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1 Introduction

1.1 Motivation

According to the First Fundamental Theorem of Welfare Economics, an allocation of a perfectly competitive equilibrium is Pareto optimal (Mas-Colell et al., 1995). The concept of a perfectly competitive equilibrium is connected to certain conditions. In particular, all market participants are assumed to be price takers, externalities should be absent and markets should be complete "*in the sense that there is a market for every relevant commodity*".[1] If market imperfections, i.e. deviations from the conditions of a perfectly competitive equilibrium, occur in a market, the resulting market outcome is not Pareto optimal anymore. Market imperfections include market power, transaction costs and missing markets. Given that hardly any real market outcome fulfills the theoretical standards of a perfectly competitive equilibrium, market imperfections are rather the norm than the exception (Joskow, 2010a). As long as the resulting inefficiencies are small compared to the welfare of the perfectly competitive equilibrium, this may be acceptable from a regulatory point of view. However, market imperfections can also lead to significant inefficiencies potentially justifying market interventions. Therefore, research that identifies market imperfections, quantifies the inefficiencies caused by them and finds potential countermeasures to them has a high practical relevance.

If market imperfections are present in energy markets, this can have a negative impact on the macroeconomic performance of countries because energy is an important production factor for all sectors of modern economies (for an overview of literature that considers energy as a production factor cf. Kümmel et al. (2015)). In addition, affordable energy is essential for household consumers because energy is required to fulfill basic human needs such as heating, lighting and cooking. Therefore, political decision makers and regulators aim to incentivize competition in energy markets.

Given this high importance of competitive energy markets, the European Union (EU) liberalized its energy markets starting with first directives in 1996 (for electricity) and 1998 (for natural gas) formulating the goal of a single European market.

[1] Page 327 in Mas-Colell et al. (1995)

Previously, the markets were organized as regional monopolies leading to high electricity and natural gas prices. Second energy directives advanced the liberalization in and after 2003, whereas finally the Third Energy Package came into force in 2009 requiring ownership unbundling, i.e. the separation of transmission systems from the production and trading, and the creation of national regulatory bodies that inter alia determine transmission tariffs (European Commission, 2018b). Due to this regulatory framework, competitive and liquid natural gas and electricity markets existed in many EU member states in 2016 (ACER (2017a) and ACER (2017b)). Nevertheless, as also discussed in this thesis, in specific energy markets of certain countries, competition is still restricted, e.g. by regulations in countries that are not part of the EU. Therefore, the single European market for natural gas and electricity is not fully realized yet. Against this backdrop, this thesis analyzes market imperfections in European energy markets that have already been resolved, are still existing and could potentially emerge in the future.

Three chapters of this thesis focus on market imperfections in natural gas markets: Chapter 2 analyzes the Lithuanian gas market in which a state funded import terminal for liquefied natural gas (LNG) was built in 2014 breaking the gas monopoly of Russia's Gazprom. Chapter 3 investigates potential reasons underlying price premiums of the Italian wholesale gas market Punto di Scambio Virtuale (PSV) to the German wholesale gas market NetConnect Germany (NCG). Whereas Chapter 2 and Chapter 3 have a historical and current focus, Chapter 4 investigates whether Turkey could exert market power with gas transits through the Southern Gas Corridor in 2030.

Finally, Chapter 5 focuses on the missing market for hourly balancing power products in the German balancing power market design in 2014. Impacts of shorter provision durations on the market efficiency and market concentration are investigated.

Each chapter of this thesis is based on an article to which all authors contributed equally:

- LNG Import Quotas in Lithuania – Economic Effects of Breaking Gazprom's Natural Gas Monopoly (joint work with Simon Schulte)
- Non-physical Barriers to Natural Gas Trade – Gas Price Differences between Germany and Italy

- Natural Gas Transits and Market Power – The Case of Turkey (joint work with Simon Schulte, based on Schulte and Weiser (2017))
- Tender Frequency and Market Concentration in Balancing Power Markets (joint work with Andreas Knaut and Frank Obermüller, based on Knaut et al. (2017))

The research questions and key findings of each chapter are discussed in more detail in the following. Afterwards, the methodology and the assumptions underlying the applied models are introduced.

1.2 Outline of the Thesis

1.2.1 LNG Import Quotas in Lithuania – Economic Effects of Breaking Gazprom's Natural Gas Monopoly

Chapter 2 assesses the decision of the Lithuanian state to finance an LNG import terminal and to require yearly minimum LNG imports by signing a long-term contract (LTC) for LNG. Those measures taken in 2014 broke Gazprom's gas monopoly in Lithuania. LNG is competitively priced, but has higher marginal supply costs than Russian gas. It is shown in general that there is an economic rationale to incentivize imports from a competitive fringe having high marginal supply costs into a market up until then supplied by a dominant firm with low marginal supply costs. A minimum import volume quota can be found that optimizes the consumer surplus adjusted by compensation payments to the competitive fringe. The developed model is parameterized for the Lithuanian gas market. We infer that the decision to build the regasification terminal and to sign a LTC for LNG was a feasible way to address Gazprom's market power.

1.2.2 Non-physical Barriers to Natural Gas Trade – Gas Price Differences between Germany and Italy

In Chapter 3 price premiums of the Italian wholesale gas market PSV compared to the German wholesale gas market NCG are investigated. The price spreads between the markets in the second half of 2014 exceeded the regulated transmission tariff on the Austrian pipeline system connecting the markets significantly. Despite the high price spreads, the Transitgas pipeline in Switzerland that also connects the markets was not used to the full extent pointing to non-physical barriers to trade in Switzerland.

High transmission costs, potentially caused by transaction costs in the market for Swiss transmission rights, and market power, i.e. withholding of Swiss gas flows in order to increase the Italian gas price, are considered as two relevant explanation approaches for the Italian gas price premium. A parameterized model for the trade between the markets is developed in which a model configuration for the market power explanation as well as a model configuration for the high transmission costs explanation are considered. Based on different statistical indicators and tests for comparing the outcomes of the two different model configurations, it is found that market power in the Italian gas market is a better explanation for the historical Italian gas prices than high transmission costs. In addition, different measures to mitigate the market power are discussed. As a policy implication, an application of EU rules for capacity trading in the non-EU country Switzerland is recommended.

1.2.3 Natural Gas Transits and Market Power - The Case of Turkey

Chapter 4 focuses on the role of Turkey in the Southern Gas Corridor that consists of planned pipeline projects connecting the natural gas producers in the Caspian region and the Middle East with the European natural gas markets. Turkey has a key role in realizing those projects due to its geographical location. Instead of taking a pure transit role, BOTAŞ, the Turkish national oil and gas company, has the perception to buy gas arriving at the Eastern borders of Turkey and sell it at a profit to European customers (Skalamera, 2016). In economic terms, BOTAŞ wants to exercise market power with gas transits (transit market power). Therefore, Chapter 4 quantifies the implications of Turkish transit market power for the European gas markets with a global partial equilibrium gas market model. The Turkish behavior is examined in two different upstream market configurations, (1) an oligopolistic upstream market based on a calibration to the European gas markets in 2014, and (2) a competitive upstream market based on a calibration to the European gas markets in 2016. It is found that Turkish market power would reduce the European consumer surplus by 6.6 billion EUR in the case of an olgiopolistic upstream market in 2030. In a competitive European upstream setup, however, the impact of Turkey's behavior on European gas markets is limited due to the comparably high costs of the gas supplies from the Southern Gas Corridor. As a policy implication, the EU should either avoid dependencies on transit countries such as Turkey or harmonize the energy laws of the transit countries with EU rules that sanction market power abuses.

1.2.4 Tender Frequency and Market Concentration in Balancing Power Markets

Whereas Chapter 2, Chapter 3 and Chapter 4 analyze natural gas markets, Chapter 5 focuses on the design of balancing power markets. In 2014, primary and secondary balancing power was procured in a weekly auction in Germany giving rise to a missing market for hourly balancing power products. Our analysis evaluates implications of a shortening of the provision duration to a daily and hourly procurement for the market efficiency and market concentration based on a summer week and a winter week in 2014. A unit commitment model for the German electricity market accounting for balancing power markets characteristics and power plants features is applied in the analysis. We find that pooling effects within power plant portfolios of the large German operators reduce balancing power costs significantly in the weekly market design compared to a case without pooling in which specific power plants would have to offer the balancing power during a whole week. Allowing a shorter provision duration further lowers the cost of balancing power provision by up to 15% compared to a weekly market design. However, the analysis identifies cases in which shorter tender frequencies for balancing power lead to higher market concentrations. Therefore, regulators should carefully monitor market concentration and price levels after a shortening of provision duration.

1.3 Methodology

In order to answer the research questions of this thesis, fundamental models for energy markets are applied. Whereas the model in Chapter 2 is solved analytically, the models in Chapter 3, Chapter 4 and Chapter 5 are numerical simulation models. It is inevitable to discuss the underlying assumptions of the models in order to interpret and evaluate the results.

In Chapter 2 the demand side as well as the supply side is assumed to be able to influence prices strategically in a sequential model. The sequential order of stages in the model is connected to the assumption that a country is able to decide on the quota before the market conduct. This is justified if the market intervention is a credible announcement by the government or regulator of the country. Additional assumptions taken in Chapter 2 are linear demand and supply functions when applying the developed model to the Lithuanian gas market. However, as shown in Section 2.3, more sophisticated functional forms would not change the key result that there is a rationale behind incentivizing the LNG imports to Lithuania as long as the demand function would not be too concave and the marginal costs of the LNG suppliers would not be too high.

In Chapter 3 a model of capacity constraint traders is used in order to rationalize gas price differences between the German and Italian gas markets. An important assumption of this analysis is that traders buying gas in Germany set the Italian gas price. This is justified due to the high competitiveness and flexibility of gas volumes sourced at the liquid Central European gas hubs compared to alternative supply options to the Italian market. Furthermore, we assume that the German gas price is not influenced by the trade with Italy. This is approximately appropriate given that the traded volumes in Central European gas hubs to which the German market is connected are much larger than the volumes traded in Italy, i.e. the arbitrage volumes between Central Europe and Italy can be considered to be small. For modeling the price formation in gas markets, frictions in the markets, e.g. features of LTCs and the costs of long-term bookings, have to be considered. In order to account for an uncertainty about the model parameters describing those frictions, sensitivity analyses are used in Chapter 3 to test the robustness of the results against variations of those parameters.

The analysis in Chapter 4 is based on the global gas market model COLUMBUS. It is formulated as a mixed complementarity problem with linear functions for the inverse demand and production costs. General model features and potential caveats of the COLUMBUS model are discussed by Hecking (2014). Because the analysis in Chapter 4 focuses on the year 2030, there is an uncertainty about the future development of gas markets. In order to account for this uncertainty, two potential market structures are considered, i.e. a competitive upstream behavior and an oligopolistic upstream behavior. Furthermore, an important assumption is that the analysis in Chapter 4 is based on a pure economic rationale and does not account for any political constraints. Although this is a simplifying assumption, such an analysis helps to identify drivers of stakeholders in the Southern Gas Corridor, and is an essential step towards a comprehensive understanding of Turkey's role for the European gas supply.

Balancing power markets that are in the focus of Chapter 5 are based on opportunity costs relative to the day ahead electricity market. The reason for this is that power plant capacity which is marketed as balancing power cannot be offered anymore at the day ahead market. Therefore, the day ahead market has to be considered in studies of balancing power markets. In order to account for characteristics of specific power plants, e.g. technical features as well as information about the ownership of the plants, a cost minimizing mixed integer problem is used in Chapter 5. Whereas electricity prices cannot be derived with a non-convex mixed integer problem[2], this methodology allows to determine a simultaneous dispatch of the day ahead and balancing power markets. Cost minimization implies a cost efficient dispatch of those markets as achieved under perfect competition. For the day ahead market, this assumption is approximately justified according to the findings of the German regulator (Bundesnetzagentur, 2014). For balancing power markets, the cost efficient dispatch allows to determine cost advantages of balancing power suppliers in specific situations. Such cost advantages can result in high market shares of certain suppliers. A final assessment to which extent balancing power suppliers with high market shares would be able to increase prices for balancing power is left for further research.

Besides the discussion of the methodology in this section, the following chapters of the thesis contain sections with detailed descriptions of the methodology.

[2]The marginal of the market clearing constraint cannot be interpreted as an estimator for electricity prices in mixed integer problems.

2 LNG Import Quotas in Lithuania – Economic Effects of Breaking Gazprom's Natural Gas Monopoly

Until 2014, Russia's Gazprom had a natural gas monopoly in Lithuania. In order to break the Russian monopoly, the Lithuanian state financed an import terminal for liquefied natural gas (LNG) in Klaipėda. In addition to building the terminal, Lithuania signed a long-term contract (LTC) which can be interpreted as a minimum import volume quota for LNG having higher marginal supply costs than Russian gas. This study assesses the potential of such a minimum import volume quota to mitigate the market power of a monopolistic supplier. A market consisting of a dominant supplier with low marginal supply costs and a competitive fringe with high marginal supply costs is analyzed. It is shown that there is a minimum import volume quota for fringe supplies that optimizes the consumer surplus, which is adjusted by a compensation paid for the fringe's market entry. Therefore, the Lithuanian decision to incentivize the market entry of high-cost LNG can be rationalized.

2.1 Introduction

In recent years, natural gas prices in Eastern Europe have been significantly higher than in Central or Western Europe (ACER, 2016), primarily due to the dominant position of Russia's gas exporter Gazprom in the Eastern European gas markets (Henderson and Mitrova, 2015). As of 2013, several European Union (EU) member states were subject to a Russian gas supply monopoly: Lithuania, Latvia, Estonia and Finland (ACER, 2014). Apart from the economic disadvantages resulting from Gazprom's monopoly, political actors in those countries feared that Russian gas deliveries could be used as a political tool by the Russian administration. Against this background, Lithuania, built an import terminal for liquefied natural gas (LNG) in Klaipėda in 2014 with financial support from the EU to allow LNG suppliers access to their market, thus breaking Gazprom's monopoly (Pakalkaitė, 2016).

Although the political goal of supply diversification was achieved by this measure, an economic assessment of the terminal crucially depends on global LNG market developments.[1] Lithuania secured a long-term contract (LTC) with the Norwegian supplier Statoil in 2014 to provide must-run LNG imports ensuring the continuous utilization of the newly built terminal. The marginal supply costs of Gazprom were generally considered to be much lower than those of LNG, which has to be liquefied, transported by ship and regasified at the destination. In addition, there was a global scarcity of liquefaction plants in the mid 2010s, which led to a high utilization of existing plants and an increase in LNG prices compared to previous years (International Gas Union, 2015).

The objective of this paper, therefore, is to investigate the economic rationale behind the Lithuanian policy to incentivize must-run imports of high-cost LNG. Such incentives may not be necessary in the case of comparably low LNG prices, i.e. LNG would be imported without a minimum import requirement if an LNG import terminal has been constructed. However, the LTC leads to economic disadvantages for the owner of the LNG terminal if LNG import prices are higher than the gas price paid to the dominant supplier. If the owner of the LNG terminal is the state, as is the case in Lithuania, the potential losses generated by the LNG imports are then passed on to the citizens or gas customers in one way or another. Hence, one would intuitively think that securing a LTC for LNG may induce additional burdens for gas customers in situations with comparably high LNG import prices. However, the study at hand argues that a minimum import requirement for LNG could enhance Lithuanian national welfare[2] even if the LNG import prices would be above the former Russian monopoly price. This is due to the reaction of the dominant supplier on the market intervention. Hence, the Lithuanian decision to build the terminal and sign a LTC can be rationalized as a feasible instrument to address Gazprom's market power.

Generally speaking, our analysis investigates a market consisting of a dominant supplier with low marginal supply costs and a competitive fringe with high marginal supply costs. In this setting, a minimum volume quota[3] for the fringe supply is considered. It is shown that a minimum volume quota can increase the consumer surplus of an importing country adjusted by the compensation payments necessary to introduce the quota.

The structure of the paper is as follows: Section 2.2 gives an overview of the liter-

[1] LNG is a global commodity as analyzed by e.g. Barnes and Bosworth (2015).

[2] Due to the fact that Lithuania does not have indigenous natural gas resources and thus no production, national welfare is identical to the consumer surplus.

[3] A volume quota means that a fixed amount of fringe volume needs to be imported in the market. A share quota, however, would mean that a certain share of the demand needs to be supplied by the fringe.

ature relevant for this analysis. Section 2.3 focuses on a stylized model in which the implications of a minimum volume quota are discussed analytically. In Section 2.4, the model is applied with parameters characterizing the Lithuanian gas market in 2014. Finally, Section 2.5 concludes.

2.2 Literature Review

There are two aspects of our research that, to the best of our knowledge, have yet to be investigated in the literature. First, a minimum import volume quota for a high-cost fringe as a trade policy instrument to increase the consumer surplus of a national market is a novelty. Second, the application of this policy instrument to the Lithuanian natural gas market is new. We have identified three different branches of literature that are relevant for our investigation: 1) literature on (strategic) trade theory, 2) industrial organization literature focusing on fringe-firm intervention and multiple sourcing, and 3) literature on the Lithuanian natural gas market.

Strategic trade theory (also referred to as "strategic trade policy") investigates policy instruments affecting the output of a dominant foreign firm. Within the literature, there exist several studies analyzing the effects of tariffs and quotas for the national welfare of a country. The first seminal work to examine the equivalence of different trade restrictions was Bhagwati (1965). He shows equivalence of tariffs and quotas for a market configuration with a dominant foreign firm and a domestic producer that is assumed to be competitive. Based on his findings, but relaxing the assumption of a competitive domestic producer, Shibata (1968), Yadav (1968) and Bhagwati (1968) show non-equivalence of tariffs and quotas because the domestic producer benefits from monopoly power under a quota. Furthermore, Hwang and Mai (1988) illustrate that the equivalence of tariffs and quotas also depends on the market behavior of the firms analyzed. By using a conjectural variation approach with different conjectures, they expose that equivalence holds only for the Cournot case. Other works investigate quotas and tariffs separately. Brander and Spencer (1981), for instance, analyze tariff policies in an imperfectly competitive market. They show how a tariff can be used to extract rents from a foreign exporter. Moreover, their results illustrate the benefits regarding the national welfare of using a tariff to support the market entry of a domestic firm. Eaton and Grossman (1986) focus on Bertrand competition rather than Cournot competition analyzing the welfare effects of trade policy under oligopoly. They find that a tax optimizes national welfare with Bertrand competition. Breton and Zaccour (2001) focus on import quotas in an abstraction of European gas markets in the 1980s. They consider an asymmetric oligopoly with a diversification constraint on a player representing the Soviet Union. Krishna (1989) studies the effect of an import quota in a duopoly of a home firm and a foreign firm. He examines the increasing profitability of a home firm that is able to raise its prices when imports are restricted. He shows that the home consumers are the losers of the maximum import quota.

The aforementioned literature analyzes instruments having a direct effect on the dominant supplier. A minimum quota in our study supports the market entry of the high-cost supplier and has thereby only an indirect effect on the output of the dominant firm. A similar effect is examined by Brander and Spencer (1985): Based on a two stage game, they show that export subsidies may be an attractive trade policy instrument from a domestic point of view. While governments set subsidies in a first stage, firms set their output levels based on the subsidy and on the rivals' output in a second stage. The results of Brander and Spencer (1985) illustrate that the export subsidy lowers a good's world price and increases the domestic firm's profit by extracting rents from the foreign firm. Whereas the subsidy analyzed in the work of Brander and Spencer (1985) supports the domestic producer, the study at hand considers a minimum import quota to incentivize the entry of an external high-cost competitive supplier.

A further stream of literature that is relevant for this analysis can be clustered under the concepts of multiple sourcing and fringe-firm intervention as part of the literature on partial industry regulation. According to Ayres and Braithwaite (1992), fringe-firm intervention means that a regulator or private company supports the entry of a competitive fringe into a market with a dominant player. In line with Stigler (1964) and Tirole (1988), an increasing number of competitors in a market results in increasing competition. Hence, competition is induced without a direct regulatory restrain to the dominant firm. Examples for markets in which fringe-firm intervention takes place are the defense or the automotive industry, e.g. Riordan and Sappington (1989), Farrell and Gallini (1988), Anton and Yao (1987) and Demski et al. (1987). However, literature on fringe-firm interventions of private companies is limited because private companies are faced with a free-rider problem: If one company decides to support the market entry of a competitive fringe, and the fringe produces an input for the company, also the company's competitors would benefit. Moreover, the examples provided in the literature focus on complex and differentiated goods as defense systems. In our work we analyze the market for natural gas, which is a homogeneous good. An import quota as investigated in the following, is only applicable to a homogeneous good.

There are only a few contributions in the literature on resource markets addressing the Lithuanian energy market. Works that include the Baltic gas markets in analyzing the European gas security of supply are e.g. Richter and Holz (2015) and Baltensperger et al. (2017). Hinchey (2018) discusses Russian natural gas pricing in Europe in the presence of alternative supply options for gas. In doing so, a special focus is put on the Lithuanian LNG terminal. Similar to our paper, Hinchey (2018) finds that importing LNG was economically rational for Lithuania. However, her focus is rather on a bargaining solution than on a non-cooperative game. In addition, compared to the analysis of Hinchey (2018) who only examines prices, our study evaluates the welfare impacts of LNG imports for the Lithuanian gas market.

2.3 Theoretical Model

Before the Lithuanian natural gas market is analyzed in more detail, the effect of a minimum import quota on a market for a homogenous good is analyzed within a theoretical framework. First, general functional forms of the cost and supply functions in the model are considered. Later on, linear simplifications for those functions are used.

2.3.1 General Model Setup

A country demands a homogeneous good q from abroad. The demand is given by $q(p)$, and $p(q)$ is the inverse demand function. The law of demand is assumed to hold.

There are two sources for the good: (i) a dominant supplier D and (ii) a competitive fringe F. The cost functions of both supply sources $C_D(q)$ and $C_F(q)$ are convex. The dominant supplier is more cost efficient than the competitive fringe, i.e. has lower marginal supply costs: $C_D'(q) < C_F'(q)$. The importing country considers introducing a quota L for imports from the competitive fringe. The question is whether a quota increases national welfare, and how it is optimally chosen. We analyze this in a two stage interaction model. In the first stage, L is determined by the country with the objective to maximize national welfare, which is equivalent to the consumer surplus in the absence of indigenous production. Afterwards, there is supply by the dominant supplier and the fringe firms.[4]

Fringe firms sell their output at the marginal cost $C_F^{'}$ to meet the quota. Thus, the country's expenditures for the import from the fringe firms will be $L \cdot C_F^{'}(L)$. The dominant supplier takes the quota as given and maximizes profit with respect to the residual demand $q_R(p) = q(p) - L$. Graphically, the residual demand is a parallel shift of the demand function. The dominant supplier chooses a quantity q_D:

$$q_D \in \arg\max_{q_D} p(q_D + L) \cdot q_D - C_D(q_D). \tag{2.1}$$

The country chooses L^* to maximize national consumer surplus adjusted by a compensation paid to the fringe firms (from now on called "adjusted consumer surplus"):

$$\begin{aligned} L^* &\in \arg\max_L CS(L), && (2.2) \\ \text{where } CS(L) &= \int_0^{q_D+L} p(x)\,dx - p(q_D)q_D - LC_F^{'}(L). && (2.3) \end{aligned}$$

Assuming an interior solution, the optimal national quota is given by:

$$\frac{\partial CS}{\partial L} = \left(1 + \frac{\partial q_D}{\partial L}\right) p(q_D + L) - \frac{\partial q_D}{\partial L}\left(\frac{\partial p}{\partial q} q_D + p(q_D)\right) - C_F^{''}L - C_F^{'} \stackrel{!}{=} 0. \tag{2.4}$$

This can be reformulated as follows:

$$p(q_D + L) - C_F^{'} - C_F^{''}L = -\frac{\partial q_D}{\partial L} p(q_D + L) + \frac{\partial q_D}{\partial L}\left(p(q_D) + \frac{\partial p}{\partial q} q_D\right). \tag{2.5}$$

On the left hand side of equation (2.5), there is the change in consumer surplus due to receiving one (marginal) unit more from the fringe firms when (marginally) increasing the quota: The first term represents the additional consumer surplus, the second term the cost for the additional unit, and the third term the change in cost for all inframarginal units bought from the fringe. On the right hand side, there is the change from the reaction of the dominant supplier. If the supply of the dominant supplier decreases ($\partial q_D / \partial L < 0$), the consumer surplus is reduced (first term).

[4] Similar to the game in the seminal analysis of Brander and Spencer (1985), the country's action takes place before the firm's actions. Brander and Spencer (1985) mention that the market intervention announced by the government is assumed to be credible as the reason why the country is able to move first.

However, less supply from the incumbent saves the cost for this reduced supply (first part of the expression in brackets in the second term) but also drives up the price for all inframarginal units (second part of the expression in brackets in the second term).

A strictly positive quota $L > 0$ is optimal, if the following condition holds:

$$\left.\frac{\partial CS}{\partial L}\right|_{L=0} = \left(1+\frac{\partial q_D}{\partial L}\right)p\left(q_D\right) - C_F^{'}\left(0\right) - \frac{\partial q_D}{\partial L}\left(\frac{\partial p}{\partial q}q_D + p\left(q_D\right)\right) > 0. \tag{2.6}$$

Proposition 2.1. *A strictly positive quota, $L > 0$, increases the importing country's adjusted consumer surplus if (a) the fringe firms' marginal costs are not too high, and (b) the inverse demand function is not too convex.*

Proof. The first order conditions of the dominant supplier's problem are given by:

$$\frac{\partial p}{\partial q}q + p\left(q+L\right) - \frac{\partial C_D}{\partial q} = 0. \tag{2.7}$$

Thus, for an interior solution q_D satisfying this condition, the implicit function theorem implies

$$\frac{\partial q_D}{\partial L} = \frac{-p'}{p''q + 2p' - C_D^{''}}. \tag{2.8}$$

The numerator of the right hand side of equation (2.8) is positive because p' is negative due to the law of demand. The denominator, however, is negative because of the second order conditions of the dominant supplier's problem. Hence, the total expression on the right hand side of equation (2.8) is negative. The right hand of equation (2.8) is larger than -1 if and only if $C'' - p' > p''q$, which holds as long as p'' is not too large, i.e. if the inverse demand function is not too convex. In that case, $0 > \frac{\partial q_D}{\partial L} > -1$ holds. This means that the first and the third term of equation (2.6) are strictly positive (note that the dominant supplier's optimization implies that the expression in brackets in the third term is weakly larger than the (positive) dominant supplier's marginal costs). In that case, the left hand side of equation (2.6) is positive if $C_F^{'}(0)$ is not too large. □

The requirement that the fringe's marginal costs should not be too high intuitively makes sense. Importing fringe volume by the quota is more expensive, the higher the marginal costs of the fringe. The condition about the convexity of the inverse demand function, however, is more difficult to interpret intuitively because there are two opposing effects: 1) A very convex inverse demand function implies that a parallel leftward shift of the inverse demand will ceteris paribus lead to higher outputs by the dominant supplier (for any q, the slope of the inverse demand is flatter, and placing additional units in the market requires a smaller decrease of price). This leads to a decrease in price. 2) However, the additional consumer surplus due to the decrease in price is small if the inverse demand is very convex. Then, a situation can occur in which the compensation paid to the fringe exceeds the additional consumer surplus leading to a negative total effect.

Besides the impact of the quota on the importing country's adjusted consumer surplus, the total welfare (including the producer surplus of the dominant supplier and the fringe firms) is of interest. The welfare is defined as:

$$W(L) = \int_0^{q_D+L} p(x)\,dx - C_D(q_D) - C_F(L). \tag{2.9}$$

As shown in Appendix 2.6, the welfare does not increase if a positive volume quota is introduced.

