground for the EU internal electricity market. After intense negotiations an electricity market target model have been developed that was based on the principle of a EU-wide wholesale electricity market on which energy should be traded on basis of variable generation costs. Whereas the potential for market failures stemming from the nature of electricity in general and its economic consequences have already been considered at that time, the overwhelming change the large-scale integration of renewable electricity into markets would bring about, have still not been anticipated. Another pillar of the agreed target model was the implicit allocation of available cross-border capacity within the market-clearing process in order to facilitate international trade.

With regard to the provision of ancillary services[3] the electricity directives required also a switch to market-based instruments. It has been claimed that the transmission system operators should maintain system stability through the market-based procurement and subsequent activation of reserve capacity. TSOs should automatically and manually activate these capacities in a way to balance short-term deviations of actual generation and load from market schedules and load profiles. The corresponding procurements are nowadays typically organized as one-sided multi-dimensional auctions, whereas the actual auction de-

[1] Commission's white paper on The Internal Energy Market

[2] `https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition`

[3] This terminology refers according to ENTSO-E to " ... a range of functions which TSOs contract so that they can guarantee system security. These include black start capability (the ability to restart a grid following a blackout); frequency response (to maintain system frequency with automatic and very fast responses); fast reserve (which can provide additional energy when needed); the provision of reactive power and various other services."

sign significantly varies across European countries. Recently, ENTSO-E drafted a *Network Code on Electricity Balancing* (EB) ENTSO-E (2017) containing guidelines to which national electricity balancing markets across EU member states need to comply with. The EB is one out of eight network codes compiled in the course of ongoing electricity market reforms with the aim to realize the EU internal electricity market. The envisaged vision in that respect is to provide a credible real-time electricity price reflecting the real value of short-term flexibility provision across the EU. In its newest set of legal proposals called the "Energy Union Winter Package" the European Commission emphasizes the importance that prices should "... reflect the real value of electricity in time and location (scarcity pricing) in order to drive investments towards the flexible assets most needed for the system, including demand-response and storage EC (2017b)."

In the above mentioned context two things become apparent. First, the European Commission is currently advocating the transfer of as much coordination tasks as possible concerning the functioning of the energy industry from regulated central planning towards markets. Second, in its newest legal proposals the European Commission seems to emphasize the importance of credible real-time electricity prices as ultimate coordination instrument for an efficient functioning of the integrated electricity market of the European Union. This emphasizes the perceived relevance of short-term electricity markets in Europe.

Energy policies in the European Union are multi-faceted. Electricity markets are both regulated on the national and the European level. Each member state has individual preferences of their generation mix and the most suitable market design related to that mix, as well as the applied policy instruments to support and to regulate renewable energy and renewable electricity in particular. As a result, in the European Union many different diverging and converging market design and regulatory trends emerge in parallel. Sometimes they contradict, sometimes they complement each other. The European Commission is strongly pushing for centralization of decision making and strives for the implementation a truly integrated market that fosters competition and therefore maximizes efficiency across Europe. This approach, however, neglects economic arguments in favor of decentralization and political-economic hurdles against the transfer of power to supranational bodies.

To this day, no definitive answer to the question what regulatory framework, nor what market design elements might be best suitable to efficiently and effectively reach the strategic long-term goals of the European Union can be given. For example, the question about the future importance of centralized generation combined with super grids versus decentralized generation embedded in smart grids is still subject to intense discussions. Another unresolved question is whether in a future world with lots of generation with nearly zero marginal generation costs the coordination of generation dispatch can still be carried out by energy-only markets or whether this task need to be performed by centralized system operation. In particular, it is unclear if the currently intended market design target model is able to generate market prices that truly reflects the value of all products that will be requested in the future. Is is also subject to intense discussions, whether demand for capacity can intrinsically be valued via energy-only pricing and how exactly the trade-off between the level of supply security versus an efficient generation stock can be efficiently coordinated through market-based instruments. Also "non-physical" values like own generation, ownership of generation and transmission facilities and more holistic individual consumer solutions will gain importance in the future. In this respect the consumer values will get multidimensional and the historical business model of selling energy content will have to change towards the sale of services and tailored product-bundles. Against this background it is far from clear what product-bundles will be valued the most in the future and how current wholesale and retail structures are suitable to capture these values in the form of prices. The modest goal of the present work is to add a small piece of knowledge to above-mentioned issues through picking out one distinct element of todays market framework and to study the potential relevance of this segment in the future.

1.2. Marketing opportunities for electricity

In order to classify the field of research comprehensive overview of the existing electricity market framework in Europe is provided, containing all its components and relevant inter-linkages to lay the background for the subsequent analysis.

Figure 1.1 shows the available marketing opportunities of electricity as existing in most European countries. Basically, each entity that constitutes or are at least part of any approved balancing group and which fulfills the regulatory preconditions to be a recognized trading partner of any exchange related to the corresponding market area can in principle use all the shown opportunities to trade his or her open positions. The majority of market participants consist of energy companies that have their own generation portfolios, a certain costumer base and who want to sell and buy electricity most profitably. A smaller but growing fraction of market players are trading companies and large-scale consumers or aggregators. Each company have three distinct options to trade. The vast majority of trades falls into the category of electricity wholesale markets. Trades in these markets are organized bilaterally on *Over-The-Counter* (OTC) platforms that offer options for individualized products and on recognized power exchanges with standardized products. In both segments trading options range from long-term to short-term time frames ahead of physical delivery. The greater percentage of trading volumes are related to long-term trading of derivatives, which are typically financially cleared. The smaller, but increasing fraction of volumes are traded in short-term or spot markets, respectively. Due to its short time frames trades in spot markets are merely cleared by physical delivery. The second main option that is gaining more and more relevance is to directly reach out in contracting a pool of costumers on the retail level. In this market segment the own consumption, storing and sale of surplus electricity from decentralized generation becomes an increasingly attractive business model for many consumers across Europe. In the light of new technologies like *Blockchains* bilateral trade becomes at least a technical possibility, even though many regulatory and legal aspects of such trading are still undetermined. Finally, through public auctions a number of additional services are requested. On the one hand these are all kind of ancillary services related to the safe operation and maintenance of power grids that are typically procured by transmission grid operators on a regular basis. On the other hand, a couple of countries are conducting dedicated auctions for the provision of generating and/or load-shedding capacity that are arranged in order to ensure an adequate level of system adequacy, that otherwise could not be achieved with the reliance on energy-only markets alone — at least from the perspective of national regulators and policy makers. In order to study a specific market segment one have to be aware about interlinkages that exist with other market segments. Most interlinkages are based on arbitrage opportunities between alternative marketing options. Others are based on the underlying mechanisms that are implemented.

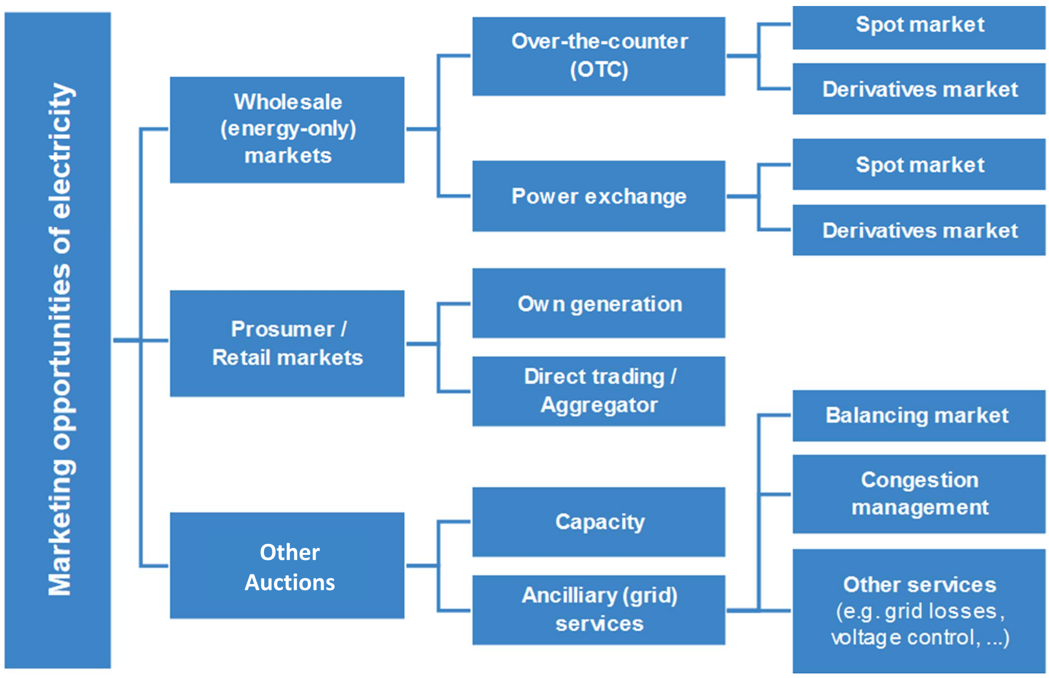


Figure 1.1.: Trading opportunities in liberalized electricity markets.

1.3. Motivation and contribution of this work

1.3.1. Methodology-wise research motivation

In the process of introducing competition in electricity industries across the globe different approaches were followed, cf. Barroso (2005), IEA-RETD (2016). These approaches essentially differ with regard to whether coordination of supply, demand and transmission is taking place on a central or on a decentralized level. Another distinction is the granularity of pricing zones within a certain power system. Whereas in most jurisdictions long-term coordination mainly relies on market prices, for short-term coordination different designs have been implemented ranging from *self-dispatch* systems relying on fully decentralized markets to *central dispatch* solutions where one distinct entity manages the dispatch of resources.

In **central dispatch** systems large-scale mixed-integer optimization models are solved by Independent System Operators (ISOs). Electricity suppliers submit multi-part bids containing their detailed cost structure (including start-up and ramping costs, etc.) and production capabilities (e.g. minimum load, etc...) of each generating or consumption unit to the ISO. The ISO integrates this data into her model and apply a multi-part, discriminatory pricing mechanism. Such mechanisms typically include next to a non-discriminatory uniform price additional unit-specific side-payments. Those payments are derived from the optimal solution of the respective model runs.

In contrast, **self-dispatch** systems use organized power exchanges to determine market prices. Power exchanges receive bidding curves from buyers and sellers of electricity and run a complex market clearing algorithm to match supply and demand under a number of additional constraints (e.g. no-loss requirement). The common practice in power exchanges is to avoid additional compensation payments totally and to derive non-discriminatory linear market prices.

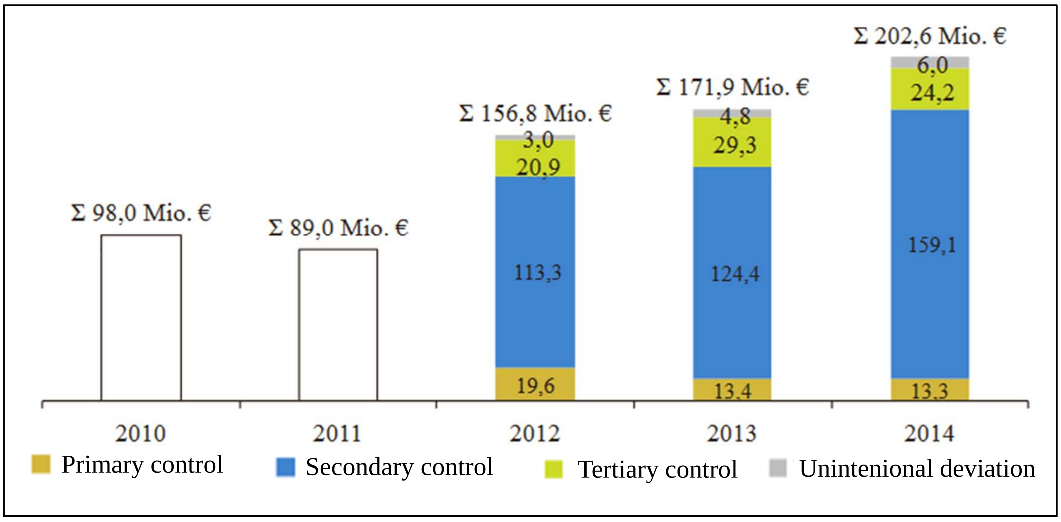
Both approaches put different emphasis on the trade-off between tighter coordination of supply, demand and transmission versus a greater reliance on markets. In order to study the behavior of electricity markets often least-cost or welfare maximization optimization algorithms are used to mimic the outcome of power exchanges, cf. Frontier Economics (2016), Hirth (2016), Kallabis et al. (2016) and Everts et al. (2016).

In these approaches the optimal dual variables related to the market-clearing equations serve as a proxy for market prices. It has been shown that this procedure is only valid in case of convex problem formulations (e.g. Hogan and Ring (2003), O'Neill et al. (2005), Van Vyve and others (2011)). In large-scale market analysis like e.g. the analysis of the day-ahead spot market of the Central West Europe (CWE) region this assumption is reasonably justified, (e.g. Starr (1969). However, in smaller markets, e.g. the Austrian balancing market with less participants and thus a much lower granularity, the non-convex characteristics of bids cannot be neglected anymore. Examples of such cases are electricity balancing reserve auctions in European countries. In these auctions often only national players are eligible and thus only a small number of participants compete for an exogenously given amount of capacity demand (typically 5% of peak load). Since in such auctions resources are procured that are required to be dispatched on a very short timescale the detailed consideration of technical production capabilities is a prerequisite to derive accurate model results. In this case the question arises how exchange-based market prices can be derived without having bidding curves. There is still only a limited amount of research tackling this issue. The first part of this work is therefore dedicated to an in-depth research of suitable modeling frameworks for the analysis of exchange-based markets including non-convex preferences of players. The main contribution of this part to the literature is to apply a novel modeling approach in order to derive market prices that constitute a competitive equilibrium in short-term electricity markets with non-convex preferences.

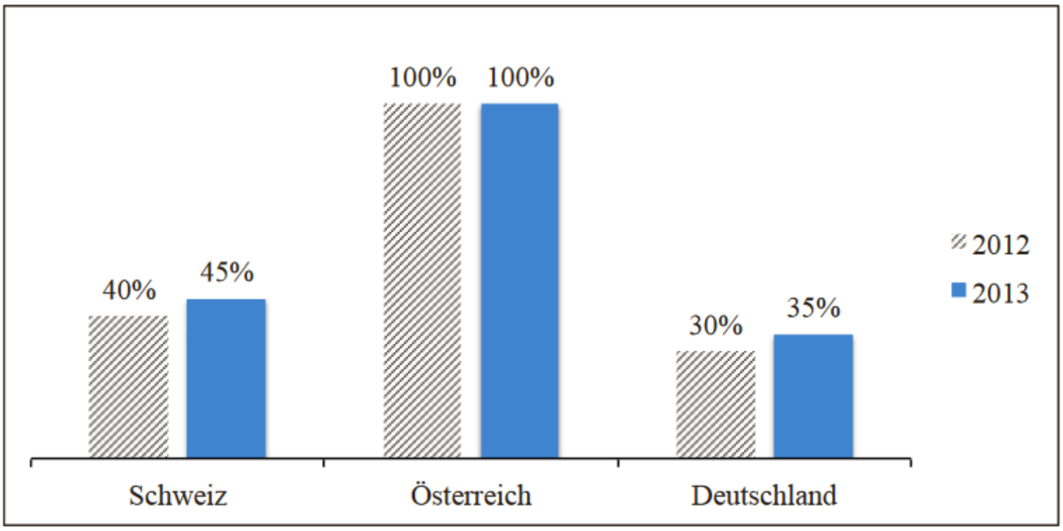
1.3.2. Content-wise research motivation

In Austria auctions for balancing reserve capacity have been introduced in the year 2012. This initiative has been in-line with other efforts of EU member states to realize the EU internal electricity market and thus to perform an increasing number of coordination tasks by the use of market-based instruments. However, the transition from regulated activities towards well-functioning markets has proven to be difficult and showed different levels of success in different countries. One essential success criteria of well-functioning markets is the level of competition. In the beginning of electricity sector liberalization the focus of analysts have been laid on studies concerning the competitiveness of day-ahead wholesale markets across Europe. Due to its high market concentration, the German electricity wholesale market experience a large number of sector inquiries. In 2001 the European Commission published their first benchmarking report on the implementation of the internal electricity and gas market (EC, 2001). The German Federal Cartel Office investigated the sector in 2011, Office Federal Cartel (2011). A number of distinct studies focused on the role of market power in the German electricity wholesale markets (cf. (Hirschhausen et al., 2007), (Lang, 2006), or (Müsgens, 2006)).

All this studies aimed to derive a competitive benchmark in order to assess deviations from this benchmark and thus to conclude on potential abuse of market power. In the recent literature, other German short-term market segments like the balancing market have been studied with a focus on the level of competition. On the contrary, so far there are only a handful studies focusing on the Austrian balancing market. Figure 1.2a and 1.2b show two indicative comparisons of total costs related to the Austrian balancing market. Figure 1.2a illustrate the historical development of total costs in the Austrian balancing market before (transparent blocks) and after (colored bars) the introduction of market-based procurement of reserves needed for balancing. Between both periods an abrupt increase followed by a constant rise of costs can be observed. Since during that period also a considerable amount of additional capacities from renewable electricity has been added within Central Europe, this increase might partly be explained by a rising demand. Furthermore, a comparison of total costs of Austria compared to the ones occurred in neighboring countries in the same period showed a considerable discrepancy. Figure 1.2b illustrates total costs of balancing one unit of system imbalance in Austria related to the neighboring countries Germany and Switzerland in 2012 and 2013. Although the respective market designs in parts differ significantly a comparison is still meaningful, because comparable services are offered and all costs to provide this services are included in the data. Therefore, remaining differences might be explained by a distinct stock of available technologies and corresponding cost structure on part of the supply-side, different calling frequency of reserves and diverse distributions of welfare stemming from different auction designs. This qualifies the Austrian market to be of interest for a deeper investigation. Therefore, the second part of this work is dedicated to the aim of deriving competitive benchmark prices in the Austrian electricity balancing market. The main contribution of this part to the literature is that to the best of the author's knowledge no such a fundamental analysis have been carried out before.



(a) Development of total costs for balancing in Austria.



(b) International comparison of normalized (EUR/MWh) total costs related to Austria for the years 2012 and 2013.

Figure 1.2.: Total costs in the Austrian electricity balancing mechanism. Source: Neubarth (2014)

1.3.3. Future importance of short-term electricity markets

In recent years the major power exchanges across Europe experienced increasing trading volumes. In particular, short-term markets gained increasing relevance. Figure 1.3 show the development of exchange-traded electricity volumes related to gross electricity consumption for three big market areas in Europe. It is apparent that short-term markets became more liquid over time. In particular, the share of day-ahead trading (DA) considerably increased in all shown market areas and covered already approximately 40 percent of gross electricity consumption in the German-Austria market area. The same development can be observed for intra-day markets as well, however, a bit less pronounced. Finally, the amount of control area specific imbalances varied over time in all market areas. We can conclude that in major market areas across Europe short-term markets became more important over time.

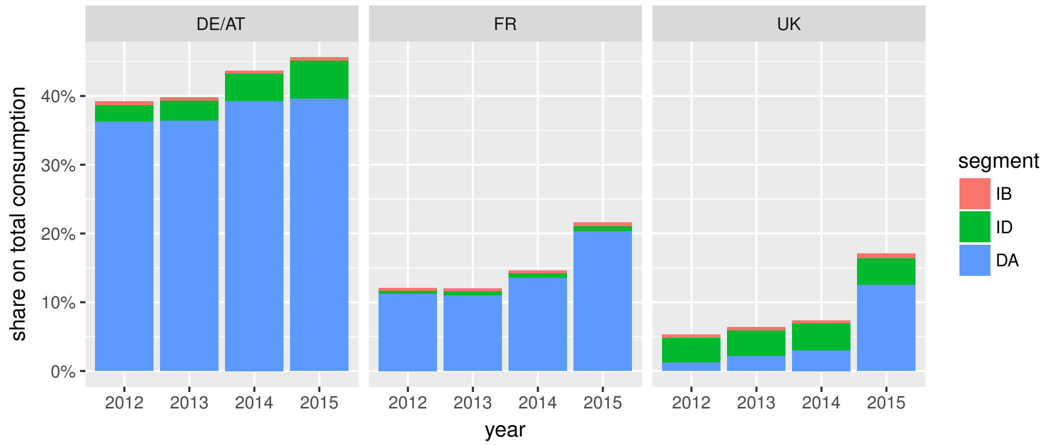


Figure 1.3.: Share of short-term market segments (DA: day-ahead, ID: intra-day, IB: control zone imbalances) on gross electricity consumption. Source: EPEX and APX annual reports, ENTSO-E transparency platform[4]

One reason for this development is the ongoing integration of increasing shares of variable renewable electricity (vRES), e.g. like wind and photovoltaics, into grids and markets across Europe. Due to the stochastic nature of the primary energy carrier of these technologies, they feature electricity generation time profiles that are very distinct from conventional electricity consumption profiles with regard to their variability and predictability. Consequently, the need for more short-term oriented marketing strategies and respective products arose. In order to get basic insights into whether this statement is true or not, in Figure 1.4 the share of exchange-traded volumes related to overall consumption has been plotted against the share of variable renewable electricity related to overall consumption. Indeed, it can be observed that day-ahead market volumes increased together with increasing shares of renewable electricity. Whereas this is in particular true for the market areas France and United Kingdom with lower shares of vRES, in the German-Austrian market area, which is already characterized by a higher penetration of vRES, the importance of intra-day markets are increasing. In case of imbalances the link to vRES shares is not obvious. This is because the volume of imbalances is impacted by a number of opposing trends.

Historically decreasing volumes of imbalances are mainly caused by the merge of smaller control areas into bigger ones; the so-called *imbalance-netting* process, cf. (Nussbaummüller, 2016). For example, the fusion of the previous four German and adjacent control zones in the course of the international grid control cooperation (IGCC) led from end of 2011 to mid of 2014 to cost savings in the range of 100 million Euro[5]. These savings were a result of reduced imbalances due to netting effects within larger control areas. On the contrary, the increasing share of vRES inevitably causes a need for short-term schedule adjustments due to the limited predictability of actual generation over longer time frames. This explains the increasing importance of intra-day markets in the German-Austria market area. However, the remainder of forecast errors that cannot be traded on continuous spot markets materializes in the form of one component that adds up to the overall system imbalance and thus might increase volumes.

Which of these trends will dominate is subject to great uncertainty, because on the one hand international imbalance cooperations are constantly enlarged and on the other hand the absolute amount and type of vRES required in the long-term is also uncertain with regard to progress made on part of energy efficiency measures and other important framework conditions. Finally, the relevance of the balancing market as a whole in terms of financial volume depends on market prices as well. In this respect, it is important to consider ongoing efforts of TSOs within Europe to couple their national markets and in doing so to provide balancing resources across national borders. This market coupling is supposed to lead to a convergence of prices across coupled regions. However, due to the high complexity of the operation of balancing markets the process of harmonizing market designs and integrating different technical systems into each other has proven to be very difficult and is thus very time consuming. Therefore, it is subject to uncertainty how much progress can be made with regard to a European-wide market coupling of balancing markets. Only a few studies have been carried out so far that assess potential benefits from such cooperations. The European Commission launched a study to assess the impact of a European balancing market (MacDonald, 2013). Several approaches had been applied in order to study different models for market coupling. The authors based their findings mainly on historical bid data. A number of studies that assess benefits of market integration for selected regions within Europe. Clemens Gerbaulet et al. (2014) study the so-called ALPINA region Germany, Austria and Switzerland. Farahmand et al. (2012) and Veen et al. (2011) perform case studies assessing the market integration of Germany and the Nordic countries. Gebrekiros et al. (2013) presents a suitable model framework to assess benefits from cooperation. The findings are only based on a small example.

All these studies based their findings either on the calibration of their models to his-

[4] `https://www.epexspot.com/en/extras/download-center/activity_reports`, `https://transparency.entsoe.eu/`

[5] TransNet BW Press Release: "International Grid Control Cooperation (IGCC) increases quality in operation and brings benefits on energy and monetary level", June 26th 2014

[6] `https://www.epexspot.com/en/extras/download-center/activity_reports`, `http://www.green-x.at/`

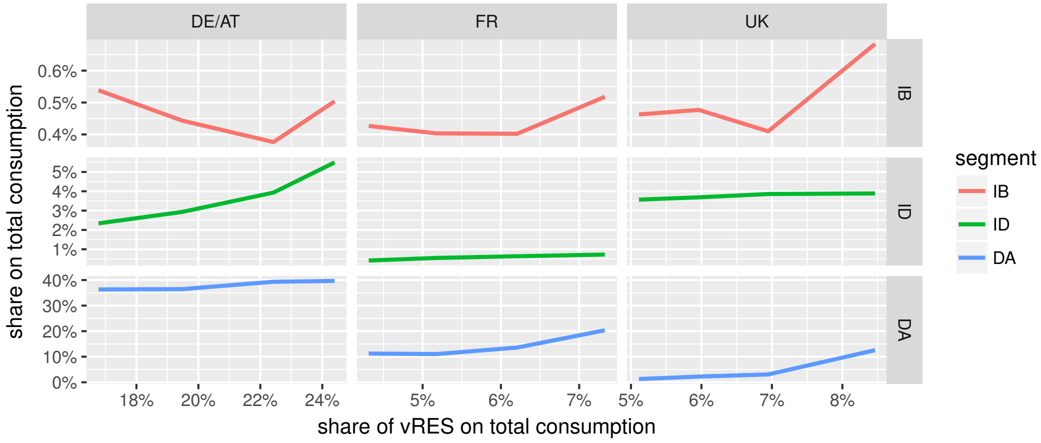


Figure 1.4.: Share of different short-term market segments (DA: day-ahead, ID: intra-day, IB: control zone imbalances) on gross electricity consumption subject to share of vRES on gross electricity consumption. Source: EPEX annual reports, Green-X[6]

torical data and/or only considered cooperation benefits arising from cross-border capacity reserve provision and do neglect how much savings could arise through imbalance netting. The European Commission performed in their impact assessment of the winter package a comprehensive market modeling including balancing markets. However, from the publicly available documentation of the work carried out (EC, 2017a) it is not exactly clear what methodology and which assumptions have been used in detail in order to derive the results. To the best of the author's knowledge all studies do not consider a detailed bottom-up modeling of future demand of balancing energy that is impacted by afore-mentioned opposing trends. In the third part of this work a similar method as shown in Garcia and Kirschen (2006) is applied in order to derive the future amount of system imbalances in all European Member States. Based on this demand a comprehensive modeling framework is used to assess the future relevance of balancing markets in the light of changing framework conditions. The results of this analysis contribute to the ongoing debate about interactions of RES policy and electricity market design, the efficiency gains of market integration of short-term electricity markets and provide next to the impact assessment accompanying the EU winter package another estimate on the future value of flexibility and its importance for revenues of different supply technologies within European countries.

1.4. Objectives, research questions and applied methodologies

The overall objective guiding this thesis is to reveal fundamental drivers of electricity balancing markets and to show how such drivers can be formally captured and arranged in a way to derive competitive market prices. To this end, first, a suitable methodology is identified and evaluated. Based on this methodology it is shown on a real-world example how competitive prices can be derived to benchmark actual prices in these market segment. Finally, in the light of rapidly changing framework conditions in the electricity sector it is shown via the application of the same methodology how balancing markets might be impacted in the period up to 2030.

The topical scope of this thesis is the analysis of short-term electricity markets operated on organized power exchanges like the European Power Exchange *EPEX Spot SA*.[7] as well as auctions conducted by national transmission system operators in the course of managing their electricity balancing activities. Both market segments seem very relevant with regard to the large-scale integration of variable renewable electricity into markets and grids across Europe. The geographical scope of this thesis is laid on the countries of the European Union and Austria in particular. The case studies of this work focus on the years 2014/15 and 2030, respectively. A detailed description of the approach followed in this thesis and the corresponding specific objectives and methodologies is given in the following.

In order to quantitatively study short-term electricity markets an understanding of how these markets can be adequately modeled, considering all relevant interactions and special characteristics had to be developed. In the literature there are currently no convincing approaches on how to model equilibrium prices in the European market context, in particular with respect to non-divisible output of electricity generators and considering that start-up costs need to be remunerated via market prices. To this end, it is first of interest to answer the question

- What conditions constitute competitive energy and capacity prices for balancing reserves in exchange-based electricity markets?

In this thesis these conditions are derived from a sound mathematical formulation of the problem at hand and serve as a basis to develop suitable modeling approaches capturing the particular characteristics of electricity balancing markets. The method chosen in this thesis in order to derive such prices is the design and application of optimization and equilibrium models. In particular, a mathematical program with equilibrium constraints (MPEC) is presented that explicitly incorporates the conditions that constitute an equilibrium. Derived prices from this model reflect a market equilibrium in the economic sense and consider all relevant interlinkages to other markets like arbitrage opportunities, or regulatory requirements. A key innovation of this approach is that the model accounts for non-convexities stemming from technical features of the underlying generation technologies and indivisibilities of their energy production. In case no equilibrium exists the model delivers a feasible solution that minimizes the amount of additional discriminatory payments to generators, which are needed to compensate them for quantity constraints that deviate from their optimal decision.

This approach and MPEC problems in general are computationally very demanding and thus cannot be upscaled to large problems containing many variables and constraints. For that reason, it is of interest to what extent commonly used unit-commitment models can

[7] `https://www.epexspot.com/`

be used in order to derive prices and quantities that come close to the ones delivered by the MPEC model. Such models have the advantage that they can be efficiently solved. This implies that they can also be applied to solve large-scale problems with an extensive number of variables and constraints, i.e. to model the outcome of real-world markets. In order to derive quantitative insights into how much unit-commitment models deviate from the solution of the MPEC model a comparison of results is conducted. In the course of this comparison the following questions are answered:

- How can market prices be derived from classical unit-commitment models?
- How do the results of these models differ to modeled market equilibria with regard to
  - Deviation in prices
  - Deviation in dispatch and unit-commitment
  - Size of disequilibrium costs / compensation payments in case no equilibrium exists

The models that are part of the comparison are as follows. First, the above mentioned mathematical program with equilibrium constraints (MPEC) referred to as *Binary Equilibrium* approach is used to derived equilibrium prices that can be interpreted as prices from self-committed electricity markets. Second, a *Social Planner* model represents the commonly used unit-commitment model with binary variables — also referred to in the literature as *least-cost* approach — is applied to mimic the outcome of centrally-committed electricity markets. Finally, the *relaxed Social Planner* model is the same model as in the Social Planner approach, whereas the binary variables in this version are relaxed to continuous variables in between the range $[0, 1]$. Consequently, the resulting model is linear and can therefore be solved very fast.

All models have been calibrated with historical time series and the structure of the generation mix in Germany in the year 2012 in a stylized way. Based on hourly time series for the whole year, 8 average and 2 extreme days have been chosen for the model comparison in order to ensure a certain level of generality. It is shown that the *Social Planner* approach delivers results sufficiently close to the *Binary Equilibrium* approach. The *linearized Social Planner* approach proved to be not suitable in order to derive the prices of interest. The results of this research are also described in Ortner et al. (2017). The findings of this comparison serve to justify the development and application of large-scale unit-commitment models in order to simulate real-world markets in the subsequent chapters of this thesis.

The third chapter of this work is dedicated to the question what fundamental drivers of electricity balancing markets are and what competitive market prices might result from those drivers[8]. This research question is elaborated on the example of the Austrian electricity balancing market for the time frame of September 2014 to October 2015. Through the application of a Social-Planner modeling framework a benchmark for competitive market prices are derived. The simulation of markets as performed herein is based on the *efficiency*

[8]The work in this chapter is motivated by the historical market results of Austria and has been prepared in cooperation with the Austrian energy regulator

hypothesis, assuming perfect competition, no information asymmetries and no entry barriers. Furthermore, a dedicated aim of this part of the work is to explicitly consider the complex techno-economic constraints of the Austrian generation mix in a detailed manner. The results of this study are published in a report carried out for the Austrian energy market regulator E-Control Austria, cf. Ortner (2016).

The following research questions are answered with the modeling work carried out:

- What is a benchmark for competitive market prices in the Austrian electricity balancing market?

- How do different pricing strategies, the opportunity to build generation portfolios and fundamental hydrological constraints impact these prices?

A comparison of modeled total costs with historic costs in the considered time period showed that the actual cost of capacity reservation and energy calling exceeded the modeled costs by a factor of more than two. In particular, this large discrepancy could be traced back to a difference in prices for energy calling of secondary capacity reserves. Actual prices in this market segment were one order of magnitude higher than the modeled prices. The comparison of historic with modeled prices for the provision of capacity showed that actual prices could be explained very well through the model. This means that price formation has been built on fundamental data and incentives of profit maximizing actors under perfect competition. Based on these findings, the author concluded that among others the low level of competition might have impacted the deviation of model results from historical values and emphasized the need to increase efforts of national and international market opening in this particular market segment.

Finally, based on the findings what market drivers and competitive market prices would be in today's framework conditions the fourth chapter of this thesis focuses on the year 2030 to conclude on the future development of balancing markets in an European context. Due to the markable trends towards European integration of markets such a study necessarily has to include other relevant market areas as well in its analysis. The guiding question motivating this research is whether electricity balancing markets will gain considerably more importance in the context of an increasing share of variable renewable electricity (vRES) in the European generation mix or not. It can be argued that if additional generating capacity from vRES is installed the absolute amount of generation forecast errors will increase as well. The netted sum of these additional forecast errors might act as a significant factor increasing demand for electricity balancing. The first step in answering the research question in this chapter is therefore to derive short-term forecast error time series of generation and consumption for the year 2030. On the basis of these time series the first set of concrete subquestions to be answered is

- How much does demand for electricity balancing increase in selected European countries given reasonable expectations on the future development of forecast errors in these countries?

- What are the most important sources of balancing demand?
- How much do these independent sources counterbalance each other, i.e. how much lower is the resulting amount of system imbalances as compared to the overall sum of energy contents of forecast errors?

Forecast errors of variable renewable generation, as well as unplanned outages of conventional generators have been identified to be the main driver of balancing demand. The results showed that wind onshore accounts for the main source of balancing demand in many countries. The second most important source of balancing demand are consumption forecast errors. The remaining sources of balancing demand, e.g. unplanned generator outages, forecast errors of photovoltaics and wind offshore are in relation to overall consumption rather insignificant. The size of netting effects stemming from counterbalances of forecast errors and outages have shown to be in the range of -/+ 0.3 percent of gross electricity consumption.

These findings relate to the demand side of balancing markets. In order to fully answer the research questions of this chapter also the supply side and how balancing markets will be designed needs to be considered. The markets are coordinated by the transmission system operators. These operators increasingly coordinate their actions in order to increase the efficiency of balancing markets as a whole and to mitigate the potential rise of imbalances. On the one hand, this is achieved by transmitting the direction and amount of system imbalances in real-time to neighboring control zones. This type of real-time information helps to prevent opposing balancing calls by means of utilizing cross-border imbalance netting effects. On the other hand, national balancing markets are opened to international competition. In such settings the activation of cross-border calls are possible to the extent of free transmission capacity. The question of how electricity balancing markets might develop in the near future therefore necessarily needs to be answered by taking an integrated European perspective. Because at the time of writing it is still not clear to what extent cooperation activities will take place and who will cooperate with whom a scenario analysis is carried out including a variation of potential framework conditions. By also taking the supply side into consideration the following particular research questions are posed:

- How large is the overall monetary market volume of electricity balancing markets as compared to day-ahead markets in various European countries with high shares of variable renewable electricity?
- How is this volume impacted by different assumptions on the level of international cooperation?

The results showed that although the amount of balancing energy is expected to increase in the mid-term, electricity balancing markets will still lay in the range of a few percent of day-ahead market volumes.

Finally, even if the overall size of electricity balancing markets might be comparatively small, these markets could be important for certain types of generation technologies. Therefore, the last subquestion posed is:

- How significant are revenues from balancing markets for different generation technologies?

The results showed that in general variable renewable generators significantly profit from international market integration, whereas dispatchable generators might lose their dominant position in national markets.

Due to the European-wide balancing market that has been considered in this chapter, the impact of non-convexities on the model results is negligible. Therefore, in this case study the results were derived from an existing European electricity market model formulated as linear optimization model. In the course of this work, this model has been extended by a simplified representation of electricity balancing markets.

Parts of the work related to this thesis have been peer-reviewed and published. The most relevant publications are

- Ortner, A., Graf, C., Huppmann, D., 2017. Efficient electricity prices in liberalized electricity markets involving non-convexities, working paper, submitted to European Journal of Operations Research.

- Ortner, A., 2016. Modellbasierte Analyse des österreichischen Regelenergiemarktes, report prepared for the Austrian energy regulator E-Control, Vienna.

- Ortner, A., Graf, C., 2013. Multi-market unit-commitment and capacity reserve prices in systems with a large share of hydro power: A case study. In: 2013 10th International Conference on the European Energy Market (EEM). pp. 1–8.

- Ortner, A., Kruijer, T., 2014. Transmission grid representations in power system models. The trade-off between model accuracy and computational time, 37th IAEE International Conference, New York, USA.

1.5. Structure of this thesis

The above mentioned research topics are documented in three topical chapters. In chapter 2 the available modeling frameworks are discussed with regard to their suitability to derive equilibrium prices in markets with non-convex preferences. In chapter 3 one of these modeling frameworks is applied in order to answer the question to what extent historical prices in the Austrian balancing market can be explained by fundamental drivers. In chapter 4 the application of another suitable modeling framework is documented that were used in order to take a forward looking perspective and to assess the future relevance of different short-term electricity markets in selected European countries. Finally, chapter 5 gives a comprehensive answer to the posed research questions, discusses the findings and gives indications for future research directions.

Chapter 2

Equilibrium prices in markets with non-convexities

A comparison of linear, mixed-integer and game-theoretic modeling approaches

2.1. Nomenclature

Table 2.1.: Notation for the models applied in chapter 2.

Sets & Mappings	
$t \in T$	... time slices, hours
$i \in I$	... generators, power plant units
$z \in Z$	... set of dispatch options for each generator
$t \in T_z$	... hours in which a generator is active in dispatch option z
Primal variables	
x_i^B	... decision for generator i whether to participate in balancing market
x_{ti}^G	... on/off decision for generator i
$z_{ti}^{\text{on}}, z_{ti}^{\text{off}}$	... inter-temporal start-up/shut-down decision
g_{ti}	... actual generation by generator i in hour t
$g_{ti}^{(\mathbf{B})}$	... generation if participating in balancing market ($x_i^B = 1$)
$g_{ti}^{(\not\mathbf{B})}$	... optimal generation if participating in balancing market ($x_i^B = 0$)
$g_{ti}^{(\mathbf{1})}$	... generation if not participating in balancing market, but operating in hour t
b_i^+	... actual positive reserve capacity
b_i^-	... actual negative reserve capacity
$b_i^{+(\mathbf{B})}$	... positive reserve capacity if participating in reserve market
$b_i^{-(\mathbf{B})}$	... negative reserve capacity if participating in reserve market
d_t	... demand (load) in hour t
Dual variables	
$\alpha_{ti}^{(\mathbf{1})}, \beta_{ti}^{(\mathbf{1})}$	... dual to minimum activity/maximum generation capacity
$\alpha_{ti}^{(\mathbf{B})}, \beta_{ti}^{(\mathbf{B})}$	... dual to minimum activity/maximum generation capacity
$\lambda_i^{(\mathbf{B})}$	... dual to upper bound on positive reserve capacity
$\mu_i^{(\mathbf{B})}$	... dual to upper bound on negative reserve capacity
p_t^S	... spot market price
p_i^{B+}	... balancing market price for positive capacity
p_i^{B-}	... balancing market price for negative capacity
ν_t	... dual to maximum load constraint
Switch and compensation variables	
$\kappa_{ti}^{\text{on}}, \kappa_{ti}^{\text{off}}$	... switch value
ζ_i	... compensation payment
Parameters	
c_i^G	... linear generation costs
$c_i^{\text{on}}, c_i^{\text{off}}$	... start-up/shut-down costs
c_{zi}^D	... total start-up/shut-down costs in dispatch option z
c_i^B	... start-up/shut-down costs if participating in balancing market
g_i^{min}	... minimum activity level if power plant is online
g_i^{max}	... maximum generation capacity
x_i^{init}	... power plant status at start of model horizon ($t = 0$)
u_t^D	... utility of demand (or value of lost load)
d_t^{max}	... maximum load of unit j

2.2. Literature review

As many other products electricity is nowadays traded on organized exchanges, which were implemented in the course of liberalization of electricity industries all over the world. On the first sight electricity appears to be a perfectly homogeneous good and thus the well-established economic principle of marginal cost pricing seems to be adequate for valuation of electricity. This might be a reasonable assumption on a macro-scale level; however, when zooming into the details of supply and demand one observes indivisibilities in quantities (e.g. minimum and discrete levels of power output/consumption), non-convex generation costs (e.g. startup costs, lower part-load conversion efficiency) and intertemporal constraints (e.g. ramping limits, minimum-up/down times), which are inherent features of traditional electrical systems and thus making it difficult to derive prices from marginal costs (Scarf, 1994). Certainly, there is a trend of increasing flexibility both in supply and demand for the sake of efficiently integrating variable renewable power generation into markets and grids, but also renewable generation technologies exhibit to a certain extent some kind of aforementioned non-convexities.

2.2.1. Central- vs. self-dispatch market architectures

Many different approaches have been proposed to deal with markets involving non-convexities, e.g. (Hogan and Ring, 2003; Galiana et al., 2003; O'Neill et al., 2005; Sioshansi et al., 2008). The major implemented market models around the world mainly differ along the trade-off between implementing the efficient dispatch and unit commitment solution versus the proper provision of incentives to market participants for truthfully revealing their costs and utility, respectively (Sioshansi and Nicholson, 2011). The former one can mostly be found within America (e.g. PJM, NYISO, ERCOT, AESO, ...) and the latter has been dominantly implemented within European countries (e.g. EPEX, Nordpool, APX, ...). In market models striving for implementing the efficient solution typically an independent system operator (ISO) takes over the responsibility of determining which units are committed and how they are dispatched, we therefore refer to it as *central-dispatch* approach. The participation of all market players in the auctions is obligatory in this market model. The ISO receives detailed information on the cost structure of all units[1] and decide which units are to be operated based on a large-scale mixed-integer optimization model with endogenous representation of the feasible (non-convex) generation and consumption possibilities as well as system-security constraints (transmission limits, balancing capacity reserves)[2]. The ISO is also responsible for the real-time operation of the power grid. Thus, the algorithm determines the units that should provide balancing reserves as well.

In a subsequent step the ISO determines market prices. This task is not trivial, because

[1] In the past in many power systems consumers have not actively participated within markets, their demand has been forecasted and have been considered to be inelastic in the short-run. Nowadays, the integration of the demand side in markets is strongly facilitated in order to increase the flexibility of power systems

[2] In practice, due to computational limitations and time restrictions these models are frequently not solved to optimality and a certain optimality gap remains.

due to the prevalence of non-convexities there exists in general no uniform price vector supporting the announced production and consumption schedules in the sense of a Walrasian equilibrium — or equivalently a competitive equilibrium — that holds when marginal cost pricing is applied (Madrigal and Quintana, 2001)(Motto and Galiana, 2002). This means that any announced uniform price vector will leave some executed orders out-of-the-money and/or some rejected orders in-the-money.

In order to implement the efficient solution the ISO pays side-payments to market participants with the aim to make them at least indifferent between her best response (given the announced prices) and the least-cost generation or consumption schedule. It is important to mention that in this approach side-payments are calculated on the basis of the costs and utilities the market players initially delivered to the ISO. Oren and Ross (2005) show that market participants can have incentives to misstate their costs and utilities and thus increasing their profit in such market models. Some studies also suggest that incentive compatibility issues in these market models can be further exacerbated if the ISO are not able to solve the optimization model to optimality (Johnson et al., 1997)(Sioshansi et al., 2008). The literature focusing on central dispatch approaches that involve the provision of balancing reserves typically make use of the term *co-optimization* or *integrated modeling*, respectively, of energy and reserves or ancilliary services. Ma et al. (1999) proposes a LP-based joint dispatch model of simultaneous optimization of energy and reserve capacity while introducing trading across zones. Wu et al. (2004) presents a detailed AC optimal power flow formulation for simultaneous auctions energy and ancilliary services. The paper provides a detailed description on the pricing of multi-products based on Lagrange multipliers. Tan and Kirschen (2006) puts the focus on the effect of demand side participation on the costs of providing reserves. Vlachos and Biskas (2011) develop an innovative approach considering multi-area complex pricing schemes and explicitly consider bids from demand side units. In Chen et al. (2003) this approach is extended by the incorporation of grid security constraints. Cheung et al. (2000) and Gan and Litvinov (2003) study the effect of different market designs on the optimized dispatch of energy and reserves and incurred opportunity costs. Chen (2005) applies a hybrid direct search method in order to derive the optimal dispatch of generators subject to exogenous cost functions for energy and reserves. Zheng and Litvinov (2006) presents an ex-post pricing scheme of reserve providers based on the ex-post marginal opportunity costs of a co-optimized dispatch. Ehsani et al. (2009) extends the prior research by identifying the impact of composite system risks in the valuation of reserves. Azadani et al. (2010) offers a new approach based on constrained particle swarm optimization in order to evaluate the effect of non-smooth cost functions on the optimized dispatch.

