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Electricity Market Design in Europe

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Abstract

The European Union (EU) seeks to achieve 35% of electricity production in the EU to be renewable by 2020. The significant share of renewable electricity generation creates a dilemma within European power markets: On the one hand, the renewable capacities receive financial subsidies in most European countries, which reduces electricity prices and creates challenges for large utilities' traditional business models. On the other hand, conventional power capacities such as coal or natural gas power plants are necessary in times of large renewable penetration to balance the grid and offer back-up power capacity for days of low wind speeds and little solar irradiation. In order to assess the financial performance of conventional power plants in a high renewable penetration scenario and to evaluate the consequences of political decisions on prospective market organization, an enhancement of the existing EnerPol wholesale market models is required.

Therefore, this thesis aims to improve the market modeling of the EnerPol software for a more realistic representation of the current wholesale electricity market structures. To reach this target the EnerPol code is enhanced by an ancillary service, a day-ahead and an intra-day market model. An optimization routine is developed to determine the profit-optimized weekly production strategy of power plants on the different electricity market segments. To reduce computational effort, parallelization by means of a multi-processing approach is successfully implemented in the strategy optimization routine. Weekly ancillary service auctions and daily day-ahead market auctions are performed in conjunction with an optimum power flow simulation. Subsequently, a stochastic model introduces deviations from the planned day-ahead market production by accounting for erroneous forecasts of electricity demand, solar and wind power production, as well as for power plant forced outages. This stochastic model is the foundation for the intra-day market which is simulated with an hourly resolution. In addition, the market model is extended into a multi-country framework including different cross-border transfer capacity allocation mechanisms. The multi-country setup is used in a case study for Switzerland and its neighboring countries (Austria, France, Germany and Italy) to evaluate financial and physical effects of switching from an explicit cross-border transfer capacity allocation mechanism to a fully coupled market. In a second study, a capacity market framework is designed for the time period of 2020-2045 for the German electricity market. Required capacity payments for newly installed generators are determined by connecting EnerPol multi-year simulations with an internal rate of return analysis.

In validations against historic market data from Germany, the developed production optimization models are found to produce realistic results. The simulation predicted prices for offered ancillary service capacities are in accordance with prices found in the German ancillary service market. The developed day-ahead market model predicts day-ahead market prices in Germany for the year 2015 with an hourly error of 10.7 €/MWh, which corresponds to a relative error of 33.8% when compared to average day-ahead market prices. With the introduced ancillary service market model 72% of the low-price day-ahead market hours below 20 €/MWh are correctly identified by the simulation. With the described characteristics, the developed wholesale market models are applicable for the evaluation of power plant performance and market development analyses in simulated future scenarios.

The analyzed multi-country setup for Switzerland and its neighboring countries predicts electricity cross-border flows to be increased by 14% when the explicit cross-border transfer capacity auction is replaced by a coupled market framework. Switzerland is used as transit country to bring additional electricity produced in France to Italy. The required capacity payments for newly installed power plants in the performed German capacity market study are found to decrease between the years 2020 to 2045 from 169 €/kW/year to 157 €/kW/year for coal power plants and from 50 €/kW/year to 10 €/kW/year for natural gas combined cycle power plants. Moreover, the simulation finds most newly installed natural gas combined cycle power plants with construction years between 2040 and 2045 to be financially self-sufficient of capacity payments due to their flexibility in exploiting growing ancillary service market potential. In contrast to that finding, future coal power plants investments are non-competitive in the analyzed capacity market framework which results in a required production technology flexibility upgrade. The overall average yearly costs of the capacity market are predicted to be 1.25 billion € for Germany with a maximum yearly payment for end consumers of 0.55 Cents/kWh, which is factor 10 below German subsidies for renewable energy sources in the year 2016. This result shows that policy makers could introduce a capacity market without putting large financial burdens on the end consumers as a solution to increase the share of renewables in the electricity mix while ensuring grid stability.

The simulation capabilities are enhanced for different target audiences. Political stakeholders can assess the financial effects of future electricity market designs. Original equipment manufacturers are able to quantify the importance of future power plant flexibility to profit from growing ancillary service markets.

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Nomenclature

Acronyms and Abbreviations

AC	alternative current
ASM	ancillary service market
AT	Austria
BFE	Swiss Federal Office for Energy
BG	balance group
BRP	balancing responsible party
CH	Switzerland
CM	capital and maintenance costs
DAM	day-ahead market
DE	Germany
EEG	Erneuerbare Energien Gesetz
$ENTSO-E$	European Network of Transmission System Operators for Electricity
EOM	energy-only-market
$EPEX$	European Power Exchange
EU	European Union
FR	France
IBM	imbalance market
IDM	intra-day market
$inst.$	installed
IRR	internal rate of return
IT	Italy
LEC	Laboratory for Energy Conversion
$NGCC$	natural gas combined cycle
NTC	net transfer capacity
OTE	the Czech electricity and gas market operator
P	active power flow
P_L	line losses
PCR	primary containment reserve
PRL	primary reserve
Q	reactive power flow

R	resistance
SRL	secondary reserve
TRL	tertiary reserve
TRM	transmission reliability margin
TSO	transmission system operator
TTC	total transfer capacity
USD	U.S. Dollar
V	voltage

Chapter 1

Introduction

1.1 Motivation

The European Union (EU) seeks to achieve 35% of electricity production in the EU to be renewable by 2020, which represents a two-fold increase compared to 2008. The significant increase in renewable penetration creates a dilemma within European power markets: On the one hand, the renewable capacities are financially subsidized in most European countries, which reduces electricity prices and threatens large utilities traditional business models. On the other hand, conventional power capacities such as coal or natural gas power plants are necessary in times of large renewable penetration to balance the grid and offer back-up power capacity for days of low wind speeds and little solar irradiation. One solution for this dilemma is the so-called capacity market, in which the utilities are not only paid for the energy (in MWh) delivered to the market, but also the power capacity (in MW) offered to the grid. This additional payment is planned to incentivize investments in new conventional power plants, which will be necessary to operate the grid safely in the future. [1] In reality, approaches to ensure back-up capacities during phases of high expected wind electricity generation are already present. In Germany, the TSOs procure winter reserve capacities to ensure grid stability during the winter months with high grid loadings.

Besides the development in renewable power generation and the resulting challenges for the conventional power plants also the organization of the European wholesale electricity market is changing and worth an investigation. Electricity is nowadays traded on many different markets with different time horizons. The procurement of electricity can be done on long time-scales of months or years on the Future's market or shortly before electricity is required meaning time spans from days up to 15 minutes before delivery on the intra-day market. This dynamic market environment creates challenges to the power producers to determine their production strategy among the different markets to optimize their financial results. In contrast to international financial markets, today's electricity markets are still mainly organized as national markets. But there is a clear trend visible of coupling individual country electricity markets to a European-wide electricity market to reduce inefficiencies stemming from for example complex cross-border transfer capacity auctions, where power producers have to procure cross-border transfer capacities first, before they are able to participate in foreign electricity markets. To enable a more efficient utilization of cross-border transfer capacities, the European Union defined standards in 2009 for the interconnection of markets to create a European internal electricity market - known as market coupling. [2] Market coupling simplifies electricity procurement from abroad and is considered to be economically beneficial since it leads to the cheapest dispatch combination of power plants in the coupled region.

1.2 Objectives

EnerPol, Laboratory for Energy Conversion's (LEC) system-wide, bottom-to-top integrated framework simulates the geographically-indexed production, transmission and demand of electricity on the scale of a region, country or continent. Using detailed physical, technical and financial models, the technical operation of infrastructure, the needs for development, and economic perspectives can be evaluated. [1]

In its current implementation EnerPol simulates the wholesale electricity market of interconnected countries in a single optimum power flow simulation with hourly resolution. The key aspect of the EnerPol code lies on the reproduction of the physical electricity flows and the evaluation of future scenarios. In this thesis, the financial aspects of the electricity markets are the main topic. Only with improved market models which are able to reproduce the physical and financial aspects of the different wholesale electricity market segments, it is possible to evaluate benefits of market couplings and costs of introducing a capacity market. Therefore, the following list summarizes the main steps which are required to reproduce the most important wholesale electricity market characteristics:

- The current EnerPol code does not differentiate among the different market segments present on the wholesale electricity market, such as day-ahead or intra-day market. In a first step, a detailed new modeling approach for the different market segments with different time horizons needs to be developed. A market mechanism must be introduced where power plants can place their bids for power production.
- Additionally, a detailed ancillary service mechanism has to be created which can handle stochastic deviations from planned production which may result from wrong electricity demand, wind or solar production forecasts, as well as from unexpected forced outages.
- Once this new market modeling approach is created for individual countries, the cross-border capacity auction mechanism needs to be added to the model to allow for multi-country simulations.

The developed market models can be seen as toolbox which allow for the financial evaluation of different future scenarios. In this thesis, the main focus is laid on two different investigations:

- As a first analysis, the effects of switching cross-border auction mechanisms towards a full market coupling on the physical electricity flows and corresponding financial consequences for power plants and TSOs will be analyzed. The chosen multi-country framework will be Switzerland and its neighboring countries (Austria, France, Germany and Italy). This is an interesting framework since Switzerland still trades cross-border transfer capacities differently in contrast to most countries in Europe.
- A future scenario of the years 2020-2045 for the German wholesale electricity market is regarded to quantify the effects of renewable capacity increase on the financial performance of conventional power plants. In a first step, the required amount of newly installed conventional power plants as well as the year of construction must be determined. These power plants are constructed to stabilize the grid which is heavily penetrated by intermittent renewable generation. Nowadays, the concept of a capacity market is often discussed to incentive future investments in conventional power plants as back-up for grid stability. In this context, it will be evaluated which financial effort would be necessary for the introduction of a capacity market in Germany. For this purpose, EnerPol simulations in a multi-year framework are carried out for the time span 2020-2045.

1.3 Structure of Thesis

This thesis is structured as follows. In chapter 2 the European wholesale electricity market is analyzed and the key aspects and numbers are identified for the modeling of this market. Afterwards in chapter 3, the developed market models are presented and explained in some detail. Additionally, the created models are validated and the applicability for future usage in capacity markets scenarios or multi-country frameworks is discussed. Chapter 4 presents a developed concept for a future capacity market to ensure grid stability. This chapter is followed by results chapter 5. In this chapter, the findings of a cross-border auction mechanism study for Switzerland and its neighboring countries (Austria, France, Germany and Italy) are presented. As a second study, the results of a performed capacity market framework simulation for Germany for the time span 2020-20245 are analyzed. The required capacity payments for newly installed generation capacities and the total costs of a capacity market framework are the main points of this analysis. Finally, the project is summarized in chapter 6. Main findings are concluded and potential further enhancements are proposed in the outlook section of the thesis.

Chapter 2

European Wholesale Electricity Market Analysis

This chapter gives an introduction to the current structures of the European wholesale electricity market and serves as basis for the chapter 3, which introduces the developed market models for the existing EnerPol software. Not all of the presented market segments of this chapter are implemented in the developed market models for EnerPol. The justification why a particular market segment is included in the simulation setup is given in chapter 3.

2.1 Special Characteristics of the Traded Commodity Electricity

Electricity is a physical product - the flow of electrons. It is a secondary energy source, which results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water. It is not visible, but it can be turned on and off and measured. [3]

Electricity as a commodity has special characteristics. On the one hand, the storage possibilities are limited and on the other hand, electricity needs to be transported from producers to consumers using the electricity grid. To guarantee a stable grid frequency, demand and supply have to be balanced at each instance in time to maintain a constant grid frequency of 50Hz in Europe. The effect of an imbalance of supply and demand is illustrated in figure 2.1. Electricity cannot be disposed. Finally, electricity is hardly substitutable in particular in a short time period. A disruption of electricity can therefore cause high costs. Following this, maintaining a high reliability of the electrical grid is a key requirement. [4]

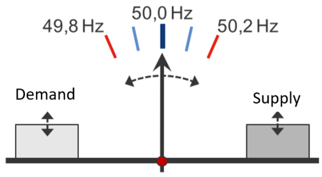

Figure 2.1: Effects of demand-supply balance on electric grid frequency [5]

2.2 Wholesale and Retail Electricity Market

In competitive markets, prices reflect the factors driving supply and demand - the physical fundamentals. Key supply factors that affect electricity prices include fuel prices, capital costs, transmission capacity and constraints and the operating characteristics of power plants. Changes in demand affect prices as well, especially if less-efficient, more-expensive power plants must be turned on to serve load. [3]

Electricity markets have retail and wholesale components. Retail markets involve the sales of electricity to consumers. Wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. [3] The different actors in retail and wholesale electricity markets are illustrated in figure 2.2. Energy on wholesale level can be traded on bilateral basis or via a power exchange.

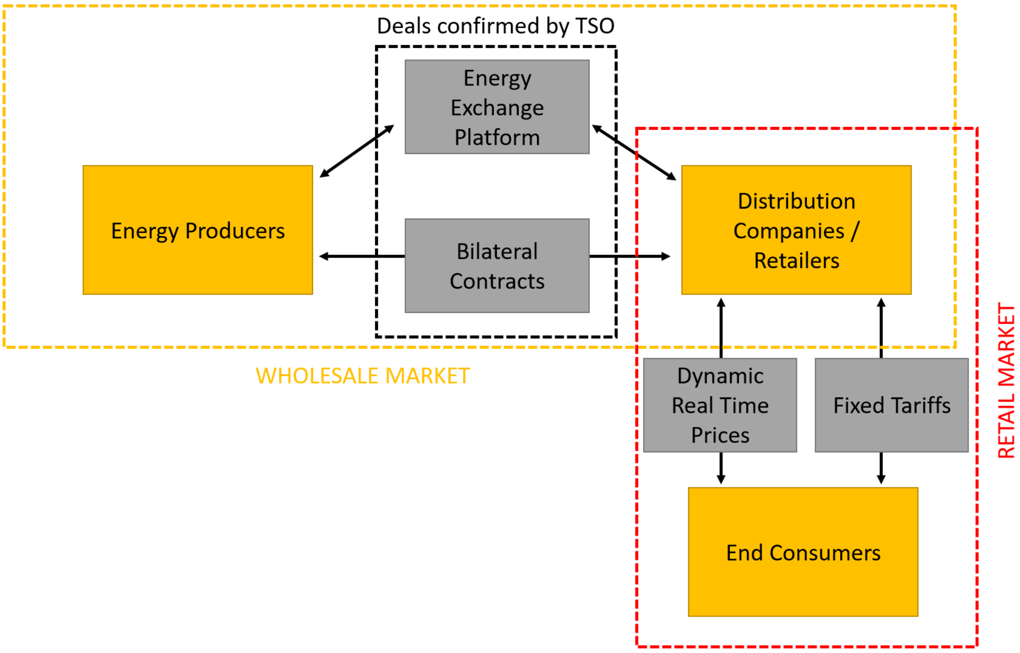

Figure 2.2: Connection between wholesale and retail electricity market

2.3 Wholesale Electricity Market Participants

Before the working principle of the wholesale electricity market is defined, the market players and their respective responsibilities are briefly explained.

Suppliers

Suppliers, often called generators or power producers, own generation assets used to supply electricity. The generated electricity can be sold on different electricity markets to distribution companies/balance groups. There are different kind of power producers with different typical production profiles, production availability times and market strategies. While plants are only able to generate electricity, storage facilities can transfer limited amounts of electricity from one point in time to another. Power plants are differentiated by the used primary fuel as well as their technological characteristics. Technological characteristics determine the flexibility of a generator, which means its ability to change output in a given time span. Flexibility plays an important role in maintaining the reliability of electricity supply as it determines the ability to handle given imbalances in the demand-supply equality in a short amount of time. [4]

Consumers

Households and industries form the group of final demand which is called load. Industries may be able to change their demand in short timespan for example by using own generation assets or altering the production cycle, i.e. they might react elastic in the short run. In contrast, households are rather inelastic in the short term. Technologies such as smart metering and storage facilities on the household side can improve short-term price reaction. However, these measures are still at an early stage of deployment. [4]

Distribution Utilities

To satisfy the consumers' electricity demand the electricity has to be transported to the end consumers. Distribution utilities organize the electric power distribution to their customers. Electric power distribution is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers.

Transmission System Operators

The transmission system operator (TSO) is responsible for operating the transmission system and, thus, for maintaining reliability of the electricity system. [4] European transmission system operators are all members in the ENTSO-E (European Network of Transmission System Operators for Electricity).

In addition, the TSO defines the final dispatch schedule of the power plants in their control area. This means that the TSO is the final decision maker which power plants are allowed to run after the received power plant production schedules are checked.

The TSOs are also responsible for redispatching. If overloading of lines in the grid can be foreseen, the TSO is allowed to adjust demand and supply schedules. This process is called redispatching. Redispatching occurs due to network problems. In contrast to reserve activation, redispatching takes place before delivery time. [4] At real time, demand and supply become known. As they are likely to deviate from their expected value, an imbalance occurs and reliability requires reserve activation. For this purpose the TSO procures reserves with different availability time horizons and pays the power plants which provide this service. [4] Furthermore, the TSO procures further ancillary services for being able to guarantee the grid stability. More details on the exact ancillary service categories are presented in subsection 3.6.

Important for a stable grid are the precision and accuracy of the sent-in production / demand schedules. To provide an incentive for the balance groups to fulfill their confirmed schedules, any deviations will be financially penalized by the TSO.

Regulatory Authority

The regulatory authority establishes and monitors the market environment. [4] The regulatory authority is usually an independent governmental regulator with main purpose of supervision of compliance with electricity and energy laws. Another task is the monitoring of electricity prices and tariffs, the control of security of supply and the organization of international transmission and trading rules. [6]

Balance Groups

For billing and measurement purposes, generators and consumers are organized in balancing groups (BG). A balance group is a group of various generators and / or consumers which is represented by a single balancing responsible party (BRP). The measurement of energy used or supplied takes place at the balance group level. The balancing responsible party is responsible for communication between the TSO and the balance group. [4]

The balance group has to be balanced in every hour of a week. This means that its energy balance based on generation, electricity procurements and sales, as well as balance groups consumption must sum up to zero. For each hour a schedule of planned production, sales, procurements and demand forecast has to be submitted to the TSO. This process is presented schematically in figure 2.3.

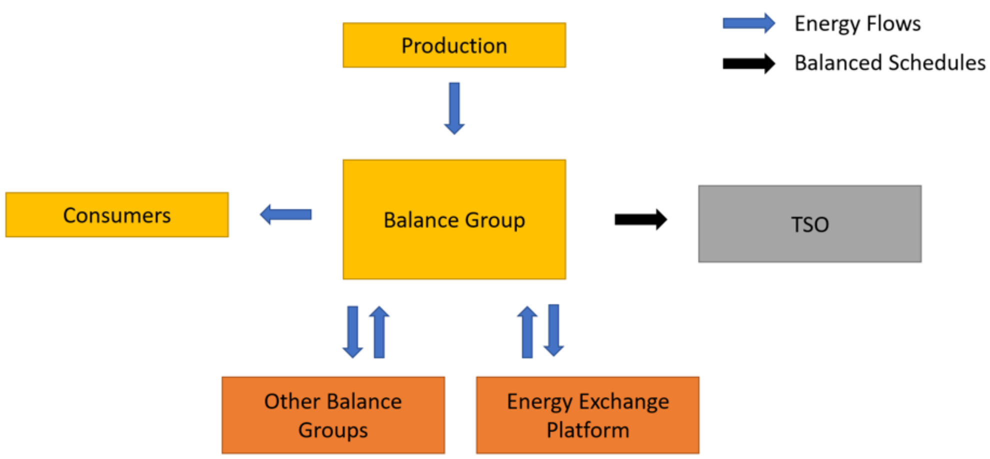

Figure 2.3: Energy flow concept for balance groups

2.4 Wholesale Electricity Market Segments

On the wholesale electricity market level different market segments with different functions and time horizons exist. In order to address the reliability requirement electricity markets are organized in two different sub-market segments. Based on demand and supply forecasts the energy-only market (EOM) balances expected demand and supply. The TSO needs to take control over the electricity system at some point in time in order to maintain the stability of the transmission grid. The TSO analyzes whether the proposed demand and supply schedules are feasible from a transmission point of view. If overloading of lines in the grid can be foreseen, the TSO is allowed to adjust demand and supply schedules. This process is called redispatching. [4]

At real-time demand and supply become known. As they most likely deviate from their expected value, an imbalance occurs and reliability requires its elimination which is handled in the ancillary service market. In order to adress these imbalances, generation capacity is needed. To guarantee that capacity is available and not contracted for energy sales, the capacity needs to be procured at the same time or before the EOM is cleared. Therefore, the ancillary service market equates the imbalance with the procured reserve capacity. [4]

The following list provides an overview of the sub-markets present in the EOM and ancillary service market. These sub-segments will be discussed in the following subsections.

- Energy-only-market (EOM)
  - Futures market
  - Day-ahead market (DAM)
  - Intra-day market (IDM)
  - Secondary market (bilateral contracts)
- Ancillary service market (ASM)
  - Primary reserves (PRL)
  - Secondary reserves (SRL)
  - Tertiary reserves (TRL+ and TRL-)
  - Loss compensation
  - Black start
  - Reactive power

The presented market analysis focusses on the following countries:

- France
- Germany/Austria
- Italy
- Poland
- Czech Republic
- Switzerland

The focus was laid on these countries since the organization of the different market segments and the installed generation structure are quite different. The analysis of the wholesale electricity markets of these countries reflects the variety of today's market structures in Europe well. Furthermore, all of these countries are involved in plans for an European-wide market coupling. These countries are therefore an interesting case study for evaluating future scenarios.

2.4.1 Bilateral Contracts

Before the first power exchanges were established, the complete electricity trading business was conducted on a bilateral basis between energy producers. Nowadays, the trend shows that the share of electricity traded on power exchanges is increasing every year. For the year 2016 the average hourly load for Germany was around 56 GW according to ENTSO-E data whereas around 26 GW were procured on the day-ahead market, which is a power exchange platform. [7] This corresponds to 46% of the total energy demand which is already procured on a power exchange. The remaining 54% belong to procurement by bilateral contracts or short-term energy procurements in the intra-day market or to ancillary reserve activations.

The increasing importance of power exchanges compared to bilateral contracts can also be seen when the total trading volume on the European Power Exchange (EPEXSPOT) is considered. From the year 2014 to the year 2015 the traded volume on EPEXSPOT increased by 19%. [8]

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2.4.2 Futures Market

The different market player want to hedge their long-term market positions. This means that the market participants want to neutralize the risk of adverse price development for existing physical positions as much as possible. The power producers have to sell power in the future and want to hedge against decreasing market prices. The energy buyers on the other side have to purchase power in the future and want to hedge against increasing prices. [9]

One potential hedging option is to hedge by buying futures on the futures market. Futures in the electricity sector are standardized products which are traded on the futures market of a power exchange. In Europe the futures are called Phelix Futures. In contrast to the day-ahead market and the intra-day market there is no underlying physical delivery of energy in the futures market. The futures market is purely cash settled and the required energy has to be bought on spot market separately. The trading horizons on the futures market reach typically up to three years. Longer time spans can also be traded, but usually the market is not liquid enough for longer time periods. Trading can be done for the upcoming years, quarters, months, weeks, weekends and days in the two product categories: base and peak. Base means the time period of a complete week and peak belongs to the expected high-price hours from 8 a.m. to 8 p.m. for the five weekdays. [9] [10]

2.4.3 Day-Ahead Market

The day-ahead market is a sub-market of the energy-only market where the electricity for the upcoming day (called D+1 in this work) is traded.

Day-Ahead Market in France, Germany/Austria, Switzerland

Austria, France, Germany and Switzerland have their day-ahead market organized by the European Power Exchange (EPEX) in Paris, and show therefore similar characteristics. The day-ahead market in these countries is organized as a uniform auction with hourly contracts. It opens 45 days before delivery time and is cleared the day before around noon. The offered prices on the day-ahead market have to lie within the range of -500€ /MWh up to 3'000€ /MWh. The auction results in pay-as-cleared energy payment. The most important market characteristics are summarized in the following tables and lists. [4]

Traded Products

- Standard block orders
  - Baseload (1-24 h)
  - Peak (8-20 h)
  - Off-peak (1-8h and 21-24h)
  - Specialised blocks of several hours (complete list can be found in appendix A.1.3)
- User-defined blocks
- Single hours

For day-ahead and intra-day markets many different offer specifications can be specified by the power producers when they place their bids on the markets. An overview of the possible offer strategies is presented for the day-ahead markets operated by EPEXSPOT in the following list. [11] Similar offers are also present in day-ahead and intra-day markets of other power exchange platforms.

- Unlimited order: Buy or sell orders without a price limit that are executed at the price determined by the algorithm of the market operator.
- Limited order: Limited orders are buy or sell orders executed at a specified price or better.
- All-or-none order: All-or-none orders are executed for their entire offer volume and expiries, or is totally rejected.
- Linked block order: A linked block order is a set of block orders which have linked execution constraint together.
- Child block order: A child block order has the execution constraints of a simple block order, and can be executed only if the parent block order is executed as well.

Auction Organization

- Daily auction for 24 hours of upcoming day
- Minimum volume 0.1MW
- Volume increment 0.1MW

The day-ahead market auction in Switzerland closes at 11 a.m., which is one hour prior to the auction closing in Austria and Germany. This can be seen as a disadvantage for Swiss market participants. Price expectations and forecasts of loads or renewable generation become more accurate with decreasing remaining time until delivery. An early day-ahead market closing can result in offers which are based on less reliable data.

Given the day-ahead results as well as forward and over-the-counter contracts (bilateral), the balancing responsible parties (BRP) of buyer and seller have to submit their schedules to the TSO until a specified time in the afternoon. The TSO verifies that the schedules match and allows for rescheduling in the case of mismatches. [4]

Day-Ahead Market Italy

The day-ahead market hosts most of the electricity sale and purchase transactions in Italy. Hourly energy blocks are traded for the next day. Participants submit bids/asks where they specify the quantity and the minimum/maximum price at which they are willing to sell/purchase. The DAM sitting opens at 8 a.m. of the ninth day before the day of delivery, and closes at 12 p.m. of the day before the day of delivery. The results of the DAM are made known by 12.55 p.m. of the day before the day of delivery. Bids/asks are accepted after the closure of the market sitting based on the economic merit-order criterion and considering transmission capacity limits between grid zones in Italy. Therefore, the DAM in Italy is also an auction market and not a continuous-trading market. [12]

The day-ahead market price is determined, for each hour, and is differentiated from zone to zone when transmission capacity limits are saturated. An important term is the Prezzo Unico Nazionale (PUN - national single price); this price is equal to the average of the prices of geographical zones, weighted for the quantities purchased in these zones. For the deals in the DAM the Italian TSO Terna acts as a central counterparty, and the power exchange platform is operated by GME the Italian market operator. [12]

A special electricity market form exists in Italy: the daily products market. The daily products market is the venue for the trading of daily products with the obligation of energy delivery. Trading in the daily products market takes place in continuous mode. The daily products market allows trading daily products with Baseload or Peak load profiles The sessions of the daily products market take place on weekdays, as specified below: [12]

- From 8.00 a.m. to 5.00 p.m. of D-2. If D-2 is a public holiday, the session will take place from 8.00 to 5.00 p.m. on the working day immediately before
- 8.00 a.m. to 9.00 a.m. of D-1, only if such day is not a public holiday

Day-Ahead Market Poland

The Polish day-ahead market is operated by the Polish Energy Exchange TGE. In the Polish day-ahead market there also exist block offers and offers for individual hours. The main difference to the other analyzed European day-ahead market structures is that the day-ahead market in Poland is not organized as a pure hourly auction. The day-ahead market consists of both continuous-trading sessions as well as standard hourly auctions. The trading of the products starts only 2-3 days before delivery depending on the traded electricity product. In addition, energy is traded in the currency of Poland (Zloty) and not in Euros as in the other analyzed markets. [13]

Day-Ahead Market Czech Republic

The day-ahead market in the Czech Republic is organized similarly to the markets in Austria, Germany, France or Switzerland. Hourly auctions are performed for the upcoming day. Offers have to be submitted until 11 a.m. Electricity is traded in Euros and the auction is operated by OTE, the Czech electricity and gas market operator. [14]

2.4.4 Intra-Day Market

The second very important sub-market in the energy-only market is the intra-day market. The intra-day market opens after the publications of the day-ahead market results, and usually closes 15-60 minutes before delivery due time of the electricity. Many of the imbalances can be foreseen until the closing of the intra-day market trading session. Therefore, the intra-day market clearly reduces the need for ancillary service reserve activations. The chronological embedding of the intra-day market into the day-ahead market framework can be seen in figure 2.4.

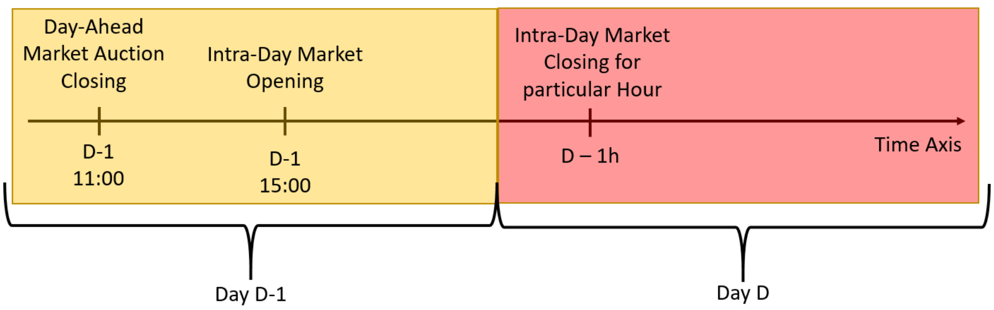

Figure 2.4: Intra-day timing (example for Switzerland)

Intra-Day Market France, Germany/Austria, Switzerland

Electricity is continuously traded after the gate opening at 3 p.m. the day before delivery. Hourly and quarter-hourly contracts as well as block contracts are traded. The minimum bid size and increment is set to 0.1 MW. Prices have to be in the range from -9'999 to 9'999 € /MWh. Thus, the allowed price range in the intra-day market is higher than in the day-ahead market. [4]

Important characteristics of the intra-day trading in France, Germany/Austria and Switzerland are summarized in the following list and table 2.1.

Traded Products

- Block orders
- Single hours
- Quarter hours
  - Germany: daily auction at 3 p.m. for following day
  - Switzerland: continuous trading
  - France: no quarter hours available for trading

Table 2.1: Intra-day market closure

Country	Trading Closing
France	30 minutes before delivery
Germany/Austria	30 minutes before delivery
Switzerland	60 minutes before delivery

The trading volume on the intra-day market is significantly smaller compared to the volume traded on the day-ahead market. For the case of Switzerland in the year 2015 the intra-day volume corresponds to only around 6.3% of the day-ahead electricity volume according to data from the European power exchange. [8] [4]

After each successful trade in the intra-day market the BRP of buyer and seller have to update their day-ahead schedules, and report them to the TSO, which continuously verifies them. After finally verifying these schedules with foreign control areas, final schedules are fixed 15 minutes before real-time at the latest. [4]

Intra-Day Market Italy

The intra-day market in Italy works differently compared to the market model in Austria, France, Germany and Switzerland. In Italy, the intra-day market allows market participants to modify the schedules defined in the day-ahead market by submitting additional supply offers or demand bids. The intra-day market takes place in seven sessions: MI1, MI2, MI3, MI4, MI5, MI6 and MI7. A pay-as-cleared price mechanism is used, and there is no possibility to trade quarter-hourly products in Italy. [12]

Supply offers and demand bids are selected under the same criteria as described for the day-ahead market. Unlike in the day-ahead market, accepted demand bids are valued at the zonal price. [12]

Intra-Day Market Poland

Like the day-ahead market the intra-day market is also organized by the Polish power exchange TGE. The continuous intra-day trading takes place in two sessions with a pay-as-cleared price mechanism. No possibility to trade quarter-hourly products on the intra-day market exists in Poland. On the day before delivery from 11.30 a.m. to 2.30 p.m. and on the day of delivery starting from 8 a.m. with 8 different closing times depending on the traded hour of the day. The detailed trading schedule can be found in appendix A.1.4. [15]

Intra-Day Market Czech Republic

OTE operates the intra-day market in Czech Republic. It is organized as continuous trading market with market closing 60 minutes before delivery. A significant difference is that the price cap and floor are chosen differently compared to the EPEXSPOT countries. The maximum price is 3'500€ and the minimum price is set to -3'500€ . In Czech Republic no quarter-hourly products can be traded on the intra-day market. [16]

Intra-Day Market Coupling - XBID Project

A project for the harmonization and coupling of the intra-day markets of several country exists in Europe. This project is called XBID. Intraday markets are an important tool for market parties to keep positions balanced as injections and/or off-take may change between the day-ahead stage and real-time operations. The growth of intermittent generation capacity has increased the importance of efficient intra-day markets.

Consequently, the European Commission has established a target model for intra-day markets, based on continuous energy trading where cross-zonal transmission capacity is allocated through implicit continuous allocation. The European power exchanges EPEXSPOT, GME, Nord Pool Spot and OMIE are responding to the needs of the market by establishing a continuous intraday trading environment to enable market parties to trade out their intraday positions. The possibility for market parties to trade out their imbalances is thereby significantly improved as they do not only benefit from the national available intra-day liquidity, but also from the available liquidity in other areas.

In order to help realizing this goad the power exchanges together with the transmission system operators (TSOs) from 12 countries have launched an initiative called the XBID market project to create a joint integrated intra-day cross-zonal market. The purpose of the XBID market project is to enable continuous cross-zonal trading and increase the overall efficiency of intra-day trading on the single cross-zonal intra-day market across Europe. [17]

2.4.5 Ancillary Services Market

Ancillary services maintain electric reliability and support of the transmission of electricity. The European Network of Transmission System Operators for Electricity (ENTSOE) and the regional TSOs determine the minimum amount of each ancillary service category that is required for maintaining grid reliability. [3]

The ancillary service market is characterized as a single-buyer market. The TSOs act as single buyer to guarantee grid stability. The following list provides an overview over the different types of ancillary services:

- Reserve market
  - Primary reserve (PRL) (spinning reserve)
  - Secondary reserve (SRL) (spinning reserve)
  - Tertiary reserve (TRL) (non-spinning reserve)
- Loss compensation
- Reactive power
- Black start, island operation

These different ancillary service categories will be explained in some details on the following pages.

Reserve Market

Imbalance or reserve markets eliminate the imbalance between demand and supply at real time. Therefore, reserve markets are cleared after the realization of supply and demand are known. Two general types of imbalances can occur:

- Deterministic imbalances: These imbalances are known before the revelation of uncertainty. Scheduled leaps belong to this class as they arise when it is not possible to match the contract length in the EOM with instantaneous changes in demand and supply.
- Uncertain imbalances: Uncertain imbalances are caused by the fact that demand and supply cannot be forecasted with certainty, and include e.g. unforeseen plant shut-down and errors in the forecast of renewable generation.

In the imbalance market consumers and generators are demand and supply party at the same time. On the one hand, they demand energy in-/decrease in order to equate the imbalance they caused. On the other hand, this change in production pattern is provided by the generators. In principle, demand parties are also able to provide reserve capacity by de-/increasing load. This possibility existed e.g. in Germany until the end of 2015. As the TSO is responsible for system stability, it usually serves as the market-maker in the sense of clearing and supply. [4]

It is important to emphasize special characteristics of balancing markets:

- **Inelastic demand in balance markets**: Imbalances are the demand in reserve markets. Uncovered demand leads to failure of the electricity system. Therefore, demands needs to be covered entirely by balancing facilities in every point in time. Demand is completely inelastic during the balance management. [4]
- **Positive and negative balancing power**: Balancing power can be positive or negative. A positive balancing power is a situation in which consumption unexpectedly exceeds electricity generation causing a need for additional supply. In contrast to that, a negative balancing power situation requires a decrease in generation. [4]
- **Capacity availability**: Supply of reserve energy i.e. additional generation, needs to be procured before or simultaneously with the EOM. This is necessary to ensure that the capacity is available and not blocked by contracts of the EOM. This stage is called the reserve procurement or reserve market. Conversely, negative reserve - the decrease in generation - requires that the supplier is generating (i.e. has a contract on the EOM). Following this, supply needs to be procured before demand is known. [4]
- **Procured balancing power capacities exceed the required balancing power**: Additionally, due to the fact that reserve should be able to always restore the demand and supply balance, the procured balancing power capacities usually exceed the required balancing power. [4]
- **Importance of flexibility**: Besides the differentiation of positive and negative reserve power, products are differentiated by their flexibility (which means their ability to deliver energy within a pre-defined amount of time). Figure 2.5 gives an overview over the different types of reserves required after a power plant outage event. The arrow indicates an unforeseen drop in the power supply. The imbalance is recognized by a drop in the grid frequency. Primary reserve is immediately and automatically activated. The primary reserve does not have to be activated in the area where the imbalance occurs, but can be activated anywhere in the synchronized grid (solidarity principle). Primary control is replaced by secondary reserve which has to be available within 30 seconds and fully activated within 5 minutes (the

TSO sends a signal to the plant which automatically changes output). In contrast to primary reserve, it is usually activated at a location close to the point of disruption. Tertiary reserve which is also called minute reserve or replacement reserve both complements and replaces secondary control. Tertiary reserve has to be completely activated within 15 minutes and to last for at least one hour up to a maximum of four hours. [4] [5] [18]

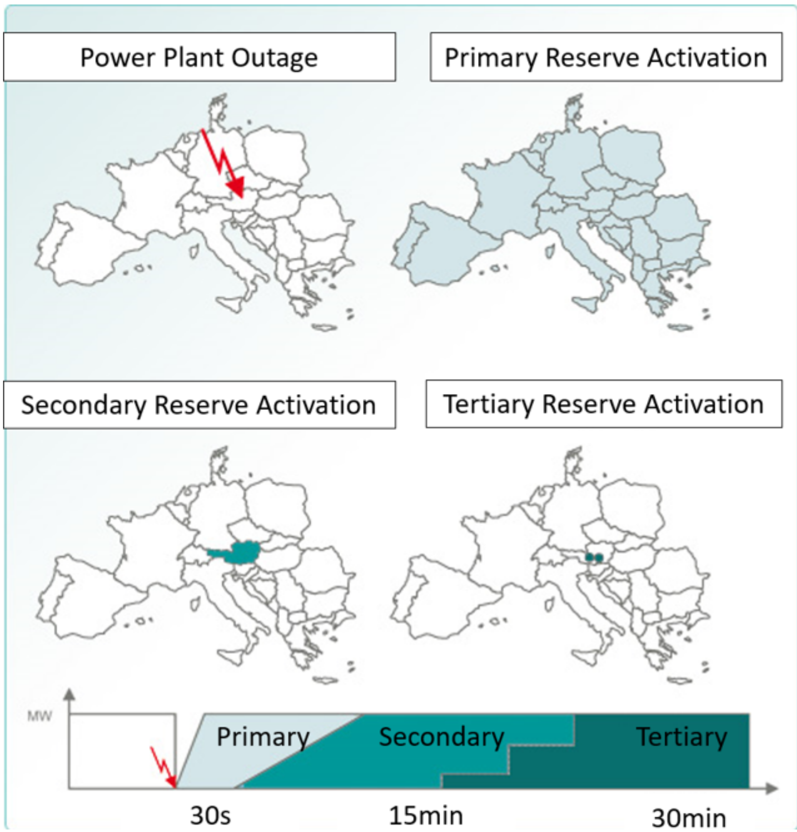

Figure 2.5: Sequence of reserve activations in case of power plant outage with according timings [19]

- **Power plant pre-qualification**: Which power plants are allowed to contribute to the different kinds of reserve power depends on the technical characteristic. A power plant has to fulfill the pre-qualification criteria set by the TSO. Depending on whether a plant has to produce when offering balancing capacity, reserves are sometimes called (non-) spinning reserves. [4]

- **Procurement mechanism**: The TSO procures reserve capacity in order to ensure against imbalances leading to system blackouts. In contrast to the EOM, the product in the balancing market is capacity (valued in €/MW) which in the case of an imbalance can be used to produce more or less energy. Thus, besides designing the capacity procurement, the market maker also needs to specify a mechanism how to reimburse costs caused by energy delivery. While the product differentiation based on the flexibility of the reserve providers is fixed based on technical grounds the capacity product needs to be further detailed along the time and spatial dimension, i.e., the contract length and possible nodal differentiation need to be determined. Concerning the market clearing mechanism, the regulator has to decide whether the procurement should be market-based or whether delivery of reserve capacity is mandatory. Finally, the TSO needs to decide about the demand for reserve capacity which is based on a reliability criterion, e.g., the probability that load is not served. Depending on whether the TSO uses a static or dynamic approach, i.e., determines capacity demand only once or updates demand, that is called static or dynamic sizing. [4] [20]

- **Reimbursement mechanism**: Balancing causes two type of cost: the cost of reserving the capacity and the cost of generating energy in the case of an imbalance. The two processes are necessary in order to allocate these costs. First, imbalance needs to be measured for each generator and consumer which is called imbalance settlement. Second, the cost need to be allocated. As system stability is a service to the final consumers, one can argue that cost should be refinanced via a uniform surcharge on the final electricity price. On the other hand, allocating cost to parties that cause the imbalance avoids strategic behavior. [4]

- **Contract length**: Besides determining a mechanism to allocate capacity and energy cost, the regulator needs to specify the contract length, i.e. for which time intervals imbalance prices are determined. Moreover, the gate closure determines the point in time when cost allocation is carried out. A particularly important question is whether market participants are allowed to trade imbalances before the cost allocation takes place. In day-after markets a party with a positive and one with a negative imbalance are allowed to net their positions, and thus avoid paying the imbalance cost. [4]

Primary Reserve Country-Specific Procurement

The primary reserve (PRL) belongs to the category of spinning reserves. To provide spinning reserve a generator must be on line (synchronized to the system frequency) with some unloaded spare capacity and be capable of increasing its electricity output within the desired time period of 30 seconds for primary reserves. During normal operation, these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources. [3]

According to ENTSO-E operation handbook the PRL requirement for continental Europe is equal to +/-3'000 MW. The value of 3'000 MW is based on the assumption of an outage of the biggest unit in the European synchronized grid. This 3'000 MW are fully dispatched when the frequency deviation is equal to 200 mHz in either direction. [18]

Most of the TSOs in the European countries organize the primary reserve market as weekly auction where the cheapest offers are taken. Only the capacity is reimbursed. It is assumed that the short-term activation of the primary reserve nets to zero in a weekly perspective. The amount procured is determined by ENTSO-E, which correlates the required PRL amount of each country to its average yearly hourly load. Typically for the activation the power plants are dispatched proportionally to their accepted volume in the PRL auction. Minimum offered volume in the primary reserve auctions are 1 MW with incremental size of 1 MW. Table 2.2 summarizes the different PRL procurement markets of the analyzed countries. Values indicated by a star are based on author's own calculation based on ENTSO-E guidelines.