2.3.2 Optimal Quota for Linear Inverse Demand and Cost Functions

As a simplification, we now assume a linear inverse demand function:

$$P(q_D + L) = \alpha - \beta \cdot (q_D + L). \tag{2.10}$$

Additionally, linear cost functions for the dominant supplier D and the fringe F are assumed:

$$C_i(q_i) = a_i + C_i^{'} \cdot q_i \text{ for } i = D, F. \tag{2.11}$$

Plugging this into equation (2.5), we get:

$$L_{opt} = -\frac{1}{\beta} \cdot \frac{\partial C_F}{\partial L} + \frac{\alpha}{\beta} + q_D \cdot \frac{\partial q_D}{\partial L}. \tag{2.12}$$

Equation (2.8) becomes for the linear simplification: $\frac{\partial q_D}{\partial L} = -\frac{1}{2}$. Then, the following solution is obtained:

$$L_{opt} = -\frac{1}{\beta} \cdot \frac{\partial C_F}{\partial L} + \frac{\alpha}{\beta} - q_D \cdot \frac{1}{2}. \tag{2.13}$$

$$q_D = \frac{\frac{\partial C_F}{\partial L} - \frac{\partial C_D}{\partial L}}{\frac{3}{2}\beta}. \tag{2.14}$$

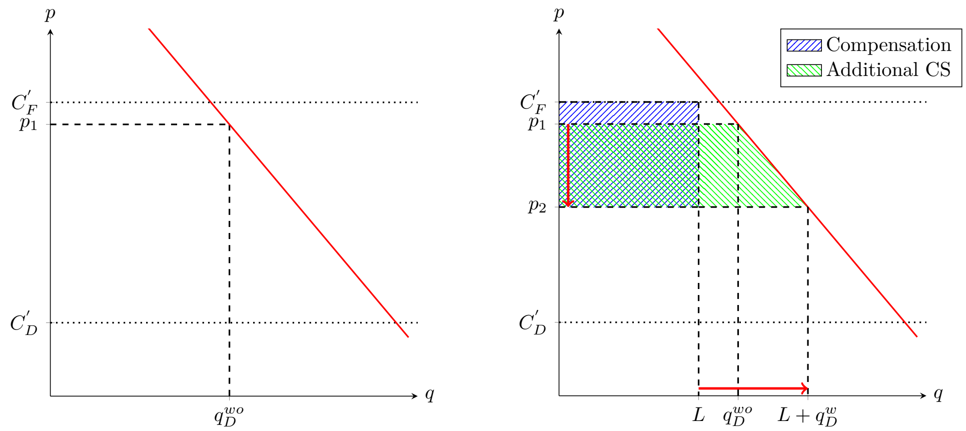


Figure 2.1: Market without a quota (left hand side) and with a quota (right hand side)

Figure 2.1 illustrates the effect of the minimum import quota schematically for linear inverse demand and cost functions. On the left hand side, the situation without a quota is shown. No fringe volumes enter the market due to the fringe's high constant marginal supply costs. On the right hand side, the quota has been introduced. It can be seen that the volumes supplied by the dominant supplier are reduced by the introduction of the quota. However, because the dominant supplier has market power, the reduction of her volume, $\frac{L}{2}$, is lower than the quota volume, L. Hence, the total supplied volumes increase by the introduction of the quota leading to a decrease in price and to additional consumer surplus. However, since the marginal supply costs of the fringe exceed the resulting market price, the fringe firms must be compensated for the difference between the market price and marginal supply costs. Although the additional consumer surplus is reduced by this compensation, there is still a positive effect on the consumer surplus.

After it was shown in general that it is possible to design volume quotas optimizing the consumer surplus adjusted by payments to the fringe firms, the introduced model is applied to the case of the Lithuanian gas market in the next section.

2.4 Application to the Lithuanian Natural Gas Market

As outlined in the introduction, the Lithuanian gas market changed in 2014 from a monopoly structure to a market structure with a dominant supplier having low marginal supply costs and a competitive fringe having high marginal supply costs. In addition, Lithuania signed a LTC for LNG, which can be interpreted as a minimum volume quota for LNG allowing us to apply the theoretical considerations developed in Section 2.3 to the Lithuanian gas market.

2.4.1 Background

In absence of natural gas resources, Lithuania is 100% dependent on imports. Because the country was a former part of the Soviet Union, its only import pipeline is connected to Russia. Prior to December 2014, when the LNG import terminal in Klaipėda started operation, Gazprom had a monopoly for gas sales to Lithuania, which resulted in comparably high gas prices (ACER, 2015a). In the fourth quarter of 2014, the Lithuanian gas price was 408 € /1000m^3, whereas the gas price at the Dutch hub Title Transfer Facility (TTF), the most liquid European gas hub, was 247 € /1000m^3 (European Commission, 2014).

In addition to building the LNG terminal, Lithuania signed a LTC with Norway's Statoil with an annual contracted quantity (ACQ) of 0.55 bcm and a take-or-pay (TOP) volume of 0.44 bcm of LNG.[5] The LNG price was based on the natural gas price of the National Balancing Point (NBP), the natural gas hub of the United Kingdom, with a surcharge (Pakalkaité, 2016).

Historically, the purpose of LTCs in the gas industry was to mitigate price and volume risks and ensure the usage of certain infrastructure elements, e.g. pipelines and LNG terminals. In the Lithuanian case, this may have been a motivation behind signing the LTC, too. However, it is clear that the LTC would be a bad decision from the point of view of a profit optimizing terminal owner if the marginal supply costs of LNG would be above the gas price in the Lithuanian gas market (the price having to be paid to Gazprom). Because the marginal supply costs of LNG are higher than the marginal supply costs of Russian gas, there is indeed the risk of such unfavorable market conditions for the LNG terminal. Therefore, it is unlikely that private actors would have financed a LNG terminal in Lithuania. Indeed, no actor other than the

[5] It is assumed that the TOP volume is 80 percent of the ACQ. This is a typical annual flexibility for LTCs (Franza, 2014).

Lithuanian state took the risk of the investment. The costs of the investments were passed on to the gas customers by supplements on gas (Pakalkaitė, 2016). However, even in the absence of a private business case for the terminal, the enhancing effects of minimum import quotas for the consumer surplus discussed in Section 2.3 indicate that the decision of the Lithuanian state to build the terminal and sign a LTC can be rationalized from a domestic point of view.

The assumptions of the model framework described in Section 2.3 fit well for the Lithuanian gas market. Due to the coupling of the LTC prices to the NBP, the LNG imports can be assumed to be competitively priced, even though the LTC was secured with only one company. As in the theoretical model, capacity constraints of the gas infrastructure are not relevant for Lithuania. The pipeline connection from Russia allows imports of more than 10 bcm/a and the LNG terminal has a regasification capacity of 4 bcm/a (Gas Infrastructure Europe, 2017), whereas the Lithuanian gas demand was only 2.54 bcm in 2014 (IEA, 2016).[6]

2.4.2 Initial Monopoly Situation

In this subsection the monopoly situation before the construction of the LNG terminal is considered. The analysis is based on linear functions for the inverse demand and supply costs.

In line with Bros (2012), marginal costs for Russian gas of 0.07 €$/m^3$ are assumed.[7] We introduce a reference price P_{ref}, a reference demand D_{ref} and a point measure for the price elasticity of demand ϵ. The parameters of the inverse demand function α and β can be related to those parameters:

$$\beta = -P_{ref}/D_{ref}/\epsilon, \tag{2.15}$$

$$\alpha = P_{ref} + \beta \cdot D_{ref}. \tag{2.16}$$

Due to the fact that the Lithuanian LNG terminal was commissioned in December of 2014, it is assumed that the average price and demand situation in 2014 still

[6] Even if the interconnection point between Lithuania and Latvia in Kiemėnai having a capacity of 2 bcm/a would be fully used to reexport gas from Lithuania, Russian import pipeline capacities would still be sufficient to cover the Lithuanian demand and the reexports to Latvia.

[7] This includes the Russian gas production costs, mineral extraction tax and transportation costs in Russia. However, the Russian export duty is not included as a cost component because it is considered to be part of the Russian producer surplus from exporting gas.

corresponded to a monopoly situation. With the historic demand of 2.54 bcm and the price of 394 € /1000m^3 that is the weighted average price of Russian gas deliveries to Lithuania in 2014 (European Commission, 2016) the point elasticity is chosen so that the monopoly quantity matches the reference demand. Then, the monopoly price also corresponds to the reference price by construction. This value of the point elasticity is given by:

$$\epsilon = \frac{P_{ref}}{C_D^{'} - P_{ref}}. \tag{2.17}$$

With the parameters discussed above, this results in a point elasticity of -1.22.[8] As can be seen in Table 2.1, this parameterization leads to a Russian profit Φ of 822 million Euro while the Lithuanian consumer surplus CS is 411 million Euro. After discussing the monopoly situation, the impact of LNG imports on the Lithuanian market will be analyzed in the next section.

Table 2.1: Characteristics of the Lithuanian gas market in 2014

Parameter	Value	Unit
$C_D^{'}$	70	€ /1000m^3
P_{ref}	394	€ /1000m^3
D_{ref}	2.54	bcm
ϵ	-1.22	-
CS	411	million €
Φ	822	million €

2.4.3 The Effects of a minimum LNG Import Quota

Based on the inverse demand function of 2014, the Lithuanian decision to sign the LTC for 0.44 bcm/a of LNG is now evaluated. Because the marginal supply costs $C_F^{'}$ of LNG were uncertain when the LTC was signed, market implications of LNG imports are discussed in dependence on the costs $C_F^{'}$.

[8]This is close to -1.25, which is the empirically determined value for the long-run price elasticity of natural gas demand according to Burke and Yang (2016). As also mentioned by Burke and Yang (2016), the literature reports small (inelastic) values for the price elasticity in the short-run. Especially for households, the demand is usually assumed to be very inelastic in the short-run due to the requirement to heat in the cold period of the year. Since a monopolist chooses a point on the elastic segment of the demand function according to basic economic theory, it seems plausible that his pricing behavior is rather determined by the long-run price elasticity of demand.

The left hand side of Figure 2.2 illustrates the Lithuanian LNG import volumes when the costs $C_F^{'}$ are varied. The figure shows three different setups: (1) imports without a quota (solid graph), (2) imports with the quota of 0.44 bcm/a as introduced by the Lithuanian government (dashed graph), and (3) imports with an optimal quota maximizing the adjusted consumer surplus as described in Section 2.3 (dashed-dotted graph). Without a quota, LNG enters the market at costs $C_F^{'}$ lower than the monopoly price of 394 €/1000m^3, whereas no LNG imports would take place if the costs $C_F^{'}$ would be above the monopoly price. However, with the Lithuanian quota, at least 0.44 bcm of LNG would be imported irrespective of the costs $C_F^{'}$. With the optimal quota, more LNG compared to the two other illustrated cases would be imported. For instance, the optimal minimum import quota would be approximately 1.7 bcm at the monopoly price.

The right hand side of Figure 2.2 shows the development of Russian gas imports in dependence on the marginal supply costs for LNG for the case without a quota, with the Lithuanian quota and an optimal quota. Obviously, a binding import quota for LNG lowers the gas imports from Russia compared to the case without a quota.

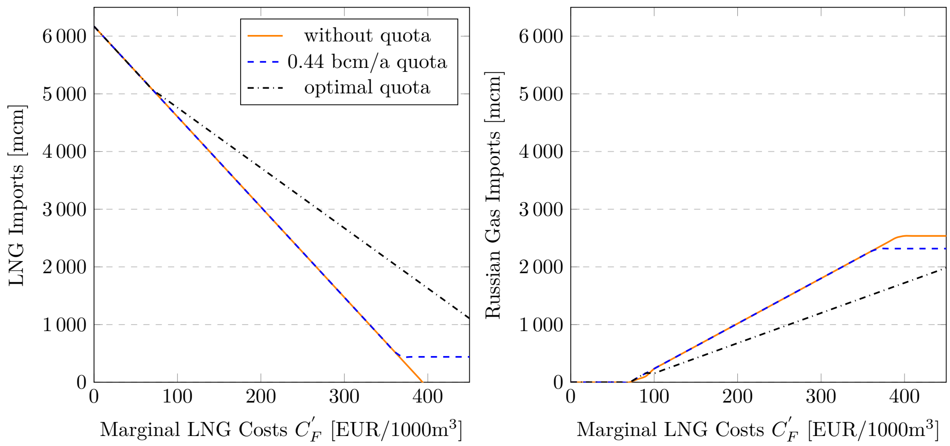


Figure 2.2: LNG imports (left hand side) and Russian gas imports (right hand side) in dependence on $C_F^{'}$

After discussing the implications of a minimum quota on import volumes, the effects on gas prices are analyzed in a next step. Hereto, Figure 2.3 shows the Lithuanian gas price in dependence on the LNG costs $C_F^{'}$. As long as the import requirement is over-fulfilled, the prices without a quota and with the Lithuanian quota (solid and dashed graphs) are matching and correspond to the costs $C_F^{'}$. In other words, the marginal supply costs of LNG set the price in the Lithuanian gas market. However, at high costs $C_F^{'}$, the Lithuanian gas price with the quota of 0.44 bcm/a is lower than the gas price without a quota. In such situations, private owners of the LNG import terminal would generate a loss because their expense per imported LNG unit, $C_F^{'}$, would be above the price in the market. In 2014, the average global LNG price was approximately 445 €/1000m^3 (International Gas Union, 2015). Hence, LNG prices above the Lithuanian monopoly price were historically already observed. With an optimal import quota, the Lithuanian gas price is below the price without a quota as long as the marginal LNG costs $C_F^{'}$ are above the dominant supplier's marginal costs $C_D^{'}$.

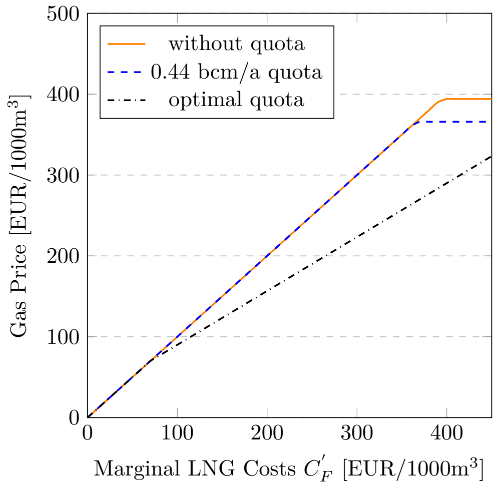


Figure 2.3: Lithuanian gas price in dependence on $C_F^{'}$

Besides gas prices, the influence of the LNG import quota on the Lithuanian consumer surplus adjusted by the payment for the LNG imports is analyzed. Figure 2.4 illustrates the adjusted consumer surplus in dependence on the marginal supply costs $C_F^{'}$. In line with the conventions in the previously discussed diagrams, the function illustrated by the dashed graph indicates the adjusted consumer surplus with the Lithuanian import quota of 0.44 bcm/a, whereas the dashed-dotted graph describes the situation with an optimal quota. The solid graph is the benchmark of no quota. For values of $C_F^{'}$ above the monopoly price of 394 €/1000m^3, the solid graph corresponds to the consumer surplus in the monopoly case. The solid and the dashed graphs match for low $C_F^{'}$ when more LNG than 0.44 bcm/a is imported and the quota is therefore over-fulfilled. However, at high $C_F^{'}$, a binding volume quota leads to additional consumer surplus. While no disadvantages of the quota occur with low $C_F^{'}$, advantages can be realized if high LNG supply costs lead to a situation in which the dominant supplier could still exercise market power in the absence of minimum import requirements.

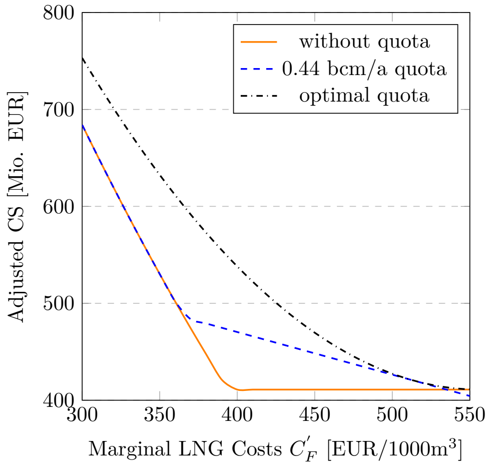


Figure 2.4: Lithuanian adjusted consumer surplus in dependence on $C_F^{'}$

Figure 2.2, Figure 2.3 and Figure 2.4 suggest that the actual Lithuanian import quota of 0.44 bcm/a would be below the optimal quota. However, if $C_F^{'}$ would be too high, the change in adjusted consumer surplus relative to the monopoly case could become negative for a given value of a quota. The dashed graph in Figure 2.4 intersects with the solid graph at $C_F^{'} = 535$ € $/1000m^3$. For higher $C_F^{'}$, the quota of 0.44 bcm/a would not enhance the Lithuanian national welfare anymore. For larger quotas than 0.44 bcm/a, this threshold value of $C_F^{'}$ is lower. For instance, the optimal quota at the monopoly price of approximately 1.7 bcm (cf. Figure 2.2) would lead to a negative national welfare effect already at a value of $C_F^{'} = 477$€ $/1000m^3$. Hence, committing to import a high minimum volume leads to the risk that the difference of the adjusted consumer surplus relative to the monopoly case becomes negative at high $C_F^{'}$. Risk averse actors may therefore prefer to commit to a comparably small volume for the quota. Alternatively, the importers could introduce quotas with volume flexibility, i.e. require additional imports in situations with low $C_F^{'}$ and require reduced imports in situations with high $C_F^{'}$.

The construction costs of the Klaipėda terminal add up to 101 million EUR, and a yearly lease of 55.3 million EUR needs to be paid (The Baltic Course, 2015). If we assume a life time of the investment of 20 years and an exemplary discount rate of 8%, the yearly annuity for the investment costs is 10.3 million EUR. Hence, the total yearly fixed costs of the terminal amount to 65.3 million EUR. The benchmark of the consumer surplus in the monopoly case is 411 million EUR. As can be seen in Figure 2.4, the additional consumer surplus due to the LTC of 0.44 bcm/a is in the same range as the total yearly fixed costs of the terminal if $C_F^{'}$ is in the range between 380 and 400 €/1000m^3. At $C_F^{'}$ below 380 €/1000m^3, the quota of 0.44 bcm/a would be over-fulfilled. Nevertheless, the consumer surplus would increase significantly compared to the monopoly case due to the competitiveness of the LNG imports.

Figure 2.5 shows the development of the welfare (with consideration of the producer surplus of the dominant supplier and the fringe firms) in the cases without an import quota for LNG, with a quota of 0.44 bcm/a and with an optimal quota. It can be seen that the imposition of a binding quota leads generally to a lower welfare compared to the case without a quota (cf. Appendix 2.6 for a formal discussion of the welfare implications of a quota). In the monopolistic case, the welfare amounts to 1.2 billion EUR. With perfect competition (the dominant supplier and the fringe firms bid their marginal supply costs), however, the welfare would be at 1.6 billion EUR.

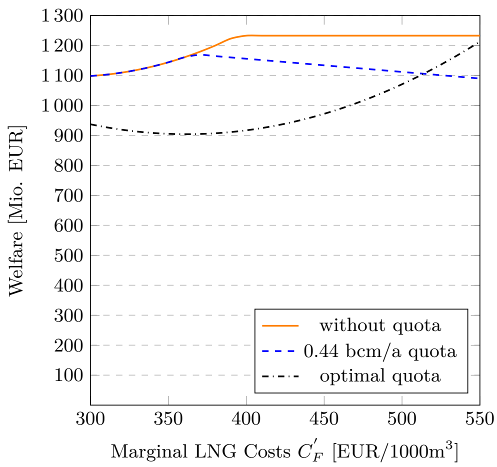


Figure 2.5: Welfare in dependence on $C_F^{'}$

The fact that the welfare is lowered by the quota indicates that the dominant supplier and the gas consuming country could be both better off if the dominant supplier would offer a price below the monopoly price and the gas consuming country would abstain from introducing a quota. The exact price offered by the dominant supplier would then be the outcome of a bargaining game. Because Lithuania regarded the diversification (away from Russian gas) as desirable also for security of supply reasons, it may have preferred the quota over a potential bargaining solution.

2.4.4 Discussion of Results

In order to evaluate the Lithuanian strategy to mitigate Gazprom's market power, alternative concepts to reduce market power should be considered. Such other potential strategies include, e.g., a further integration of markets by additional pipeline connections[9], gas release auctions and unbundling of the dominant supplier. Economic theory indicates that the most efficient way to mitigate market power would be to set a maximum price being equal to the marginal supply costs of the dominant supplier if those were known. From a practical point of view, however, unilateral actions of authorities (e.g. regulator, government) against the dominant supplier potentially give rise to the risk that the dominant supplier cuts off the supply. In particular, in markets for products with limited substitution options and high values of lost load, e.g. in energy markets, taking such a risk could be costly. Therefore, a practicable option to mitigate market power is to incentivize the entry of new suppliers instead of taking direct actions against the dominant supplier.

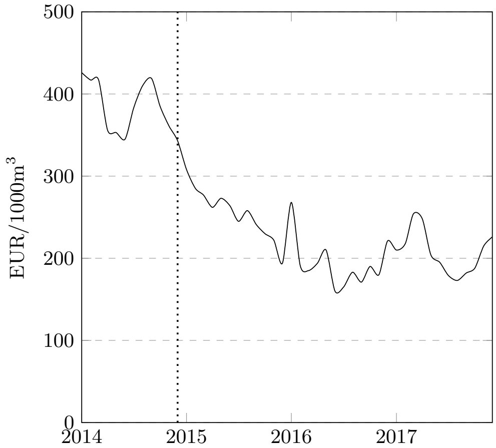


Figure 2.6: Historical development of the Lithuanian weighted average import gas price

Source: Lithuanian National Commission for Energy Control and Prices (2017); vertical dotted line in December 2014 illustrates when the Lithuanian LNG terminal came online

As can be seen in Figure 2.6, gas prices in Lithuania decreased indeed significantly in 2015 and 2016 compared to 2014. In 2015, the LTC for LNG was binding, whereas Lithuania imported more than the contracted volumes in 2016. It would

[9]In principle, competitively priced pipeline gas could have been incentivized in Lithuania instead of LNG. However, Gazprom had also a dominant position in the markets of the neighboring Poland and Latvia leading to comparably high gas prices in those countries (European Commission, 2014).

be interesting to test empirically the theoretical prediction that a binding LTC led to higher Lithuanian welfare in 2015 compared to a counterfactual situation without a minimum import quota. However, a development parallel to the commencing LNG imports was the decrease in global oil prices. Because Russian LTCs in Europe were still coupled to oil prices, this led generally to a lower level of Russian LTC prices (European Commission, 2015a). Hence, even in the absence of LNG supplies, Russia may not have been able to enforce a monopoly price in 2015 and 2016 due to its contractual obligations. Additionally, because of substitution effects between natural gas and biofuels (Pakalkaitė, 2016), the structure of the demand function for natural gas could have changed after 2014. Hence, empirically disentangling the different price decreasing effects in the Lithuanian gas market after 2014 is left for further research.

2.5 Conclusion

This analysis explains the economic rationale to incentivize the import of LNG in isolated gas markets like Lithuania by a minimum import quota. Before building the LNG terminal, Russia had a monopoly for natural gas in Lithuania, which led to high gas prices. In such a situation, supplier diversification can increase the national welfare due to a decrease in prices. If the price of LNG available at the global market is in the range of the marginal supply costs of the dominant supplier, the profitability of the LNG terminal can be ensured without market intervention. The analysis at hand, however, focuses on a situation in which the fringe volumes have higher marginal supply costs compared to the dominant supplier leading to a situation in which the dominant supplier can still exercise market power despite the existence of alternative supplies. It is shown that a minimum volume quota for the high-cost fringe leads to an increase in the consumer surplus adjusted by a compensation paid to the fringe firms. For a specific market situation, an optimal quota, from the point of view of the importing country, can be found. As a policy implication, countries with gas markets with dominant suppliers other than Lithuania could also consider to incentivize the import of competitively priced gas, ideally with flexible volume quotas.

2.6 Appendix: Welfare Implications of a Quota

Proposition 2.2. *The imposition of a strictly positive quota $L > 0$ does not increase the total welfare.*

Proof. A quota would not increase the welfare if $\frac{\partial W}{\partial L}|_{L=0} \leq 0$ holds. Therefore, we consider the first order condition of welfare optimization:

$$\frac{\partial W}{\partial L} = \left(1 + \frac{\partial q_D}{\partial L}\right) p\left(q_D + L\right) - C_D^{'}\left(q_D\right) \cdot \frac{\partial q_D}{\partial L} - C_F^{'}\left(L\right). \tag{2.18}$$

This yields:

$$\left.\frac{\partial W}{\partial L}\right|_{L=0} = p\left(q_D\right) + \left(p\left(q_D\right) - C_D^{'}\left(q_D\right)\right) \cdot \frac{\partial q_D}{\partial L} - C_F^{'}\left(0\right). \tag{2.19}$$

The second term is zero or negative because:

- $\left(p\left(q_D\right) - C_D^{'}\left(q_D\right)\right) \geq 0$ due to the profit optimization of the dominant supplier (she would not bid below marginal costs)
- $\frac{\partial q_D}{\partial L} < 0$ (cf. proof for Proposition 2.1)

Therefore, it follows:

$$\left.\frac{\partial W}{\partial L}\right|_{L=0} \leq p\left(q_D\right) - C_F^{'}\left(0\right). \tag{2.20}$$

For $C_F^{'}\left(0\right) \geq p\left(q_D\right)$, it holds true that the welfare does not increase:

$$\left.\frac{\partial W}{\partial L}\right|_{L=0} \leq 0. \tag{2.21}$$

□

Please note that the welfare strictly decreases for $C_F^{'}\left(0\right) > p\left(q_D\right)$.

3 Non-physical Barriers to Natural Gas Trade – Gas Price Differences between Germany and Italy

In recent years, there were periods in which Italian wholesale gas prices were significantly higher than German wholesale gas prices. While the Austrian pipelines between Germany and Italy were congested during the periods with high price spreads, the Transitgas pipeline in Switzerland was not always used to the full extent in those periods. Therefore, this study discusses two non-physical barriers to gas trade as possible explanations for the high Italian gas prices: (1) withholding of Swiss gas flows to increase Italian gas prices, and (2) high transmission costs in Switzerland. A fundamental model for the gas trade between Germany and Italy is applied to a historical gas market situation in 2014 with persistently high price spreads while accounting for the market imperfections in Switzerland. Based on this model framework, it is found that withholding Swiss gas flows can rationalize historic Italian gas prices and gas flows between Germany and Italy. As a policy implication, an application of congestion management procedures for Swiss gas transmission rights is recommended.

3.1 Introduction

In the European gas target model, the Agency for the Cooperation of Energy Regulators (ACER) formulates the vision "*of a competitive European gas market (...) where market integration is served by appropriate levels of infrastructure, which is utilized efficiently and enables gas to move freely between market areas to the locations where it is most highly valued by gas market participants*".[1] In the countries adjacent to the Dutch Title Transfer Facility (TTF), the most liquid natural gas hub in Continental Europe, this vision can be considered to be realized because wholesale gas price differences between those countries are mainly driven by regulated transmission tariffs in the absence of physical congestion in the gas infrastructure (Heather,

[1]Page 4 in ACER (2015b)

2015).[2] However, the Italian gas market area Punto di Scambio Virtuale (PSV) showed occasionally large prices in recent years (2014, 2015 and 2016) compared to the South German market area NetConnect Germany (NCG) although there are two direct pipeline links through Austria and Switzerland connecting the markets. The Germany-Austria interconnection point in Oberkappel was physically congested in the periods with large Italian price premiums[3], whereas the Swiss Transitgas pipeline was not fully used pointing to non-physical barriers to trade (Petrovich et al., 2016). Since firstly the network codes of the European Union (EU) that require congestion management procedures and market transparency for gas transmission rights[4] are not binding in the non-EU country Switzerland, and because secondly more than 80% of the transmission rights in Switzerland are booked long-term by one company (Petrovich et al., 2016), the non-physical trade barriers are likely due to regulatory inefficiencies in Switzerland. Against this background, the research objective of this study is to analyze the drivers of the Italian gas price premium.

Harris et al. (2013), a study about international experiences in pipeline capacity trading, mention "*two main 'market failures' that can prevent capacity trading. First, the transaction costs of selling capacity could be too large. (...) Second, the capacity holder may have market power.*"[5] Petrovich (2014) also discusses those two non-physical trade barriers that could be responsible for the price difference between PSV and other European hubs. Therefore, this analysis focuses on high transmission costs[6], potentially caused by transaction costs in the Swiss market for gas transmission rights, and market power, i.e. withholding of Swiss gas flows to increase Italian

[2]In European gas markets, there is a regulated tariff that covers fixed and variable network costs. In the case of congestion in the network, an additional congestion fee would have to be paid.

[3]With the term "Italian price premium", the following is meant: PSV gas price minus the NCG gas price minus the regulated tariff for shipping gas from Germany through Austria to Italy.

[4]In European gas markets, traders book entry and exit capacity into market areas instead of capacity of specific pipelines. With the term "transmission right", bookings of the capacities in Austria and Switzerland enabling to ship gas from Germany to Italy is meant.

[5]Page 4 in Harris et al. (2013)

[6]With the term "transmission costs", the transmission tariff, i.e. the price for using the transmission capacity as determined by the transmission system operator (TSO), plus any additional costs in order to realize the transmission is meant. In EU countries, there should be no additional cost besides the regulated transmission tariff (in the absence of congestion). However, in the Swiss case, this could be different: For instance, ACER (2014) mentions a tariff for transiting through Switzerland of 0.81 EUR/MWh in 2014. Considering the German exit tariff to Switzerland and the Italian entry tariff from Switzerland, the total tariff for transporting gas from Germany to Italy through Switzerland would be 1.67 EUR/MWh in 2014 according to ACER (2014). When referring to the efficient Swiss transmission tariff, this figure is meant. However, because this figure is even below the regulated tariff to transport gas from Germany through Austria to Italy in 2014 (1.77 EUR/MWh), the efficient Swiss transmission tariff alone cannot be responsible for the gas price spreads between Germany and Italy in 2014, as also discussed by Petrovich et al. (2016). It is possible that transaction costs in the market for Swiss transmission rights occur leading to higher transmission costs than the tariff, e.g. search, information and bargaining costs.

gas prices, as explanation approaches for the Italian gas price premium.

