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Contents

List of Figures

List of Tables

List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
API	American Petroleum Institute
ARA FOB	Amsterdam-Rotterdam-Antwerp Free on Board
BDI	Baltic Dry Index
BEIS	Department for Business, Energy and Industrial Strategy
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
DA	Day-Ahead
EIA	U.S. Energy Information Administration
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EU	European Union
EUR	Euro Currency
ETS	Emissions Trading System
GDP	Gross Domestic Product
GIE	Gas Infrastructure Europe
ID	Intraday
IEA	International Energy Agency
KKT	Karush-Kuhn-Tucker Conditions
LNG	Liquefied Natural Gas
LT	Long-term
MCP	Mixed Complementarity Problem
MILP	Mixed Integer Linear Programming
NC CAM	Network Code on Capacity Allocation Mechanisms
NC TAR	Network Code on Tariff Harmonisation
NGL	Natural Gas Liquids
NRA	National Regulatory Authority
OPEC	Organization of the Petroleum Exporting Countries

PRL	Primärregelleistung (Primary Control Power)
PV	Photovoltaics
RES	Renewable Energy Systems
SRL	Sekundärregelleistung (Secondary Control Power)
ST	Short-term
TES	Thermal Energy Storage
TSO	Transmission System Operator
TTF	Title Transfer Facility
US	United States
USA	United States of America
USD	United States Dollar Currency
VAR	Vector Autoregressive

1. Introduction

Energy markets are highly complex, interdependent markets with different energy carriers. In this respect, energy economics is a diverse field that provides the researcher with ample opportunities to analyse these complex systems and to investigate different types of research questions. This multi-faceted nature of energy economics is reflected in this thesis with its various research questions focusing on the modeling and analysis of different energy markets and systems, which differ not only in the types of energy carriers but also in their spatial scopes.

In Chapter 2, a theoretical analysis of the multiplier system in the European Union for pricing short-term gas transmission capacities is provided. Chapter 3 builds upon the theoretical findings of Chapter 2 and extends the analysis with a numerical optimisation model to investigate the internal and external effects of multipliers and to provide insight into optimal multiplier levels in different regions in the European Union. Chapter 4 deals with a global market with a different energy carrier, where the global crude oil market is modelled and the development of the market structure for the period 2013–2017 is analysed. Chapter 5 considers an individual system and analyses the optimal (i.e. profit-maximising) dispatch of a coal-fired power plant with an integrated thermal energy storage.

Thus, the thesis consists of four main chapters. Each chapter is based on an individual article as shown below:

- Chapter 2: Pricing Short-Term Gas Transmission Capacity: A Theoretical Approach to Understand the Diverse Effects of the Multiplier System (based on Çam and Lencz (2021b), both authors contributed equally)
- Chapter 3: Internal and External Effects of Pricing Short-Term Gas Transmission Capacity via Multipliers (based on Çam and Lencz (2021a), both authors contributed equally)
- Chapter 4: The Shift in Global Crude Oil Market Structure: A Model-Based Analysis of the Period 2013–2017 (based on Berk and Çam (2020), both authors contributed equally)

- Chapter 5: Optimal Dispatch of a Coal-Fired Power Plant with Integrated Thermal Energy Storage (based on Çam (2020))

In the next section, a short summary of the individual chapters is provided, which is then followed by a discussion of the methodology and key assumptions employed in each chapter.

1.1. Outline of the thesis

Chapter 2: Pricing Short-Term Gas Transmission Capacity: A Theoretical Approach to Understand the Diverse Effects of the Multiplier System

Chapter 2 analyses the effects of multipliers when pricing short-term gas transmission capacities. In the European Union's (EU) gas transmission system, traders are required to book the necessary transmission capacities when transporting gas. For this purpose, in addition to the long-term yearly capacities, transmission system operators offer short-term transmission capacities (quarterly, monthly, daily and within-day). The prices of short-term capacities are determined by multiplying the long-term tariffs with factors called multipliers, which are set by national regulators within the allowed ranges in the EU. However, multipliers directly affect the proportion of booked capacities by making short-term capacities more expensive and therefore may have significant effects on infrastructure utilisation, prices and welfare. In order to analyse those effects, a stylised theoretical model that depicts the gas procurement, storage, and transmission capacity booking is developed. By utilising the stylised theoretical framework, the impacts of multipliers on the gas transport and storage infrastructure, prices and welfare are analysed.

High multipliers are shown to result in increased storage utilisation by causing bookings to shift from short-term capacities to long-term capacity. This also leads to a more uniform usage of transport capacities. However these effects are found to be not universal and depend on the elasticity of traders' capacity demand. The analysis shows that, depending on the proportion of multipliers with respect to storage and transmission tariff levels, situations with inelastic capacity demand can occur. It is shown that multipliers that are sufficiently low with respect to the tariffs can lead to gas storages not being utilised in the context of capacity bookings. Multipliers that are considerably high, on the other hand, can cause only long-term capacities to be booked. Regarding the effects of multipliers on hub prices, increasing the multipliers is shown to cause maximum regional price spreads to increase, implying higher volatility in regional price spreads. Multipliers greater than 1 are shown to be associated with higher total system costs and consequently lower total welfare. Nevertheless, the analysis finds that, depending on the relative tariff levels (which can vary among regions), there can exist optimal multipliers that allow the transport tariffs to be minimised and consumer surplus to be maximised. Hence, policymakers who are willing to maximise the consumer surplus may prefer to use higher multipliers.

Chapter 3: Internal and External Effects of Pricing Short-Term Gas Transmission Capacity via Multipliers

Chapter 3 builds upon the theoretical findings of Chapter 2 and extends the knowledge regarding the effects of multipliers. Chapter 2 showed that, depending on the regions, optimal multipliers that can minimise transport tariffs and maximise consumer surplus do exist. Since a substantial share of the surpluses generated by producers, storage operators, and traders arise outside the EU, it is plausible to assume that regulators in the EU would consider consumer-surplus-maximising multipliers as optimal and set the multipliers accordingly. Compared to the stylised setting of Chapter 2, in a more realistic, complex setting, additional aspects would influence the effects of multipliers and, consequently, the optimal multiplier levels. The EU gas system is characterised by booking and dispatch decisions taking place in a setting with multiple time periods, multiple regions and limited infrastructure capacities. In such a setting, the gas demand profile and infrastructure limitations in a region can also greatly influence the effects that ensue in that region when it adjusts its multipliers. Moreover, a region adjusting its multipliers can also cause externalities in other regions. Because of that, even if regional regulators apply the individually optimal multipliers, it is not clear if this would lead to a joint EU optimum. Hence, this chapter aims to identify and distinguish between the internal and external effects of multipliers in different regions in the EU, providing insight into optimal multiplier levels. For that purpose, a numerical optimisation model simulating the EU gas dispatch is used.

The analysis identifies significant regional effects with regards to multipliers. In regions characterised by relatively flat gas demand profiles (e.g. Spain and Portugal) multipliers are found to not have notable effects. Long-term capacities are shown to be booked in these regions independent of the multiplier levels. Whereas, in regions that have highly volatile demand profiles (e.g. Britain) but limited supply flexibility via storages, multipliers can strongly affect the base and peak prices due to marginal cost of supply being determined by multipliers. Setting the multipliers can therefore have strong distributional effects on the allocation of consumer surplus between the base and peak consumers—an aspect that the regulators would have to consider additionally when deciding on multiplier levels in such regions. Adjusting multipliers in a region is found to cause external effects in other regions, largely depending on the relative location along the gas transport chain. Consumer surplus gains in transit regions (e.g. Central Europe) via multipliers are passed on to downstream regions (e.g. Italy). Downstream regions can affect the transit regions indirectly by influencing the storage utilisation in the transit regions. Multiplier levels in peripheral regions (e.g. South East Europe) that are receiving their gas directly from the production regions can also influence other regions by indirectly affecting the procurement prices in the production regions. As a result of the external effects of multipliers, the analysis finds that individually optimal multipliers do not lead to a joint EU optimum. With 92 million EUR per year, the potential EU consumer surplus gains with individually optimal multipliers are found to be 9% lower than the maximum achievable EU consumer surplus gains via multipliers.

Chapter 4: The Shift in Global Crude Oil Market Structure: A Model-Based Analysis of the Period 2013–2017

The third biggest oil price collapse since the 1980s occurred during the second half of 2014. In the aftermath of the 2014 price collapse, contrary to expectations, OPEC members, and in particular Saudi Arabia—commonly regarded as the global swing supplier—have not reduced their production levels. This is generally attributed to the rationale of OPEC members that low prices would decrease shale investments, forcing shale producers out of the market. Nevertheless, shale oil production proved resilient under the low price regime and profits of OPEC members in the aftermath of the price collapse started diminishing. Following this, major OPEC members started shifting their strategy from flooding the market to capacity withholding starting from the second half of 2016. During the 171st OPEC meeting, a "Declaration of Cooperation" between OPEC and various non-OPEC producers, including

Russia, Mexico, Azerbaijan and Brazil, was signed. This cooperation is also known as the OPEC+ agreement and targeted production cuts of 1.76 million bbl/day effective as of 2017. In line with the agreement, OPEC+ participants have shown high compliance levels throughout 2017. As an immediate effect of the OPEC+ agreement, oil prices, once having declined to historically low levels of around $26/bbl in January 2016, increased up to around $67/bbl in December 2017. Against this backdrop, the analysis in this chapter aims to investigate how the market structure evolved over the period 2013–2017 and whether a shift in the market structure occurred after the 2014 price collapse. Moreover, the analysis aims to shed light into the motivation of the OPEC+ agreement and to show if it was successful at reclaiming market power. For this purpose, a global oil market simulation model is applied and the market is simulated under different market structure setups.

The model results show that oligopolistic market structures fit best to the observed market fundamentals in the considered period, successfully simulating the price levels before the price collapse. However, oligopolistic market structures cannot explain the low prices observed during 2015 and 2016, which are found to lie close to perfectly competitive levels estimated by the model. Hence, it can be concluded that the market structure in the post-2014 price decline has progressed in a more competitive direction. In this respect, attaining pre-2014 prices of around $100/bbl is shown to be possible only under strong OPEC cartel behaviour. Market power potential of Saudi Arabia and OPEC as a whole are shown to have significantly decreased following the price crash, making a market share strategy more likely. In the case of OPEC, additional profits via cartel behaviour are found to be much more limited, as significant market share is lost to Russia which fills the ensuing supply gap. This indicates why the inclusion of Russia was important when jointly cutting production and explains the motivation behind the historical OPEC+ agreement. With regards to OPEC+ agreement, the analysis investigates whether planned and observed production cuts could be explained by the non-competitive market structure setups considered in the model. The model results show that both planned and actual cut levels were significantly below the simulated levels. Hence, OPEC+ production cuts were not enough to reclaim market power for the participants of the agreement. This supports the argument that OPEC+ production cuts actually aimed to stabilise the prices at levels which are high enough not to hurt the fiscal regimes of the suppliers, while being low enough not to promote shale oil supply.

Chapter 5: Optimal Dispatch of a Coal-Fired Power Plant with Integrated Thermal Energy Storage

In order to reach the climate targets, a substantial amount of decarbonisation of the power sector in the medium term is necessary. In line with this, the share of intermittent renewables are expected to further increase while the share of conventional generation capacity decreases. This also means that, in order to balance the deviations in the intermittent renewable based generation, the remaining fleet of conventional power plants will have to operate with increased flexibility. In this regard, integrating a thermal energy storage (TES) into the water-steam cycle of the plant is a novel method that can result in substantial increases in power plant flexibility. In such a configuration, the TES is charged with the heat extracted from the water-steam cycle of the plant during low power demand (i.e. during low electricity prices) and the stored energy is then discharged to the plant cycle during high power demand (i.e. during high electricity prices). Hence, the TES system provides the plant with the capability to conduct energy arbitrage. The case of Germany is particularly interesting for the analysis of such a system as the share of wind and solar photovoltaic energy in electricity generation has increased strongly in the last decade, bringing with it increased flexibility requirements on thermal power plants. Previous literature indicates that the economic benefits of flexibility improvements in hard coal power plants are potentially higher than similar improvements in gas-fired plants (Hübel et al., 2018), which makes the case of coal-fired plants with integrated TES especially worth analysing. Despite the fact that investing in an integral TES system in coal-fired plants in Germany may not be practical anymore due to the coal exit decision, a techno-economic analysis of such a system in the German setting can nevertheless be useful for identifying patterns that can be indicative for other regions that are expected to see high intermittent renewables penetration in the medium term.

Against this backdrop, this chapter provides an analysis of the effects of an integrated TES system on the optimal (i.e. profit maximising) dispatch of a coal-fired power plant located in Germany, for the historical year of 2019. For this purpose, a mixed integer linear programming (MILP) model depicting the dispatch of the coal-fired plant with an an integrated TES is developed and applied. The dispatch simulation considers the dispatch on the day-ahead, intraday power markets as well as the markets for primary (PRL) and secondary (SRL) control power, and quantifies the additional profits that can be obtained via the TES system on these markets. Assuming a reference TES system specification as presented in Richter et al. (2019), the analysis finds that a TES with a 0.5 hours of storage capacity can increase the total profits of the plant by 2.4% in the considered year of 2019, achieving 377,000 EUR of additional profits. A large majority (about 60%) of the additional profits are obtained on the PRL market, followed by profits due to energy arbitrage on the continuous intraday market (about 20%). It is shown that, while larger storage capacities result in higher energy arbitrage profits, the increases are rather limited. On the other hand, very substantial profits on the SRL market can be achieved as storage capacity increases. In addition to the reference TES system, an alternative high-efficiency TES is also considered. The higher TES efficiency allows significant increases in the energy arbitrage profits on the day-ahead and intraday markets. Regarding the effects on the plant dispatch, it is found that TES systems can increase the full load hours of the plant; thus, potentially causing the CO_2 emissions of the individual plant to rise. The increase is found to be marginal (less than 1%) for a TES storage capacity of 0.5 h; however, it becomes significant with larger TES capacities.

1.2. Methodology

In this thesis, different research questions are addressed with different types of models. In Chapter 2, a theoretical framework with an analytic solution is applied, whereas in Chapter 3, Chapter 4 and Chapter 5 numerical simulation models are used. The analysis conducted in each chapter relies on specific assumptions, which are necessary to isolate and identify the effects related to the investigated research questions. Therefore, in order to interpret the applicability of the results to reality, it is essential to provide an overview of the applied methodologies and discuss the underlying assumptions.

In **Chapter 2**, in order to analyse the effects of multipliers, a stylised theoretical model that represents the gas procurement, storage, and transmission capacity booking in the EU gas market is developed. The model considers two points in time and two nodes (one supply node and one demand node). Five different groups of players interacting with each other are represented. Those are: traders, producers, storage operators, and the transmission system operator (TSO). Major assumptions of the model are that it depicts a setting of perfect competition with perfect foresight, where the gas demand is assumed to be inelastic in the short-run. The optimal allocation under perfect competition then becomes equivalent to the solution of the planner's problem, which corresponds to maximising welfare by minimising the total costs. Hence, the problem is formulated as a cost-minimisation problem, where the total cost of gas procurement, transport and storage are minimised. The resulting linear cost minimisation problem is solved analytically using Karush-Kuhn-Tucker (KKT) conditions. In this analysis, capacities of production and infrastructure (pipeline and storages) are assumed to be unrestricted and represent the situation that sufficient capacities exist. It should be noted that, while there are cases in reality with chronic infrastructure bottlenecks, this assumption is generally representative of the overall situation in the European gas system. The assumption of perfectly inelastic demand is a common assumption for short-run gas market models; however, gas demand can nevertheless have a certain short-run elasticity, in particular in the power sector due to fuel switching between gas and coal-fired plants. While this would not change the main findings of the analysis, the effects of multipliers during peak prices could be more pronounced in reality in this case.

In **Chapter 3**, the internal and external effects of multipliers are analysed with the numerical simulation model TIGER, developed at the Institute of Energy Economics (EWI) at the University of Cologne. The model simulates the gas dispatch in Europe under perfect competition and perfect foresight. It is formulated as a linear optimisation problem and has the objective function to minimise total system costs. Producers, consumers, traders and storage operators are represented and detailed historical data on production capacities, demand regions, pipeline network, gas storages and LNG terminals are included. Using historical demand profiles and historical infrastructure capacities allows for a more realistic representation of the regional characteristics. For the analysis presented in this chapter, cost of capacity booking is included in the objective function of the TIGER model and the corresponding restrictions are specified. In order to be able to identify robust regional effects, six regional clusters of countries are considered. The gas dispatch for the gas year of 2017–2018 is simulated with a monthly resolution and the effects of the multipliers on infrastructure utilisation, prices, and welfare distribution are quantified. As in the analysis presented in Chapter 2, gas demand is assumed to be perfectly inelastic and is specified as an exogenous parameter. Hence, the argument regarding this assumption applies here as well. The analysis considers a simplified spatial structure with aggregated regions in order to better isolate and identify effects. In reality, due to the more complex spatial structure with numerous interconnected transit countries, the effects of multipliers can be more amplified due to the so-called tariff pancaking effect. It should also be noted that the assumption of perfect foresight in the model results in optimal capacity booking. Nevertheless, in reality, because of uncertainty and forecast errors, not all booked capacities are optimal and booked capacities remaining unused is a common occurrence. In this regard, extending the model by including stochasticity in capacity demand to represent the realistic situation of imperfect information could be a part of future research.

In **Chapter 4**, a global oil market simulation model named DROPS is applied to analyse the market structure and OPEC behaviour. DROPS is a partial equilibrium model formulated as a mixed complementarity problem (MCP). The MCP formulation allows multiple agents having different interests with their own optimisation problems to be represented, enabling the crude oil market to be simulated under various market structure assumptions. Consumers in the model are assigned their respective inverse linear demand functions, which are estimated by using a reference price and a reference demand in the corresponding countries in combination with the elasticity of oil demand obtained from recent literature. Producers are modelled with piece-wise linear supply functions derived from relevant literature, where the corresponding production capacities are allocated to each cost level. The model assumes a crude oil product of homogeneous quality. In reality, there is significant variation in the properties of crude oil and different regions can prefer specific types of crude oil for their downstream sector. The indirect effect of the quality difference is considered with region-specific mark-ups on production costs in accordance with the literature. Consideration of quality differences in crude oil would particularly be important if the refinery sector was modelled. However, since the model focuses on the upstream oil industry, representing the quality differences by a cost margin is deemed satisfactory. Another assumption is that oil exporters in the model are all countries and not oil companies. In reality, especially in the USA, numerous private companies are active in the upstream sector. Nevertheless, since private companies are generally price takers, they do not have significant market power. Moreover, the exporters with the largest potential of capacity withholding are Saudi Arabia, other OPEC members and Russia, all having national oil companies. Therefore, considering the scope of the analysis, the omission of private oil companies should not have a significant impact on the findings.

In **Chapter 5**, the optimal dispatch of a coal-fired power plant with an integrated thermal energy storage (TES) is simulated with a mixed-integer linear programming (MILP) model. The objective function of the optimisation problem corresponds to maximising total profits obtained from the dispatch on wholesale electricity markets and the markets for control power. The problem is subject to system constraints of the power plant and the TES as well as various market-specific constraints such as the prequalification criteria for control power provision. The wholesale electricity markets considered in the model are the day-ahead auction with hourly products and the continuous intraday market with quarter-hourly products, which is chosen for being theoretically more profitable for storage systems due to its higher volatility. The model optimises the dispatch on the primary (PRL) and secondary (SRL) control markets simultaneously with the day-ahead market, allowing the optimal capacities offered on the control power markets to be determined endogenously. A major assumption of the analysis is that the plant operator is a price taker and has perfect foresight. Hence, the optimal total profit simulated by the model represents an upper benchmark. In future research, a more realistic dispatch and the corresponding profit simulation under imperfect information could be analysed by extending the model within a stochastic framework in order to account for price uncertainty. Additionally, the analysis presented in this chapter considers only the potential of the TES for energy arbitrage and control power provision. TES systems can also provide other types of flexibility such as providing additional heat during the start-up phase of the plant to reduce start-up time, which can be considered in future research.

The discussion presented in this section aims to provide a general overview of the methodology and assumptions used in this thesis. A detailed discussion of the methodologies and assumptions are provided in the respective chapters.

2. Pricing Short-Term Gas Transmission Capacity: A Theoretical Approach to Understand the Diverse Effects of the Multiplier System

In the European Union's (EU) gas transmission system, transporting gas requires the booking of transmission capacities. For this purpose, long-term and short-term capacity products are offered. Short-term capacities are priced by multiplying long-term capacity tariffs with factors called multipliers, making them comparably more expensive. Therefore, the level of multipliers directly affects how capacity is booked and may significantly impact infrastructure utilisation and welfare—an issue that has not received attention in the literature so far. Using a theoretical approach, we show that multipliers equal to 1 minimise costs and maximise welfare. In contrast, higher multipliers are associated with decreasing welfare. Yet, policymakers may favour higher multipliers, as we find that multipliers greater than 1 but sufficiently low can maximise consumer surplus by leading to reduced hub prices and lower regional price spreads on average. These findings are expected to hold for the large majority of the EU countries. Nevertheless, we also identify situations in which capacity demand can become inelastic depending on the proportion of multipliers with respect to the relative cost of transmission versus storage. In such cases, varying multipliers are found to have no effect on infrastructure utilisation, prices and welfare.

2.1. Introduction

Efficient operation of gas transmission networks is crucial for the gas supply system and overall welfare. Due to the direct effect on network utilisation and the resulting welfare, the applied pricing policy for financing of networks is particularly important. Principles of microeconomics indicate that economic efficiency is maximised when prices reflect short-run marginal costs (Borenstein, 2016). However, the existence of high fixed costs in gas networks necessitates charging tariffs higher than short-run marginal costs so that revenues cover the total network costs.[1] The networks are dimensioned according to maximum (i.e. peak) capacity demand, which in turn largely determines the fixed costs. An important issue when designing the tariff structures then becomes how to charge the network users for the cost of capacity. A common approach for financing networks is to apply capacity tariffs used to distribute the network costs among users depending on their peak capacity demand. Therefore, in contrast to a pure commodity tariff[2] regime where only the transported volumes are charged, capacity tariffs[3] incentivise the reduction of yearly peak capacity demand and potentially reduce the need for capacity extensions.

Financing of gas networks in the EU occurs via the entry-exit regime. Operated by transmission system operators (TSOs), the EU gas grid consists of numerous regional gas transmission networks (i.e. market areas) which connect producers and neighbouring networks with storage facilities (henceforth storages) and downstream distribution networks. In this context, the entry-exit system requires network users to book entry and exit capacities in explicit auctions whenever transporting gas into or out of a certain market area, paying the corresponding tariffs.[4] When the entry-exit tariff system was first introduced in the EU with Regulation 2009/715, the offered capacities were limited to yearly capacities. This meant traders were not charged according to the actual transported gas volumes but rather for their expected peak capacity demand, which essentially corresponded to a pure capacity pricing regime. However, in some cases, offering only yearly capacities caused inefficient short-term utilisation of the existing pipelines, where significantly high price spreads between market areas occurred despite the absence of physical congestion (ENTSOG, 2017). This inefficiency was caused by arbitrageurs not being able to exploit short-term regional price spreads without procuring capacity covering a whole year.

In order to reduce the inefficiencies resulting from offering only yearly capacities, the EU Commission introduced the Network Code on Capacity

[1] This is also observed in other natural monopolies such as telecommunication, electricity and railway networks.

[2] Commodity tariffs are also commonly referred to as energy charges or volumetric charges.

[3] Capacity tariffs are also commonly referred to as capacity charges or demand charges.

[4] The booking of capacities occurs in capacity auctions performed by trading platforms (such as PRISMA, GSA, RBP) in which the reserve prices correspond to the transmission tariffs. In a large share of the EU capacity auctions, demand for capacity remains below the offered capacity (ACER, 2019b). In the remaining cases where demand for capacity exceeds the offered capacity a congestion premium arises.

Allocation Mechanisms (NC CAM) with Regulation 2013/984, extending the available capacity products to cover sub-annual durations. The regulation thus required TSOs to offer short-term (ST) transmission capacities, i.e. quarterly, monthly, daily and within-day capacities, while the previously introduced yearly capacities were defined as long-term (LT) capacities. Instead of the necessity to cover the yearly peak demand with a yearly product, capacities could now be booked according to the actual transmission demand. This enabled traders to make capacity bookings corresponding to the actual transported volumes, similar to what would occur under a commodity pricing regime. LT and ST capacities generally do not cost the same. According to EU regulations, ST capacities should be priced low enough to incentivise short-term trade but sufficiently high to support enough LT bookings to achieve stable TSO revenues and tariffs. In this context, in the EU, ST products are priced by multiplying the LT tariff with factors called multipliers. Those multipliers are individually specified by the respective national regulatory authorities (NRAs).[5]

By making ST products comparatively more expensive, NRAs can influence the emphasis of capacity vs. commodity pricing in the pricing of transmission capacities in the EU entry-exit tariff structure. This can be best illustrated with two extreme cases: If the multipliers were equal to 1, then the ST capacities would cost the same as LT capacity. In this case, any capacity booking pattern that includes LT capacities can not be cheaper than booking solely ST capacities.[6] As a result, traders would only book a combination of ST capacities which exactly satisfies their demand profile for transmission capacity. In such a setting, network users behave as being exposed to commodity pricing since they pay for the exact amount of volumes, i.e. the energy they transport. Whereas, if the multipliers were sufficiently high, so that booking LT capacity would be always cheaper than booking ST capacities, then the traders would book only LT capacity. This would essentially result in network users behaving as being exposed to a pure capacity pricing regime, as traders would be required to book enough transmission capacity

[5] When NC CAM came into force, multipliers largely varied among countries spanning a wide range from 1 to as high as 5.5 and mostly increased as the run-time of the capacity product decreased. The EU Commission tightened the rules regarding multipliers in their network code on tariff harmonisation (NC TAR) from the EU regulation 2017/460. The regulation limits the range for multipliers for member states to 1–3 from June 2019 onward. Moreover, the EU Agency for the Cooperation of Energy Regulators (ACER) has to decide by April 1st, 2021 whether multipliers are to be further restricted within a range of 1–1.5 starting from April 2023.

[6] It is assumed that no transaction costs exist and enough capacity products are offered.

to cover their yearly peak demand even if their average capacity demand is lower; hence, resulting in them paying for the capacity rather than the energy.

The reality lies somewhere in between these two extreme cases. In a large majority of EU member countries, multipliers are greater than 1 but are still sufficiently low so that both LT and ST bookings are observed (ACER, 2019a). Hence, transmission network users in these countries are implicitly charged a combination of capacity and commodity tariffs. The extent to which aspect dominates over the other, and the ensuing effects on infrastructure and welfare, are determined by the multipliers and the underlying tariff structures—the analysis of which constitutes the focus of this paper.

The issue of how to design tariffs within the EU entry-exit framework has been analysed in the literature, where aspects such as cost recovery, cost distribution and efficiency have been considered. Bermúdez et al. (2016), analysing different methodologies of setting LT tariffs, argues that more cost-reflective methodologies ensure more efficient utilisation of the transmission network. Mosácula et al. (2019), however, points out that approaches which charge full costs at EU interconnectors are unlikely to maximise social welfare. This is also mentioned in Hecking (2015), which suggests to reduce inefficiencies by setting entry and exit tariffs equal to short-run marginal costs for interconnectors within the EU while applying sufficiently high tariffs at the EU outer borders to finance the EU transmission grid. In addition to increasing the efficiency of the gas dispatch, the study estimates that such a tariff regime would also allow to redistribute considerable share of network costs towards suppliers at the EU borders, indicating the relevance of tariff design on the distribution of network costs.

The pricing of LT vs. ST capacities and the topic of multipliers have not been analysed in the academic literature so far.[7] To our knowledge, a tariff framework similar to the current tariff structure of the EU gas transmission capacities is also not observed in any other regulated network neither in the EU nor in other regions, hence the lack of comparable literature. Nevertheless, when multipliers are larger than 1, the EU tariff structure has similarities with the concept of peak-load pricing. In peak-load pricing, higher prices are charged in peak periods than in off-peak periods. Similarly, in the EU entry-exit system, when ST capacity is more expensive than LT capacity, traders are incentivised to

[7] The topic is qualitatively addressed only in several consulting studies and technical reports (ACER, 2019a, ACER and CEER, 2019, DNV-GL, 2018, EY and REKK, 2018, Rüster et al., 2012, Strategy& and PwC, 2015).

procure the cheaper LT capacity for meeting base load demand whilst procuring the more expensive ST capacity to meet their peak-load demand. This implicitly results in higher capacity costs for peak periods than for off-peak hours. The founding works of Boiteux (1949) and Steiner (1957) on peak-load pricing have shown that allocating the costs of capacity to peak-load consumers and charging them consequently higher tariffs impacts the networks utilisation and leads to higher long-term efficiency. Further, Gravelle (1976) and Nguyen (1976) indicate that the problem of peak-load pricing remains a valid issue even when storage (with significant costs) is available, which is undeniably the case in the majority of EU gas systems. These findings further underpin the relevance of analysing the effects of the multipliers on network utilisation, efficiency and cost distribution.

In order to improve the understanding of the effects of multipliers and fill the research gap in the literature, we develop a stylised theoretical framework with an analytic solution that depicts the gas procurement, storage, and transmission capacity booking in the EU gas market. The model considers two points in time and two nodes under a setting of perfect competition and perfect foresight. We solve the resulting linear cost minimisation problem analytically using Karush-Kuhn-Tucker (KKT) conditions, providing analyses on the effects of multipliers. The analysed aspects can be grouped into three main categories; the direct impact of multipliers on infrastructure utilisation, effects on hub prices and welfare implications.

Our model results show that high multipliers indeed reinforce the capacity pricing component and cause bookings to shift from ST capacities to LT capacity, resulting in increased storage utilisation. This leads to a more uniform usage of transport capacities, implying decreased volatility of pipeline transportation. The findings above are expected to be valid for the EU gas system in the majority of situations. Nevertheless, we find that these effects are not universal and depend strongly on whether the traders' capacity demand is elastic or not. We define the elasticity as the shift in capacity demand from the peak period to an off-peak period in response to an increase in the relative price of ST capacity (i.e. the multiplier). This elasticity largely results from gas storages, which provide the traders with inter-temporal flexibility, and give them the possibility of meeting their short-term needs with withdrawals from storages instead of booking ST capacities.

We find that certain proportions of multipliers with respect to the ratio of storage tariffs to transmission tariffs can lead to inelastic capacity demand:

Multipliers that are sufficiently low (but still larger than 1) compared to the marginal cost of gas storage—or when no storage capacity exists—can result in a domain with inelastic capacity demand, where a change in multipliers does not affect the volume of booked capacities in the respective time periods. Similarly, we show that sufficiently high multipliers can lead to the same behaviour as in a pure capacity pricing regime, with only LT capacity being booked and the volume of booked capacity being independent of the multiplier level.

Regarding the impact of multipliers on temporal hub prices we identify several effects. We find that maximum regional price spreads increase with higher multipliers, an implication also mentioned by ACER (2019a). However, unlike ACER, who argues that ST capacity tariffs would act as reference prices for the regional spreads, we show that ST tariffs rather form the upper bounds for the spreads. As such, our results imply that the volatility in regional price spreads increases with higher multipliers. Further, we find that increases in multipliers can cause increased temporal volatility in hub prices if storage tariffs are comparably high or if storage capacity is unavailable.

The model results indicate that higher multipliers are associated with higher total system costs and consequently lower total welfare in the short-run. However, for the identified multiplier domain which is representative of the majority of the situations in the EU gas system, our results show that there exists a multiplier level potentially larger than 1, which maximises the total consumer surplus.

Therefore, despite the stylised setting, the implications of our model results are highly relevant for policymakers. Maximising total welfare requires the multiplier to be no greater than 1. However, policymakers, who aim to maximise consumer surplus, may favour a multiplier larger than 1, since transmission tariffs can be lowered by the TSOs, which leads to lower average hub prices. Multipliers higher than 1 also foster the redistribution of the network costs from base load towards peak-load consumers, in line with the principle of peak-load pricing.

The contribution of our paper can be summarised as follows: Academic literature on the effects of short-term transmission capacity multipliers is nonexistent. Hence, being the first of its kind, our paper aims to close this research gap. Thanks to the developed theoretical framework, direct effects and implications are identified within the valid tariff domains. Since our analysis shows that multipliers have significant effects on welfare, distinguishing between ranges of validity also helps support tailor-made policymaking.

2.2. Model

We develop a theoretical model which depicts the procurement and the subsequent transmission capacity booking in the EU gas market. The model represents the relevant actors in a realistic manner, yet it is simplified enough to have a closed form solution. In this respect, the model considers two points in time (t_1, t_2), and five different groups of players interacting with each other: traders, producers, storage operators, the transmission system operator (TSO), and consumers. The structure of the model and the main assumptions for the considered agents are illustrated in Figure 2.1.

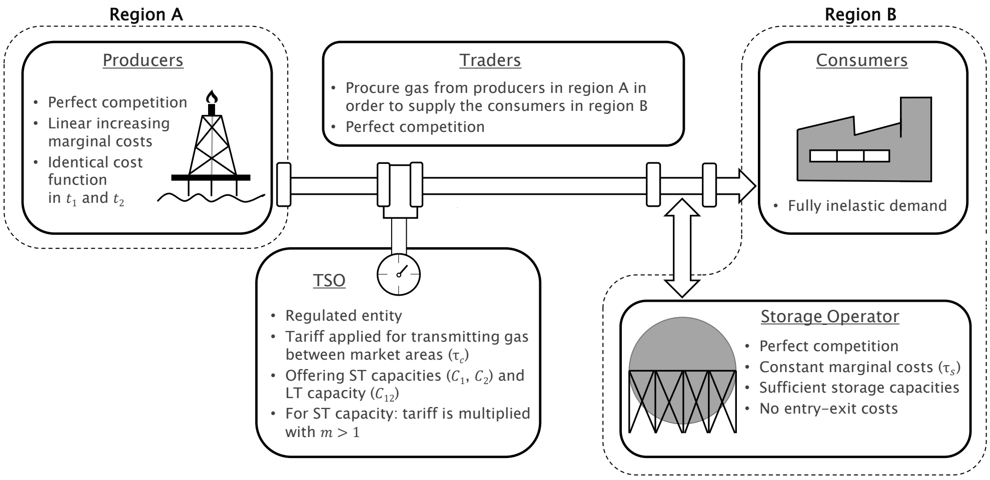


Figure 2.1.: Schematic representation of the model structure and the main assumptions

We assume that the traders are obliged to meet the gas demand of their customers (i.e. consumers) under a perfectly competitive market setting. Accordingly, traders procure gas from the gas producers located at market area A and transport it using the gas transmission network to the consumers which are located at market area B. In order to transport gas over the transmission network, traders need to book sufficient transmission capacities. Furthermore, the traders can store gas in gas storages in t_1 and withdraw it in t_2 to serve the gas demand in t_2. We assume that traders book capacities rationally and efficiently.[8]

[8]This is a realistic assumption also supported by the empirical analysis of Keller et al. (2019).

We assume producers to face positive and linearly increasing marginal costs[9] and have sufficient capacities. Their aggregated cumulative cost function is linear and remains unchanged in both points in time. The producers are assumed to be under perfect competition and offer their gas at a rate that is equal to their marginal costs. This is in line with the simulations of Schulte and Weiser (2019a), which indicate that gas suppliers to Europe behaved competitively in 2016.[10] The aggregated inverse supply function p_t of the producers can be then formulated as follows:

$$p_t(Q_t) = a + b\,Q_t \qquad \forall\, t \in (t_1, t_2) \tag{2.1}$$

where $Q_t > 0$ represents the aggregated gas procurement volumes of the traders.

The storage capacities of the storage operators are located in market area B where the consumers are located. We assume storage operators to face constant positive marginal costs under perfect competition. We further assume that the storage operators have sufficient capacities to meet the demand at all times and therefore offer their storage capacity at a rate equal to their marginal costs τ_s. This assumption is in line with the situation observed in the EU, where storage operators have been unbundled since the introduction of the third energy package (European Commission, 2010) and have ample storage capacities in the absence of supply disruptions (ACER, 2019a). Furthermore, we assume storage operators to be fully exempt from transmission tariffs when withdrawing or injecting gas in the transmission network.[11]

The consumers have a positive gas demand. The aggregated gas demand of the consumers at t_1 equals d_1. Similarly, the demand in t_2 is equal to d_2. Demand is assumed to be perfectly inelastic. This is a common assumption for stylised short-run gas market models and is also supported by the empirical analysis of Burke and Yang (2016), which finds that short-term elasticities for gas demand are generally low, and for the case of households, do not significantly differ from zero. Demand is assumed to be higher in the second period than in the first

[9]Having carried out the analysis also by assuming a supply function with quadratic marginal costs, we find that the main findings regarding the effect of multipliers on gas dispatch remain unchanged. Hence, for the sake of clarity, we assume linear increasing marginal costs for producers in this paper.

[10]With increasing LNG supply and lower prices it can be safely assumed that gas markets have become even more competitive in recent years.

[11]Such an exemption is observed in several EU countries (e.g. Spain, Denmark and Austria) with the goal of inducing positive externalities such as reducing pipeline investment costs and increasing security of supply (ACER, 2019a). In other countries, storages are exempted by at least 50% due to NC TAR regulation; though, most countries apply higher exemptions (ENTSOG, 2019).

period, i.e. $d_2 > d_1 > 0$, representing a winter (d_2) and a summer period (d_1). To be able to examine distributional effects among different consumer groups we assume the aggregated consumer demand (i.e. d_1 and d_2) to be split into two demand groups: first, the demand of the base-load consumers (e.g. industry companies) which equals d_1 in both periods, and second, the demand of the peak-load consumers (e.g. households) which only occurs in t_2 and equals $(d_2 - d_1)$.

The TSO operates a transmission grid which connects the producers in market area A with the storages and consumers in market area B. We assume that sufficient transmission capacity exists and is not congested. The TSO is a regulated entity which is allowed to apply a tariff for transmitting gas between the two market areas. As in the case of the EU, the TSO offers LT and ST transmission capacity. The LT capacity product (C_{12}) covers both periods and the ST capacity products cover only a single period (i.e. C_1 in t_1 and C_2 in t_2). Traders need to book sufficient transmission capacity rights such that desired gas volumes can be transported to the costumers and the storages in market area B. Similarly to the EU with the regulation NC CAM, traders in our model are permitted to trade booked capacities in secondary capacity markets. As a consequence, in the given setting of perfect foresight, the sum of bookings of many individual traders would be identical to the booking of a single competitive trader who faces the cumulative demand of these many traders.[12] Since $d_2 > d_1$ and production costs are represented by a quadratic function of production volumes, it is inherently assumed that injection to storages occurs in t_1 and withdrawal occurs in t_2 to meet the higher demand. Zero storage losses are assumed; injection and withdrawal rates in both periods are the same and equal the stored volumes S. Hence, the supply constraints, where demand in each period is satisfied with corresponding capacity bookings and storage utilisation, can be stated as in Equations 2.2 and 2.3.

$$C_{12} + C_1 \geq d_1 + S \tag{2.2}$$

$$C_{12} + C_2 \geq d_2 - S \tag{2.3}$$

The regulated tariff for a unit of LT capacity equals τ_c (with $\tau_c > 0$) per time period and is fixed for both periods. The total LT tariff which runs over both

[12] Due to the assumptions of perfect competition with perfect foresight, as well as the availability of sufficient transmission capacities and an efficient secondary capacity market, the traders in our model have no incentive to block capacities, as over-booking causes additional costs without additional benefits.

periods then becomes $2\,\tau_c$. The tariff for the ST capacity is similarly regulated and is set to $m\,\tau_c$. In reality, as regulated entities, TSOs set the entry-exit tariffs (corresponding to the LT tariff τ_c in our model) such that their expected revenues cover their costs, adjusting the tariffs each year as necessary.

In our main analysis, the effects of multipliers on the players' behaviour and welfare implications are derived analytically in a closed form. For that purpose, we keep τ_c fixed and assume τ_c to be sufficiently high such that the TSO covers its costs in a setting without multipliers ($m = 1$). Therefore, the TSO may generate additional surplus if multipliers are larger than 1 ($m > 1$). After having derived the equations describing the behaviour of the players, we analyse the effects of m when the transmission tariff is adjusted. This allows us to derive the effects of m in the more realistic setting where the TSO surplus is independent of m (see Section 2.3.4).

The model depicts a setting of perfect competition and consumers' demand is perfectly inelastic in the short-run. Hence, the optimal allocation under perfect competition is equivalent to the solution of the planner's problem of maximising welfare by minimising the total costs ($Cost^{Tot}$). Since the total costs are the sum of production costs ($Cost^{Pro}$), transportation costs ($Cost^{Tra}$), and storage costs ($Cost^{Sto}$), the minimisation problem can be expressed as follows:

$$\min Cost^{Tot} = Cost^{Pro} + Cost^{Tra} + Cost^{Sto} \tag{2.4}$$

The production costs correspond to the integral of the price function $p_t(Q_t)$ with respect to production quantity Q_t:

$$\begin{aligned} Cost^{Pro} &= \int p_t(Q_t)\, dQ_t \\ &= Q_t\,(a + \frac{1}{2}\,b\,Q_t) \end{aligned} \tag{2.5}$$

The aggregated gas procurement Q_t is equal to $Q_1 = d_1 + S$ in t_1 and $Q_2 = d_2 - S$ in t_2. Substituting these into Equation 2.5, total production costs are obtained.

$$Cost^{Pro} = a\,(d_1 + d_2) + \frac{1}{2}\left[b\,(d_1 + S)^2 + b\,(d_2 - S)^2\right] \tag{2.6}$$

The storage costs correspond to the product of the stored gas volume S and the tariff for storing, τ_s:

$$Cost^{Sto} = S\,\tau_s \tag{2.7}$$

The costs for purchasing the capacity rights for transmission is equal to:

$$Cost^{Tra} = \left[m\,(C_1 + C_2) + 2\,C_{12}\right]\tau_c \tag{2.8}$$

Hence, the minimisation problem can be expressed as in Equation 2.9, subject to the constraints that demand needs to be satisfied in both periods and the non-negativity constraints discussed previously.

$$\begin{aligned}
\min_{S,C_1,C_2,C_{12}} \; Cost^{Tot} &= a\,(d_1 + d_2) + \frac{1}{2}\left[b\,(d_1+S)^2 + b\,(d_2-S)^2\right] \\
&+\; \left[m\,(C_1 + C_2) + 2\,C_{12}\right]\tau_c \\
&+\; S\,\tau_s \\
s.t. \qquad & C_{12} + C_1 \;\geq\; d_1 + S \\
& C_{12} + C_2 \;\geq\; d_2 - S \\
& C_{12},\; C_1,\; C_2,\; S \;\geq\; 0
\end{aligned} \tag{2.9}$$

Assigning Lagrange multipliers $(\mu_1, \mu_2 ..., \mu_6)$ to the inequality constraints, the Lagrangian of the optimisation problem and the corresponding KKT conditions are obtained. The Lagrangian formulation and the KKT conditions can be found in Appendix A.1.

2.3. Results

2.3.1. Deriving the effects on infrastructure utilisation

In this section, the solutions of the cost minimisation problem illustrated above are presented. We solve this convex optimisation problem by deriving the KKT conditions and finding the feasible KKT points, which provide us with analytic expressions of the analysed variables. Since the problem fulfils Slater's condition, the analysed KKT points are the optimal solutions of the optimisation problem.[13] As the effects of multipliers largely depend on whether they emphasise the commodity or the capacity pricing aspect, we divide our analysis into two subsections. The cases which, by design, correspond to a pure commodity pricing or conversely to pure capacity regime are considered separately from the cases that occur under a mixed-pricing policy—which are more common in reality and comprise more complex effects.

Pure commodity pricing ($m \leq 1$) or pure capacity pricing ($m \geq 2$)

As multipliers determine the relative price of ST capacities with respect to LT capacity, the outcomes of a pure commodity or capacity pricing regime can arise depending on the level of multipliers. For the case of our two-period model, these instances are shown in Proposition 1.

Proposition 1. *Multipliers $m \leq 1$ correspond to a pure commodity pricing regime, whereas multipliers $m \geq 2$ correspond to a pure capacity pricing regime.*

Proof. If $m \leq 1$, there exists no demand pattern where booking LT capacity is cheaper than booking ST capacity products. Therefore, the LT product is ignored and only ST capacities are booked. This corresponds to traders being charged for the actual transported volumes. Hence, the behaviour is the same as in a pure commodity pricing regime. If storage tariffs are sufficiently low ($\tau_s < 2b(d_2 - d_1)$), then traders also use storages to meet the demand in the peak period. Else ($\tau_s \geq 2b(d_2 - d_1)$), the demand is met only by booking the ST products at each period, where the transported volumes exactly correspond to the respective demand in each period (d_1 in t_1 and d_2 in t_2). See Appendix A.2 Case 1 (a) for the detailed proof.

If $m \geq 2$, there exists no demand pattern where booking ST capacities is cheaper than booking LT capacity. Hence, only the LT product is booked, inducing the same behaviour seen in a pure capacity pricing regime. Whether gas transmission is aligned between the periods or capacity rights are wasted depends on the ratio of storage tariff to transmission tariff levels: If the relative costs of storage with respect to transmission costs are sufficiently low ($\tau_s \leq 2\tau_c$), storage utilisation aligns transports completely such that the LT

[13] To ensure that no optimal solution is omitted, an extensive analysis of all the possible cases including the non-optimal points are presented in Appendix A.2.

capacity is fully utilised. If the storage costs are comparatively high ($\tau_s > 2\tau_c$), the booked LT capacity in off-peak period is underutilised, i.e. some capacity is wasted: Under this condition, if $\tau_s < 2\tau_c + 2b(d_2 - d_1)$, storages align transports partially. In the case that $\tau_s \geq 2\tau_c + 2b(d_2 - d_1)$, storage utilisation is zero. See Appendix A.2 Case 4 (c) for the detailed proof. □

For $m = 1$, traders' costs are the same as in a pure commodity tariff regime; namely, overall transported volumes determine the traders' transport costs. Further reductions in the multiplier do not change the optimisation rationale of the traders and welfare. For this reason, and since the EU regulation NC TAR 2017 also does not allow for multipliers below 1, the minimum multiplier value considered in the analysis of this paper is $m = 1$.