Table 2.2: Primary reserve country summary table [18] [21] [22]

Country	Austria	Czech Republic	France	Germany
Symmetric Product	yes	yes	yes	yes
Amount [MW]	62	60	571	583
Organization	auction	auction	mandatory provision	auction
Procurement	weekly	long-term contracts	weekly	weekly
Reimbursement	capacity: pay-as-bid	-	-	capacity: pay-as-bid
Activation	automatically by frequency	automatically by frequency	automatically by frequency	automatically by frequency

Country	Italy	Poland	Switzerland
Symmetric Product	yes	yes	yes
Amount [MW]	330*	170	68
Organization	mandatory provision without reservation	mandatory provision without reservation	auction
Procurement	weekly	weekly	weekly
Reimbursement	-	-	capacity: pay-as-bid
Activation	automatically by frequency	automatically by frequency	automatically by frequency

PRL Cooperation:

During the last years, a first primary reserve procurement cooperation was established around Germany. As the first cooperation partner the Swiss TSO Swissgrid participated from March 12^{th} 2012 to April 4^{th} 2015 in the joint tenders with the German TSOs via www.regelleistung.net. 25 MW of the Swiss primary containment reserve (PCR) requirement was procured in the common auctions. Since 7^{th} January 2014, TenneT NL participates in the joint PCR tendering procedure and currently purchases about 70% of the Dutch need for PCR on the internet platform.

As of 7^{th} April 2015, the international cooperation is linked to the Austrian-Swiss PCR tendering procedure. As of 1^{st} August 2016 Belgium and as of 16^{th} January of 2017 France joined the cooperation. This increases the liquidity from the TSO demand side on the PCR market and unlocks new sales options for the participating suppliers. By coupling the PCR markets, the largest PCR market of Europe is created. In a later stage, the participation of the Danish system operator Energinet.dk is planned.

The joint call for tenders by Germany, Belgium, the Netherlands, Austria and Switzerland uses the tendering systems that are already in place and is open to all pre-qualified suppliers. [23]

The total volume of this cooperation market is 1'250MW. The maximum amount for PRL exports is limited to 30% of the country-specific primary reserve need but never less than 90MW. Resulting export maxima for the participating countries: [23]

- 90MW - Belgium, Denmark, Netherlands, Austria, Switzerland
- 173MW - Germany
- 84MW - France (first step, entrance 2017)

Secondary Reserve Country-Specific Procurement

Secondary reserve is also called secondary control or frequency restoration reserve or spinning reserve. By the activation of primary reserves, a further grid frequency drop can be prevented. In a next step, the secondary reserve is activated, and restores the frequency again to its desired level of 50 Hz in the European grid. The power plants providing SRL must be able to provide their contracted SRL capacity within 5 minutes. Due to this short reaction time, the secondary reserve is also a spinning reserve, meaning that power plants which provide this service have to be constantly in generation mode.

In contrast to the primary reserves, the amount of procured secondary and tertiary reserves can be determined by the TSOs and is not prescribed by the ENTSO-E. Typically, a large installed capacity of renewables and hydro power plants results in higher amounts of procured secondary and tertiary reserves by the TSOs. The following tables 2.3 summarizes the most important characteristics of the secondary reserve procurement in the analyzed countries.

Apart from Germany all countries included in the analysis handle secondary reserves as symmetric product. The product is mainly procured on weekly basis with a pay-as-bid mechanism for the procured capacity as well as for the activation. The activation of the secondary reserves is based on an electrical signal which is automatically transmitted from the TSO to the contracted power plants.

The organization of the secondary and tertiary reserve markets in Italy is quite different compared to the other countries in this analysis. Further details on the exact procurement of secondary and tertiary reserves are provided in appendix A.1.5.

Table 2.3: Secondary reserve country summary table [18] [21] [22]

Country	**Austria**	**Czech Republic**	**France**	**Germany**
Symmetric Product	yes	yes	yes	no
Amount [MW]	200	170	750	+2'020/-1'960
Organization	auction (Peak/Off-Peak)	auction	mandatory provision	auction (Peak/Off-Peak)
Procurement	weekly	long-term contracts	weekly	weekly
Reimbursement Capacity	pay-as-bid	-	-	pay-as-bid
Reimbursement Activation	pay-as-bid	-	-	pay-as-bid
Activation	automatic TSO signal	automatic TSO signal	automatic TSO signal	automatic TSO signal

Country	**Italy**	**Poland**	**Switzerland**
Symmetric Product	yes	yes	yes
Amount [MW]	-	500	400
Organization	auction sessions	mandatory provision without reservation	auction
Procurement	daily	weekly	weekly
Reimbursement Capacity	-	-	pay-as-bid
Reimbursement Activation	-	-	linked to spot prices
Activation	automatic TSO signal	automatic TSO signal	automatic TSO signal

Tertiary Reserve Country-Specific Procurement

Tertiary reserve can be categorized as non-spinning reserve. Non-spinning reserves come from generating units that can be brought online in 15 minutes. Non-spinning reserve can also be provided by demand-side resources. [3]

Typically, the tertiary reserve procurement is split into positive and negative offers to give more market players with production and load flexibility the chance to offer in this market segment. These additional offers are needed since the procured amount of tertiary reserves is often bigger than the amounts in the primary and secondary reserve categories. This splitting of the product allows for example for nuclear power plants to offer only down-ramping. This is more in line with their general baseload production strategy due to their low marginal costs.

Important to notice is that Italy does not have a tertiary reserve market. Further details for the special case Italy are presented in appendix A.1.5.

Tertiary reserve procurement is often carried out in "4 hour blocks" which allows for flexibility in procurement for the TSO and increases the number of potential auction participants. The activation of the tertiary reserves is created by a manual signal from the TSO to a contracted power plant.

Table 2.4: Tertiary reserve country summary table [18] [21] [22]

Country	Austria	Czech Republic	France	Germany
Symmetric Product	no	no	no	no
Amount [MW]	+280/-170	+340/-70	+800/-450	+2'050/-1'940
Organization	auction (4h blocks (Mo-Fr,Sa-So))	auction	yearly auction	auction (4h blocks)
Procurement	weekly and daily	long-term contracts	weekly	daily
Reimbursement Capacity	pay-as-bid	-	pay-as-bid	pay-as-bid
Reimbursement Activation	pay-as-bid	-	annual bonus	pay-as-bid
Activation	manual TSO signal	manual TSO signal	manual TSO signal	manual TSO signal

Country	Italy	Poland	Switzerland
Symmetric Product	-	no	no
Amount [MW]	-	9% of load - PRL - SRL	+450/-300
Organization	-	mandatory provision without reservation	auction
Procurement	-	daily	weekly and daily
Reimbursement Capacity	-	-	pay-as-bid
Reimbursement Activation	-	-	pay-as-bid
Activation	-	manual TSO signal	manual TSO signal

Black Start

Black start generating units have the ability to go from a shut-down condition to an operating condition, and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have these capabilities. These are the first facilities to be started up in the event of a system collapse or blackout to restore the rest of the grid. [3]

Since the black start procurement heavily relates on detailed contracts between the TSO and the service providing power plants the detailed mechanism explanation is based on the example of Switzerland, where most information is freely available.

Example of Switzerland

In Switzerland the procurement of ancillary services is not yet a market. Swissgrid has contracts with several power stations (typically hydro power plants). But a market creation is planned for the black start ancillary service in Switzerland. The existing contracts define the location of the supplying power station, the installed capacity, dependency of other cascades and the required auxiliary equipment. As financial provision power plants which offer black start capabilities receive a premium for the yearly black start tests, the training of the personnel as well as for the used water during the black start functionality tests. [24]

Important for the development of a market model is also the financial significance of wholesale electricity market segment. As example here the hydro power plant company Kraftwerke Oberhasli is mentioned. An analysis of the yearly financial reports of the years 2006-2016 of the Kraftwerke Obershasli showed that around 5% of the yearly electricity revenues come from the provision of black start capabilities and reactive power services.

Losses

Transporting electricity through transmission lines creates electrical losses which have to be compensated to guarantee for a functioning and stable European electrical grid. The market for loss compensation is a rather simple market. The required loss compensation amounts can be precisely estimated by load flow simulations of the TSOs. In most cases the loss compensation is handled as long-term auctions (often monthly). In the following the loss compensation mechanism used in Switzerland is presented as an example for a typical loss compensation market.

Example of Switzerland

In Switzerland the required loss compensation amounts are announced by the TSO in monthly intervals. The loss compensation offers have to be handed in as 5MW blocks for this monthly intervals. The power plants are reimbursed with a pay-as-bid mechanism. To compensate these expenses the TSO asks for a financial payment by the grid users which is called Netzentgelt. [24]

Reactive Power / Voltage Control

Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains the electric and magnetic field in alternative current (AC) equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic system equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can both produce real and reactive power, and can be adjusted to change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage. [3]

Example of Switzerland

Reactive power procurement in Switzerland is organized by bilateral contracts. All running synchronous generators provide compliant reactive power. If additional reactive power adjustment is necessary, the contracted power plants provide additional voltage control for a fixed tariff (around 3 CHF/Mvarh). There is no fixed reactive power amount contracted. But the contracted power plants are under constraint to make defined generators available for the voltage control. The machines provide voltage control in the desired direction. The reimbursement includes the following three components: [24] [25]

- exchanged reactive power (tariff in CHF/Mvarh)
- provision for required machines starts for reactive power control
- additional provision for each operating hour of a machine activated by TSO

2.4.6 National Markets and Market Coupling

Nowadays, wholesale electricity markets in Europe are still mainly organized as national markets. During the last two decades first steps towards a coupled European wholesale market were carried out.

To enable a more efficient utilization of cross-border transport capacities, the European Union defined standards in 2009 for the interconnection of the markets to create an European internal electricity market - known as market coupling. For the day-ahead market, in which the energy trading for the following day is carried out, the foundation stone was laid for the European internal electricity market as long ago as 2006, in the form of the Trilateral Market Coupling between France, Belgium and the Netherlands. In the meantime, this process for the creation of an integrated internal electricity market has already advanced quite considerably. For the intra-day market, in which energy is traded for the current day, market coupling is only at the preparatory stage. The chronological steps of the day-ahead market coupling in Europe are presented in figure 2.6. [2]

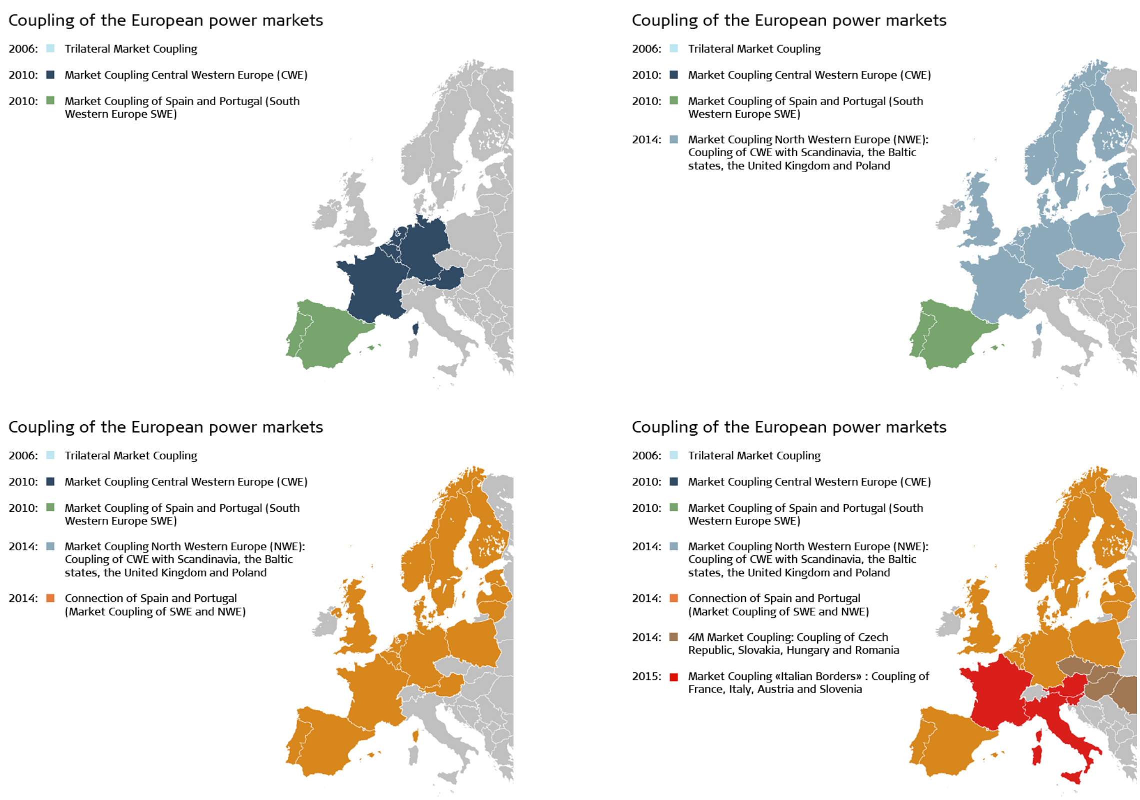

Figure 2.6: European electricity market coupling milestones [2]

Final goal of the current ongoing market coupling is a completely coupled European electricity market, which is considered to be the economic most efficient market solution which maximizes social welfare.

2.4.7 Cross-Border Trading and Transfer Capacities

Due to the central role of the transmission grid for system stability, international trade of electricity is more complicated than in other markets. This is mainly caused by the fact that international trade requires coordination of two or more TSOs and the fact that the commodity electricity has to be balanced all the time. For managing the grid, each TSO has to know the amount injected or withdrawn at the cross-border connections. A mechanism is therefore needed to allocate the cross-border transmission capacities to parties that have internationally traded in the EOM or balancing market. One possibility is an explicit auction of the cross-border capacities which is run in parallel to the EOM and reserve capacity procurement. In contrast to that there exist implicit cross-border transfer capacity auction procedures where the individual markets are cleared in combination with the cross-border capacity auction under the transmission constraints provided by the TSOs. Another option is a full market coupling. In such a system traders provide their bids to the market and TSOs analyze these bids. The market maker clears the market over all regions participating in the market coupling. [4]

Explicit Auctions

Due to the required market price difference anticipation between adjacent countries, the following negative aspects of explicit transfer capacity allocations can be summarized: [26]

- timing
- direction
- efficiency

Explicit auctions can still be found between the EU and Switzerland as well as between EU countries and other third countries apart from Switzerland. Explicit auctions are also present at the borders of countries belonging to different coupled market regions inside the European Union. Market data of the transfer capacity auctions can be found on the homepage of the Joint Allocation Office service company.

For the case of Switzerland and its neighboring countries the following cross-border capacities can be traded in explicit auctions. The difference between the directional capacity values mainly stems from country-internal bottlenecks in the electric grid. [26]

Table 2.5: Cross-border capacities Switzerland [MW] in January 2016 according to ENTSO-E transparency webpage

	From Switzerland	**To Switzerland**
Austria	1’200	350
Germany	4’000	600
France	1’100	3’200
Italy	3’500	1’900

Implicit Auctions

The implicit transfer-capacity auction mechanism shows several advantages compared to explicit transfer capacity auctions. The most important characteristics and advantages of implicit auctions are summarized in the following list: [26]

- simultaneous clearing of capacity rights and spot trading
- optimal allocation of capacity
- reduced potential for capacity hoarding
- capacity is administered by involved TSO's
- reduced uncertainty concerning use of explicitly auctioned capacity allows more capacity to actually be allocated

Implicit transfer capacity allocations can be found in regions where market coupling already has been introduced. For example in:

- NWE (North-Western Europe, Denmark, Finland, Norway, Sweden, Great Britain, Belgium, France, Germany, Luxemburg, Netherlands) and SWE (South-Western Europe, Spain and Portugal)
- "Italian Borders" (Italy, France, Slovenia, Austria)
- 4M-Market (Czech Republic, Slovakia, Hungary, Romania)

Chapter 3

Wholesale Electricity Market Models for EnerPol

3.1 Previous EnerPol Simulation Framework

EnerPol is an integrated, high-resolution, system-wide, electricity and gas networks model. The geographic coverage of EnerPol includes most of Europe, substantial portions of USA and Canada, and parts of Africa and Asia. For central Europe, the modeled transmission grid has 1'900 individual transmission lines (220, 380 and 400 kV) with a total length of 70'000 km; 3'000 individual conventional and renewable power plants are geo-referenced in EnerPol's framework. [27]

For the electricity market, hourly chronological simulations are undertaken. In the electricity market model, generation, transmission and demand are modeled at the level of substations with dispatch that is optimized based on physical constraints and economic considerations. This holistic, comprehensive framework allows for the data-driven analysis of a broad range of scenarios related to power and energy mixes, market performance, investments, and impact of policy. [27]

Before this work the wholesale electricity market was modeled as follows in EnerPol:

- EnerPol simulates the wholesale electricity market with an hourly optimum power flow simulation. The code does not differentiate between the different energy-only market segments (day-ahead market and intra-day market).
- Due to the missing intra-day market model, the current code does not provide any stochastic models to simulate power plant outages or forecast errors of demand, solar or wind production. Thus, the EnerPol wholesale electricity market is purely deterministic.
- The implemented ancillary service model is very rudimentary. 10% of the hourly demand are modeled as ancillary service reserves, which can only be provided by the most flexible generators. No differentiation is made between primary, secondary and tertiary reserves in the code.
- The optimum power flow solver choses the power plants according to their marginal costs for production. This means, that the power plants are not individually optimizing their own operational schedules in a unit commitment sense.
- Hydro power plants maximum production amounts are determined according to weekly demand variations (pump-storage power plants) or yearly demand variations (hydro dams).

3.2 Overview of Developed Electricity Market Models

In this section, an overview of the developed market modeling approach for the European wholesale market is presented. In a first step, the main differences to the existing market model are summarized.

The developed market model introduces a day-ahead market (presented in section 3.7) and an intra-day market (section 3.9). The power plants optimize their weekly production strategies to create well-priced bids for the different markets. The rudimentary ancillary service model is replaced by a realistic reserve modeling which introduces procured capacities of primary, secondary and tertiary reserves by the TSOs (section 3.6). A stochastic model (section 3.8) introduces deviations from the planned day-ahead market production profiles of the power plants. The deviations due to wrong forecasts for wind, solar or demand and power plant outages serve as base for the introduction of an intra-day market. A part of the deviations is too short-term, and must be balanced by reserve activation, which is called balancing energy. The main differences are again presented in figure 3.1. Justification about neglected market sub-segments will be given in section 3.11. A short overview about the included and neglected market segments is the designed model is already presented in figure 3.2.

Previous EnerPol Implementation		New Market Model Approach
Europe as one **perfectly coupled power market** (Europe as «one country»)	⟺	Europe split in **individual country electricity markets**
Market price based on production costs of power plants	⟺	**Market price based on offered bids** of power plants according to weekly strategy
Rudimentary model for ancillary services (10% of total production)	⟺	Includes different ancillary service categories (**PRL,SRL,TRL+/TRL-**) in weekly auctions
No differentiation between day-ahead and intra-day market	⟺	Differentiation between **day-ahead and intra-day market**
No stochastic models	⟺	Stochastic models for intra-day market and ancillary reserve activation

Figure 3.1: Differences between previous and developed market model

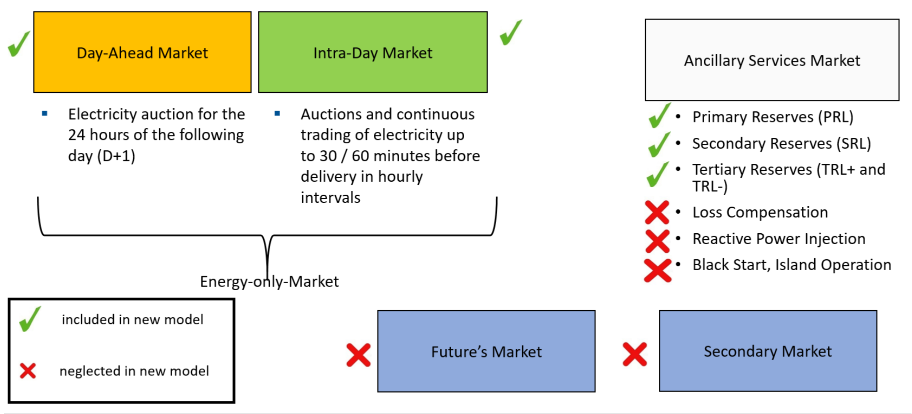

Figure 3.2: Overview of features covered by new wholesale market model

3.3 Power Plant Strategy Optimization

3.3.1 Power Plant Optimization Model Description

Due to the variety of market segments in the wholesale electricity market, power producers need to determine the best strategy for offers and bids on these market segments to maximize their profit. The introduction of a power plant optimum strategy model was therefore a key element in the development of the new market model approach. Due the nature of most ancillary service market auctions which are performed in a weekly setting and a typical weekdays / weekends market price pattern, power plants perform in reality a weekly power plant portfolio optimization. In the current implementation of EnerPol no ownership information of the different power plants is available. As it was shown in the work of Dimitrova [28] it is difficult to model power plant portfolios without accurate information on power plant ownership. Therefore, the chosen market model approach is based on power-plant strategy optimization instead of portfolio strategy optimization.

The developed optimization module is based on a Pyomo model, which is an optimization extension of the programming language Python. The module optimizes the power plant production strategy to maximize the financial performance of an individual power plant for a period of a week, but it can also be used for different time horizons (days or years). This flexibility of the module is a benefit since it can also be used for the yearly production optimization of hydro dams or the daily production strategy updates of power plants. The developed strategy optimization tool performs a multi-time step strategy optimization for a given price forecast. The hourly day-ahead market prices of the past week are used as price forecast for the upcoming week. An analysis of the day-ahead market prices for Germany for the year 2016 revealed that hourly prices can be predicted with a mean absolute error of 6.7 €/MWh when the prices of the previous week are used as price forecast. The average price level in the analysis period was 29 €/MWh. This corresponds to a relative hourly prediction error of 23%. The relative hourly prediction error can be compared to the COMPLATT price forecast challenge, where academics and professionals forecasted electricity prices for a given five day period for the Spanish day-ahead market. The winning team reached a relative hourly day-ahead market price prediction error of around 16% for a five day forecast period. [29] The results of the COMPLATT challenge clearly point out the difficulty of accurately predicting day-ahead market prices and justify the neglection of developing a price forecast tool within the time span of this thesis which would have been beyond the scope of this project.

The optimization module considers the following costs for the determination of the economic strategy:

- production volume costs (costs for constantly producing a certain amount of power)
- ramping costs (costs created by changing the output of a power plant from one time-step to the next)
- start-up costs (costs created when a power plant must be re-started after a complete shutdown)
- pumping costs (costs for pump-storage power plants which must procure electricity for the pumping activities and running the pumps)

Additionally, the power plant faces production restrictions out of the weekly ancillary service auctions. Therefore, the maximum and minimum production values of power plants can be changed and are considered in the model. Hydro power plants must take into account the reservoir levels in their production decisions. The hydro power plant model will be explained in more details in the following section 3.4.

The optimization module minimizes the following objective function which calculates the negative profit of the power plant in the determined time period (e.g. 168 hours):

$$\sum_{t=1}^{168} min(-(ElPrice[t] \times G[t] - \text{rampCosts[t]} - \text{prodCosts[t]} - \text{pumpCosts[t]} - \text{startCosts[t]})) \quad (3.1)$$

The used abbreviations in the formulas of this section are summarized in the following list:

- $G[t]$ stands for the generation output of the power plant in the time step t.
- $P[t]$ stands for the pumping output of pump-storage power plants in time step t
- $ElPrice[t]$ means the expected electricity price for the time period based on the prices of the previous week
- $rampCosts[t]$ = ramping costs
- $prodCosts[t]$ = production volume costs
- $pumpCosts[t]$ = pumping costs
- $startCosts[t]$ = start-up costs

The individual costs are calculated as follows:

Ramping Costs

The ramping costs are based on formula 3.2. The ramp cost base factor is generator specific, and the values were taken over from the existing EnerPol code which is based on an Intertek APTECH study about power plant cycling costs. [30]

$$\text{rampCosts[t]} = |\text{G[t]} - \text{G[t-1]}| \times \text{rampCostFactor} \quad (3.2)$$

Production Costs

The production costs are linearly interpolated from the given production output and cost pairs from the EnerPol code. These costs are based on the power plant fuel costs which are divided by the power plant efficiencies.

Pumping Costs

Pumping costs for pump-storage power plants consider the costs for the electricity procurement for the pumping activities as well as the costs for pumping. As a simplification, it was assumed, that the costs for pumping water are equal to the costs of turbining water. The expression for calculating pumping costs is presented in formula 3.3.

$$\text{pumpCosts[t]}=\text{P[t]}\times\text{ElPrice[t]}+\text{prodCosts(G[t]} = \text{P[t])} \tag{3.3}$$

Start-up Costs

The start-up costs are calculated based on different cost categories: Capital and maintenance costs (CM), start-up fuel costs and other start-up costs. The values for the different cost categories were copied from the existing EnerPol code which is again based on the APTECH power plant cycling study. [30] The start-up cost calculation is presented in formula 3.4.

$$\text{startCosts[t]}=\text{plantCapacity}\times(\text{CMcosts}+\text{otherCosts}+\text{fuelPrice}\times\text{fuelCostFactor}) \tag{3.4}$$

Start-up and shut-down events indicate discrete events which can be represented by logical conditions. Typically, optimization solvers only accept variables, parameters and constraints as inputs but no dynamic evaluation of logical conditions inside of constraints. To represent discrete events in optimization programming languages Wiley suggests to use discrete Boolean variables. [31] The modeling of the linearization of binary conditions used in this project is presented in appendix A.1.1.

Out of the mixture of Boolean variables and continuous variables such as the power plant generation or pumping output a mathematical problem of the mixed-integer class results. Even more precisely, the problem can be categorized as a mixed-binary problem. The nature of mixed-integer problems and the resulting non-convex cost structures make the mathematical problem computationally very expensive. The Pyomo model is solved on the ETH cluster Euler with the pre-installed commercial optimization software Gurobi, which was found to be the best solver for non-convex mixed-integer problems. Due to the simulation effort required for the solution of mixed-integer problems two different Pyomo models were developed in this project: A detailed version including all the constraints and a relaxed version, which is a trade-off between an accurate problem modeling and computational speed. The two versions of the Pyomo model are called "FULL" and "FAST". The differences between the two models are presented below:

FULL Model:

- The production costs are interpolated in the categories 0-20%, 20-40%, 40-60%, 60-80% and 80-100% power plant output. Every category requires additional Boolean variables.
- Off-hours are tracked and counted throughout the optimization period.
- Based on the counted off-hours eventual start-ups of power plants are categorized into hot, warm and cold starts with different associated costs.

FAST Model

- The production costs are interpolated linearly in between 0-100% of the power plant output.
- Off-hours are not counted, there is only a state differentiation if the power plant is running or standing still.
- Following this, no differentiation between different start-up categories can be made. Therefore all start-ups are treated as warm starts with the associated costs.

The simplifications considering the treatment of all start-ups as warm-starts are expected to effect optimization results only minimal. There are very few situations were a hot start of thermal power plants is economically efficient. In addition, only thermal power plants with high marginal costs will, under normal price patterns, be in shut-down mode for several days in a row which requires a cold start. The power plant start-up costs of a single start-up can be reimbursed during the complete week of production such that the cost difference of a warm and cold start is expected to have only marginal effect on the optimum production strategy. The linear interpolation of the production costs between 0 and 100% in the FAST version can have stronger effects on the optimization results. Production costs of power plants can be strongly non-linear. Therefore, different production levels for low-price periods are expected when the FAST and the FULL model are compared against each other. The result and computational speed comparison of the two Pyomo model versions will be presented in the validation subsection 3.3.2.

As last topic of the optimization module the simplifications of the model are discussed. There is no probability distribution included in the price forecast used for the model. This means that forecasted prices at the end of the week are expected to have the same probability of occurrence as the prices of hour one of the week. This weakness of the module is corrected by introducing daily production strategy updates which consider price deviations from the forecast and correct the forecast prices of the remaining week.

3.3.2 Power Plant Optimization Model Feasibility Check

In the next paragraphs, the results of the FULL and FAST optimization routines are compared for different power plant types. The resulting profiles are checked for their feasibility in terms of financial optimum strategy and physical plausibility (e.g. no unnecessary rampings).

To evaluate if the FULL or FAST optimization routine should be used, a comparison of the resulting weekly production strategies for power plants was carried out. For this purpose, the resulting power plant optimum production strategies were evaluated for weeks in different seasons of the year 2013. The evaluation included a power plant for all relevant power plant categories (hydro dam, pumped-storage, coal, lignite, nuclear and natural gas). The most important characteristics of the simulation are summarized in table 3.1. The average weekly optimum profit difference of the FAST version compared to the FULL version was determined to be 4%. The uncertainties introduced by using the last week day-ahead prices as forecast for the upcoming week are higher. A day-ahead market price analysis for Germany for the year 2016 showed that an average hourly forecast error of 6.7 €/MWh is introduced when the prices of the previous week are compared to the resulting prices of the upcoming week. The average price level for the year 2016 in Germany on the day-ahead market was 29 €/MWh. This corresponds to a relative price error of around 23%. In comparison to this value, the introduced deviation of 4% of optimum weekly profits by the usage of the FAST version is negligible. Even if a top-of-the art price forecast tool would have been designed, the introduced price forecast error can be assumed to be higher than 4% as the already mentioned COMPLATT challenge result showed. Additionally, the fact that the power plant costs are predicted to be 6% lower and the resulting profits 4% higher in the FAST model version is another indicator that the resulting production strategies of the two models FULL and FAST are very similar.

Table 3.1: Performance comparison for developed optimization models

	FULL Model	**FAST Model**
Relative Speed	1x	20x
Relative Total Profits	1	1.04
Relative Total Costs	1	0.94

The FAST version enables a speed-up factor of 20 compared to the FULL version. The difference in speed results from the additional number of mixed-integer variables of the FULL version which make the determination of the global minimum for the solver more difficult. However, a speed-up factor of 20 is interesting since simulation time was one of the main challenges during this market model development project. Due to the linearization of the production cost structure for the FAST version the production level during low-price hours for thermal power plants could be different. Figure 3.3 shows the difference in the cost structure for the two optimization variants for a nuclear power plant. The differences for other power plants are smaller, the nuclear case is shown here as an extreme example.

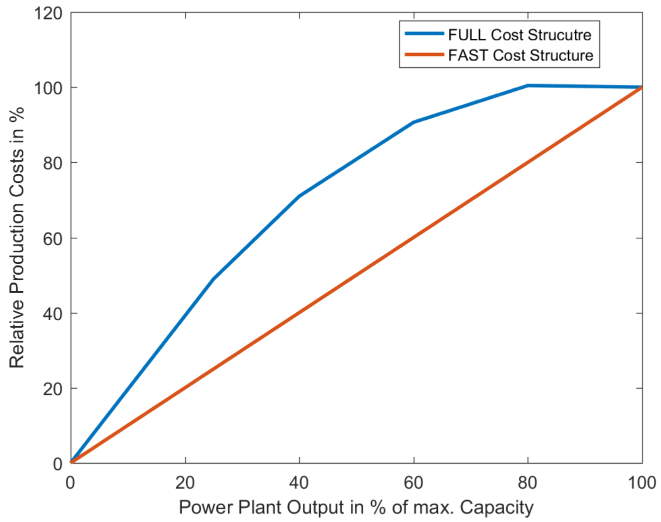

Figure 3.3: Difference of implemented production cost structures for a nuclear power plant for the two optimization routine versions FULL and FAST

In the following paragraphs, production profiles for the FULL and FAST optimization routine version are compared for a nuclear, coal, lignite, hydro dam and pump-storage power plant. No results are presented for natural gas power plants. Due to the natural gas combined cycle production volume costs of around 80€/MW and for simple cycle arrangements above 100€/MW, the optimum financial strategy for the analyzed weeks was to stay in a shut-down mode.

Nuclear Power Plant

Nuclear power plants are power plants with low marginal costs. In figure 3.4 it can be seen that both optimization routines prescribe for most of the hours of the week a full-load production to maximize the profit. In hour 75, the FAST version reduces output for several hours whereas the FULL version stays at 100% load. This difference comes from the linearization of the production costs which was already presented in figure 3.3. For production volumes around 50% load the FAST version underestimates the production costs. As a result, a reduction of the output becomes economically reasonable for the FAST version. The underestimation of the production is also the reason for the difference in the production profiles at the beginning of the week. With the shown results the FAST model is able to reproduce the most important production characteristics of a nuclear power plant: The nuclear power plant mainly produces baseload electricity and ramps down production in low price periods. There are differences compared to the FULL model in the number of production reduction periods. But since errors introduced by using the last week prices as forecast can be significant, using the FULL model and increasing computational effort by factor 20 is not guaranteed to improve overall simulation results. Therefore, using the FAST model for predicting nuclear power production can be justified.

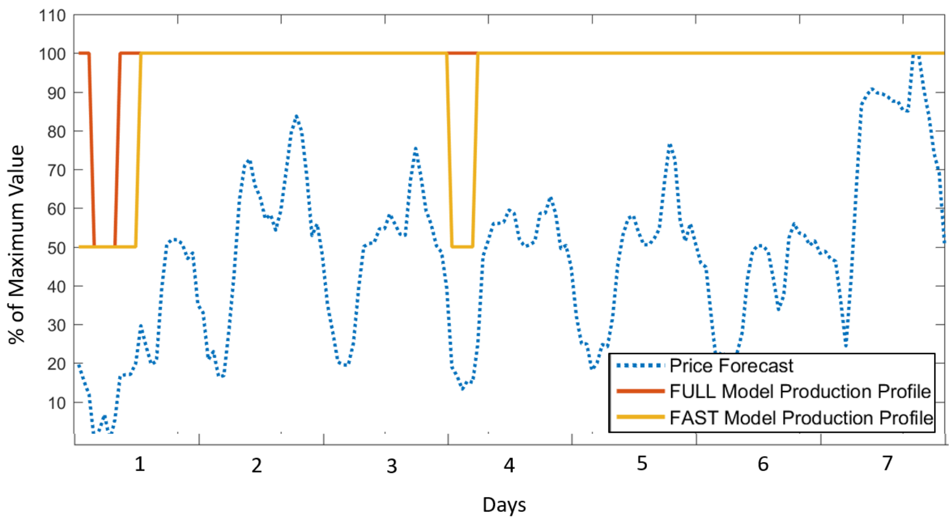

Figure 3.4: Comparison of resulting optimized production profiles for a nuclear power plant predicted by FULL and FAST optimization routines

Lignite and Coal Power Plant

The predicted optimum production profiles of the FULL and FAST optimization routines in figure 3.5 can be categorized as physically and economically reasonable strategies. Power plant output ramping is only performed to reduce production in longer low-price periods. If the low-price periods are only a few hours as in between day six and seven, the lignite power plant stays at full-load production level to optimize its financial result.

As figure 3.5 indicates, the optimum production profiles for the two routines FAST and FULL for lignite only differ for some hours with prices around the marginal costs of the lignite power plant. In these four hours, production in the FAST model remains around 40% rated capacity whereas in the FULL case production is increased to around 60% rated capacity. These small differences stem from the simplified production costs in the FAST optimization routine. The results for coal are very similar to the ones presented here for lignite. Therefore, no additional plot is shown for the coal case.

With the resulting physically and economically meaningful production profiles and only small differences in hours with prices around marginal costs, both routines FAST and FULL can be used as tool to determine optimum weekly strategies and price bids on different markets.

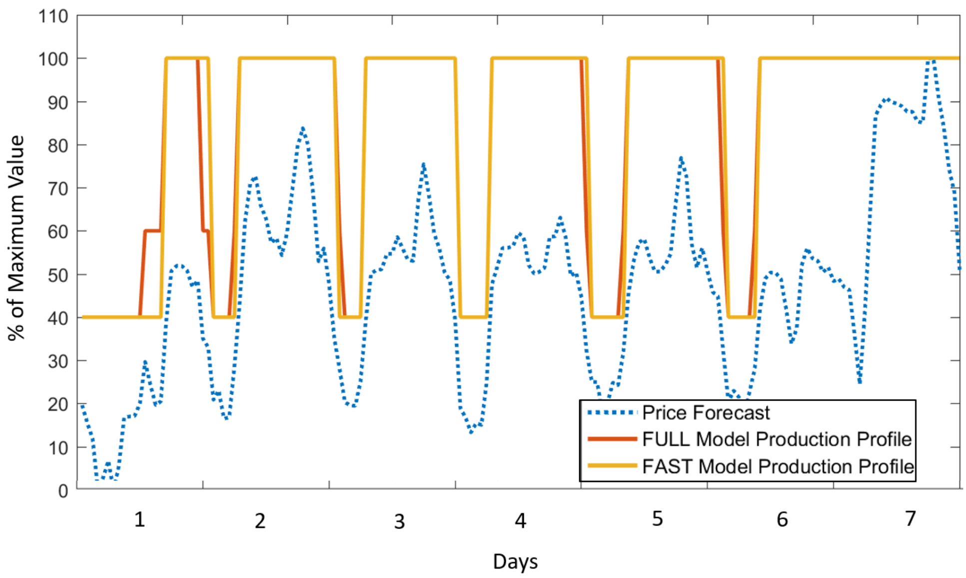

Figure 3.5: Comparison of resulting optimized production profiles for a lignite power plant predicted by FULL and FAST optimization routines

Hydro Dam and Pump-Storage Power Plant

Figures 3.6 and 3.7 indicate for both models FULL and FAST economic logical production profiles. Hydro dams concentrate production in expected high-price hours and pump-storage power plants produce in high-price hours and pump water in low-price hours. A more detailed discussion about optimum strategies of hydro power plants can be found in section 3.4.2.

As already seen in the production profile comparisons of nuclear and lignite power plants, only small differences in the production pattern can be observed for hydro power plants. Both models result in financially logical production profiles and therefore both models can be used in the developed market models.

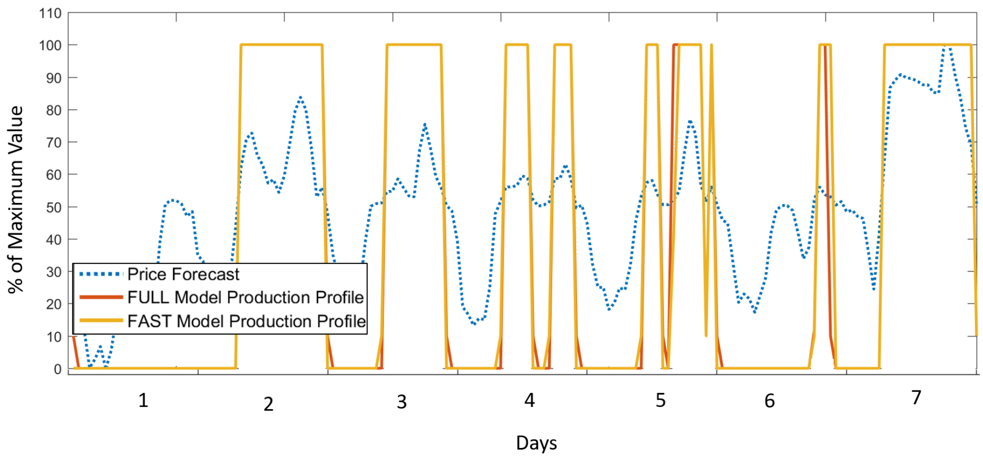

Figure 3.6: Comparison of resulting optimized production profiles for a hydro dam power plant predicted by FULL and FAST optimization routines

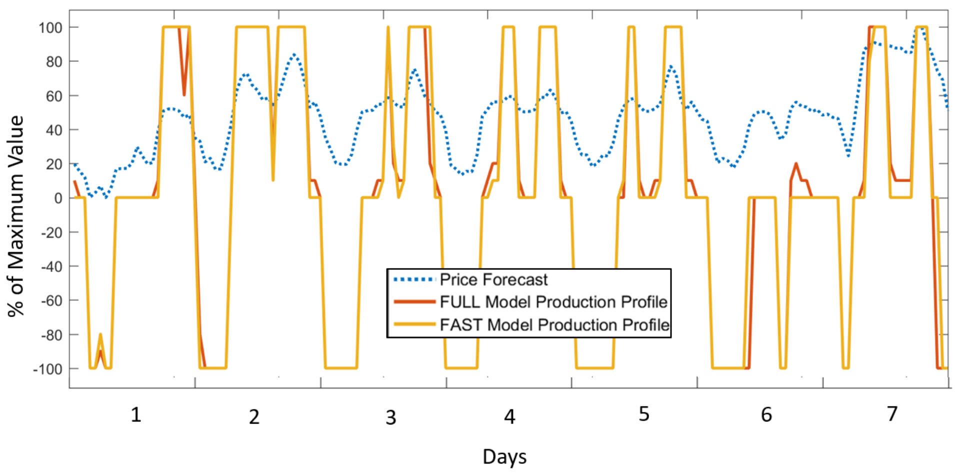

Figure 3.7: Comparison of resulting optimized production profiles for a pump-storage power plant predicted by FULL and FAST optimization routines

Comparison to real Power Plant Production Data

After comparing the two developed optimization routines, the production profiles predicted by the FAST optimization code is compared against real production data of German power plants. For this analysis, the first three weeks of 2016 were chosen since the price profiles of these weeks show a weekly increase in average day-ahead price level which should be reflected in different power plant production behavior. The year 2016 started with a Friday, therefore days 2 and 3 shown in the plots correspond to weekend days Saturday and Sunday. When optimization results are compared against real production data, different aspects have to be regarded: First of all, ancillary service auction results are anonymous. This means that it is not clear whether a particular power plant was providing ancillary services when measured production data is regarded. Therefore, real production data is compared against the results of a pure day-ahead market optimization without any ancillary service market constraints. Additionally, balance groups optimize their strategy for the complete power plant portfolio in reality, whereas the optimization routine seeks the optimum strategy for an individual power plant. These differences can be sources for different power plant strategies seen in reality.

a) Lignite Power Plant

When real production data of the German lignite power plant Niederaussem are compared to optimization results, it can be seen that optimization routine predicts a shut-down in week 1 during days 2 and 3 whereas in reality only a reduction of production volume can be seen. Possible reasons for this deviation are too high implemented production costs for lignite power plants or wrong start-up costs or eventually the power plant is providing ancillary services during this week and is therefore forced to maintain production even in low-price periods. Generally, it can be stated, that the simulation correctly predicts the full-load production phases. In week two, most production reduction periods are correctly predicted. However, in week 2 the optimization predicts a ramping down to 40% of rated capacity whereas in reality the power plant does not reduce production below 60% or rated capacity. In week 3, the optimization predicts a reduction in production between day 2 and 3. Probably, this can also be explained by different marginal costs or ramping costs in reality. The rest of the week is correctly predicted to be a constant full-load production period. Overall, the comparison shows that the optimization routine is able to predict physically and financially reasonable production profiles compared to real production data.