A fundamental model for the trade between the German and the Italian gas market is developed. Parameterized versions of the model for the high transmission costs hypothesis and the market power hypothesis are used to simulate the historical gas market situation in the second half of 2014 when persistently high spreads were observed. Different statistical indicators/tests are used to compare the model results showing that market power in the Italian gas market is a better explanation for the Italian gas price premium than high transmission costs in Switzerland. In addition, this study sheds light on possible countermeasures against the market power.

The structure of the paper is as follows: After a literature review, a background discussion about the gas markets of Italy and Germany is given. Then, the theoretical analysis in Section 3.4 and an application of the theoretical model with parameters for the historic gas market situation in Section 3.5 follow. Section 3.6 discusses the results and Section 3.7 concludes this analysis.

3.2 Literature Review

There are three streams of literature that are of relevance for this study: 1) literature on the specific price difference between NCG and PSV, 2) empirical literature on spatial price differences in commodity markets and 3) industrial organization (IO) literature on identifying market structures.

Within the first stream of literature, Petrovich (2014) analyzes gas price correlations among European hubs based on over the counter (OTC) prices finding a persistent premium of PSV over NCG in 2012. Physical congestion, non-physical trade barriers and inefficient pricing in the Italian gas market are discussed as possible reasons for the premium. In Petrovich (2015), the price correlation analysis is updated for 2014 and the costs of the price delinkage are estimated to 330 Mio. EUR. Unlike Petrovich (2014), Petrovich (2015) focuses only on non-physical trade barriers as potential reasons underlying the Italian price premium. Physical congestion can be excluded as an explanation because a rarely fully used Swiss capacity is observed. Given periods without large price premiums when the Austrian pipeline was not congested, inefficient pricing can also be excluded as an explanation. Finally, Petrovich et al. (2016) aim to reproduce historical bottlenecks in 2014 in a simulation with the European gas market model TIGER. In the efficient benchmark of the cost minimizing TIGER simulation, the Swiss pipeline connection was used to the full capacity in 2014. In reality, however, full utilization was only reached at single days in 2014 implying an inefficient capacity usage. Whereas the so far mentioned contributions discuss the reasons behind the Italian gas price premium only qualitatively, our study compares different explanation approaches on a quantitative basis.

Among the empirical analyses about spatial price differences in commodity markets, many studies focus on the concept of cointegration, e.g. Growitsch et al. (2015) who study German gas markets and Siliverstovs et al. (2005) who focus on international gas markets. Nick and Tischler (2014) apply a threshold cointegration analysis to time series of U.S. American and British gas prices. Whereas those approaches have the aim to identify a long-run equilibrium between price time series, they do not consider trade flows as is done in this study. Therefore, cointegration analyses are not suitable to distinguish between different trade regimes, e.g. between a situation with and without congestion on a specific trade route. Empirical methodologies capable of taking trade regimes into account are parity bounds models. Massol and Banal-Estanol (2016) apply this methodology to the gas markets of the UK and Belgium that are connected by the capacity constraint interconnector pipeline. They detect imperfect competition in the years 2003-2006. In the case of the German and Italian gas markets, however, this methodology cannot be applied without additional assumptions because the physical flows between the markets contain unobserved long-term contract (LTC) volumes from Norway and the Netherlands besides arbitrage driven trade flows. Furthermore, parity bounds models rely on maximum likelihood estimations and the model outcomes are influenced by assumptions about the distribution of error terms in each trade regime.

The IO literature that focuses on market structure is relevant for this analysis because distinguishing between two explanation approaches for the Italian gas price premium in this analysis is methodologically similar to e.g. distinguishing between different forms of competition in other markets. Within this stream of IO literature, there are simulation based contributions (for an overview of applications to energy and resource markets cf. Lorenczik and Panke (2016)) as well as econometric contributions (for an overview cf. Berry and Reiss (2007)). In this study, a simulation based methodology is used because this approach offers flexibility to model different market setups, i.e. market power, high transmission costs as well as a configuration with an efficient regulation in Switzerland that can be used to quantify the welfare loss due to the non-physical barriers to gas trade.

As a summary, the novelty of our research is the quantitative analysis of drivers for the price premium of PSV. Since Germany and Italy were the largest and third largest gas markets in the EU in 2014-2016 (IEA, 2017), barriers to trade between those markets have a high policy relevance.

3.3 Background

Figure 3.1 shows the daily development of the spreads between NCG and PSV[7] in the years 2013, 2014 and 2015 and the regulated transmission tariff on the Austrian pipeline route (ACER, 2014). Whereas the spread was close to (or even below) the Austrian transmission tariff on most days in 2013 and the first half of 2014, long periods with high price premiums occurred afterwards. The second half of 2014 was the time period within the years 2013-2015 in which (a) the spread persistently exceeded the Austrian transmission tariff for the longest duration and (b) the highest values of the Italian price premium occurred.[8] Therefore, the focus of this analysis is especially on the second half of 2014.

[7]Source for the prices underlying the spreads: NCG Day Ahead price data were downloaded from the NCG homepage (NetConnect Germany, 2017). More than 95% of the traded volumes in the Italian gas market were OTC volumes in 2014 (Heather, 2015). OTC price data, however, are not in the public domain. Previous research, e.g. Petrovich (2016), used the product PBGas G+1 as a proxy for the Italian day ahead gas price. PBGas G+1 is gas in storage used for balancing purposes. Petrovich (2016) shows that the PBGas G+1 product was aligned most of the time in 2015 with OTC prices (median difference lower than 0.4 EUR/MWh). Hence, within this analysis, the PBGas G+1 product is also used as a measure for the Italian day ahead gas price. PBGas G+1 price data can be downloaded on the website of the Italian power exchange (Gestore dei Mercati Energetici, 2016). The Italian balancing regime changed in 2016. Therefore, the PBGas G+1 product can only be used as a proxy for the Italian day ahead gas price previous to 2016.

[8]While there were periods with Italian gas price premiums in 2016, a situation comparable to the second half of 2014 (in terms of magnitude of the premium and duration of the situation) did also not occur in 2016 (Heather and Petrovich, 2017). The highest Italian gas price premium ever (above 50 EUR/MWh) occurred in December 2017. However, the reason for this price spike was not a non-physical trade barrier but an accident in a compressor station in Baumgarten (European Commission, 2017c).

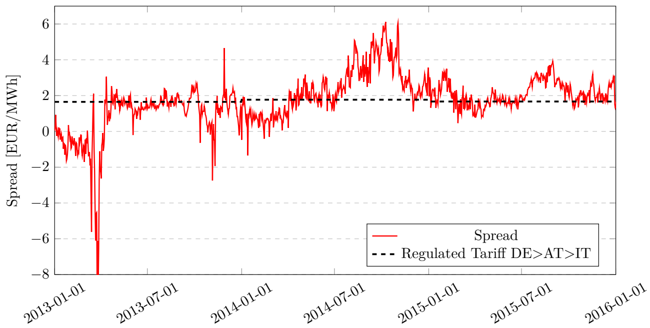
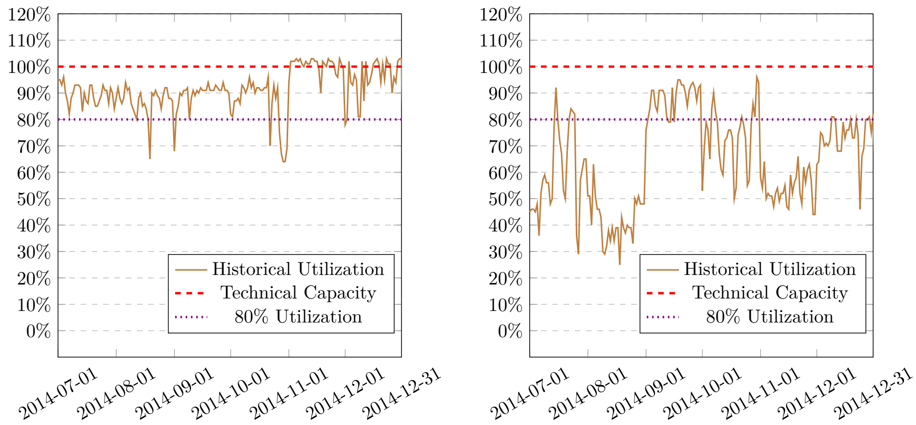


Figure 3.1: Daily gas price spreads between Germany and Italy in comparison to the regulated tariff on the Austrian route in 2013, 2014 and 2015

Source: NetConnect Germany (2017), Gestore dei Mercati Energetici (2016), ACER (2013), ACER (2014), ACER (2015a)

The left hand side of Figure 3.2 shows the daily utilization of the Austrian pipeline connection in the second half of 2014 based on the flows at the interconnection point in Oberkappel.[9] The right hand side of the figure illustrates the daily utilization of the pipeline connection through Switzerland based on flows between Switzerland and Italy at Passo Gries. Previous studies, e.g. Petrovich (2015) and Massol and Banal-Estanol (2016), mention an interconnector utilization of more than 80% as a rough indicator for physical congestion. Whereas the Austrian pipeline utilization was above 80% almost continuously in the second half of 2014, the utilization on the Swiss route rarely exceeded 80%.

[9]There is also a connection between Germany and Austria in Überackern. However, the pipeline starting in Überackern (Penta-West) connects to the WAG pipeline starting in Oberkappel that can be used to transport gas to Italy. Shippers holding transmission rights in Oberkappel have priority access to the WAG, whereas only interruptible entry capacity into the Austrian market area is available at Überackern (E-Control, 2014). Previous studies, e.g. Petrovich et al. (2016), also consider the flows in Operkappel as the relevant flows for the trade between Germany and Italy.



(i) Austrian pipeline connection

(ii) Swiss pipeline connection

Figure 3.2: Daily utilization of pipeline connections between Germany and Italy in the second half of 2014

Source: ENTSO-G (2016)

Combining Figures 3.1 and 3.2, Figure 3.3 shows a scatter plot of the daily spreads and the daily Swiss pipeline utilization. It can be seen that many points lie in the dashed window defining the area with spreads above the efficient Swiss transmission tariff according to ACER (2014) and Swiss pipe utilization below 80%. This illustrates non-physical barriers to trade being present in the second half of 2014. Against this backdrop, a theoretical model is developed in the next section to shed light upon those non-physical trade barriers.

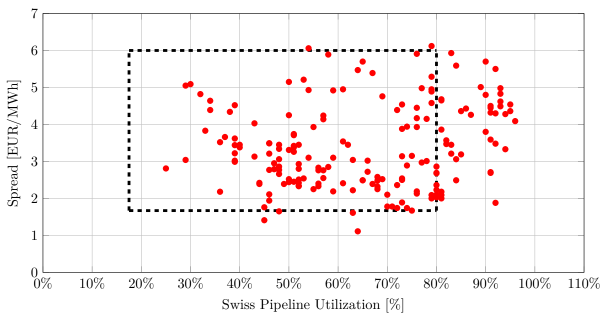


Figure 3.3: Scatter plot of daily Swiss pipeline utilizations and daily gas price differences between Germany and Italy in the second half of 2014

Source: NetConnect Germany (2017), ENTSO-G (2016), Gestore dei Mercati Energetici (2016)

3.4 Theoretical Analysis

The theoretical analysis is based on the assumption of two markets, M_1 and M_2. A maximum capacity cap restricts the trade between the two markets, which is split into a route I with capacity cap_I and a route E with capacity cap_E. It is assumed that the endowment of traders with transmission rights allowing them to use the capacities on the routes is exogenously given.[10] There is one trader I controlling all capacity cap_I, and one trader E controlling all capacity cap_E. Traders that use capacity have to pay a charge per unit of trade between the regions, i.e. the transmission costs T_I on the route I and the transmission costs T_E on the route E. The traded volume on route E (respectively route I) is denoted with q_E (respectively q_I), and the total traded volume between the markets is $q = q_E + q_I$. Figure 3.4 illustrates this setup schematically.

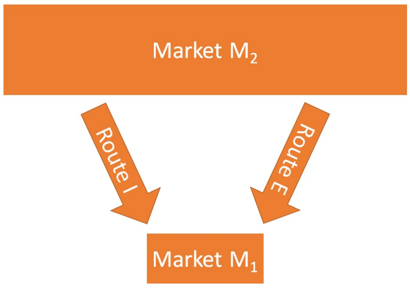


Figure 3.4: Schematic illustration of the model for the trade between market M_2 and market M_1

M_2 is large, in particular in relation to q, such that its price is independent of the trade between the two markets. For the purpose of this analysis, it is exogenously given by P_2. M_2 is assumed to be the low price region, i.e. the only direction of trade will be from M_2 to M_1. M_1 is small and its price is determined by the trade between the two regions, $P_1 = P_1(q)$, with $\frac{\partial P_1(q)}{\partial q} < 0$.

Trader E is assumed to be efficiently regulated. This means that all capacity on route E will always be fully used as long as the price difference between the markets exceeds the transmission costs T_E. Put differently: Trader E is assumed to have no market power in market M_1.

For trader I, we distinguish two model configurations that can both lead to a price difference $\Delta P = P_1(q) - P_2$ exceeding T_E: (1) also trader I has no market power,

[10]The issue of the total amount of capacities available and how the capacities may be allocated to traders will be discussed later (cf. Section 3.6).

but has to pay high transmission costs $T_I > T_E$, (2) trader I has market power in market M_1, i.e., when choosing her traded quantity q_I, $0 \leq q_I \leq cap_I$, trader I may withhold some of it to drive up the price difference between the two markets.

We are interested in explaining a situation in which ΔP exceeds T_E while the utilization of the route I is non-negative but below 100%. In the model, such a situation is only possible in the following cases:

1 $P_1(cap_E + q_I) - P_2 = T_I$: High transmission costs on route I determine the price differences ΔP (high transmission costs hypothesis)

2 $P_1(cap_E + q_I) - P_2 > T_I$: Trader I withholds traded volumes in order to drive up the profit on the inframarginal units q_I (market power hypothesis)

When traders E and I are assumed to be profit maximizing, their first order conditions can be formulated as a mixed complementarity problem (cf. Appendix 3.8.1). Based on conjectural variations, a configuration with a competitive trader I having high transmission costs as well as a configuration in which trader I exerts market power in M_1 can be considered. Both model configurations are parameterized in the following to the historical gas market situation in the second half of 2014.

3.5 Application of the theoretical Model to the historical Gas Market Situation

3.5.1 Model Parameterization

For the model application, a linear approach for the inverse demand function for traded volumes q is considered as a simplification:

$$P_1(q) = \alpha - \beta \cdot q. \tag{3.1}$$

All variables and the parameters P_2, α and β of the model[11] are assumed to be time dependent with a daily resolution in the following. M_1 corresponds to the Italian gas market PSV, and M_2 to the German gas market NCG.[12]

[11] The model is formally given by equations (3.11)-(3.14) in Appendix 3.8.1.

[12] In 2014, the two most liquid and well integrated European gas hubs TTF and NBP that are the price benchmark for NCG had together a traded volume of more than 33,000 TWh, whereas only 550 TWh were traded in Italy (Heather, 2015). Against this background, it is justified to consider the volumes transported to Italy as small in comparison to the total traded volumes in the liquid Central European gas markets.

Parameterization of the Pipeline Capacities available for Short-Term Trade

The flows from Switzerland to Italy in Passo Gries are used to calibrate the trade on route I, q_I.[13] However, the flows between Austria and Italy contain not only gas volumes from Central Europe, but mainly Russian volumes from the Ukrainian corridor. Therefore, the flows from Germany to Austria in Oberkappel are used for calibrating the trade on route E, q_E. Because physical gas flows consist either of LTC driven flows or short-term trade flows between different markets, two factors restrict the capacity for short-term trade between the German and the Italian gas market:

- There are LTC driven flows within the physical flows in Oberkappel and Passo Gries denoted with $flow_{DE>AT,must-run}$ and $flow_{CH>IT,must-run}$.
- In Oberkappel, not all short-term trade flows are directed to Italy because the Austrian pipeline system is connected to the Austrian demand and to neighboring countries such as Slovakia. This alternative usage of the Austrian pipelines is denoted with $f_{a,t}$.

While the technical capacities $cap_{E,technical}$ and $cap_{I,technical}$ are taken from ENTSO-G (2016), the remaining capacity available for short-term trade between the German and the Italian gas market is calculated as follows:

$$cap_E = cap_{E,technical} - flow_{DE>AT,must-run} - f_{a,t} \text{ and} \tag{3.2}$$

$$cap_I = cap_{I,technical} - flow_{CH>IT,must-run}. \tag{3.3}$$

Italian importers hold 111 TWh of Norwegian and Dutch LTCs (Neumann et al., 2015) that are transported through Switzerland (Honoré, 2013). In addition, there are 14 TWh of Norwegian contracts to Austria (Neumann et al., 2015), which pass the border between Germany and Austria. Besides those annual contracted quantities (ACQ), the exact contract features are private information. The daily contracted quantity (DCQ) is defined as ACQ/365. In this analysis, 80% of the DCQ is assumed as a steady must-run flow because LTCs with a high degree of hub indexation such as

[13] Besides being connected to Germany in Wallbach with 0.58 TWh/d, the Swiss Transitgas pipeline has a connection to France in Oltingue with 0.22 TWh/d (ENTSO-G, 2014). Because the price development of NCG and the French hub PEG Nord were aligned in 2014 (Petrovich et al., 2016), profit optimizing traders would be (almost) indifferent between sourcing gas volumes in Germany and France.

Norwegian and Dutch LTCs have only limited volume flexibility (Chyong, 2015).[14]

In the course of the Ukrainian crisis, gas was transported from Germany through Austria and Slovakia to Ukraine (ACER, 2015b) starting in September 2014. The physical flows from Austria to Slovakia that occurred for the first time in September 2014 according to ENTSO-G (2016) are used as a proxy for the alternative usage of the Austrian pipelines $f_{a,t}$ (cf. Figure 3.5).[15] Given an auction premium[16] at the congested interconnection in Oberkappel exceeding the spread between the German and the Austrian gas market in the second half of 2014 (ACER, 2015b), a profit optimizing trader would not buy transmission rights in order to serve the Austrian demand. Therefore, it is assumed that the gas from Germany was either transported to Eastern Europe or to Italy.

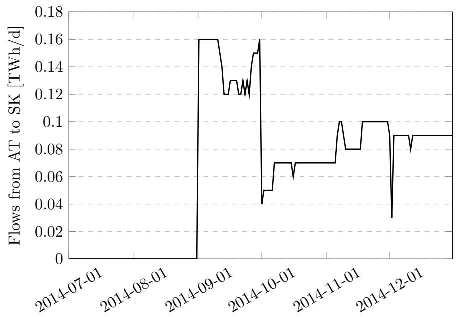


Figure 3.5: Physical gas flows from Austria to Slovakia

Source: ENTSO-G (2016)

[14]The producers regained control about the flexibility when introducing hub indexation in contracts (Franza, 2014). The flexibility can then be marketed as a separate product. Even if there would be flexibility in the contracts, the flexible volumes would also be hub indexed. With perfect hub indexation, traders in our model would be indifferent between sourcing contracted flexibility and spot volumes directly. The figure of 80% is oriented on typical take-or-pay volumes of LTCs. In Appendix 3.8.4, other percentages of the DCQ are considered as must-run flows in model sensitivities.

[15]This implies that all the flows crossing the Austria-Slovakia border have their origin in Germany. Because (a) Austria's hub CEGH has only limited liquidity compared to Central European hubs (Heather, 2015) and (b) key people of the Austrian incumbent OMV made statements in 2014 to not sell any gas to Ukraine (The Wall Street Journal, 2014), this assumption seems approximately appropriate.

[16]There is an auction for the transmission rights. If the demand for transmission rights exceeds the technical capacity, an auction premium occurs leading to a price for the transmission right above the regulated tariff.

Parameterization of the Italian Inverse Demand Function

The slope β_t of the inverse demand function is approximated by using a reference demand $D_{ref,t}$ based on Snam Rete Gas (2016), a reference price $P_{ref,t}$ from Gestore dei Mercati Energetici (2016) and a point elasticity of demand ϵ based on Egging et al. (2010)[17]:

$$\beta_t = -P_{ref,t}/D_{ref,t}/\epsilon.$$

Furthermore, a maximum willingness to pay $\alpha_{tot,t}$ is determined by:

$$\alpha_{tot,t} = P_{ref,t} + D_{ref,t} \cdot \beta_t.$$

$\alpha_{tot,t}$ is the maximum willingness to pay in the Italian gas market. However, the relevant parameter for our analysis is α_t, the maximum willingness to pay if no trade from the German market to the Italian market would be conducted. Besides the price setting trade volumes, the Italian gas market is supplied by non-spot volumes that have flexibility constraints on a short-term basis (cf. Section 3.8.2 for a discussion about the different supplies to the Italian gas market). α_t can be calculated with the flexibility constraint volumes $q_{con,t}$:

$$\alpha_t = \alpha_{tot,t} - \beta \cdot q_{con,t}. \tag{3.4}$$

$q_{con,t}$ is determined by subtracting an estimation for the historic short-term trade between Germany and Italy from the total demand. With the historical physical flows in Oberkappel $flow_{AT>DE}$ and in Passo Gries $flow_{CH>IT}$, $q_{con,t}$ is calculated as follows:

$$q_{con,t} = D_{ref,t} - flow_{AT>DE} + flow_{DE>AT,must-run} + f_{a,t} - flow_{CH>IT} + flow_{CH>IT,must-run}. \tag{3.5}$$

[17] For more information about the chosen values for $D_{ref,t}$, $P_{ref,t}$ and ϵ, cf. Table 3.1.

General Model Parameters

The NCG gas prices are taken from NetConnect Germany (2017). The Austrian transmission costs are based on the regulated tariff from ACER (2014). The value for the Swiss transmission costs T_I is varied in the different model configurations. For the market power model, a value of 0 EUR/MWh is assumed because the Italian gas importer owning more than 80% of Swiss transmission rights booked them long-term (Petrovich et al., 2016) and long-term bookings can be considered as sunk costs for short-term trade.[18] In the high transmission costs model, 2.9 EUR/MWh is assumed for T_I because the average utilization of the Swiss pipeline in the high transmission costs model for this value of T_I corresponds to the average utilization in the historical data in the second half of 2014 (approximately 0.44 TWh/day).

Overview of Parameters

Table 3.1 gives an overview of the parameters that are either direct inputs to the model or are used to determine input parameters. For the parameters $flow_{DE>AT,must-run}$, $flow_{CH>IT,must-run}$ and ϵ, either no exact values or only ranges of values are known from the literature. Therefore, sensitivity analyses with focus on those parameters will later be conducted in order to test the impact of the used assumptions on the results (cf. Appendix 3.8.4).

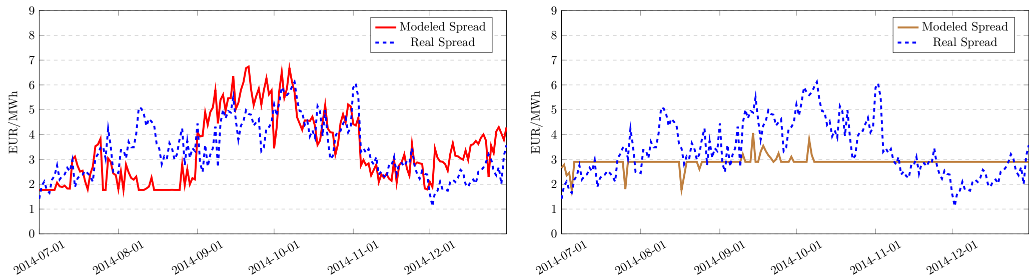
[18] In Appendix 3.8.4, different values for T_I are considered and the impact of this parameter on the model results is discussed.

Table 3.1: Overview of model parameterization

Parameter	**Description**	**Value**	**Source & Assumptions**
		Austrian Pipeline	
$cap_{E,technical}$	Austrian pipeline capacity	0.25 TWh/d	ENTSO-G (2016)
$flow_{DE>AT,must-run}$	LTC driven must-run flow from Germany to Austria	0.03 TWh/d	DCQ based on Neumann et al. (2015), $0.8 \cdot$ DCQ assumed as a steady flow
$f_{a,t}$	Alternative usage of Austrian pipeline	daily time series	Flows AT>SK based on ENTSO-G (2016)
		Swiss Pipeline	
$cap_{I,technical}$	Swiss pipeline capacity	0.68 TWh/d	ENTSO-G (2016)
$flow_{CH>IT,must-run}$	LTC driven must-run flow from Switzerland to Italy	0.24 TWh/d	DCQ based on Neumann et al. (2015), $0.8 \cdot$ DCQ assumed as a steady flow
		Inverse Demand Function	
$P_{ref,t}$	Italian reference price	daily time series	Gestore dei Mercati Energetici (2016)
$D_{ref,t}$	Italian reference demand	daily time series	Snam Rete Gas (2016), storage inflows (respectively outflows) are added (respectively subtracted) from the demand
ϵ	Italian point elasticity of demand	-0.75	Egging et al. (2010) use values between -0.25 and -0.75
$flow_{CH>IT}$	Pipeline flows in Passo Gries	daily time series	ENTSO-G (2016)
$flow_{DE>AT}$	Pipeline flows in Oberkappel	daily time series	ENTSO-G (2016)
		General Model Parameters	
$P_{2,t}$	German gas price	daily time series	NetConnect Germany (2017)
T_E	Austrian transmission costs	1.77 EUR/MWh	Regulated tariff based on ACER (2014)
T_I	Swiss transmission costs	0 / 2.9 EUR/MWh	Assumption depending on model configuration, i.e. 0 EUR/MWh in market power model and 2.9 EUR/MWh in high transmission costs model

3.5.2 Model Results for the Second Half of 2014

Figure 3.6 illustrates the historical spreads between the German and the Italian gas market in the second half of 2014 in comparison to the modeled spreads with the parameterization discussed in Section 3.5.1. Based on visual inspection, the market power model reproduces the level and certain structural elements of the historical time series, whereas the spreads of the high transmission costs model seem to be worse with respect to the level and structure. This impression can be confirmed by comparing the arithmetic means as well as the standard deviations of the spreads in the different model configurations to those indicators for the historical data (cf. Table 3.2).



(i) Market power model (ii) High transmission costs model

Figure 3.6: Historical spreads in comparison to modeled spreads in the second half of 2014

Table 3.2: Arithmetic mean and standard deviation of spreads in historical data and in different model configurations

[EUR/MWh]	Data	Market power model	High transmission costs model
Arithmetic Mean	3.40	3.42	2.90
Standard Deviation	1.13	1.40	0.21

In order to obtain further quantitative insights, the coefficient of determination R^2 for both model configurations can be considered. With an observed time series s_t^{obs} and a modeled time series s_t^{model}, both having T elements, R^2 is defined as follows:

$$R^2 = 1 - \frac{\sum_{t=1}^{T}(s_t^{obs} - s_t^{model})^2}{\sum_{t=1}^{T}(s_t^{obs})^2}. \tag{3.6}$$

However, R^2 cannot be generally interpreted as the variance explained by the model if the residuals $s_t^{obs} - s_t^{model}$ do not sum to zero.[19] Therefore, the normalized mean bias is calculated in addition:

$$\text{NMB} = \frac{\sum_{t=1}^{T}(s_t^{obs} - s_t^{model})}{\sum_{t=1}^{T} s_t^{obs}}. \tag{3.7}$$

As can be seen in Table 3.3, both models have a comparably high R^2. Whereas the low NMB value for the market power model implies only a small overestimation, the high transmission cost model is more biased, i.e. the insights that can be derived from the high R^2 value for the high transmission costs model are limited.

Table 3.3: R^2 and NMB for spreads from market power model and high transmission costs model in the second half of 2014

	Market Power Model	High Transmission Costs Model
R^2	0.90	0.89
NMB	0.01	-0.17

Given the shortcomings of R^2, an encompassing test for the Italian gas prices as also applied by Bushnell et al. (2008) is a more formal way in order to compare both models to each other. Because the market power model is not a restricted version of the alternative high transmission costs model or the other way around, the models are non-nested. In order to compare them, an encompassing model nesting both models is constructed. p_t^{obs} denotes the historical Italian prices, p_t^{mp} the Italian prices in the market power model and p_t^{htc} the Italian prices in the high transmission costs model. Because the price time series are non-stationary, the literature, e.g. Fair and Shiller (1989), Fang (2003) and Newbold and Harvey (2004), suggests to regress actual changes $\Delta p_t^{obs} = p_t^{obs} - p_{t-1}^{obs}$ on predicted changes[20]:

$$\Delta p_t^{obs} = \gamma_1 \cdot (p_t^{mp} - p_{t-1}^{obs}) + \gamma_2 \cdot (p_t^{htc} - p_{t-1}^{obs}) + u_t. \tag{3.8}$$

In the regression conducted by means of ordinary least squares, the standard errors are corrected to account for heteroskedasticity and autocorrelation (Newey and West, 1987). Table 3.4 shows the regression results. The coefficient for the market power model is significant at the 5% level, whereas the coefficient for the high

[19] In the case of an OLS regression, the residuals sum to zero if a constant is included in the regression. However, if the output of a fundamental model is compared to data, this is not necessarily the case.

