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Impact of mandatory capacity pricing on balancing groups with high shares of variable renewable electricity generation

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Abstract

Low price levels of the energy-only-market endanger the profitability of already operating power plants and hence reduce incentives for investments in new generation capacities. However, capacity mechanisms might provide such incentives.

The aim of the thesis is to clarify how two fictitious balancing groups, in consideration of different capacity capturing options and their economic feasibility, cover their load deficit in case mandatory capacity mechanisms and therefore capacity prices are implemented.

The analysis is based on a linear optimisation problem that gives the cost-minimal solution for the additional installation of capacities of a single, pre-defined balancing group to cover its load deficit. The model can choose from different options like purchasing the needed capacity from the capacity market or building new power capacities such as gas power plants, wind parks, photovoltaic systems or energy storages.

The results show that the installation of new generation facilities is dominant at the time when the capacity price exceeds twice the annuity of a combined cycle gas turbine. However, an adequate capacity price highly depends on the annual excess generation in the respective balancing group. Additional installations are dominated by combined cycle gas turbines. Energy storages only support the covering of the load deficit if high excess generation is available in the corresponding balancing group. Due to higher costs neither renewables nor gas turbine power plants are considered for additional installations by the model.

As only a single balancing group is analysed further studies should investigate the interaction of different balancing groups to clarify possible simultaneity effects.

Kurzfassung

Das niedrige Preisniveau am Energy-Only-Markt gefährdet die Profitabilität bereits bestehender Kraftwerke und vermindert dadurch Anreize für die Installation von neuen, zusätzlichen Kraftwerkskapazitäten. Kapazitätsmechanismen könnten jedoch solche Anreize schaffen.

Ziel dieser Arbeit ist es aus Sicht zweier fiktiver Bilanzgruppen zu klären, wie diese ihr Leistungsdefizit, unter Berücksichtigung verschiedener Kapazitätsoptionen und deren Wirtschaftlichkeit, decken, wenn verpflichtende Kapazitätsmechanismen auf die Bilanzgruppen wirken.

Das verwendete Modell basiert auf einem linearen Optimierungsproblem, welches die jährlichen durch die Deckung des Leistungsdefizits anfallenden Gesamtkosten einer Bilanzgruppe minimiert. Die Leistungsdeckung kann durch einen Zukauf am Kapazitätsmarkt, aber auch durch die Installation zusätzlicher Erzeugungseinheiten, wie Gaskraftwerke, PV-Anlagen, Windkraftanlagen und Stromspeicher, erfolgen.

Die Ergebnisse zeigen, dass Installationen in zusätzliche Kraftwerkseinheiten in beiden Bilanzgruppen dann dominieren, wenn der Kapazitätspreis das Zweifache der Annuität eines GuD-Kraftwerks übersteigt. Der geeignete Kapazitätspreis ist jedoch von der jährlichen Überschusserzeugung der jeweiligen Bilanzgruppe abhängig. Die zusätzlichen Installationen werden von GuD-Kraftwerken dominiert. Energiespeicher unterstützen die Lastdeckung nur in Bilanzgruppen mit hohem Erzeugungsüberschuss. Weder erneuerbare Energien noch Gasturbinen-Kraftwerke werden aufgrund ihrer höheren Kosten vom Modell zur Lastdeckung herangezogen.

Diese Arbeit betrachtet jeweils nur eine einzelne Bilanzgruppe. Für nachfolgende Arbeiten wäre es interessant, die Interaktion mehrerer Bilanzgruppen zu implementieren um mögliche Gleichzeitigkeitsfaktoren berücksichtigen zu können.

Contents

Nomenclature

Abbreviations

BLG	Balancing group
CCGT	Combined cycle gas turbine
CM	Capacity market
EOM	Energy-only-market
ES	Energy storage
GT	Gas turbine
PV	Photovoltaic
RES	Renewable energy sources
WP	Wind power
CAPEX	Capital expenditure
OPEX	Operational expenditure
mn EUR	Million euro

Decision variables

$P_{CCGT,t}$	Power of CCGT power plant in quarter hour t (MW)
$P_{CCGT,inst}$	Installed power of CCGT power plant (MW)
$P_{GT,t}$	Power of GT power plant in quarter hour t (MW)
$P_{GT,inst}$	Installed power of GT power plant (MW)
$b_{GT,t}$	Boolean variable that indicates if electricity is stored and/or sold in quarter hour t (0,1)
$P^{in}_{SM,t}$	Power purchased from the spot market in quarter hour t (MWh/h)
$P^{out}_{SM,t}$	Power sold on the spot market in quarter hour t (MWh/h)

$P_{SM,max}$	Maximum power that can be sold on or purchased from the spot market (MWh/h)
$P_{PV,i}$	Power produced by PV systems in region i (MW)
$P_{WP,i}$	Power produced by wind parks in region i (MW)
$P^{in}_{ES,t}$	Power used to charge energy storages in quarter hour t (MW)
$P^{out}_{ES,t}$	Power used to discharge energy storages in quarter hour t (MW)
$P_{ES,inst}$	Installed power of energy storages for charging and discharging (MW)
$L_{ES,t}$	Amount of energy stored in the energy storages in quarter hour t (MWh)

Parameters

t	Time index for the corresponding quarter hour of a year
T	Total amount of quarter hours in a year
i	Index for the regional model
I_X	Annuity of investment costs of technology X (k€/MW-yr)
c_{gas}	Gas price (€/MWh)
η_{CCGT}	Electrical efficiency of CCGT power plant (1)
η_{GT}	Electrical efficiency of GT power plant (1)
$p_{SM,t}$	Spot market price in quarter hour t (€/MWh)
p_{cap}	Yearly capacity price (k€/MW-yr)
CPF	Capacity price factor (1)
D_t	Demand of balancing group in quarter hour t (MW)
$P_{PRE,t}$	Pre-installed power capacity available in quarter hour t (MW)
$PP_{PV,i,t}$	Power of annual PV time series in region i in quarter hour t (MW)
$PP_{WP,i,t}$	Power of annual wind power time series in region i in quarter hour t (MW)
RES_{min}	Minimal amount of RES peak power in additional installed power capacity (MW)
HES	Amount of hours energy storage can be filled to reach full capacity (h)
η^{in}_{ES}	Charging efficiency of energy storages (1)
η^{out}_{ES}	Discharging efficiency of energy storages (1)

1. Introduction

1.1. Motivation

The growing amount of renewable energy sources and overcapacities in the electricity generation system reduces the price levels of the energy-only-market. As the income of power plants highly relies on the achieved spot market prices the profitability of operating power plants is decreased. For this reason investments in installations of new power plants are endangered as well. There is simply no incentive to invest in new generation capacities. Capacity mechanisms are discussed to solve these possible failures of the current energy-only-market design, in which only electricity in terms of energy is traded.

The intention of this thesis is to analyse the impact of a capacity mechanism on the whole electricity market by its subdivision into individual balancing groups. The focus is especially set on balancing groups with high amounts of pre-installed renewable energy sources with a high possibility of volatile generation capacities. Those balancing groups may have high amounts of excess electricity in case the generation from wind and PV is high due to ideal weather conditions. During cloudy or windless time periods with low electricity generation balancing groups have to cover their load deficit (and energy deficit respectively).

In the currently implemented energy-only-market the cheapest way to cover the electricity deficit is from the spot market as the spot market prices are low. Hence, the balancing groups have no incentives to invest in or to build extra generation facilities to cover their occurring load deficits.

The main question of the thesis is whether and how a mandatory capacity mechanism can change this situation. More precisely, if a capacity price is able to provide incentives for investments in additional generation facilities.

1.2. Methodology

The applied methodology relies on fictitious balancing groups that are defined by demand and pre-installed power capacities. The demand is based on standard load profiles for households and general businesses from 2015. The pre-installed generation facilities are composed of different annual generation profiles of different years provided by electricity system operators. Hence, each balancing group has periods of load deficits during a year.

One option to compensate these load deficits could be the additional installation of power capacities of different types including gas power, wind power, PV and energy storages. Another option could be the purchase of the needed power capacity from the capacity market, which is defined by an annual capacity price and which limits the amount of electricity supplied by the spot market. Spot market prices are based on the quarter hour spot market prices of 2015 in Austria and Germany, while the gas price is set equally to the annual average price in 2015 in Germany.

All options result in costs that are combined in the objective function. Thus, the aim of the optimisation model is to minimise the total annual costs that arise from covering the load deficit. Additionally, the model takes account of the applied constraints of the different technologies and external, optionally implemented interventions such as minimum shares of renewable energy sources.

The resulting optimisation model is implemented as a linear optimisation problem in MATLAB R2015B supported by the modelling language YALMIP and the GUROBI optimiser. [10] [7]

1.3. Structure of the thesis

Chapter 2 gives a short introduction on how today's electricity markets work and which challenges they face nowadays and might face in the future. Furthermore, the chapter offers an overview on the controversially discussed and already partially implemented capacity mechanisms as a solution to the challenges.

Chapter 3 presents the optimisation model as a foundation of the thesis. Its aim is the cost-minimal installation of generation capacities to cover the power deficit of balancing groups. Subsequently, the applied model constraints and simplifications are explained. The chapter ends by introducing the balancing groups and all other parameters used in the model.

In Chapter 4 it is at first verified whether the model mirrors the current situation of electricity markets, the so-called reference scenario. Secondly, the variation of different input parameters allows an insight into the impact of different parameters on the model. The capacity price scenario verifies the effects of different capacity prices on the defined balancing groups and tries to determine an appropriate capacity price. The subsequent scenario examines the effect a minimal share of renewable energy sources in additional installations has on other generation technologies. Finally, the two scenarios are combined to the combination scenario.

The results of the scenario simulations in Chapter 4 are summarised and discussed in Chapter 5. Chapter 6 gives a conclusion of the findings and proposals for further research activities.

2. State of the Art

This chapter gives an overview of today's electricity system that experiences a persistent change due to a growing share of renewable energy sources. It describes how the energy-only-market (EOM) works and how it is affected by wind and photovoltaic power. Additionally, capacity mechanisms are explained. These have recently been discussed controversially as addition to EOM with the aim to assure incentives for investments in the electricity system. Based on the before mentioned overviews the purpose of this thesis is described at the end of the chapter.

2.1. Today's electricity market

Electricity in terms of energy is mainly sold and purchased on the energy stock exchange[1], where short term auctions are operated by the spot market and long term auctions are operated by the futures market.

Prices that suppliers can achieve are determined by supply and demand. This means every supplier can bid a certain amount of energy for every hour at a certain price. The price mainly depends on the short term marginal costs of the respective power plant. These costs are primarily set by the fuel costs. After the bidding process, the bids are sorted in ascending order, the so-called merit order. This order shows which power plants are to serve the energy demand to the corresponding hour. Those power plants with the lowest marginal costs are brought online at first. Power plants with higher marginal costs are added until the total energy demand is covered. Finally, the power plant with the highest marginal costs added at last sets the spot market price.

[1]Germany: EEX, Austria: EXA

All power plants with marginal costs higher than the resulting spot market price lose the auction and are not online during the hour in question. Consequently, all power plants with marginal costs lower than the spot market price gain profit or a marginal return, which is the major income for utilities in an EOM. [9]

The balancing market is another income source for utilities. If a power plant is not able to provide the before offered electricity, buffer power plants supply the needed electricity to ensure net and frequency stability. While on the spot market only energy is paid, the provided capacity is also compensated on the balancing market. [6]

2.1.1. Challenges for today's and future electricity market

Renewable energy sources (RES) have a crucial impact on today's electricity market. Marginal costs of RES, like wind power and photovoltaic (PV), can be neglected since they do not need any fuels to produce electricity. In addition, electricity generated from RES has to be consumed at first (e.g. unlimited priority feed-in for electricity generated from renewable energy sources in Germany). As a consequence, RES are always at the bottom of the merit order and shift the demand to power plants with lower marginal costs. Hence, all power plants earn less profit since the average spot market prices decrease and the capacity utilisation of conventional power plants is reduced into the bargain, which limits financial incentives to build new power capacities. [9][12]

The supply of wind parks and PV is highly influenced by weather conditions and time of day. To compensate weak or negligible energy generation of RES, and in case of a lack of enough power storage capacity, conventional power plants, like coal or gas fired power plants, are used to provide great security of supply. While mostly old coal power plants are already depreciated and thus can produce electricity at low marginal costs[2], it is claimed that new, flexible and efficient combined cycle gas power plants, due to their much

[2]Marginal costs of coal power plants are mainly depending on the prices of coal and CO2 certificates. As the CO2 market is not working as intentioned due to the affluence of CO2 certificates on the market, CO2 certificate prices are low. Therefore the marginal cost of a coal power plant is mainly affected by the price of coal.

higher marginal costs, cannot compete sufficiently with spot market prices to be profitable. Even though their flexibility is crucial in future energy markets with high amounts of volatile RES. [9][12]

Energy storage technologies are also essential for a power system dominated by RES. However, RES not only decrease the spot market prices as mentioned before but also reduce the gap between highest and lowest prices and cut profits of energy storages as their business model relies on these price differences. [9]

Those opposing trends are questioning and challenging the currently implemented EOM design.

2.2. Capacity mechanisms

To assure resource adequacy and thus to guarantee the needed financial incentives to invest in new, flexible power plants capacity mechanisms have been widely discussed. They represent another possibility for utilities to generate income. Instead of earning income from selling electricity, utilities are paid for providing power capacity in the long term (similar to the balancing market in the short term).

2.2.1. Overview of possible mechanisms

Four different types of capacity mechanisms were considered in Germany:

- **Strategic Reserve (SR)**: In the centrally managed SR all power plants that are not able to produce profitably and are consequently in danger of a close-down are included. The power plants act as a reserve and do not participate in the EOM. [15]
- **Comprehensive capacity market (CCM)**: Already existing as well as planned power plants participate in the CCM. Additionally, energy storages and flexible consumers may take part in the market to use the whole potential of existing power. All power plants are still allowed to sell energy on EOM and provide capacity for the balancing market to assure intense competition. [15]

- **Selective or focused capacity market (FCM)**: The FCM is centrally managed and split into two different market segments. In the market segment for existing power plants, power plants that are at risk of closure and controllable loads compete for capacity payments of one to four years. A second market segment includes new-built power plants, that meet high environmental and flexibility requirements, and storages. Those are in competition for capacity payments over 15 years to guarantee planning reliability. Successful bidder may participate in the EOM. [12]
- **Decentralised capacity market (DCM)**: Provision and payment of capacity is not managed by a central agency, but by a capacity market itself. Traded capacity certificates provided by suppliers of secured power (e.g. conventional and combined cycle power plants, storages and controllable RES) should assure the adequate amount of secured power to a market efficient price. Therefore, consumer are responsible to determine their future capacity demand and to buy the necessary amount of capacity certificates. [15]

Each of the aforementioned options for capacity mechanisms has its benefits and its drawbacks. Among other things, they differ in complexity, in intensity of the emerging competition and in the arising extra costs. For in-depth analysis reference is made to the cited literature.

2.2.2. Controversial discussion in literature

It is still controversial if there is a definite need for capacity mechanisms in the electricity market design. Critics argue that the current low spot market prices are - besides the growing amount of RES - to some extent a result of overcapacities in the market, which shows the proper functionality of the current market design and not a market failure. If overcapacities disappear from the market higher market prices may come back. [13]
Additionally, in an EOM capacity is already sold implicitly as contracts for secured delivery between suppliers and costumers are concluded. Furthermore, in theory EOM design provides scarcity prices at times of high demand and low supply. These prices are much higher than the marginal costs of the last power plant being at disposal and they generate income even for the power plant being online with the highest marginal costs. These incomes can

be used to finance investments as well. However, this assumption is based on the elasticity of demand, which is mostly inelastic (because of technology reasons). Demand side management implemented in the near future is seen as a possible solution for this issue. Smart metering and smart grid solutions as well as the batteries in the growing number of electric cars may affect the demand flexibility. [11] [4]
Due to the mentioned uncertainties of future electricity market developments and reactions on them CM measures are to be introduced step-by-step. In the beginning low market complexity should be guaranteed that in case their necessity vanishes exit-strategies for CMs can be followed easily. [11]
Therefore, before adopting CMs it is recommended that less invasive market design enhancements should be exploited at first and secondly the definite purpose of a CM in question should be defined as a CM can unfold its benefetis, like resource adequacy, only in the long term. Additionally, regulatory imperfections owing to political forces and politically induced uncertainties make a CM inefficient and have to be tackled before its implementation. [4]

2.2.3. Situation in Europe

The controversial opinions in the literature about the future electricity market design are also mirrored in the European context. Different kinds of national policies are pursued in different countries. While some countries (e.g. Austria) rely on the EOM, others already operate strategic reserves (e.g. Finland, Norway, Sweden, Poland) or practice capacity payments (e.g. Italy, Portugal, Spain). Furthermore, the UK has recently installed a CM and France is in the process of introducing a capacity mechanism. [13] [11] [14]
Germany is going to develop an 'electricity market 2.0', where a strategic reserve on stand-alone basis separated from the electricity market should ensure the security of supply. [2]
In the worst case scenario, these unequally implemented national systems may distort cross-border markets. [14]

2.3. Purpose of the thesis

The above mentioned challenges and uncertainties affect every utility and balancing group to some extent. For policy makers it is essential to know how their policies may influence different balancing groups. Especially capacity mechanisms may have a fundamental impact on the whole electricity market. If capacity prices are defined improperly the actual outcomes may be contrary to the intended ones.