The multiplier threshold that corresponds to a pure capacity pricing regime equals to LT product duration expressed in terms of number of ST products. As our model has two time periods, this threshold is found to be equal to 2, as shown in Proposition 1. For such multipliers, we find that capacity wasting occurs if gas transports do not align in t_1 and t_2. Thereby, Proposition 1 implies that even in a market with perfect foresight, perfect competition, and secondary trading of capacity at no cost, some capacity rights may remain unused with high multipliers if capacity demand is inelastic due to comparatively high storage tariffs or when no storage capacities exist. Increasing multipliers above 2 does not affect the results, as traders do not procure ST capacity, where multipliers are applied. Hence, the highest multiplier considered in this paper is $m = 2$. In the EU, such multipliers, which by design correspond to pure capacity pricing , are ruled out with Regulation NC TAR 2017 as the EU aims to allow for and encourage ST capacity bookings.[14]

Mixed-pricing regime ($1 < m < 2$)

In most EU countries, the range of applied multipliers facilitates traders to consider both long-term and short-term bookings, allowing for an inherent mixed-pricing regime in which capacity and commodity pricing effects are simultaneously present. In our model, this range of multipliers corresponds to $1 < m < 2$.

[14] The multiplier threshold in the actual EU tariff structure would be equal to 12 between the yearly and monthly products, for instance, or equal to 4 between the yearly and quarterly products. As multipliers are required to be below 3, feasible multipliers are sufficiently low to incentivise ST bookings when storage tariffs are low.

In the following propositions we present how multipliers influence the capacity booking as well as storage decision and we relate the market outcomes to the regimes of capacity and commodity pricing. We identify specific thresholds for m that affect how changes in m influence the system. We define the lower threshold as $\underline{m}$ and the upper threshold as $\overline{m}$, which then constitute three domains. Despite the inherent mixed-pricing regime, we identify two domains ($m \leq \underline{m}$ and $m \geq \overline{m}$) where the capacity demand is inelastic due to underlying tariff structures. In these domains, the capacity demand in the off-peak and peak periods, and the proportion of LT to ST bookings, are independent of the multiplier. The third domain corresponds to the case with elastic capacity demand ($\underline{m} < m < \overline{m}$) which is representative of the majority of the actual situations observed in the EU gas system.

Proposition 2. *If $m \geq 1$, but sufficiently small ($m \leq \underline{m} = 1 + \frac{\tau_s}{2\,\tau_c} - \frac{b}{\tau_c}\,(d_2 - d_1)$) storages are not utilised, LT capacity is booked to cover the demand in t_1, and the remaining demand in the peak period t_2 is met with the ST product. The proportion of ST to LT bookings is independent of m. The capacity booking and storage volumes are:*

$$\begin{aligned} C_1 &= 0 \\ C_2 &= d_2 - d_1 \\ C_{12} &= d_1 \\ S &= 0 \end{aligned} \tag{2.10}$$

Proof. See Case 5 (a) i. in Appendix A.2 for the proof.

□

Proposition 2 indicates that multipliers which are sufficiently low with respect to the ratio of storage to transmission tariffs can result in demand in peak periods to be exclusively met by ST capacities rather than storage withdrawals. The reason for that can be clearly seen by rewriting the $m \leq \underline{m}$ condition as $b\,(d_2 - d_1) + m\,\tau_c \leq \tau_c + \frac{\tau_s}{2}$. In this domain, meeting the additional demand in t_2 by procuring the additional volumes in t_2, and correspondingly booking ST capacity, is cheaper than the combined cost of booking LT capacity and storage utilisation. As a result, storages are not utilised and transported volumes in t_1 and t_2 exactly equal the demand d_1 and d_2. Hence, the capacity demand in the two periods remains independent of the multiplier; i.e. capacity demand is inelastic. Given that ratios of base transmission to storage tariffs allow for

$m \leq \underline{m}$, network utilisation is the same as if pure commodity pricing ($m \leq 1$) is applied. This domain can appear in reality in the presence of low multipliers if storage tariffs are comparatively high or if no storage capacities exist.

Proposition 3. *If $m \leq 2$, but is sufficiently large ($m \geq \overline{m} = 1+\frac{\tau_s}{2\tau_c}$), traders book LT capacity only and transport the same volumes in t_1 and t_2. The proportion of ST to LT bookings is independent of m. The capacity booking and storage volumes are:*

$$\begin{aligned} C_1 &= 0 \\ C_2 &= 0 \\ C_{12} &= \frac{d_2 + d_1}{2} \\ S &= \frac{d_2 - d_1}{2} \end{aligned} \tag{2.11}$$

Proof. See Case 4 (a) in Appendix A.2 for the proof. □

Proposition 3 shows that even in situations where m is set to levels, which theoretically allow for ST bookings in the optimum ($m < 2$), ST bookings may not necessarily be part of the optimal solution. This occurs when m is high in comparison to the ratio of storage to transmission tariff such that ST capacities cost more than the combined cost of LT capacity and storage. This can be clearly seen by rewriting the $m \geq \overline{m}$ condition as $m\,\tau_c \geq \tau_c + \frac{\tau_s}{2}$. As a result, the capacity demand is met by booking only LT capacity and using storages. Since transports in both periods align, and consequently there is no potential to shift capacity demand from the peak period to the off-peak period, capacity demand is inelastic. As traders do not procure ST capacity, market outcomes for such multipliers ($m \geq \overline{m}$) are the same as if no ST capacity would be offered; namely, as in a pure capacity pricing regime similar to the one that was in place in the EU before the introduction of NC CAM 2013.

Proposition 4. *If $1 \leq m \leq 2$ and $\underline{m} < m < \overline{m}$, the traders book LT capacity to cover the base load and ST capacity C_2 to cover the additional demand in the peak period (t_2). Traders utilise gas storages. The proportion of ST to LT bookings* *depends on m. The capacity booking and storage volumes are:*

$$
\begin{aligned}
C_1 &= 0 \\
C_2 &= \frac{\tau_s}{2b} - \frac{\tau_c(m-1)}{b} \\
C_{12} &= \frac{d_2+d_1}{2} - \frac{\tau_s}{4b} + \frac{\tau_c(m-1)}{2b} \\
S &= \frac{d_2-d_1}{2} - \frac{\tau_s}{4b} + \frac{\tau_c(m-1)}{2b}
\end{aligned}
\tag{2.12}
$$

Proof. See Case 5 (a) ii. in Appendix A.2 for the proof.

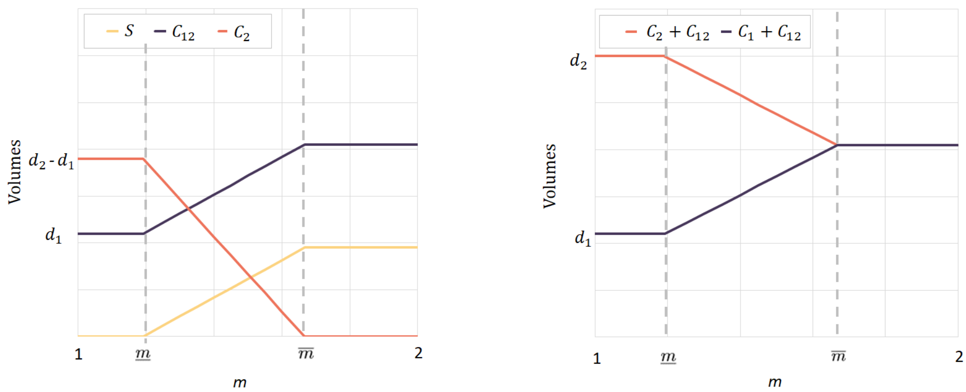
□

Proposition 4 shows the results for multipliers, which lie in the domain of moderate multipliers with respect to the ratio of storage to transmission tariffs. The results represent the only solution where the following three aspects occur simultaneously: Both LT and ST capacity are booked, and storages are utilised to satisfy the demand in the peak-period. This corresponds to a situation which can be observed in the EU for most countries. In this domain, the capacity demand is elastic since the capacity demand shifts from peak to off-peak period with increasing multipliers. With increasing m, ST capacity bookings are replaced with LT capacity booking and storage withdrawals. The extent of the effects of an increase in m for the domain $\underline{m} < m < \overline{m}$ can be obtained by taking partial derivatives with respect to m. Thus, an increase in m increases LT bookings by $\frac{\tau_c}{2b}$, decreases ST bookings by $\frac{\tau_c}{b}$, and increases the demand for storage by $\frac{\tau_c}{2b}$.

It can be seen that Propositions 2 and 4 include $m = 1$, the multiplier level that induces the same behaviour as in a pure commodity pricing regime (see Proposition 1). This is because for $m = 1$, traders are indifferent between solely procuring ST capacity, or rather booking LT capacity for the base load and ST capacity for the peak load.[15] The same holds for $m = 2$, the multiplier inducing the behaviour seen in a pure capacity pricing regime (see Proposition 1). A multiplier of 2 is valid in Propositions 3 and 4. This is because for $m = 2$, traders are indifferent between booking solely LT capacity, or rather procuring LT capacity to meet the base load and ST capacity for the peak load.[16] Therefore, the resulting dispatch and the ensuing welfare are not affected by the choices in these cases. This allows us to analyse the effects of the multipliers that induce a pure commodity and capacity regime behaviour by design (i.e. $m = 1$ and

[15] A proof can be found in Appendix A.2 Case 3 (a).
[16] A proof can be found in Appendix A.2 Case 5 (c).

$m = 2$, respectively) in the remainder of the analysis without incorporating separate formulas for such multipliers. Thus, for $1 < m < 2$, the identified KKT points in the Propositions 2, 3 and 4 are unique optimal solutions, which allow for a mixed-pricing regime.



(a) Booking and storage volumes

(b) Transported volumes

Figure 2.2.: Development of the volumes for storage, ST capacity and LT capacity with respect to the multiplier (a); and development of transported volumes at time periods t_1 and t_2 with respect to the multiplier (b)

In Figure 2.2a we illustrate the findings of Propositions 2, 3 and 4 by plotting the traders' booking and storage decision with respect to m.[17] To be able to illustrate the results for all three identified domains, a setting is chosen in which feasible $\underline{m}$ as well as $\overline{m}$ exist (i.e. $\underline{m} > 1$ and $\overline{m} < 2$). This applies to all the figures in this paper, in which the effects are plotted for the respective multiplier domains. However, it should be noted that, depending on tariff levels, feasible $\underline{m}$ as well as $\overline{m}$ may not exist. In that case, storages would be utilised and transports would differ also for $m = 1$ as well as for $m = 2$.

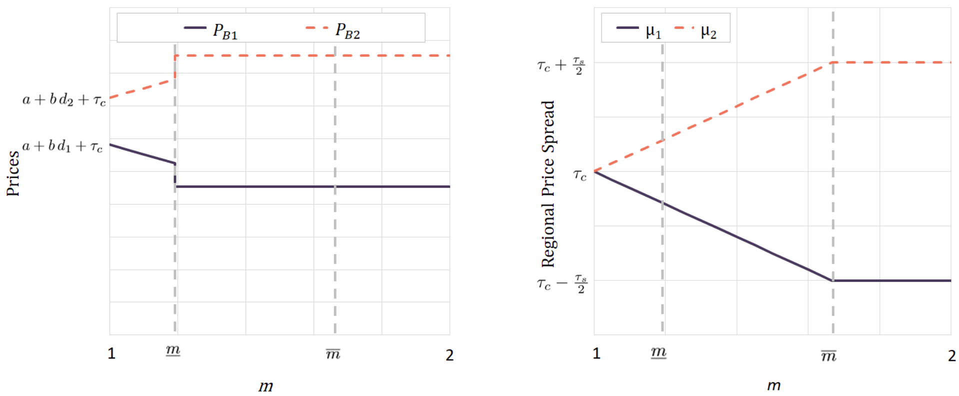
Figure 2.2b shows the transported volumes, which are equal to the sum of booked capacities in each period (i.e. $C_{12} + C_1$ in t_1 and $C_{12} + C_2$ in t_2). While the overall transported volume remains unaffected by m, the temporal spread of the transports, which can be interpreted as an indicator for transport volatility, decreases with m. In the multiplier range $m > \overline{m}$, the same amount of volumes are transported in both periods.

[17]The parameters assumed for the figures in this section are as follows: $d_1 = 11$, $d_2 = 30$, $\tau_c = 6$, $\tau_s = 8$, $a = 4$, $b = 0.15$.

2.3.2. Deriving the effects on prices and price spreads

In a next step we derive the hub prices. In the analysed setting of perfect competition, prices correspond to the marginal cost of supply with respect to demand. Therefore, to obtain the prices in the demand region[18], we insert the solutions derived in the Propositions 2, 3, and 4 in the total cost function shown in Equation 2.9, and differentiate with respect to d_1 and d_2.

$$
\begin{aligned}
P_{B1} &= \frac{\partial Cost^{Tot}}{\partial d_1} = \begin{cases} a + b\,d_1 + (2-m)\,\tau_c & \text{for } m \leq \underline{m} \\ a + b\left(\dfrac{d_1+d_2}{2}\right) + \tau_c - \dfrac{\tau_s}{2} & \text{for } m > \underline{m} \end{cases} \\
P_{B2} &= \frac{\partial Cost^{Tot}}{\partial d_2} = \begin{cases} a + b\,d_2 + m\,\tau_c & \text{for } m \leq \underline{m} \\ a + b\left(\dfrac{d_1+d_2}{2}\right) + \tau_c + \dfrac{\tau_s}{2} & \text{for } m > \underline{m} \end{cases}
\end{aligned} \tag{2.13}
$$



(a) Prices **(b)** Regional Price Spreads

Figure 2.3.: Development of the hub prices in region B (a) and the regional price spread between regions A and B (b), at time period t_1 and t_2 with respect to the multiplier

The functions describing the consumer prices in the demand region are plotted in Figure 2.3a. For the domain $m < \overline{m}$, in which the traders do not use storages and their capacity demand is inelastic, the price in peak period (P_{B2}) increases. This occurs as marginal demand is transported using additional ST capacity whose price increases in m. Conversely, the price in off-peak period (P_{B1}) decreases as additional demand is met by a shift from ST to LT capacity

[18]Our analysis does not focus on the prices in production regions. For the sake of completeness, we derive the prices in the production region A in Appendix A.3.

in this period. Such a reallocation of network costs from off-peak users towards peak consumers is in line with the concept of peak-load pricing.

In the domain $\underline{m} < m < \overline{m}$, the traders were shown to have elastic capacity demand, meaning that they are able to switch from ST to LT capacities with increasing m by using storages. The prices in this case remain constant over m which may seem counter-intuitive since ST transmission tariffs increase in m. However, this is due to additional demand being met by an increase in LT capacity booking and storage usage while ST capacity bookings remain unchanged. This applies to both d_1 and d_2, resulting in consumer prices (P_{B1} and P_{B2}) to be independent of m. In line with the findings of Nguyen (1976), we also show here that the peak price exceeds the off-peak price by the cost of storage (i.e. $P_{B2} - P_{B1} = \tau_s$). In the domain of $m \geq \overline{m}$, despite the inelastic capacity demand, prices are unaffected by changes in m. This is due to the absence of ST bookings and the utilisation of storages. Furthermore, the temporal price spread here is also set by storages.

Interpreting the temporal price spread as price volatility, it can be said that higher multipliers can cause increased volatility in hub prices unless storages are utilised—which requires enough storage capacities to be available and that storage tariffs are sufficiently low compared to transmission tariffs.

In contrast, we find the average hub price to be constant and independent of the multiplier. The average hub price is equal to the gas procurement price that arises when volumes are bought evenly in both periods, plus the base transmission tariff:

$$\frac{P_{B1} + P_{B2}}{2} = a + b\left(\frac{d_1 + d_2}{2}\right) + \tau_c \tag{2.14}$$

The regional price spreads between the modelled regions A and B correspond to the Lagrange multipliers[19] μ_1 and μ_2, for the time periods t_1 and t_2, respectively. As derived in Case 5 (a) in Appendix A.2, those spreads are presented in Equation

[19] Alternatively, regional price spreads can be derived by subtracting the prices in regions A and B.

2.15 and are plotted in Figure 2.3b for the corresponding multiplier domains.

$$
\begin{aligned}
P_{B1} - P_{A1} = \mu_1 &= \begin{cases} \tau_c\,(2-m) & \text{for } m < \overline{m} \\ \tau_c - \dfrac{\tau_s}{2} & \text{for } m \geq \overline{m} \end{cases} \\
P_{B2} - P_{A2} = \mu_2 &= \begin{cases} m\,\tau_c & \text{for } m < \overline{m} \\ \tau_c + \dfrac{\tau_s}{2} & \text{for } m \geq \overline{m} \end{cases}
\end{aligned}
\tag{2.15}
$$

Results indicate that multipliers cause temporal variation in regional spreads: In the peak period, additional transport demand is met by procuring ST capacity, resulting in a price spread of $m\,\tau_c$. In contrast, additional transport demand in the off-peak period is met by replacing ST capacity with LT capacity, inducing regional spreads of $\tau_c\ (2-m)$. Thus, higher multipliers lead to the widening of the temporal price margin of regional spreads. In sum, the effects in the two periods cancel each other out, such that average regional price spreads remain constant over m.

On the other hand, regional spreads in the domain with pure capacity pricing behaviour ($m \geq \overline{m}$) are found to be independent of the multiplier. As the same volumes are transported in both periods (due to only LT product being booked with storage utilisation), the regional spreads in this case are defined by the storage tariff and are constant. Nevertheless, since the majority of real situations in the EU are expected to correspond to mixed-pricing regimes, our results indicate that higher multipliers are likely to cause increased volatility in regional price spreads.

2.3.3. Deriving the effects on surpluses and welfare

Having illustrated the impacts of multipliers on prices and price spreads, we now proceed with the analysis of the effects on the surplus of consumers, gas producers, the TSO and the traders as well as on the resulting welfare.

Consumer surplus
To allow for a clear illustration of welfare effects we assume the consumer surplus of base-load and peak-load consumers[20] to be zero for the range of

[20] Remember, consumers are assumed to be divided into two groups: Base-load consumers with a flat demand equal to d_1 in both periods and peak-load consumers who consume $d_2 - d_1$ in t_2.

multipliers which result in the highest costs for those consumers. As a result, consumer surplus is obtained as a function of the multiplier, corresponding to the difference between this threshold and the respective consumer costs. The respective consumer surpluses (CS) can be expressed as follows:

$$
\begin{aligned}
\textit{Base-load } CS &= 0 \\
\textit{Peak-load } CS &= \begin{cases} \frac{1}{2}\left(d_2 - d_1\right)\left(\tau_s - 2\,\tau_c\left(m-1\right) - b\left(d_2 - d_1\right)\right) & \text{for } m \leq \underline{m} \\ 0 & \text{for } m > \underline{m} \end{cases}
\end{aligned}
\tag{2.16}
$$

In Figure 2.4, which plots the derived surplus and welfare functions of the respective agents in the model, the development of consumer surplus in the identified multiplier domains can be seen. Base-load consumers do not earn a surplus with increasing m since their overall costs are not affected by m due to the average prices being constant and their demand being inelastic. For peak-load consumers, in contrast, total costs depend on m as more gas is bought in t_2 than in t_1. Therefore, when prices in t_2 increase and prices in t_1 decrease with the same magnitude, despite the average price remaining constant, overall consumer costs increase. Hence, when P_{B2} is highest (i.e. $m > \underline{m}$) consumers do not earn any surplus. Consumer surplus is greatest, when P_{B2} is lowest (i.e. $m = 1$).

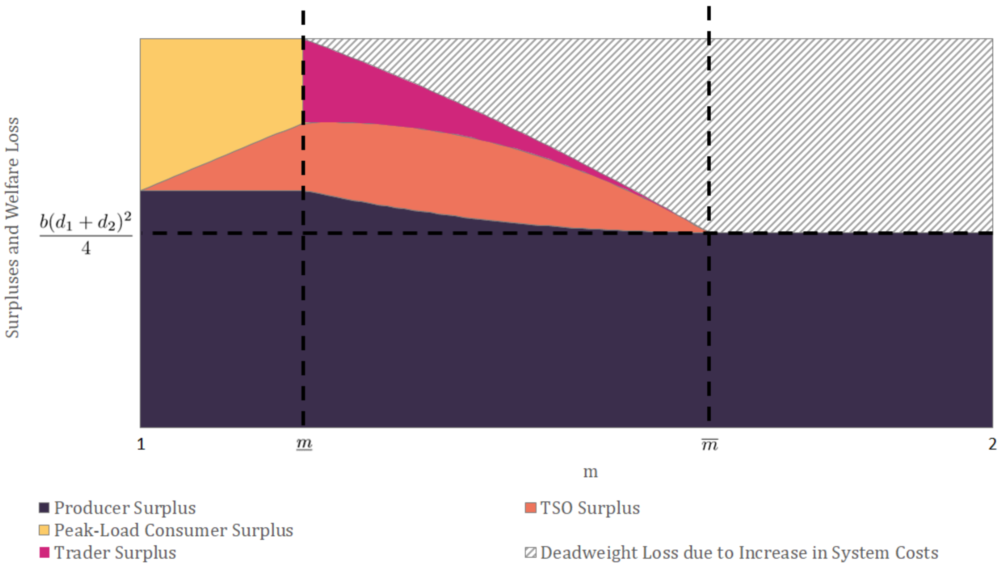


Figure 2.4.: Producer, trader, consumer and TSO surpluses, and deadweight loss with respect to m

Producer surplus

Producers earn a surplus by selling their gas for a price which is higher than their marginal costs. Producer surplus occurs since marginal costs increase in procured volumes in the model setting, which is representative of the real cost structures for the producers. The resulting surplus thus equals:

$$Producer\ Surplus = \begin{cases} \dfrac{b\left(d_1^2 + d_2^2\right)}{2} & \text{for } m \leq \underline{m} \\ \dfrac{b\left(d_1 + d_2\right)^2}{4} + \dfrac{\left(2\tau_c\left(m-1\right) - \tau_s\right)^2}{16b} & \text{for } \underline{m} < m < \overline{m} \\ \dfrac{b\left(d_1 + d_2\right)^2}{4} & \text{for } m \geq \overline{m} \end{cases} \tag{2.17}$$

Producer surplus is highest when $m < \underline{m}$ and lowest for $m \geq \overline{m}$. For multipliers lying in the interval $\underline{m} < m < \overline{m}$, producer surplus decreases with m. This is because profits depend exponentially on sold volumes per period, and as such, producer surplus decreases as sold volumes in t_1 and t_2 converge to the same value.

TSO surplus

The TSO receives revenues from the capacity products booked by the traders. We assume the TSO's revenues to be sufficient to cover costs in a setting without multipliers (i.e. $m = 1$) and any increase in the multiplier level can therefore result in surplus revenues. The resulting surplus can then be expressed as follows:

$$TSO\ surplus = \begin{cases} \tau_c\left(d_2 - d_1\right)\left(m-1\right) & \text{for } m \leq \underline{m} \\ \dfrac{\tau_c\,\tau_s\left(m-1\right)}{2b} - \dfrac{\tau_c^2\left(m-1\right)^2}{b} & \text{for } \underline{m} < m < \overline{m} \\ 0 & \text{for } m \geq \overline{m} \end{cases} \tag{2.18}$$

When $m = 1$ or when solely LT capacities are booked, i.e. $m \geq \overline{m}$, the TSO does not earn a surplus. Between those thresholds, the TSO surplus follows a concave form and reaches its maximum at $m = 1 + \frac{\tau_s}{\tau_c}$, as can be seen in Figure 2.4. The path of the surplus function is based on the combination of two effects: Firstly, the TSO's income increases with increasing m directly due to ST capacity becoming more expensive—an effect that exists for all $m > 1$. Secondly, as traders increasingly shift their bookings from ST to LT capacity with increasing m, the additional revenue generated by the TSO due to more expensive ST capacities is reduced. This effect emerges when m reaches $\underline{m}$, as the storages become utilised and switches from ST to LT booking start to take place. For $m < 1 + \frac{\tau_s}{\tau_c}$, the first effect is more dominant; while for larger values of m, the second effect dominates.

Storage operator surplus
Storage operators do not earn any surplus under perfect competition as they are assumed to have constant marginal costs.

Trader surplus
Surplus of the traders equals the difference of consumer prices and costs of gas provision (i.e. sum of procurement, transport and storage) which is equal to:

$$Trader\ surplus = \begin{cases} \dfrac{\big(\tau_s - 2\,\tau_c\,(m-1)\big)^2}{8\,b} & \text{for } \underline{m} < m < \overline{m} \\ 0 & \text{otherwise} \end{cases} \tag{2.19}$$

Traders start making surplus when the multipliers cross the $\underline{m}$ threshold. This is because storages become part of the optimal solution. The utilisation of storages creates markups of $\frac{\tau_s}{2}$ in the peak period (t_2) and markdowns of $\frac{\tau_s}{2}$ in the off-peak period (t_1). Since sold volumes in t_2 are higher, a profit is generated. However, as storage utilisation increases with increasing m, this results in higher storage costs and subsequently diminished profits. Traders also bear the additional ST capacity costs arising from increased multipliers, which further reduce the trader surplus.

Welfare
Having derived the individual surplus functions of all the relevant agents of the model, we now derive the total welfare function. Total welfare corresponds to the sum of consumer, producer, TSO, and trader surplus. This equals:

$$Welfare = \begin{cases} \dfrac{(d_2 - d_1)\,\tau_s}{2} + b\,\big(d_1\,d_2\big) & \text{for } m \leq \underline{m} \\ \dfrac{b\,(d_1 + d_2)^2}{4} + \dfrac{(\tau_s - 2(m-1)\,\tau_c)(3\tau_s + 2(m-1)\,\tau_c)}{16\,b} & \text{for } \underline{m} < m < \overline{m} \\ \dfrac{b\,(d_1 + d_2)^2}{4} & \text{for } m \geq \underline{m} \end{cases} \tag{2.20}$$

Welfare is maximal when the gas dispatch is not distorted by transmission tariffs. In our model with perfectly inelastic consumer demand, efficient outcomes with maximal welfare are achieved for $m < \underline{m}$ in the case where $\underline{m} \geq 1$ (plotted in Figure 2.4), or for $m = 1$ if $\underline{m}$ does not exist in the feasible multiplier domain (plotted in Figure A.2 in Appendix A.4).[21] Note that the welfare being maximal when $m = 1$ is not surprising and can be considered as a trivial solution since the transport costs are not affected by multipliers.

As soon as $m > \underline{m}$, higher multipliers reduce welfare by causing additional costs, which occurs as a result of two opposing effects: On the one hand, since the total production cost function is quadratic, total costs of gas production decrease as gas is produced more evenly. On the other hand, total costs of storing gas increase. However, as the increase in storage costs is higher than the decrease in production costs, welfare declines with increasing m. Welfare becomes independent of the multiplier when the multiplier reaches the threshold $\overline{m}$ as gas production in t_1 and t_2 fully converges.

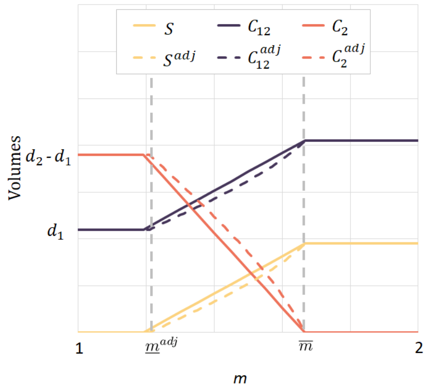
2.3.4. The regulated TSO: transmission tariff adjustment

We have shown that the TSO makes a surplus as long as $m > 1$ and the traders book ST capacity when $m < \overline{m}$. In reality, being natural monopolies, TSOs are regulated entities and are not allowed to exceed certain revenue caps. Hence, in the case of a potential surplus due to multipliers, the TSO would have to lower its transmission tariffs (i.e. entry/exit tariffs) accordingly for the next year in order to remain at the regulated revenue cap. In this model extension, we consider this aspect by introducing the adjusted transmission tariff τ_c^{adj} which is set such that the TSO surplus is zero for all m. Since τ_c^{adj} is only a parameter for the agents of our model and does not change the nature of the problem; the optimisation rationale of the agents remains the same as in our main model.

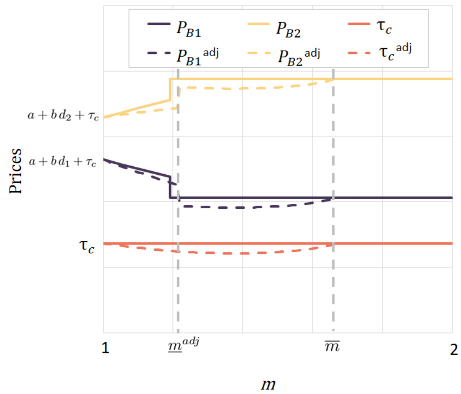
We find that the results with adjusted transmission tariff τ_c^{adj} are similar to the model results with fixed τ_c. All the general findings regarding the effect of m on volumes and prices and price spreads remain intact. The lowered τ_c^{adj} slightly increases $\underline{m}$, the multiplier threshold which is sufficient to incentivise the use of storages. The upper threshold $\overline{m}$ remains unchanged. We define this adjusted threshold as $\underline{m}^{adj}$. Plotting the capacity and storage volumes resulting from adjusted tariffs in Figure 2.5a, we see that adjusting the transmission tariff also slightly increases ST capacity bookings, decreases LT bookings, and as a

[21] According to economic theory, when consumers' demand is elastic, variable transmission tariffs to cover fixed network costs reduce welfare since they reduce consumers' demand. Such variable costs arise in the entry-exit system independent of the level of multipliers. To achieve more efficient outcomes in the presence of elastic demand, other tariff regimes (e.g. fixed grid fees) may be more appropriate (Borenstein, 2016).

consequence, results in lower utilisation of storages for $\underline{m}^{adj} < m < \overline{m}$. New hub prices as a result of adjusted tariffs are plotted in Figure 2.5b. The average regional price spread still equals the transmission tariff. However, since τ_c^{adj} is lower than τ_c for $1 < m < \overline{m}$, tariff adjustment leads to lower average regional price spreads for $m > 1$. The price spreads are lowest for $m = 1 + \frac{\tau_s}{\tau_c^{adj}}$. Similarly, the lowered transmission tariff translates directly to lower gas consumer prices, hence the average prices are also lowest at $m = 1 + \frac{\tau_s}{\tau_c^{adj}}$.



(a) Volumes



(b) Prices and average regional price spread (τ_c^{adj})

Figure 2.5.: Volumes and prices when τ_c is adjusted such that the TSO does not earn a surplus

The surpluses and welfare effects are plotted in Figure 2.6. When transmission tariffs are adjusted, the TSO does not earn a surplus anymore. The surpluses of traders and gas producer surplus are impacted very slightly. These effects result from the changes in the production pattern and storage volumes and not from a shift of the TSO's surplus. Instead, the tariff adjustment redistributes all of the surplus formerly earned by the TSO to the consumers. Base-load consumers, who did not earn any surplus when the tariff was fixed, earn a surplus with adjusted tariffs. In the domain $m < \underline{m}^{adj}$, the surplus of base-load consumers increases in m. In the domain $\underline{m}^{adj} < m < \overline{m}$, surpluses of both base-load and peak-load consumers increase in m for sufficiently low multiplier levels ($m < m^{CS,max}$) due to lower consumer prices resulting from decreased LT tariffs. This implies that if feasible $\underline{m}^{adj}$ does not exist due to tariff structures, a multiplier level equal to $m^{CS,max} = 1 + \frac{\tau_s}{\tau_c^{adj}}$ maximises the total consumer surplus (such a case is plotted in Appendix A.4). For $m > m^{CS,max}$, consumer surplus decreases with m due to increasing system costs. In the domain $m > \overline{m}$, consumer surplus is zero, which was also the case with fixed tariffs.

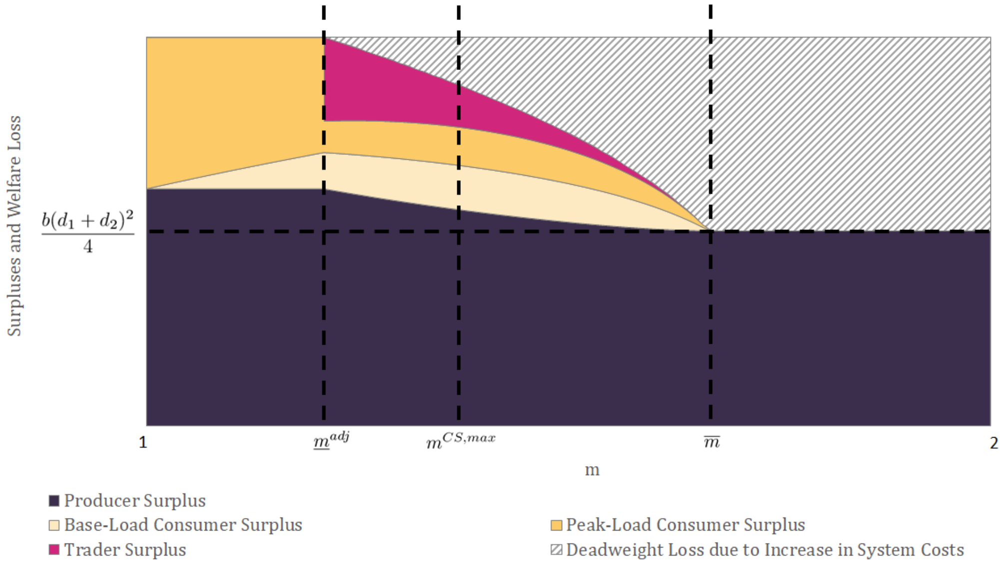


Figure 2.6.: Producer, trader, consumer and TSO surpluses, and deadweight loss with respect to m when τ_c is adjusted such that the TSO does not earn a surplus

2.4. Discussion

2.4.1. Effects on infrastructure utilisation

Multipliers, by making ST products comparably more expensive, can cause a switch from ST capacities to LT capacities, decrease the volatility of pipeline transports and consequently lead to more uniform capacity utilisation. These aspects associated with higher multipliers have also been mentioned in several studies related to the EU tariff structures (ACER and CEER, 2019, DNV-GL, 2018, EY and REKK, 2018, Rüster et al., 2012, Strategy& and PwC, 2015). We also find that gas storages can have increased utilisation rates with higher multipliers. However, these effects are not universal and strongly depend on the underlying tariff structures, i.e. occurring only when multipliers are neither too high nor too low with respect to the ratio of storage to transmission tariffs such that the capacity demand of the traders is elastic, meaning that the traders can switch between LT and ST products.

The proportions of these tariffs and multipliers constitute the multiplier thresholds (i.e. $\underline{m}$ and $\overline{m}$), which define domains with varying effects of multipliers. We find that multipliers equal to 1 or lower than the threshold $\underline{m}$ result in users to behave as if in a pure commodity pricing regime, while multipliers larger than $\overline{m}$ induce the same behaviour as observed in a pure capacity tariff regime. When multipliers are in between $\underline{m}$ and $\overline{m}$ an inherent mixed regime of capacity and commodity pricing occurs.

The multiplier domains identified by the theoretical model can also be observed in the EU gas markets. Depending on the circumstances, multipliers in the EU can lie in each of the domains identified by the model, their magnitude corresponding to values smaller than $\underline{m}$, higher than $\overline{m}$ or to those that lie in between.

The domain $m < \underline{m}$, for instance, represents a situation where storages are not used. This would occur when marginal storage costs are sufficiently high compared to m. Further, cross-border transports in each period match the corresponding demand. An utmost example, in this regard, would be the case of Finland where there are no gas storages and all of the gas was imported only from a single source until recently[22]; namely, Russia (Jääskeläinen et al., 2018). This implies infinitely large storage tariffs ($\tau_s \to \infty$) for Finland, irrespective of the existing multiplier levels in the country. Hence, any multiplier lies below the lower threshold $\underline{m}$.

Situations corresponding to the domain $m > \overline{m}$, on the other hand, occur when the transported volumes are constant and storages fill the gap between the demand and the imports instead. This would be observed when transmission capacity tariffs are sufficiently high with respect to the multiplier. Such instances can arise for pipelines that are consistently operated at their full capacities as this indirectly corresponds to transmission tariffs being infinitely high for marginal capacity demand ($\tau_c \to \infty$). Hence, any $m > 1$ would already be larger than the upper threshold $\overline{m}$.

In the majority of situations including connections between market areas, both pipelines and storages are utilised and neither of the two operate at their full capacity. These situations correspond to the $\underline{m} < m < \overline{m}$ domain where an inherent mixed regime of capacity and commodity pricing occurs, and as a result, the transmission capacity demand of traders is elastic. This is also valid for

[22] As of 1 January 2020, Finland is connected with Estonia via the Balticconnector pipeline (European Commission, 2020).

countries that apply multipliers equal to 1, where both LT and ST capacities are booked and storages are utilised (this implies feasible $\underline{m}$ does not exist).[23]

Even though we have implied here the possibility of directly observing those domains and their effects in the EU gas transmission system for various country pairs and pipelines, it is likely that a mixture of these effects would be prevalent in numerous regions. This is because all the analysed domains arise simultaneously within the EU and on its outer borders, and gas is often transported through several countries. On average, the aggregate effect on volumes, prices and, surpluses would likely be a combination of all of those domains for the EU.

2.4.2. Effects on hub prices

Regarding hub price levels in gas importing regions, model results have several implications: Temporal price spread increases with increasing m if storage utilisation is zero due to comparably high storage tariffs or unavailability of storage capacity (i.e. the domain $m \leq \underline{m}$). In such cases, higher multipliers can cause increased volatility in hub prices. In the case storages are utilised (i.e. the domain $m \geq \underline{m}$), then the storages dampen the effect on temporal price spreads.

Our analysis indicates that increasing multipliers can result in higher regional price spreads, since the upper limit of the spread is shown to be equal to the price of ST capacities ($m\,\tau_c$).[24] ACER refers to such a price spread ($m\,\tau_c$) as the "reference" regional spread (ACER, 2019a), implying that price spreads increase with increasing multipliers on average. In our model, in contrast, increases in spreads are only limited to temporal variations (i.e. increased volatility in spreads), while the average regional price spread remains equal to the transmission tariff (τ_c). This is because the marginal demand is satisfied by LT capacity. In reality, uncertainty as well as frictions in the secondary market for capacity may require the booking of ST capacity to satisfy marginal demand in some situations. As a result, average price spreads are likely to be between LT and ST capacity tariffs.

Whether multipliers increase or decrease regional price spreads also depends on the effect of multipliers on the LT tariff. In our model extension in Section

[23]A corresponding example is the case of Germany during the period 2012–2015 before the introduction of the BEATE regulation. More information can be found in the resolutions BK7-10-001 and BK9-14/608 of the German regulatory agency Bundesnetzagentur.

[24]Applies to uncongested pipelines.

2.3.4, which takes into account transmission tariff adjustments by the TSO, we have shown that increases in m allow the TSO to reduce the tariff (τ_c^{adj}) if multipliers are sufficiently low ($m < \frac{\tau_s}{\tau_c^{adj}}$), an aspect also mentioned in several consulting studies (Rüster et al., 2012, Strategy& and PwC, 2015). Therefore, increases in m can both decrease average hub prices and average regional price spreads, which were shown to depend on the transmission tariff. This is an aspect, which studies such as ACER (2019a) and EY and REKK (2018) apparently do not consider when stating that increases in multipliers are likely to increase regional price spreads. By reducing LT tariffs, sufficiently high multipliers may also help support tariff stability by mitigating the tariff increase which is expected to occur when historical LT bookings expire (ACER, 2019a).[25] However, if policymakers set multipliers too high such that they discourage traders from booking ST capacities, we have shown that increasing m elevates the transmission tariff and prices.

2.4.3. Effects on surpluses and welfare

Model results show that the lowest total system costs and correspondingly the highest total welfare are associated with lower multipliers. This is because higher multipliers cause the gas dispatch to deviate from an ideal dispatch based on short-run marginal costs. Nevertheless, the notion that an increase in m always results in higher system costs and lower welfare does not universally apply, but is highly dependent on which domain the system lies in (i.e. the ratio of storage to transmission tariffs with respect to multipliers).

For the identified domain without storage utilisation ($m < \underline{m}$), an increase in m does not cause additional system costs and no consequent welfare losses, as the transported volumes are fixed and independent of m. Similarly, producer surplus remains constant due to fixed volumes. Because storage utilisation is zero in this domain, traders do not make any surplus as they cannot exploit the intertemporal arbitrage potential. Consumer surplus, on the other hand, decreases with increasing m and is passed on to the TSO as a surplus unless the transmission tariffs (τ_c) are adjusted. In the case where the tariffs are adjusted

[25] For instance, during the period 2016–2018, about 80% of the total capacity used by traders stemmed from existing LT bookings which were undertaken before ST capacities were introduced (ACER, 2019a), the majority having been booked upfront covering multiple years. As those old bookings start expiring during 2020–2030, the prevalent situation of overbooked capacities and the sunk costs associated with them will start disappearing such that the cost of new bookings will represent the actual opportunity costs (EY and REKK, 2018).

such that the TSO does not make surplus (i.e. no additional TSO revenue than the regulated amount), higher multipliers cause consumer surplus to be redistributed from peak-load consumers (i.e. households) to base-load consumers (i.e. industry). This finding is in line with the implications stated by Strategy& and PwC (2015) and DNV-GL (2018).

We have also shown that sufficiently high multipliers ($m > \overline{m}$) are associated with higher total system costs and lower total welfare. In this setting, the surpluses of the consumers, traders and the TSO are all zero while only the producers make a constant surplus.

In the domain where storages are utilised and both ST and LT products are booked ($\underline{m} < m < \overline{m}$)—a case which is likely to be present in the majority of EU countries—increasing m results in increased system costs and decreased welfare. Trader surplus exists in this domain. However, it decreases exponentially with increasing m as gains by intertemporal arbitrage are reduced due to higher storage utilisation and the respective convergence in gas prices in the production region. The same effect causes the producer surplus to decrease as well. This also offers an explanation why gas traders such as Uniper SE and Gazprom Export and gas producers such as Shell Energy request low multipliers in their statements during the multiplier consultations (BNetzA, 2019).

TSO makes surplus for $m > 1$ if the transmission tariff is not adjusted. For multipliers that are sufficiently low ($m < 1 + \frac{\tau_s}{\tau_c}$), the TSO surplus increases initially with increasing m due to the additional revenue from ST products. As TSOs may be able to retain at least some of this surplus, they have an incentive to request higher multipliers than traders and producers do. Something which can be observed in the consultation statements of TSOs such as Open Grid Europe, Bayernets, ONTRAS (BNetzA, 2019). When the transmission tariff is adjusted for zero TSO surplus, then the surplus is passed on to the consumers due to lower hub prices.

The results also indicate that for the domain where the capacity demand of traders is elastic and which is representative of the majority of the situations observed in the EU, there exists a multiplier larger than 1 that maximises consumer surplus (i.e. $m = 1 + \frac{\tau_s}{\tau_c^{adj}}$).

This presents us with an interesting trade-off: Minimising total system costs and maximising total welfare in the short-run requires setting the multiplier equal to 1. However, a policymaker willing to maximise consumer surplus would aim for a multiplier greater than 1 but sufficiently low. Furthermore, higher multipliers may enhance security of supply due to increased storage utilisation and potentially resulting in storage investments. Since higher multipliers are more in line with peak-load pricing, and thus help decrease the peak-load capacity demand, the policymaker may also prefer higher multipliers to reduce the need for capacity expansion and to increase long-term efficiency.

We assume demand to be perfectly inelastic, although one could argue that the gas demand from power generation has a certain elasticity due to fuel switching between gas and coal plants. This could have the following effects. As we have shown, multipliers larger than 1 decrease average prices and thereby would increase demand and consumer surplus if overall demand was elastic. On the other hand, if only peak demand was elastic, peak prices may increase, which would decrease demand and consumer surplus.

We should note that the assumption of perfectly efficient secondary markets is relevant when interpreting our model results regarding welfare. The importance of developed and liquid secondary capacity markets for efficient explicit auction mechanisms is highlighted in the literature (Kristiansen, 2007, Oren et al., 1985, Peŕez-Arriaga and Olmos, 2005). Secondary markets allow traders to exchange booked capacities, enabling them to adjust their commercial positions (Peŕez-Arriaga and Olmos, 2005) and balance their marginal benefits (Oren et al., 1985). Therefore, an imperfect secondary market can hinder the exchange of some booked LT capacities and can lead to instances of contractual congestion[26], even if sufficient technical capacity is available to meet the demand. In such a situation, some traders waste their capacity rights, whereas other traders, whilst having positive capacity demand, are not able to book capacities—a phenomenon that consequently results in underutilised pipelines and inefficient dispatch. As such, Hallack and Vazquez (2013) argues within the context of the EU entry-exit tariff system that secondary markets help relieve contractual congestion. We have shown that the ratio of LT bookings increases with increasing multipliers. Therefore, in the case where secondary markets for gas transmission capacities in the EU are not efficient, higher multipliers could cause additional welfare losses due to more frequent instances of contractual congestion, a view shared also in several technical reports (Rüster et al., 2012, Strategy& and PwC, 2015). Hence, in order to

[26]Contractual congestion means a situation where the level of firm capacity demand exceeds the technical capacity of a pipeline.

minimise those additional welfare losses, policymakers should further promote efficient secondary markets.

2.5. Conclusion

In this paper, we take a theoretical perspective on the effects of multipliers on gas infrastructure, hub prices and welfare. The model developed for this purpose depicts a setting of perfect competition and is solved analytically by minimising total costs using KKT conditions. The effects of multipliers are then derived from the various solutions to the problem.

Our model results indicate that higher multipliers can cause a switch from short-term (ST) transmission capacity bookings to long-term (LT) bookings, lead to more uniform pipeline transports, and increase gas storage utilisation. In the majority of countries and situations these findings are expected to hold. However, the effects are not universal and are found to depend on the traders' elasticity of capacity demand. Depending on the proportion of multipliers with respect to storage and transmission tariff levels, situations with inelastic capacity demand can arise. It is possible when multipliers are sufficiently low with respect to the tariffs, gas storages are not utilised in the context of capacity bookings. On the other hand, multipliers that are considerably high can cause only LT capacities to be booked.

Regarding the effects of multipliers on hub prices, we find that higher multipliers cause maximum regional price spreads to increase, indicating that they can result in increased volatility in regional price spreads. However, on average, we show that hub prices and regional price spreads can decrease with increasing multipliers, as long as multipliers remain sufficiently low. These effects occur since higher multipliers allow the TSO to lower the transmission tariffs.

Model results show that higher multipliers are associated with higher total system costs and consequently lower total welfare in the short-run. Despite that, for the identified multiplier domain, which is representative of the majority of the situations in the EU gas system, our results indicate that the multiplier maximising total consumer surplus is larger than 1.

Our findings have various policy implications: Setting the multipliers equal to 1 minimises total costs of gas dispatch and thereby maximises total welfare.

However, if the aim of the policymakers is to maximise consumer surplus, then opting for multipliers that are greater than 1 but are still sufficiently low can help in achieving the desired outcome. Moreover, a multiplier greater than 1 would lead to redistributing the consumer surplus from peak-load consumers to base-load consumers, if that is desired. In that sense, higher multipliers can also help reduce peak load and therefore result in potential welfare gains in the long-term due to a decreased need for new capacity investments. Since we have shown that higher multipliers cause increased storage utilisation, it could be argued that setting multipliers sufficiently high can also contribute to security of supply by incentivising additional storage investments. Multipliers that are considerably high, however, increase regional price spreads and undermine market integration; and if sufficiently high, can cause only LT capacities to be booked, potentially impeding efficient gas dispatch.