[20] Bushnell et al. (2008) use level data in the regression instead of actual and predicted changes. However, if the considered time series are non-stationary, a regression with level data can be problematic due to spurious correlations.

transmission costs model is insignificant.

Table 3.4: Regression results for the prices in the market power model and the high transmission costs model in the second half of 2014

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

	Value	Standard Error
γ_1	0.06*	0.03
γ_2	0.03	0.03

After fitting equation (3.8), the actual encompassing test is conducted. A Wald test is used in order to compare the market power model and the high transmission costs model separately to the encompassing model given by equation (3.8). The test rejects the hypothesis $\gamma_1 = 0$ at the 5% level, but does not reject the hypothesis $\gamma_2 = 0$. The intuition behind this is that the high transmission costs model is significantly worse than the encompassing model, whereas the market power model is not significantly worse than the encompassing model.

Besides price based measures, it is also important to consider gas flows when evaluating the models. In Appendix 3.8.3, the indicators and tests introduced in this section are used to compare modeled flows to the historical flows. It is found that the modeled flows in the market power model and the high transmission costs model are similar. Both models reproduce the historical flows to an extent that it is not possible to reject a model as inappropriate purely based on the flows.[21]

However, since the market power model is able to explain prices besides flows, it is unambiguous that the market power model is overall a better explanation for the historical data than the high transmission costs model.[22] In Appendix 3.8.4, robustness checks are conducted by varying key parameters of the models confirming this result.

[21] The flows in both model configurations are similar to the historical flows because (a) the efficiently regulated Austrian route is used up to capacity on most days in both model configurations, (b) because the value of T_I was chosen in the high transmission costs model to reproduce the historical utilization of the Swiss route, and (c) the same must-run flows are assumed in both model configurations.

[22] Nevertheless, the indicators/tests for the prices in this section reveal slight deviations between the market power model and the data. Market imperfections that are not modeled, e.g. imperfect information and behavioral aspects of gas traders, could be responsible for this. Furthermore, the historical pipeline capacity could have deviated slightly from the maximum technical capacity assumed in the model (cf. discussion in Appendix 3.8.3).

3.6 Discussion of Results

3.6.1 Welfare Effects

An indication for the loss of consumer surplus due to withholding of Swiss gas flows can be derived by comparing the market power model to a model representing an efficient Swiss regulation, i.e. a competitive Swiss trader with $T_I = 1.67$ EUR/MWh according to the efficient Swiss transmission tariff from ACER (2014). Based on this methodology, the loss of consumer surplus in the Italian gas market is quantified to 502 million EUR in the second half of 2014.[23] Whereas the producer surplus from trading gas between NCG and PSV by using Swiss pipelines is 0 EUR in the case of an efficient Swiss regulation, it amounts to 128 million EUR in the market power case. While there are transmission revenues in the efficient regulation case in Switzerland (116 million EUR in the second half of 2014 excluding LTC volumes), there are no revenues from arbitrage driven trade in the market power model because $T_I = 0$ was assumed in line with an interpretation of long-term booking costs as sunk costs on short time scales. Nevertheless, costs for the long-term bookings occurred on longer time scales, i.e. the Swiss TSO generated revenue by selling long-term transmission rights.

3.6.2 Potential Swiss Incentives for Inefficient Regulation

The Swiss TSO could benefit from the exertion of market power by capturing a part of the producer surplus, e.g. by auctioning off the transmission rights or bargaining with traders interested in buying the transmission rights.[24] As long as the surplus captured by the Swiss TSO monotonically increases with the total generated surplus, the Swiss TSO would have an interest to uphold the regulation enabling market

[23] There are two opposing effects influencing the consumer surplus when changing the model representing an efficient Swiss regulation to the market power model: (1) the consumer surplus is increased due to a lower value of T_I in the market power model, but (2) the consumer surplus is decreased by the exertion of market power. The dominating effect of market power leads to an overall negative effect.

[24] At a first glance, it may be surprising that the revenues that the Swiss TSO could generate from transiting arbitrage driven trade flows in the competitive scenario (116 million EUR) are in the same range as the producer surplus for the trader with market power (128 million EUR). However, the company owning the Swiss transmission rights also controls other supply options of the Italian gas market which is not modeled. In fact, the respective company had a market share of 55% in the Italian gas market in 2014 (Eni S.p.A., 2017). Hence, the total producer surplus due to withholding of Swiss gas flows could be larger than the producer surplus from the trade volumes only. Therefore, a situation is conceivable in which both the trader with market power and the Swiss TSO could be better off in the inefficient regulation regime that enables market power.

power. If this would be the case, the question arises why pipeline capacity was built in the first place in order to withhold some of it later. The answer could be that the profit optimizing transmission quantity varies in time. Depending on the elasticity of the residual demand that owners of the Swiss transmission rights face, withholding could be more or less profitable in specific situations. Therefore, it can make sense to build capacity that is sometimes fully used, but sometimes is left partly idle. Against this backdrop, further research could focus on how traders acquire the transmission rights. While it would be possible to consider a profit optimizing TSO constructing the capacity in a first step and selling transmission rights for the capacity later within a theoretical analysis, the calibration of such a model to historical data could be challenging given (a) the lack of public knowledge about relevant parameters, e.g. prices of transmission rights in long-term booking agreements (Petrovich et al., 2016), (b) because of extensive data requirements, e.g. long-term time series for the Italian gas price, and (c) due to the fact that the gas pipelines in Switzerland were at least partly built in the time previous to the liberalization of European energy markets (Transitgas SA, 2018) in which other incentives to invest into infrastructure existed than today.

3.6.3 Countermeasures against Market Power

Furthermore, a natural follow-up question to this analysis is about the EU's options for countermeasures to mitigate the market power. The Italian government announced plans to create a so called "liquidity corridor" as part of its national energy strategy 2017, i.e. a regulated body should buy transmission rights connecting the Netherlands through Germany and Switzerland to Italy and offer the rights in auctions with reserve prices below 0 EUR/MWh (ICIS, 2017). Such a measure would allow the application of EU rules also on Swiss pipelines and would likely lower the Italian gas prices significantly. However, it remains unclear at which price the Swiss transmission rights could be bought and how a sale could be enforced. In addition, there is strong opposition against the plans, e.g. by the European Federation of Energy Traders (2018) that fears that the plans could be "*highly distortive to competition*" and "*produce negative impacts on neighbouring hubs*".[25]

Less controversially, the Italian regulator could aim to create more gas market competition on short time scales for traders, e.g. by reducing the existing security of supply requirements for storage operators (Honoré, 2013). Another possi-

[25]Page 2 in European Federation of Energy Traders (2018)

ble strategy to address the Swiss regulatory inefficiency could be to increase the Austrian transmission capacity. Figure 3.7 shows the influence of additional Austrian transmission capacity on the mean of the modeled price spreads in the market power model in the second half of 2014. In order to reach levels of the spread below 2 EUR/MWh, more than 0.25 TWh/day of additional capacity through Austria would have to be built. Based on Lochner (2011), a rough estimate for the cost of such an investment would be in the range of 300 million EUR.

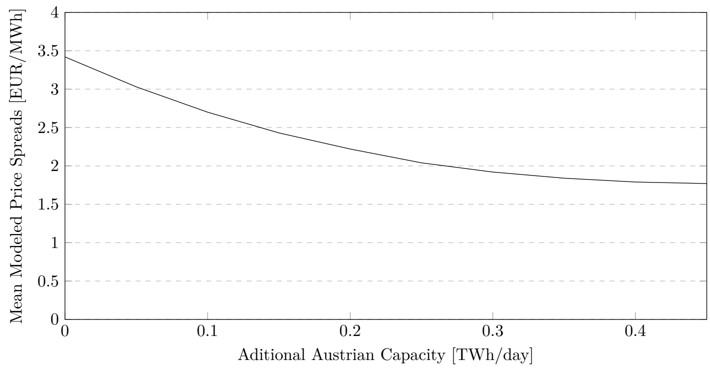


Figure 3.7: Effect of additional Austrian capacity on the mean of the modeled spreads in the second half of 2014

Alternatively, the EU could aim to free the existing Austrian capacity from usage other than trade within the EU. According to the market power model, the average gas price spread between NCG and PSV would have been 0.60 EUR/MWh lower in the second half of 2014 without the reverse flows from Central Europe to Ukraine. Projects like the planned capacity addition in Hermanowice at the border between Poland and Ukraine could therefore decrease the Italian gas price. Obviously, increasing the EU-Swiss energy cooperation with the goal to implement EU network codes in Switzerland would be the most efficient way to mitigate the market power. Talks about the EU-Swiss energy cooperation, though, were suspended after a Swiss anti-immigration vote in 2014 (Pollitt, 2017).

3.7 Conclusion

In the second half of 2014, the price spread between the German gas market NCG and the Italian gas market PSV exceeded the regulated tariff on the congested Austrian pipeline significantly. Since the Swiss pipeline was not used to the full extent in this time period, a non-physical trade barrier is claimed to be the reason underlying the high Italian gas prices. The Italian gas prices (as well as observed gas flows) can be rationalized by a trader withholding Swiss gas flows to increase gas prices in Italy. This is plausible given that EU rules for congestion management do not apply in the non-EU country Switzerland and because more than 80% of Swiss transmission rights have been booked long-term by one company. Statistical indicators/tests show that the model with market power is a better explanation for the observed prices than a competitive Swiss trader with high transmission costs. Against this background, regulatory measures aiming to decrease transmission costs, e.g. reduce transaction costs for trading transmission rights in Switzerland, may not be successful in eliminating the non-physical bottleneck on their own. Instead, congestion management procedures like the enforcement of the use-it-or-loose-it principle for Swiss transmission rights would mitigate the market power in the Italian gas market. From this analysis, the policy implication arises that the EU should find an agreement with Switzerland leading to the harmonization of energy markets regulation.

3.8 Appendix

3.8.1 Formal Model Description

The profit maximizing problem of the traders I and E competing in quantities q_I and q_E is given by:

$$\max_{q_E} \Pi_E(q_E) \text{ with } \Pi_E(q_E) = (P_1(q) - P_2 - T_E) \cdot q_E \text{ subject to } 0 \leq q_E \leq cap_E, \quad (3.9)$$

$$\max_{q_I} \Pi_I(q_I) \text{ with } \Pi_I(q_I) = (P_1(q) - P_2 - T_I) \cdot q_I \text{ subject to } 0 \leq q_I \leq cap_I. \quad (3.10)$$

The first order conditions of the problems are given with the conjectural variations $r_E = \frac{\partial q_I}{\partial q_E}$ and $r_I = \frac{\partial q_E}{\partial q_I}$ by:

$$-P_1(q) + P_2 + T_E - \frac{\partial P_1(q)}{\partial q_E} \cdot q_E \cdot (1 + r_E) + \lambda_E \geq 0 \perp q_E \geq 0, \quad (3.11)$$

$$cap_E - q_E \geq 0 \perp \lambda_E \geq 0, \quad (3.12)$$

$$-P_1(q) + P_2 + T_I - \frac{\partial P_1(q)}{\partial q_I} \cdot q_I \cdot (1 + r_I) + \lambda_I \geq 0 \perp q_I \geq 0, \quad (3.13)$$

$$cap_I - q_I \geq 0 \perp \lambda_I \geq 0. \quad (3.14)$$

Since trader E behaves competitively, the conjectural variation r_E is assumed to have the value -1. For trader I, the following two cases are distinguished:

1 Market power in market M_1: Cournot-Nash conjecture $r_I = 0$

2 High transmission costs: Competitive conjecture $r_I = -1$, $T_I > T_E$

3.8.2 Discussion of Flexibility Constraint Supplies to the Italian Gas Market

The model introduced in Section 3.4 implies that traders buying gas at the exogenous price P_2 in Central Europe set the price in the Italian gas market. This means that other gas supplies would not be relevant for the price formation in Italy. On a cost basis, the trade volumes from Central Europe are likely to be the supply option with lowest marginal costs in Italy after must-run supplies (contracted volumes, indigenous production) due to the competitiveness of the Central European gas hubs.

In addition, it can be argued that supply options other than spot based trade volumes in Italy have only limited flexibility to react on short-term market developments. A typical LNG supply chain response to high price signals in a specific market usually takes 1-3 weeks (Timera Energy, 2016). Hence, spot based LNG imports can be considered as inflexible on a daily basis. Ejections from LNG storage at the site of a regasification terminal are rather driven by contractual and technical constraints of the terminal than by commercial considerations, e.g. the arrival of a new cargo leads to the requirement to deplete the storage (Timera Energy, 2017). Furthermore, underground storage sites are able to provide short-term flexibility. However, Italian storage can be considered as price unresponsive due to strong security of supply regulations that require e.g. a national strategic gas reserve (European Commission, 2015b). According to Honoré (2013), "*storage is not used for trading opportunities*"[26] in Italy and rather serves to balance the household demand. Apart from the specifics of the Italian gas market, price taking behavior of natural gas storage is a common assumption in strategic gas market models (cf. Growitsch et al. (2014)). Another potential supply source are flexible long-term contract volumes (pipeline gas or LNG). Whereas hub indexed contracts usually have only limited flexibility, contracts with oil indexed elements have a certain flexibility. In particular, volumes above the take-or-pay volume can be used flexibly. While the exact flexibility features of the contracts are confidential, the flexibility is mainly intended to address seasonal fluctuations of gas demand, not short-term fluctuations based on market developments. Generally, in the literature on gas markets, the prevailing view is that long-term contracts lost importance in the price finding of European hubs after 2009 and that there is a trend towards hub indexation (Franza, 2014).

[26]Page 60 in Honoré (2013)

3.8.3 Comparison of modeled and historical Flows

For the following comparisons of flows, contracted must-run volumes and in the Austrian case additionally the alternative usage of the capacity $f_{a,t}$ are added to the modeled trade flows. This allows a consistent comparison of the modeled flows to the historically observed physical flows. As in Section 3.5.2, an elasticity of -0.75 and LTC driven must-run flows of 80% of the DCQ are assumed.

Table 3.5: Arithmetic mean and standard deviation of flows in historical data and in different model configurations

[TWh/d]	Data	Market Power Model	High Transmission Costs Model
		Swiss Flows	
Arithmetic Mean	0.44	0.42	0.44
Standard Deviation	0.12	0.07	0.14
		Austrian Flows	
Arithmetic Mean	0.23	0.24	0.25
Standard Deviation	0.02	0.02	0.01

As can be seen in Table 3.5, the means of the modeled flows are close to the mean of the historical flows (within the standard deviation of the historical data). The market power model slightly underestimates the Swiss flows, but overestimates the Austrian flows less than the high transmission costs model. The mean of the Swiss flows in the high transmission costs model matches the mean of the historical Swiss flows by construction because the value of T_I was chosen in order to reproduce the historical average utilization on Swiss pipelines. In the case of the Austrian flows, both considered model configurations reproduce the congestion on the Austrian route, i.e. the modeled Austrian flows correspond to the assumed capacity on most days. However, the historic flows deviate slightly from the reported technical capacity (cf. Figure 3.2) because e.g. the actually available capacity could have changed in time due to temperature and dispatch decisions on pipelines upstream and downstream to the Austrian pipelines. Because a varying capacity is not modeled, there are small deviations between modeled and historical flows even on days with congestion on the Austrian route.

Table 3.6 shows the values for R^2 and NMB for the flows. Both models have high R^2 values and comparably low NMB values.[27]

[27] Because T_I in the high transmission costs model was chosen in order to reproduce the historical average utilization on Swiss pipelines, the residuals of the modeled flows $s_t^{obs} - s_t^{model}$ sum to 0 by construction resulting in a value for NMB of 0.

Table 3.6: R^2 and NMB for the flows in the market power model and high transmission costs model in the second half of 2014

	Market Power Model	High Transmission Costs Model
Swiss Flows		
R^2	0.98	0.99
NMB	-0.04	0.00
Austrian Flows		
R^2	0.98	0.98
NMB	0.06	0.09

Repeating the encompassing test based on equation (3.8) for the flows leads to the outcome that both coefficients γ_1 and γ_2 are significant (cf. Table 3.7). Therefore, no inference can be made based on the test which of the two models is the better one.[28]

Table 3.7: Regression results for the flows in the market power model and the high transmission costs model in the second half of 2014

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

	Value	Standard Error
Swiss Flows		
γ_1	0.25***	0.06
γ_2	0.51***	0.07
Austrian Flows		
γ_1	0.08*	0.03
γ_2	0.26**	0.10

[28]As discussed by Ghali et al. (2009), a situation when encompassing tests fail to distinguish between the models is common when both models fit the data well, i.e. have high coefficients of determination.

3.8.4 Robustness Checks: Parameter Variations

Variation of LTC driven Must-Run Flows and Price Elasticity of Demand

Table 3.8 and 3.9 show the results of the regression given by equation (3.8) with prices from the competing models on historical data when the LTC driven must-run flows and the elasticity is varied.[29] Coefficients for the prices in the market power model are significant at the 5% level for explaining the data, whereas the coefficients for the prices generated by the high transmission costs model are not significant. Furthermore, the absolute values of the coefficients change only slightly when varying the LTC driven must-run flows and the elasticity.

Table 3.8: Regression results for the prices with different LTC driven must-run flows

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

Coefficient	Share of DCQ	Value	Standard Error
γ_1	60%	0.06*	0.03
γ_2	60%	0.03	0.02
γ_1	65%	0.06*	0.03
γ_2	65%	0.03	0.03
γ_1	70%	0.06*	0.03
γ_2	70%	0.03	0.03
γ_1	75%	0.06*	0.03
γ_2	75%	0.03	0.03
γ_1	80%	0.06*	0.03
γ_2	80%	0.03	0.03
γ_1	85%	0.07*	0.03
γ_2	85%	0.03	0.03
γ_1	90%	0.07*	0.03
γ_2	90%	0.02	0.03

[29]In the considered parameter range, the average utilization of the Swiss pipeline route in the high transmission costs model still matches the historical average utilization in the second half of 2014 with only minor deviations. Therefore, the value of T_I=2.9 EUR/MWh is not varied.

Table 3.9: Regression results for the prices with different elasticities

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

Coefficient	elasticity	Value	Standard Error
γ_1	-0.60	0.05*	0.02
γ_2	-0.60	0.03	0.02
γ_1	-0.65	0.05*	0.02
γ_2	-0.65	0.03	0.02
γ_1	-0.70	0.06*	0.03
γ_2	-0.70	0.03	0.03
γ_1	-0.75	0.06*	0.03
γ_2	-0.75	0.03	0.03
γ_1	-0.80	0.07*	0.03
γ_2	-0.80	0.03	0.03
γ_1	-0.85	0.08*	0.03
γ_2	-0.85	0.03	0.03
γ_1	-0.90	0.08*	0.03
γ_2	-0.90	0.02	0.03

Furthermore, as shown in Table 3.10 and Table 3.11, the result that no model can be rejected based on the encompassing tests for the flows is robust to variations of the LTC driven must-run flows and the elasticity. While both coefficients for the Swiss flows are significant at the 0.1% level in the considered parameter range, the significance of the coefficients for the Austrian flows varies with varying parameters.

Table 3.10: Regression results for the flows with different LTC driven must-run flows

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

Coefficient	Share of DCQ	Value	Standard Error
Swiss Flows			
γ_1	60%	0.29***	0.07
γ_2	60%	0.48***	0.07
γ_1	65%	0.29***	0.07
γ_2	65%	0.49***	0.07
γ_1	70%	0.28***	0.06
γ_2	70%	0.48***	0.07
γ_1	75%	0.27***	0.06
γ_2	75%	0.50***	0.07
γ_1	80%	0.25***	0.06
γ_2	80%	0.51***	0.07
γ_1	85%	0.23***	0.07
γ_2	85%	0.52***	0.07
γ_1	90%	0.20***	0.07
γ_2	90%	0.54***	0.07
Austrian Flows			
γ_1	60%	0.11**	0.04
γ_2	60%	0.23*	0.09
γ_1	65%	0.10*	0.05
γ_2	65%	0.24**	0.09
γ_1	70%	0.09*	0.05
γ_2	70%	0.25**	0.09
γ_1	75%	0.08*	0.04
γ_2	75%	0.26**	0.10
γ_1	80%	0.08*	0.03
γ_2	80%	0.26**	0.10
γ_1	85%	0.07*	0.03
γ_2	85%	0.26**	0.09
γ_1	90%	0.05	0.03
γ_2	90%	0.27**	0.09

Table 3.11: Regression results for the flows with different elasticities

*: 5% significance level, **: 1% significance level, ***: 0.1 % significance level

Coefficient	Share of DCQ	Value	Standard Error
	Swiss Flows		
γ_1	-0.60	0.21***	0.06
γ_2	-0.60	0.62***	0.07
γ_1	-0.65	0.23***	0.06
γ_2	-0.65	0.58***	0.07
γ_1	-0.70	0.24***	0.06
γ_2	-0.70	0.55***	0.07
γ_1	-0.75	0.25***	0.06
γ_2	-0.75	0.51***	0.07
γ_1	-0.80	0.24***	0.06
γ_2	-0.80	0.55***	0.07
γ_1	-0.85	0.27***	0.07
γ_2	-0.85	0.45***	0.07
γ_1	-0.90	0.28***	0.07
γ_2	-0.90	0.42***	0.07
	Austrian Flows		
γ_1	-0.60	0.11*	0.05
γ_2	-0.60	0.22*	0.10
γ_1	-0.65	0.10*	0.04
γ_2	-0.65	0.24*	0.10
γ_1	-0.70	0.10*	0.04
γ_2	-0.70	0.24*	0.10
γ_1	-0.75	0.08*	0.03
γ_2	-0.75	0.26**	0.10
γ_1	-0.80	0.10*	0.04
γ_2	-0.80	0.24*	0.10
γ_1	-0.85	0.06*	0.03
γ_2	-0.85	0.28**	0.09
γ_1	-0.90	0.06*	0.03
γ_2	-0.90	0.28**	0.09

Variation of Swiss Transmission Costs in the Market Power Model

Besides the LTC driven must-run flows and the elasticity, another important parameter for the analysis are the Swiss transmission costs T_I. Whereas T_I was chosen as 2.9 EUR/MWh in the high transmission costs model (a value at which the average utilization of the Swiss route matches the historical utilization), T_I in the market power model is chosen as 0 EUR/MWh. As Figure 3.8 illustrates, higher values of T_I lead to lower R^2 values for the spreads in the market power model compared to $T_I = 0$ EUR/MWh. This indicates that the interpretation of sunk costs in the market power model leads to better results than the assumption that trader I considers transmission costs when holding back volumes.

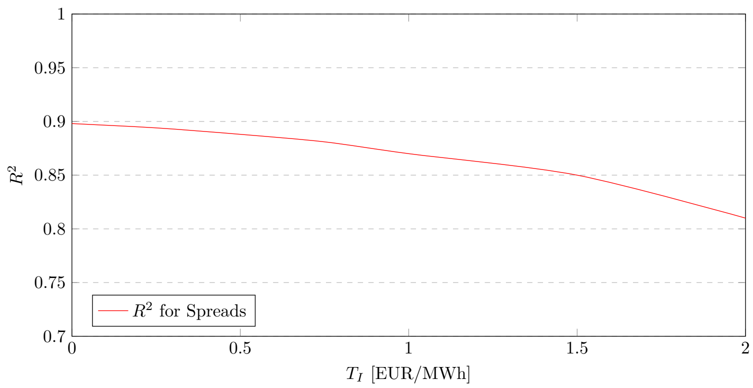


Figure 3.8: Development of R^2 for the spreads in the market power model in dependence on Swiss transmission costs T_I

4 Natural Gas Transits and Market Power – The Case of Turkey

Turkey is a key country in order to realize the Southern Gas Corridor (SGC) due to its geographical location. However, as the main transit country within the SGC, Turkey could potentially exert market power with gas transits. Whether Turkey exerts market power or not, is crucial for an economic assessment of the SGC. Hence, this study investigates this issue quantitatively using a global partial equilibrium gas market model. An oligopolistic and a competitive supply structure in the European upstream market in 2030 are considered in the model based on calibrations to historical gas market situations. If the European gas market in 2030 is characterized by an oligopolistic supply, Turkey is able to exert market power resulting in higher prices compared to competitive transits, in particular in South Eastern Europe. In a competitive market structure, however, the importance of the SGC and thus the potential of Turkish market power with gas transits is limited.

4.1 Introduction

The Southern Gas Corridor (SGC) consists of planned pipeline projects that connect the natural gas producers in the Caspian region and the Middle East (Azerbaijan, Turkmenistan, Iran, Iraq and Israel) with the natural gas markets of the European Union (EU). The EU promotes the SGC for two reasons: (1) it would like to diversify its natural gas supplies and (2) it aims to close its growing supply gap that arises due to decreasing indigenous production. Turkey has a key role in realizing the SGC because Turkey's geographical location is between the producing countries and the EU. This crucial role of Turkey is widely discussed in the literature.[1] Compared to Ukraine, which is a single-source transit country for Russian gas only, Turkey has the potential to become a multi-source transit country fed by several suppliers from the Caspian region and the Middle East or Russia. The goal of the Turkish government, however, is not only to aim for a pure transit role for Turkey, i.e. allow

[1]See for instance Berk et al. (2017), Tagliapietra (2014a), Tagliapietra (2014b), Winrow (2013), Wigen (2012) or Lise et al. (2008)

upstream producers the access to the Turkish transmission network and to the EU downstream market, but rather to use its multi-source advantage for actively trading in the natural gas markets, as is outlined in Skalamera (2016): "*Turkey, however, bargained hard against a straightforward transit role, intending instead to take over the role of a hub, which means that it would buy gas arriving at its borders, consume what it needs, and sell on the balance at profit.*"[2]

However, this perception is far away from the economic definition of an energy hub.[3] In economic terms, the Turkish perception means that Turkey wishes to use its geographical location to exercise market power in the European natural gas market (transit market power). If the natural gas producers have market power themselves, Turkey's plans would give rise to double marginalization (Tirole, 1988). This perspective is missing within the current discussion about the SGC although it could potentially eliminate the economic benefits of the entire project.

Hence, the research objective of this paper is to investigate possible implications of Turkey's strategic behavior for the EU natural gas markets and for the economic feasibility of the SGC project. The global natural gas market model COLUMBUS (Hecking and Panke, 2012) is extended and applied in order to simulate strategic behavior of transit countries like Turkey.[4] In a simulation for the year 2030, a case with competitive Turkish transits, i.e. a scenario in which upstream producers have to pay only a tariff covering variable and fixed network costs to ship gas through Turkey to European markets, is compared to a case with Turkish market power. Besides varying the Turkish behavior, different market structures in the European upstream market are considered, i.e. an oligopolistic upstream market and a competitive upstream market, in order to derive a comprehensive understanding of Turkey's role in the SGC. It is found that Turkish transit market power could have a negative impact on the European consumer surplus especially in a setup with an oligopolistic upstream market.

The structure of the paper is as follows: In Section 4.2, a review of literature that is

[2] Page 4 in Skalamera (2016)

[3] Heather (2015), for instance, identifies five important requirements for an energy hub: a high level of (1) liquidity, (2) volatility and (3) anonymity as well as (4) market transparency and (5) traded volumes. Furthermore, a physical hub is a location where several pipelines coming from and going to different directions converge and enable physical trade and competition. The Turkish perception of becoming a hub rarely fulfills those requirements. For a deeper discussion of this topic see also Berk et al. (2017).

[4] In reality, besides buying gas volumes upstream and reselling them downstream, a transit country could exert market power by inducing high transit fees or imposing taxes for gas transits on its territory. Those measures would result in a mark-up increasing the price of gas deliveries through the transit country and hence have a similar effect for the final customers as a policy of the transit country to explicitly buy and resell gas.

relevant for the analysis is given. A stylized theoretical model to discuss the problem of Turkish transits is developed in Section 4.3. Subsequently, the global natural gas market model COLUMBUS and its inputs are described in Section 4.4. Afterwards, the model calibration is discussed. Based on the calibration, Section 4.5 focuses on the model results and discusses the implications of Turkish transit market power for the EU. Finally, Section 4.6 concludes.

4.2 Literature Review

There are four different streams of literature to which this work is related to: (a) literature on gas market modeling based on non-cooperative game theory, (b) literature on natural gas transits, (c) publications about Turkey's energy relations, and (d) literature focusing on vertical externalities like double marginalization.

The first literature stream is based on simulation models that are programmed as mixed complementarity problems (MCP). As the COLUMBUS model that is used within this work, MCPs allow the simulation of market behavior and thus to consider different forms of competition on different stages of the value chain. An early study is provided by Boots et al. (2004) in which gas producers are represented as oligopolists in a static model called GASTALE. The model considers downstream traders that act either oligopolistically or competitively. The study shows that successive oligopolies in gas markets lead to high prices - similar to the case of successive oligopolies in the SGC in this study. Later on, a dynamic version of GASTALE is developed by Lise and Hobbs (2009) that consider the SGC producers Azerbaijan, Iran and Iraq as potential suppliers for Europe. A further early work is Gabriel et al. (2005a). It also considers the natural gas supply chain as a MCP in which the traders marketing gas of the producers had market power. Several existence and uniqueness results are provided as well as illustrative numerical results. Gabriel et al. (2005b) considers more in-depth numerical simulations of a version of this model for the North American natural gas market. In a later contribution by Holz et al. (2008), a static model named GASMOD is applied to analyze the European gas markets with regard to their market structure. Using data of 2003 they analyze different combinations of competition in upstream and downstream markets and come to the conclusion that Cournot competition in both markets (double marginalization) is the most accurate representation to model the European gas market. In Section 4.4.3, a similar calibration is conducted for the years 2014 and 2016. In later research, Holz (2009) extends the static GASMOD model into a dynamic version.