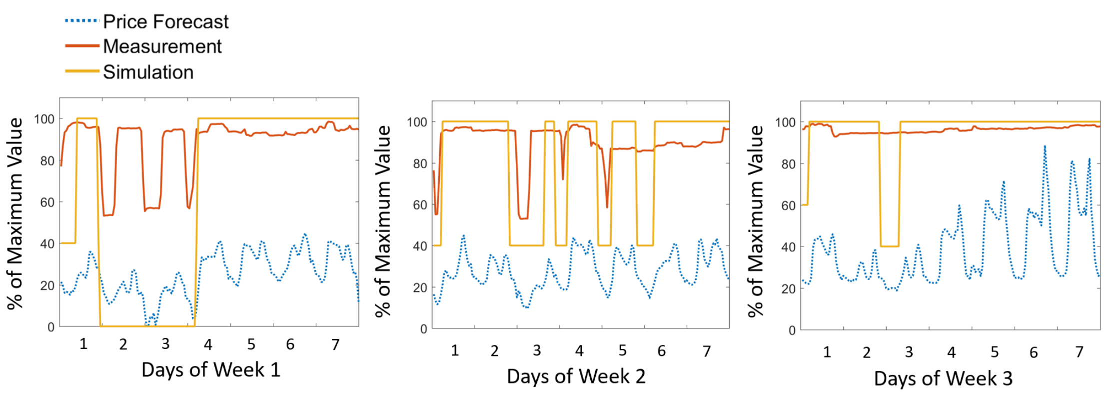

Figure 3.8: Comparison of resulting optimized production profiles predicted by FAST version for a lignite power plant Niederaussem block C with real production data provided by ENTSO-E for the frist three weeks of 2016

b) Pump-Storage Power Plant

The optimization routine correctly predicts for the German pump-storage power plant Goldisthal an increase in total production from week 1 to week 3 as comparison with real production data indicates. Interestingly, the optimization routine choses in the second week day 4 for maximum production whereas in reality day 5 was chosen. This probably comes from the fact that both days have very similar price patterns, and the power plant expected day 5 to be the day with higher peak prices. In reality, day 4 showed higher day-ahead market prices. Thus, the optimization routine which used real day-ahead market prices as forecast in this analysis, choses day 4 for maximum production. Interestingly, the optimization underestimates production during weekends (days 2 and 3 of the weeks). As it can be seen, price spreads between peak and off-peak hours are smaller compared to the week-days. This means that the optimization routine slightly overestimates the required price spread for financially profitable production of pump-storage power plants. Additionally, the optimization correctly predicts strong rampings of pump-storage power plants and no production during low-price night hours. It can be stated, that the optimization is able to reproduce well pump-storage production behavior.

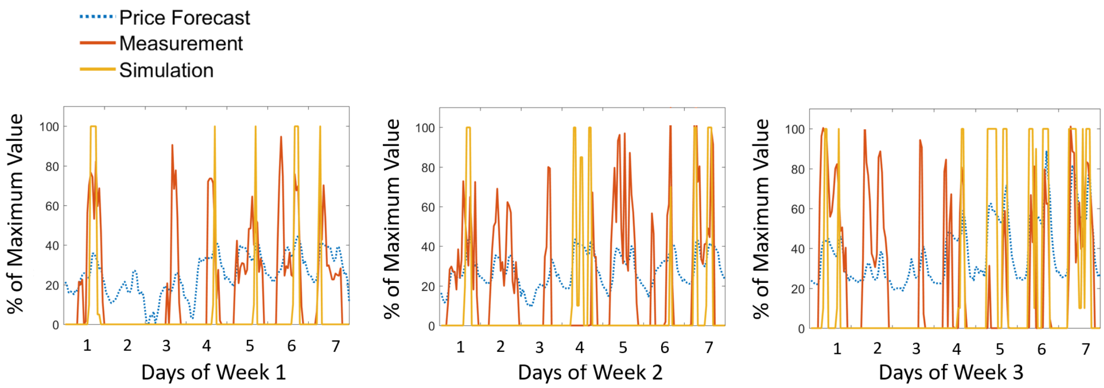

Figure 3.9: Comparison of resulting optimized production profiles predicted by FAST version for pump-storage power plant Goldisthal block A with real production data provided by ENTSO-E for first three weeks of 2016

c) Nuclear Power Plant

When production data of the German nuclear power plant Isar 2 is compared to optimization predicted production, it can be stated that ramping is overestimated by the optimization routine. Data analysis shows the nuclear power plant Isar 2 is rarely ramping below 70% of rated capacity as it can be seen in figure 3.11. Therefore, the implemented ramping capabilities based on French nuclear power plants load following studies [32] are presumably beyond the technical capabilities of German nuclear power plants. To improve performance of the optimization routine, detailed information about the different nuclear power plant technologies could be implemented into the existing EnerPol framework. Nevertheless, the simulation correctly predicts the reduction in ramping when comparing week 1 with week 3, as well as the baseload production during week 3 as well as the pre-dominant baseload production throughout all weeks.

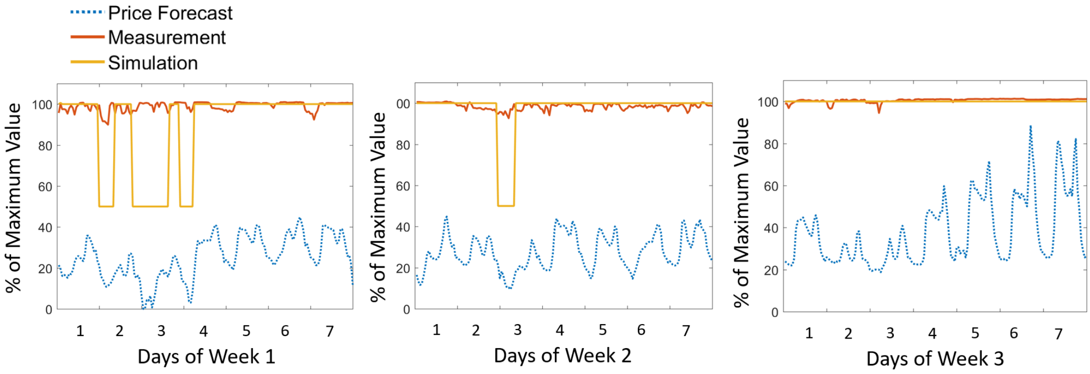

Figure 3.10: Comparison of resulting optimized production profiles predicted by FAST version for nuclear power plant Isar 2 with real production data provided by ENTSO-E for first three weeks of 2016

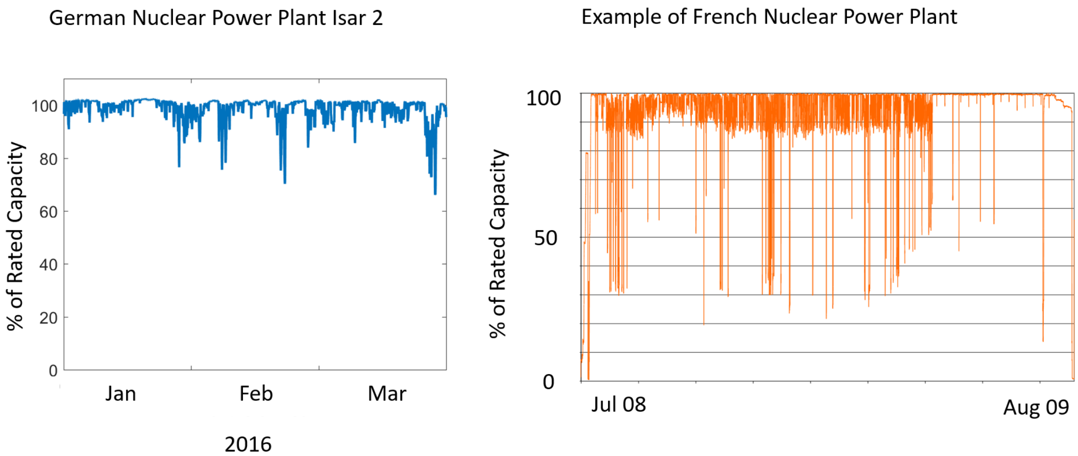

Figure 3.11: Real production pattern of German nuclear power plant Isar 2 compared to a typical French nuclear power plant load following cycle [32]

To sum up, the optimization routine is able to reproduce the correct power plant production trends for different price level weeks and can therefore be used to price power plant offers on different electricity market segments. However, the correct prediction of ramping and start-up remains challenging. The model can be improved if more technical details about the different power plants would be implemented into the EnerPol data base.

Optimization Routine Choice

One of the main challenges of this project was the simulation time which had to be kept as low as possible for being able to run yearly simulations within the time frame of the project and making the developed models useful for future application in the EnerPol framework of the LEC. Therefore, the speed-up factor generated by the FAST version is a huge advantage compared to the FULL version. As it was shown in this section, the predicted financial profits only differ by 4% and the physical production profiles which result out of the FAST optimization routine are very similar to the FULL version results. Therefore, the FAST version was chosen for the implementation and usage in the developed market models.

3.4 Hydro Power Plant Modeling

3.4.1 Hydro Power Plant Model Description

Hydro power plants must be treated differently compared to conventional thermal power plant due to:

- their storage capacities and energy shift potential in a temporal perspective
- their limited production resource water due to inflow and storage constraints
- their fast ramp-up times

In the EnerPol code three different types of hydro power plants are modeled: Hydro dams, pump-storage plants and run-of-river power plants. The subsequent three paragraphs explain the developed model for the specified hydro power plant types in some details.

Hydro Dams

Hydro dams have large water reservoirs which act as a seasonal storage facility. Typically, water from the spring and summer (high inflow periods) is stored for electricity production in the winter season where wholesale electricity prices are expected to be higher due to the increased demand. Thus, hydro dams optimize their production strategy on a yearly basis. Production will not be equally split among the months of a year. Water has a value which changes with reservoir level and demand. This value is often referred to as water value.

In the developed model, hydro dam power plants optimize their strategy based on a yearly price forecast and monthly varying inflows according to the EnerPol internal hydro regimes runoff values. This is different to the conventional power plant optimization which takes place on a weekly basis. Fossil fuels are assumed to be subject to price changes but permanently available in contrast to the resource water. For hydro dams the reservoir level at the end of the year is constrained to be equal to the starting reservoir filling level. As data from the Federal Office for Energy in Switzerland (BFE) shows, reservoir levels at the beginning of the year tend to be around 60% of the maximum reservoir level (as indicated by figure 3.12). [33] This value was chosen as initial reservoir filling condition. As a result of this yearly optimization the hydro plant receives a weekly water budget which can be used in the different market segments. The concrete offer strategies on the particular market segments will be discussed when the market-segment models are introduced.

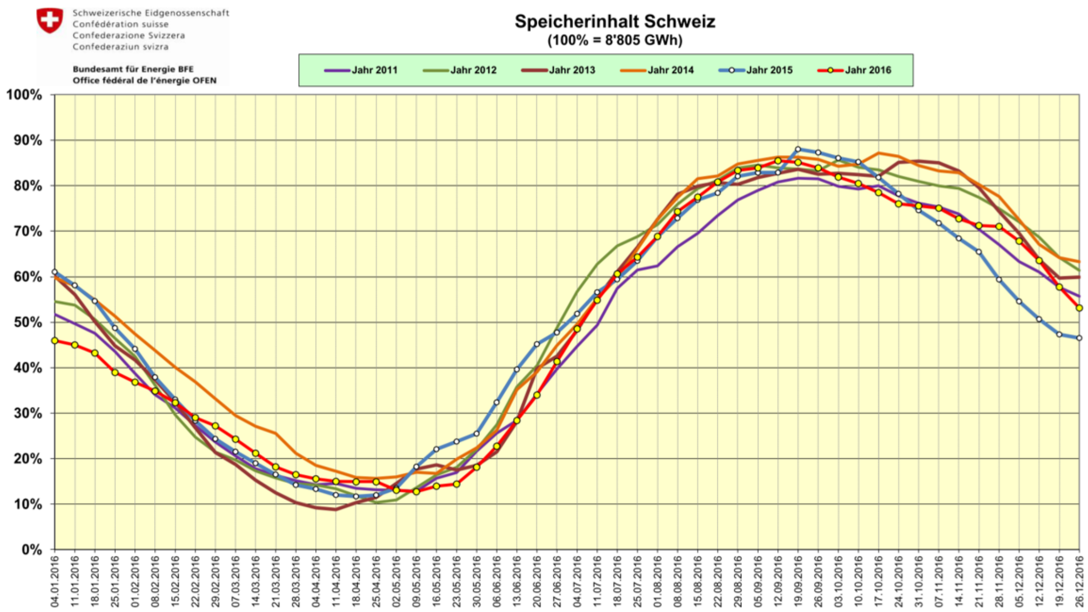

Figure 3.12: Weekly reservoir level development in Switzerland for the years 2011-2016 [33]

EnerPol does not include in its data base information about reservoir size, decline or expected annual production of hydro power plants. Therefore, the reservoir capacity, the total yearly inflows and the decline were correlated to the only power plant information available in the data base, which is power plant production capacity. The correlations are based on BFE data which was complemented with online research data of the power plant companies. [34] Information about the determined correlations and the summarized hydro power plant data for this analysis can be found in Appendix A.1.2.

Pump Storage Power Plants

Pump-storage facilities usually have small water reservoirs which can only be used for some hours of full-load production. Afterwards, the reservoir must be refilled again by switching to pumping mode. Typically, the reservoirs are empty after 8 (e.g. pump-storage power plant Goldisthal (DE)) to 35 hours (e.g. Nant-de-Drance (CH)) of full production. For the developed model a reservoir size for the pump-storage power plant was assumed, which allows for 24 hours of full-load production until the reservoir is empty.

Since pump-storage power plants profit from price differences between peak and off-peak hours, reservoirs can be assumed to be typically completely filled at 6 a.m. at Monday morning, before the first high-price hours of the week start. Therefore, a weekly refilling cycle with a repeatability rule is implemented in the pump-storage modeling. Plants possess the optimization target of 80% reservoir filling level at start of the optimization period at Sunday 12 p.m., which corresponds to the reservoirs being completely filled by Monday 6 a.m.

The hourly inflows for pump-storage power plants are set to zero, meaning that all water that is turbined has to be pumped in advance. Pumping activities of pump-storage power plants are modeled as dispatchable loads. A simple approach to dispatchable or price-sensitive loads is to model them as negative real power injections with associated negative costs. This is done by specifying a generator with a negative output, ranging from a minimum injection equal to the negative of the largest possible load to a maximum injection of zero. It should be noted that, with this definition of dispatchable loads as negative generators, if the negative costs correspond to a benefit for consumption, minimizing the cost of generation is equivalent to maximizing social welfare. [35]

Run-of-River Power Plants

The run-of-river modeling was transferred from the existing EnerPol code version. In this code, the maximum production capacity of a run-of-river power plant is correlated with the relative monthly hydro regime runoff values. Run-of-river power plants do not have storage possibilities but can bypass water in case of electricity prices below production costs.

3.4.2 Hydro Power Plant Model Feasibility Check

Hydro Dam Model Feasibility Check

In this subsection a hydro dam model feasibility check is performed. The presented figures belong to the hydro dam power plants Bitsch (Biel) and Bieudron in Switzerland. Switzerland was chosen for the validation of this particular segment due to availability of validation data from the hydro power plant companies and the Swiss Federal Office of Energy (BFE).

Figures 3.13 and 3.14 indicate that the yearly hydro dam optimization is able to reproduce the most important characteristics of dams yearly production pattern. The reservoir level development over the analyzed year 2015 is similar to the expected curve for hydro dam reservoir filling levels from BFE presented in figure 3.12. For example, the optimization routine predicted Bitsch hydro dam (Biel) weekly percental filling level shows a mean absolute error of 7.7% of the reservoir volume when compared to weekly average filling levels of hydro dam power plants in Switzerland for the year 2014. The standard deviation is 4.5% of the reservoir volume. This means that in 95% of all considered weeks, the reservoir level is predicted with a deviation smaller than 9% of the reservoir volume when compared to the weekly average reservoir filling levels of Swiss hydro dams. Simulation predicted reservoir levels are compared against 2014 data due to the fact that for the years 2015 and 2016 untypical reservoir level developments over the year could be seen due to nuclear outages in Switzerland.

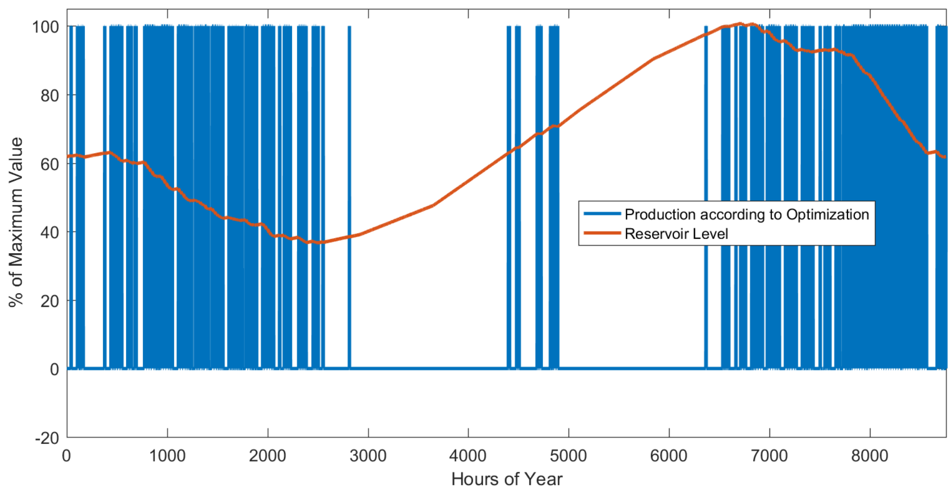

Figure 3.13: Resulting reservoir level and hourly production out of yearly optimization run for hydro dam Bieudron (CH)

As the figures 3.13 and 3.14 indicate, the reservoir level is decreased in periods of high production in autumn and winter periods. After the high-inflow summer periods the reservoir level is nearly completely filled. The maximum reservoir filling level is reached after around 6’000 hours of the year. This fits well to the expected maximum reservoir filling levels at the end of August up to mid of September according to BFE data.

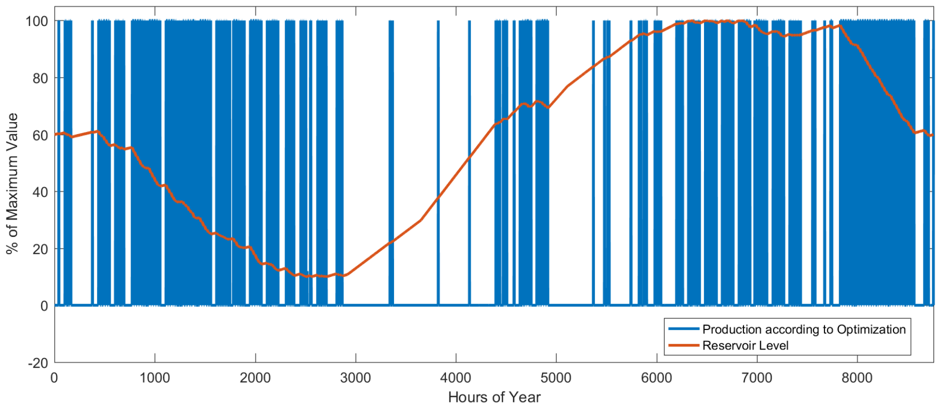

Figure 3.14: Resulting reservoir level and hourly production out of yearly optimization run for hydro dam Bitsch (CH)

Table 3.2: Hydro dam yearly production validation for the year 2015 for the power plants Bitsch und Bieudron

	Optimization	**Real Hydro Plant Data [36]**
<u>Bitsch</u>		
Yearly Production (GWh)	576 GWh	564 GWh
Summer-Winter Production Splitting	22% / 78%	97% / 3%
<u>Bieudron</u>		
Yearly Production (GWh)	1'850 GWh	1'780 GWh
Summer-Winter Production Splitting	13% / 87%	29% / 71%

The yearly production amount was correlated to the installed power plant capacity since it was the only information available in the EnerPol data base. As table 3.2 shows, the resulting overall yearly production of the power plants is close to the expected yearly production according to BFE data. But when the production splitting in summer and winter period is analyzed, it can be seen that the model is not able to correctly predict the splitting for the power plant Bitsch. One explanation for this wrong splitting could be, that the monthly inflow scaling values coming from the EnerPol hydro regimes do not reflect the inflow situation for this power plant correctly. But the main reason for this wrong production splitting is the small reservoir size of around 9 million cubic meters for the power plant Bitsch. The combination of the smallest reservoir volume of the considered hydro dams in combination with a large installed capacity of 340MW is not correctly reflected by the correlation. The correlation would expect a reservoir size of around 150 million cubic meters for these power plant data. In reality, the small reservoir is filled quickly during the rainy summer periods and therefore a lot of water is turbined during summer periods. It must be stressed that Bitsch is the worst-case example which is shown here. It is presented to underline the importance of improving the hydro power plant data base in the future or launching a project for finding more sophisticated correlations for hydro dam reservoir volumes and annual inflows.

To sum up, the model is able to reproduce a typical production pattern of hydro dam power plants, but it is not able to reproduce the correct summer winter production splitting for extreme cases such as the power plant Bitsch with a small reservoir volume. The resulting consequences on hydro dominated countries such as Austria or Switzerland are discussed in one of the following paragraphs.

An important remark must be made here: The optimization results for hydro dam power plants are based on a yearly optimization, and are not equal to the dispatched amounts which results from the optimum power flow simulations. The yearly optimization of hydro dams at the beginning of the year only determines the weekly water budget of a hydro dam which can be used on the different market segments. The final resulting production profile of the dam can be significantly different when the plant is chosen to provide ancillary services in particular weeks. Therefore, the differences between optimization results and real hydro power plant data have to be regarded in this context.

Required Adaption of Hydro Power Plant Model for Multi-Country Setup

First test simulations where the framework Switzerland and its neighboring countries were simulated including the new market models in EnerPol showed that the hydro model is not able to lead to meaningful results for a multi-country framework with hydro power dominated countries such as Switzerland and Austria. The power plants optimize their strategies according to the electricity market prices of the previous week. These prices do not reflect holidays, renewable forecasts of the upcoming week or heavy demand changes due to temperature variations. In addition, due to the missing reservoir volume data, pump-storage power plants were assumed to have all a basin size which allows for 24 hours of full-load production. This leads to a very similar optimum strategy of all pump-storage power plants for the upcoming week. The concentration of the production and pumping hours of the pump-storage power plants leads to unrealistic price patterns and a shortage of offers in expected low price hours. Therefore, for the multi-country setup the pump-storage production and pumping amounts were correlated to the hourly demand in a weekly time framework, a similar approach which was implemented previously in EnerPol.

The same problematic of offer concentration in expected high price hours was encountered for the hydro dams. A further challenge comes from the fact that in the yearly optimization of hydro dams, which determines the weekly water budget, hydro dam production is reduced to a minimum for expected low price weeks. Nevertheless, in reality the demand during these periods is not this low that no hydro dam production is required. Therefore, the hourly offer amount was determined by using a fit function which relates the hourly hydro dam production to the electricity demand of the particular hour. This approach corresponds to the approach which was used before this project in EnerPol.

The challenges of the hydro model can be identified in the modeling approach as well as in the missing hydro power plant data base. On the one hand, the yearly optimization routine of hydro dams is too deterministic and mathematical, meaning that the yearly day-ahead market prices which are used as price forecast are used as if they were certain. This leads to a underestimation of the hydro production in low price periods. On the other hand, the hydro power plant model reveals the importance of implementing a detailed hydro power plant data base. As it was shown in the hydro dam feasibility check section 3.7.2, in reality the hydro power plants face very different hydro reservoir and cascade production constraints which cannot be reflected by the simple correlations which were used in this project. These constraints force some hydro dams to produce even in low price hours or during the summer months. Out of this, there are for every hour hydro power plants which offer production. In a future work, it could be analyzed if the hydro model is able to reproduce day-ahead market prices in hydro dominated countries if the correct hydro data base information are implemented (cascades, reservoir size, drainage area) or if a further adaption of the yearly optimization routine is necessary.

Pump-Storage Model Feasiblity Check

Figure 3.15 shows the resulting optimized day-ahead market production profile of the German pump-storage power plant Waldeck 2 with an installed capacity of 480 MW for week 1 of the year 2013. As price forecast the real day-ahead market prices of this particular week were used. The result shows the expected behavior of the pump-storage power plant: The production is concentrated in the high price hours of the week, and water is pumped when prices are cheapest. This is the strategy which pump-storage power plants also operate in reality. Additionally, there are hours where no water is pumped or turbined. This could also be expected since a price spread between production and pumping hours has to be present to be profitable. The resulting production profile shows that the optimization routine is able to reproduce the typical behavior of pump-storage power plants. After this validation, the optimization routine can be used as pricing tool for the bids of pump-storage power plants on the market.

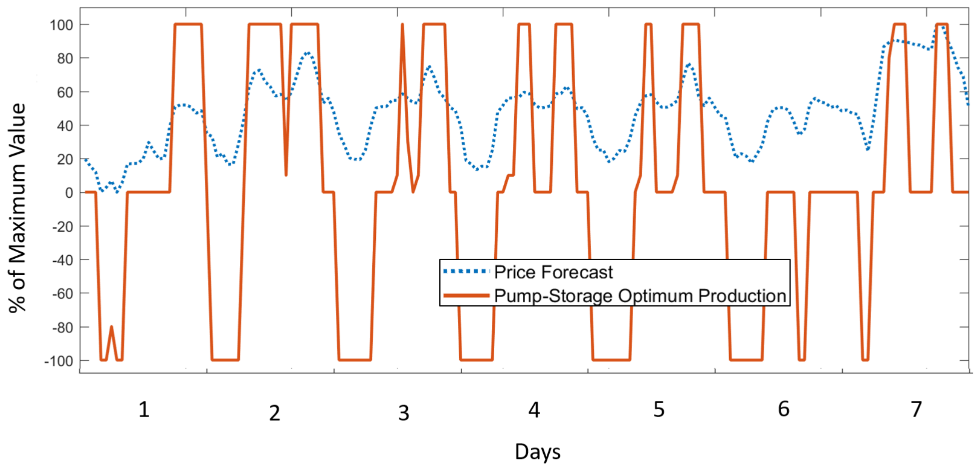

Figure 3.15: Optimized production strategy for pump-storage power plant Waldeck II for the first week in 2013 according to the day-ahead price forecast

Run-of-River Model Feasiblity Check

Since the run-of-river model was taken over from the current EnerPol validation no feasibility check was performed.

3.5 Weekly Simulation Concept

Before the details of the individual simulation modules are presented, the general simulation process of the developed market model for an individual country is explained. The described process can also be found in graphical form in figure 3.16. At the beginning of the week each power plant determines its own optimum production strategy for the upcoming week on the day-ahead market based on the market prices of the previous week, which was explained in section 3.3. This financial result is then used as financial reference value for determining the offer prices for the different ancillary service categories, which are modeled on a weekly basis. For each simulated ancillary service category (PRL, SRL, TRL+/-) another optimization run is performed with production restrictions according to the ancillary service category. The resulting profit difference between pure day-ahead market and ancillary service optimization run determines the offer price for the ancillary services. In a next step, the ancillary service auctions are performed by a central control instance represented by the OPF solver in the model. The OPF solver choses the cheapest power plant offers. In reality, the OPF solver corresponds to the electricity market power exchange platforms operated for example by EPEXSPOT for the TSOs of the corresponding countries. The dispatched power plants in the ancillary service auctions have to update their weekly strategy again due to the resulting min. / max. production constraints.

After the determination of the power plants providing ancillary services, the daily simulation sequence starts, consisting of day-ahead market and intra-day market. The power plants place their bids for the next 24 hours on the day-ahead market, and optimum power flow simulations on hourly basis are performed which determine the most economical combination of power plants to dispatch. In this sense, the OPF algorithm corresponds to the TSO deciding over the operation of each individual power plant based on their bids. The last accepted bid determines the day-ahead market price (pay-as-cleared price mechanism). The OPF performs a physical load flow simulation for each hour of the day-ahead market, and includes transmission constraints given by the current European electrical grid.

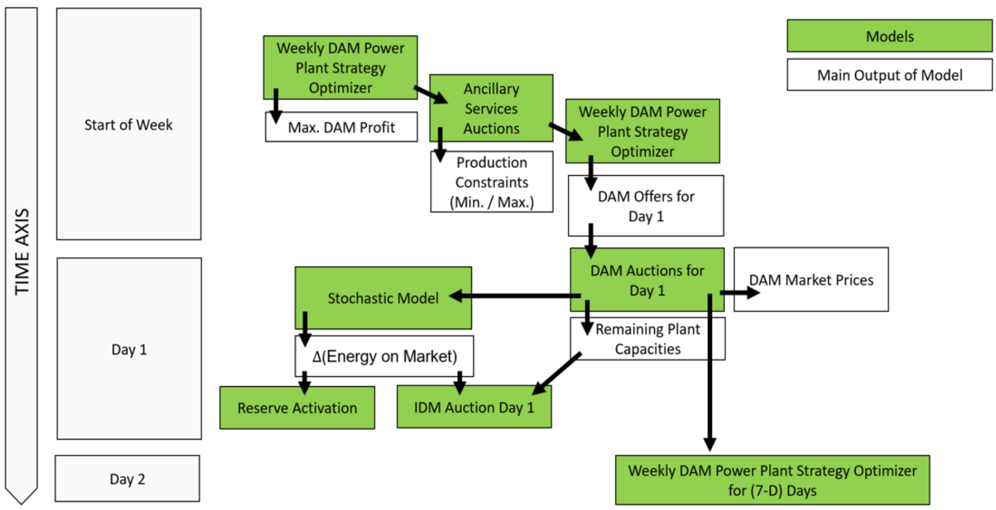

Figure 3.16: Simplified weekly market model simulation concept

In a consecutive step, a stochastic model is called which generates a deviation from the planned day-ahead market production profile due to outages and forecast errors. The resulting energy delta is partly balanced by reserve activation and partly traded on the intra-day market. On the intra-day market, power plants with free production capacities can again place their bids. The auction is again closed with a pay-as-cleared mechanism which is performed by the optimum power flow solver.

The complete simulation process described in this section is very close to the sequence of events in reality. Power plants typically optimize their strategy on a weekly basis to evaluate also the financial options available in the ancillary service markets as well as the typical weekly water budgets of hydro power plants which typically show a peak / off-peak production differentiation pattern. However, in reality there are also daily ancillary service auctions which create more options for strategy updates during the week than modeled in the created market models.

3.6 Ancillary Service Market Model

3.6.1 Ancillary Service Model Description

This subsection starts with a short introduction and justification of the weekly ancillary service auction principle. Afterwards, the different ancillary service auctions are explained in some detail.

Weekly Ancillary Service Auctions Principle

As the wholesale electricity market analysis showed, all the investigated countries show weekly primary reserve auctions and a mixture between weekly and daily auctions for the secondary and tertiary reserves. For this project the primary, secondary and tertiary reserve auctions are modeled as weekly auctions. The neglection of the daily SRL and TRL auctions was necessary to keep the simulation time in a useful time range. A first test showed that modeling the ancillary service auctions on a daily basis doubles the overall simulation time and increases the simulation time of the ancillary service module by a factor of 7.

For the weekly auctions, the following simulation steps are performed:

- For each weekly auction (PRL, SRL, TRL pos. and neg.) the maximum profit is determined which can be reached on the DAM while offering the particular ancillary service.
- This profit is compared to the profit which is expected on the DAM without offering ancillary services. Since offering ancillary services always entails a limitation on minimum or maximum power production, the resultant profit of the weekly optimization with ancillary services will always be lower than the weekly optimization without any ancillary service offers.
- The resulting loss of the weekly optimization with ancillary services is then divided by the offered energy amount in the ancillary service market in the current week to determine the offer price in Euros/MW/h. This corresponds to the remuneration the power plants will be asking to incentivize offering the ancillary service.
- The detailed offer amount determination is explained in the section of the particular ASM category (following subsections a) to c)). Main idea is to lock-in the profit on the ASM and therefore to reduce the open positions and the corresponding market price risk on the DAM.
- Power plants are allowed to participate on all weekly reserve actions simultaneously. They prioritize their offers in the categories which show the lowest ratio of reserve category offer price divided by the most expensive chosen unit in this particular category during the previous week. This corresponds to reality, where power plants have only limited capacities to offer and they have to decide on which ancillary service market auctions they want to offer the biggest share of their capacity.

- There is an offer control mechanism implemented: If the total offer amount in a particular ASM category is below the required TSO threshold value, the expected price for the following week is increased, and the control mechanism is performed again until this condition is satisfied. This step ensures that in every week enough ancillary service reserve capacities are available. This control mechanism is realistic. If in reality the ancillary service capacities offered to the TSOs are too low, there will be another call for bids. From this moment on, the power companies know that there is shortage of offered ancillary service capacities in this category and they will offer additional capacities in this market since higher prices can be expected.

- The auctions are performed in the sequence in which they appear in most central European countries (DE, CH, F, AT) (PRL on Tuesday, SRL on Wednesday, TRL on Thursday).

- Resulting from the reserve auctions, production constraints for the selected power plants (minimum and maximum production) exist. The remaining free production capacities have to be updated for the following daily day-ahead market auctions.

- The selection of the cheapest offers is performed by the OPF solver. In addition, a congestion check is performed by the OPF solver by assuming that grid is already critically loaded (80%). Motivation behind this step is, that the ancillary reserves should not all be procured from one geographical region that in case of strong positive reserve activation the already loaded grid is driven into situations of congestion. In this case, the reserves could not fulfill their function as grid stabilization elements.

a) Weekly PRL Auction

All power plants, with the exception of renewables (solar and wind) and pump-storage power plants, are allowed to participate in the weekly primary reserve auction. Since primary reserves are spinning reserves, the power plants which want to provide this service have to be continuously producing. Renewables cannot provide this service due to their intermittency in generation depending on weather conditions. Pump-storage power plants are excluded from all ancillary service auctions in the developed model. In reality, pump-storage power plants participate mainly in the daily ancillary service auctions. Due to their limited reservoir levels they are typically not active in weekly auctions. Only exception, if the pump-storage power plant is part of a pool of hydro power plants, then a participation in weekly ancillary service auctions is possible. In the current version of EnerPol, no data base information for pools or cascades of hydro power plants are available. Otherwise, the pump-storage power plant would have to pump and produce simultaneously in the model for a significant period of the day to fulfill the weekly refilling cycle. This mode is called hydraulic short-circuit operation (in German: Hydraulischer Kurzschluss Betrieb), and only appears very rarely in reality. As in reality, the primary reserves are modeled as symmetric product, meaning that power plants which offer this service have to be able to ramp up and down the offered capacity volume during the ancillary service period. The offer volume of the power plants is set to 3% of the rated capacity of the power plant. This value was derived from Swissgrid auction publication results. The highest offers in these auctions where around 35MW. Since the biggest unit in Switzerland is the nuclear power plant Leibstadt with 1'200MW capacity, the value of 35MW corresponds roughly to 3% of the power plant capacity.

b) Weekly SRL Auction

The secondary reserves also belong to the category of spinning reserves as the primary reserves. Therefore, the same categories of power plants are allowed to participate in the auction as in the PRL case. When providing SRL, the contracted amount must be fully activated within 5 minutes. As shown in the market analysis chapter, most countries except Germany perform the secondary reserve auction as symmetric product. In this model, a symmetric model approach was used as well. To incorporate the five-minute activation rule, the offer amount is restricted to 1/12 of the hourly ramping capability of a power plant. For hydro dams the allowed offer amount is additionally restricted by the weekly planned water usage. In contrast to the PRL activation, the resulting dispatched SRL activation amount is not necessarily considered to be balanced to zero over a weekly period. Therefore, the worst-case assumption of permanent positive activation by the TSO has to be included when the offer amounts on the SRL market for hydro dam power plants are determined. In reality, non-availability of providing the guaranteed reserves results in heavy financial penalties.

c) Weekly TRL Auction

Since tertiary reserve is a non-spinning reserve, the power plant which offers such a service does not have to be running continuously. This introduces different production constraints for the power plants which provide tertiary reserves. For power plants which are offering positive tertiary reserves, only the maximum production capacity is reduced. For negative tertiary reserve, only the minimum production amount is affected. Thus, power plants which provide tertiary reserves are more flexible in their day-ahead market activities compared to the power plants providing PRL and SRL. Exactly the same power plant types are allowed to take part in this auction as for the PRL and SRL case. The maximum capacity a power plant can offer in this ancillary service market segment is 1/4 of their hourly ramping rate due to the response time of 15 minutes.

Reserve Activation

Primary reserve activation does not result in an activation payment if the reserve is activated. Since this frequency control is permanently active for generators that are online, it is assumed that positive and negative activation equalize over a weekly period.

Secondary reserve activation in most countries is organized in a pay-as-bid mechanism but not in Switzerland. In Switzerland, a tariff linked to the day-ahead market price is received / paid by the generators providing this service. Since it is quite difficult to price short-term activations in the range of 30 seconds up to 5 minutes, the Swiss approach with a tariff premium of 20% of the day-ahead market price is used to reimburse activation in the developed model. For positive activation the generators receive 120% of the actual day-ahead market price and for negative activation the generators pay 80% of the day-ahead market price to the TSO, which means they are able to buy back power from the market at 80% of the current market price.

Due to the full activation rules of 5 minutes and 15 minutes, secondary and tertiary reserve activation are both too short-term to fully simulate within an hourly simulation framework. For being able to include their activation payment into the model a splitting concept for the delta energy from the stochastic model had to be derived. If the energy delta (introduced by the stochastic model) part which cannot be handled by the IDM (20% of total energy delta) shows for two subsequent time steps the same sign, the smaller of the two values is considered to be the part which has to be covered by tertiary reserve. The reasoning behind that: If the sign of the delta energy stays the same for two subsequent time steps in the stochastic model (30 minutes), the disturbance is assumed to be persistent. Therefore, this part of the delta energy has to be compensated by tertiary reserve. The rest of the delta energy, which must be covered by reserve activation, is then assumed to be handled by secondary reserve activation.

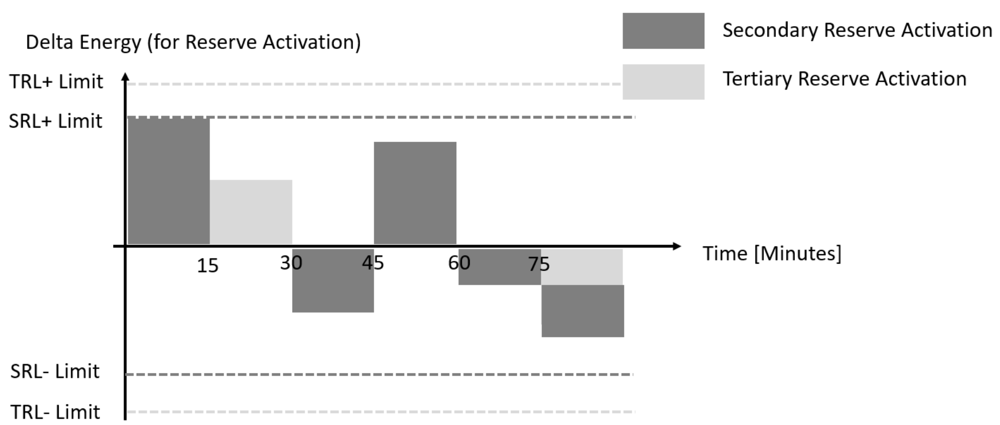

Figure 3.17: Example of splitting-up of reserve activation delta energy into SRL and TRL activation

The tertiary reserve activation prices are calculated based on increased / lowered production costs due to the activation volumes of the TSO. The power plants calculate in eventually required start-ups as well as the resulting changing ramping costs in their offers. This is possible since in reality power plants are allowed to update their activation prices offered to the TSO on a daily basis.

3.6.2 Acillary Service Model Validation

Effect on Power Plant Production

In a first step, the general effect of offering ancillary services on a weekly production profile of a power plant is presented. In figure 3.18 the production profiles resulting from the weekly production strategy optimization can be seen for a nuclear power plant. On the left side of the figure, the optimization production strategy result prior to any ancillary service market auctions is plotted. Therefore, the nuclear power plant can freely ramp in between the minimum production level, which for nuclear power plants typically is around 40-50% of their rated capacity, and the maximum production capacity indicated by the rated capacity of the power plant. In this particular week, this nuclear power plant was chosen to provide the ancillary services TRL- (24 MW) and SRL (57 MW). Since SRL is categorized as spinning reserve and modeled as symmetric product, this increases the minimum production level and decreases the allowed maximum production level. The power plant always has to be able to ramp up or down 57 MW. In addition, the lower production limit is again increased by 24 MW due to the TRL- service provided to the TSO. However, it must be mentioned that typically nuclear power plants only provide TRL- ancillary services. Nevertheless, the dispatching of the power plant in the SRL auction can be explained by the fact that the analyzed week was a low-price week with a relatively long period of negative prices. Most thermal power plants would not offer production for these prices. Since nuclear power plants are continuously producing and avoid complete shut-downs, the change in the optimum production pattern through the ancillary service production constraints is relatively small. This is the reason why the nuclear power plants could offer cheaper in the SRL auction for the analyzed time period.

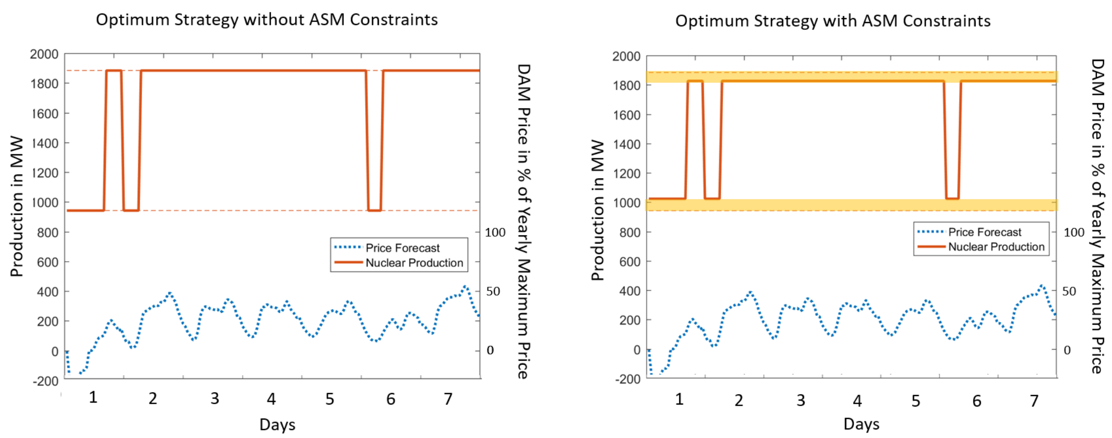

Figure 3.18: Optimum production profile for a nuclear power plant for given price forecast with and without ASM provision

Effect on Day-Ahead Market Prices

Figure 3.19 shows that a market model simulation which neglects the ancillary service market will rarely produce day-ahead market prices below 25 €/MWh. When the ancillary service market model is included into the simulation, the low-price periods can be well predicted. Justification of the improved prediction of low-price day-ahead market price periods is given by data in table 3.3. Without the ASM model zero hours in the year show market prices below 20€/MWh. Real data indicates 1'278 hours in the year which are priced below 20€/MWh. By including the ASM model 925 hours are predicted to be below 20€/MWh. This corresponds to 72% of the total low-price hours which are anticipated by the simulation.