We have shown that optimal level and thresholds for multipliers depend on the level of transmission and storage tariffs. Therefore, it is important to consider the existing tariff structures when setting multipliers. As the current EU tariff landscape has significant variation in tariff structures and levels, this implies a one-size-fits-all approach with a single uniform EU multiplier may not lead to optimal outcomes for individual countries. We therefore find it appropriate that EU regulation specifies the allowed multiplier levels in ranges and not in absolute values. Nevertheless, whether the specified range covers the optimal levels or is too restrictive remains to be researched.

In future work, the model can be applied in a real-world setting by incorporating more time periods and a realistic network structure representative of the EU gas transmission system. The extended model can be used to quantify the effects of multipliers with numerical simulations. This would allow to analyse the effects of regional variations in multiplier levels throughout the EU. An interesting aspect in this case would be to evaluate whether optimal multipliers for individual countries are also optimal for the overall EU system, or whether they cause negative externalities on other countries. Another possibility would be to extend the model by including stochasticity regarding capacity demand in order to represent the realistic situation of imperfect information and uncertainty.

3. Internal and External Effects of Pricing Short-Term Gas Transmission Capacity via Multipliers

In the European Union's (EU) gas transmission system the relative prices of short-term transmission capacities are specified via factors called multipliers. Previous literature indicates that, depending on the region, there exist optimal multiplier levels that can allow transport tariffs to be reduced and consumer surplus to be maximised. However, since multiplier levels in a region can cause externalities in other regions, it is not clear if individually optimal multipliers in regions would also lead to a joint optimum. In order to provide insight into optimal multiplier levels in different regions in the EU we use a numerical optimisation model to simulate the European gas dispatch. We analyse the effects of multipliers in regional clusters; identify and differentiate between internal and external effects. We show that those effects and the individually optimal multiplier levels vary among regions depending on factors such as demand structure and storage availability. Our analysis confirms that individually adjusting multipliers in a region can cause external effects in other regions, depending largely on the location along the gas transport chain. With 92 million EUR per year, the potential EU consumer surplus gains with individually optimal multipliers is found to be 9% lower than the maximum achievable EU consumer surplus gains via multipliers. Hence, we show that because of the external effects of multipliers, individually optimal multipliers do not result in the EU optimum.

3.1. Introduction

When a region decides on network pricing, different circumstances lead to different optimal tariff settings. In this context, two questions arise in particular: First, how does the optimal tariff setting vary among different regions? And second, because networks connect multiple regions, do the individual regional optima contribute to the joint optimum or do they cause negative externalities such that only a superordinate regulator can achieve the joint optimum?

These questions also arise in the case of the gas transmission network of the European Union (EU), which connect different regional networks called market areas. To finance the networks in the individual market areas the transmission system operators (TSO) charge transmission tariffs. Regulation (EC) 2009/715 introduced a tariff regime that obligates gas traders to book entry and exit capacity when transporting gas from one market area into another.[1] In this context, traders are offered capacity products with varying run-times: long-term (LT) yearly products, and the short-term (ST), quarterly, monthly, daily, and intra-daily products. Regulation (EC) 2009/715 allows each national regulator to define their relative price of ST versus LT capacities within specified ranges. The relative prices of the ST capacities are defined by factors called multipliers, i.e, the ST capacity prices are equal to the LT capacity price multiplied by the corresponding multipliers. The levels of those multipliers are found to affect the proportion of ST to LT capacity booking and consequently impact the infrastructure utilisation, prices, and welfare distribution (Çam and Lencz, 2021b).

The effects of multipliers in the EU gas system are expected to become more amplified in the coming decades. A major contributor in this regard will be the expiration of old long-term bookings.[2] For instance, between 2016 and 2019, about 80% of the total capacity used by traders stemmed from existing long-term bookings which were undertaken before the current system of LT and ST capacities were introduced (ACER, 2020b). For some connections between market areas these old long-term bookings exceeded the demand for capacity, inducing marginal transmission costs of zero. As those old bookings are about to expire over the period 2020–2035, the prevalent situation of overbooked capacities, and the sunk costs associated with them, will start disappearing.[3] In

[1] Capacities are booked in capacity auctions performed on trading platforms (such as PRISMA, GSA, RBP) in which the reserve prices correspond to the transmission tariffs. In a large share of the capacity auctions in the EU, demand for capacity remains below the offered capacity (ACER, 2019c). In the remaining cases where demand for capacity exceeds the offered capacity, a congestion premium occurs.

[2] A large share of current transmission capacity is booked by previous LT bookings at a time when ST capacity products did not exist. Those long-term bookings covered usually multiple years upfront.

[3] ACER (2020b) states that more than a third of such old long-term capacity bookings in place at the end of 2019 will have expired by the end of 2023, while more than 60% of them will no longer be in place by 2028. Old long-term contracts will almost completely expire by the end of 2035.

the future, the cost of new bookings will represent the actual opportunity costs, a development that is also mentioned in a study commissioned by the EU on gas market design (EY and REKK, 2018).

Our paper is strongly motivated by Çam and Lencz (2021b), which has analysed the effects of multipliers on gas infrastructure utilisation, prices, and welfare using a theoretical model within a stylised setting. Applying the stylised theoretical model with two time periods and two regions, where pipeline and storage capacities were assumed to be unlimited, Çam and Lencz (2021b) showed that a multiplier value of 1 leads to highest total welfare and multipliers greater than 1 cause welfare loss. The paper found that higher multipliers can nevertheless maximise the consumer surplus depending on the cost of gas transport and storage. This indicates that the consumer-surplus-maximising multiplier levels can differ between individual regions. In this respect, it is plausible to assume that EU would rather aim to maximise the consumer surplus instead of total welfare, since a substantial share of the surpluses generated by producers, storage operators, and traders arise outside the EU. Hence, we refer to consumer-surplus-maximising multipliers as optimal multipliers.

In a more complex setting with multiple time periods, multiple regions and limited infrastructure capacities—such as in the case of the EU gas transmission system—there are additional aspects that would influence the optimal multiplier levels. For instance, the temporal profile of gas demand in a region could substantially influence the proportion of LT to ST bookings. In countries that have relatively flat demand profiles throughout the year, gas imports and bookings would be at similar levels during winter and summer, allowing for a very high share of LT bookings. In this case, effects of multipliers can be limited if LT bookings are preferred irrespective of the multiplier levels. In contrast, in regions with highly seasonal demand but limited storage capacities, booking ST capacities could be preferred. With sufficiently high multipliers, booking ST capacities to cover the peak winter demand could eventually become more expensive than booking only LT capacity. In this case, traders could choose to book only LT capacity while letting some capacity during the summer months remain unused. Multipliers could therefore exacerbate this type of booking patterns in such regions. Hence, due to having different features as mentioned above, individual regions can be affected differently by multipliers and can have varying optimal multiplier levels. In order to determine the individually optimal multiplier levels, it is necessary to represent these regional features and analyse the internal effects of multipliers in a more realistic model setting.

In addition to inducing internal effects, multiplier levels in a region can cause externalities in other regions due to the fact that gas is transported through different regions. It is commonly acknowledged that tariff adjustments in a country can cause external effects in another country within the EU gas network, depending on their location along the gas transport chain. For instance, Cervigni et al. (2019) points out that national regulators can impact the sharing of transport costs between the consumers of individual countries through their selection of entry and exit tariff levels. It is argued that a transit country can transfer the cost of transmission investments, which largely benefit its own citizens, to a downstream country's consumers via its choice of entry-exit tariffs at the interconectors. Similarly, Petrov et al. (2019) mentions that the tariff adjustments in Germany (in the context of the REGENT regulation) can cause significant costs in the neighbouring market areas of Czechia and Italy when the costs of the network tariff change are passed on to the gas consumers in these regions. Since multipliers influence the relative tariff levels of ST capacities, it is therefore natural to think that they can also cause external effects. Therefore, it is not clear whether a multiplier level that is optimal for a region would also be optimal for the whole system. If not, then the question arises whether the individual multipliers should rather be set by a superordinate regulator. These questions can be answered by analysing the external effects of multipliers in a more realistic model setting that considers the spatial characteristics of the gas network.

In order to identify the internal and external effects of multipliers in different regions in the EU, and to provide insight into optimal multiplier levels, we use for our analysis the numerical simulation model, TIGER.[4] The TIGER model optimises the gas dispatch in Europe under perfect foresight and perfect competition. We extend the model by including the costs of capacity booking and specifying the necessary restrictions. The model has a monthly temporal resolution, where yearly, quarterly, and monthly capacity products are offered. Six regional clusters of countries are considered: Central Europe, British Isles, South East Europe, Italy, Iberia, and Baltics. The aggregation of countries takes into account the geographical location of individual countries, existence of interconnecting pipelines, and at what stage a country lies in the gas transport

[4]A detailed formulation of the model can be found in Lochner (2012).

chain (i.e. transit, downstream or peripheral). We simulate the gas dispatch for the gas year of 2017–2018 and analyse and quantify the effects of the multipliers on infrastructure utilisation, prices, and welfare distribution.

We identify significant regional effects with regards to multipliers. Our analysis shows that in regions characterised by relatively flat gas demand profiles (such as Spain and Portugal), multipliers do not have notable effects, as LT capacities are preferred irrespective of the multiplier levels. In contrast, in regions that have a highly volatile demand but limited supply flexibility via storages (e.g. Britain), multipliers can have a strong impact on the base and peak prices, as they determine the marginal supply costs. Therefore, when specifying multipliers in such regions, regulators would also have to consider the strong distributional effect on the allocation of consumer surplus between the base and peak consumers.

We find that adjusting multipliers in a region can cause external effects in other regions. Consumer surplus gains in transit regions (e.g. Central Europe) due to multipliers are passed on to regions that lie downstream (e.g. Italy). We show that downstream regions can influence the transit regions indirectly by affecting the storage utilisation in the transit regions. Peripheral regions (e.g. South East Europe), which receive their gas directly from the production regions, can also influence other regions by affecting procurement prices in the production regions. Because of those external effects of multipliers, we find that individually optimal multipliers do not lead to the maximum total EU consumer surplus. Despite that, when comparing the gains in consumer surplus from applying multipliers, individually optimal multipliers result in about 12% higher consumer surplus gains in the EU compared to an optimal uniform EU-wide multiplier level. Hence, the current EU regulation of specifying allowed multipliers in ranges instead of absolute values is appropriate and can increase the EU consumer surplus. However, we show that the surplus gains achieved by individually optimal multipliers are about 9% lower than the maximum achievable EU consumer surplus gains by multipliers. This indicates that letting national regulators set the multipliers may not lead to an EU optimum.

Our paper is related to two streams of literature. The first relevant literature stream includes the analysis or modelling of capacity bookings in the European gas markets. Keller et al. (2019) analyses historical capacity bookings in German gas market areas. Using historical data from the PRISMA capacity booking platform for the year 2016, the paper shows that network users make efficient booking decisions and choose transport alternatives with the lowest tariffs. Grimm et al. (2019) presents a mathematical framework depicting the entry-exit gas markets. The paper shows that, under perfect competition, the booking and nomination decisions can be analysed in a single level and that this aggregated market level has a unique equilibrium. Dueñas et al. (2015) develops a combined gas-electricity model, which simulates the gas procurement and capacity booking of a gas-fired generation plant under residual demand uncertainty. The analysis shows that the capacity booking behaviour of the individual generator is significantly affected by how risk-averse it is.

The second relevant stream of literature analyses gas markets using numerical simulations based on cost minimisation models. It is common within this literature stream to analyse the effects of various developments on the gas infrastructure, identify possible bottlenecks and simulate potential effects on prices. In this context, previous versions of the TIGER model are applied to address various questions (Dieckhöner, 2012, Dieckhöner et al., 2013, Lochner, 2011a,b, 2012). Dieckhöner et al. (2013) for instance simulates the European gas dispatch under different scenarios and analyses the level of market integration and potential congestions. Using a similar model, Hauser et al. (2019) investigates whether increasing natural gas demand in the power sector could cause congestions in the German gas grid. Eser et al. (2019) combines a Monte-Carlo simulation model for annual gas sourcing with a cost minimisation model that optimises the detailed hourly gas dispatch.

The contribution of our paper with regards to the above-mentioned literature can be summarised as follows: The capacity booking system and the effects of multipliers have not been yet analysed in the literature using numerical simulation models of gas dispatch. Thus, by integrating capacity booking into a cost minimisation model and simulating the European gas dispatch, we show that the level of multipliers can significantly impact infrastructure utilisation, prices, and welfare distribution. We identify and differentiate between internal and external effects of multipliers over a range of regional clusters, and provide insight into those effects that influence the optimal multiplier levels in the EU.

3.2. Identifying the main drivers

When a region adjusts its multipliers, it can affect the gas dispatch, regional prices and welfare within that region. This is shown by Çam and Lencz (2021b) using a stylised model containing one demand region and two periods. The paper also finds that optimal multiplier levels for maximising consumer surplus can vary depending on the storage and transport costs. In addition, demand structures among regions vary, which can also play an important role on the effects of multipliers. It is therefore natural to assume that different regions could be affected differently from multipliers and would have varying optimal levels of multipliers. However, it is not clear if individually optimal multipliers would also be optimal for the whole system, since multipliers can additionally cause external effects. This would imply that the adjustment of multipliers in one region can affect market results in other regions. In this section, building upon the theoretical findings of Çam and Lencz (2021b), we extend the discussion on internal effects of multipliers by highlighting several aspects which were not considered in that paper. We then present some intuition on the potential external effects of multipliers.

3.2.1. Internal effects of multipliers

A multiplier value of 1 results in a pricing regime similar to commodity pricing. In this case, traders, who transport gas from one market area into another, would book a combination of ST capacities that would perfectly satisfy their demand profile and pay for the exact amount of volumes they transported.[5] Higher multipliers incentivise traders to avoid ST capacities, encouraging them to book yearly (LT) capacities and flatten their winter and summer transports by increasingly storing gas in the demand regions. When multipliers reach a certain threshold, traders book solely LT capacity and behave as being exposed to a capacity pricing regime, irrespective of the costs of LT capacity and storage. Applying this finding from Çam and Lencz (2021b) to the twelve-period model used in our current analysis, such multipliers are found to be 4 for quarterly and 12 for monthly capacity (see Lemma 1 in Appendix B.1 for proof).

Çam and Lencz (2021b) shows that, due to the relative costs of transmission and storage, in the majority of the situations already lower multipliers can induce a capacity pricing regime. This means that traders would book only LT capacity to cover their yearly peak demand, resulting in them paying for the

[5]Multiplier levels below 1 would neither change the optimisation rationale of the traders nor the market results (see Çam and Lencz (2021b) for a more detailed discussion). For this reason, and since the EU regulation NC TAR 2017 does not allow for multipliers below 1, the minimum multiplier value considered in this paper is equal to 1.

capacity rather than the energy.[6] When only LT capacity is booked, increasing the multipliers does not affect market results. This is because LT tariffs are not affected since TSO revenues remain unchanged.

According to Çam and Lencz (2021b), multipliers also affect gas prices, which in turn impact overall consumer surplus as well as its distribution among base and peak consumers. In this case, the minimum demand level is assigned to base consumers, which is constant throughout the considered time periods. Any demand that is above this minimum level is then defined as peak demand and is attributed to peak consumers.

When storage capacity is abundant, gas prices are affected by the LT transmission and storage tariffs. When multipliers are increased, TSOs can charge higher tariffs for ST capacity, allowing them to reduce the price for LT capacity. Thereby, gas prices decrease such that peak and base consumers profit. However, this effect is counteracted by bookings shifting from ST towards LT capacity. When supply flexibility from storages is restricted, Çam and Lencz (2021b) finds that peak prices are determined by the price for short-term capacity. Hence, with increasing multipliers, peak prices increase. Off-peak prices on the other hand are found to decrease, reinforcing the distributional effect between base and peak consumers.

The above-mentioned findings are derived from the analysis presented in Çam and Lencz (2021b), which uses a stylised theoretical model with two regions and two time periods. However, additional internal effects with respect to multipliers are to be expected in a more complex setting with multiple regions, multiple time periods, and more than one type of ST capacity product—such as in the case of the EU. It is to be expected that in regions with relatively flat demand profiles comparably less ST capacities would be booked, making the effect of multipliers limited. In contrast, in regions with volatile demand structures, multipliers would have a much higher impact on the proportion of bookings and, consequently, on the prices and welfare.

An additional effect that would be observed in a more realistic setting would be related to the costs of gas storages. Çam and Lencz (2021b) assumes constant storage costs for the stylised model. In reality, gas storages have varying operating costs depending on their physical characteristics (Neumann and Zachmann, 2009). With higher multipliers, as more of the storage

[6]For a more detailed discussion of capacity pricing and commodity pricing aspects of multipliers, please see Çam and Lencz (2021b).

capacities are used, the more expensive storage types would be utilised. This means that marginal cost of storage would increase, causing higher temporal spreads in regional prices. While increased spreads would not affect the overall costs for base consumers, peak consumers would end up paying more.

The fact that storage capacities as well as the injection/withdrawal rates are limited in reality, which were assumed to be unlimited in Çam and Lencz (2021b), can result in multipliers causing additional effects. When supply flexibility from storage capacities is exhausted, the seasonal spread in regional prices is not defined by the cost of storage, but by the cost of importing gas in the short term, which increases the temporal spread in prices even further. In such a setting, booking solely LT capacity while letting some seasonal capacity remain unused[7] can be optimal when multipliers reach a certain threshold (see Lemma 2 in Appendix B.1 for proof)—an effect which cannot be observed in the simplified two-period model with unlimited capacities. Overall, as outlined above, additional internal effects due to multipliers would be observed in a more complex setting.

3.2.2. External effects of multipliers

When regions adjust their multiplier levels they may also affect other regions. To what extent a multiplier adjustment would have an external effect largely depends on how a region is located along the gas transport chain. In this context, a region can be classified into one of the four region types, as schematically shown in Figure 3.1: production, transit, downstream, and peripheral. Gas is transported from a production region (e.g. Russia) through a transit region (e.g. Central Europe) to downstream regions (e.g. Italy). Countries which do not lie downstream of a transit region but receive their gas directly from the production region can be referred to as peripheral regions (e.g. Baltic countries). While a transit region imports and re-exports substantial amount of gas volumes, downstream and peripheral regions import but do not re-export significant volumes.

[7] Letting some booked capacity remain unused is also referred to as capacity wasting.

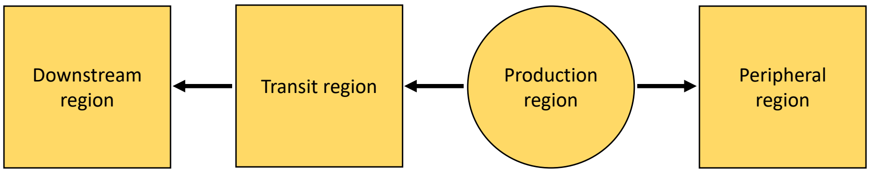


Figure 3.1.: Schematic representation of the types of regions

When traders transport gas through several borders, tariffs are accumulated, which is commonly referred to as tariff pancaking (EY and REKK, 2018). Due to pancaking, downstream regions are generally affected by the tariff structures and the ensuing effects over the whole transport chain. Therefore, price and welfare effects caused by changes in multiplier levels in transit regions would also likely be passed on to the connected downstream regions. Additionally, traders who want their gas to be shipped from a transit region to a downstream region have to procure capacity for exiting the transit region. Increasing multipliers in the transit region would therefore incentivise traders to book long-term and to flatten transports from the transit region to downstream regions. As a result, at what levels the multipliers are set in the transit regions can create direct external effects on the downstream regions. In contrast, any changes in multiplier levels in the downstream or peripheral regions would not have direct external effects on other regions, as changes in tariffs are not passed through to other regions. Nevertheless, it is possible that multiplier levels in any region can also cause external effects in other regions indirectly. By influencing the seasonal gas procurement patterns, multipliers can affect the temporal spreads in the regions where gas is imported from, as also shown in Çam and Lencz (2021b). This would in turn influence the price levels in other regions which import gas from the same region.

Due to the above-mentioned internal and external effects, it is likely that different regions in the EU could be affected differently from multipliers, hence having varying optimal levels of multipliers. Then the question arises whether the individually optimal multipliers would also be optimal for the whole EU, since countries individually specifying multipliers could cause externalities in other countries. In this paper, we aim to address these questions with the help of a gas dispatch optimisation model.

3.3. Methodology

3.3.1. Model

To analyse the effects of multipliers in the EU we apply and extend the TIGER model developed at the Institute of Energy Economics (EWI) at the University of Cologne.[8] TIGER simulates the gas dispatch in Europe in a setting with perfect competition and perfect foresight. The model is formulated as a linear optimisation problem with the objective function of minimising total system costs. It models the producers, consumers, traders and storage operators and includes the production capacities, demand regions, pipeline network, gas storages and LNG terminals.

The TIGER model is extended by including the costs of capacity booking in the objective function and specifying the necessary restrictions. A complete notation of the model extension is presented in Table 3.1.

Table 3.1.: Notation used in the TIGER model extension

Sets	$t \in T$	Points in time
	$i, j \in N$	Nodes in the pipeline network
	$p \in P$	Capacity products (defined by duration, start and end date)
Parameters	m_p	Tariff multiplier per capacity product
	$\tau_{i,j}$	Base entry/exit tariff
Variables	$C^{Tra}_{t,i,j,p}$	TSO revenue (Gas transport costs)
	$CB_{t,i,j,p}$	Booked capacities per product type
	$TR^{CB}_{t,i,j,p}$	Volumes transported per product type
	$TR_{t,i,j}$	Total volumes transported
	$CB^{Map}_{i,j,p}$	Capacity booking mapping parameter

The objective function corresponds to minimisation of total costs (C^{Tot}). Total costs are equal to the sum of production costs (C^{Pro}), transport costs (C^{Tra}), storage costs (C^{Sto}) and costs associated with LNG imports and

[8]For a comprehensive formulation of the model see Lochner (2012).

regasification (C^{LNG}).

$$\min C^{Tot} = C^{Pro} + C^{Tra} + C^{Sto} + C^{LNG} \tag{3.1}$$

Gas transport costs at time t from node i to j for a particular capacity product p equal the level of booked capacities $CB_{t,i,j,p}$ multiplied with the base entry-exit tariff $\tau_{i,j}$ and the corresponding product multiplier m_p. Like in the EU, traders have to procure entry and exit capacity when transporting gas between market areas where entry-exit tariffs are applied.[9] Furthermore, we assume storage operators to be fully exempt from transmission tariffs when withdrawing or injecting gas in the transmission network.[10]

$$C^{Tra}_{t,i,j,p} = CB_{t,i,j,p} \cdot \tau_{i,j} \cdot m_p \tag{3.2}$$

TSOs are regulated entities and are allowed certain revenue caps. If adjusting the multipliers causes the revenues of a TSO to change, then the TSO would adjust the entry-exit tariffs accordingly to reach the same revenue cap. This fact is considered in our analysis. As each TSO's revenue should be independent from the multipliers applied, the base entry-exit tariff $\tau_{i,j}$ has to be adjusted such that a TSO's revenue (C^{Tra}) for each entry-exit point remains constant. This results in a quadratic function that cannot be solved in a linear model. Therefore, an iterative approach is applied to solve the model. In the first run, the $\tau_{i,j}$ is kept constant, resulting in increased TSO revenue for high multipliers. In the next iteration $\tau_{i,j}$ is adjusted in order to reach the intended TSO revenue for each multiplier level. As the adjusted tariff levels may result in an adjusted booking behaviour, the procedure is repeated until the revenues of all TSOs equal the intended individual levels.[11]

[9]In the EU gas markets, traders are able to trade booked capacities in secondary markets. We assume in our analysis these secondary markets to be perfect. Therefore, under the model assumption of perfect foresight, the total booked capacities of individual traders would be identical to the booked capacities of a single competitive trader who faces the cumulative demand of all these traders. For a detailed discussion of secondary markets see Çam and Lencz (2021b).

[10]Storages are commonly exempted from transmission tariffs in the EU to a varying extent with the goal of inducing positive externalities such as reducing pipeline investment costs and increasing security of supply (ACER, 2019a). For example, several EU countries grant full exemption (e.g. Spain and Denmark). Storages are exempted by at least 50% due to NC TAR regulation in other countries; however, most countries apply higher exemptions (ENTSOG, 2019).

[11]Due to the convexity of the problem the converged solution is a global optimum.

Booked capacities at each entry-exit pipeline are required to be greater than or equal to the transported volumes associated with the particular capacity product (Equation 3.3). Each capacity product (e.g. quarterly capacity for October, November and December) is valid only in its dedicated time period. (e.g. $t = 1, 2, 3$). Therefore, for the model with monthly resolution, one yearly, four quarterly and twelve monthly capacity products are offered for each entry-exit point.

$$CB_{t,i,j,p} \geq TR^{CB}_{t,i,j,p} \tag{3.3}$$

To ensure that each capacity booking is booked with the same level of capacity for the whole period it is valid in, a mapping equation is introduced as in Equation 3.4. This equation forces the booked capacities ($CB_{t,i,j,p}$) to be equal to the same value for each t it is valid in.

$$CB_{t,i,j,p} = cb^{Map}_{i,j,p} \tag{3.4}$$

Finally, the physically transported volumes on a pipeline must be equal to the sum of flows per capacity products.

$$TR_{t,i,j} = \sum_{p} TR^{CB}_{t,i,j,p} \tag{3.5}$$

3.3.2. Assumptions and data

For the purposes of this paper, the TIGER model is adjusted with regards to its spatial resolution where six regions are considered in order to be able to identify robust regional effects. The regional aggregation takes into account the geographical location of individual countries, existence of pipelines between them and whether a country is transit, downstream or peripheral. A transit country imports gas from a production region and re-exports significant volumes of gas to a downstream region. A downstream country imports from the transit region but does not re-export significant volumes. A peripheral country imports directly from the production region, but does not import significant volumes from a transit region and also does not re-export. Hence, despite the lower spatial resolution, the aggregation aims to represent the inter-regional gas flow patterns in a realistic manner. The spatial structure of the model as well as the considered regions and the countries they include can be seen in Figure 3.2.

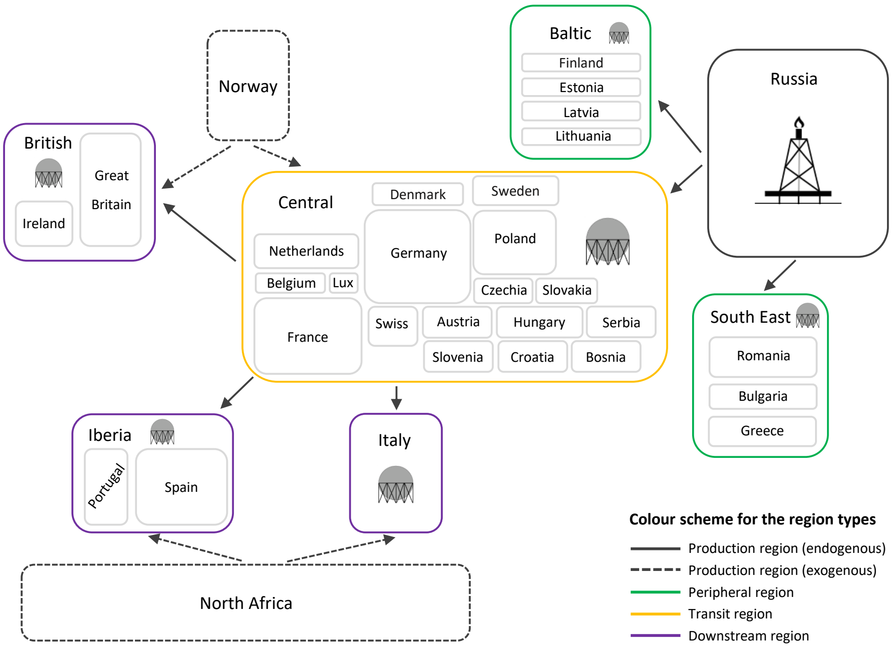


Figure 3.2.: Schematic representation of the spatial model structure

The transit Central region receives gas from the Norwegian and Russian production regions and can transport gas to southern downstream regions such as Italy and Iberia. Those regions also receive gas over North Africa. The downstream British region is connected to Norway and the Central region. The peripheral Baltic and the South East regions receive pipeline gas only from the Russian production region. Furthermore, all demand regions can import gas through their LNG regasification terminals. All demand regions have gas storage as well.

The model covers the historical gas year of 2017–2018, which starts on 1. October 2017 and ends on 30. September 2018. The gas year of 2017–2018 is chosen due to being the most recent gas year with publicly available data at the time of our analysis.[12] The model has a monthly temporal resolution. Correspondingly, yearly, quarterly and monthly capacity products are offered in the model. We assume that traders book their capacity in the analysed year.

[12]The methodology is nevertheless not only applicable to different gas years but can also consider multiple consecutive years. Optimising multiple consecutive years would not change the rationale of the model since long-term capacity booking decisions are made on a yearly scale.

Historical capacity bookings are not considered, which allows us to assess the effects of multipliers more generally.[13]

The existing pipeline network, storages and LNG import capacities of 2018 are considered. The pipelines connecting individual regions are assigned their historical capacities based on TSO information and ENTSOG data for pipelines (ENTSOG, 2019). Within regions, pipeline capacities are assumed to be not restricted.[14]

Storage data, such as maximum storage volume as well as maximum injection and withdrawal rates for all storages in Europe, is based on Gas Infrastructure Europe (GIE, 2018) as well as storage operators' data. Similarly, data for LNG import terminals are obtained from ENTSOG and GIE LNG map (GIE, 2019). Thereby, LNG import, regasification and storage capacities are considered. The costs for storing gas are based on several studies (Enervis, 2012, Le Fevre, 2013, Redpoint, 2012) and consider the cost variation among different types of storages. We assume linear increasing marginal costs for storages, implementing it into the model as a step-wise linear function. Tariffs for the entry-exit zones are historical values observed in 2018 and are acquired from ACER (2019a).

Gas demand is assumed to be perfectly inelastic and is specified as an exogenous parameter. Historical country-level consumption data for the analysed period is used.[15] The Russian production region is the only flexible gas producer in the model. The Russian supply function to Europe is assumed to be linear increasing and is integrated into the model as a step-wise linear function.[16] Annual production capacities for other producers are assumed to be equal to their historical production levels observed in 2018 (BP, 2019) and are specified as exogenous parameters.

The model considers a simplified LNG supply structure due to several reasons. The previously explained iterative approach to have constant TSO revenues requires yearly import and export levels to be unaffected by changes in

[13]This situation will be more prevalent from the year 2035 onward when historical long-term capacity bookings are almost completely expired (ACER, 2020b).

[14]The majority of the interconnection points in the EU are physically not congested, making this assumption plausible. According to ACER (2020a), physical congestion was likely to have happened in 2019 only in the 7 interconnection points among the 239 interconnection points considered in the study.

[15]Consumption data is sourced from EUROSTAT and websites of TSOs.

[16]The cost function is calibrated with respect to historical import volumes and prices and implicitly considers the transmission costs to Ukraine and Belarus. See Appendix B.2 for the reference case and model validation.

multipliers, since otherwise TSO revenues would not converge. If LNG provision would be modelled as in the case of Russian supply, the level of LNG and Russian supply would be affected by multiplier levels. This would in turn result in yearly import and export levels to vary and prevent the model results to converge. Therefore, LNG imports are modelled in the following manner: While yearly LNG imports are fixed to historical levels, LNG imports are allowed to be shifted within the year. For example, if high multipliers incentivise flatter pipeline import profiles, then LNG imports can be shifted to months with high gas demand. Such shifts of LNG imports are associated with costs. Hence, the stronger the deviation from the historical import profile, the higher the associated costs.

3.4. Results

In this section, we investigate the internal and external effects of multipliers. For this purpose, we apply the model presented in Section 3.3 and optimise the gas dispatch with different multiplier levels. The multiplier levels ($m1$, $m2$, ..., $m10$) we chose for the quarterly and monthly capacity products for the analysis are presented in Table 3.2. The quarterly and monthly multiplier pairs used in this analysis are derived with an exponential function in order to represent a realistic range of the currently applied multiplier levels in the EU while also including the extreme levels that per definition induce commodity or capacity pricing.[17] We take the German multiplier levels ($m4$) according to the BEATE regulation as reference, which are also representative of the EU average of multipliers (ENTSOG, 2018).

Note that the multiplier level $m1$ corresponds to the case of commodity pricing, as both products have a multiplier of 1. The multiplier level $m10$, where the quarterly multiplier is greater than 4 and the monthly multiplier is greater than 12, corresponds to capacity pricing. From 01.01.2019 onward the EU regulation 2017/459 limits quarterly and monthly multipliers to 1.5. The $m5$ level, with a multiplier of 1.47 for the monthly capacities, is just below this threshold. Multiplier levels greater than the $m5$ level (i.e. $m6$, $m7$, ..., $m10$) lie above this threshold.

[17] The formula used for deriving the multiplier pairs is as follows: $m_n = (m_{n-1})1.88 + 1$ for $n \geq 3$, where n is the multiplier pair number $n \in \{1, 2, ..., 10\}$. The m_2 level is specified manually as 1.03 for the quarterly product and as 1.07 for the monthly product.

Table 3.2.: The chosen multiplier levels for the analysis

	Quarterly	Monthly
$m1$ (commodity pricing)	1.00	1.00
$m2$	1.03	1.07
$m3$	1.05	1.13
$m4$ (default)	1.10	1.25
$m5$	1.19	1.47
$m6$	1.35	1.88
$m7$	1.66	2.66
$m8$	2.25	4.12
$m9$	3.35	6.87
$m10$ (capacity pricing)	5.42	12.04

In order for the results to have explanatory power, the model is first validated comparing the simulated prices, import volumes, and storage utilisation with the historical values observed over the considered time period. For this purpose, uniform multipliers equal to the default BEATE levels are assumed for the whole EU. Since many countries in the EU have multipliers similar to the BEATE levels, this is a realistic approximation. Results for model validation are presented in Appendix B.2.

If a region individually adjusts its multipliers, it induces internal effects in the region itself. However, as highlighted in Section 3.2, it is possible for it to cause external effects on other regions. In order to identify those internal and external effects in this section we first consider a case where regions individually and independently adjust their own multiplier levels.

3.4.1. Internal effects

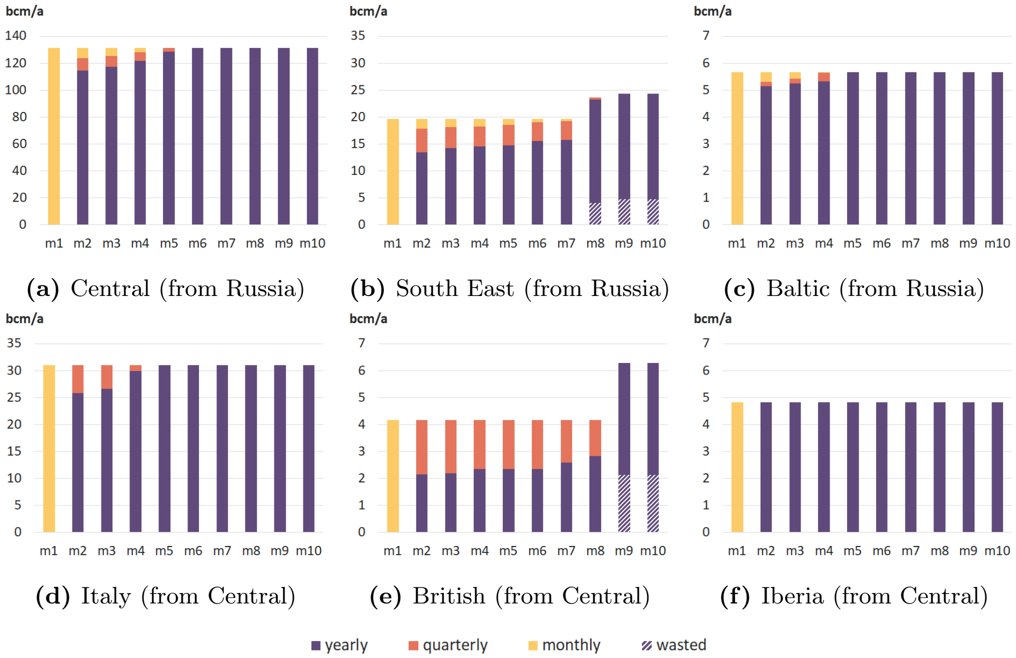
In a first step we investigate the internal effects of multipliers. For this purpose, we vary the multipliers in each of the six regions individually while keeping the multipliers in the other regions constant.[18] The internal effects in each region on capacity bookings, infrastructure utilisation, prices and consumer surplus are analysed.

[18]Multipliers are fixed to the default $m4$ level as this represents the average multipliers in the EU according to ENTSOG (2018).

Capacity bookings

The change in the volumes of booked capacities with respect to varying multipliers in the considered regions is plotted in Figure 3.3. The absolute height of the bar charts represent the total booked capacities, corresponding to the sum of yearly, quarterly and monthly bookings. It can be seen that when regions individually increase their multipliers, the share of ST bookings (i.e. monthly and quarterly) in these regions decreases, while the proportion of yearly bookings increases. This is as expected, since higher multipliers make ST capacities proportionally more expensive and incentivise the booking of LT capacities instead. It is also observed that when multipliers reach high enough levels, such as the $m6$ level in Central, they indirectly induce a capacity pricing regime and cause only LT capacities to be booked. The individual level of multipliers that induce capacity pricing differ among the regions. For example, while a higher multiplier level of $m9$ causes capacity pricing in South East, a lower level of $m5$ is enough to cause capacity pricing in the Baltic region and Italy. These findings are in line with the theoretical findings of Çam and Lencz (2021b).

Note that in South East and the British region, traders waste LT capacity when multipliers reach $m8$ and $m9$, respectively. This is because in those regions traders cannot fully flatten their monthly imports due to limited storage capacities, resulting in some LT capacity to remain unused, i.e. to be wasted (shown with dashed lines in the figure). Hence, unlike the theoretical model used in Çam and Lencz (2021b) with two time periods and unlimited storage capacities, capacity wasting can occur in a realistic setting with multiple time periods and limited storage capacities.



(a) Central (from Russia) (b) South East (from Russia) (c) Baltic (from Russia)

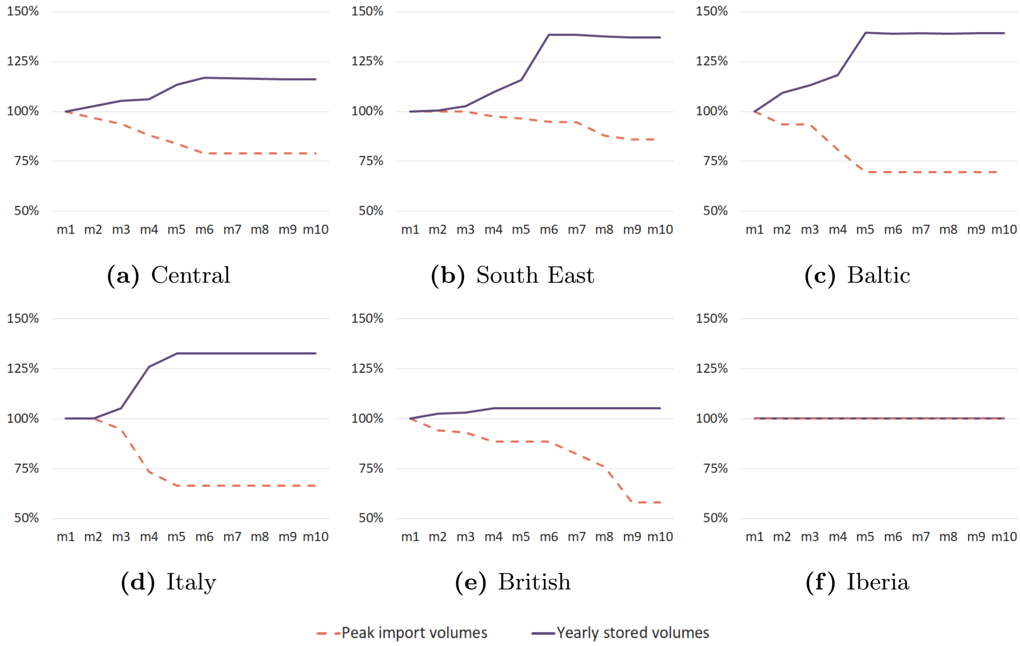
(d) Italy (from Central) (e) British (from Central) (f) Iberia (from Central)

Figure 3.3.: Capacity bookings by run-time and wasted capacity in each region when adjusting their multipliers

In Iberia, as soon as multipliers reach $m2$, only yearly capacity is booked. This is due to two reasons. On the one hand, Iberia is a downstream region, connected to the transit region Central. Hence, it is still subject to the default multipliers ($m4$) set in Central. On the other hand, the seasonal demand profile is relatively flat (i.e. low winter-summer demand spread) such that even very low multipliers are sufficient to fully flatten the transports between Central to Iberia. Therefore, it can be deduced that the structure of the demand profile in a region can greatly influence how multipliers affect capacity booking.

Infrastructure utilisation

In Figure 3.4, the yearly stored gas volumes and the monthly peak import volumes per region are plotted against varying multiplier levels. The monthly peak import in a region corresponds to the highest monthly volumes imported by that region in the considered year. In all the analysed regions except Iberia, a general trend can be observed: As the multipliers increase, the transported peak volumes decrease. In parallel with this, the stored volumes increase. These findings are in line with Çam and Lencz (2021b) and occur due to higher multipliers strengthening the capacity pricing aspect. In Iberia, infrastructure utilisation is not affected by multipliers since capacity booking is independent of multiplier levels, as shown previously.



(a) Central **(b)** South East **(c)** Baltic

(d) Italy **(e)** British **(f)** Iberia

Figure 3.4.: Relative change in import volumes in the peak-demand month and yearly storage volumes in each region when adjusting their multipliers

Prices

In a competitive market, regional prices are determined by marginal costs of gas provision. Çam and Lencz (2021b) shows that average marginal costs of gas provision are equal to the costs of gas procurement plus the costs for long-term (i.e. yearly) import transmission capacity. Hence, when multipliers affect yearly import (entry-exit) transmission capacity tariffs they also influence the average prices in regions.

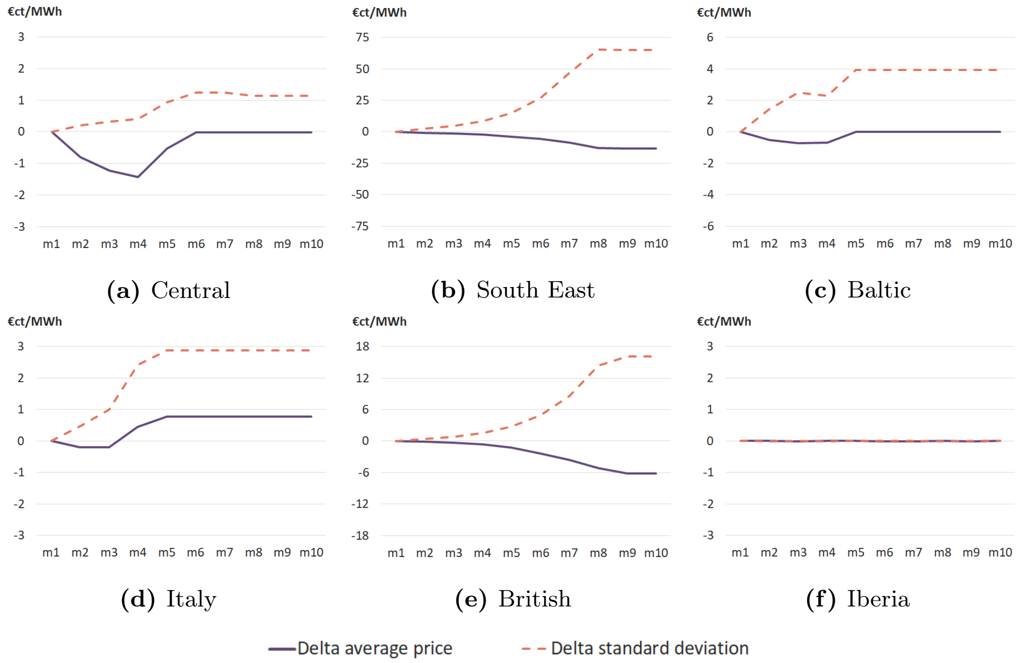
Model results on the effects of multipliers on prices are plotted in Figure 3.5 for each individual region. In all regions where both LT and ST products are booked (see Figure 3.3), increasing multipliers up to a sufficient level causes the average prices to decline. This is because increasing the multipliers allows TSOs to reduce the tariff for their LT product.

In South East and the British region, however, the average price levels remain constant after they reach their minimum, which is caused by the capacity wasting that occurs in these regions with high multipliers. In Iberia, as only LT capacities are booked irrespective of multiplier levels, no price effects are observed.

As can be seen in Figure 3.5, multipliers not only have an impact on the average price levels, but also affect the temporal price volatility i.e. the standard deviation of the prices. When flexibility from storage and LNG imports is not fully utilised, the maximum price spread is defined by the marginal costs of such flexibility in the respective region. We have shown previously (see Figure 3.4) that multipliers increase the volumes stored in storages. As more expensive storage capacities start being used, the regional prices in peak months increase because marginal costs of storage increase. Since the differences in marginal storage costs are limited, the effect on temporal spreads is less pronounced for regions where storage capacities are not fully utilised (i.e. Central, Italy, Baltic).

In contrast, in British and South East regions, flexibility from storage capacities as well as LNG is fully utilised when the multiplier level reaches $m4$ and $m6$, respectively. In these cases, the maximum price spread is determined by the marginal costs for ST (i.e. monthly) capacity. As increasing multipliers result in higher prices for monthly capacity bookings, the maximum price spread increases. This process stops as soon as booking yearly capacity—which is not subject to multipliers—gets cheaper than booking monthly capacity. For the British and South East regions this is the case when multipliers reach $m9$ and $m8$, respectively.

Multipliers also affect the regional price spreads, as the average regional price spread corresponds to the yearly transmission tariff. Therefore, multipliers that minimise the average price also minimise the average regional spread with respect to the region exporting gas. Furthermore, we find that higher multipliers increase the volatility in regional price spreads, thus, confirming the findings of Çam and Lencz (2021b). We identify two effects which drive the volatility in regional spreads. The price volatility in a region that increases its multipliers rises. At the same time, the increase in multipliers tends to decrease the temporal volatility in the exporting region. As a result, these two effects combined together amplify the volatility of the price spread between those two regions. A detailed analysis of the regional price spreads can be found in Appendix B.3.