Within the stream of literature that focuses on gas transits, Yegorov and Wirl (2010) analyze games that appear in the context of gas transits. They distinguish between games with a transit country as a net gas exporter (such as the case of Turkem gas transits through Russia) and with a transit country as a net gas importer (such as Turkey). They conclude that the game structure arising from a transit problem is not absolute but depends on geography and international law. Furthermore, von Hirschhausen et al. (2005) analyze Ukrainian market power for Russian gas exports to Central Europe. They focus on the effects of an alternative Russian export route to Central Europe, the Yamal pipeline via Belarus and how cooperation between Ukraine and Russia could have made the investment into the Yamal pipeline unnecessary. Dieckhöner (2012) analyzes Ukrainian transits from a security of supply perspective discussing potential diversification options for Europe like the Nabucco pipeline. Later, Chyong and Hobbs (2014) introduce a strategic European natural gas market model to analyze a gas transit country. They apply their model to investigate the case of the South Stream gas pipeline. The question of Ukrainian transit market power is hereby important for the profitability of this offshore pipeline. Transit market power is represented by a conjectured transit demand curve approach. However, the conjectural variations of the transit country are chosen as a calibration parameter and vary between 0 and 1. This approach is common in natural gas market modeling but also often criticized, e.g. by Perry (1982), Dockner (1992) and Smeers (2008). Within the literature on transit problems, there are further cooperative game theory approaches: Hubert and Ikonnikova (2004), Hubert and Suleymanova (2008), and Hubert and Ikonnikova (2011), for instance, analyze market power of transit countries within the Eurasian supply chain. Furthermore, they examine strategic investments into alternative infrastructure projects to bypass the transit countries and reduce their market power. However, the above-mentioned works focus all on Ukraine, a single source transit country fed by Russian gas only. In the study at hand, the potential multi-source transit country Turkey that would not be dependent on a single dominant exporter is in the focus of investigation.

Within the literature on Turkey's energy relations, there are geopolitical and economic contributions. Cagaptay (2013) discusses geopolitical factors associated with different potential gas suppliers for Turkey. Skalamera (2016) finds that there are many obstacles for Turkey to become a gas hub. Furthermore, Berk and Schulte (2017) show that Turkey's potential to become an important transit country for natural gas is strongly restricted in a competitive European upstream gas market. Moreover, they quantify different drivers that could increase Turkish transit volumes. However, contrary to our study, they do not consider market power exerted by Turkey as a factor impacting the transits.

Apart from a specific gas market context, there are studies that discuss options to avoid double marginalization. Joskow (2010b) analyzes different factors that impact the decision of companies to either rely on markets to source supplies or to integrate vertically. Double marginalization would be a neoclassical factor favoring vertical integration. In the context of this study, competitive access for upstream gas producers to the Turkish transmission grid would lead to the same shipment quantities through Turkey that vertically integrated companies, i.e. upstream producers owning pipelines through Turkey, would choose. Besides vertical integration, other options to avoid the vertical externality of double marginalization caused by Turkish strategic behavior could be contractual agreements in which Turkey would gain a part of the upstream producers' rent. Therefore, it is important to note that the simulated configurations (competitive transits and double marginalization) are two extreme outcomes, and bargaining about the rents could also lead to a solution in between.

The value added to the literature of this analysis is two-fold. Firstly, it considers the specific case of Turkey and quantitatively examines its potential to exercise transit market power in the EU gas market. Secondly, a double marginalization approach (successive oligopolies) is used to describe a multi-source transit country like Turkey.[5]

4.3 Stylized Theoretical Model

Tirole (1988) describes double marginalization in the most basic setting, the succession of two monopolies in a vertical integrated value chain. In this section, an extended version of this textbook model is introduced to describe a market structure with a multi-source transit country potentially giving rise to double marginalization and suppliers that are not dependent on the transit country. Therefore, a setup with 4 players, 3 producers having constant marginal costs and the multi-source transit country, is considered in order to obtain insights into the functioning of transit market power. It is assumed that the transit country and the producers are not vertically integrated. Producer 1 sells volumes q_1 directly to the final market representing a value chain without double marginalization. Producer 2 (respectively producer 3) is

[5] In contrast to Chyong and Hobbs (2014), the conjectural variation of a transit country in our study takes on either the value of the Cournot conjecture or the competitive conjecture. Thus, the critique of arbitrary conjectural variations does not apply to this analysis.

dependent on the transit country and thus can only sell volumes q_2 (respectively q_3) to the transit country that then resells the volumes $q_T = q_2 + q_3$ to the final market. Figure 4.1 illustrates the stylized model. The assumption that all the volumes entering the transit country are resold corresponds to the assumption that no domestic market of the transit country needs to be served (in the absence of indigenous production of the transit country).

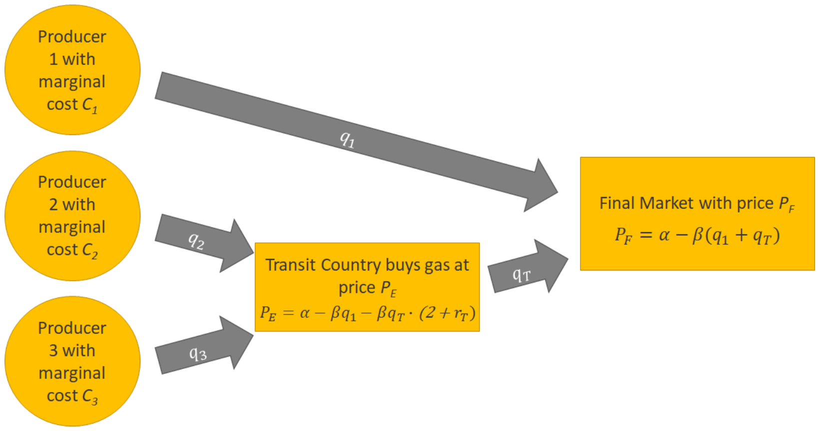


Figure 4.1: Illustration of the stylized model describing a multi-source transit country

The final market has a price P_F and a total supply $Q = q_1 + q_T$. The inverse demand function of the final market is assumed to be linear with an intercept α and a slope β:

$$P_F(Q) = \alpha - \beta Q.$$

The profit-maximization problem of producer 1 with her marginal cost C_1 is given by:

$$max(\Pi_{P1}) \text{ with } \Pi_{P1} = (P_F(Q) - C_1) \cdot q_1 \text{ subject to } q_1 \geq 0. \tag{4.1}$$

The corresponding first-order conditions with a conjectural variation $r_1 = \frac{\partial q_T}{\partial q_1}$, which takes on the value of 0 for Cournot behavior and -1 for competitive behavior of producer 1, are:

$$C_1 - P_F + \beta \cdot (1 + r_1) \cdot q_1 \geq 0 \perp q_1 \geq 0. \tag{4.2}$$

Producer 2 (respectively producer 3) produces gas at marginal cost C_2 (respectively C_3) and sells it to the transit country at the price P_E. The problems of the producers 2 and 3 are given by:

$$max(\Pi_{Pi}) \text{ with } \Pi_{Pi} = (P_E(q_i) - C_i) \cdot q_i \text{ subject to } q_i \geq 0 \text{ for } i = 2,3. \tag{4.3}$$

The corresponding first-order conditions are:

$$C_i - P_E - \frac{\partial P_E}{\partial q_i} \cdot q_i \geq 0 \perp q_i \geq 0 \text{ for } i = 2,3. \tag{4.4}$$

The inverse demand function $P_E(q_T)$ is found by considering the transit country's profit maximizing problem and its first-order conditions with the conjectural variation $r_T = \frac{\partial q_1}{\partial q_T}$. The transit country's profit is determined by the difference between the price of the final market $P_F(Q)$ and the price for which the transit country can buy volumes from the upstream producer P_E:

$$max(\Pi_{TR}) \text{ with } \Pi_{TR} = (P_F(Q) - P_E) \cdot q_T \text{ subject to } q_T \geq 0. \tag{4.5}$$

The first-order conditions are given by:

$$P_E - \alpha + \beta q_1 + \beta q_T + \beta \cdot (1 + r_T) \cdot q_T \geq 0 \perp q_T \geq 0. \tag{4.6}$$

If r_T has the value -1, transits are modeled as competitive, whereas the value of 0 corresponds to a situation in which the transit country exerts market power (Cournot conjecture). If $q_T > 0$ is fulfilled, equation (4.6) can be rewritten as:

$$P_E = \alpha - \beta q_1 - \beta q_T \cdot (2 + r_T). \tag{4.7}$$

With $q_T = q_2 + q_3$, this can be plugged into equation (4.4). With $r_2 = \frac{\partial q_3}{\partial q_2}$ and $r_3 = \frac{\partial q_2}{\partial q_3}$, this yields:

$$C_i - P_E + \beta \cdot (1 + r_i) \cdot (2 + r_T) \cdot q_i \geq 0 \perp q_i \geq 0 \text{ for } i = 2,3. \tag{4.8}$$

Equations (4.2) and (4.8) define the mixed complementarity problem for the stylized model. The important insight is that the inverse transit demand function can be included in the first-order conditions of producer 2 and producer 3. Turkey's inverse transit demand function is implemented in the global gas market model COLUMBUS accordingly as described in detail in Appendix 4.7.2.

4.4 Methodology: The Global Gas Market Model COLUMBUS

4.4.1 Model Description & Overview

In order to analyze the double marginalization induced by a multi-source transit country within a more complex market, the global natural gas market model COLUMBUS (cf. Hecking and Panke (2012), Growitsch et al. (2014), Hecking et al. (2016), Berk and Schulte (2017) as well as Berk et al. (2017)) is extended and applied. It is an intertemporal partial equilibrium model. Formulated as an MCP, it is able to account for strategic behavior of the upstream sector. Inputs are assumptions about production capacities, demand and gas infrastructure. COLUMBUS is a dynamic model which means that demand for investment into gas production and infrastructure are determined endogenously based on exogenously given economic factors such as investment costs and discount rates.

In its standard version, the COLUMBUS model is only able to consider strategic behavior of the vertical integrated suppliers defined "as a trading unit associated with one or more production regions" (Hecking and Panke, 2012). Transit countries, as in the focus of this study, are not associated with their own production region but can buy gas at their border from the neighboring countries. Therefore, the model is extended by introducing transit countries such as Turkey as profit-optimizing exporters. Technical details of the model extensions as well as a detailed technical description of the standard version of the COLUMBUS model can be found in the appendix.

The COLUMBUS model is calibrated with the data described in Section 4.4.2. Two calibrations with different conjectural variations are considered, one calibration to the year 2014 and one calibration to the year 2016. Both years are relevant because we aim on having calibrated configurations for an oligopolistic and a competitive upstream sector. As shown in Section 4.4.3, the European gas market of 2014 fits better to an oligopolistic setup, whereas the European gas market of 2016 fits better to the competitive assumption.

4.4.2 Input Data and Assumptions

Market Characteristics

In line with political and regulatory targets of the EU[6] (ACER, 2015b), further integration of the natural gas markets until 2030 is assumed. The EU market is aggregated into two clusters of countries: (1) a Northern & Western European (NWE) market and (2) a South Eastern European (SEE) market. The respective countries of each cluster are shown in Figure 4.2. The SEE market consists of the Balkan peninsula and Italy that will be connected in 2020 by the Trans Adriatic Pipeline (TAP) via Greece to the Trans Anatolian Pipeline (TANAP) in Turkey. The NWE market is composed of the remaining EU countries. The countries of each cluster are assumed to form an integrated market. Integration means that only one entry tariff (respectively exit tariff) has to be paid in order to ship gas into (respectively out of) the integrated market area.[7] A prerequisite for such a market design are investments in pipeline connections between the countries of the market area to reduce the risk of structural congestion.[8] An integrated market implies that there is only one gas price within each market area.

While the NWE market is already today characterized by a high degree of market integration in terms of sufficient infrastructure, competitive hub pricing and a high number of supply sources, the SEE market currently lacks connecting infrastructure and is dominated by Russian gas supply and oil-indexed long-term contracts (ACER, 2015a). However, there are various infrastructure projects, e.g. the CESEC initiative (European Commission, 2018a), and regulatory incentives, e.g. agreements between the European Commission and Gazprom about destination clauses and pricing issues in LTCs (European Commission, 2017a), aiming to increase the market integration within the SEE region. Hence, the assumption of an integrated market in SEE in 2030 is in line with the EU's long-term energy strategy. The modeling of two segments of the EU gas market allows a differentiation of effects of imports via the SGC on the NWE and SEE markets.

[6]Within this study the EU includes the United Kingdom, Switzerland, Norway and all states of former Yugoslavia.

[7]Uniform entry/exit tariffs are assumed that are calculated as a capacity weighted average of historical tariffs from the ACER market monitoring reports (ACER (2014) and ACER (2016)). Basing the analysis on historical tariffs implies that the costs of further investments into the natural gas infrastructure would be regained at the exit points to the customers. For an interesting discussion of how to derive entry/exit fees in an integrated European market cf. Hecking (2015).

[8]Persistent congestion within a market area would lead to high redispatch costs that would have to be distributed to the gas customers within the market area.

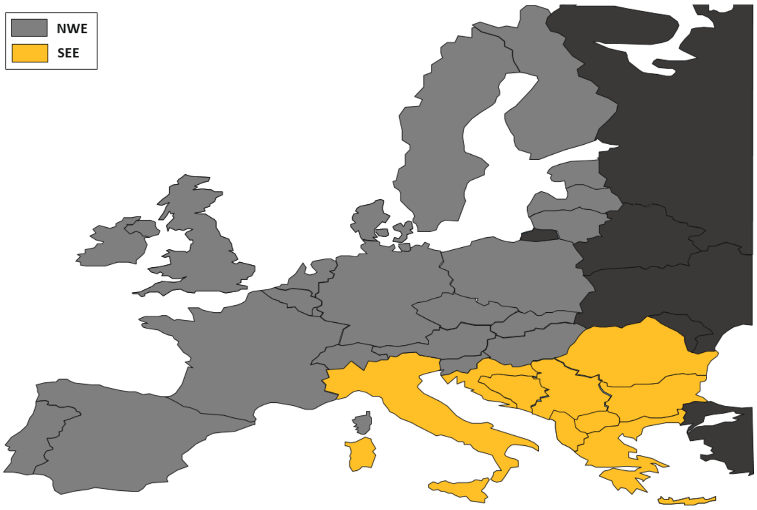


Figure 4.2: Definition of the two clusters NWE & SEE

Demand

The model is based on linear demand functions as in Lise et al. (2008). Inputs for each demand region are a reference demand, reference price and point elasticity of demand.[9] The fundamental data source for the historical reference demand is the Natural Gas Information 2017 (IEA, 2017). The future development of the reference demand is based on the projections of the New Policies Scenario of the World Energy Outlook 2015 (WEO) (IEA, 2015b). Hence, a nearly constant demand development in the EU is considered in this analysis. The European reference price is based on the Title Transfer Facility (TTF) price for the history[10], whereas the future development of reference prices is in line with IEA (2015b). The point elasticities of demand are chosen in line with Growitsch et al. (2014) and Egging et al. (2010). Thus, for instance, for Europe a price elasticity of -0.25 is assumed.

Production

The indigenous production of the EU is modeled exogenously, i.e. the respective EU reference demand is reduced by indigenous production. However, the production of all external natural gas suppliers relevant for the EU, i.e. Norway, Russia,

[9]The general level of the demand is an input to the model as the reference demand. However, given the fact that the model is an equilibrium model, the equilibrium demand is an output of the model and can deviate slightly from the input demand path.
[10]TTF prices can be obtained in a daily granularity from NetConnect Germany (2017).

North African suppliers, potential suppliers from the SGC and global LNG suppliers, is modeled endogenously. The input data about production capacities, operational and capital costs is based on a comprehensive literature research of current and historic upstream projects. Data has been obtained from Seeliger (2006), Aguilera et al. (2009), Henderson and Mitrova (2015), Henderson (2016), Aissaoui (2016), current press notifications about new field discoveries / developments, and by exchange with industry experts.

Infrastructure

The COLUMBUS model encompasses the major elements of the global gas infrastructure including pipelines and LNG terminals. Some projects having reached the financial investment decision (FID) status are exogenously given to the model (e.g. LNG terminals in the USA and Australia). The data for the existing pipeline infrastructure in Europe is based on the capacity map and the Ten Year Network Development Plan (TYNDP) of the European Network of Transmission System Operators for Gas (ENTSOG, 2015). In Turkey, the existing pipeline connections from Russia (Blue Stream), Georgia (Southern Gas Pipeline) and Iran (Tabriz-Ankara Pipeline) are modeled. Additionally, the first stage of the TANAP and the TAP are considered in the model with commissioning in 2018 and 2020. Information regarding LNG liquefaction and regasification capacities has been gathered from publications of Gas Infrastructure Europe (GIE) (GIE, 2015) and from the LNG Industry Report 2015 (GIIGNL, 2016). Facts about gas storage originate from reports of Gas Storage Europe (GIE, 2015) and the Natural Gas Information 2017 (IEA, 2017).

Besides investment costs, short-run marginal transport costs are relevant for the market equilibrium. As already mentioned in Section 4.4.2, for the two considered European market areas, uniform capacity weighted entry/exit tariffs based on ACER (2014) for 2014 and on ACER (2016) for 2016 and 2030 are used.[11] The Ukrainian entry/exit tariffs are from Interfax (2015).[12] Transport costs for the SGC, for the South Caspian Pipeline (SCP), for the TANAP and for the TAP are based on a detailed analysis by Pirani (2016). A distance-based approach is applied to derive transport costs for other non-European world regions for which no detailed cost data

[11] Due to the fact that we consider only two market regions within Europe changes of entry/exit tariffs have only a minor impact due to averaging effects.

[12] The assumed Ukrainian tariffs from 2015 imply that the Ukrainian route is the most expensive Russian export option to Europe. So despite not modeling the Ukrainian market power with respect to transit volumes endogenously, the Ukrainian market power is reflected in the exogenous tariff assumption.

is available.

The analysis is based on a pure economic rationale. This means that if not explicitly stated no political constraints are considered. Such constraints could be, for example, limited pipeline investment options between countries hostile to each other, or limited production capacities in countries that are politically unstable. While we know that political factors should be taken into account for a comprehensive analysis of Turkey's role in the SGC, we nevertheless believe that the economic perspective is helpful to understand drivers of all relevant stakeholders in the SGC including political actors. Furthermore, the model does not consider discrete investment choices. Therefore, the simulation may also identify small capacity demands for investment into infrastructure that would not take place in reality.

4.4.3 Model Calibration

The calibration results are shown in Figure 4.3 and Figure 4.4. Figure 4.3 illustrates the modeled and historical EU natural gas supply by source in 2014 and 2016. The respective bar in the middle depicts historical data from IEA (2017). The left bar illustrates the COLUMBUS simulation results if the upstream sector behaves oligopolistically, and the right bar is the result for competitive behavior. For 2014, it becomes clear that the oligopolistic case matches history better than the results with the competitive assumption. In the competitive case, about 5% more gas would have reached the EU gas markets compared to the historical imports. According to the model results, especially Russia withheld gas volumes in 2014. In 2016, there is an opposing picture. Figure 4.3 shows that the simulation of competitive behavior of the upstream producers matches reality better than oligopolistic behavior. In a market with oligopolisitc behavior, 6% less gas would have been consumed in 2016 compared to the actual consumption. However, when comparing both behaviors, it becomes clear that Russia was able to deter additional LNG imports in 2016 by offering its gas at more competitive prices.

Furthermore, Figure 4.4 shows the historical average European import natural gas prices of 2014 and 2016.[13] It depicts also the price results of the COLUMBUS simulation, differentiated for the NWE and the SEE market as well as for an oligopolistic and a competitive upstream behavior for each respective year. Again, it can be seen that in 2014 the simulation of oligopolistic suppliers fits the reality best. For 2016,

[13] The average import border price is based on World Bank (2017) with applied exchange rates of 1.32 EUR/USD (2014) and 1.10 EUR/USD (2016).

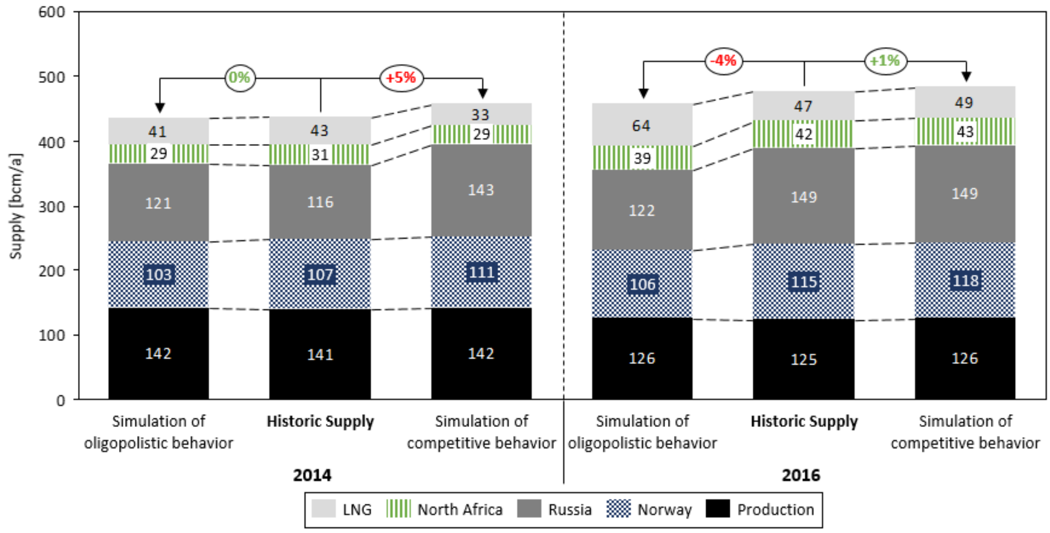


Figure 4.3: Comparison of historical imports to model results for 2014 and 2016

historic prices match better with a simulation of competitive suppliers.

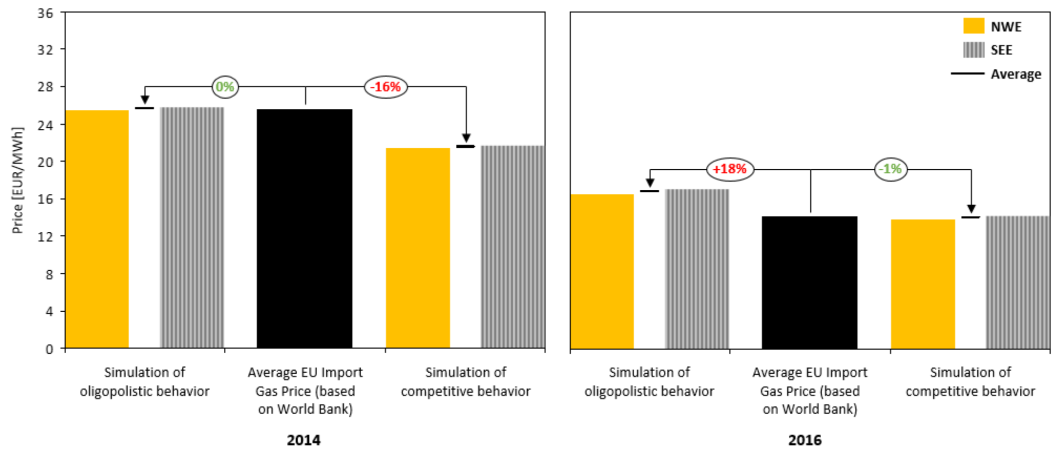


Figure 4.4: Comparison of historical prices to model results for 2014 and 2016

However, it is hard to predict today if the upstream producers will behave oligopolistically or competitively in 2030. Therefore, both potential developments are considered in the following analysis.

4.5 Simulation Results

4.5.1 Turkish Transit Market Power in an oligopolistic European Gas Market

In order to analyze the effects of Turkish transit market power in an oligopolistic EU upstream gas market (based on the conjectural variations for the model calibration to 2014)[14], two different scenarios are investigated: (1) a scenario with competitive Turkish transits, i.e. the SGC producers can access the Turkish transmission system, and (2) a scenario with Turkish transit market power, i.e. the SGC producers have no own access to the Turkish transmission system and need to sell the volumes to an Turkish exporter (for an overview of all considered scenarios in this analysis cf. Table 4.6 in Appendix 4.7.3).[15]

Initially, a scenario with competitive Turkish transits is considered. The left bar of Figure 4.5 illustrates the simulated EU supply mix with competitive Turkish transits in 2030. Due to exhausting resources, the EU natural gas production declines from 125 bcm in 2016 to 98 bcm in 2030. For similar reasons, Norwegian imports are diminished from 115 bcm in 2016 to 65 bcm in 2030. In addition, Russian imports decrease from 149 bcm in 2016 to 112 bcm in 2030 in the oligopolistic scenario due to the withholding of quantities. The LNG market, which is assumed to be competitive, partly fills the resulting supply gap. Another part is filled by imports from the SGC via Turkey. On this route 45 bcm reach the EU market in 2030. Assuming that 10 bcm/a of SGC capacity is already financed in the TAP project and will be realized, this means that an additional pipeline capacity investment into the SGC of 35 bcm/a would be economically viable according to the model results. Turkey and the SGC producers could benefit from an oligopolistic EU market situation with high prices in 2030. Hence, the share of EU's gas consumption that arrives via the SGC could be about 9%.

[14]The SGC producers Azerbaijan, Turkmenistan, Iran, Iraq and Israel are also assumed to act strategically in 2030, i.e. they potentially withhold quantities to generate higher prices.

[15]In Appendix 4.7.4, a sensitivity analysis on the conjectural variation of Turkey with values between -1 (competitive) and 0 (Cournot behavior) is considered.

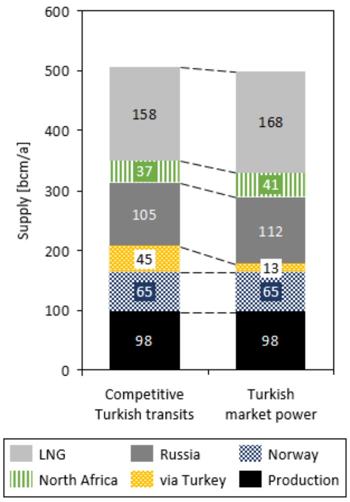


Figure 4.5: EU supply mix per source in dependence on Turkish behavior in 2030

Besides the scenario with competitive transits, a scenario in which Turkey acts as a Cournot player earning a profit with the transits is considered. Because the SGC producers are modeled as Cournot players as well, this implies successive oligopolies with double marginalization as described in Section 4.3.[16] The SGC producers are assumed to have pipeline access to the EU market via Turkey only. Pipeline investments on Russian territory by non-Russian actors are thereby excluded. This assumption is relaxed in Appendix 4.7.4. The simulation results of the scenario when Turkey exerts market power are shown in the right bar of Figure 4.5. If Turkey exerts market power, Turkish re-exports would be much lower than in the competitive case at 13 bcm/a or additionally to the TAP capacity 3 bcm/a in 2030. For the EU this would mean higher gas prices and thus a slightly lower demand (-10 bcm/a). However, most of the gas that would originally be imported via Turkey could be replaced by higher LNG imports (+10 bcm/a) as well as higher direct imports from Russia (+7 bcm/a).

The effect of Turkish transit market power on the EU gas market prices in 2030 is shown in Figure 4.6.[17] The figure again compares a situation with (left bar) and

[16] Russian transits through Turkey are still assumed to be competitive. Russian volumes are not bought by the Turkish Cournot player but can be sold to the European markets through Turkey directly by the Russian exporter that pays competitive transit fees. Turkey is not in the position to force Russia into a double marginalization structure as long as Russia has alternative channels to supply the European markets. Russia's direct investment options to Europe are not restricted and Russia rather prefers such direct routes to the EU as Nord Stream 2 due to lower costs compared to the Turkish transit option (even with competitive Turkish transit fees).

[17] Prices are in real terms based on EUR 2014.

without (right bar) the exertion of Turkish transit market power. Additionally, due to the differentiation of the EU markets into a NWE and a SEE market, regional prices in Europe can be analyzed. In the competitive scenario, prices are lower in SEE than in NWE in 2030. This is opposed to today's situation in which prices in South Eastern Europe are the highest on the continent. As already illustrated in Figure 4.4 in Section 4.4.3, the calibration results also show higher prices in SEE in 2014 and 2016 than in NWE. This can be explained with the fewer number of exporters that offer gas in the SEE market compared to NWE. If the SGC producers enter the market as new suppliers via Turkey, competition increases in the SEE market leading to lower prices. However, if Turkey would exert market power, the positive effect of further market entries diminishes resulting again in higher prices in SEE. It can be observed that by the exertion of Turkish transit market power prices in NWE would be 4.3% higher, while prices in SEE would be 6.9% higher than in a situation with a competitively behaving Turkey. This points out that in an oligopolistic European gas market structure the strategic behavior of Turkey would have a significant economic impact, in particular on the SEE market.