2.2.2. Pricing of services in electricity balancing markets

When it comes to pricing of services and determination of corresponding side-payments derived from models where non-convexities are explicitly considered two main approaches are applied in the literature. The first is to increase the dimension of prices and switch to multi-part (non-linear) prices (Hotelling, 1938). Following these lines O'Neill et al. (2005)

proposes a two-step approach. In a first step the optimal commitment decisions are derived from a mixed-integer optimization model. In the second step these commitment decision variables are then fixed to its optimal values in additional model equations. O'Neill et al. (2005) shows that the optimal dual variables from the market-clearing equations and the additional fixing equations in the resulting linear model can be interpreted as market-clearing energy prices and necessary generator-specific side-payments, respectively. In Gabriel et al. (2012) this idea is elaborated and further proofs are provided for the possibility of introducing different levels of price discrimination among committed units. Sioshansi (2014) shows that this market model has some important implications for long-run capacity investment. The second approach proposed is to deviate from marginal-cost-pricing to a "second-best" market outcome, such that no player should lose money from participating (Baumol and Bradford, 1970), which was known under the term *make-whole* payments or *bid cost recovery* in the literature, e.g. (Sioshansi et al., 2008). The idea behind is that no market participant should lose money from executing the schedule announced by the ISO; any profits in turn are not collected from participants. Thus, the necessary compensation payments are calculated ex-post based on the submitted costs and utilities by market participants. It is not clear that any general conclusion can be made about whether or not make-whole payments correspond to equlibrium pricing (Fuller, 2010). However, this approach at least removes an obvious disequilibrium feature, namely negative profits.

In the other market model to which will be referred to in the following as *self-dispatch* approach the operational decision of any unit is a result of market outcomes. Market players have the option either to trade via customized long-term contracts, over-the-counter (OTC) or at dedicated power exchanges (PE). Electricity trade at exchanges is organized via sequential clearing of several markets, ranging from months-ahead until the so-called gate closure time, which is typically one hour before delivery. After gate closure the corresponding transmission system operator (TSO) takes over responsibility for the operation of the power grid. In this approach capacity reserves are procured by the TSO with long-term contracts. The TSO specifies the amount of capacity needed to keep the system balanced and host consecutive auctions, where both generators and consumers can participate. Currently, many different auction designs are implemented in existing markets. One distinctive feature of the designs is if bids have to be offered on a unit-base (e.g. France, Norway and Spain (ENTSO-E, 2016)) or if bids consisting of aggregated portfolios are eligible as well (e.g. Austria, Germany and Switzerland (ENTSO-E, 2016)). Recently, some grid operators have already begun to implement hybrid models of long-term contracts and short-term integration of bids after gate closure in order to increase the efficiency of balancing capacity reserve provision.

2.2.3. Modeling approaches

Whereas there is broad body of literature modeling central-dispatch approaches, self-dispatch implementations including balancing capacity reserve procurements have not been studied extensively. Richter (2012) lays some theoretical foundations on existence and uniqueness of equilibria in case of provision of positive spinning capacity reserves. Sioshansi and Nicholson

(2011) presents a stylized symmetric duopoly model to examine equilibrium behavior, pricing, and settlement costs in centrally and self-committed electricity markets. In Just and Weber (2008) an iterative linear solution procedure is used to estimate the dispatch decision of thermal units and to derive auction prices for positive reserve capacity. Just and Weber (2010) proposes an equilibrium model formulated as a mixed-integer problem in order to model auction prices of reserve capacity under several contract periods and discusses the impact of different contracting periods for reserve procurement in Germany. In both papers the authors do not explicitly consider non-convexities in their approach. The proposed iterative approaches also do not guarantee that an actual market equilibrium is achieved at the point the algorithm reaches the stopping criterion. Martin et al. (2014) presents a large-scale mathematical program with equilibrium constraints (MPEC) including binary variables to solve the problem power exchanges face when matching supply and demand bids. Hogan and Ring (2003) and Gribik et al. (2007) give a good introduction in the kind of problems of finding equilibrium prices in markets involving non-convexities and present a methodology for determination of minimum side-payments based on a modeling framework based on fixed optimality conditions of generators. Van Vyve and others (2011) compares central-dispatch and self-dispatch market models and proposes an intermediate market model that combines advantages of both models. Although (Hogan and Ring, 2003),(Gribik et al., 2007) and (Van Vyve and others, 2011) deal with basic problematic of pricing under non-convexities the provision and valuation of balancing capacity is not considered within their models.

2.2.4. Contribution to the literature

In this part of the work I contribute to the relevant literature mentioned above with the proposal of a novel modeling approach that finds competitive equilibrium prices of energy in spot markets and balancing capacity, which is procured in dedicated auctions as found in self-dispatch market models across Europe. The implemented capacity auction design is motived by automatic Frequency Restoration Reserves (aFRR), which require that units providing available capacity are online for the whole contracting period. However, the model extension to other reserve qualities and market designs is straight forward. The proposed modeling framework is built on the methodology presented in Huppmann and Siddiqui (2015), which has been developed to find Nash equilibria in games with binary decision variables. This is achieved by including incentive-compatibility constraints from non-cooperative game theory directly into an overall optimization framework that explicitly considers non-convexities and indivisibilities of supply and demand.

2.3. Competitive market equilibria

In this section a formal definition of the type of equilibria that are of interest in this work is provided. The definitions are a special case of the more general definitions given in Huppmann and Siddiqui (2015). I assume that the electricity market is composed by a set of players $j \in \mathcal{J}$, representing generation companies, consumers and depending on the specific market model a power exchange (PE) and the transmission system opertor (TSO), or an independent system operator (ISO), respectively, representing both institutions in one entity. Generating companies and consumers compete with each other on the market under the assumption of perfect competition, the PE strives for welfare-maximizing market clearing and the TSO/ISO maintains reliable system operation. Each player controls a portfolio of units expressed by a vector $y_j \in \mathbb{R}^{m_j}$ composed by continuous variables representing, e.g., generated or consumed electricity of her units and a vector $x_j \in \{0,1\}^{n_j}$ composed by binary activities, which indicates, e.g. whether a unit is operating, or committed to provide reserve capacity, respectively. Each player faces a set of k_j constraints $g_j : \mathbb{R}^{m_j} \times \{0,1\}^{n_j} \to \mathbb{R}^{k_j}$ and seeks to minimize an objective function $f_j(\cdot)$. The feasible region of each player is denoted by $K_j = \{(x_j, y_j) \,|\, g_j(x_j, y_j) \leq 0\}$. The competition among generating companies and consumers drive them towards a market equilibrium. Therefore, the following statements only refer to competing players. The relation to other players will be introduced in section 2.4.2.

Each player faces the following optimization problem:

$$\min_{x_j \in \{0,1\}^{n_j},\, y_j \in \mathbb{R}^{m_j}} \quad f_j\left(x_j, y_j, p\right) \tag{2.1a}$$

$$\text{s.t.} \quad g_j\left(x_j, y_j\right) \leq 0 \tag{2.1b}$$

The objective function of generation companies might be to maximize short-run profits of their portfolios, or to minimize short-run generation costs, respectively, given the assumption of perfect competition where player's face a vector of exogenous market prices p. Profits might be earned from different markets, e.g. day-ahead, intra-day or balancing capacity auctions. Typical constraints are of technical nature and restrict the output of generators in terms of level and rate of change. Consumers objective is to maximize their utility under restrictions related to their capabilities to consume electricity again typically specified in terms of possible levels and rates of change. Each player is assumed to act in a perfectly competitive manner in the sense that in equation (2.1a) he does not consider the impact of his own decisions on market prices, thus take prices as exogenous and truthfully bid his cost to the market operator. An equilibrium with perfect competition to this game is a set of strategies such that no player has an incentive to change her dispatch and commitment decision given a fixed vector of market prices.

Definition 1. (Equilibrium with perfect competition in a binary game). The binary game is defined as a set of market players $j \in \mathcal{J}$, each seeking to solve an optimization problem as given in (2.1), whereas market prices p are exogenous to their optimization problem. A competitive equilibrium to this game is a vector $((x_j^*, y_j^*) \in K_j)_{j \in \mathcal{J}}$ such that y_j^* is the optimal decision (i.e., best response) by player j given x_j^*,

$$f_j(x_j^*, y_j^*, p) \leq f_j(x_j^*, y_j, p) \quad \forall y_j \in \{y_j \,|\, g_j(x_j^*, y_j) \leq 0\} \, \forall j \in \mathcal{J} \tag{2.2}$$

and such that there is no profitable deviation with regard to the binary variable,

$$f_j(x_j^*, y_j^*, p) \leq f_j(x_j^\varphi, y_j^\varphi, p) \quad \forall j \in \mathcal{J} \quad \forall x_j^\varphi \in \Phi_j, \tag{2.3}$$

whereas x_j^φ is an alternative vector to x_j^* taken from the set of all feasible vectors Φ_j, and y_j^φ is a best response of player j given x_j^φ.

The existence or uniqueness of competitive equilibria (in pure strategies) in games involving binary variables as in Definition 1 cannot be guaranteed in general, cf. Madrigal and Quintana (2001). Therefore, I follow the approach presented in (Huppmann and Siddiqui, 2015) and introduce a market operator as upper-level player, which fulfills the function of a equilibrium selection mechanism. To make sure that a solution to the binary game exists, I introduce the notion of a *quasi-equilibrium*. In this definition the binary decision variables of players are determined by an upper-level player. I therefore write $\overline{\mathbf{x}}_j$ to refer to an exogenous variable-setting of player j.

Definition 2. (Quasi-equilibrium with perfect competition in a binary game with compensation). I define the binary game with compensation as a set of market players $j \in \mathcal{J}$, each seeking to solve an optimization problem as given in (2.1), whereas market prices p are exogenous to their optimization problem. A quasi-equilibrium to this game is a vector $((\overline{\mathbf{x}}_j, \overline{y}_j) \in K_j)_{j \in \mathcal{J}}$ and a corresponding compensation payment $\zeta_j(x_j) : \{0,1\}^{n_j} \to \mathbb{R}_+$ such that for each player:

1. $\overline{y}_j$ is the optimal decision (i.e., best response) by player j given $\overline{\mathbf{x}}_j$,

$$f_j(\overline{\mathbf{x}}_j, \overline{y}_j, p) \leq f_j(\overline{\mathbf{x}}_j, y_j, p) \quad \forall y_j \in \{y_j \,|\, g_j(\overline{\mathbf{x}}_j, y_j) \leq 0\} \, \forall j \in \mathcal{J} \tag{2.4}$$

2. there is no profitable deviation with regard to the binary vector

$$f_j(\overline{\mathbf{x}}_j, \overline{y}_j, p) - \zeta_j(\overline{\mathbf{x}}_j) \leq f_j(x_j^\varphi, y_j^\varphi, p) \quad \forall j \in \mathcal{J} \, \forall x_j^\varphi \in \Phi_j \tag{2.5}$$

   such that each player is at most indifferent between all her other feasible decisions x_j^φ, i.e. including her optimal decision x_j^*, and the vector $\overline{\mathbf{x}}_j$, if additional compensation payments $\zeta_j(\overline{\mathbf{x}}_j)$ are paid, where y_j^φ is a best response of player j given x_j^φ,

3. and the compensation payment to incentivize each player to be indifferent between her optimal decision (x_j^*, y_j^*) and $(\overline{\mathbf{x}}_j, \overline{y}_j)$ is minimal, i.e.

$$\zeta_j(\overline{\mathbf{x}}_j) = \sup_{\zeta_i \in \mathbb{R}^+} \{\zeta_i \,|\, f_j(\overline{\mathbf{x}}_j, \overline{y}_j, p) - \zeta_i \leq f_j(x_j^*, y_j^*, p)\} \tag{2.6}$$

It is important to recognize that in case of $\overline{\mathbf{x}}_j = x_j^*$ for each player the quasi-equilibrium turns into a competitive market equilibrium according to Definition 1. That is,

Lemma 1. A quasi-equilibrium as defined in Definition 2 fulfills all requirements of a competitive equilibrium as defined in Definition 1 iff the binary vector $\overline{\mathbf{x}}_j$ determined by the market operator is an optimal decision x_j^* of problem (2.1) for each player.

Proof. Since $\overline{\mathbf{x}}_j = x_j^*$ for each player j, $\overline{y}_j$ equals y_j^* and (2.4) translates into (2.2), thus condition 1 in Definition 1 is fulfilled. According to (2.6) the compensation payment $\zeta_j(x_j^*)$ is zero for each player j, therefore (2.5) translates into (2.3) and condition 2 in Definition 1 is fulfilled. □

Note, that in Definition 2 only the status of the binary variable is predefined by an upper-level player, i.e. the market operator. The continuous variables of each player are still the optimal choice of each generator given the fixed binary variables. However, the market operator typically faces market-clearing constraints, which require that the sum of continuous variables of all players equals any constant, e.g. electricity demand in any instance of time. Such constraints require the market operator to accept only a certain portion of single bids in continuous variables, because a change in prices cannot resolve this problem. Such a case would then not constitute a quasi-equilibrium in the sense of Definition 2, since therein neither compensation payments nor quantity restrictions are foreseen for deviations in continuous variables. However, in our model configuration the curtailed generator is often price-setting, therefore compensation would not be required since his short-run profit is zero for any quantity. If demand-side units would be implemented as well this assumption is not valid any more. Another possibility of required compensation payments is the case when any player whose binary variables are determined to be zero would have a profitable incentive to switch-on at prevailing market prices. These payments are basically included within Definition 2, however, it should be mentioned that it is a controversial issue to compensate generators who are constrained off. It is common practice in existing power exchanges not to pay any loss of profits to generators in such cases. Such orders are typically called *Paradoxically Rejected Blocks*, cf. Madani and Vyve (2014).

Finally, the presented modeling approach in this paper requires the introduction of a specific slack-variable, which I will refer to as *switch value*.

Definition 3. (Switch value). I define the switch-value $\kappa_j(x_j) : \{0,1\}^{n_j} \to \mathbb{R}^+$ of player j as slack variable of inequalities (2.3) and (2.5) such that

$$f_j(x_j^*, y_j^*, p) + \kappa_j(x_j^\varphi) = f_j(x_j^\varphi, y_j^\varphi, p) \quad \forall j \in \mathcal{J} \quad \forall x_j^\varphi \in \Phi_j, \tag{2.7}$$

and

$$f_j(\overline{\mathbf{x}}_j, \overline{y}_j, p) + \kappa_j(x_j^\varphi) - \zeta_j(\overline{\mathbf{x}}_j) = f_j(x_j^\varphi, y_j^\varphi, p) \quad \forall j \in \mathcal{J} \quad \forall x_j^\varphi \in \Phi_j \tag{2.8}$$

holds.

The switch value can be interpreted as loss incurred by switching from the optimal or predetermined, respectively, binary vector to an alternative feasible vector. It is therefore related to the interpretation of dual variables in convex optimization problems in the sense that it represents the impact of a discretized relaxation of any constraint on the objective function, rather than a marginal relaxation. In the approach below I use the switch value to implement the constraints ensuring incentive-compatibility as equations, rather than inequalities. This allows to determine necessary compensation payments *zeta* in case no competitive equilibrium exists. These payments are then minimized together with the objective to maximize social welfare in order to find a quasi-equilibrium that is closest to an equilibrium that would emerge when neglecting non-convex preferences.

2.4. Applied optimization framework

In this section I formally introduce the two model formulations I want to contrast with each other. Both approaches contain binary variables representing non-convex preferences of generators. I start with the central-dispatch approach, which I will refer to as *Social Planner* (SP) model and then describe in detail a novel problem formulation for modeling the self-dispatch market model. Because I will try to find a market equilibrium including non-convexities, I refer to this model as *Binary Equilibrium* (BE) model. The applied notation of sets, parameters and variables are common to both models and are summarized in Table 2.1.

2.4.1. Social planner model (Central-dispatch approach)

I apply a standard unit-commitment model of the form described in O'Neill et al. (2005). An independent system operator (ISO) seeks to maximize social welfare for provision of electricity and withholding of spinning capacity reserves. To do so, the operator is in control of vectors composed by continuous variables g_{ti} representing generated electricity and a vector composed by binary activities z_{ti}, which indicate e.g. whether a generator is operating, or switched on or off, respectively. The indexes i and t range over generators and different time periods. For each generator a non-convex cost function $C_i(g, z) = \sum_t c_i^G g_{ti} + \sum_t c_i^{\text{on}} z_{ti}^{\text{on}} + c_i^{\text{off}} z_{ti}^{\text{off}}$ is assumed, whose coefficients c_i^G, c_i^{on} and c_i^{off} are related to incurred costs by continuous and binary activities of generator i and, which I assume, are truthfully communicated to the ISO. In the interest of a concise and simple exposition of the basic concept I also assume that only generators compete for supplying an exogenous quantity of demand and each player owns only one unit. The incorporation of demand-side players into the model can be easily done via adding players with a cost function containing negative coefficients. The resulting mixed-integer linear optimization model reads as follows,

SP:

$$\max_{d_t, g_{ti}, x^G_{ti}, b^+_i, b^-_i} \quad \sum_{t \in T} u^D_t d_t - c^G_i g_{ti} - c^{\text{on}}_i z^{\text{on}}_{ti} - c^{\text{off}}_i z^{\text{off}}_{ti} \tag{2.9a}$$

$$\text{s.t. } d_t - \sum_{i \in I} g_{ti} = 0 \quad (p^S_t) \tag{2.9b}$$

$$d_t \leq d^{max}_t \quad (\nu_t) \tag{2.9c}$$

$$\sum_{i \in I} b^+_i \geq b^{+\,req} \quad (p^{B+}_i) \tag{2.9d}$$

$$\sum_{i \in I} b^-_i \geq b^{-\,req} \quad (p^{B-}_i) \tag{2.9e}$$

$$g_{ti} + b^+_i \leq x^G_{ti} g^{max}_i \quad (\beta_{ti}) \tag{2.9f}$$

$$g_{ti} - b^-_i \geq x^G_{ti} g^{min}_i \quad (\alpha_{ti}) \tag{2.9g}$$

$$b^+_i \leq x^G_{ti} b^{+\,max}_i \quad (\lambda_i) \tag{2.9h}$$

$$b^-_i \leq x^G_{ti} b^{-\,max}_i \quad (\mu_i) \tag{2.9i}$$

$$x^G_{(t-1)i} - x^G_{ti} + z^{\text{on}}_{ti} - z^{\text{off}}_{ti} = 0 \quad (\gamma_{ti}) \tag{2.9j}$$

$$1 - z^{\text{on}}_{ti} \geq \sum_{\tau \in [t, t+T^{\text{on}}]} z^{\text{off}}_{\tau i} \quad (\sigma_{ti}) \tag{2.9k}$$

$$1 - z^{\text{off}}_{ti} \geq \sum_{\tau \in [t, t+T^{\text{off}}]} z^{\text{on}}_{\tau i} \quad (\rho_{ti}) \tag{2.9l}$$

$$x^G_{ti} \in \{0, 1\}, \quad d_t, g_{ti}, b^+_i, b^-_i, z^{\text{on}}_{ti}, z^{\text{off}}_{ti} \in \mathbb{R}_+$$

The ISO aims to maximize utility of electricity supply and to minimize generation costs. In this example I set u^D_t to the value of lost load, i.e. a scalar, however, it could also be defined as a linear utility function defined over a non-convex set. The optimization therefore seeks for a least-cost dispatch and unit commitment under given generation and flexibility constraints (2.9f)-(2.9j), the market clearing condition (2.9b) and exogenously given demand for reserve capacity, (2.9d) and (2.9e). The linear generation costs of each generator are given by c^G_i, the (binary) start-up costs are given by c^{on}_i, and the (binary) shut-down costs are given by c^{off}_i. The unit-commitment decisions in each hour t are denoted by x^G_{ti}, the decision how much electricity is generated and sold to the power exchange is g_{ti}. The contribution of generator i to the positive or negative reserve capacity, respectively, is given by b^+_i and b^-_i and constant for all $t \in T$. Constraints (2.9f)-(2.9g) restrict the feasible output of each generator, in particular given his reserve capacity commitments. The binary state variable x^G_{ti} in these constraints causes a non-convex feasible generation area. (2.9h)-(2.9i) constrain the contribution of generator i to reserve capacity. The binary state variables therein model one fundamental requirement of spinning reserves, i.e. a generator providing reserve capacity has to stay online throughout the whole procurement period. The remaining equations map inter-temporal on-/off decisions of generators into start-up z^{on}_{ti} and shut-down variables z^{off}_{ti} and minimum on/off periods. While z variables are binary in nature, they can be relaxed to positive real numbers, since integrality is ensured via equation (2.9j). Relevant dual variables to model constraints are written in brackets next to the constraint.

The ISO pays each generator the market price p_t^S for each unit of generated electricity, prices for provision of reserve capacity $p_i^{B+/-}$ and a side payment p_{ti}^G for her binary activities x_{ti}^G. There are different ways to determine the necessary side payments. O'Neill et al. (2005) proposes a two-step approach, where in a first step the mixed-integer model **SP** has to be solved and in a second step a linear model is constructed via adding an equation to **SP** (cf. equations 2.9), which fixes the binary variables to their optimal values from the first run. The dual variables to this *fixing*-equations are then the needed side-payments to each generator. In the literature such payments have been known as *O'Neill payments*. They can also be derived ex-post from the optimal dual variables of the "fixed" **SP** model, which I will refer to as $\mathbf{linSP}(x_{ti}^{G*})$. This model is a constrained (linear) version of problem (2.9), where x_{ti}^G are fixed to the optimal solution of **SP**. Optimal solutions from both models are marked with a star.

Theorem 2. A *competitive equilibrium* of problem **SP** is a set of prices $\{p_t^{S*}, p_i^{B+*}, p_i^{B-*}, p_{ti}^G \ \forall i, t\}$ and allocations $\{g_{ti}^*, b_i^{+*}, b_i^{-*}, x_{ti}^{G*} \ \forall i, t\}$ for all generators i, where

1. g_{ti}^*,b_i^{+*},b_i^{-*} and x_{ti}^{G*} are optimal primal values from **SP**,
2. $p_t^{S*}, p_i^{B+*}, p_i^{B-*}$ are optimal dual variables derived from equations (2.9b), (2.9d) and (2.9e) in $\mathbf{linSP}(x_{ti}^{G*})$ and
3. $p_{ti}^G = \beta_{ti} g_i^{max} - \alpha_{ti} g_i^{min} + \lambda_i b_i^{+\,max} + \mu_i b_i^{-\,max} + (\gamma_{t+1,i} - \gamma_{ti})$, whereas the dual variables herein are also derived from $\mathbf{linSP}(x_{ti}^{G*})$.

Proof. Consider problem **SP** with additional constraints $x_{ti}^G = x_{ti}^{G*}$, corresponding dual variables w_{ti} and a linear relaxation of x_{ti}^G; lets call this problem $\mathbf{OSP}(x_{ti}^{G*})$, the *O'Neill* **SP** model. The KKT-condition of $\mathbf{OSP}(x_{ti}^{G*})$ with respect to x_{ti}^G reads as $-\beta_{ti} g_i^{max} + \alpha_{ti} g_i^{min} - \lambda_i b_i^{+\,max} - \mu_i b_i^{-\,max} - (\gamma_{ti} - \gamma_{t+1,i}) + w_{ti} = 0$. From this equation I can derive the O'Neill payments w_{ti} which equal p_{ti}^G by definition. Thus, I can drop this KKT-condition from the problem. The remaining KKT-conditions exactly match the ones of problem $\mathbf{linSP}(x_{ti}^{G*})$. The optimal primal variables of $\mathbf{OSP}(x_{ti}^{G*})$ and $\mathbf{linSP}(x_{ti}^{G*})$ are the same, because the binary variables have been fixed in both models and the remaining equations are the same. The optimal primal variables of $\mathbf{linSP}(x_{ti}^{G*})$ and **SP** are also the same, because **SP** is $\mathbf{linSP}(x_{ti}^{G*})$ with the additional constraints that the integer variables are constrained to their optimal values. The proof that under the conditions of Theorem 2 a competitive equilibrium holds, is given in O'Neill et al. (2005). □

O'Neill payments are discriminatory and can take positive or negative values. Negative values mean that generators pay their profits to the ISO, i.e. O'Neill payments ensure that the no-profit condition holds. This condition is problematic with regard to the long-term perspective. Fuller (2010) shows that even if only positive O'Neill payments are paid to generators and no negative payments are collected by the ISO the equilibrium conditions still hold. However, the decomposition of O'Neill payments in Theorem 2 reveals another problem. Since the optimal dual variables in $\mathbf{linSP}(x_{ti}^{G*})$ are not unique, there are several possible O'Neill payment allocations as well. I will therefore apply another approach to determine necessary compensation payments for the **SP** model, namely *make-whole* payments.

These payments make sure that no participant incurs a loss when complying with the ISO's schedule and are determined ex-post

$$p_{ti}^G = \min\{0, (c_i^G - p_t^{S*})g_{ti}^* + c_i^{\text{on}} z_{ti}^{\text{on}*} + c_i^{\text{off}} z_{ti}^{\text{off}*}\}. \tag{2.10}$$

2.4.2. The binary equilibrium model (Self-dispatch approach)

Following the basic methodology of Huppmann and Siddiqui (2015) I set up the binary equilibrium model of the electricity market as a two-level game involving a transmission system operator (TSO) and a power exchange (PE) in the upper level and a set of competing generators in the lower level (cf. Figure 2.1). The objective of generators is to maximize their short-run profit given a set of generation constraints involving non-convex costs and indivisibilities of output. Since I aim to model efficient market prices I assume perfect competition among generators, i.e. generators only decide on their unit-commitment and dispatch given a set of exogenous market prices. The PE sets spot market prices so that welfare is maximized under the condition of market clearing and under the assumption of perfect competition. Because I did not incorporate demand-side players in the lower level, I also require the PE to control the aggregated demand curve. The TSO procures a fixed amount of capacity reserves for the sake of balancing short-term deviations of actual supply and demand from forecasts. The TSO pays capacity prices to generators in order to incentivize them to withhold capacity from the spot market and to keep committed generators running within the required period of time.

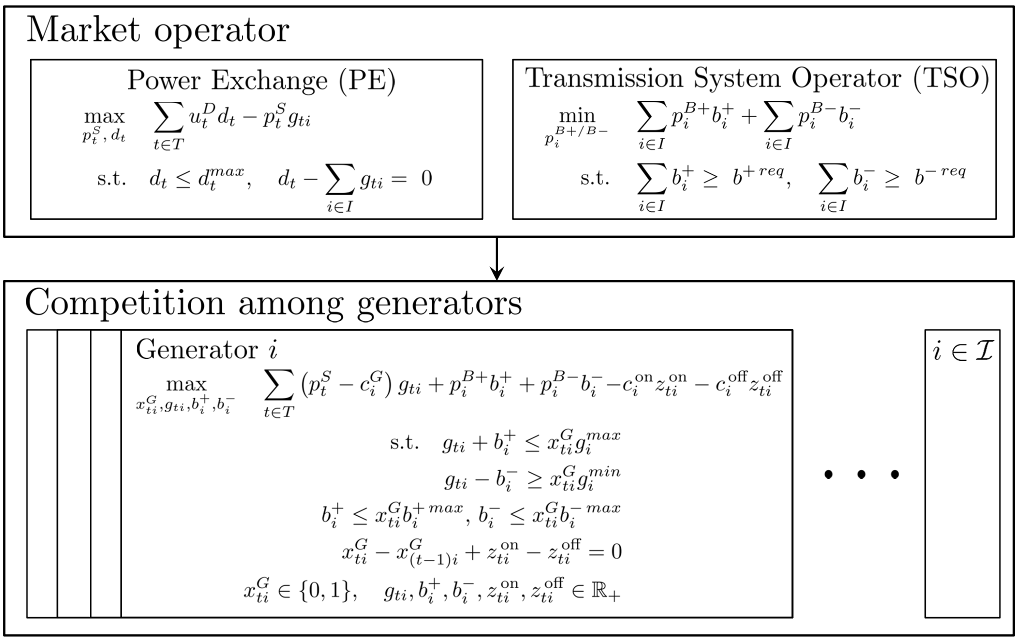


Figure 2.1.: Electricity market modeled as binary two-level game.

2.4.2.1. Upper level: The PE and TSO optimization problems

I assume that both the PE and the TSO act simultaneously on the same level and consequently I can combine their objective functions into a single function to be maximized:

$$\max_{p_t^S, d_t, p_i^{B+}, p_i^{B-}} \sum_{t \in T} u_t^D d_t - p_t^S g_{ti} - \sum_{i \in I} p_i^{B+} b_i^+ - \sum_{i \in I} p_i^{B-} b_i^- \tag{2.11a}$$

$$\text{s.t. } d_t \leq d_t^{max} \qquad \forall t \in T \tag{2.11b}$$

$$d_t - \sum_{i \in I} g_{ti} = 0 \qquad \forall t \in T, i \in I \tag{2.11c}$$

$$\sum_{i \in I} b_i^+ \geq b^{+\,req} \tag{2.11d}$$

$$\sum_{i \in I} b_i^- \geq b^{-\,req}. \tag{2.11e}$$

Both players together maximize consumer surplus by setting the lowest possible prices that clear the market, i.e. in this way the assumption of perfect competition is implemented. The upper-level player anticipate the profit-maximizing reaction of generators as a result of different market prices. Due to the absence of demand-side units the upper-level player also represents the aggregated demand curve.

The price for electricity, positive and negative reserve capacity (p_t^S, p_i^{B+} and p_i^{B-}) are chosen under consideration of the best responses of all players as reaction to these prices. The modeling of the *best response* of each generator given a set of prices is documented in the section concerning the lower-level of the model. The presented modeling framework is able to capture a distinct market-design feature of electricity markets, namely *pay-as-bid* versus *uniform pricing*. I can include the option whether each generator should be offered the same price or not via adding additional constraints

$$p_i^{B+} = p^{B+} \quad \forall\, i \in I \tag{2.12a}$$

$$p_i^{B-} = p^{B-} \quad \forall\, i \in I \tag{2.12b}$$

to the model. For generality, I will use the unit-specific price in the following notation.

2.4.2.2. Lower-level: The generator problem

Each generator $i \in I$ seeks to maximize his short-run profits from selling generated electricity and spinning reserve capacity over the time horizon $t \in T$. The feasible region of each generator is the same as in the **SP** model (2.9). The corresponding optimization problem reads as follows:

$$\max_{x^G_{ti}, g_{ti}, b^+_i, b^-_i} \quad \sum_{t\in T} \left(p^S_t - c^G_i\right) g_{ti} + p^{B+}_i b^+_i + p^{B-}_i b^-_i - c^{\text{on}}_i z^{\text{on}}_{ti} - c^{\text{off}}_i z^{\text{off}}_{ti} \tag{2.13a}$$

$$\text{s.t. } g_{ti} + b^+_i \le x^G_{ti} g^{max}_i \quad (\beta_{ti}) \qquad \forall i \in I,\, t \in T \tag{2.13b}$$

$$g_{ti} - b^-_i \ge x^G_{ti} g^{min}_i \quad (\alpha_{ti}) \qquad \forall i \in I,\, t \in T \tag{2.13c}$$

$$b^+_i \le x^G_{ti} b^{+\,max}_i \quad (\lambda_i) \qquad \forall i \in I \tag{2.13d}$$

$$b^-_i \le x^G_{ti} b^{-\,max}_i \quad (\mu_i) \qquad \forall i \in I \tag{2.13e}$$

$$x^G_{ti} - x^G_{(t-1)i} + z^{\text{on}}_{ti} - z^{\text{off}}_{ti} = 0 \qquad \forall i \in I,\, t \in T \tag{2.13f}$$

$$x^G_{ti} \in \{0,1\}, \quad g_{ti}, b^+_i, b^-_i, z^{\text{on}}_{ti}, z^{\text{off}}_{ti} \in \mathbb{R}_+.$$

Optimal response in continuous variables The shadow variables $(\beta_{ti}, \alpha_{ti}, \beta_{ti}, \lambda_i, \mu_i)$ of problem (2.13) are only meaningful given a fixed (binary) unit-commitment schedule x^G_{ti}. For a certain fixed schedule, the optimal dispatch and capacity decisions g_{ti}, $b^{+,-}_i$ and corresponding dual variables can be determined by solving generator's first-order optimality (KKT) conditions[3]. To get the best response of generator i, i.e. optimal primal and dual variables to problem (2.13), I therefore have to derive the KKT conditions for each unit-commitment schedule of interest separately. I introduce additional continuous model variables for two sets of relevant KKT-conditions. The primal and dual variables that correspond to these sets of KKT-conditions are marked with superscript symbols $^{(\mathbf{B})}$,$^{(\not\mathbf{B})}$ and $^{(\mathbf{1})}$. Which schedule x^G_{ti} each generator finally chooses in order to maximize his overall profit is subject to a binary decision problem, which is depicted in Figure 2.2.

If a generator decides to provide spinning reserve capacity he is obliged to keep the respective unit online over the whole time period. Consequently, I fix in problem (2.13) x^G_{ti} to 1 for each time step and derive the KKT-conditions for generator i

$$0 = c^G_i - p^S_t + \beta^{(\mathbf{B})}_{ti} - \alpha^{(\mathbf{B})}_{ti} \quad , \quad g^{(\mathbf{B})}_{ti} \text{ (free)} \tag{2.14a}$$

$$0 \le -p^{B+}_i + \sum_{t\in T} \beta^{(\mathbf{B})}_{ti} + \lambda^{(\mathbf{B})}_i \quad \perp \quad b^{+(\mathbf{B})}_i \ge 0 \tag{2.14b}$$

$$0 \le -p^{B-}_i + \sum_{t\in T} \alpha^{(\mathbf{B})}_{ti} + \mu^{(\mathbf{B})}_i \quad \perp \quad b^{-(\mathbf{B})}_i \ge 0 \tag{2.14c}$$

$$0 \le b^{+\,max}_i - b^{+(\mathbf{B})}_i \quad \perp \quad \lambda^{(\mathbf{B})}_i \ge 0 \tag{2.14d}$$

$$0 \le b^{-\,max}_i - b^{-(\mathbf{B})}_i \quad \perp \quad \mu^{(\mathbf{B})}_i \ge 0 \tag{2.14e}$$

$$0 \le -g^{min}_{ti} + g^{(\mathbf{B})}_{ti} + b^{-(\mathbf{B})}_i \quad \perp \quad \alpha^{(\mathbf{B})}_{ti} \ge 0 \tag{2.14f}$$

$$0 \le g^{max}_{ti} - g^{(\mathbf{B})}_{ti} - b^{+(\mathbf{B})}_i \quad \perp \quad \beta^{(\mathbf{B})}_{ti} \ge 0. \tag{2.14g}$$

[3]Since all our constraints are linear for a fixed binary vector x the corresponding gradients to all (binding) constraints at any given feasible solution (g, b) are linearly independent and therefore the *linear independence constraint qualification* (LICQ) holds, which means that KKT conditions can be meaningfully written for (g, b)

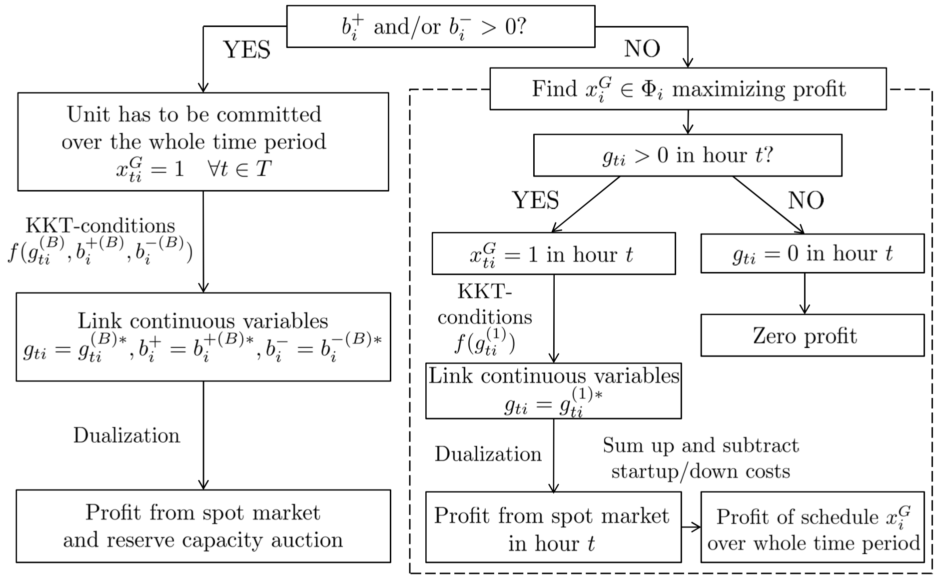


Figure 2.2.: Decision tree of generators.

The primal and dual variables that solve this system of equations are the profit maximizing continuous variables of generator i in case of reserve capacity provision. These variables are marked by the superscript $^{(\mathbf{B})}$. In section 2.4.2.2 it is described how the actual generation and capacity variables of generator i are linked to these variables. Finally, the respective generator profit follows from the objective function of generator i. If the generator does not provide capacity reserves, i.e. $b_i^{+/-} = 0$, he has to decide on the unit-commitment schedule over period T. The KKT conditions when generator i is operational in hour t read as follows:

$$0 = c_i^G - p_t^S + \beta_{ti}^{(\mathbf{1})} - \alpha_{ti}^{(\mathbf{1})} \quad , \quad g_{ti}^{(\mathbf{1})} \text{ (free)} \tag{2.15a}$$

$$0 \leq -g_{ti}^{min} + g_{ti}^{(\mathbf{1})} \quad \perp \quad \alpha_{ti}^{(\mathbf{1})} \geq 0 \tag{2.15b}$$

$$0 \leq g_{ti}^{max} - g_{ti}^{(\mathbf{1})} \quad \perp \quad \beta_{ti}^{(\mathbf{1})} \geq 0. \tag{2.15c}$$

The additional decision variables and duals for this case are marked by superscript $^{(\mathbf{1})}$. When generator i is not operational in hour t no KKT-conditions need to be derived, since the output and consequently the profit is zero in that specific hour. However, due to intertemporal costs a negative profit may occur over a period of time, when the generator is operated at any previous hour and shut-down costs need to be accounted for. How intertemporal costs are implemented in the model is described in section 2.4.2.2.

Linking binary decisions to sets of KKT-conditions In order to derive optimal continuous variables to a given unit-commitment schedule x_{ti}^G they need to be linked to their corresponding set of KKT-conditions. To do so the same binary variables are used that determine the unit-commitment schedule. The linking requires that additional inequalities are added to the model. In order to reduce the number of variables in the model the binary variable x_i^B are introduced, which indicates that generator i provides reserve capacity in period T. Variable x_i^B set to 1 implies that $x_{ti}^G = 1\,\forall t \in T$. Therefore, all x_{ti}^G in (2.13) are replaced with x_i^B and in this way the number of binary variables in the model is reduced by a factor of $|T|$. I fix the generation level g to $g^{(\mathbf{B})}$ or $g^{(\cancel{\mathbf{B}})}$, respectively, depending on whether the unit provides reserve capacity or not ($x^B = 1|0$)

$$g_{ti}^{(\cancel{\mathbf{B}})} - x_i^B\, g_{ti}^{max} \leq g_{ti} \leq g_{ti}^{(\cancel{\mathbf{B}})} + x_i^B\, g_{ti}^{max} \tag{2.16a}$$
$$g_i^{(\mathbf{B})} - (1 - x_i^B)\, g_{ti}^{max} \leq g_{ti} \leq g_{ti}^{(\mathbf{B})} + (1 - x_i^B)\, g_{ti}^{max}. \tag{2.16b}$$

If the unit provides reserve capacity ($x^B = 1$), b_i^+ and b_i^- are fixed to the optimal variables from the corresponding KKT-conditions of this case

$$0 \leq b_i^+ + b_i^- \leq x_i^B b_i^{max} \tag{2.16c}$$
$$b_i^{+(\mathbf{B})} - (1 - x_i^B)\, b_i^{+\,max} \leq b_i^+ \leq b_i^{+(\mathbf{B})} + (1 - x_i^B)\, b_i^{-\,max} \tag{2.16d}$$
$$b_i^{-(\mathbf{B})} - (1 - x_i^B)\, b_i^{-\,max} \leq b_i^- \leq b_i^{-(\mathbf{B})} + (1 - x_i^B)\, b_i^{-\,max}, \tag{2.16e}$$

otherwise they are zero. If $x_i^B = 0$ then the generation level g_{ti} has already been fixed to $g_{ti}^{(\cancel{\mathbf{B}})}$ (cf. 2.16a). This variable is then fixed to zero if it is out of operation ($x_{ti}^G = 0$) or to $g_{ti}^{(\mathbf{1})}$ if it is operated:

$$0 \leq g_{ti}^{(\cancel{\mathbf{B}})} \leq x_{ti}^G\, g_{ti}^{max} \tag{2.16f}$$
$$g_{ti}^{(\mathbf{1})} - (1 - x_{ti}^G)\, g_{ti}^{max} \leq g_{ti}^{(\cancel{\mathbf{B}})} \leq g_{ti}^{(\mathbf{1})} + (1 - x_{ti}^G)\, g_{ti}^{max}. \tag{2.16g}$$

Incentive-compatibility conditions In a last step, we need to establish what is the profit-maximizing unit-commitment and dispatch decision for each generator; in game-theoretic terms, we add constraints to ensure *incentive-compatibility.* I strive to find conditions, which constitute competitive market equilibria according to Definition 1. It has already been stated that neither the existence nor uniqueness of competitive equilibria (in pure strategies) in games involving binary variables can be guaranteed in general. Therefore, I directly aim to find quasi-equilibria according to Definition 2 in order to guarantee feasibility. According to Lemma 1 a quasi-equilibrium automatically constitute a competitive equilibrium in case necessary compensation payments are zero. I use this feature to search for quasi-equilibria, which come closest to meet the requirements of a competitive equilibrium. As a measure of what I mean by "close" I use the sum of necessary compensation payments to all generators as defined in Definition 2. I include this measure by adding[4] the term

$$\sum_i -k^P \zeta_i, \quad k^P, \zeta_i \in \mathbb{R}^+ \tag{2.17}$$

[4]Since problem (2.11) is stated as maximization problem the sum has to be negative in order to be minimized.

to the objective function (2.11a) to implement our aim of finding the closest feasible quasi-equilibrium. Note, that by minimizing the sum over all compensation payments I already fulfill requirement (3) of Definition 2. Requirement (1) of Definition 2 is fulfilled as well, since I ensure optimal values (i.e. best responses) of continuous variables given any fixed unit-commitment schedule x^G_{ti} through the added KKT conditions (cf. 2.4.2.2) and corresponding variable fixations (cf. 2.4.2.2). Finally, I add constraints to fulfill requirement (2) of Definition 2. As depicted in Figure 2.2 the profits generators can earn in each path of the tree have to be compared to each other in order to determine their optimal strategy.

First, it is determined which unit-commitment schedule x^G_{ti} is optimal under the assumption that the unit does not provide reserve capacity. It is not economically meaningful to allocate start-up and shut-down costs to a certain hour. I therefore have to compare not only the objective functions of different schedules per hour, but also as sum over the whole time period to capture all costs. Thereby, I separate short-term deviation incentives from compensation payments that ensure deviation alignment over the entire time horizon. To differentiate hourly variables from variables concerning the whole period, I introduce the slack variable $\delta_{ti}(x^G_{ti}) \in \mathbb{R}$ that represents (short-term) gains ($\equiv \zeta_{ti}$) minus losses ($\equiv \kappa_{ti}$), respectively, resulting from a change in unit-commitment schedule. Short-term deviation incentives can be interpreted such that there may be a loss in one period, which the generator is willing to suffer in order to gain larger profits in a different period. I implement short-term deviations subject to x^G_{ti} according to Definition 2.2

$$f^{(\mathbf{1})}_{ti} - \delta^{(\mathbf{1})}_{ti} = f^{(\mathbf{0})}_{ti} - \delta^{(\mathbf{0})}_{ti} \qquad \forall i \in I,\, \forall t \in T \tag{2.18a}$$

$$|\delta^{(\mathbf{1})}_{ti}| \leq x^G_{ti}\, \widetilde{K}^G \qquad \forall i \in I,\, \forall t \in T \tag{2.18b}$$

$$|\delta^{(\mathbf{0})}_{ti}| \leq (1 - x^G_{ti})\, \widetilde{K}^G \qquad \forall i \in I,\, \forall t \in T \tag{2.18c}$$

by making use of the binary variables themselves, whereby $\widetilde{K}^G$ is a sufficiently large constant. The objective functions $f^{(\mathbf{1})}_{ti}$ and $f^{(\mathbf{0})}_{ti}$ relate to hourly attends of equation (2.13a), the hourly profit of generator i, for both states of x^G_{ti}. Note that, as argued before, I neglect start-up/shut-down costs within the frame of short-term deviations. Thus, for $x^G_{ti} = 0$ the generator profit is zero. In case $x^G_{ti} = 1$ I get for $f^{(\mathbf{1})}_{ti}$ the expression $\left(p^S_t - c^G_i\right) g_{ti} + p^{B+}_i b^+_i + p^{B-}_i b^-_i$. This term is linear from the perspective of the lower-level players, since spot market and capacity prices are exogenous to them. However, this formulation yields non-linear model constraints. I linearize this term by making use of the dual of a hourly summand of problem (2.13), whereas $x^G_{ti} = 1$:

$$\min_{\beta_{ti}, \alpha_{ti}, \lambda_i, \mu_i} \; g^{min}_i \alpha_{ti} - g^{max}_i \beta_{ti} - b^{+\,max}_i \lambda_i - b^{-\,max}_i \mu_i \tag{2.19a}$$

$$\text{s.t. } \alpha_{ti} - \beta_{ti} \geq p^S_t - c^G_i \quad (g_{ti}) \quad \forall i \in I,\, \forall t \in T \tag{2.19b}$$

$$-\lambda_i \geq p^{B+}_i \quad (b^+_i) \quad \forall i \in I,\, \forall t \in T \tag{2.19c}$$

$$-\mu_i \geq p^{B-}_i \quad (b^-_i) \quad \forall i \in I,\, \forall t \in T. \tag{2.19d}$$

Because strong duality holds

$$\begin{aligned}\left(p_t^S - c_i^G\right) g_{ti} + p_i^{B+} b_i^+ + p_i^{B-} b_i^- \equiv \\ g_i^{min} \alpha_{ti} - g_i^{max} \beta_{ti} - b_i^{+\,max} \lambda_i - b_i^{-\,max} \mu_i\end{aligned} \tag{2.20a}$$

and since I additionally assumed that $x_i^B = 0$, it follows that $b_i^{+,-}$, λ_i and μ_i are zero. I can therefore write instead of equation (2.18a)

$$\beta_{ti}^{(\mathbf{1})} g_{ti}^{max} - \alpha_{ti}^{(\mathbf{1})} g_{ti}^{min} - \delta_{ti}^{(\mathbf{1})} = 0 - \delta_{ti}^{(\mathbf{0})} \quad \forall i \in I,\, \forall t \in T. \tag{2.20b}$$

Now, I sum up short-term deviations over the whole period, include start-up/shut-down costs and compensation payments and ensure incentive compatibility according to Definition 2.2 with

$$\begin{aligned}\sum_{t \in T} \left(\delta_{ti}^{(\mathbf{1})} - c_i^{\text{on}} z_{ti}^{\text{on}} - c_i^{\text{off}} z_{ti}^{\text{off}}\right) + \zeta_i^{(\mathbf{1})} = \\ \sum_{t \in T_\varphi} \left(\beta_{ti}^{(\mathbf{1})} g_{ti}^{max} - \alpha_{ti}^{(\mathbf{1})} g_{ti}^{min}\right) - c_{\varphi i}^{\text{Switch}} \quad \forall T_\varphi \in \Phi,\, i \in I\end{aligned} \tag{2.20c}$$

whereby T_φ is the set of hours in which the generator is operating according to a certain feasible unit-commitment schedule and $c_{\varphi i}^{\text{Switch}}$ is the sum of all start-up/shut-down costs that corresponds to this schedule. Note, that the duals on the right-hand-side of (2.20c) are fix for all schedules φ, i.e. a change of prices as a result of own actions is not considered within this approach (perfect competition).