(a) Central (b) South East (c) Baltic (d) Italy (e) British (f) Iberia

Figure 3.5.: Absolute change in the average price (i.e. delta LT tariff) with respect to m1 level and the absolute change in the standard deviation in each region when adjusting their multipliers individually

Consumer surplus

We have shown that multipliers affect the average price levels as well as the peak prices. As such, they directly affect the consumer surplus in the individual regions and how it is distributed between different types of consumers with varying demand patterns (i.e. base vs peak). In Figure 3.6, the change in consumer surplus in each region with respect to multipliers is plotted. The consumer surplus is defined relative to the $m1$ level. Since the gas demand is inelastic, consumer surplus corresponds to the change in prices multiplied with the demand. Further, we distinguish between base consumer surplus and the peak consumer surplus. Base consumer surplus corresponds to change in average prices multiplied by the base demand. Base demand is assumed to be constant throughout the year and equals the overall minimum monthly demand of a region. Any demand above this base level is then defined as peak demand. Thus, peak consumer surplus corresponds to the peak demand multiplied by the change in the corresponding prices.

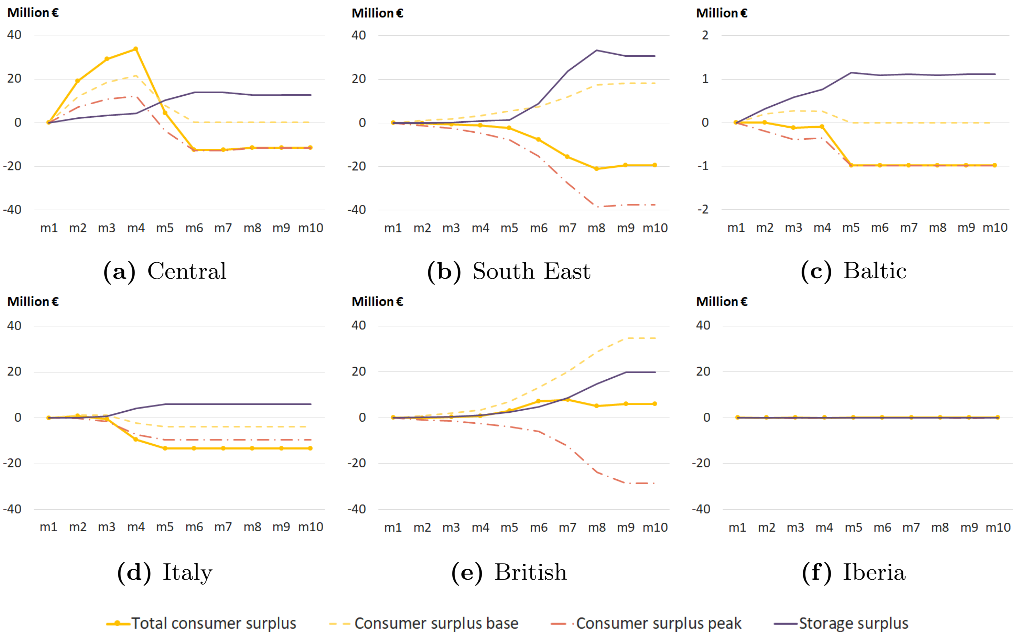
Consumer surplus and its distribution between base and peak consumers are affected differently in each region with increasing multipliers, depending on which of the following three effects dominates:

- **Effect 1**: The first effect is the change in average prices due to tariff adjustment, which affects the overall consumer surplus. In this case, both base and peak consumers benefit if the tariffs are reduced or both consumer types lose if the tariffs are increased.
- **Effect 2**: The second effect is the increased spreads between off-peak and peak prices caused by higher storage utilisation. With higher storage utilisation, more expensive storages are used, which increase the spread between peak and off-peak prices. In this case, base consumers are not affected, while peak consumers lose.
- **Effect 3**: In case that flexibility from storage and LNG imports is exhausted, there exists a third effect: The prices in the peak periods are determined by the price of ST capacity, resulting in increased peak prices. Therefore, as multipliers increase, peak prices also increase, causing the peak consumer surplus to decrease.

In Central, the reduction in the average price causes both the base and peak consumer surplus to increase and reach a maximum at the multiplier level of $m4$ (Effect 1). Nevertheless, both peak and base consumer surplus decrease with higher multipliers as the LT tariff is increased due to the shift to LT capacity. Peak consumer surplus decreases additionally because of higher storage utilisation (Effect 2).

In the South East and Baltic regions, base consumers also increasingly benefit from the average price reduction with higher multipliers (Effect 1) while the peak consumers lose due to higher peak prices caused by increased storage utilisation (Effect 2). In South East, flexibility from storages is exhausted at $m6$ and from then onward Effect 3 dominates, causing a large decrease in the peak consumer surplus and reducing the overall consumer surplus substantially. In both the South East and Baltic regions, low multipliers ($m1$) maximise the overall consumer surplus, which is due to the relatively small size of those regions in terms of gas demand as well as their position as peripheral regions. When the two regions increase their imports in summer and decrease them in winter because of higher multipliers, prices in Russia are affected (lowering effect on winter prices and raising effect on summer prices). However, the transit Central region mitigates the effect on Russian prices almost fully when it exploits the lowered temporal Russian price spread. The mitigating effect is more pronounced since imports of the transit Central regions are five times higher than the sum of both peripheral regions' imports. Hence, Effect 2, which reduces peak consumer surplus, is reinforced such that optimal multipliers in the peripheral regions Baltic and South East are found to be low.

In Italy, the decrease in average prices causes a slight increase in the total consumer surplus, which reaches a maximum at the multiplier level of $m2$. Due to the peak price effect caused by higher storage utilisation (Effect 2), peak consumer surplus decline is steeper than the decline in base consumer surplus. Effect 2 is reinforced by Italy's relative position as a downstream region from Central. As Italy flattens its import profile from Central, gas storage is shifted from Central to Italy, reducing the summer-winter price spread in Central. In response, Central adjusts its import behaviour and imports more gas during winter. This mitigates the effect on the temporal price spread in Central, which further causes increased storage utilisation in Italy.



(a) Central (b) South East (c) Baltic

(d) Italy (e) British (f) Iberia

Figure 3.6.: Consumer and storage operator surplus in each region when adjusting their multipliers individually

In the British region, the effects are similar to those observed in South East. However, in contrast to South East, import tariffs can be reduced to a larger extent, such that Effect 1 dominates and total consumer surplus is maximised at $m7$. This is because, irrespective of multipliers, imports occur predominantly in winter. As the TSO revenue is kept constant, LT tariffs can be reduced significantly, limiting the increases in ST tariffs. In Iberia, the consumer surplus is unaffected since only LT capacity is booked irrespective of the multiplier level.

3.4.2. External effects

As highlighted in Section 3.2, if a region individually adjusts its multipliers, it is possible for it to also cause external effects on other regions. Those external effects can be direct or indirect, and depend on whether the regions that adjust their multipliers are transit, downstream or peripheral.

Transit region adjusts its multipliers

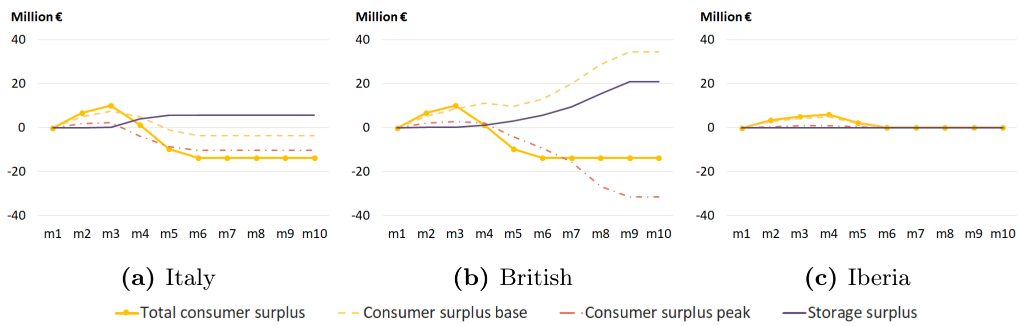
In this case, the transit Central region is allowed to vary its multipliers while all the other regions have unchanged multipliers equal to the default ($m4$) levels. Adjusting multipliers in the Central region has direct effects on the peripheral regions that are connected and lie downstream such as Iberia, Italy and the British region. Figure 3.7 shows the changes in consumer surplus and storage surplus in these regions with respect to multiplier levels in the Central region.

The first direct external effect arises from the change in average prices in Central which is passed on to the downstream regions (arising from Effect 1 in Central). This external effect can be clearly observed in Iberia, where minimum average prices in Central for $m4$ also lead to lowest prices (i.e. highest consumer surplus) in Iberia.

For Italy and the British region, changes in multipliers also impact the booking behaviour and the gas dispatch for transports from Central, which induces additional external effects in the downstream peripheral regions. These effects depend on which of the previously discussed three effects ensue and dominate.

In Italy, the consumer surplus of peak consumers falls significantly with increasing multipliers. This is because higher multipliers for exporting gas from Central to Italy incentivise the flattening of transports from Central to Italy. The required utilisation of more expensive storages in Italy increases the peak prices in Italy, reducing the peak consumer surplus (Effect 2). In combination, the sum of the two external effects (Effect 1 and Effect 2) is highest for $m3$.

Similarly, when transporting gas from Central to the British region, traders are also incentivised to flatten transports with higher multipliers. In the case of the British region, as flexibility from storage and LNG is limited, a full flattening of transports is not possible. Hence, in peak periods the cost of ST capacity determines the prices, causing significant decline in the peak consumer surplus (Effect 3). Similar to the individual adjustment case, base consumer surplus increases due to tariff reduction (Effect 1). Overall, the highest positive external effect from Central on the British region arises for $m3$ due to combination of Effect 1 and Effect 3.

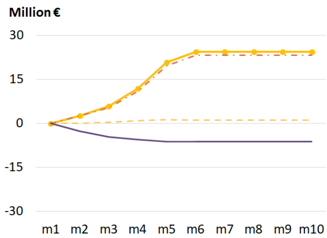


(a) Italy **(b)** British **(c)** Iberia

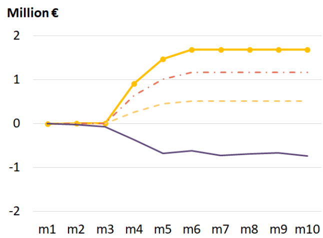
Figure 3.7.: Changes in the consumer and storage operator surplus in the regions which lie downstream of Central when Central adjusts its multipliers: (a) Italy, (b) British, (c) Iberia

Adjusting multipliers in the transit Central region also induces indirect external effects on the peripheral regions which are not directly connected with it such as the South East and the Baltic regions. Figure 3.8 shows the development of consumer and storage surplus in South East and Baltic with respect to changing multipliers in Central. Increasing the multipliers in Central causes the spread between peak and off-peak procurement prices in the Russian production region to decrease, i.e. off-peak prices increase and peak prices decrease. As a result, in the South East and Baltic regions, peak consumer surplus increases.[19]

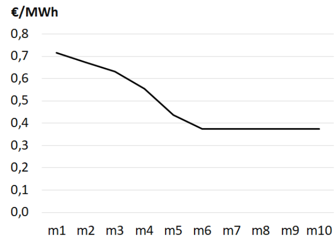
[19]Due to cheaper procurement prices during the peak period, more ST products are booked in South East and Baltic regions to transport Russian gas to cover the peak demand. The increased share of ST bookings allows the TSOs to slightly reduce their transport tariffs, such that the overall prices in the South East and Baltic regions sightly decrease, benefiting both the peak consumers and the base consumers. Here, this effect can be more easily seen in the case of the Baltic region.



(a) South East



(b) Baltic



(c) Standard deviation of Russian prices

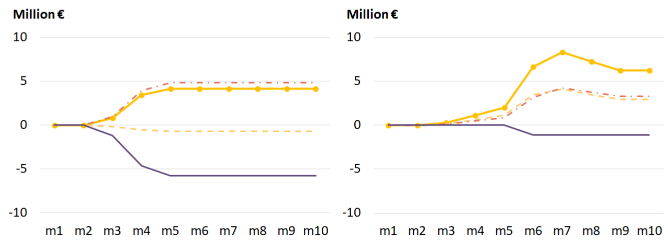
Figure 3.8.: Changes in the consumer and storage operator surplus in the regions which are not directly connected to Central when Central adjusts its multipliers: (a) South East, (b) Baltic, and (c) the corresponding development of the standard deviation of Russian prices

Downstream or peripheral region adjusts its multipliers

When downstream or peripheral regions adjust their multipliers, they can also cause external effects on other regions. Figure 3.9 shows the changes in storage and consumer surplus in Central with respect to the multiplier levels in Italy and South East, respectively. In the case of Italy, multipliers in Italy are varied while other regions have the default multiplier level. Similarly, in the case of South East, only the multipliers in South East are varied while other regions have the default multiplier level. In both cases, we observe significant impact on the Central region.

In the case of adjustments in Italy, higher storage utilisation in Italy due to increased multipliers results in storages in Central to be utilised less. As a result, peak prices in Central decrease and peak consumer surplus increases consecutively.

The overall impact from changes in the multipliers in South East on the consumer surplus in Central arises from a combination of two specific effects: Increasing the multipliers in South East causes the spread between peak and off-peak procurement prices in the Russian production region to decrease, i.e. off-peak prices increase and peak prices decrease. At the same time, due to cheaper procurement prices during the peak period, more ST products are booked in Central to transport Russian gas to cover the peak demand. Increased amount of ST bookings allows the TSO to reduce the transport tariffs. Consequently, overall prices in Central decrease, benefiting both the peak consumers and the base consumers.



(a) Central, when Italy adjusts **(b)** Central, when South East adjusts

Total consumer surplus   Consumer surplus base   Consumer surplus peak   Storage surplus

Figure 3.9.: Changes in the consumer and storage operator surplus in Central (a) when Italy adjusts its multipliers, (b) when South East adjusts its multipliers

The external effects of multiplier adjustments in Italy and South East on other regions except Central are found to be very small. Any multiplier adjustment in the British region is found to have negligible impact on other regions because a large share of gas consumption is produced within the region or imported by LNG. Baltic region is found to cause similar external effects as the other peripheral region South East, albeit at a much smaller scale, because the imported volumes are comparably low. Iberia, having shown that no internal effects ensue with respect to multipliers, does not cause any external effects either. Those cases are not shown in this section explicitly but can be found in Appendix B.4, where the external effects of multiplier adjustments of all the regions are presented.

3.4.3. Overall distributional effects

We have shown that multipliers can cause both significant internal and external effects in various regions in the EU by influencing the price levels and the consumer surplus. Higher multipliers were also shown to cause increased storage utilisation (storage surplus), resulting in flattened import profiles from the Russian production region. These effects would also have an impact on the producer surplus and the trader surplus. As such, multipliers would influence the welfare and its distribution in the EU and in the production regions.

In order to clearly show the overall distributional effects of multipliers in the EU and in the production regions, we assume in a first step that the multipliers are specified in the EU by a superordinate regulator and every region has the same uniform multiplier level. In Figure 3.10, the changes in surplus of the consumers, producers, traders and storage operators as well as the change in overall welfare with increasing multipliers are plotted. All the values are defined and plotted in relation to the case where multipliers are equal to 1 ($m1$). Hence, at $m1$ the change in surpluses and welfare are zero. It can be seen that the overall consumer surplus increases significantly with higher multiplier levels and reaches a maximum of about 82 million EUR at $m4$. Peak-load consumers receive a much smaller share (31% at $m4$) of this additional consumer surplus compared to base-load consumers (69% at $m4$).

Producer surplus decreases substantially with increasing multipliers. The reason for that is the rise in yearly bookings and a corresponding decrease in purchased volumes from Russia in the peak periods. The producer surplus decreases as the purchased volumes in the peak and off-peak periods converge. At the consumer-surplus-maximising multiplier level of $m4$, Russian producers incur a loss of 69 million EUR compared to the $m1$ level.

Storage operators have surplus gains with higher multipliers due to increased storage utilisation, as more of the expensive storages are used that set the price of storage. At $m4$, the storage operator surplus equals 5 million EUR. When multipliers reach $m6$ and storages are fully utilised in the British and South East region, storage operators can charge bottleneck prices, increasing the storage operator surplus up to 77 million EUR for multiplier levels of $m9$ and $m10$, almost 15 times greater than the surplus observed with $m4$.

Trader surplus equals the revenue from selling gas to consumers minus the costs of gas provision, i.e., the costs for gas procurement, transport and storage. When the uniform multipliers increase to $m4$ levels, traders make less profit (-43 million EUR) as consumer prices decrease while at the same time booking costs remain constant. For higher multipliers, trader surplus increases again. This happens mainly due to increased consumer price levels. In addition to the consumer price effect, traders profit from lower gas procurement costs but bear higher costs for storing natural gas. Those two effects largely cancel each other out.

Welfare is defined as the sum of all surpluses and is highest for $m1$. Higher multipliers increase the distorting effect of transmission tariffs, causing the gas dispatch to further deviate from an optimal dispatch that is based on short-run marginal costs, as was also shown in Çam and Lencz (2021b). Higher multipliers reduce welfare by causing additional costs, which occur as a result of two opposing effects. On the one hand, total costs of gas production decrease as gas is produced more evenly. On the other hand, total costs of storing gas increase. However, as the increase in storage costs is higher than the decrease in production costs, welfare declines with increasing multipliers. For multipliers higher than $m6$, welfare becomes mostly independent from increases in multipliers, as traders start to behave as being subject to capacity pricing in an increasing number of regions as shown previously, such that increases in multipliers do not affect procurement or storage volumes.

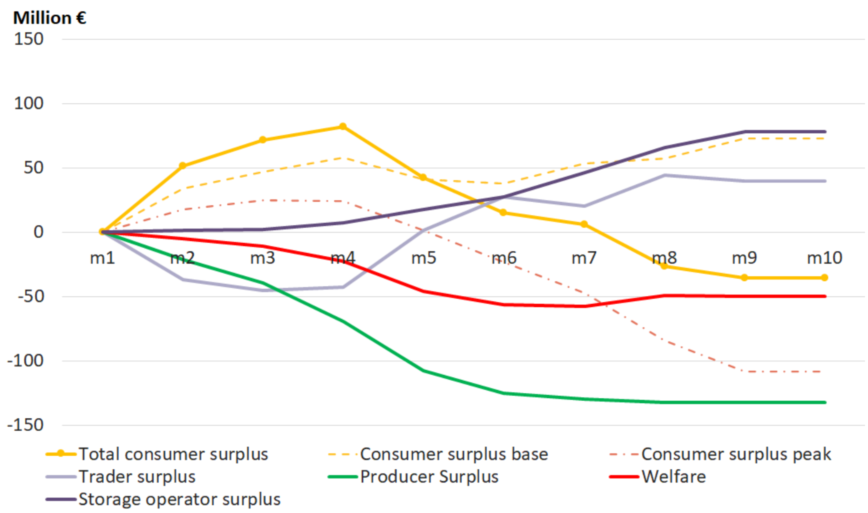


Figure 3.10.: Changes in the consumer, producer, trader, and storage surplus and welfare with respect to multipliers in the EU

3.4.4. Comparing different optimal multiplier levels

A major research question of this paper is whether multipliers in the EU should be set by a superordinate regulator or whether individually optimal multipliers can lead to a joint (i.e. EU-wide) optimum. In this part of our analysis we aim to answer those questions. To do so, we compare consumer surpluses for three cases: (1) EU-wide uniform optimal multiplier level, (2) individually optimal multipliers that maximise the consumer surpluses in the individual regions, and (3) multipliers for individual regions that lead to a joint optimum. Optimal multipliers in this context correspond to multipliers that maximise the consumer surplus.

From Section 3.4.3 we know that the EU-wide uniform multiplier level resulting in the highest consumer surplus is $m4$. Furthermore, we have shown previously in Section 3.4.1 that the individually optimal multiplier levels vary among the analysed regions. For Central, the optimal level was found to be $m4$ while for Italy $m2$ was shown to be optimal. In South East and Baltic regions, optimal multipliers should be as low as possible; namely equal to $m1$. In contrast, in the British region, multipliers as high as $m7$ were found to be optimal. In Iberia no effects with respect to multipliers were observed.

To find the multiplier levels resulting in the EU-wide joint optimum, we vary the multiplier levels of the four regions that were found to cause significant external effects (i.e. Central, South East, Baltic and Italy) in combination. With 4 regions and 10 multiplier levels, this corresponds to 10^4, namely, 10000 combinations. Multiplier level in the British region is set to its individually optimal level of $m7$, while Iberia is set to the default level of $m4$. We find that individually optimal multipliers for Central and Italy also lead to the joint optimum. In contrast, the jointly optimal multiplier level for the peripheral regions, South East and Baltic, differ from their individually optimal levels and are found to be $m6$ and $m5$, respectively. The optimal multiplier levels in the three cases are summarised in Table 3.3.

Table 3.3.: Multiplier levels maximising consumer surplus

Region	Uniform multipliers	Individual optimum	Joint optimum
Central	$m4$	$m4$	$m4$
South East	$m4$	$m1$	$m6$
Baltic	$m4$	$m1$	$m5$
Italy	$m4$	$m2$	$m2$
British	$m4$	$m7$	$m7$
Iberia	$m4$	$m4$	$m4$

Figure 3.11 shows the corresponding change in consumer surplus for the optimal multiplier levels in the three cases. The delta consumer surplus is calculated relative to the consumer surplus resulting from uniform multipliers in all regions equal to $m1$. It can be seen that the uniform optimal multiplier level of $m4$ increases consumer surplus substantially compared to a uniform multiplier level of $m1$. The overall gains in consumer surplus amount to 82 million EUR. The optimal uniform multiplier level of $m4$ is also the individually

optimal multiplier of the Central region. Since Central was shown to cause the highest internal and external effects, the uniform $m4$ level results in a significant increase in the EU-wide consumer surplus.

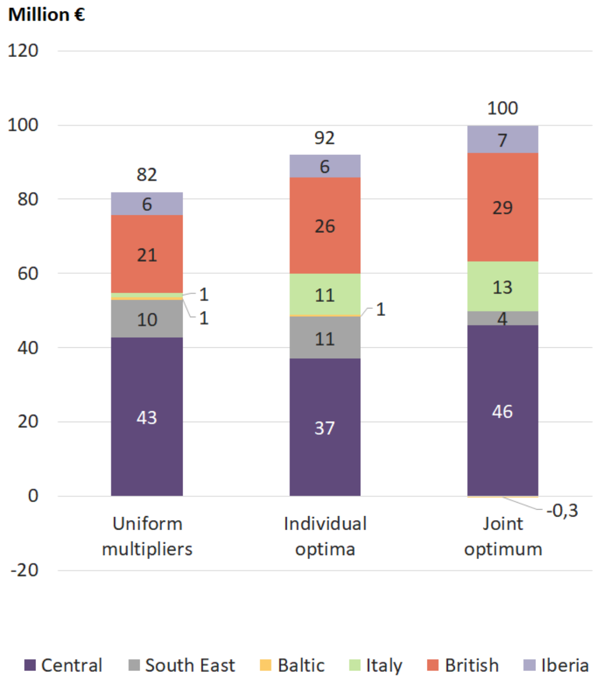


Figure 3.11.: Changes in regional consumer surplus with respect to how the multipliers are specified

When regions specify their individually optimal multipliers, total consumer surplus in the EU increases by 10 million EUR compared to the maximum consumer surplus achieved with uniform multipliers. Hence, the internal increase in consumer surplus by setting multipliers individually outweighs the negative external effects. However, consumers in Central are worse off. This occurs mainly because Italy sets lower multipliers, shifting storage utilisation from Italy to Central. As more expensive storages are utilised in Central, peak prices increase, reducing peak consumer surplus in Central.

In the case that regional regulators specify the multipliers in order to maximise the joint EU-wide consumer surplus, total consumer surplus increases by another 8 million EUR. The effect is limited, because for the majority of regions the individually and jointly optimal multiplier levels coincide. For Central, this occurs as downstream regions profit from lower average prices in Central such that both external and internal effects due to multipliers are highest for $m4$. For Italy, the positive internal effect on consumer surplus outweighs the negative impacts on the consumer surplus in Central. For British and Iberia, multipliers are found to have negligible external effects such that the individual and joint optima also coincide. Whereas, in South East and Baltic regions, jointly optimal multipliers ($m6$ and $m5$) diverge from the individually optimal multiplier level $m1$. Hence, the positive external effects from setting multipliers relatively high in South East and Baltic outweigh the negative internal effects. As outlined previously, this occurs because high multipliers in peripheral regions reduce the temporal price spread in the Russian production region, from which the other gas importing regions profit.

3.5. Discussion

3.5.1. Overall effects

Our analysis has shown several adverse impacts that multipliers can have on the overall gas dispatch. A multiplier of 1 is shown to be the optimal multiplier level that maximises overall welfare. This is not surprising, since higher multipliers reinforce the capacity pricing aspect and cause the gas dispatch to further deviate from an ideal dispatch that would be based on short-term marginal costs. Therefore, increasing multipliers more than necessary would also increase the inefficiency in gas dispatch and cause welfare losses as our analysis has shown. Furthermore, higher multipliers are shown to increase volatility of prices and regional price spreads. Hence, unnecessarily high multipliers may be detrimental to the integration of the EU gas market.

Despite the above-mentioned inefficiencies associated with multipliers, multipliers that are sufficiently high can nevertheless be favoured by the regulators for several reasons. We have shown that multipliers determine how gas transmission capacity is booked, in turn affecting how gas infrastructure is utilised. Overall, higher multipliers were shown to decrease the peak transport volumes and increase the volumes stored in gas storages. In this respect, it can be argued that higher multipliers may strengthen the security of supply of the system by reducing the volatility of gas import volumes and promoting storage. Furthermore, the ensuing flatter gas import profiles may also reduce the need for future capacity extensions, potentially resulting in higher long-term efficiency.

Regulators can also favour higher multipliers due to their distributional effect. Multipliers that are sufficiently high can maximise consumer surplus by allowing transport tariffs to be reduced. Setting the multipliers for the purpose of maximising consumer surplus penalises the traders and the producers while benefiting the storage operators. The producers in this case are the Russian gas production companies and the traders would be the various EU and non-EU energy and trading companies. Storage operators are predominantly EU companies with some storages owned by non-EU firms (e.g. Gazprom). Therefore, from an EU perspective, setting the multipliers to maximise consumer surplus would likely be optimal as it would largely benefit the consumers in the EU while penalising the non-EU producers.

3.5.2. Regional effects

National regulators can set the multipliers accordingly to maximise the consumer surplus. However, we have shown that the effects of multipliers vary significantly among regions. According to our analysis, the issue of choosing optimal multipliers becomes less important in regions with a relatively flat demand profile such as Iberia (Spain and Portugal), since in these regions exclusively LT capacities are booked in the model. In reality, due to decision-making under uncertainty—especially with respect to highly uncertain and volatile LNG prices—ST capacities are observed and imports from continental Europe via pipeline are less flat. The fact that overall LNG imports may be affected by multipliers may also contribute to the observation of ST bookings.

In regions with limited storage flexibility such as in the British region (United Kingdom and Ireland) and South East Europe (Romania, Bulgaria and Greece), we find that higher multipliers can cause substantial increases in the temporal price spread, benefiting base consumers while penalising peak consumers. When specifying multipliers, regulators in these regions would also have to take into account this strong distributional effect on the allocation of consumer surplus between the base and peak consumers.

In South East Europe and the British region, we have shown that wasting of booked capacities can occur with sufficiently high multipliers. This means that a portion of the booked capacities remain unused because traders cannot fully flatten their monthly import profile due to limited storage capacities. In our model, this occurs only with very high multiplier levels that lie out of the range suggested by the EU. In reality, due to decision-making under uncertainty, the capacity wasting effect of multipliers could occur even in regions with sufficient storage flexibility and with lower multipliers, being much more prevalent than what our model with perfect foresight projects. Therefore, regulators may opt for lower multipliers if it is desired to reduce the wasting of booked capacities.

Our analysis indicates significant variation in the individually optimal multiplier levels for maximising the consumer surplus in the respective regions. We have shown that these multiplier levels are influenced by three main effects. The first effect is the reduction of the overall regional price due to TSOs being able to reduce the transport tariffs. The second effect is the increase in peak prices due to higher storage costs caused by increased storage utilisation. And the third effect is the increase in peak prices when storage flexibility is limited as the prices in this case are determined by the cost of ST capacities. For the Central region considered in the model, which is an aggregation of numerous transit countries in Central and West Europe, we find that the first effect dominates. Whereas, in Italy, a downstream region with abundant storage capacities that imports gas from the transit Central region, the second effect plays an important role. In the downstream British region as well as the peripheral South East and Baltic regions with limited storage flexibility, the third effect is found to be the dominant effect. Thus, our analysis indicates that multipliers can reinforce different effects in different regions.

3.5.3. External effects and the EU optimum

National regulators can set the multipliers accordingly to maximise the consumer surplus. However, our results confirm that adjusting multiplier levels in a region does not only cause effects in that region itself but can also induce external effects in other regions. We have shown that consumer surplus gains in transit regions are directly passed on to regions that lie downstream of the transit regions (i.e. import gas from the transit region). In contrast, a direct transfer of consumer surplus gains in the downstream and peripheral regions to transit regions does not occur. Nevertheless, our results show that multiplier adjustments in the peripheral and downstream regions can still influence the transit regions in more indirect ways, such as via affecting the procurement prices in the production region or affecting the storage utilisation in the transit region itself, respectively. Consequently, setting multipliers to maximise the consumer surplus in the individual regions, i.e. setting individually optimal multipliers, does not maximise the total EU consumer surplus.

We find that individually optimal multipliers nevertheless result in a significantly higher EU consumer surplus compared to an optimal EU uniform multiplier level that applies in every region. In our analysis, the maximum EU potential consumer surplus gains via a uniform multiplier level is 82 million EUR per year while the individually optimal multipliers increase this value by 12% to 92 million EUR. In this sense, we find it appropriate that EU regulation provides an allowed range of multipliers and not absolute values. Yet, we show that this allowed range can be too restricting for some regions. While the individually optimal multipliers in the majority of regions considered in the model lie lower than the maximum allowed multipliers in the EU, the British region is found to have a much higher optimal multiplier. Hence, our results imply that the current range of allowed multipliers can be too restricting for this region, limiting the potential consumer surplus gains.

When multipliers are set in individual regions with the purpose of maximising the total EU consumer surplus, the surplus gains increase by 9% to 100 million EUR. This indicates that letting national regulators set the multiplier levels—as is the case with the current EU regulation—may not lead to an EU optimum. In the EU optimum case, we have shown that the consumers in the transit and downstream regions benefit while those in the peripheral regions are worse off compared to the individually optimal case. As such, national regulators in the peripheral regions would have little incentive to choose EU-optimal multipliers. Therefore, incentivising those regions would require some of the EU consumer surplus gains to be redistributed to peripheral regions.

The maximum consumer surplus gains in the EU of almost 100 millions EUR estimated by our model are relatively low when compared to overall EU gas market costs. The yearly EU internal gas market purchases alone are estimated to be 100 billion EUR in total (ACER, 2020b). However, contemplating those gains via multipliers with the total costs associated with the entry into the EU and entry-exit between EU market areas is more meaningful. In our model such costs amount to 4.6 billion EUR. Hence, multipliers that maximise overall consumer surplus shift approximately 2.2% of the transmission costs from the consumers to the producers and traders compared to the situation without multipliers.[20]

In our analysis, we group several market areas into individual regions and ignore the transmission costs within the regions that occur in reality. Because of that, real-world transmission costs would be higher than those in our model. Cervigni et al. (2019) estimate the total costs associated with the entry into the EU and entry-exit between EU market areas to be 5.7 billion EUR for the year of 2017. These transmission costs are 24% higher than the corresponding costs in our model, supporting the notion that the overall effects of multipliers on the consumer surplus would be higher in reality due to additional transmission costs within the regions. Another aspect which would further reinforce the effects of multipliers in reality is the presence of uncertainty. Compared to in our model with perfect foresight, traders in reality would be more inclined to book short-term capacities when there is short-term uncertainty with respect to their capacity demand. Since multipliers increase the prices of short-term capacities, the distributional effects of multipliers could be more pronounced in this case. We assume in our analysis all storages to be fully exempt from transmission tariffs. While the majority of countries in the EU either fully exempt storages from transport tariffs or apply very large discounts up to 90%, there are also countries where tariff discounts for storages are not as high. In these regions, the effects of multipliers on storage utilisation would be less pronounced and comparably more short-term products would be booked. This would allow long-term tariffs to be further decreased, increasing potential consumer surplus gains via setting multipliers optimally.

Despite the above-mentioned aspects, potential consumer surplus gains via optimal multipliers could in some cases be smaller in reality due to existing long-term bookings. In our analysis, we ignore the historical long-term capacity bookings that are already in place. In regions with particularly high proportion of historical long-term bookings, multipliers would have overall less impact due to less demand for short-term capacities. This would especially be the case where historically booked capacities exceed the demand for capacity such that traders face zero marginal costs for transmission. Nevertheless, since the historical capacity bookings will almost completely expire until 2035, it will eventually become less of a factor.

[20] Trader surplus decreases even further as traders also bear the costs from increased storage utilisation. Producer surplus also decreases further due to reduced profits from selling less gas in peak periods.

3.6. Conclusion

In the European Union's gas transmission system, the relative prices of short-term transmission capacities are specified via multipliers. Multipliers can have varying internal effects in different regions, resulting in consumer-surplus-maximising multipliers to differ between the regions. Moreover, even if individual regions specify their own optimal multipliers, it is not obvious if it would lead to an EU optimum. This is because multiplier levels in one region can cause external effects in other regions. In order to address these issues, this paper analyses the effects of multipliers on regional prices, infrastructure utilisation, and welfare. A numerical simulation model is used to simulate the European gas dispatch and quantify the effects of multipliers in a spatial setting with six different representative regional clusters in Europe.

Overall, our results show that sufficiently high multipliers can help maximise consumer surplus by allowing transport tariffs to be reduced. Hence, optimal multiplier levels that maximise consumer surplus on a regional level or in the whole EU do exist. Nevertheless, we show that multiplier effects and consequently optimal multiplier levels depend strongly on regional characteristics. In regions with relatively flat demand profiles, i.e. with low winter-summer variation in demand, such as Portugal and Spain, only long-term capacities are booked under the model assumption of perfect foresight, irrespective of the multiplier level. In reality, under the presence of uncertainty, ST bookings are also observed. Nevertheless, our results indicate setting multipliers optimally is comparably less of an issue in such regions with flat demand profiles. In contrast, we show that in regions with limited supply flexibility via storages, such as Britain and South East Europe, higher multipliers significantly reduce the consumer surplus of peak consumers while base consumers profit. In such regions, the effects on the internal redistribution of consumer surplus between peak and base consumers should also be taken into account when specifying the multipliers.

Our analysis indicates that multiplier levels in a region can cause external effects in other regions. In transit regions, which import and re-export significant gas volumes (e.g. Central Europe) consumer surplus gains are passed on to regions that lie downstream (e.g. Italy). We show that multipliers in downstream regions can influence the transit regions indirectly due to adjusted import structure, affecting the storage utilisation in the transit region. Peripheral regions (e.g. South East Europe) can influence other regions also by affecting the temporal price spreads in the procurement prices in the production regions (e.g. Russia). Because of those external effects caused by multipliers, individually optimal multipliers do not necessarily lead to the EU optimum.

Allowing the regions to set their multipliers individually, nevertheless, results in a much more optimal outcome with 92 million EUR consumer surplus gains annually, 12% higher than what can be achieved with a uniform multiplier level applied in all regions. In this respect, it is appropriate that the current EU regulation specifies allowed multipliers in ranges and not in absolute values, as it can allow for consumer surplus gains in the EU. Nevertheless, our results indicate that letting national regulators set the multipliers may not lead to an EU optimum since the consumer surplus gains with individually optimal multipliers is found to be 9% lower than the maximum achievable consumer surplus.

In our analysis we considered a simplified spatial structure with aggregated regions for the purpose of isolating and identifying effects. In reality, due to high number of individual transit countries interconnected with each other, multiplier levels in a transit region can have a more amplified impact on the downstream regions and the whole system due to the pancaking effect. Additionally, we assumed perfect foresight when simulating the gas dispatch and the capacity booking, which results in the capacities in our model to be booked optimally as necessary. In reality, because of uncertainty and forecast errors, not all booked capacities are optimal and wasting of booked capacities is a common occurrence. We have shown that higher multipliers can result in capacity wasting. In this context, regulators may have to take into account these aspects as well when specifying the multipliers.

In future work, the modelling framework could be extended to include stochasticity in order to consider the influence of imperfect information and uncertainty on the capacity booking behaviour and their impact on the effects of multipliers. Significant changes in the gas demand structure are expected to occur in the next decades. As the share of intermittent renewables in electricity generation increases as part of the energy transition to meet the climate targets, volatile residual load will be increasingly met by flexible gas-fired generation. This will correspond to increased demand for short-term transmission capacity, especially for daily and intra-daily capacities. Therefore, it would also be worthwhile to extend the analysis by including a more granular temporal resolution and modelling daily and intra-daily capacity bookings.

4. The Shift in Global Crude Oil Market Structure: A Model-Based Analysis of the Period 2013–2017

This paper analyses the recent developments in the global oil market, investigating how the 2014–2016 price collapse and the following OPEC+ agreement affected the crude oil market structure and the behavior of major suppliers. To this end, we develop a partial equilibrium model with a spatial structure for the global crude oil market and simulate the market for the period between 2013 and 2017 under different market structure setups. The simulation results reveal that, although the oligopolistic market structures fit overall well to the realised market outcomes, they are not successful at explaining the low prices during 2015 and 2016, which instead are closer to estimated competitive levels. We further suggest that from 2014 onward, the market power potential of major suppliers has shrunk considerably, supporting the view that the market has become more competitive. We also analyse the Saudi Arabia- and Russia-led OPEC+ agreement, and find that planned production cuts in 2017, particularly of Saudi Arabia and Russia, were below the levels of estimated non-competitive market structure setups.

4.1. Introduction

The global oil market went through significant turmoil in recent years. After a period of increasing oil prices in the 2000s, prices sky-rocketed to record highs in summer 2008. Although the credit-crunch put a temporary halt on high prices, the fast recovery of the global economy stabilised the oil prices at an average of \$100 per barrel (bbl) during the period between 2011 and 2013. High oil prices over this period triggered two major developments in the global oil markets: First, renewable energy investments were intensified, leading to a decline in future expected demand for all fossil fuels. Second, higher cost resources, especially shale oil in the USA, became an economically viable option for producers, which caused a glut in global oil supply capacity. Both developments had profound effects on the market, particularly beginning with the second half of 2014, represented by the third biggest oil price collapse since the 1980s (Baffes et al., 2015).

There have been numerous attempts to analyse the drivers of the 2014 oil market crash.[1] Some researchers have attributed the decline in the price to supply side developments, i.e., high production levels both in non-OPEC (mostly US shale oil) and in OPEC countries (Husain et al., 2015). As correctly noted by Baffes et al. (2015), there were also other factors such as weakening global oil demand, appreciation of the US dollar, OPEC's policy responses to price declines and loosening of geopolitical conflicts (e.g., lifting sanctions on Iran[2]). Although the price collapse has created a shift in the perception on how OPEC's role might evolve in the future, Dale (2016) notes that some of the core principles, such as oil being exhaustible, supply being price inelastic, oil flowing from East to West, and the principle of OPEC being the central force in the market, are still valid for the global oil market.[3]

A significant number of studies in the literature attribute the price collapse to the policy of OPEC and specifically to that of Saudi Arabia.[4] In the aftermath of the 2014 price collapse, OPEC members, and in particular Saudi Arabia, which is generally regarded as the global swing supplier, have not reduced production levels. This was most likely based on the expectation that low prices would decrease shale investments, forcing shale producers out of the market. According to Fattouh et al. (2016), the underlying logic in this decision was to protect market share assuming shale oil supply is price elastic. On the other hand, US shale oil production has increased gradually, mainly thanks to the developments in hydraulic fracturing technologies, which further reduced the break-even prices for shale oil. Hence, OPEC's and particularly Saudi Arabia's strategy to ultimately drive shale oil producers out of the market did not pay off as shale oil proved itself to be more resilient than expected (Behar and Ritz, 2017).

[1] e.g. Baffes et al. (2015), Dale (2016), Fantazzini (2016), Fattouh et al. (2016), Huppmann and Holz (2015), Husain et al. (2015), Khan (2017)

[2] Having been significantly affected by the long-lasting sanctions, Iranian oil supply strongly increased after the partial lifting of sanctions in January 2016, rising about an additional 0.5 million barrels per day in the following period in 2016 (Dudlák, 2018).

[3] Analysis of the economic dynamics and the market structure of the oil market as well as the behaviour of OPEC dates back to the oil crises period of 1970s. Please see Crémer and Weitzman (1976), Salant (1976) Adelman (1980), Erickson (1980), Gately (1984), Griffin (1985), Jones (1990), Crémer and Salehi-Isfahani (1991), Dahl and Yücel (1991), Griffin and Neilson (1994), Gülen (1996), Alhajji and Huettner (2000a,b), among others.

[4] e.g.Ansari (2017), Baffes et al. (2015), Baumeister and Kilian (2016), Behar and Ritz (2017), Coy (2015), Fattouh and Sen (2016), Gause (2015), Huppmann and Livingston (2015), Prest (2018)

The 2014 price collapse had severe implications for major oil exporters; namely, Russia and OPEC members. Despite that OPEC countries have lower production costs, their government budgets rely heavily on oil export revenues. According to Ramady and Mahdi (2015), the minimum fiscal break-even price for OPEC members is \$60/bbl. Hence, an oil price floating in the \$40–50/bbl range has been a burden for their economies. Both due to the performance of shale oil under the low price regime and diminishing profits of OPEC members in the aftermath of the price collapse, major OPEC members started to shift their strategy from flooding the market to capacity withholding starting from the second half of 2016. On September 28, 2016 (during the 170^{th} OPEC meeting) it was announced that the members had agreed to cut production for the first time in eight years. Afterwards, during the 171^{st} OPEC meeting, a “Declaration of Cooperation" between OPEC and some non-OPEC producers, including Russia, Mexico, Azerbaijan and Brazil, was signed. Within the context of this cooperation (which is now known as the OPEC+ agreement), OPEC members, excluding Iran, should have cut 1.2 million bbl/day effective as of 2017, while their non-OPEC counter-parts were assigned a cut of 0.56 million bbl/day. Saudi Arabia and Russia led the OPEC+ agreement with agreed cut levels of 486 and 300 thousand bbl/day, respectively.

In line with the agreement, OPEC+ participants have shown high compliance levels throughout 2017. As an immediate effect of the OPEC+ agreement, oil prices, once having declined to historically low levels of around \$26/bbl in January 2016, increased up to around \$67/bbl in December 2017.[5] At first glance, the shift from a market flooding strategy of Saudi Arabia and of various other major suppliers within and outside OPEC during 2015 and most of 2016, to a more cooperative capacity withholding strategy within the context of the OPEC+ agreement in 2017, seems to have been successful. Hence, it is also plausible to ask whether the OPEC+ agreement was able to change the market structure back to what it was prior to the price collapse. If this is indeed the case, then it can be said that the agreement was deliberately designed to help major OPEC+ participants, particularly the leaders of the agreement, i.e. Saudi Arabia and Russia, to reclaim market power against the shale oil suppliers.

In the light of recent developments in the crude oil market, this paper aims to answer the following research questions: i) How did the market structure evolve

[5]For the data source please refer to `https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm`. Access Date: March, 13, 2019.

over the period 2013–2017? Did a shift in the market structure occur after the 2014 price collapse? ii) How can the behaviour of key suppliers be explained by the estimated market structures during the period following the price collapse? iii) Was it the aim of the OPEC+ agreement to change the market structure, and, if so, was it successful at reclaiming market power for the participants of the agreement? In order to answer those questions, we develop a global oil market simulation model, named DROPS, which is a computable equilibrium model, formulated as a mixed complementarity problem (MCP). MCP based models have been extensively used in the literature for the analysis of energy commodity markets due to their versatility.[6] The advantage of the MCP formulation is that it allows to include multiple agents with different interests each having their own optimisation problem, allowing the simulation of markets under various market structure assumptions. Applying our model, we simulate the crude oil market with quarter-yearly resolution during the period between 2013 and 2017 under different market structure setups, such as perfectly competitive, oligopolistic and cartel.[7] By comparing model estimations with historical data, we are able to decide on the best-fitting market structure assumptions for individual periods and can tell whether a shift regarding the market structure and the market power of suppliers occurred during the analysed time period.

There is a wide stream of literature which deals with the structure of the crude oil market and market power of the suppliers. In many studies, the crude oil market is referred to as a good example of a market in which at least some of the suppliers exert considerable market power (e.g. Alhajji and Huettner, 2000a,b, Dahl, 2004, Smith, 2005). Golombek et al. (2018) for instance, using a parsimonious dominant firm model for the global crude oil market, finds that OPEC has exerted considerable market power between the years 1986 and 2016. Yet, some researchers suggest that the oil market has moved to a more competitive structure in the aftermath of the 2014 price collapse (Baumeister and Kilian, 2016, Prest, 2018). Both Baumeister and Kilian (2016) and Prest (2018) utilise empirical methodologies. While, Baumeister and Kilian (2016), using a structural VAR model, mentions that the main driver of the price collapse was the demand side, Prest (2018) suggests that Saudi Arabia and

[6]For example: natural gas markets (Berk and Schulte, 2017, Gabriel et al., 2005, Growitsch et al., 2014, Schulte and Weiser, 2019b); coal markets (Hecking and Panke, 2015, Trüby, 2013); and oil markets (Ansari, 2017, Huppmann and Holz, 2012, Langer et al., 2016).

[7]We exclude 2018 data from our analyses due to rather volatile OPEC+ compliance levels during that year, which were also strongly driven by external factors such as the Venezuelan crisis. Refer to Section 4.5 for more detailed information.

OPEC have lost market power in the aftermath of the 2014 price collapse. A similar result has been previously provided by Huppmann and Holz (2012), who analysed the market structure in the crude oil market during the period between 2005 and 2009, suggest that the market was closer to a Stackelberg leader structure between 2005 and 2008 and more competitive after the price decline in 2008 following the global economic crisis.