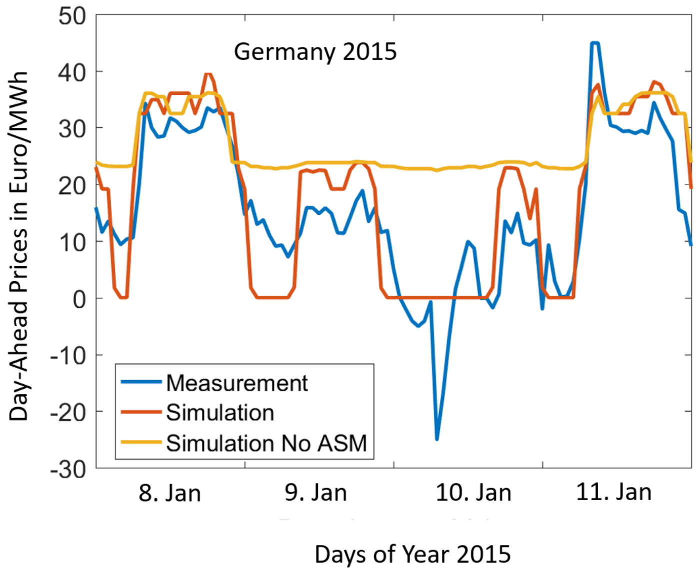

Figure 3.19: Resulting day-ahead market prices for the period of 8. - 11. January 2015 for Germany for a simulation with and one without ancillary service market compared to measured price data

Table 3.3: Comparison of measured low-price day-ahead market periods with simulation predicted results (with and without ancillary services) for Germany for the year 2015

	Number of Hourly Appearances
DAM Price below 20€ /MWh	
Measurement	1'278
Simulation with ASM	925
Simulation no ASM	0

The reason for the low-price periods created by the ancillary service market is, that power plants which offer spinning reserves (PRL and SRL) and tertiary negative ancillary services, are forced to continuously produce during the period where they provide this ancillary service. They are not allowed to shut-down their production completely for being able to balance electrical load fluctuations in the grid. Thus, these power plants offer their electrical production for very low or even negative prices to find a counterparty on the day-ahead market. In combination with low electricity demand periods and high renewable energy generation this can lead to day-ahead market prices around zero or even in the negative region. If the power plants which provide ancillary services are not able to sell the energy on the day-ahead market, the power plants are forced to pay for balancing energy which is expensive. The low offering prices for production capacities already sold on the ancillary service markets does not mean that the power plants are unable to generate profits. In the model, they calculate in the additional costs for continuously producing in their ASM offers such that the power plant is able to generate the same financial result as if it would act on the day-ahead market only. In reality, power plants will follow similar strategies to prevent generating losses when acting on the ancillary service market. Additionally, ancillary service markets revenues do not only include capacity payments for the continuous production, but also payments when the power plants are activated to balance the grid. This activation phase is another source of incomes for power plants.

As a consequence, an ancillary service model is required on the one hand to quantify the costs for the grid stabilization with ancillary services and on the other hand to correctly predict the low-price phases in the year as well as to model correctly the different revenue segments of individual power plants.

Reserve Capacity Offers

As a next step, a closer look on the ancillary service capacity prices received by the power plants is taken. Generally, it is expected that spinning reserves (PRL and SRL) ancillary service category show higher average capacity prices than non-spinning reserve. The permanent availability influences the production flexibility of power plants which has to be reimbursed by the TSO to which the ancillary services are offered. As tables 3.4 up to 3.6 show is that the case. Average capacity prices for the categories PRL and SRL are clearly higher than the prices demanded in the categories TRL+ and TRL-.

Subsequently PRL capacity prices are compared to the prices which were paid in reality in the German ancillary service market in 2015. This comparison shows that weighted mean selected real prices are priced 9.2€ /MW/h above the price predicted by the simulation. The deviation can come from different sources: On the one hand PRL offer amount is set to 3% of the rated capacity of a power plant in the simulation setup. However, in reality the offer amount for a particular power plant may deviate from this value. A different offer amount introduces new production constraints for the upcoming week for a power plant, which will result in different offer prices for the capacity. Another potential reason for the difference is the fact, that in the simulation the power plants are allowed to take part in different weekly ancillary service auctions, and priorize their offers on the different sub-markets based on a ancillary service capacity prices of the previous week. These prices can change from week to week, which can result in a wrong offer priorization. Additionally, it has to be mentioned, that power plants need to go through a pre-qualification process in reality for providing ancillary services. This pre-qualification process is not included in the simulation and results eventually in too many power plant being able to offer in PRL market, which lowers the average price levels. Another explanation for the difference stems from the fact that the average day-ahead market price of the simulation setup is above the real day-ahead market price in Germany for the year 2015. This fact will be discussed in the day-ahead market validation section 3.7.2. Higher market prices result in more power plants willing to be constantly producing. These power plants do not have to include start-up costs in their ancillary service capacity offers, which can decrease their offer price. Finally, the power plants calculate their capacity offer prices in the simulation setup based on the day-ahead market prices of the previous week, which they assume to be a reasonable price forecast for the upcoming week. However, there is no risk premium included in their offers which reflects the potential deviations from this price forecast. Another argument which can be listed as explanation for higher prices for PRL capacity in reality is market power. For being able to offer weekly PRL services the power plant has to be able to continuously run. Some power plant types such as pump-storage plants and renewables cannot offer weekly baseload production and other power plants such as natural gas power plants can only offer for high capacity prices due to their high marginal costs. Therefore, this gives baseload production plants such as nuclear, coal or lignite some market power in the PRL market which can be an explanation for the higher PRL capacity prices when comparing real data with simulation. The presented reasoning about potential sources of deviating ASM prices underlines the difficulty in reproducing ASM bid prices. With an average price difference of 9.2€ /MW/h the model can nevertheless be assumed for being able to reproduce future power plant revenue developments in the PRL segment.

Table 3.4: Primary reserve capacity simulation predicted and measured prices for Germany 2015 [37]

	Real Price Data	**Simulation**
PRL		
Weighted Mean Selected Bid Price (€ /MW/h)	21.6	12.4
Average Weekly Highest Selected Bid Price (€ /MW/h)	23.3	14.8

When comparing simulation predicted SRL and TRL capacity prices with real price data, the modeling approach of the different categories chosen in this project must be included in the analysis. Secondary reserves are modeled as symmetric product in the simulation framework, in reality the product was recently re-defined as non-symmetric product in Germany, and there is also a splitting of the product in peak and off-peak time spans. As table 3.5 indicates, simulation predicts highest weekly SRL capacity prices of 20.8 € /MW/h. This value is a factor 2.9 higher than the prices for the most expensive SRL category in reality (SRL+ Off-Peak).

This splitting in peak and off-peak time spans allows for new actors on the secondary reserve markets (especially pump-storage power plants). Pump- storage power plants are not allowed to take part in the ancillary service markets in the model due to their limited reservoir constraints which prevents a participation on the modeled weekly ASM auctions. The additional participation of pump-storage power plants is a potential reason for the lower real secondary reserve prices. The splitting of the product allows for each power plant category to offer only in the SRL segment which fits best with their DAM optimum strategy. This is expected to have a strong effect on the spinning reserve ASM pricing and is considered to be the main reason for the price difference between simulation and reality in the SRL market. Considering the difference between modeled SRL product and real SRL product categories, the resulting SRL price of the simulation is in an expected range to the real SRL capacity prices. Therefore, the model can be used for future EnerPol simulations with financial evaluations.

Table 3.5: Secondary reserve capacity simulation predicted and measured prices for Germany 2015 [37]

	Average Weekly Highest Selected Bid Price (€ /MW/h)
Real Price Data	
SRL+ Peak	4.0
SRL + Off-Peak	7.1
SRL - Peak	2.5
SRL - Off-Peak	6.4
Simulation	
SRL	20.8

The simulation predicts very low prices for the tertiary reserve capacities. Weighted mean selected bid prices for TRL+ and TRL- are predicted to be around 0.8 and 0.5 €/MW/h. This comes from the fact that natural gas power plants are expected to be in shut-down mode for many hours of the week. Therefore, they can offer tertiary upwards regulation capacity relatively cheap. On the other side, nuclear power plants are constantly producing baseload production and are only reducing production in a few low-price hours. This results in very cheap TRL- offer from nuclear power plants. Another reason for low tertiary reserve capacity prices is, that power plants want to be selected in the ancillary service market auction to profit in a next step from relatively high activation prices during the ancillary service provision time period.

Tertiary reserves are mainly procured on a daily basis in 4-hour blocks in reality but are modeled as weekly auctions in this thesis. However, the effect of the product splitting on TRL capacity prices is expected to be smaller than in the SRL case. TRL is a non-spinning reserve which reduces the impact on the power plant flexibility in production profile while offering ASM. As table 3.6 illustrates, the weighted mean prices of the selected TRL+ bids are predited with a difference of only 0.1 €/MW/h. The TRL real capacity prices shown in table 3.6 are average values of all daily 4-hour categories for the year 2015 in Germany. TRL- prices are clearly underestimated by the simulation. The simulation predicts a weighted mean price 0.5 €/MW/h whereas in reality a price of 1.9€/MW/h is found. The main explanation for this difference is that day-ahead market prices are overestimated by the simulation framework by around 3.5 €/MWh. This can affect heavily the TRL- capacity prices since this ASM category offers are mainly provided by nuclear power plants. If the average day-ahead market price is lower, nuclear power plants are expected to have significantly more phases with minimum production. These minimum production phases are the main price-determining factor for TRL- offers since TRL- offers increase the allowed minimum production level. Considering this explanation and the small absolute deviations to real tertiary reserve prices, the TRL pricing module can be assumed to work correctly, and can be included in the developed market model.

Table 3.6: Tertiary reserve capacity simulation predicted and measured prices for Germany 2015 [37]

	Weighted Mean Selected Bid Price (€/MW/h)
Real Price Data	
TRL+	0.7
TRL-	1.9
Simulation	
TRL+	0.8
TRL -	0.5

	Average Weekly Highest Selected Bid Price (€/MW/h)
Simulation	
TRL+	1.8
TRL-	1.2

Reserve Activation Splitting

The chosen simplified splitting mechanism for SRL and TRL activation on a 15-minutes basis is able to correctly reproduce a dominant SRL activation compared to TRL activated volumes. Simulation predicts for SRL activation a share of 72% at the total activated SRL and TRL volumes as table 3.7 shows. In reality, the SRL activation is corresponding to 90% of the activated TRL and SRL volumes. However, this change is assumed to mainly come from the stochastic model discussed in section 3.8. Since in 88% of the simulated hours positive activation is necessary compared to 67% positive activation hours seen in reality, an increased tertiary positive activation prediction by the model is expected. Two quarter hour periods in series with required positive balancing energy activation lead to TRL+ activation in the chosen modeling approach. With a correctly predicted dominant SRL activation the reserve activation splitting module is expected for being able to reproduce realistic reserve activation patterns on the ancillary service market.

Table 3.7: SRL - TRL splitting predicted by simulation compared to ENTSO-E measurement data [38]

	SRL-Activation Share (%)	**TRL-Activation Share (%)**
Simulation	72	28
Measurement	90	10

Concluding statement to ancillary service market model validation

After the validation of the ancillary service market model, it can be stated that the model is able to reproduce the most important effects of an ancillary market. The model introduces the low-price day-ahead market hours, and is therefore a key element for a realistic market model. On the other hand, the prices demanded by the power plants for their ancillary service capacity offers are in a realistic range compared to reality. The module correctly predicts a dominant SRL activation. With the mentioned characteristics, the model can be applied in EnerPol scenario simulations.

3.7 Day-Ahead Market Model

3.7.1 Day-Ahead Market Model Description

As presented in the market analysis chapter, in the day-ahead market, offers for the 24 hours of the upcoming day must be placed on the electricity exchange platform until noon. The actors on the day-ahead market represent a balance group for which they procure or sell energy such that the overall energy balance of the balance group is balanced for the next day. As Dimitrova [28] showed in her Master thesis, an accurate modeling of balance groups without the information of the exact ownership of power plants and the unclear grouping of end consumers to a particular balance group is beyond the scope of this work. Therefore, in this project the assumption was made that each individual power plant represents a small mini-balance group and acts on the market to maximize its profit.

In reality, power plants optimize their offer strategies on a weekly basis including the ancillary service auctions. After each day, a strategy update for the remaining days of the week is carried out based on the dispatching of the current day as well as on deviations from the price forecast at the beginning of the week. Power plants update their price forecast for the rest of the week on a daily basis. The schematic of the strategy updates in a weekly framework can be seen in figure 3.20 and was also implemented in a similar way in the day-ahead market model.

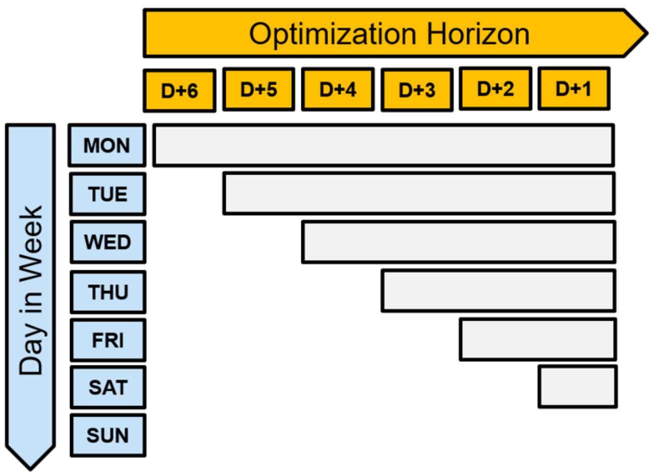

Figure 3.20: Day-ahead market daily strategy update for one week with according optimization time horizon

In the development phase of the day-ahead market model two different bidding concepts for the thermal power plants on the day-ahead market were constructed:

Dynamic Bidding Approach: In this approach the thermal power plants offer their capacity according to their optimum production profile based on the weekly expected prices in four categories:

1. Minimum production capacity amount for providing ancillary services is offered for zero at the day-ahead market. This is a realistic assumption since power plants which offer ancillary services in the categories PRL and SRL are forced to be continuously running. To ensure being dispatched, they offer their minimum production amount for low prices, which prevents being forced to pay balancing energy.
2. Production above the minimum production value according to optimum strategy is offered at costs of production.
3. Capacity above the optimum strategy production is offered for the costs of additional ramping, start-up and production. The start-up costs are only included if the optimum strategy was to be in shut-down mode in the particular hour. The start-up costs are divided by a factor of 12. Usually, if no production is planned but the demand is higher than expected, the power plant can be expected to be dispatched during the 12 peak hours of the day. This results in higher prices for production above optimum strategy which can be interpreted as a premium for running a production strategy which is considered to not be financially optimal.
4. If the additional capacity offer of a power plants exceeds the hourly ramping factor, an extra price premium is added to the power plant day-ahead offer. Strong rampings reduce life time of a power plant and increase maintenance expenses. Therefore, power plants want to reimburse these cost factors by adding an additional premium.

First test simulations showed that this approach is very sensitive to an accurate price forecast for the upcoming week. Additionally, the incorporation of financial premiums for strong rampings and deviations from optimum strategy production creates another big challenge. Non-intuitive solutions can be the outcome of the simulation, meaning that power plants in phases of expected low prices offer only a limited amount of their production capacity for normal market prices and for the remaining capacity they ask for a premium for the deviation from their optimum strategy. Following this, market prices in expected low price hours can exceed market prices in peak-hours.

The optimum production profile of a power plant depends on the market price profile. Since this market price is not known a priori, the offering phase of power plants on the day-ahead market can be seen as a point of inefficiency for the power plants. This hidden information about the market price of the upcoming day, makes the pricing in of ramping and start-up costs in the production offers extremely challenging for power plants. Thus, for using such a dynamic bidding approach a more accurate price forecast prediction routine would be required. If once such a tool is available, the introduction of a multi-period OPF simulation with different offer options for power plants (such as linked offers or offer dependency specifications) in combination with a dynamic bidding concept could be an interesting approach to improve the market model. Out of these challenges the decision was made to use a marginal cost bidding approach for this project. The approach is described in the following paragraph.

Marginal Cost Bidding Approach: The marginal cost approach uses only two different categories for the offers of thermal power plants:

1. The minimum production capacity amount for providing ancillary services is offered for zero at the day-ahead market.
2. Remaining capacities of conventional thermal power plants are offered for the marginal production costs of the individual power plant.

The marginal cost bidding approach is beneficial since it reduces the dependency from accurate day-ahead market price forecasts.

Hydro power plants offer in the day-ahead market according to their optimum strategy for the hourly expected price during the production hours. In this project, the assumption was made that all the renewable generators receive feed-in tariffs and offer therefore for zero at the day-ahead market. This is still a realistic assumption since only very few renewable generators in reality perform a direct marketing of their produced electricity on the market.

The day-ahead market model includes price boundaries from the EPEXSPOT day-ahead auction platform. Day-ahead market prices are forced to be in the range of -500 up to 3'000 €/MWh.

3.7.2 Day-Ahead Market Model Validation

The validation of the day-ahead market model starts with a comparison of real day-ahead market prices and day ahead-market prices predicted by the simulation for the test case of Germany for the year 2015. The presented plots show a best case - worst case comparison for a quarter year time frame. Afterwards, aggregated production per generator type data is compared to real ENTSO-E production data of the year 2015.

Best Case Day-Ahead Market Price Matching

Figure 3.21 illustrates the comparison of the simulation predicted day-ahead market price and the real day-ahead market price stemming from the auction platform of EPEXSPOT for the first three months of the year 2015 in Germany. It can be seen that the simulation often correctly predicts the low-price periods around a price of zero. Generally, the predicted day-ahead market price shows the correct wave movements of the day-ahead market price over the presented time period. The mean absolute error for the simulation predicted hourly day-ahead market price is 8.4€ /MWh which corresponds to 26.6% of the real mean day-ahead market price in this time span.

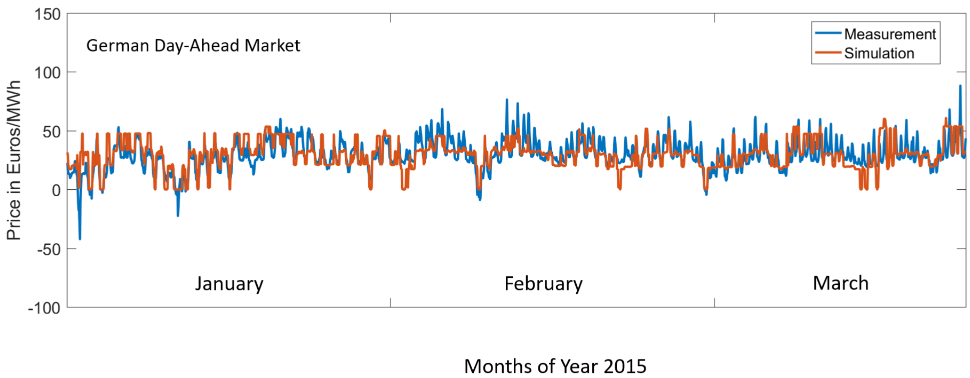

Figure 3.21: Day-ahead market price comparsion between simualtion and reality for Germany for the months January - March of the year 2015

Worst Case Day-Ahead Market Price Matching

In contrast to the winter months of the year, the simulation has difficulty to predict the market price movements for the summer period. As it can be seen in figure 3.22, the simulation is overestimating high price periods around 50 € /MWh, and even shows for some high demand hours dimples around 100 € /MWh. The mean absolute error in this time period is 11.9 € /MWh (37.7% of yearly mean day-ahead market price).

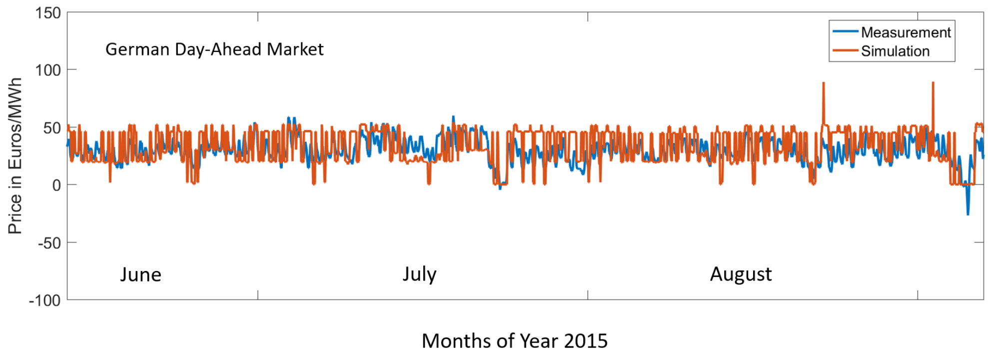

Figure 3.22: Day-ahead market price comparsion between simualtion and reality for Germany for a time span in the months June - September of the year 2015

The following paragraphs try to identify the reasons for the challenging day-ahead market price prediction in the summer months:

Electricity Imports

Figure 3.23 presents the overall hourly electricity imports to Germany for the year 2015. Negative values indicate electricity exports. As it becomes visible Germany is a net electricity exporter for most time of the year. Only during the summer months hours of imports and exports are alternating in a unregular way. The export balance can switch from importing 5 GW to exporting 10 GW in a few hours.

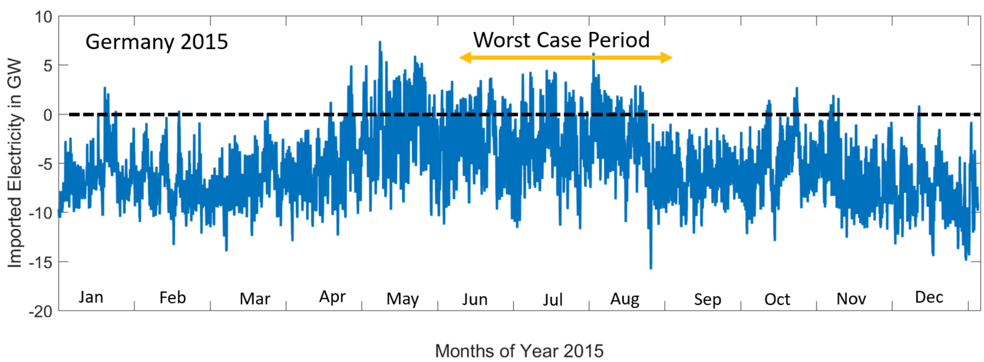

Figure 3.23: Hourly electrictiy imports to Germany in 2015

Presumably, these heavy changes are due to the heavily varying renewable generation in Europe (high solar production in Southern Europe during the day hours). Additionally, during summer months nuclear power plant refueling takes place which reduces the amount of available cheap baseload capacity which can make Germany to a net electricity importer. One important thing to keep in mind is that in hours of net electricity import, the German market price is influenced by power plants producing abroad. Since in the chosen simulation setup cross-border flows were used as boundary conditions and not hourly market prices from neighboring countries, this could be an explanation for the challenging modeling of summer day-ahead market prices in summary.

Renewable Production

Another point to mention is that on the day-ahead market, electricity for the upcoming day is being traded. Therefore, the market price reflects the expected renewable production for the upcoming day. Plagowski showed in his Master Thesis that the market predicts renewable generation with an error of 2.6% day-ahead. [39] The EnerPol weather data which is used in this project is based on a meso-scale weather simulation for the year 2015 of Europe. This weather data cannot reflect the standing of information in terms of renewable generation which the power plant operators had one day-before electricity delivery in reality. This explains a general challenge in predicting day-ahead market prices with an EnerPol simulation framework. But, this does not hold as an explanation for the difficulties the model shows to predict day-ahead prices in the summer months. To explain this difficulty, one has to analyze the hourly differences of EnerPol predicted renewable generation and ENTSO-E renewable generation data. Data comparison reveals that over- and underprediction of renewables alternate. One reason for this can also be that to match the installed renewable generation capacity in Germany for the year 2015, the existing renewable generators of the 2013 EnerPol data base were scaled-up. In reality, these wind and solar plants were mostly placed at new locations, leading to a different hourly electricity production profile. In combination with the fixed cross-border flows, which strongly fluctuate between importing and exporting electricity, heavy load errors can result. A short explanatory example: A 5 GW underprediction of renewable generation in a particular hour in combination with the fixed cross-border flows leads to a shift of the dispatch curve of the complete amount of 5 GW. This phenomenon could explain the high price dimples in the summer periods. In particular hours, some expensive thermal power plants such as simple cycle natural gas plants have to be switched on.

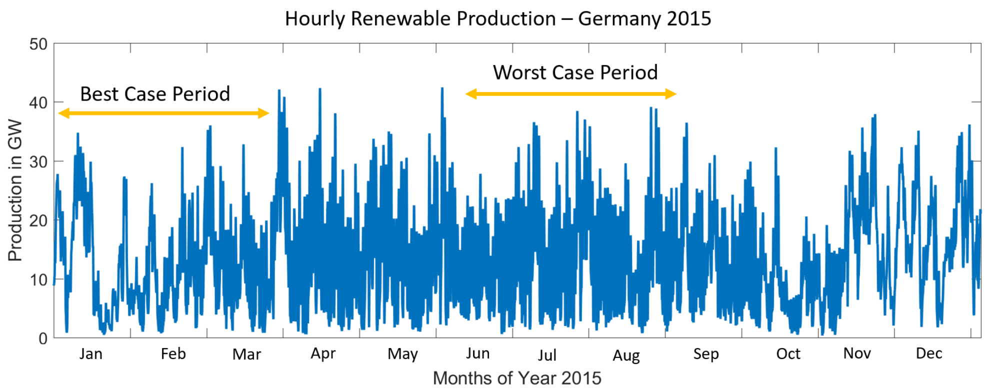

Figure 3.24: Hourly renewable generation in Germany in the year 2015

The mentioned heavily varying renewable generation (see figure 3.24) in the summer months from 2 GW to 40 GW production in only a few hours creates complex import-export electricity pattern. These patterns cannot be well reflected by the electricity price of the previous week. But the power plants optimize their strategy and place bids on the different markets according to this forecast in the simulation. If the price forecast is not accurate for the upcoming week, presumably the wrong power plants get dispatched on the ancillary service market which affects day-ahead price levels, and additionally it is difficult for hydro power plant to optimize their strategy in such complex production patterns.

Overall Day-Ahead Market Price Prediction Summary

Table 3.8 summarizes the hourly price differences between simulation and real day-ahead market prices. The average market price is overestimated by the simulation by 11%. This mainly due to a wrong price prediction in the summer periods. Possibly, also the marginal costs for natural gas power plants are not correctly calculated in the code, resulting in higher prices during peak periods in summer. Additionally, it has to be kept in mind that the day-ahead market in reality covers only around 50% of the total electricity trading volume as it was mentioned in chapter 2.4.1. The remaining trading volume is traded mainly bilaterally. This bilateral trading can affect the day-ahead market prices since it influences offer and demand curve. The hourly relative prediction error of 33.8% is not sufficient if yearly market prices on hourly basis are desired to be forecasted. But the relative error decreases to around 26% for the winter periods. With these characteristics, the developed market model is nevertheless well suited to perform future scenarios, and gives good approximations about costs for electricity procurement on the day-ahead market.

Table 3.8: Day-ahead market prices for Germany 2015

Real Mean DAM Price (€ /MWh)	31.6
Simulation Mean DAM Price (€ /MWh)	35.1
Absolute Hourly Prediction Error (€ /MWh)	10.7
Hourly Error relative to Mean DAM Price (%)	33.8

Aggregated Production of Main Conventional Power Plant Types for Germany

In a next step, the resulting aggregated production profiles for the main conventional power plant categories in Germany are presented for a representative time slot of the year 2015. The trends which can be seen in the quarter year plot remain the same over the complete year. Conventional electricity generation in Germany is dominated by coal and lignite power plants.

In general, figures 3.25 and 3.26 show that the developed market model is able to correctly predict the main thermal generation trends of coal and lignite. High and low production periods are correctly predicted. The code overestimates the generation especially of lignite by a constant offset of around 3 GW. It is difficult to assess why lignite power plants in reality never produce at their production limits. Possible reasons are potential ancillary service upwards regulation offered by lignite power plants which is not correctly predicted by the code. Verification of this thesis is not possible, since ancillary service result publication is anonymous. Another possible reason are too high marginal costs implemented for natural gas power plants which is underestimated in the simulation framework. Perhaps, there are also production limitations by coal mining and transport, which prevent a constant full load production of lignite.

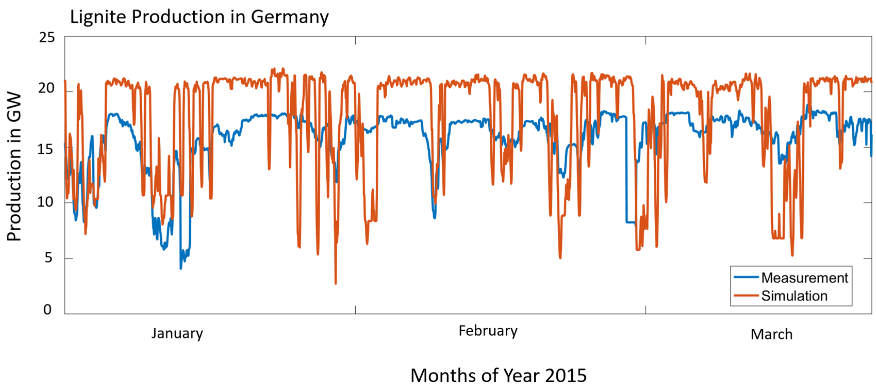

Figure 3.25: Aggregated lignite production in Germany predicted by simulation versus ENTSO-E data

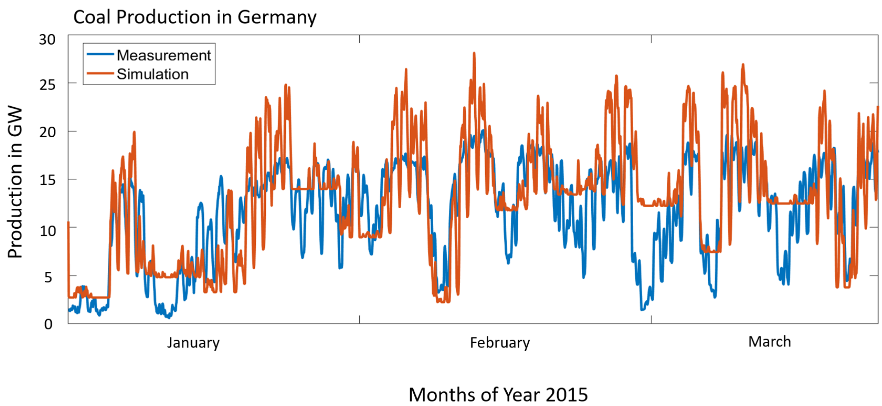

Figure 3.26: Aggregated coal production in Germany predicted by simulation versus ENTSO-E data

The simulation frequently overpredicts coal production during high-production periods by 5 GW. One reason for the overestimation of coal production is an underestimation of natural gas production during high demand periods. Additionally, it has to be mentioned that ENTSO-E aggregated generation data includes a generator category "other" which shows for the presented time frame an average production volume of 7.3 GW. Thus, ENTSO-E power plant categorization seems to be different from the power plant categories used in EnerPol. Therefore, all the offsets seen for thermal generator types have to be regarded in this context.

The simulation is not able to correctly predict all the production downturns for coal power plants to around 5 GW of total production which can be observed in measurement data. The production level in these periods remains above 10 GW. Different ancillary service dispatching compared to reality is expected to be the reason for this overestimation of coal production during downturn periods. Since production costs differences between lignite, coal and biomass power plants are in the order of 10 €/MWh. Under this condition, the share of selected coal power plants on the different ancillary service markets heavily depends on the price forecast and the matching to the coal power plant production characteristics. Since the model uses prices of the previous week as forecast for the next week, information about renewable generation, demand changes and holidays are missing in the forecasted price. This can lead to a different ancillary service dispatching compared to reality. This thesis is supported by the fact that downturns of coal production in other periods (for example in the first half of February) are correctly predicted by the model.

The presented day-ahead production profile predicted by the simulation shows much stronger ramping rates than ENTSO-E data would suggest. One has to remember that the presented production profiles of the simulation framework is the result of the day ahead market auction whereas ENTSO-E data represents the real production of the power plants after the intra-day market. The average trading volume of the intra-day market will be discussed in the intra-day market section, but it is obvious that a part of this strong ramps can be smoothed in the intra-day market auctions, where power plants can offer remaining free production capacities. Power plants which have strong ramping rates in their day-ahead production profile will offer cheap on the intra-day market to arrive in a smoother production profile. But the intra-day market will not compensate all the strong ramping dimples seen in figures 3.26 and 3.25. The used market model is a pure financial dispatching construct of individual hours. The OPF solver is not provided with any dispatching constraints (e.g. in terms of ramping) in between individual hours. The only constraints are given by the offered production volumes of the power plants. The marginal cost bidding approach for the power plants does not include ramping costs for power plant since it is difficult to include ramping costs in individual hour offers without knowing the dispatched production capacities a priori. With these simplifications heavier ramping rates could be expected. However, to improve the ramping behavior of the developed day-ahead market model the introduction of a multi-period OPF optimization with linked and block orders is suggested. The developed market model concept gives room for future optimization by using multi-period OPF optimization which is for example allowed by MATPOWER enhancement MOST in combination with linked and block orders. This combination should be able to reduce the strong ramping rates in the day-ahead dispatching profile since power plants then are able to price-in ramping and start-up costs for different potential dispatching profiles. These optionalities are expected to heavily influence simulation time which is already in the current framework a critical issue. In its current state, the model is able to predict correctly high production and low production phases of the dominant thermal generator types, but shows extreme rampings. Therefore, enhancement of the day-ahead market model in the future is essential to reduce ramping rates of power plants.

3.8 Demand and Supply Stochastics

The developed models for the demand and supply stochastics are mainly based on the ENTSO-E data for Germany for the year 2016. Germany is the biggest and therefore most important electricity market in Europe, which justifies the choice.

The stochastic model contains four sources of deviations from planned production and load profile: Wind, solar and demand forecast errors as well as forced power plant outages. All four categories will be described in this subsection.

Generally the relative forecast errors presented in the plots are defined as follows:

$$\text{Relative Forecast Error} = \frac{Measurement - Forecast}{Forecast} \tag{3.5}$$

This is not a statistical definition, but appropriate for the developed statistical model which gets as inputs expected solar and wind production values as well as an expected demand. The day-ahead market is based on these forecasts, and the stochastic model creates in a next step the deviations from the forecasted values. Therefore, the forecast values were taken to norm the difference between measurement and forecast.

Demand Forecast Error Modeling

The error of the day-ahead demand forecast in a particular control area is modeled with a normal distribution fit curve according to ENTSO-E data. For this analysis 15-minutes load forecast data of Germany for the year 2016 is compared to the actual load in Germany. The resulting distribution of the relative demand forecast error for the day-ahead time horizon is plotted in figure 3.27. As it can be seen, the resulting distribution can be well approximated by a normal distribution curve with a standard deviation of 2.7% of the forecast value and a mean value of 1.6% of the forecast value. This means that on average, demand is underestimated by 1.6%. This is interesting since one could expect a value around zero for the average relative forecast error. One potential explanation could be a statistical abnormality of the year 2016, which was used for this analysis. 95% of all forecast errors lie within -4% and + 7% (2-σ).

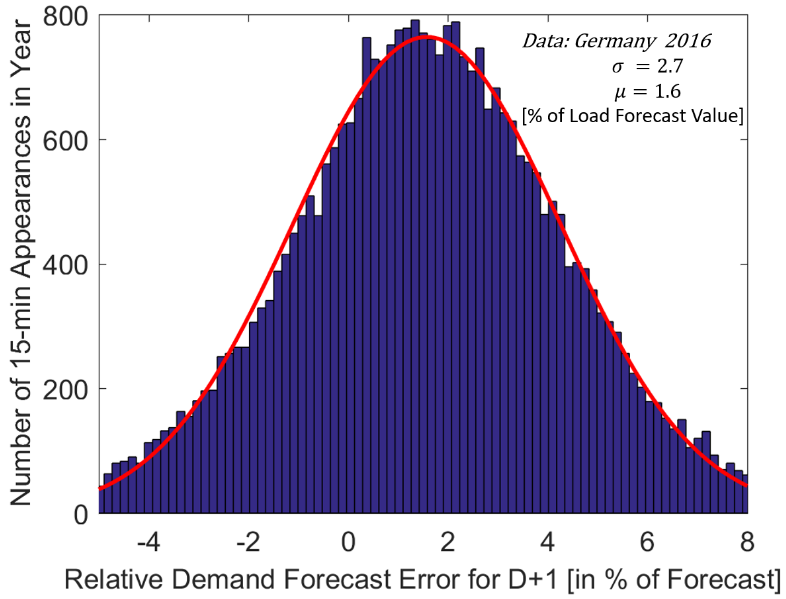

Figure 3.27: Day-ahead demand forecast error for Germany in the year 2016 with corresponding normal distribution curve

Wind Forecast Error Modeling

The relative wind forecast error can be sufficiently well approximated by a normal distribution curve. The resulting differences from a perfect normal distribution curve could stem from the fact that the wind power production is plotted and not the wind speed. Depending on the position on the power curve of a wind turbine, differences in wind speed can create a cubic error, whereas in other positions of the wind power curve differences in wind speed do not influence wind power production. For the validation of the feasibility of the developed intra-day market model, bigger forecast errors are the decisive criterion. With the resulting normal distribution curve with a standard deviation of 13.9% of relative forecast error, these high forecast error regions can be sufficiently well reproduced. The mean of the relative wind forecast error lies at -2.2%. According to ENTSO-E data of the year 2016 for Germany, wind power production is overestimated by the day-ahead forecast by 2.2% on average.

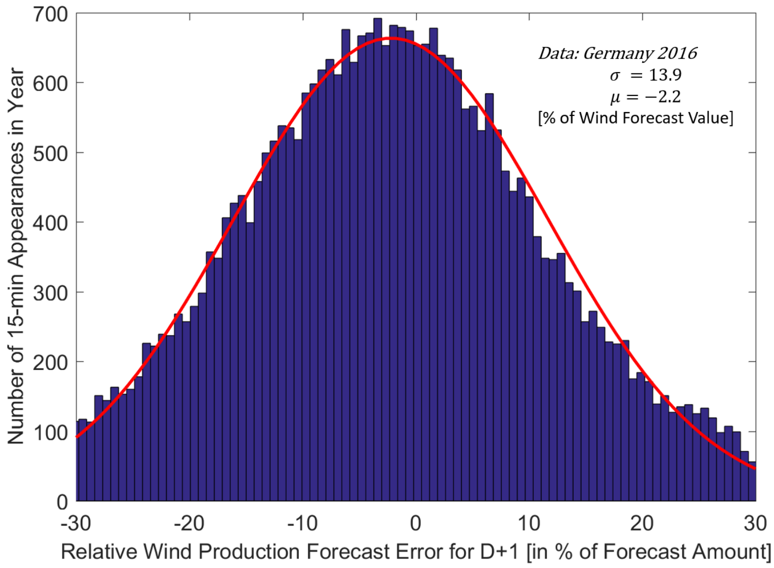

Figure 3.28: Day-ahead wind forecast error for Germany in the year 2016 with corresponding normal distribution curve

Solar Forecast Error Modeling

Similarly to the wind forecast error, the relative solar forecast error cannot be perfectly approximated by a normal distribution function as it can be seen in figure 3.29. The normal distribution function minimizes the total deviation from the histogram for a standard deviation of 8.8% of the relative forecast error and a mean value of -1.5%. A reduced amount of data points is regarded compared to the wind and demand forecast values since only the day hours have to be taken into account for solar power production. This is a potential explanation for the deviation from a perfect normal distribution.

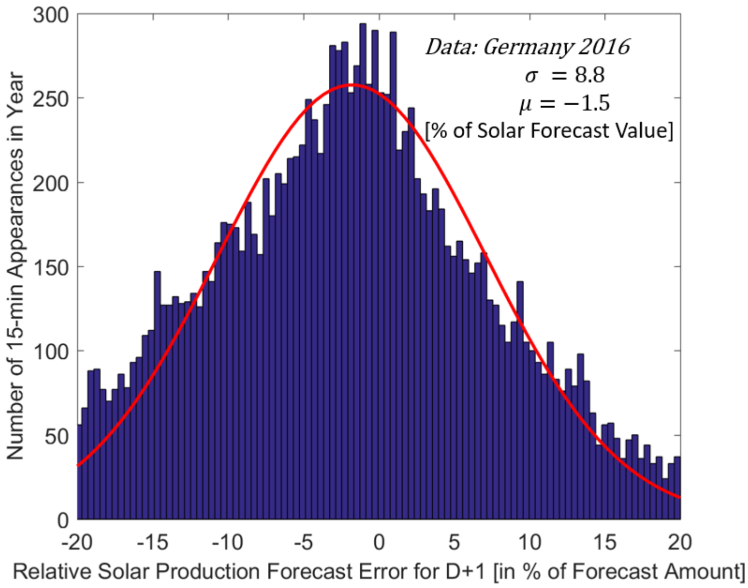

Figure 3.29: Day-ahead wind solar error for Germany in the year 2016 with corresponding normal distribution curve

Conventional Power Plant Outage Modeling

To create a realistic and efficient power plant outage model, statistical data of outages were studied and analyzed. The data analysis is based on ENTSO-E data for Germany for the year 2016. ENTSO-E outage data include outage type (e.g. forced / planned), outage amount, power plant type and duration of the outage.

The most important characteristic of forced outage data from Germany is the probability of occurrence. In the year 2016 2'580 forced outage events took place in Germany. In other words the probability of a forced outage in a particular hour is around 29%. Figure 3.30 shows the outage amount distribution in the particular year. Average forced outage capacity per outage event was 262MW.

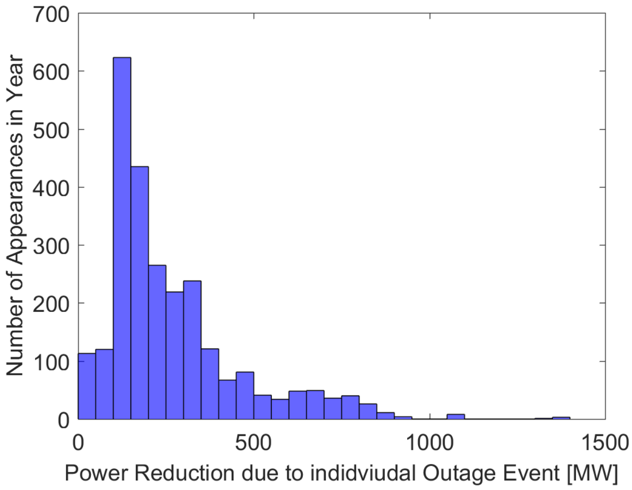

Figure 3.30: Histogram of forced outage amount per outage event for Germany in the year 2016

As the distribution of outage events over a complete year shows, no clear trend of a yearly outage pattern can be seen. Only a slight increase during the summer period (June until August) can be observed. Therefore, the model assumes the outage probability to be constant throughout the year.