Finally, the profits from the optimal unit-commitment and dispatch schedule when not providing capacity reserves are compared with the profits if the generator would reserve capacities: According to Definition 2.2 and by use of equivalence 2.20a

$$\begin{aligned}\sum_{t \in T} \left(\beta_{ti}^{(\mathbf{B})} g_{ti}^{max} - \alpha_{ti}^{(\mathbf{B})} g_{ti}^{min}\right) - \lambda_i^{(\mathbf{B})} b_i^{+\,max} - \mu_i^{(\mathbf{B})} b_i^{-\,max} - c_i^{\text{Switch}} - \kappa_i^{(\mathbf{B})} + \zeta_i^{(\mathbf{B})} \\ = \sum_{t \in T} \left(\delta_{ti}^{(\mathbf{1})} - c_i^{\text{on}} z_{ti}^{\text{on}} - c_i^{\text{off}} z_{ti}^{\text{off}}\right) - \kappa_i^{(\cancel{\mathbf{B}})} + \zeta_i^{(\cancel{\mathbf{B}})} \quad \forall i \in I\end{aligned} \tag{2.21a}$$

$$\kappa_i^{(\mathbf{B})} + \zeta_i^{(\mathbf{B})} \leq x_i^B \widetilde{K}^B \quad \forall i \in I \tag{2.21b}$$

$$\kappa_i^{(\cancel{\mathbf{B}})} + \zeta_i^{(\cancel{\mathbf{B}})} \leq \left(1 - x_i^B\right) \widetilde{K}^B \quad \forall i \in I. \tag{2.21c}$$

whereby $\widetilde{K}^B$ is a sufficiently large constant. Note, that this approach is innovative in making a double-use of binary variables. They are not only determining the unit-commitment schedule, but also serve as *variable-fixers* needed to implement nested if-else decisions.

Now I can formally sum up the binary equilibrium model, **BE**:

$$\max \sum_{i \in I,\, t \in T} u_t^D d_t - p_t^S g_{ti} - \sum_{i \in I} \left(p_i^{B+} b_i^+ + p_i^{B-} b_i^- + \zeta_i^{(\mathbf{1})} + \zeta_i^{(\mathbf{B})} + \zeta_i^{(\cancel{\mathbf{B}})}\right)$$

$$
\text{s.t.} \begin{cases}
\text{Market clearing conditions of the PE and TSO (Equations 2.11b-2.11e)} \\
\text{Market design options (Equations 2.12)} \\
\text{KKT-conditions of generators (Equations 2.14-2.15)} \\
\text{Linking equations (Equations 2.16)} \\
\text{Incentive compatibility conditions (Equations 2.20b,2.18b,2.18c,2.20c,2.21c)}
\end{cases}
$$

2.5. Numerical example

It is of interest to derive some basic quantitative insights about deviations between the **SP** and the **BE** model. In particular, I will show deviations of unit-commitment and dispatch decisions as well as compensation payments and prices. I contrast both model approaches with each other based on hourly load, cross-border exchanges and renewable electricity infeed data of Germany in 2012. The data has been gathered from the four German TSOs[5]. Based on hourly time series of renewable electricity infeed and total load the residual demand, i.e. the remaining load to be covered by other generation than renewable electricity, have been constructed. In order to illustrate some indicative results of the described model approaches I constructed a stylized model of this data set. From the total dataset ten representative days have been selected based on the σ-μ-diagram[6] shown in Figure 2.3. In order to fit this data to a smaller set of generators the residual load characterized in Figure 2.3 has been scaled, however, load and renewable generation patterns are preserved within the data. The days that have been selected cover the wide range of occurred combinations of mean and variance and additionally incorporated two average days.

The generation side is represented by a set of ten generators based on five different technologies. To mimic the curvature of the actual average supply curve of Germany more than one plant with slightly different conversion efficiency according to the existing age structure have been implemented per technology. The techno-economic characteristics of the implemented plants are show in Table 2.3. The considered non-convexities of the plants are minimal load, minimum/maximum run-time and start-up costs. The potential contribution of each plant to spinning reserve capacity has been derived based on their assumed maximal achievable ramping within a ten minutes time period. The unit size and start-up costs are typical values for each technology and have been taken from Schröder et al. (2013). The marginal costs are indicative values derived from average fuel and carbon prices within 2012. The demand for spinning reserve capacity is exogenous to the model and has been set to 5% of peak load.

[5] `http://www.amprion.de` , `http://www.50hertz.com`,
`http://www.tennet.eu` , `https://www.transnetbw.de`

[6] This diagram shows on the x-axis the mean of the residual load profile of each day and on the y-axis the corresponding standard deviation σ of the load profile

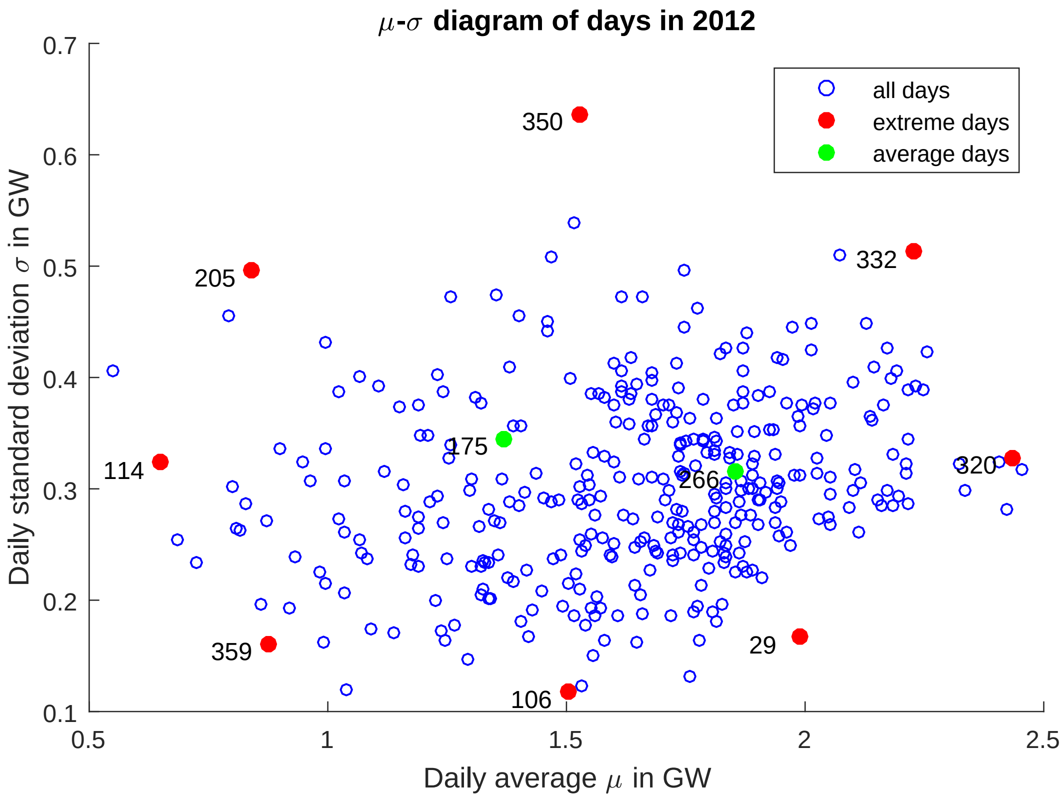


Figure 2.3.: σ-μ diagram of residual load from days in 2012.

Table 2.3.: Techno-economic data of implemented plants.

Technology	Unit size MW	# units	Minimum load %MWp	Maximum gradient %MWp/min	Marginal costs €/MWh	Startup costs €/MW
Nuclear	1200	1	50	5	5	125
Coal	320	2	40	4	45	85
CCGT	200	3	35	5	65	102
GT	160	3	20	10	112	102
Oil	80	1	10	10	164	85

2.6. Results

In this section deviations between model results derived from the binary equilibrium implementation (BE), the social planner implementation (SP) and its integer relaxed solution (RSP) are shown. The focus of this study is laid on derived prices and dispatch decisions. Additionally, a comparison of required compensation payments to generators is carried out. All results are shown for each of the selected days. In day 205 and 302 it was in the BE approach not possible to achieve a quasi-equilibrium according to Definition 2. This means that linear prices alone do not incentivize generators to take the dispatch decisions intended by the PE. Therefore, additional measures, like generation curtailments, would be needed to enforce the socially optimal dispatch.

Figure 2.4 shows the resulting spot prices for each hour of the modeled days and the three model implementations. In the SP and RSP model the prices are derived from to dual variables of the market clearing equation (2.9b), whereas the spot price in the BE approach is a dedicated model variable. In general, the prices of SP and BE do match quite well in form and level. Now and then there are peaks and tales, where the models deliver different prices. The RSP approach in general delivers lower prices with less variability, which is not surprising due to the fact that it neglects inflexibilities of generators. As such, spot prices from the RSP approach do not allow generators to recover their full generation costs. Therefore, in small markets where convexities of generators matter, prices from linearized models do not deliver adequate proxies for spot prices.

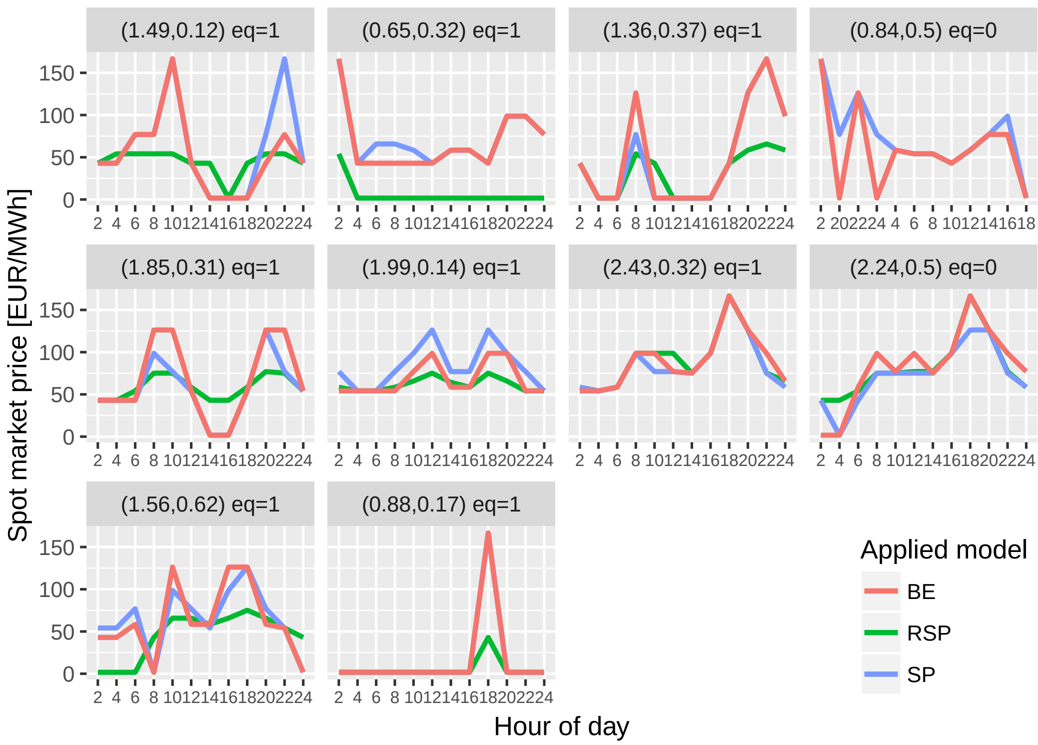


Figure 2.4.: Comparison of resulting spot prices of three modeling approaches for different days. Within the grey headings the (μ,σ)-tuple of the corresponding day and whether the resulting prices constitute an equilibrium or not are indicated.

The resulting prices for reserve capacity are illustrated in Figure 2.5 for both positive and negative reserves and the three model implementations. In general, the BE model leads to higher prices than the SP approach for both types of reserves. However, as in case of spot prices the SP approach deliver reserve prices, which match the ones of the BE model approach quite well. The RSP produces prices that are sometimes overestimate and sometimes underestimate the prices from the other approaches. There are, however, some days in which the resulting RSP price is closer to the one of BE than the one of the SP model. With the RSP approach it was not possible to produce any price for negative reserve capacity since there is no strict minimum load constraint.

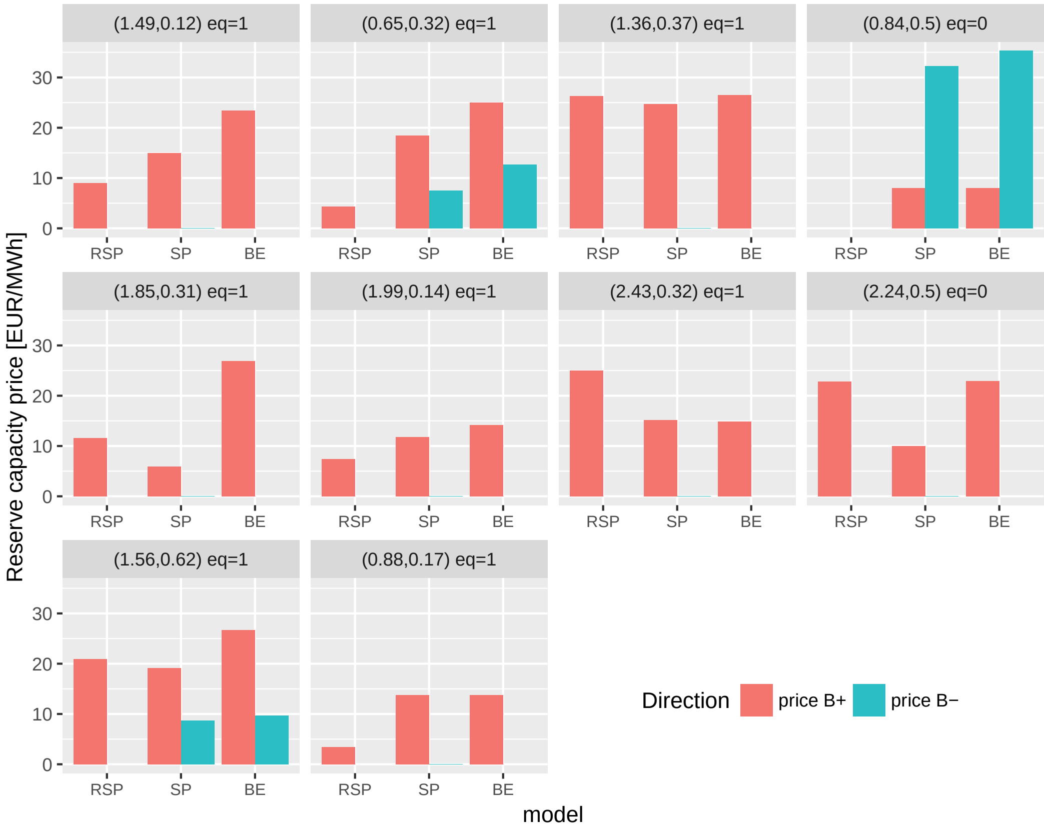


Figure 2.5.: Comparison of reserve capacity prices of three modeling approaches for different days. Within the grey headings the (μ,σ)-tuple of the corresponding day and whether the resulting prices constitute an equilibrium or not are indicated.

When it comes to deviations in generator dispatch and commitment for the sake of simplicity only the SP and the BE model are contrasted to each other. In Figure 2.6 the difference in generation of each generator related to the load in the corresponding hour are shown over time and for each day. There are a couple of days where dispatch deviations are negligible. There is another group of days where deviations are within the range of 10 percent and two days where deviations actual reach 20 percent of total load. Note, that relative deviations are more significant at lower levels of actual load. Therefore the higher deviations stem from times of low load and are less outstanding in absolute terms.

Finally, a comparison of necessary compensation payments to generators are shown. In contrast to the SP approach, where side payments are a part of the actual market design, in the BE approach the aim was to minimize these payments in order to come closest to the case linear prices alone would suffice to recover all generation costs. The sum of payments to all generators for each day are shown in Figure 2.7. The payments ζ_i resulting from the BE

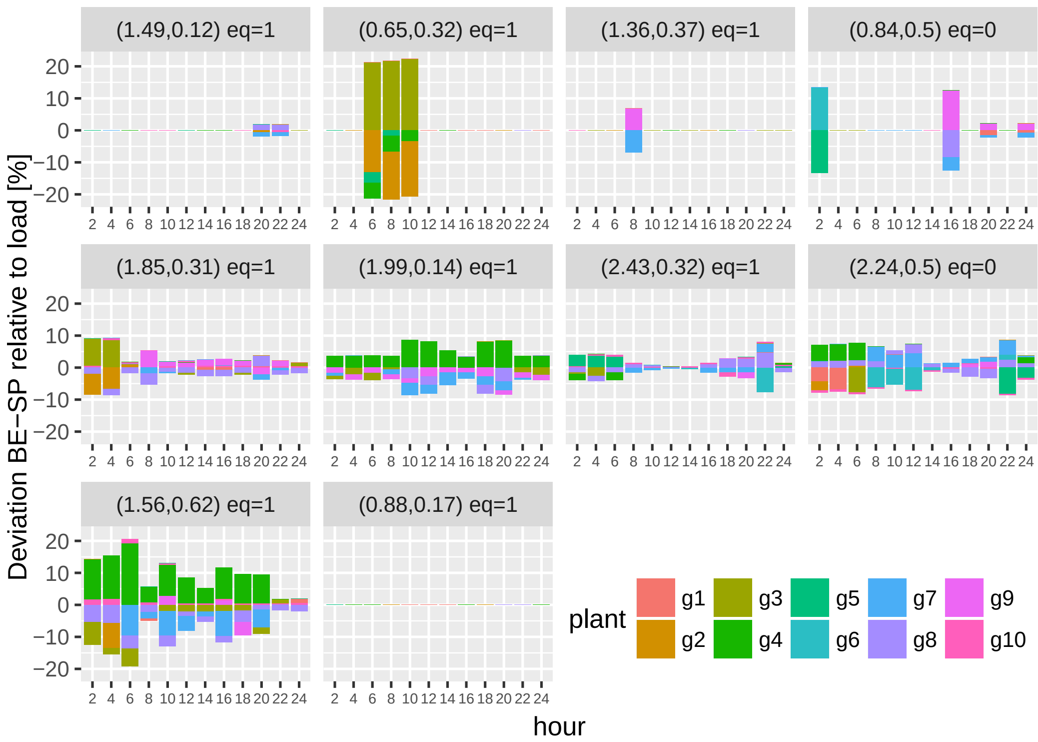


Figure 2.6.: Dispatch deviations of generators between the SP and the BE model approach relative to total consumption for different days. Within the grey headings the (μ,σ)-tuple of the corresponding day and whether the resulting prices constitute an equilibrium or not are indicated.

model are marked as *Comp*. For the SP model two payment schemes have been considered, make-whole payments and positive O'Neill payments. Whereas positive O'Neill payments do also constitute equilibria, make-whole payments assume that generators are forced to follow a certain unit dispatch and commitment and thus do not constitute equilibria as defined. It is obvious from Figure 2.7 that also in the BE model it is not possible to eliminate all compensation payments to generators. However, compensation payments are significantly lower than the ones resulting from the SP model and are often in the range of make-whole payments. The day (0.84,0.5) is outstanding as compensation payment to generator 1 resulting from the BE model is even higher than the O'Neill payment. Since in two of these three days also the generator dispatch deviates from the SP model it can be concluded that due to lower market revenues stemming from lower prices more compensation payments were needed for generator 1, whereas the payments to other generators were significantly lower.

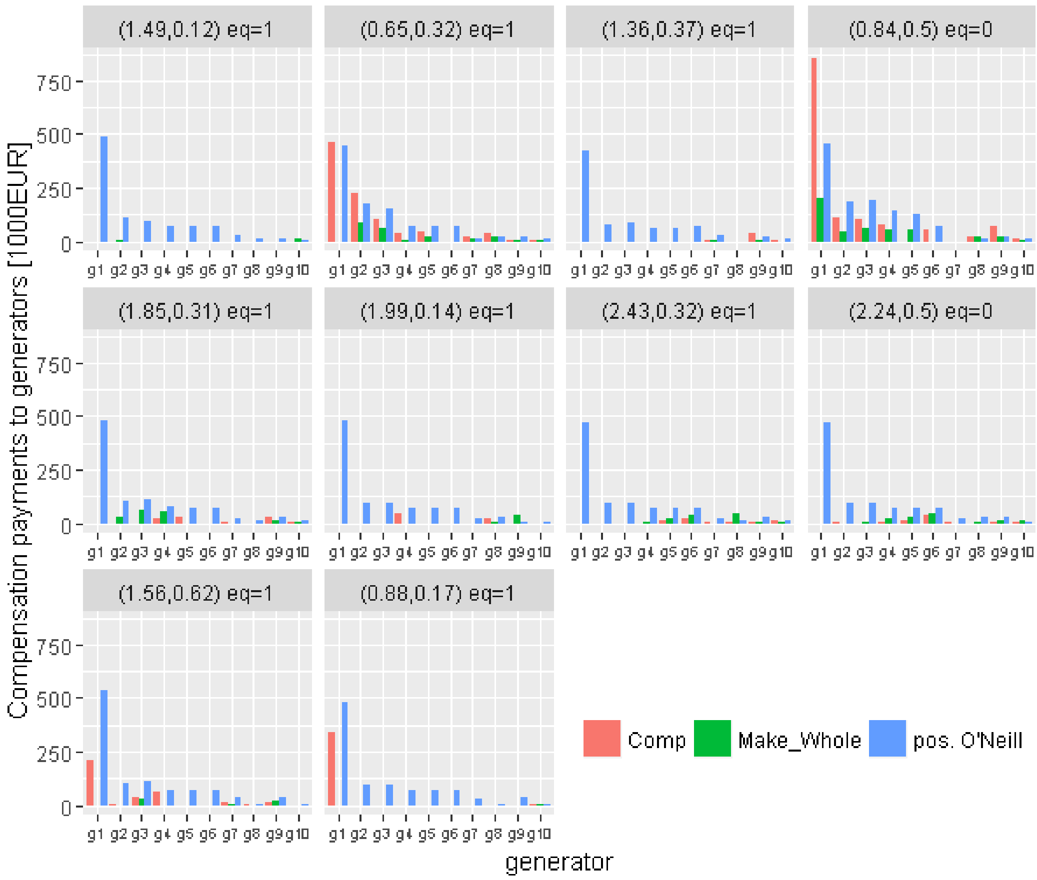


Figure 2.7.: Required compensation payments of generators for different days. Within the grey headings the (μ,σ)-tuple of the corresponding day and whether the resulting prices constitute an equilibrium or not are indicated.

2.7. Discussion of results

In this section a novel mixed-integer linear problem formulation of a mathematical program with equilibrium constraints (MPEC) has been presented that is designed in a way to model pricing of spinning capacity reserves in self-dispatched market models including non-convexities. This optimization framework have been formulated in a way that competitive quasi-equilibria (CQE) in electricity spot markets including auctions for reserve capacity can be derived.

The results of this model (BE model) are considered as benchmark and were contrasted with the results of two other modeling approaches that are commonly used in the literature to simulate electricity prices. In the literature these approaches are known as *least-cost-solution*, or *central-planner approach*. These other approaches are of particular interest since they are classical unit-commitment models used by system operators that manage centrally committed electricity markets. From the comparison of model results it became apparent that the CQE did not maximize economic surplus to market participants. The deviations in dispatch and unit-commitment decisions from all generators ranged in between 10 to 20% of actual load. This deviation led to average welfare losses of 5% against the least-cost solution.

With regard to market and auction prices the model results showed that the classical unit-commitment model, i.e. the least-cost approach, delivered reasonable similar prices than the CQE model. The prices derived from a linear relaxation of the unit-commitment model proved to be not a suitable proxy for competitive market prices that would constitute an equilibrium. Based on this argumentation it can be concluded that the classical unit-commitment model used by system operators in centrally committed electricity markets can be applied to derive market and reserve auction prices that are fairly close to the ones of a quasi-equilibrium, as the one that is established on exchange-based markets like the ones in Europe. Due to the fact that the QCE-approach has very limited scalability, this conclusion is very useful, because it enables the large-scale modeling of prices in liberalized electricity markets including non-convex preferences. This approach is applied in the subsequent chapters of this thesis.

Chapter 3

The Austrian electricity balancing market

A case study

3.1. Nomenclature

Table 3.1.: Description of sets, scalars and parameters used in the yearly dispatch model

Sets & Mappings	
$t \in T$	... hours in whole time period T
t^{start}, t^{end}	... first and last hour of modeled time period T
$f \in F$	... technology and fossil fuel category
$s \in S$	... (pumped-) hydro storages and run-of-river power plants
$chp(f)$	... subset of combined heat & power conventional generators
$r \in R$	... type of reserve (SRL, TRL)
$res \in RES$	... reservoirs of the hydro grid
$UP(s, res)$	... upper reservoir of res connected via plant s
$UP(res)$	... set of upper reservoirs
$LO(s, res)$	... lower reservoir of res connected via plant s
Scalars and Parameters	
c_f^G	... average marginal electricity generation costs of group f
g_f^{max}	... maximum generation capacity of group f
$g_{chp,t}^{min}$	... minimum required generation induced by exogenous heat demand
$g_{st}^{turb,max}$	... maximum generation of turbines in plant s
$d_{st}^{pump,max}$	... maximum demand of pumps in plant s
k_{fr}	... parameter accounting for minimum-load requirement for reserve type r
G^{pump}	... total yearly amount of electricity used for pumping
FL_t^{UP}	... aggregated total fill-level of upper reservoirs in hour t
η_s	... conversion efficiency of turbines/pumps in plant s
g_0	... standard gravity of earth
$\Delta h_{res,s}^{UP}$	... height difference between res and upper reservoir via s
$\Delta h_{res,s}^{LO}$	... height difference between res and lower reservoir via s
$b_{rf}^{+/-\,max}$	... maximum pos/neg capacity to be offered for reserve r
$r_f^{\mathrm{up}}, r_f^{\mathrm{down}}$	... maximum aggregated up-/down-ramping rate (in $\%\, g_f^{max}$/h)
$b_{rt}^{+/-\,req}$	... exogenous demand for pos/neg reserve capacity r in hour t
p_t^S	... electricity spot market price in hour t

Table 3.2.: Description of variables used in the yearly dispatch model

Variables

Positive continuous variables

g_{ft}	... electricity generation of group f in hour t
$g_{ft}^{\mathrm{up}}, g_{ft}^{\mathrm{down}}$	... hourly up-/down-ramping of generation group f
g_{st}^{turb}	... electricity generated through turbining of plant s in hour t
d_{st}^{pump}	... electricity consumed through pumping of plant s in hour t
$b_{r,f/s,t}^{+/-}$	... provided pos/neg reserve capacity of type r from generation group f / plant s in hour t
$fl_{res,t}$	... fill-level of reservoir res in hour t
$\phi_{res,t}^{In}$	... natural water inflow into reservoir res in hour t
$\phi_{res,t}^{Spill}$	... spilled water from reservoir res in hour t

Table 3.3.: Description of sets, scalars and parameters used in the capacity reservation model

Sets & Mappings	
$t \in T$	... hours in whole time period T
t^{start}, t^{end}	... first and last hour of modeled time period T
$i \in I$	... power plants
$c(i) \in I$	... thermal power plants
$s(i) \in I$	... (pumped-) hydro storages and run-of-river power plants
$chpFix(c)$	... inflexible combined heat & power conventional generators
$chpFlex(c)$	... flexible combined heat & power conventional generators
$o \in O$	... plant owner/operator o
$P(o, i)$	... plants i within the portfolio of owner o
$\pi \in \Pi$	... market product π (time slice)
$r \in R$	... type of reserve (SRL, TRL)
$TS(\pi, r, t)$	... hours within product π and reserve type r
$res \in RES$	... reservoirs of the hydro grid
$UP(s, res)$	... upper reservoir of res connected via plant s
$LO(s, res)$	... lower reservoir of res connected via plant s
Scalars and Parameters	
$t^{\text{up}}, t^{\text{down}}$	... minimum online/offline hours
c_c^G	... marginal electricity generation costs of plant c
$c_c^{\text{on}}, c_c^{\text{off}}$	... start-up/shut-down costs per MW of plant c
c_c^{PL}	... marginal generation costs at part-load (g^{min})
g_c^{min}	... must-run generation if power plant c is online
g_c^{max}	... maximum generation capacity of plant c
g_{ct}^{Heat}	... required generation induced by exogenous heat demand
$g_{st}^{turb,max}$	... maximum generation of turbines in plant s
$d_{st}^{pump,max}$	... maximum demand of pumps in plant s
ps_s	... number of output steps of pumps installed in plant s
ms_s	... number of machine sets in plant s
η_s	... conversion efficiency of turbines/pumps in plant s
g_0	... standard gravity of earth
$\Delta h_{res,s}^{UP}$	... height difference between res and upper reservoir via s
$\Delta h_{res,s}^{LO}$	... height difference between res and lower reservoir via s
$b_{ri}^{+/-\,max}$	... maximum pos/neg capacity to be offered for reserve r
$r_c^{\text{up}}, r_c^{\text{down}}$	... maximum up-/down-ramping rate (in % g^{max}/h)
bal_{ri}	... binary parameter =1 if plant i is eligible to provide reserves r
$b_{rt}^{+/-\,req}$	... exogenous demand for pos/neg reserve capacity r in hour t
$b_r^{+/-\,MR,min}$	... minimum allowed bid size of pos/neg reserve capacity r
$b_r^{+/-\,MR,max}$	... maximum allowed bid size of pos/neg reserve capacity r
$p_r^W es$	... marginal water value of reservoir res in hour t
p_t^S	... electricity spot market price in hour t

Table 3.4.: Description of variables used in the capacity reservation model

Variables	
Positive continuous variables	
g_{ct}	... electricity generation of plant c in hour t
$g_{ct}^{\text{up}}, g_{ct}^{\text{down}}$	... hourly up-/down-ramping of plant c
g_{st}^{turb}	... electricity generated through turbining of plant s in hour t
d_{st}^{pump}	... electricity consumed through pumping of plant s in hour t
$b_{rit}^{+/-}$	... provided pos/neg reserve capacity of type r from plant i in hour t
$z_{tc}^{\text{on}}, z_{tc}^{\text{off}}$	... inter-temporal start-up/shut-down decision of plant c
$fl_{res,t}$	... fill-level of reservoir res in hour t
ϵ_{res}	... deviation of end fill-level from level defined in the yearly model
$\phi_{res,t}^{In}$	... natural water inflow into reservoir res in hour t
$\phi_{res,t}^{Spill}$	... spilled water from reservoir res in hour t
Binary and integer variables	
x_{ct}^{G}	... on/off decision of power plant c
x_{st}^{turb}	... number of active turbines in power plant s
x_{st}^{pump}	... number of active pump steps in power plant s

Table 3.5.: Description of sets, scalars, parameters and variables used in the balancing energy call model

Sets & Mappings	
$t \in T$	... hours in whole time period T
$q \in Q$	... quarter-hours within an hour
$p \in P$	... parts within an quarter-hour
$r \in R$	... type of reserve (SRL, TRL)
$i \in I$	... generators and demand-side applications
$T(t,q,p)$	... set linking hours, quarter-hours and parts
Scalars and Parameters	
$p_{rit}^{Call+/-}$	... marginal costs of balancing power call
σ_{trqp}^{+}	... share of duration of pos. balancing power call of r within part p of quarter-hour q of hour t
$b_{rit}^{+/-}$	... provided pos/neg reserve capacity of type r from plant i in hour t
$cap_{rtqp}^{+/-\,req}$	... required balancing power of reserve r in part p of quarter-hour q of hour t
Variables	
Positive continuous variables	
$cap_{ritqp}^{+/-}$	... called pos/neg balancing power of unit i for reserve r in part p of quarter-hour q of hour t

3.2. Literature review

3.2.1. General literature

In the literature there are a couple of distinct methods applied to study the energy sector in general and the electricity sector in particular. Ventosa et al. (2005) provides a good overview on modeling trends in electricity markets. The methods differ in their methodological approach, the model focus with regard to spatial and temporal data resolution and the level of detail in which actors and technologies are incorporated in the models. The several methodologies exhibit different inherent strengths and weaknesses and therefore the choice of methodology depends on the concrete research question to be answered.

In general, methods used to study electricity balancing markets can be categorized in top-down and bottom-up approaches (cf. Figure 3.1). In top-down approaches the market is considered to be a black box and only aggregated in- and output data are analyzed. An often used example for this approach in the context of electricity markets are different kinds of econometric models that aim to describe market prices as a result of only a few influencing exogenous parameters, e.g. (Graf et al., 2013).

Bottom-up approaches are based on a detailed representation of techno-economic characteristics of actors and/or components. Market prices are a result of decisions taken by several market participants, their available technical units and corresponding cost structure. Implementations of such approaches are therefore often referred to as fundamental modeling. This group of models can be subdivided into simulation models, optimization models and game-theoretic models. These models typically differ in their assumptions concerning the behavior of market players and the degree of detail with regard to concrete market design and regulations.

While simulation models are typically able to describe behavior of agents only by use of simple rules, optimization models deliver the optimum behavior of market participants by means of profit-maximizing strategies. However, this often comes at the cost of a less detailed description of their actual constraints. Large-scale optimization models applied to study markets thus normally do not contain any sort of non-linear dependencies, which may arise, for example, in oligopolistic markets when market players are able to influence market prices with their actions.

Simulation models are often implemented in agent-based model frameworks, where assumptions on agent's incentives drive them in an iterative process towards their preferred system states. In an ideal case the model outcome converges after a limited amount of iterations to any market equilibrium, where no agent have any remaining incentive to change his state. Weidlich and Veit (2008) provides a critical survey on agent-based models used to study wholesale electricity markets in general.

The existing electricity balancing markets throughout Europe significantly differ in their design and regulation, cf. (ENTSO-E, 2016) and (Ocker et al., 2016). A direct comparison of implemented designs and regulation is therefore difficult.

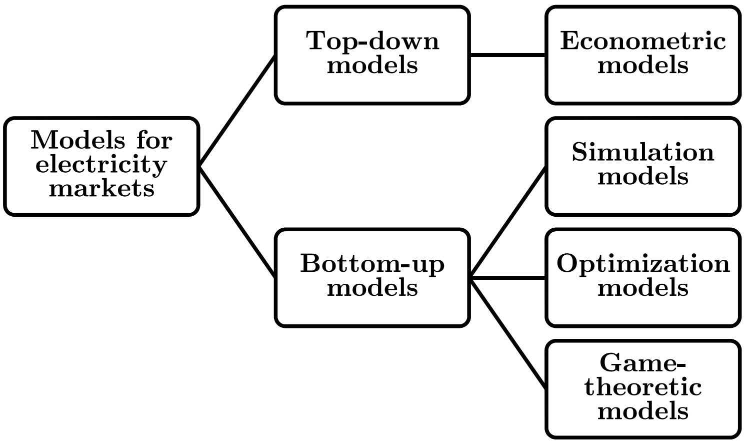


Figure 3.1.: Applied approaches to model electricity markets.

3.2.2. Specific literature

The procurement of balancing reserve capacities through auctions have been established in Austria in the year 2012. The performance of these auctions has not been extensively analyzed so far. However, most recently the outcome of these auctions increasingly attracted the attention of researches, market analysts and generation companies. I present the relevant literature based on the structure in Figure 3.1. According to this structure in the literature there are different methodologies used for the analysis of balancing markets.

First, there are some empirical studies focused on the Austrian balancing market. Kabinger et al. (2014) performed an empirical analysis of historic auction prices for different balancing reserves. Different econometric models have been applied to test whether auction results could be explained by fundamental market data. The authors were able to quantify price elasticity and the impact of cross-border participation in auctions for primary balancing reserves. Results on auctions for secondary and tertiary balancing reserves have not been presented. Esterl et al. (2016) empirically studied the relation between calling frequency and energy prices in the Austrian market. Neubarth (2014) focused his analysis on a international comparison of balancing energy costs for wind energy. On part of the simulation model approaches two prominent projects included the Austrian balancing market. The EU-funded project eBADGE (2015) studied potential cost reductions of a common-merit-order list between Austria, Slovenia and Italy based on historical prices. In the iwpp flex (2017) project the Austrian Institute of Technology and others study the market potential of coordinated heat pump portfolios in the Austrian balancing market. The author categorized these models under simulation models, since prices have been assumed to be exogenous to the models and only classical portfolio optimization techniques have been applied. The study of market results by means of welfare optimization models have been performed by Ortner and Graf (2013) and Clemens Gerbaulet et al. (2014), who focused on impacts of (balancing) market coupling between Austria, Switzerland and Germany. Finally, the only study of the

Austrian balancing market that are based on game-theoretic reflections has been carried out by Petritsch (2017).

The balancing electricity market architecture of Germany and Switzerland is organized in a similar fashion. The German market differs from the Austrian market mainly through the generation mix of market participants, as well as the liquidity and trading volumes of auctions. The number of studies concerning the German balancing electricity market, in particular related to the procurement of balancing reserve capacities, is also limited. A good overview on economic fundamentals related to the provision of balancing reserves in context of the German market is given in Müsgens et al. (2014). Just and Weber (2010) and Müsgens et al. (2012) elaborate on the impact of gate-closure-time on market results. A methodology to study market prices for procurement of positive balancing reserves in the German market design has been presented in Just and Weber (2008). Heim (2011) has performed a comprehensive empirical study on historic market results in Germany and found indications for temporary exertion of market power. Bergler et al. (2016) showed that market participants might have incentives to act collusively in German pay-as-bid auctions. The author does not know any relevant studies dealing with Swiss balancing reserve procurement auctions. Ocker et al. (2015) focuses on a game-theoretic analysis of the German market for secondary reserves.

In conclusion, there is a need for in-depth analysis of balancing electricity markets in the European context and in particular for the Austrian market. A number of top-down analyses have been performed, which, however, did only provide fundamental insights in procurements of primary reserve capacity. A comprehensive bottom-up analysis of reserve capacity provisions for all relevant products has not been carried out so far. For this reason the aim of this study is to develop a comprehensive modeling framework to study capacity and energy prices that resulted from past balancing reserve capacity procurements in Austria. In particular, the focus is laid on the procurement of secondary and tertiary balancing reserves.

This chapter is organized as follows. First, a concise overview on the electricity market architecture in Austria is given to provide the reader with the necessary understanding of the modeling results. Second, the modeling framework is described in detail and relevant input data for the models is documented. Third, the analyzed scenarios are presented. Finally, the model results are shown and compared with historical prices and costs in these markets.

3.3. Electricity market architecture in Austria

The market design elements in Europe's electricity markets are constantly refined and adjusted to meet the requirements of the envisioned target model for the EU internal electricity market. The Austrian electricity market is implicitly coupled to all neighboring market areas and part of the pan-European market coupling process that foresees the integration of all electricity market segments across Europe. At the time this thesis has been written the Austrian market was part of the common German/Austrian market area. Within this area no trade restrictions were imposed between both countries. Consequently, the majority of wholesale market design elements in Austria have been evolved in a similar fashion like the ones implemented in Germany. However, due to bottlenecks of available transmission capacity within this market area an increasing amount of actual physical flows had to bypass the direct route between Germany and Austria trough neighboring countries. These so-called *loop-flows* were the reason why the involved energy regulators agreed on a market-splitting of the German/Austrian market zone[1]. A detailed description of the currently implemented market design in Austria would therefore not only be beyond the scope of this work, but also out-of-date at the time of writing. Nevertheless, the basis elements of the markets remain relatively constant over time. This section therefore documents the basic architecture of the market and provides a snapshot of the currently implemented time frames in the Austrian electricity market with a particular focus on the electricity balancing mechanism.

3.3.1. Intertemporal organization of market segments

The time frames where electricity trading is possible range from years-ahead to minutes-ahead of physical delivery. The market is basically organized as a sequence of multiple sequentially clearing market segments that are loosely coupled through the opportunity of arbitrage activities. Due to the fact that this work focuses on short-term electricity markets, forward and future markets are excluded in the following. Figure 3.2 gives a graphical illustration of the chronological sequence of available short-term marketing opportunities in Austria (Kabinger et al., 2014). All available marketing opportunities can be grouped into three categories. The first category consists of exchange-based and bilateral trades related to a certain amount of energy to be physically delivered over a specified time period in the future. The most liquid market places are the hourly day-ahead markets on the EPEX Spot and the EXAA power exchange, which mostly differ by the number of participants as well as the gate open and gate closure time. The EPEX Spot also operates Intra-day markets in which trading for participants located in the Austrian control zone until 45 minutes ahead of physical delivery is possible. On bilateral trading platforms (OTC-trading) trading can take place until 15 minutes ahead of physical delivery. The second group of available marketing opportunities consists of only one element, which is based on the remuneration of balancing groups that counterbalance imbalances of the overall control area. This marketing opportunity is made available through the fact that balancing groups in Austria are not legally obliged to stick to their announced schedules. They are even paid the real-time price of system imbalances in case they help to reduce the overall system imbalance, which is publicly published by the TSO in real time. In this work we will abstract from all those different trading activities mentioned above and refer to it as the *spot market*. The third option for revenues are stemming from the so-called *balancing mechanism* and are only available for companies that have physical assets. These companies can offer the TSO their assets for electricity balancing. The TSO regularly carry out auctions in order to procure a predetermined quantity of reserve capacities that are called to counterbalance high-frequency control area imbalances. The lower part of Figure 3.2 shows the currently implemented

[1] `https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/DE/2017/15052017_DE_AU.html`

trading windows of the three traded reserve qualities. The next section gives a more detailed description of the design of these auctions.

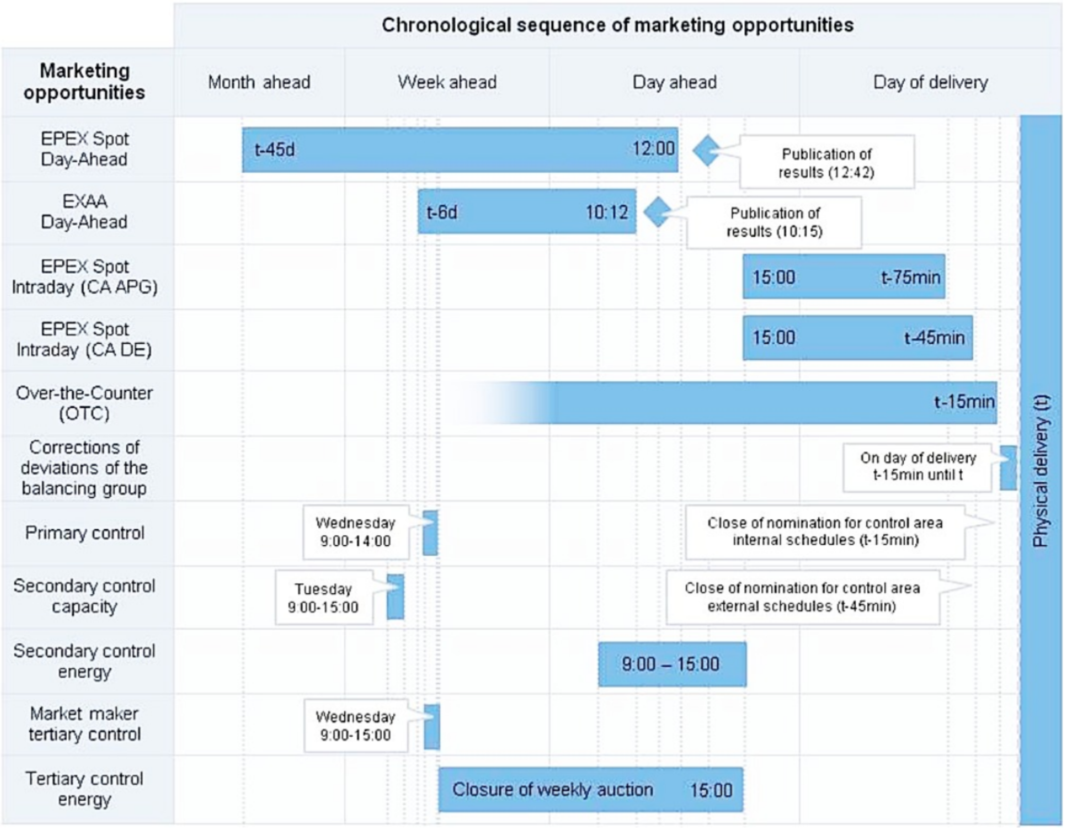


Figure 3.2.: Intertemporal sequence of marketing opportunities in Austria. Source: Kabinger et al. (2014).