Our paper is one of the few quantitative papers using a computable partial equilibrium model to investigate the 2014 price collapse in the oil market. We are only aware of one other paper, namely Ansari (2017), that uses a similar methodology in order to simulate the global crude oil market around the 2014 price collapse.[8] Ansari (2017), similarly, using computable partial equilibrium models with different market setups, investigates the behavior of major suppliers during the period from the fourth quarter of 2011 to the fourth quarter of 2015 and comes to the conclusion that low prices in 2015 cannot be explained by static competition; rather, they are a result of the dynamic calculus of OPEC, who have possibly pursued a market share strategy. We on the other hand, reaching a similar conclusion for the oil market developments during 2015 and 2016, extend the analyses to cover the developments in 2017, the first year of the OPEC+ agreement. We also focus on the market power potential of OPEC and investigate how it has changed throughout the analysed time frame. An established approach in the literature on market structure analysis when using spatial models is to compare simulated trade flows to historical flows, which has been commonly used, for instance, in the analysis of coal markets (e.g., Kolstad and Abbey, 1984, Lorenczik and Panke, 2016, Trüby, 2013). The methodology, however, to the best of our knowledge, has so far not been applied to crude oil markets. Therefore, it can be said that another major contribution of our paper is the spatial structure of our model and the simulation of crude oil trade flows in order to decide on best-fitting market structures.

The main findings of our paper can be summarised as follows: First, according to our model results, while oligopolistic market structures fit best to the observed crude oil market fundamentals throughout the considered time period and are also successful at simulating the prices before the price collapse, they cannot explain the low prices during 2015 and 2016, which instead converge toward the estimated perfectly competitive levels. This leads us to conclude that, despite

[8]Previous studies have proposed global oil market simulation models (e.g., Al-Qahtani et al., 2008, Aune et al., 2010, Huppmann and Holz, 2012). Their analyses, however, cover previous developments in the oil market before the 2014 price decline.

the market continuing to have an oligopolistic structure, the market structure in the post-2014 price decline has progressed in a more competitive direction. Accordingly, we find that attaining pre-2014 price levels of around \$100/bbl is possible only with strong OPEC cartel behaviour. Second, we observe that the market power potential of Saudi Arabia and OPEC as a whole has significantly decreased following the price crash, making it much more likely for them to pursue a market share strategy instead. Moreover, in the case of OPEC, we see that additional profits via cartelisation is much more limited, as significant market share is lost to Russia which fills the ensuing supply gap. This, in turn, implies it was necessary to have Russia on board when jointly cutting production; thus, explaining the motivation behind the historical OPEC+ agreement. Third, focusing on the OPEC+ agreement, we evaluate whether planned and observed production cut levels within the context of the agreement could be explained by the considered non-competitive market structure setups. We find that both planned and actual cut levels were significantly below those that are estimated by our model. Hence, it can be said the OPEC+ production cuts were not enough to reclaim market power for the participants of the agreement; rather, they were probably aimed at stabilising the prices at levels which are high enough not to hurt the fiscal regimes of the suppliers, while being low enough not to promote shale supply.

The remainder of the paper is structured as follows: In Section 4.2, we present the model used for the analysis in detail and discuss the assumptions and the data. In Section 4.3, we introduce the market structure setups that were investigated in the model and present our results for the period 2013–2017 in the form of simulated prices and statistical analyses to decide on the best-fitting market structure. The 2014 price crash and the behaviour of the major suppliers in the following period is then presented and discussed in Section 4.4. Section 4.5 proceeds to highlight the developments that have led to the OPEC+ agreement and presents model results, elaborating on the rationale of the OPEC+ signatories as well as discussing the effects of the deal. Finally, Section 4.6 concludes with policy implications.

4.2. Methodology, assumptions and data

The DROPS model developed in the framework of this study is a partial equilibrium model which allows the simulation of the global crude oil market for a desired time-period. It is formulated as a mixed complementarity problem (MCP) and is implemented in the software package GAMS and is solved using the PATH solver (Ferris and Munson, 2000). MCP modelling requires first-order conditions to be used instead of an objective function in order to find the optimal solution. Hence, solving the problem corresponds to finding a vector satisfying those conditions. Multiple agents with different interests (e.g. OPEC and non-OPEC suppliers) can be modelled, each of them having their own optimisation problem. Such a formulation allows us to simulate various market structures. For instance, an oligopolistic market structure can be simulated where producers have the market power to strategically withhold capacities in order to maximise their profits. In the global oil market, one of the prominent discussions since the foundation of OPEC in 1960 has been how OPEC really functions. Our model is thus capable of simulating some of the common behaviour assumptions for OPEC. The case of a true cartel, or a cartel dominated by core producers, or yet a slightly looser Cournot oligopoly — where each member aims to maximise its individual profit — can be represented with the help of the conjectural variation structure implemented in the model.[9] With this approach, we are able to investigate the historical market conditions and determine the most likely strategy followed by OPEC by deciding on the most fitting market setup. The mathematical structure of the model, the Karush-Kuhn-Tucker (KKT) conditions, as well as the sets, variables and parameters are presented in Appendix C.1.

DROPS considers the spatial structure of the global market for crude oil where the producers and consumers are mapped in a nodal network, similar to the structure of the COLUMBUS model (Hecking and Panke, 2006). Production nodes are assigned to the producing regions and consumption nodes are assigned to the demand centres. The respective nodes are connected by arcs representing pipelines or naval tanker routes, while infrastructure constraints such as pipeline capacities are taken into account. Note that, while the majority of producer countries are assigned single production nodes, countries with multiple distant production regions such as the Russian Federation and the United States are taken into account with multiple production nodes. The model consists of a total of 86 nodes made up of 43 production nodes, 34 consumption nodes as well as 9 straits and choke points which play a key role in the tanker transport of crude oil.

[9]For detailed explanation of the conjectural variation approach in MCP models see Perry (1982) and Dockner (1992).

Consumers in the model are represented by their respective inverse linear demand function. The demand function is estimated by using a reference price and a reference demand as well as the elasticity of demand in that country. Producers are assigned a piece-wise linear supply function, with corresponding production capacities allocated to each cost level. Besides consumers and producers, the model also includes exporters which can control one or multiple production nodes. The exporter of a particular production node decides on how much to produce at that node as well as how much quantity to supply to individual demand nodes. By including exporters in the model, we can model market imperfections, particularly monopoly or cartel behaviour, by assigning production nodes in different regions to a single exporter.[10] For instance, OPEC is considered as a single exporter in the case of assuming cartel behaviour.

There are various assumptions and simplifications made in the model and the associated data. First of all, the demand side is considered by assuming linear inverse demand functions for individual countries and for various country groupings. Each function is obtained using a reference price, reference demand and an elasticity of crude oil demand for that country, based on the methodology illustrated in Lise et al. (2008). Reference price data (in \$/bbl) is taken from the international statistics of U.S. Energy Information Administration (EIA International Statistics, 2018). Brent crude oil prices are chosen to represent the reference prices for each demand node.[11] Moreover, reference demand data (in bbl) is compiled from EIA International Statistics, IEA Medium Term Market Reports (IEA, 2014a, 2015a, 2016a) and Market Report Series (IEA, 2017a, 2018a).[12]

The topic of demand elasticities for crude oil has been widely covered in the literature, where short-term price elasticities in the range of 0.001 to -0.34 having been suggested (e.g., Baron et al., 2014, Cooper, 2003, Fattouh, 2007, Hamilton,

[10] Additionally, the set of exporters also include arbitrageurs which do not possess any production nodes and are defined to be active only at the consumption nodes. Arbitrageurs exploit the price differences between different regions and represent the traders in real life. Inclusion of arbitrageurs is commonly used for pool-pricing in oil market models (see for instance, Huppmann and Holz (2012)), in order to control for strong co-integration between different oil price benchmarks.

[11] Price of Brent crude is chosen as the reference price because of the fact that it is widely used as the main international benchmark. As explained in Appendix C.1, the model estimates prices of oil consumed by each demand node at the equilibrium.

[12] Data used for reference demand includes monthly data from EIA for the largest OECD consumers (US, Japan, South Korea, Canada, Italy, UK, Germany, France), quarterly data from IEA Medium-Term Oil Market Reports for the largest non-OECD consumers (China, India, Brasil, Russia, Saudi Arabia, Iran), and annual data from EIA for all the other smaller consumers.

2009). Considering the findings in recent literature on oil demand elasticities (Caldara et al., 2019, Javan and Zahran, 2015), and also in line with the latest oil market model applications in the literature (e.g., Ansari, 2017, Huppmann and Holz, 2012), we assume in our analysis the short-term price elasticity of demand to be equal to -0.1 for all the considered demand regions in the model.

Production data is compiled from Oil, Gas, Coal, and Electricity Quarterly Statistics of the International Energy Agency (IEA, 2014b, 2015b, 2016b, 2017b, 2018b).[13] Historical i.e. actual spare capacities for OPEC members are based on the estimates provided in IEA Medium-Term Oil Market Reports (IEA, 2014a, 2015a, 2016a) and IEA Market Report Series (IEA, 2017a, 2018a). For non-OPEC producers, we assume that historical production corresponds to 97% of the available capacity and the remaining 3% is taken as their spare capacity, in line with Behar and Ritz (2017) and Ansari (2017). Production costs used in the study are acquired from multiple sources such as Aguilera et al. (2009) and BEIS Fossil Fuel Supply Curves (2016) as well as industry professionals. Production costs follow the structure outlined in Golombek et al. (1995), with marginal costs rising greatly as production approaches the capacity limit. We differentiate between transportation via pipeline and tanker shipping, where the costs are assumed to increase linearly with distance. Tanker shipping costs are calibrated according to the Baltic Dry Index (BDI) (Bloomberg, 2018).

We further assume in our model that the crude oil supplied is of homogeneous quality. In reality, crude oil varies considerably in its properties and different regions can prefer to consume a specific type of crude oil. In our model, this issue is indirectly controlled by taking into account the API gravity and sulphur content including a mark-up on the production costs of regions with lower oil quality, as also discussed in Huppmann and Holz (2012) and Ansari (2017). Consideration of quality differences in crude oil would be beneficial if the refinery sector was explicitly modeled. However, since we are concentrating on upstream oil industry only, controlling quality differences by a cost margin serves our purpose.

We assume that all exporters in the model are countries, not oil companies. On the other hand, the largest crude oil production is taking place in the USA and is conducted by numerous private companies. Nevertheless, private companies are generally price takers, and thus are unlikely to have market power. Their omission, therefore, does not have a significant impact considering the purpose of

[13]The data is taken from Tables A1 and A2, and following the IEA methodology, is the sum of crude oil and natural gas liquids (NGL) production.

our analysis. Additionally, the exporters with the largest potential to withhold capacity — namely Saudi Arabia and other OPEC members as well as Russia — have national oil companies. Therefore, this approach is considered to represent the players in the global crude oil market sufficiently well.

4.3. A numerical application of the model: market structure in the period 2013–2017

In this section we apply the crude oil market model introduced in the previous section for the period 2013–2017 under different market structure assumptions.[14] The market structure setups and the reasoning behind choosing them are as follows:

i. **Competition**: Perfectly competitive market setup, where each supplier acts as price-taker. Conjectural variation parameter of every supplier is equal to 0.

ii. **Oligo_OPEC**: In this setup, OPEC members are assumed to have market power (i.e. their conjectural variation parameter is equal to one) and to behave as an oligopoly while other suppliers form a competitive fringe (all non-OPEC suppliers have a conjectural variation equal to zero).

iii. **Cournot**: All suppliers can exert market power and they compete against each other in a static Cournot setup.

iv. **Cartel_OPEC**: OPEC members jointly maximise profit as a whole and compete in a static Cournot setup against other suppliers.

v. **Cartel_OPEC_core**: Due to the significant variation in cost structures as well as different political aims of the members, it is common in literature to consider OPEC as two distinct parts; namely, a collusive core group and a non-core rest (e.g., Aune et al., 2017, Gately, 2004, Gülen, 1996). In this market setup, similar to Aune et al. (2017) and Golombek et al. (2018), we consider that OPEC countries which are also members of the Gulf Cooperation Council, namely Saudi Arabia, Kuwait, United

[14] Production capacities of OPEC members and OPEC+ participants in the model can be found in Appendix C.1.5.

Arab Emirates and Qatar[15] form a cartel, while the non-core OPEC as well as the rest of suppliers separately play a Cournot game.[16]

vi. **Cartel_OPEC+**: Signatories of the OPEC+ agreement from 2016 onward are assumed to act as a cartel and jointly maximise profit while every other supplier separately plays a Cournot game. This market structure setup is defined specifically for the analysis of OPEC+ agreement and is considered solely in Section 4.5.

In Figure 4.1, crude oil prices[17] from the model simulations for different market setups are plotted against historical Brent crude oil prices for the period 2013–2017. It can be seen that the Cournot and the Competitive market assumptions form a price corridor around the historical prices. The Oligo_OPEC setup, with oligopolistic OPEC members and a competitive fringe, seems to fit the historical prices particularly well for the 2013–2014 period before the price plunge. From the second half of 2014 onward, however, the historical prices move towards the estimated competitive levels. It is only after the second half of 2017, following the implementation of the OPEC+ agreement, that the prices again start increasing in the non-competitive direction. Nevertheless, model results indicate that attaining pre-2014 price levels of around \$100/bbl during 2015–2017 is only possible with strong cartel behaviour.

[15] Our analyses are based on the period until the end of 2017. Qatar has terminated its OPEC membership starting 1 January 2019.

[16] The main reasoning behind this is that the core OPEC countries, being producers with low production costs and high GDP per capita, are more likely to have similar interests and therefore are less likely to deviate from the cartel obligations compared to members with higher production costs and weaker economies.

[17] For consistency, these prices correspond to the price levels observed in the West Europe demand node in the model.

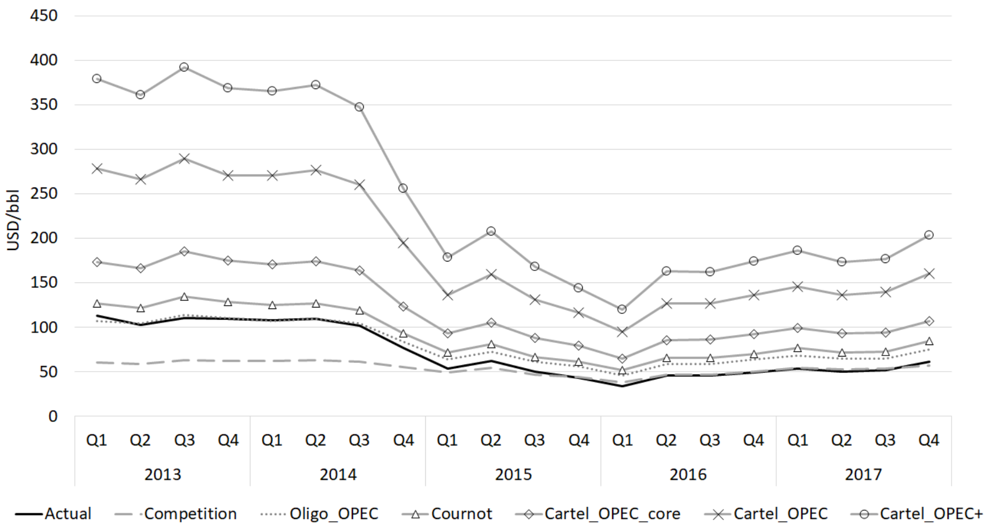


Figure 4.1.: Historical development of the Brent price index and the simulated prices, 2013–2017

Another observation is that historical prices during the period 2015–2017 remain at times below the model estimated competitive levels. This is in parallel with the findings presented in Ansari (2017), implying that in those instances prices possibly fell below marginal costs of production for some producers. However, we should also note that this phenomenon, in our case, is quite cost sensitive. Assuming 30% lower production costs for all producers, for instance, eliminates those instances.[18] Nevertheless, it can be argued that our model, with its static profit-maximisation structure, cannot perfectly explain the historical prices in some occasions. It is possible that the rapid scaling potential of the US supply has caused Saudi Arabia to weigh its short-term gains by withholding capacity against long-term losses due to a potentially even larger US oil industry. This dynamic consideration could have played a role in Saudi Arabia's market-share strategy and driven the actual prices, which in this case would differ from the model-estimated prices that are strictly static game theoretic results.

In order to decide on the market structure which is most representative of the considered time period, we would like to see how well the simulated trade flows match the actual flows. For this purpose, we conduct several statistical tests:

[18]See Appendix C.3 for the results of the sensitivity analysis.

Linear hypothesis testing, Spearman's rank correlation, and Theil's inequality coefficient.[19]

The p-values of the linear hypothesis test are presented in Table 4.1 for the individual years.[20] The hypothesis that the perfectly competitive case predicts trade flows is rejected on the 99.9% level for all the considered years. Similarly, the hypothesis with the Cartel_OPEC_core setup can be rejected in every year except 2017. On the other hand, the Cournot setup is not rejected for any year and the Oligo_OPEC setup cannot be rejected except for 2017. Note that Cartel_OPEC_core setup, despite being rejected for the period 2013–2016 period at various significance levels, cannot be rejected for the year 2017. This is also the year when the joint production cuts agreed on OPEC+ deal started being implemented, hence it is possible that a degree of cartelisation was prevalent in the market and is thus reflected in the historical trade flows.

Table 4.1.: P-values of the linear hypothesis tests ($\beta_0 = 0$ and $\beta_1 = 1$)

	Competition	Oligo_OPEC	Cournot	Cartel_OPEC_core
2013	0.000 ***	0.411	0.258	0.008 **
2014	0.000 ***	0.214	0.332	0.019 *
2015	0.000 ***	0.201	0.451	0.056
2016	0.000 ***	0.256	0.469	0.034 *
2017	0.000 ***	0.025 *	0.333	0.154

Significance codes: 0 '***' 0.001 '**' 0.01 '*' 0.05

Figure 4.2, where Spearman's rank correlation coefficients and Theil's inequality coefficients are plotted, allow us to compare the relative quality of the fit of simulated to actual flows between different models.[21] Throughout the

[19] The idea behind the linear hypothesis testing is to check how well model trade flows conform with actual flows by regressing the simulated flows on the actual flows. In the case of a perfect match, the slope of the linear equation would be equal to one and its intercept would be zero. In order to see whether the slope and intercept are jointly equal to one and zero, respectively, a linear hypothesis test is conducted. See Appendix C.2 for a detailed description of the statistical methods used.

[20] The market structure setups, Perfect, Oligo_OPEC and Cournot, each have 65 observations (i.e. trade flows) for the respective years. The Cartel_OPEC_Core setup has 50. Cartel_OPEC and Cartel_OPEC+ setups are not considered due to limited number of trade flows.

[21] The Cartel_OPEC_core setup is not considered in this analysis due to the smaller sample size.

considered years, both of the oligopolistic setups perform better than the Competition setup with respect to the Spearman and Theil coefficients. The Oligo_OPEC setup performs consistently better than the Cournot setup with respect to the considered statistical coefficients. On the other hand, it can be said that the Cournot setup outperforms Oligo_OPEC in the linear hypothesis testing.[22]

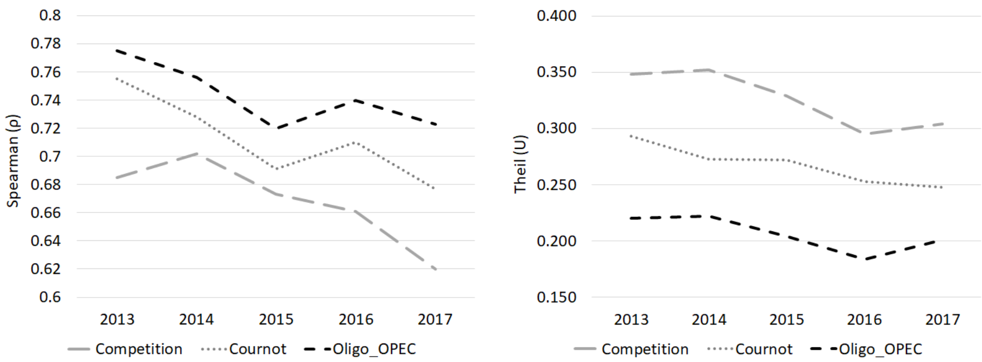


Figure 4.2.: Spearman's correlation coefficients and Theil's inequality coefficients for the analysed time period of 2013–2017

Our results can be summarised as follows: According to the trade flow analysis, the global crude oil market structure throughout the period 2013–2017 can best be represented by the oligopolistic setups among the market setups considered; i.e. either by the Oligo_OPEC setup, with OPEC oligopoly and competitive fringe; or the Cournot setup, where every supplier acts as a Cournot player. However, while oligopolistic models are successful at explaining prices before 2014, we see that historical prices converge towards the estimated competitive levels during the period 2015–2016. This leads us to conclude that the market structure in the post-2014 price decline has moved towards a more competitive direction, with various suppliers possibly losing market power, while the market remains to have an oligopolistic structure. This further supports the view in the literature (Ansari, 2017) that the behaviour of OPEC, in particular that of Saudi Arabia, has not become perfectly competitive in the aftermath of the price decline of 2015; rather, it is a reflection of the loss of its market power in the face

[22]Similar to Trüby (2013), we can also confirm that oligopolistic models, because of their higher trade diversification, outperform the perfectly competitive setup with respect to trade flow accuracy. In non-competitive models, since the marginal revenue of an oligopolist at an importing region decreases as its market share in that region increases, diversifying its exports yields higher profits for the oligopolist. As a result, trade with regions occur that typically are not seen in the perfectly competitive case where trade flows occur purely based on cost relationships.

of strong competition from increasing levels of shale oil supply on the market. The new realities of the market have thus potentially constrained the extent to which the suppliers such as Saudi Arabia and other OPEC members could react. Section 4.4, where the behavior of major suppliers during the 2014–2016 price collapse are analysed, illustrates this aspect in more detail.

4.4. A shift in the crude oil market: the 2014–2016 oil price plunge

The global crude oil market went through quite a volatile period over the last decade as can be observed in Figure 4.3. A major shift in the crude oil market occurred in the second half of 2014, culminating in two important turning points: First, thanks particularly to the shale oil revolution, the USA became the largest crude oil producer, surpassing Saudi Arabia. By the end of 2018, crude oil production in the USA increased to around 16.2 million bbl/day, while Saudi Arabian and Russian production stayed at levels of 12.4 million bbl/day and 11.8 million bbl/day, respectively. Second, oil prices collapsed from around \$110/bbl to historically low levels of around \$35/bbl during the period from the second half of 2014 until the beginning of 2016.

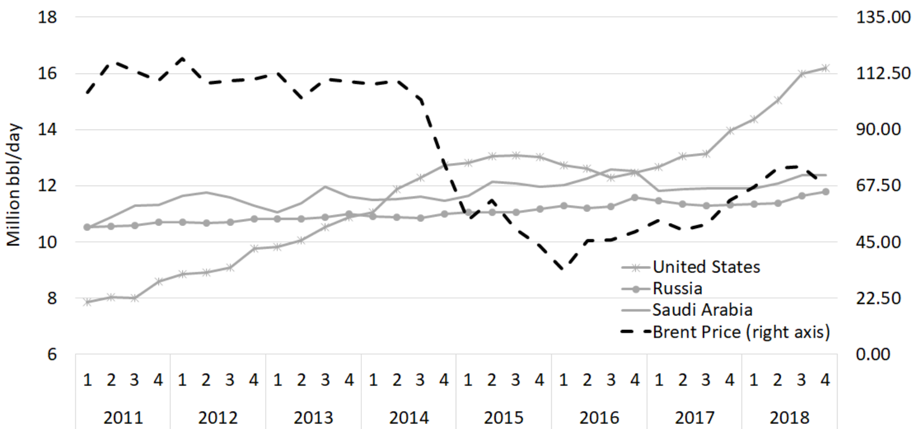


Figure 4.3.: Crude oil production in the USA, Saudi Arabia and Russia (in million bbl/day on the left-axis) and Brent Prices (in USD/bbl on the right-axis), over the period between 2011 and 2018

The reasons and implications of the 2014–2016 oil price collapse have been extensively discussed in the literature. Some researchers have attributed the plunge in oil prices to the increase in the non-OPEC supply, particularly to the shale oil production capacity in the USA (see for instance, Husain et al. (2015)). Yet, as suggested by previous literature (Ansari, 2017, Behar and Ritz, 2017) and as can clearly be seen in Figure 4.3, US production has increased quite gradually for some time while the oil prices collapsed abruptly. Hence there is still room to be skeptical of this reasoning. Another suggested driver behind the price collapse was OPEC's, mainly Saudi Arabian, policy not to cut production in the wake of price collapse but rather keep flooding the market. As can be observed in Figure 4.3, Saudi Arabia continued to increase the production level gradually until the first quarter of 2016 in contrast to expectations that it would withhold significant amount of capacity in order to increase the prices. In fact, Saudi Arabia did not cut production before early 2017, at the time when the OPEC+ agreement had finally become active.[23]

Various reasons behind Saudi Arabia's policy of flooding the market have been mentioned in the literature; such as testing shale oil resilience (Behar and Ritz, 2017), Saudi Arabian expectation from other OPEC members to also withhold capacities (Fattouh et al., 2016, Fattouh and Sen, 2016), and inner Saudi Arabian politics.[24] Whereas in reality the Saudi Arabian strategy was likely a result of numerous simultaneous factors combined together as mentioned above, we investigate how the transformation in market structure as well as a potential loss of market power could have nevertheless limited the options for other types of strategies.

[23]Please see Section 4.5 for detailed discussion on the OPEC+ agreement and its implications on the market.

[24]For example: Crown Prince Bin Salman's vision to relieve the country's economy from oil revenue dependency. Please see https://vision2030.gov.sa/en/foreword, accessed on 21.02.2019

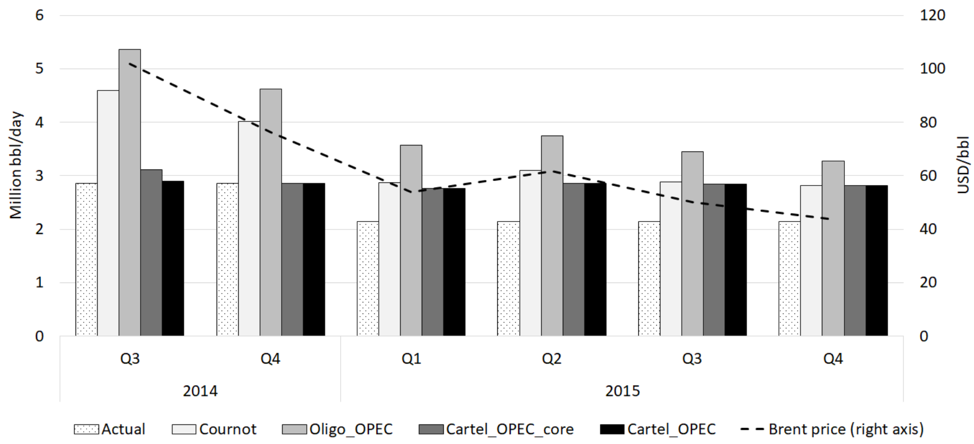


Figure 4.4.: Realised and simulated spare capacity of Saudi Arabia vs. actual crude oil price

Notes: Simulated spare capacities are calculated as the difference between exogenous production capacity assigned to the supplier and simulated production volumes.

Figure 4.4 plots actual and model-estimated spare capacities of Saudi Arabia under different market structure assumptions. Starting with the third quarter of 2014, Saudi Arabia would have cut more volumes (i.e. withheld more capacity) in all non-competitive assumptions in the aftermath of the price collapse, compared to their historical capacity withholding.[25] Nevertheless, the capacities that would have been withheld in non-competitive assumptions have significantly declined in 2015, especially in the Cournot and Oligo_OPEC variants, which were previously shown to represent the underlying market structure most successfully. This implies that, after 2014, Saudi Arabia's potential of capacity withholding for profit maximisation was actually relatively limited, which was due to a combination of slower demand growth and increasing US shale oil capacities. This made it, therefore, more likely for Saudi Arabia to shift its policy towards a market-share protection strategy instead, as also mentioned by Fattouh et al. (2016) and of Ansari (2017).

[25]Spare capacities in the perfectly competitive case are not presented in Figure 4.4 for the sake of clarity. In the case of Saudi Arabia, it does not withhold any capacity when behaving as a price-taker due to its significantly lower production costs.

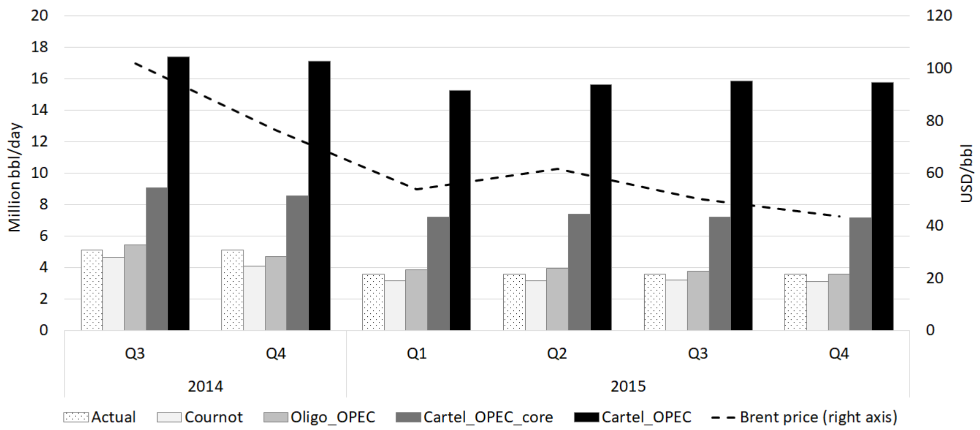


Figure 4.5.: Realised and simulated spare capacity of OPEC vs. actual crude oil price

Since the oil crises periods in 1970s, there has been a long-lasting debate on whether OPEC behaves as a cartel in the oil market.[26] It has even been referred to by some as a "clumsy-cartel" (Adelman, 1980). The behaviour of OPEC after the 2014 price crash also comprises an important part of our research question. In this regard, realised and estimated spare capacities of OPEC members in total are plotted in Figure 4.5 from the third quarter of 2014 till the fourth quarter of 2015. It can be seen that OPEC has historically withheld significantly less capacity after the price collapse, compared to previous periods. Moreover, OPEC's historical capacity withholding is quite comparable with levels observed in Cournot and Oligo_OPEC scenarios. Figure 4.5 also indicates that if OPEC had acted as a joint Cartel (i.e. as in the Cartel_OPEC setup), the capacity withholding would have been more than three times that of the historical levels. Such a high level of cooperation and cartelisation is of course very unlikely in reality due to OPEC members each having different economic and political interests. Nevertheless, the hypothetical Cartel_OPEC_core market structure, where only OPEC countries who constitute the low-cost producers of OPEC and who share similar GDP per capita levels[27] are assumed to act as a cartel, reflects theoretically a more probable case. Even in this theoretically more realistic, weaker cartel setup, we see that OPEC would still have withheld much higher capacities than it actually

[26] See for instance, Adelman (1996), Alhajji and Huettner (2000a,b), Brémond et al. (2012), Gately (1984), Golombek et al. (2018), Griffin and Neilson (1994), Gülen (1996), Huppmann and Holz (2015), Smith (2005), among others.

[27] The considered OPEC producers are also members of the Gulf Cooperation Council; namely Saudi Arabia, United Arab Emirates, Kuwait, and Qatar.

did. Our findings therefore lead us to rule out strong cartel behaviour for OPEC during the considered period, implying an OPEC structure as an oligopoly or a very loose cartel was most possibly the prevalent structure.

A similar analysis on Russia would also shed some light on how a major non-OPEC supplier behaved over the same period (Figure 4.6). Findings suggest quite comparable results to that of Saudi Arabia, such that, one would expect significantly higher levels of capacity withholding from Russia, particularly during 2015, if Russia had behaved as a Cournot supplier. Hence, in line with Ansari (2017), we suggest that instead of short-term profit maximisation behavior, other strategic concerns such as market-share protection must have interfered with Russian oil supply dynamics. It is also plausible that Russia would not choose a bilateral production cut without the back-up from Saudi Arabia and other OPEC members.

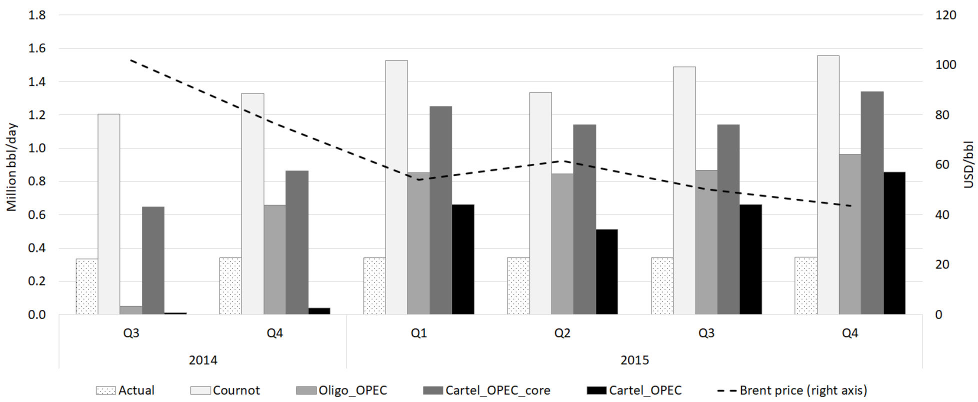


Figure 4.6.: Realised and simulated spare capacity of Russia vs. actual crude oil price

The findings discussed so far suggest that major suppliers in the oil market would have cut more production during the 2014–2016 oil price plunge if they had exerted market power to full extent. This could lead to a conclusion that, while at least some of the crude oil market suppliers could exert market power, market became relatively more competitive after the price crash. Prest (2018) points out this development by stating: “In summary, there is little evidence supporting the claim of strategic behavior by Saudi Arabia, and economic theory suggests many reasons why such behavior would be irrational. Rather, it is more plausible that Saudi Arabia’s recent behavior is consistent with that of a competitive supplier”.

Prest (2018) based his conclusions on the fact that over the recent years demand side of the market, rather than the supply side, has become more determining on the price movements in the oil market as also suggested by Kilian (2009). Using a structural VAR model Baumeister and Kilian (2016) similarly found that demand side expectations due to a weakening global economy have been the main driver behind the 2014 oil price collapse.[28]

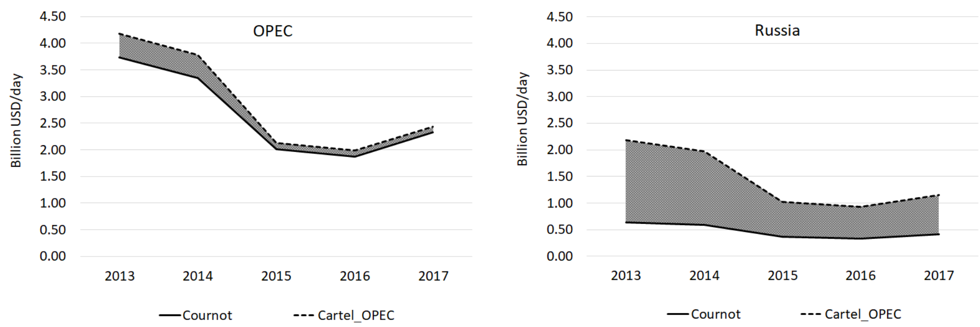


Figure 4.7.: Development of the simulated profits of OPEC and Russia

We can observe how the 2014 oil price collapse diminished the market power potential of the major suppliers by also looking at how their estimated profits change over the years. As can be seen in Figure 4.7, OPEC members and Russia experienced substantial profit losses in the years following the price decline. Whereas cartelisation is estimated to yield substantial profits for OPEC as a whole in 2013, additional profit gains for OPEC by collusion are quite limited in the post-2014 era. Cutting production as a unified cartel strongly benefits Russia, as Russia fills the ensuing supply gap and grabs OPEC market share. Hence, we can say that the diminished market power of Saudi Arabia and OPEC in the post-price collapse period, combined with the potential loss of market share to Russia in the case of capacity withholding, meant that it was necessary for Saudi Arabia and other OPEC members to take Russia on board for implementing effective production cuts. These factors formed the driving force behind the OPEC+ agreement, which we discuss and analyse in detail in the following section.

[28] After FED and ECB abandoned monetary easing policies pursued in the aftermath of the global crisis in 2008, short-term capital inflows that financed high growth rates of developing economies started to slow down. This brought expectations on slower than expected energy demand growth globally (IEA, 2015a, 2016a).

4.5. The change in Saudi Arabian policy and the OPEC+ agreement

Another turning point in the oil market since 2014 occurred in the second quarter of 2016 when oil prices began to rise again after a long-lasting decline. This date corresponds to a shift in the Saudi Arabian strategy from waiting and flooding the market to a more cooperative capacity withholding strategy, which eventually led to announcements of production cuts by several OPEC and non-OPEC suppliers within the context of the Saudi Arabia and Russia led OPEC+ agreement in November 2016. Although market share protection seemed to be a reasonable strategy in the aftermath of the price collapse, it also seems that strong resilience of US shale along with pressures on the fiscal budget emerged as important dynamics of the shift in the strategy of Saudi Arabia.

According to Ansari (2017), on the other hand, this shift in Saudi strategy was not entirely due to defense against shale, but rather due to the fact that circumstances supported such a decision. As previously mentioned, different studies suggested that Saudi Arabia would consider cutting production only if other major OPEC and non-OPEC suppliers are also on board with the Kingdom (Fattouh et al., 2016, Fattouh and Sen, 2016). This is in line with our findings so far, such that even if Saudi Arabia would have unilaterally cut production following the 2014 price collapse, prices as well as profits would have remained below pre-2014 levels due to the diminished market power potential. Production cuts with OPEC acting as a joint cartel, on the other hand, would not have been as effective in the new post-2014 era as it was during pre-2014, unless Russia also agreed to cooperate and jointly cut production. From this perspective, Saudi Arabia's waiting strategy seems to have paid off, since with the OPEC+ agreement, in parallel with the increase in oil prices, market power potential of suppliers, the profits of Saudi Arabia, of other OPEC members and of Russia increased. Accordingly, this section evaluates the historical background of the OPEC+ agreement and its implications for the oil market in 2017, the first year of production cuts.

Although the OPEC+ agreement became effective in 2017, signals pointing at the necessity to take precautionary steps to decrease volatility in the market were already mentioned by OPEC officials in 2015 during the 167^{th} and 168^{th} OPEC meetings. Yet, it was not until the 169^{th} OPEC meeting on June 2, 2016 when the importance of OPEC and non-OPEC cooperation to ensure market stability was emphasised. It took almost four more months for OPEC to agree on a production cut, for the first time in eight years, at the 170^{th} Extraordinary OPEC meeting that took place on September 28, 2016 in Algiers, Algeria. During this meeting, the “High Level Committee” (HLC) to develop consultations between OPEC and non-OPEC suppliers was established. This establishment, which is now known as the “Algiers Accord”, was an important turning point in the oil market, such that it was during the HLC’s first meeting which was held one month later in Vienna with the participation of six non-OPEC countries — namely, Azerbaijan, Brazil, Kazakhstan, Mexico, Oman and Russia — that the first traces of an OPEC+ agreement became apparent. Finally on November 30, 2016 during the 171^{st} OPEC meeting, the “Declaration of Cooperation” (known as the OPEC+ agreement) was signed. According to the agreement, OPEC members were allocated a total production cut of 1.2 million bbl/day and non-OPEC participants were to cut 558 000 bbl/day starting from January 1, 2017. Moreover, due to the continuing turmoil in the market throughout 2017, OPEC announced on November 30, 2017 the extension of the OPEC+ agreement over the year 2018.[29]

Figure 4.8 presents overall compliance[30] to agreed production cuts within the context of OPEC+ agreement by OPEC members, non-OPEC participants and by two major producers; namely, Saudi Arabia and Russia. As can be seen, overall compliance levels of the participants were quite high during 2017 and stabilised at almost 100% in the fourth quarter of 2017. Given that participants of the OPEC+ agreement, particularly OPEC members, showed almost 100% compliance during 2017, the question is whether the OPEC+ agreement was meant to change the market structure back to what it was during the pre-collapse period and help certain exporters such as Saudi Arabia and Russia reclaim market power potential. In order to address this question, we compare the planned production cuts with the actual production cuts, as well as with the model estimated cuts that would have occurred under different market structure

[29] The main source for the information provided in this paragraph is the OPEC website on press releases. Please refer to `https://www.opec.org/opec_web/en/press_room/28.htm` for further details. The OPEC+ agreement was effective at the time of writing this paper as on December 7, 2018 during the 175^{th} OPEC meeting the agreement was further expanded to cover the first 6 months of 2019. It is yet to be decided if a further extension would be made at the next OPEC Meeting, which will be held in June 2019.

[30] Compliance means the ratio of actual cuts to planned cuts. A compliance over 100% means cutting more than the planned, whereas a compliance below 100% is cutting less than planned i.e. cheating the agreement. Negative compliance means the supplier, instead of cutting, has actually increased production.

setups for selected suppliers.[31] Along with the two market setups that were shown to represent best the historical market structure, namely the Cournot and Oligo_OPEC setups, we also consider a hypothetical Cartel_OPEC+ setup, in which participants of the OPEC+ agreement behave strictly as a cartel and jointly maximise profit while other suppliers are competing against the cartel in a Cournot setup. The rationale behind this market setup is to understand whether the OPEC+ agreement was meant to create a new cartel formed by OPEC members and some non-OPEC suppliers including Russia.[32]

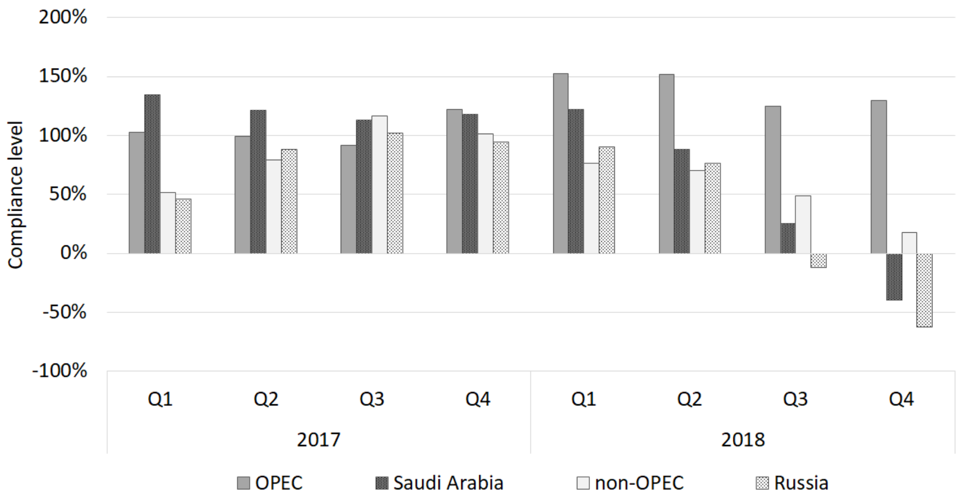


Figure 4.8.: Production cut compliance levels of OPEC and non-OPEC participants of the OPEC+ agreement

Note: OPEC compliance includes Saudi Arabia and non-OPEC compliance includes Russia.

Source: https://www.bloomberg.com/graphics/opec-production-targets (Accessed on 23.01.2019)

[31] We exclude 2018 data from our analyses because of the rather volatile trend of the compliance levels during that year. For instance, in the second quarter of 2018, compliance of OPEC members in total reached around 150%. On the other hand, over-compliance during 2018, particularly of OPEC, were attributed to various external factors such as the Venezuelan crisis (Halff et al., 2018) rather than deliberately made decisions. Moreover, due to high compliance levels it seems that Saudi Arabia and Russia started to cheat the agreement during the fourth quarter of 2018, which created another big oil price decline. According to the EIA, Brent oil prices declined by 41% from $85.63/bbl in October 2, 2018 to $50.57/bbl in December 27, 2018.(`https://www.eia.gov/dnav/pet/hist/RBRTED.htm`).

[32] Please note that Iran did not participate in the OPEC+ agreement. We, therefore, also exclude Iran from the Cartel_OPEC+ setup.

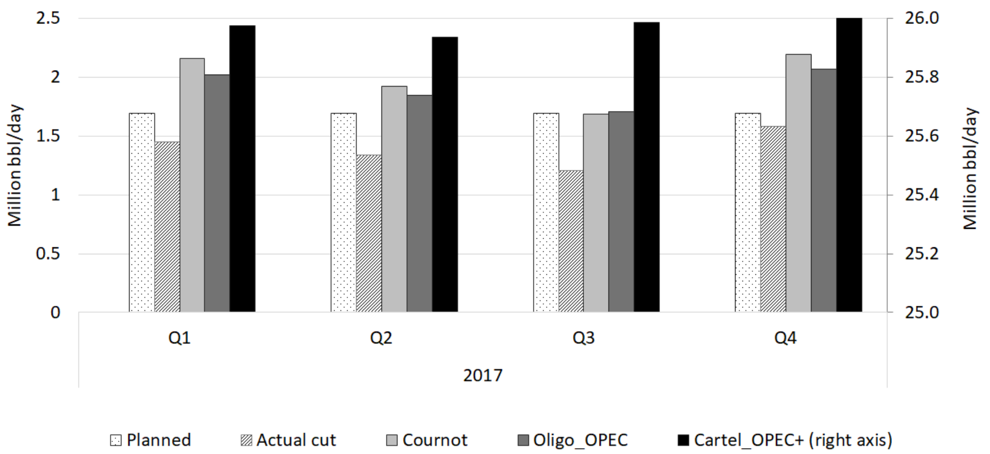


Figure 4.9.: Planned, actual and estimated cuts for major OPEC+ participants

Notes: OPEC+ participants include Russia, Mexico, Oman, Azerbaijan, Kazakhstan and Malaysia in addition to OPEC members except Iran. We are forced to exclude Bahrain, Brunei, South Sudan and Sudan, whose data is not available as there is no production node defined in the model for these countries. Yet, mentioned countries had only a planned cut of 26 thousand bbl/day in 2017; hence they are negligible.

In Figure 4.9, we compare planned, actual and simulated production cuts for all OPEC+ participants. According to the OPEC+ agreement that was signed in November 2016, production cut targets for 2017 were established relative to the observed November 2016 production levels of the participants. Model cut estimates, therefore, correspond to the difference between production estimates in the respective quarter of 2017 and the historical production levels that were observed during the last quarter of 2016. The planned cut for all OPEC+ participants together was around 1.7 million bbl/day, whereas the average actual cut was 1.39 million bbl/day during 2017. On the other hand, under the Cartel_OPEC+ setup, model results indicate that the members as a whole would have cut as much as 26 million bbl/day on average. This indicates that if the OPEC+ agreement was indeed meant to create a new form of cartel structure in the oil market, the planned cuts should have been vastly larger than what they actually are. Hence, this extreme scenario can be ruled out. Similarly, the cuts that occur under the previously best-performing Oligo_OPEC (1.91 million bbl/day) and Cournot (1.99 million bbl/day) market structure setups also lie above the planned and actual cuts, indicating that OPEC+ cuts were neither planned nor implemented to fully exert market power. In order to understand the underlying reasons why the OPEC+ agreement was not designed for higher level of output cuts, we analyse the behavior of leading producers taking part in the agreement, namely Saudi Arabia and Russia.