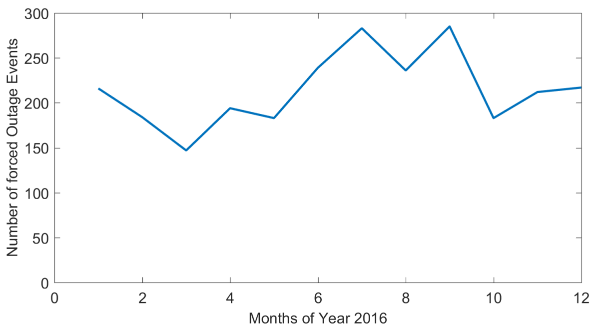

Figure 3.31: Measured monthly distribution of forced outage events in Germany for the year 2016

Figure 3.32 shows the histogram of the forced outage duration for the year 2016 in Germany. As it can be seen, most outages are rather short-lived, lasting one to two days. The mean outage duration is around 30 hours. Following this, the developed outage model assumes that outages only last for the remaining hours of the day. This simplification reduces the computational complexity since otherwise a capacity reduction tracking module would be required which complicates the stochastic model and affects intra-day and day-ahead simulations of the upcoming days. With this simplification, the model is not able to reproduce the effects of large capacity outages (e.g. a nuclear power plant) in small countries such as Switzerland on the day-ahead market prices of the upcoming days. However, for large countries such as Germany the effect of this simplification on the usability of the simulation results is assumed to be small.

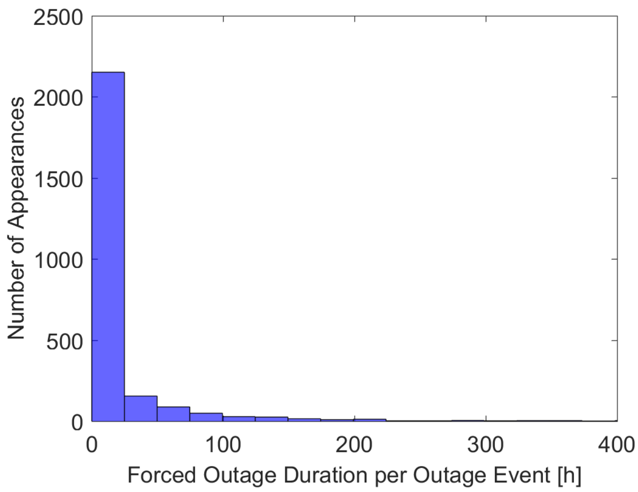

Figure 3.32: Histogram of durations of forced outage events in Germany for the year 2016

The outage probability differentiates between different power plant categories. Table 3.9 summarizes the found probabilities of outages per installed capacity as well as the outage amount per outage event. There is a clearly higher outage tendency for coal, lignite and pump-storage power plants. The average outage amount does not show significant variances and fluctuates around the mean of 262 MW. It must be stressed that only forced outages were considered in this analysis, but no refueling outages of nuclear power plants.

Table 3.9: Forced outage events information per generator type (based on ENTSO-E data from year 2016)

Generator Type	**Outages/installed Capacity [GW]**	∅ **Outage Amount/Event [MW]**
Lignite	24.7	274
Coal	41.5	256
Natural Gas	15.6	277
Pump-Storage	31.7	189
Hydro Dam (CH)	7.3	230
Nuclear	11.5	250

The outage stochastic model can be categorized as top-down model which is performed in 15-minutes intervals. Since the simulation time was a critical issue in this project, a model was chosen that minimizes the required random number generation amount since random numbers are computationally expensive to generate. The order of sequence in the outage model can be described as follows:

1. For each country a probability of an outage for a particular 15-minutes time interval is determined based on the generation mix and the outage probabilities of the different power plant categories. The resulting country outage probabilities are summarized in table 3.10. In a first step, for each quarter hour of the simulation period the outage model decides if there are outage events in the simulated country.

2. If there is an outage, the outage amount is determined by a normal distribution curve with mean of 262 MW and a variance of 194 MW. If negative values occur, the outage amount in this time step is set to the mean value.

3. In a next step, a random power plant is chosen which is affected by the outage. If the power plant output is smaller than the outage amount, another power plant is considered to be out of service as well. If the outage amount is smaller than the power plant output, the power plant is not completely out of service. The maximum production capacity is reduced by the outage amount, meaning that only several blocks of the power plants are affected by the outage. Generally, outages of renewables (wind and solar) are not included in this outage model. The short-term outages of renewable generators can be assumed to be partially included in the solar and wind forecast model. Additionally, no exact data about the availability and outages of individual renewable power plants are available, which prevent exact modeling.

4. The outage lasts for the remaining hours of the current day (until midnight). For this time span the maximum production capacity remains reduced. A strength of the modeling approach is its reduction of computational effort while simultaneously covering most of the outage events which occur in reality as figure 3.32 showed.

Table 3.10: Model predicted outage event probability for simulated countries for a 15-minutes time interval

Country	Probability of a Forced Outage Event in a 15 Minutes Time Interval
Austria	1.1%
Belgium	0.9%
Czech Republic	1.1%
France	6.5%
Germany	7.4%
Italy	5.3%
Netherlands	1.7%
Poland	2%
Switzerland	0.8%

Resulting Delta Energy

The different stochastic processes mentioned in the previous paragraphs have to be summed up to determine the overall energy difference compared to day-ahead planned production. This energy difference is called delta energy and abbreviated by the symbol ΔE in this thesis. This delta energy can be calculated as follows:

$$\Delta E = \Delta Wind + \Delta Solar - \Delta Outage - \Delta Demand \tag{3.6}$$

Sign convention: Positive deviations for wind and solar mean higher production than expected day-ahead. Outages are defined as a positive number which have to be subtracted to account for the missing energy on the market. Positive demand deviations mean a higher demand than expected, resulting in a negative sign in the energy balance.

A positive resulting ΔE means that there is an energy surplus on the electricity market, and a negative energy delta indicates an energy deficit. The energy delta is assumed to be partially anticipatable. A comparison of intra-day market and reserve activation data for the Germany and Switzerland for the year 2016 showed that typically around 80% of the energy delta can be traded on the intra-day market, and the remaining part is covered by reserve activation. This splitting factor was therefore used in the model for splitting up the delta energy into a intra-day and a reserve activation part.

Since the intra-day market is performed in hourly resolution, the intra-day delta energy is the average of the four 15 minutes intra-day delta energies.

Interestingly, the positioning of the mean values of the relative error distributions of wind, solar and demand forecast lead to an expected average energy deficit on the intra-day market. In the considered year 2016, wind and solar energy production were overestimated in the day-ahead forecast. Simultaneously, the energy demand was underestimated in day-ahead perspective. Combining these two facts with potential forced outages, there will be more hours in the model, where additional production is required on the intra-day market. Two explanations for this behavior can be given: On the one hand, it could be that from an economic efficiency perspective it is more desirable to have an energy deficit situation where production has to be increased instead of an energy surplus in the grid. In extreme energy surplus cases consumption may has to be increased which is not desirable from an energy efficiency point of view. A second potential explanation is that these mean values are just a result of stochastics. If the same analysis is performed for several years for Germany, these mean relative error values are expected to vary. The mean values found in a ENTSO-E data analysis lead to an energy deficit situation in 88% of the cases predicted by the simulation. However, comparison to balancing energy activation data of the year 2016 shows, that in Germany positive activation was required in 67% of the cases. Therefore, the general positioning of the mean values tends to be correctly. However, the resulting more frequent positive activation in the stochastic model compared to measurement data is expected to increase intra-day market prices.

3.9 Intra-Day Market Model

3.9.1 Inta-Day Market Model Description

The intra-day market allows market participants to balance short-term deviation in demand or supply without being forced to pay balancing energy. As already explained in subsection 3.8, 80% of the resulting energy delta is traded on the intra-day market in the chosen model. Figure 3.33 gives an overview of the market players in the intra-day market differentiated by the two cases 'energy surplus' or 'energy deficit'. Generally, power plants can increase their production up to their rated capacity, or ramp down to minimum production, or even do a complete shut-down.

As there are ambitions in Europe to create a continental intra-day market (XBID project), it is reasonable to apply a common intra-day market model for all the European countries in the developed market model. In reality, 15 minutes time interval intra-day market auctions already exist. According to EPEXSPOT data of July 2017, the volume of these 15-minutes auctions is around 11% of the hourly continuous intra-day market for Austria, Germany and Switzerland. [40] Due to the fact that the hourly auction volume still dominates the quarter hourly auctions and the intra-day optimum power flow simulation effort can be reduced by a factor of 4, an hourly time resolution for the intra-day market auctions was chosen.

Due to the water balance, hydro dams and pump-storage power plants are forced to follow additional constraints in the developed model. Hydro dams are only allowed to offer the total weekly water budget which is above the minimum production level required for providing ancillary services. Pump-storage power plants have very limited reservoirs and therefore strictly follow their optimum production strategies determined by the optimization routine. In the model, they only offer deviations from the planned optimum day-ahead production profile on the intra-day market to prevent water reservoir conflicts.

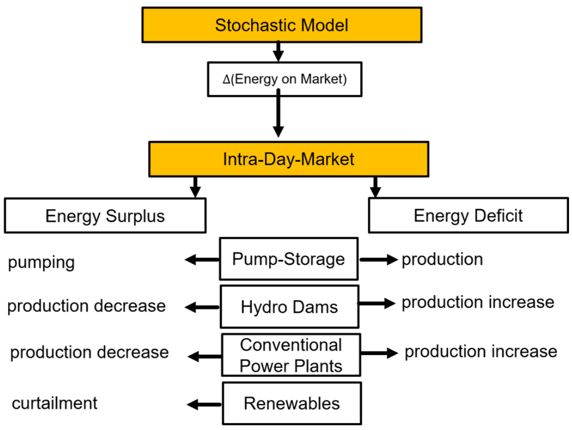

Figure 3.33: Data flow from stochastic model to intra-day market model and main actors in intra-day market model with their production adaption options

In the following list a short overview of the offer price strategies for the different power plant types is presented:

Pos. Intra-Day Market Offers (Energy Deficit Case)

- additional energy or demand reduction required on electricity market
- modeled actors for such offers:
  - pump-storage power plants: offer additional energy if price above average weekly production prices
  - hydro dams: offer additional production price above average weekly production prices
  - thermal plants: offer additional production capacities if price covers additional ramping, production and start-up costs

Neg. Intra-Day Market Offers (Energy Surplus Case)

- production reduction or demand increase required on intra-day market
- modeled actors for such offers:
  - renewable curtailment (wind and solar): willing to buy energy on the market if prices are below the negative feed-in tariffs. The feed-in tariffs were taken from the EEG 2017 in Germany which proposed the following values: [41]
    * Wind off-shore: 154 €/MWh
    * Wind on-shore: 46.6 €/MWh
    * Solar: 89.1 €/MWh
  - thermal plants, pump storage plants and hydro dams: willing to buy electricity on the market if market price is below production costs of planned production minus ramping costs created by deviation from planned production profile.

3.9.2 Intra-Day Market Model Validation

The intra-day market model validation focusses on the resulting prices and traded volumes on hourly basis. An hourly comparison to real intra-day market prices is not presented since the intra-day market in the market model is based on a stochastic model which will create completely different hourly deviations from the planned day-ahead production than in reality when hourly data of the year 2015 is concerned. However, if the model is working properly, statistical averages of prices and procured intra-day volumes should be in accordance with measurement data from EPEXPSOT.

Table 3.11: Intra-day market price characteristics for Germany

	EPEXSpot 2015	**Simulation**
Prices		
Mean Price (€ /MWh)	31.7	42.3
Maximum Price (€ /MWh)	121.7	193.0
Minimum Price (€ /MWh)	-81	-82.2
Price Difference IDM-DAM (€ /MWh)	0.2	7.2

Table 3.11 indicates that the average simulation intra-day market price of 42.3 € /MWh is 33% above the real intra-day market price of 31.7 € /MWh seen at EPEXSPOT for Germany for the year 2015. The extreme negative prices resulting in the intra-day market model stem from renewable curtailment processes. In the model, the OPF solver is allowed to shut-off renewable power plants for their guaranteed feed-in tariffs. As the maximum and minimum price values of the simulation show, a similar intra-day market price spread can be observed in reality.

Intra-day market trading appears after the closing of the day-ahead market. In contrast to the day-ahead market offering phase, the power plant exactly knows which day-ahead market profile they will have to produce after the publication of the day-ahead auction results. Therefore, it is possible to calculate in the costs of ramping away from the day-ahead production profile and price in also eventually necessary start-up costs. The reasons for the discrepancy between simulation predicted and real intra-day average market price of 10.5 € /MWh are summarized in the following list:

- Pricing in start-up and ramping costs and DAM cascade effect: As it could be seen in the day-ahead market validation, a marginal costs offer approach without including ramping costs or start-up costs is able to reproduce the mean day-ahead market price level with an average overestimation of around 4€ /MWh. Thus, it is expected that the resulting intra-day market price of the model which also includes start-up and ramping costs overestimates the real intra-day market price more significantly.

- Modeled offer constraints on IDM: Additionally, it must be mentioned that the model adds some offer constraints for the power plants which are active in the intra-day market in reality. Hydro-dam power plants are only allowed to use a specified percentage of the remaining weekly water budget on the intra-day market auctions to fulfill reservoir filling level rules. Pump-storage power plants are only allowed to offer the non-dispatched production volumes of their optimum day-ahead market strategy. This constraint is based on the very narrow reservoir limits of the pump-storage power plants. Since hydro power plants have low marginal costs, the increased offer amount of hydro power plants on the IDM in reality is expected to lead to lower prices than predicted by the simulation.

- Negative delta energy: For the simulated year 2015, an overall negative energy delta could be determined for the simulated case which can be explained by the mean values of the stochastic models. In 88% of the simulated hours a positive activation was required. Thus, there were significantly more hours where additional energy was asked for than hours where too much energy was on the market. This fact results in an expected average yearly intra-day market price which should lie above the day-ahead market price. In reality, the average intra-day and day-ahead market prices were almost identical which is interesting since measurement data shows a dominant positive activation in 67% of the time slots on the ancillary service market. This would translate into an expected additional energy demand on the intra-day market and higher expected prices on the intra-day market compared to the day-ahead market. However, the model predicted 88% share of energy deficit situations on the intra-day market compared to 67% seen on measured ASM data for Germany is another important source for the overestimated intra-day market prices by the simulation.
- Reduced remaining lignite and coal capacities: As it was shown in the validation of the day-ahead market model, the simulation overpredicts the production of lignite and coal. The aggregated production of these power plant types is already above the ENTSO-E data which corresponds to real production data after IDM. Thus, there is less remaining coal and lignite production left on the intra-day market meaning that more natural gas must be dispatched on the IDM which is more expensive.

Considering the resulting price spreads, it can be stated that the general pricing mechanism of the IDM module is working correctly and can be used for financial evaluation of future scenarios. For future scenarios, the introduction of an intra-day market is crucial since the trend is going into more electricity being traded very shortly before delivery. Furthermore, the growing amounts of installed renewable generation capacities requires a short-time energy balancing tool. The intra-day market is the main tool besides the reserve activations to compensate for such production fluctuations. The model in its current state is clearly overpredicting average IDM prices by around 33% due to a dominant positive offer requirement on the IDM and DAM cascade effects. Based on the given justification for the observed deviations, the model is considered to be working correctly. Day-ahead market volume is by a factor of 8.8 higher than the intra-day volume as it can be seen in table 3.12. Thus, errors in the day-ahead market model can significantly influence the intra-day market model results. Thus, to improve IDM model performance, day-ahead market model has to be enhanced first.

Table 3.12: Intra-day market trading volumes for Germany [8]

Average of traded Volumes in MW/h	
EPEXSPOT IDM 2014	2'388
EPEXSPOT IDM 2015	3'420
Simulation IDM	1'452
EPEXSPOT DAM 2015	30'150

Table 3.12 indicates that the intra-day model predicts an average hourly traded volume on the intra-day market of around 1'450MW. This value is clearly below the average traded volume seen

on the EPEXSPOT intra-day markets in the years 2014 and 2015. Nevertheless, this does not mean that the stochastic model is not working correctly. The justification of the significant difference comes from the fact that the model does not know ownership information. The OPF solver receives only the information about the different sources of deviations from the day-ahead market profile. If stochastic deviations are compensating each other (for example more wind production than expected but also a higher demand) there is no energy traded on the intra-day market in the model. However, in reality if the sources of the deviations stem from different balance groups, the energy is traded on the intra-day market even though the overall country energy balance was always equalized. So, the introduced model can be seen as a more efficient intra-day market model than it exists in reality. Real intra-day market is based on the principle of balance groups balancing whereas the introduced intra-day market model is based on system balancing. But as Dimitrova [28] showed in her Master Thesis balance group modeling is challenging without ownership information in the EnerPol data base. The financial effect of these energy volumes which cannot be reproduced by the intra-day market model is assumed to be small. Because in cases with balancing groups with excess production, the balance group will offer energy cheap which can be procured by the balancing group with a short-term production deficit / demand surplus. The "balanced" intra-day trade as explained before is not accounted for in the model, but this case will produce stable and low prices in the range of the day-ahead market prices.

Another important reason for the observed difference between real traded IDM volume and simulation predicted IDM trading volumes come from the fact that the stochastic model is based on 15-minutes intervals but the intra-day market is modeled in an hourly resolution as it is dominantly the case in reality. The hourly IDM amount is equal to the average of the four quarter hour intervals of demand, solar and wind forecast deviations plus the sum of all outages appearing in this particular hour. This means that all the four quarter hour intervals are considered to be completely independent. However in reality, there is an increased probability that wrong forecasts on 15-minutes basis are correlated to each other when individual hours are regarded. Therefore, the resulting IDM trading volume is assumed to underestimate the real IDM trading volume.

With a 33% increased average price level and predicted extreme price values in the range of - 82 € /MWh up to 193 € /MWh the model deviates from real IDM prices. Due to the chosen modeling approach also the traded intra-day amount deviates by a factor of 1.6 up to 2.4 from real IDM data for the years 2014 and 2015. But as already mentioned, for the deviations justified explanations could be given. Therefore, it can be assumed that the developed intra-day market model is able to estimate energy procurement costs on the intra-day market when future scenarios are performed.

3.10 Multi-Country Model

3.10.1 Cross-Border Transfer Capacity Model Description

Many European countries show tendencies for a day-ahead market coupling with implicit cross-border transfer capacity allocations. But there remain also explicit cross-border transfer capacity auctions as it is the case between Switzerland and its neighboring countries. The market models presented so far only apply for individual countries. This subsection introduces the linking of individual countries to a European wide electricity simulation with the EnerPol setup. In reality, there is an energy transfer from low price countries to high price countries which, in the ideal case, leads to a complete matching of the prices among all interconnected countries. The principle can also be seen in figure 3.34. The points marked with index one correspond to the financial equilibrium of the individual countries whereas points with index 2 reflect the market price equilibrium after the energy transfer between the countries. Often transmission constraints prevent complete assimilation of prices between countries. In this case transmission capacity becomes financially valuable. It is equivalent to the difference of the market prices between two countries and is often referred to as congestion income for the TSOs.

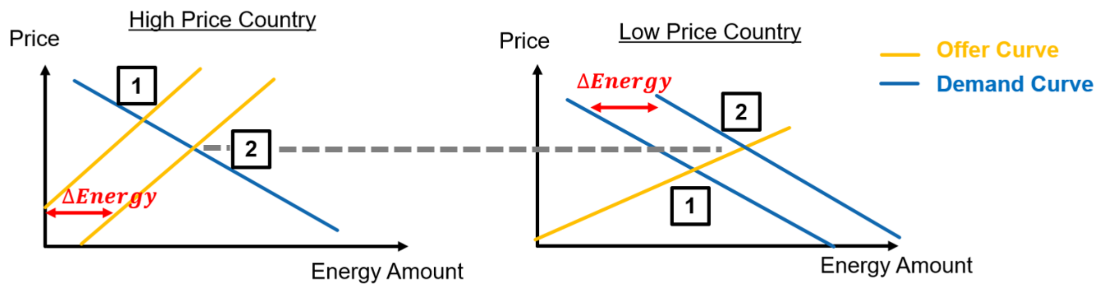

Figure 3.34: Effects of cross-border energy transfer on market price equilibrium in high and low-price country

The total transfer capacity (TTC) represents the maximum feasible power exchange, which can be transmitted between two systems A and B reliably and without affecting the system security. The transmission reliability margin (TRM) covers the forecasted uncertainties of tie-line power flows due to imperfect information from market players and unexpected real-time events. Information from market players is imperfect at the time the transfer capacities have to be communicated. [42]

$$NTC = TTC - TRM \tag{3.7}$$

NTC stands for the net transfer capacity and this value can be interpreted as the expected maximum volume of generation that can be wheeled through the interface between the two systems, which does not lead to network constraints in either systems respecting some technical uncertainties on future network conditions. The dependency of NTC-values on total transfer capacity is also shown in equation 3.7. Every international transaction (cross-border exchange) between two countries in a connected multi-country framework affects, to a greater or lesser extent, the system loading in all other interconnected transmission systems. Thus, the NTC-values are so strongly interdependent that a publication of realistic international exchange scenarios for the whole internal market of electricity in Europe is very challenging. An infinite number of combinations would have to be analyzed. This would be completely non-transparent, and difficult to interpret for market participants and TSOs. [42]

In order to given an understandable picture of the electricity transfer possibilities to market participants, the TSOs will therefore normally calculate NTCs for a forecasted time frame only between pairs of regions without considering the effects on the NTCs in other regions. [42]

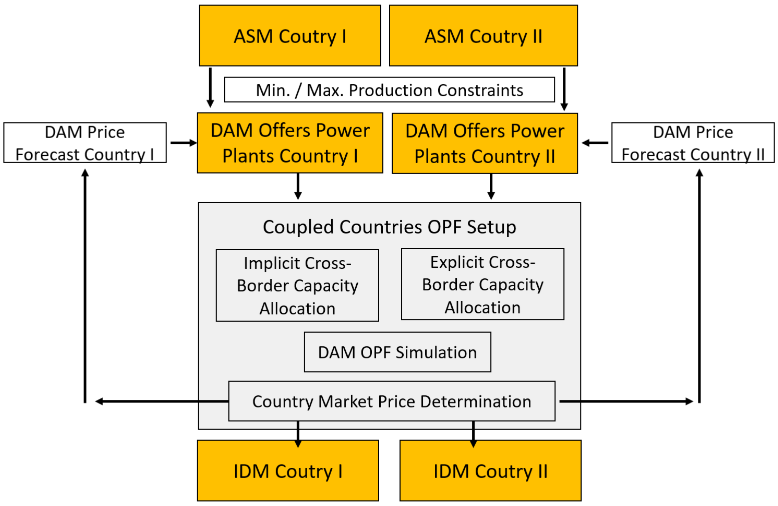

Figure 3.35: Cross-border capacity model simulation concept

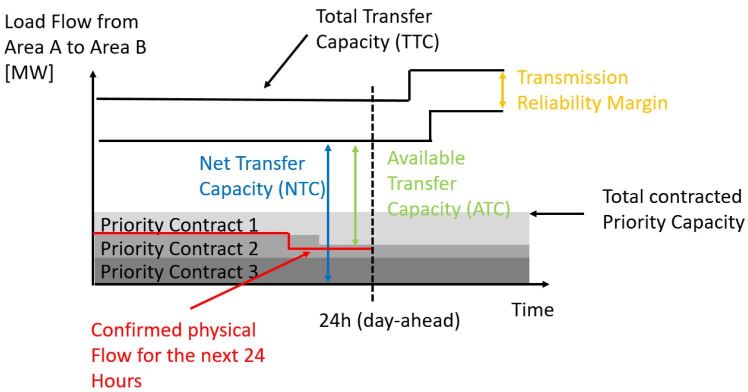

Figure 3.36: Cross-border capacitiy definitions

A schematical flow chart of the developed cross-border capacity model is illustrated in figure 3.35. The developed cross-border capacity model works in the following steps:

1. The ancillary service market is simulated on individual country basis which is realistic. In reality, ancillary service markets are even performed on individual country level for markets which are already coupled such as Germany and Austria.
2. Based on the results of the ancillary service market auctions and the country-specific price forecasts for the upcoming week the power plants place their bids for the first day of the day-ahead market auctions. This step is still performed on individual country level.

3. These bids are then transferred to the OPF setup of the coupled region.
4. In this coupled multi-country setup the code identifies the inter-country transmission lines and adapts their capacity. Depending on the kind of cross-border capacity allocation the transmission capacity allocation is carried out the following way:
    - **Implicit allocations:** The NTC set by the TSOs can show directional differences due to intra-country bottlenecks. Since these internal bottlenecks are accounted for in optimum power flow simulations, in implicit cross-border capacity allocations the higher capacity value of the two cross-border directions is chosen. Usually, in implicit allocations only ATC (available transfer capacity) values are allocated. The difference between NTC and ATC values belongs to long-term contracted capacities on the cross-border lines. Since in this project no bilateral contracts are modeled, the complete NTC values are included in the cross-border allocation procedure in this project. An explanatory schematic for the different capacity terms can be seen in figure 3.36.
    - **Explicit allocations:** The explicit cross-border allocation procedure is modeled similarly in comparison to the implicit allocation. The main difference is that the directional value of the cross-border capacity is chosen according to the expected market price difference between the two countries for the particular hour. The value is chosen for the direction from the expected low-price to the high-price country.
5. In a next step, one single optimum power flow simulation is performed for the day-ahead market in the selected countries using the fully interconnected transmission grid of the simulated countries. The previously determined NTC limits are imposed as constraints on the cross-border transmissions lines.
6. A module of the code finally determines the market prices in the individual countries based on the most expensive chosen bid in each country and a net electricity import balance. The resulting market prices on individual country level can then be used as price forecast for the optimum strategy determination for the upcoming week. Additionally, the value of the cross-border transmission capacity can be determined based on the differences of the market prices between two neighboring countries.
7. In reality, no intra-day market coupling has been introduced yet, even if there are ambitions to do so (XBID project). Therefore, the intra-day market simulation is performed on individual country level.

3.10.2 Cross-Border Transfer Capacity Model Validation

The validation of the cross-border transfer capacity model is based on the setup of Switzerland and its neighboring countries. The validation is performed in an explicit cross-border transfer capacity auction framework. The reason for this choice is that Switzerland is one of the last countries in Europe which uses explicit cross-border transfer capacity auctions. In the result section 5.1, the effects of replacing the explicit cross-border capacity auctions by a perfect market coupling with the neighboring countries are discussed.

Summary of Hydro Model Adaptions for Hydro-Dominated Country Framework

To make the developed market models usable in a multi-country framework including hydro power generation dominated countries such as Switzerland and Austria, adaptions on the hydro power plant modeling were required as discussed in the hydro power plant validation section 3.4.2. The most important changes are again summarized in the following list:

- Pump-storage power plants offer amounts are determined by weekly relative demand variations as it was implemented in the previous EnerPol framework.
- A fit function of the previous EnerPol setup is used to correlate the hourly hydro dam production to the yearly demand variations. The sum of the production volumes determined on an hourly basis determines the weekly water budget of hydro dam power plants The weekly water budget can then be used to provide ancillary services or to act on the day-ahead market.
- Due to the limited amount of power plant technologies present in hydro dominated countries such as Switzerland and Austria, day-ahead market prices are mostly determined by the hydro power plants in hours of electricity exports. As it was shown the used correlations for representing the missing hydro power plant reservoir sizes and yearly production amount are not able to reproduce the variability of production patterns of the different hydro power plants in Switzerland. Due to the missing hydro power plant data base information, a demand-based offering of the hydro power plants had to be applied to guarantee for availability of production resources during the complete year. With this approach, the pricing routine of the individual country setup cannot be applied. The hydro dam day-ahead market offer price is therefore determined by using demand information, the German day-ahead market price level as reference value as well as domestic prices of the past week. This approach corresponds to hydro power producers trying to maximize their profit by using their market knowledge which is what can be observed on the real market.

NTC Values for Swiss Borders

As a first step of the validation process the NTC values provided by the ENTSO-E were compared to the actual physical cross-border flows for the year 2016. As figures 3.37 to 3.39 indicate, there are significant differences between the NTC values and the physical cross-border flows for the Northern border of Switzerland containing Austria, France and Germany. In extreme cases the physical flows at the German-Swiss border are by a factor of 4 higher than the NTC values.

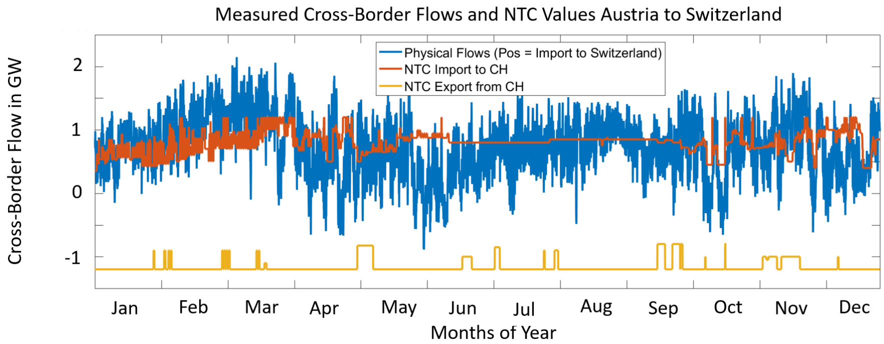

Figure 3.37: Measured cross-border flows and NTC values for Austrian-Swiss border

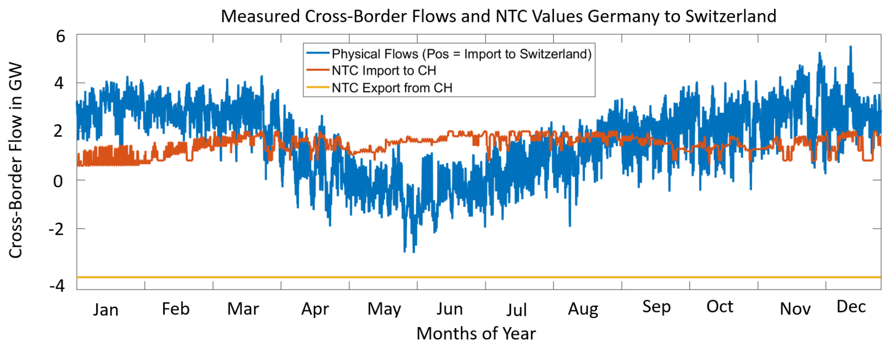

Figure 3.38: Measured cross-border flows and NTC values for German-Swiss border

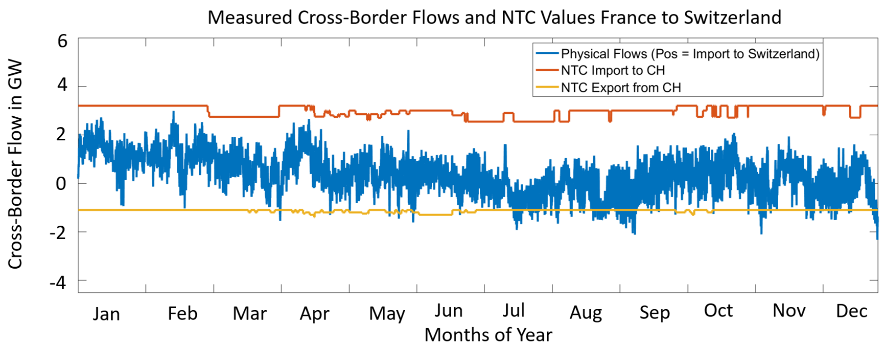

Figure 3.39: Measured cross-border flows and NTC values for French-Swiss border

The explanation for the significant differences between physical flow of electricity and NTC values at the Northern border of Switzerland are complex. On the one hand, the transformation between the high voltage levels 220kV and 380kV plays a role. But more important are so called ring flows which influence the NTC values. In reality, electricity flows the path of the least resistance. This means that often energy which is delivered from France to Switzerland does not flow directly by the French-Swiss border but flows through Germany into Switzerland. These flows load the German-Swiss transmission lines, and prevent a further line usage for more commercial trades and electricity flows from Germany to Switzerland. Therefore, the NTC values and physical flows of the Swiss borders to Austria, France and Germany have to be regarded as one border, often referred to as North roof ("Norddach"). [43] The added cross-border flows and NTC values for the northern Swiss border are plotted in figure 3.40. The maximum physical flows and the NTC values match better than if individual countries are observed. The remaining overshooting of physical electricity flows compared to NTC values could be due to slight intra-day adaptions of NTC values by the TSO since the plotted NTC values correspond to day-ahead forecasted NTC values. Another reason for some short-term overhootings of individual hours could be outage events anywhere in Europe which require strong solidary PRL activation (maximum activation of 3'000 MW). These outage events and the resulting ancillary service activations can influence the cross-border flows on an hourly basis.

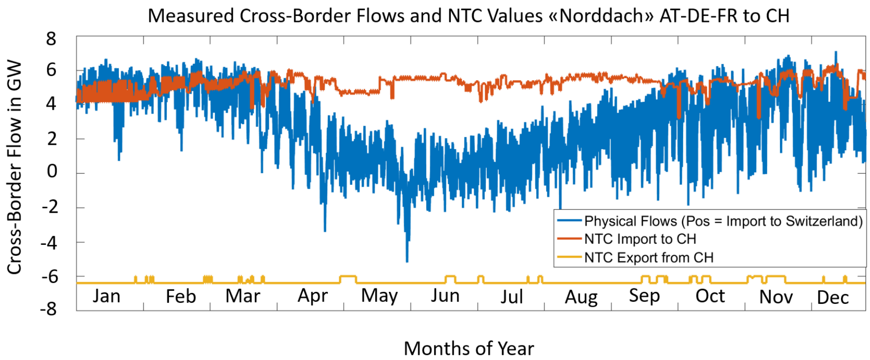

Figure 3.40: Measured cross-border flows and NTC values for "Norddach" border (AT-DE-FR to CH)

For the Swiss border to Italy the maximum NTC values correlate well to the maximum physical flows. In figure 3.41 it has to be stated that the Italian TSO does not provide physical flow values for free for the year 2016. Therefore, the ENTSO-E cross-border flows do not contain any information about the periods when electricity flows from Italy to Switzerland. Thus, no values in the positive region of the plot can be found in figure 3.41.

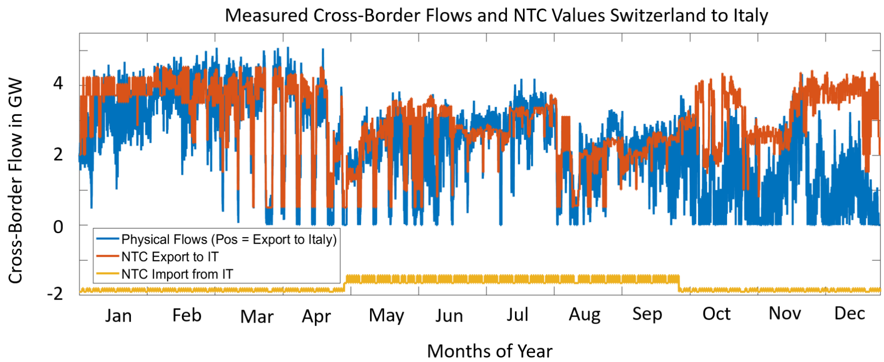

Figure 3.41: Measured cross-border flows and NTC values for Italian-Swiss border

Implementing Cross-Border Constraints

As a result of the seen deviations of physical flows and NTC values for the Swiss borders, the cross-border capacity limiting NTC values were modeled as the maximum of the directional physical flows in a yearly period. These values are assumed to be constant. When the real NTC values are studied, it can be seen that there is no clear yearly trend visible, but rather short-term adaptions which are challenging to forecast and include into the model. Limiting the transfer capacities to the maximum physical flow values allows to reproduce the physical cross-border flows if the model is working properly which is advantageous. These cross-border flows were used as validation criterion for the cross-border transfer capacity model. To allow for convergence in the OPF framework and to adjust for the non-proportional usage of connecting transmission lines between countries, as well as for the difference in voltage levels of the lines (220kV and 380kV) the physical flow value had to be multiplied by 1.3.

Cross-Border Flow Comparison

Finally, the resulting simulation predicted cross-border physical electricity flows for the Swiss borders with the modeled explicit transfer capacity auction framework which represents today's auction situation are compared to ENTSO-E data.

As a first part of the analysis the resulting weekly average cross-border flows are analyzed and shown in figure 3.42. Important criterion to evaluate the cross-border model is the general import export trend between the countries. The model correctly predicts net imports from Austria, France and Germany and a significant electricity net export to Italy. However, it can be seen that in summer months the net exports to Germany cannot be correctly reproduced and instead exports to Italy are overestimated. A potential explanation on the cross-border transmission constraint level could be, that the assumed constant NTC value for exports to Italy in the model is reduced in reality during summer months from around 4 GW to around 2.5 GW as it could be seen in figure 3.41. This constraint would prevent the high summer flows seen in the explicit simulation result.

Figure 3.42: Comparison of simulation predicted cross-border flows for explicit cross-border auctions and measured cross-border flows for Swiss borders for the year 2013

In a next step the average cross-border flows are compared to measurement data for the year 2013. Table 3.13 shows that the average hourly cross-border flows are predicted with an relative error which is smaller than 25% for the Swiss borders to Austria, France and Italy. Due to the wrong net direction during summer months the relative error is amplified to 72% for the Swiss-German border. Additionally, the model correctly predicts Switzerland to be a net electricity exporter. The difference between measured and simulation predicted net export can be explained by a potentially different Swiss conventional power plant (nuclear and gas) dispatching than seen in reality which can be caused by the inability of the simulation to correctly reproduce Swiss market price patterns. In contrast to hydro power plants, thermal power plant production is only limited by maximum production capabilities and ASM constraints. Therefore, ASM dispatching and resulting conventional power plant production can vary according to market prices and influence the electricity export potential of Switzerland. Additionally, the scaling of hydro power plant production offer amounts in EnerPol by demand variations creates another deviation from real hydro dam production patterns which can influence the import export balance as well. Finally, the used hydro power pricing strategy is not able to reproduce complex Swiss day-ahead market price patterns. Therefore, a too aggressive hydro offer pricing can gamble away electricity export potential and be another source of a resulting lower net electricity export.

Table 3.13: Average of hourly simulation predicted explicit auction cross-border flows compared to measurement for Swiss borders in 2013

Border	**Simulation (MW)**	**Measurement (MW)**	**Relative Error (%)**
CH to AT	-597	-800	-25
CH to FR	-729	-840	-13
CH to IT	2’691	2’528	6
CH to DE	-1’300	-756	72
CH overall Electricity Export	65	132	

The total amount of electricity flows crossing Swiss borders is predicted correctly by 1.5% when comparing to measurements and considering the complete year 2013. With the general ability to predict average cross-border flow direction trends correctly, the cross-border model can be used in a case study to analyze a change in cross-border transfer capacity allcoation mechanism at the Swiss borders.

Simulation Predicted Day-Ahead Market Prices

The developed cross-border simulation model is also desired to predict effects of switching cross-border auction mechanisms on day-ahead market price levels or congestion revenues. But since the currently implemented hydro power pricing model is not able to reproduce the complex market price patterns for Switzerland, simulation predicted day-ahead market prices are excluded from the analysis. In reality, the Swiss market price shows similar price trends compared to the German day-ahead market price but with a typical off-set of around 5-10€ /MWh during winter months and similar prices during the summer months. Besides congestion, this off-set during winter months is assumed to stem from Swiss hydro producers exploiting their market knowledge and market power. Market knowledge and market power is difficult to model. Prices of hydro dominated countries can influence price level of neighboring countries during net export hours. Since power plants optimize their strategy and ASM offers based on the resulting prices of the previous week, deviating hydro dominated country prices prevent an exact reproduction of real day-ahead market prices. Therefore, the following analyses in the result section 5.1, where the effects of switching cross-border transfer capacity mechanisms are discussed, are mainly based on observations in the physical flow field and not on simulation predicted day-ahead market prices.

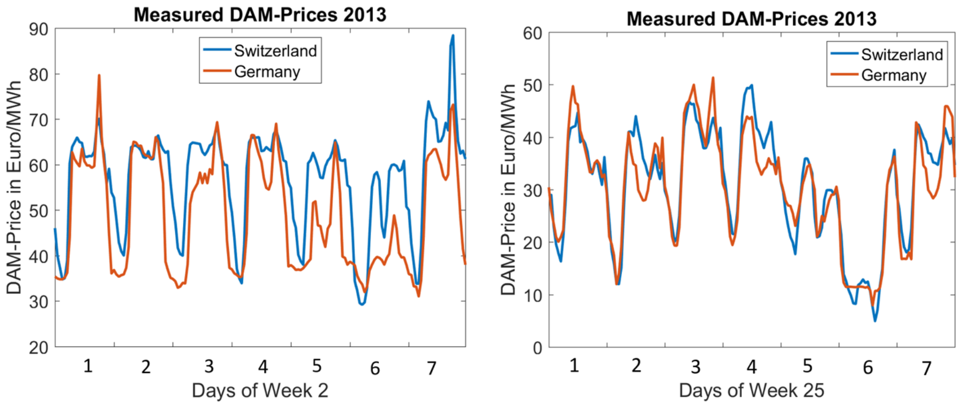

Figure 3.43: Comparison of measured DAM prices for Germany and Switzerland for a winter and a summer week of 2013

To sum up, the validation of the cross-border model showed that the main flow directions of electricity at the Swiss borders can be correctly predicted which allows to quantify the effects on electricity flows when switching the cross-border transfer capacity allocation mechanism. In its current state, the code provides tools to analyze resulting day-ahead market prices as well as resulting congestion revenues for TSOs. For a future reliable assessment of these financial parameters, a detailed hydro power plant data base is required which allows to use the hydro power plant pricing tool applied in the single-country framework.

3.11 Electricity Market Segments Excluded from Developed Market Model

After the presentation and validation of the implemented market model components a discussion about neglected market segments is necessary. Justification for these neglections will be given in the following paragraphs.

Futures Market

As already discussed in chapter 2, the futures market is mainly used for long-term hedging of physical production assets or required electricity for end-consumers. The market is cash settled and no physical delivery of electricity results out of it. Since EnerPol is based on a physical optimum power flow simulations, an additional model for the futures market is not of primary interest.

Since no physical delivery of electricity is required, more players can be active on this market. These players, such as trading companies or financial institutes, create another step of complexity which make accurate modeling very challenging.

Secondary Markets / Bilateral Contracts

The bilateral contracts are not modeled in this project due to two main reasons: First, bilateral contract see yearly decreasing trading volume shares compared to the electricity volume traded on power exchanges. The current trading volume of bilateral contracts is around 50% of the total traded electricity, but this value used to be around 90% 5-10 years ago. [7] This means that bilateral contracts will become less important to model the wholesale electricity market. Secondly, due to the nature of bilateral contracts which give the contract parties a lot of freedom for individual contractual conditions, accurate modeling of bilateral contracts is extremely challenging. Bilateral contracts are not traded transparently, and are therefore challenging to model. If the assumption is made, that bilateral markets are liquid and the market players profit-oriented, neglecting the bilateral contracts and modeling the complete wholesale market as power exchange can be justified.