3.3.2. Auctions for reserve capacity

In Europe the TSOs maintain system stability through the market-based procurement and subsequent activation of reserve capacity. TSOs automatically and manually activate these capacities in a way to balance short-term deviations of actual generation and load from market schedules and load profiles. The corresponding procurements are typically organized as one-sided multi-dimensional auctions, whereas the actual auction design significantly varies across European countries, cf. ENTSO-E (2016). All tendered products consist of time slices in which a certain quality[2] of capacity needs to be reserved in order to be called at any time within that period. In Austria this capacity is procured in dedicated single-side demand auctions, which are currently conducted one day until one week-ahead of product delivery. Figure 3.3 shows some details concerning the implemented auction design. Each of the shown products is traded independently on an organized online platform[3] operated by the Austrian

[2]The quality manifests itself in the form of different maximum reaction times after the capacity is called.
[3]`https://www.apg.at/emwebapgrem/startApp.do`

transmission system operator *Austrian power grid* (APG). At the time this study has been carried out secondary reserve products have been traded with a weekly delivery period in peak-, off-peak hours during working days and around the clock on weekends for both upward (positive) and downward (negative) regulation. Tertiary reserves were traded as 4-hour time slices during the day and for both positive and negative reserve capacities. Distinct products for positive and negative reserves are an important design element, which also enables actors with asymmetric controllability (e.g. demand shedding/shifting or downward regulation of wind turbines) to participate in such markets. With regard to comparability of prices and a concise presentation of the results the prices in the results section are expressed in units of EUR/MWh and averaged over peak, off-Peak and base products.

	Auction ahead of delivery	Auctioned products	Product structure / Total volumes	Award procedure
Primary control	• **Week-ahead** Fri. 12:00 to Tue. 15:00	POS and NEG together • **Week** Mon.-Sun. 00:00-24:00	**2-part product** • Capacity price [€/MW] • Amount [MW] > 1 MW **Total volume** +/- 62 MW (AT) International cooperations Germany: 603 MW Switzerland: 68 MW Netherlands: 107 MW	Merit-order of **capacity price** (pay-as-bid) In case of equal price offer • First-come, first-served
Secondary control	• **Week-ahead** Fri. 12:00 to Wed. 15:00	For each POS and NEG: • **Peak Week** Mon.-Fri. 08:00-20:00 • **Off-peak Week** Mon.-Fri. 20:00-08:00 Sat.,Sun. 00:00-24:00	**3-part product** • Capacity price [€/MW] • Energy price [€/MWh] • Amount [MW] > 5 MW **Total volume** Positive: + 200 MW Negative: – 200 MW Cooperation with DE	Merit-order of **capacity price** (pay-as-bid) In case of equal price offer • (lowest:POS, hightest:NEG) energy price • First-come, first-served Calling of balancing power in order of the energy prices (pay-as-bid)
Tertiary control	• **Week-ahead** • **Day-ahead** from Mon. to Fri. • On Fri. for whole weekend	For each POS and NEG: • **12 four-hour time slots**	**3-part product** • Capacity price [€/MW] • Energy price [€/MWh] • Amount [MW] > 1 MW **Total volume** Positive: + 280 MW Negative: – 170 MW	Merit-order of **capacity price** (pay-as-bid) In case of equal price offer • (lowest:POS, hightest:NEG) energy price • First-come, first-served Calling of balancing power in order of the energy prices (pay-as-bid)

Figure 3.3.: Implemented design of auctions for balancing reserves in Austria.

3.4. Method of approach

The mathematical foundation of bottom-up modeling balancing markets has already been given in chapter 2. In this section the described methods are adapted and extended in order to be suitable to model a real-word market with all its complexities. In particular, the fact that the Austrian generation mix is characterized by a high share of hydro power plants, including large-scale storages and a considerable number of thermal power plants simultaneously providing heat and power, significantly complicates the required modeling framework. A detailed description of how these two technologies and their characteristics have been capture in the model are given in Annex A. Besides the complex technological constraints of the involved technologies another factor complicates the analysis of this market segment. The fact that operational planning of large-scale hydro storages happens within forecast periods up to one year requires the model to cover this time frame as well. On the other hand a detailed analysis of short-term markets calls for a focus on time steps in the range of seconds to minutes. The necessity to cover both long and short-term periods within the modeling framework is approached by combining several models with different complexity and time scope.

The aim of the modeling work is to provide market results under the assumption of perfect competition, i.e. incentives to exert market power are not modeled and it is assumed that no information asymmetry exists between market players. Also, the proposed modeling framework is deterministic, i.e. market participants can perfectly forecast all relevant input data of their profit-maximization problem. The resulting prices of this model shall therefore be interpreted as a lower bound of prices stemming from a perfectly competitive market. As such they can serve as a benchmark in order to study fundamental price drivers in these markets and to assess potential impacts of different market designs and regulations.

3.4.1. Description of applied modeling framework

In order to meet above mentioned criteria three mathematical optimization models with different scopes have been combined. The three-stage model coupling is needed in order to adequately capture the complexity of the problem to be solved. Figure 3.4 gives a graphical representation of the modeling framework.

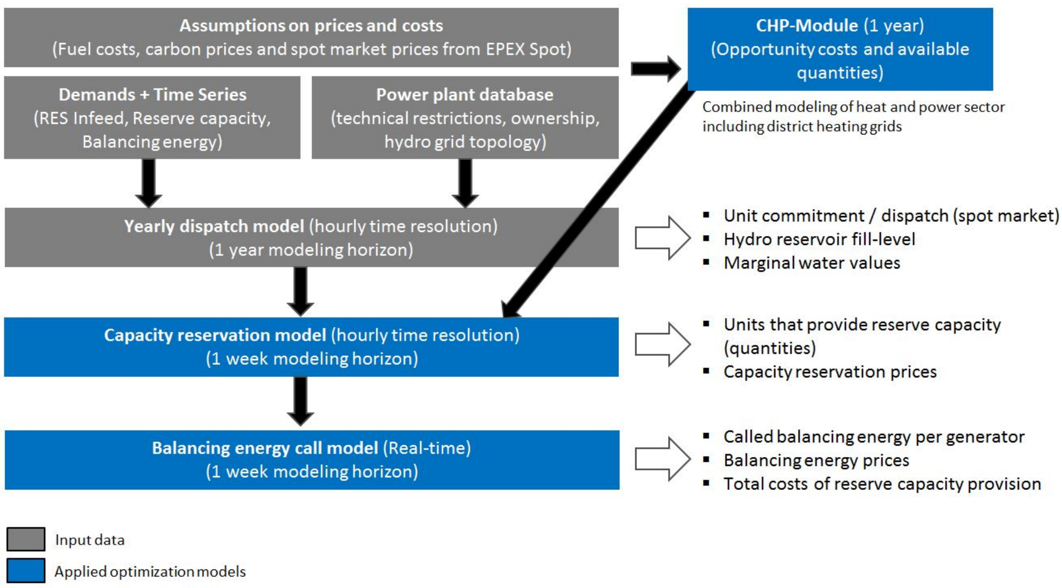


Figure 3.4.: Structure of the modeling framework.

All models use the same input database and are operated sequentially. Each of the models provides a certain part of the overall results. The output of all models except the last one in the sequence serve as additional input data to the subsequent model. The spot-market model has to be interpreted as proxy for all short-term energy-only markets (i.e. day-ahead, intra-day markets) and provides the optimal yearly dispatch of generators. In case more countries or price zones are implemented the model also provides inter-zonal power flows. Other important outcomes of this model are the fill level of reservoirs and the corresponding water values in each time step, which are then forwarded to the capacity provision model. This model determines the generators that should be committed in the spot-market and the ones providing reserve capacity. The cost structure of those generators serves as a basis to calculate the costs and subsequently the prices of capacity reserve provision. Finally, the energy call model determines costs and prices of actually called balancing energy. In the following each of the models is described in more detail.

3.4.1.1. Yearly dispatch model

The first optimization model generally serves to account for the long planning horizon of large-scale hydro storage power plants. This model has a hourly time resolution and considers a time period of one year. The main aim of the model is to derive optimal fill-levels of each reservoirs from a yearly perspective. These fill-levels then inform the capacity reservation model on optimal weekly start and end fill-levels. A further important output of this model are hourly water values for a specific reservoir, as well as water values converted and related to the generation of a specific hydro power plant. In order to account for capacities, which are withhold from electricity generation in the spot market a simplified representation of capacity reserve provision is also implemented. Table 3.1 and 3.2 located at the beginning of this chapter in section 3.1 provide an description of the nomenclature containing a short description of parameters and variables implemented in the model.

The objective of the model is to maximize profits of all generators under the assumption of fixed exogenous spot-market prices (c.f. equations 3.1). This means it has been assumed that the spot-market operated under the condition of perfect competition. In the current version of the model historic day-ahead prices of the Austrian/German price zone have been taken as proxy of the spot market price. The day-ahead auction accounts for the main share of revenues of generators from power exchanges. However, also any kind of generator-specific additional revenues, e.g. intra-day revenues, could be easily integrated in this model framework. Thermal generators are aggregated into categories according to primary fuel type and technology. Respective parameters for each group have been derived from capacity-weighted averages of plant-specific parameters within the group. Because of the highly meshed hydro power grid in Austria each single hydro power plant and the respective reservoir topology have been implemented. The costs within this model mainly arise from marginal generation costs and ramping costs of thermal generators.

$$
\begin{aligned}
\max\,(\text{Profit}) = \max\,(\,\text{Revenues - Costs}\,) \quad & = \\
\sum_{f,t} p_t^S g_{ft} + \sum_{s,t} p_t^S (g_{st}^{turb} - d_{st}^{pump}) \quad & (\text{Market revenues}) && (3.1a) \\
- \sum_{f,t} c_f^G g_{ft} \quad & (\text{Generation costs}) && (3.1b) \\
- \sum_{f,t} g_{ft}^{\text{up}} c_f^{\text{up}} + g_{ft}^{\text{down}} c_f^{\text{down}} \quad & (\text{Ramping costs}) && (3.1c)
\end{aligned}
$$

The implemented model constraints comprise restrictions on *output level* and *output change*. Hourly electricity generation g_{ft} of each group is constrained by the maximum generating capacity of the specific group and the amount of reserves it provides (cf. equation 3.2a). Must-run generation is neglected within the yearly dispatch model. However, the provision of secondary capacity reserves require the generator to be online in order to react quickly on a call request. In order to account for this requirement equations (3.2b) and (3.2c) state a linearized proxy for the minimum load requirement, which is specific to each technology and reserve type and depends on the amount of reserves that is offered. The minimum load requirement for negative reserves is more strict than the one for positive, because after full down-ramping the generator should still remain online. Equation (3.2d) accounts for a certain amount of electricity that needs to be generated from chp plants so they are able to meet their heat demand profile. This demand is exogenous to the model and has been derived from a dedicated heat model described in (Büchele et al., 2015). The total amount of reserves that can be provided per group f is restricted by equations (3.2e) and (3.2f). In equation (3.3) the up- and down-ramping capacity that follows from changes in electricity generation is defined.

$$
\begin{aligned}
g_{ft} + \sum_r b_{rft}^+ &\leq g_f^{max} && \forall f \in F,\, t \in T && (3.2a) \\
g_{ft} &\geq \sum_r k_{fr}\, b_{rft}^+ && \forall f \in F,\, t \in T && (3.2b) \\
g_{ft} &\geq \sum_r (1 + k_{fr})\, b_{rft}^- && \forall f \in F,\, t \in T && (3.2c) \\
\sum_{chp} g_{chp,t} &\geq \sum_{chp} g_{chp,t}^{min} && \forall t \in T && (3.2d) \\
b_{rft}^+ &\leq b_{rf}^{+\,max} && \forall r \in R,\, f \in F,\, t \in T && (3.2e) \\
b_{rft}^- &\leq b_{rf}^{-\,max} && \forall r \in R,\, f \in F,\, t \in T && (3.2f)
\end{aligned}
$$

$$
g_{ft} - g_{f(t-1)} = g_{ft}^{\text{up}} - g_{ft}^{\text{down}} \qquad \forall f \in F,\, t \in T \qquad (3.3)
$$

The hydro power output restrictions are defined by the maximum turbine, or pump capacity of each plant, respectively, and the provision of capacity reserves. For simplicity in the yearly dispatch model it has been assumed that both turbine and pump can provide positive and negative reserve capacity and that turbining and pumping is not mutually exclusive in the strict sense, cf. equations (3.4a)-(3.4c). A more sophisticated formulation of this constraints is implemented in the capacity reservation model described in section 3.4.1.2. Due to the fact that pumps have been implemented much more flexible in the linear model as they actually are, in equation (3.4d) the total amount of electricity consumed from pumping has been limited to the actual historic consumption in that year.

$$g_{st}^{turb} + \sum_r b_{rst}^{+} \leq g_s^{turb,max} \qquad \forall\, s \in I,\, t \in T \tag{3.4a}$$

$$d_{st}^{pump} + \sum_r b_{rst}^{-} \leq d_s^{pump,max} \qquad \forall\, s \in I,\, t \in T \tag{3.4b}$$

$$g_{st}^{turb} + d_{st}^{pump} + \sum_r b_{rst}^{+/-} \leq \max\left(g_s^{turb,max}, d_s^{pump,max}\right) \qquad \forall\, s \in I,\, t \in T \tag{3.4c}$$

$$\sum_{s,t} g_{st}^{pump} \leq G^{pump} \tag{3.4d}$$

In this model a detailed representation of a cascaded hydro grid have been implemented. According to the topology of the grid, the operation of plants and natural water inflows each reservoir experience water in- and outflows. In equation (3.5) these flows are linked to the fill-level of the reservoirs. Each reservoir is implemented with three sources of inflows and three sources of outflows. The inflows stem from turbining of water from upper reservoirs and/or pumping of water from lower reservoirs. Additionally the reservoir may be filled by natural water inflows. Equivalently, the outflows are caused by turbining into lower reservoirs, or pumping into upper reservoirs. If the maximum fill-level of any reservoir is reached the model allows to spill the excess amount of water.

$$fl_{res,t} = fl_{res,(t-1)} + \sum_{s \in UP(s,res)} 10^3 \frac{g_{st}^{turb}}{\eta_s\, g_0\, \Delta h_{res,s}^{UP}} + \sum_{s \in LO(s,res)} 10^3 \frac{\eta_s\, d_{st}^{pump}}{g_0\, \Delta h_{res,s}^{LO}} \tag{3.5a}$$

$$- \sum_{s \in LO(s,res)} 10^3 \frac{g_{st}^{turb}}{\eta_s\, g_0\, \Delta h_{res,s}^{LO}} - \sum_{s \in UP(s,res)} 10^3 \frac{\eta_s\, d_{st}^{pump}}{g_0\, \Delta h_{res,s}^{UP}} \tag{3.5b}$$

$$+\phi_{res,t}^{In} - \phi_{res,t}^{Spill} \qquad \forall\, res \in RES,\, \forall t > 1 \in T \tag{3.5c}$$

In the linear model fill-levels simply have to be positive and are constrained by the maximum storage capacity of the reservoir, cf. equation (3.6). Additionally, the aggregated fill-levels of all upper reservoirs at the beginning and the end of the year are bound to exogenous levels in equation (3.7).

$$0 \leq fl_{res,t} \leq fl_{res}^{max} \qquad \forall\, res \in RES,\, \forall t \in T \tag{3.6}$$

$$\sum_{res \in UP(res)} fl_{res,t^{start}} = FL^{UP}_{t^{start}} \tag{3.7a}$$

$$\sum_{res \in UP(res)} fl_{res,t^{end}} = FL^{UP}_{t^{end}} \tag{3.7b}$$

In order to ensure that the required level of reserves is withhold from the market additional demand equations for different types of positive and negative reserves are implemented in equation (3.8).

$$\sum_{f} b^{+}_{rft} + \sum_{s} b^{+}_{rst} = b^{+req}_{rt} \qquad \forall f \in F,\, r \in R,\, t \in T \tag{3.8a}$$

$$\sum_{f} b^{-}_{rft} + \sum_{s} b^{-}_{rst} = b^{-req}_{rt} \qquad \forall f \in F,\, r \in R,\, t \in T \tag{3.8b}$$

3.4.1.2. Capacity reservation model

The capacity reservation model aims to find the specific power plants that are able to provide capacity reserves most efficiently. This means that those plants are chosen by the model, which have the lowest opportunity costs for providing capacity reserves of a certain type and over a certain time period. The amount those plants can contribute to overall capacity demand is determined by the model under consideration of their technical constraints and other framework conditions, like market regulations. Another important output of this model are a set of indicators that allow for the ex-post calculation of plant-specific opportunity costs related to the provision of reserve capacity. These costs form the basis for the calculation of capacity prices for the different types of reserves. By following this approach the model simulates reserve capacity auctions with perfect competition[4]. The model has an hourly time resolution and covers the time period of a week. The shorter time period allows for a more detailed representation of the technical constraints of power plants. These constraints are decisive for the correct determination of opportunity costs, because inflexibilities of generation and consumption causes a significant amount of additional costs. In the capacity reservation model each single power plant has been implemented. Hydro storage power plants are even more disaggregated down to the level of distinct machine sets. This level of disaggregation has been proven to be important to adequately capture the operational characteristics of these plants. A detailed listing of parameters and variables used in the model is shown in table (3.3) and (3.4) located at the beginning of this chapter in section 3.1.

The objective of the capacity reservation model is to maximize the profit of all generators given exogenous prices of the spot market. In that sense this model is similar to the linear dispatch model. However, the capacity reservation model is different in a way that it con-

[4]It should be noted that in chapter 2 it has been shown that the market outcome in case of profit-maximizing actors might slightly differ from the least-cost solution. However, since differences have been proven to be small, both market outcomes are considered to be equal in this chapter

siders a much more detailed representation of plants and their technical inflexibilities, i.e. operational constraints. As such, it involves a large number of binary and integer variables that account for these inflexibilities. The objective function states in equation (3.9) therefore comprise additional cost components like startup/shutdown costs and part-load costs stemming from a reduced conversion efficiency at lower output levels. The model receives for each week the start and end fill-levels of each reservoir, since they already have been implemented in the linear model. Due the additional inflexibilities in the capacity reservation model the required end fill-level might not be reached. Deviations from this fill-level are priced with the respective water value of the reservoir in order to integrate the long-term perspective into the weekly optimization.

$$\max\,(\text{Profit}) = \max\,(\,\text{Revenues - Costs}\,) \qquad =$$

$$\sum_{c,t} p_t^S g_{ct} + \sum_{s,t} p_t^S (g_{st}^{turb} - d_{st}^{pump}) \qquad \text{(Market revenues)} \tag{3.9a}$$

$$-\sum_{c,t} c_c^G g_{ct} \qquad \text{(Generation costs)} \tag{3.9b}$$

$$-\sum_{c,t} g_c^{max} (c_c^{\text{on}} z_{ct}^{\text{on}} + c_c^{\text{off}} z_{ct}^{\text{off}}) \qquad \text{(Startup/-down costs)} \tag{3.9c}$$

$$-\sum_{c,t} g_{ct}^{\text{up}} c_c^{\text{up}} + g_{ct}^{\text{down}} c_c^{\text{down}} \qquad \text{(Ramping costs)} \tag{3.9d}$$

$$-\sum_{c,t} c_c^{PL} \left(x_{ct}^G - \frac{g_{ct} - g_c^{min}}{g_c^{max} - g_c^{min}} \right) \qquad \text{(Part-load costs)} \tag{3.9e}$$

$$-\sum_{res} p_{res,t^{end}}^W \epsilon_{res} \qquad \text{(Fill-level deviations)} \tag{3.9f}$$

The output of thermal power plants is restricted by their maximum generating capacity and their provisions to reserve capacity, cf. equation (3.10a). The binary variables x^G do need to be set to 1 in order to allow for any generation that is greater than zero. This variable is used to implement the minimum-load conditions stated in equation (3.10b). The provision of secondary reserve capacity (SRL) also forces x^G to 1, since this type of reserve requires the generator providing it to be online. Equations (3.10e) to (3.10g) account for intertemporal constraints like minimum on/off-line hours of each generator.

$$g_{ct} + \sum_r b^+_{rct} \leq x^G_{ct} g^{max}_c \qquad \forall\, c \in I,\, t \in T \tag{3.10a}$$

$$g_{ct} - \sum_r b^-_{rct} \geq x^G_{ct} g^{min}_c \qquad \forall\, c \in I,\, t \in T \tag{3.10b}$$

$$b^{+/-}_{rct} \leq x^G_{ct} b^{+/-\,max}_{rc} \qquad \forall\, r \in \{SRL\},\, c \in I,\, t \in T \tag{3.10c}$$

$$b^{+/-}_{rct} \leq b^{+/-\,max}_{rc} \qquad \forall\, r \in \{TRL\},\, c \in I,\, t \in T \tag{3.10d}$$

$$x^G_{c(t-1)} - x^G_{ct} + z^{\text{on}}_{ct} - z^{\text{off}}_{ct} = 0 \qquad \forall\, c \in I,\, t \in T \tag{3.10e}$$

$$1 - z^{\text{on}}_{c(t-t^{\text{up}})} \geq \sum_{\tau \geq t - t^{\text{up}}}^{\tau < t} z^{\text{on}}_{c\tau} \qquad \forall\, c \in I,\, t \in T \tag{3.10f}$$

$$1 - z^{\text{off}}_{c(t-t^{\text{down}})} \geq \sum_{\tau \geq t - t^{\text{down}}}^{\tau < t} z^{\text{off}}_{c\tau} \qquad \forall\, c \in I,\, t \in T \tag{3.10g}$$

$$x^G_{ct} \in \{0,1\} \quad z^{\text{on}}_{ct}, z^{\text{off}}_{ct} \in \mathbb{R}_+$$

The ramping constraints of thermal units are stated in equation (3.11). These equations cover the worst-case scenario since it is not clear upfront, how balancing energy calls will impact the actual output of each generator. Therefore, it is assumed that generation ramping is limited under the assumption that both reserve directions are consecutively called in both directions.

$$g^{\text{up}}_{ct} + \sum_r \left(b^+_{rct} - b^-_{rc(t-1)} \right) \leq 60\, r^{\text{up}}_c g^{max}_c \qquad \forall\, c \in I,\, t \in T \tag{3.11a}$$

$$g^{\text{down}}_{ct} + \sum_r \left(b^+_{rc(t-1)} - b^-_{rct} \right) \leq 60\, r^{\text{down}}_c g^{max}_c \qquad \forall\, c \in I,\, t \in T \tag{3.11b}$$

$$g_{ct} - g_{c(t-1)} = g^{\text{up}}_{ct} - g^{\text{down}}_{ct} \qquad \forall\, c \in I,\, t \in T \tag{3.11c}$$

$$r^{\text{up}}_c, r^{\text{down}}_c \in [0,1]$$

The model differentiates between flexible and *inflexible* CHP plants. As *flexible* plants have been considered those, which are either composed of extraction-steam turbines, and/or have access to a heat storage. The remaining CHP plants have been assumed to be *inflexible* and are not qualified for provision of reserve capacities. The amount of electricity that is required from each CHP plant in order to fulfill its obligations for heat delivery have been derived from a dedicated heat model (Büchele et al., 2015). Flexible CHP plants have been assumed to be able to shift their minimum required electricity generation within a day d.

$$g_{chpFix,t} = g^{Heat}_{chpFix,t} \qquad \forall\, chpFix \in I,\, t \in T \tag{3.12a}$$

$$\sum_{t \in d} g_{chpFlex,t} \geq \sum_{t \in d} g^{Heat}_{chpFlex,t} \qquad \forall\, chpFlex \in I,\, d \in D,\, t \in T \tag{3.12b}$$

The feasible output of turbines and pumps in the capacity reservation model has been restricted with a dedicated set of additional constraints. The discrete output steps are realized via the introduction of plant-specific integer variables x^{turb} and x^{pump}. It can be seen in equations (3.13a) to (3.13d) to both, the turbine and the pump have discrete upper and lower output limits which are further constrained in case the units provide reserve capacity. The integer variable is divided by the number of machine sets ms installed in the plant. Pumps are further divided in distinct pump steps, since some existing pumps are able to be operated at multiple output levels, cf. equation (3.13e). In case power plants do not have a hydraulic bypass equation (3.13f) restricts the simultaneous operation of turbine and pump on the level of machine sets. A graphical representation of equations (3.13) can be found in Figures 3.28 and 3.29.

$$g_{st}^{turb} + \sum_r b_{rst}^{+} \leq \frac{1}{ms_s} x_{st}^{turb} g_{st}^{turb,max} \qquad \forall\, s \in I,\, t \in T \tag{3.13a}$$

$$g_{st}^{turb} - \sum_r b_{rst}^{-} \geq \frac{1}{ms_s} x_{st}^{turb} g_{st}^{turb,min} \qquad \forall\, s \in I,\, t \in T \tag{3.13b}$$

$$d_{st}^{pump} + \sum_r b_{rst}^{+} \leq \frac{1}{ms_s\, ps_s} x_{st}^{pump} d_{st}^{pump,max} \qquad \forall\, s \in I,\, t \in T \tag{3.13c}$$

$$d_{st}^{pump} - \sum_r b_{rst}^{+} \geq \frac{1}{ms_s\, ps_s} x_{st}^{pump} d_{st}^{pump,min} \qquad \forall\, s \in I,\, t \in T \tag{3.13d}$$

$$d_{st}^{pump} = \frac{1}{ps_s\, ms_s} x_{st}^{pump} d_{s}^{pump,max} \qquad \forall s \in I,\, t \in T \tag{3.13e}$$

$$x_{st}^{turb} + \frac{1}{ps_s} x_{st}^{pump} \leq ms_s \qquad \forall s \in I,\, t \in T \tag{3.13f}$$

$$x_{st}^{turb}, x_{st}^{pump} \in \mathbb{N}^{+}$$

The reservoir balance equations (3.14) are similar to the ones implemented in the linear model. The fill-level of each reservoir for the first and the last hour of each week is exogenously given and based on the results of the linear model run, cf. equations (3.15).

$$fl_{res,t} = fl_{res,(t-1)} + \sum_{s \in UP(s,res)} 10^3 \frac{g_{st}^{turb}}{\eta_s\, \mathrm{g}_0\, \Delta h_{res,s}^{UP}} + \sum_{s \in LO(s,res)} 10^3 \frac{\eta_s\, d_{st}^{pump}}{\mathrm{g}_0\, \Delta h_{res,s}^{LO}} \tag{3.14a}$$

$$- \sum_{s \in LO(s,res)} 10^3 \frac{g_{st}^{turb}}{\eta_s\, \mathrm{g}_0\, \Delta h_{res,s}^{LO}} - \sum_{s \in UP(s,res)} 10^3 \frac{\eta_s\, d_{st}^{pump}}{\mathrm{g}_0\, \Delta h_{res,s}^{UP}} \tag{3.14b}$$

$$+\phi_{res,t}^{In} - \phi_{res,t}^{Spill} \qquad \forall\, res \in RES,\, \forall t > 1 \in T \tag{3.14c}$$

$$fl_{res,t^{start}} = fl_{res,t^{start}}^{yearly} \qquad \forall\, res \in RES \tag{3.15a}$$

$$fl_{res,t^{end}} = fl_{res,t^{end}}^{yearly} + \epsilon_{res} \qquad \forall\, res \in RES \tag{3.15b}$$

Additionally to the output restrictions of turbines and pumps also the reservoir fill-levels are further constrained in the case of reserve capacity restrictions, cf. equations (3.16). The constraints can be grouped according to control direction. When positive reserve capacities are called water runs from upper to lower reservoir, or less water is pumped into the upper reservoir, respectively. The net flow of water is from upper to lower reservoir. In that case the storage operator would have to first ensure that the required amount of water is available in the upper reservoir and second that this amount fits into the lower reservoir. The total amount of water to be reserved depends on the maximum expected consecutive duration of positive energy calls. This expectation is implemented via the parameter SR. The respective equations are equation (3.16a) and (3.16b). Equivalently, when negative reserves are provided the net water flow in case of a energy call goes from the lower to the upper reservoir and the limits change accordingly, cf. equations (3.16c) and (3.16d).

$$fl_{res,t} - \sum_{\substack{t\,\in \\ [t\text{-SR},\, t+\text{SR})}} 10^3 \sum_{\substack{s\,\in \\ UP(s,res)}} \frac{\sum_r b^+_{rst}}{\eta_s\, \mathrm{g}_0\, \Delta h^{UP}_{res,s}} \geq 0 \qquad \forall\, res \in RES,\, \forall t \in T \tag{3.16a}$$

$$fl_{res,t} + \sum_{\substack{t\,\in \\ [t\text{-SR},\, t+\text{SR})}} 10^3 \sum_{\substack{s\,\in \\ LO(s,res)}} \frac{\eta_s \sum_r b^+_{rst}}{\mathrm{g}_0\, \Delta h^{LO}_{res,s}} \leq fl^{max}_{res} \qquad \forall\, res \in RES,\, \forall t \in T \tag{3.16b}$$

$$fl_{res,t} - \sum_{\substack{t\,\in \\ [t\text{-SR},\, t+\text{SR})}} 10^3 \sum_{\substack{s\,\in \\ LO(s,res)}} \frac{\eta_s \sum_r b^-_{rst}}{\mathrm{g}_0\, \Delta h^{LO}_{res,s}} \geq 0 \qquad \forall\, res \in RES,\, \forall t \in T \tag{3.16c}$$

$$fl_{res,t} + \sum_{\substack{t\,\in \\ [t\text{-SR},\, t+\text{SR})}} 10^3 \sum_{\substack{s\,\in \\ UP(s,res)}} \frac{\sum_r b^-_{rst}}{\eta_s\, \mathrm{g}_0\, \Delta h^{UP}_{res,s}} \leq fl^{max}_{res} \qquad \forall\, res \in RES,\, \forall t \in T \tag{3.16d}$$

The maximum possible amount of reserve capacity per plant depends on its maximum output gradient. These gradients are typically defined as share of rated generating capacity per minute, $r^{\,\mathrm{up}}$ and $r^{\,\mathrm{down}}$. The two modeled types of reserves require generators to be able to reach their promised capacity within different time frames. Whereas SRL providers need to be fully ramped up or down within five minutes, TRL providers are only required to do this within a 15min Interval, cf. equations (3.17).

$$b^{+\,max}_{(SRL)c} = 5\, r^{\,\mathrm{up}}_c g^{max}_c\, bal_{(SRL)c} \qquad \forall\, c \in I \tag{3.17a}$$

$$b^{+\,max}_{(TRL)c} = 15\, r^{\,\mathrm{up}}_c g^{max}_c\, bal_{(TRL)c} \qquad \forall\, c \in I \tag{3.17b}$$

$$b^{-\,max}_{(SRL)c} = 5\, r^{\,\mathrm{down}}_c g^{max}_c\, bal_{(SRL)c} \qquad \forall\, c \in I \tag{3.17c}$$

$$b^{-\,max}_{(TRL)c} = 15\, r^{\,\mathrm{down}}_c g^{max}_c\, bal_{(TRL)c} \qquad \forall\, c \in I \tag{3.17d}$$

$$\tag{3.17e}$$

Hydro power plants generally can ajust their output very quickly. Turbines and pumps typically can change their output from zero to hundred percent within seconds to minutes. Therefore, the maximum contribution to reserve capacity is merely limited by the generating or consuming capacity of these units, cf. equations (3.18).

$$b_{rs}^{+/-\,max} = \min\left(g_{st}^{turb,max}, d_{st}^{pump,max}\right) bal_{rs} \qquad \forall\, s \in I \wedge d > 0 \tag{3.18a}$$

$$b_{rs}^{+/-\,max} = g_{st}^{turb,max}\, bal_{rs} \qquad \forall\, s \in I \wedge d = 0 \tag{3.18b}$$

Equations (3.19) ensure that the total amount of required reserves in the respective control zone is met. In addition, some additional restrictions arise from minimum and maximum bid offers stated in the auction rules, cf. equations (3.20).

$$\sum_i b_{rit}^{+} = b_{rt}^{+\,req} \qquad \forall i \in I,\, r \in R,\, t \in T \tag{3.19a}$$

$$\sum_i b_{rit}^{-} = b_{rt}^{-\,req} \qquad \forall i \in I,\, r \in R,\, t \in T \tag{3.19b}$$

$$\sum_{i \in P(o,i)} b_{rit}^{+/-} \geq b_{r}^{+/-\,MR,min}\, bal_{rs} \qquad \forall\, r \in R,\, t \in T,\, o \in O \tag{3.20a}$$

$$\sum_{i \in P(o,i)} b_{rit}^{+/-} \leq b_{r}^{+/-\,MR,max} \qquad \forall\, r \in R,\, t \in T,\, o \in O \tag{3.20b}$$

Finally, equations (3.21) and (3.20) account for the requirement that the offered reserve capacity is provided throughout the whole time period of the corresponding product that has been auctioned. These equations are defined for all hours within the product π of reserve r except for the ones at the start of a new product. When portfolio-bidding is allowed then the capacity can be provided from the whole portfolio,

$$\sum_{i \in P(o,i)} b_{rit}^{+/-} = \sum_{i \in P(o,i)} b_{ri(t-1)}^{+/-} \qquad \forall\, r \in R,\, o \in O, \quad \forall t > 1 \in TS(\pi, r, t)\ \wedge \forall \pi \in \Pi, \tag{3.21a}$$

or for each single plant

$$b_{rit}^{+/-} = b_{ri(t-1)}^{+/-} \qquad \forall\, r \in R,\, i \in I,\, o \in O, \quad \forall t > 1 \in TS(\pi, r, t)\ \wedge \forall \pi \in \Pi, \tag{3.22a}$$

when portfolio-bidding is not allowed.

3.4.2. Calculation of capacity reservation prices

The capacity reservation prices have been calculated ex-post to the model run. In order to show how these prices have been calculated I start with stating the unit-specific reservation costs from which prices can be subsequently derived. Basically, the TSO auctions a pre-defined amount of reserves for both positive ${b_{rt}^{+}}^{req}$ and negative capacity ${b_{rt}^{+}}^{req}$ separately and awards all offers $b_{rit}^{+/-}$ in ascending order of their capacity price bid p_{ri}^{B} until the total amount of capacity is satisfied. The TSO may only accept parts of the offered quantities in case the required amount is exceeded.

The costs of each generator for providing positive balancing power result from two different cost components. The *opportunity costs* represent forgone profits in the spot market that occur due to the amount of positive reserve power that has to be withhold. The second cost component is a peculiarity of the technical flexibility constraints of power plants. Because the start-up of a power plant needs a certain time the plants have to be operated on minimum stable output in order to react quickly enough on a call of the respective capacity. Thus, at least all thermal plants that provide reserve capacity must run at least at their minimum output in the spot market. The costs that might occur from this condition are called *must-run costs* Just and Weber (2008).

The objective function of the TSO is to minimize procurement costs of positive C_{rit}^{B+} and negative C_{rit}^{B-} reserves subject to quantities $\Omega = \{b_{rit}^{+}, b_{rit}^{-} \mid \forall b \in \mathbb{R}^{+}\}$, the amount of positive and negative reserve capacity that are offered for each product r by generator i in time step t[5].

In case of truthful bidding each generator would base her bid on the sum of these two cost components[6]. Formally, these costs can be written as

$$C_{rit}^{B+} = p_{rit}^{B+,OC} \cdot b_{rit}^{+} + p_{i}^{B+,MR} \cdot g_{i}^{min} \quad \forall i \in I \tag{3.23a}$$

$$C_{rit}^{B-} = p_{rit}^{B-,MR} \cdot \left(b_{rit}^{-} + g_{i}^{min}\right) \quad \forall i \in I, \tag{3.23b}$$

whereas the superscripts OC (opportunity costs) and MR (must-run) indicate above mentioned cost components. Note that equations 3.23 are only defined for the generators that provide reserves, i.e. for $b_{rit}^{+/-} > 0$. For the sake of simplicity, in the following we make use of the notation $(\cdot)^{+}$ to describe a function that returns the value within brackets in case of a positive argument and returns 0 when the argument is negative. For thermal generators the cost terms above can be expressed as the nonlinear integrals

[5] Actually, the TSO receives anonymous price-quantity bids that relate to the whole time period of a certain product r. The portfolio optimization is performed by the bidding companies. In the modeling I abstract from that and assume that the TSO take over this task.

[6] Currently implemented market designs of reserve auctions show a broad range of distinctive design elements, which can additionally influence capacity price bids. For example, additional expected revenues stemming from the calling of balancing energy can be priced in the reserve price. However, at this stage I am not concerned with the analysis of strategic bidding rather than the calculation of true costs

$$p_{rit}^{B+,OC} \cdot b_{rit}^{+} = \int\limits_{g_{it}}^{g_{it}+b_{rit}^{+}} \Big(p_t^S(g) - c_i^G(g)\Big)^+ dg \tag{3.24a}$$

$$p_{rit}^{B+,MR} \cdot g_{rit}^{min} = \int\limits_{0}^{g_i^{min}} \Big(c_i^G(g) - p_t^S(g)\Big)^+ dg \tag{3.24b}$$

$$p_{rit}^{B-,MR} \cdot \big(b_{rit}^{-} + g_i^{min}\big) = \int\limits_{0}^{b_{rit}^{-}+g_i^{min}} \Big(c_i^G(g) - p_t^S(g)\Big)^+ dg \tag{3.24c}$$

Since we assumed perfect competition in the sport market, the spot market price function $p_t^S(g)$ in 3.24 turns into an exogenous parameter p_t^S. As documented in equations 3.9 I linearized the variable generation cost function $c_i^G(g)$ with the method documented in Nahmmacher (2012) in order to implement part-load efficiency losses. The same formula is used to calculate the size of variable generation costs at the actual point of generation $c_i^G(g_{it}) = c_{it}^{PL}$ With both assumptions we can simplify the integrals in equations 3.24 and turn equations 3.23 into

$$C_{rit}^{B+} = \Big(p_t^S(g) - c_{it}^{PL}\Big)^+ \cdot b_{rit}^{+} + \Big(c_{it}^{PL} - p_t^S(g)\Big)^+ \cdot g_i^{min} \quad \forall i \in I \tag{3.25a}$$

$$C_{rit}^{B-} = \Big(c_{it}^{PL} - p_t^S\Big)^+ \cdot \big(b_{rit}^{-} + g_i^{min}\big) \quad \forall i \in I \tag{3.25b}$$

to get the true unit-specific costs of capacity reserve provision. If we divide these costs through the amount of offered capacity, sum over all time steps related to reserve type r we get

$$p_{ri}^{B+} = \sum_{t \in TS(r,t)} \Big(p_t^S - c_{it}^{PL}\Big)^+ + \Big(c_{it}^{PL} - p_t^S\Big)^+ \cdot \frac{g_i^{min}}{b_{rit}^{+}} \quad \forall i \in I \tag{3.26a}$$

$$p_{ri}^{B-} = \sum_{t \in TS(r,t)} \Big(c_{it}^{PL} - p_t^S\Big)^+ \cdot \left(1 + \frac{g_i^{min}}{b_{rit}^{-}}\right) \quad \forall i \in I, \tag{3.26b}$$

which are the unit-specific capacity reservation prices of unit i for reserve type r[7]. For CHP units the capacity reservation prices have been directly derived from the exogenous heat model. The capacity reservation costs of hydro storage units are calculated in a different way. Prices from these generators can be directly derived from the proper sums of optimal dual variables from the hydrological constraints 3.13 and 3.16[8].

[7] For the sake of simplicity I neglected in this notation the separate products π related to each reserve type r. The values above can be interpreted as average prices over all products π.

[8] Before the sum is built the dual variables of equations 3.16 have to be converted from the unit €/m^3 into €/MWh.

3.4.3. Balancing energy call model

The balancing energy call model minimizes the total cost of balancing energy calls from the reserve capacities that have been determined by the capacity reservation model. It has been implemented as an traditional unit dispatch model that operates on a quarter-hourly time resolution. The objective function of the model is to minimize total costs in order to fulfill an exogenously given amount of positive and negative balancing power. Table 3.5 located at the beginning of this chapter in section 3.1 summarizes the applied notation in the subsequent equations.

$$\min \text{(Total Call Costs)} =$$

$$\sum_{r,i,t} p^{Call+}_{rit} \left(1/4 \sum_{(q,p)\in T(t,q,p)} \sigma^{+}_{trqp}\ cap^{+}_{ritqp} \right) \quad \big(\text{Costs for Positive Calls}\big) \tag{3.27a}$$

$$\sum_{r,i,t} p^{Call-}_{rit} \left(1/4 \sum_{(q,p)\in T(t,q,p)} \left(1-\sigma^{+}_{trqp}\right)\ cap^{-}_{ritqp} \right) \quad \big(\text{Costs for Negative Calls}\big) \tag{3.27b}$$

The output constraints $b^{+/-}_{rit}$ of the model are derived from the model results of the capacity reservation model.

$$cap^{+/-}_{ritqp} \leq b^{+/-}_{rit} \qquad \forall r \in R,\ i \in I,\ t \in T \wedge (q,p) \in T(t,q,p) \tag{3.28}$$

Demand for balancing power has been derived form historical data in the Austrian control zone.

$$\sum_{i} cap^{+/-}_{ritqp} = cap^{+/-\ req}_{rtqp} \qquad \forall r \in R,\ q \in Q,\ p \in P \tag{3.29a}$$

3.4.4. Calculation of balancing call prices

The marginal energy prices related to balancing calls have been derived from the optimal dual variables of equations 3.29a. The pay-as-bid curves are based on the true costs $p^{Call+/-}$ that are based on the marginal generation costs[9], or water values[10], respectively, of accepted units that were selected to provide capacity reserves.

3.5. Applied input data

In this section an overview about type and source of the most important input data for the models is given. One part of the data has been gathered from public sources and another

[9] These costs have been derived from the linearized cost function $c^G_i(g)$ plus an add-on for wear and tear from cycling

[10] These are the dual variables of equation 3.5

part of the data has been taken from existing databases maintained at the Energy Economics Group[11] from the Vienna University of Technology. In case some required input data is not publicly available educated guesses have been made. In the following the input data of the models is shown in an aggregated style.

3.5.1. Generation

The applied models in this study are different forms of dispatch- and unit-commitment models. In order to get reasonable results from such models a detailed power plant database is required. The Austrian energy regulator *E-Control* publishes only a highly aggregated table of the generation mix on their homepage[12]. In order to get a more disaggregated dataset a detailed list of the Austrian power plants has been developed based on existing databases of the Energy Economics Group. In Figure 3.5 the plants from this list have been aggregated and compared to the generation mix of E-Control. In certain categories the numbers did not add up exactly the same. In these cases a *slack* power plant has been introduced that have been sized to fill the gap. The slack power plant accounts for the sum of small power plants, which are not included in the plant database. Furthermore, small differences remain in the allocation of plants to certain plant type categories. Mostly this concerns different definitions of what is accounted as run-of-river or as hydro storage power plant, respectively. Also, to reduce complexity the number of applied fuels has been reduced to the main applied fuels. In case a plant is operated with multiple fuels the primary fuel has been defined to be the plant fuel type. In particular, volatile renewable electricity generators, namely wind and solar PV, have been aggregated to a country generation profile. This simplification does not impact the model results; however, it significantly reduces the model run time.

Besides the techno-economic data the power plant database also contains the owner of the plant. Due to a lack of information it has been assumed that the owner of the plant is also the operator of the plants. A further assumption was that the owner operates all her plants in a portfolio, if this is allowed in the model. Figure 3.6 shows the ownership structure of installed capacities in absolute and relative numbers. Although Verbund AG and Austrian Hydro Power (AHP) belong to the same holding, it has been assumed that their corresponding plants are operated as two distinct portfolios. AHP operates nearly a quarter of all installed capacities in Austria. In terms of energy this number even increases due to the relatively high full load hours of hydro power plants.

3.5.1.1. CHP electricity generation

CHP plants simultaneously produce heat and electricity. To what extend these plants are able to decouple electricity output from their heat output depends on their construction design and whether a heat storage is additionally available (cf. section A.2). The operation mode of CHP plants is often heat-driven, i.e. they are obliged to produce a certain share of

[11] `http://eeg.tuwien.ac.at/`
[12] `https://www.e-control.at/statistik/strom/bestandsstatistik`

			Actual numbers		Model implementation	
			Number	Capacity in MW	Number	Capacity in MW
Hydro power	Run-of-River	> 10 MW	93	4,488	85	4,787
		<= 10 MW	2,677	1,093	19	123
	Storages	> 10 MW	67	7,693	68	8,561
		<= 10 MW	45	154	17	84
	Sum of hydro power plants		**2,882**	**13,427**	**189**	**13,555**
Thermal power plants	Fossil fuels and derivatives	Coal	4	1,171	6	1,579
		Derivatives	6	414		
		Oil	11	360	3	360
		Gas	64	5,119	21	5,119
		Sum	**85**	**7,065**	**30**	**7,058**
	Biofuels	Solid	117	405	1	405
		Liquid	26	5	1	5
		Gasified	300	84	1	84
		Waste	50	23	1	23
		Sum	**493**	**517**	**4**	**517**
	Other biofuels		4	115	4	115
	Other fuels		10	80		
	Mixed fuel		10	497	1	736
	Sum of thermal power plants		**602**	**8,273**	**34**	**8,426**
	(of which CHP plants)		190	6,578	29	6,149
Renewable energy	Wind		351	1,675	40	1,675
	Photovoltaics		39,798	447	1	447
	Geothermal		2	1		
	Sum of renewable energy		**40,151**	**2,122**	**41**	**2,122**
Total generation capacity			**43,635**	**23,823**	**298**	**24,103**

Figure 3.5.: Aggregated stock of power plants in Austria in 2014. Comparison of declared data by E-Control and the aggregated data of the EEG-database.