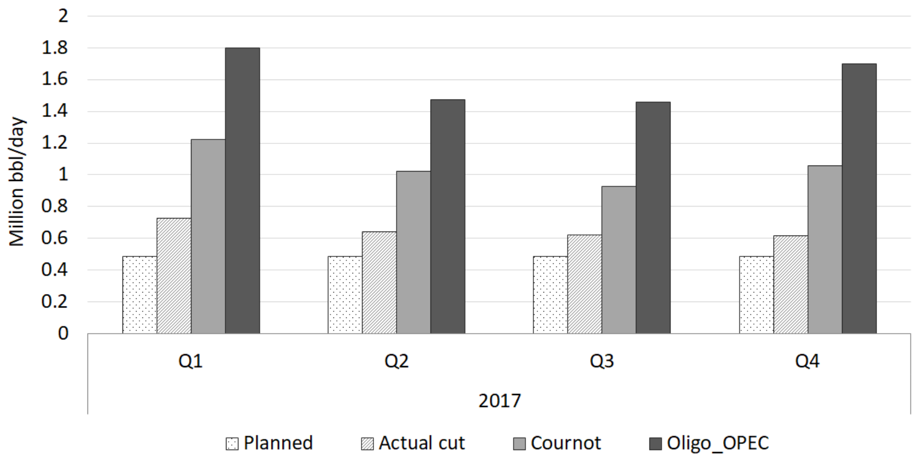


Figure 4.10.: Planned, actual and estimated cuts for Saudi Arabia in 2017

We present the planned, actual and simulated production cuts by Saudi Arabia in Figure 4.10 for each quarter in 2017 for the best-performing setups. While the planned production cut of Saudi Arabia was only 486 thousand bbl/day, the actual average production cut was significantly higher with 730 thousand bbl/day in the first quarter, which then declined to 640 thousand bbl/day in the second quarter. The realised cut remained relatively stable in the third and fourth quarters of 2017 with 620 thousand bbl/day. Model results, on the other hand, indicate that, during 2017, the required average Saudi production cut would have actually been 1.06 million bbl/day and 1.61 million bbl/day within Cournot and Oligo_OPEC market setups, respectively. A similar analysis is provided for Russia in Figure 4.11, the other leading country in OPEC+ agreement. While the planned production cut agreed upon by Russia was 300 thousand bbl/day, the actual cut averaged around 230 thousand bbl/day during 2017. In contrast, in the Cournot and Oligo_OPEC market setups, Russia cuts significantly higher volumes on average, amounting to 1.45 million bbl/day in the Cournot and 730 thousand bbl/day in the Oligo_OPEC setup. Hence, for both Saudi Arabia and Russia, we see that the planned and actual production cuts within the OPEC+ agreement have been significantly lower than their production cut potential estimated by the model.

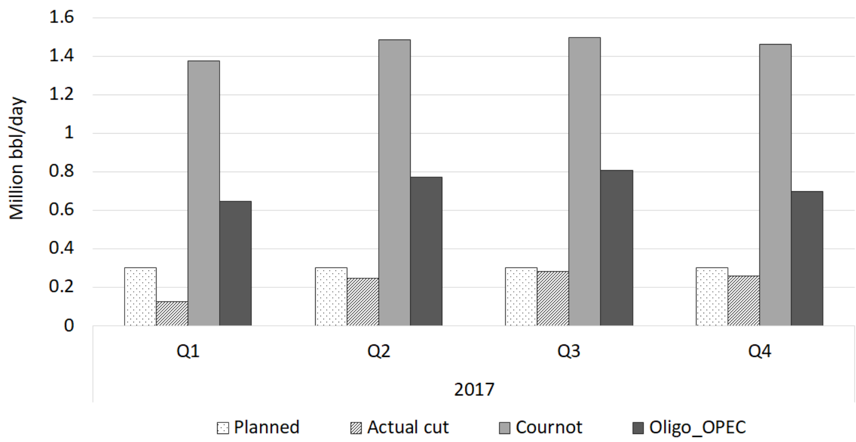


Figure 4.11.: Planned, actual and estimated cuts for Russia in 2017

The OPEC+ deal has so far demonstrated itself to be a successful tool to rebalance the oil market in the short-run as oil prices started to increase in the second quarter of 2016, with the Saudi Arabian efforts eventually having led to the agreement. Moreover, according to Economou and Fattouh (2018), OECD crude oil stocks declined below their five-year averages at the end of 2017. Although several officials indicated OPEC's interest in sustaining and even "institutionalising"[33] the cooperation in the long-run, our results suggest that the production cuts that are planned within the context of the deal were not enough for a long-term structural change in the crude oil market. This leads us to conclude that the OPEC+ agreement, instead of changing the market structure, was possibly conceived to keep the prices within an acceptable range.

[33]During the 174th OPEC meeting, Suhail Mohamed Al Mazrouei, the president of the conference, explicitly stated that OPEC would be further interested to "institutionalise this cooperation in order to adapt ongoing market dynamics". Although it is not clear what Mr. Al Mazrouei meant by the term "institutionalising", our results under the Cartel_OPEC+ market setup rule out the possibility of institutionalising meaning to form a new Cartel in the oil market. Please see: https://www.opec.org/opec_web/en/press_room/5071.htm. Access date: 01.06.2019

4.6. Conclusions and policy implications

This paper investigates recent developments in the global crude oil market which have had substantial impact; namely, the 2014–2016 price crash and the following Cooperation of Declaration (i.e. the OPEC+ agreement) signed between the OPEC and non-OPEC suppliers which resulted in the production cuts of 2017. In the light of these developments, we investigate whether a shift in the market structure has occurred and how the behavior of major suppliers has been affected. To this end, we present a global upstream oil market simulation model; DROPS, a partial equilibrium model formulated as a mixed complementarity problem (MCP) with a spatial structure. We simulate the oil market under different market structure setups for the period between 2013 and 2017: perfectly competitive, Cournot competition, OPEC oligopoly with competitive fringe, as well as OPEC as a cartel, and a cartel being formed by a core group of OPEC.

Comparing simulated trade flows and price levels with historical values, we observe that among the considered market setups, oligopolistic market structure assumptions (i.e. Cournot competition, and OPEC oligopoly with competitive fringe) perform best at representing the market throughout the period 2013–2017. Oligopolistic market structure setups, however, even though being highly successful at simulating prices before the 2014 price collapse, cannot predict the prices after the collapse, which instead, are closer to the estimated competitive levels. We also see that reaching pre-2014 price levels around $100/bbl is possible only under strong cartelisation. Our results thus indicate that although the market continued to have an oligopolistic structure, it has moved in a more competitive direction after the 2014 price decline.

We further analyse the behaviour of major suppliers during the 2014–2015 period, a phase with increased shale oil supply and reduced oil demand growth expectations, and observe how their market power potential has developed. For this purpose, we compare the simulated and historical production spare capacities under different market structure setups. Our findings are as follows: Despite their production levels still being best explained by oligopolistic behaviour, we see that the market power potential of OPEC and Saudi Arabia has significantly decreased after the price collapse. This explains why Saudi Arabia, instead of cutting production, continued to increase its supply since a unilateral production cut would not have had the desired effect. It is therefore much more likely that Saudi Arabia followed a market share protection strategy instead, with the ultimate aim of driving shale producers out of the market which is also mentioned by (Behar and Ritz, 2017, Fattouh et al., 2016). On the other hand, in the case of a joint OPEC action, our model results indicate that profit gains by collusion are much more restricted. Any unilateral production cut by OPEC results in a loss of market share to Russia; thus, significantly limiting profit gains. This is why Saudi Arabia and other OPEC members were reluctant to hold capacity unilaterally and rather waited for cooperative production cuts with non-OPEC producers, which eventually was agreed upon with the realisation of the OPEC+ agreement in November 2016.

Provided that Saudi Arabia and Russia lead the OPEC+ agreement with the largest planned production cuts, one would expect them to have planned the production cuts such that they would reclaim market power. Yet, according to the model-estimated production cuts, in reality, both Saudi Arabia and Russia have withheld significantly less capacities than they do under the non-competitive market structure assumptions. Hence, rather than helping some of the producers to exert market power to full extent, the OPEC+ agreement seems to have been designed to put a halt on tumbling oil prices. Apparently, Saudi Arabia, and Russia to a certain extent, did not push for more cuts within the OPEC+ agreement as the collapsing profits would have motivated them to do so. In this sense, it can be said that the OPEC+ productions cuts have aimed to stabilise the prices in an acceptable margin, which would be high enough to support the governmental budgets of oil-export dependent countries but low enough not to further promote shale oil investments in the USA. This price range is also referred to as the "sweet price range" (Fattouh, 2017).

Our modelling approach, to some degree, is an abstraction from reality and includes various assumptions and simplifications. Nevertheless, we can say that the method used provides a scientific approach to answer important questions and helps us gain insight into the recent developments in the crude oil market. In future work, the methodology used in this paper could be extended to analyse the dynamic interdependencies in the upstream crude oil market and simulate the development of production capacities under different market structure assumptions. The simulations could be used to provide an outlook for future developments in the oil market and help analyse potential future strategies of the oil producing countries. Moreover, implementing a temporal structure for the development of production costs, especially in the case of non-conventional crude oil sources, would further help in a realistic simulation of future investment decisions.

5. Optimal Dispatch of a Coal-Fired Power Plant with Integrated Thermal Energy Storage

As the share of intermittent renewable electricity generation increases, the remaining fleet of conventional power plants will have to operate with higher flexibility. One of the methods to increase power plant flexibility is to integrate a thermal energy storage (TES) into the water-steam cycle of the plant. TES can provide flexibility and achieve profits by engaging in energy arbitrage on the spot markets and by providing additional power on the control power markets. This paper considers a reference coal-fired power plant with an integrated TES system for the year 2019 in Germany. Optimal dispatch for profit maximisation with TES is simulated on the hourly day-ahead and quarter-hourly continuous intraday markets as well as on the markets for primary (PRL) and secondary (SRL) control power. Analysing the effects of TES round-trip efficiency and storage capacity on dispatch and the profits, I find that smaller TES systems with up to one hour of storage capacity can achieve substantial profits on the PRL market while also realising profits from energy arbitrage on the continuous intraday market. Higher TES round-trip efficiencies can help TES achieve significant profits also on the day-ahead market. The analysis shows that a storage capacity of 2–3 hours is enough to realise most of the energy arbitrage potential, while larger storage capacities can greatly increase TES profits on the SRL market. Small TES systems are found to increase the full load hours of the plant marginally. However, the increase becomes significant with larger storage capacities and can lead to higher CO_2 emissions for the individual plant.

5.1. Introduction

The share of renewable energies in global electricity generation has grown substantially in the last decades and is expected to further increase in the future. International Energy Agency, in its Stated Policies scenario of the World Energy Outlook 2019, foresees the global share of wind and solar PV in the electricity mix to increase from 7% in 2018 to 17.2% in 2030. In the Sustainable Development scenario, which considers a setting with a higher probability of reaching the climate targets, this share increases to 25% (IEA, 2019). Intermittent renewable generation is highly weather-dependent and fluctuations are largely compensated by conventional power plants in the current energy system. As the share of intermittent renewables further increases and conventional capacity decreases, the remaining fleet of conventional power plants will need to operate with increased flexibility.[1]

The main specifications of a conventional power plant that define its flexibility can be stated as its minimum load, load change rate (i.e. ramping rate), and start-up duration and start-up costs.[2] A relatively flexible plant would be characterised by a low minimum load, a high load change rate and low start-up duration with lower start-up costs. While lowering the minimum load of the plant reduces the losses in low price hours and helps avoid shut-downs and subsequent start-ups, increasing the load change rate would allow to generate additional revenues on the electricity markets (e.g. on intraday and control power markets), as also pointed out by Richter et al. (2019). Therefore, increased flexibility can directly translate to higher profits for the power plant operator. Additionally, increased flexibility of power plants can also have system benefits as they allow the integration of more wind and solar power (Agora Energiewende, 2017). With increased wind penetration, the ramping capabilities of the existing power plant fleet becomes much more important, since more flexible operation of the existing fleet would allow for a higher degree of intermittent wind integration (Hong et al., 2012). Moreover, flexible thermal power plants can help reduce wind curtailment and increase resilience to wind ramping (Kubik et al., 2015).

An effective method to increase power plant flexibility is to utilise thermal energy storages (TES). Zhao et al. (2018b) and Zhao et al. (2018a) simulate a coal-fired power plant and show that, by controlling the internal thermal storages inherent to the thermal system of the plant, it is possible to enhance the ramping rate of the plant.[3] More substantial increases in flexibility are

[1] Using optimal power flow simulations to compare the years 2013 and 2020, Eser et al. (2016) finds that increased penetration of renewables in Central Western and Eastern Europe can cause the number of starts of power plants to increase by up to 23% and the number of load ramps by up to 181%.

[2] For more information on these parameters, see Hentschel et al. (2016), Agora Energiewende (2017) and Richter et al. (2019).

[3] Among the strategies investigated in these papers, the largest additional contribution to ramping rates has an average power ramp rate of 6.19% per minute (40.89 MW/min) with a very limited energy capacity of 5.58 MWh.

possible by integrating a thermal energy storage into the water-steam cycle of the plant. With these configurations, the TES is charged with the heat extracted from the water-steam cycle of the plant when power demand is low (i.e. electricity prices are low) and the stored energy is then discharged to the plant cycle when power demand is high (i.e. electricity prices are high), allowing energy arbitrage to be conducted. Wojcik and Wang (2017) investigate the integration of a TES into a sub-critical oil-fired conventional power plant, focusing on the simulation of charging and discharging processes. Li et al. (2017) consider a combined-cycle gas turbine plant with integrated TES. Li and Wang (2018) and Cao et al. (2020) analyse the feasibility of integrating a high temperature thermal energy storage in a coal-fired power plant. Richter et al. (2019), also simulating a coal-fired plant, consider the integration of a steam accumulator TES. In all of these studies, it is shown that plant load can be reduced or increased significantly by charging or discharging the TES, respectively. The investigated concepts and the associated parameters are summarised in Table 5.1.

Table 5.1.: An overview of the various simulations of TES applications in power plants observed in the literature

Source	Considered power plant	TES-charging Δ net power	TES-discharging Δ net power	Storage capacity
Wojcik and Wang (2017)	Oil-fired (375 MW)	-13%	14%	n/a
Li et al. (2017)	CCGT (137 MW)	-11.7%	5.8%	0.3 h
Li and Wang (2018)	Coal-fired (600 MW)	-13.3%	7.4%	1-4 h
Cao et al. (2020)	Coal-fired (600 MW)	-16.7%	6.2%	8 h
Richter et al. (2019)	Coal-fired (695 MW)	-7.0%	4.3%	0.5 h

In Germany, the share of wind and solar PV in gross electricity generation has increased from 8% in 2010 to 28.6% in 2019 (AG Energiebilanzen, 2020), reaching its highest percentage observed until then. As such, the flexibility requirements on thermal power plants has also increased substantially. This makes the case of Germany in 2019 particularly suitable for the analysis of the applicability of TES-integrated plants and their optimal dispatch. As the economic benefits of flexibility improvements in hard coal power plants are potentially higher than the benefits from similar changes at gas-fired plants (Hübel et al., 2018), it is especially worth considering the case of coal-fired power plants. While a TES investment in coal-fired plants in Germany due to the coal exit decision[4] may not be practical any more, the analysis of the German case can nevertheless be indicative for other regions having significant coal-fired capacities, where high renewable penetration is expected in the medium-term.

In this context, this paper analyses the effects of an integrated TES system on the optimal (profit maximising) dispatch of a coal-fired power plant in Germany for the year of 2019. For this purpose, a mixed integer linear programming (MILP) model is developed to simulate the optimal dispatch of the plant with TES. Additional profits due to TES on various electricity markets (i.e. day-ahead, intraday, primary (PRL) and secondary (SRL) control power markets)[5] are calculated. The relevance of individual TES parameters regarding the profit potential on the individual markets is analysed and charging/discharging patterns are identified.

Considering a reference TES system specification as presented in Richter et al. (2019), I find that the TES with a 0.5 hours of storage capacity can achieve 377,000 EUR of additional profits in the dispatch year of 2019, increasing the total profits of the plant by 2.4%. Profits on the PRL market are found to make up a large majority (about 60%) of the profits, followed by those obtained via energy arbitrage due to dispatch on the intraday continuous market (about 20%). Larger storage capacities allow for higher energy arbitrage profits; albeit the increase in profits due to arbitrage is limited. In contrast, very substantial increases in the profits on the SRL market can be achieved with larger storage capacities. Considering also an alternative high-efficiency TES, I show that energy arbitrage profits on both day-ahead and intraday markets can be greatly increased if the round-trip efficiency of the TES system is higher. While the analysis shows that integrating a TES system can provide the plant with significant additional flexibility and profits, TES is found to increase the full load hours of the plant. The increase is marginal (less than 1%) for a TES storage capacity of 0.5 h; however, it becomes significant with larger capacities and can potentially increase the CO_2 emissions of the individual plant.

This paper is primarily related to two streams of literature. The first relevant stream of literature deals with simulating optimal dispatch using MILP models. MILP models have been widely used in the literature for solving unit

[4]Germany has passed legislation to end coal-fired generation by 2038 at the latest. (Source: Kohleverstromungsbeendigungsgesetz - KVBG, 08.08.2020)

[5]PRL is also referred to as Frequency Containment Reserve (FCR). SRL is also referred to as Frequency Restoration Reserve with Automatic Activation (aFRR).

commitment problems (see Ostrowski et al. (2012), Frangioni et al. (2009) and Richter et al. (2016)). It is also common to apply MILP models to determine optimal scheduling of individual power plants and to simulate profitability and conduct techno-economic analyses. Kazempour et al. (2008) provides an optimal dispatch model for a pumped-storage plant that is active in both energy and regulation markets, simulating expected weekly profits. Knaut and Paschmann (2017) uses a MILP model to compare profitability of a CCGT plant to that of a lignite-fired power plant on different electricity markets in Germany (i.e. day-ahead auction and intraday auction). Beiron et al. (2020) analyses various flexibility options using a MILP optimal dispatch model for a waste incineration plant with combined heat and power (CHP). Similarly, Beiron et al. (2020) uses a MILP-based approach for the analysis of a CCGT CHP plant's flexibility potential.

The second stream of literature relevant to this paper focuses on techno-economic assessment of storage systems and energy arbitrage. Energy arbitrage with storage systems has been a common topic in literature (see Walawalkar et al. (2007), Sioshansi et al. (2009) and Bradbury et al. (2014)), where the research has focused on optimal location, sizing and parametrisation of various storage technologies. With decreasing battery costs, recent years have especially seen a surge in studies analysing energy arbitrage with Li-Ion batteries. Dufo-López (2015), simulating the operation of a Li-Ion battery storage system for the Spanish electricity market pool of 2013, finds that the considered storage system is not profitable with the contemporary investment costs. Arcos-Vargas et al. (2020), similarly considering a Li-Ion battery system for the Iberian market during the period 2016–2017, finds that energy arbitrage will only be profitable from 2024 onward with sustained decreases in battery costs. Metz and Saraiva (2018) simulates energy arbitrage with a Li-Ion battery on the German hourly and quarter-hourly intraday auctions for the period 2011–2016, finding that the analysed system does not break even with the historical volatility of prices and the contemporary storage investment costs.

Energy arbitrage with TES has been considered in the literature for different types of energy systems. Sioshansi and Denholm (2010) shows that TES can increase the value of concentrated solar power (CSP) plants as it allows the shifting of generation to hours with higher electricity prices. Scapino et al. (2020) considers an energy system with sorption TES for the electricity markets of Belgium in 2013 and the UK in 2017, and finds that the TES system is not profitable when only operating on the day-ahead market, but becomes profitable when it also provides balancing services. Risthaus and Madlener (2017) simulates the optimal dispatch of a heat pump with TES, which is integrated partially[6] (i.e. only for the discharging phase) to a coal-fired power plant and a CCGT in Germany, as well as to a CSP in Spain, for the year of 2016. The study finds that revenues from energy arbitrage are not enough to cover the high investment costs.

Against this backdrop, the contribution of this paper can be summarised as follows: The analysis conducted in this paper is the first of its kind, providing insight into the optimal dispatch of a coal-fired plant with a TES that is completely integrated in the steam-water cycle. Moreover, the paper distinguishes itself by the inclusion of the primary and secondary control power markets as well as the intraday continuous market in the dispatch simulation. Optimal profits of the system in the participated spot and control powers are calculated and the effects of TES parametrisation on dispatch and profits are investigated. The analysis is conducted for a power plant located in Germany with German historical market prices. However, the methodology can also be applied to other regions.

5.2. Model

In this section, I introduce a dispatch model of a power plant with an integrated TES system. The overall structure of the stylised model is schematically depicted in Figure 5.1. In line with Richter et al. (2019), the TES is integrated in the power plant water-steam cycle between the steam generator and the turbine. As such, steam from the steam generator can be directed to the TES, charging the TES and reducing the turbine output. Similarly, the TES can be discharged and the stored steam can then be used to increase the turbine output. In this setting, the plant operator has the task of maximising the total profit by optimising the dispatch decisions on various markets the power plant is active on. When doing this, the operator needs to take into account, in addition to the standard power plant constraints, also the additional constraints of the TES system.

[6] During the charging phase, the heat is generated by the heat pump and is stored in the TES. The heat is then supplied from the TES to the plant water-steam cycle during discharging.

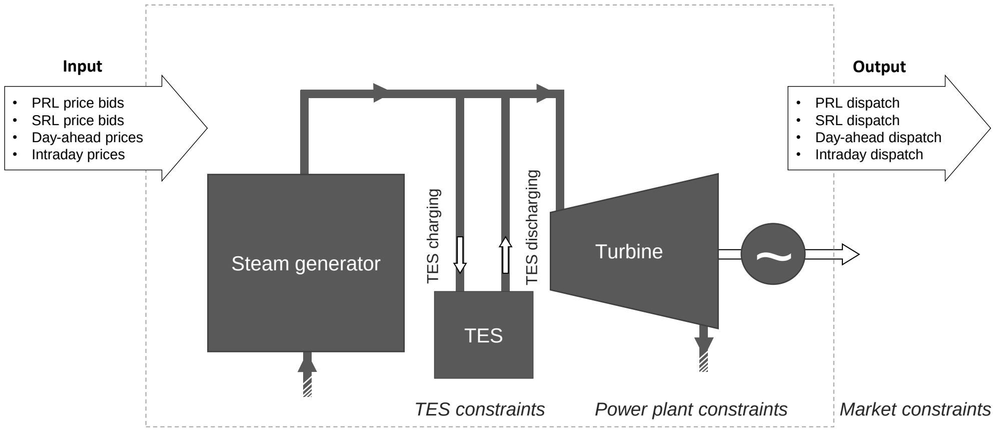


Figure 5.1.: Schematic representation of the model structure

The problem of the plant operator is formulated as a mixed-integer linear programming (MILP) model. The objective function corresponds to maximising total profits from the dispatch on the wholesale electricity markets and the markets for control power, subject to power plant and TES system constraints and various market-specific constraints (i.e. prequalification criteria for providing control power). The considered wholesale electricity markets are the day-ahead (DA) auction with hourly products and the continuous intraday (ID) trade with quarter-hourly products. The continuous ID market with quarter-hourly products is particularly chosen due to its higher volatility, which makes it theoretically more profitable for storage systems. Additionally, the plant is assumed to provide primary and secondary control power, PRL and SRL, respectively.

Taking prices for the PRL, SRL, DA and ID markets as input, the model optimises the dispatch on these markets. Optimising the dispatch on PRL and SRL markets simultaneously with the DA market allows the optimal capacities on the control power markets to be endogenously determined by the model. The coal-fired plant without the TES system is assumed not to be able to participate on the continuous ID market by itself as it lacks the necessary operational flexibility. The TES, however, can be activated within several minutes (Richter et al., 2019), providing the necessary flexibility to be able to react to price signals and offer capacities on the continuous ID market. Similarly, the TES increases the technical capability for providing control power on the PRL and SRL markets. The plant operator is assumed to be price taker and to have perfect foresight. Therefore, the optimal total profit obtained by the model represents an upper benchmark.

The operator maximises the total profit which is equal to the sum of total revenues R_{da} on the DA, R_{id} on the ID, R_{srlp} on the positive SRL, R_{srln} on the negative SRL and R_{prl} on the PRL markets, minus the variable costs C_{var} and the start-up costs C_{su}. The objective function of the problem can then be written as follows:

$$\max Profit = \sum_{t}^{T}(R^t_{da} + R^t_{id} + R^t_{srlp} + R^t_{srln} + R^t_{prl} - C^t_{var} - C^t_{su}) \tag{5.1}$$

The capacity offered on the DA market equals the actual total output X_{da} of the plant with TES on the DA market, plus the volumes that were initially sold on the DA auction but are bought back on the ID market $TES_{id,in}$ by charging the TES. Thus, the DA revenue is obtained by mutliplying the total capacity offered on the DA market with the corresponding DA prices, and with 0.25 since the model has a quarter-hourly resolution:

$$R^t_{da} = 0.25 p^t_{da}(X^t_{da} + TES^t_{id,in}) \tag{5.2}$$

The ID revenue equals the volumes sold on the ID market $TES_{id,out}$ by discharging the TES minus the volumes bought $TES_{id,in}$ by charging, multiplied with the ID prices:

$$R^t_{id} = 0.25 p^t_{id}(TES^t_{id,out} - TES^t_{id,in}) \tag{5.3}$$

On top of the standalone SRL capability PL_{srlp} of the plant, TES can provide additional positive SRL capacity TES_{srlp} by discharging. The revenue obtained on the positive SRL market consists of two components: the capacity component and the energy component. The operator generates revenue by offering control power capacity, independent of whether the plant is activated for SRL or not. The price it receives per MW of capacity is represented by $p_{srlp,c}$. As for the energy component, I assume that the plant can be activated for positive SRL with an exogenous average probability of w_{srlp}, receiving the SRL energy price of $p_{srlp,e}$. Similarly, TES can increase the total negative SRL offered by the plant by TES_{srln} on top of the standalone capacity PL_{srln}. The operator receives the capacity price $p_{srln,c}$, and with an average probability of w_{srln} the energy price $p_{srln,e}$. The capacity prices for both positive and negative SRL products ($p_{srlp,c}$ and $p_{srln,c}$) correspond to the pay-as-bid capacity prices of the power plant, which are directly derived from its opportunity costs over the DA market[7] and are limited by the historical marginal capacity prices. The revenues for providing positive and negative SRL then become:

$$
\begin{aligned}
R^t_{srlp} &= (p^t_{srlp,c} + 0.25p^t_{srlp,e}w_{srlp})(PL^t_{srlp} + TES^t_{srlp}) \\
R^t_{srln} &= (p^t_{srln,c} + 0.25p^t_{srln,e}w_{srln})(PL^t_{srln} + TES^t_{srln})
\end{aligned}
\tag{5.4}
$$

The standalone PRL capacity offered by the plant is PL_{prl}. Note that PRL is a symmetrical product. Therefore, the plant offering PRL is obligated to provide the same capacity in both directions, i.e. when it reduces or increases output depending on the PRL activation signal. As such, being able to reduce turbine output by charging and to increase it by discharging, TES can increase the offered PRL capacity by TES_{prl}. The PRL revenue is then equal to the total offered capacity multiplied by the PRL price p_{prl}[8]:

$$R^t_{prl} = p^t_{prl}(PL^t_{prl} + TES^t_{prl}) \tag{5.5}$$

Variable costs of the plant are represented by a linear approximation of the fuel costs using the methodology presented in Swider and Weber (2007) as shown in Equation 5.6. Given fuel costs p_{fuel} and the efficiency, the variable costs depend on the plant output X_{pl}, the upper bound of which is defined by the maximum plant capacity $k_{pl,max}$. The minimum load $k_{pl,min}$ defines its lower bound. Note that the plant output X_{pl} is the electrical representation of the output of the steam generator. Hence, it corresponds to the standalone output of the plant without the TES. As the efficiency at minimum load η_{ml} is lower than the efficiency at full load η_{fl} the operator is incentivised to avoid running at minimum load. The variable costs also include other variable costs represented

[7]See Müsgens et al. (2014), Knaut et al. (2017) and Künle (2018) for the methodology.

[8]PRL prices are also assumed to correspond to the opportunity cost bids over the DA market, limited by the historical PRL settlement prices.

by c_{ot}. Note that the binary variable B_{on} is equal to 1 when the plant is online.

$$C_{var}^{t} = 0.25 p_{fuel} \left(\frac{X_{pl}^{t}}{\eta_{fl}} + \left(\frac{1}{\eta_{ml}} - \frac{1}{\eta_{fl}} \right) (k_{pl,max} B_{on}^{t} - X_{pl}^{t}) \frac{k_{pl,min}}{k_{pl,max} - k_{pl,min}} \right) + 0.25 c_{ot} X_{pl}^{t} \tag{5.6}$$

When the plant is switched on, it incurs start-up costs while ramping up to reach the minimum load. Those costs mainly ensue from the usage of secondary fuel and are represented by Equation 5.7, where the binary variable B_{su} is equal to 1 when the plant starts up. To avoid additional complexity, the model does not distinguish between different start-up types (e.g. cold, warm, hot); rather, a single start-up type with average representative costs c_{su} is assumed.

$$C_{su} = c_{su} B_{su}^{t} \tag{5.7}$$

The plant output is defined by Equation 5.8, where it is either equal to zero when turned off or lies between the minimum load and the maximum plant capacity when online.

$$\begin{aligned} &X_{pl}^{t} = k_{pl,min} B_{on}^{t} + X_{overmin}^{t}, \\ &where \quad X_{overmin}^{t} \leq (k_{pl,max} - k_{pl,min}) B_{on}^{t} \end{aligned} \tag{5.8}$$

Equation 5.9 considers that the change in plant output between the time periods $t-1$ and t (when the plant is online in both time periods) is restricted by the load change rates; namely, equals to r_{up} when ramping up and r_{down} when ramping down. Additionally, it is ensured that when the plant has started up and has become online, it starts at minimum load. Likewise, when the plant is shutting down, it reduces its output to minimum load first and then to zero.

$$\begin{aligned} X_{pl}^{t} - X_{pl}^{t-1} &\leq r_{up} B_{on}^{t-1} + k_{pl,min} (B_{on}^{t} - B_{on}^{t-1}) \\ X_{pl}^{t-1} - X_{pl}^{t} &\leq r_{do} B_{on}^{t} + k_{pl,min} (B_{on}^{t-1} - B_{on}^{t}) \end{aligned} \tag{5.9}$$

The binary states of starting up B_{su} and shutting down B_{sd} are defined, taking into account the corresponding durations d_{su} and d_{sd}, respectively:

$$B_{on}^{t} - B_{on}^{t-1} = \sum_{t1=t-d_{su}}^{t1<t} B_{su}^{t1} - \sum_{t=t1-d_{sd}}^{t<t1} B_{sd}^{t} \tag{5.10}$$

An additional restriction ensures that the shut-down and start-up periods do not intersect:

$$B_{su}^{t} + \sum_{t1>t}^{t1 \leq t+d_{sd}} B_{sd}^{t1} + \sum_{t1>t}^{t1 \leq t+d_{sd}+d_{su}} B_{su}^{t1} \leq 1 \tag{5.11}$$

At time point t, if not offline, the plant can only be active in one of the states "starting up" (B_{su}), "online" (B_{on}) or "shutdown" (B_{sd}):

$$B_{su}^{t} + B_{on}^{t} + B_{sd}^{t} \leq 1 \tag{5.12}$$

The output level of the plant X_{pl} is determined by the markets it is actively providing capacity for and whether the TES is being charged or discharged as expressed in Equation 5.13. Discharging the TES on the DA market with the power $TES_{da,out}$ increases the total capacity active on the DA market X_{da}. Similarly, charging the TES on the DA market with $TES_{da,in}$ decreases the total capacity active on the DA market. The plant output level is also determined by the total positive and negative SRL provision multiplied with the respective activation probabilities.

$$\begin{aligned} X_{pl}^{t} + TES_{da,out}^{t} - TES_{da,in}^{t} =& X_{da}^{t} + TES_{id,in}^{t} \\ &+ w_{srlp}(PL_{srlp}^{t} + TES_{srlp}^{t}) - w_{srln}(PL_{srln}^{t} + TES_{srln}^{t}) \end{aligned} \tag{5.13}$$

The capacity provided in the respective markets is constrained by the physical plant restrictions. As expressed in Equation 5.14, the total capacity provided on the day-ahead market (X_{da}+$TES_{id,in}$) plus the positive SRL and PRL capacities, in case they are fully activated, cannot be greater than the maximum plant capacity modified by the net TES output (discharging minus charging). Similarly, Equation 5.15 shows that the total day-ahead capacity minus a full activation of negative SRL and PRL capacities cannot be lower then the minimum load of the plant, which is modified by the net TES output. Additionally, PRL provision by the plant requires that the plant output is above a certain threshold, which necessitates the inclusion of an additional binary term that increases the required minimum plant output by an additional f_{prl} percent of total plant capacity.[9]

$$X_{da}^{t} + TES_{id,in}^{t} + PL_{srlp}^{t} + PL_{prl}^{t} \leq k_{pl,max} B_{on}^{t} + TES_{da,out}^{t} - TES_{da,in}^{t} \tag{5.14}$$

$$X_{da}^{t} + TES_{id,in}^{t} - PL_{srln}^{t} - PL_{prl}^{t} \geq k_{pl,min} B_{on}^{t} + f_{prl} k_{pl,max} B_{prl}^{t} + TES_{da,out}^{t} - TES_{da,in}^{t} \tag{5.15}$$

[9] The minimum PRL threshold of the plant is assumed to be 60% of full load. Hence f_{prl} equals 40% as the minimum load is assumed to be 20% of full load.

In order for the plant output with TES not to exceed the minimum and maximum achievable total load levels when providing PRL and SRL, additional constraints are included as shown in Equations 5.16–5.18.

$$X_{da}^t + TES_{id,in}^t + PL_{srlp}^t + PL_{prl}^t + TES_{id,out}^t \leq B_{on}^t k_{pl,max} + k_{tes,max,out}(1 - B_{prl}^t) \tag{5.16}$$

$$X_{da}^t + TES_{id,in}^t + PL_{srlp}^t + PL_{prl}^t + TES_{id,out}^t \leq B_{on}^t k_{pl,max} + k_{tes,max,out}(1 - B_{srl,pos}^t) \tag{5.17}$$

$$X_{da}^t - PL_{srln}^t \geq B_{on}^t k_{pl,min} - k_{tes,max,in}(1 - B_{srl,neg}^t) \tag{5.18}$$

TES power output when charging and discharging depends directly on the plant output (X_{pl}) (Richter et al., 2019). Therefore, I include this variation in the model by linearising the power capacity as shown in Equation 5.19 with the use of exogenous parameters $\gamma_{0,in}$ and $\gamma_{1,in}$ when charging, and $\gamma_{0,out}$ and $\gamma_{1,out}$ when discharging.

$$\begin{aligned} TES_{da,in}^t + TES_{id,in}^t + TES_{srln}^t + TES_{prl}^t &\leq \gamma_{0,in} B_{on}^t + \gamma_{1,in} X_{pl}^t \\ TES_{da,out}^t + TES_{id,out}^t + TES_{srlp}^t + TES_{prl}^t &\leq \gamma_{0,out} B_{on}^t + \gamma_{1,out} X_{pl}^t \end{aligned} \tag{5.19}$$

TES charging and discharging power on the day-ahead and intraday markets are additionally restricted and binary variables $B_{tes,in}$ (equal to 1 when charging) and $B_{tes,out}$ (equal to 1 when discharging) are defined:

$$\begin{aligned} TES_{da,in}^t + TES_{id,in}^t &\leq k_{tes,max,in} B_{tes,in}^t \\ TES_{da,out}^t + TES_{id,out}^t &\leq k_{tes,max,out} B_{tes,out}^t \end{aligned} \tag{5.20}$$

The minimum charging and discharging power for the TES are restricted at 1 MW (as the binary variables are either 0 or 1):

$$\begin{aligned} TES_{da,in}^t + TES_{id,in}^t &\geq B_{tes,in}^t \\ TES_{da,out}^t + TES_{id,out}^t &\geq B_{tes,out}^t \end{aligned} \tag{5.21}$$

The energy flow $E_{tes,in}$ into the TES is equal to the energy input by charging on the DA and ID markets as well as charging due to activation of negative SRL, as shown in Equation 5.22. The overall energy losses incurred by the TES system are considered with the average round-trip-efficiency η_{tes} and included in the charging phase.[10] Likewise, Equation 5.23 shows the energy output of the TES, $E_{tes,out}$, which consists of discharging on the DA and ID markets and the activation on the positive SRL market.

$$E^t_{tes,in} = 0.25\eta_{tes}(TES^t_{da,in} + TES^t_{id,in} + w_{srln}TES^t_{srln}) \quad (5.22)$$
$$E^t_{tes,out} = 0.25(TES^t_{da,out} + TES^t_{id,out} + w_{srlp}TES^t_{srlp}) \quad (5.23)$$

Stored energy in TES at time period t is equal to the stored energy in the previous time period $t-1$ plus the net energy exchange that occurs in t as shown in Equation 5.24.[11]

$$S^t_{tes} = S^{t-1}_{tes} + E^t_{tes,in} - E^t_{tes,out} \quad (5.24)$$

Due to the prequalification requirements on the control power markets, storage level needs to account for the necessary energy when providing control power. TES needs to have enough energy when discharging in order to provide positive SRL and PRL. Similarly, TES needs to have enough storage capacity when charging for providing negative SRL and PRL. These requirements are represented by Equations 5.25–5.28, where t_{srlp}, t_{srln} and t_{prl} stand for the necessary durations for prequalification on the respective market.[12]

$$S^t_{tes} \geq t_{srlp}TES^{bh}_{srlp} \quad (5.25)$$
$$S^t_{tes} \leq s_{tes,max} - t_{srln}TES^{bh}_{srln} \quad (5.26)$$
$$S^t_{tes} \geq t_{prl}TES^{bh}_{prl} \quad (5.27)$$
$$S^t_{tes} \leq s_{tes,max} - t_{prl}TES^{bh}_{prl} \quad (5.28)$$

There are also various logical constraints that represent the physical restrictions of the TES system. TES is not allowed to charge and discharge at the same time:

$$B^t_{tes,in} + B^t_{tes,out} \leq 1 \quad (5.29)$$

[10] Note that the model and the conducted analysis in this paper assumes average round-trip efficiencies for the TES system. In reality, the round-trip efficiency varies in real-time as it also depends on the plant-load level the TES system is charged and discharged at.

[11] The model does not consider any standby heat losses from the TES since those tend to not exceed 1% per day (Evans et al., 2012) and are thus negligible for the considered storage capacities in this paper.

[12] t_{prl} = 0.75 h and $t_{srlp} = t_{srln}$ = 5 h. (Source: Präqualifikationsverfahren für Regelreserveanbieter (FCR, aFRR, mFRR) in Deutschland, 26. October 2018)

Further, TES can be charged or discharged only when the power plant is online:

$$B^t_{tes,in} + B^t_{tes,out} - B^t_{on} \leq 0 \tag{5.30}$$

TES cannot be simultaneously active in more than one market:

$$B^t_{tes,srlp} + B^t_{tes,srln} + B^t_{tes,prl} + B^t_{tes,in} + B^t_{tes,out} \leq 1 \tag{5.31}$$

In the case that the plant is active on the SRL markets, it is assumed to bid all its SRL capability:

$$\begin{aligned} PL^t_{srlp} &= v_{srl,max} B^t_{srlp} \\ PL^t_{srln} &= v_{srl,max} B^t_{srln} \end{aligned} \tag{5.32}$$

The additional SRL capacity bids due to TES are allowed to vary. The maximum additional positive and negative SRL capacities of TES are limited by the maximum discharging and charging power of the TES, respectively.

$$\begin{aligned} TES^t_{srlp} &\geq v_{srl,min} B^t_{tes,srlp} \\ TES^t_{srln} &\geq v_{srl,min} B^t_{tes,srln} \\ TES^t_{srlp} &\leq k_{tes,max,out} B^t_{tes,srlp} \\ TES^t_{srln} &\leq k_{tes,max,in} B^t_{tes,srlp} \end{aligned} \tag{5.33}$$

Due to technical limitations (Richter et al., 2019), TES can only provide additional capacity when the plant is providing SRL, but cannot provide standalone SRL capacity on its own. This condition is included with logical constraints as follows:

$$\begin{aligned} B_{tes,srlp} - B_{srlp} &\leq 0 \\ B_{tes,srln} - B_{srln} &\leq 0 \end{aligned} \tag{5.34}$$

In the case that the plant is active on the PRL market, it is assumed to bid all its PRL capability:

$$PL^t_{prl} = v_{prl,max} B^t_{prl} \tag{5.35}$$

Additional PRL capacity via TES is allowed to vary. It cannot be less than the minimum PRL capability $v_{tes,prl,min}$ of the TES and cannot be greater than the maximum PRL capability $v_{tes,prl,max}$ of the TES:

$$\begin{aligned} TES_{prl}^{t} &\geq v_{tes,prl,min} B_{tes,prl}^{t} \\ TES_{prl}^{t} &\leq v_{tes,prl,max} B_{tes,prl}^{t} \end{aligned} \tag{5.36}$$

Note that in contrast to SRL provision, TES can provide standalone PRL capacity even if the plant is not providing PRL. Therefore, additional constraints such as in Equation 5.34 are not included for the case of PRL provision.

Finally, the quarter hourly control power capacities are mapped to corresponding 4-hour-blocks:

$$\begin{aligned} PL_{srlp}^{bh} = PL_{srlp}^{t},\ PL_{srln}^{bh} = PL_{srln}^{t},\ PL_{prl}^{bh} = PL_{prl}^{t} \\ TES_{srlp}^{bh} = TES_{srlp}^{t},\ TES_{srln}^{bh} = TES_{srln}^{t},\ TES_{prl}^{bh} = TES_{prl}^{t} \end{aligned} \tag{5.37}$$

The problem is solved with a quarter-hourly resolution and in weekly time blocks (i.e. $T = 672$). Optimising in weekly blocks instead of a complete year helps the problem to have reduced solution times. The weekly blocks are linked by carrying over the optimal solutions for the plant production level X_{pl}^{q} and the TES energy level S_{tes}^{q} ensuing at the end of a week as the initial values to the next week.

An overview of the model sets, parameters and variables in a tabular format can be found in Appendix D.1.

5.3. Results

5.3.1. Input data

The considered reference power plant in this paper is assumed to be a newer generation coal-fired power plant (e.g. similar to Walsum 10 in Germany) with a relatively high efficiency and low minimum load. The parameters of the plant are presented in Table 5.2.

Table 5.2.: Input parameters assumed for the coal-fired power plant

Installed net capacity	740	MW
Minimum load	148	MW
Efficiency at full load	46	%
Efficiency at minimum load	36.8	%
Start-up duration	3	h
Shut-down duration	2.5	h
Load change rate	±10	MW/minute
SRL capability	50	MW
PRL capability	20	MW
Start-up costs	70,000	EUR
Fuel costs	18.54	EUR/MWh$_{th}$
Other variable costs	1.3	EUR/MWh

Note that start-up costs are assumed to be on average 70,000 EUR in line with Schill et al. (2016) and 1.3 EUR/MWh of other variable costs are assumed (r2b, 2019). Fuel costs include the 2019 historical average ARA FOB thermal coal price of 9.1 EUR/MWh$_{th}$ plus additional transport costs of 1.25 EUR/MWh$_{th}$ (r2b, 2019). On top of this, costs for emission certificates are added with the average 2019 EU ETS CO_2 price of 24.86 EUR/tCO_2 and an assumed specific emissions factor of 0.33 tCO_2/MWh$_{th}$ (Agora Energiewende, 2017). The data for fuel cost calculation is presented in Table 5.3.

Table 5.3.: Input data for fuel cost calculation

Thermal coal price	9.1	EUR/MWh$_{th}$
Transport costs	1.25	EUR/MWh$_{th}$
CO_2 price	24.86	EUR/tCO_2
Specific CO_2 emissions	0.33	tCO2/MWh$_{th}$

For input DA electricity prices, historical hourly time series data from EPEX SPOT for 2019 is used. For the continuous ID prices, quarter hourly weighted average price series for 2019 are used. The statistics of the input prices are summarised in Table 5.4. The average prices in both markets are almost identical. However, by comparing the average daily standard deviation of the prices, it can be seen that the volatility on the intraday market is significantly higher.

Table 5.4.: Statistics of input prices on the hourly day-ahead and the quarter-hourly continuous intraday electricity markets (in EUR/MWh)

	Mean	Avg. daily std. dev.	Min.	Max.
Day-ahead	37.69	8.80	-90.01	121.46
Intraday	37.77	12.97	-244.47	577.25

Historical marginal capacity and settlement prices for the year 2019 are used in the method of calculating bids on SRL and PRL markets as mentioned in Section 5.2, respectively. For the energy prices in the SRL market, we assume that the plant bids on average its variable costs with a mark-up. The plant is assumed to bid double its variable costs as energy prices on the positive SRL market and half of its variable costs on the negative SRL market. On both SRL markets, an average 20% probability of activation is assumed.

5.3.2. Dispatch without TES

The optimal power plant dispatch in 2019 on the German day-ahead electricity market and the control power markets for SRL and PRL is simulated without TES. The results of the simulation are summarised in Table 5.5. Market-specific profits are provided. The profits on the DA market correspond to a case where the plant is only active on the DA market. Profits on PRL market corresponds to additional profits when the plant is providing PRL in addition to being active on the DA market. In the same manner, profits for SRL are the additional profits the plant realises when it provides SRL on top of its DA and PRL commitments.

Table 5.5.: Summary results of the power plant dispatch simulation without TES

Profits TOTAL (EUR)	Profits DA (EUR)	Profits PRL (EUR)	Profits SRL (EUR)	Full load hours (h)	Start-ups
15,532,855	14,000,255	32,915	1,499,685	3232	39

Note that the comparably low PRL profits are strongly driven by the significant decreases in the price of the PRL product in the last years due to increasing battery capacities that provide PRL with much lower costs. In contrast, profits from SRL provision are substantial and make up almost 10% of the total profits. The relatively low full load hours and the high number of start-ups reflect the requirement for flexible operation in a market with depressed average electricity prices due to increasing RES share and increased fuel costs with higher CO_2 prices.[13]

5.3.3. Dispatch with TES

In this section, the optimal dispatch of the reference coal-fired plant with TES is simulated. The analysis includes two TES variants: A reference TES whose parameters are derived from the TES specifications stated in Richter et al. (2019) and a similar TES but with a higher round-trip efficiency.The discharging power of the high-efficiency TES at full load is adjusted accordingly to reflect the higher efficiency and the charging power at full load is increased proportionally. The parameters of both TES types are presented in Table 5.6. Charging and discharging power of the TES depends on at which plant load level the TES is charged and discharged, respectively. The discharging power is less than the charging power due to efficiency losses. Further, note that discharging power of the TES at minimum plant load is very restricted.[14] This variation in the charging and discharging power is included in the model as a linear function of plant load level.