This thesis analyses and discusses the impacts of mandatory capacity mechanisms and determined minimal amounts of renewable energy sources on two different balancing groups. Each of them has different pre-installed power capacities and hence different load deficits, that have to be covered by additional installations to provide the demanded electricity. An optimisation model gives the cost-minimal solution for the additional installation of each balancing group.

3. Method

3.1. Introduction: Cost-minimal compensation

The aim of this work is to investigate how a balancing group may react cost-minimally under certain external factors of influence in order to compensate its load deficit. For compensation the balancing group has either the opportunity to build new power generation facilities such as gas power plants (gas turbine GT and combined cycle gas turbine CCGT), RES in four different regions (photovoltaic systems and wind power plants) or purchasing capacity from the capacity market to be able to purchase electricity from the spot market. Furthermore, the respective balancing group can build energy storages to store excess electricity for later hours. Selling excess electricity on the spot market is another option the balancing group is able to choose from to generate revenues and to reduce costs.

The implemented optimisation model, as well as its features and constraints, are explained in Section 3.2. The used simplifications of the model and all input values are described in Sections 3.3 and 3.4.

3.2. Optimisation model

3.2.1. Objective function

As mentioned before, the aim of the optimisation model is to minimise yearly costs that are caused by compensating the load deficit. The total costs of the system consist of the investment costs I_{tot} to build new power plants, fuel costs for gas burnt in the gas power plants C_{gas}, costs for electricity purchased from the spot market C_{spot} and costs for capacity purchased from the capacity

Table 3.1.: Overview of decision variables and parameters used in the optimisation model.

Variable	Unit	Description
$P_{CCGT,t}$	MW	Power of CCGT power plant in quarter hour t
$P_{CCGT,inst}$	MW	Installed power of CCGT power plant
$P_{GT,t}$	MW	Power of GT power plant in quarter hour t
$P_{GT,inst}$	MW	Installed power of GT power plant
$b_{GT,t}$		Boolean variable that indicates if electricity is stored and/or sold in quarter hour t (0,1)
$P^{in}_{SM,t}$	MWh/h	Power purchased from the spot market in quarter hour t
$P^{out}_{SM,t}$	MWh/h	Power sold on the spot market in quarter hour t
$P_{SM,max}$	MWh/h	Maximum power that can be sold on or purchased from the spot market
$P_{PV,i}$	MW	Power produced by PV systems in region i
$P_{WP,i}$	MW	Power produced by wind parks in region i
$P^{in}_{ES,t}$	MW	Power used to charge energy storages in quarter hour t
$P^{out}_{ES,t}$	MW	Power used to discharge energy storages in quarter hour t
$P_{ES,inst}$	MW	Installed power of energy storages for charging and discharging
$L_{ES,t}$	MWh	Amount of energy stored in energy storages in quarter hour t

Parameter	Unit	Description
t		Time index for the corresponding quarter hour of a year
T		Total amount of quarter hours in a year
i		Index for the regional model
I_X	k€/MW-yr	Annuity of investment costs of technology X
c_{gas}	€/MWh	Gas price
η_{CCGT}	1	Electrical efficiency of CCGT power plant
η_{GT}	1	Electrical efficiency of GT power plant
$p_{SM,t}$	€/MWh	Spot market price in quarter hour t
p_{cap}	k€/MW-yr	Yearly capacity price
CPF	1	Capacity price factor
D_t	MW	Demand of balancing group in quarter hour t
$P_{PRE,t}$	MW	Pre-installed power capacity available in quarter hour t
$PP_{PV,i,t}$	MW	Power of annual PV time series in region i in quarter hour t
$PP_{WP,i,t}$	MW	Power of annual wind power time series in region i in quarter hour t
RES_{min}	MW	Minimal amount of RES peak power in additional installed power capacity
HES	h	Amount of hours energy storages can be filled to reach full capacity
η^{in}_{ES}	1	Charging efficiency of energy storages
η^{out}_{ES}	1	Discharging efficiency of energy storages

market C_{cap}. The total costs are reduced by selling electricity on the spot market, therefore generating revenues R_{spot}. Thus, the objective function of the optimisation model leads to

$$\min_{\mathbf{x}} \quad I_{tot} + C_{gas} + C_{SM} + C_{cap} - R_{SM} \;, \tag{3.1}$$

with decision variables grouped in vector

$$\begin{aligned}\mathbf{x} = [&P_{CCGT,t}, P_{CCGT,inst}, P_{GT,t}, P_{GT,inst}, b_{GT,t}, P^{in}_{SM,t}, P^{out}_{SM,t}, P_{SM,max},\\ &P_{PV,1}, P_{PV,2}, P_{PV,3}, P_{PV,4}, P_{WP,1}, P_{WP,2}, P_{WP,3}, P_{WP,4},\\ &P^{in}_{ES,t}, P^{out}_{ES,t}, P_{ES,inst}, L_{ES,t}] \;.\end{aligned}$$

Here and below, the time index t describes a quarter hour of the year and T the total amount of quarter hours per year.
The yearly investment costs are calculated by

$$\begin{aligned}I_{tot} =& I_{CCGT} \cdot P_{CCGT,inst} + I_{GT} \cdot P_{GT,inst}\\ &+ I_{PV} \cdot P_{PV,inst} + I_{WP} \cdot P_{WP,inst} + I_{ES} \cdot P_{ES,inst} \;,\end{aligned} \tag{3.2}$$

where I_X are the annuities of the investment costs and $P_{X,inst}$ is the installed peak power for the respective power generation technology.
The fuel costs for gas are derived by

$$C_{gas} = c_{gas} \sum_{t=1}^{T} \left(\frac{1}{\eta_{CCGT}} P_{CCGT,t} \frac{1}{4} h + \frac{1}{\eta_{GT}} P_{GT,t} \frac{1}{4} h \right) \;. \tag{3.3}$$

$P_{GT,t}\frac{1}{4}h$ and $P_{CCTGT,t}\frac{1}{4}h$ describe the electricity generated per quarter hour by both gas power plants with their current power values $P_{GT,t}$ and $P_{CCGT,t}$. Over the entire simulation period a constant gas price c_{gas} is used in consideration of the efficiency factors of the gas power plants η_{GT} and η_{CCGT}.
The costs for purchasing electricity from and the revenues of selling electricity on the spot market are affected by the spot market price $p_{SM,t}$ and the electricity purchased $P^{in}_{SM,t}\frac{1}{4}h$ and sold $P^{out}_{SM,t}\frac{1}{4}h$ per quarter hour t:

$$C_{SM} = \sum_{t=1}^{T} p_{SM,t} \cdot P^{in}_{SM,t} \frac{1}{4} h \tag{3.4a}$$

$$R_{SM} = \sum_{t=1}^{T} p_{SM,t} \cdot P^{out}_{SM,t} \frac{1}{4} h \tag{3.4b}$$

The yearly costs for purchasing power capacity (e.g. from a capacity market) is calculated with

$$C_{cap} = p_{cap} \cdot P_{SM,max} \,, \tag{3.5}$$

where $P_{SM,max}$ times $\frac{1}{4}h$ is the maximum amount of electricity per quarter hour that can be provided by the spot market. p_{cap} is derived from the capacity price factor CPF times the annuity of the CCGT power plant I_{CCGT}, therefore $p_{cap} = CPF \cdot I_{CCGT}$.
The different technologies to capture the load deficit are constrained by side conditions which are explained in the following subsection.

3.2.2. Capacity capturing options

Gas power plant

The power values of the gas power plants during quarter hour t are constrained by their maximum installed power capacities $P_{GT,inst}$ and $P_{CCGT,inst}$ respectively,

$$0 \leq P_{GT,t} \leq P_{GT,inst} \,, \tag{3.6a}$$

$$0 \leq P_{CCGT,t} \leq P_{CCGT,inst}. \tag{3.6b}$$

To ensure that additional gas power plants are mainly used for compensating the load deficit instead of primarily selling electricity generated by gas power plants on the spot market, the sum of the power of installed gas power plants is limited by the maximum of the demand time series D of the balancing group

$$0 \leq P_{GT,inst} + P_{CCGT,inst} \leq \max D \,. \tag{3.7}$$

Typically, CCGT power plants are used, on the one hand, to compensate the load deficit and, on the other hand, to provide excess electricity for selling it on the spot market at times of high spot market prices. In contrast, GT power plants are mainly used to only compensate the load deficit. Therefore, GT power plants are not operated when excess electricity is sold or stored. To take this fact into consideration the optional constraints are implemented as

$$b_{GT,t} \leq 1 - \frac{1}{M}\left(P^{out}_{SM,t} + P^{in}_{ES,t}\right), \quad b_{GT,t} \in \{0,1\} \tag{3.8a}$$

$$P_{GT,t} \leq M \cdot b_{GT,t}, \tag{3.8b}$$

with $M \approx 2 \max D$. The binary variable $b_{GT,t}$ is one when no electricity is sold and/or stored and zero else.

Selling on and purchasing from spot market

$P_{SM,max}$ times $\frac{1}{4}h$ limits the maximum amount of electricity that is sold on and purchased from the spot market per quarter hour t and therefore the power values are bounded by

$$0 \leq P^{out}_{SM,t} \leq P_{SM,max}, \tag{3.9a}$$

$$0 \leq P^{in}_{SM,t} \leq P_{SM,max}. \tag{3.9b}$$

Additionally, selling energy on the spot market is constrained by the available power at quarter hour t

$$P^{out}_{SM,t} \leq P_{PRE,t} + P_{GT,t} + P_{CCGT,t} + P_{PV,t} + P_{WP,t} + P^{out}_{ES,t}, \tag{3.10}$$

where P_{PRE} is the pre-installed power generation time series of the corresponding balancing group.

Renewable energy sources

PV and wind power plants can be installed in four different regions i. Their power capacities have to be positive

$$0 \leq P_{PV,i}, \quad 0 \leq P_{WP,i} \quad \text{with } i = 1,2,3,4. \tag{3.11}$$

The total power per installed RES technology is the sum of the power capacities (which equals the peak power) over all regions

$$P_{PV,inst} = \sum_{i=1}^{4} P_{PV,i} \,, \quad P_{WP,inst} = \sum_{i=1}^{4} P_{WP,i} \,. \tag{3.12}$$

Each region has a specific annual wind and photovoltaic power profile PP. Thus, the power for each RES technology during quarter hour t leads to

$$P_{PV,t} = \sum_{i=1}^{4} P_{PV,i} \cdot PP_{PV,i,t} \,, \tag{3.13a}$$

$$P_{WP,t} = \sum_{i=1}^{4} P_{WP,i} \cdot PP_{WP,i,t} \,. \tag{3.13b}$$

An additional measure to optionally force the model to install a minimum amount of RES (RES_{min}) in the additional installation is implemented as

$$RES_{min} \cdot P_{tot} \leq P_{PV,inst} + P_{WP,inst} \,, \tag{3.14}$$

where $P_{tot} = P_{GT,inst} + P_{CCGT,inst} + P_{SM,max} + P_{PV,inst} + P_{WP,inst}$ is the peak power in the additional installation (the maximum power of the energy storage $P_{ES,inst}$ is excluded).

Energy storage

The available power to charge and to discharge the storage, $P^{in}_{ES,t}$ and $P^{out}_{ES,t}$ respectively, are both limited by the maximum power $P_{ES,inst}$. Furthermore, the energy capacity stored in the energy storage $L_{ES,t}$ is also constrained by the maximum power times HES (hours of energy storage):

$$0 \leq P^{in}_{ES,t} \leq P_{ES,inst} \tag{3.15a}$$

$$0 \leq P^{out}_{ES,t} \leq P_{ES,inst} \tag{3.15b}$$

$$0 \leq L_{ES,t} \leq HES \cdot P_{ES,inst} \tag{3.15c}$$

$P^{in}_{ES,t}$ is not only bounded by the maximum power, but also by the available power at quarter hour t:

$$P^{in}_{ES,t} \leq P_{PRE,t} + P_{GT,t} + P_{CCGT,t} + P^{in}_{SM,t} + P_{PV,t} + P_{WP,t} \tag{3.16}$$

The following storage equation incorporates the charge and discharge efficiencies of the energy storage, η_{ES}^{in} and η_{ES}^{out}. Additionally, the storage capacity at $t = T + 1$ equals the capacity at $t = 1$:

$$L_{ES,t+1} = L_{ES,t} + \frac{1}{4}h\left(\eta_{ES}^{in} \cdot P_{ES,t}^{in} - \frac{1}{\eta_{ES}^{out}} \cdot P_{ES,t}^{out}\right) \tag{3.17a}$$

$$L_{ES,T+1} = L_{ES,1} \tag{3.17b}$$

3.2.3. Demand

To guarantee that the demand D_t is covered in each quarter hour the following constraint is implemented:

$$\begin{aligned} D_t \leq & P_{PRE,t} + P_{GT,t} + P_{CCGT,t} + P_{SM,t}^{in} + P_{PV,t} + P_{WP,t} \\ & + P_{ES,t}^{out} - P_{SM,t}^{out} - P_{ES,t}^{in} \end{aligned} \tag{3.18}$$

3.3. Assumptions and simplifications

- The balancing group is a price taker. Independent from the amount of electricity purchased from or sold on the spot market the spot market cannot be changed by the balancing group. The spot market price is an exogenous time series.
- In the model there are no ramping and start-up costs for gas power plants. Therefore, gas power plants can be switched on and off from one time point to the next and can use their total power capacity installed at once.
- The electricity grid is an ideal copper plate. Neither losses caused by distribution nor losses due to the distance between different regions are considered.
- The maximum amount of power capacity of gas power plants is restricted to prevent the model from selling too much excess electricity on the spot market. The installed amount can either be built or necessary capacity can be bought from power plant operators - the model does not differentiate between these options.

- Apart from fuel costs for gas power plants, no other variable costs are incorporated in the model.

3.4. Input data and scaling

3.4.1. Economic parameters of used technologies

The investment costs and technical lifetime of the used technologies are shown in Table 3.2. Other economical and technical parameters can be found in Table 3.3. These values are used to calculate the annuity I_X of the investment costs used in (3.2) with

$$I_X = IC \cdot \frac{(1+IR)^{LT}}{(1+IR)^{LT}-1} \ . \tag{3.19}$$

Table 3.2.: Investment costs and economic lifetime of used technologies including the sensitivity range applied in Chapter 4.

Technology X	Investment costs IC / [Sensitivity range] in k€/MW	Lifetime LT / [Sensitivity range] in yrs
CCGT	800[b]	25[b]
GT	600[b]	25[b]
ES	1700[c] / [500-1700]	60[b]
PV	1500[b] / [500-1500][b]	25[b] / [25-30][b]
WP	1430[a] / [800-1430][b]	20[a] / [20-30][b]

[a] acc. to [8]
[b] acc. to technology data for energy plants [5]
[c] acc. to electricity storage handbook [1]

3.4.2. Demand

The demand is based on standard load profiles available for 2015[1]. This dataset provides, among others, the electricity consumption time series in quarter hour resolution of households ('$H0$') and general businesses ('$G0$') and is normalised to 1 MWh. In order to get the amount of power for each quarter

[1] http://www.apcs.at/de/clearing/technisches-clearing/lastprofile

Table 3.3.: Other model parameters applied in the optimisation model.