Loss Compensation

Transmission losses typically sum up to a maximum of 5% percent of the total electricity load in the grid as it is also shown in figure 3.44. [44] Most TSOs procure the required power to compensate the transmission losses in auctions according to their electricity flow forecasts. These markets do not show significant dynamics in price developments, market structure changes or cooperation intentions. Following this, the loss compensation market is not modeled as market. But the optimum power flow solver dispatches additional power plants to provide the required additional power. In Switzerland, comparison of EPEXSPOT day-ahead market data and Swissgrid report data for the year 2015 shows that loss compensation causes costs which correspond to 5.1% of the day-ahead market volume. Since the loss compensation market has a negligible size compared to the other market segments, it is not modeled in this work.

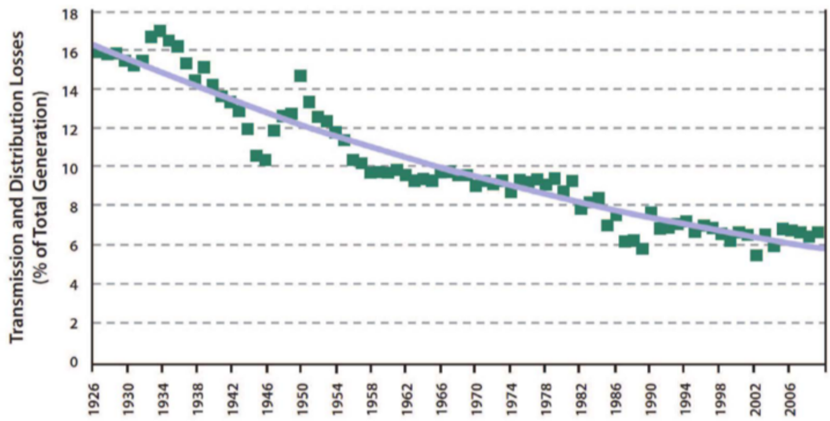

Figure 3.44: Development of transmission and distribution losses in the United States since 1926 [44]

Reactive Power

Reactive power procurement is different to standard electricity trading. Reactive power cannot be transported over longer distances and can therefore be classified as regional product. Minimization of reactive power transport is also motivated by the reduction of the Joule losses on the line. In fact, these losses are expressed by the equation 3.8:

$$\Delta P_L = 3RI^2 = R\frac{P^2 + Q^2}{V^2} \tag{3.8}$$

where not only the active power P but also the reactive power flow Q contributes to line losses. R stands for the resistance and V corresponds to the voltage. Because the thermal limit is defined by the admissible current for any network element, the reactive power transfer reduces the amount of active power transmission flow. From these considerations, the following statement concerning reactive power line transfer is apparent: Reactive power flow on the line increases line losses. [45]

Therefore, no significant future cooperation of countries in the area of reactive power can be expected and the potential for structural changes in this market are limited. Hence, the reactive power market also is not the main point of interest when future scenarios are simulated with the EnerPol framework. When for the year 2015 the total procurement costs of the TSO Swissgrid is compared to the volume of the day-ahead market in Switzerland, it can be seen that reactive power procurement only is responsible for 3.9% of the financial volume of DAM traded volume.

Black Start, Island Operation

EnerPol performs steady-state power flow simulations with an hourly resolution. System start-ups or black-outs are not simulated directly. Such events are only addressed by non-converged optimum power flow results. Black start / island operation ancillary services are thus neglected in the presented market modeling approach.

3.12 Performance Enhancement Potential for Developed Market Models

After the presentation and validation of the different market model modules, a short discussion about future improvements of the market models is presented in this section.

- Block orders, linked orders and order specification options for offers for the different electricity markets (day-ahead and intra-day markets) are not included in the presented models. A main difficulty during the project was the increasing simulation time which had to be handled by using parallelization on multiple cores on the cluster. If the individual optimum power flow simulations show dependencies among each other due to linked orders, the computational effort would increase dramatically and prevented an efficient usage of the developed models within this project. However, if the resulting ramping rates of power plants want to be reduced, linked and block orders are the suggested strategy to follow.
- If complete data about power plant ownership and consumer grouping information was available, it would allow for a proper balance group modeling and more realistic market modeling. In this case, the optimum strategies could be determined on balance group level instead of individual power plant level. Balance group strategy optimization is what is done on real markets.
- Another important step to improve the market models in the future is a hydro power plant data base. A realistic market model for hydro power plants requires information about reservoir size, vertical height between basin and turbine, number of turbines, turbine type, cascade / pool information, as well as yearly production and inflow data. Cascade effects and reservoir constraints can dominate the optimum hydro power plant production strategies and are therefore crucial for an appropriate application of the developed hydro models in hydro-dominated country frameworks.

Chapter 4

Capacity Market Model

The European Union seeks to achieve 35% of electricity generation delivered by renewable energy sources until 2020. Renewable electricity production is intermittent due to its weather dependency. Following this, conventional generators are still required as back-up capacities in times of low solar irradiance and no wind. With the low electricity prices seen at the markets during the past years, there is no incentive to maintain conventional thermal power plants or initiate investments in new conventional power plants. As an example, one can mention the power plant Irsching, one of the most efficient gas power plants in the world. [46] The operator desires to decommission the power plant due to insufficient financial performance. In addition, more and more conventional power plants (e.g. nuclear power plants) are planned to be decommissioned in the next years. To get out of this dilemma, one has to create incentives for future investments into conventional power plants. One potential solution is the introduction of a so-called capacity market, where power plants receive fixed capacity availability payments over a certain time period. An interesting question resulting out of this proposal is: What capacity payment tariff would be required to make investments in conventional power plants profitable again? To answer this question, a capacity market concept was developed for the EnerPol simulation framework.

4.1 Required Conventional Power Plant Capacities

There are two main reasons why there is a need for new conventional power plants in the future. On the one hand, existing power plants reach their life time limit and have to be decommissioned and on the other hand, due to the increasing share of renewable generation, backup capacities are required. Out of the expected load for the future years, the renewable generation capacity and the decommissioning of power plants, an estimation about the required conventional power plant capacity can be done. There are two conservative main scaling criteria:

- As a worst case assumption the expected peak load in the particular year has to be covered by conventional power plant generation. Underlying consideration for this criterion is, that on a worst-case day with no solar irradiance, no wind and defect transmission lines to neighboring countries (or neighboring countries facing the same situation), the electricity demand of the country has to be covered by conventional generation units. This extreme case is considered to be too conservative, which would lead to a conventional capacity requirement that is too high. Therefore, on the following pages, a reasonable relaxation for this criterion is introduced.

- The ancillary service procurement amounts which are in relation to the grid stability have to be satisfied. Since ancillary services cannot be provided by renewables, there is a need for conventional generation capacity. As it was shown in the stochastic model chapter, demand, wind and solar forecasts are often wrong, and introduce a stochastic delta energy. Since these fluctuations are very short-term (in the range of seconds and minutes), the installed conventional capacity which must handle these changes in production has to be very flexible. Most probably this capacity amount must mainly be covered by natural gas power plants. In appendix A.1.5 correlations between the average hourly load, the installed renewable capacities and the procured ancillary service amounts were determined. These correlations can be used in the capacity market model to determine the required ancillary service amounts in the future years.

For this project it is assumed that power plants have to be decommissioned after a certain age threshold depending on the generator type. The decommissioning age limits for each of the respective generator types will be presented on the following pages. With this life time assumption and determined future scenario scaling factors, for each year of the analysis the required newly installed conventional capacity can be determined. EnerPol simulations are performed in 5 years time steps for the years 2020-2045. For each newly installed power plant a 45 year pay-back period is considered. The years after 2045 are not simulated in an EnerPol framework. The cash flows for the years 2045 onwards are assumed to be the same as the cash flows of the year 2045. The general capacity market working principle is illustrated in figure 4.1.

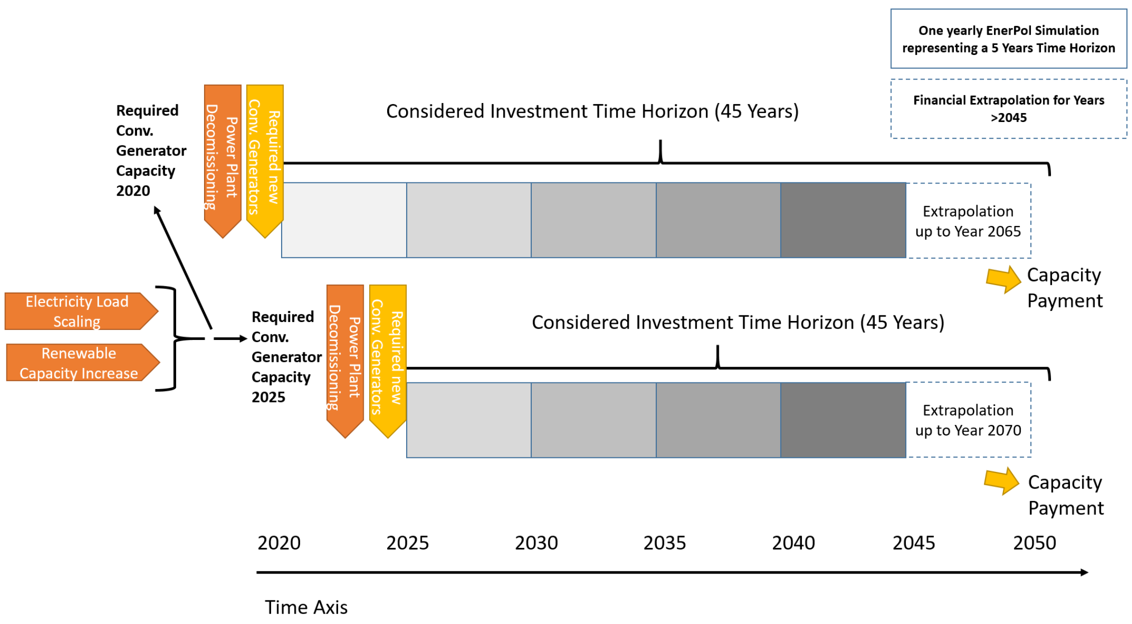

Figure 4.1: Schematic of the working principle of the capacity market model

Power plant types which are installed in future years must satisfy two main requirements: Flexibility in production for fast adaptions to renewable generation as well as low production costs for being able to persist in the competitive electricity market. Since in Europe no private investments in nuclear power plants can be seen, due to public acceptance and the high cost of decommissioning, this power plant type was neglected in the capacity market analysis. Lignite power plants were also expected to be no alternative, due to their high CO2 emissions. Therefore, the new installed capacity was chosen to be a mix from coal power plants and flexible natural gas power plants.

Ancillary Service Amount Criterion

In a first step, the required amount of new natural gas power plants is determined for all the analyzed years such that the ancillary service requirement criterion is satisfied. Since primary reserves are automatically provided by power plants connected to the grid and tertiary reserve have relatively long allowed response times of around 15 minutes which allows for large capacity amounts offered by generators, the decisive criterion for determining the required amount of flexible natural gas capacities is the secondary reserve amount.

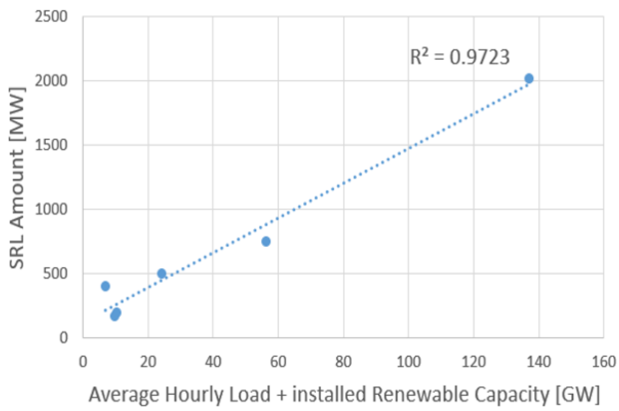

Figure 4.2: Correlation of procured secondary reserve capacities with average hourly load of country and installed renewable capacities

In contrast to primary reserve which is provided solidary among the European countries, secondary and tertiary reserves have to be provided from the control area which causes the grid imbalance. Therefore, the procured amounts of secondary and tertiary reserves are assumed to scale with grid imbalance risk factors such as wrong demand or renewable generation forecasts. A pure scaling with the average hourly load of the country does not provide satisfying results. Germany and France have similar average load values of around 55 GW but there is a huge difference in procured secondary reserve amounts (around 1’200 MW) as it can be seen in figure A.6. If the installed renewable capacity is added to the average country electricity load, the correlation fits well. With an R^2 value above 0.97, the correlation can be categorized as strong. The found correlation is based on the European countries Austria, Czech Republic, Switzerland, France, Germany and Poland. Detailed explanation about the finding of the different ASM correlations is given in appendix A.1.5. The required SRL amount in the developed capacity market setup for the future years is therefore determined by equation 4.1:

$$SRL_{Req}(MW) = 123.9 + \frac{AvHourlyLoad(MW) + insRenewableCap(MW)}{1000} \times 13.5 \qquad (4.1)$$

In the market model, natural gas power plants are modeled as being able to ramp 100% of their rated capacity in an hour. For providing secondary reserves, the contracted reserve amount must be made completely available at the latest five minutes after the receiving of the activation signal. Therefore, in the model, the capacity which can be offered by power plants is limited to 1/12 of the hourly ramping potential. Therefore, natural gas power plants are allowed to offer 8% of their rated capacity for providing ancillary services. Out of this, the required capacity of flexible gas power plants can be determined as shown in equation 4.2:

$$\text{Required Flexible Gas Capacity (MW)} = 1/(\frac{RelativeHourlyRampingPotential}{12}) \times SRL_{Req} \quad (4.2)$$

The difference between existing flexible capacities (hydro dam, pump-storage and natural gas power plants) and the determined required minimum amount of flexible capacities determines if in a particular year additional gas power plants are required.

Peak Load Criterion

As a second check after the ancillary service criterion, it is checked whether the existing conventional power plants in combination with the new gas power plants sum up to sufficient baseload equivalent capacity to cover the expected peak load design criterion of the analyzed region. If not, additional coal power plants are added since they have lower marginal costs than natural gas power plants assuming that the fuel cost ratio between coal and gas does not change significantly during the analyzed time period.

As already mentioned the peak load criterion is based on the following assumptions:

- no solar irradiance and hence no photovoltaic production
- no wind
- no possibilities for electricity import

To prevent a too conservative capacity requirement calculation this criterion is relaxed. Two potential worst cases are differentiated: A "day" and "night" worst case scenario. The worst cases consist out of the following scenario: A load which is higher than 95% of the appearing loads during days / nights as well as a wind and solar production which is lower than in 95% of all considered time intervalls (2-σ analysis). All the presented values in table 4.1 are based on ENTSO-E data analysis for Germany for the year 2016. With this assumption 99.9% of all potential load situations can be handled $(1 - (0.05 \times 0.05 \times 0.05) = 0.999)$

Table 4.1: Peak load criterion modeling values

	Day Scenario	**Night Scenario**
$Peak_{95\%}$	93% of Peak Load	84% of Peak Load
$Wind_{Min}$	2.6% of inst. Wind Cap.	3.7% of inst. Wind Cap.
$Solar_{Min}$	4.1% of inst. Solar Cap.	0% of inst. Solar Cap.

Numerical values in GW of the peak load criterion are presented for Germany for the year 2016 in table 4.2.

Table 4.2: Peak load criterion calculation example for Germany 2016

	Day Scenario	**Night Scenario**
$Peak_{95\%}$ (GW)	70.7	64.0
$Wind_{Min}$ (GW)	1.1	1.6
$Solar_{Min}$ (GW)	1.6	0
$Peak\ Criterion$ (GW)	68.0	62.4

As it can be seen in table 4.1, the more critical case in terms of peak load coverage is clearly the day period with a calculated peak criterion of 68 GW compared to 62.4 GW for the night case. For the capacity market analysis, the worst case scenario day was therefore chosen, since this is the decisive criterion to determine future grid stability. The mathematical formulation of the described process to identify the critical load scenario is given by equation 4.3.

$$\text{Peak Criterion required conventional Capacity (MW)} = max_{Scenarios}(Peak_{95\%} - Wind_{Min} - Solar_{Min}) \tag{4.3}$$

To account for reduced power plant output for providing ancillary services and non-optimum power plant location choice for newly installed generators, the total conventional installed capacity has to be increased by using a safety factor S_F. In this project the safety factor was chosen to be 1.1. 10% additional capacity translates for the year 2016 into another 6.8 GW of installed baseload capacity. Since the peak load criterion for the analyzed period 2020-2045 constantly is above 60 GW, the 10% margin allows to compensate for the expected SRL and TRL+ maximum production capacity reduction due to the expected increased amount of required ancillary services which are around 3 GW each for the year 2045. Forced outages are covered by the continuously available ancillary service capacities. Non-availabilities of power plants due to maintenance or refueling are planned events which can be compensated by importing electricity and are therefore not calculated in in the peak load criterion. The required total conventional capacity is therefore given by equation 4.4.

$$\text{Required total conventional Capacity (MW)} = S_F \times \text{Peak Criteria required conventional Capacity} \tag{4.4}$$

4.2 Power Plant Decommissioning Model

Typically, the life time of fired power plants is estimated to be around 50 years. This threshold value was used for the decommissioning model of the capacity market for the power plant categories coal, lignite and gas. According to the political decision in Germany for nuclear phase out, all nuclear power plants have to be decommissioned until 2022 which is accounted for in the model. In contrast to thermal power plants, hydro power plants are assumed to have a life time of 100 years in the model. The placement of new hydro power plants is geographically constrained, and most countries do not show a huge remaining potential for the usage of hydro energy. Therefore, the high life time assumption for hydro power plants is justified, which transfers into a status-quo assumption for hydro power plants for the future scenarios. Similar considerations lead to the value of 100 for the decommissioning of biomass power plant. Most biomass power plants were built later than coal and lignite plants and can therefore be assumed to last for the analysis period of 2020-2045. Decommissioned biomass power plants are assumed to be replaced immediately.

Table 4.3: Power plant life time threshold values

	Modeled power plant lifetime of conventional generators in years
Biomass	100
Coal	50
Lignite	50
Natural Gas	50
Nuclear	Phase Out until 2022
Hydro Dam	100
Pump-Storage	100
Run-of-River	100

4.3 Financial Attractiveness for Investment into a Power Plant Project

To make an investment in a power plant project attractive for investors, a certain return on their invested capital is required. Therefore, in a first step of the financial analysis, the determination of the target internal rate of return will be discussed.

Typically the desired rate of return rate of an investor consists of a base risk and an additional risk premium, depending on the investment security of a particular country. This relationship is presented in equation 4.5.

$$\text{Target Internal Rate of Return} = \text{Base Risk} + \text{Country Risk} \tag{4.5}$$

In this thesis the base risk was assumed to be 7%. Pfeiffer uses in her Master thesis a target IRR of 7.5% for investments in conventional thermal power plants in Western Europe. [47] The chosen value of 7% is also in line with a publication of Partners Group which targets 8-9% IRR for investments in thermal power plants in developed countries. [48] The respective country risk premium was set according to calculations of Prof. A. Damodaran from the Stern School of Business. The country risk interest premium for specified European countries can be found in table 4.4.

Table 4.4: Country risk premiums to account for differences in investment security [49]

	Risk Premium in %
Austria	0.56
Czech Republic	1.00
France	0.71
Germany	0.00
Italy	2.71
Poland	1.21
Switzerland	0.00

The two interest components base risk and country risk sum up to the desired target internal rate of return. The target internal rate of return is required to determine the needed capacity payment of newly installed generators in a internal rate of return discounted cash flow method. This method will be presented in the following section 4.4.

4.4 Financial Performance Evaluation of Power Plants during Life Time

Once the target internal rate of return of an investor is known, the required capacity payment to reach this internal rate of return can be determined by performing an internal rate of return analysis using discounted cash flows for the desired investment time period. For this analysis, a pay-back period of 45 years is analyzed. For this financial analysis additional data are required:

- power plant investment costs I
- power plant revenues from day-ahead market R_{DAM}
- power plant revenues from intra-day market R_{IDM}
- power plant revenues from providing ancillary services to TSOs R_{ASM}
- power plant production costs C_{PROD}
- power plant fixed costs C_{FIX}
- power plant capacity payment R_{CAP}

With these financial information the internal rate of return (IRR) formula for an investment time horizon of 45 years can be written as:

$$-I + \sum_{t=1}^{45} \frac{R_{CAP} + R_{DAM}(t) + R_{IDM}(t) + R_{ASM}(t) - C_{PROD}(t) - C_{FIX}(t)}{(1 + IRR_{TARGET})^t} = 0 \tag{4.6}$$

t indicates the considered year in the investment time span.

Since yearly simulation progress was beyond the time horizon of this project and the yearly changes are rather small in electricity markets, five year time steps are applied in the developed capacity market model framework. So EnerPol simulations for the years 2020, 2025, 2030, 2035, 2040 and 2045 are performed. The years between the performed time steps are assumed to stay the same.

Whereas the power plant revenues from the DAM, IDM and ASM as well as the production costs of the power plants stem from EnerPol simulation results with the new market model approach, investment costs and power plant fixed costs are based on literature.

Investment and Fixed Costs

Important financial parameters for the internal rate of return analysis are the investment costs of a new power plant as well as the fixed costs which are required to run a particular power plant. These values cannot be taken out of the EnerPol simulation framework but have to be set according to literature.

Table 4.5: Investment costs and fixed costs for different power plant technologies [50] [51]

Technology	Capital Costs (USD/kW)	Fixed Costs (USD/kW/Year)	Added Power Plant Size (MW)
Coal	4’000	30	600
NGCC	1’000	11	500

The values presented in table 4.5 represent averages over the different power plant combustion technologies of a particular power plant type which are in use today. The power plants added in the future EnerPol simulation years are natural gas combined cycle power plants in blocks of 500 MW as well as coal power plants with a uniform block size of 600 MW. The capital costs and fixed costs for the newly installed power plants are calculated according to the values presented in table 4.5.

Figure 4.3 summarizes the concept of how the required capacity payment is determined in the developed capacity market framework. Out of the EnerPol simulations, which are performed in 5 year time steps, revenues and variable costs can be determined. With the set target internal rate of return and initial and fixed cost estimations coming from literature the required capacity payment can be evaluated. The required capacity payment per generator can be determined by solving equation 4.6 for the variable capacity payment R_{CAP}.

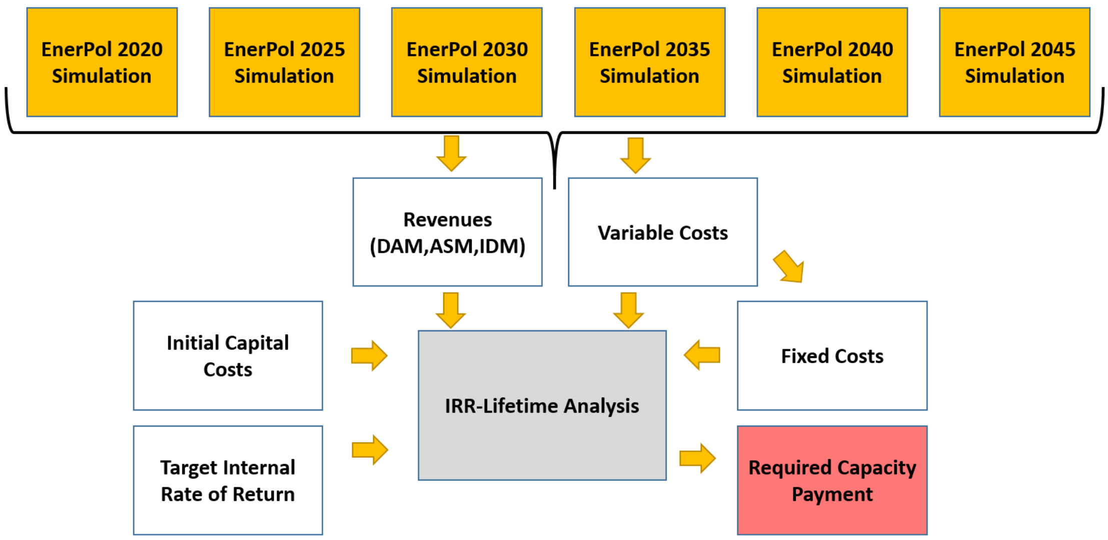

Figure 4.3: Basic principle to evaluate financial performance of power plants in a multi-year framework to determine required capacity payments

4.5 Capacity Market Organisation Concept

The capacity market concept developed in this project is based on the following characteristics:

- The TSO determines the required new capacity values for 5 year intervals.
- General idea is that there is a fixed yearly capacity payment in € /kW/year for new conventional generators for a time span of 45 years.
- An auction is performed 5 years before the capacity is required.
- New power plant projects are allowed to offer which yearly capacity payment they require.
- To minimize capacity payment costs a pay-as-bid payment mechanism is proposed.
- The financial payments start in the year of the capacity requirement. Consequently, this means, that the capacity payment tariff will vary depending on the year of construction of the power plants. In the developed setting, there will be a capacity auction every 5 years.
- The required flexible capacity is procured within the ordinary capacity market auction but with additional pre-qualifications for power plants which want to apply for this part of the capacity market auction.

4.6 Future Scenario for Germany for the Years 2020-2045

Before the results of the future scenario simulation framework for Germany for the years 2020-2045 are discussed in result section 5.2, the assumptions behind the simulated scenarios are presented on the following pages. The study was performed for Germany since it is the biggest electricity market in Europe which already shows a significant amount of installed renewable electricity. The decommissioning plans for the nuclear power plants and the reaching of the life time limits for many other conventional power plants make Germany an interesting field for such future scenario simulations.

To simulate the future years of electrical power flows in Germany a scaling factor concept was applied to adapt the EnerPol 2013 data base. Table 4.6 shown on this page summarizes the most important scaling factors which were used to perform the EnerPol simulations for Germany for the years 2020-2045.

Table 4.6: Simulation scenario for Germany for the period 2020-2045

	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Demand							
Population (Mio.)	81.6	80.7	79.8	78.5	77	75.4	73.5
GDP per Capita (%)	100	110	116	123	132	142	153
Energy Efficiency (%)	100	106	112	119	125	130	135
Overall Electricity Demand (%)	100	103	101	99	100	100	101
Urbanisation							
Urbanisation (%)	100	103	105	107	108	109	110
Renewables							
Wind Capacity (GW)	34	60	70	80	85	88	90
Solar Capacity (GW)	36	50	60	65	68	70	72
Commodity and Emission Prices							
Gas Price (%)	100	100	100	128	128	128	128
Coal Price (%)	100	87	89	92	95	97	100
Uranium Price (%)	100	100	100	100	100	100	100
CO2 Price (%)	100	113	133	153	200	247	313

The reasoning behind the chosen values is presented in the following paragraphs. Generally it can be stated, that the chosen scenario can be categorized as rather conservative than aggressive in terms of changes of the demand scaling factors over the analyzed period.

Electricity Demand

In the considered scenario the future electricity demand is estimated using three scaling factors: the population development, a GDP per capita trend as well as assumptions about future energy efficiency improvements. The German population forecasts predicts a decreasing population for the analyzed time period. [52] The energy efficiency factor was derived from data from the Swiss "Energiestrategie 2050". [53] The GDP forecast is based on data published by the OECD. [54]

$$\text{Demand Scaling Factor} D_F = \frac{F_{Population} \times F_{GDPperCapita}}{F_{F_{EnergyEfficiency}}} \tag{4.7}$$

The effect of the scaling factors on the energy demand can be seen in equation 4.7. It has to be clarified that an energy efficiency above 100% means a reduction of electricity consumption.

The relative GDP per capita increase of 53% by 2045 corresponds roughly to a constant yearly 2% GDP growth for the period. The GDP increase assumption is derived from a OECD long-term GDP forecast. [54]

The effect of electrical mobility was not separately accounted for in this demand scaling approach. Growth in electric mobility sector is expected to increase the electricity consumption overnight due to battery charging. However, this capacity market focusses on the required capacities to cover peak load which mainly appear during work time periods. Thus, battery vehicles are expected to have a rather small influence on peak load.

A only slight increase of overall electricity demand can also be expected when historical data on the electricity consumption per capita is studied. The electricity consumption has shown a strong rise over the past 50 years but stagnated over the last 5-10 years as it can be seen in figure 4.4.

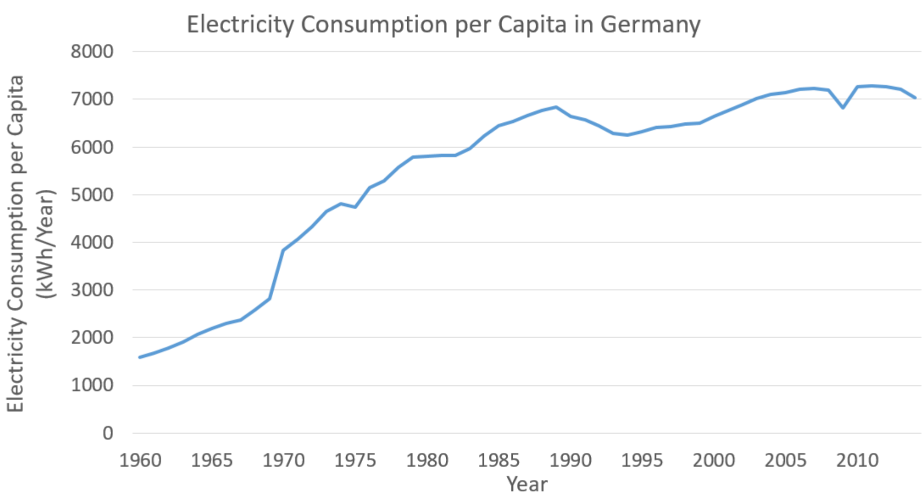

Figure 4.4: Electricity consumption per capita for Germany [55]

Commodity and Emission Prices

The prices for the fossil fuel energy sources were set according to market price forecasts. [56] [57] As an example for such data, a natural gas forecast is presented in figure 4.5. Generally, a slight increase of fossil fuel prices is expected, which is plausible since these natural resource reserves are diminishing. Due to new environmental legislations, the price for CO2 emissions is expected to increase strongly by a factor of 3. [58]

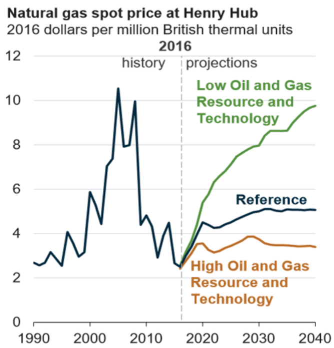

Figure 4.5: Historical and expected Henry hub gas price [57]

Installed Renewable Capacity

The future scenario for the installed renewable capacity is based on the assumption that the heavy growth rate of installed capacity will decrease strongly in the years 2030-2045. As reference points for the expected installed renewable capacity served a study about wind energy scenarios for the year 2030 of the European Wind Energy Association. [59]

Chapter 5

Results and Discussion

5.1 Cross-Border Transfer Capacity Allocation Studies for Switzerland

In this section, the effects of changing the cross-border transfer capacity auction mechanism on the physical electricity flows are analyzed for the case of Switzerland and its neighboring countries Austria, France, Germany and Italy. As already stated in section 3.10 financial studies based on simulation predicted day-ahead market prices are excluded from this analysis since an improved hydro power plant data base is required to successfully apply the hydro model developed in the single-country code version in a multi-country setup including hydro power generation dominated countries such as Switzerland. The adapted hydro model for usage in the multi-country framework in combination with the used hydro pricing model is not able to reproduce the complex day-ahead market prices in hydro dominated countries such as Switzerland.

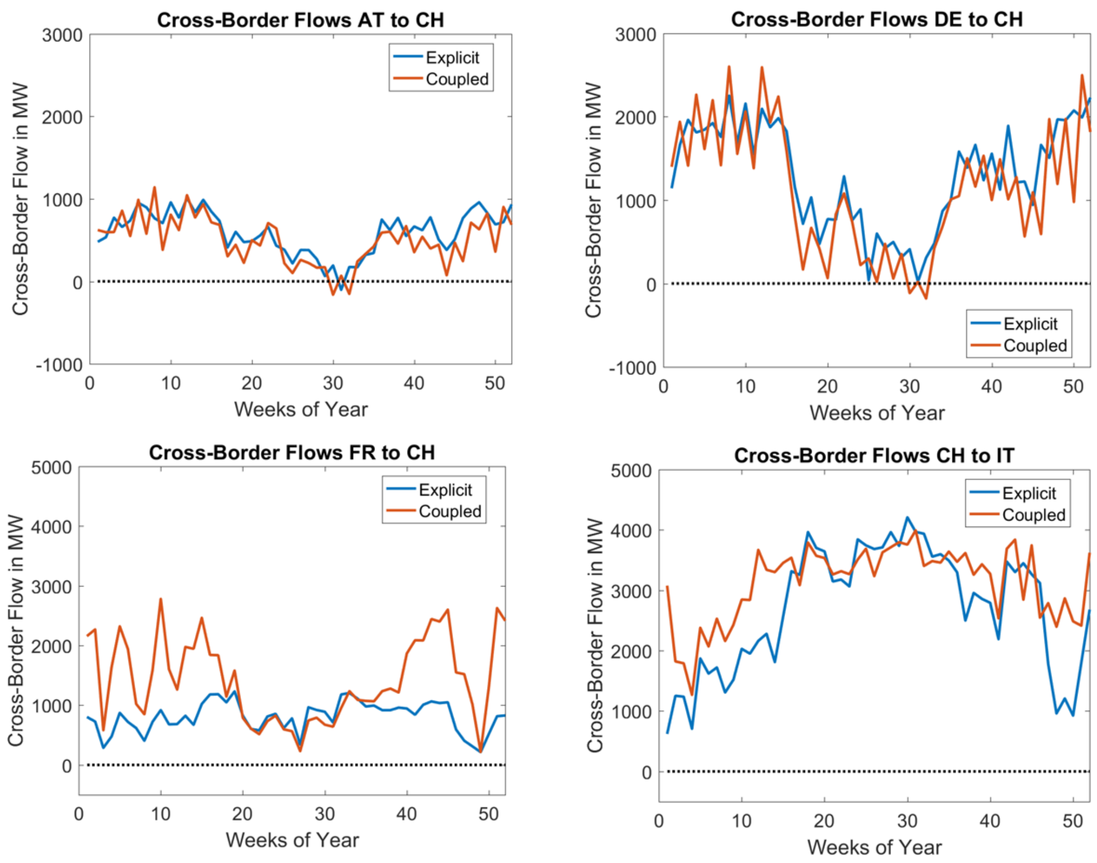

Figure 5.1: Simulation predicted physical cross-border flows for different cross-border transfer capacity auction mechanisms (explicit auctions and coupled market)

In figure 5.1 the resulting physical cross-border electricity flows are plotted for the explicit transfer capacity auction case and a coupled market simulation setup. Especially in the winter months the simulation predicts changes in cross-border flows. As a reduction of transmission constraints leads to assimilation of market prices it could be expected that electricity import from France is increased, since France showed the lowest average day-ahead market prices in the explicit auction setup. Average yearly cross-border flows from France to Switzerland are 95% higher when compared to the explicit auction case. The electricity exports from Switzerland to Italy in the winter periods are clearly increased in the coupled simulation case which also translates into expected decreasing day-ahead market prices in Italy when a market coupling of Switzerland and its neighboring countries is performed. A statement about the strength of the decrease in Italian day-ahead prices is not made here due to the reasons discussed at the beginning of this chapter. But it can be stated that Switzerland is used as transit country to bring additional French electricity generated by nuclear power plants to Italy in the coupled market case. The market coupling creates additional options for Swiss hydro producers acting as balancing agents in the European electricity system. Once a detailed hydro power plant data base is implemented into EnerPol and the hydro power plant pricing tool is improved, further investigations about the profit potential for Swiss hydro power plants can be done. During summer months, the physical flows only show slight changes when comparing explicit auction simulation with coupled market results as it can be seen in figure 5.1. Main reason for this observation is that Switzerland is a net electricity exporter in summer periods. The exported amount is given by the water resources available in Switzerland. Since these resources are fixed, a further reduction of transmission constraints does not generate a potential for stronger electricity exports.

The overall average export balance changes only by 4 MW which was expected since hydro dominated Switzerland's production resources are mainly given by the limited water reserves. Beside the changing cross-border flows and assimilating day-ahead market prices, market coupling is also expected to affect the congestion revenues earned by the TSOs when auctioning cross-border transfer capacities. Table 5.2 summarizes the real congestion revenues generated at the Swiss borders in 2013. Total congestion revenues summed up to 370.5 million € with 69% of total revenues gained at the Swiss Italian border according to Joint Allocation Office data [60]. Large cross-border transfer capacity shares are blocked by long-term contracts and therefore not included in the auctions performed by the Joint Allocation Office data. (e.g. around 40% of the transfer capacities at the French Swiss border are blocked by these long-term contracts [26]). In a fully coupled market, no cross-border transfer capacities have to be procured. Typically, congestion revenues are equally split between the TSOs of a particular border. Subsequently, the Swiss TSO would not earn the 185.25 million € of revenues generated from transfer capacity auctions when a market coupling at the Swiss borders would be activated. These revenues were so far dedicated for upgrading the grid and removing congestion points.

Table 5.1: Change in average hourly simulation predicted cross-border flows for Swiss borders in 2013 between explicit auction and coupled market

Border	**Explicit (MW)**	**Coupled (MW)**	**Difference (MW)**	**Change in absolute Value (%)**
CH to AT	-597	-501	+96	-16
CH to FR	-729	-1'420	-691	+95
CH to IT	2'691	3'125	+434	+16
CH to DE	-1'300	-1'135	+165	-15

Table 5.2: Measured congestion revenues on Swiss borders in the year 2013 (Joint Allocation Office Auction Data from yearly, monthly and daily auctions) [60]

Border	**Revenue (Mio. €)**
CH-AT	36.1
CH-DE	62.1
CH-FR	18.2
CH-IT	254.1
CH overall	370.5

When the explicit auction mechanism is switched to a perfect coupled market the cross-border flows are increased by 14% in the case of a perfect market coupling compared to the explicit auction case. The increased amount of transmission flows through Switzerland translates into higher requirements of loss compensation by the Swiss TSO Swissgrid. Nowadays, losses already sum up to a significant share of 4.4 TWh for Switzerland for today's explicit auction case which corresponds to 7.6% of Switzerland's total production. [6] The value of 4.4 TWh of loss compensation required in 2015 corresponds to 2.9% of the sum of electricity imports, exports and domestic generation in Switzerland which is in a expected range for losses in electrical grids as it was shown in chapter 3.11. For the same production level and 14% increased cross-border flows the losses sum up to 4.75 TWh which corresponds to an increase of 350'000 MWh. Assuming that the Swiss TSO has to pay the Swiss base day-ahead market price of the analyzed year 2013 of 44.7€/MWh in the loss compensation ancillary service market, this corresponds to further expenses of:

$$\text{Additional Costs for Loss Compensation} = 350'000MWh \times 44.7€/MWh = 15.6Mio.€ \quad (5.1)$$

15.6 million € of additional costs correspond to only around 4% of total procurement costs for ancillary services of Swissgrid according to their annual report in 2013. [61] Therefore, this value cannot be seen as argument against a market coupling of Switzerland and its neighboring countries.

Summary and Assessment of Cross-Border Auction Mechanism Study

To sum up, the simulation showed that switching from an explicit transfer capacity mechanism to a market coupling increases average cross-border flows from France to Switzerland by 95% and is mainly transferred to Italy, which is predicted to reduce day-ahead market prices in Italy. From a social welfare perspective, market coupling is beneficial since it leads to the most economic dispatch combination within the coupled region. Switching from explicit transfer capacity auctions to a coupled market is predicted to increase cross-border flows at Swiss borders by 14%. The additional transit flows are expected to increase expenditure of the Swiss TSO Swissgrid for loss compensation procurements and other ancillary service categories such as reactive power management. Additionally, the generated 180.25 million € of congestion revenues in the year 2013 by the TSO Swissgrid will disappear in a coupled market. These revenues were used so far to upgrade the grid and reduce congestion points. So, market coupling generates challenges in the financing of the TSOs. But on the other hand, market coupling is expected to increase also the procurement possibilities of ancillary service reserve in neighboring countries. The additional competition on the ancillary service market is assumed to lower reserve capacity prices from which TSOs could profit. The disappearing procurement costs of transfer capacity rights are a financial benefit for all the power producers across Europe since it removes the inefficiency of anticipating cross-border flows and fair values of transmission capacity rights in explicit auctions. The French power plants profit from an increased electricity export potential to Italy and Italy is expecting lower day-ahead market prices. On the other hand, former low-price net exporting countries France and Germany are predicted to see increasing day-ahead market prices due to price assimilation in coupled markets. Therefore, further investigation is required with an improved hydro power plant data base which allows to use the developed pricing mechanisms of the single country code version to assess the effect on German and French price levels to deduce the overall political interests of the European Union in a market coupling of Switzerland and its neighboring countries. In a coupled market, Switzerland's position as electricity transmission and trading hub is strengthened and better exploitation of Swiss hydro producers balancing agent potential is expected. But on the other hand, the market coupling is assumed to lead to assimilation of Swiss market prices to the Italian market which showed a by 5-17 €/MWh higher average price level in the years 2013-2016. Additionally, the increased electricity transit leads to a higher grid loading in Switzerland which requires higher expenses for ancillary services. To sum up, market coupling affects a lot of financial and physical parameters of the electrical grid. Therefore, a more detailed financial analysis on this topic is necessary including an in-depth study on the resulting day-ahead market price levels. To do so, the hydro power plant data base in EnerPol should be improved to represent the varieties of different reservoir sizes, cascade arrangements and yearly inflow patterns, which are required to correctly reproduce price signals in hydro dominated countries with the developed market models.

5.2 Capacity Market Model in a Multi-Year Framework

a) Required new Generator Capacity Installations per Year

Out of the capacity market model for Germany (presented in chapter 4) for the analyzed period of 2020-2045 the following new generator installations are required which are illustrated in figure 5.2. The determined new generator installations are not an outcome of an EnerPol simulation but determined by a market capacity analysis based on the scaling factors assumed for the scenario (section 4.6) and the decommissioning model (section 4.2) applied in this capacity market framework.

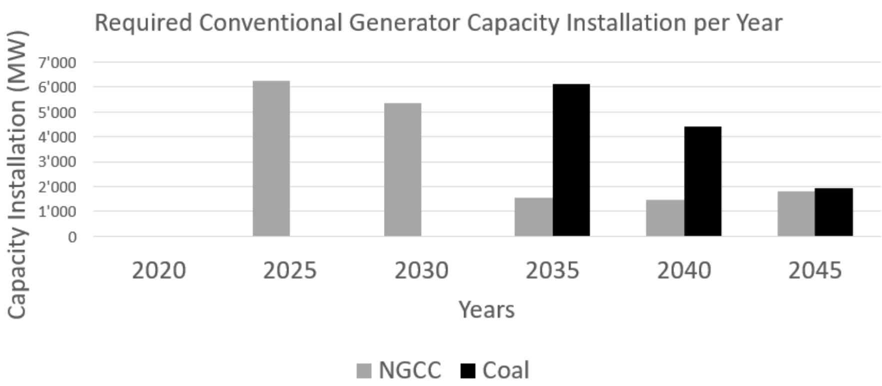

Figure 5.2: Determined required new natural gas combined cycle and coal capacities to guarantee future grid stability

It can be summarized that new power plants are needed from the year 2025 onwards. In a first phase until 2035 mainly flexible natural gas combined cycle power plants are required to balance the strong expected renewable capacity installation increase in this time span. The strong increase of renewables requires higher ancillary service reserves. Representatively, a plot of the predicted required SRL amounts for the future years is plotted in figure 5.3 and the resulting need of flexible capacity is summarized in figure 5.4. Natural gas as well as pump-storage and hydro dam power plants were categorized as flexible capacities in chapter 4. In the chosen scenario, the installed renewable capacity is assumed to double from 2013 until 2035 as it was discussed in section 4.6. In a later phase from 2035 until 2045, a total amount of around 12 GW of new base load power plants are required to compensate for the decommissioning of nuclear and thermal power plants. The remaining baseload equivalent thermal and hydro power plant capacities with and without addition of new generators are plotted in figure 5.5. For the calculation of the total available baseload capacities, hydro power plants were accounted for with baseload equivalent factors mentioned in chapter 4.