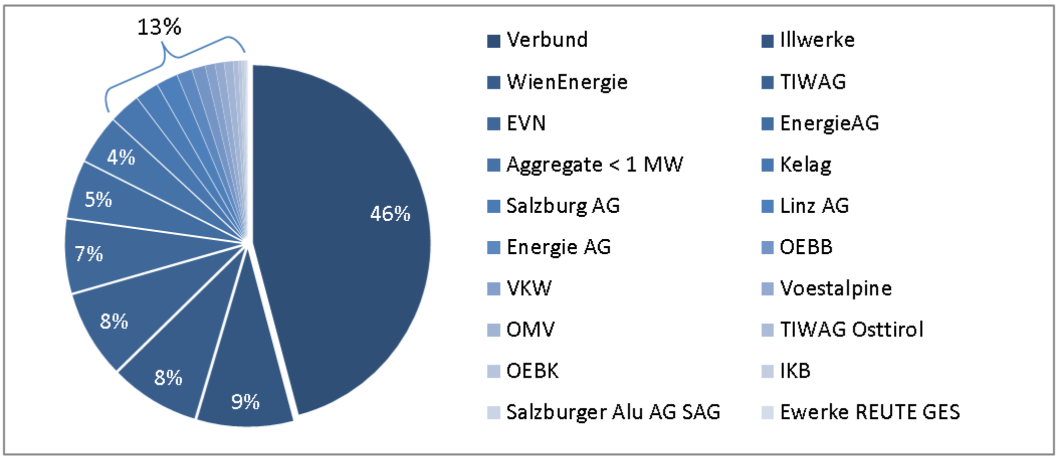


Figure 3.6.: Ownership structure of installed generating capacity in Austria in 2014.

heat demand within the district heating grid they are connected to. The generated electricity from plants in this operation mode is seen as side product. An increasing number of plants, however, are operated in power-driven mode, i.e. they strive to maximize their revenues from electricity markets and deliver heat as a side product. In Austria the majority of fossil-fired plants are designed as CHP plants. In order to derive the electricity generation from these plants and the available flexibility for providing reserve capacities a heat model developed from Büchele et al. (2015) has been applied. From this model the hourly electricity generation profiles from the main CHP plants in Austria have been derived. This generation profiles has been used to define the operating point of CHP plants in the unit-commitment model. Additionally the heat model delivered opportunity costs for providing reserve capacities. These opportunity costs depend on the respective heat demand the fill level of their heat storage's and prevailing electricity prices. Figure 3.7 exemplary shows the hourly generation profiles of heat generators in Vienna's district heating grid. During winter in times of high heat demand the availability of CHP units for providing reserves is limited, because the plants are needed to cover head demand. In summer lots of CHP plants are completely switched-off because the demand for district heating strongly declines. Most recently, in Vienna also a district cooling service has been introduced. This offers opportunities for CHP plants to be operated also during summer times.

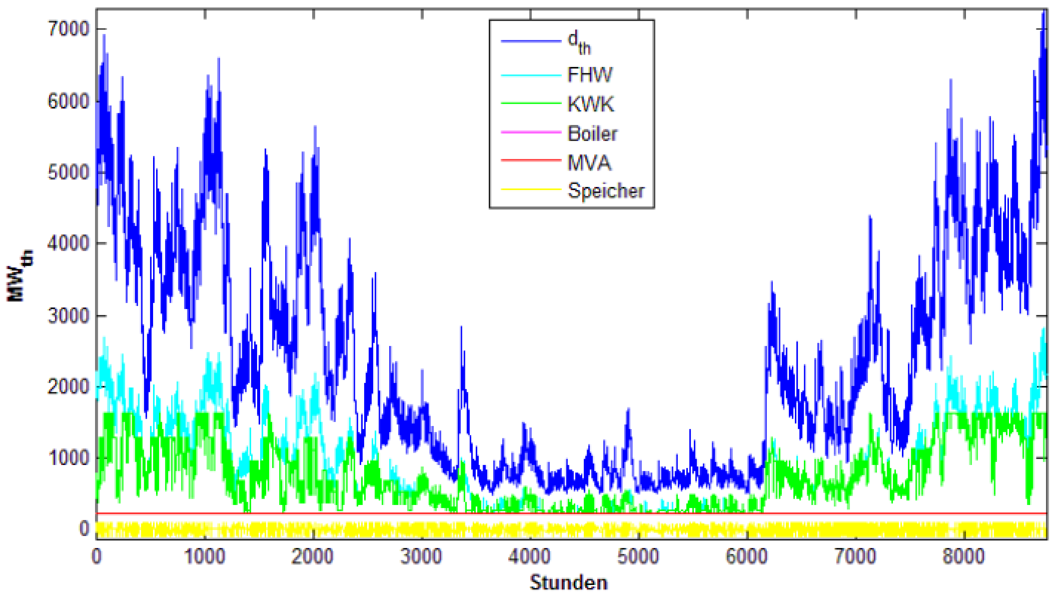


Figure 3.7.: Exemplary CHP heat generation profiles from a district heating model of Vienna (Büchele et al., 2015).

3.5.1.2. Technical potential of electricity balancing reserves

In order to be eligible to participate in tenders for reserve capacity power plants need to be prequalified. These prequalification requirements do pose relatively high demands on power output controllability of participating units. The requirements are defined by the responsible transmission system operator for each control zone separately and were subject to frequent changes in the past. The aim of the adjustments was to remove any kind of discrimination among certain types of generating or demand-side units in order to enlarge the pool of potential market participants and to increase market efficiency. The prequalification criteria differ according to the type of reserve capacity and are available in its current version on the homepage of the Austrian transmission grid operator APG[13]. APG do not provide any information on the absolute amount, nor on the type of capacities that are currently prequalified to participate in reserve capacity auctions. For this reason, the total technical potential of capacities suitable to provide balancing reserves had been derived based on simple assumptions. First, a preselection of eligible power plants have been conducted. Inflexible plants, e.g. CHP plant in back-pressure turbine design without additional heat storage, have been excluded from the pool. For the majority of run-of-river plants it has been assumed that hydro-peaking, i.e. the accumulation of water in upstream basins, is not allowed. Thus, many run-of-river plants have also been considered to be inflexible. Second, the maximum feasible power output change of technologies within a time interval of 5 minutes (for SRL) and 15 minutes (for TRL) has been calculated for each technology. This calculation is based on standard values on maximum ramping rates per minute derived from the literature. The values are normalized to nameplate capacity and range from 2-4%/min for steam turbines to 25%/min for hydro power plants. The nameplate capacity of each plant has been multiplied by its corresponding flexibility factor and the time interval in minutes to derive the maximum available capacity in the respective time frame. The aggregated sums of resulting capacities are shown in figure 3.8. From these capacities the unit-commitment model chooses the ones that can fulfill demand for reserves most efficiently and within the given restrictions.

Assumed technical potential of available units in MW

Technology	SRL(+)	SRL (-)	TRL(+)	TRL(-)
Combined cycle gas	0	0	572	0
Open cycle gas	0	0	63	0
Mixed fuel	0	0	0	0
Pumped Storage	7409	3496	7409	3496
Biomass	0	0	2	0
Coal	0	0	200	0
Gas CHP	0	0	172	0
Oil	0	0	0	0
Waste	0	0	0	0
Run-of-River	0	0	0	0
Total	**7409**	**3496**	**8417**	**3496**

Maximum ramping per minute in % of nameplate capacity

Flexibility	%/min
Combined Cycle Gas	6%
Coal	4%
Gas CHP	6%
Open Cycle Gas	20%
Oil	6%
Biomass	2%
Biogas	2%
Waste	2%
Mixed fuel	2%
Pumped Storage	25%
Run-of-River	25%

Figure 3.8.: Technical potential of prequalified generating capacity and ramping flexibility by technology in Austria. The terminology SRL and TRL refers to the product definitions described in Figure 3.3.

[13]https://www.apg.at/en/market/balancing/conditions-for-participation

3.5.2. The Austrian hydro power system

The Austrian power system is characterized through a high share of hydro power. In particular, the whole hydro power system is built to a significant part within the Alps region of Austria. Consequently, the Austrian hydrogrid is highly cascaded and consists of a large number of large reservoirs. The adequate modeling of this system requires a detailed representation of all major hydro power plants, its connection among each other and the reservoirs in between.

3.5.2.1. Topology

The Austrian power system is characterized through a high share of hydro power. In particular, the whole hydropower system is built to a significant part within the Alps region of Austria. Consequently, the Austrian hydrogrid is highly cascaded and consists of a large number of large reservoirs. The adequate modeling of this system requires a detailed representation of all major hydro power plants, its connection among each other and the reservoirs in between. The hydrogrid used in this study has been developed at the Energy Economics Group, cf. Kemendy (2012). Figure 3.9 shows the location and type of hydro power plants greater than 5 MW contained in the database.

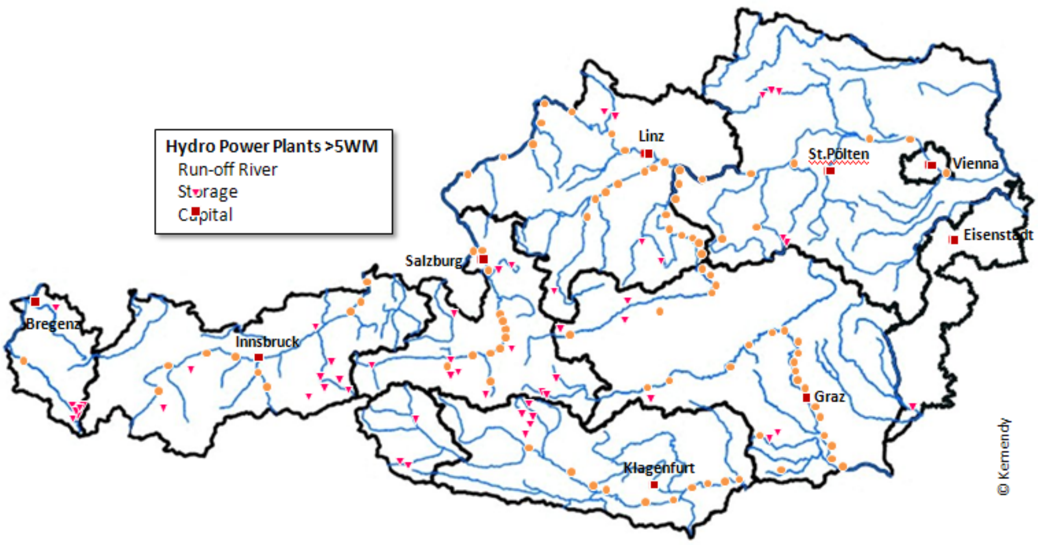


Figure 3.9.: Overview on the implemented hydro power plants (> 5MW) in Austria. Source: (Kemendy, 2012)

The power plants are connected through water pipes and rivers to reservoirs. Reservoirs are characterized through an altitude as well as maximum and minimum fill levels. The model contains a detailed description of pumped hydro storage power plants, their reservoirs and how they are connected. Figure 3.10 shows a schematic overview of this hydro storage grid.

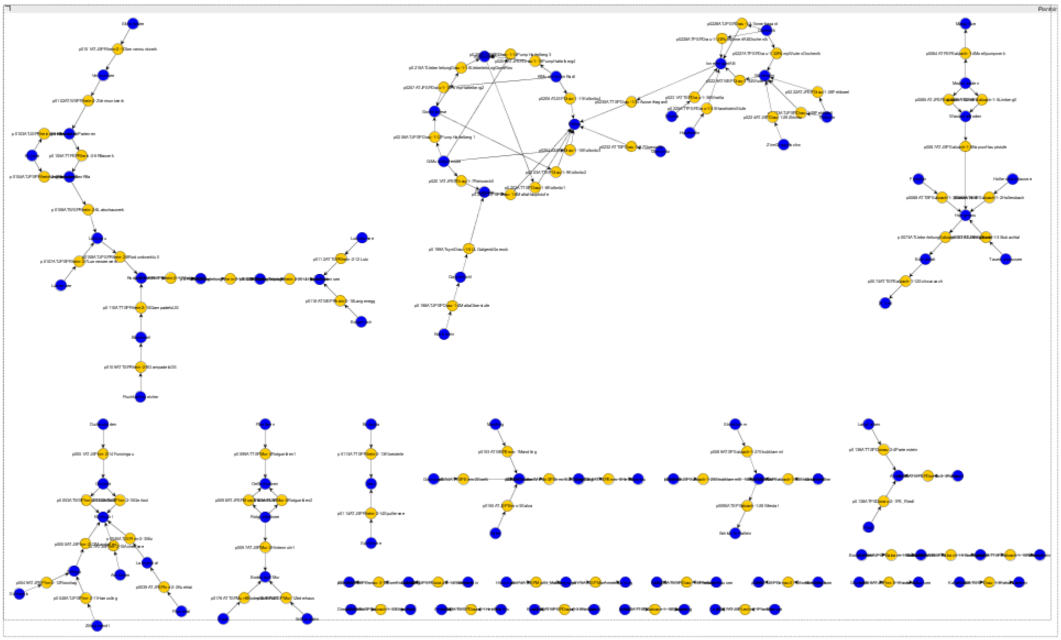


Figure 3.10.: Implemented hydro system topology of implemented pumped hydro storage power plants (yellow circles) and corresponding reservoirs (blue circles).

Figure 3.11 shows how the run-of-river plants are represented. In this Figure the plants along the Mur river are shown. It can be seen that also a height profile and water basins are considered along a river.

3.5.2.2. Water inflows

Due to varying availability of inflows also electricity generation from hydro power considerable varies over years. Consequently, an adequate modeling of the hydro power system not only requires that the topology of the hydro grid is considered, but also that natural inflows into reservoirs and river basins are implemented. However, there are not publicly available data on historical inflows into single reservoirs. To derive hourly inflow profiles for all reservoirs historic measurement data for the last ten years from water flow sensors located at most Austria's rivers have been collected to derive daily average values of inflows. These inflow time series have been scaled in a way that the electricity generation from a certain plant as a result of the inflow series allocated to it matches the mean average electricity generation as indicated in public sources. Figure 3.12 exemplary shows how the water flow measurement data has been added up to derive the inflow profile for run-of-river plants located at the Inn river. In the graph annual average values are shown. However, in deriving inflow time profiles daily average values have been used.

In Figure 3.13 the resulting time series of daily natural inflows into selected reservoirs in Austria are exemplary shown for the year 2009. The inflows considerably vary across the year. A general yearly trend that can be observed is that inflows increase in spring

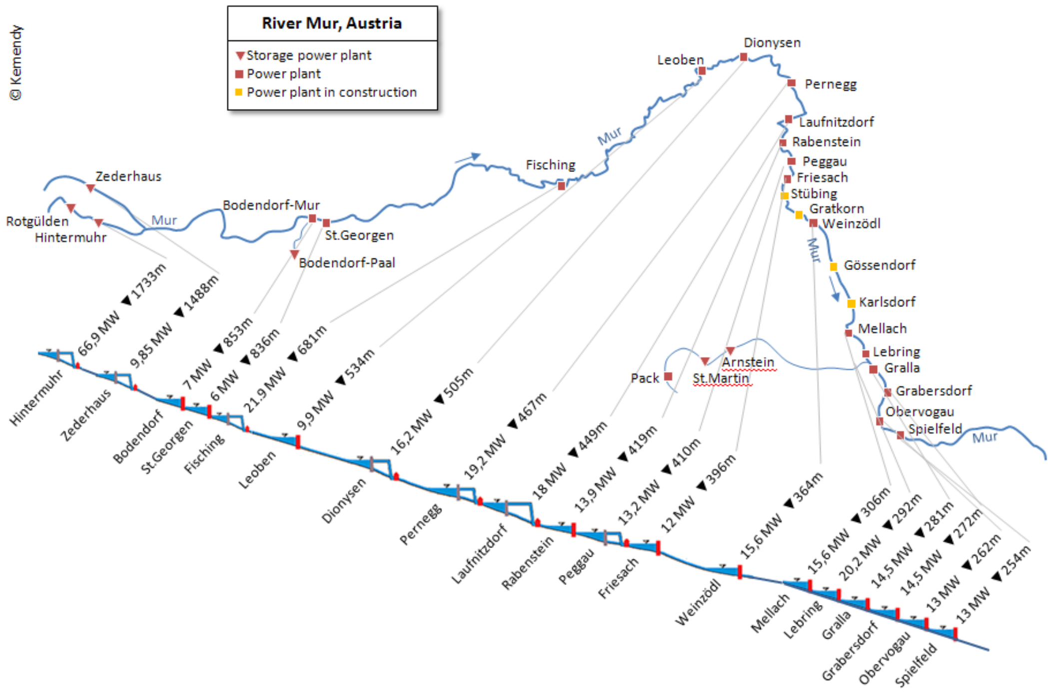


Figure 3.11.: Detailed view on the implemented run-of-river plants along the Mur river. Source: (Kemendy, 2012)

when ice from glaciers and snow from mountains start to meltdown and decrease again in autumn. These natural inflows into river basins and reservoirs are an important determinant of resulting water flows within the hydro grid of the model.

3.5.3. Demand

In the main model runs demand profiles had been considered to be exogenous. Neither any kind of demand elasticity, nor any demand-side actors have been implemented. At the time this study has been prepared this assumption was justified, because only generators participated in balancing markets. Most recently, more and more industry firms and demand-side aggregators entered the market. This trend will be partially evaluated in chapter 4. Nine different demand time series have been implemented in the model. The spot market demand for electricity is represented by the estimated day-ahead consumption of Austria. The data is available in hourly time resolution and has been gathered from ENTSO-E[14]. Besides the day-ahead market, there are also other market segments (e.g. intra-day, forward markets) that play a role in the marketing of electricity. However, profits from the day-ahead market are still the fundamental driver of opportunity costs, which in turn determine results in the balancing market. Therefore, it has been decided to exclude other spot market segments in order to reduce the model complexity. In the future intra-day market will most likely

[14] https://transparency.entsoe.eu/

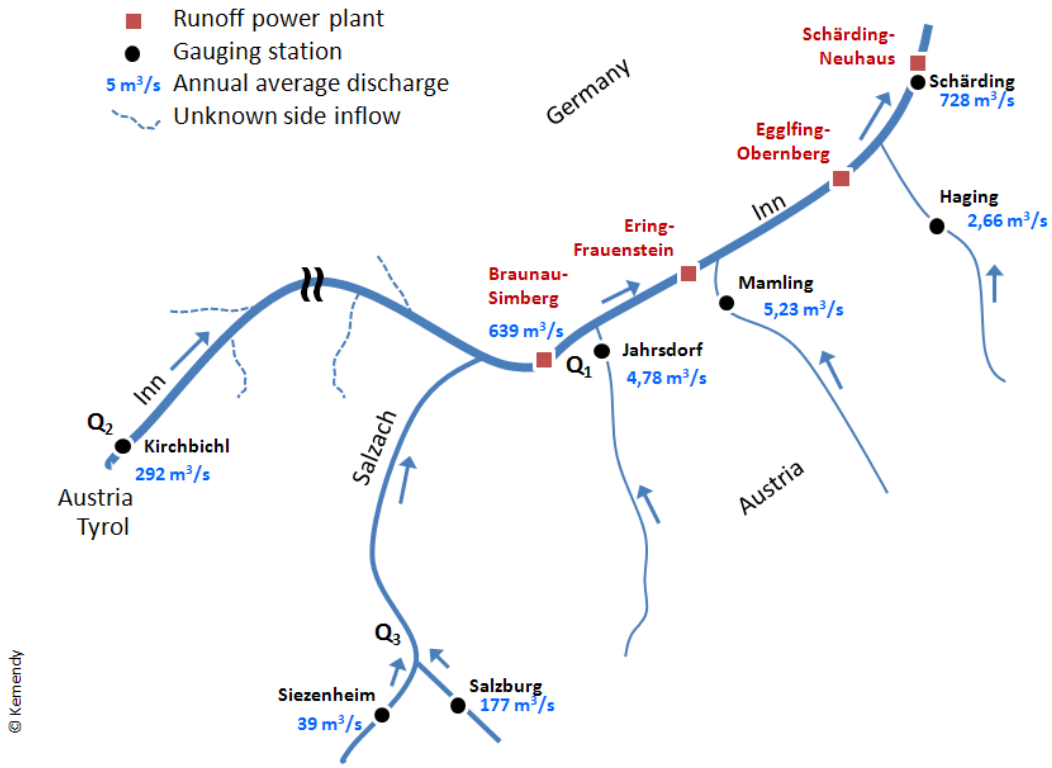


Figure 3.12.: Schematic illustration of average water inflows along the Inn. Source: (Kemendy, 2012)

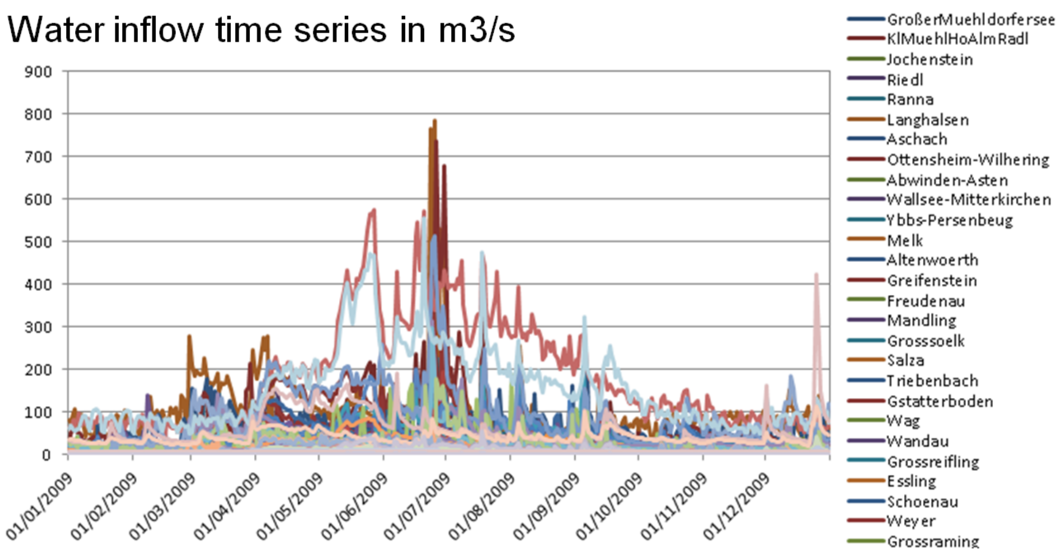


Figure 3.13.: Illustration of historical inflow time series into selected reservoirs in Austria. Source: (Kemendy, 2012)

gain more importance. The impact of this development on balancing markets is broached in chapter 4. The remaining eight time series are related to the balancing market. Half of the time series represent demand for reserve capacities the other half represent demand for actually called balancing energy. The time series are divided in the four categories secondary balancing reserves (SRL), secondary balancing energy (SRE) and tertiary balancing reserves (TRL) and tertiary balancing energy (SRE). For each category a time series for both positive and negative direction of call is available. The data has been gathered from historical procurement results from the Homepage of the Austria transmission grid operator APG[15].

3.5.4. Assumptions on prices for primary energy carriers and carbon

The short-run marginal costs of thermal generators have been derived on the basis of primary energy carrier and carbon prices. There are no public data available on plant specific energy carrier prices. Prices from coal, gas and oil from the *Bundesamt für Wirtschaft und Ausfuhrkontrolle* (BAFA)[16] have been used as proxy. Carbon prices have been taken from the European Exchange EEX[17]. An extract from these prices are illustrated in figure 3.14.

The energy and carbon prices together with plant-specific information has been used to calculate the short-run marginal costs of thermal power plants. Other relevant techno-economic parameters of generators are startup/shutdown times and costs, maximal power output gradients, minimal load and online/offline times as well as partial load conversion efficiency curves. All this data has been taken from Schröder et al. (2013). Die full-load conversion efficiency are plant-specific and were derived from the power plant database of the Energy Economics Group. The reference electricity prices of model runs related to present years are the historic PHELIX day-ahead electricity prices of the market area Austria/Germany from the exchange EPEX Spot SE (cf. Figure 3.15).

[15] https://www.apg.at/emwebapgrem/startApp.do, www.regelleistung.net
[16] http://www.bafa.de/
[17] http://www.eex.com/

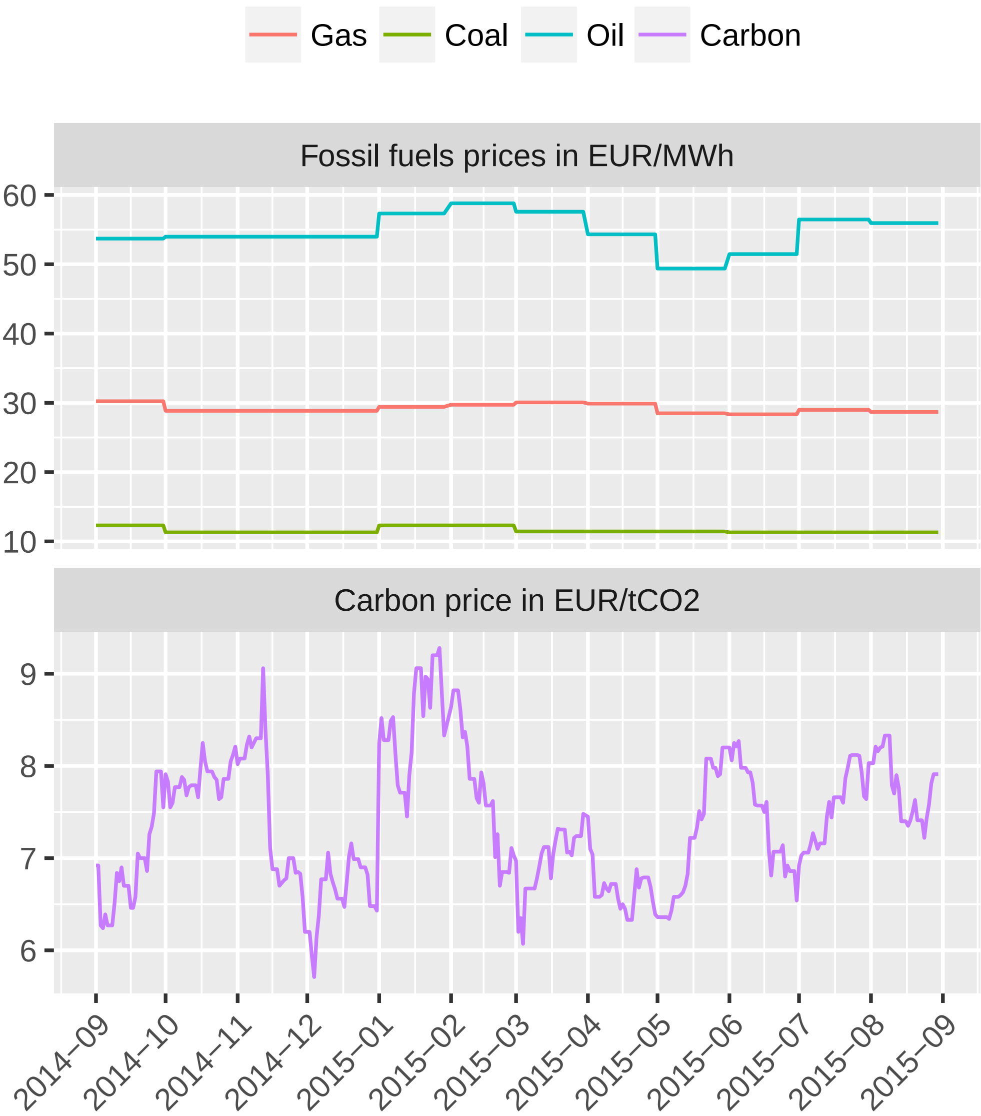


Figure 3.14.: Model assumptions on energy carrier and carbon prices in the period of September 2014 to September 2015.

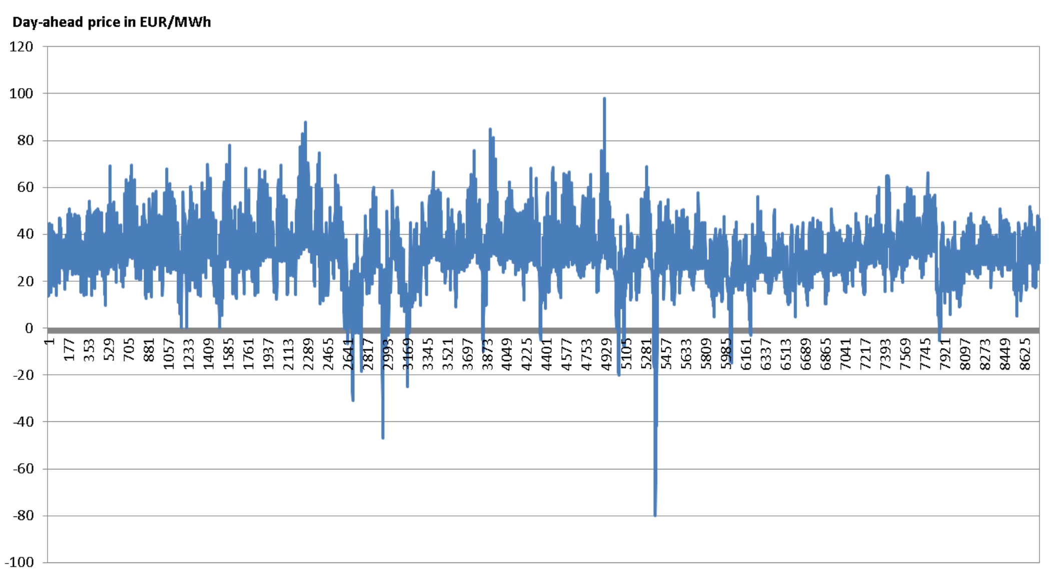


Figure 3.15.: Hourly day-ahead electricity price PHELIX in the period of September 2014 to September 2015.

3.6. Model parameter variations

3.6.1. Dimension 1: Framework conditions

Some assumptions related to framework conditions under which balancing markets operate have been shown to significantly impact model results. Two of such conditions are of particular interest with regard to the Austrian market and should therefore be subject of dedicated model runs. First, an important question for hydro storage operators, whose plants participate in balancing markets, is to what extent a certain amount of storage volume should be reserved for calls of balancing energy. This restriction on the working volume of storages is of particular interest if for any reason only positive or negative reserves are offered, or if there is a sustained consecutive call of energy in one direction. How operators deal with that issue depends on their expectations and marketing strategy. In order to account for this uncertainty we consider the case with and without restrictions on the working volume of reservoirs. In the first case it is assumed that storage operators do always bid for positive and negative reserve capacities and assume that the called balancing energy in positive and negative direction neutralizes each other. Consequently, there are no dedicated restriction on storage fill levels is required. The other case is more conservative in this manner and assumes that cases of 12 hours consecutive unidirectional calls of balancing energy can occur. Thus, a volume of 12 hours times the offered reserve capacity is being reserved for balancing energy calls in the upper and lower reservoirs. This assumption is based on a review of historical time series of balancing energy calls.

Another important framework condition of balancing markets is whether the market rules require unit-bidding or allow portfolio-bidding. In the Austrian balancing market participants are allowed to pool their technical units. This means that participants ensure that their offered capacity is available within and can be called from a portfolio rather than a single technical unit. On the one hand this increases the flexibility on part of the bidder, because he or she can freely decide, which unit is activated to deliver balancing energy in each point in time during the contracted period. On the other hand trading of pools with units of different cost structure is more complicated, because expectations about hours of activation for each unit have to be included in bid pricing. Traders may add risk premiums to their bids in order to account for that uncertainty, or only pool units with similar cost structure.

A further aspect, which is important with regard to framework conditions, is the claimed level of collateralization in a certain market. In the Austrian balancing market a collateralization of 100 per cent is required. This is not considered to be a problem, because portfolios do necessarily have a much greater available capacity than the one offered to the market. However, in case of unit-bidding this requirement would cause additional costs that were factored in the prices of the bids.

All these factors impact pricing of bids in real markets. The fact that information about pricing is private and trader-specific some simplifying assumptions have to be made. Risk premiums have not been added, because they are unknown and are not considered to have a substantial impact on the results. The price of a portfolio call is always set to the price of the marginal generator that is called. This can be interpreted as the case when portfolio operators do have perfect knowledge on future calls and therefore are able to calculate average call prices of the portfolio. It has been assumed that the operator of a plant is also its operator and that she can pool all plants in her ownership. The group of plants with unknown ownership cannot be pooled in the model.

3.6.2. Dimension 2: Pricing

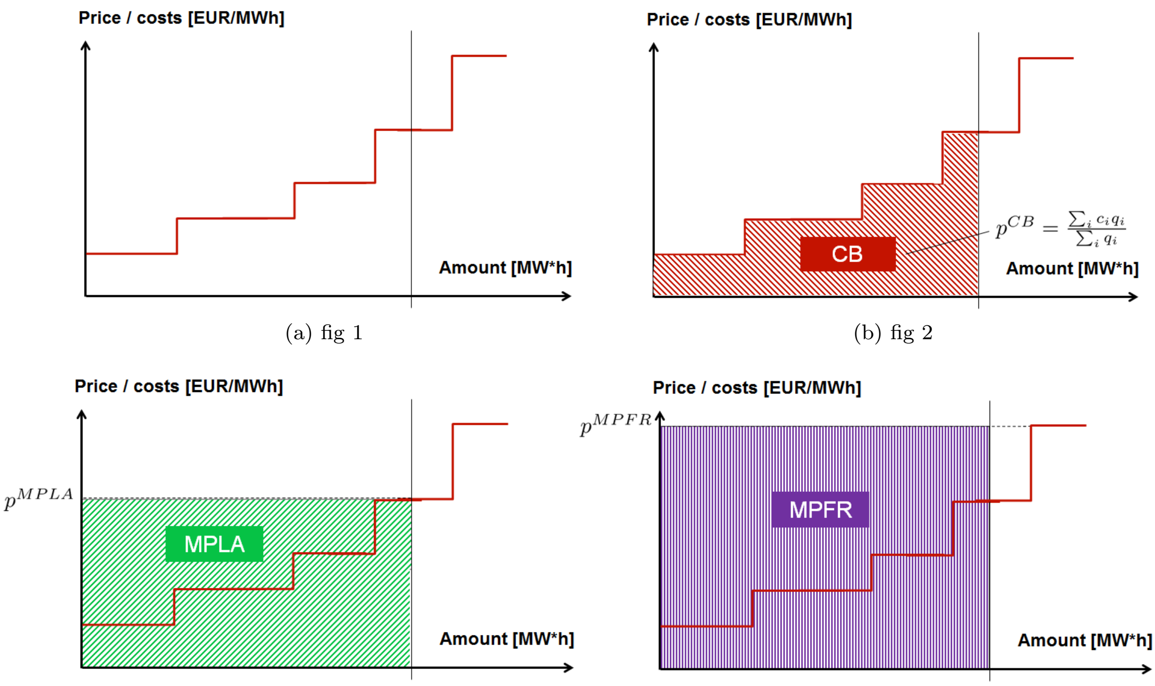
The payment rule in Austria's balancing markets is for both capacity and energy defined to be according to the *pay-as-bid* procedure. As discussed in Ocker et al. (2016) this rule do not ensure incentive compatibility from a game-theoretic perspective. In theory and practice it can be shown that this market design element leads to a game where each market player aims to guess the marginal price bid Son et al. (2004). In order to account for players' strategies the model results are presented for three different pricing schemes.

The *cost-based pricing method* (CB) is meant to deliver a lower bound for possible prices in balancing markets. In this scheme it is assumed that market participants price their bids according to their costs. The resulting prices are volume-weighted cost bids. The other two pricing schemes aim to capture actual pricing behavior of traders in a competitive market.

The *marginal price last accepted* (MPLA) pricing rule assumes that each market player is able to perfectly guess the marginal price of the last accepted bid.

In the *marginal price first rejected* (MPFR) pricing rule it is assumed that the resulting price is perfectly oriented on the marginal price of the lowest bid that have not been accepted to cover demand. In case of continuous supply curves the prices resulting from MPLA and MPFR would be equal. However, in markets with low liquidity step-wise supply curves can be observed. At the time this analysis has been carried out this was the case for the balancing electricity market in Austria. Figure 3.16 illustrates the resulting prices and short-run contribution margins from the three pricing schemes.

The above mentioned parameter variations do materialize in the form of three model runs with a different parameter setting. All model runs are presented for each of the model runs separately. The short names and corresponding parameter settings are summarized in Table 3.17.



(a) fig 1 (b) fig 2 (c) fig 3 (d) fig 4

Figure 3.16.: Schematic supply curve (left) and resulting prices and short-run contribution margins of different pricing schemes.

Szenario short name	Description
P0˙SR12	• Building of portfolios not allowed (unit-based bidding) • Hydro storages are required to restrict reservoir fill-levels in relation to the size and type of reserve capacity provision
P1˙SR0	• Building of portfolios is allowed • No additional limits on reservoirs fill-levels due to provision of reserve capacity
P1˙SR12	• Building of portfolios is allowed • Hydro storages are required to restrict reservoir fill-levels in relation to the size and type of reserve capacity provision

Figure 3.17.: Description of three parameter settings used to perform an impact analysis.

3.7. Results

In this chapter the results of the modeling work are documented and contrasted with historical prices and costs from the period September 2014 to September 2015. We start with listing total costs for provision of reserve capacities and balancing energy for the mentioned period and the interpretation of these costs in the light of actual costs occurred in Austria's balancing market. In the following sections we present a detailed documentation of the model results for both the provision of reserves and the energy delivery of balancing power. The last section of this chapter concludes with an in-depth analysis of fundamental hydrological drivers of costs in the Austrian market is given.

3.7.1. Total costs

In Figure 3.18 the historic and modeled total yearly costs of the Austrian balancing markets for SRL and TRL is given. The costs are split up in capacity reservation and deployment. The historic costs are the costs that actually occurred in these markets in the modeled period. The modeled costs are presented for the three different pricing methods discussed in 3.6.2. The total costs exceed the modeled costs more than twice. A closer look on the cost components reveals that the discrepancy results from a difference in the energy calling costs, which can not be explained by the model[18]. This finding will be discussed in-depth in the conclusions chapter. With regard to capacity reservation costs of SRL the results show that the historic costs lie in between the model results of the MPLA and MPFR pricing scheme. The historic TRL capacity reservation prices are even in the range of modeled costs in the cost-based pricing scheme, i.e. very close to the lower bound of costs.

	Capacity Reservation		Energy Calling		
	SRL	TRL	SRL	TRL	Total
	Mio. EUR	Mio. EUR	Mio. EUR	Mio. EUR	Mio. EUR
Historic	17.96	8.73	121.44	13.04	161.17
Modell (CB)	3.83	5.28	3.19	-0.11	12.21
Modell (MPLA)	6.63	14.55	11.13	1.20	33.51
Modell (MPFR)	36.83	22.61	11.13*	1.20*	71.77

*) Because market entry without previously accepted offer is not allowed, MPFR and MPLA prices equal

Figure 3.18.: Summary of historic and modeled total costs of secondary and tertiary control for the period September 2015 to September 2015.

3.7.2. Capacity reservation

In this section the model results related to capacity prices of the balancing reserves procurement are shown. To derive these prices it has been assumed that only cost components that originally arise from potential profits and losses caused by the reservation of reserve capacity are contained in the capacity price. This implies that no profits or losses, which may arise in the course of energy calling, are considered in the capacity price. However, the author acknowledges that actual trading strategies might lead to pricing that deviates from that assumption. The cost/volume-combinations that represent all accepted and rejected bids are shown for the whole modeling period in Figure 3.19. The costs in this figure represent the actual opportunity costs of single power plants. In the cost-based pricing scheme that costs match the offered bid price. The volume indicates the amount of capacity that corresponds to the bid. The results indicate that costs for SRL and TRL do not significantly differ.

[18]Note that the aim of this study was to derive a competitive benchmark. One important reason for a deviation of historic and modeled prices are strategic bidding.

This can be explained by the fact that the hydrological and technical constraints for both products are very similar. A fundamental difference is the need for fossil generators to be online during delivery of secondary reserve capacity. However, hydro power generators are not obliged to fulfill that requirement. Therefore, this distinguishing feature does not play an important role in the Austrian hydro power dominated SRL market. Another characteristic of the cost/volume-combinations in 3.19 is that costs of negative reserve capacities are higher than the ones for positive. A relevant cost driver for that difference is the inflexibility of installed pumps in existing pumped hydro storage power plants. A closer look to economic impacts of this inflexibility is given in section 3.7.4. The option to build portfolios leads in accordance to expectations to a broader spread of bids, because the contracted capacity can be delivered by multiple power plants. The hydro storage constraints cause an increase in costs of certain plants, however, also lead to decreasing costs of other plants. Note, that Figure 3.19 contains both accepted and rejected cost/volume bids. The resulting prices are only impacted by accepted bids.

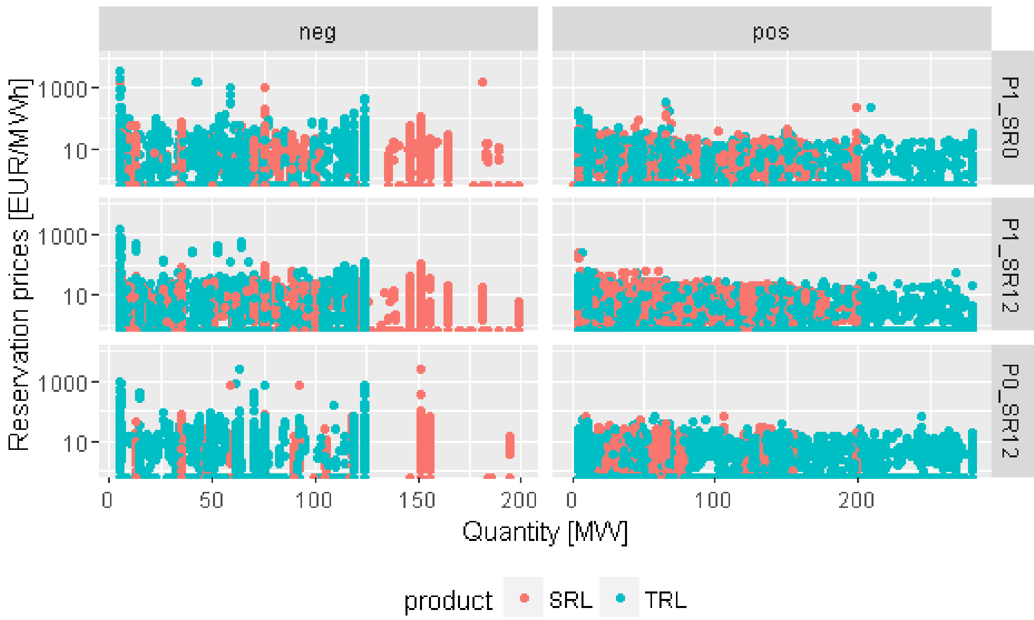


Figure 3.19.: Modeled cost/volume combinations that represent all accepted and rejected bids of capacity reservation in the respective period.

In Figure 3.20 and 3.21 the modeled prices of SRL and TRL, respectively, which result from above cost/quantity-combinations, have been plotted against the historic prices in the respective time period. It can be concluded from Figure 3.20 that the actual prices level off in between the MPLA and MPFR prices. Also the results reveal that modeled as well as historic prices of SRL lift off from beginning until mid of 2015. In particular, also the CB prices rise, which means that this increase in prices can partly be explained by fundamental data. From June 2015 on, in the middle of melting ice period and the resulting water inflows into reservoirs prices for negative reserves start declining again and reach zero level until the end of the modeled period. Prices for positive reserves are strongly oriented towards MPFR prices rather than CB prices. Historic capacity prices of TRL are best described by MPLA prices (cf. Figure 3.21). Again as in the case of SRL it can be seen that historic price variations can be partly explained by the influence of fundamental parameters like water scarcity that lead to peak prices and rising water inflows in spring time causing a convergence of prices towards lower levels.

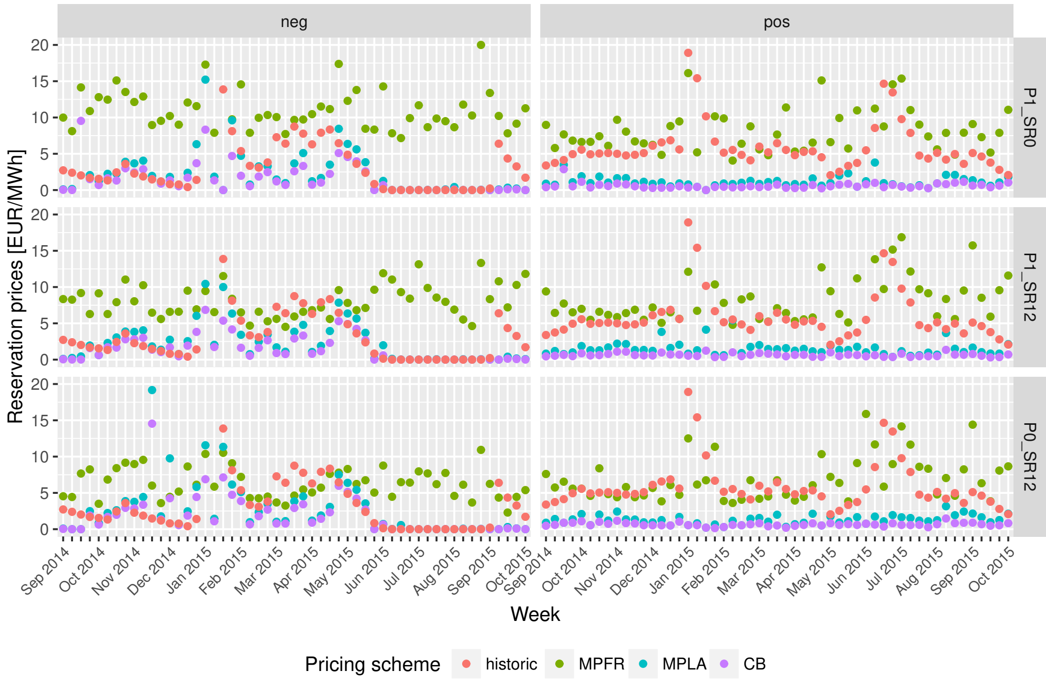


Figure 3.20.: Modeled and historic average prices of capacity reservation for SRL.