Symbol	Parameter	Unit	Reference Scenario / [Sensitivity range]
c_{gas}	Gas price	€/MWh	20[a] / [5-35]
η_{GT}	Electrical efficiency of GT power plant	1	0.4[b]
η_{CCGT}	Electrical efficiency of CCGT power plant	1	0.6[b]
CPF	Capacity price factor	1	0 / [0.2-3.4]
HES	Hours of energy storage	h	10[c]
η_{ES}^{in}	Charging efficiency of energy storage	1	0.9[b]
η_{ES}^{out}	Discharging efficiency of energy storage	1	0.9[b]
IR	Interest rate	%	5

[a] acc. to gas prices in Germany 2015 [3]
[b] acc. to technology data for energy plants [5]
[c] acc. to electricity storage handbook [1]

hour the dataset is multiplied by four and, additionally, multiplied by three as the average annual electricity consumption of households accounts for approximately 3 MWh. 100 households and 100 general businesses are then combined to form the demand time series D in (3.18).

3.4.3. Regional model - RES in different regions

Four different regions are described by PV, wind power and hydro power generation profiles respectively. Data for PV and wind power is provided by different electricity grid operators[2][3][4][5] on a quarterly hour basis for different years. Quarter hour generation profiles for hydro power are available from Romania, while data for hydro power from Sweden is only available on an hourly basis. While PV and wind power time series can be used directly time series for hydro power from Romania[6] and Sweden[7] have to undergo manipulations as the daily data shows a high dependency on the demand. Therefore, the hydro power data is smoothed with an average filter (filter window of 24 h). It is assumed that the hydro power potential in all four regions is already

[2] http://www.50hertz.com/
[3] http://www.amprion.net/
[4] https://www.transnetbw.de
[5] https://www.apg.at/
[6] http://transelectrica.ro/
[7] http://www.svk.se/aktorsportalen/elmarknad/statistik/

exhausted, therefore hydro power technology is excluded from additional installation to compensate the power deficit in the optimisation model.
All generation profiles are scaled to 1 MW peak per year. Figure 3.1 shows an example week of the different generation profiles in the different regions, that are used for $PP_{PV,i}$ and $PP_{WP,i}$ in (3.13).

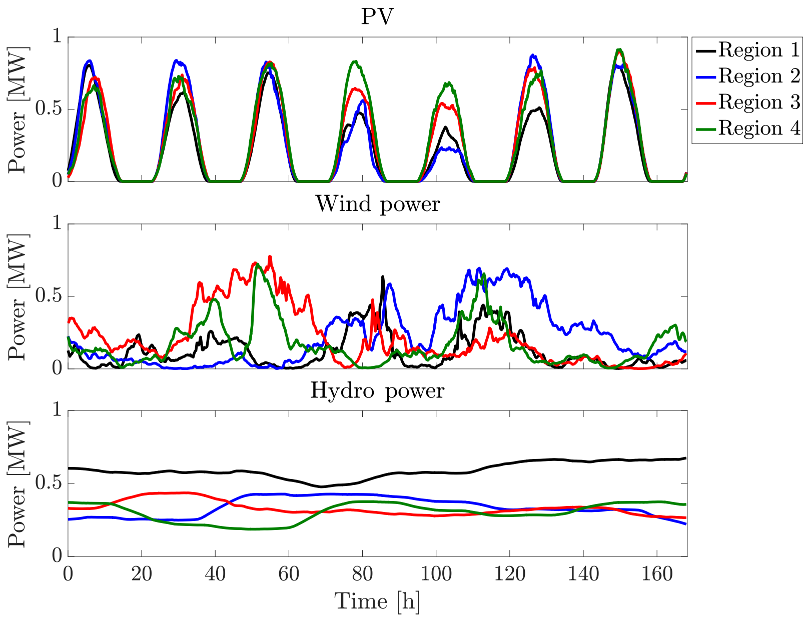


Figure 3.1.: Different generation profiles of PV, wind power and hydro power in different regions during one week.

3.4.4. Balancing groups

Two balancing groups, BLG1 and BLG2 respectively, are implemented. The pre-installed power generation of BLG1 with a peak power of 92 MW totally relies on hydro power plants (REG1: 40 MW, REG2: 20 MW, REG1: 12 MW, REG1: 20 MW) and hence, there are only slight changes between winter and summer time in its production profile as can be seen in Figure 3.2. In contrast the pre-installed power generation of BLG2 only consists of volatile RES as PV and wind power with a peak power of 410 MW (REG1: PV/wind power

20/40 MW, REG2: 100/20MW, REG3: 80/30MW, REG4: 60/60MW). In contrast to BLG1 in BLG2 the periods of load deficit and load excess are changing randomly. A seasonal change can be seen as well as a limitation of electricity generation from PV during the winter season (see Figure 3.3). The amount of power is chosen totally arbitrarily, but it is ensured that there are both times of excess generation and times of electricity deficits. The resulting total amounts of annual energy deficits are 397 GWh in BLG1 and 263GWh in BLG2, while the total amount of annual energy excess is 11 GWh in BLG1 and 129GWh in BLG2.

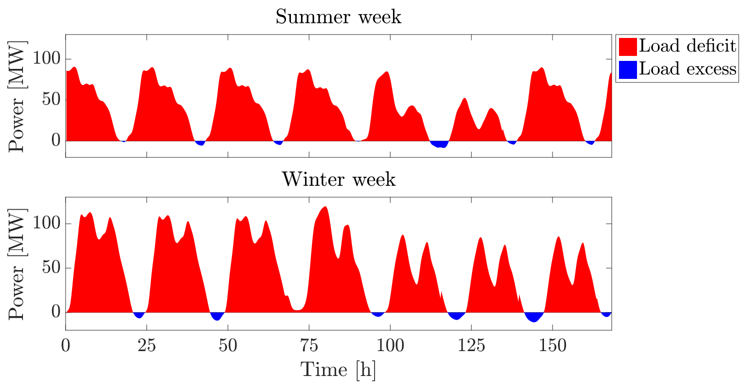


Figure 3.2.: Load deficit and load excess of BLG1 in a typical summer and winter week.

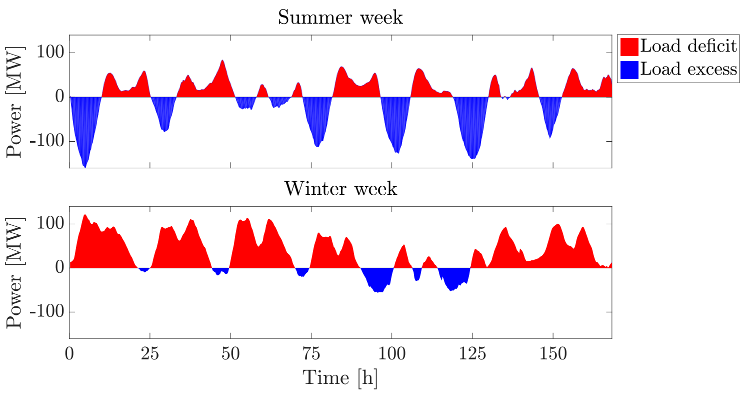


Figure 3.3.: Load deficit and load excess of BLG2 in a typical summer and winter week.

4. Results and Discussion

In this chapter all simulation results of the optimisation model introduced in Chapter 3 are illustrated and discussed. Apart from the reference scenario, which demonstrates today's challenges in the electricity market, scenarios with capacity prices and externally defined minimal RES shares in the additional installation of power capacities are included. In each scenario the impacts of differing investment costs and other parameters such as gas prices are investigated to verify the competitiveness of the different technologies.

4.1. Reference scenario - the status quo

The aim of the reference scenario is to examine how the two balancing groups defined in Subsection 3.4.4 react under current market conditions.

For the reference scenario the optimisation model is simulated with the reference parameters defined in Tables 3.2 and 3.3. Neither a capacity price nor a minimal amount of RES share is included. To ensure that the optimisation model remains bounded and therefore feasible an upper limit of 500 MWh/h for $P_{SM,max}$ is set. This means that the maximum amount of electricity purchased from or sold on the spot market per quarter hour cannot exceed 125 MWh.

Figures 4.1 and 4.2 both depict the results of typical weeks in BLG1 and BLG2. In both balancing groups the load deficit is compensated by only purchasing electricity from the spot market. Additionally, arising excess generation is directly sold on the spot market. Neither gas power plants nor RES or energy storages are installed in this scenario. Hence, CAPEX is zero in both balancing groups as shown in Table 4.1. OPEX that is generated by purchasing electricity on the spot market is decreased by the revenues for selling electricity.

Overall, total costs of EUR 13.8 m and EUR 5.6 m incur for BLG1 and BLG2 respectively.

The results of this scenario highlight the problems of today's electricity markets as due to cheap spot market prices there is no incentive to build any extra power plant capacities to cover the occurring load deficit in the balancing groups.

Table 4.1.: Overview of additionally installed power capacity and extra costs in BLG1 and BLG2 in the reference scenario.

		BLG1	**BLG2**
CCGT	[MW]	0	0
GT	[MW]	0	0
Spot	[MWh/h]	500	500
Storage	[MW]	0	0
PV	[MW]	0	0
Wind	[MW]	0	0
CAPEX	[mn EUR]	0.0	0.0
OPEX	[mn EUR]	14.0	9.2
Revenues	[mn EUR]	-0.2	-3.7
Saldo	[mn EUR]	13.8	5.6

4.1.1. Gas price variation

The profitability of gas power plants in the optimisation model highly depends on the relation between gas and spot market prices. On an annual basis gas power plants are only cheaper than the spot market if the annual fuel costs plus the annuity of investment costs per installed power capacity is lower than the yearly costs for purchasing electricity on the spot market. As the monthly average gas prices have undergone a steady decrease since the end of 2014 to around 20 €/MWh at the end of 2015 (see [3]), it is analysed at which gas price gas power plants would be installed.

The result is the same for both balancing groups (see 4.2 and A.1). Already a gas price of 15 €/MWh would lead to an installation of CCGT power plants. In the model the maximum amount of power capacity of gas power plants is installed. In case the spot market price is high enough above the gas price, the

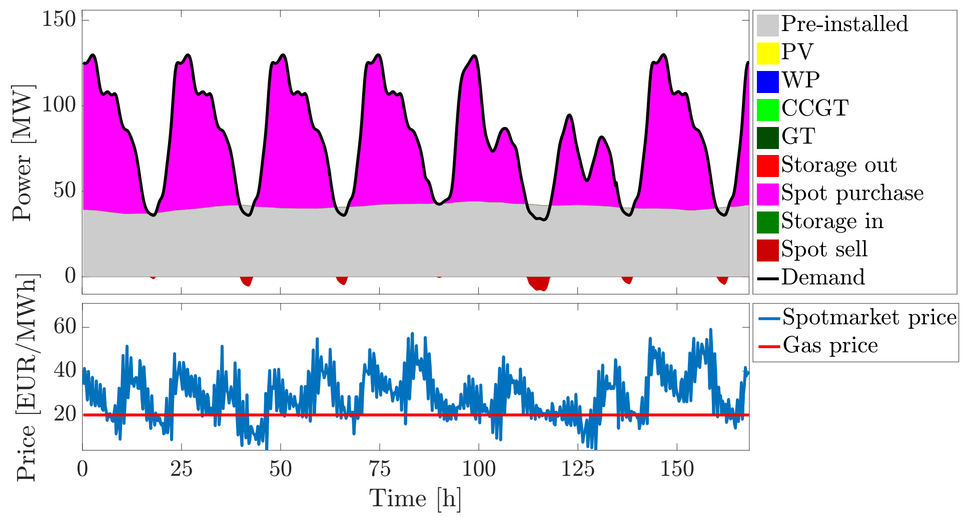


Figure 4.1.: Typical week of production in the reference scenario in BLG1.

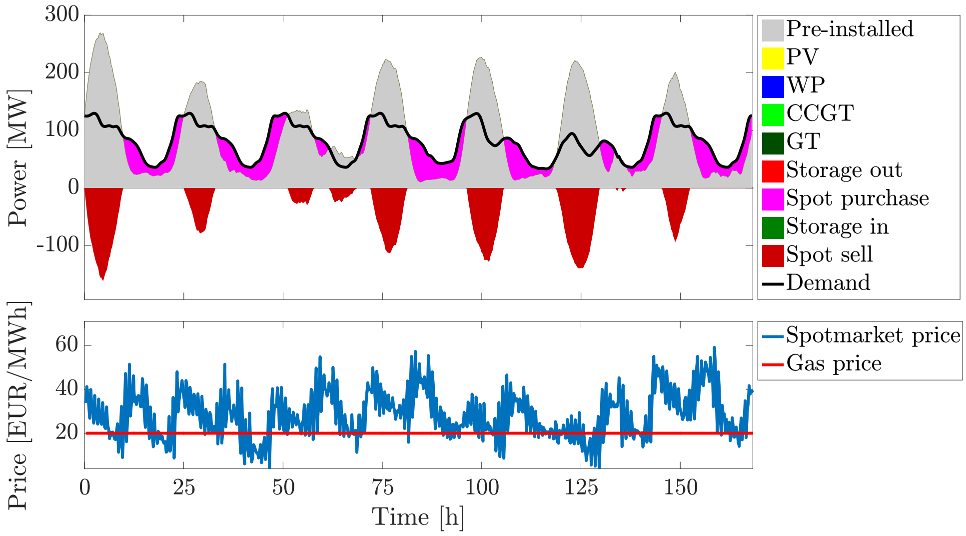


Figure 4.2.: Typical week of production in the reference scenario in BLG2.

gas power plant generates electricity and sells it directly on the spot market to earn revenues. At a gas price of 5 €/MWh the revenues are even higher than the total costs. At this price the balancing group gains already profits without incomes from providing customers with electricity.

Table 4.2.: Overview of additionally installed power capacity and extra costs at different gas prices in the reference scenario in BLG1.

Gas price	**[€/MWh]**	**5**	**10**	**15**	**20**	**25**	**30**	**35**
CCGT	[MW]	161	161	161	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	9.1	9.1	9.1	0.0	0.0	0.0	0.0
OPEX	[mn EUR]	10.8	20.3	24.9	14.0	14.0	14.0	14.0
Revenues	[mn EUR]	-30.4	-29.1	-24.4	-0.2	-0.2	-0.2	-0.2
Saldo	[mn EUR]	-10.5	0.3	9.6	13.8	13.8	13.8	13.8

4.1.2. Variation of investment costs of RES

RES do not take part in the reference scenario of the optimisation model under the defined conditions. Since enormous amounts of PV and wind power capacities will be installed in the future, the investment costs will further decrease. It is predicted that the wind park investment costs will be reduced to 1220 €/kW by 2050, which will be 15% lower than nowadays. Additionally, the lifetime of wind parks might increase to 30 years, which will reduce the annuity of investment costs and therefore will improve their competitiveness. PV system investment costs will also undergo a further reduction from 1500 €/kW today to 900 €/kW by 2050 (minus 40%). The lifetime of PV will rise to 30 years as well. [5]

The simulation results show that the reduction of investment costs as mentioned before is insufficient for both technologies to be competitive. As depicted in Table 4.3 for BLG1 (the results for BLG2 are the same, see Table A.2) the investment costs for wind power plants have to decrease to 1000 €/kW

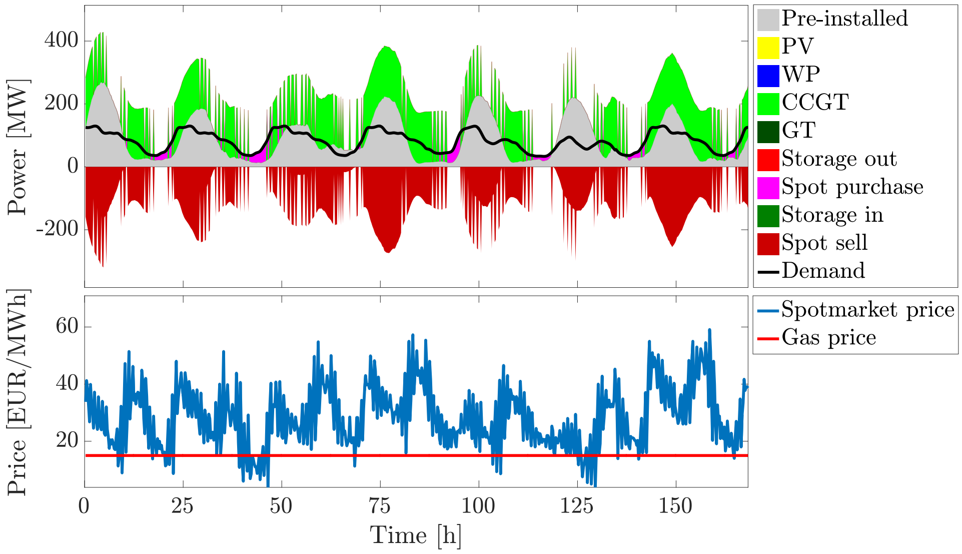


Figure 4.3.: Typical week of production in the reference scenario at a gas price of 15 €/MWh in BLG2.