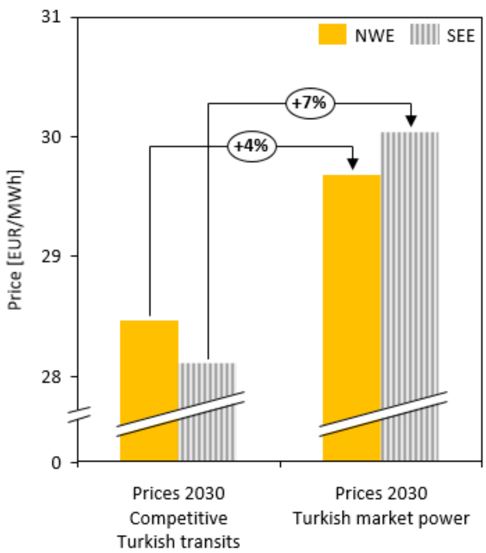


Figure 4.6: Natural gas prices in dependence on Turkish behavior in 2030

Figure 4.7 shows the implication of Turkish transit market power on the profits of Turkey, Russia and the SGC producers. Additionally, the figure points out the impact on the EU consumer surplus. It shows the differences in profits and consumer surplus between a competitively acting Turkey and when Turkey exerts transit market power. In the competitive case, the Turkish profits are by definition 0. However, if Turkey exerts market power, it earns profits of 1.8 billion EUR in 2030. Due to less SGC gas within the EU gas markets, more Russian gas is exported to the EU in the transit market power case which leads to higher Russian profits of 2.5 billion EUR. However, profits of the SGC producers are 13.1 billion EUR lower in 2030. The EU suffers a loss of consumer surplus by 6.6 billion EUR.

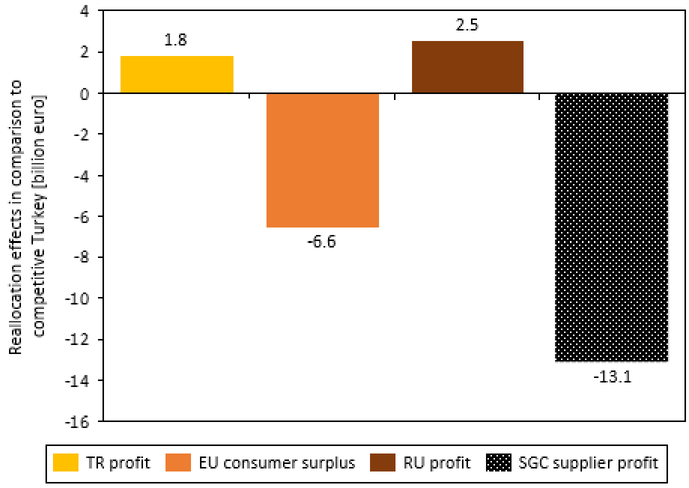


Figure 4.7: Development of profits and consumer surplus if Turkey exerts market power in 2030

The results discussed so far have focused on transits of the SGC producers via Turkey to the EU. However, it is also important to look at the domestic Turkish gas market. Within this study, it is assumed that Turkey would not exert market power in its domestic market. This is in line with a policy of the Turkish government to aim on low domestic gas prices that support economic growth. Thus, the domestic market can be directly supplied by all connected exporters. In the scenario with competitive Turkish transits, Turkey's modeled gas demand grows to 63 bcm in 2030 from 46 bcm in 2016. If Turkey exerts transit market power, its domestic demand is expected to amount to 65 bcm in 2030 according to the model results. In the market power case, the SGC producers have an incentive to ship gas to the Turkish domestic market instead of using the expensive transit option to the EU. Therefore, the competition in the Turkish domestic market increases leading to 5% lower gas prices and hence to 1.1 billion EUR additional Turkish consumer surplus compared to the case with competitive Turkish transits. Thus, Turkey benefits twice by the exertion of transit market power: (1) by profits from transits and (2) by a higher consumer surplus in its domestic market.

Figure 4.8 shows the origin of the gas exports of Turkey to the EU in 2030. It compares the transits for both considered scenarios (with and without the exertion of Turkish transit market power). If Turkey behaves competitively, about two thirds or 30 bcm of Turkish transits to the EU is Azerbaijani gas from the Shah Deniz field in the Caspian Sea. Since no Iranian sanctions are considered (pure economic rationale), an additional 11 bcm of Iranian gas would reach the EU market via Turkey in 2030. This figure seems to be quite small compared to the fact that Iran has the world's largest natural gas reserves (BP, 2016). Nevertheless, according to the model results, Iran supplies other markets than the EU such as Pakistan, India or the global LNG market.[18] Furthermore, about 4 bcm of expensive Israeli off-shore gas from the Mediterranean Sea would reach the EU. Turkmenistan and Iraq would not transit gas via Turkey to the EU due to comparably low price signals and the far distance. They would only supply the Turkish domestic market (both would deliver about 7 bcm). Whereas Turkmenistan would supply gas to Asian customers, the exports from Iraq are limited due to the increasing indigenous demand (mainly gas demand from the crude oil production).

On the contrary, if Turkey exerts market power, nearly all of the 13 bcm gas transits that would reach the EU would be from Azerbaijan. The reason lies in the country's missing alternative demand sinks and thus the strong Azerbaijani dependence on Turkey compared to Iran that can ship gas to the above mentioned alternative markets. Gas from Israel, however, would be too expensive and not exploited. Again, Turkmenistan and Iraq would deliver to the Turkish domestic market only (Turkmenistan: 12 bcm, Iraq: 10 bcm). Besides that, Turkmenistan would focus on non-European markets. Against this background, Appendix 4.7.4 considers a sensitivity analysis in which Azerbaijan can ship gas through Russian territory to the EU. In such a setup, market power exerted by Turkey would reduce the transit volumes through the SGC to below 7 bcm in 2030.

[18] For a more detailed discussion about Iranian exports see Berk and Schulte (2017).

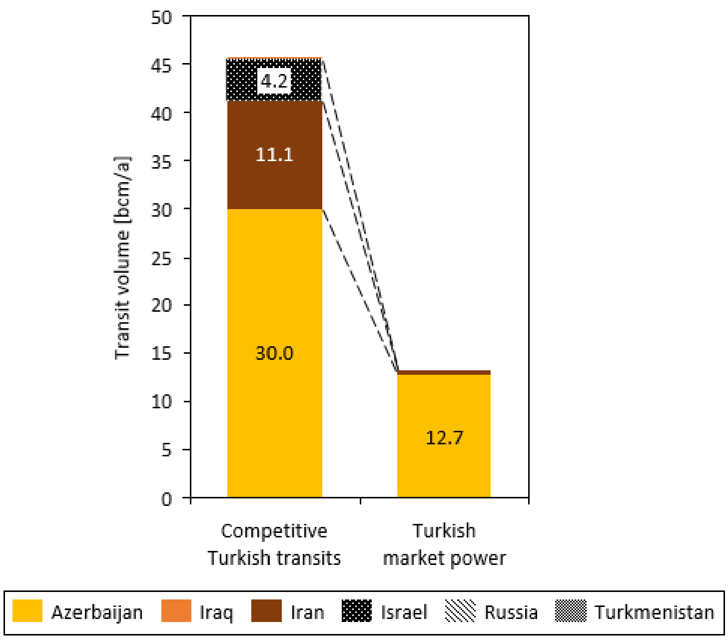


Figure 4.8: Turkish gas transits into the EU per source in dependence on Turkish behavior in 2030

4.5.2 Turkish Transit Market Power in a competitive European Gas Market

In the next step, the effects of Turkish transit market power in a competitive EU market are investigated. Hereto, we use the same conjectural variations as for the model calibration for 2016 (cf. Section 4.4.3). However, as already shown by Berk and Schulte (2017)[19], the chance of Turkey to become an important transit country for the EU is quite limited under competitive market conditions. There is only a minor demand for expensive gas from the SGC in a competitive EU gas market setting with a nearly constant future gas demand development. Similar results are found in this study.

If Turkey behaves competitively and SGC producers have only to pay the current TANAP transit fees, 23 bcm of gas would pass through Turkey to the EU in 2030. Nearly 18 bcm would come from Azerbaijan and approximately 5 bcm form Iran. Gas from Israel would be too expensive to reach the EU markets. However, even in this situation Turkey would be able to exert transit market power. Hereby it would

[19]A further study that investigates the role of the SGC under competitive market conditions is Hecking et al. (2016).

earn profits of 0.5 billion EUR. Nonetheless, if Turkey would exert market power in such a competitive environment, the potential of the SGC to diversify the EU gas markets is negligibly small. Only approximately 5 bcm from Azerbaijan would reach the EU gas markets. That means that even the capacity of the already financed first stage of the SGC would be oversized. That underlines the minor importance of the SGC under competitive market conditions.

4.6 Conclusion

The results of the study illustrate that Turkey has the potential to exert market power in the EU natural gas markets if an oligopolistic market structure (similar to the historical gas market situation in 2014) is assumed. If Turkey behaves competitively in this market environment, 45 bcm of Turkish transit volumes would arrive in Europe in 2030 according to the model outcome. In such a situation, gas prices in the SEE region could be lower than in the NWE region because the SGC producers would increase the competition, in particular in the SEE region. In the case of Turkish transit market power, however, the transits through Turkey would be reduced to 13 bcm in 2030, illustrating a big potential to withhold quantities from the markets. According to the model outcome, gas prices in the NWE region would be 4.3% higher in this setting in 2030 compared to a situation with competitive Turkish transits. However, SEE would be most significantly affected by 6.9% higher prices if Turkey exercises market power. The consumer surplus of the EU would be 6.6 billion EUR lower compared to the case in which Turkey behaves competitively. If Turkey would only withhold quantities to the European markets and not to its domestic market, lower gas prices in Turkey would be the consequence. Hence, Turkey could increase its consumer surplus (by 1.1 billion EUR) besides earning profits from transits (1.8 billion EUR) making it attractive for Turkey to use the market power option.

However, in a competitive future gas market setting (similar to the historical gas market situation in 2016), gas imports via Turkey and the SGC would be only of minor importance, even if Turkey behaves competitively. Hence, also the Turkish potential of pursuing transit market power is limited.

Our analysis illustrates that the economic raison d'être for the SGC is only given for an EU gas market that is characterized by oligopolistic natural gas suppliers. However, in this oligopolistic environment, Turkey could benefit from exerting market power and hereby eliminate the potential benefits of the SGC for the EU. As a policy implication, the EU could prefer direct connections between supply and demand avoiding new dependencies on transit countries. Another potential policy measure would be the harmonization of Turkey's energy laws with EU directives that guarantee a non-discriminative access to transmission grids.

4.7 Appendix

4.7.1 Model Description

The following model description is based on Hecking and Panke (2012). The COLUMBUS model is a spatial model consisting of vertices and edges. Vertices can be either sources (production facilities) or sinks (demand). Pipelines and LNG shipping routes are connected with edges.

Notation: Sets, Variables and Parameters

Table 4.1, Table 4.2, Table 4.3 and Table 4.4 give an overview of all sets, parameters and variables in the COLUMBUS model.

Table 4.1: Sets in the COLUMBUS model

Set	Description
$n, n1 \in N$	all model nodes
$c \in C$	cost levels (steps of piecewise linear supply function)
$t \in T$	months
$y \in Y$	years
$p \in P \in N$	producer / production regions
$e \in E \in N$	exporter / trader
$d \in D \in N$	final customer / demand regions
$r \in R \in N$	regasifiers
$l \in L \in N$	liquefiers
$s \in S \in N$	storage

Table 4.2: Primal variables in the COLUMBUS model

Primal variable	Description
$pr_{p,c,t}$	produced gas volumes
$fl_{e,n,n1,t}$	physical gas flows
$tr_{e,d,t}$	traded gas volumes
$st_{s,t}$	gas stock in storage
$si_{s,t}$	injected gas volumes in storage
$sd_{s,t}$	depleted gas volumes from storage
$dr_{p,c,y}$	depleted resources
$ip_{p,c,y}$	annual investment into production capacity
$it_{n,n1,y}$	annual investment into pipeline transport capacity
$is_{s,y}$	annual investment into storage capacity
$ilng_{y}$	annual investment into LNG transport capacity
$ir_{r,y}$	annual investment into regasification capacity
$il_{l,y}$	annual investment into liquefaction capacity
$mdo_{e,d,t}$	minimal delivery obligation

Table 4.3: Dual variables in the COLUMBUS model

Dual variable	Description
$\lambda_{p,c,t}$	marginal costs of physical gas supply by exporter e to node n in time period t
$\sigma_{s,t}$	(intertemporal) marginal costs of storage injection
$\alpha_{p,c,y}$	marginal value of resources in node n at cost level c in year y
$\beta_{d,t}$	marginal costs / price in node n in time period t
$\mu_{p,c,t}$	marginal benefit of an additional unit of production capacity
$\phi_{n,n1,t}$	marginal benefit of an additional unit of pipeline capacity
$\epsilon_{s,t}$	marginal benefit of an additional unit of storage capacity
$\psi_{s,t}$	marginal benefit of an additional unit of storage injection capacity
$\theta_{s,t}$	marginal benefit of an additional unit of storage depletion capacity
ι_{t}	marginal benefit of an additional unit of LNG transport capacity
$\gamma_{r,t}$	marginal benefit of an additional unit of regasification capacity
$\zeta_{l,t}$	marginal benefit of an additional unit of liquefaction capacity
$\chi_{e,d,t}$	marginal costs of delivery obligation

Table 4.4: Parameters in the COLUMBUS model

Parameter	Description
$dem_{d,t}$	final customer's demand for natural gas
$cap_{n,t/n,n1,t/n,c,t}$	monthly infrastructure capacity
$res_{n,c,y}$	maximum resources
$trc_{n,n1,t}$	transport costs
$prc_{n,c,t}$	production costs
$opc_{n,t}$	operating costs
$inc_{n,y/n,n1,y/n,c,y}$	investment costs
$dist_{n,n1}$	distance between node n and node n1 in km
$LNGcap$	initial LNG capacity
$speed$	speed of LNG tankers in km/h
cf_s	conversion factor used for storage inj. and depl. capacity
elt	economic life time of an asset
$slope_{d,t}$	slope of the linear demand function in node d
cv_e	conjectural function of exporter e; market power level

KKT Conditions

The COLUMBUS model is based on profit optimization problems of the different players (exporters, producers, transmission system operators, liquefiers, regasifiers). Each profit optimization problem has corresponding first order conditions. Together with the market clearing conditions, the first order conditions define the model. The KKT conditions for the exporters are given by:

$$-\beta_{d,t}+(cv_e+1)\cdot \text{slope}_{d,t}\cdot tr_{e,d,t}-\chi_{e,d,t}+\lambda_{e,d,t} \geq 0 \quad \perp \quad tr_{e,d,t} \geq 0 \qquad \forall e,d,t, \tag{4.9}$$

$$\begin{aligned}-\lambda_{e,n,n1,t} + \lambda_{e,n,t} + trc_{n,n1,t} + trc_{n,n1,t} + opc_{n,t}& \\ + \phi_{n,n1,t} + \zeta_{l,t} + \gamma_{r,t}& \\ + \iota_t \cdot 2 \cdot dist_{l,r} \geq 0 \quad \perp \quad fl_{e,n,n1,t} \geq 0 \qquad \forall e,n,n1,t.&\end{aligned} \tag{4.10}$$

The KKT conditions for the producers are given by:

$$-\lambda_{e,p,t} + prc_{p,c,t} + \sum_{y \in Y_t} \alpha_{p,c,y} + \mu_{p,c,t} \geq 0 \quad \perp \quad pr_{p,c,t} \geq 0 \qquad \forall p,c,t, \tag{4.11}$$

$$\alpha_{p,c,y+1} - \alpha_{p,c,y} \leq 0 \quad \perp \quad dr_{p,c,y} \geq 0 \qquad \forall p,c,y, \tag{4.12}$$

$$inc_{c,p,y} - \sum_{t \in T(y)} \mu_{p,c,y} \geq 0 \quad \perp \quad ip_{p,c,y} \geq 0 \qquad \forall p,c,y. \tag{4.13}$$

The KKT conditions for the transmission system operators are given by:

$$inc_{n,n1,y} - \sum_{t \in T_y} \phi_{n,n1,t} \geq 0 \quad \perp \quad it_{n,n1,y} \geq 0 \qquad \forall n,n1,y. \tag{4.14}$$

The KKT conditions for the liquefiers are given by:

$$inc_{l,y} - \sum_{t \in T_y} \zeta_{l,t} \geq 0 \quad \perp \quad il_{l,y} \geq 0 \qquad \forall l,y. \tag{4.15}$$

The KKT conditions for the regasifiers are given by:

$$inc_{r,y} - \sum_{t \in T_y} \gamma_{r,t} \geq 0 \quad \perp \quad ir_{r,y} \geq 0 \qquad \forall r, y. \tag{4.16}$$

The KKT conditions for the LNG shippers are given by:

$$inc_y - \sum_{t \in T_y} (\iota_t \cdot 8760/12 \cdot speed) \geq 0 \quad \perp \quad ilng_y \geq 0 \qquad \forall y. \tag{4.17}$$

The KKT conditions for the storage operators are given by:

$$-\beta_{d,t} + \sigma_{s,t} + \theta_{s,t} \geq 0 \quad \perp \quad sd_{s,t} \geq 0 \qquad \forall s, t, \tag{4.18}$$

$$-\sigma_{s,t} + \beta_{s,t} + \rho_{s,t} \geq 0 \quad \perp \quad si_{s,t} \geq 0 \qquad \forall s, t, \tag{4.19}$$

$$\epsilon_{s,t} = \Delta\sigma_{s,t} = \sigma_{s,t+1} - \sigma_{s,t} \leq 0 \quad \perp \quad st_{s,t} \leq 0 \qquad \forall s, t, \tag{4.20}$$

$$in_{c,s} - \sum_{t \in T_y} [\epsilon_{s,t} + cf_{s,t} \cdot (\rho_s, t + \theta_{s,t})] \geq 0 \quad \perp \quad is_{s,y} \geq 0 \qquad \forall s, y. \tag{4.21}$$

The market clearing conditions are given by the following equations:

$$\sum_{c \in C} pr_{p,c,t} - tr_{e,d,t} + \sum_{n1 \in (n1,n) \in A} fl_{e,n1,n,t} - \sum_{n1 \in (n,n1) \in A} fl_{e,n,n1,t} = 0 \quad \perp \quad \lambda_{e,n,t} \quad \text{free} \qquad \forall e, n, t, \tag{4.22}$$

$$\sum_{e \in E} tr_{e,d,t} + mdo_{e,d,t} + sd_{s,t} + si_{s,t} - dem_{d,t} = 0 \quad \perp \quad \beta_{d,t} \quad \text{free} \qquad \forall d, t. \tag{4.23}$$

Equation (4.22) must be fulfilled for each exporter $e \in E$ that is active at the node $n \in N_e$. Additionally, the equation ensures equality of traded volumes and physical flows. Equation (4.23) defines the gas balance at demand nodes d in month t making sure that the final demand is met.

4.7.2 Model Extensions

Equation (4.9) defines the first-order conditions of the exporter's problem.[20] This problem is re-formulated to optimize profits of exporters that sell volumes to a transit country with the transit country's conjectural variation cv_{tr} and the slope of the final demand region $slope_{dem,t}$[21]:

$$-\beta_{d,t}+(cv_e+1)\cdot(2+cv_{tr})\cdot slope_{dem,t}\cdot tr_{e,d,t}-\chi_{e,d,t}+\lambda_{e,d,t}\geq 0\perp tr_{e,d,t}\geq 0\ \forall e,d,t. \tag{4.24}$$

Equation (4.24) has the structure of equation (4.8). The transit country can be modeled as competitive (conjectural variation $cv_{tr}=-1$) or as a Cournot player (conjectural variation $cv_{tr}=0$). The exporters supplying final markets (including the transit country itself) have still first-order conditions of the form of equation (4.9).

Furthermore, the market clearing conditions given by equations (4.22) and (4.23) need to be extended. The volumes bought by the transit country $transit_t$ need to be included in those market clearing constraints for the nodes at the border of the transit country where it buys the transit volumes $n\in N_{TR}$:

$$\sum_{c\in C}pr_{p,c,t}+transit_t-tr_{e,d,t}+\sum_{n1\in(n1,n)\in A}fl_{e,n1,n,t}-\sum_{n1\in(n,n1)\in A}fl_{e,n,n1,t}=0\perp\lambda_{e,n,t}\text{ free }\forall e,n\in N_{TR},t. \tag{4.25}$$

The volumes bought by the transit country $transit_t$ are included in the second market clearing constraint as follows:

$$\sum_{e\in E}tr_{e,d,t}+sd_{s,t}-si_{s,t}-transit_t=0\perp\beta_{d,t}\text{ free }\forall d,t. \tag{4.26}$$

[20] Growitsch et al. (2014) use a different convention of conjectural variations. This explains the difference between equation (11) in Growitsch et al. (2014) and equation (4.9).

[21] In the study at hand this is the slope of the linear demand function of the EU market, which is modeled in two regions. A more detailed description of the regions is given in Section 4.4.2. It is based on the countries' linear demand functions that are aggregated for the respective EU regions. The parameters of the EU demand functions determine the demand function for Turkish transit gas.

4.7.3 Data Sources and Scenarios

Table 4.5 lists the most important data sources of this study, whereas Table 4.6 gives an overview of the considered scenarios.

Table 4.5: Data and Sources

Model Input	Source
Reference demand	Natural Gas Information 2017 (IEA, 2017), World Energy Outlook 2015 (New Policies Scenario) (IEA, 2015a)
Price elasticities	Growitsch et al. (2014) and Egging et al. (2010)
Reference price	Based on TTF 2014 (NetConnect Germany, 2017)
Production costs	Seeliger (2006), Aguilera et al. (2009), Henderson and Mitrova (2015), Henderson (2016), Aissaoui (2016)
Existing pipelines	Ten Year Network Development Plan (ENTSOG, 2015)
LNG facilities	Capacity Map (GIE, 2015), LNG Industry Report (GIIGNL, 2016)
Storage facilities	Gas Storage Map (GIE, 2015), Natural Gas Information 2017 (IEA, 2017)
Transportation costs	ACER Market Report 2014 (ACER, 2015b), Interfax (2015) and Pirani and Yafimava (2016)

Table 4.6: Scenario overview

Scenario Number	Section	Upstream Sector	Turkish Behavior	Further Scenario Characteristics
1.1	Section 4.5.1	oligopolistic	competitive	-
1.2	Section 4.5.1	oligopolistic	oligopolistic	-
2.1	Section 4.5.2	competitive	competitive	-
2.2	Section 4.5.2	competitive	oligopolistic	-
A.1	Appendix 4.7.4	oligopolistic	oligopolistic	transits from Azerbaijan and Turkmenistan via Russia possible
A.2	Appendix 4.7.4	oligopolistic	oligopolistic	cartel of Russia, Azerbaijan and Turkmenistan

4.7.4 Sensitivity Analysis

Sensitivity on Turkish behavior in an oligopolistic European Gas Market

Figure 4.9 illustrates how the Turkish transits (by origin) vary if the conjectural variation of Turkey is varied between -1 and 0 in the oligopolistic gas market configuration. It becomes clear that Israel and Iran are very sensitive on Turkey's transit behavior. If Turkey decides to exert market power, transits of these countries via Turkey to Europe are not competitive. Azerbaijan, however, is less sensitive because it is only able to export gas via Turkey (cf. Appendix 4.7.4 for a sensitivity in which this assumption is relaxed).

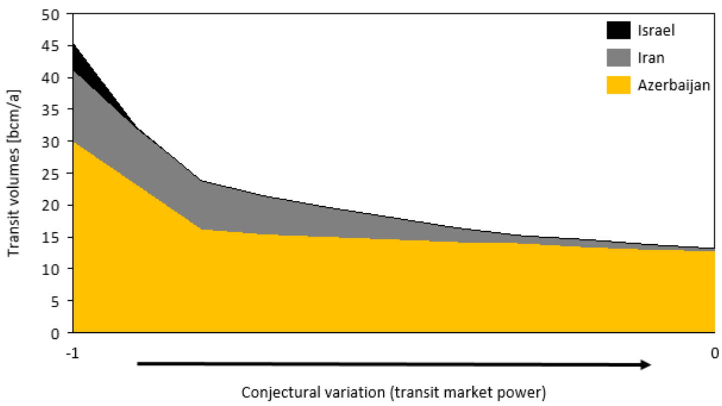


Figure 4.9: Turkish gas transits into the EU per source in dependence on Turkish behavior in 2030

Figure 4.10 illustrates how the Turkish conjectural variation affects natural gas prices in SEE and NWE. While the SEE price is below the NWE price with competitive Turkish transits, this interrelation changes when market power is exerted: For conjectural variations larger than -0.8, the SEE price is larger than the NWE price.

The market situations with Turkish conjectural variations between -1 and 0 illustrated in the Figures 4.9 and 4.10 are cases in which both the EU and Turkey would benefit from the SGC, i.e. Turkey would earn some profits from transiting, and the EU would enjoy lower gas prices compared to a situation with double marginalization. Such a market situation could be e.g. the result of a bargaining process between gas consumers and the transit country (similar to the bargaining between upstream producers and the transit country mentioned in Section 4.2). However, it is important to note that such a bargaining solution could become obsolete if a competitive upstream market structure is assumed instead of an oligopolistic market because fewer volumes would pass through the SGC in the competitive setup.

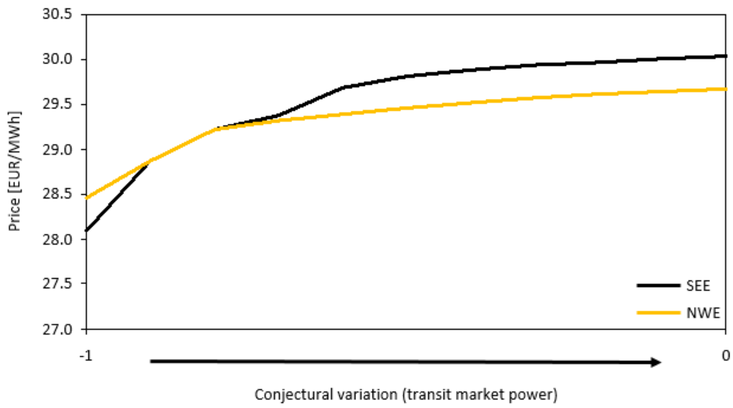


Figure 4.10: Natural gas prices in SEE and NWE in dependence on Turkish behavior in 2030

Caspian Gas via Russia in an oligopolistic European Gas Market

In Section 4.5, it was assumed that Azerbaijan would be able to only deliver gas via Turkey to the EU markets. Besides the EU, Azerbaijan could solely sell its gas to Georgia or Turkey. However, the Turkish and Georgian demand for Azerbaijani gas is relatively small and accounted for only 8 bcm in 2015 (Pirani, 2016). Looking into the past, Azerbaijan delivered up to 2 bcm of gas to Russia in 2012 (Pirani, 2016). Since then, supplies have declined to zero in 2015. As of 2016, Azerbaijan is even importing about 2 bcm/a from Russia (Azernews, 2016). The main reason is the increasing domestic demand and the underdeveloped production of the Shah Deniz field. This situation may change when the Shah Deniz stage 2 will come online. Then, Azerbaijan would be able again to export gas also to Russia or even via Russia into the EU.

The sensitivities discussed in the following are implemented within an oligopolistic upstream market structure in 2030. Therefore, the results from Section 4.5.1 are the relevant reference to compare the sensitivities to. In a first sensitivity, it is assumed that Azerbaijan and also Turkmenistan are able to deliver gas competitively via Russia to the EU while Turkey is exerting transit market power. As a consequence, both countries would not deliver any gas via Turkey and the total Turkish transits to the EU would only be at 6.7 bcm in 2030. As shown in Figure 4.11, these 6.7 bcm of natural gas that would reach the EU are Iranian gas. Due to reduced competition in the first-stage oligopoly (SGC producers competing about the transits through Turkey) compared to a situation in which Azerbaijan and Turkmenistan are part of this oligopoly, the remaining SGC producers can exercise more market power when selling gas to Turkey. Hence, it becomes more profitable for Iran to export gas via Turkey to the EU. The EU, however, benefits from Azerbaijani and Turkmen gas supplies via Russia. While EU prices would be 1.5% (0.9%) lower in SEE (NWE) compared to the scenario "Turkish market power" without outside options of Azerbaijan and Turkmenistan, EU's consumer surplus would be 1.6 billion EUR higher. As can be seen in Figure 4.11, due to lower natural gas transits, Turkey's profit would be 0.5 billion EUR if Azerbaijan and Turkmenistan can circumvent Turkey instead of previously 1.8 billion EUR. However, because of lower European gas prices and stronger competition with Azerbaijan and Turkmenistan in its key markets, Russia would also lose 0.7 billion EUR revenues as well as 0.2 billion EUR of profits by allowing transits on its territory compared to the case in which Turkey exercises market power and no SGC producer can ship through Russia. Thus, a situation in which Russia would allow Azerbaijan and Turkmenistan to use its infrastructure to bring additional gas amounts into the EU seems to be an unlikely solution for a more competitive European upstream gas market.