The resulting total costs of capacity reserve provision that are calculated from above prices are shown in Figure 3.22. It is interesting to see that total cost of CB- and MPLA-prices are not much impacted by the fact whether portfolios are allowed or not, nor whether storage operators are obliged to withhold a certain share of reservoir volume for balancing energy calls. However, MPFR prices do significantly change with these factors. It can be seen that with allowance of portfolio building and without any restrictions on storage volume resulting total costs are the lowest. This emphasizes the role of design options and trading strategies on the outcome of prices and costs.

3.7.3. Balancing energy calls

The costs of energy calls are determined in the model by the marginal costs of an increase or decrease of generation or consumption (or equivalently a decrease/increase of pumping), respectively. The marginal generation costs of thermal generators are determined by their

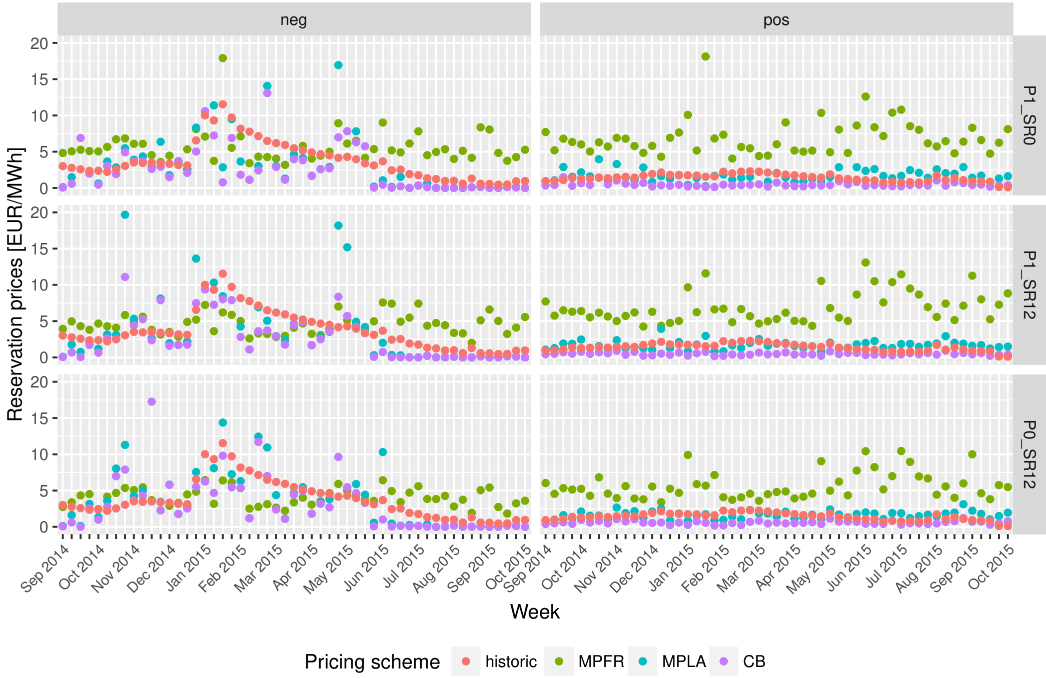


Figure 3.21.: Modeled and historic average prices of capacity reservation for TRL.

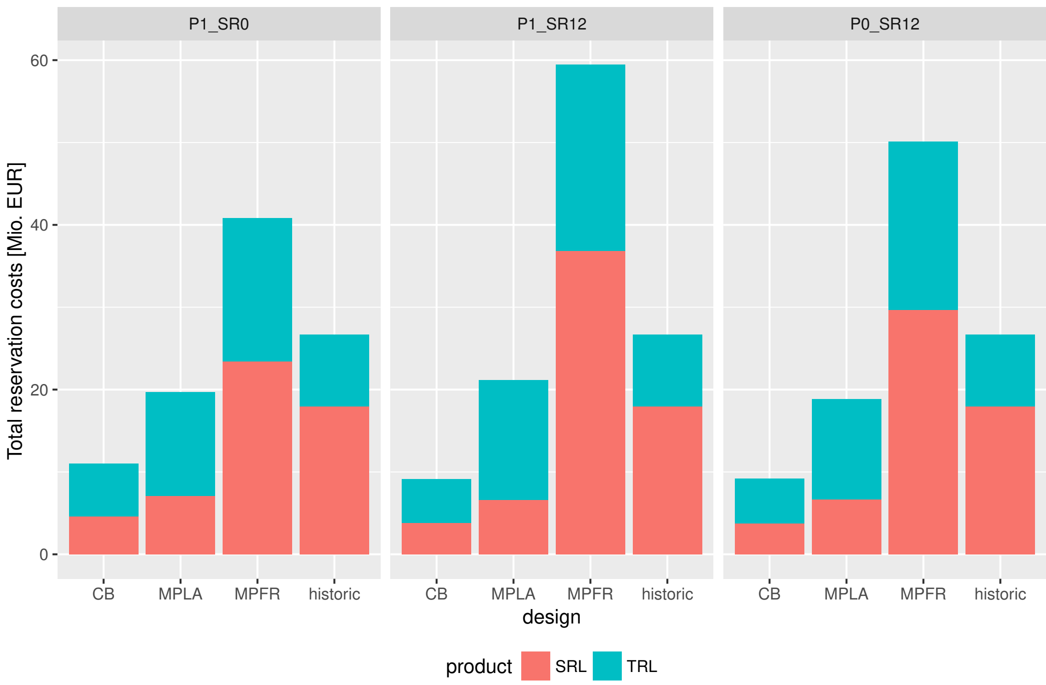


Figure 3.22.: Modeled and historic total costs of capacity reservation.

conversion efficiency at their respective operating point. The marginal costs of hydro power units are defined through the respective water value at a certain point in time. Figures 3.23 to 3.26 show historic and modeled call prices of SRE (secondary balancing energy calls) and TRE (tertiary balancing energy calls) in the considered time period. Due to the fact that historic prices differ by one order of magnitude, prices of both SRE and TRE are shown twice, once with a focus on historic prices and once with a zoom into modeled prices.

Figure 3.23.: Modeled and historic average prices of called energy for SRE. By convention it is assumed that for positive calls energy delivery q is positive $q > 0$, and for negative calls $q < 0$. If the payment $p \cdot q$ is positive, the TSO pays the respective amount to the providers and vice versa.

From a cost-based perspective providers of negative balancing energy are willing to pay a certain amount of money in order to be called. This arises from the fact that thermal generators can save fuel costs when reducing their output[19] and hydro storage operators either keep or pump, respectively, water with a positive value[20] in their upper reservoirs. By convention the sign of quantities of negative balancing energy is negative. Therefore, if money is paid from market participants to the grid operator the sign of prices needs to be positive and vice versa.

In Figure 3.23 the prices for delivery of negative SRE are thoroughly negative, i.e. market

[19]A reduction of output typically causes lower conversion efficiency. However, in general this effect does not out-weight saved fuel costs.

[20]In the case storage operators face a strict constraint on maximum fill levels of their reservoirs and spillage is not possible the water value could turn negative. However, in this study it has been assumed that water spillage is always possible.

participants have been paid to call negative reserves. The modeled prices for negative SRE are solely positive, i.e. participants are willing to pay these prices to the grid operator. In case of the MPLA accepted scenario the prices are in most cases zero. That means that in most cases the participant, which is willing to pay the lowest price to the grid operator, does not face any cost savings as a result of calling negative balancing energy. MPFR prices are not considered for balancing energy within the model, because in the time period analyzed only generators that previously had been accepted to provide reserves were eligible to provide balancing energy. Consequently, there is no rejected bid available for calling[21]. Historic prices range in between zero and -625 EUR/MWh and are most of the time much lower than the modeled prices.

The interpretation of price for delivery of positive balancing energy is strait forward. If prices are positive, participants are paid in case of calling. Similarly as in the case of negative reserves historic prices are again much higher than the ones derived from the model runs. However, the resulting prices are lower than the ones for negative balancing energy. A zoom into the modeled SRE prices is given in Figure 3.24. Herein, the historic prices do only temporarily show up in the all-time low from July to September 2015. In contrast to historic prices, the modeled prices for positive reserves are higher than the ones in negative direction. However, all modeled prices are in the range between zero and 60 EUR/MWh, which is oriented on actual day-ahead electricity prices. In section 3.7.4 a more in-depth discussion on the underlying water values is given.

The basic key conclusions as for SRE remain valid for delivery of TRE. It is striking that in historic TRE prices a structural break with increasing prices can be observed in spring 2015 that can not be explained by the model (cf. Figure 3.25). This break arises in both positive and negative control direction. Figure 3.26 shows the modeled prices for TRE in detail. Neither any structural break can be observed nor any kind of trend. The range of variation lies as for SRE in the bandwidth of day-ahead electricity prices.

The resulting total costs of balancing energy calls reflect these findings (cf. Figure 3.27). The historic costs by far exceed the modeled costs in all assumed pricing schemes. The next section aims to interpret the resulting prices against the background of fundamental hydrological parameters, because hydro technologies play an overarching role in the Austrian context and therefore are an important factor in the price building process. In the conclusions section a critical review of possible reasons for the discrepancy between modeled and historical call prices is given.

3.7.4. Fundamental hydrological impact factors on costs

The Austrian generation mix is characterized by a high share of hydro power generators. In particular, some of the largest pumped hydro storage power plants are located in Austria. Due to the fact that current balancing markets are still nationalized and that hydro power generators are basically very flexible, hydro power plays an important role in the context of

[21] Recently, the Austrian grid operator occasionally also allowed bids to participate in balancing energy calling, which were not previously procured within the preceding procurement auction.

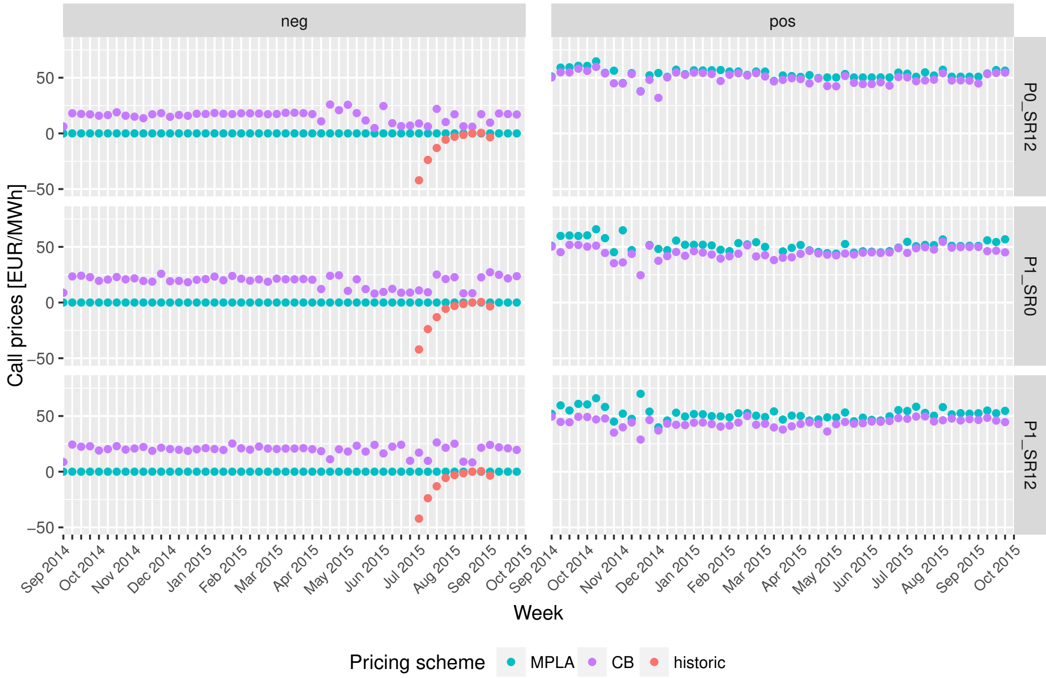


Figure 3.24.: Modeled and historic average prices of called energy for SRE (zoom). By convention it is assumed that for positive calls energy delivery q is positive $q > 0$, and for negative calls $q < 0$. If the payment $p \cdot q$ is positive, the TSO pays the respective amount to the providers and vice versa.

the Austrian balancing market. Since hydro power features some specific operational features in this section a few hydrological impact factors that determine costs of generators for providing capacity reserves and balancing energy are shown in order to understand some of the fundamentals of price formation in the Austrian balancing market. The costs for services to the balancing market are essentially opportunity costs. This means, that costs in this market basically arise from arbitrage opportunities in other electricity market segments, markets or other valuable activities. The potential to realize profits in these other opportunities is constrained by constrained generating capacity, reserved working volumes in reservoirs or a loss of valuable water. For the sake of clarity in this work the costs drivers of costs for capacity reserves and those for the deployment of balancing capacity, i.e. a calling of those reserves, have been differentiated. Therefore, the impact factors for reservation and calling can be separately identified.

3.7.4.1. Cost drivers of capacity reservation

In Figure 3.28 the constraints of the feasible operating region of turbines and pumps that arise through capacity reservation are schematically illustrated. From left to right the constraints of both control directions are shown. The upper part of each graph shows the respective constraints of the pump, the lower graph the ones of the turbine. The constraints

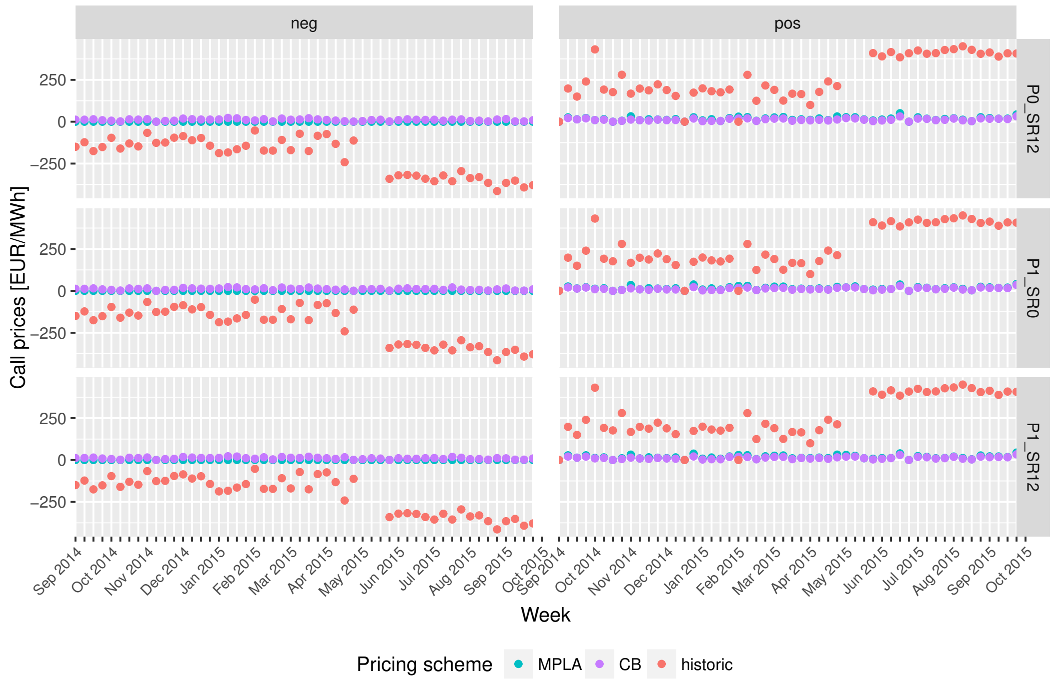


Figure 3.25.: Modeled and historic average prices of called energy for TRE. By convention it is assumed that for positive calls energy delivery q is positive $q > 0$, and for negative calls $q < 0$. If the payment $p \cdot q$ is positive, the TSO pays the respective amount to the providers and vice versa.

of both control directions are inversely related to one another. Both the feasible operational states of turbine and pump are partially discrete. The turbine needs to be operated above a minimum level "Turb_min" or has to be switched off. Above the minimum level turbines can be generally operated on a continuous scale; However, with varying conversion efficiency. Pumps, on the other hand, do also have a minimum pumping level. Besides that they typically can only operate at discrete states, indicated in the graph with "Pump_1" to "Pump_max"[22]. Any single pump can even in most cases just be switched on or off. Therefore, the pump in the graph can be interpreted to be an aggregate of multiple pumps. The gray area marks the feasible operating region of the turbine and pump while respecting constraints arising from an obligation to reserve capacity. Note that, although the gray area of pumps is shown as continuous spectrum, the pump can still only be operated at the discrete levels as described above. The blue line represents a hypothetical amount of reserved capacity. The red line marks the actual constraint on the operating region that is required in order to fulfill the capacity obligation. The afore-mentioned discrete feasible operation states of pumps lead to a gap between required and actual constraint. The actual constraints need to be more restrictive than the required limits. In this way, the actual limit overfulfills the required limit. This necessity causes some difficulties for pumped hydro

[22]It should be noted, that pump turbines with variable speed control offer some additional degree of freedom.

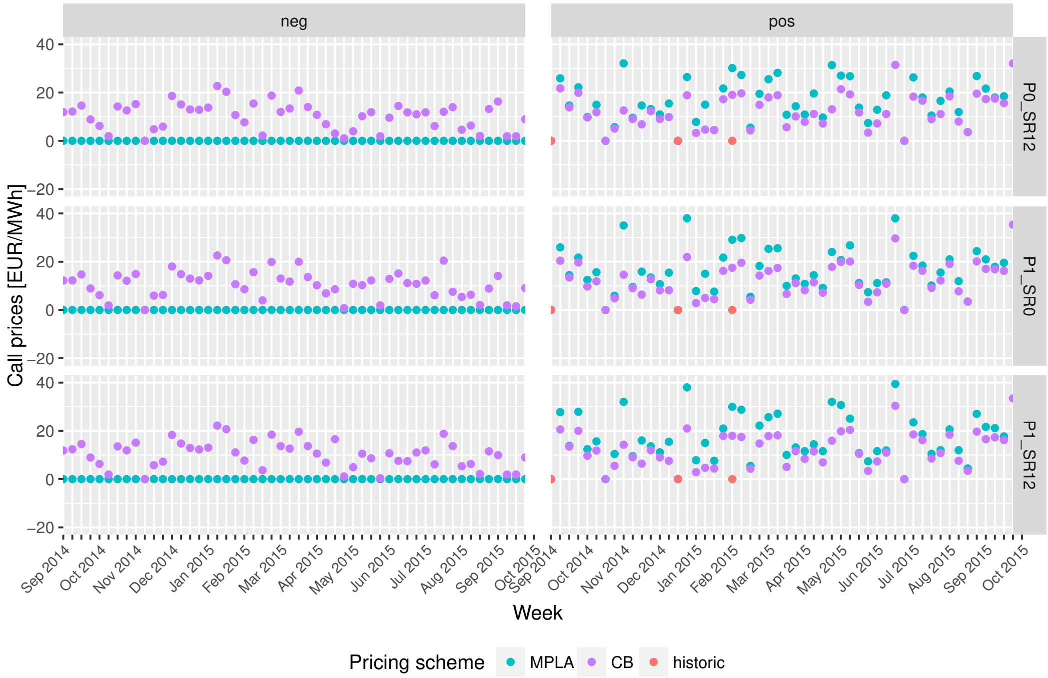


Figure 3.26.: Modeled and historic average prices of called energy for TRE (zoom). By convention it is assumed that for positive calls energy delivery q is positive $q > 0$, and for negative calls $q < 0$. If the payment $p \cdot q$ is positive, the TSO pays the respective amount to the providers and vice versa.

storage operators with ternary machine sets that participate in balancing markets. Even if a capacity is offered that matches in size one of the discrete operation levels of the pump, this capacity is in most cases only fractionally called in the process of energy balancing. In order to compensate for the remaining gap, either a turbine in the same power plant needs to be operated simultaneously – what requires the presence of a hydrological bypass – or a turbine from another power plant in the same portfolio has to be activated. However, since these complexities are related to the process of energy calling they are not considered as cost components related to capacity reservation.

Further constraints arise from the theoretical possibility that reserve capacities may be called in one direction over a longer period of time. This is in particular relevant in times when reservoir fill levels are close to their limits. In order to guarantee that the promised capacity is available throughout the contracted time period a so-called *working volume* need to be reserved as well. These working volumes restrict upper and lower reservoirs of a certain power plant and are different for each control direction. The respective restrictions of reservoir limits are shown in Figure 3.29. The graphs exemplarily show in which areas fill-levels are allowed in order to ensure a constant calling of the total reserved capacity over a duration of SR hours. The parameter *SR* indicates the storage run time, a parameter that accounts for the number of hours of consecutive calling of energy in one direction.

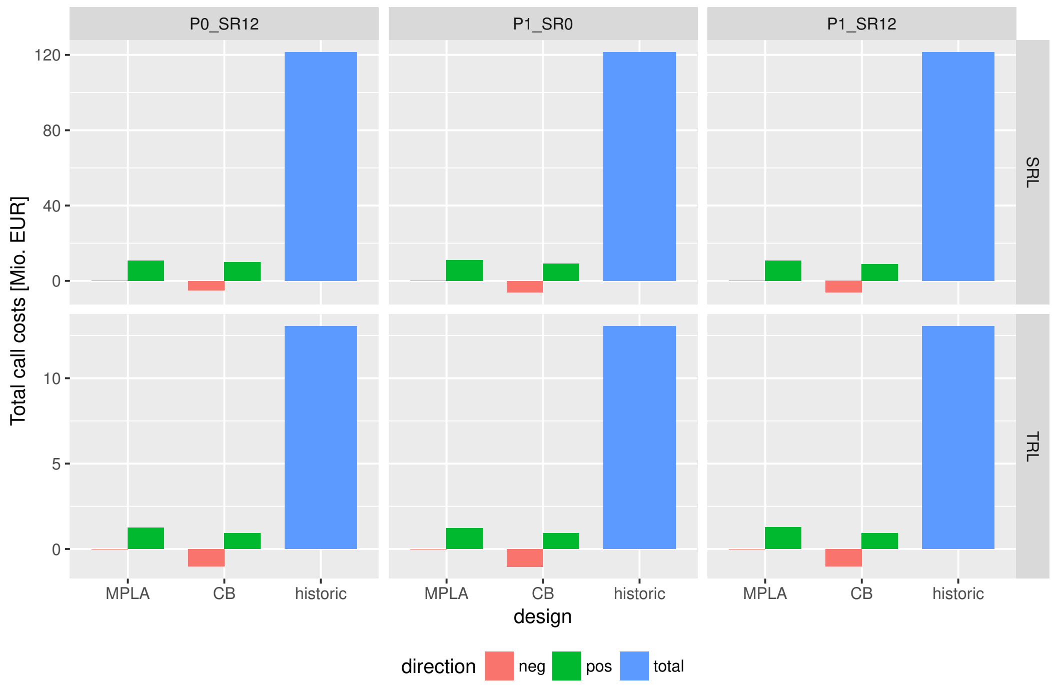


Figure 3.27.: Modeled and historic total costs of called energy.

In the present analysis this parameter has been parametrized to be 12 hours. This value has been derived from the study of historical imbalance time series in the Austrian control zone. In general, reservoir constraints are only of importance when a storage operator provides reserves in only one direction, e.g. because there is no pump installed. In case both directions are offered positive and negative callings typically offset one another and strict volume restrictions lose their importance, since the average fill level remains despite balancing calls relatively constant. However, if pricing of positive and negative balancing energy is quite different, this assumption might not be justified. Also when portfolios are eligible to participate in markets these constraints lose their relevance, because it occurs rarely that all storages in the portfolio are hitting their fill-level limits simultaneously.

All the mentioned constraints are represented as distinct mathematical equations in the models described in section 3.4.1. One part of the optimal solution of these models are so-called dual variables, which indicate the marginal loss from tightening the respective constraint. These variables can be interpreted as the costs that arise from a certain constraint. The sum of all dual variables related to the provision of a certain type of reserves adds up to the costs of the respective reservation (cf. section 3.4.2).

The optimal dual variables that correspond to the above discussed constraints and are the basis of the modeled prices and costs of section 3.7 are shown in Figure 3.30 for SRL and in Figure 3.30 for TRL. The shown numbers are the maximum values over all power plants irrespective of whether they have been participating in the market or not, i.e. both Figures

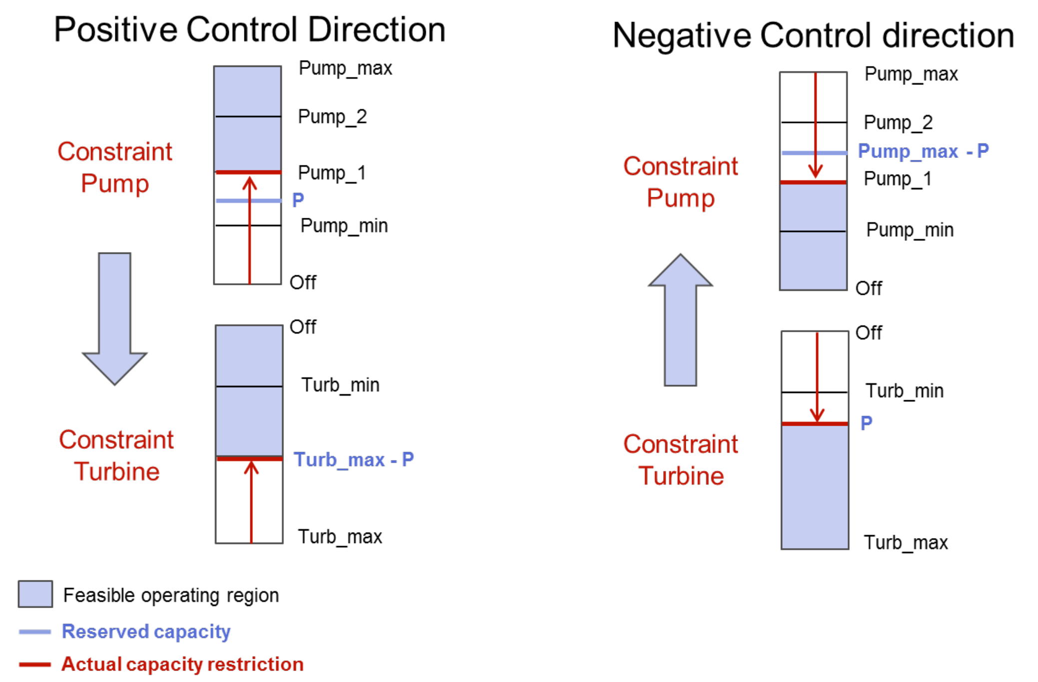


Figure 3.28.: Restriction of the feasible operating region of turbines and pumps due to the reservation of reserve capacity. Technically feasible operating states are marked with horizontal lines.

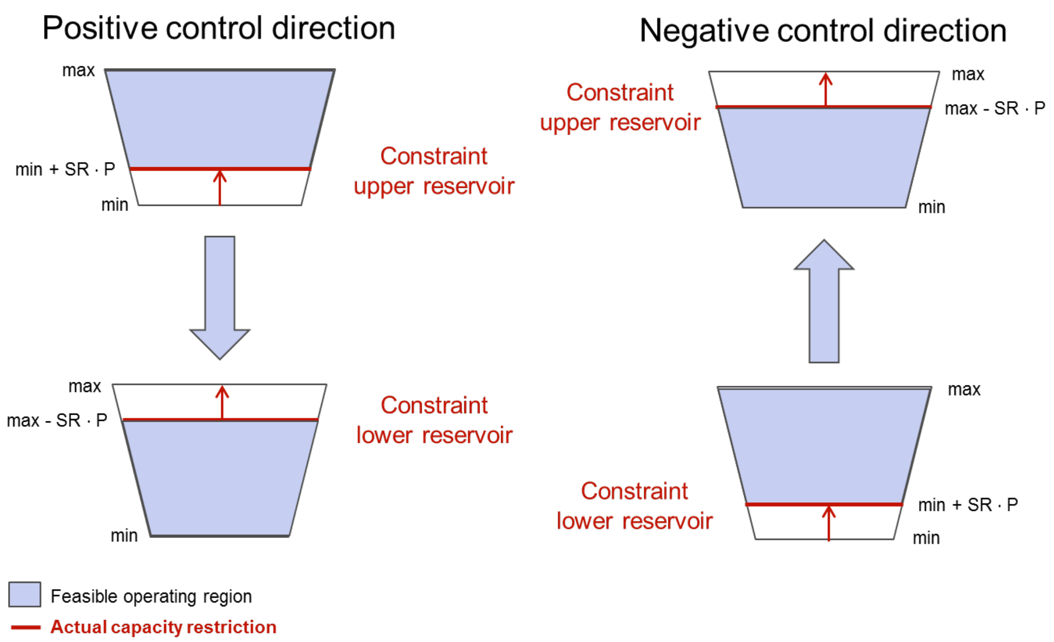


Figure 3.29.: Schematic illustration of hydrological constraints of reservoirs due to the reservation of reserve capacity.

contain timely and plant-wise maximum values.

When comparing both Figures it becomes apparent that costs for provision of positive reserve capacities are significantly lower than the ones of reserved capacities for negative calls. That means it is more costly to restrict pumps in their capacity to transport water from lower to upper reservoirs. This pertains particularly to pumps that are located in the lower part of a hydro cascade, because the missing water is also lost for all upper reservoirs. Constraints on reservoir working volumes are of lower importance than the ones that restrict the operation regions of turbines and pumps. For the provision of negative reserves the dual variables of these constraints even disappeared. It also can be concluded that restrictions on turbine and pump capacity increase with the absence of portfolio building and stronger restrictions on reservoir fill levels. However, it should be noted that Figure 3.30 and 3.31 contain costs of all plants, i.e. in particular those that are not chosen to provide capacity reserves. The presented values are meant to give an indication on the relative importance of single hydrological constraints with regard to the cost structure of capacity reservation.

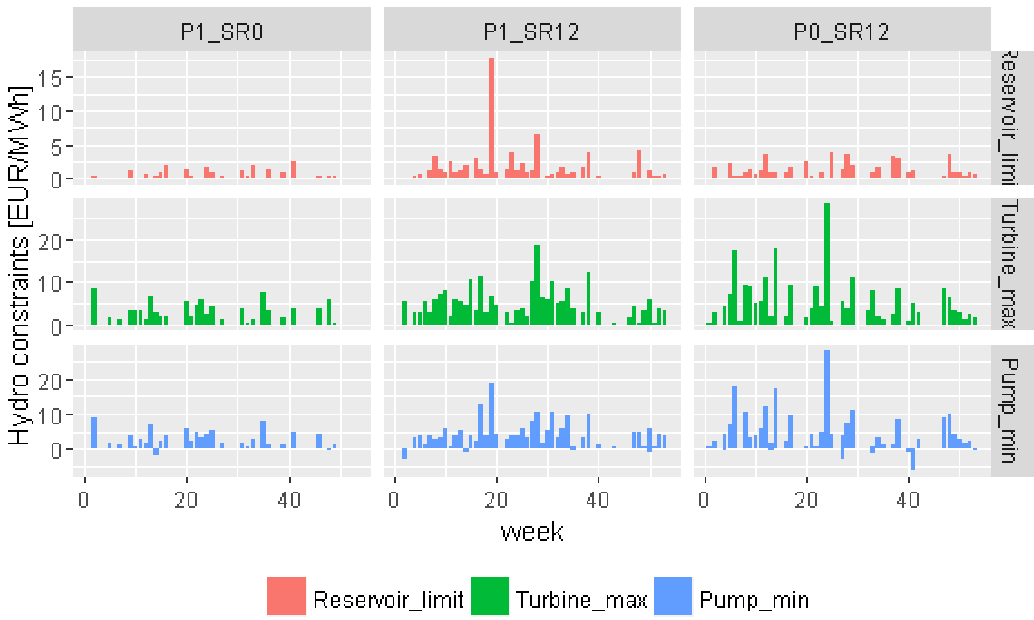


Figure 3.30.: Maximum prices of hydrological constraints as a result of the capacity reservation for positive balancing power.

3.7.4.2. Cost drivers of balancing energy calls

In a hydrological system the value of water in each reservoir indicates the opportunity value of using a unit of water for a certain purpose and at a certain point in time. In general, water is used for multiple purposes, e.g. irrigation of agricultural areas, or simply for drinking water supply. In this study we solely assign water a value for its potential to run through

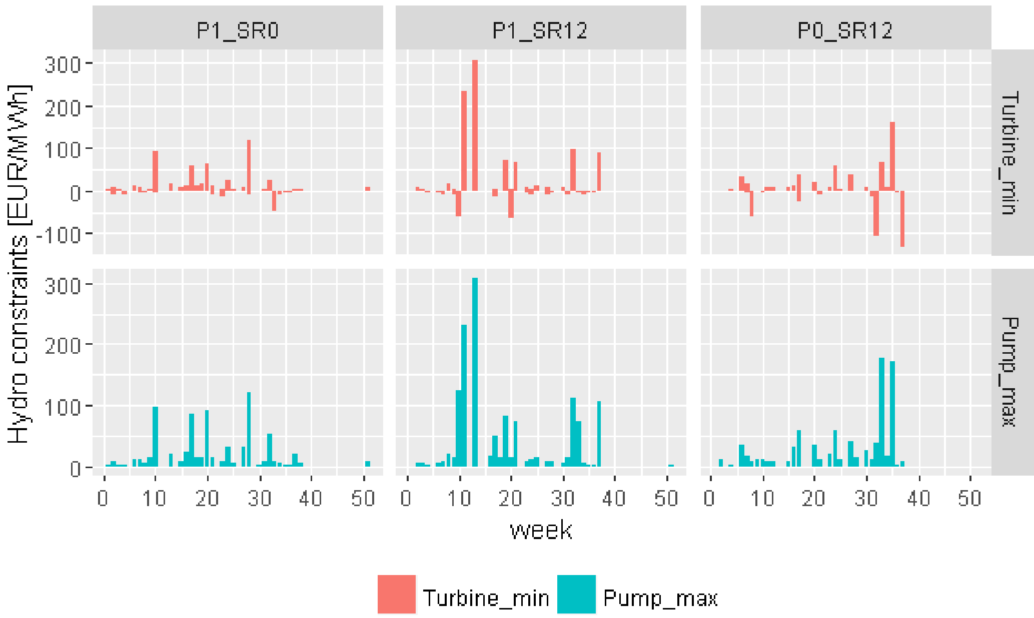


Figure 3.31.: Maximum prices of hydrological constraints as a result of the capacity reservation for negative balancing power.

turbines which in turn generate electricity that is sold on wholesale markets. In Austria this value accounts for the most significant share of the overall economic water value. In order to derive these water values the dual variables of the reservoir balance equations (cf. equations 3.5) can be used. Each variable indicates the value of one additional m3 of water in the respective reservoir and for a certain point in time. The marginal costs of a certain power plant to generate or, respectively, not to generate one additional MWh of electricity can be derived from the difference of water values in their upper and lower reservoir. Figure 3.32 contains time series of marginal water values of selected pumped hydro storage power plants in Austria. These water values have been taken as proxy for marginal costs of hydro plants related to calls of balancing energy. It can be seen that the water values are strongly directed towards day-ahead electricity prices. The reason is, that in normal operation of hydro systems the maximum value a certain MWh can generate is the highest electricity price that occurs within a certain time window specific to the power plant. There is one theoretical situation when marginal water values can exceed the highest electricity price. This situation can only occur in a hydro cascade. If all lower reservoirs of a hydro cascade are on their upper fill level limit and it is allowed to spill water than the value of one additional m3 of water in all these reservoirs gets zero. If in such a situation the uppermost reservoir is forced to turbine, the fair marginal cost of this action is the sum of water values of all plants along the lower hydro cascade. This can be explained by the fact that because of this action the additional amount of water needs to be spilled after the uppermost power plant and cannot be utilized anymore in the lower hydro chain. If the uppermost reservoir would store the water for later use when the lower reservoirs are not anymore on their upper limit the water could be utilized along the whole chain. The situation described above is very unlikely and might only occur in very special and rare circumstances. However, the question arises why exactly those plants affected from such an event should be used to provide balancing energy. All the previous statements are based on the assumption that water spilling is possible and allowed. Therefore, water values of turbining and pumping are similar. When upper limits on reservoir fill levels are strict and spilling of water is not an option, water values can even turn negative. The negative value reflects the costs that occur because of non-optimal water use in other reservoirs in order to ensure that the upper fill level limit can be met. However, in the present study no such limitations have been assumed. In conclusion, in proper designed hydro power systems with normal operating conditions the maximum water values should not exceed the highest occurred or expected electricity prices.

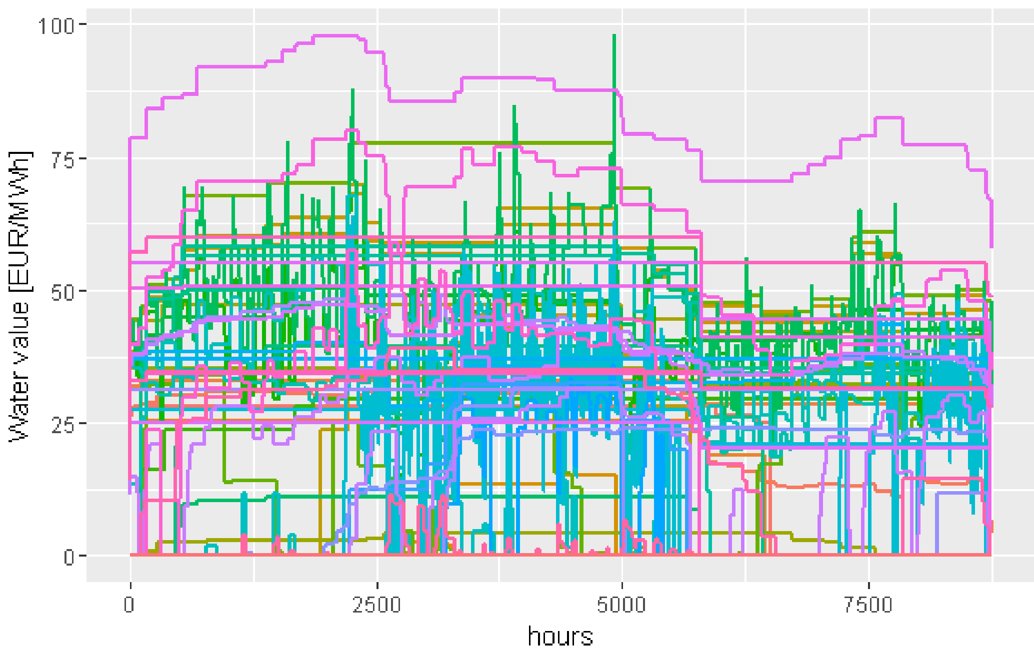


Figure 3.32.: Marginal water values of selected pumped hydro storage power plants. These values are relevant for short-run costs of balancing energy calls.

3.8. Discussion of results

The results obtained in this part of the work have shown that the level and variance of historical capacity prices of secondary and tertiary reserves in Austria can be reproduced fairly well by considering fundamental cost drivers and standard bidding strategies. Due to the large amount of hydro power generators the main cost drivers in these auctions were restrictions on the maximum available capacity of pumps, turbines and reservoirs that resulted in high opportunity costs, in particular in times of large inflows. CHP units also had just limited availability, especially in times of extremely low and extremely high heat demand. On the contrary, historical prices for called energy had been an order of magnitude higher than the ones derived from the modeling work. The model considered marginal (linear) water values of reservoirs as basis for the calculation of energy price bids of hydro power units. This assumption can be criticized for a number of reasons. First, due to the strong impact of non-convex technical constraints the use of "marginal" water values might differ from "average" water values that results from the calling of energy over a longer period of time. However, in the future it is planned to drastically reduce product lengths, which should lead to a convergence of both water values. Second, actual bids are based on uncertainties of the future evolvement of critical parameters like spot market prices and hydro inflows. That is, sometimes week-ahead forecasts need to be made in order to place a bid. This uncertainty is incorporated into bids via mark-ups. Such mark-ups have been assessed in the literature to be in the range of around 1 EUR/MWh. They are therefore not relevant with regard to contribution to the explanation of the large discrepancy between actual and modeled energy prices. Finally, the probably most important explanation for this deviation might be expectations on future profits from balancing energy calls. Expectations on such profits would then be considered in the pricing of bids. This might be the explanation for the deviation of modeling results and historical prices. However, since the objective of this work was to derive benchmark prices for perfect competition such profit expectations have been excluded from the analysis.

Chapter 4

Relevance of Europeans electricity balancing markets in a 2030 context

A forward looking perspective

In the previous chapters the focus of the analysis has been laid on providing the theoretical fundamentals of modeling electricity balancing markets and on the critical analysis of historical market outcomes on the example of Austria. In this chapter the objective is to derive insights on the potential relevance of electricity balancing markets across Europe in the 2030 time frame. The findings of this chapter are based on the results of an existing electricity market model that covers the European electricity market. In order to carry out this analysis the existing model that was originally designed to model day-ahead electricity prices are extended by a simplified representation of intra-day and balancing markets. A major contribution of this work to the status quo is the preparation of high-frequency demand time series for several European countries that are needed as model input for balancing markets.

4.1. Contribution to the literature

There is plenty of literature studying electricity balancing markets across Europe from a national perspective, see e.g. literature review in section 3.2. This is completely justified, since todays markets are merely national with a low level of international cooperation. However, concerning the impact of an European-wide market coupling of balancing markets their is currently only a limited amount of literature. The most prominent studies have been launched by the European Commission with the aim to assess potential benefits of different design options for cooperation mechanisms between national balancing markets. In EC (2013) the authors explore the advantages and disadvantages of different market design options and underpin their argumentation with a quantitative analysis relying on historical market data from 2011. In EC (2016) this analysis has been fundamentally updated and the time scope has been put to the period up to 2030. Both impact assessments have been prepared with the intention to support decision making of European policy makers and therefore are written in a very concise form and a lack of transparency concerning the concrete assumptions that were taken. On part of the scientific literature there are a number of articles concerning the 2030 time frame. For example, Burgholzer (2016) presents a methodology to assess the impact of different market arrangements on overall costs and benefits of electricity balancing markets. Gebrekiros et al. (2013) quantifies the amount of reduced costs that might result from imbalance netting across Europe. Both papers are concerned with the question of how different market design elements and internationalization of markets could impact the overall costs of electricity balancing. The main contribution of this work is to answer the question of how relevant balancing markets might be at all in the 2030 time frame. *General relevance* in this context is meant in the sense of physical volumes as related to overall electricity consumption and monetary market volume of balancing markets related to day-ahead market volume. *Specific relevance* relates to different types of generation technologies and is understood as the share of revenues from the balancing market as compared to day-ahead market revenues. A main contribution of this work along these objectives is that the relation between increasing shares of variable renewable electricity in the European generation mix and the resulting demand for balancing energy has been explicitly worked out by the use of statistical models. Although the suitability of such models for this purpose has already been shown in the literature, cf. (Garcia and Kirschen, 2006) or (Foley et al., 2012), to the best knowledge of the author no comprehensive and consistent quantification of the size and form of high-frequency forecast error time series for different generation technologies and all major European countries have been carried out so far for the time frame until 2030.

4.2. Applied methodology

As in previous chapters, the central approach in order to derive quantitative results in this chapter is the application of an optimization model. Figure 4.1 illustrates the most important components of the applied modeling framework. Each market simulation needs to assume a certain market design, develop a representation of the demand and supply side, as well as consider available trading capacities in case more market areas are coupled with each other.

In the case of electricity balancing markets the demand side is composed by the netted sum of forecast errors of generation and consumption in a certain control area. In Europe transmission system operators perform day-ahead forecasts on the aggregated generation of wind onshore, wind offshore and photovoltaics in their control zone[1]. These forecasts together with data on actual generation are used to construct historical forecast error time series of variable renewable electricity across Europe. The time series are normalized to installed generating capacity and their statistical characteristics are captured by *Autoregressive Integrated Moving Average* (ARIMA) models, whereas actual generation has been considered as additional explanatory variable. In the literature such models are known as ARIMAX models. In this way a formal relationship between forecast errors and the generation profile of variable renewable electricity are established. This relationship is used to construct synthetic forecast error time series based on expectations on the future generation profiles of wind onshore, wind offshore and photovoltaics for different European countries. Unplanned outages of dispatchable generators have been simulated based on historical statistics. The netted sum of both time series, forecast errors and unplanned outages are used to represent demand for electricity balancing. A detailed description of the applied algorithms is given in section 4.3.2.

In this work two extreme scenarios for available cross-border transmission capacities for electricity balancing markets are considered. In one scenario only national markets are assumed, therefore the available transmission capacity is zero. In the alternative scenario it is assumed that cross-border flows of electricity balancing markets are only limited by the physical transmission limits of the network and by the extent these capacities are already utilized by trade flows from day-ahead and intra-day markets. The assumptions related to the market design including the approach towards scenario analysis are outlined in section 4.6. To include cross-border trade limits into the modeling, a physical representation of the European transmission grid were developed and integrated in the market clearing algorithm of the power system model. A more detailed description of the grid model is given in section

[1] cf. `https://transparency.entsoe.eu/`

4.4. In order to represent physical flows from day-ahead and intra-day markets, they are also modeled in order to forward the corresponding results to the balancing market model run. In section this procedure is described in more detail.