(approx. minus 30%) to be installed in the reference scenario. For PV systems an even higher reduction of investment costs is necessary. As shown in Table 4.4 for BLG1 investment costs of 600 €/kW (minus 60% compared to the reference value) are needed for PV power plants to be able to participate in the electricity generation of the reference scenario. The analysis in BLG2 produces the same findings.

Nevertheless, the lower the investment costs for both technologies the more capacities are installed to gain revenues by selling the additionally generated electricity on the spot market.

4.1.3. Variation of investment costs of energy storages

Energy storages play an important role in today's electricity system. At times of overproduction or low spot market prices balancing groups can charge their energy storages to discharge them at times of energy deficit and high spot market prices. The difference between these spot market price levels

Table 4.3.: Overview of additionally installed power capacity and extra costs at different wind power investment costs and runtimes in the reference scenario in BLG1.

IC	**[€/kW]**	**1430**	**1320**	**1290**	**1220**	**1000**	**900**	**800**
LT	**[a]**	**20**	**20**	**25**	**30**	**30**	**30**	**30**
CCGT	[MW]	0	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	846	1171	1379
CAPEX	[mn EUR]	0	0	0	0	55.1	68.6	71.8
OPEX	[mn EUR]	14.0	14.0	14.0	14.0	0.9	-0.2	-0.3
Revenues	[mn EUR]	-0.3	-0.3	-0.3	-0.3	-48.6	-67.5	-79.0
Saldo	[mn EUR]	13.8	13.8	13.8	13.8	7.4	0.9	-7.5

Table 4.4.: Overview of additionally installed power capacity and extra costs at different PV investment costs and runtimes in the reference scenario in BLG2.

IC	**[€/kW]**	**1500**	**1300**	**1100**	**900**	**700**	**600**	**500**
LT	**[a]**	**25**	**30**	**30**	**30**	**30**	**30**	**30**
CCGT	[MW]	0	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	416	588
Wind	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	0.0	0.0	0.0	0.0	0.0	16.2	19.1
OPEX	[mn EUR]	9.2	9.2	9.2	9.2	9.2	6.9	6.5
Revenues	[mn EUR]	-3.7	-3.7	-3.7	-3.7	-3.7	-18.2	-23.9
Saldo	[mn EUR]	5.6	5.6	5.6	5.6	5.6	5.0	1.7

determines the revenues of an energy storage. Although, energy storages already play an important role in today's electricity system, the simulated reference scenario does not involve any storages (see Table 4.1). Thus, it needs to be verified at which investment costs the situation changes.

Therefore the investment costs for energy storages are reduced from 1700 €/kW to 500 €/kW as shown in Table 4.5. As the result illustrates the investment costs of energy storages need to decrease by approximately 40% to ensure the implementation of energy storages in the reference scenario. The simulation for BLG1 shows once again the same results (see Table A.4).

It is unclear if the mentioned cost reduction is possible in the future. The hydro pump storage technology is an old one and therefore decreasing costs are highly questionable. On the contrary significant developments take place in the research of battery systems. Therefore the aforementioned cost reduction might be realistic.

Table 4.5.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs in the reference scenario in BLG2.

IC	**[€/kW]**	**1700**	**1500**	**1250**	**1000**	**750**	**500**
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500
Storage	[MW]	0	0	0	445	492	527
PV	[MW]	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0
CAPEX	[mn EUR]	0	0	0	23.5	19.5	13.9
OPEX	[mn EUR]	9.3	9.3	9.3	34.6	37.5	39.1
Revenues	[mn EUR]	-3.7	-3.7	-3.7	-53.9	-59.0	-61.8
Saldo	[mn EUR]	5.6	5.6	5.6	4.23	-2.0	-8.8

4.2. Capacity price implementation

The reference scenario illustrates the dominance of the spot market to cover the power deficit in balancing groups. To downsize this dominance and to provide incentives to invest in alternatives a capacity mechanism implemented by policy makers might be successful. The way a capacity mechanism looks like, is not part of this thesis. The appropriate capacity price that evolves from such a mechanism is of more interest. The main purpose of a capacity price is to financially support controllable power plants, that can generate electricity at times when RES cannot. This is the reason why the CCGT power plant and more specifically its annuity of investment costs constitutes a good starting point to find an adequate capacity price. As mentioned in Chapter 3 the capacity price is the price that has to be paid by the balancing group for the amount of interaction per time unit (selling and purchasing electricity) with the spot market.[1]

Table 4.6.: Overview of additionally installed power capacity and extra costs in BLG1 and BLG2 at a capacity price equal to the annuity of CCGT.

		BLG1	**BLG2**
CCGT	[MW]	84	74
GT	[MW]	0	0
CM	[MW]	38	65
Storage	[MW]	0	5
PV	[MW]	0	0
Wind	[MW]	0	0
CAPEX	[mn EUR]	6.9	8.4
OPEX	[mn EUR]	14.7	11.2
Revenues	[mn EUR]	-3.3	-7.4
Saldo	[mn EUR]	18.3	12.2

The comparison in Table 4.6 and the Figures 4.4 and 4.5 give an overview of what a capacity price equal to the annuity of CCGT power plants causes in the two balancing groups. As intended, compared to the reference scenario the interaction with the spot market is limited and CCGT power plants with a higher power capacity than the capacity market[2] are installed. While in BLG1 the gas power plants already dominate the additional installed power capacity, in BLG2 the total amount of power capacity is almost equally shared between the two options. Additionally, a small amount of energy storage capacity is only implemented in BLG2. The cost increase of additional EUR

[1] e.g. buying an annual capacity of 50 MW denotes that the total amount of electricity sold on or purchased from the spot market cannot exceed 50 MWh per hour or 12.5 MWh per quarter hour.

[2] The capacity of the capacity market describes now the maximum amount of electricity than can be purchased or sold on the spot market.

4.5 mn for BLG1 and EUR 6.6 mn for BLG2 due to the capacity price is an important finding. Although the generated revenues are slightly higher than in the reference scenario the additional CAPEX cannot be compensated.

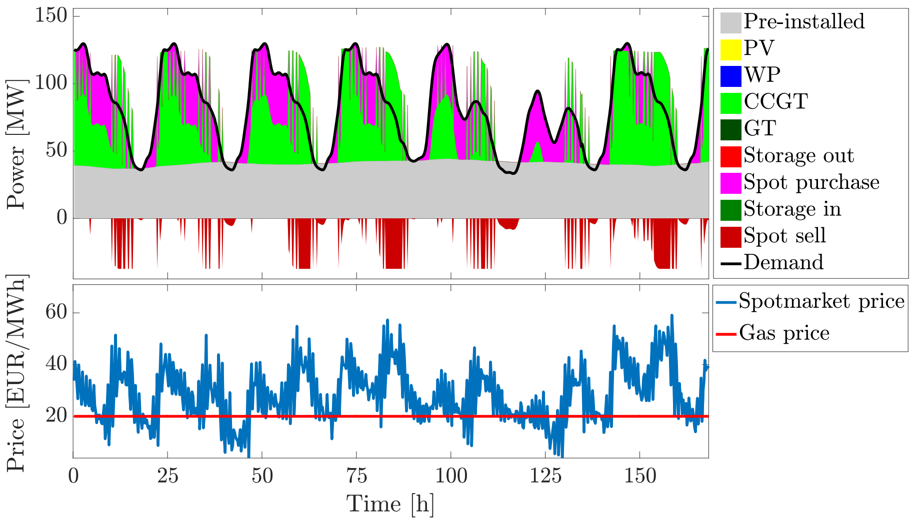


Figure 4.4.: Typical week of production in the capacity price scenario in BLG1 with a capacity price equal to the annuity of CCGT.

4.2.1. Capacity price variation

As shown before, the capacity price has a positive impact on the support of the additional installation of power plants such as gas power plants. However, a capacity price equal to the annuity of CCGT is insufficient for BLG2. A capacity price that is suitable for both balancing groups can be found by varying the capacity price factor CPF from 0.2 to 3.4 as shown in Figure 4.6 and Table 4.7 for BLG1 and in Figure 4.7 and Table 4.8 for BLG2.

The variation of CPF depicts in both balancing groups the intended impact of a decrease in power capacity of the capacity market (CM) with a higher capacity price factor whereas the power capacity of CCGT increases. However, the rate of increase of the CCGT power capacity highly depends on the balancing

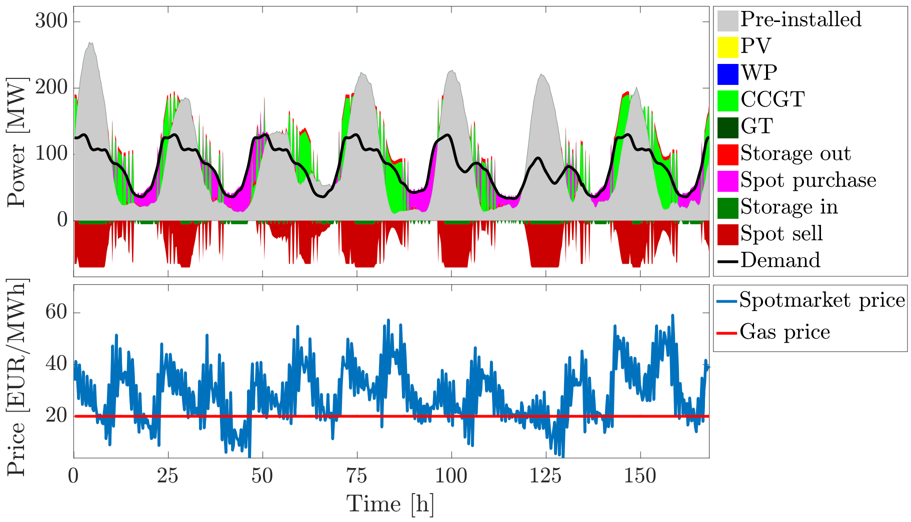


Figure 4.5.: Typical week of production in the capacity price scenario in BLG2 with a capacity price equal to the annuity of CCGT.

group. While in BLG1 a capacity price factor between 1.0 and 1.4 already causes the installed power capacity of CCGT to be three times higher than the CM capacity, in BLG2 a factor of 2.2 is needed to lead to the same result. The high amount of excess electricity generated by the pre-installed volatile power plants of BLG2 probably causes this difference. The excess electricity is sold to gain revenues, which is only possible with a certain amount of available CM capacity. Therefore, the spot market also takes part in generation at a higher capacity price factor.

A higher capacity price factor also has a positive effect on the installation of energy storages in balancing groups with a high amount of pre-installed excess energy as in BLG2. The energy storage serves as an alternative to the decreasing CM capacity and finally supports a spot market free electricity generation at a capacity price factor of 3.4 as no electricity is purchased from the spot market.

Important to note is the development of the system revenues at different capacity price factors in BLG2 (see Table 4.8). At a low *CPF* of 0.2 only pre-installed excess electricity is sold as no CCGTs are installed. At a CPF of 0.6 CCGTs are already competitive and are used not only to cover the power deficit, but also to generate additional revenues. The revenues peak at a CPF of 1.0 and decrease at higher capacity price factors as the CM capacities become increasingly expensive and therefore its capacity amount is reduced. A similar trend can be observed in BLG1.

Overall, a capacity price of 2.2 times the annuity of CCGT power plants can ensure the dominance of CCGTs and is therefore used in the following simulations.

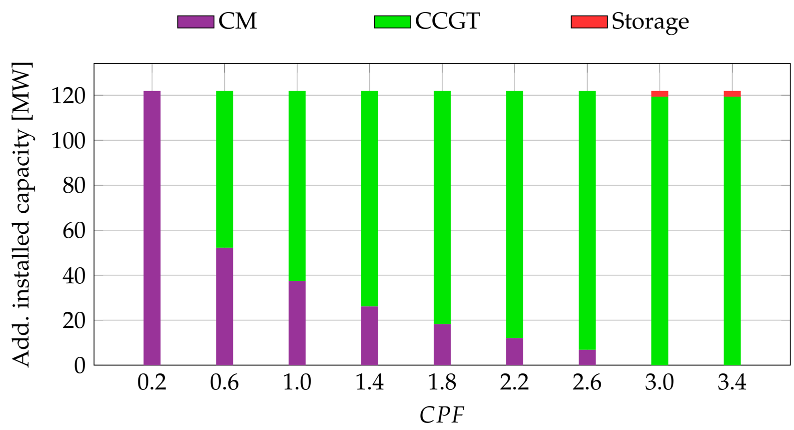


Figure 4.6.: Additionally installed power capacity at different capacity prices in BLG1.

4.2.2. Gas price variation at a fixed capacity price

As described in the previous section gas prices have a crucial influence on the competitiveness of gas power plants. The lower the gas price is in relation to the spot market prices the more the profitability of gas power plants improves. Although gas prices follow a decreasing trend today, the development in the future is unclear. For this reason it needs to be clarified how gas prices may affect the additional installation of balancing groups with a fixed capacity price. Therefore a simulation is run in which the annual gas price is varied

Table 4.7.: Overview of additionally installed power capacity and extra costs at different capacity prices in BLG1.

CPF		**0.2**	**0.6**	**1.0**	**1.4**	**1.8**	**2.2**	**2.6**	**3.0**	**3.4**
CCGT	[MW]	0	70	84	96	104	110	115	119	119
GT	[MW]	0	0	0	0	0	0	0	0	0
CM	[MW]	122	52	38	26	18	12	7	0	0
Storage	[MW]	0	0	0	0	0	0	0	3	3
PV	[MW]	0	0	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0	0	0	0
CAPEX	[mn EUR]	1.4	5.7	6.9	7.5	7.8	7.7	7.5	7.0	7.0
OPEX	[mn EUR]	14.4	14.3	14.7	14.8	14.6	14.2	13.8	13.1	13.1
Revenues	[mn EUR]	-0.3	-2.7	-3.3	-3.3	-2.8	-2.1	-1.3	0.0	0.0
Saldo	[mn EUR]	15.5	17.3	18.3	19.0	19.5	19.9	20.1	20.1	20.1

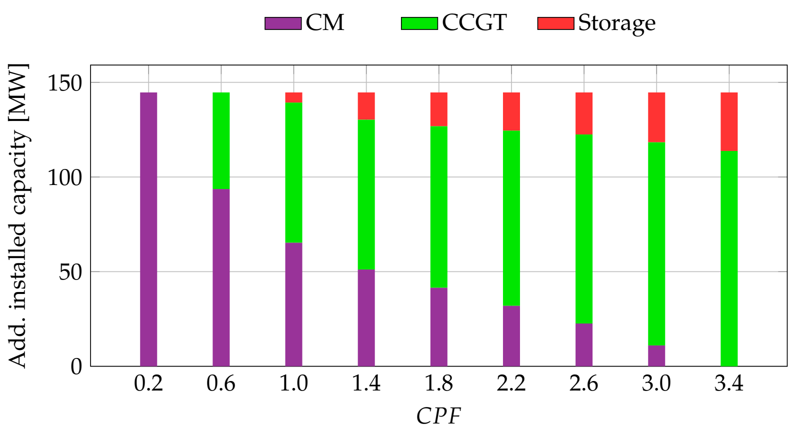


Figure 4.7.: Additionally installed power capacity at different capacity prices in BLG2.

Table 4.8.: Overview of additionally installed power capacity and extra costs at different capacity prices in BLG2.

CPF		**0.2**	**0.6**	**1.0**	**1.4**	**1.8**	**2.2**	**2.6**	**3.0**	**3.4**
CCGT	[MW]	0	51	74	79	85	93	100	107	114
GT	[MW]	0	0	0	0	0	0	0	0	0
CM	[MW]	145	94	65	51	41	32	23	11	0
Storage	[MW]	0	0	5	14	18	20	22	26	31
PV	[MW]	0	0	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0	0	0	0
CAPEX	[mn EUR]	1.6	6.1	8.4	9.8	10.7	11.1	11.0	10.3	9.2
OPEX	[mn EUR]	9.6	10.4	11.2	10.9	10.6	10.0	9.3	8.2	7.3
Revenues	[mn EUR]	-3.6	-6.0	-7.4	-7.3	-6.7	-5.7	-4.3	-2.2	0.0
Saldo	[mn EUR]	7.6	10.4	12.2	13.5	14.5	15.4	16.0	16.4	16.5

from 5 €/MWh to 35 €/MWh. The results are illustrated in Tables 4.9 and 4.10 and in Figures 4.8 and 4.10.