Table 5.6.: Technical parameters of the analysed TES systems

	Plant load	Charging power (MW)	Discharging power (MW)	Avg. round-trip efficiency
Reference TES	20%	51.8	6.7	61.4%
	100%	37.0	31.8	
High-efficiency TES	20%	51.8	6.7	85.0%
	100%	51.2	44.0	

The optimal dispatch for the reference TES with 2 hours of storage capacity at charging power is plotted in Figure 5.2 for a representative day. On this particular day (January 16, 2019) the TES is active on all four markets (DA, PRL, SRL and ID). The figure of the plant dispatch with TES shows the

[13] The Walsum 10 power plant, being similar to the reference power plant used in this paper with respect to its technical parameters, had 3462 full load hours and 42 start-ups in 2019 (ENTSO-E Transparency Platform, 2020).

[14] For more information on technical characteristics of charging and discharging powers see Richter et al. (2019).

generator output (without control power activation), the intraday volumes bought and sold by charging and discharging the TES, and the control power volumes bid by the plant and those provided by the TES. The second figure below plots the TES load and stored energy, where the charging and discharging power on day-ahead and intraday markets and the corresponding energy level can be seen. Note that the stored energy level includes the activation probability of SRL provision. In these figures it can be seen that the TES is used to provide PRL and negative SRL during time periods when the price spreads are not profitable for energy arbitrage. In the periods when spreads are profitable the TES is charged and discharged accordingly to engage in energy arbitrage on DA and ID markets. Since the amount of profitable spreads are determined by the round-trip efficiency of the TES, TES systems with higher efficiencies can result in increased energy arbitrage. A dispatch example that illustrates this effect is provided in Appendix D.2 for the high-efficiency TES.

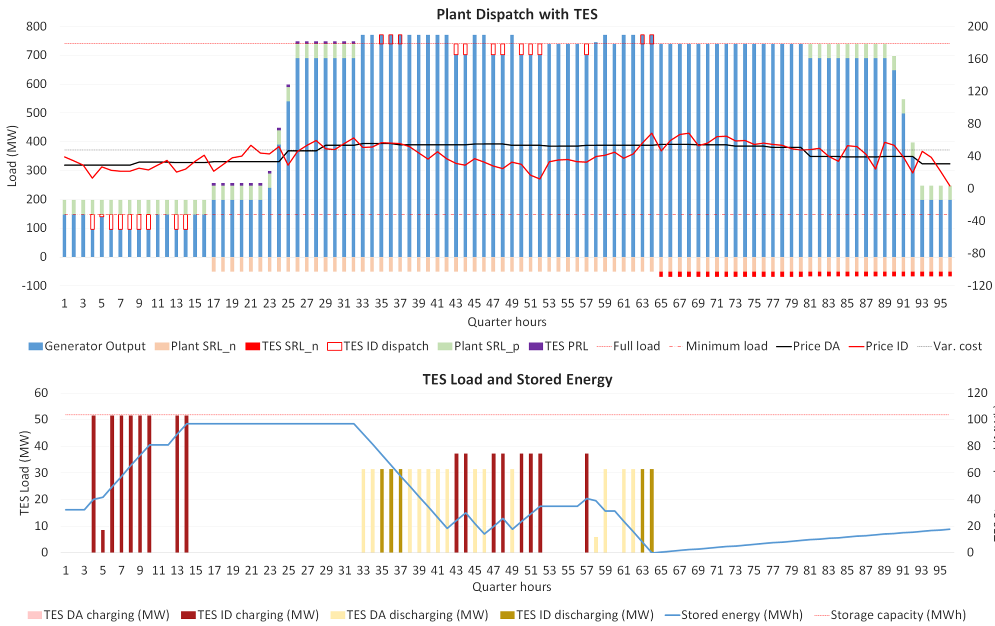


Figure 5.2.: Dispatch example of the reference TES with 2 hours of storage capacity on the simulated day of January 16, 2019

Effect of TES parameters on dispatch and profits

TES storage capacity and efficiency are the major parameters which affect how the plant with TES is dispatched, determining the amount of additional profits obtained via TES. Therefore, in this section, plant dispatch is simulated with the reference and the high-efficiency TES variants where the TES storage capacity is varied. Figure 5.3 plots the development of the full load hours of the plant and the number of start-ups with respect to TES storage capacity. A storage capacity of 0 corresponds to dispatch without TES. It can be seen that the TES system slightly increases the full load hours of the plant. For a small-sized TES with 0.5 h of capacity, full load hours increase marginally by 0.4% with the reference TES and 1.1% with the high-efficiency TES. As the storage capacity gets larger, the increase in full load hours gets more pronounced, which eventually starts plateauing after a capacity of 2-3 h. For the largest storage capacity of 8 h considered in this analysis, the increase in full load hours rises with the reference TES to 7% and with the high-efficiency TES to 9%. In Figure 5.3 it can also be observed that the TES can marginally increase or decrease the number of start-ups; however, a clear relationship between the TES storage capacity and number of start-ups cannot be identified.

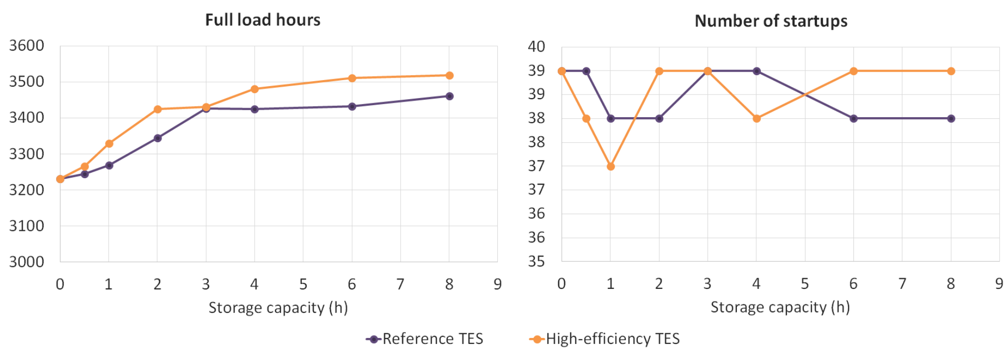


Figure 5.3.: Impact of TES on overall plant dispatch characteristics

The effect of TES storage capacity and efficiency on the profits the system achieves on individual markets is also analysed in this section. Figure 5.4 plots the additional profits achieved by TES dispatch with respect to storage capacity for both the reference and the high-efficiency TES variants. The reference TES with a 0.5 hours of storage capacity can provide additional profits of 377,000 EUR, increasing the plant profits by 2.4%. The high-efficiency TES with the same size brings 545,000 EUR of additional profits; a 3.5% increase in the plant profits. Moreover, it can be seen that as the storage capacity increases, the additional profits with TES also significantly increase. However, the relative increase in the profits decreases as the storage capacity gets larger. This effect becomes more pronounced with the reference TES for capacities greater than 4 hours, and in the case of high-efficiency TES, for capacities greater than 6 hours.

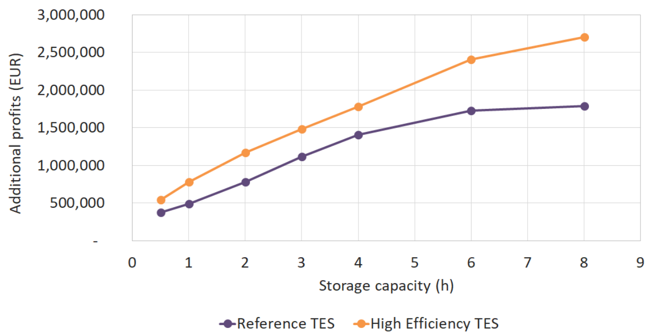


Figure 5.4.: Additional profits due to TES

The development of TES profits with respect to storage capacity and efficiency can be better understood by analysing the share of profits realised in the respective markets that TES participates in, as shown in Figure 5.5. For this analysis, the markets that TES participates in are extended one by one (i.e. DA only, DA+PRL, DA+PRL+SRL, DA+PRL+SRL+ID) and the consecutive difference in the total profits is calculated in each case to obtain the additional profits on the included market.

Significant differences in the profit distribution between the reference and the high-efficiency TES can be observed. For the reference TES with lower round-trip efficiency, price spreads on the DA market are not high enough and the profit on the DA market remains limited. On the other hand, high-efficiency TES achieves substantial profits on the DA market. Despite its lower efficiency, reference TES can nevertheless obtain significant profits on the ID market thanks to higher price volatility on the ID market. A storage capacity of 3 hours is found to be enough to maximise the ID profits. In the case of the high-efficiency TES, the ID profits are maximised around a storage capacity of 2 hours and are on average higher than twice the ID profits of the reference TES. Thus, it can be concluded that profits from energy arbitrage are strongly correlated with the round-trip efficiency of the TES, as expected.

Looking at the profits obtained from control power provision for both TES types, it can be seen that smaller TES systems (storage capacity < 1h) can nevertheless achieve substantial additional profits on the PRL market. However, due to increased storage requirement for prequalification on the SRL market, smaller TES systems can provide only a limited amount of SRL power and therefore achieve low SRL profits. In contrast, SRL profits constitute the major portion of total profits for larger storage capacities. For the reference

TES, SRL profits exceed all other profits combined starting from a storage capacity of slightly less than 3 hours, whereas for the high-efficiency TES this occurs at a capacity slightly larger than 4 hours. For the reference TES, profits obtained by providing control power (i.e. SRL+PRL) make up the majority of total profits irrespective of the considered storage capacities in this analysis.

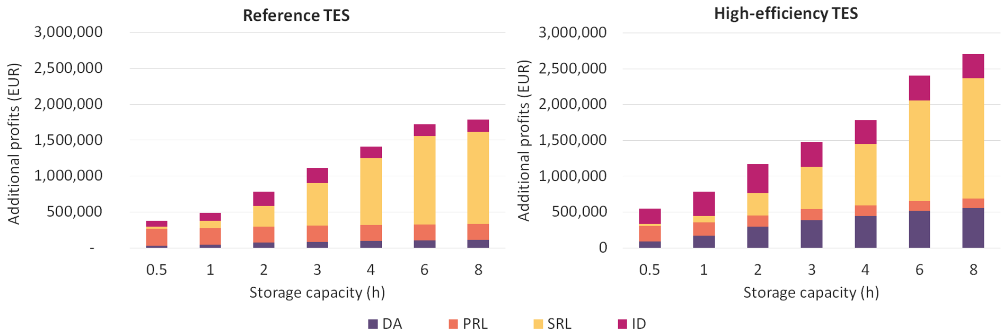


Figure 5.5.: Distribution of TES profits on the participated markets

Charging and discharging patterns

In contrast to the perfect foresight assumption in this paper, dispatching the TES system with the coal-fired power plant would occur in reality under imperfect information and price uncertainty. This requires the plant dispatch with charging and discharging instances of the TES to be planned according to forecasts and would deviate from the optimal results. In this respect, analysing the optimal dispatch simulation and identifying patterns in charging and discharging instances at respective plant load levels would support developing TES dispatch strategies.

Figure 5.6 illustrates the distribution of charging and discharging instances at different plant load levels for the reference TES with respect to storage capacity. For this analysis, plant load is considered in four levels of equal load range and any instances, where TES is charging or discharging in these load levels, are summed up. The overwhelming majority of TES activity (i.e. charging or discharging) is found to occur close to plant minimum load (20–40% load range) and around plant full load (80–100% load range), while TES activity in the mid ranges (40–80% load range) is very limited.

The majority of charging occurs around minimum load while the majority of discharging occurs around full load. This is as expected since—assuming no control power is provided—the plant would run at minimum load during low electricity prices that lie below its variable costs and would run at full load during higher profitable prices. Nevertheless, both the ratio of charging around full load and the ratio of discharging around minimum load increase as the storage capacity gets smaller. For small TES capacities (<1h) these occurrences are very substantial. With the 0.5 h capacity TES, about 40% of the total charging instances occur near full load and almost 30% of discharging takes place near minimum load. This is because the smaller storage capacity restricts the arbitrage potential between minimum load and full load periods where the absolute spreads are highest, and instead, forces more of the arbitrage to be made in shorter intervals on constant load levels.

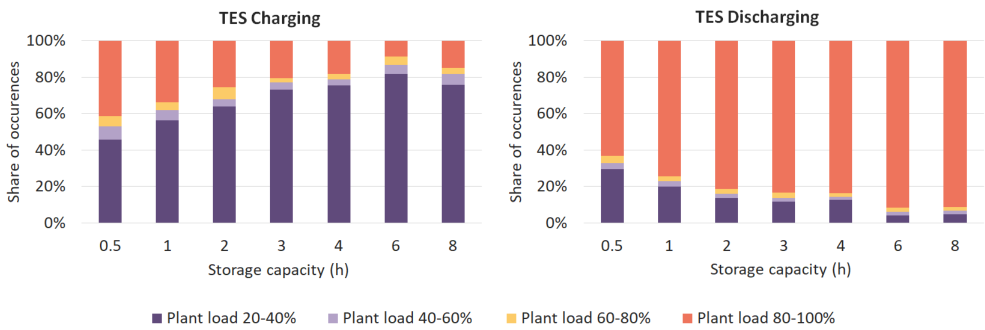


Figure 5.6.: Distribution of charging and discharging instances of the reference TES at different plant load levels

The same analysis is provided in Figure 5.7 for the high-efficiency TES. The frequency of discharging is similar to the reference TES case and takes place predominantly near full load. The charging frequencies, however, differ significantly from those of the reference TES. The ratio of charging instances near full load increases substantially for all the considered storage capacities. Similarly, this ratio increases with decreasing storage capacity, making up 64% of total charging instances for a TES with 0.5 h of capacity. The same reason of restricted arbitrage potential between the minimum load and full load periods due to limited storage capacity is also valid here. However, due to increased efficiency, more of the spreads can be profitably utilised for arbitrage, which significantly increases the share of charging instances near full load.

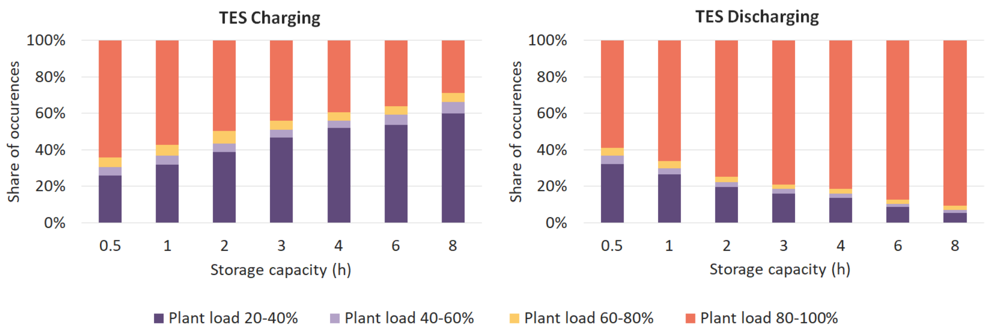


Figure 5.7.: Distribution of charging and discharging instances of the high-efficiency TES at different plant load levels

5.4. Conclusion

This paper analyses the optimal dispatch of a coal-fired power plant with an integrated TES system in Germany for the year of 2019, using a mixed integer linear programming model. The TES is assumed to be able to conduct energy arbitrage on the hourly day-ahead and the quarter hourly continuous intraday markets. Moreover, it can enhance primary and secondary control power provision. In this context, the effects of TES on the dispatch characteristics of the plant is investigated and additional profits due to TES are calculated. The relevance of individual TES parameters regarding the profit potential on the respective markets is shown and charging/discharging patterns are identified.

I find that smaller TES systems (storage capacity $\leq$ 1 h) achieve substantial profits (about 230,000 EUR) on the PRL market by providing additional PRL flexibility and can also realize significant profits from energy arbitrage on intraday market (up to about 115,000 EUR) thanks to the more volatile price structure. Increasing the round-trip efficiency of the TES system can allow a higher share of profits to be realised also on the day-ahead market and greatly increase total gains via energy arbitrage. I also show that a storage capacity of 2–3 h is enough to exploit most of the energy arbitrage potential. However, further increasing the storage capacity enhances profits on the SRL market. I find that the TES system with lower round-trip efficiency is predominantly charged close to minimum plant load and discharged near full load because of the limited availability of profitable price spreads due to low efficiency. With higher efficiency, charging near plant full load becomes more common as the number of profitable spreads increases.

The analysis shows that the TES systems increase the full load hours of the power plant. This increase can especially be significant for large TES systems, meaning that TES systems can also increase the CO_2 emissions of the individual plants. Despite that, the net effects on the system would depend on the specific CO_2 emissions of other technologies which provide similar type of flexibility to the system. Therefore, increasing the flexibility potential of conventional power plants via TES can nevertheless help integrating significant shares of renewables in the medium term. As noted also by Agora Energiewende (2017), countries with few other flexibility options and large share of inflexible conventional plants such as Poland and South Africa can especially benefit from the additional flexibility.

The analysis conducted in this paper shows only the energy arbitrage and control power provision potential of the TES. However, TES can also be used to provide other types of flexibility. For instance, TES can provide additional heat during start-up in order to reduce start-up time and costs. TES systems can also be integrated into combined heat and power plants that provide district heating, providing additional flexibility between the heating and the electricity market. Those aspects can be considered in future research by extending the presented model. The existing modelling framework assumes perfect foresight and provides an upper benchmark. For a more realistic dispatch and profit simulation under imperfect information, the model could be extended with stochastic components to account for price uncertainty. This paper does not provide assumptions or modelling regarding the costs of TES investment and integration of the TES into the plant. In future research, the analysis could be extended to take these costs into account in order to evaluate the profitability of the investment.

A. Supplementary Material for Chapter 2

A.1. Formal representation of the theoretical model

The cost minimisation problem can be formulated as the Lagrangian $\mathcal{L}$ with the Lagrange multipliers $\mu_1, \mu_2, \mu_3, \mu_4, \mu_5, \mu_6$:

$$
\begin{aligned}
&\mathcal{L}(S, C_1, C_2, C_{12}, \mu_1, \mu_2, ..., \mu_6) = \\
&a\,(d_1 + d_2) + \frac{1}{2}\left[b\,(d_1 + S)^2 + b\,(d_2 - S)^2\right] \\
&+\ \left[m\,(C_1 + C_2) + 2\,C_{12}\right]\tau_c \\
&+\ S\,\tau_s \\
&+ \mu_1\,(d_1 + S - C_{12} - C_1) \\
&+ \mu_2\,(d_2 - S - C_{12} - C_2) \\
&+ \mu_3\,(-S) + \mu_4\,(-C_1) + \mu_5\,(-C_2) + \mu_6\,(-C_{12}))
\end{aligned}
$$

The Karush-Kuhn-Tucker (KKT) conditions that need to be fulfilled are as follows:

Stationarity conditions:

$$\frac{\partial \mathcal{L}}{\partial C_1} = m\,\tau_c - \mu_1 - \mu_4 = 0 \tag{A.1}$$

$$\frac{\partial \mathcal{L}}{\partial C_2} = m\,\tau_c - \mu_2 - \mu_5 = 0 \tag{A.2}$$

$$\frac{\partial \mathcal{L}}{\partial C_{12}} = 2\,\tau_c - \mu_1 - \mu_2 - \mu_6 = 0 \tag{A.3}$$

$$\frac{\partial \mathcal{L}}{\partial S} = \tau_s + 2\,b\,(d_1 + 2\,S - d_2) + \mu_1 - \mu_2 - \mu_3 = 0 \tag{A.4}$$

<u>Dual feasibility and complementary slackness:</u>

$$\mu_1 \, (d_1 + S - C_{12} - C_1) = 0 \tag{A.5}$$

$$\mu_2 \, (d_2 - S - C_{12} - C_2) = 0 \tag{A.6}$$

$$\mu_3 \, S = 0 \tag{A.7}$$

$$\mu_4 \, C_1 = 0 \tag{A.8}$$

$$\mu_5 \, C_2 = 0 \tag{A.9}$$

$$\mu_6 \, C_{12} = 0 \tag{A.10}$$

$$\mu_1,\, \mu_2,\, \mu_3,\, \mu_4,\, \mu_5,\, \mu_6 \,\geq 0 \tag{A.11}$$

<u>Primal feasibility:</u>

$$C_{12} + C_1 \geq d_1 + S \tag{A.12}$$

$$C_{12} + C_2 \geq d_2 - S \tag{A.13}$$

$$S,\, C_1,\, C_2,\, C_{12} \,\geq 0. \tag{A.14}$$

A.2. KKT points

In order to find the optimal KKT points of the optimisation problem and identify the conditions under which they apply, we consider in this section all the realistically possible cases. Those cases correspond to the possible combinations of the Lagrange multipliers of the capacity bookings, C_1, C_2, and C_{12}. The combinations that cannot result in demand being satisfied at both time points, i.e. $(C_1 = C_2 = C_{12} = 0)$, $(C_1 = C_{12} = 0,\ C_2 > 0)$ and $(C_2 = C_{12} = 0,\ C_1 > 0)$, are ruled out. The remaining possible cases are as follows:

1. $C_1,\ C_2 > 0$ and $C_{12} = 0$ (i.e. $\mu_4 = \mu_5 = 0$ and $\mu_6 \geq 0$)
2. $C_1,\ C_{12} > 0$ and $C_2 = 0$ (i.e. $\mu_4 = \mu_6 = 0$ and $\mu_5 \geq 0$)
3. $C_1,\ C_2,\ C_{12} > 0$ (i.e. $\mu_4\,, \mu_5\,, \mu_6 = 0$)
4. $C_{12} > 0$ and $C_1,\ C_2 = 0$ (i.e. $\mu_6 = 0$ and $\mu_4,\ \mu_5 \geq 0$)
5. $C_2,\ C_{12} > 0$ and $C_1 = 0$ (i.e. $\mu_5 = \mu_6 = 0$ and $\mu_4 \geq 0$)

In addition to the main cases listed above, all four sub-cases arising from supply constraints (A.5) and (A.6) and their respective Lagrange multipliers μ_1 and μ_2 are considered. For clarity, the storage constraint (A.7) and its respective Lagrange multiplier, μ_3, if applicable, are considered within the four sub-cases.

1. **Case: $\boldsymbol{C_1,\ C_2 > 0}$ and $\boldsymbol{C_{12} = 0}$**
   This case corresponds to $\mu_4 = \mu_5 = 0$ and $\mu_6 \geq 0$. In order to obtain the conditions under which this case becomes valid, we need to go through the associated sub-cases.

   a) Supply constraints are binding in t_1 and t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 \geq 0$):
   From Equations A.1 and A.2 $\mu_1 = \mu_2 = m\,\tau_c$ is obtained. Substituting these into Equation A.3 yields:

   $$\mu_6 = 2\,\tau_c\,(1 - m)$$

   Since $\mu_6 \geq 0$, the condition for the validity of this case is $m \leq 1$. We now consider two sub-cases where storage S is equal to zero or non-zero, i.e. $\mu_3 \geq 0$ or $\mu_3 = 0$, respectively.

i. <u>$S = 0$:</u> From Equation A.4 with $\mu_1 = \mu_2 = m\,\tau_c$ and $S = 0$, we obtain:

$$\mu_3 = \tau_s + 2\,b\,(d_1 - d_2)$$

Since $\mu_3 \geq 0$, the condition for the storage tariff becomes $\tau_s \geq 2\,b\,(d_2 - d_1)$.

From Equations A.5 and A.6 the optimal values for the capacity bookings are obtained:

$$C_1 = d_1$$
$$C_2 = d_2$$

ii. <u>$S > 0$:</u> From Equation A.4 with $\mu_1 = \mu_2 = m\,\tau_c$ and $\mu_3 = 0$, we obtain:

$$S = \frac{d_2 - d_1}{2} - \frac{\tau_s}{4\,b}$$

Since $S > 0$, the condition for the storage tariff becomes $\tau_s < 2\,b\,(d_2 - d_1)$. From Equations A.5 and A.6 the optimal values for the capacity bookings are obtained:

$$C_1 = \frac{d_1 + d_2}{2} - \frac{\tau_s}{4\,b}$$
$$C_2 = \frac{d_1 + d_2}{2} + \frac{\tau_s}{4\,b}$$

The results indicate that when $m \leq 1$ only ST capacity products (C_1 and C_2) are booked and LT product (C_{12}) is not booked. If the storage tariff is sufficiently low ($\tau_s < 2\,b\,(d_2 - d_1)$), then the traders utilise storages by booking and transporting more than the required demand in t_1 period ($C_1 > d_1$) and less than the demand in t_2 period ($C_2 < d_2$). However, if the storage tariff is sufficiently high ($\tau_s \geq 2\,b\,(d_2 - d_1)$), then the traders do not use storages and book in both periods the respective demand ($C_1 = d_1$, $C_2 = d_2$).

b) <u>Supply constraint is binding in t_1 but not in t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 = 0$):</u> Substituting $\mu_2 = 0$ into Equation A.2 with $\mu_5 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

c) Supply constraint is binding in t_2 but not in t_1 (i.e. $\mu_1 = 0$, $\mu_2 \geq 0$):
Substituting $\mu_1 = 0$ into Equation A.1 with $\mu_4 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

d) Supply constraints are neither binding in t_1 nor in t_2 (i.e. $\mu_1 = 0$, $\mu_2 = 0$):
Substituting $\mu_1 = 0$ into Equation A.1 with $\mu_4 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

2. **Case: $\boldsymbol{C_1, C_{12} > 0}$ and $\boldsymbol{C_2 = 0}$**
This case corresponds to $\mu_4 = \mu_6 = 0$ and $\mu_5 \geq 0$. This case is possible for $m > 1$ only if $d_1 > d_2$. However, since by definition $d_2 > d_1$, this is not a valid case.

3. **Case: $\boldsymbol{C_1, C_2, C_{12} > 0}$**

This case corresponds to $\mu_4 = \mu_5 = \mu_6 = 0$. In order to obtain the conditions under which this case becomes valid, we need to go through the associated sub-cases.

a) Supply constraints are binding in t_1 and t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 \geq 0$):
From Equations A.1 and A.2 $\mu_1 = \mu_2 = m\,\tau_c$ is obtained. Substituting these into Equation A.3 yields:

$$m = 1$$

We now consider two sub-cases where storage S is equal to zero or non-zero, i.e. $\mu_3 \geq 0$ or $\mu_3 = 0$.

i. $S = 0$: From Equation A.4 with $\mu_1 = \mu_2 = m\,\tau_c$ and $S = 0$, we obtain:

$$\mu_3 = \tau_s + 2\,b\,(d_1 - d_2)$$

Since $\mu_3 \geq 0$, the condition for the storage tariff becomes $\tau_s \geq 2\,b\,(d_2 - d_1)$.

By rearranging the condition for τ_s to obtain $d_2 - d_1 \leq \frac{\tau_s}{2\,b}$ and plugging into Equation A.5 subtracted from Equation A.6, we obtain:

$$C_2 - C_1 \leq \frac{\tau_s}{2\,b}$$

We do not obtain unique results for C_1, C_2, and C_{12}. Instead, all combinations of positive C_1, C_2, and C_{12} that fulfil the condition above in addition to the constraints stated in Equations A.12) and A.13 are KKT points and hence optimal solutions.

ii. <u>$S > 0$:</u> From Equation A.4 with $\mu_1 = \mu_2 = m\,\tau_c$ and $\mu_3 = 0$, we obtain:

$$S = \frac{d_2 - d_1}{2} - \frac{\tau_s}{4\,b}$$

Since $S > 0$, the condition for the storage tariff becomes $\tau_s < 2\,b\,(d_2 - d_1)$. By rearranging the condition for τ_s to obtain $d_2 - d_1 > \frac{\tau_s}{2\,b}$ and plugging into Equation A.5 subtracted from Equation A.6, we obtain:

$$C_2 - C_1 > \frac{\tau_s}{2\,b}$$

Again, we do not obtain unique results for C_1, C_2, and C_{12}. All combinations of positive C_1, C_2, and C_{12} that fulfil the condition above in addition to the constraints stated in Equations A.12 and A.13 are KKT points and hence optimal solutions.

b) <u>Supply constraint is binding in t_1 but not in t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 = 0$):</u>
Substituting $\mu_2 = 0$ into Equation A.2 with $\mu_5 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

c) <u>Supply constraint is binding in t_2 but not in t_1 (i.e. $\mu_1 = 0$, $\mu_2 \geq 0$):</u>
Substituting $\mu_1 = 0$ into Equation A.1 with $\mu_4 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

d) <u>Supply constraints are neither binding in t_1 nor in t_2 (i.e. $\mu_1 = 0$, $\mu_2 = 0$):</u>
Substituting $\mu_1 = 0$ into Equation A.1 with $\mu_4 = 0$ yields $m\,\tau_c = 0$. Since by definition $m > 0$ and $\tau_c > 0$, this is not a valid case.

4. **Case: $C_1 = C_2 = 0$ and $C_{12} > 0$**

   This case corresponds to μ_4, $\mu_5 \geq 0$ and $\mu_6 = 0$. In order to obtain the conditions under which this case becomes valid, we need to go through the associated sub-cases.

   a) Supply constraints are binding in t_1 and t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 \geq 0$):
   From Equations $A.5$ and $A.6$ it follows that $S = \frac{d_2 - d_1}{2}$ and the corresponding Lagrange multiplier $\mu_3 = 0$. The value for the long-term capacity booking is also obtained as $C_{12} = \frac{d_2 + d_1}{2}$. Stationarity conditions then take the form:

   $$\begin{aligned} m\,\tau_c - \mu_1 - \mu_4 &= 0 \\ m\,\tau_c - \mu_2 - \mu_5 &= 0 \\ 2\,\tau_c - \mu_1 - \mu_2 &= 0 \\ \tau_s + \mu_1 - \mu_2 &= 0 \end{aligned}$$

   Solving the system of equations above yields the following results:

   $$\begin{aligned} \mu_1 &= \tau_c - \frac{\tau_s}{2} \\ \mu_2 &= \tau_c + \frac{\tau_s}{2} \\ \mu_4 &= \tau_c\,(m-1) + \frac{\tau_s}{2} \\ \mu_5 &= \tau_c\,(m-1) - \frac{\tau_s}{2} \end{aligned}$$

   From the condition μ_1, μ_2, μ_4, $\mu_5 \geq 0$ it follows:

   $$\begin{aligned} 2\,\tau_c &\geq \tau_s \\ m &\geq 1 + \frac{\tau_s}{2\,\tau_c} \end{aligned}$$

   To fulfil both equations simultaneously, $m \leq 2$ is required. This implies when multiplier is sufficiently high, but still below 2, and the storage tariff is sufficiently low, then the transported volumes align and only long-term capacity is booked.

   b) Supply constraint is binding in t_1 but not in t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 = 0$):

In this case, the stationary conditions reduce to:

$$\begin{aligned}(m-2)\,\tau_c &= \mu_4\\ m\,\tau_c &= \mu_5\\ 2\,\tau_c &= \mu_1\\ \tau_s + 2\,b\,(d_1+2S-d_2) + 2\,\tau_c &= \mu_3\end{aligned}$$

So $m \geq 2$ since $\mu_4 \geq 0$.
In addition we get from Equations A.5 and A.9 that:

$$\begin{aligned}C_{12} &= d_1 + S\\ S &= \frac{d_1-d_2}{2} - \frac{1}{2b}\,\tau_c - \frac{1}{4b}\,\tau_s\end{aligned}$$

Substituting C_{12} into Equation A.13, we obtain:

$$S \geq \frac{d_2-d_1}{2}$$

Substituting the previously obtained storage value into the inequality above yields:

$$0 \geq 2\tau_c + \tau_s.$$

This is not possible since τ_s, τ_c > 0. Hence, this case is not valid.

c) Supply constraint is binding in t_2 but not in t_1 (i.e. $\mu_1 = 0$, $\mu_2 \geq 0$):
In this case, the stationary conditions reduce to:

$$\begin{aligned}m\,\tau_c &= \mu_4\\ 2\,\tau_c &= \mu_2\\ (m-2)\,\tau_c &= \mu_5\\ \tau_s + 2\,b\,(d_1+2S-d_2) - 2\,\tau_c &= \mu_3\end{aligned}$$

The case is valid for $m \geq 2$ since $\mu_5 \geq 0$.

We now consider two sub-cases where storage S is equal to zero or non-zero, i.e. $\mu_3 \geq 0$ or $\mu_3 = 0$:

i. $\underline{S = 0}$: From Equations A.12 and A.13, and the assumption $d_2 > d_1$ we derive:

$$C_{12} = d_2$$

To ensure $\mu_3 \geq 0$ the following condition needs to hold:

$$\tau_s \geq 2\tau_c + 2b\,(d_2 - d_1)$$

It can be seen that in this case a portion of C_{12} equal to $d_2 - d_1$ is not utilised i.e. wasted in t_1.

ii. $\underline{S > 0}$: In this case $\mu_3 = 0$.

Plugging the given information into Equations A.4 and A.6 allows to solve for S and C_{12}:

$$\begin{aligned} S &= \frac{d_2 - d_1}{2} + \frac{1}{2b}\tau_c - \frac{1}{4b}\tau_s \\ C_{12} &= \frac{d_2 + d_1}{2} - \frac{1}{2b}\tau_c + \frac{1}{4b}\tau_s \end{aligned}$$

To ensure $S > 0$ and that the supply constraint as shown in Equation A.12 is satisfied, τ_s has to lie in the range between:

$$2\tau_c \leq \tau_s < 2\tau_c + 2b\,(d_2 - d_1)$$

If $\tau_s > 2\tau_c$, a portion of C_{12} equal to $\frac{\tau_s}{2b} - \frac{\tau_c}{b}$ is wasted in t_1. For $\tau_s = 2\tau_c$, this term becomes zero and thus transmissions in t_1 and t_2 align and no capacity booking is wasted.

The results indicate that under the condition $m \geq 2$ only LT capacity is booked for both periods. When the storage tariff is sufficiently high ($\tau_s > 2\,\tau_c$), storage utilisation is not sufficient to align transports in t_1 and t_2 such that some LT capacity is wasted in t_1. For $\tau_s = 2\,\tau_c$, transported volumes in both periods align, such that no LT capacity is wasted.

d) Supply constraints are neither binding in t_1 nor in t_2 (i.e. $\mu_1 = 0$, $\mu_2 = 0$):

In this case the stationary conditions reduce to:

$$m\,\tau_c = \mu_4$$
$$m\,\tau_c = \mu_5$$
$$2\,\tau_c = 0$$
$$\tau_s + 2\,b\,(d_1 + 2\,S - d_2) = \mu_3$$

This is not a valid case since it yields $\tau_c = 0$, where by definition $\tau_c > 0$.

5. **Case: $C_1 = 0$ and C_2, $C_{12} > 0$**

This case corresponds to $\mu_4 \geq 0$ and $\mu_5 = \mu_6 = 0$. In order to obtain the conditions under which this case becomes valid, we need to go through the associated sub-cases.

a) Supply constraints are binding in t_1 and t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 \geq 0$):
From Equations $A.5$ and $A.6$ it follows:

$$S = \frac{d_2 - d_1}{2} - \frac{C_2}{2} \tag{A.15}$$

Since $\mu_5 = \mu_6 = 0$, from Equations A.1, A.2 and A.3 we obtain:

$$\mu_1 = \tau_c\,(2 - m)$$
$$\mu_2 = m\,\tau_c$$
$$\mu_4 = 2\,\tau_c\,(m - 1)$$

From the condition that μ_1, μ_2, $\mu_4 \geq 0$ it follows that:

$$1 \leq m \leq 2$$

Substituting the previously obtained μ_1 and μ_2 into Equation A.4 yields the following:

$$\tau_s + 2\,b\,(d_1 + 2\,S - d_2) + 2\,\tau_c\,(1 - m) - \mu_3 = 0 \tag{A.16}$$

We now consider two sub-cases where storage, S, is equal to zero or non-zero, i.e. $\mu_3 \geq 0$ or $\mu_3 = 0$:

i. $\underline{S = 0}$: In this case $\mu_3 \geq 0$. Setting Equation A.15 to zero, we obtain:

$$C_2 = d_2 - d_1$$
$$C_{12} = d_1$$

Similarly, substituting $S = 0$ in Equation A.16 yields:

$$\mu_3 = \tau_s + 2\,b\,(d_1 - d_2) + 2\,\tau_c\,(1 - m)$$

Since $\mu_3 \geq 0$, the condition for this case becomes:

$$\tau_s \geq 2\,b\,(d_2 - d_1) + 2\,\tau_c\,(m - 1)$$

which can be rewritten as:

$$m \leq 1 + \frac{\tau_s}{2\,\tau_c} - \frac{b}{\tau_c}\,(d_2 - d_1) \tag{A.17}$$

The implication of this finding is that given the multiplier m and model parameters, when the storage tariff τ_s is sufficiently large no gas will be stored in the storage. Similarly, given the parameters, when the multiplier m is less than or equal to the right-hand side of the condition presented in Equation A.17 no gas will be stored in the storage.

ii. $\underline{S > 0}$: In this case $\mu_3 = 0$. From Equation A.16 the optimal storage value then becomes:

$$S = \frac{d_2 - d_1}{2} - \frac{\tau_s}{4b} + \frac{\tau_c(m-1)}{2b} \tag{A.18}$$

From Equations A.5 and A.6, we similarly obtain the optimal values for the capacities:

$$C_2 = \frac{\tau_s}{2b} - \frac{\tau_c(m-1)}{b} \tag{A.19}$$
$$C_{12} = \frac{d_2 + d_1}{2} - \frac{\tau_s}{4b} + \frac{\tau_c(m-1)}{2b} \tag{A.20}$$

Taking into account that S, C_{12}, $C_2 > 0$, the conditions for the validity of the case are obtained as follows:

$$\tau_s < 2\,b\,(d_2 - d_1) + 2\,\tau_c\,(m-1)$$

which can be rewritten as:

$$m > 1 + \frac{\tau_s}{2\,\tau_c} - \frac{b}{\tau_c}\,(d_2 - d_1) \tag{A.21}$$

and:

$$m < 1 + \frac{\tau_s}{2\,\tau_c} \tag{A.22}$$

The results indicate that while the conditions stated in Equations A.21 and A.22 are valid, i.e.

$$1 + \frac{\tau_s}{2\,\tau_c} - \frac{b}{\tau_c}\,(d_2 - d_1) < \; m \; < \; 1 + \frac{\tau_s}{2\,\tau_c} \tag{A.23}$$

long-term capacity C_{12} is booked for both periods, short-term capacity C_2 is booked for t_2, no short-term capacity C_1 is booked for t_1, and the storages are utilised.

b) <u>Supply constraint is binding in t_1 but not in t_2 (i.e. $\mu_1 \geq 0$, $\mu_2 = 0$):</u>

Substituting $\mu_5 = \mu_2 = 0$ into Equation A.2 yields:

$$m\,\tau_c = 0$$

Since both m and τ_c are by definition non-zero, this case is not valid.

c) <u>Supply constraint is binding in t_2 but not in t_1 (i.e. $\mu_1 = 0$, $\mu_2 \geq 0$):</u>

Considering that $\mu_5 = \mu_6 = \mu_1 = 0$, we obtain from Equations A.1, A.2 and A.3:

$$2\,\tau_c = m\,\tau_c$$
$$m = 2$$

We now consider two sub-cases where storage S is equal to zero or non-zero, i.e. $\mu_3 \geq 0$ or $\mu_3 = 0$, respectively.

i. <u>$S = 0$:</u> In this case $\mu_3 \geq 0$. From Equation A.4 we obtain:

$$\mu_3 = \tau_s + 2\,b\,(d_1 - d_2) - m\,\tau_c$$

Since $\mu_3 \geq 0$, the condition for this case becomes:

$$\tau_s \geq 2\,b\,(d_2 - d_1) + m\,\tau_c$$

The conditions from the supply constraints are as follows:

$$C_{12} \geq d_1$$
$$C_{12} = d_2 - C_2$$

It can be seen that there exists no unique solution for C_2, and C_{12}. All combinations of positive C_2 and C_{12} that fulfil the conditions above are KKT points and hence optimal solutions.

ii. <u>$S > 0$:</u> In this case $\mu_3 = 0$. From Equation A.4 we obtain:

$$S = \frac{d_2 - d_1}{2} + \frac{m\tau_c}{4\,b} - \frac{\tau_s}{4\,b}$$

Since $S > 0$, the condition for this case becomes:

$$\tau_s < 2\,b\,(d_2 - d_1) + m\,\tau_c$$

The conditions from the supply constraints are as follows:

$$C_{12} \geq d_1 + S$$
$$C_{12} = d_2 - C_2 - S$$

Again, there exists no unique solution for C_2, and C_{12}. All combinations of positive C_2 and C_{12} that fulfil the conditions above are KKT points and hence optimal solutions.

d) <u>Supply constraints are neither binding in t_1 nor in t_2 (i.e. $\mu_1 = 0$, $\mu_2 = 0$):</u>

Again, substituting $\mu_5 = \mu_2 = 0$ in Equation A.2 yields:

$$m\,\tau_c = 0$$

Similarly, substituting $\mu_1 = \mu_2 = \mu_6 = 0$ in Equation A.3 yields:

$$2\,\tau_c = 0$$

Since both m and τ_c are by definition non-zero, this case is not valid.

A.3. Prices in region A

Deriving prices in region A is less straightforward, since for the sake of simplicity no demand in region A is integrated. To derive the prices in region A one can add a fictional demand d_{A1} and d_{A2} to the procurement cost equation and differentiate it by d_{A1} and d_{A2}. Alternatively, one can subtract the Lagrange multipliers μ_1 and μ_2 from the prices in region B, since the Lagrange multipliers represent the marginal costs for transporting gas from region A to B.

$$P_{A1} = P_{B1} - \mu_1 = \begin{cases} a + b\, d_1 & \text{for } m < \underline{m} \\ a + b\left(\dfrac{d_1 + d_2}{2}\right) + \tau_c\,(m-1) - \dfrac{\tau_s}{2} & \text{for } \underline{m} < m < \overline{m} \\ a + b\left(\dfrac{d_1 + d_2}{2}\right) & \text{for } \overline{m} < m \end{cases}$$

$$P_{A2} = P_{B2} - \mu_2 = \begin{cases} a + b\, d_2 & \text{for } m < \underline{m} \\ a + b\left(\dfrac{d_1 + d_2}{2}\right) - \tau_c\,(m-1) + \dfrac{\tau_s}{2} & \text{for } \underline{m} < m < \overline{m} \\ a + b\left(\dfrac{d_1 + d_2}{2}\right) & \text{for } \overline{m} < m \end{cases} \tag{A.24}$$

The functions describing the consumer prices in region A are plotted in Figure A.1. Although individual consumer prices are influenced by m for $m < \overline{m}$, unweighted average prices remain constant.

The average price in region A is equal to the gas procurement prices which arise when overall demand is split evenly among periods:

$$\frac{P_{A2} + P_{A1}}{2} = a + b\,(\frac{d_2 + d_1}{2})$$

As can be seen in Figure A.1, when $m \leq \underline{m}$, the prices in region A are independent of the multiplier due to storages not being used and prices solely reflecting the costs for gas production. In the domain $\underline{m} < m < \overline{m}$, as storages start being utilised and the marginal costs of storage utilisation is included in the prices, an offset in prices (decrease in t_1, increase in t_2) occurs. With increasing m, prices in region A start converging as production volumes

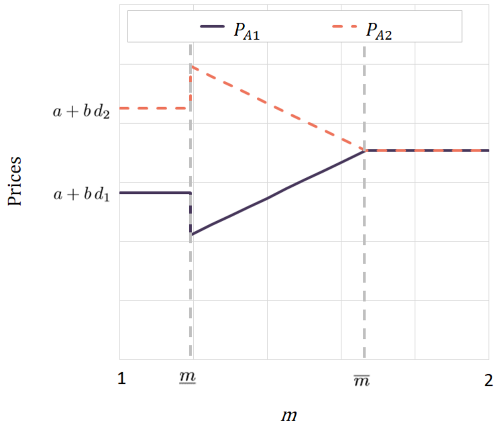


Figure A.1.: Development of prices in region A at time periods t_1 and t_2 with respect to the multiplier

increasingly align. With $m \geq \overline{m}$, production volumes fully converge and the same prices in both periods are observed in region A.

A.4. Surpluses and deadweight loss when no feasible $\underline{m}$ and $\overline{m}$ exist

Depending on the tariff structures (i.e. the proportion of τ_s and τ_c), $\underline{m}$ and $\overline{m}$ may not exist in the feasible multiplier range of $1 \leq m \leq 2$. In such a case, the previously identified domains $m < \underline{m}$ and $m > \overline{m}$ do not exist. Hence, Proposition 4 holds throughout the feasible multiplier range (i.e. $1 \leq m \leq 2$) and storages are utilised as well as ST and LT capacities are booked for all such multipliers.

The surpluses of the agents in the model and the deadweight loss are plotted in Figure A.2.[1]

[1]The parameters assumed for the figure are as follows: $d_1 = 11$, $d_2 = 30$, $\tau_c = 2.9$, $\tau_s = 5.7$, $a = 4$, $b = 0.15$.