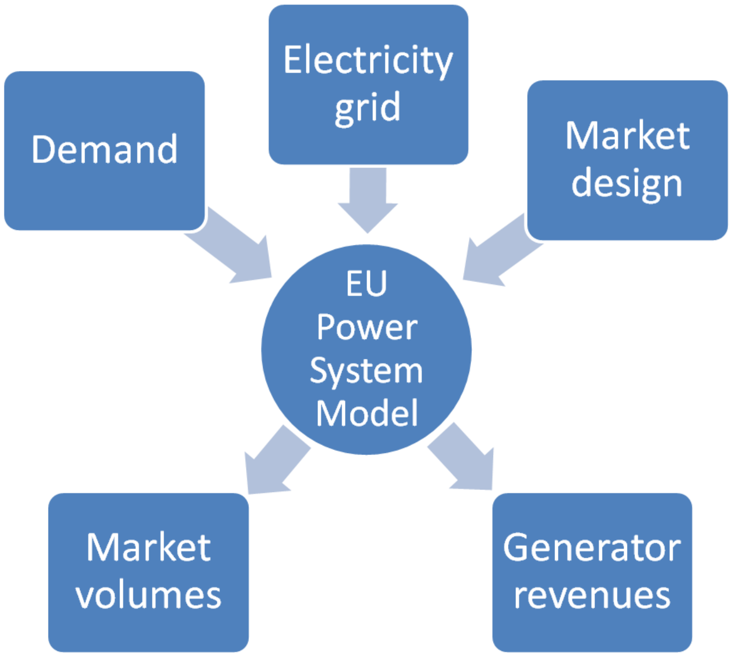


Figure 4.1.: Applied modeling framework for the European case study.

4.3. Development of high-frequency demand time series

The demand side has been modeled by three parts. The first part represents the inelastic amount of electricity demand. This part is incorporated into the model via exogenous time series. The second part is comprised by a set of demand-side applications, which offer a country-specific potential to shift and to vary, respectively electricity demand related to electricity prices, e.g. heat pumps, electric boilers and batteries. Also large-scale pumped hydro storages are implemented in an aggregated form into the model. This part is represented in the form of distinct technologies in the applied power system model. Finally, the third part consists of uncertainties of consumption and unplanned outages of generation[2] that are a result of contingencies and the deviations between predicted and actual generation profiles of variable renewable electricity infeed. The following two subsections describe in detail how the exogenous demand profiles are derived.

[2]Outages of generators can either be labeled as reduced generation or additional demand for electricity. In this section unplanned outages are treated in the context of the demand side.

4.3.1. Load profiles of electricity consumption

The yearly electricity consumption for each EU country until 2030 is also based on recent model results of PRIMES[3]. In the EUCO27 scenario it is assumed that gross electricity consumption of the EU will rise from 3260 TWh in 2015 by approximately 8 percent to 3512 TWh in 2030. The procedure of deriving quarter-hourly load profiles was similar to the one applied in order to construct the infeed profiles of renewable electricity (cf. section B.1.2). The characteristics of quarter-hourly load for each country have been derived from historic load time series of the ENTSO-E transparency platform[4].

4.3.2. Demand for electricity balancing

Demand for balancing energy arises from imbalances between real-time generation and consumption of electricity in a certain control area. Such system imbalances are the netted sum of schedule deviations over all balancing groups in this control area. Deviations of balancing groups can be categorized in intended and unintended deviations.

Intended schedule deviations are partly expected, because on power exchanges energy rather than power is traded. Common products are energy delivery over a certain time interval with no requirements on power gradients within that interval. Generators typically prefer to keep their output constant, therefore in between intervals rapid schedule leaps occur. On the contrary, electricity consumption is continuous. Because of the discrepancy between discrete generation and continuous consumption balancing energy is needed to keep the system in balance. The second part of intended deviations is of strategic nature and applies only to a specific design option of the imbalance settlement. Across the EU imbalances are settled via one-price, or two-price mechanisms. In one-price mechanisms balancing groups with deviations in line with the overall imbalance of the control zone are punished with a certain price. In contrast, balancing groups that have deviations against the imbalance of the control zone are remunerated with exactly the same price. Balancing groups with lots of dispatchable generation are therefore incentivized to forecast the system imbalance and to deviate their actual generation against this imbalance in order to earn additional profits. In two-price systems this incentive is removed, because deviations against the system imbalance are paid a price lower than the one that penalizes reverse deviations[5]. Vandezande et al. (2010) discusses advantages and disadvantages of both design options with regard to wind power integration. In this work the author do not account for balancing energy stemming from intended schedule deviates. First, it is assumed that deterministic schedule deviations resulting from market design are moderated in the future. Second, it is also assumed that the volume of strategic deviations based on asymmetric information decreases over time and gets less relevant in the long-term.

[3] The PRIMES model has been developed and are operated by the National Technical University of Athens — Institute of Communication and Computer Systems, c.f. `http://www.e3mlab.ntua.gr/e3mlab/`

[4] `https://transparency.entsoe.eu/`

[5] Typically, the spot market price is chosen as second price. In that case generators earn exactly the same for any opposing deviation as if they would market it in the spot market.

The remaining part of balancing energy consists of **unintended schedule deviations**. These deviations are solely caused by forecast errors of generation, consumption as well as inevitable high-frequency noise. The sources of balancing energy can be independently analyzed via a composite approach, e.g. IWES (2015). The main sources of forecast errors and noise is shown in figure 4.2. All the sources in figure 4.2 produce forecast errors, which can be summed up in order to derive the net forecast error of the overall control zone. In this respect, it has been assumed that only one big balancing group comprises the whole generation and consumer portfolio. This is justified since also the used dataset is based on the large portfolios that are currently marketed by TSO's. In the following a concise description of the method of approach for the derivation of forecast errors for the different sources is given.

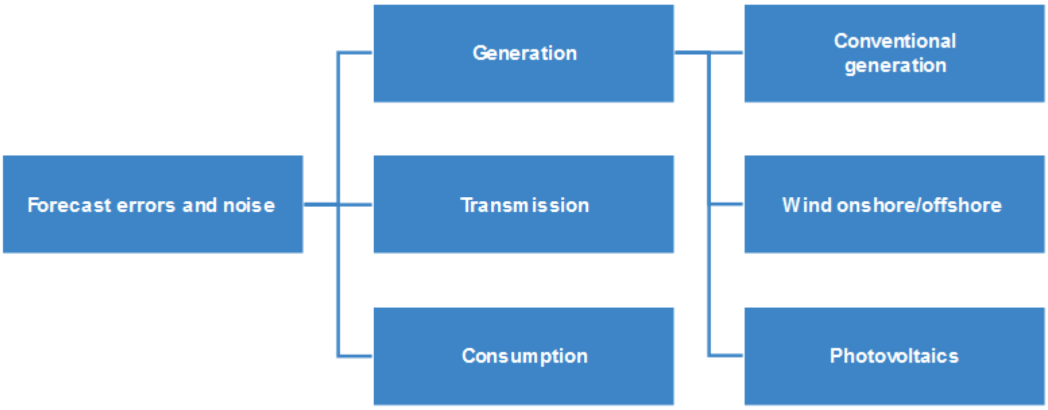


Figure 4.2.: Sources of forecast errors and noise. Own illustration based on IWES (2015)

On part of generation it has been differentiated between conventional plants and variable renewable sources (vRES). While the forecast error of conventional power plants are solely based on statistics of unplanned outages, assumptions concerning the forecast error from variable renewable energy sources have been derived based on an empirical approach applying ARIMAX models.

For **conventional power plants** (including dispatchable renewable electricity plants) it has been assumed that historical unplanned outage rates reoccur in the future. Historical outage statistics have been taken from the North American Electric Reliability Corporation NERC (NERC, 2015). All used indicators and terms are related to IEEE Norm 762 (IEEE, 2007). As appropriate indicator for unplanned outages the *forced outage rate* (FOR) has been selected. Data on the *medium forced outage duration* (MFOD) has been gathered from the Canadian Electricity Association CEA (2007). The typical plant size has been derived as average of plant sizes in the European power plant database PLATTS (PLATTS, 2011).

In order to derive the amount of unplanned outages from conventional power plants in each country the steps as outlined in algorithm 1 have been taken.

In the subsequent modeling work the resulting matrix $P^{OUT}_{t,c,h}$ from algorithm 1 were split

Table 4.1.: Assumptions related to unplanned outages of conventional power plants. Sources: (NERC, 2015; CEA, 2007)

Technology	[MW] Typical size	[%] FOR	[hours] MFOD
Run-of-River	100	3.96	64.97
Hydro Storage	350	3.96	64.97
Pumped Hydro Storage	350	9.22	64.97
Biomass Extraction Turbine	25	10.00	22.60
Biomass Backpressure Turbine	50	10.00	43.15
Other dispatchable RES	1	5.00	22.60
Gas Combined Cycle	300	4.71	22.60
Gas turbine	5	12.00	22.60
Oil	100	26.20	22.60
Coal	500	7.01	43.15
Lignite	600	4.20	43.15
Nuclear power	1500	2.72	518.98

into two parts. The matrix $P^{OUT,Bal}_{t,c,h}$ indicates the amount of outages that are balanced within balancing markets. It is assumed that only the first hour of a single outage becomes visible in these markets. The remaining outage hours $MFOR - 1$ of any of the outages were transferred to the matrix matrix $P^{OUT,Spot}_{t,c,h}$, which accounts for impacts of these outages on the spot market. Both matrices were subtracted from the maximum available generating capacity in both balancing and spot markets and thus reduce the available generating capacity on part of the supply side.

Forecast errors of **variable renewable energy sources** (vRES), most prominently wind power and photovoltaics, have been derived from historical forecast errors via the application of *Autoregressive Integrated Moving Average with Explanatory Variable* (ARIMAX) model. The applied dataset currently comprises quarter-hourly data for the years 2015 and 2016 of day-ahead forecasts and actual generation of wind onshore, wind offshore and photovoltaics. The dataset has been derived from the ENTSO-E transparency platform[6].

Forecast errors of vRES for all countries and future years have been derived via algorithm 2. In this algorithm the information from historical dependencies of actual and forecasted generation is used to develop an ARIMAX model. The model have been selected based on the *corrected Akaike information criterion* (AICc). The goodness of the fit has been checked ex-post via a comparison of mean and variance of forecast errors.

The method to derive noise and forecast errors of electricity consumption is based on findings of Hodge et al. (2013) and Taylor (2008). Hodge 2013 found that error distributions of forecast errors of load on day-ahead time scale do not follow a normal distribution, but

[6]https://transparency.entsoe.eu//

Algorithm 1 Unplanned outages of conventional power plants

1: For each technology t, country c and hour h: divide total hourly generation by typical size $\rightarrow$ number of online plants $N^{OP}_{t,c,h}$
2: For each $n^{OP}_{t,c,h} \in N^{OP}_{t,c,h}$ generate a number $OUT_{t,c,h}$ from the binominal distribution with probability FOR_t
3: **if** $OUT_{n,t,c,h} = 0$ **then**
4: $\quad t \leftarrow t + 1$ and proceed with step 2
5: **else**
6: $\quad \forall \tau \in [t+1, t+MFOD-1], OUT_{n,\tau,c,h} = 1$, $t \leftarrow t+MFOD$ and proceed with step 2
7: For each technology, country and hour: $P^{OUT}_{t,c,h} = \sum_n OUT_{n,t,c,h} \cdot TS_t$ (Typical Size). The resulting matrix $P^{OUT}_{t,c,h}$ indicates the amount of capacity that is affected by an unplanned outage.

Algorithm 2 Forecast errors from variable renewable energy

1: For each technology t, country c and quater-hours qh in week w: Find best fitted week (by means of lowest RMSE) between normalized generation $GEN^{ACT}_{t,c,qh}$ from the 2030 time series and the total time series of normalized historical generation $GEN^{ACT,hist}_{t,c,qh}$
2: Find the best ARIMAX model (lowest AICc) explaining forecasted generation $GEN^{FCA,hist}_{t,c,qh}$, subject to the explanatory variable $GEN^{ACT,hist}_{t,c,qh}$.
3: Produce a forecast for the normalized forecasted generation $GEN^{FCA}_{t,c,qh}$ with the ARIMAX model from step 2, whereas the normalized actual generation $GEN^{ACT}_{t,c,qh}$ is used as explanatory variable.
4: Calculate the normalized forecast error $GEN^{FCE}_{t,c,qh}$ over week w and multiply it with the installed capacity to derive the absolute quarter-hourly forecast error of technology t in country c over week w.
5: Transform quarter-hourly forecast error to 5-min time resolution ensuring that quarter-hourly averages of both time series remain equal.

rather a hyperbolic distribution. Taylor (2008) shows error metrics of British minute-by-minute electricity consumption data for forecast horizons ranging from 2 minutes up to 30 minutes. Considering the current gate closure time of 30 minutes ahead of real-time delivery the author decided to scale historic day-ahead forecast errors in order to match the average error metric of 30 minute forecasts stated in Taylor (2008). The forecast errors of consumption have been simulated by algorithm 3.

Algorithm 3 Forecast errors from electricity consumption

1: Split normalized quarter-hourly consumption forecast error $DEM_{c,qh}^{FCE,hist}$ of each country c into $n \in [1,6]$ classes. The classes γ^n are differentiated by the value of normalized actual consumption $DEM_{c,qh}^{ACT,hist}$ at the same point in time and are equally distributed over the range of actual consumption.

2: For each class γ^n derive the maximum likelihood estimate for the parameters of the hyperbolic distribution via application of the Nelder and Mead method[7].

3: For each country c and week w: Assign each quarter-hourly value of normalized actual consumption $DEM_{c,qh}^{ACT}$ to class γ^n.

4: For each class γ^n derive a time series of normalized forecast errors $DEM_{c,qh}^{FCE}$ via generating numbers from the parametrized distribution of the respective class.

5: Multiply normalized forecast error of all classes with the peak load of the corresponding period to derive the absolute quarter hourly forecast error of country c.

6: Transform quarter-hourly forecast error to 5-min time resolution ensuring that quarter-hourly averages of both time series remain equal.

With the use of algorithms 1 to 3 temporarily high-resolved time series of forecast errors of wind onshore, wind offshore, photovoltaics and electricity consumption have been derive for all EU countries. The sum of all time series served as demand time series of balancing energy used in the subsequent modeling work. Because of uncertainties on the future capability of supply-side resources to provide flexibility over different short-term horizons a further distinction between balancing demand in different short-term time scales, e.g. differentiation into aFRR and mFRR[8], have not been made. Noise that occurs below a time-resolution of 5 minutes has been neglected in this work.

4.4. Transmission grid representation

In many liberalized electricity markets around the world markets clear without considering the physical characteristics of power transmission[9]. The transmission grid limits the space

[8]This is the ENTSO-E terminology used for standard products in electricity balancing markets. A definition of terms can be found for example at `https://www.entsoe.eu/Documents/MCdocuments/balancing_ancillary/2017-03-07/161123_WGAS_Draft_proposal_for_Standard_Products.pdf`

[9]The following concepts are based on previous work of the author documented in (Ortner and Kruijer, 2014; Kruijer, 2014; Busch and Ortner, 2016)

of possible transactions between generators and consumers at different locations or zones, respectively. Due to the specific characteristics of AC transmission networks a power injection at a certain node has an impact on several transmission lines, the so-called loop flows. Traditionally, one approach in market clearing algorithms to abstract from this behavior has been to calculate so-called *net transfer capacities* (NTC) that represent the available transfer capacity for commercial trades in between two zones and are valid for a certain period of time. However, the classical NTC-approach has shortcomings. Loop flows are taken into account via applying a "worst-case" scenario in the sense that physical transfer capacities are reduced to account for potential transfer limitations stemming from other power flows and further to maintain the n-1 stability criteria. This leads to an inefficient utilization of the transmission grid, because in many operating points the restriction to the worst case is not binding. Second, from this approach it is not possible to analyze how transfer zones/countries are influenced by commercial trades of third parties. In the future such parties might react via the introduction of Flexible AC Transmission System (FACTS) devices, which will have a direct influence on cross-zonal power flows. Finally, since market schedules resulting from clearing algorithms with simplified grid representations might be infeasible with regard to physical transmission opportunities, these schedules need to be corrected by TSO's in the form of redispatch activities. These redispatch activities primarily focus on readjustment of schedules towards a feasible power grid state, rather than on economic efficiency of dispatch. Therefore, such adjustments are typically costly for TSO's. Against this background, the TSO's of the Central-Western-Europe (CWE) region stated in 2007 a memorandum of understanding stating the intention to introduce the so-called (physical) "flow-based market coupling" within the CWE region. On 20th May of 2015 the flow-based market coupling has been successfully launched in the day-ahead market coupling process of the CWE region. In the next years it is planned to expand the flow-based market coupling approach throughout the whole EU internal electricity market. Van den Bergh et al. (2016) gives a good overview of relevant terminology and the underlying concept of the applied approach.

4.4.1. The European transmission grid model

In order to capture the characteristics of physical power flows in the applied modeling framework a suitable representation of the European transmission grid has been developed. There are different options how to incorporate a transmission grid representation into a electricity market model. The author rejects the NTC approach due to the above mentioned shortcomings. The implementation of the flow-based market coupling approach currently applied by *EPEX Spot SE* to assess future market results based on current grid parameters is also not meaningful. Due to the fact that the transmission grid modeling based on a full-grid representation is computationally demanding, a number of approaches have been developed to tailor the methodology of technically oriented grid studies, e.g. (Jang et al., 2013; Egerer et al., 2013; Chatzivasileiadis et al., 2013) to the needs of power market analysis, e.g. (Allen et al., 2008; Cheng and Overbye, 2005; Shi and Tylavsky, 2012; Papaemmanouil and Andersson, 2011; Oh, 2010). Most of these approaches derive grid equivalents based on a certain base operating-point. However, the more the outcome of the market differs from this base case, the greater the errors in terms of actual power flows. In this work the reduced grid model approach developed in Kruijer (2014) has been applied. This approach overcomes the afore-mentioned problems by using knowledge from market operation in the grid simplification method. On the left side of Figure 3 a representation of the full ENTSO-E transmission grid is shown. It is based on the ENTSO-E grid map of 2012. The grid map has been transformed to numerical data using the software package *QGIS*. In this software the ENTSO-E grid map has been projected onto a vector map and was then geo-referenced, from which the topographical data from the high voltage grid could have been retrieved.

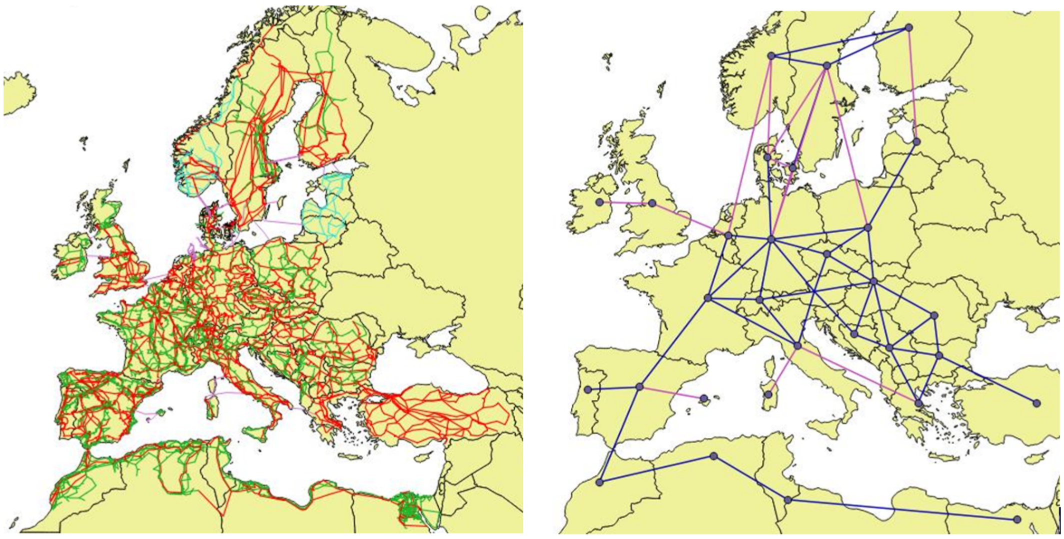


Figure 4.3.: Full ENTSO-E high voltage transmission grid (left figure). Simplified grid representation of Ortner and Kruijer (2014) (right side).

The full grid model for all connected countries within Europe contains 5141 nodes and 6737 power lines (including transformers). The size of this model is too large for long-term simulations, as the computation time would take too long and/or the required computation power would disproportionally large. Therefore, the model has been reduced to a smaller equivalent version of the full grid and as such includes a significantly lower amount of nodes and lines. The method that was used for grid reduction is described in detail in Kruijer (2014). This reduced grid model has been used in the current work to enable the simulation of market prices across Europe on the basis of flow-based market coupling.

4.5. The power system model *HiREPS*

4.2 The **Hi**gh **Re**solution **P**ower **S**ystem Model (*HiREPS*) developed at the Energy Economics Group of the Technical University of Vienna (Totschnig et al., 2017) is applied in this work to bring together supply, the transmission grid and demand in a way that simulates electricity prices for the scenarios outlined in section 4.6. *HiREPS* is a large-scale mixed integer optimization model[10] covering the electricity and heat sector in all EU member states including Norway, Switzerland, the Western Balkan countries, North Africa and Turkey. A schematic overview on the model structure is given in Figure 4.4.

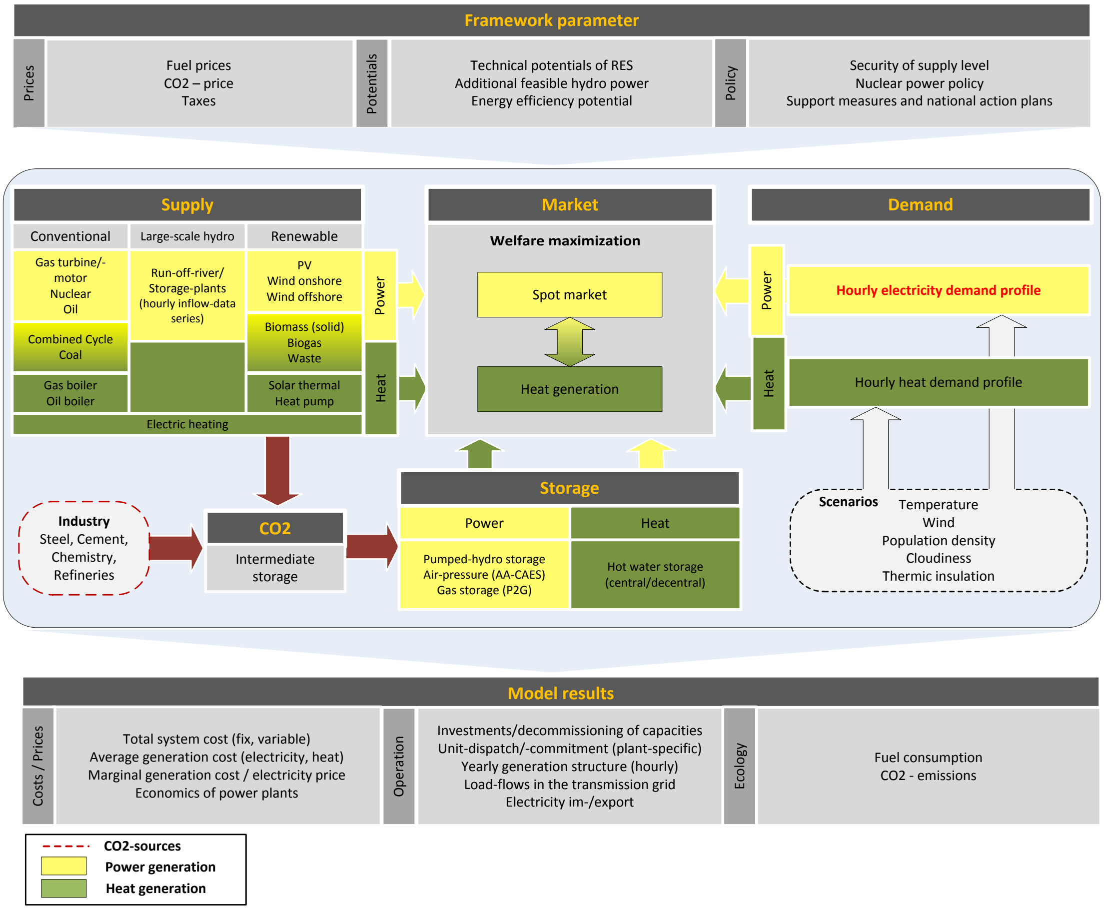


Figure 4.4.: Schematic overview of the power system model *HiREPS*, cf. Totschnig et al. (2017)

The model needs a comprehensive set of framework parameters concerning prices and taxes, available resources to be optimized and exogenous policy measures. The key assumptions related to the supply side of the model are documented in Annex B. The additional input assumptions that are of specific importance for the research question posed in this chapter concern the high-frequency demand time series described in section 4.3.2. The model covers both the electricity and the heat sector. Thus, on the supply-side the model contains detailed techno-economic data on electricity-only, heat-only and combined-heat-and-power plants for all countries within Europe. For the sake of this study renewable electricity infeed has been modeled as exogenous time series as described in section B.1.2. The electricity

[10]This is an optimization model that contains both discrete and continuous decision variables.

demand profiles for the spot and balancing markets have been derived as outlined in section 4.3 and 4.3.2. These time series are exogenous to the model as well. A European transmission grid representation that has been documented in section 4.4.1 allows for an accurate calculation of physical power flows across Europe, i.e. it has been assumed that the concept of *flow-based market coupling* as already partly implemented in Europe is applied to the whole modeled region.

The model has been originally be designed to model day-head electricity market prices. In this work the model has been extended in its functionality in order to be able to model hourly intra-day auctions, as well as real-time balancing markets (5min resolution) for each country in Europe. In Figure 4.5 the consecutive model runs including the corresponding assumptions that are newly implemented are shown. First a day-ahead model run simulates the yearly dispatch of storages, their water values and trade flows resulting from the market clearing of this market segment. In this model run only day-ahead forecasts are available for all exogenous time series are available to the model. In a second step this results are refined by intra-day model runs, whereas already more accurate forecast about exogenous time series are applied. Statistics on the size of forecast errors of different technologies and forecast time horizons have been taken from the literature. In the intra-day model the cross-border flows and the generation dispatch are updated. Finally, with the information on real-time generation profiles of variable renewable generation, the remaining cross-border transmission capacity and available generation capacities for up- and downramping the balancing market model run is carried out. The result of this model run are the real-time electricity price of electricity balancing.

	Day-ahead market	Intra-day market	Balancing market
Design	Uniform price auction	Uniform price auction	Uniform price auction
Uncertain data input	24-hour forecasts (= day-ahead profiles)	Day-ahead profiles + difference between 24h forecasts and hourly forecasts (= intra-day profiles)	Intra-day profiles + difference between hourly forecasts and real-time profiles
Time resolution	1 hour	1 hour	5 minutes
Modeled time period	1 week for each month	1 week for each month	1 week for each month
Model approach	Representation of whole time period in 1 model run	1 model run for each hour in the time period (Rolling horizon)	1 model run for each 5min-window in the time period (Rolling horizon)
Results	• Day-ahead prices • Storage reservoir levels • Cross-border flows and remaining transmission capacity	• Intra-day prices considering unplanned outages until next day and day- ahead forecast errors • Updated cross-border flows and remaining transmission capacity	• Real-time electricity prices and quantities considering unplanned outages for 1 hour and intra-day forecast errors

Figure 4.5.: Description of performed model runs.

Together with the assumed demand time series documented in section 4.3 the results enable the author to assess the future monetary relevance of balancing markets across the EU under different assumptions of framework conditions. In that way, it is possible to assess the benefit of market integration (i.e. cross-border participation and imbalance netting) of balancing markets within the EU internal market and to quantify for different technologies the share of revenues from balancing markets on their total revenues.

4.6. Assumed market design and scenarios

The policy framework concerning the EU internal electricity market comprising all market segments is under constant revision. It is therefore at the time of writing not possible to take any harmonized market design and set of regulations as given in the 2030 time frame. However, there are some ongoing processes that can serve as an orientation towards the envisaged target model, in particular with regard to electricity balancing markets. The European Agency for the Cooperation of Energy Regulators (ACER) have established guidelines for common rules and standards concerning the design and operation of electricity markets in Europe. Based on these guidelines the European Network of Transmission System Operators for Electricity (ENTSO-E) drafted eight network codes with the aim to enable the implementation of this envisaged target model. These network codes have the legal status of directives. The network codes on Capacity Allocation and Congestion Management (CACM) and Electricity Balancing (EB) (ENTSO-E, 2017) concern the design and operation of short-term electricity markets across EU member states and thus provide a frame under which potential developments of these markets can be studied. From the content of these network codes it becomes apparent that short-term electricity markets, i.e. day-ahead, intra-day and balancing markets, will be designed in a way that facilitates trading across borders. Therein, it is emphasized that all market segments will provide non-discriminatory access to all technically capable technologies. Furthermore, in November 2016 the Commission published a communication concerning a policy package related to the newly developed concept of the Energy Union entitled "Clean Energy For All Europeans"[11]. Therein, it is stated that trading and bidding in all electricity market segments should reach as close as possible to physical delivery. With regard to electricity balancing markets the Commission expressed their opinion that the amount of ex-ante capacity reservation for the purpose of electricity balancing should be as small as possible. At the time of writing it is however still not clear how the network codes and proposed directives of the existing policy proposals and guidelines will exactly be translated into national legislation and whether consensus and acceptance will be reached among member states and stakeholders about the concrete content of the proposals at all. Therefore, the future framework conditions related to electricity market design and accompanying regulations are subject to considerable uncertainty.

In this thesis the above mentioned uncertainties are considered in the form of various scenarios. Each of the scenarios materializes in the form of concrete modeling assumptions of the applied power system model HiREPS. Basically, there are two ways in which scenario analyses can be performed. In a *sensitivity analysis* the focus is laid on the question of how

[11] `https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition`

a certain model parameter impacts the model results. This type of analysis is used to assess how sensitive selected model results are with regard to a change of one input parameter. On the contrary, a *portfolio analysis* is used to assess different bundles of probable parameter changes against each other. This type of analysis is often chosen to contrast the development of different possible framework conditions with each other.

In this work a portfolio analysis is applied in order to assess the relevance of electricity balancing markets under different framework conditions. The analysis comprises two dimensions. The first dimensions is related to the market design and accompanied regulations concerning day-ahead and intra-day markets. The second dimension concerns the level of cooperation among TSO's in managing grid stability and is thus related to electricity balancing markets. Figure 4.6 shows the definition of the four scenarios that result from these two dimensions. In the following more detailed description of the kind of assumptions that are packed into each of the dimensions is given.

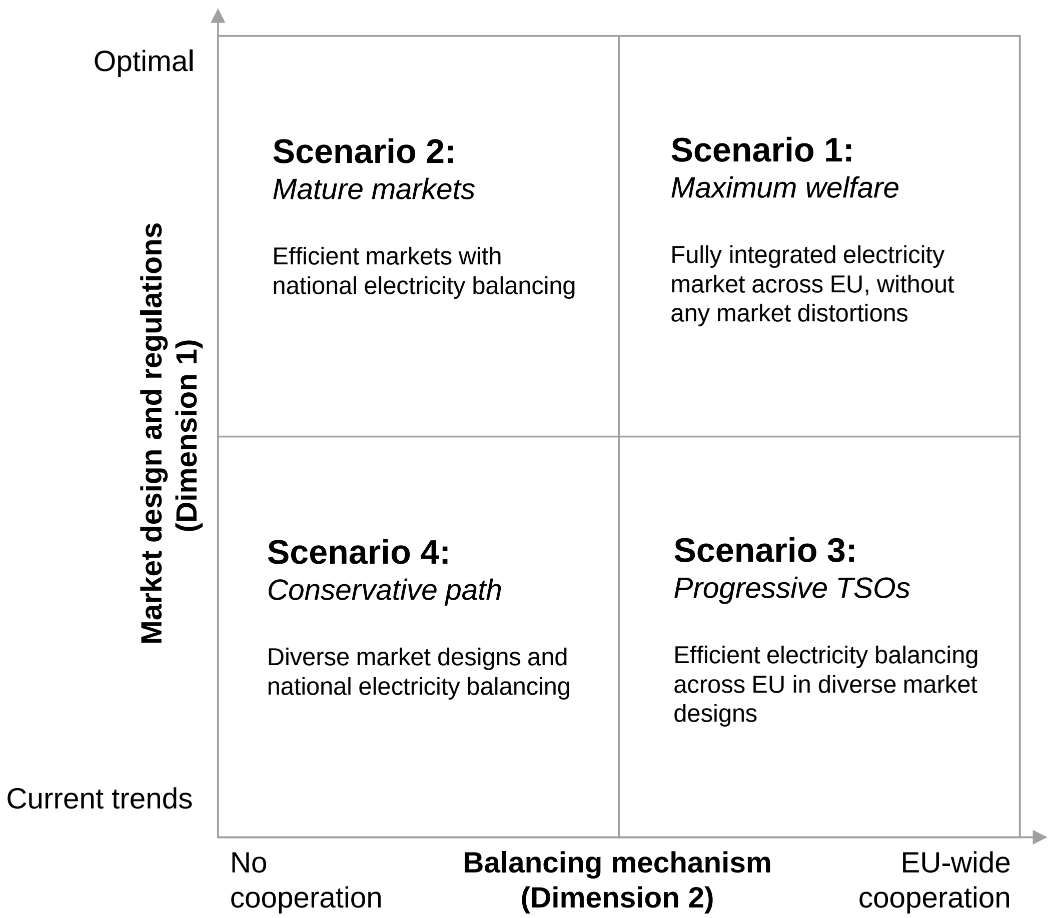


Figure 4.6.: Categorization of modeled scenarios according to two dimensions.

4.6.1. Dimension 1: Development of market design and regulations in day-ahead and intra-day electricity markets

Due to the possibility of arbitrage, day-ahead, intra-day and balancing markets are tightly coupled with each other. Consequently, a variation of framework conditions related to day-ahead and intra-day markets do also impact electricity balancing markets and vice versa. This dimension aims to reflect the uncertainty of important factors that significantly impact prices in day-ahead and intra-day markets. For each of these factors two distinct assumptions on their future development have been taken in order present two alternative, possible developments.

The *Current trends* assumption reflects a future development based on planned or actually happening progress that can be currently observed in different EU member states. On the contrary, the *Optimal* assumption is meant to reflect first-best solutions for the market design and accompanying regulations to be implemented according to standard economic theory. In this work three relevant factors have been identified that significantly impact the results of day-ahead and intra-day markets. These are the available transmission capacity between countries, whether additional capacity mechanisms will be implemented or not and to which extent demand side flexibility can be utilized.

The *level of physical interconnection* and subsequently the available trading capacity between countries impacts among others the extent to which markets can be coupled and thus the *efficient operation* of Europeans markets. The expansion of cross-border transmission lines is planned and organized in the framework of the *Ten-Year-Network-Development-Plan* (TYNDP) worked out by ENTSO-E. In its monitoring of progress related to the implementation of the TYNDP, ENTSO-E notices that "around 30% of the projects encounter delays in implementation". The main identified cause for these delays is according to ENTSO-E the difficulty in gaining permits and public support. In this work this fact is reflected in the *Current trends* assumption via excluding the respective projects from the list of grid enforcements. This ongoing trend of a 30% delay has been perpetuated until 2050 in a similar fashion. In the *Optimal* assumptions all projects according to the TYNDP can be realized.

The discussion on how to guarantee proper investment incentives to ensure generation adequacy within Europe mainly turns around the issue of whether an energy-only market will suffice, or any *additional capacity mechanisms* need to be introduced. Across Europe some member states have already introduced, or are about to introduce some kind of capacity mechanism, which is in most cases driven by national demand for peak capacity. In the *Current trends* assumption capacity markets have been implemented in countries were capacity payments are about to be introduced or in which their introduction is currently debated. All remaining countries were assumed to operate Energy-Only markets. In the *Optimal* assumptions all markets across Europe are implicitly coupled and only one integrated Energy-Only market including scarcity pricing is operated.

The trend towards increasing *utilization of demand-side response* have been considered in the applied market model with the option to activate electric heaters, heat pumps and small-scale storages. In the *Current trends* scenario such options are not available. In the *Optimal* scenario it has been assumed that all these additional flexibility options can participate in the markets. The concrete potential of each option has been determined and documented in other research activities of the author, cf. see Prüggler et al. (2015).

4.6.2. Dimension 2: Level of international cooperation in electricity balancing markets

This dimension concerns the TSO's task to manage grid stability by means of providing balancing electricity in order to counterbalance forecast errors of generation and consumption. Because TSO's in Europe typically run regular auctions to procure resources in order to perform this task, the balancing mechanism is often referred to as balancing market. In line with efforts to open electricity markets for international competition, also TSOs were searching for possibilities to increase the efficiency of their auctions. International cooperation has proven to be a fruitful option to decrease costs. Such cooperations have been introduced in two steps. First, because deviations in a certain control zone can be both positive and negative, the enlargement and/or coordination of control zones brought benefits from balancing demand smoothing. These benefits arose from the neutralization of opposing imbalances between previously independent control zones. This kind of cooperations between control zones have been known as *imbalance netting.* The remaining imbalances were still counterbalanced by national capacity reserves. In a second step, also the procurement of balancing reserves have been internationalized step-by-step. Currently, there are proposals to form so-called *Coordinated Balancing Areas* (CoBA's) in which balancing markets are fully integrated and the design is harmonized. To this date, it is not clear how many and which countries will be included in what CoBA, i.e. the envisaged level of international cooperation of balancing markets is unclear. In order to reflect this development in the modeling work two extreme assumptions have been taken. First, it is assumed that balancing markets are solely operated on a national level and no kind of cooperation takes place. On the contrary, in a second assumption all TSO's across Europe cooperate on the basis of a fully integrated European balancing market, i.e. both imbalance netting and cross-border activation of balancing reserves.

4.7. Results

The price formation in electricity balancing markets, like in all markets, is driven by demand and supply. In our case the demand side is mainly composed by forecast errors related to the generation of variable renewable electricity, actual consumption and unplanned outages of conventional generators. For the calculation of forecast errors a gate closure time of 45min ahead of physical delivery has been assumed. In order to assess the relevance of different sources with regard to their relative importance in Figure 4.7 the resulting energy content of all sources contributing to balancing electricity demand has been aggregated and related to the gross electricity consumption. Due to netting effects the overall sum of all sources is smaller than the sum of energy contents. Figure 4.7 therefore also shows this difference that expresses the size of this netting effect. The composition of sources shows that wind onshore accounts for the main source of balancing demand in many countries and ranges between -2.3 and 0.9 percent. It also becomes apparent that the amount of negative forecast errors, i.e. actual generation has been higher than predicted, exceed the amount of positive forecast errors in many countries. The second most important source of balancing demand are consumption forecast errors, which are in the range of 0.5 percent of consumption for positive errors and around -0.1 for negative errors. The skewness of the consumption forecast error distribution has been empirically verified by Hodge et al. (2013). The remaining sources of balancing demand, e.g. unplanned generator outages, forecast errors of photovoltaics and wind offshore are in relation to overall consumption rather insignificant. The size of netting effects stemming from counterbalances of forecast errors and outages are in the range of -/+ 0.3 percent of electricity consumption. +000

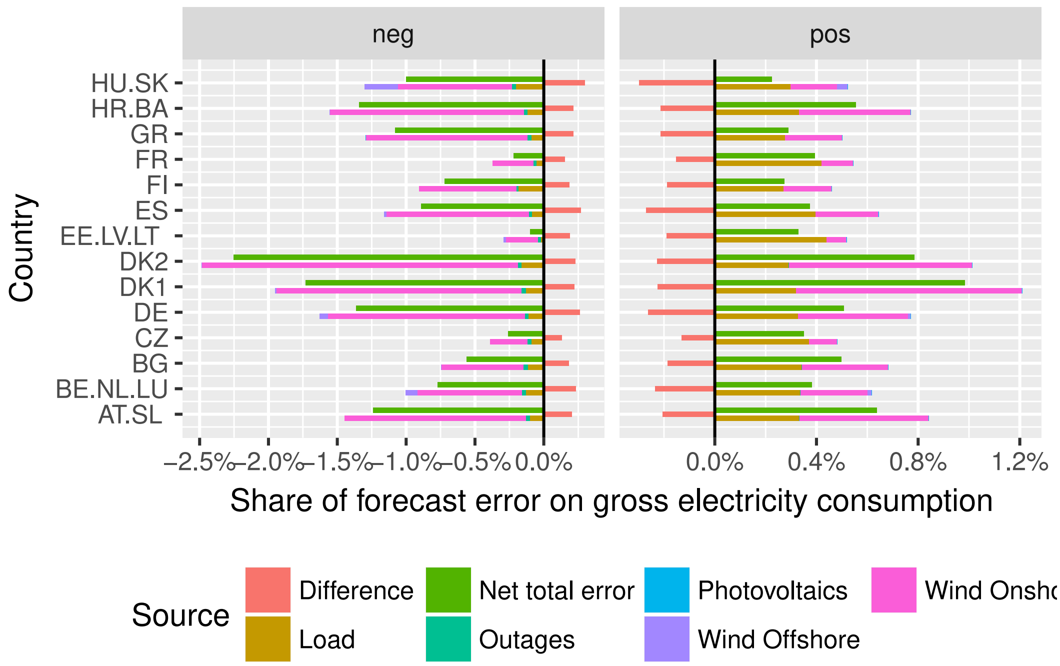


Figure 4.7.: Share of forecast errors (predicted minus actual generation) and unplanned outages on gross electricity consumption by source. Additionally, the difference between the aggregated errors and the resulting net deviation of the control zone is shown.

The future monetary volume of electricity balancing markets varies according to the four selected scenarios. Figure 4.8 shows the relative importance of balancing markets as share of market volume as compared to day-ahead market volume. Due to the fact that prices tend to be more volatile in electricity balancing markets than in day-ahead markets the share of monetary volumes is slightly higher than the share of physical volumes shown in Figure 4.7. The range of outcomes significantly varies across countries. The market shares for positive imbalances are in the range of 0.2 to 2.8 percent and the ones for negative balancing energy from -3.4 to 0.2 percent. In general, it can be seen that all the scenarios that limit international cooperation, i.e. scenarios 2, 3 and 4 increase the share of the balancing market, because in these cases prices are more volatile. However, the impact considerably varies across countries. There are countries with a very competitive generation mix, where more market integration leads to higher prices due to increasing demand from outside. Another interesting result is that the several scenarios impact both control directions of the balancing markets differently. Whereas the share of the positive balancing market segment is merely driven by the day-ahead market design, the international market integration of balancing markets seems to be a crucial element determining the volume of this segment. One major reason of this finding is that the demand for negative balancing energy was in general higher than the one for positive imbalances. As a result, also the impacts of imbalance nettings due to market coupling becomes larger. This is also reflected in the different market volumes of both control directions.

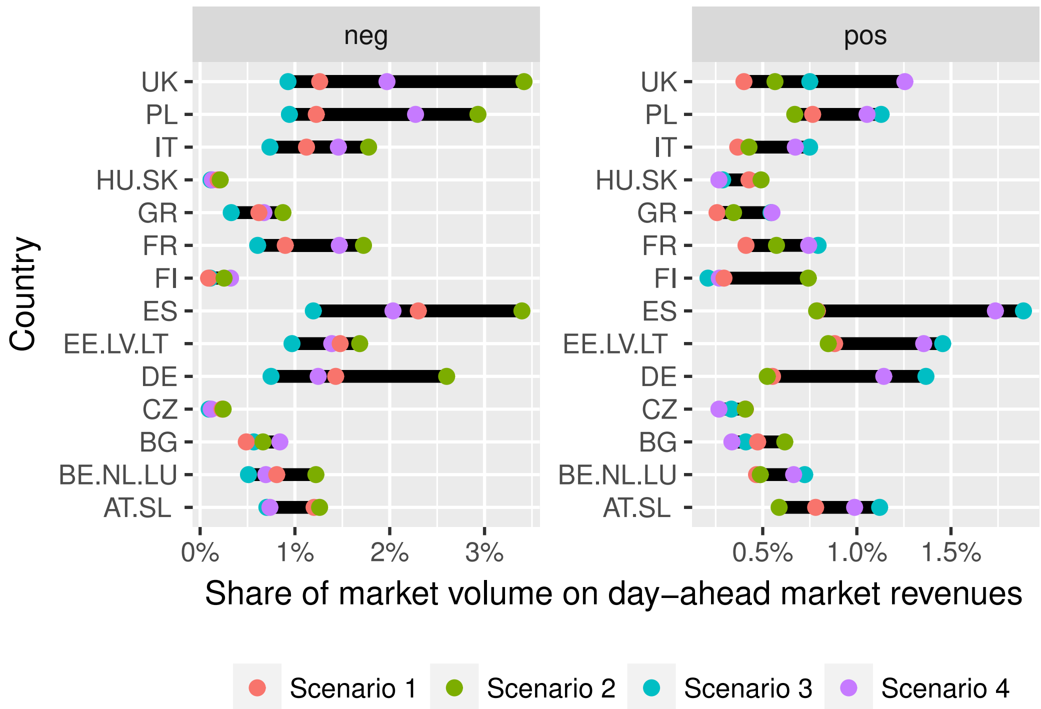


Figure 4.8.: Monetary volume of electricity balancing markets as compared to day-ahead market volume for different scenarios in 2030.

The previous results confirm that the expected market share of electricity balancing markets might lay in the range of a few percent of day-ahead market volume. However, the importance of revenues from this market segment significantly varies across generation[12] technologies. In Figure 4.9 the costs and benefits stemming from electricity balancing related to their revenues in day-ahead electricity markets are shown for renewable generation technologies. In general, costs arise from the forecast errors or unplanned outages, which are in the same direction as the imbalance of the overall control zone, whereas benefits arise from payments related to forecast errors that act contrary to the imbalance of the overall control zone. Whether actual payments are positive or negative additionally depends on the sign of the corresponding prices. In the modeling it has been assumed that vRES generators can down-ramp their generation in case they would incur losses otherwise. The major result from Figure 4.9 is that vRES generators significantly profit from international market coupling of electricity balancing markets. Because of imbalance nettings and international competition the costs for forecast errors sharply decrease and benefits of deviations that support grid stability are rewarded higher. This is in particular important for wind onshore and wind offshore. The case of photovoltaics show that because of its low forecast errors neither costs nor benefits from balancing markets might be significant for this technology. Biomass generators are due to their capability to adjust their power output a provider of balancing energy. The only source of costs are unplanned outages. In contrary to vRES these generators profit from national electricity balancing markets and loose in case of international market coupling.