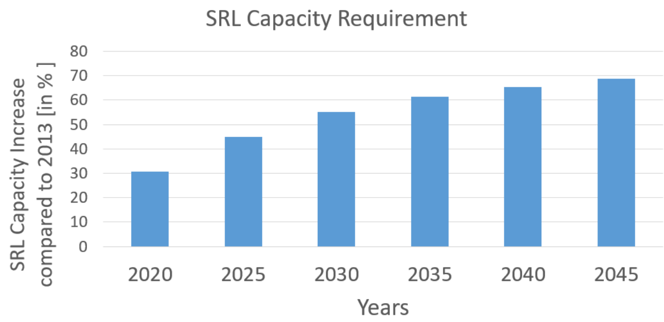

Figure 5.3: Predicted SRL capacity requirement for the time span 2020-2045

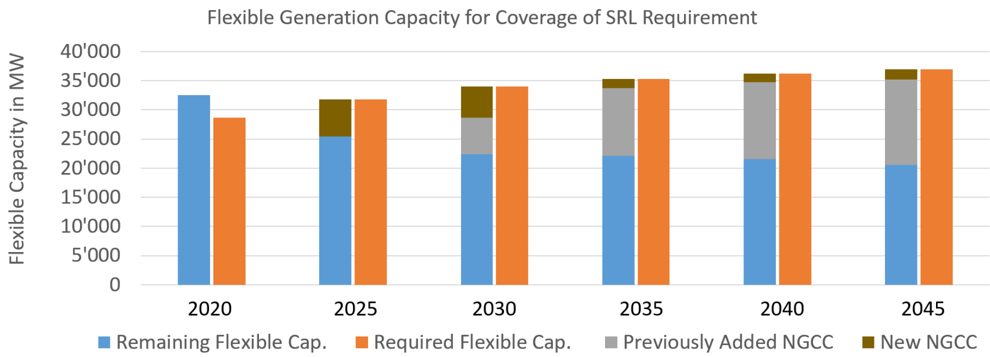

Figure 5.4: Required and remaining flexible capacities for the time span 2020-2045 and the resulting need for new NGCC power plants

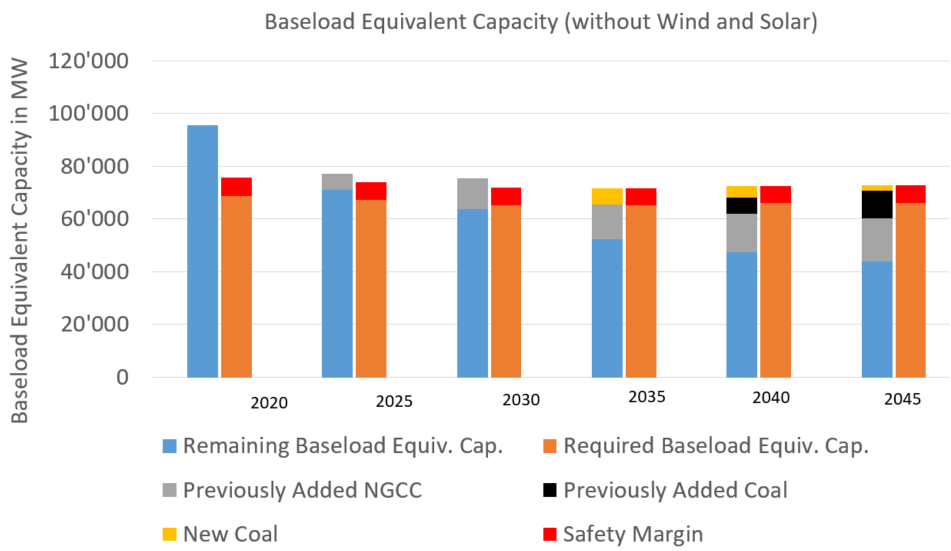

Figure 5.5: Required and remaining baseload equivalent capacities for the time span 2020-2045 and the resulting need for new coal power plants

b) Required Capacity Payment

In a next step, the yearly EnerPol simulations of the years 2025, 2030, 2035, 2040 and 2045 were financially evaluated with a post-processing routine to determine the required capacity payment for the newly installed power plants to reach their desired target internal rate of return. For this thesis, an aggressive value for the target internal rate of return of 7% was chosen as already discussed in the capacity market chapter section 4.3. This means that cash flows in the last year of the considered 45 year pay-back period are discounted by a factor of 21. To evaluate the sensitivity of the capacity payment to varying target internal rate of returns, a sensitivity study was performed which is presented later in this subsection.

Electricity Market Environment

To understand the trends in the capacity payments predicted by the simulation framework, the general day-ahead market price trends have to be regarded first. The resulting production costs for the newly installed power plants are also summarized in table 5.3. Entries market with a star correspond to years where no power plants of this type were newly installed.

Table 5.3 indicates that average day-ahead market prices are continuously decreasing until the year 2030 down to 23 €/MWh. For the years 2040 and 2045 the day-ahead market price is predicted to jump back to a level above 40 €/MWh which corresponds to day-ahead market prices seen around the year 2013. For the decrease in the day-ahead market prices for the years 2025-2035 the following reasons can be summarized:

- Main reason for the decreasing day-ahead market prices below 25 €/MWh is the significant increase of renewable generation capacity by a factor 2 from 70 GW to 145 GW. Since renewable generators are assumed to be part of a feed-in tariff system, they offer for zero on the day-ahead market in the model. Therefore, the average day-ahead market price shown in table 5.3 is not equal to the end consumer price. The end consumer price is determined by the day-ahead market price and the additions for the subsidies for the renewable energy sources in Germany determined by the Erneuerbare Energien Gesetz (EEG).
- A second driver for decreasing day-ahead market prices is the ancillary services requirement criterion. Due to the strong increase in renewables, more flexible capacity is required to balance the intermittency of renewable generation. Thus, new gas combined cycle power plants are installed in the years 2025 up to 2035. Through the increased amount of required spinning reserves more power plants are continuously producing and offer their minimum production capacity for zero at the market in the chosen modeling approach.

Table 5.3: Simulation predicted average day-ahead market prices and production costs (inclusive CO2 tax) for the newly installed coal and natural gas combined-cycle power plants with reference values of the year 2013

	2013	**2025**	**2030**	**2035**	**2040**	**2045**
Predicted ∅ DAM Price (€/MWh)	38	29	23	27	42	44
NGCC Prod. Costs (€/MW)	78	79	100	101	102	104
Coal Prod. Costs (€/MW)	48	*	*	52	55	62

The recovery of the day-ahead market prices back to 40 €/MWh in the years 2030-2045 can be explained by the following aspects listed below. To illustrate the discussed points two dispatch curves for the year 2030 and the year 2045 are plotted in figure 5.6. The hydro power plants (run-of-river 0.6, pump-storage 0.2, hydro dam 0.3) and renewable capacities (wind 0.3, solar 0.2) were accounted for with respective capacity factors when plotting the dispatch curves.

- The annual new installations of wind and solar power plants are assumed to be decreased to around 2-3 GW each per 5 year period. This increase in renewables is compensated by decommissioning of thermal power plants which leads to an overall stabilization of the economic situation of the remaining conventional power plants on the day-ahead market. This can be seen in figure 5.6 where for 2030 and 2045 the baseload equivalent capacities of renewables and lignite sum up to around 50 GW. Therefore, no further decrease in price could be assumed.
- Additionally, coal production costs increase from around 50 €/MW to 62 €/MW in the years 2030 to 2045 which translates into an percental increase of roughly 25%. With only 9 GW of remaining lignite capacity, coal is in many hours with typical load values around 65 GW the price-determining technology. The increase in coal production costs is strongly driven by increasing CO2 taxes and an assumed increased price for coal on the market. The resulting price jump in the period from 2030 until 2045 is heavily based on the increasing coal prices.
- The remaining part of the price increase is predicted to come from a different dispatching structure on the ancillary service market. Due to the decreasing number of cheap lignite baseload thermal power plants some power plants are providing multiple ancillary services. Additionally, more ancillary services are provided by natural gas power plants which are most flexible in terms of ramping capabilities. Hence, natural gas power plants can offer more ancillary services per minimum production capacity. Both, power plants providing multiple ancillary services as well as more natural gas power plants providing spinning reserves decreases the electricity amount which is offered at zero in the model. This increases day-ahead market prices as well.
- The increasing ancillary service requirements seen in figure 5.3 lead to increased capacity shares being blocked for providing positive activation on the ancillary service market. Therefore, parts of the plotted dispatch curves are cut out and cannot be offered on the day-ahead market leading to more expensive power plants being dispatched in day-ahead market peak hours. In some peak demand hours with low renewable generation, dispatching of natural gas simple cycle power plants with production costs around 220 €/MW can be observed, which is another driver for the increased day-ahead market prices in 2040 and 2045.

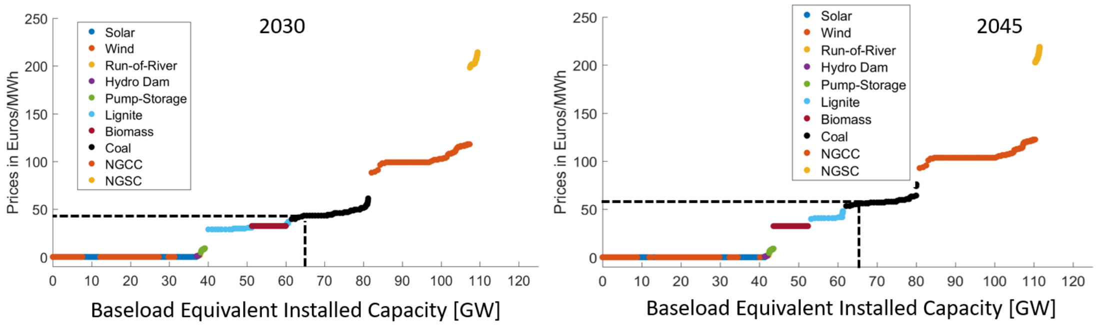

Figure 5.6: Baseload equivalent capacity dispatch cuves in the years 2030 and 2045

In contrast to price development trends discussed above, the resulting average day-ahead market prices predicted by the simulation cannot be directly read from the plotted dispatch curves due to the following reasons:

- The renewable production is strongly varying which leads to significant shifts in the dispatch curve. Additionally, wind and solar generation typically show seasonal production patterns.
- Additionally, the dispatch curves plotted in figure 5.6 do not account for ancillary service dispatching. Minimum production volumes required for providing spinning reserves are offered for zero at the day-ahead market in the chosen modeling approach. Since secondary reserves are mainly provided by natural gas power plants in the simulated scenario, this leads to a shift of the dispatch curve to the right which translates into lower day-ahead market prices.
- As already mentioned in the discussion of the increasing market prices in the period of 2030-2045, the provision of upwards regulation leads to constraints on the maximum production volumes which cut out parts of the dispatch curve and can lead to more expensive power plants being dispatched on the day-ahead market during peak hours.

Newly Installed Natural Gas Power Plants

2025 is the first year for which the conducted backup capacity requirement calculation predicts new generator installations. According to these calculations 13 natural gas combined cycle (NGCC) power plants are installed to compensate for flexible power plants being decommissioned and the additional need of flexible power plants due to the increase of renewable power generation. After performing the EnerPol simulations with 5-year time steps and evaluating the financial performance of the power plants in a considered pay-back period of 45 years, the required yearly capacity payments for each individual power plant are plotted in figure 5.7. The presented results correspond to an internal rate of return target value of 7%. As it can be seen in figure 5.7, the resulting capacity payments in the year 2025 vary in the range of 40 €/kW/year up to 55 €/kW/year. The total added amount of new gas capacity was 6'300 MW split into 12 power plants with standard size 500 MW as well as an additional smaller power plant with 300 MW capacity. For being able to properly compare capacity payment trends between different years without power plant size effects, only the capacity payments for the 500 MW blocks are plotted in figure 5.7. As figure 5.7 and table 5.4 show, there is a clear trend of decreasing required capacity payments from the year 2025 to the year 2045. This observation fits well to the general cash flow trend seen for a representative natural gas power plant built in 2025 in figure 5.8.

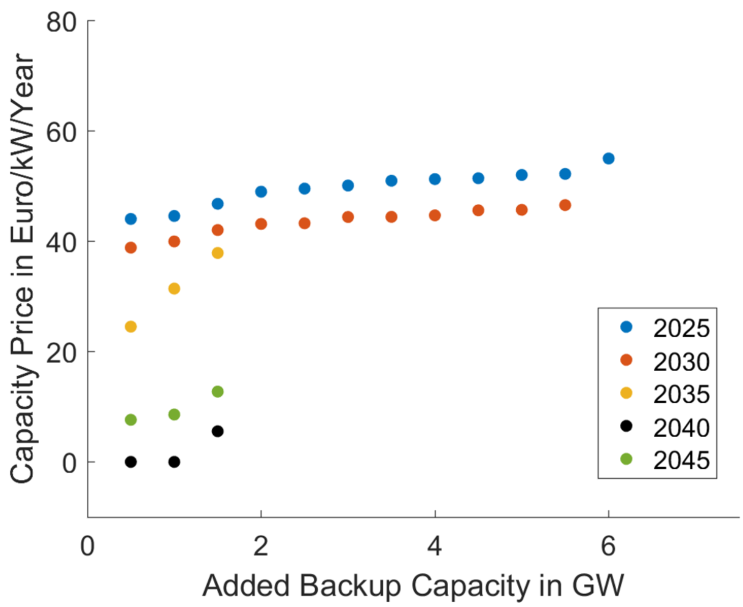

Figure 5.7: Yearly capacity payment requirement for added natural gas combined cycle power plants

Table 5.4: Average required capacity payments for NGCC power plants in different construction years

	∅ Capacity Payment (€ /kW/year)
2025	50
2030	43
2035	31
2040	2
2045	10

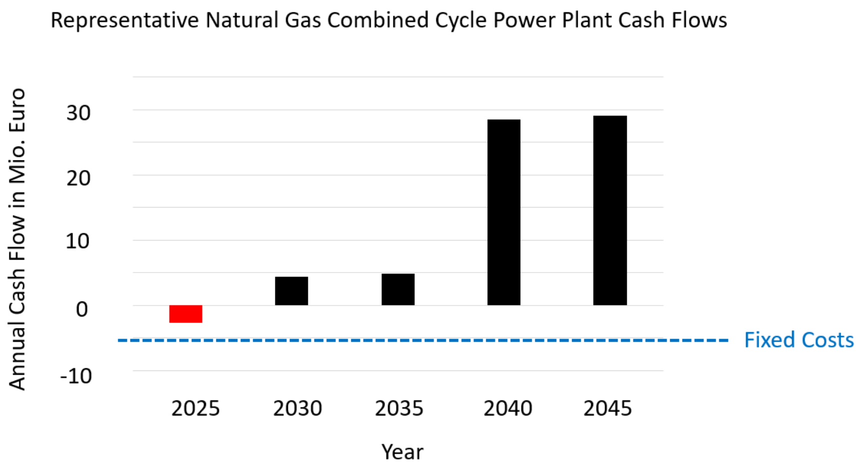

Figure 5.8: Simulation predicted annual cash flow for a representative gas power plant built in 2025

In the year 2030 additional 11 natural gas power plants were added according to the backup capacity requirement calculations. The resulting capacity payments for the power plants constructed in 2030 is already lower compared to 2025 and around 43 € /kW/year. The financial cash flow analysis shows that for natural gas power plants it is difficult for being profitable in the years 2025-2035 as it can be seen in figure 5.8. The remaining lignite power plants can produce cheap baseload production which reduces day-ahead market prices in combination with the heavily increased renewable production. From the year 2040 onwards, all power plants show strong positive cash flows. In the internal rate of return analysis, the future cash flows are discounted to account for the time value. Since for power plants with construction year 2030 the less profitable period of 2025 can be omitted and there are more years with strong positive cash flows, the reduced capacity market payments could be expected. The aggressive choice of the target IRR of 7% intensifies the importance of the financial results of the first years on the resulting capacity payment. Following the simulation results of the year 2030, the TSO could set a capacity market auction limit for the natural gas power plants with construction year 2030 of around 50 € /kW/year.

As figure 5.7 shows, the required capacity payment for natural gas power plants continues to decrease for the years 2035 and 2040. The required payment is in the year 2040 in the range of 0-5 € /kW/year. Interestingly, 2 out of 3 natural gas power plants which are constructed in the year 2040 need no capacity payment for their expected life time of 45 years. The required capacity payments for the natural gas power plants in 2045 is slightly above the values of 2045 and in the range of 10€ /kW/year. Main reason for that increase in capacity payment is a slight reduction of the income on the intra-day market due to stochastic deviations from year to year and the exact placement of the power plants. Importantly, it can be stated that natural gas power plants are able to generate an IRR of 7% with almost no capacity payment in the construction years 2040 and 2045. Main advantage is their flexibility in offering ancillary services. In the year 2045, a representative natural gas power plant creates 50% of its revenues on the ancillary service market. To sum up, as a consequence of the limited number of opponents on the ancillary service markets, for the German market, almost no capacity payments for natural gas power plants can be assumed from the year 2040 onwards. This means that natural gas power plants which are currently being switched-off against TSOs will, can become profitable again without subventions from the year 2040 onwards.

Generally, the resulting financial performances of natural gas power plants correlate with day-ahead market price levels. But as figure 5.8 indicate, for natural gas power plants also the developments on the ancillary service markets are important. In the years 2025 until 2035 day-ahead market prices remain on a low level below 30 €/MWh. Nevertheless, natural gas power plants see a tendency of increasing cash flows due to the growing ancillary service and intra-day market with a decreasing number of opponents due to decommissioning of lignite and coal power plants.

It is interesting that natural gas combined cycle power plants can be profitable in the chosen simulation framework although average day-ahead market prices are well below production costs of NGCC power plants. Reason for that is, that natural gas power plants are able to generate the difference between actual market price and production costs at the ancillary service market. Highest selected bid prices on the SRL market can go up to 500€/MW/h during weeks where day-ahead market prices remain at zero for almost the complete week due to extreme renewable electricity generation. Therefore, almost the complete production costs around 105 €/MW (in the year 2045) for natural gas power plants must be reimbursed on the ancillary service market.

<u>Newly Installed Coal Power Plants</u>

For the first time in 2035, coal power plants are added to secure peak load coverage in Germany. Since capital costs per capacity for a coal power plant are by a factor 4 higher compared to natural gas power plants, the resulting capacity payment requirement can be assumed to be clearly higher than for natural gas power plants in the analyzed high target IRR scenario. The average resulting required capacity payments in the year 2045 are around 170€/kW/year.

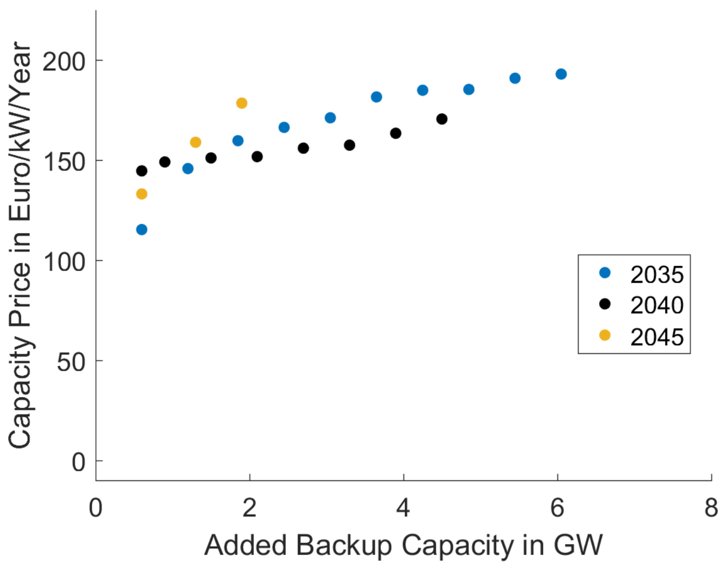

Figure 5.9: Yearly capacity payment requirement for added coal power plants

The general trend of decreasing capacity payments already seen for natural gas power plants applies also for coal as table 5.5 indicates. In the year 2040, the coal power plants average capacity payment is in the region of 155 € /kW/year. The average capacity payments for the coal power plants can be seen in table 5.5. There are different reasons which explain the improving financial performance of newly installed coal power plants for the years 2040 and 2045. Due to the decommissioning of most of lignite capacity and old coal power plants reaching the life time limit of 50 years, opponents on the day-ahead market disappear. Therefore, the market prices in hours of low renewable penetration increase. Additionally, the intra-day market and ancillary service opportunities increase for the remaining market actors.

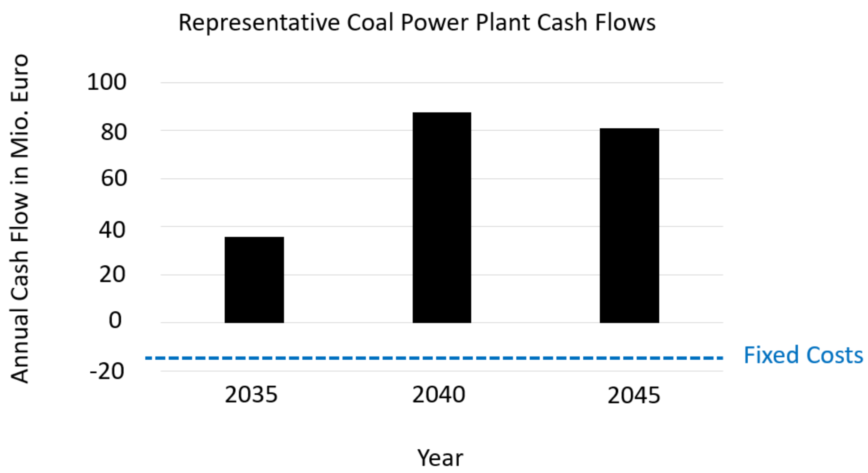

Figure 5.10: Simulation predicted annual cash flow for representative coal power plant built in 2035

Nevertheless, the capacity payment for the years 2040 and 2045 cannot be reduced below 155 € /kW/year. As it can be seen in figure 5.10 the annual positive cash flow for a representative coal power plants shows a decrease of 8% from 2040 to 2045 although day-ahead market revenues have increased. Main reason is the high CO2 tax increase in this time period and an expected increase in coal price which leads to an overall increase in production costs of around 13%. Since CO2 emissions are higher for coal power plants than for natural gas combined cycle power plants, the CO2 tax lowers the difference in marginal costs of coal and natural gas power plants. Thus, reduced profits in hours were natural gas power plants were dispatched on the day-ahead market are the consequence. Since coal power plants still generate their main income in 2045 on the day-ahead market (65%), this effect influences the financial results of coal power plants. Therefore, the slightly increased capacity payment for coal power plants in the year 2045 can be explained by the reduced margin in terms of production costs on the day-ahead and intra-day market compared to natural gas.

Table 5.5: Average required capacity payments for coal power plants in different construction years

	2035	**2040**	**2045**
∅ Coal Capacity Payment (€ /kW/year)	169	156	157

When the representative coal power plant cash flow change from the year 2035 to 2040 is analyzed, it can be seen that through the increase in day-ahead market prices and increased ancillary service market opportunities the yearly positive cash flow can be raised by around 52 million € which is higher when compared to natural gas combined cycle power plants (24 million €increase). This could be expected since coal production costs remain below natural gas production costs. Power plants with lower marginal costs can increase their profit margins in the pay-as-cleared day-ahead market more significantly. Nevertheless, this is not sufficient to drive down required coal capacity payments in the range of natural gas power plants. As a consequence, in a pay-as-bid capacity market auction performed by the TSOs, only natural gas projects would have been selected. But this would lead to significantly higher expected day-ahead market prices which is opposing end consumer interests. Therefore, further investigations could be done in simulating a natural-gas-only capacity market framework and quantifying the resulting day-ahead market price increase. Additionally, the results show clearly the need for coal power plant producers to improve the flexibility of their products to fit future success factor flexibility on the electricity market.

Expected Yearly Capacity Market Costs

From all these new installations of power plants there result capacity payment costs which have to be summed up to get the full consequences of a capacity market. As figure 5.11 illustrates there are increasing yearly capacity payment costs predicted up to the year 2045. A maximum yearly payment of 2.7 billion €is predicted. However, when the total costs generated in the period from 2020-2045 are summed up and divided by the 25-year time span, this corresponds to average yearly costs of 1.25 billion €for the proposed capacity market. When it is assumed that the end-consumer of electricity is forced to pay these costs this translates into a maximum payment in the year 2045 of 0.55 Cents/kWh. The found capacity payment of 0.55 Cents/kWh is in line with findings of the Swiss utilities BKW and Axpo, which have been proposing different capacity remuneration methods that lead to end-consumer payments of 0.6 and 1.2 Cents/kWh respectively [62] More detail about BKW's and Axpo's methodologies can be found in appendix A.2.

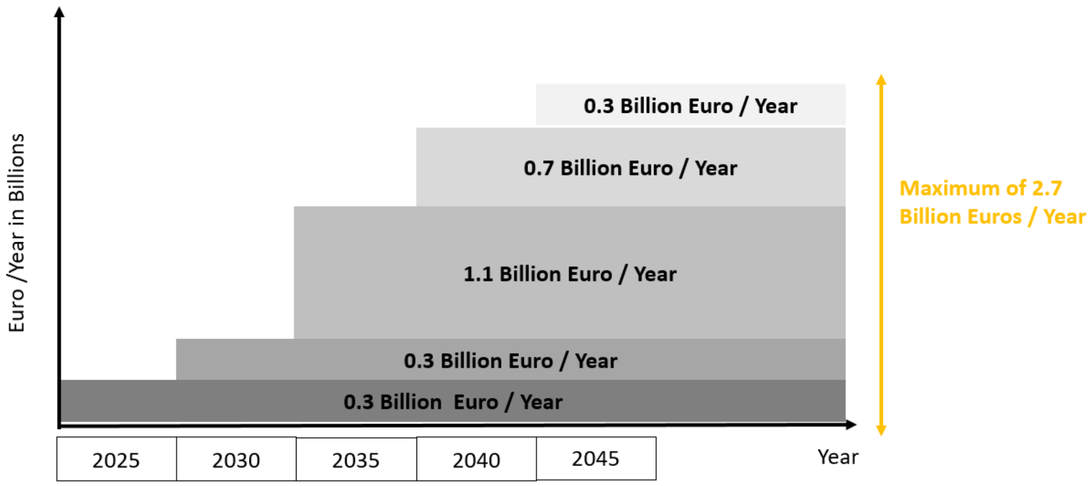

Figure 5.11: Predicted yearly total costs generated by capacity market payments for Germany

Target Internal Rate of Return Sensitivity Study

A sensitivity study for the target internal rate of return was performed to evaluate how dominant this value is for the total costs which can be expected for a capacity market in Germany. Therefore, the aggressive value of 7% was reduced to 5% and 3% in the performed study. The resulting yearly costs for performing such a capacity market are illustrated in figure 5.12.

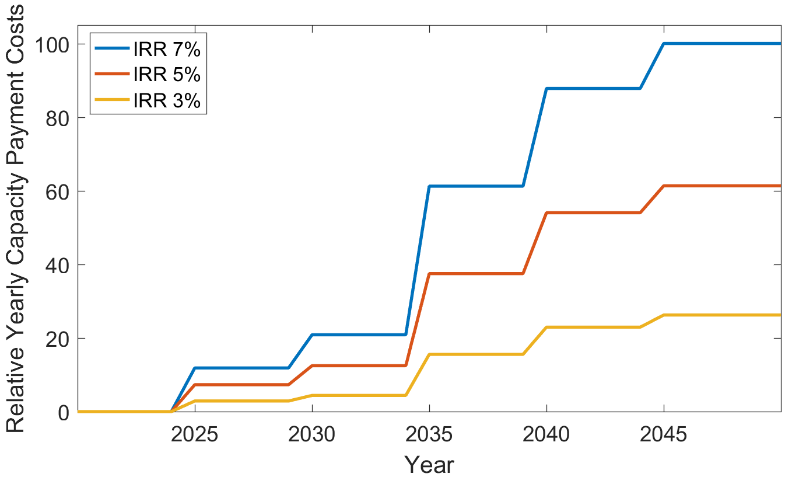

Figure 5.12: Sensitivity of predicted capacity market costs for Germany to changes in target internal rate of return value

As expected the predicted costs heavily depend on the target internal rate of return value. For a target internal rate of return value of 3% the predicted costs in 2045 are only around 25% of the costs which are expected when an IRR target value of 7% is used. Following this, it can be summarized that the calculated costs with an IRR target of 7% can be seen as upper limit for expected capacity market costs. Choosing an appropriate target IRR value is a key step, when costs of a capacity market are evaluated.

In a next step, average capacity payments for coal and natural gas power plants built in the years 2025-2045 are compared for different target IRR values in table 5.6.

Table 5.6: Required average capacity payment sensitivity study for different construction years

	IRR=7%	**IRR=3%**
2025		
Coal (€ /kW/year)	-	-
NGCC (€ /kW/year)	50	12
2030		
Coal (€ /kW/year)	-	-
NGCC (€ /kW/year)	43	7
2035		
Coal (€ /kW/year)	169	48
NGCC (€ /kW/year)	31	2
2040		
Coal (€ /kW/year)	156	43
NGCC (€ /kW/year)	2	0
2045		
Coal (€ /kW/year)	157	44
NGCC (€ /kW/year)	10	0

As table 5.6 indicates, coal power plant capacity payments remain higher also for a target internal rate of return of 3%. Therefore, the simulation predicted more attractive investment into natural gas power plants in future years compared to coal is not based on a too aggressively chosen target IRR value of 7%.

CO2 Emission Price Effects

As it could be seen in the production cost analysis at the beginning of this chapter, coal remains the cheaper production technology compared to natural gas in the developed scenario with an assumed CO2 price increase of 313% compared to the 2013 level. In a next step, it is analyzed for which CO2 price coal would become more expensive in power generation compared to natural gas. This gives an indication how sensitive the obtained results are in terms of assumed CO2 price increase. The base CO2 price in 2013 was 5.4 €/ton CO2 emission. Assuming gas production costs of 75 €/MW and coal production costs of 44€/MW without CO2 taxes in 2013, this translates into a production cost price difference of 31 €/MW. The most important key numbers are summarized in table 5.7.

Table 5.7: CO2 emission cost calculation key numbers

NGCC	
Production Costs in 2013 (€/MW)	75
CO2 Emissions (ton CO2/MWh)	0.5
Coal	
Production Costs in 2013 (€/MW)	43
CO2 Emissions (ton CO2/MWh)	0.9
CO2 Price in 2013 (€/ton CO2 emissions)	5.4

With the numbers presented in table 5.7 a CO2 price increase by a factor of 13 would be required to make coal the more expensive electricity production technology compared to natural gas combined cycle power plants. Therefore, it can be stated that the assumed value for the CO2 increase is not in a critical range for creating a complete switch in the merit order of the analyzed technologies coal and gas.

Nuclear Phase Out Effects

As it was shown in this chapter, gas power plants constructed in the years 2040 and 2045 require only very low capacity payments. In contrast to the simulation result, there exist natural gas power plants which are currently switched off against will of the TSOs to prevent further annual financial losses as the already mentioned example Irsching shows. Therefore, a delayed nuclear phase out scenario was analyzed, were in the year 2035 still 6 GW of nuclear power plant capacity are active in the market and the last nuclear power plants are decommissioned in 2040. This scenario is resembling the current situation in the German market where conventional power plants face strong competition by subsidized renewables and cheap baseload power plants. Due to the fact that marginal costs of nuclear power plants are assumed to be around 20 €/MW lower compared to the next conventional power technology in the merit order, day-ahead market prices are predicted to drop heavily to around 17 €/MWh compared to a price level of 27 €/MWh in the case without nuclear power plants. In addition, nuclear power plants are well suited for providing TRL- ancillary services. Therefore, coal and natural gas power plants lose market share in the ancillary service market. Due to more different power plant technologies providing the same amount of ancillary services, the minimum production amount offered for zero in the model is also increased which is another explanation for the decreasing day-ahead market prices. Figure 5.13 shows that especially the coal power plants which gain a significant share of their revenues on the day-ahead market suffer strongly from nuclear power plants active on the market. The cash flow of the representative coal power plant is reduced by almost 35 million € in this case. This means, that thermal power plants in a high renewable share future scenario heavily profit from the nuclear phase out decided by the German government. Required capacity payments for new coal installations in the year 2035 are reduced in the case without nuclear power plants by around 15 €/kW/year. Additionally, natural gas power plants are not able to cover their fixed costs and creating losses in a 2035 market scenario with nuclear power plants. The absence of nuclear power plant translates into a reduction in required capacity payments for natural gas combined cycle power plants of around 5 €/kW/year. The analyzed scenario indicates similar difficulties faced by natural gas power plants in today's market environment with low day-ahead market prices and different power plant technologies being present in the market.

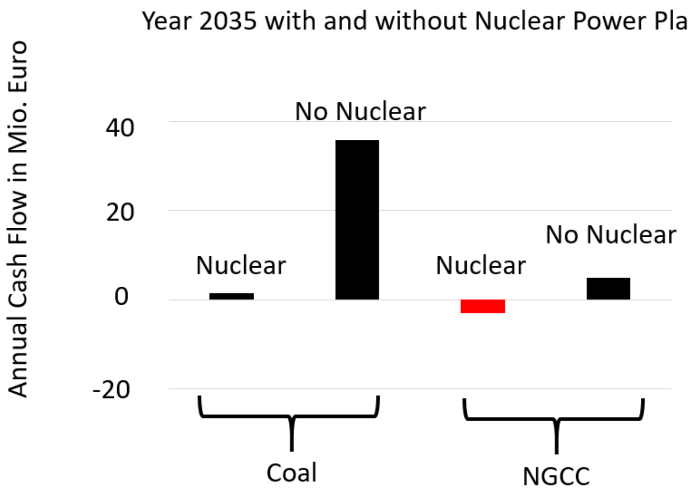

Figure 5.13: Simulation predicted annual cash flows for the year 2035 for representative gas and coal power plants in a delayed nuclear phase out scenario

e) Summary and Assessment of Capacity Market Results

The predicted capacity payments for the newly installed power plants are predicted to be 0.55 Cents/kWh. The costs are lower as predicted by power companies. Since these companies want to improve their financial situation their proposals have to be seen in a political context. Therefore, the suggested capacity payments by power companies can be regarded as upper limit of potential costs for capacity markets. In reality, the decreasing number of thermal power plants improves the competitive situation of the power plants and increases the market power of individual power plants in situations of low renewable production which could lead to a price premium incorporated in the offer bids by the power plants. Furthermore, the financial result may improve when a continental Europe setting is regarded. In hours of strong renewable generation, the electricity exports could be increased which increases market prices in Germany and creates additional options for power plants. When all these points are regarded in conjunction with the aggressively chosen target IRR, the calculated capacity payments could be too pessimistic and could therefore be used for TSOs to set upper price boundaries for a pay-as-bid capacity market design.

The predicted expenses have to be put into comparison to costs for feed-in tariffs for renewables. For Germany households paid a premium of around 6.35 Cents/kWh. [63] So in relation to the costs for the renewable subsidies the costs for an introduction of a capacity market which secures grid stability are by a factor 10 lower. As it can be seen in figure 5.14 the costs for electricity of German households have seen a strong increase of around 50% in the last ten years. The increase is mainly driven by the taxes paid for renewable energies. The last years have created a interesting situation of decreasing wholesale electricity prices and increasing end-consumer prices.

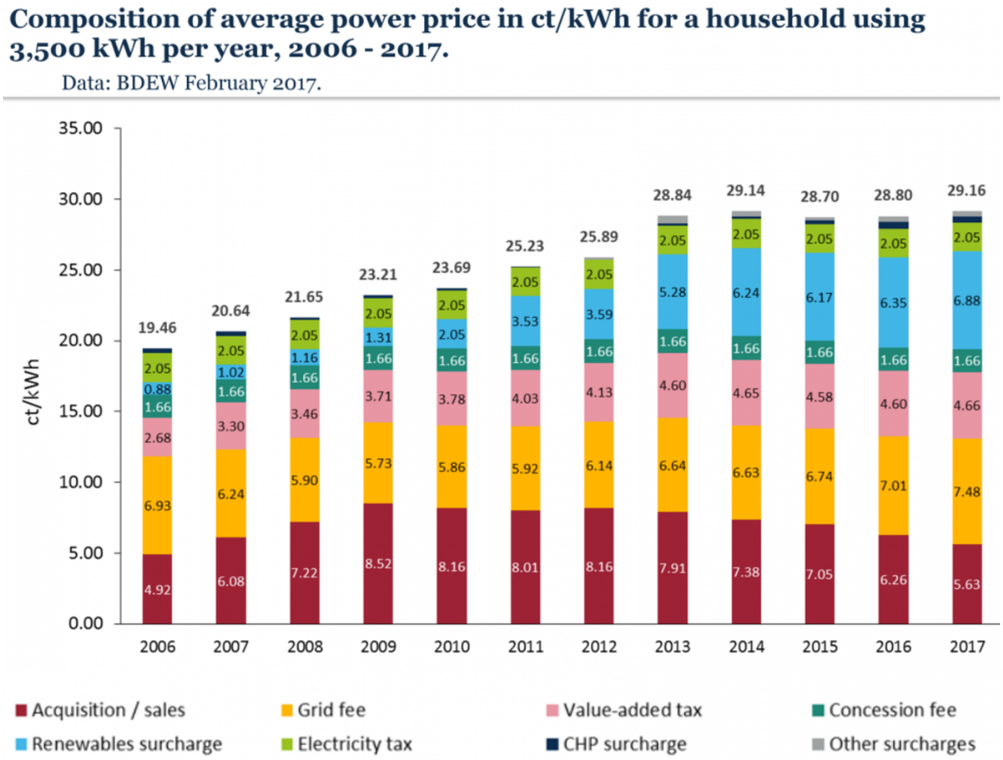

Figure 5.14: Composition of average power price for German households [63]

The economic situation of power plants improves over the analyzed period such that the profits increase due to lignite decommissioning and growing intra-day and ancillary service markets. Therefore, the total required yearly capacity payment costs can be assumed to remain on a similar level from the year 2045 onwards. Even more interesting is the distribution of the required new generator installations over the period from 2020-2045. It was shown, that in a first step additional flexible gas power plants are required from the year 2025 onwards. In a later step starting from 2035, a 12 GW installation of baseload power plants is required to guarantee peak load coverage.

Natural gas power plants are predicted to generate internal rate of returns of around 7% from the year 2040 onwards. This means that natural gas power plants which are currently switched off against the will of TSOs become profitable and attractive for investors again.

Coal power plants are predicted to require high capacity payments above 150 €/kW/year. This means that coal power plants would not be selected in performed capacity market auctions by the TSOs. This fact underlines the urgency for coal producers to upgrade their production technology in terms of flexibility to successfully compete natural gas power plants on the growing intra-day and ancillary service markets.

As a future work, it would be interesting to analyze the effect of switching from fixed feed-in tariffs for renewables to a direct marketing approach and compare the resulting required capacity payments for the newly installed coal and gas power plants. It is assumed that this step increases the percentage of the total revenues generated on the day-ahead market and reduces the income on the ancillary service markets. However, this could be interesting for coal power plants since it increases the profit potential for power plants with marginal costs below the market price due to the fact that the day-ahead market is cleared with a pay-as-cleared mechanism whereas the ancillary service market is cleared pay-as-bid. Since coal power plant production costs can be assumed to stay below gas production costs, the potential benefit of switching away from a feed-in tariff system is higher for coal power plants. Nevertheless, the financial improvement potential of this step is related to the prices which result from renewable direct marketing offering.

Another interesting aspect to analyze is the effect of performing a capacity market analysis in a multi-country framework. As already mentioned the prices in high renewable generation and low-price hours are expected to increase due to the electricity export potential, but on the other hand the effect of importing electricity in high price hours from nuclear plants in France or solar production in Southern Europe can even deteriorate the financial situation of the thermal power plants in Germany.

5.3 Computational Statistics

Table 5.8 shows the runtime parameters of the most important conducted simulations. The mentioned simulation times are exclusive case file generation, due to the fact that this part of the code can be executed separately.

Table 5.8: Computational statistics of the conducted simulations

	Wall-clock time (in h) on Euler (24 Nodes)
DE - ASM, DAM, IDM and Reserve Activation	35
DE - ASM and DAM only	20
AT-CH-DE-FR-IT - ASM and DAM only	50

The most important modules and their relative time consumption is listed below. It must be stated that the percental time consumption of the individual modules can vary depending on the simulated EnerPol area respectively on the number of simulated power plants.

- weekly ancillary service auctions and required ASM power plant optimizations ($*$) 20%
- weekly optimum DAM strategy determination and daily strategy update for hydro power plants ($*$) 10%
- day-ahead market module (including OPF simulations) 30%
- intra-day market module (including OPF simulations, IDM bidding and stochastic model) 40%

Parallelization by using multiple cores on the Euler cluster in conjunction with Python multi-processing approach was successfully implemented for the power plant strategy optimizations routines (corresponding modules are marked with ($*$)).

Chapter 6

Summary

The overall goal of this thesis was to develop realistic electricity market models for the existing EnerPol framework to allow for financial evaluations of EnerPol future scenarios. To reach this goal the current European wholesale electricity market was analyzed in a first step. Secondly, a detailed market model covering the relevant and dominant parts of the wholesale electricity market, namely ancillary service, day-ahead and stochasticity-driven intra-day market as well as cross-border transfer capacity auctions was developed. For being able to price power plant offers on the different wholesale market segments, a power plant optimum strategy routine was designed. The models were then used to evaluate the financial capacity payments required in a future capacity market setup to maintain grid stability in an electricity market design with a strong renewable electricity generation share. Additionally, for Switzerland which still trades electricity using explicit cross-border transfer capacity auctions, the effects of changing the cross-border auction mechanism to a coupled market were evaluated in a multi-country setup. The most important findings to each of the mentioned steps are summarized in the following paragraphs.