Gas prices up to 25 €/MWh have no significant impact on the capacity share in additional installations in BLG1. This situation changes dramatically with gas prices higher than 25 €/MWh as the power capacity of CCGT is almost completely taken over by the capacity market and energy storages at a gas price of 35 €/MWh. Despite the capacity price gas power plants are not competitive any more.

The dominance of CCGT in BLG2 is also kept to a gas price level of 25 €/MWh, although the CCGT capacities are already reduced by the installation of energy storages. The loss of dominance is not as tremendous as in BLG1 as at a set gas price of 35 €/MWh gas power plant capacities are still available. However, the contribution of CCGT in electricity generation is limited due to the high gas price. Most of the energy needed to cover the energy deficit is provided by the spot market and energy storages (see 4.11).

Although the gas power plant capacity decreases with a growing gas price a local peak of capacity can be observed in both balancing groups (BLG1 at a gas price of 20 €/MWh; BLG2 at a gas price of 15 €/MWh). An explanation could be the fact that at low gas prices the spot market is mainly used to sell excess generation produced by the CCGT power plants. With growing gas prices less electricity is generated by the CCGT as burning gas is becoming increasingly expensive. Hence, less excess electricity can be sold on the spot market and consequently the CM capacity can be reduced. A smaller CM capacity leads to less electricity purchased from the spot market. Finally, this reduction needs to be compensated by a slightly higher CCGT capacity (compare Figures 4.10 and 4.11).

Apart from the 5 €/MWh gas price scenario the additional installed power capacity is constant in both balancing groups.

Table 4.9.: Overview of additionally installed power capacity and extra costs at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG1.

Gas price	**[€/MWh]**	**5**	**10**	**15**	**20**	**25**	**30**	**35**
CCGT	[MW]	161	102	107	110	106	34	5
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	92	20	15	12	16	48	60
Storage	[MW]	0	0	0	0	0	40	56
PV	[MW]	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	20.6	8.3	7.9	7.7	8.0	11.5	12.9
OPEX	[mn EUR]	9.1	8.6	11.7	14.2	16.7	14.0	13.0
Revenues	[mn EUR]	-23.5	-4.6	-3.3	-2.1	-1.7	-0.6	-0.7
Saldo	[mn EUR]	6.2	12.3	16.3	19.8	23.0	24.9	25.2

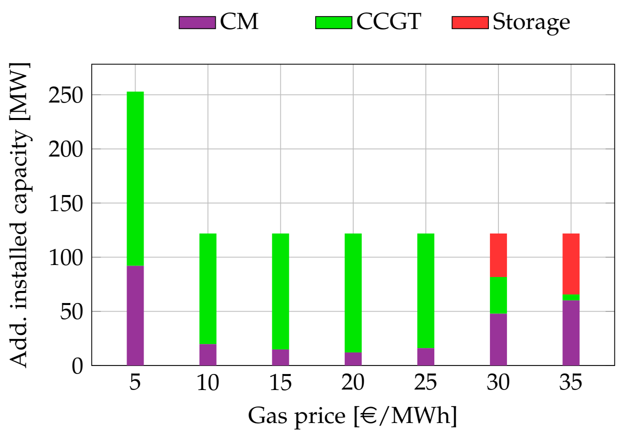


Figure 4.8.: Additionally installed power capacity at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG1.

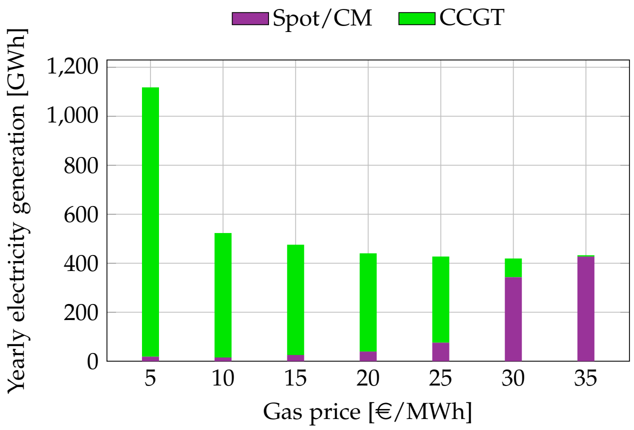


Figure 4.9.: Total additionally and annually generated/supplied electricity by CCGT and Spot/CM at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG1.

Table 4.10.: Overview of additionally installed power capacity and extra costs at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG2.

Gas price	**[€/MWh]**	**5**	**10**	**15**	**20**	**25**	**30**	**35**
CCGT	[MW]	161	100	105	93	75	53	35
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	120	45	39	32	35	44	53
Storage	[MW]	0	0	0	20	35	47	57
PV	[MW]	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	24.1	11.3	10.9	11.1	11.7	12.8	13.7
OPEX	[mn EUR]	8.8	8.2	10.4	10.0	9.7	8.8	8.3
Revenues	[mn EUR]	-29.9	-10.3	-8.4	-5.7	-4.4	-3.8	-3.8
Saldo	[mn EUR]	2.9	9.2	12.8	15.4	17.0	17.8	18.2

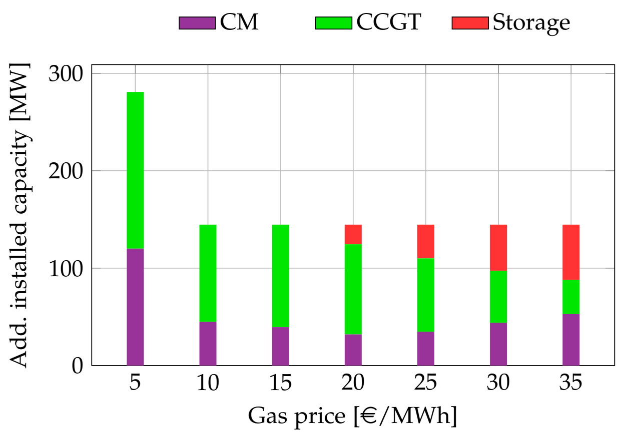


Figure 4.10.: Additionally installed power capacity at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG2.

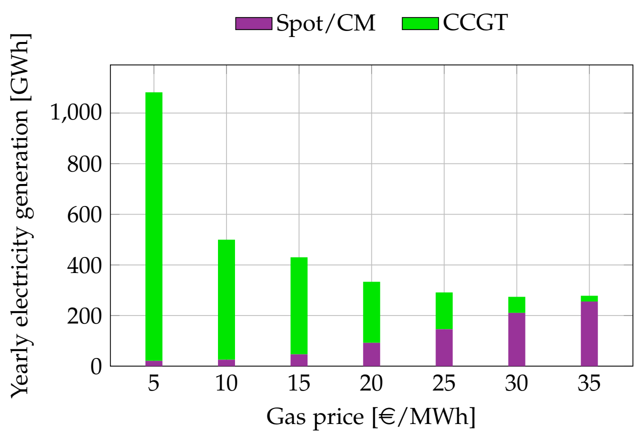


Figure 4.11.: Total additionally and annually generated/supplied electricity by CCGT and Spot/CM at different gas prices and a fixed capacity price (*CPF* of 2.2) in BLG2.

4.2.3. Gas turbine versus combined cycle gas turbine power plant

As the implemented GT power plant is not installed in the above scenarios, this subsection should illustrate the difference between GT and CCGT. These technologies differ in investment costs and efficiency. While GT is cheaper to build, CCGT has a higher efficiency in transforming gas to electricity. Consequently, the GT is only more profitable in short term utilisations.

Figure 4.12 shows the comparison of the two technologies during five days in BLG1. One simulation is only run with CCGT, a second simulation only with GT, in which additionally the binary decision variable introduced in (3.8) is used (this constraint is not included in any other scenario of the thesis). To avoid excessive calculation times caused by the binary decision variable the simulation time is limited to seven days. A capacity price factor of 1.0 and a minimal RES share of 50% are set. All other parameters remain the same as in the reference scenario. The binary decision variable ensures that when GT operates no electricity is stored or sold. This is a common mode of operation for GT power plants as balancing groups simply may not have any interest in an interaction with the spot market.

The CCGT power plant still generates electricity at times of excess generation to additionally charge the energy storage. Thus, a lower amount of CCGT capacity is installed as shown in Table 4.11. In the GT case only the pre-installed capacities and the additionally installed PV capacities charge the energy storage, whose capacity is therefore lower than in the CCGT case. In total the GT system is approximately EUR 0.1 mn more expensive than the CCGT system.

Table 4.11.: Comparison of additionally installed power capacities and extra costs between GT and CCGT power plants (NOTE: The simulation included only seven days).

		CCGT	**GT**
CCGT/GT	[MW]	22	26
CM	[MW]	0	0
Storage	[MW]	40	33
PV	[MW]	44	52
Wind	[MW]	0	0
CAPEX	[mn EUR]	9.5	9.6
OPEX	[mn EUR]	0.1	0.1
Revenues	[mn EUR]	0.0	0.0
Saldo	[mn EUR]	9.6	9.7

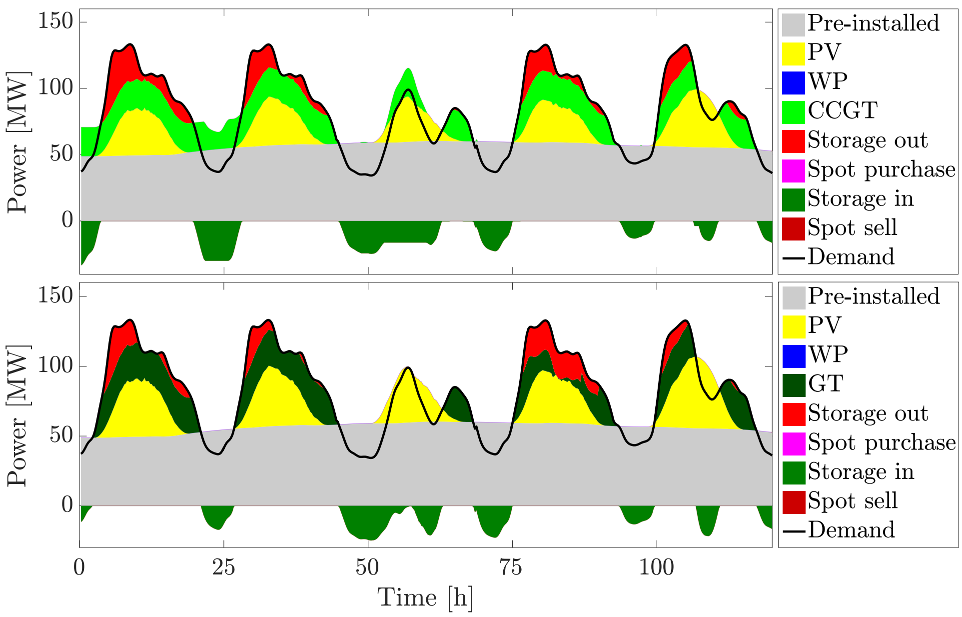


Figure 4.12.: Comparison of the different utilizations of CCGT and GT.

4.2.4. Variation of investment costs of RES

As the capacity price factor of 2.2 works as intended, it needs to be clarified, if there is an impact on the installations of RES as well. In the previous simulations of the capacity scenario RES are not included by the model. For this reason the investment costs of wind power and PV are varied again. The results are directly compared to the reference scenario and are illustrated in Figure 4.13.

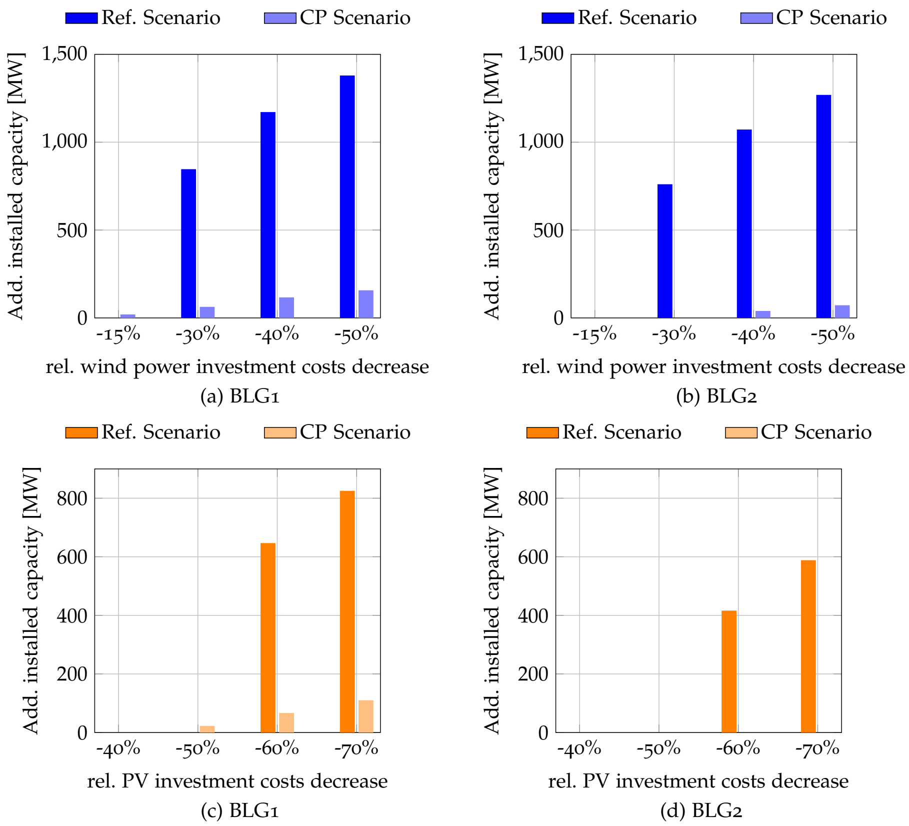


Figure 4.13.: Comparison of additionally installed wind power and PV capacity at different investment costs in the reference and in the capacity price scenario.

The comparison shows that in BLG1 wind parks as well as PV systems are already installed at higher investment costs in the capacity price scenario than in the reference scenario. The investment costs for wind power need to be reduced by 15% (reference scenario minus 30%), while PV plants need a reduction of 50% (instead of minus 60% in the reference scenario). Therefore it can be deduced that a capacity price has a positive effect on RES in balancing groups with a low amount of pre-installed excess energy as in BLG1.

However, the findings for BLG2 are totally different as an investment cost reduction of over minus 70% is needed for wind power plants to be installed. The decrease for PV systems has to be even higher as no capacity is installed with the used values. Hence, the impact of capacity prices on RES in balancing groups with a high amount of pre-installed excess electricity and a high amount of volatile is adverse.

A higher amount of RES is equal to a higher amount of excess electricity in the system. In the reference scenario the excess electricity generated by RES is directly sold on the spot market. The revenues only need to compensate the installation costs for additional renewables. In the capacity price scenario, not only costs for the installation of additional RES arise, but also costs for the capacity to sell electricity on the spot market need to be paid. Therefore the revenues need to be higher, or the investment costs of RES need to be lower to minimise costs.

In case wind power capacities are added to the generation park other capacities are replaced with the support of energy storages (see Figure 4.14). As shown in Figure 4.15 for PV systems almost no reduction of other power capacities is observable. Overall, RES increase the total amount of additionally installed power capacity.

4.2.5. Variation of investment costs of energy storages

As mentioned in the previous section, on the one hand, the model may install energy storages to support RES. Energy storages can be charged with excess generation and can be discharged when RES cannot produce. On the other hand, storages may serve as alternative to the spot market. The impact of the capacity price on energy storages will be discussed in this subsection. Therefore, the model is simulated again with different investment costs of

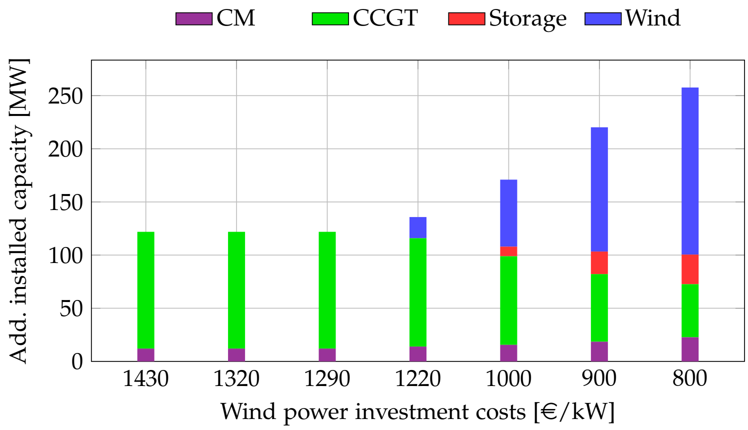


Figure 4.14.: Additionally installed power capacity at different wind power investment costs and a fixed capacity price (*CPF* of 2.2) in BLG1.