In a similar manner, Figure 4.10 shows the costs and benefits of electricity balancing related to day-ahead market revenues for the conventional generation technologies with the highest shares. For coal, gas and waste generators the basic result can be observed as for biomass generators. Positive revenues arise from national balancing markets, whereas these revenues diminish in case market are coupled. In the case of an fully integrated electricity market across the EU (Scenario 1) only the costs of unplanned outages have to be borne by these technologies. The results show that storages are a very active player in electricity balancing markets. Unlike other technologies, storages profit from both positive and negative imbalances. They pay a price for negative balancing energy, however, a price that is in general lower than the one that storages could capture in day-ahead markets. In turn, electricity can be sold for higher prices than in day-ahead markets. As a result, storages realize savings in either way and thus might become a very important market player of the future.

[12] In the near future also demand side applications might participate in these markets. In the present work such technologies have not been considered.

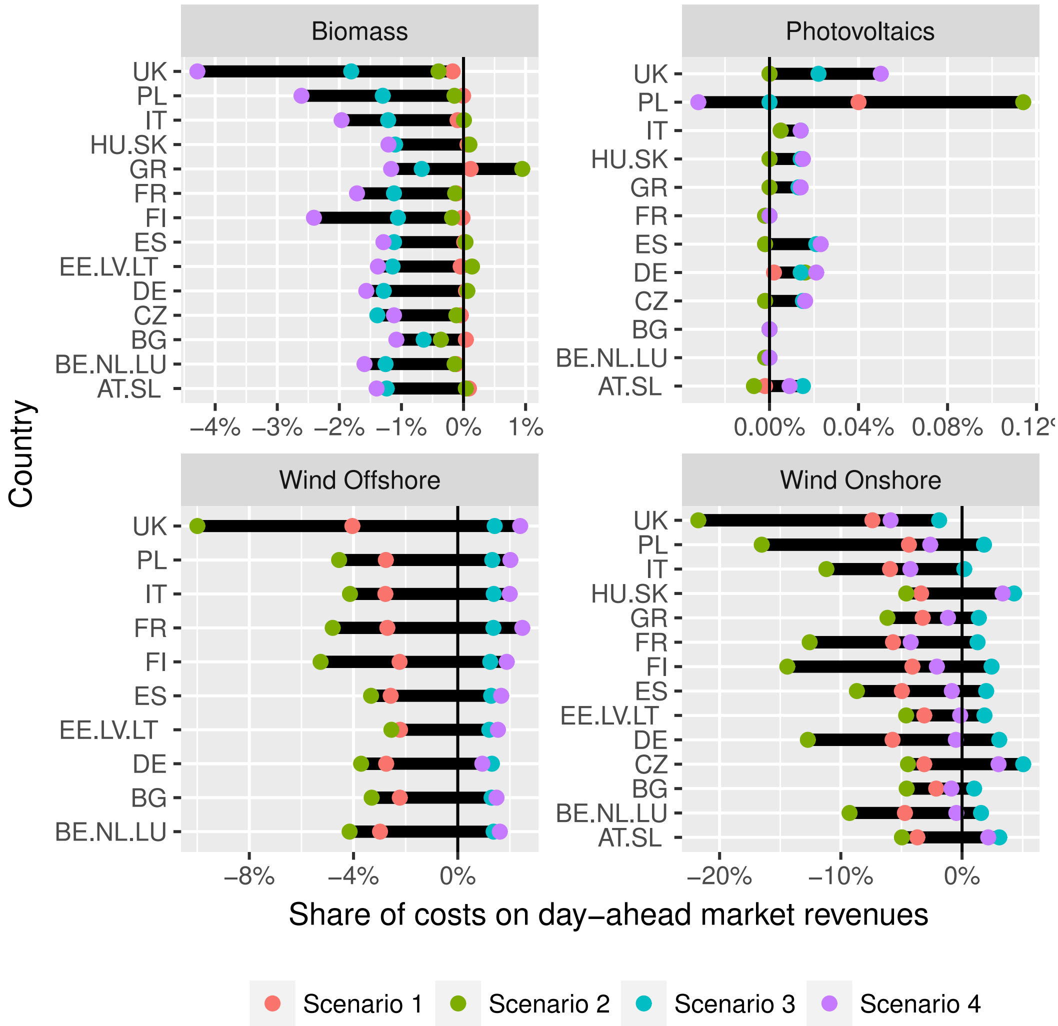


Figure 4.9.: Costs (positive) and benefits (negative) from electricity balancing as compared to day-ahead market revenues for different vRES technologies and scenarios.

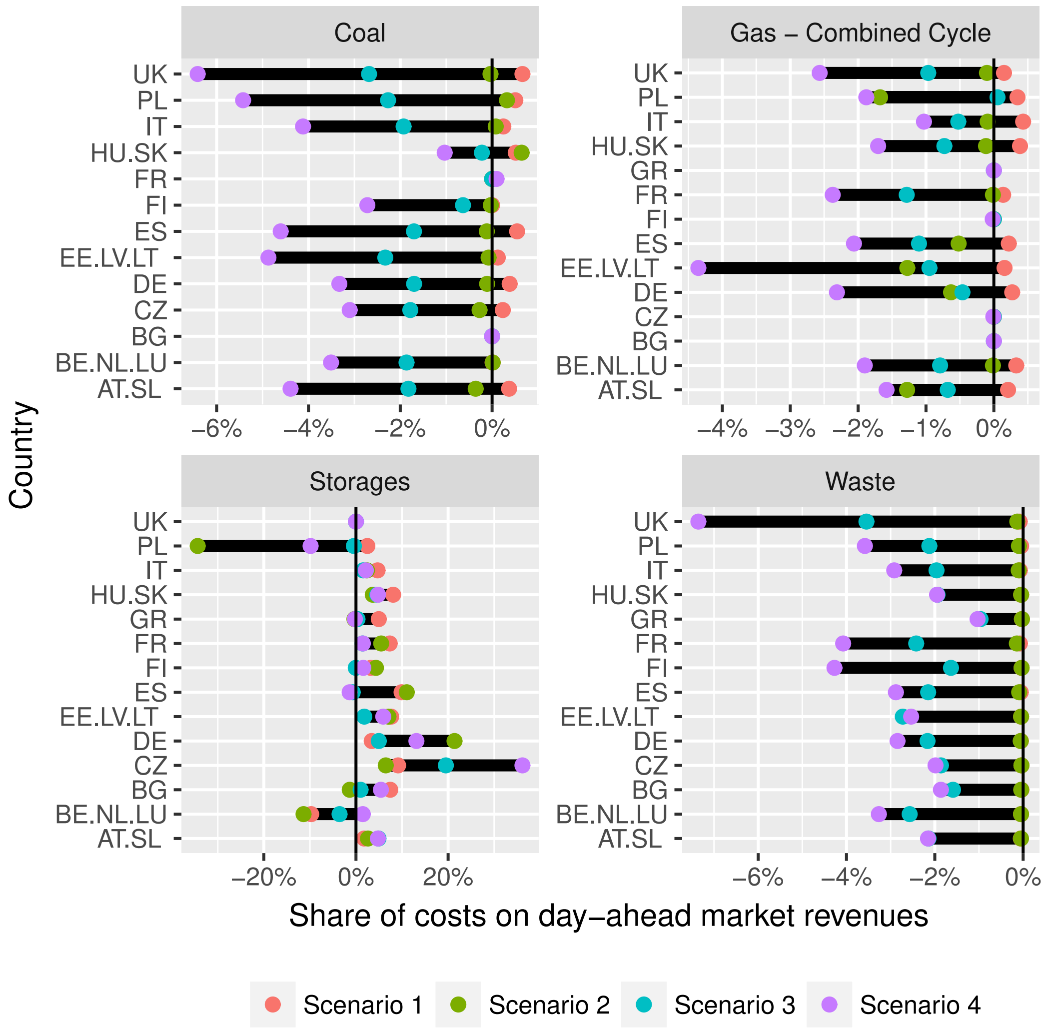


Figure 4.10.: Costs (positive) and benefits (negative) from electricity balancing markets as compared to day-ahead market revenues for different conventional technologies and scenarios.

4.8. Discussion of results

The above presented results indicate that the physical volumes of control zone imbalances are expected to increase compared to current levels. The amount of this increase are strongly related to the amount of vRES that is integrated in a certain country. From the results can be derived that wind onshore accounts for the main share of demand for balancing energy. The netting effect from different sources of system imbalances has proven to be an important factor to be considered. However, as compared to overall physical volume of gross electricity consumption the resulting imbalances can be considered to be rather low in the mid-term. It should be critically noted that all results are based on historical forecast data series. The current work do not consider any structural changes in the forecast quality nor do they contain expected improvements of forecasting accuracy. These results can be therefore classified as upper boundary on the mid-term relevance of this market segment. The relevance of electricity balancing markets in monetary terms has been evaluated to be minor as compared to day-ahead market volumes. The results also confirmed that the concrete size of these markets are considerably impacted by the development of framework conditions, whereas the framework conditions itself have distinct impacts on different countries. It can be argued that the price formation as it has been modeled is biased because the underlying assumptions on the characteristics and type of considered technologies do not adequately capture and probably will never capture the expected diversity of new market actors in the future. Indeed, the modeling results have to be interpreted in the view of this shortcoming. Again, an appropriate interpretation of these results might consider them to be an upper boundary of the relevance of electricity balancing markets in the mid-term. Furthermore, also the findings on potential market revenues of different technologies from electricity balancing markets have to be interpreted against this background. It should be further noted that in this work revenues rather than profits have been assessed. The actual attractiveness of electricity balancing markets for different market actors in terms of potential additional profits is therefore an interesting field for further research.

Chapter 5

Conclusions and Future Work

There is consent among researchers that the decarbonization of our society requires among others the large-scale substitution of fossil-based energy sources by renewable energy sources. From many techno-economic studies concerning the power sector in Europe we know that variable renewable sources (vRES), namely wind power and photovoltaics, will account for the major share of this substitution[1]. Due to the fact that electricity generation profiles from these sources are characterized by an unprecedented level of variability and difficulties in forecasting them, the importance and volume of short-term trading has increased with the level of market penetration of vRES. Based on this argumentation it can be assumed that short-term markets will get increasingly important in the future. The majority of current literature that deal with the analysis of electricity markets focus on day-ahead markets and is thus tackling the "variability" challenge of vRES. Much less literature deal with the analysis of electricity balancing markets and mechanisms, which focus on the "forecastability" issue posed by increasing shares of vRES. The objective of this thesis was therefore to shed light on this important segment of electricity markets. To this end, I worked out some of the theoretical fundamentals to model such markets, assessed historical auction results with regard to how much they were driven by fundamental drivers and provided a quantitative assessment on the future relevance of these markets against the background of ongoing trends towards internationalization. In the following all the findings and discussion points with regard to the particular research questions raised in the various parts of this thesis are synthesized. Furthermore, these findings are critically reflected and implications of the performed analysis on the overall research area are highlighted.

5.1. Synthesis of major results and conclusions

The first objective of this thesis was to set out a theoretical foundation on which basis suitable modeling approaches could be developed. The formal definition of what exactly constitute competitive equilibria in markets including integer decisions served as a starting point. This definition contains two conditions that must hold in order to establish a competitive market equilibrium. However, it is known from the literature that, in general, whether the existence, neither the uniqueness of equilibria in binary games can be guaranteed. In order to model equilibrium prices that are at least "close" to these equilibrium conditions the terminology of a quasi-equilibrium has been formally introduced. This definition in particular specifies what "close" in this context exactly means. The quasi-equilibrium has been defined in a way that it fulfills all the necessary conditions of a real equilibrium in all cases where one exists. On the basis of this definition an optimization framework has been formulated that is able to calculate competitive quasi-equilibria (CQE) in electricity spot markets including auctions for reserve capacity. I considered the results of this model as benchmark and contrasted them against the results of two other modeling approaches that are commonly used in the literature to simulate electricity prices. In the literature these approaches are known as *least-cost-solution*, or *central-planner approach.* These other approaches are of particular interest

[1]This only relates to new installations. A large share of hydro power is already installed.

since they are classical unit-commitment models used by system operators that manage centrally committed electricity markets. From the comparison of model results it became apparent that the CQE did not maximize economic surplus to market participants. The deviations in dispatch and unit-commitment decisions from all generators ranged in between 10 to 20% of actual load. This deviation led to average welfare losses of 5% against the least-cost solution. When comparing the required compensation payments to generators the results showed that payments in the CQE were on average 35% lower than the ones that would result from positive O'Neill payments. O'Neill payments are required to maintain a CQE while enforcing the welfare-maximal unit-commitment and dispatch solution. On the other hand, most system operators do only pay so-called *make-whole payments* to generators, which only compensate for losses that they would occur when following the welfare-maximal schedule. The payments required in the CQE were approximately 60% larger as the make-whole payments that would result from the least-cost approach. Such make-whole payments, however, do not constitute equilibrium in an economic sense, because generators are not compensated for opportunity losses. In general, the share of compensation payments in the modeled example was very high in all approaches and ranged in between 50 to 100% of generator profits. This share is unrealistically high and can be explained by the small model size in terms of number of generators as well as time steps and is therefore a model artefact. The share of make-whole payments in real electricity markets typically range in between 1 to 2% of spot market volume. According to Müsgens (2006) the producer surplus was approximately half of the market volume in the spot market. On this basis I therefore conclude that non-paid compensation payments of the CQE approach would actually be on average in the range of 0.8 to 1.6% of generator profits. With regard to market and auction prices the model results showed that the classical unit-commitment model, i.e. the least-cost approach, delivered reasonable similar prices than the CQE model. The prices derived from a linear relaxation of the unit-commitment model proved to be not a suitable proxy for competitive market prices that would constitute an equilibrium. Based on this argumentation I conclude that the classical unit-commitment model used by system operators in centrally committed electricity markets can be applied to derive market and reserve auction prices that are fairly close to the ones of a quasi-equilibrium, like the one that is established on exchange-based markets like the ones in Europe. Due to the fact that the QCE-approach has very limited scalability, this conclusion is very useful, because it enables the large-scale modeling of prices in liberalized electricity markets including non-convex preferences.

In the second and third part of this thesis this finding is used to justify the application of very detailed and large-scale central-planner models. In the second part of this thesis, the applied optimization models have been designed and calibrated in a way to derive numerical results of the Austrian balancing market. This enabled a comparison of modeled and historic market outcomes. A number of model runs with different parameter settings have been undertaken to analyze the impact of hydrological constraints and the effect of portfolio-bidding. Furthermore, the results have been presented for three distinct pricing schemes in order to get a more realistic picture of actual trading strategies in these markets. A comparison of modeled total costs with historic costs in the considered time period showed that the actual cost of capacity reservation and energy calling exceeded the modeled costs by a factor of more than two. In particular, this large discrepancy could be traced back to a difference in prices for energy calling of secondary capacity reserves. Actual prices in this market segment were one order of magnitude higher than the modeled prices. The basis of modeled prices for balancing energy calls were the short-run marginal costs of thermal generators and the marginal water values related to the upper and lower reservoirs of hydro storage power plants. It has been discussed that in a hypothetical scenario the marginal water values could exceed yearly peak electricity prices. However, I argue that under normal operating conditions of existing hydro systems such an event is not very likely to occur. It should be critically reflected, that there are also a number of arguments why the costs of calling balancing energy might exceed the ones derived from marginal water values and short-run marginal generation costs. First, marginal water values do only account for the loss of one additional unit of water that is used to generate electricity. In practice, however, any call typically requires greater amounts of water to be moved. This can be difficult for pumped hydro storage power plants, because lots of currently installed pumps can only be controlled within discrete steps. As a result, a single call may require the sub-optimal redispatch of multiple power plants over a certain time period. If that redispatch cost are allocated to the respective call and are divided by the delivered balancing energy the so derived average call costs could exceed the marginal costs. Second, in the present optimization framework it has been assumed that all participants have perfect forecasts available, i.e. the framework is deterministic. In fact, market participants need to forecast market prices, natural water inflows and the availability of their generating units up to one week ahead of physical delivery. Because of the uncertainty the bidding process is more complicated and this is typically recognized by traders in the form of additional risk premiums on prices. The third and probably most relevant reason is missing competition. Since the auction design in the form it had been implemented at the time this study was carried out the selection of bids very solely based on capacity prices. As a consequence, market participants were able to impose higher energy prices. From a gaming perspective, potential profits from prices above marginal costs could even be passed on to reduce the capacity price of the offer. As such, in the absence of competition this market design inherently leads to a collapse of capacity prices and to high energy prices. This finding could easily be included in the model results via adding on top of marginal water values — which are solely based on profit expectations of the spot market — a term that expresses expectations on potential future profits from balancing energy calls. However, since the aim of this work was to derive competitive prices rather than reproduction of actual prices I did not include such add-ons. The comparison of historic with modeled prices for the provision of capacity showed that actual prices could be explained very well through the model. This means that price formation has been built on fundamental data and incentives of profit maximizing actors under perfect competition. The costs of pumped hydro power generators for participating in the balancing market were found to be based on costs, which arise from restrictions of turbines and pumps, as well as restrictions on the working volume of their reservoirs. The cost drivers of thermal power generators were higher marginal generation costs in case of part-load operation and the limited availability of CHP plants during summer time. With regard to the large share of costs related to the calling of balancing energy that could not be explained by the model and the small number of actors in the Austrian balancing market it is recommended that the market should be widely opened to national as well as international competition and that the currently implemented market design should be revised. Furthermore, based on the insights gained from the modeling work performed in this study it might be advisable to monitor hydrological and technical fundamental data of market participants in order to have a better basis for the judgment of market outcomes.

Finally, in the third part of this thesis I focused on the mid-term relevance of electricity balancing markets in Europe. In order to carry out such an analysis the political background and ongoing debate about potential changes in market design had to be brought together. The focus on the mid-term time frame necessarily brings some degree of uncertainty into the analysis. However, it would have been totally out of scope of this thesis to perform all kinds of sensitivity analysis on each of the uncertain parameters. Already the evaluation of uncertain parameters by itself is a very ambitious goal, since the type and concrete magnitude of uncertainty is not known in advance. In this thesis an alternative path has been taken. Instead of performing sensitivity analyses four combinations of possible future developments of framework conditions have been grouped together in the form of scenarios. In this work these kind of analysis have been referred to as portfolio analysis. The scenarios have been selected and categorized in a way to represent in the opinion of the author the two critical dimensions that will considerably impact the future development of electricity balancing markets. First, since the price building process in electricity balancing markets is economically linked to all other electricity market segments via arbitrage opportunities and some technical requirements, the design and subsequent functioning of other market segments is of utmost importance for their development. The currently ongoing trends of electricity market design and regulation has been worked out in previous work of the author and summarized within this thesis. The identified trends have then been linked to concrete modeling assumptions in order to assess their impact. All the specific modeling assumptions have been grouped together within a so-called "Current Trends" scenario and have been contrasted against an in economic terms first-best "Optimal" scenario that is comprises by ideal framework conditions in the sense of maximum economic welfare. In the second dimension, the ongoing trend in Europe towards international market coupling has been separately considered for electricity balancing markets. Due to the high technical complexity and the short-time frames involved in this segment, it is currently not clear to which extent a European-wide electricity balancing market can be realized at all, or whether only regional cooperation centers will emerge. The second dimension therefore compares the two extreme cases, i.e. national electricity balancing markets versus a fully integrated European balancing market. The results showed that although the amount of balancing energy is expected to increase in the mid-term, electricity balancing markets will still lay in the range of a few percent of day-ahead market volumes. The results also confirmed that the concrete size of market share is considerably impacted by the development of framework conditions, whereas the framework conditions itself have distinct impacts on different countries. With regard to the importance of revenue streams and costs related to electricity balancing for different generation technologies the results showed that in general variable renewable generators significantly profit from international market integration, whereas dispatchable generators might lose their dominant position in national markets. Electricity storages have proven to be a very vital element of electricity balancing markets, because they profit from both positive and negative imbalance provision and thus are able to earn additional profits.

5.2. Critical reflection and future work

In this thesis electricity markets were studied through the application of fundamental optimization models. The usage of such models is only one out of several recognized methods to examine these markets, as already mentioned in the respective sections of this work. However, in this section the author would like to elaborate a bit more on the question why solely fundamental optimization models have been used, what advantages and disadvantages different concrete implementations have and how the results of these models have to be interpreted against the background of their short-comings. Also, where applicable, some interesting starting points for future research activities are given.

The overall objective of this thesis formulated in detail by the set of concrete research questions has been to get insights in the functioning of electricity markets and their fundamental drivers under perfect competition. Due to the fact that operations in the electricity industry were centrally optimized for a long time, todays liberalized electricity markets are still very much driven by similar fundamental factors as in the past. Therefore, the same kind of optimization models that have been previously used can be applied to a certain extent today in order to study the theoretically "ideal" outcome of electricity wholesale markets under the precondition that the taken model assumptions were true. If they are not, it can at least be argued that this would be the ideal market outcome in the case the assumptions are applicable. In the same way, it can be argued that a relative change of the market outcome induced by changes of selected model input assumptions can be meaningfully assessed with the use of optimization models. Both fields for potential applications of optimization models fit the purpose of this thesis very well. The use of econometric models might have been interesting if the actual behavior of historical market prices should have been analyzed in a top-down manner, or if the development of short-term price forecast would have been the objective of this work. The application of agent-based modeling approaches might have been proven beneficial for an in-depth study of bidding strategies under different market designs. However, because the focus of the analysis in the thesis at hand is laid on 1) competitive market outcomes under prescribed framework conditions, 2) the analysis of underlying drivers that yield this outcome and 3) the assessment of the mid-term market development, the use of optimization models seem to be superior to the application of other approaches. The extensive use of such models in this context supports this statement. The greatest disadvantages related to the application of large-scale optimization models is that in order to build, calibrate, run, maintain and interpret these models a relatively large amount of workload, computational resources and time has to be allocated. Consequently, this method of analysis is rather not advisable for one-shot applications. A promising field of research is therefore the proposal of suitable model simplifications that e.g. reduce the time to solve a certain model while keeping the deviation of results under a reasonable threshold. In that sense, one could elaborate on the proposed modeling approach in chapter 2 of this thesis. In order to accelerate and to consolidate the development of this research area such papers should make their source codes public and thus enable other researchers to build on existing work rather to start from scratch.

With regard to the concrete modeling frameworks developed in this thesis a few remarks should be made. In chapter 2 a so-called mathematical program with equilibrium constraints (MPEC) problem has been solved. Due to the fact that such models are computationally expensive, only a very stylized model has been used on which basis the conclusions have been drawn. One problem with small-scale models is that they tend to overestimate certain effects that might be less relevant in real-world applications. In general, the transfer of conclusions from small-scale to large-scale examples should therefore be done with great caution and critically reflected. A linking point for further research activities in this respect therefore is to upscale the model by use of smart data clustering and/or reduction of binary variables wherever possible. It could be beneficial to choose a common model input dataset, like the IEEE study cases, in order to produce more comparable results.

The models of chapters 3 and 4 are all deterministic. Due to the fact that uncertainty is an intrinsic feature of short-term electricity markets one can argue that stochastic modeling approaches might be better suited for the purpose of modeling market prices. This argument should however also be judged in the context of already existing computational limitations. Stochastic optimization models have been proven very useful, when it comes to portfolio optimization tasks with a limited number of generating units involved. The analysis of a whole market segment could easily become computationally intractable when considering even only scenario trees with a very limited set of branches. The added value of stochastic optimization versus the loss of model accuracy by means of data aggregation has to be weighed against each other. In any case, the use of deterministic models can be interpreted in a way that the used input parameter sets are the best available forecast common to all market participants and that each participant is risk neutral. Further work could investigate the impact of risk adverse behavior on model results and assess the size of risk premia in this particular context.

With respect to the 2030 outlook taken in chapter 4 two more critical remarks should be added. The correct model implementation of currently discussed market design elements in Europe is a viable field of current research. In particular, the interdependencies of coupled markets with different designs, e.g. market with and without capacity mechanisms, are still not sufficiently studied. Against this background, the results of the models used in this thesis should be therefore also only interpreted with a detailed knowledge of what market design have been assumed and how it has been implemented. Finally, the increasing share of decentralized generation mostly located in distribution grids has the potential to fundamentally change the future operation of grids and markets. The models applied in this thesis do have a very detailed representation of the large-scale generating units. However, the demand side has been merely assumed to be inelastic and applications for demand side shifting or shedding have been only considered in an aggregated form. In order to adequately capture the current trend towards decentralized and small-scale applications the applied models in this thesis need to integrate, or at least should be coupled with specialized models focusing on the framework conditions and incentives applicable to decentralized generators and demand-side applications.

Appendix A

Appendix to chapter 3

A.1. Implementation of hydro storage power plants

It is often stated that hydro power is one of the most flexible sources of electricity generation, e.g. Huertas-Hernando et al. (2017). In this respect it seems reasonable to think that also the provision of balancing reserve capacity should be comparably cheaper in power systems with a high share of hydro power as compared to systems that are dominated by thermal generators and nuclear power. Indeed, studies that apply simple linear hydro power models in their analysis find that the costs of reserve capacity provision in such systems is very low and mainly depend on the availability of water inflows (Ortner and Graf, 2013).

However, when assessing the short-run operational flexibility of existing hydro power plants it gets apparent that there are a large number of technical and hydrological constraints that restrict the flexibility of these plants. Hydrological constraints mainly arise from limits on reservoir fill levels and water flows integrated in a certain hydro grid topology. A detailed description of the existing hydro grid topology in Austria is given in 3.5.2. The technical constraints arise due to inflexibilities in the feasible output of generation units within a power plant. Power plants typically consist of several generation units with a certain type of machine set. There are substantial differences in the technical characteristics of different types. Therefore, it is necessary to break down power plants into machine sets in order to describe their overall operational flexibility.

Figure A.1 gives an overview about existing machine set categories and its mainly implemented components in pumped hydro storage power plants (Kathan et al., 2012). There a two types of machine sets. In the ternary machine set (also called conventional machine set) the turbine and the pump are independent components, whereas in reversible pump turbine sets the turbine and the pump is constructed as a single mechanical unit. In ternary machine sets Pelton-, Francis- and Kaplan turbines are applied. Pumps are available in axial-, radial-, or mixed-form design. What turbine or pump is best suited for a certain plant mainly depends on the height difference between upper and lower reservoir (drop height) and thus on the magnitude of water pressure prevailing at the intake of the turbine or pump as well as the size of water flow through the components. Pump turbines are solely constructed in

Francis-type design. All components have different feasible states of operation, differ in their flexibility to change these states and show specific conversion efficiency curves. Finally, the type of generator impacts the controllability of the machine set with regard to power output.

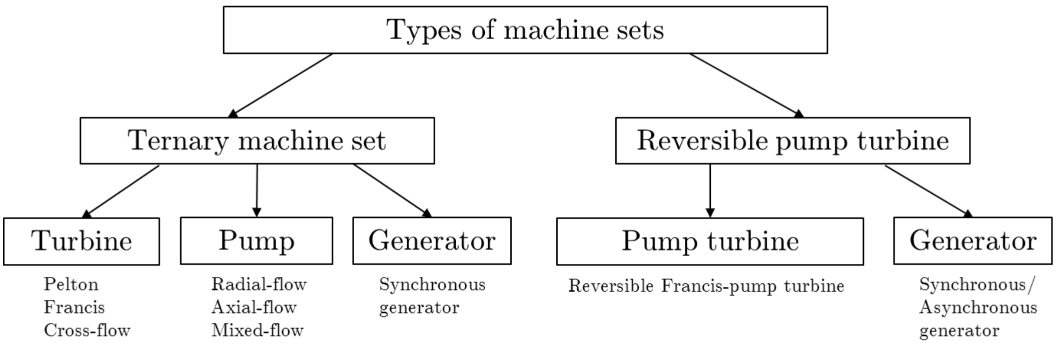


Figure A.1.: Types of most common machine sets in existing pumped hydro storage power plants. Own illustration, based on Kathan et al. (2012)

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Figure A.2 shows the implemented machine sets of the model and its feasible operational states. It can be seen that pumps are subject to very strict output constraints. In most designs pumps can only be switched on or off without any further options to regulate the water flow. Only variable pump turbines in combination with asynchronous generators are able to down-regulate their output up to 30%. In machine concepts involving a hydraulic bypass (HBP) it is possible to operate both pump and turbine simultaneously. The HBP enables the plant to fully control the power consumption as well. The turbine designs only differ in their minimal required water flow. Whereas Francis turbines need 25% of their maximum output as minimum flow in order to operate Pelton turbines are able to start operation already at 5%.

Besides the feasible operating states the speed of change in between these states is important. In general, hydro power plants have a much slower reaction time than conventional power plants. However, also their reaction time is subject to technical limitations Kathan et al. (2012). The fastest concept is the conventional machine set. It can switch its output from turbine to pump and vice versa in between 40 to 100 seconds. Pump turbines are slower due to the fact that they need to inverse water flow. Typical switch times are in the range of 100 to 700 seconds depending on the state of the turbine. The lead time of SRE calls are 5 minutes. Thus, there is only a limited usability of pump turbines with regard to the provision of secondary control energy. The presented figures are related to machine sets. In general, a power plant contains multiple machine sets and thus the power controllability of the plants is a result of the controllability of its machine sets and the installed pipelines. In the applied model machine sets are implemented via considering the power feasible output of pumps and turbines as discrete levels. The number and size of the levels are based on the actual number and size of installed machine sets. For reasons of simplification it has been assumed that the conversion efficiency of components remains constant over different

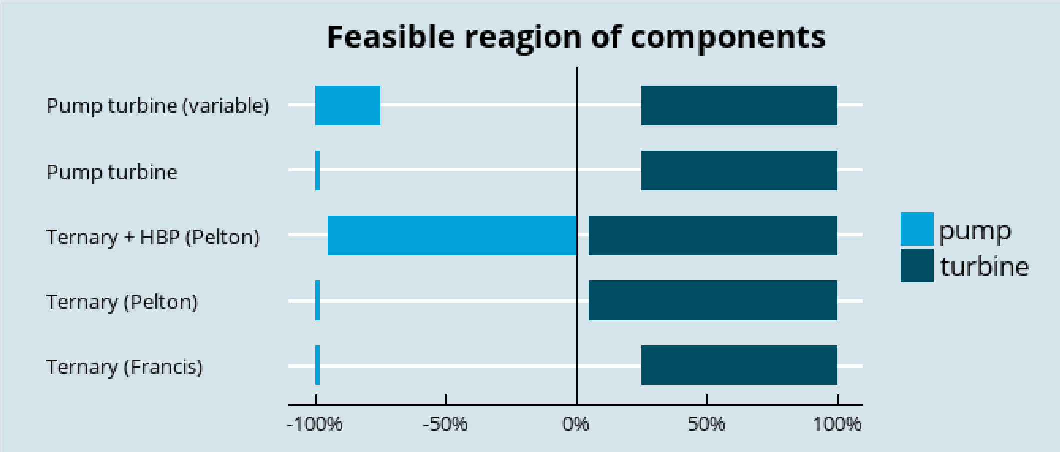

Figure A.2.: Feasible power outputs of different machine sets implemented in pumped hydro storages. Own illustration, based on Höller (2014)

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states. In order to provide balancing energy such plants typically switch the state of certain machine sets. Therefore, the resulting bidding sizes of these plants lie also in the range of the size of their machine sets.

A.2. Implementation of combined-heat-and-power plants

In Austria combined heat and power (CHP) plants play an important role. The main share of fossil fired power plants are operated in CHP mode. There are two construction designs that different with regard to power output controllability and conversion efficiency. Figure A.3 shows the power-heat (PQ) curve of these designs (Büchele et al., 2015). The left graph shows the PQ-curve of the *back-pressure* turbine design. In this design the power output is proportional to its heat demand. Plants with such designs are dominantly operated in heat-driven mode, i.e. the plant is obliged to fulfill a certain heat demand profile and the power produced is proportionally to that demand profile. For this reason, without any additional technical components such plants are not able to provide reserve capacity for electricity balancing. The right graph in A.3 shows the PQ-curve of a *extraction-steam* turbine. This curve has to be interpreted as the envelope of the feasible operating region of technical units with such design. It can be seen that the power output is partially decoupled from the heat output, but with increasing heat output the maximum available power output decreases. However, such plants can withhold a certain share of capacity to up- or down-regulate its power output while still fulfilling their heat demand profile.

Back-pressure turbines are primarily installed in small-scale applications due to their lower investment costs and higher conversion efficiencies. If such plants additionally equipped with a heat storage they are also able to decouple their power output from the heat output and to provide reserve capacities. The underlying principle is illustrated in figure A.4. A back-

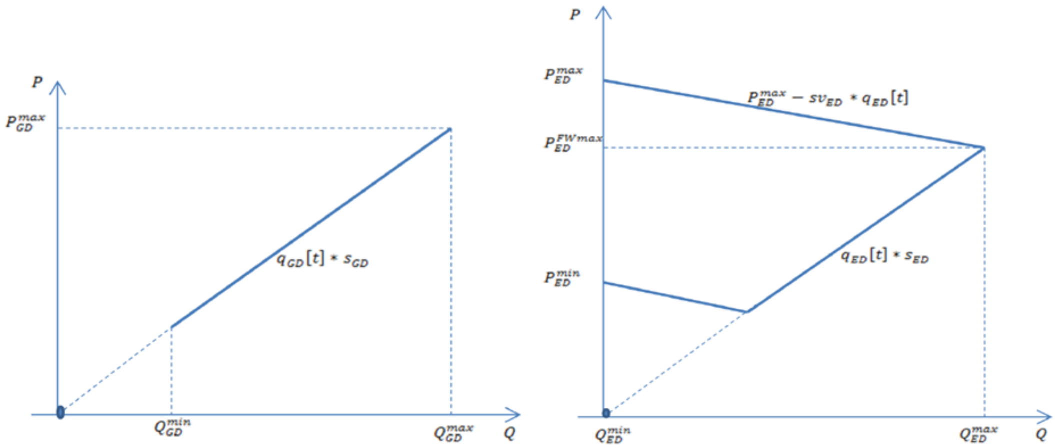

Figure A.3.: Power(P)-Heat(Q) curve of a back-pressure turbine (left) and a extraction-steam turbine (right) (Büchele et al., 2015).

pressure turbine is obliged to fulfill a constant heat demand H(t). Without any additional components the power output E(t) is necessarily also constant (left side of the graph). The right side of the graph shows the same generation unit with an additional heat storage. The power output E(t) can now vary as long as the sum over a certain time period is the same generated electricity as in the case without heat storage. In the shown example this means that the mean value of the varying power output has to be equal to the constant power output without storage. In the right side of the example the same amount of generated electricity is produced within half of the time. This implies that the power generating capacity has to be twice as high as in case of constant power delivery. The heat storage is also loaded with the same pattern and acts as buffer in order to deliver the constant heat demand. The previous example shows the decisive determinants of a flexibilization of back-pressure turbines. The amount of flexibility in power output determines the needed additional capacity of the generator and the capacity of the heat storage has to be sized accordingly.

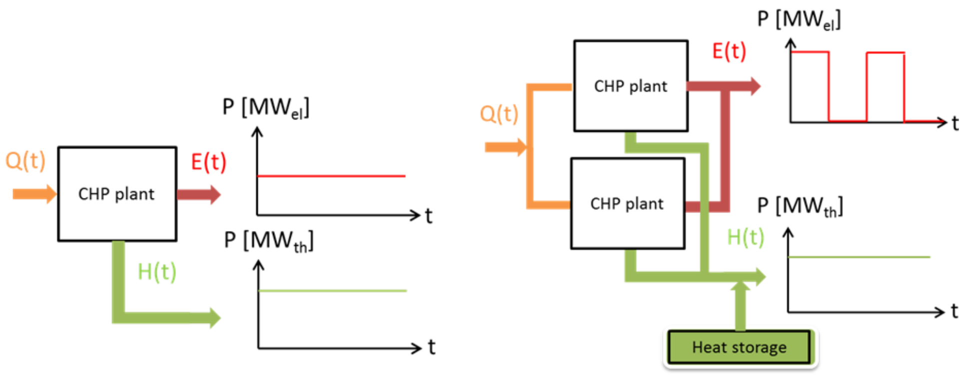

Figure A.4.: Back-pressure turbine without (left) and in combination with heat storage (right) (Ortner et al., 2012).

The flexibilitation of CHP plants is of particular importance in case of biomass and biogas generators that receive a fixed feed-in-tariff. These plants do have no economic incentive to adjust their power output according to electricity price signals or to invest in technical components to operate more flexible, respectively. Germany introduced with the *EEG Novelle 2012* a flexibility premium for biogas generators that invested in measures to flexibilize their power output. This amendment also allowed for a so-called "direct marketing" of these plants. In these support scheme operators of supported plants are allowed to sell their electricity wherever they expect the greatest value, i.e. in particular in balancing electricity markets. The operators receive an additional standardized premium on top of their market revenues in order to cover their generation costs. By the time this study has been prepared the situation in Austria still is that renewable electricity generators that receive public support are bundled within the *Ökostrombilanzgruppe* and are not marketed in balancing electricity markets. Consequently, an important potential supplier of balancing reserves is currently not incentivized or even allowed to enter these markets, because the design of the renewable electricity support schemes and the institutional setting in Austria do not favor that.

Appendix B

Appendix to chapter 4

B.1. Detailed assumptions concerning the supply side of the applied electricity market model

B.1.1. Conventional generating capacities

Current electricity generation capacities based on fossil fuels and nuclear power have been taken from the PLATTS power plant database (PLATTS, 2011). This database contains detailed information on techno-economic data, e.g. primary fuel, age structure, conversion efficiencies, of all large conventional power plants across Europe. For the future development of these capacities a mixed approach were applied. First, it has been assumed that each type of generation technology matches the aggregated values of the ENTSO-E Scenario Outlook & Adequacy Forecast (SO&AF) 2014-2030 (ENTSO-E, 2014). Beyond 2030, the applied power system model endogenously models additional in- and divestments of generation capacities. The model decisions had been restricted by a political layer that considered policy-induced in- and divestments, like the nuclear phase-out plan of Germany, or the construction of the Hinkley Point C nuclear power plant in Great Britain.

B.1.2. Renewable generation

Assumptions on future RES-E deployment have been derived from results of the RES investment model Green-X [1]. Within the framework of the EU-funded project Towards2030[2] a reference pathway for the development of electricity generation within the EU until 2030 has been constructed. This pathway is based on the assumption that the EU reaches its overall RES target of 27% on gross final energy consumption in 2030 and that this target could be achieved in a cost-efficient manner, i.e. generators are built the most in sectors and countries were costs (including country-specific cost structures and risk premiums) are lowest. The respective pathway together with the share of RES on gross electricity demand for the EU as a total is shown in figure B.1. It can be seen that the share of RES electricity

[1] http://www.green-x.at/
[2] http://towards2030.eu/

in the EU reaches almost 50% in 2030 in this pathway. In this pathway the largest share of renewable energy in 2030 will be constituted by the so-called variable renewable energy, i.e. wind and solar PV. This fact is important with regard to the objective of this work, since the increasing variability of electricity generation needs to be backed-up by different sources of flexibility, like dispatchable generation, demand response, grid expansions and storages. Not only because renewable generation significantly varies in short-time frames, but also because it is nearly impossible to exactly forecast this generation over longer time horizons the importance of short-term electricity markets might increase until 2030.

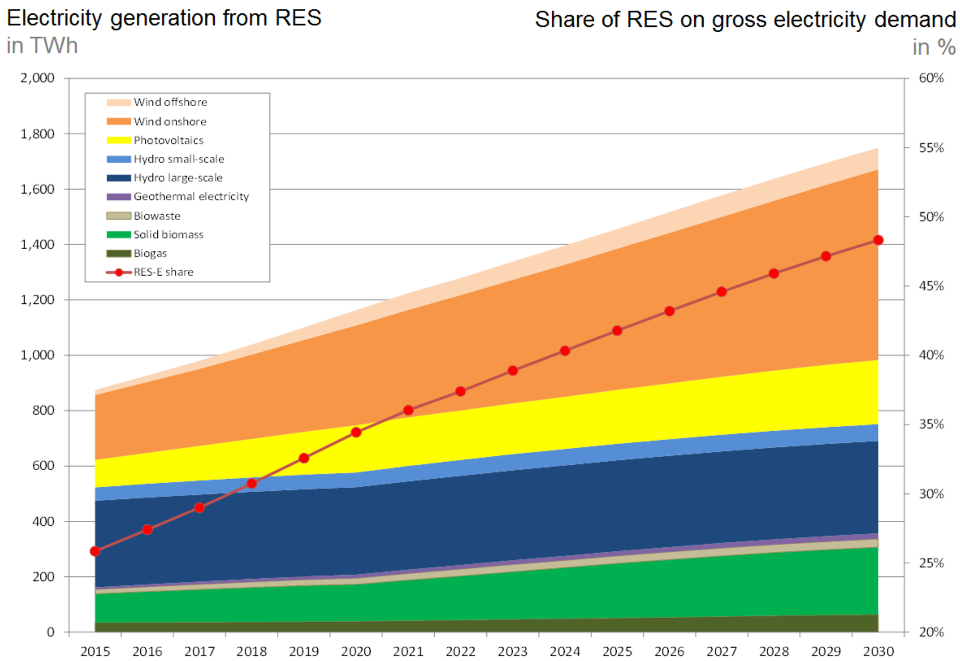

Figure B.1.: Assumption on the development of RES electricity generation until 2030. Source: Resch et al. (2015)

The output of the Green-X model on electricity generation is available in yearly time resolution. In order to derive higher time resolutions a step-by-step approach has been taken. First, a comprehensive database containing historical time series of hourly meteorological key data for several years, e.g. wind speed, direct and indirect solar irradiation and water inflows across the EU had been normalized[3]. Second, based on these time series technology-specific power curves were used to derive hourly electricity infeed profiles, whose energy content matched the yearly average values in figure B.1. More details about these two steps can be found in the reports of EU-funded projects the author was involved[4]. Third, through the application of curve fitting methods these so derived hourly infeed profiles have been transformed into quarter-hourly time series in a way that the averages over each hour

[3]The Energy Economics Group maintains large databases on historical and current meteorological measurements

[4]For example, AutRES100 (`www.eeg.tuwien.ac.at/AutRES100`), BETTER (`http://www.better-project.net/`), DIA-CORE (`http://www.diacore.eu/`), Towards2030 (`http://towards2030.eu/`)

remained the same and quarter-hourly gradients had to be minimal at the same time. These profiles have been subsequently used as input to HiREPS.

B.1.3. Primary energy carrier costs and carbon prices

Electricity prices are significantly driven by prices of coal, gas and carbon emission certificates. In order to be consistent with EU impact assessments of the afore-mentioned "Winter package" the author decided to align assumptions on future prices with the ones taken by the European Commission. The assumptions are based on the PRIMES EUCO27 scenario[5]. PRIMES is an energy system model of the EU that has delivered results for the analysis underpinning the Commission's proposal on the EU 2020 targets, the Energy 2050 Roadmaps as well as the 2030 policy framework for climate and energy.

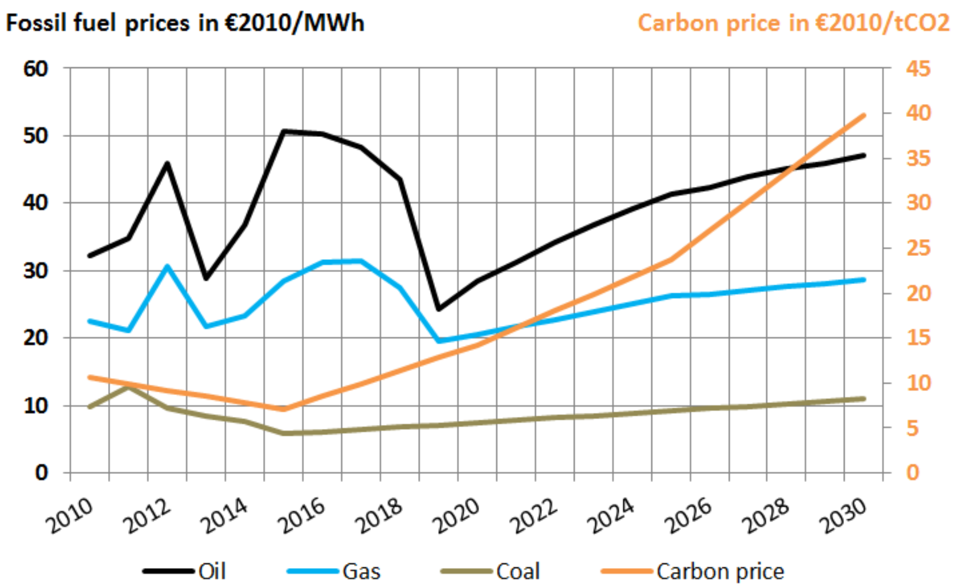

Figure B.2.: Assumed fossil fuel and carbon prices. Source: PRIMES 2016

Figure B.2 shows the assumed development of fossil fuel prices and the price for EU ETS emission certificates according to the PRIMES 2016 EUCO 27 scenario. In the PRIMES modeling it has been assumed that the R/P ratio of each of the primary energy carrier remains constant until 2030. It can be seen that after 2020 only moderate increases of fossil fuel prices are assumed. The carbon price is assumed to constantly rise from under 10 €/tCO2 in 2015 to approximately 40 €/tCO2 in 2030.

[5]National PRIMES and macro modeling results are available here: `http://ec.europa.eu/energy/en/data-analysis/energy-modelling`

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