Power Plant Strategy Optimization

- Since power plants can be active on different electricity market segments simultaneously, a pricing routine was required which allows the power plants to prize their offers on the different markets segments. The developed routine is able to determine the power plant financial optimum production strategy on a weekly basis by including production, ramping, start-up and pumping costs, as well as power plant production and ramping constraints.
- The combination of continuous and discrete variables such as start-up detections create a computationally expensive mixed integer problem. In a validation framework including all relevant power plant technologies, a simplified model, being reduced in number of mixed integer variables, deviated only by 4% in predicted optimum power plant profit compared to the full mixed-integer model. For this optimization routine, the mixed-integer non-linear solver Gurobi was used. A multi-processing approach was successfully implemented which optimizes 24 power plants simultaneously and reduces module runtime by a factor of 20.

Ancillary Service Market Model

- The existing EnerPol code was enhanced by introducing a detailed ancillary service model. The ancillary service model includes weekly auctions for primary, secondary and tertiary reserves. The introduction of an ASM model allows to reproduce 72% of the low-price hours with prices below 20€/MWh in the year 2015 in Germany.

Day-Ahead Market Model

- The day-ahead market is simulated in the EnerPol framework within an hourly resolution as it is the case in reality. The used marginal cost day-ahead market bidding approach is able to predict the hourly German day-ahead market price with an error of 10.7 €/MWh for the year 2015 which corresponds to a relative hourly error compared to the mean DAM price of 33.8%. The model predicts winter months more accurately with an hourly relative error of 26.6%, but has difficulties to reproduce day-ahead market prices in summer months were import and export hours are alternating in Germany and prices are influenced by non-German power plants.
- With a predicted average German day-ahead market price in 2015 of 35.1 €/MWh (compared to measurement which shows 31.6€/MWh), the model is able to estimate costs of electricity procurements and power plant incomes on the day-ahead market in future scenarios reasonably well.
- Since a pure financial dispatching of the cheapest received hourly bids is performed by the OPF solver, the resulting aggregated production profiles for the most important thermal power plant technologies coal and lignite show stronger ramping rates than seen in reality.

Intra-day Market Model

- Intra-day market enables balance groups to balance short-term deviations from planned production and consumption schedules. To simulate stochastic deviations from planned day-ahead market production and consumption, a top-down stochastic model was introduced into the existing deterministic EnerPol code. The stochastic model introduces deviations with quarter hourly resolution in wind and solar production, accounts for the fact that demand forecasts can be wrong and includes forced outages in the simulation framework based on data analysis for the German market.
- Validation of the intra-day market model revealed an overestimation of average intra-day market prices by 33%. One of the main reasons for this difference is that the introduced stochastic model predicts an energy deficit in 88% of the 15-minutes time intervals for the year 2015 compared to 67% found in measurement data. Additionally, the overestimation of intra-day market prices can be partially attributed to cascade effects of overestimated day-ahead market prices.

Cross-Border Transfer Capacity Allocation Model

- In a next step, the market model was extended for usage in a multi-country framework. The developed cross-border transfer capacity allocation model allows for three different types of cross-border auctions: explicit and implicit cross-border transfer capacity auctions and fully coupled market without additional economic cross-border transmission constraints.
- The resulting cross-border flows at the Swiss borders were compared to ENTSO-E data of the year 2013. The yearly average cross-border flows can be predicted with an accuracy between 6% and 25% for the borders to Austria, France and Italy. For the German border the average cross-border flow is predicted with a relative error of 72%. The error is amplified at the German border due to the inability of the simulation to reproduce net electricity exports to Germany during summer periods. The ability to predict the main cross-border flow trends allows for the application of the model to evaluate physical flow and financial effects of switching the cross-border auction mechanism for Switzerland and its neighboring countries.

Case Study I - Changing Transfer Capacity Allocation Mechanisms for Swiss Borders

- Simulation results predict a strong increase of average cross-border flows from France to Switzerland by 95% and Switzerland to Italy by 16% when switching from explicit cross-border auctions to a coupled market. Switzerland is used as transit country to bring cheap nuclear electricity from France to Italy. Overall cross-border flows at Swiss borders are increased by 14%. A coupled electricity market around the Swiss borders reduces inefficiencies from a power plant perspective. Since in a coupled market no transmission rights for transferring electricity across borders have to be procured, this translates into savings of 370 million € for utilities as data analysis showed. Market coupling is more efficient since uncertainties in timing, direction and amount of cross-border flows can be omitted.

Case Study II - Capacity Market in Germany for the Time Frame 2020-2045

- In a second case study, the future capacity payments required by newly installed power plants in a high renewable electricity generation scenario were determined, which allows to quantify the financial dimension of a future capacity market in Germany. To evaluate future backup capacities to guarantee grid stability for Germany in the year 2020-2045, two different criteria were derived: A first criterion is based on the required amount of flexible power plants to cover SRL requirements. The second criterion deals with peak demand coverage by backup capacities in times of low wind and solar generation.

- In a market analysis it was found that in a first period from 2025-2030 additional 11 GW of flexible capacity provided by NGCC power plants is required to compensate the heavy increase in renewable electricity generation. In a later phase in the years 2035 up to 2045, 12 GW of baseload coal power plants are required to account for the decommissioning of thermal power plants reaching their life time limit of 50 years.

- To determine the required capacity payment of newly installed power plants a multi-year EnerPol simulation framework was designed which performs simulations for the years 2020-2045 in 5 year time steps. A post-processing routines performs a financial evaluation of EnerPol power plant simulation results and conducts an internal rate or return analysis with a chosen internal rate of return target value of 7%.

- The simulation predicts required average capacity payments for new natural gas combined cycle power plants to decrease from the year 2025 to the year 2045 from 50 € /kW/year to 10 € /kW/year. Due to the production flexibility of natural gas power plants they are exploiting growig ancillary service market potential and can generate 50% of their income in the ASM segment in the years 2040 and 2045.

- The required average coal capacity payments are predicted to lie within 156-169 € /kW/Year. Although coal power plants are generating higher yearly positive cash flows than natural gas combined cycle power plants, they require higher capacity payments.

- The total induced cost by the proposed capacity market sum up to a maximum yearly cost of 2.7 billion € in 2045. When it is assumed that end-consumers of electricity are forced to pay these costs, this translates into a maximum payment of 0.55 Cents/kWh in the year 2045. If the complete time span of 2020-2045 is analyzed the capacity market creates average annual costs of 1.25 billion € .

Chapter 7

Conclusion

Out of the results obtained in this thesis the most important conclusions are summarized in the following list:

Case Study I - Changing Transfer Capacity Allocation Mechanisms for Swiss Borders

- Changing the cross-border auction mechanism makes Switzerland an even more important electricity transit country, and it is expected to create additional opportunities for Swiss hydro producers acting as balancing agents. Several political stakeholders could be interested in a performed market coupling of Switzerland and its neighboring countries. The European Union is supporting market coupling activities by legislation and could profit from decreasing day-ahead market prices in Italy through the increased electricity transport through Switzerland to Italy. Swiss power producers see a further export potential to the Italian market. But on the other hand, the market coupling is assumed to lead to assimilation of Swiss market prices to the Italian market which showed a by 5-17 €/MWh higher average price level in the years 2013-2016. Additionally, the increased electricty transit leads to a higher grid loading in Switzerland which requires higher expenses for ancillary services. Therefore, a more detailed financial analyis on this topic is necessary. To use the developed multi-country simulation framework for this purpose, further improvement of the hydro power plant data base in EnerPol in combination with an enhanced hydro power plant pricing tool is required.

Case Study II - Capacity Market in Germany for the Time Frame 2020-2045

- Interestingly, power plant capacity payments show tendency to decrease for the construction years 2025-2045. Natural gas combined cycle power plants built in 2040-2045 are expected to require average capacity payments below 10 €/kW/year which corresponds to only 1% of their construction costs. Therefore, it is predicted that the capacity market is only essentially required for natural gas power plants in the time frame 2025-2035. This means that from the years 2040 onwards, natural gas power plants are financially viable for investors even without subsidies. This can be seen as important statement for gas power plant producers and owners, which are currently thinking about mothballing their natural gas power plants against the will of the TSOs.

- Coal power plants are predicted to require substantially higher capacity payments compared to natural gas power plants. In reality, this would mean that in the capacity market auctions only natural gas projects would be selected by the TSO to ensure the required backup capacities. This underlines the importance of increasing the flexibility of coal power plants in order to enable more participation on the growing ancillary services markets. Otherwise, investment costs are too high for coal power plant projects to reach desired target internal rate of returns, which means that power producers will tend to build new gas power plants instead. However, a capacity market which only selects natural gas power plant projects is expected to significantly increase day-ahead market prices which disposes financial savings for end consumers generated by low capacity market payment costs and requires further investigation on this topic.

- Overall costs of the designed capacity market for Germany are evaluated to be around 1.25 billion € per year in the time frame 2020-2045 and reach their maximum value of 2.7 billion € per year in 2045. The calculated costs of a capacity framework are conservative since increasing market power, further electricity export potential and a reduction of future feed-in tariffs are not included in the financial evaluation. The proposed costs can therefore be seen as maximum expenses to calculate for TSOs. However, the resulting costs are low compared to current expenses for renewable feed-in tariffs (by a factor of 10). Therefore, the induced costs of around 1.25 billion € per year are well invested to guarantee grid stability in a framework with 160 GW installed renewable capacity which is an important step towards a sustainable power sector.

Chapter 8

Outlook

In this outlook chapter, further interesting topics as well as points for future improvements are summarized in different categories.

Power Plant Data Base Development Potential

During this project a hydro power plant modeling approach based on reservoir levels and water balances was introduced. Since no information about the reservoir levels, hydro power plant pool arrangements and decline height of the water was available, linear correlations were used to determine the missing information. The approach shows to work well for countries with a relatively small amount of hydro generation, but reveals its limitations for hydro dominated countries such as Switzerland or Austria. Therefore, it is proposed to improve the hydro power plant data base of EnerPol to get the full usage of the introduced hydro power plant model with water balances. A possibility to estimate the hourly inflows into the hydro dam reservoirs could also be to use image recognition to determine the ridges of the mountains to derive the size of the inflow regime. Once hydro power plant pool arrangement information is available, it allows also for pump-storage power plants to participate in the ancillary service reserve markets, which brings the developed market model even closer to reality. Additionally, accounting for different reservoir sizes of pump-storage power plants introduces a more realistic capacity offering behavior since the optimum power plant strategy will heavily differ if the reservoir size allows for a different time span of full load production.

Market Model Development Potential

As it was shown in this project, the developed market model approach is able to reproduce the electricity day-ahead market price reasonably accurate which allows for the financial evaluation of future scenarios within the developed framework. Nevertheless, the model clearly overpredicts the ramping of power plants. As already discussed in the validation chapter of the day-ahead market 3.7.2, there are two potential ways to improve the simulation predicted ramping behavior. One the one hand, a sophisticated market price forecast tool could be developed or as an alternative, the market model could allow for block orders and specification of linking of different orders. The second possibility gives the power plants a tool to reduce inefficiencies and place bids for different price developments during the upcoming week. The working principle of linked block orders is illustrated in figure 8.1. Nevertheless, it must be considered that linked and block orders require a multi-period OPF optimization for the 24 hours of the upcoming day which translates into an expected heavy increase of computational effort. Since already in this project, simulation time was a critical issue, a clever solution to speed-up this multi-period optimizations is required. A completely different approach could be to use machine learning algorithms to let power plants learn from their previous weeks offer placements.

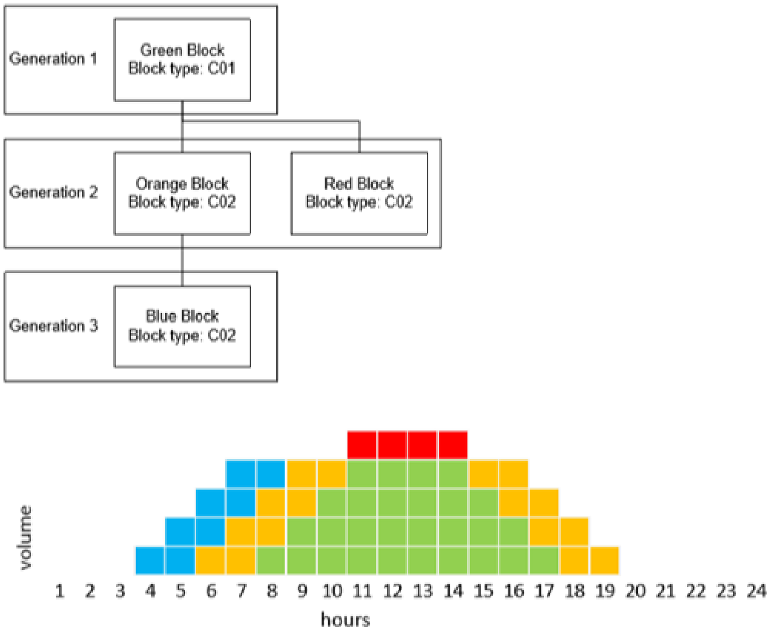

Figure 8.1: Schematic of block order working prinicple on EPEXSPOT day-ahead market [64]

Additionally, the results obtained in the multi-country model revealed the difficulty of pricing bids in purely hydro-dominated countries during net export phases. Therefore, a more sophisticated offer pricing model should be developed which includes the price expectations of the neighbouring countries and weather forecasts besides the price expectations of the domestic country.

Capacity Market

Based on the presented required conventional power plant installations for the future years, the capacity market simulations could be re-done to assess the effects of different direct marketing concepts for renewable energy generation.

It would be interesting to analyze the effect of switching from fixed feed-in tariffs for renewables to a direct marketing approach and compare the resulting required capacity payments for the newly installed coal and gas power plants. It is assumed that this step increases the percentage of the total revenues generated on the day-ahead market due to increased day-ahead market prices and reduces the income on the ancillary service markets. However, this could be beneficial for coal power plants which are predicted to require significantly higher capacity payments compared to natural gas combined cycle power plants. Increasing day-ahead market prices increase the profit potential for power plants with marginal costs below the market price due to the fact that the day-ahead market is cleared with a pay-as-cleared mechanism in contrast to pay-as-bid cleared ancillary service market. Coal power plants show lower production costs compared to natural gas power plants in the simulated scenario. Therefore, the financial profit potential of reducing feed-in tariffs is bigger for coal power plants compared to natural gas. Nevertheless, the financial improvement potential of this step is related to the prices which result from renewable direct marketing offering and requires further investigation.

Additionally, it would be interesting to analyze the effects of including the additional electricity import and export potential on the financial result of the power plants when the capacity market framework is performed in a multi-country framework.

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Appendix A

Appendix

A.1 Developed Market Model Details

A.1.1 Optimum Strategy - Logical Condition Linearization

In the following equations an example of how logical conditions were modeled in the developed Pyomo model is presented. The δ stands for a Boolean variable.

$$\delta_1\delta_2 = 0 \tag{A.1}$$

represents the condition:

$$\delta_1 = 0 \vee \delta_2 = 0 \tag{A.2}$$

Such a product of Boolean variables can be made linear by the following steps:

1. The product of δ_1 and δ_2 is replaced by a another 0-1 variable δ_3.
2. Impose the logical condition:

$$\delta_3 = 1 \iff \delta_1 = 1 \wedge \delta_2 = 1 \tag{A.3}$$

by means of the extra constraints:

$$-\delta_1 + \delta_3 \leqslant 0 \tag{A.4}$$

$$-\delta_2 + \delta_3 \leqslant 0 \tag{A.5}$$

$$\delta_1 + \delta_2 - \delta_3 \leqslant 1 \tag{A.6}$$

A.1.2 Hydro Power Plant Model Details

Hydro Dam Power Plants

Due to the missing hydro power plant data base in the EnerPol code, the required data (reservoir size and yearly production) of hydro dams are correlated to the only avaiable hydro dam power plant information: the power plant capacity (in MW). For this purpose a linear fit was used. This fit is not based on physical laws, but it is used to minimize the introduced errors. Since the code should not only be applicable for Switzerland, where some reservoir and hydro plant production data are available, correlations were used instead of hard-coded values. The hydro dam data used for the correlations stem from an own online recherche based on the following main sources for Swiss hydro dams:

- Alpiq Homepage
- Axpo Homepage
- KWO Homepage
- BFE Homepage
- Wasserkraftanlagenstatistik BFE

Vertical Height (m):

First, a correlation for the vertical height between reservoirs and turbines of the hydro dam power plants is presented. The found correlation predicts declines which are around 600 m or higher. This values are appropriate for countries of the Alpes such as Switzerland and Austria. For countries with mountains with small altitudes, these values may too high. But it has to be considered that hydro power is only dominant for Switzerland and Austria in the simulated EnerPol framework.

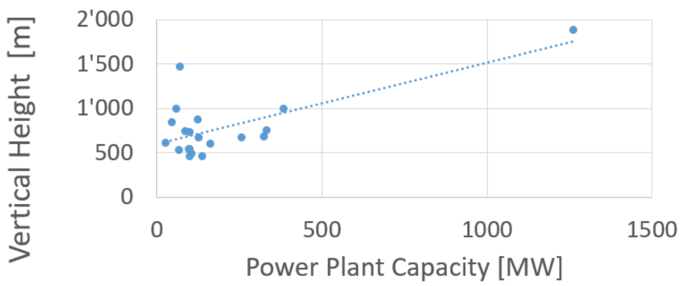


Figure A.1: Decline correlation with power plant capacity

The vertical height d in meter is approximated by:

$$d = 0.91 \cdot ratedCapacity + 597 \tag{A.7}$$

Energy Equivalent Value (MWh/m^3):

The energy equivalent value (EEV) in MWh/m^3 is approximated by the following correlation:

$$EEV = \frac{9.81 \cdot 1'000 \cdot d}{3'600 \cdot 10^6} \tag{A.8}$$

Reservoir Size (m^3):

Hydro power plants are often found in a cascade framework, where the outflow of one power plant serves as inflow into the next one. Since no cascade and reservoir size information is implemented in the EnerPol framework, it is unclear if a power plant has one or more water reservoirs or if the water of a reservoir has to be shared with other power plants. Additionally, for most power plants with several reservoirs the data availability of the different reservoir sizes is poor as data analysis showed. Therefore, the reservoir size correlation is based on a reduced amount of data points. These data points correspond to Swiss hydro dams which are not in a cascade framework, show trustworthy reservoir data and have only a single reservoir. For an efficient water balance handling during the code runs, the reservoir size is converted from m^3 to MWh. The reservoir volume $V_{Reservoir}$ in MWh is approximated by:

$$V_{Reservoir} = (278'000 \cdot ratedCapacity + 50'000'000) \cdot EEV \tag{A.9}$$

Annual Production (MWh):

For the most important hydro dams the Swiss Federal Office for Energy (BFE) publicates the expected annual production values in MWh.

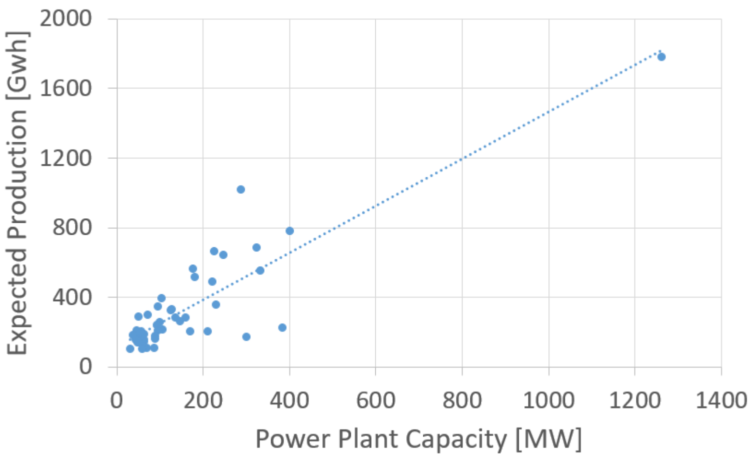


Figure A.2: Yearly production correlation with power plant capacity

Out of the expected annual production values from the BFE homepage the following correlation for the yearly production (in MWh) was found:

$$P_{annual} = 1'000 \cdot (1.35 \cdot ratedCapacity + 116.3) \tag{A.10}$$

A.1.3 Day-Ahead Market Model Details

Traded Products in Austria/Germany, Switzerland and France

The following list gives a complete overview of all products which can be traded on the day-ahead market in Austria, Germany, Switzerland and France.

- Standard Block Orders
  - Baseload (1-24 h)
  - Peak (8-20 h)
  - Off-Peak (1-8h and 21-24h)
  - Night (1-6h)
  - Morning (7-10h)
  - High Noon (11-14h)
  - Afternoon (15-18h)
  - Evening (19-24h)
  - Rush Hour (17-20h)
  - Off-Peak 1 (1-8h)
  - Off-Peak 2 (21-24h)
  - Business (9-16h)
  - Middle-Night (1-4h)
  - Early Morning (5-8h)
  - Late Morning (9-12h)
  - Early Afternoon (13-16h)
  - Off-Peak (1-8h and 21-24h)
  - Sun-Peak (11-16h)
- User-defined Blocks
- Single Hours

A.1.4 Intra-Day Market Model Details

Details Italy

As already mentioned in the market analysis chapter Italy organizes its intra-day market quite differently compared to the EPEXSPOT countries Austria, France, Germany and Switzerland. Therefore, it is explained in some details subsequently.

The sitting of the MI1 takes place after the closing of the day-ahead market. It opens at 12.55 p.m. of the day before the day of delivery and closes at 3 p.m. of the same day. The results of the MI1 are made known within 3.30 p.m. of the day before the day of delivery.

The sitting of the MI2 opens at 12.55 p.m. of the day before the day of delivery and closes at 4.30 p.m. of the same day. The results of the MI2 are made known within 5 p.m. of the day before the day of delivery.

The sitting of the MI3 opens at 5.30 p.m. of the day before the day of delivery and closes at 11.45 p.m. of the same day. The results of the MI3 are made known within 00.15 p.m. of the day of delivery.

The sitting of the MI4 opens at 5.30 p.m. of the day before the day of delivery and closes at 3.45 a.m. of the day of delivery. The results of the MI4 are made known within 4.15 a.m. of the day of closing of the sitting.

The sitting of the MI5 opens at 5.30 p.m. of the day before the day of delivery and closes at 7.45 a.m. of the day of delivery. The results of the MI5 are made known within 8.15 a.m. of the day of closing of the sitting.

The sitting of the MI6 opens at 5.30 p.m. of the day before the day of delivery and closes at 11.15 a.m. of the day of delivery. The results of the MI6 are made known within 11.45 a.m. of the day of closing of the sitting.

The sitting of the MI7 opens at 5.30 p.m. of the day before the day of delivery and closes at 3.45 p.m. of the day of delivery. The results of the MI7 are made known within 4.15 p.m. of the day of closing of the sitting.

[12]

TIMELINE OF ACTIVITIES ON THE MPE IN RESPECT OF THE DAY D

Reference Day	D-1				D															
	MGP	MI1	MI2	MSD1	MB1	MI3	MSD2	MB2	MI4	MSD3	MB3	MI5	MSD4	MB4	MI6	MSD5	MB5	MI7	MSD6	MB6
Preliminary information	11.30	15.00	16.30	n.d.	n.d.	23.45*	n.d.	n.d.	3.45	n.d.	n.d.	7.45	n.d.	n.d.	11.15	n.d.	n.d	15.45	n.d.	n.d
Openingof sitting	08.00**	12.55	12.55	12.55	°	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*	17.30*	°	22.30*
Closing of sitting	12.00	15.00	16.30	17.30	°	23.45*	°	3.00	3.45	°	7.00	7.45	°	11.00	11.15	°	15.00	15.45	°	19.00
Provisional results	12.42	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Final results	12.55	15.30	17.00	21.45	#	0.15	2.15	#	4.15	6.15	#	8.15	10.15	#	11.45	14.15	#	16.15	18.15	#

*the time refers to the day D-9
**the time refers to the day D-1
°use is made of bid/offers entered into the MSD1
#Dispaching Rules

Figure A.3: Daily auction schedule for Italian electricity market [12]

The following legend explains the used Italien abbreviations in figure A.3.

- MPE = spot electricity market
- MPEG = daily products market
- MGP = day-ahead market
- MSD = ancillary service market
- MI = intra-day market

__Details Poland__

The Polish intra-day market shows different auction timings and sequences than the EPEXSPOT countries. The detailed order of sequence of the Polish day-ahead market can be read from figure A.4.

<table>
<tr><th>Time</th><th>Quotation phase</th></tr>
<tr><td>Till 6:30 p.m. 2 days before the Delivery Day</td><td>Collaterals update
Introducing of current collaterals.</td></tr>
<tr><td>From 11:30 a.m. 1 day before the Delivery Day till 2:30 p.m. 1 day before the Delivery Day</td><td>Continuous trading
Acceptance of orders for all instruments of the Delivery Day; the orders may be cancelled and modified. The orders are validated as regards the collateral status.</td></tr>
<tr><td>Till 6:30 p.m. 1 day before the Delivery Day</td><td>Collaterals update
Introducing of current collaterals.</td></tr>
<tr><td>From 8:00 a.m. on the Delivery Day till 2:30 p.m. on the Delivery Day</td><td>Continuous trading
Acceptance of the orders for the instruments during the periods specified in the table below; the orders may be cancelled and modified; the orders are validated as regards the collateral status.
<table>
<tr><th>the instruments being quoted</th><th>The quotation period</th></tr>
<tr><td>RDBk_DD-MM-RRRR_H12</td><td>from 08:00 till 8:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H13</td><td>from 08:00 till 9:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H14</td><td>from 08:00 till 10:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H15</td><td>from 08:00 till 11:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H16</td><td>from 08:00 till 12:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H17</td><td>from 08:00 till 13:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H18</td><td rowspan="7">from 08:00 till 14:30</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H19</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H20</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H21</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H22</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H23</td></tr>
<tr><td>RDBk_DD-MM-RRRR_H24</td></tr>
</table>
* HGG means the delivery hour, for example H12 means the period between 11:00 and 12:00</td></tr>
<tr><td>Till 3:30 p.m. on the Delivery Day</td><td>Publication of quotation results on the Public Web Site</td></tr>
</table>

Figure A.4: Intra-day market time schedule for Poland [15]

A.1.5 Ancillary Service Market Model Details

Ancillary Service Amount Correlations

Since the availability of the procured ancillary service amount data of the TSOs can vary heavily in between countries, for a further expansion of the EnerPol framework to more countries, relationships to determine the required ancillary service capacities were derived.

a) PRL Correlation

Primary reserve directly scales with the average electricity load of a country. The amount which each TSO has to procure is determined by ENTSO-E following this load criteria. Therefore it expected that a good linear correlation can be found when ENTSO-E load data of the year 2016 is compared to the procured primary reserve capacities of different countries. As figure A.5 indicates this expected correlation can be seen.

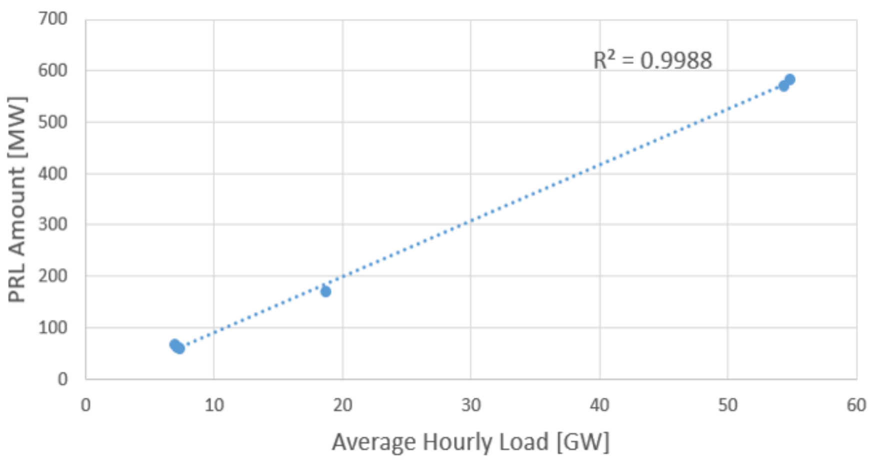


Figure A.5: Correlation of procured primary reserve capacities and average hourly load of country

$$\text{PRL Requirement (MW)} = 10.9 \times \text{Load (GW)} - 17.7 \tag{A.11}$$

In contrast to primary reserve which is provided solidary among the European countries, secondary and tertiary reserves have to be provided from the control area which causes the grid imbalance. Therefore the procured amounts of secondary and tertiary reserves are assumed to scale with grid imbalance risk factors such as wrong demand or renewable generation forecasts. A pure scaling with the average hourly load of the country does not provide satisfying results as it can be seen in figures A.6 up to A.8. Germany and France have similar load values around 55 GW but there is a huge difference in procured reserve amounts (around 1'200 MW). When additionally the installed renewable capacity is added to the average country electricity load, the correlation fits well. With an R^2 value above 0.9, the correlation can be categorized as strong.

b) SRL Correlation

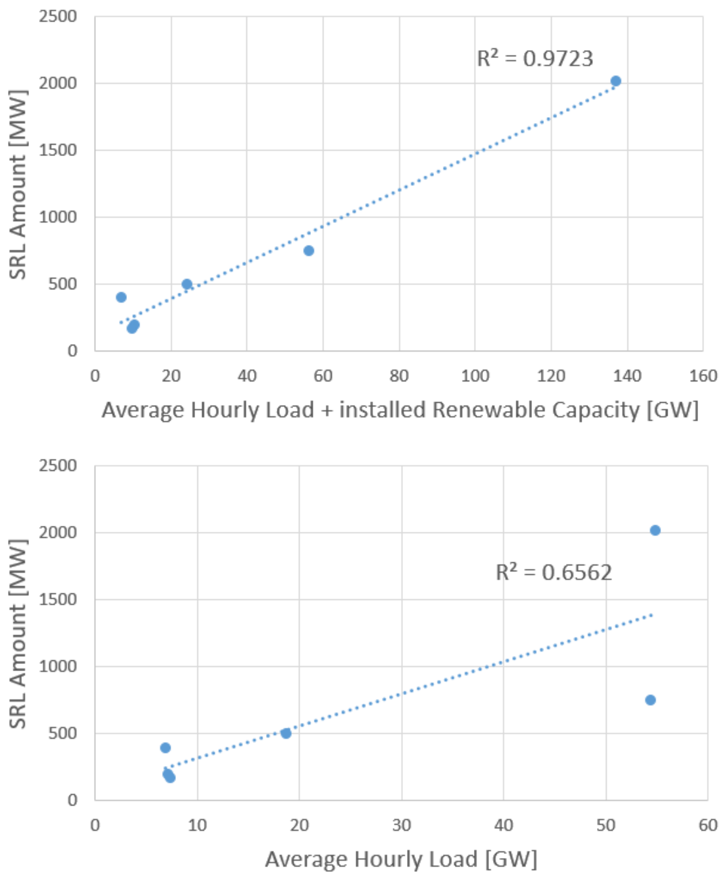
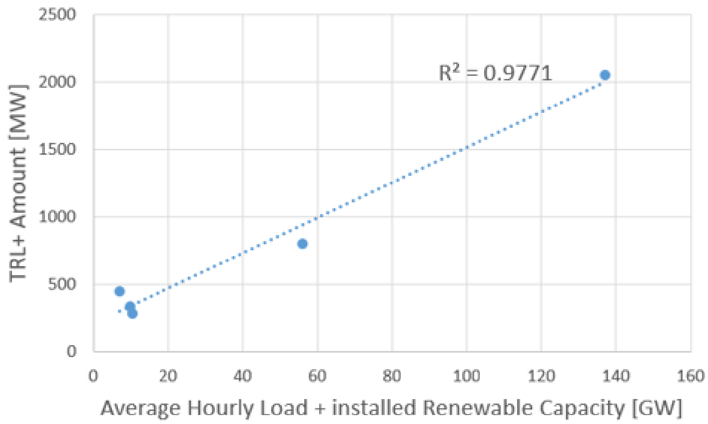


Figure A.6: Correlation of procured secondary reserve capacities with average hourly load of country and installed renewable capacities

$$\text{SRL Requirement (MW)} = 13.5 \times (\text{Load (GW)} + \text{installed Renewable Capacity (GW)}) + 123.9 \quad \text{(A.12)}$$

c) TRL+ Correlation



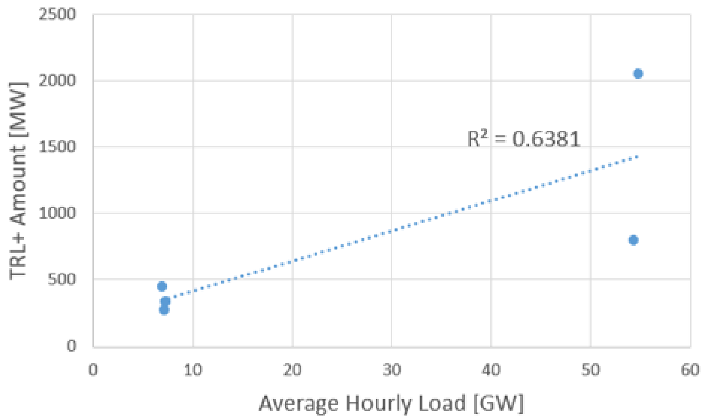
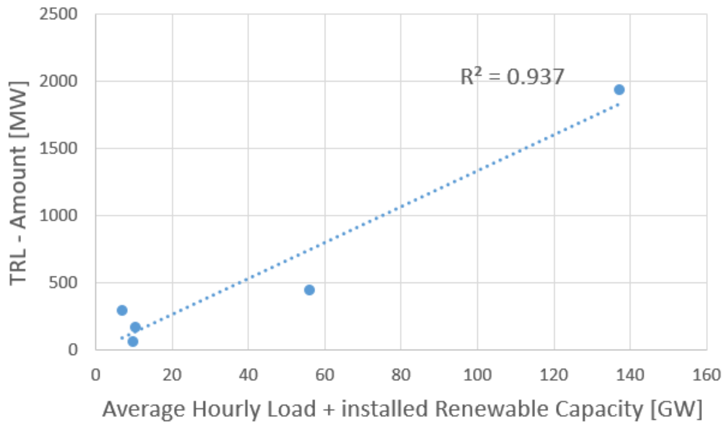


Figure A.7: Correlation of procured positive tertiary reserve capacities with average hourly load of country and installed renewable capacities

$$\text{TRL+ Requirement (MW)} = 13.0 \times (\text{Load (GW)} + \text{installed Renewable Capacity (GW)}) + 210.9 \tag{A.13}$$

d) TRL- Correlation



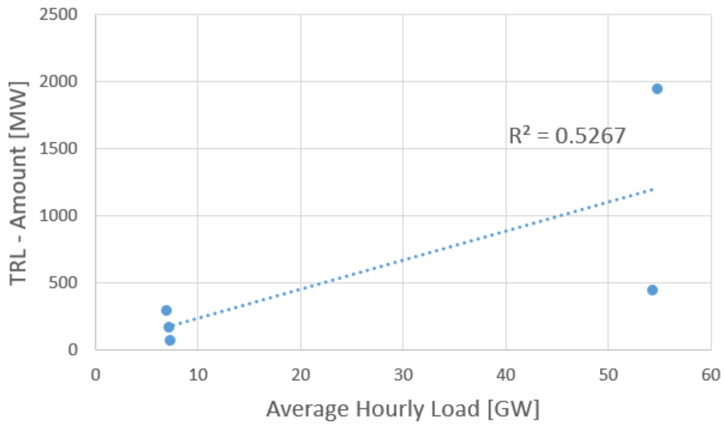


Figure A.8: Correlation of procured negative tertiary reserve capacities with average hourly load of country and installed renewable capacities

$$\text{TRL- Requirement (MW)} = 13.4 \times (\text{Load (GW)} + \text{installed Renewable Capacity (GW)}) - 1.5 \quad \text{(A.14)}$$

Ancillary Service Market Details Italy

The ancillary services market (MSD) is the venue where Terna S.p.A. procures the resources that it requires for managing and monitoring the system relief of intra-zonal congestions, creation of energy reserve, real-time balancing. In the MSD, Terna acts as a central counterparty and accepted offers are remunerated at the price offered (pay-as-bid).

The MSD consists of a scheduling substage (ex-ante MSD) and Balancing Market (MB). The ex-ante MSD and MB take place in multiple sessions, as provided in the dispatching rules.

The ex-ante MSD consists of six scheduling substages: MSD1, MSD2, MSD3, MSD4, MSD5 and MSD6. The sitting for bid/ask submission into the ex-ante MSD is a single one. It opens at 12.55 p.m. of the day before the day of delivery and closes at 5.30 p.m. of the same day. The results of the MSD1 are made known within 9.45 p.m. of the day before the day of delivery. GME notifies Market Participants of the individual results of the MSD2 session (as specified in the dispatching rules) concerning the bids/asks accepted by Terna within 2.15 a.m. of the day of delivery. GME notifies Market Participants of the individual results of the MSD3 session (as specified in the dispatching rules) concerning the bids/asks accepted by Terna within 6.15 a.m. of the day of delivery.

GME notifies Market Participants of the individual results of the MSD4 session (as specified in the dispatching rules) concerning the bids/asks accepted by Terna within 10.15 a.m. of the day of delivery. GME notifies Market Participants of the individual results of the MSD5 session, (as specified in the dispatching rules), concerning the bids/asks accepted by Terna within 2.15 p.m. of the day of delivery. GME notifies Market Participants of the individual results of the MSD6 session, (as specified in the dispatching rules), concerning the bids/asks accepted by Terna within 6.15 p.m. of the day of delivery. In the ex-ante MSD, Terna accepts energy demand bids and supply offers in order to relieve residual congestions and to create reserve margins.

The MB takes place in different sessions, during which Terna selects bids/asks in respect of groups of hours of the same day on which the related MB session takes place. At present, the MB consists of 6 sessions. The first session of the MB takes into consideration the valid bids/asks that Participants have submitted in the previous ex-ante MSD session. For the other sessions of the MB, all the sittings for bid/ask submission open at 10.30 p.m. of the day before the day of delivery (and anyway not before the results of the previous session of the ex-ante MSD are made known) and close 1 hour and a half before the first hour which may be negotiated in each session. In the MB, Terna accepts energy demand bids and supply offers in order to provide its service of secondary control and to balance energy injections and withdrawals into/from the grid in real time.

[12]

A.2 Capacity Market Model Details

A.2.1 Comparison of Propsed Capacity Payment Systems and Costs

During the time span of this project, different power plant companies in Switzerland proposed models how to ensure future generation capacity availability and how they would propose to reimburse backup capacity. The two models and the expected costs are sketched shortly to compare the simulation predicted capacity payment against this data.

Switzerland - Model BKW - Auctions

The Swiss energy producer BKW proposes a long-term capacity auction model. The model is based on yearly auctions which are performed for the year Y+4 (meaning the year in 4 years time from now). Allowed market participants are existing electricity producers and new enterprises with new solutions for electricity generation. The auction price is guaranteed for 1 year, for new years even for 15 years. The costs are proposed to be paid by the end-consumer. The costs are assumed to be around 300 million Swiss Francs per year, which translates into around 0.6 Rp./kWh for the electricity consumers. [62]

Switzerland - Model Axpo - CO2 Tax

The company Axpo proposes a CO2 tax for production of electricity which creates CO2 emissions. The tax includes also electricity imports from abroad. This tax proposal can be seen as attempt to privilege Swiss hydro power and nuclear energy in the future since with this approach the costs for electricity production with new gas combined cycle power plants would increase heavily. As in the BKW case, Axpo proposed that end-consumers will pay the costs for these subventions by higher electricity prices. This approach for future backup capacities would translate in expected costs of around 500-600 million Swiss francs which translates into around 1.2 Rp./kWh. [62]

Germany

In an interview, Martin Schmitz, CEO of the German power producer RWE mentioned for a capacity market approach in Germany costs of around 2 billion € per year which can be expected. [65]

A.2.2 Effect of Power Plant Investment Costs and Target IRR Choice on Required Annual Cash Flow

To evaluate the sensitivity of the simulation predicted capacity payments on the chosen capital cost values for new power plant installations, the required average annual cash flows for reaching a certain target IRR are evaluated for different capital costs levels. In the chosen framework, new coal power plants were modeled as 600 MW blocks and new natural gas combined cycle power plants were chosen as 500 MW blocks. The resulting required cash flows for different target IRR values can be seen in tables A.1 and A.2.

Table A.1: Required annual cash flow to reach target IRR value with specified power plant investment costs for a 600MW block

	600 MW Plant Blocks (Coal Case)	
Capital Costs (USD/kW)	**Req. Cash Flow for IRR = 7% (Mio. €)**	**Req. Cash Flow for IRR = 3% (Mio. €)**
4’000	159	89
3’500	139	78
3’000	119	66
2’000	79	44
1’500	60	33
1’000	40	22

Table A.2: Required annual cash flow to reach target IRR value with specified power plant investment costs for a 500MW block

	500 MW Plant Blocks (NGCC Case)	
Capital Costs (USD/kW)	**Req. Cash Flow for IRR = 7% (Mio. €)**	**Req. Cash Flow for IRR = 3% (Mio. €)**
4’000	132	74
3’500	116	64
3’000	99	55
2’000	66	37
1’500	50	28
1’000	33	18

As simulation results showed, coal power plants are able to generate profits in the range of 60-80 million € in the year 2045, whereas natural gas power plant show profits of around 30 million € in the same year. In this project, the capital costs were set to 4’000 USD/kW for coal power plants and 1’000 USD/kW for natural gas combined cycle power plants based on power plant cost studies found in literature. [50] [51]

A.3 EnerPol Data Base Update for the Year 2015

Since EEX unitwise and generator type aggregated production data is only available for the years 2015 up to today, the EnerPol data base for Germany of the year 2013 had to be updated for the year 2015 for being able to validate simulation results. On the this page, the most relevant facts about the simulated case for Germany in the year 2015 is presented since it was used for the validation of the market models.

Renewable Scaling Factors

To account for the newly installed renewable capacities the existing renewable generators in the EnerPol 2013 data base were scaled up by the factors listed in table A.3. The installed capacities for the year 2015 were taken over from the ENTSO-E transparency platform. [38]

Table A.3: Renewable scaling factors for Germany for EnerPol data base update

	Scaling Factor
Wind	1.14
Solar	1.03

Fossil Fuel Prices

The prices for natural gas and coal both decreased in the period from 2013 to 2015 by around 35% as a market analysis showed. Event though lignite is not a product which is traded globally due to its low calorific value, the price of lignite was adapted as well (decreased by 20%) to keep the lignite production costs in a similar price ratio to the coal production as in the year 2013. [57] [56]

Weather Data

A weather simulation with the WRF model for the year 2015 was performed by Patrick Eser. Therefore, the analysis of the year 2015 could be done with the according weather data (solar irradiance, wind data, temperatures) of the year 2015.

Currencies

Due to the fact that the EnerPol intern cost structures are implemented in Dollars, the currencies have to be taken into account for the case of Europe when the new market model approach with yearly hydro dam optimization and power plant strategy determination according to price forecast inputs in Euro/MWh is used. For the time period between 2013 and 2015 a change of the Dollar-Euro exchange rate could be determined. The listed prices below are yearly average exchange currencies provided by Bloomberg [66]:

US-Dollar to Euro Exchange Rate:

- 2013: 1.33
- 2015: 1.11