Another possible scenario would be that Russia buys gas from Azerbaijan and Turkmenistan and resells it to the EU instead of allowing competitive transits - similar to Turkey's assumed behavior. However, it is questionable if double marginalization would be the appropriate approach to describe this setting because Russia has a huge indigenous gas production with comparably low production costs. Hence, Azerbaijan and Turkmenistan are not in a good position to exert market power against the Russian exporter.[22] Therefore, the scenario in which Russia buys gas from Azerbaijan and Turkmenistan is modeled as a cartel situation in which the three countries offer their gas amounts jointly as one player[23]. Together, these countries are in a strong position to act strategically. Thus, compared to the scenario in which all SGC producers have to sell gas to an oligopolistic Turkey in order to deliver gas to European markets, gas prices are higher in both modeled EU market areas (SEE and NWE) by about 2.8%. This leads to a loss in EU consumer surplus of 3.6 billion EUR compared to the Turkish market power scenario with all SGC producers selling to Turkey. Nonetheless, as illustrated in Figure 4.11, even if Russia and the Caspian producers Azerbaijan and Turkmenistan would form a cartel, still 5.7 bcm of mainly Iranian natural gas would reach the EU markets via Turkey. Turkey could

[22]Turkey, on the other hand, does not have a significant indigenous gas production.
[23]For modeling a cartel the same modeling approach as in Egging et al. (2009) is chosen.

earn 0.4 billion EUR of profits.

Concluding, if Azerbaijan und Turkmenistan can ship gas through Russia (either competitively or by cooperation forming a cartel with Russia), the volumes that Turkey could resell to Europe would be below the already financed TAP capacity of 10 bcm/a. Similar to the setting with a competitive upstream market discussed in Section 4.5.2, the importance of the SGC for the European gas supply would be small in such a scenario.[24]

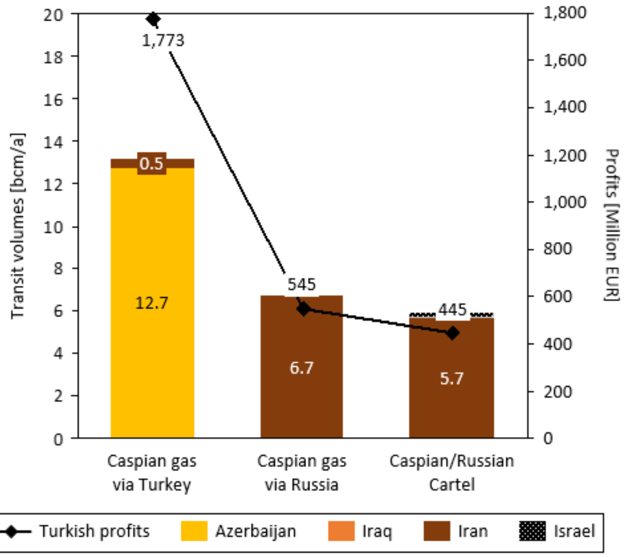


Figure 4.11: Turkish gas transits into the EU per source and Turkish profits in dependence on Caspian supply options in 2030

[24]In reality, it is possible that the Caspian countries and Russia could find a form of cooperation between competitive transits and the cartel. In principle, a transit problem can also be seen as a bargaining problem in which cooperation (cartel) and Cournot competition among the respective producers would be extreme outcomes (cf. the discussion in Section 4.2 about options to avoid double marginalization). However, both considered scenarios with respect to the relations between the Caspian countries and Russia have similar implications for the SGC, i.e. if Azerbaijan and Turkmenistan ship through Russia, the volumes coming through the SGC are diminished.

5 Tender Frequency and Market Concentration in Balancing Power Markets

Balancing power markets ensure the short-term balance of supply and demand in electricity markets and their importance may increase with a higher share of fluctuating renewable electricity production. While it is clear that shorter tender frequencies, e.g. daily or hourly, are able to increase the efficiency compared to a weekly procurement, it remains unclear in which respect market concentration will be affected. Against this background, we develop a numerical electricity market model for Germany to quantify the possible effects of shorter tender frequencies on costs and market concentration. We find that shorter time spans of procurement are able to lower the costs by up to 15%. While market concentration decreases in many markets, we – surprisingly – identify cases in which shorter time spans lead to higher concentration.

5.1 Introduction

In electricity markets supply and demand need to be equal at all times and commonly transmission system operators (TSOs) are in charge of balancing supply and demand. Due to unbundling policies, TSOs are not allowed to own generation assets and need to procure short-term flexibility from operators of power plants. These power plants need to be able to adjust their production on short notice to balance supply and demand. In Germany, balancing power (which is one kind of ancillary services) is currently procured on a weekly basis for the fastest two load balancing services of primary and secondary balancing power.[1] Operators that offer, for example, positive balancing power therefore need to withhold production capacities over the time span of a whole week and cannot sell their full capacity into the spot market. The costs that arise from balancing power provision are thus based on the opportunity costs with respect to selling the capacity in the spot market, namely the foregone profits from spot market operation.

[1] The ancillary services primary and secondary balancing power are also known as Frequency Control Reserve (FCR) and automated Frequency Restoration Reserve (aFRR), respectively.

In this paper, we take a closer look at the German balancing power markets with a special focus on two problems that may arise from the current (weekly) market design. First, the weekly procurement leads to inefficiencies as operators need to withhold capacities for a whole week and cannot fully participate in the hourly spot market. There is a missing market for hourly balancing power products that could be solved by an hourly procurement of balancing power. Secondly, we observe that large players with a broad portfolio of power plants are able to provide balancing power at lower costs, especially in a weekly auction. These economies of scale for large players may lead to highly concentrated markets and the possible abuse of market power.

Whereas in theory it is well understood that shorter time spans lower costs and might change market concentration, the magnitude of a change in market design towards shorter time spans remains unclear. In order to assess the possible impact, we develop a numerical model that accounts for the operator structure in the balancing power market and considers different time spans for balancing power procurement. Based on the model we are able to quantify the effects of different market designs (weekly, daily, hourly) on system costs and market concentration.

The modeling of balancing power markets is complex, as it is driven by the opportunity costs of operators. Just and Weber (2008) started to write down this problem analytically and solved the simplified model numerically. Later the methodology was again applied by Just (2011) to analyze the implications of different tender frequencies on the procurement costs but without considering the operator structure. Richter (2012) bases his analysis on the model developed by Just and Weber (2008) and is able to show the existence of a competitive simultaneous equilibrium in spot and balancing power markets that is unique and efficient. He finds out that the bids of the capacity providers form a u-shaped bidding function around the spot demand. This work shows that the integrated modeling of spot and balancing power markets in a fundamental model as it is done in the analysis at hand yields meaningful results. In addition, the equilibrium of the spot and balancing power market was further analyzed by Müsgens et al. (2014) in the context of the German market design. They present an analytical expression of the balancing opportunity costs as well which is used in our latter analysis. The procurement of balancing power is commonly organized via auctions. A special characteristic of the balancing power procurement process is that the cost structure of participants can be divided into two parts. One part is fixed for a period and stems from withholding capacity for balancing purposes. The second part are variable costs for the supply of energy in the case of being called during operation. Bushnell and Oren (1994) were the first to analyze the auction design of balancing power markets. Their work was later extended by Chao and Wilson (2002) in order to design incentive compatible scoring and settlement rules. They found that incentive compatible auctions can be designed by considering only the capacity bid for scoring in a uniform price auction. Nevertheless many of the implemented auction designs in Europe differ from their proposals.

The auction design of balancing markets was also studied by Müsgens et al., who analyzed the importance of timing and feedback (Müsgens and Ockenfels, 2011, Müsgens et al., 2012). The development in the tertiary reserve market and the change in rules was analyzed by Haucap et al. (2012). They find that the cooperation of the four TSOs in Germany decreased costs for the procurement of tertiary reserve.

Whereas previous literature focuses on the efficient design, high market concentrations are an additional issue in balancing power markets with few big operators. In 2010, Growitsch et al. (2010) analyzed the operator structure in the tertiary balancing power market. They find high market concentration in certain situations of the tertiary balancing power market. Heim and Götz (2013) looked at the market outcomes in the German secondary reserve market based on exclusive data provided by the BNetzA and find that the price increase in 2010 can be traced back to the bidding behavior of the two largest firms.

While the general effects of a design change towards shorter spans is well understood, the empirical importance is less clear. In order to contribute to filling this gap, we simulate one design change for the German balancing market. We compare simulation results for the current market design to simulation results for shorter time spans. Besides the changed provision duration, all other assumptions are held constant to focus solely on the effect of a shortened provision duration. From the comparison of the results, we derive a difference of 15% balancing cost in favor of shorter time spans. With respect to concentration, our model results indicate that an hourly market design for balancing power leads to certain periods with higher market concentration. This means that in some hours market concentration could increase by a change of market design from weekly to hourly, and policy makers should be aware of this. The regulatory implication of this finding could be a trade-off between a moderate level of market power over a weekly provision or a potentially high market power in certain periods of shorter provision durations. To the best of our knowledge, there are no sufficient regulatory mechanisms to mitigate market concentration or market power in occasional situations with high mark-ups. A potential price-sensitive demand function might decrease market power but with the drawback of a reduced security of supply (which would need to consider the value of lost load as well as statistical probabilities). These designs are not considered in the current European balancing market harmonization approach (cf. European Commission (2017b)). Whereas the analysis at hand is limited to market concentration, it is left for further research to determine the mark-ups that can be realized in concentrated situations and to establish a regulatory mechanism that is able to mitigate this potential market power.

The paper is organized as follows: In Section 5.2 we focus on the background information which include, among others, the general electricity market structure, bidding behavior for balancing power and the concepts of market concentration indices. Section 5.3 introduces the methodology, namely a unit-commitment model for electricity markets and the model specifications to account for the balancing power markets. Section 5.4 presents the modeling results as to the system costs and the market concentration indices. Section 5.5 concludes.

5.2 Background

5.2.1 On the Functioning of the Balancing Power Market

The balancing power market is an additional market for electricity generators, besides the classic spot markets like the day-ahead and intraday market. In the balancing power market, system operators procure spare production capacity that is called upon in case of imbalances. It is usually divided into products depending on the urgency and the direction of power provision. In Germany, the markets are divided into primary, secondary and tertiary balancing power provision, which differ mainly in reaction time. In the primary balancing power market, power plants need to be able to adjust their output in both directions (upward and downward). Secondary and tertiary balancing power markets are divided into products for positive and negative balancing power. The secondary balancing power market is further divided into a peak (HT) and off-peak product (NT). Additional information on the current German market design can also be found in Hirth and Ziegenhagen (2015).

An ongoing harmonization process of European energy and balancing markets leads to similar designs for instance in the International Grid Control Cooperation (IGCC).[2] Typical design characteristics are an inelastic demand as well as a day-

[2] IGCC aims for an increased cooperation of balancing power procurement and utilization. Participating countries in 2017 are AT, BE, CH, CZ, DE, DK, FR, NL.

ahead or week-ahead procurement of balancing power. An up to date comparison of European balancing markets is given in Ocker et al. (2016). The European Commission gives suggestions on an EU-wide balancing market, which aims at a harmonization of regulations as it is done already within the IGCC (European Commission, 2017b).

In contrast to the European *day-ahead* or *week-ahead* balancing markets, *real-time* balancing markets are implemented for instance by the regional transmission operators of PJM, MISO (formerly Midwest ISO) and ISO New England in the US (ISO New England, 2011, MISO, 2016, PJM, 2017, Vlachos and Biskas, 2013). Here, the balancing amount and corresponding prices are calculated in real-time, e.g. 5 minutes before delivery. In the subsequent paper, we focus on the implications of shorter tender frequencies in the German balancing power market for two reasons. First, the German market is the largest balancing market within Europe with similar characteristics as in other European countries. Second, shortening of the week-ahead provision duration to an hourly provision duration could be considered as a reasonable step towards real-time balancing markets. Depending on the market design, this could have impacts on efficiency and market concentration.

However, the scope of the paper is not to find an optimal market design for balancing markets (i.e. with consideration of the value of lost load and optimal demand response), but to isolate the possible economic effects of a regulatory change by a shortened provision duration.[3]

Because the balancing of imbalances has to occur in very short time periods before physical delivery, providers of balancing power have to reserve capacity for balancing purposes. This means for example that an operator for positive balancing power cannot sell all her production capacity into the spot market and needs to operate power plants below the maximum capacity level. When being called for the supply of balancing power, the power plant needs to increase its output. For the case of negative balancing power provision, operators need to run their plants above their minimum production capacity and when negative balancing power is called, these plants have to be able to decrease their electricity production.

The cost structure of participants in the balancing power market is thus different compared to the spot market. The marginal costs of generation and the opportunity costs for balancing power provision are exemplary shown for positive balancing power in Figure 5.1. If no balancing power is procured it would be optimal that

[3]For analyses of the optimal design of balancing market see for instance Chao and Wilson (2002) or Vandezande et al. (2010).

all power plants sell their full generation capacity in the spot market based on their marginal generation costs (blue dashed curve) until demand is satisfied. In the case that positive balancing power is procured, power plants need to withhold production capacity from the spot market for being able to satisfy the demand for balancing capacity. Since power plants need to operate at a minimum production level and can only offer a fraction of their generation for balancing purposes, some power plants could face a trade-off between not running and running at minimum production to offer balancing power. Two different types of opportunity costs are therefore possible which can either be inframarginal or extramarginal. Based on Müsgens et al. (2014), they can be expressed for positive balancing power as

$$CapacityCosts_{reserve} = \begin{cases} (VC - price_{DA}) & \text{, if } VC \leq price_{DA} \\ (VC - price_{DA})\frac{Cap_{min}}{Cap_{reserve}} & \text{, if } VC > price_{DA}. \end{cases} \tag{5.1}$$

Here, VC are the variable costs of generation, $Cap_{reserve}$ and Cap_{min} are the reserve capacity provision and the minimal load capacity, respectively. Inframarginal power plants have generation costs lower than the spot price and would be running in the spot market also without the existence of a balancing power market. The opportunity costs therefore just result in the difference between the spot price and their variable costs. Extramarginal power plants have generation costs higher than the spot price, but are nevertheless selling their electricity in the spot market if the loss is compensated by a high balancing price.

For example, a power plant that has marginal generation costs a bit lower than the spot market price, has very low opportunity costs for positive balancing power provision (red dash-dotted curve). If this power plant decreases its spot market production in order to offer positive balancing power, the income from the spot market is only slightly lowered. The opportunity costs for the provision of positive balancing power are thus close to zero, as can be seen for power plants close to the spot market demand of 60 GW in Figure 5.1. In contrast to this, if the power plant has very low marginal costs of production compared to the spot price, the opportunity costs for positive balancing power provision are very high, as the forgone spot market profits are very high. Opportunity costs are even higher for extramarginal power plants with high variable costs that would incur a large loss when selling electricity in the spot market.

The spot demand of electricity depends mainly on the time of consumption and fluctuates throughout the day. Therefore, prices fluctuate as well. This means oppor-

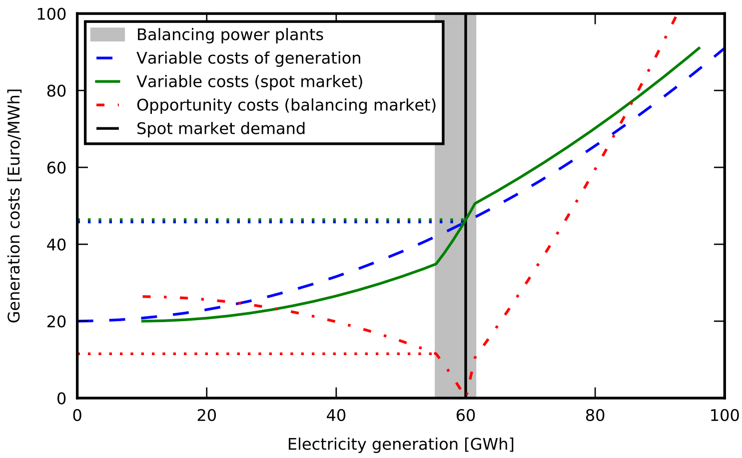


Figure 5.1: Capacity bidding behavior for balancing power markets is theoretically based on an opportunity cost strategy to the spot market (here: positive balancing power)

tunity costs of single power plants are constantly changing and providers of balancing power need to take this into account. For the case of operators owning multiple power plants with a well-diversified portfolio this effect is not as severe because in the best case they are always operating a power plant with marginal costs close to the spot price that has very low opportunity costs. This makes it obvious that bigger power plant portfolios may have significant cost advantages compared to small players.

In order to illustrate the effect of the portfolio on the opportunity costs, we consider the following example that is visualized schematically in Figure 5.2: Let us assume that there are three power plants *A*, *B*, and *C* with the same capacity but different marginal costs of 10, 20 and 30 EUR/MWh. With an ordering according to the marginal costs, we derive the simplified spot market merit order. The spot market clearing price is thus the intersection of the demand function with the merit order. We calculate the opportunity costs based on Equation (5.1) above. Note that, for this stylized example, we assume the minimum load capacity and the balancing capacity provision to be equally sized (e.g. both 50% of the total capacity). Then, both terms cancel out each other for the extramarginal case in Equation (5.1) which simplifies the example. In the modeling approach, detailed technical characteristics as to minimum load as well as capacity provision are considered.

Now, let us consider two demand situations: A low and a high spot market demand situation. In the low demand situation, the demand is lower than the total capacity of plant A. Hence, the cheapest power plant A can satisfy the total spot market demand resulting in a spot market clearing price of 10 EUR/MWh. This leads to opportunity costs of 0, 10 and 20 EUR/MWh for A, B and C respectively[4] (shown in Figure 5.2 on the lower y-axis part). In the high demand situation, the demand exceeds the joint capacity of plant A and B. Therefore, plant C determines the spot price of 30 EUR/MWh which results in opportunity costs of 20, 10 and 0 EUR/MWh for A, B and C respectively.

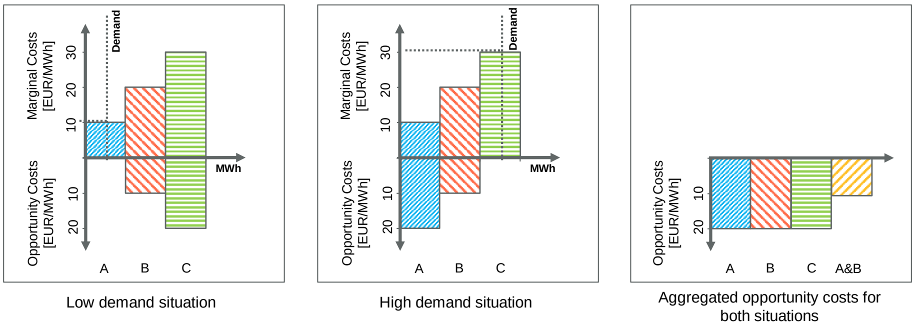


Figure 5.2: Schematic illustration of the portfolio effect

If we assume that power plants need to provide the positive balancing power for both situations, the opportunity costs in each situation sum up for each power plant:

$$TotalOpportunityCosts(p) = \sum_{i=low,high} OpportunityCosts_i(p) \qquad , \forall p \in \{A, B, C\}. \tag{5.2}$$

This results in total opportunity costs of 20 EUR/MWh for each power plant. A coalition of two power plants could reduce the joint opportunity costs. Power plants A and B could cooperate, e.g. belong to the same operator. Then, in each situation the operator can provide balancing power by her power plant with the lowest opportunity costs. She would use plant A in the low demand situation, and plant B in the high demand situation. The joint opportunity costs for power plant A and B for both situations is 10 EUR/MWh, which is lower than the individuals' 20 EUR/MWh.

[4]We assume that power plants need to run in order to provide positive balancing power (e.g. due to minimum load or ramping constraints). If plants B and C would not need to run, their opportunity costs would be 0 EUR/MWh.

For the negative balancing power, this portfolio effect does not hold in general. The opportunity costs are 0 for inframarginal power plants and usually monotonically increasing for extramarginal power plants. This leads to monotonically increasing opportunity costs in each demand situation. The sum of monotonically increasing functions is still monotonically increasing. Thus, the cheapest power plants to provide negative balancing power are always in the left segment of the merit order and there is no possibility to get better off in a portfolio.

Note that we made some simplifying assumptions in this stylized example, e.g. we neglected part load efficiency decreases and attrition costs. We assumed the capacity provision and the minimum load capacity to be equal such that it cancels out for the calculation of the extramarginal opportunity costs. Furthermore, we assumed the balancing power demand to be comparably small such that the marginal power plant can fully provide the balancing power demand. All simplifying assumptions are relaxed and accounted for in the detailed optimization model.

The portfolio effect only occurs if balancing power is procured over a long time horizon that differs from the hourly spot market tender frequency. Here, large players may have significant cost advantages because they can provide balancing power at lower costs from their portfolio. For shorter time periods of balancing power procurement, the portfolio effect is reduced.

In Figure 5.3, an exemplary merit-order for Germany divided into the main operators is shown. Power plants that do not belong to the largest five companies are considered as power plants of a fringe.[5]

As previously explained, opportunity costs in the balancing power market do strongly depend on the intersection of supply and demand in the spot market. Therefore, to investigate market concentration, we need to consider the power plant portfolio of all operators in the merit order (cf. Figure 5.3). Fuel costs as well as capacities are based on the year 2014. Detailed numbers can be found in Table 5.4 in the appendix. We can see that several ranges of the merit order are covered by only a few operators. Especially, in the left part of the merit order, there are only two to three operators covering a range of up to several Gigawatts. These are operators owning nuclear and lignite power plants with high investment costs and low marginal costs.[6] Those ranges with few operators tend to favor market concentration. By

[5]Throughout the paper we use the following abbreviation for the operators: RWE (RWE), E.ON (EON), Vattenfall (VAT), STEAG (STE), EnBW (ENB), fringe (FRI).

[6]Note that the fringe at the right of the merit order does not cause higher market concentration because those plants do not belong to a single firm.

incorporating the operators and their power plant portfolio into our modeling, we are able to show the effect of different provision duration on market concentration.

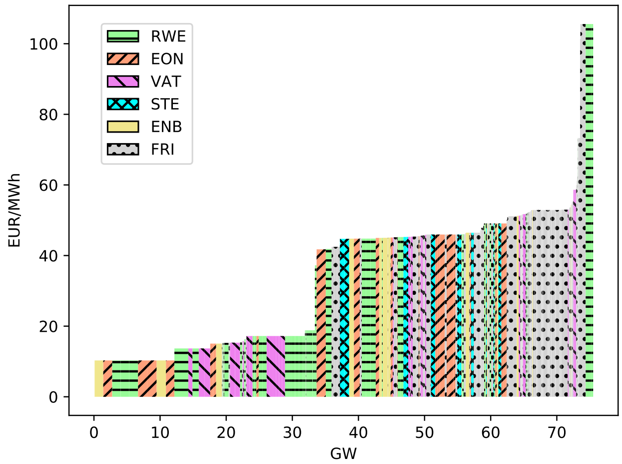


Figure 5.3: Merit order in Germany colored as to the operators

(capacity and cost data corresponds to the year 2014 and can be found in Appendix 5.6.1)

5.2.2 Market Concentration

In order to compare different levels of market concentration, we apply typical market concentration indices from the economic literature. Those indices are the Herfindahl-Hirschmann-Index (HHI, Hirschman (1964)) and the residual supplier index (RSI).[7]

The HHI uses the market shares of operators as an indicator for market concentration. It is defined as

$$HHI := \sum_{i=1}^{n} {MS_i}^2, \tag{5.3}$$

where MS_i is the market share of operator i in % and n the total number of opera-

[7] We do not focus on the pivotal supplier index (PSI) since the non-binary RSI is a refinement of the binary PSI. Furthermore, we do not investigate market concentration indices which involve prices, e.g. the Lerner-Index (Elzinga and Mills, 2011). Since we apply a mixed-integer model, prices cannot be easily derived from the results due to the convexity problem (Bjørndal and Jörnsten, 2008, Ruiz et al., 2012). Technical restrictions like minimum load or start-up costs in mixed-integer problems lead to non-convexities. Therefore, the marginal of the supply-demand-equilibrium cannot directly be interpreted as an estimator for electricity prices. Power plant specific variable costs can be above the system marginal costs of mixed-integer problems.

tors.[8] Note that we use the decimal representation of the market shares ($50\% = 0.5$). Therefore, our HHI index is in the range between 0 and 1. Comparably high market shares have a higher impact on the HHI due to the squared functional representation. If we would have only five operators in the electricity market, the HHI could not be lower than 0.2 which would be the case of equally shared capacity. Since we also consider a fringe in our numerical analysis, these lower bounds are not necessarily holding.

The RSI for operator x measures the remaining capacity without supplier x's capacity to fulfill the demand. It is defined as

$$RSI(x) := \frac{\text{TotalCapacity} - \text{Capacity}_x}{\text{demand}}, \tag{5.4}$$

where Capacity_x is the capacity of operator x (cf. Twomey et al. (2006)). In our analysis, we account only for active capacity which means capacity that is already operating. Non-operating capacities cannot provide balancing power in time or have additional start-up costs which make the opportunity costs not competitive. That means, if a power plant provides balancing power, it has to be operating (such that the production adjustment can be achieved) during the total provision duration. If pooling is allowed, this constraint is relaxed. In this case, the operator may shift the capacity within her power plant portfolio and hence is not dependent on the operation of a single power plant. The capacity of the operator in a weekly balancing power provision is defined by the minimum capacity of the operator's portfolio in the hours of the week. Note that HT and NT differentiation may apply. For comparison reasons, we focus on the inverse value, i.e. RSI^{-1}. Thus, similar to the HHI, a higher value indicates higher market concentration

The HHI represents a market concentration index based on the market share while the RSI represents a market concentration index based on the residual supply (remaining capacity). Both measures therefore give different insights on the level of market concentration.

[8] The HHI is broadly applied in energy economics, see for instance Hogan (1997) and Twomey et al. (2006). A general discussion on concentration indices can be found in Green et al. (2006).

5.3 Methodology

In this section, details of the basic modeling approach as well as data and assumptions are presented.

5.3.1 Modeling Approach

The analysis is performed with a unit-commitment model for the German power market.[9] The basic model formulation is based on the work by Ostrowski et al. (2012) and Morales-España et al. (2013) and is extended for the modeling of balancing power provision.

In this section, we explain the general modeling approach for unit-commitment models but abstract from the detailed formulation that can be found in the literature on unit-commitment models (e.g. Ostrowski et al. (2012) and Morales-España et al. (2013)). The focus is set on the introduction of additional equations that account for the characteristics of balancing power markets.

The overall goal of the unit-commitment model is to derive the cost minimal production schedule of power plants to satisfy the demand for electricity. Power plants are modeled blockwise with an hourly time resolution. Power plant blocks are denoted by the index p and hourly timesteps by the index t. The objective function of the unit-commitment model is to minimize the total costs of electricity production and can be expressed as

$$\min TotalCosts = \sum_{t,p} (VarCosts(t,p) + StartUpCosts(t,p)). \tag{5.5}$$

StartUpCosts arise if a power plant is not producing in time step t but produces electricity in time step $t+1$. The actual *StartUpCosts* are dependent on the power plant p as well as on the non-production duration (time steps since last time operating). Power plants produce electricity to satisfy the demand. This essential constraint is represented as

$$\forall sm: \qquad \sum_{p_{sm}} production(p_{sm}) + import(sm) - export(sm) = demand(sm), \tag{5.6}$$

[9] The model builds on the modelling framework **MORE** (**M**arket **O**ptimization for Electricity with **R**edispatch in **E**urope) that was developed at *ewi Energy Research and Scenarios gGmbH* and is written in GAMS (further information can be found at http://www.ewi.research-scenarios.de/en/models/more/).

and holds for every time step t and every spot market sm. Here, p_{sm} are the power plants in spot market sm, *import* considers the electricity flow from other countries (spot markets) to the respective one and vice versa for *exports*.[10] The exogenous demand is assumed to be perfectly inelastic.[11]

Technical characteristics of power plants are modeled via different constraints. An important modeling aspect of unit-commitment models is that they account for different states of power plants that can be incorporated by using binary variables. This makes the model a mixed-integer model. For example, each power plant has a range of feasible production which can be described by

$$production(p) = 0 \qquad \text{or} \tag{5.7}$$

$$minload(p) \leq production(p) \leq capacity(p). \tag{5.8}$$

Additional technical constraints of power plant blocks are also incorporated, such as part load efficiency losses, load change rates, combined heat and power operation and start up times. Part load efficiency is modeled via a convex function between the minimum load level and the full load level (according to Swider and Weber (2007)). This increases relative costs at reduced load levels due to part load losses compared to operation at full load operation. Load change rates determine technology specific ramping constraints that only allow for a certain adjustment of the power plants' production from one timestep to the next. Those constraints apply for ramp-up and ramp-down operations. We assume that the minimum load level corresponds to the grid synchronization. Thus, as soon as the power plant operates at the minimum load level, it feeds the production into the grid.