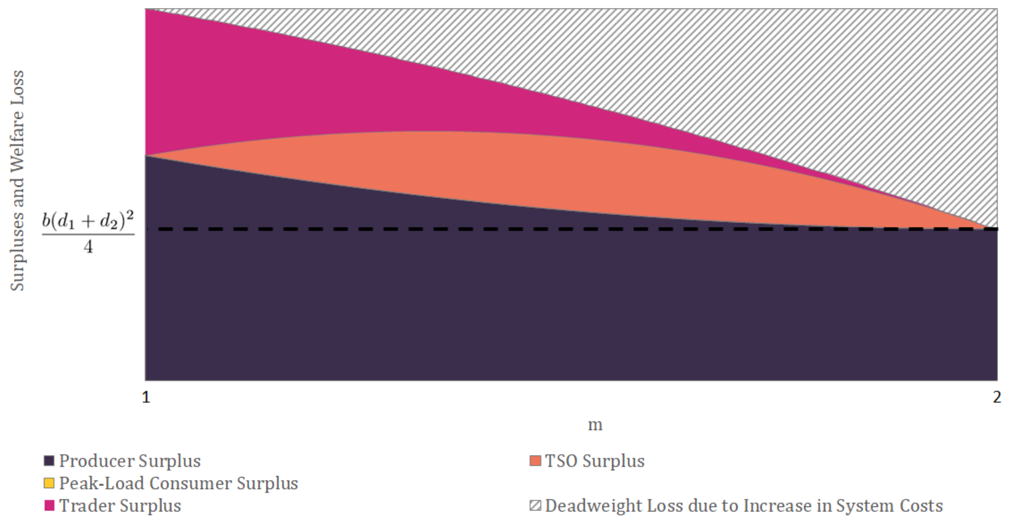


Figure A.2.: Surpluses and deadweight loss when no feasible $\underline{m}$ and $\overline{m}$ exist

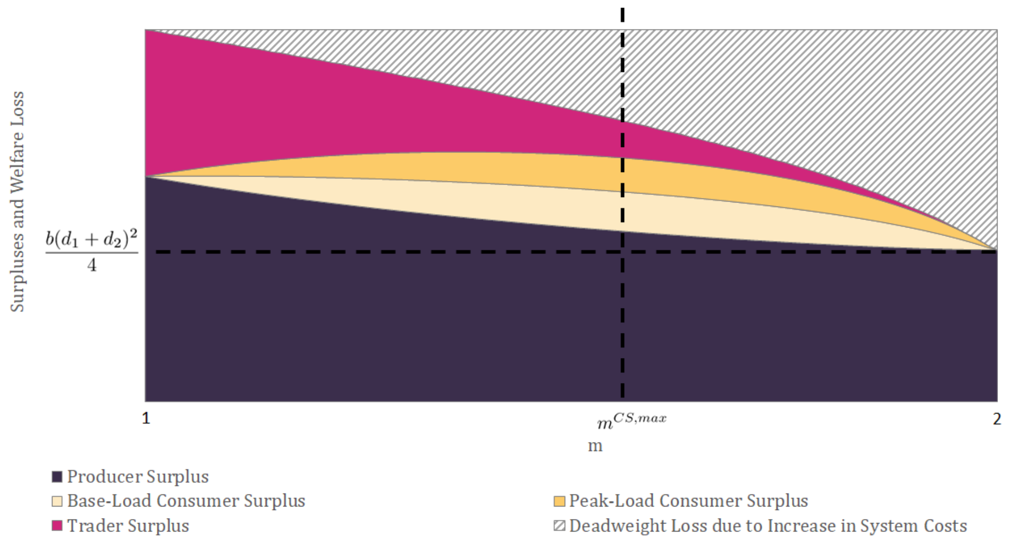


Figure A.3.: Surpluses and deadweight loss when no feasible $\underline{m}$ and $\overline{m}$ exist in the case where τ_c is adjusted

For the case when transmission tariffs (τ_c) are adjusted such that the TSO does not earn a surplus, the surpluses of the agents in the model and the deadweight loss are plotted in Figure A.3. The multiplier level that maximises the total consumer surplus is equal to $m^{CS,max} = 1 + \frac{\tau_s}{\tau_c^{adj}}$.

B. Supplementary Material for Chapter 3

B.1. Theoretical analysis

Lemma 1. *With T being the total number of time periods, it is optimal to solely book long-term capacity covering all periods if the duration of the short-term capacities products multiplied by the respective multiplier exceed T.*

Proof. The cost for a short-term (ST) capacity product is equal to $t_p m_p \tau_c$, with t_p being the duration of the capacity product p, m_p being the multiplier of the respective capacity product and τ_c being the tariff for the long-term (LT) capacity. For LT capacity that covers all the periods, no multiplier is applied and the cost is equal to $T\tau_c$. It is clear that if $t_p m_p > T$ the cost for the ST capacity product becomes higher than the cost of LT capacity. In this situation, it is always optimal to book only LT capacity. This concludes the proof. $\square$

In the paper at hand we assess the effects of multipliers in a setting with twelve periods, in which each period represents one month. A yearly (LT) capacity covering all the twelve periods, a quarterly capacity covering three periods and a monthly capacity covering one period are offered.

The cost of one unit of quarterly capacity, covering three periods, is equal to $3m_q\,\tau_c$, with m_q being the quarterly multiplier. For LT capacity, covering all the twelve periods, no multiplier is applied, so the cost is equal to $12\tau_c$. If $m_q > 4$, the cost of the quarterly capacity becomes higher than the LT capacity. The cost of one unit of monthly capacity, covering one period, is equal to $m_m\,\tau_c$, with m_m being the multiplier for monthly capacity. If $m_m > 12$, the cost of the monthly capacity becomes higher than the LT capacity. Therefore, in the setting with twelve periods, and multipliers of $m_q > 4$ and $m_m > 12$, it is always optimal for a cost-minimising trader to book only LT capacity.

Lemma 2. *If demand for transmission capacity is fully inelastic where it equals to $X - e$ in t_p periods and X in the remaining consecutive $T - t_p$ periods, under* *the condition $m_p > \frac{T}{T-t_p}$, only LT capacity is booked in the optimal solution and some capacity rights remain unused.*

Proof. A trader can either book a combination of LT and ST capacity or choose to book LT capacity only. In case it is decided to mix both types of capacities, the trader procures $X - e$ units of LT capacity, valid in all T periods, and buys additionally e units of ST capacity for the remaining consecutive $T - t_d$ periods with higher demand. t_p represents the duration of the ST capacity product p. Other combinations would result in higher costs. If it is decided to book only LT capacity instead, the trader books X units of LT capacity for the whole period. It would be optimal to book only LT capacity if the associated costs were lower, i.e. if the inequality below would hold:

$$\tau_c[(X-e)\,T + e\,(T-t_p)\,m_p] > \tau_c X\,T$$

which then simplifies to:

$$m_p > \frac{T}{(T-t_p)}$$

□

The situation of fully inelastic demand as assumed in the Lemma would occur if storages are exhausted. Applying the Lemma to a setting with twelve periods where each period represents one month—and a yearly capacity (LT) covers all the twelve periods, a quarterly capacity covers three periods and a monthly capacity covers one period—results in the following thresholds for multipliers:

In case demand equals X in eleven months and is lower in the remaining one month, solely LT capacity is booked if the monthly multiplier exceeds $m_p > \dfrac{12}{(12-1)} = 1.\overline{09}$. In case demand equals X in nine months and is lower in the remaining consecutive three months, solely LT capacity is booked if the monthly multiplier exceeds $m_p > \dfrac{12}{(12-3)} = 1.\overline{33}$. The multiplier threshold in this case is higher, as a larger share of LT capacity is wasted. The two examples show that, even in the presence of moderate multipliers, it can be optimal for traders to let some capacity remain unused.

If demand is not fully elastic, but transports are not fully aligned even in the presence of multipliers that induce a capacity pricing regime (see Lemma 1), then multipliers causing only LT capacity to be booked would lie between the thresholds resulting from Lemma 1 and Lemma 2. This would be the case if flexibility is available but the marginal cost curve for flexibility is steep.

B.2. Reference case and model validation

We validate our model against historical results for the 2018 gas year covering the period 01. October 2017–30. September 2018. For this purpose, we consider the reference case where every region has the default EU average multiplier ($m4$) levels. The simulated storage levels, imports from Russia and the price levels are then compared with the historical levels.

In Figure B.1 the simulated monthly storage levels in the EU are plotted against the historical levels.[1] Note that LNG storages are not included. It can be seen that the simulated storage levels during the winter period lie slightly below the historical levels. Nevertheless, the storage levels then follow the historical levels very closely in the summer period.

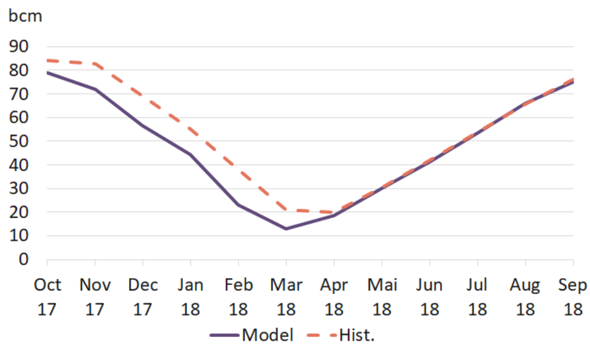


Figure B.1.: Simulated and the historical monthly storage levels in the EU

In Figure B.2 the simulated monthly imported gas volumes from Russia are plotted against the historical volumes.[2] The simulated import volumes lie slightly above the historical volumes in the winter period, while they lie slightly below the historical volumes in the summer period. The difference between the simulated and the historical results in the total yearly imported volumes is less than 1%.

[1] Historical storage levels for European countries are obtained from the AGSI+ platform (`https://agsi.gie.eu/`).

[2] Historical imports are derived from the IEA Gas Trade Flows (GTF) service (`https://www.iea.org/reports/gas-trade-flows`).

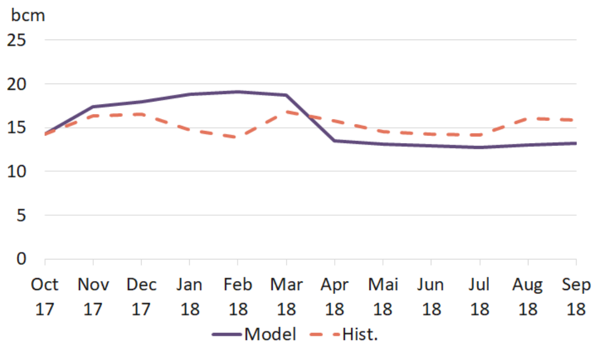


Figure B.2.: Simulated and the historical monthly import volumes from Russia into the EU

In Figure B.3 the average prices in the considered regions for the gas year 2018 and the historical TTF price during this period are plotted. It can be seen that the average price in the Central region is very close to the average TTF price. The price levels in the other regions are higher than the price level in the Central and lie in realistic ranges. Note that the prices for the Baltic and the South East regions include on top of the simulated prices markups of 3 EUR/MWh and 1.5 EUR/MWh, respectively. This is done in order to represent the realistic price levels observed in these regions due to having less competitive market structures.

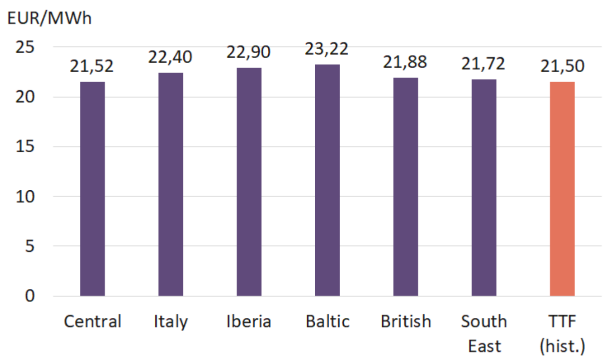


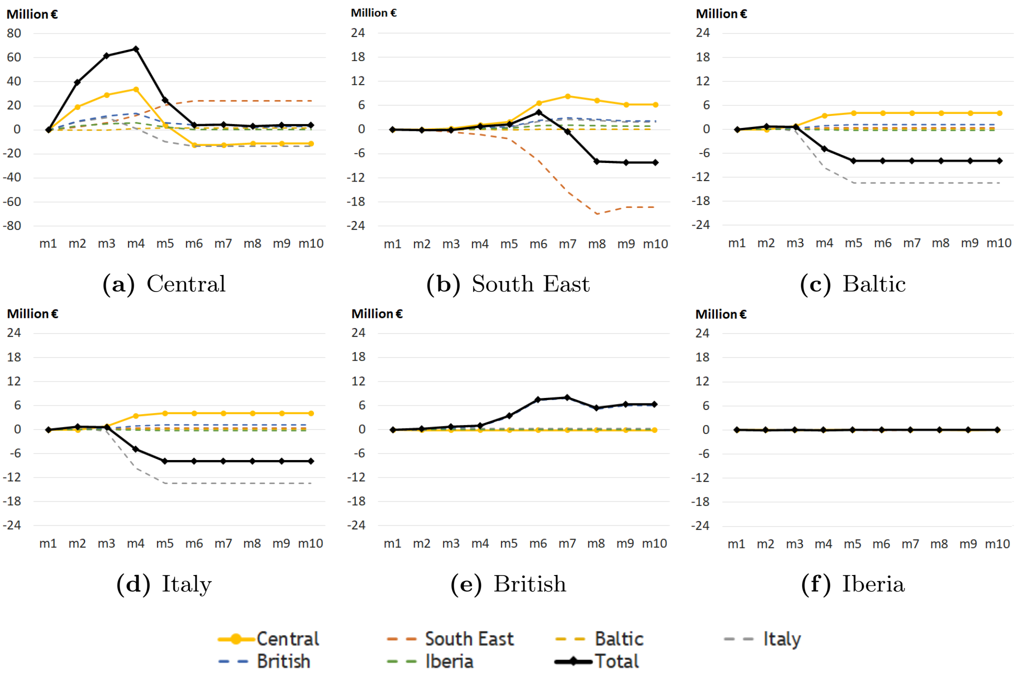
Figure B.3.: Simulated regional price levels for the gas year 2018 and the historical TTF price in the corresponding period

B.3. Overview of regional price spreads

Figure B.4.: Change in the average inter-regional price spread and its standard deviation with respect to import region when each region adjusts their multipliers individually

Figure B.4 plots the average inter-regional price spread as well as its standard deviation with respect to multipliers when regions adjust their multipliers individually in the default case. It can be seen that the change in the average regional price spreads directly follow the change in average prices due to tariff adjustments (see Figure 3.5). The standard deviation of the regional price spreads, which can also be referred to as the volatility of the regional price spreads, is shown to be increasing with multipliers in all regions except Iberia.

B.4. Overview of external effects on consumer surplus



(a) Central (b) South East (c) Baltic

(d) Italy (e) British (f) Iberia

Figure B.5.: The changes in consumer surplus in the regions and the total impact in the EU when multipliers are adjusted individually in the regions: (a) Central, (b) South East, (c) Baltic, (d) Italy, (e) British, (f) Iberia.

C. Supplementary Material for Chapter 4

C.1. Model structure

C.1.1. Model sets, variables and parameters

Sets	
$n \in N$	Nodes
$p \in P \in N$	Production regions
$d \in D \in N$	Demand regions
$e \in E$	Exporters
$c \in C$	Cost levels
$y \in Y$	Time step
Variables	
$\beta_{n,y}$	Marginal cost/price of one barrel of oil at node n
$\lambda_{e,n,y}$	Marginal cost of physical supply at node n controlled by exporter e
$\pi_{e,n,c,y}$	Production at node n and cost level c controlled by exporter e
$\tau_{e,n,n_1,y}$	Transportation from node n to node n_1 by exporter e
$\iota_{e,n,y}$	Import decision of exporter e to node n
$\mu_{e,n,y}$	Production capacity dual variable
$\phi_{n,n_1,y}$	Pipeline capacity dual variable
$a_{e,n,y}$	Amount bought by the arbitrageur at demand node n
Parameters	
$Cost^{pro}_{e,n,c,y}$	Production cost
$Cost^{tra}_{n,n_1,y}$	Transportation cost
$Conj_{e,d}$	Conjectural variation
Cap^{pro}	Production capacity
Cap^{pip}	Pipeline capacity
$Intercept_{n,y}$	Inverse demand function intercept
$Slope_{n,y}$	Inverse demand function slope

C.1.2. Model formulation

The model formulation in DROPS closely follows the structure presented in Hecking and Panke (2006) for the gas market model COLUMBUS, which is also an MCP model. In DROPS, each exporter, $e \in E$, has two maximization problems. They decide not only how much to produce at the corresponding production nodes, $p \in P$, but also how much to supply to each demand node, $d \in D$.

Exporter's problem (1):

The exporter's problem is to maximize its profit over the analyzed time period $y \in Y$, which is formulated as follows:

$$\begin{aligned} \max_{\iota_{e,d,y}} p_1^e(\iota_{e,d,y}) = \sum_{y \in Y} \sum_{d \in D} \Bigg[& Conj_{e,d} \cdot \iota_{e,d,y} \cdot \beta_{d,y}(\sum_{e \in E} \iota_{e,d,y}) \\ & + (1 - Conj_{e,d}) \cdot \iota_{e,d,y} \cdot \beta_{d,y} - \lambda_{e,d,y} \cdot \iota_{e,d,y} \Bigg] \end{aligned} \tag{C.1}$$

As can be seen in Equation C.1, the exporter maximizes the difference between its revenues and costs, where its revenue is equal to the market price of one barrel of oil β at the corresponding demand node d, multiplied with the volume supplied $\iota_{e,d,y}$ by the exporter to node d. The cost of supply to that node similarly corresponds to the cost λ of bringing one barrel of oil to node d multiplied by $\iota_{e,d,y}$. Furthermore, if the exporter has market power in particular demand nodes, it is represented by the conjectural variation parameter $Conj_{e,d}$. If $Conj_{e,d}$ equals 1 at a node d, the price $\beta_{d,y}$ that the exporter faces becomes a function of the total quantity imported by both that exporter and other exporters. Otherwise it is equal to 0, meaning that the exporter at that demand node is a price-taker.

Exporter's problem (2):

The exporter's second problem is that it needs to minimize the transportation costs of the exported oil by choosing the least-cost flow destination. As indicated in Equation C.2, this can be formulated as a maximization problem where the difference between the value of one barrel of oil at the destination node $\lambda_{e,n_1,y}$ and the value at the source node $\lambda_{e,n,y}$ minus the cost of transportation $Cost^{tra}_{n,n_1,y}$ is maximized with respect to the transported volume $\tau_{e,n,n_1,y}$. Transportation can occur via tankers or via pipelines. If transportation is taking place via pipelines, there exists a constraint that the transported volume cannot exceed the exogenous capacity of the pipeline $Cap^{pip}_{n,n_1,y}$. For tankers no capacity constraint is assumed.

$$\max_{\tau_{e,n,n_1,y}} p^e_2(\tau_{e,n,n_1,y}) = \sum_{y \in Y} (\lambda_{e,n_1,y} - \lambda_{e,n,y} - Cost^{tra}_{n,n_1,y}) \cdot \tau_{e,n,n_1,y} \tag{C.2}$$

$$s.t. \qquad Cap^{pip}_{n,n_1,y} - \sum_{e \in E} \tau_{e,n,n_1,y} \ \geq \ 0$$

Producer's problem:

Each production node in the model represents a single producer which sells its output to a single exporter. The producer at a particular node aims at maximizing its profit as represented in Equation C.3, which is defined as the revenue minus the cost of production, summed over the cost function and the respective time period. The revenue is equal to the value of oil at the production node, $\lambda_{e,p,y}$, multiplied with the produced volume, $\pi_{e,p,c,y}$. Similarly, cost of production is equal to the marginal production cost, $Cost^{pro}_{e,p,c,y}$, multiplied with the produced volume. The producer is constrained by the fact that production volumes cannot exceed production capacity.

$$\max_{\pi_{e,p,c,y}} p^{pro}(\pi_{e,p,c,y}) = \sum_{y \in Y} \sum_{c \in C} (\lambda_{e,p,y} \cdot \pi_{e,p,c,y} - Cost^{pro}_{e,p,c,y} \cdot \pi_{e,p,c,y}) \tag{C.3}$$

$$s.t. \qquad Cap^{pro} - \pi_{e,p,c,y} \ \geq \ 0$$

C.1.3. First order conditions

KKT conditions

$$-\lambda_{e,n,y} + Cost^{pro}_{e,n,c,y} + \mu_{e,n,c,y} \geq 0 \quad \perp \quad \pi_{e,n,c,y} \tag{1}$$

$$-\lambda_{e,n_1,y} + \lambda_{e,n,y} + Cost^{tra}_{n,n_1,y} + \phi_{n,n_1,y} \geq 0 \quad \perp \quad \tau_{e,n,n_1,y} \tag{2}$$

$$Conj_{e,n} \cdot Slope_{n,y} \cdot \iota_{e,n,y} - \beta_{n,y} + \lambda_{e,n,y} \geq 0 \quad \perp \quad \iota_{e,n,y} \tag{3}$$

$$-\lambda_{e,n,y} + \beta_{n,y} \geq 0 \quad \perp \quad a_{e,n,y} \tag{4}$$

Physical flow balances

$$\frac{Intercept_{n,y} - \beta_{n,y}}{Slope_{n,y}} + \sum_{e \in E} a_{e,n,y} - \sum_{e \in E} \iota_{e,n,y} = 0 \quad \perp \quad \beta_{n,y} \tag{5}$$

$$\sum_{c \in C} \pi_{e,n,c,y} + \sum_{n_1 \in N} \tau_{e,n_1,n,y} + a_{e,n,y} - \sum_{n_1 \in N} \tau_{e,n,n_1,y} + \iota_{e,n,y} = 0 \quad \perp \quad \lambda_{e,n,y} \tag{6}$$

Capacity constraints

$$Cap^{pro}_{e,n,c,y} - \pi_{e,n,c,y} \geq 0 \quad \perp \quad \mu_{e,n,y} \tag{7}$$

$$Cap^{pip}_{n,n_1,y} - \sum_{e \in E} \tau_{e,n,n_1,y} \geq 0 \quad \perp \quad \phi_{n,n_1,y} \tag{8}$$

C.1.4. List of included countries and corresponding nodes

Region	Country	Consumption node	Production node
North America	Canada	CA_cons	CA_prod
	Mexico	MX_cons	MX_prod
	United States	US_East_cons	US_PADD1_prod
		US_West_cons	US_PADD3_prod
		US_Midwest_cons	US_PADD2_4_prod
			US_PADD5_prod
South America	Argentina	OT_SAM_cons	AR_prod
	Brazil	BR_cons	BR_prod
	Chile	OT_SAM_cons	
	Colombia	OT_SAM_cons	CO_prod
	Cuba	OT_SAM_cons	
	Dominican Rep.	OT_SAM_cons	
	Ecuador	EC_cons	EC_prod
	Panama	OT_SAM_cons	
	Peru	OT_SAM_cons	
	Puerto Rico	OT_SAM_cons	
	Venezuela	VE_cons	VE_prod
	Virgin Islands, US.	OT_SAM_cons	
Africa	Algeria	DZ_cons	DZ_prod
	Angola		AO_prod
	Egypt	EG_cons	EG_prod
	Libya	LY_cons	LY_prod
	Nigeria	NG_cons	NG_prod
	South Africa	ZA_cons	
Middle East	Iran	IR_cons	IR_prod
	Iraq	OT_MEA_cons	IQ_North_prod
			IQ_South_prod
	Israel	OT_MEA_cons	
	Jordan	OT_MEA_cons	
	Kuwait	OT_MEA_cons	KW_prod
	Lebanon	OT_MEA_cons	
	Oman	OT_MEA_cons	OM_prod
	Qatar	OT_MEA_cons	QA_prod
	Saudi Arabia	SA_cons	SA_prod
	Syria	OT_MEA_cons	SY_prod
	United Arab Emirates	OT_MEA_cons	AE_prod
	Yemen	OT_MEA_cons	
Caspian Region	Azerbaijan		AZ_prod
	Kazakhstan		KZ_Caspian_prod
			KZ_Other_prod
	Turkmenistan		TM_prod
Russia	Russia	RU_cons	RU_WestSiberia_prod
			RU_FarEast_prod
			RU_VolgaUral_prod
			RU_NorthWestArctic_prod
			RU_EastSiberia_prod

Region	Country	Consumption node	Production node
Europe	Ireland	UK_cons	UK_prod
	Italy	IT_cons	
	Portugal	SP_PT_cons	
	Spain	SP_PT_cons	
	Turkey	TR_cons	TR_prod
	United Kingdom	UK_cons	UK_prod
West Europe	Belgium	W_EUR_cons	
	France	W_EUR_cons	
	Germany	W_EUR_cons	
	Luxembourg	W_EUR_cons	
	Netherlands	W_EUR_cons	
	Switzerland	W_EUR_cons	
Central Europe	Austria	C_EUR_cons	
	Czech Republic	C_EUR_cons	
	Hungary	C_EUR_cons	
	Slovakia	C_EUR_cons	
	Slovenia	C_EUR_cons	
East Europe	Bulgaria	E_EUR_cons	
	Croatia	E_EUR_cons	
	Greece	E_EUR_cons	
	Romania	E_EUR_cons	
	Serbia	E_EUR_cons	
North Europe	Denmark	N_EUR_cons	N_EUR_prod
	Finland	N_EUR_cons	N_EUR_prod
	Norway	N_EUR_cons	NO_prod
	Sweden	N_EUR_cons	N_EUR_prod
North East Europe	Belarus	NE_EUR_cons	
	Lithuania	NE_EUR_cons	
	Poland	NE_EUR_cons	
	Ukraine	NE_EUR_cons	
Asia Pacific	Australia	AU_cons	AU_prod
	Bangladesh	OT_APA_cons	
	China	CN_cons	CN_prod
	Hong Kong	OT_APA_cons	
	India	IN_cons	IN_prod
	Indonesia	ID_cons	ID_prod
	Japan	JP_cons	
	Malaysia	OT_APA_cons	MY_prod
	New Zealand	OT_APA_cons	
	Philippines	OT_APA_cons	
	Singapore	OT_APA_cons	
	South Korea	KR_cons	
	Sri Lanka	OT_APA_cons	
	Taiwan	OT_APA_cons	
	Thailand	OT_APA_cons	
	Vietnam	OT_APA_cons	

C.1.5. Production capacities of OPEC and OPEC+ members in the model

Table C.1.: Production capacities of OPEC members in the model (in million bbl/d)

	2013	2014	2015	2016	2017
Algeria	1.60	1.63	1.63	1.63	1.58
Angola	1.95	1.84	1.88	1.88	1.75
Ecuador	0.53	0.57	0.56	0.57	0.54
Iran	3.67	4.23	4.35	4.61	4.71
Iraq	3.34	3.75	4.44	4.79	4.87
Kuwait	3.44	3.35	3.18	3.25	3.25
Libya	1.47	0.89	0.44	0.69	1.05
Nigeria	2.81	2.50	2.38	2.28	2.16
Qatar	1.92	1.90	1.87	1.87	1.88
Saudi Arabia	14.4	14.4	14.1	14.2	14.1
United Arab Emirates	3.61	3.72	3.77	3.99	4.01
Venezuela	2.83	2.77	2.66	2.43	2.13
TOTAL	41.5	41.5	41.3	42.2	42.0

Table C.2.: Production capacities of OPEC+ participants in the model (in million bbl/d)

	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4
Non-OPEC	17.4	17.2	17.0	16.8	16.9
Russia	11.9	11.8	11.7	11.7	11.7
Mexico	2.44	2.40	2.38	2.22	2.19
Oman	1.04	1.00	1.00	1.00	1.00
Azerbaijan	0.81	0.79	0.81	0.80	0.82
Malaysia	0.71	0.72	0.69	0.69	0.70
Kazakhstan	0.44	0.47	0.47	0.47	0.48
OPEC*	38.0	37.0	37.3	37.6	37.2
Algeria	1.64	1.60	1.61	1.60	1.53
Angola	1.80	1.74	1.74	1.78	1.73
Ecuador	0.57	0.53	0.54	0.55	0.54
Iraq	5.01	4.86	4.89	4.87	4.84
Kuwait	3.22	3.25	3.26	3.24	3.24
Libya	0.86	0.88	0.93	1.16	1.22
Nigeria	2.25	2.03	2.12	2.25	2.23
Qatar	1.86	1.87	1.90	1.87	1.89
Saudi Arabia	14.35	14.01	14.10	14.11	14.12
United Arab Emirates	4.09	4.03	4.01	4.01	3.97
Venezuela	2.31	2.26	2.22	2.15	1.91
TOTAL	55.4	54.2	54.4	54.4	54.1

*Iran is excluded since Iran did not participate in the OPEC+ agreement.

C.2. Statistical measures

An important aspect for determining the accuracy of a spatial model is to compare actual and model-predicted trade flows. In this regard, we follow a commonly applied methodology (Bushnell et al., 2008, Kolstad and Abbey, 1984, Lorenczik and Panke, 2016, Trüby, 2013) that is used to validate models that are of similar types to ours, where we consider three different statistical measures: linear hypothesis testing, Spearman's rank correlation, and Theil's inequality coefficient. In what follows, we will be introducing these measures and discussing their application. We will also indicate possible shortcomings for the respective statistics. The applied statistics and their definitions closely follow those presented in Trüby (2013) and most recently in Lorenczik and Panke (2016).

In order to determine how well the values of the simulated trade flow matrix match with the actual flows a linear hypothesis test can be conducted. The idea here is that in the case of a perfect fit between the actual and simulated flows, plotting the values in a scatter-plot would form a line starting at zero and having a slope that is equal to one. We can therefore regress the actual trade flows A_f on the simulated flows S_f to test for the accuracy of the model. The set f stands for the trade flows between exporting regions $e \in E$ and importing regions $d \in D$.

$$A_f = \beta_0 + \beta_1 \cdot S_f + \epsilon_f \tag{C.4}$$

Equation C.4 is estimated with ordinary least squares (OLS). To be able to conclude whether simulated trade flows are consistent with actual flows, it is necessary that the joint null hypothesis of $\beta_0 = 0$ and $\beta_1 = 1$ cannot be rejected at conventional significance levels. Even though this approach is commonly used due to its advantage of allowing hypothesis testing, it is considerably sensitive to outliers.

As a second statistical measure, we use the Spearman's rank correlation coefficient (Spearman's rho) to evaluate how well the market shares of exporters in demand regions in the model estimations correlate with those in actual cases. This corresponds to comparing the ranking of actual trade flows with respect to volume with the ranking of simulated flows. Spearman's rho is defined as in Equation C.5.

$$rho = 1 - \sum_{f \in F} k_f^2 / (n^3 - n) \tag{C.5}$$

Here, k_f is the difference in the ranks of the simulated and the actual trade flows and n is the sample size. The maximum value that Spearman's rho can take is equal to one and a large value for rho is desired, indicating a good simulation of market shares. However, Spearman's rank correlation should be interpreted with caution since it does not provide a direct comparison of simulated and actual trade flows in terms of volumes. As also pointed out in Trüby (2013), let us assume two trade matrices that are equal, which therefore have a rho equal to one. Multiplying one of the matrices by two does not change the ranking of the trade flows and rho remains to be equal to one, despite that the trade volumes are now double the initial volumes.

The third statistical measure we use is Theil's inequality coefficient, U. The inequality coefficient corresponds to the root-mean-squared error of the simulated trade flows S_f and the respective actual trade flows A_f. We apply the scaled version in which U lies between 0 and 1, as can be seen in Equation C.6.

$$U = \frac{\sqrt{\sum_{f \in F} (S_f - A_f)^2}}{\sqrt{\sum_{f \in F} S_f^2} + \sqrt{\sum_{f \in F} A_f^2}} \tag{C.6}$$

A U value equal to 0 means that simulated flows are equal to actual flows. A large value close to 1, on the other hand, indicates that the simulated flows strongly differ from the actual ones. Therefore, a lower U is desired as the goal is to have simulated trade flows which are consistent with the actual flows.

C.3. Sensitivity analyses

In model-based analyses of the crude oil market, a common source of uncertainty is the large variation of production cost estimates found in the literature. Therefore, in order to check the robustness of our analysis, we conduct sensitivity analyses by varying the production costs of the suppliers. We consider a low cost case in which individual production costs of all the considered suppliers are lowered by 30%. Similarly, we consider a high cost case, where we increase the production costs of all suppliers by 30%. Figure C.1

depicts the simulated prices of the sensitivity analyses where the lower edge of the areas correspond to the prices obtained in the low cost case and the upper edges correspond to the high cost case. It can be seen that, for both considered sensitivities, market power potential of OPEC and Saudi Arabia has significantly decreased after the 2014-2016 price collapse and price levels have moved towards competitive levels. The production levels for the default case as well as for the sensitivities are presented in Table C.3. We can observe that our findings are robust with respect to the assumed cost levels.

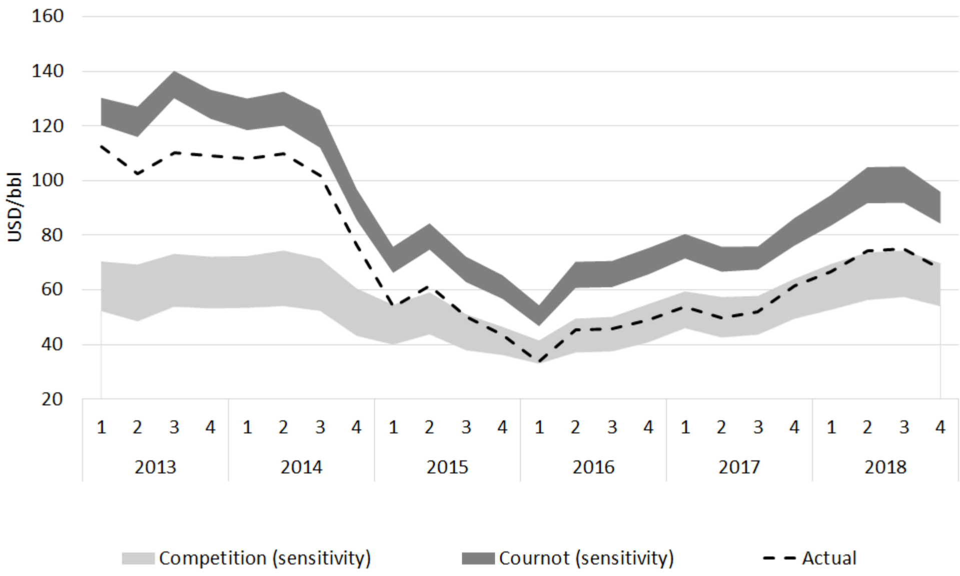


Figure C.1.: Actual crude oil price levels and the simulated prices for the perfectly competitive and Cournot setups for the respective production cost sensitivities

Table C.3.: Historical production capacities, actual production levels, and model production estimates for the default case as well as cost sensitivities for the considered market structure setups (in million bbl/d).

	Capacity	Actual	Competition			Oligo_OPEC			Cournot			Cartel_OPEC_core			Cartel_OPEC		
			Low	Default	High	Low	Default	High	Low	Default	High	Low	Default	High	Low	Default	High
2013																	
United States	10.64	10.32	9.87	9.60	9.22	10.64	10.50	10.09	10.64	10.64	10.33	10.64	10.64	10.64	10.64	10.64	10.64
Russia	11.21	10.88	10.56	10.37	10.23	11.21	11.17	10.62	10.11	9.90	9.90	10.78	10.43	10.34	11.21	11.20	11.18
Saudi Arabia	14.36	11.50	14.36	14.36	14.36	8.23	8.62	9.10	9.28	9.53	9.74	10.85	11.02	11.13	11.49	11.49	11.49
Other OPEC	27.18	24.91	27.11	27.06	26.90	27.18	27.11	27.11	27.18	27.12	27.11	21.33	21.33	21.33	12.77	12.80	12.88
Others	26.70	25.13	26.04	25.83	25.67	26.40	26.31	26.10	25.75	25.75	25.57	25.70	25.70	25.70	25.76	25.76	25.76
TOTAL	**90.09**	**82.74**	**87.93**	**87.22**	**86.37**	**83.66**	**83.71**	**83.02**	**82.95**	**82.95**	**82.65**	**79.30**	**79.12**	**79.14**	**71.87**	**71.88**	**71.94**
2014																	
United States	12.36	11.99	11.48	11.05	10.65	12.36	11.96	11.63	12.36	12.20	11.81	12.36	12.36	12.23	12.36	12.36	12.36
Russia	11.25	10.91	10.55	10.38	10.26	11.24	11.05	10.55	10.23	10.00	9.93	10.89	10.53	10.33	11.25	11.23	11.08
Saudi Arabia	14.38	11.52	14.38	14.38	14.38	8.63	9.17	9.58	9.58	9.95	10.20	11.12	11.31	11.44	11.50	11.50	11.50
Other OPEC	27.15	24.87	27.08	27.03	26.87	27.12	27.06	27.02	27.15	27.08	27.03	21.27	21.31	21.39	12.79	12.83	12.96
Others	27.17	25.58	26.44	26.23	26.07	26.86	26.65	26.47	26.18	26.11	25.92	26.14	26.14	26.09	26.19	26.19	26.19
TOTAL	**92.30**	**84.87**	**89.93**	**89.06**	**88.23**	**86.21**	**85.91**	**85.26**	**85.50**	**85.33**	**84.90**	**81.79**	**81.65**	**81.48**	**74.09**	**74.12**	**74.10**
2015																	
United States	13.39	12.99	12.14	11.29	10.80	12.73	12.08	11.47	12.99	12.30	11.75	13.39	12.68	12.33	13.39	13.39	13.07
Russia	11.43	11.09	10.55	10.24	10.14	10.93	10.55	10.35	10.10	9.95	9.88	10.51	10.21	10.10	11.35	10.76	10.62
Saudi Arabia	14.10	11.96	14.10	14.10	14.10	10.04	10.59	10.96	10.73	11.18	11.36	11.28	11.28	11.28	11.28	11.28	11.28
Other OPEC	27.16	25.69	27.04	26.89	26.89	27.08	26.88	26.85	27.08	26.92	26.87	22.28	22.74	22.85	14.03	14.36	14.59
Others	27.51	25.92	26.65	26.39	26.21	26.96	26.68	26.47	26.39	26.08	25.86	26.61	26.28	26.09	26.66	26.67	26.51
TOTAL	**93.59**	**87.66**	**90.47**	**88.91**	**88.15**	**87.74**	**86.78**	**86.10**	**87.29**	**86.44**	**85.71**	**84.07**	**83.19**	**82.66**	**76.72**	**76.46**	**76.07**
2016																	
United States	12.91	12.52	11.49	10.64	10.15	12.12	11.44	10.81	12.28	11.60	10.90	12.76	11.97	11.69	12.91	12.76	12.38
Russia	11.69	11.34	10.74	10.47	10.29	10.97	10.74	10.47	10.26	10.09	10.04	10.69	10.43	10.27	11.49	10.94	10.74
Saudi Arabia	14.17	12.36	14.17	14.17	14.17	10.40	10.86	11.24	11.05	11.40	11.66	11.34	11.34	11.34	11.34	11.34	11.34
Other OPEC	27.98	26.53	27.87	27.74	27.72	27.85	27.69	27.66	27.90	27.76	27.69	23.19	23.59	23.68	14.63	14.98	15.21
Others	26.86	25.36	25.97	25.65	25.49	26.26	25.97	25.72	25.71	25.40	25.11	25.97	25.59	25.41	26.09	26.03	25.85
TOTAL	**93.62**	**88.11**	**90.24**	**88.67**	**87.83**	**87.59**	**86.71**	**85.90**	**87.21**	**86.25**	**85.40**	**83.94**	**82.91**	**82.40**	**76.45**	**76.04**	**75.52**
2017																	
United States	13.62	13.21	12.60	11.86	11.23	13.13	12.54	11.96	13.41	12.61	11.94	13.62	13.08	12.63	13.62	13.62	13.49
Russia	11.71	11.36	10.88	10.62	10.44	11.32	10.85	10.70	10.27	10.13	10.07	10.75	10.43	10.34	11.67	11.03	10.83
Saudi Arabia	14.08	11.88	14.08	14.08	14.08	10.38	10.93	11.24	11.14	11.48	11.73	11.27	11.27	11.27	11.27	11.27	11.27
Other OPEC	27.92	26.70	27.86	27.70	27.70	27.85	27.75	27.67	27.87	27.85	27.71	23.32	23.77	23.99	14.96	15.25	15.47
Others	25.39	23.94	24.58	24.24	24.14	24.90	24.58	24.27	24.39	24.04	23.82	24.54	24.30	24.08	24.60	24.60	24.54
TOTAL	**92.72**	**87.09**	**90.01**	**88.50**	**87.60**	**87.59**	**86.66**	**85.84**	**87.07**	**86.11**	**85.26**	**83.50**	**82.85**	**82.30**	**76.12**	**75.78**	**75.61**

D. Supplementary Material for Chapter 5

D.1. Model sets, parameters and variables

Table D.1.: Sets, parameters and variables of the model

Abbreviation	Dimension	Description
Sets		
$t \in T$		Quarter-hourly model temporal resolution
$t1 \in T$		Alias of t
$bh \in BH$		SRL and PRL product time periods, in four-hour-blocks
Parameters		
p_{da}	€/MWh	Hourly day-ahead auction price
p_{id}	€/MWh	Quarter-hourly continuous intraday price
$p_{srlp,c}$	€/MW	Positive SRL capacity price
$p_{srln,c}$	€/MW	Negative SRL capacity price
$p_{srlp,e}$	€/MWh	Positive SRL energy price
$p_{srln,e}$	€/MWh	Negative SRL energy price
p_{prl}	€/MW	PRL capacity price
p_{fuel}	€/MWh$_{th}$	Fuel costs
w_{srlp}	%	Activation probability of positive SRL
w_{srln}	%	Activation probability of negative SRL
η_{fl}	MWh$_{el}$/MWh$_{th}$	Plant efficiency at full load
η_{ml}	MWh$_{el}$/MWh$_{th}$	Plant efficiency at minimum load
$k_{pl,max}$	MW	Plant generation capacity at full load
$k_{pl,min}$	MW	Plant generation capacity at minimum load
c_{ot}	€/MWh	Other variable costs
c_{su}	€	Average startup costs
η_{tes}	%	TES round-trip efficiency (electricity-to-electricity)
$k_{tes,max,in}$	MW	TES maximum charging power
$k_{tes,max,out}$	MW	TES maximum discharging power
$\gamma_{0,in}$	MW	TES constant for charging power linearisation
$\gamma_{1,in}$	%	TES slope for charging power linearisation
$\gamma_{0,out}$	MW	TES constant for discharging power linearisation
$\gamma_{1,out}$	%	TES slope for discharging power linearisation
$s_{tes,max}$	MWh	TES maximum storage volume
t_{srlp}	hour	TES prequalification requirement for positive SRL
t_{srln}	hour	TES prequalification requirement for negative SRL
t_{prl}	hour	TES prequalification requirement for PRL
$v_{srl,max}$	MW	Maximum SRL capacity bid (plant and TES combined)
$v_{srl,min}$	MW	Minimum SRL capacity bid (plant and TES combined)
$v_{prl,max}$	MW	Maximum PRL capacity bid (plant only)
$v_{prl,min}$	MW	Minimum PRL capacity bid (plant only)
$v_{tes,prl,max}$	MW	Maximum PRL capacity bid (TES only)
$v_{tes,prl,min}$	MW	Minimum PRL capacity bid (TES only)
f_{prl}	%	Minimum plant load factor to be able to provide PRL
r_{up}	quarter-hour	Positive load change rate
r_{do}	quarter-hour	Negative load change rate
d_{su}	quarter-hour	Startup duration
d_{sd}	quarter-hour	Shutdown duration

Abbreviation	Dimension	Description
Binary variables		
B_{on}		1 if the plant is currently online
B_{su}		1 if the plant has started up
B_{sd}		1 if the plant has shut down
$B_{tes,in}$		1 if the TES is charging
$B_{tes,out}$		1 if the TES is discharging
B_{srlp}		1 if the plant is offering positive SRL
B_{srln}		1 if the plant is offering negative SRL
B_{prl}		1 if the plant is offering PRL
$B_{tes,srlp}$		1 if the TES is offering positive SRL
$B_{tes,srln}$		1 if the TES is offering negative SRL
$B_{tes,prl}$		1 if the TES is offering PRL
Variables		
R_{da}	€	Total revenue on the day-ahead market
R_{id}	€	Total revenue on the intraday market
R_{srlp}	€	Total revenue on the positive SRL market
R_{srln}	€	Total revenue on the negative SRL market
R_{prl}	€	Total revenue on the PRL market
C_{var}	€	Variable costs
C_{su}	€	Startup costs
Positive Variables		
X_{da}	MW	Total output on the day-ahead market (Plant + TES)
X_{pl}	MW	Plant output without TES
$X_{overmin}$	MW	Plant output that is above the minimum load
PL_{srlp}	MW	Plant output on the positive SRL market
PL_{srln}	MW	Plant output on the negative SRL market
PL_{prl}	MW	Plant output on the PRL market
$TES_{da,in}$	MW	TES charging on the day-ahead market
$TES_{da,out}$	MW	TES discharging on the day-ahead market
$TES_{id,in}$	MW	TES charging due to buying back on the intraday market
$TES_{id,out}$	MW	TES discharging on the intraday market
TES_{srlp}	MW	TES discharging power marketed on the positive SRL market
TES_{srln}	MW	TES charging power marketed on the negative SRL market
TES_{prl}	MW	TES charging/discharging power marketed on the PRL market
$E_{tes,in}$	MWh	Energy flow into TES when charging
$E_{tes,out}$	MWh	Energy flow out of the TES when discharging
S_{tes}	MWh	Stored energy in the TES

Note: Unless specified, all the power (MW) and energy (MWh) units are electrical.

D.2. Dispatch example for the high-efficiency TES

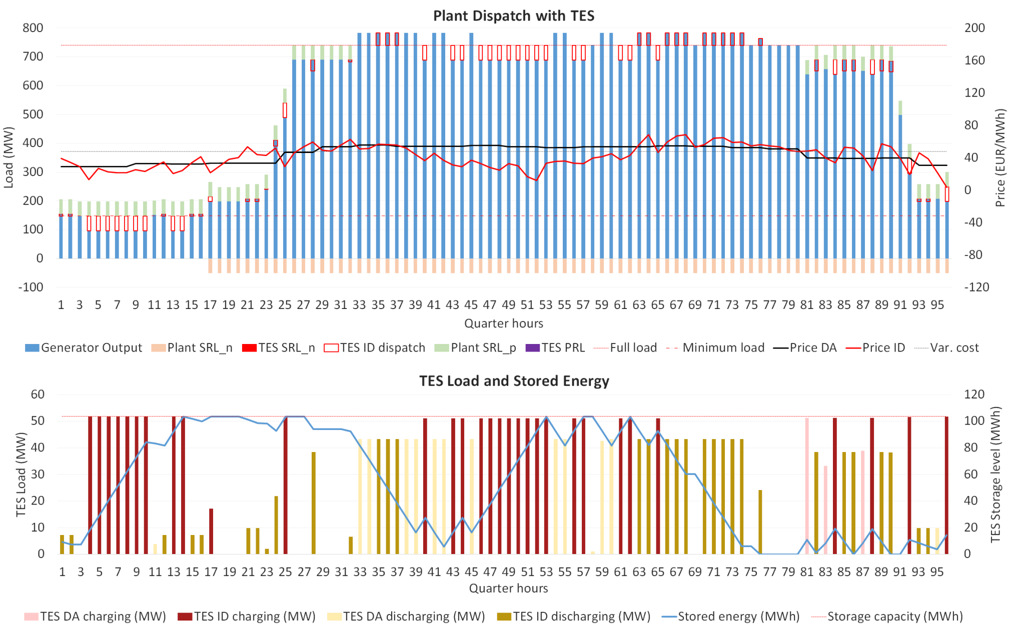


Figure D.1.: Dispatch example of the High Efficiency TES with 2 hours of storage capacity on the simulated day of January 16, 2019

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