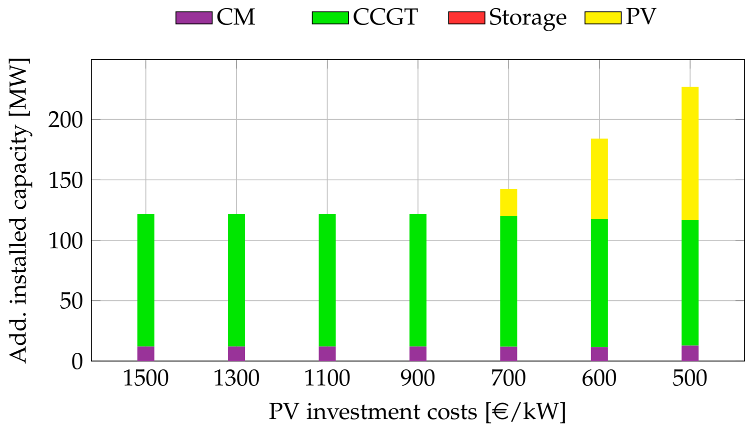
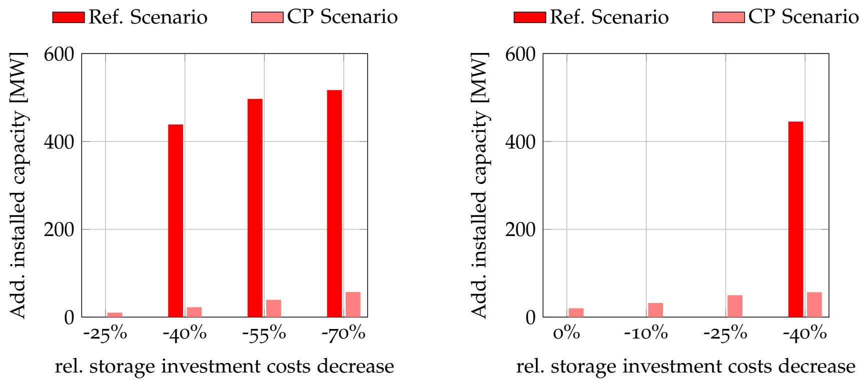


Figure 4.15.: Additionally installed power capacity at different PV investment costs and a fixed capacity price (*CPF* of 2.2) in BLG1.

energy storages as already used in the reference scenario but now with a capacity price factor of 2.2.

The comparison in Figure 4.16 depicts that the capacity price has a positive influence on the installation of energy storages. In BLG1 investment costs of storages systems have to decrease by 25% to be competitive, which is not as much as in the reference scenario (minus 40%). Energy storages in BLG2 with a capacity price factor of 2.2 are even profitable at current investment costs. This is a substantial improvement as in the reference scenario a cost reduction of 40% is needed.



(a) BLG1 (b) BLG2

Figure 4.16.: Comparison of additionally installed energy storage capacity at different storage investment costs in reference and in capacity price scenario.

Energy storages do not change the total additionally installed power capacity in the balancing group. They just replace CN as well as gas power capacities in case the investment costs of storages decrease, see Figure 4.17 and Figure 4.18. If a high amount of excess electricity is available from pre-installed capacities the CM share remains stable. In this case the storage capacities mainly replace the gas power capacities.

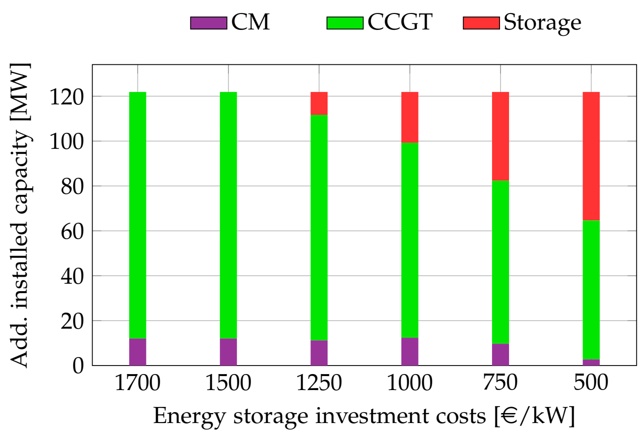


Figure 4.17.: Additionally installed power capacity at different energy storage investment costs and a fixed capacity price (CPF of 2.2) in BLG1.

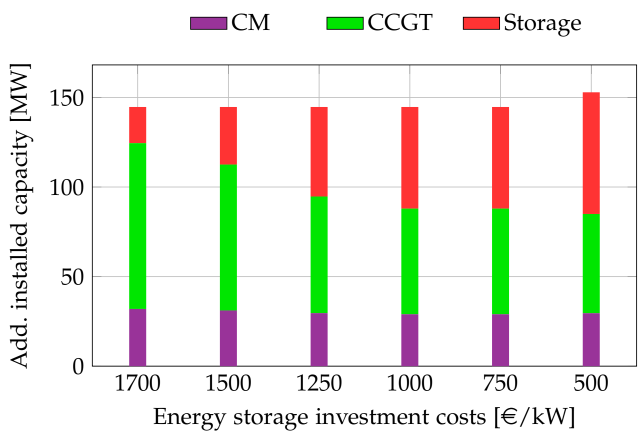


Figure 4.18.: Additionally installed power capacity at different energy storage investment costs and a fixed capacity price (CPF of 2.2) in BLG2.

4.3. Minimum amount of RES in additional power plant installation

The previous scenarios have shown that under current conditions and even with a substantial decrease of investment costs it is not likely that RES become competitive. To ensure that RES also participate in covering the load deficit an external defined regulation is needed. Hence, and as described in Chapter 3 the optimisation model is urged to include a minimum amount of RES power capacity in the additional installation. For example, a minimum amount of RES of 20% means that if the total peak power capacity to be installed is 100 MW a minimum RES power capacity of 20 MW needs to be added. The missing 80 MW of peak power capacity may come from spot market purchases or gas power plants. Important to note is the fact that energy storages are excluded from the share. Energy storages are not restricted in installation.

What this intervention may cause for the balancing group is investigated in this section. A capacity price, as introduced in the previous section, is not included in this scenario. All parameters are the same as in the reference scenario unless otherwise indicated.

4.3.1. Variation of minimum amount of RES

To verify the impact on the two balancing groups the parameter for minimum amount of RES RES_{min} from (3.14) is varied from 0%, which describes the reference scenario, to 100%, which means only RES (except from energy storages) are allowed to be built additionally. Tables 4.12 and 4.13 and Figures 4.19 and 4.21 illustrate the results for both balancing groups.

What can be observed is that already a RES_{min} of 20% limits the capacity of the spot market. With growing shares the amount of non-RES power capacity decreases and the spot market capacities are increasingly replaced by energy storages, which are not affected by the defined minimal amount. The energy storage might serve as a buffer for the spot market to compensate its capacity reduction. This is supported by the fact that the electricity purchased from spot market remains roughly constant in the 40% and 60% case (see Figures 4.20 and 4.22).

RES are dominated by wind power. Only in the 100% scenario of BLG1 a small amount of PV capacity is installed.

Due to the high capacities of RES huge amounts of excess electricity are generated and partially sold on the spot market. The remaining excess electricity is lost as the capacities for selling electricity on the spot market are limited by the minimal RES share. In the 100% scenarios the model cannot sell any electricity on the spot market. Although storages are installed to shift excess electricity to times when electricity is needed a huge amount of generated energy is lost.

An important fact that needs to be mentioned in this scenario is that the power capacity and not the generated electricity is used for the minimal amount of RES. Therefore, only in the 100% scenario the system is energetically renewable. In the other simulations it cannot be ensured that the energy storage is not charged by the spot market.

The higher the share of minimal amount of RES is the higher the costs for the balancing groups will be. The costs simply explode at the 100% scenarios as can be seen in Tables 4.12 and 4.13.

In conclusion, the minimal amount of RES not only guarantees the installation of renewable energy sources, but also limits the installation of other technologies. However, this advantage goes hand in hand with a tremendous cost increase.

Table 4.12.: Overview of additionally installed power capacity and extra costs at different minimum amounts of RES shares in BLG1. NOTE: Only in the 100% case the system is energetically renewable.

RESmin	**[%]**	**0**	**20**	**40**	**60**	**80**	**100***
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	500	113	108	65	41	0
Storage	[MW]	0	0	0	42	61	200
PV	[MW]	0	0	0	0	0	36
Wind	[MW]	0	28	72	97	166	271
CAPEX	[mn EUR]	0.0	3.3	8.2	14.9	24.5	52.8
OPEX	[mn EUR]	14.0	12.6	10.2	7.4	4.4	0.0
Revenues	[mn EUR]	-0.2	-0.6	-1.4	-2.4	-4.4	0.0
Saldo	[mn EUR]	13.8	15.3	17.1	19.9	24.4	52.8

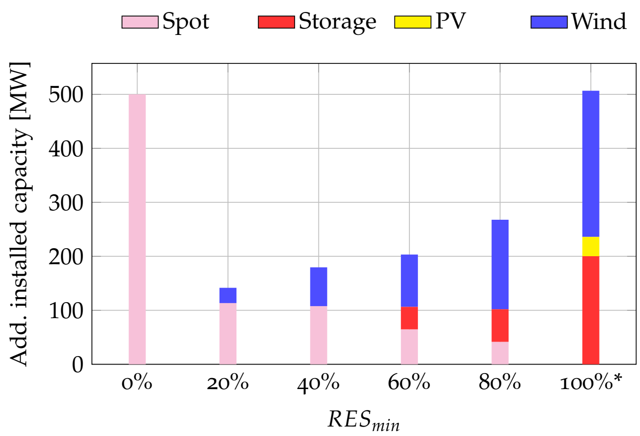


Figure 4.19.: Additionally installed power capacity at different minimum amounts of RES in BLG1.

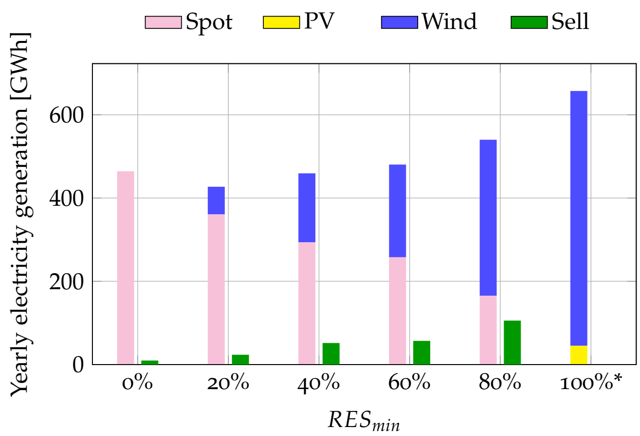


Figure 4.20.: Total additionally and annually generated/supplied/sold electricity by wind power, PV and spot market at different minimum amounts of RES in BLG1.

Table 4.13.: Overview of additionally installed power capacity and extra costs at different minimum amounts of RES shares in BLG2.

RESmin	**[%]**	**0**	**20**	**40**	**60**	**80**	**100***
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	500	143	142	77	62	0
Storage	[MW]	0	0	0	65	78	334
PV	[MW]	0	0	0	0	0	0
Wind	[MW]	0	36	95	116	249	321
CAPEX	[mn EUR]	0.0	4.1	10.9	19.1	35.6	66.9
OPEX	[mn EUR]	9.2	7.9	5.9	4.4	2.0	0.0
Revenues	[mn EUR]	-3.7	-4.5	-6.8	-9.4	-12.8	0.0
Saldo	[mn EUR]	5.6	7.5	10.0	14.1	24.8	66.9

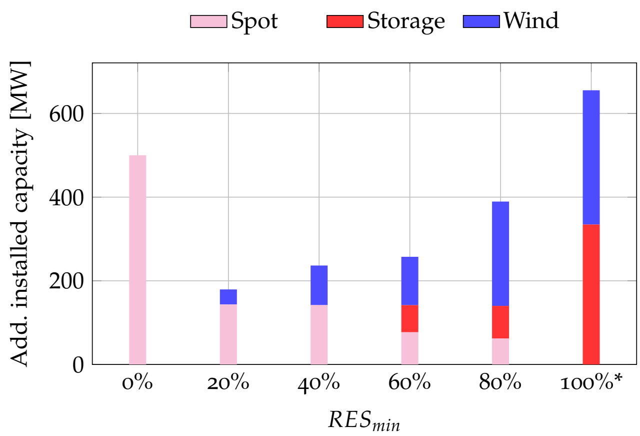


Figure 4.21.: Total additionally and annually generated/supplied/sold electricity by wind power and spot market at different minimum amounts of RES in BLG2.

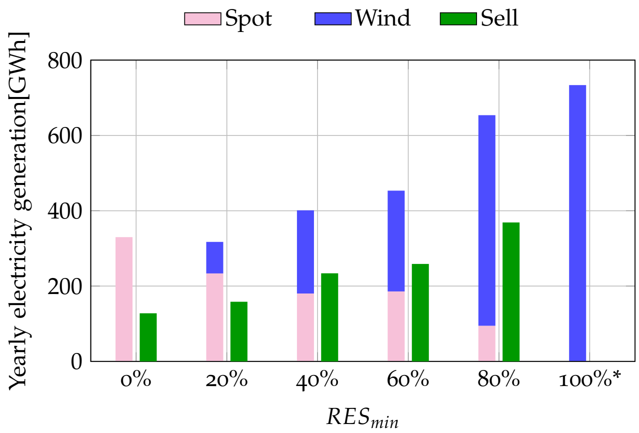


Figure 4.22.: Total additionally and annually generated/supplied/sold electricity by wind power and spot market at different minimum amounts of RES in BLG2.

4.3.2. PV competitiveness versus wind power plants

Although the defined minimal RES share can support RES, PV systems are not able to compete with wind parks. Apart from higher investment costs PV plants are not able to supply the same amount of energy over a year. As the overview of the generation potential of the defined regions in Table 4.14 illustrates a wind park with 1 MW peak power is able to serve approximately seven times more electricity than a 1 MW PV system. To compensate this difference the investment costs need to decrease, which is simulated in this section with $RES_{min} = 60\%$.

Table 4.14.: Comparison of the generation potential in different regions for a power plant with peak capacity of 1 MW for wind and PV respectively.

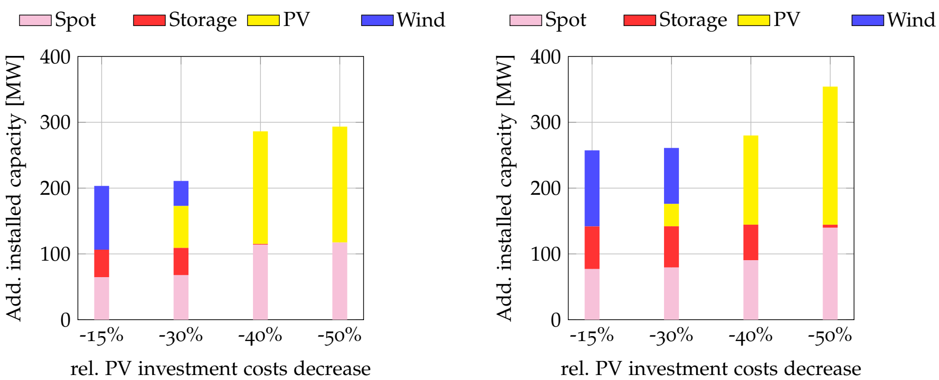
	Wind [GWh/yr]	**PV [GWh/yr]**
Region 1	9.34	1.27
Region 2	8.08	1.24
Region 3	8.97	1.26
Region 4	8.57	1.26

The results in Figure 4.23 depict that for both balancing groups the investment

Table 4.15.: Overview of additionally installed power capacity and extra costs at different PV investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG1.

IC	**[€/kW]**	**1500**	**1300**	**1100**	**900**	**700**	**500**
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	65	65	68	114	117	500
Storage	[MW]	42	42	41	1	0	0
PV	[MW]	0	0	64	171	176	750
Wind	[MW]	97	97	38	0	0	0
CAPEX	[mn EUR]	14.9	14.9	13.0	11.0	8.7	26.6
OPEX	[mn EUR]	7.4	7.4	8.1	8.9	8.8	5.4
Revenues	[mn EUR]	-2.4	-2.4	-1.4	-1.7	-1.8	-21.8
Saldo	[mn EUR]	19.9	19.9	19.7	18.2	15.7	10.3

costs of PV need to be reduced by 30% in order for PV systems to be competitive with wind parks. As implied before, the more PV capacity is installed the higher the peak power of the balancing group is. At lower PV investment costs energy storages and wind power plants are replaced by the spot market and PV capacities.



(b) BLG1 (b) BLG2

Figure 4.23.: Comparison of additionally installed power capacity at different PV investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG1 and BLG2.

4.3.3. Variation of investment costs of energy storages

The previous scenarios have already shown that energy storages play an essential role in case RES are taking part in the electricity generation. In the scenario with $RES_{min} = 60\%$ energy storages are installed at current investment costs. Hence, a reduction of investment costs will likely expand their share. As the results for both balancing groups are similar only the impact of an investment cost reduction in BLG1 is shown (see Table 4.16 and Figure 4.24).

Table 4.16.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG1.

IC	**[€/kW]**	**1700**	**1500**	**1250**	**1000**	**750**	**500**
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	65	60	56	53	51	54
Storage	[MW]	42	47	51	54	59	75
PV	[MW]	0	0	0	0	0	0
Wind	[MW]	97	90	83	80	77	80
CAPEX	[mn EUR]	14.9	14.0	13.0	12.0	11.1	11.2
OPEX	[mn EUR]	7.4	7.6	7.9	8.1	8.2	8.3
Revenues	[mn EUR]	-2.4	-2.3	-2.1	-2.0	-2.0	-3.0
Saldo	[mn EUR]	19.9	19.4	18.7	18.0	17.3	16.4

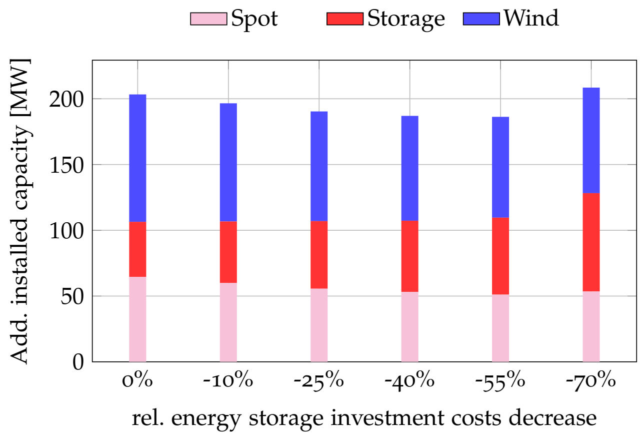


Figure 4.24.: Additionally installed power capacity at different energy storage investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG1.

While the capacity of energy storages increases continuously as it becomes cheaper, the capacities of wind power and spot market decrease. The energy storage is able to store excess electricity to discharge it when needed. Hence, less wind power capacity is installed.

4.4. Combination of capacity price and minimum amount of RES

On the one hand, capacity prices can provide incentives for investments in additional installations, such as gas power plants, but cannot support RES. On the other hand, a defined minimum amount of RES capacities supports the installation of RES, but not the additional installation of power plants. Consequently, a combination of the two scenarios may support both technology types.

To achieve this the previously concluded values for the capacity price factor $CPF = 2.2$ and the minimal share of RES $RES_{min} = 60\%$ are used in the simulation. The comparison of all four scenarios is shown in Table 4.17.

Furthermore typical weeks of production are illustrated in Figures 4.25 and 4.26.

In BLG1 the combination scenario ensures that wind power has the highest power capacity. Wind power is supported by an essential amount of energy storage capacities. Furthermore, the scenario guarantees the dominance of CCGTs compared to the CM. Even a higher amount of wind power and storage capacity is installed in BLG2. Although the chosen capacity price factor is sufficient in the capacity price scenario it seems too low for the combination scenario as the capacity market is still dominant. BLG2 with its high amount of pre-installed excess generation highly relies on the spot market to sell the excess electricity and raise revenues. Possibly, a higher capacity price factor might be a solution, but the already high additional costs would increase as well.

Having a look at the additional costs both balancing groups have the highest additional costs in the combination scenario as both interventions have to be financed. Compared to the reference scenario BLG1 has to additionally invest only EUR 10.4 mn, while BLG2 has to pay EUR 16.8 mn into the bargain (see Table 4.17).

Table 4.17.: Comparison between balancing groups with capacity price factor of $CPF = 2.2$ and minimal RES share of $RES_{min} = 60\%$.

		Reference		CPF		RESmin		Combination	
		BLG1	**BLG2**	**BLG1**	**BLG2**	**BLG1**	**BLG2**	**BLG1**	**BLG2**
CCGT	[MW]	0	0	110	93	0	0	45	28
GT	[MW]	0	0	0	0	0	0	0	0
Spot/CM	[MWh/h]	500	500	12	32	65	77	7	46
Storage	[MW]	0	0	0	20	42	65	55	68
PV	[MW]	0	0	0	0	0	0	0	0
Wind	[MW]	0	0	0	0	97	116	77	111
CAPEX	[mn EUR]	0	0	7.7	11.1	14.9	19.1	17.2	26.2
OPEX	[mn EUR]	14.0	9.2	14.2	10.0	7.4	4.4	8.0	4.8
Revenues	[mn EUR]	-0.2	-3.7	-2.1	-5.7	-2.4	-9.4	-1.0	-8.6
Saldo	[mn EUR]	13.8	5.6	19.8	15.4	19.9	14.1	24.2	22.4

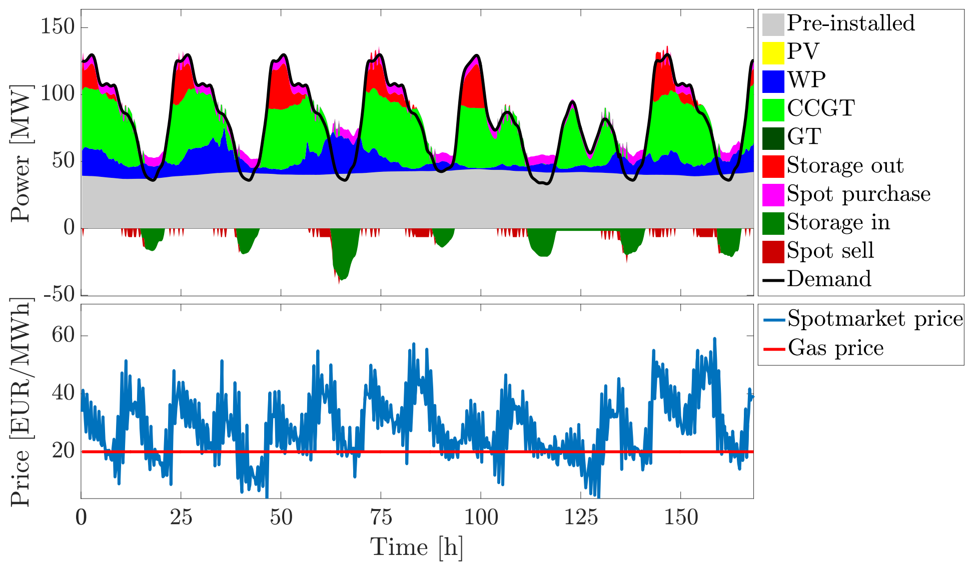


Figure 4.25.: Typical week of production in BLG1 with CPF of 2.2 and RES_{min} of 60%.

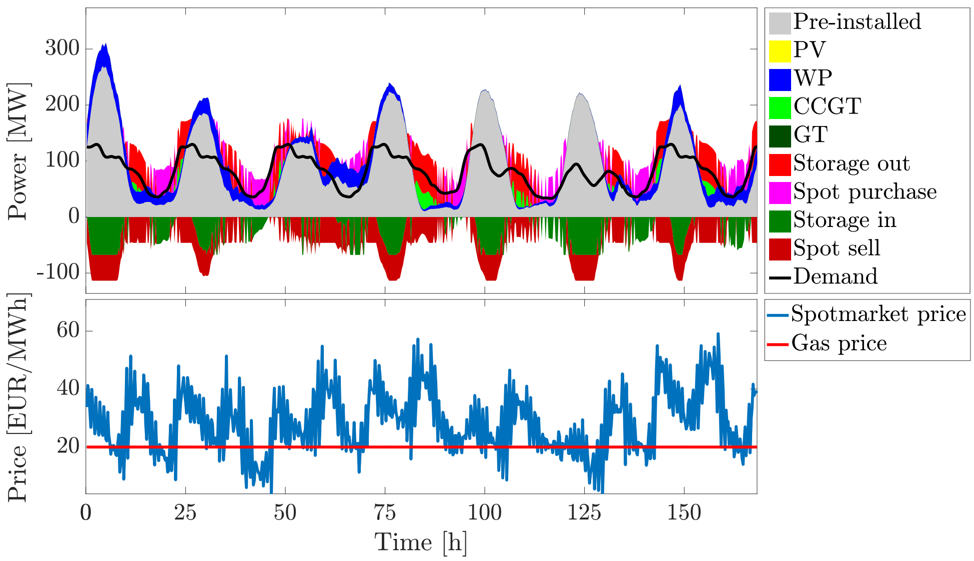


Figure 4.26.: Typical week of production in BLG2 with CPF of 2.2 and RES_{min} of 60%.

5. Synthesis of Results

The main question of this work is to verify, on the one hand, if capacity prices can generate incentives for investments in the installation of additional power capacities. On the other hand, it is discussed how predefined minimum installation shares of RES influence other technologies. The implemented optimisation model aims to compensate cost-minimally, on an annual basis, the load deficit of the respective balancing group (BLG1: no volatile RES, low amount of excess generation; BLG2: high amount of volatile RES, high amount of generation energy) by installing additional generation capacities or by buying the needed capacity on the capacity market and purchasing the needed electricity on the spot market. All simulations are run for one year with a quarter hour resolution.

The *reference scenario* mirrors the problem of today's electricity markets: Without a capacity market, for balancing groups the cheapest way to cover their load deficits is to purchase electricity from the spot market as there are no incentives to invest in gas power plants (or RES) at current spot market price levels and gas prices. Additionally, the reference scenario of the model shows that with a reduction of gas prices compared to current levels gas power plants, mostly CCGTs, become competitive. CCGTs are installed not only to capture the load deficit of the balancing group but also to generate excess electricity to sell it on the spot market and to consequently raise revenues.

With the defined investment costs (approx. 1500€/kW for PV plants and slightly lower for wind parks) RES do not participate in electricity generation of the reference scenario. Wind power would only be installed if their investment costs were decreased by 30%. Even investment costs of PV systems have to be reduced by 60% in order to make PV competitive. The same applies to energy storages: No energy storages are installed in the reference scenario as a reduction of 40% from 1700€/kW would be necessary.

In the *capacity price scenario* balancing groups have to pay not only for the electricity purchased from the spot market but also for the reserved power capacity on the capacity market. Consequently, the level of the capacity price represents a limit to the electricity delivery from the spot market as shown in the simulation. The higher the capacity price, the more power capacity of CCGT plants are installed and the less capacity is purchased from the capacity market. While in BLG1 a capacity price equal to the annuity of CCGT ensures the dominance of CCGT power plants, in BLG2 a capacity price of at least 2.2 times the annuity leads to similar results, see Figure 5.1. This difference is caused by a higher amount of pre-installed excess generation in BLG2. More pre-installed excess electricity means that more CM capacity is needed to sell it and, hence, this lowers the amount of CCGT capacity.

Gas prices higher than 25€/MWh (reference scenario 20€/MWh) counteract the intention of setting capacity prices to support the installation of additional power capacities such as CCGTs.

The effect of capacity prices on RES highly depends on the balancing group, especially on the type and volatility of its pre-installed power capacities. The investment costs for PV systems that guarantee installation in BLG1 can be slightly higher than in the reference scenario (reduction of 50% instead of 60%) and the investment costs of wind power systems have to be reduced by just 15% instead of 30%. In contrast, in BLG2 the capacity price has a negative impact on RESs as wind park investment costs have to be lower (reduction of 40% instead of 30%) and PV plants are not installed at all. Therefore, investment costs would have to decrease by more than 70%.

A capacity price supports the installation of energy storages. The reduction of energy storage investment costs results in higher storage capacities. This goes hand in hand with a decrease of CCGT capacity. The storage is charged in times of low demand by the CCGTs and can be discharged to assist at other times. Overall, less CCGT capacities are needed.

The capacity price ensures incentives for investments in gas power plants, but, to some extent, counteracts the installation of RES. A higher amount of RES causes more excess electricity in the balancing group, which would lead to a higher CM capacity to sell it. Due to the capacity price higher CM capacities result in higher system costs that need to be compensated by lower investment costs of RES.

This is the reason for defining a minimal share of RES in the peak power of the total amount of additional capacity installation supported by the *minimal RES share scenario*. In this scenario the absence of capacity prices leads to high amounts of electricity provided by the spot market at low minimal RES shares, while at high shares RES are backed by high capacities of energy storages. Gas power plants are not implemented in this scenario at all.

RES capacities are dominated by wind power, while PV is only installed in the 100% RES share in BLG1. A shift from wind parks to PV plants is only possible if the investment costs of PV decrease by at least 30% compared to the reference scenario. Compared to PV systems the main advantage of wind parks is its high amount of energy produced within a year. To generate the same amount of energy by PV plants a much higher capacity needs to be installed.

The impact on energy storages is similar to the capacity price scenario: The cheaper its investment costs are, the more capacity is installed. The decrease of investment costs of energy storage systems has only a slight impact on the generation capacities of other technologies. Hence, the more energy storage capacity is installed the less wind power and spot market capacities are added.

The *capacity price and minimal RES share scenario* combines the implementation of a capacity price at 2.2 times the annuity of CCGT and a minimal RES share of 60%. A main advantage of the spot market is its ability to gain revenues. As a result, and even though a high capacity price is implemented, CCGTs cannot compete with the spot and capacity market in BLG2, a balancing group with high pre-installed excess power capacity. Only a higher capacity price could tackle this situation, which would lead inevitably to higher system costs.

Figure 5.1 shows an overview of the power capacity distribution in the different scenarios. Important to mention is the fact that the illustrated CCGT power capacities do not necessarily need to be built by the balancing group itself. The balancing group just has to prove the availability of this capacity (e.g. with capacity certificates).

Figure 5.2 depicts the cost increase of the different scenarios relative to the reference scenario. While the cost increase of BLG1 remains within 100%, the costs of BLG2 explode to the fourfold of the costs of the reference scenario.

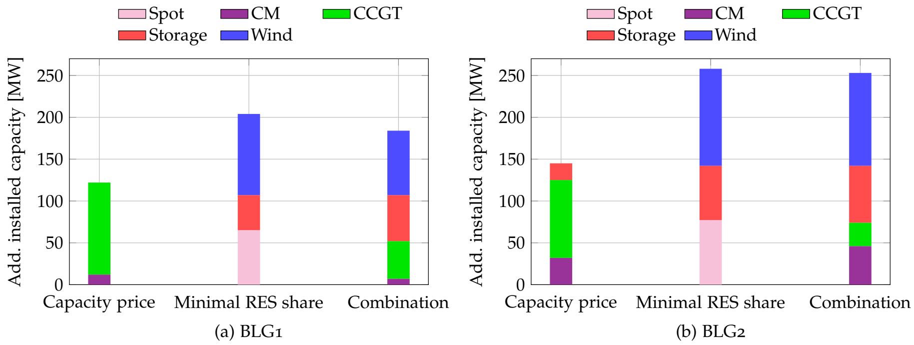


Figure 5.1.: Scenario comparisons. NOTE: Reference scenario is left out to improve legibility. In reference scenario only spot market capacities are installed.

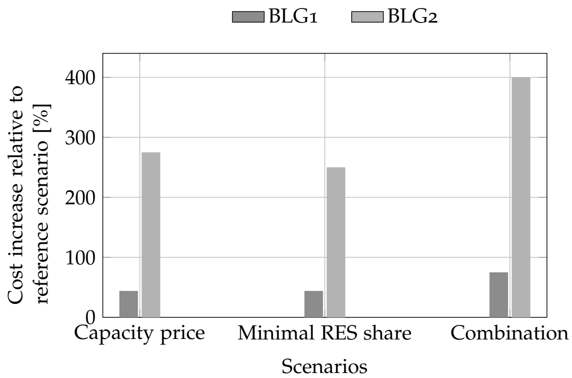


Figure 5.2.: Cost comparison of different scenarios relative to the reference scenario.

All analyses are made for a separated and, in terms of peak power, small balancing group that has no market power and acts as a price taker, since the spot market price is a fixed exogenous parameter. The model does not consider any interaction between balancing groups. Nevertheless, the work shows that a capacity price provides incentives for the investment in additional power capacities with possibly negative impacts on RES.

Extrapolating the findings of this study to numerous balancing groups with different generation time series would lead to overcapacities as every balancing group tries to compensate its load deficit on its own. As a consequence spot market price levels would decrease. Taking simultaneity effects and interaction between balancing groups into account each balancing group would not need to cover the total amount of load deficit on its own. Instead it can be supported by excess generation of other balancing groups. In total, this would lead to less capacities to be installed additionally and would decrease costs for the electricity system as a whole.

6. Conclusion and Outlook

The optimisation model clearly demonstrates the challenges of today's electricity markets already on a single balancing group scale: As spot market prices nowadays are low there is no incentive for balancing groups to build new generation capacities. It is more profitable to sell excess electricity on and purchase electricity from spot market to compensate possible generation deficits.

The implementation of a capacity price mechanism should solve this problem. Compared to the annuity of CCGT power plants a high capacity price can guarantee incentives for investments in additional power generation technologies such as CCGTs. As capacity prices can have a negative impact on additional installations of RES, policy-makers should make well-considered decisions before introducing such mechanisms. If each balancing group of a control area had to prove 100% of its capacity it would lead to overcapacities in the area. Consequently, this would result in low spot market prices and low capacity prices and therefore would regulate itself.

Furthermore, the findings of this thesis support the already implemented subsidies as feed-in tariffs for RES to provide additional installation since wind power and PV will not be competitive in the upcoming years due to high investment costs. Apart from the reference scenario all other scenarios in this work promote the installation of energy storages.

It is important to mention that all regulatory influences considered in this study result in higher costs for each balancing group. This mirrors to some extent the price for the transformation of the electricity system.

The next step for the used model could be the interaction of different types of balancing groups with each other. Through simultaneity effects they might reduce the need for additional capacity installations to cover the power deficits and, as a consequence, reduce the overall system costs. Moreover, it is interesting whether the implementation of a market model would support the findings of this thesis.

A. Appendix

Table A.1.: Overview of additionally installed power capacity and extra costs at different gas prices in the reference scenario in BLG2.

Gas price	**[€/MWh]**	**5**	**10**	**15**	**20**	**25**	**30**	**35**
CCGT	[MW]	161	161	161	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	0	0
CAPEX	[Mio. €]	9.1	9.1	9.1	0.0	0.0	0.0	0.0
OPEX	[Mio. €]	10.8	20.2	24.4	9.2	9.2	9.2	9.2
Revenues	[Mio. €]	-38.5	-37.2	-32.2	-3.7	-3.7	-3.7	-3.7
Saldo	[Mio. €]	-18.7	-7.8	1.4	5.6	5.6	5.6	5.6

Table A.2.: Overview of additionally installed power capacity and extra costs at different wind power investment costs and runtimes in the reference scenario in BLG2.

IC	**[€/kW]**	**1430**	**1320**	**1290**	**1220**	**1000**	**900**	**800**
LT	**[a]**	**20**	**20**	**25**	**30**	**30**	**30**	**30**
CCGT	[MW]	0	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	0	0
WP	[MW]	0	0	0	0	761	1072	1269
CAPEX	[Mio. €]	0.0	0.0	0.0	0.0	49.5	62.8	66.0
OPEX	[Mio. €]	9.2	9.2	9.2	9.2	0.5	-0.2	-0.3
Revenues	[Mio. €]	-3.7	-3.7	-3.7	-3.7	-50.0	-68.5	-79.3
Saldo	[Mio. €]	5.6	5.6	5.6	5.6	-0.0	-5.9	-13.5

Table A.3.: Overview of additionally installed power capacity and extra costs at different PV investment costs and runtimes in the reference scenario in BLG1.

IC **LT**	**[€/kW]** **[a]**	**1500** **25**	**1300** **30**	**1100** **30**	**900** **30**	**700** **30**	**600** **30**	**500** **30**
CCGT	[MW]	0	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500	500
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	0	646	825
WP	[MW]	0	0	0	0	0	0	0
CAPEX	[Mio. €]	0	0	0	0	55.1	68.6	71.8
OPEX	[Mio. €]	14.0	14.0	14.0	14.0	0.9	-0.2	-0.3
Revenues	[Mio. €]	-0.3	-0.3	-0.3	-0.3	-0.3	-18.2	-24.2
Saldo	[Mio. €]	13.8	13.8	13.8	13.8	13.8	12.7	7.9

Table A.4.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs in the reference scenario in BLG1.

IC	**[€/kW]**	**1700**	**1500**	**1250**	**1000**	**750**	**500**
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	500	500	500	500	500	500
Storage	[MW]	0	0	0	438	497	517
PV	[MW]	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	0
CAPEX	[Mio. €]	0.0	0.0	0.0	23.2	19.7	13.6
OPEX	[Mio. €]	14.0	14.0	14.0	37.9	41.5	42.5
Revenues	[Mio. €]	-0.2	-0.2	-0.2	-48.7	-55.0	-56.6
Saldo	[Mio. €]	13.8	13.8	13.8	12.4	6.1	-0.5

Table A.5.: Overview of additionally installed power capacity and extra costs at different wind power investment costs, runtimes and a fixed capacity price (*CPF* of 2.2) in BLG1.

IC	**[€/kW]**	**1430**	**1320**	**1290**	**1220**	**1000**	**900**	**800**
LT	**[a]**	**20**	**20**	**25**	**30**	**30**	**30**	**30**
CCGT	[MW]	110	110	110	102	83	64	50
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	12	12	12	14	16	19	23
Storage	[MW]	0	0	0	0	9	21	28
PV	[MW]	0	0	0	0	0	0	0
WP	[MW]	0	0	0	20	63	117	157
CAPEX	[mn EUR]	7.7	7.7	7.7	9.1	11.6	14.7	16.3
OPEX	[mn EUR]	14.2	14.2	14.2	13.2	10.5	7.5	5.8
Revenues	[mn EUR]	-2.1	-2.1	-2.1	-2.5	-2.8	-3.5	-4.3
Saldo	[mn EUR]	19.8	19.8	19.8	19.8	19.3	18.7	17.8

Table A.6.: Overview of additionally installed power capacity and extra costs at different wind power investment costs, runtimes and a fixed capacity price (*CPF* of 2.2) in BLG2.

IC	**[€/kW]**	**1430**	**1320**	**1290**	**1220**	**1000**	**900**	**800**
LT	**[a]**	**20**	**20**	**25**	**30**	**30**	**30**	**30**
CCGT	[MW]	93	93	93	93	93	79	69
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	32	32	32	32	32	36	40
Storage	[MW]	20	20	20	20	20	28	33
PV	[MW]	0	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	40	72
CAPEX	[mn EUR]	11.1	11.1	11.1	11.1	11.1	13.8	15.6
OPEX	[mn EUR]	10.0	10.0	10.0	10.0	10.0	8.1	7.0
Revenues	[mn EUR]	-5.7	-5.7	-5.7	-5.7	-5.7	-6.6	-7.7
Saldo	[mn EUR]	15.4	15.4	15.4	15.4	15.4	15.3	14.9

Table A.7.: Overview of additionally installed power capacity and extra costs at different PV investment costs, runtimes and a fixed capacity price (*CPF* of 2.2) in BLG1.

IC	**[€/kW]**	**1500**	**1300**	**1100**	**900**	**700**	**600**	**500**
LT	**[a]**	**25**	**30**	**30**	**30**	**30**	**30**	**30**
CCGT	[MW]	110	110	110	110	108	106	104
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	12	12	12	12	12	12	13
Storage	[MW]	0	0	0	0	0	0	0
PV	[MW]	0	0	0	0	23	67	110
WP	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	7.7	7.7	7.7	7.7	8.6	10.1	11.1
OPEX	[mn EUR]	14.2	14.2	14.2	14.2	13.3	11.6	10.2
Revenues	[mn EUR]	-2.1	-2.1	-2.1	-2.1	-2.1	-2.1	-2.4
Saldo	[mn EUR]	19.8	19.8	19.8	19.8	19.8	19.6	19.0

Table A.8.: Overview of additionally installed power capacity and extra costs at different PV investment costs, runtimes and a fixed capacity price (*CPF* of 2.2) in BLG2.

IC	**[€/kW]**	**1500**	**1300**	**1100**	**900**	**700**	**600**	**500**
LT	**[a]**	**25**	**30**	**30**	**30**	**30**	**30**	**30**
CCGT	[MW]	93	93	93	93	93	93	93
GT	[MW]	0	0	0	0	0	0	0
CM	[MW]	32	32	32	32	32	32	32
Storage	[MW]	20	20	20	20	20	20	20
PV	[MW]	0	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	0	0
CAPEX	[mn EUR]	11.1	11.1	11.1	11.1	11.1	11.1	11.1
OPEX	[mn EUR]	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Revenues	[mn EUR]	-5.7	-5.7	-5.7	-5.7	-5.7	-5.7	-5.7
Saldo	[mn EUR]	15.4	15.4	15.4	15.4	15.4	15.4	15.4

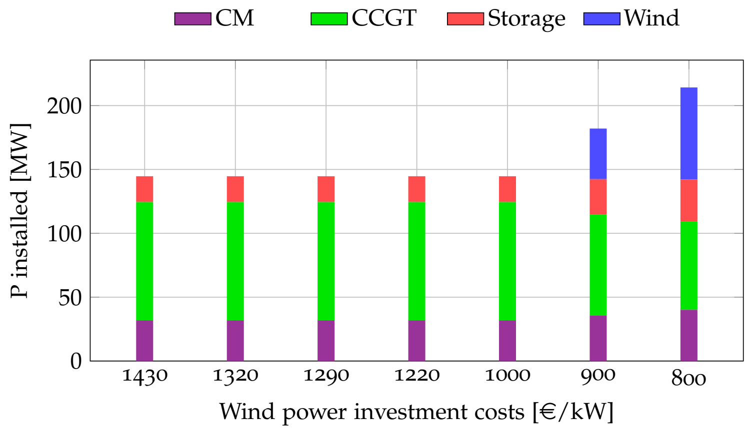


Figure A.1.: Additionally installed power capacity at different wind power investment costs and a fixed capacity price (*CPF* of 2.2) in BLG2.

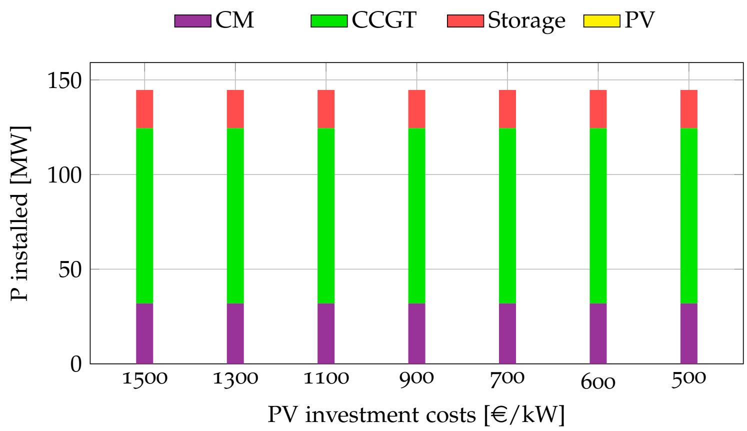


Figure A.2.: Additionally installed power capacity at different PV investment costs and a fixed capacity price (*CPF* of 2.2) in BLG2.

Table A.9.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs and a fixed capacity price (*CPF* of 2.2) in BLG1.

IC	**[€/kW]**	**1700**	**1500**	**1250**	**1000**	**750**	**500**
CCGT	[MW]	110	110	100	87	73	62
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	12	12	11	12	10	3
Storage	[MW]	0	0	10	23	40	57
PV	[MW]	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	0
CAPEX	[mn EUR]	7.7	7.7	7.8	7.7	6.9	5.4
OPEX	[mn EUR]	14.2	14.2	13.9	13.8	13.7	13.5
Revenues	[mn EUR]	-2.1	-2.1	-1.9	-1.9	-1.4	-0.4
Saldo	[mn EUR]	19.8	19.8	19.8	19.6	19.2	18.5

Table A.10.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs and a fixed capacity price (*CPF* of 2.2) in BLG2.

IC	**[€/kW]**	**1700**	**1500**	**1250**	**1000**	**750**	**500**
CCGT	[MW]	93	81	65	59	59	55
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	32	31	30	29	29	30
Storage	[MW]	20	32	50	57	57	68
PV	[MW]	0	0	0	0	0	0
WP	[MW]	0	0	0	0	0	0
CAPEX	[mn EUR]	11.1	11.1	10.7	10.0	9.2	8.6
OPEX	[mn EUR]	10.0	9.5	8.9	8.7	8.7	8.7
Revenues	[mn EUR]	-5.7	-5.4	-5.0	-4.9	-4.9	-5.0
Saldo	[mn EUR]	15.4	15.1	14.6	13.8	13.1	12.3

Table A.11.: Overview of additionally installed power capacity and extra costs at different PV investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG2.

IC	[€/kW]	1500	1300	1100	900	700	500
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	77	77	79	90	140	500
Storage	[MW]	65	65	63	54	4	0
PV	[MW]	0	0	34	135	210	750
WP	[MW]	116	116	85	0	0	0
CAPEX	[mn EUR]	19.1	19.1	18.0	13.5	10.8	26.6
OPEX	[mn EUR]	4.4	4.4	4.8	6.4	7.7	6.2
Revenues	[mn EUR]	-9.4	-9.4	-8.8	-7.3	-8.1	-28.4
Saldo	[mn EUR]	14.1	14.1	14.0	12.7	10.4	4.4

Table A.12.: Overview of additionally installed power capacity and extra costs at different energy storage investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG2.

IC	[€/kW]	1700	1500	1250	1000	750	500
CCGT	[MW]	0	0	0	0	0	0
GT	[MW]	0	0	0	0	0	0
Spot	[MWh/h]	77	76	76	74	71	67
Storage	[MW]	65	66	66	71	86	104
PV	[MW]	0	0	0	0	0	0
WP	[MW]	116	114	113	111	106	101
CAPEX	[mn EUR]	19.1	18.3	17.4	16.5	15.6	14.3
OPEX	[mn EUR]	4.4	4.4	4.4	4.5	4.9	5.2
Revenues	[mn EUR]	-9.4	-9.3	-9.3	-9.4	-9.9	-10.1
Saldo	[mn EUR]	14.1	13.4	12.5	11.6	10.6	9.3

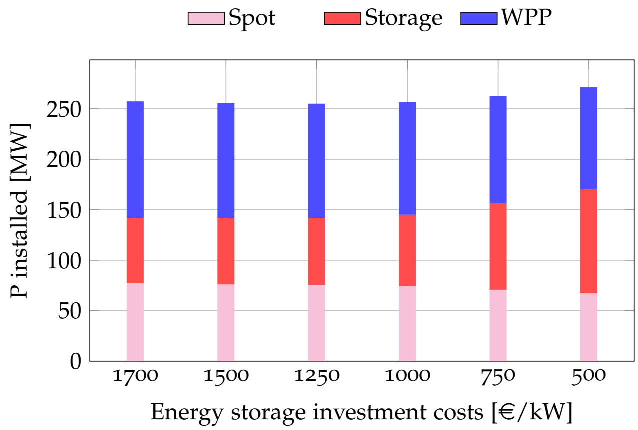


Figure A.3.: Additionally installed power capacity at different energy storage investment costs and a fixed minimum amount of RES share (RES_{min} of 60%) in BLG2.

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Eidesstattliche Erklärung

Hiermit erkläre ich, dass die vorliegende Arbeit gemäß dem Code of Conduct-Regeln zur Sicherung guter wissenschaftlicher Praxis (in der aktuellen Fassung des jeweiligen Mitteilungsblattes der TU Wien), insbesondere ohne unzulässige Hilfe Dritter und ohne Benutzung anderer als der angegebenen Hilfsmittel, angefertigt wurde. Die aus anderen Quellen direkt oder indirekt übernommenen Daten und Konzepte sind unter Angabe der Quelle gekennzeichnet.
Die Arbeit wurde bisher weder im In– noch im Ausland in gleicher oder in ähnlicher Form in anderen Prüfungsverfahren vorgelegt.

Wien, am 08.06.2016

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