The basic model is extended to account for the unique characteristics of balancing power markets. These characteristics are essentially given by (i) different provision intervals and (ii) operator structures. We therefore need to map the hourly timesteps to the balancing provision intervals as well as the different power plant blocks to operators.

Table 5.1 gives an overview of the sets, parameters and variables used for the modeling of balancing power. In the following, the equations of the model will be discussed.

[10]In the analysis at hand, only the German spot market is considered. Imports and exports are given exogenously as explained later.

[11]If this assumption would be relaxed, we expect a similar outcome with respect to balancing power provision since the intersection point of demand and supply curve at the spot market, and hence the relevant opportunity costs would not change.

Table 5.1: Overview of sets, parameters and variables

Set	
BPi	interval for balancing power provision, e.g. week, day or hour
op	operator
t	hour
p	power plant
t_BPi	set of hours in the balancing power provision interval
p_OP	set of plants that belong to respective operator
FRI	Fringe operators
Parameters	
D(BPi)	balancing power demand in interval
Variables	
BP_O(BPi, op)	balancing power provision by operator in interval
BP(t, p)	balancing power provision by plant and hour
BP_F(BPi, p)	balancing power provided by fringe operators in the interval

The total demand for balancing power during a provision interval must be satisfied by the sum of the provision of all operators:

$$\forall \quad BPi : \sum_{op} BP\_O(BPi, op) = D(BPi). \tag{5.9}$$

The balancing power provision of all operators during a provision interval is constituted by the provision of the plants of the operators in each hour:

$$\forall \quad BPi, \quad t \in t\_BPi, \quad op : \sum_{p \in p\_OP} BP(t, p) = BP\_O(BPi, op). \tag{5.10}$$

The balancing power provision of the fringe during the provision interval is constituted by the fringe power plants without the option to pool:

$$\forall \quad BPi : \sum_{p \in p\_OP(\text{“}FRI\text{”})} BP_F(BPi, p) = BP\_O(BPi, \text{“}FRI\text{”}). \tag{5.11}$$

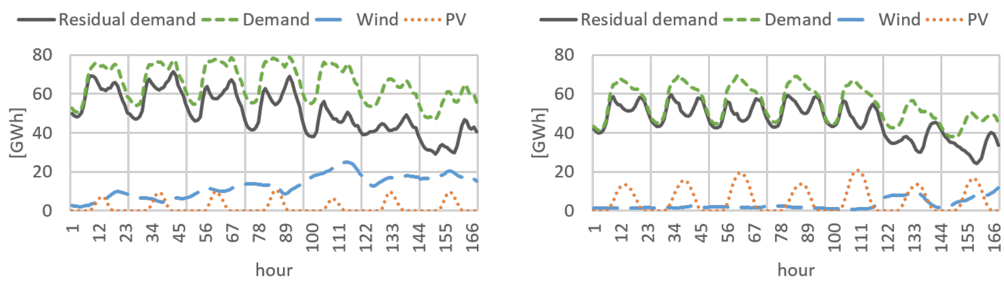
The power plant specific balancing power provision of fringe power plants is fixed in each hour of the provision interval:

$$\forall \quad BPi, \quad t \in t\_BPi, \quad p \in p\_OP(\text{“}FRI\text{”}) : \quad BP_F(BPi, p) = BP(t, p). \tag{5.12}$$

Thus, the model allows the fundamental modeling of power plants that provide balancing power accounting for the operator structure. However, calls of balancing power are not modeled. Model outputs are the hourly production per power plant, as well as, balancing power provision by operator and power plant. In combination with the operator structure, we can evaluate market concentration indices in an ex-post analysis.

5.3.2 Input Data and Assumptions

We model two representative weeks in 2014, i.e. a winter week and a summer week. Figure 5.4i shows the demand, residual demand, solar feed-in and wind feed-in during the winter week. This winter week represents a typical situation of high demand in the early evening hours combined with no or very few solar radiation during the day. Especially at the beginning of the week, the wind production is low as well. As a result, there are situations with a residual demand of up to 71.2 GW in which the conventional power plant fleet (nuclear and fossil power plants, pumped storage plants) is utilized up to 69.3%. In the last three days of the week, the residual demand is low due to low demand during the weekend and high wind feed-in. In such a situation of low residual demand, the base load power plants supply a large share of the spot market demand. Since the base load plants are owned by the large operators, situations with low demand may show a high market concentration in the spot market. This has implications for the market concentration on the balancing power markets as well.



(i) Winter week (Monday-Sunday)   (ii) Summer week (Monday-Sunday)

Figure 5.4: Demand, residual demand, solar feed-in and wind feed-in

Figure 5.4ii shows the demand, residual demand and renewable feed-in in the summer week. It can be seen that there is a contrast to the conditions of the winter week. The demand in the summer is typically low and there is high solar radiation during the day. This combination leads to a reduced utilization of the power plant fleet and therefore to lower prices. Here, even base load and mid load German power plants (lignite and hard coal power plants) reduce their production. Wind feed-in is on a relatively low level (below 10 GW in every hour), but increases during the weekend when the demand is already low. This leads to a low residual demand of only 24.3 GW on the Sunday.

Typical weeks during spring and autumn can be interpreted as a combination of the situations in the modeled weeks. The varying demand and renewable feed-in in every single hour of the modeled weeks cover a broad range of situations and therefore reflect also average situations with medium demand and/or renewable feed-in.

The assumptions on power plant capacities are based on Bundesnetzagentur (2015). Only German power plants are modeled. Imports and exports are exogenously given based on ENTSO-E data. Fuel costs and CO_2 prices are based on historical data. Installed capacities, fuel costs and techno-economic parameters of power plants can be found in the Appendix 5.6.1.

Power plants are also constrained in their balancing power provision. We consider primary and secondary balancing power in our model, but abstract from tertiary balancing power provision.[12]

We assume that all running plants can provide a certain share of their capacity as balancing power. For the fossil and nuclear power plants, this share is derived by information about the ramping speeds multiplied by the time duration until the power adjustment needs to be realized. The ramping speed deviates by the year of construction of the technology. Furthermore, we assume that the capacity (share) for positive balancing power is the same as for negative balancing power. Table 5.2 shows the maximum allowed share of the capacity to provide balancing power for different power plant technologies.[13]

[12] We do not consider tertiary balancing power since (i) technical restrictions are lower for the tertiary market, (ii) it tends to be compensated by the intraday-market (30 min before physical delivery), (iii) the current market design of tertiary balancing power has already a high tender frequency (provision duration of four hours), and (iv) there are many competitors in the tertiary market which reduces the risk of market power. Therefore, primary and secondary balancing power are in the focus of our analysis.

[13] Pumped storage plants have a high ramping speed. Therefore, they have a high technical potential to provide balancing power (up to 30 % of the capacity for the primary balancing power, and up to 45% for the secondary balancing power for a single plant). However, due to multiple bidding strategies and prequalification requirements, we assume that not all pumped storage plants are bidding their total technical potential into the balancing power markets.

Table 5.2: Share of total capacity that can be used for balancing power provision

	Primary Balancing Power	Secondary Balancing Power
CCGT	2.5 - 4%	25 - 40%
Coal	1 - 2.5%	5 - 12.5%
Lignite	1 - 2.5%	5 - 12.5%
Nuclear	2 - 2.5%	10%
OCGT	5 - 12.5%	50 - 60%
Oil	2%	20%
Pumped Storage	10%	15%

We assume that power plants that are not running have high starting costs, e.g. due to attrition and fuel consumption, and thus are not competitive in offering balancing power.[14] We do not consider balancing power provision by renewables and demand side management because those technologies were not important for the balancing power market in 2014 (Dena, 2014).

There is only one product that is procured for primary balancing power. However, in the case of secondary balancing power, we consider a positive and negative product for peak and off-peak times, respectively. Additionally we investigate the cases of shorter tendering times, namely daily and hourly. In the case of a weekly provision, the peak time are working days between 8 am and 8 pm. All other hours (night and weekends) are off-peak time. In the case of a daily provision, the peak time is the time between 8 am and 8 pm on every day (including weekends). In an hourly auction, the distinction between peak and off-peak products disappears.

We map the information about the ownership to each power plant. We consider the German power plant operators E.ON, RWE, EnBW, Vattenfall and STEAG in our model. All other power plants are mapped to the fringe. We obtain information about ownership of plants from a list of the German regulator Bundesnetzagentur.[15]

E.ON, RWE, EnBW, Vattenfall and STEAG can use pooling to provide balancing power over a time period, e.g. they can offer a certain volume of balancing power during the provision period and use different power plants within their pool to fulfill their commitment. The fringe is not allowed to pool meaning that each power plant

[14]Start-up costs for a cold start can be up to 60.000 Euro for e.g. a 500 MW CCGT or OCGT power plant with 2010 cost data (Schill, 2016). These costs would have to be reimbursed by the revenue in the balancing power markets. Additionally, a faster start-up than usually increases the attrition and has a higher consumption of equivalent operating hours (EOH).

[15]Each power plant is mapped to only one owner. This corresponds to the assumption that even if several owners have shares in one plant, only one owner is responsible for marketing balancing power.

of the fringe has to provide the balancing power of the whole provision period. This is the most restrictive assumption for the pooling of the fringe. Indeed, there are several pooling companies which aggregate smaller producers to a virtual power plant and therefore allow for pooling for subsets of the fringe. However, if we allow that the whole fringe may use pooling effects, the fringe would operate as an additional big producer. Therefore, we expect that the general results for market concentration hold and only the absolute level of market concentration deviates.[16]

5.4 Results

In this section, we present the model results for a weekly, daily and hourly provision duration. The weekly provision duration represents the status quo which is currently in operation in Germany. Daily and hourly provision duration are currently discussed as alternative market designs for the German balancing power market. We analyze the balancing power provision in three dimensions. First, we focus on the efficiency gains by a shortened provision duration which are captured in the total system costs. Second, we analyze the balancing power provision by technology and operator which enables us to shed light onto the level of market concentration for the different provision duration using the indices HHI and RSI^{-1}.[17]

5.4.1 System Costs

Power system costs of different model configurations are a benchmark for the efficiency of the market design. In order to assess the costs of balancing power provision, we additionally model the electricity system without balancing power provision. The difference between this baseline run and the model runs with balancing power provision can thus be considered as the extra costs of balancing power provision.[18]

[16] Furthermore, fringe power plants are typically gas fired power plants. Therefore, the effect on market concentration affects only situations with high residual demand as to the opportunity cost bidding strategy and the merit order.

[17] Note that we use RSI^{-1} instead of RSI. Thus, a higher value of RSI^{-1} indicates higher market concentration, similar to the interpretation of HHI.

[18] When referred to balancing power in this section, primary and secondary balancing power is meant.

Table 5.3 gives an overview of the total system costs in the simulated summer and winter week with different designs of the balancing power markets. Irrespective of if and how balancing power is provided, it can be seen that the system cost in the winter is more than EUR 50m higher than in the summer.

Table 5.3: Total system cost in reference scenario in million Euros

in mio. Euro	no provision	hourly	daily	weekly	weekly (no pooling)
Winter	175.6	176.7	176.8	177.0	178.0
Summer	124.6	125.1	125.2	125.2	125.6

As outlined above, the major power plant operators are allowed to pool their portfolio in order to provide balancing power. In order to quantify the efficiency gain resulting from pooling, a sensitivity with weekly balancing power provision in which pooling is not allowed is simulated additionally to a weekly configuration with pooling and hence included in Table 5.3.

The difference between the system costs without balancing power provision and the system costs of a configuration with hourly / daily / weekly balancing power provision can be understood as the respective costs of balancing power provision. Figure 5.5 illustrates those costs. It can be seen that not only the total modeled system costs are higher in winter, but also the costs of balancing power provision.[19]

If pooling would not be allowed, the cost of balancing power provision would be EUR 2.361m in the winter week and EUR 0.995m in the summer week. The modeled costs of the current weekly market design (with pooling of major operators) amount to EUR 1.328m in the winter week, and EUR 0.677m in the summer week. The cost difference between the weekly configuration with pooling and without pooling that can be interpreted as the efficiency gain of pooling is EUR 1.033m in the winter and EUR 0.319m in the summer.[20]

The difference between the system costs of a configuration with weekly balancing power provision and a configuration with hourly balancing power provision (from now on we only consider configurations with pooling) can be interpreted as the max-

[19] A higher residual demand level in the winter compared to the summer leads to higher total system costs. The relationship between the residual demand and the costs of balancing power provision is more complex: Depending on the steepness of the merit order, an increasing residual demand can increase the costs of balancing power provision by inframarginal power plants. However, low residual demand levels can lead to situations in which extramarginal power plants provide balancing power causing high costs of balancing power provision.

[20] An additional sensitivity analysis not included in figure 5.5 in which pooling of all fringe operators in one common fringe pool would be allowed shows no significant further efficiency gain.

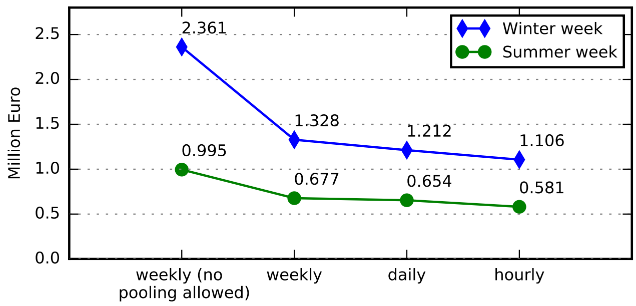


Figure 5.5: Costs of primary and secondary balancing power (compared to no provision)

imum efficiency gain from shortening the provision duration. This cost difference is EUR 222k in the winter week, and EUR 96k in the summer week.[21] The system costs of the daily balancing power provision are between the system costs for the hourly and weekly balancing power provision. Compared to the efficiency gain from pooling, this further efficiency gain by a shortened provision duration is small.

The level of renewable feed-in can influence those results. Therefore, we consider a sensitivity in which we double the values of the historically observed renewable feed-in in the simulated weeks. The detailed results are shown in Appendix 5.6.2. A higher renewable feed-in leads to higher costs of balancing power provision especially in the summer week compared to the configuration with less renewables. For instance, in the case of weekly provision in the summer, the balancing power costs increase by EUR 559k if the renewable feed-in doubles. Due to the lower and more volatile residual demand, more power plants have to be operational only in order to provide balancing power. The order of magnitude of the efficiency gain from pooling, however, remains unchanged by doubling the renewable feed-in.

The German expenses for the provision of primary and secondary balancing power was EUR 331m in 2014 (Bundesnetzagentur, 2016) corresponding to average expenses of EUR 6.37m per week.[22] This means that the average real expenses were higher than the simulated costs for the balancing power market with the weekly market design (EUR 1.328m in the winter and EUR 0.677m in the summer). Our model calculates *total costs* for power plants to provide balancing power under perfect competition and foresight. Those can be interpreted as a lower bound for pro-

[21]Due to solver inaccuracies (difference between current best integer solution and optimal value of LP relaxation), we cannot resolve the exact effect. However, we can be sure about the order of magnitude of the effect.

[22]This figure is calculated based on capacity bids, not energy bids. This is consistent with our modeling approach in which we consider only provision and not calling of balancing power.

ducers' costs for the balancing power provision. The Bundesnetzagentur publishes the *total expenditures* for the balancing power provision. These expenditures also include producers' surplus. If every operator would bid their real costs in the pay-as-bid auction (under perfect foresight and perfect information), both results should be the same. However, since it is profit maximizing for the operators to estimate and bid the system marginal costs instead of own marginal costs (see for instance Müsgens et al. (2014)), the real expenditures are higher than the modeled costs for provision. Furthermore, the exercise of market power (e.g. withholding of volumes) could even lead to higher system marginal costs and hence higher producers' surplus. Effects like strategic bidding between capacity and energy bid or sub-optimal behavior due to information asymmetries could further increase the cost difference between real expenditures and the model results. Additionally, uncertainty for e.g. residual demand, prices, and power plant shortages of the next week are included in the bids which increase costs. These aspects are not considered by the cost minimizing model under perfect foresight. Therefore, we would expect our results to be a lower bound for the possible cost reductions.

5.4.2 Provision of Balancing Power

Balancing power is provided by different types of power plants within the portfolio of operators. Depending on the portfolio of operators and the pooling within the portfolio, the balancing power provision by technology changes from hour to hour. This effect can be observed in the graphs in Figure 5.6i for different provision durations at the example of positive secondary balancing power in the winter week.

For the weekly provision, we see a strong hourly fluctuation within the technologies although operators are restricted to a weekly provision duration. This indicates that the operators make significant use of the pooling option. The operators can freely select the power plants that shall provide balancing power in certain hours of the week. Therefore, the operators choose those power plants in their portfolio which have the lowest opportunity costs with respect to the spot market. Here, obviously, operators with a large portfolio have an advantage compared to small operators. For primary balancing power as well as for the case of the summer week, the fluctuation of balancing power providing technologies are similar to the Figure 5.6i.

If we take a look at the provision by technology for daily or hourly provision duration, we find a surprisingly similar structure to the weekly provision duration. However, small differences in the diagrams can be identified. CCGT, for instance, have a more important role in peak hours with the hourly provision compared to the outcomes with longer provision duration. In the daily configuration, coal power plants provide more often balancing power compared to the other configurations. The hourly provision duration can be expected to be the efficient benchmark in which the owner structure of power plants does not matter. This means that the most cost efficient power plants in each hour provide balancing power. Since the capacity provision by technology of the weekly and daily cases are similar to the hourly benchmark, we conclude that the pooling possibilities allow a provision pattern that is close to the most efficient outcome. Even with a weekly provision duration, almost the same cost efficient technologies provide balancing power as in the case with an hourly provision. Except from the shown technology classes in Figure 5.6i, no other modeled technologies provide balancing power.[23] This interpretation is in line with the results presented in Section 5.4.1 where the efficiency gain from pooling was quantified to be EUR 1.382m in the winter week whereas the respective efficiency gain from shortening the provision duration from a weekly to an hourly market design was found to be EUR 0.222m.

Figure 5.6ii shows the modeled capacity provision by operator for positive secondary balancing power for a weekly, daily and hourly provision duration.[24] Compared to the modeled provision by technology, the modeled provision by operators differs more significantly for the three market designs. The fluctuation of market shares becomes higher with a shorter provision duration.

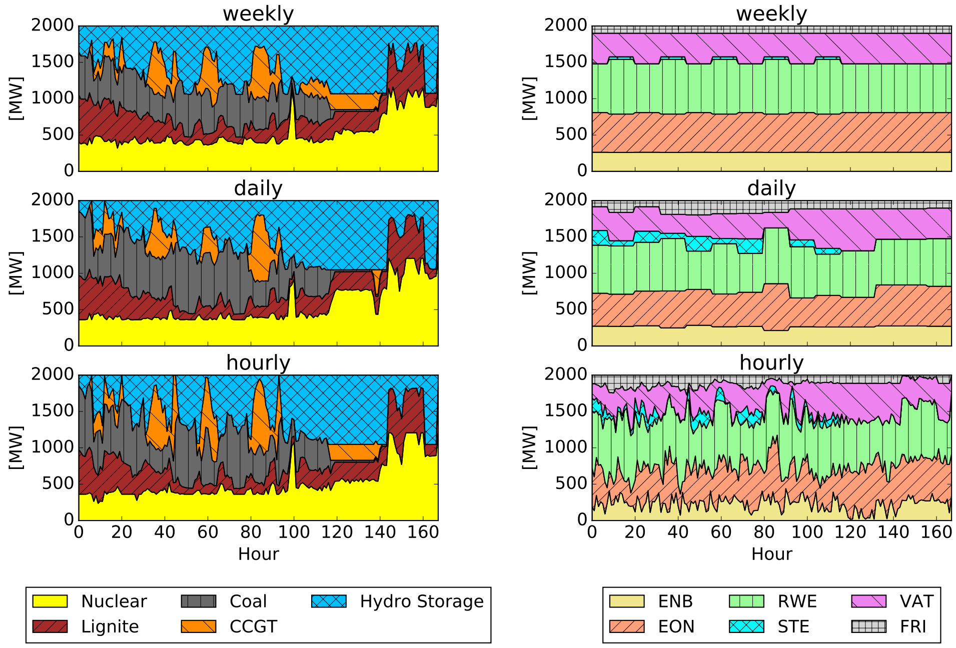
The capacity provision by operator can be considered as a first indicator for the market concentration indices. Therefore, we expect stronger fluctuation of the market concentration indices for shorter provision duration. Drivers for this are:

- the absolute residual demand level at a given time point in the time frame,
- the volatility of the residual demand level in the provided time frame,
- the steepness of the marginal cost function of the power plants and therefore the steepness of the opportunity cost function,
- the operator structure of the opportunity cost function, i.e. whether operators' capacities are in blocks or spread in the opportunity costs merit order.

Thus, the capacity provision by operator is typically dependent on the specific

[23]This result does not only hold for the case of positive secondary balancing power, but also for the other investigated products.

[24]In Appendix 5.6.3, diagrams analogous to Figure 5.6 are shown for the other modeled balancing power products and weeks.



(i) Provision by technology

(ii) Provision by operator

Figure 5.6: Comparison of the technologies (left) and operators (right) providing positive secondary balancing power for the weekly, daily and hourly provision duration in the winter week (model results)

market circumstances, e.g. the product definition, the annual season, and the provision duration. Hence, we investigate the different market designs based on market concentration indices in detail to derive further insights.

5.4.3 Market Concentration

Based on the balancing power provision by operator observed in Figure 5.6ii we compute market indices for the three balancing power products, primary, secondary positive and secondary negative balancing power. The indices vary depending on the market design and provision duration. In order to assess the different ranges of market concentration indices, we analyze the model results in histograms for the HHI (cf. Figures 5.7, 5.9 and 5.10). Those diagrams show the HHI values in the weekly market design as a solid red line. In the case of secondary balancing power, two solid red lines are present due to the two contract durations (HT and NT, as described in Section 5.2). For the hourly provision duration, 168 different products are defined and hence 168 HHI values. The histograms show the distribution of those hourly HHI values. Similar histograms for the RSI^{-1} are evaluated (cf. Figure 5.8, Figure 5.17 and Figure 5.18).[25]

For the interpretation of the results, we also add dotted lines into the histograms, which indicate threshold values for high market concentration. For the HHI, a strong market concentration exists at a value of 25% according to US Department of Justice, Federal Trade Commission (2010, §5.3) and at 20 % (with further restrictions) as to EUR-lex (2004, 19. and 20.). In the case of the RSI^{-1} we consider a threshold value of 1.11 (which corresponds to a threshold value of 0.9 for the original RSI definition).

The indices are no absolute measures, i.e. a specific index would not be sufficient to indicate market concentration. Nevertheless, high market concentration is more likely if both discussed indices point to a critical level.

Market Concentration for Primary Balancing Power Provision

For the modeled provision of primary balancing power, the HHI values are displayed in Figure 5.7. We observe that the summer seems to be slightly more concentrated in balancing power provision than the winter. The reason for this lies in the different demand profiles and the increasing production of solar generation (cf. Figure 5.4i). In the summer, a lower electricity demand and higher solar generation lead to less demand for generation from conventional power plants and therefore there are less power plants available (i.e. running) that are able to provide primary balancing power. This is also indicated by high values of the RSI^{-1} that can be seen in Figure 5.8.

Based on the model results we can infer that the primary balancing power market is prone to high market concentration. When the market design is changed from weekly provision to hourly provision we observe that the indices take on a broader range of values. This means there are hours in which market concentration is increased and hours when market concentration is lowered. An increase in market concentration may occur if the level of demand is at a level where only few operators are close to the marginal production level. As previously explained in Section 5.2 and shown in Figure 5.3, there are intervals in the merit order where only some op-

[25] Additionally, an analysis for the concentration ratio CR1 and CR3 was conducted. The CR for m firms is defined as $CR(m) := \sum_{i=1}^{m} MS_i$ where MS_i is the market share of operator i in % for the m largest firms. The analysis for CR1 and CR3 did not lead to different conclusions compared to the analysis based on HHI and RSI^{-1}. Furthermore, the CR as an market share concentration index is similar to the HHI and thus to some extent redundant.

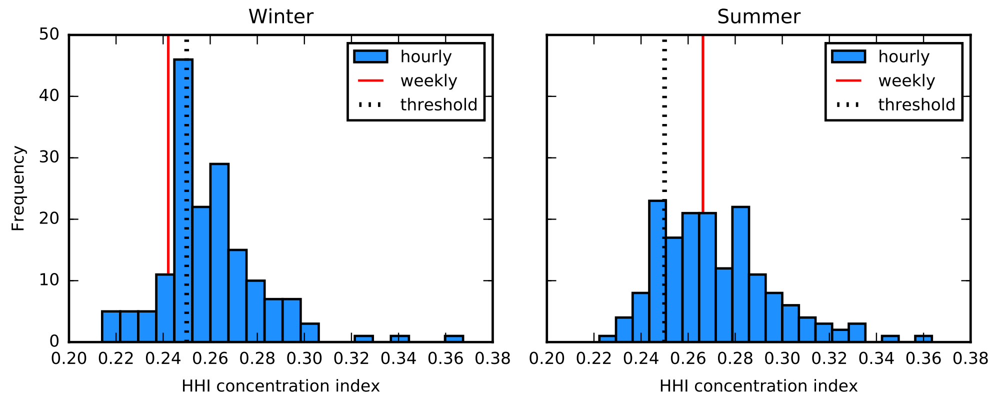


Figure 5.7: Histogram of the hourly HHI values for primary balancing power in winter week (left) and summer week (right)

erators own power plants. This is for example the case for lignite power plants that are owned by Vattenfall and RWE. When demand is low and lignite power plants are marginal in their production, they can provide balancing power at lowest cost. Since this effect only depends on one single demand period in the hourly provision case instead of multiple demand periods in the weekly design, the modeled market concentration increases in some hours. In addition, market concentration is higher in the summer because of lower demand levels and therefore less conventional power plants that are operating. The baseload power plants that are still operating are owned by fewer operators which increases market concentration.

There is no clear trend observable to conclude whether shorter provision duration structurally mitigates or favors market concentration. The RSI^{-1}, however, that can be seen in Figure 5.8 decreases in average with shorter provision duration especially in the winter week. This means that the average market concentration is reduced because there is more active capacity that could provide balancing power. Nevertheless, there are some hours when the RSI^{-1} indicates a slightly higher concentration compared to the weekly provision. In the winter, the hourly market design leads to RSI^{-1} values below the threshold in most hours. In the summer, however, the RSI^{-1} can only be decreased below the threshold in some hours. Based on the model results, the primary balancing power market seems to be highly concentrated such that even in the case with an hourly balancing power provision the average market concentration in the summer is still modeled as critically high.

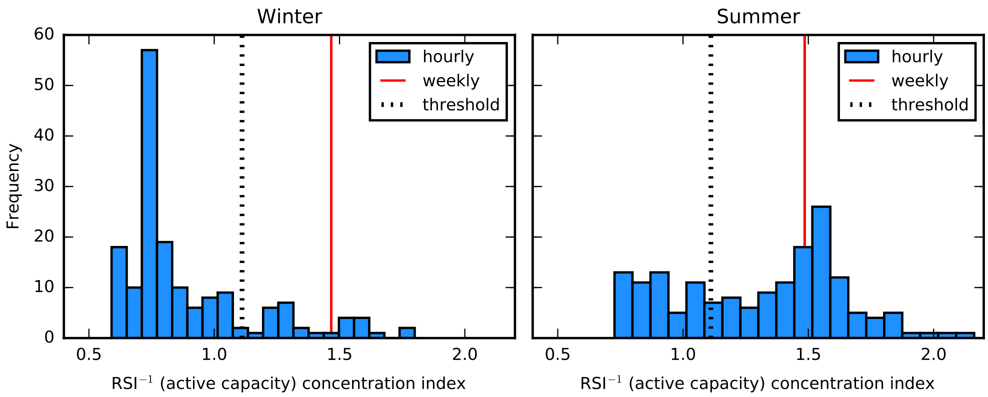


Figure 5.8: Histogram of the hourly concentration index RSI^{-1} for primary balancing power in winter week (left) and summer week (right)

Market Concentration for Positive Secondary Balancing Power Provision

Whereas primary balancing power is mostly provided by baseload power plants that are able to increase and decrease their generation, secondary balancing power is divided into positive and negative balancing power. In the case of positive balancing power, power plants provide the ability to increase their generation when being called. For the winter we see the respective technology and operator mix in Figure 5.6. The result for the summer week is similar which is the reason why it is not shown additionally. The main difference between the summer and the winter week is that more lignite power plants provide balancing power in the summer week instead of CCGTs in the winter week. Especially the high provision of balancing power from lignite power plants leads to a high market share by RWE and Vattenfall.

The market concentration indices in Figure 5.9 show a high market concentration based on the HHI. Here, again, concentration seems to be higher in the summer compared to the winter. Nevertheless, the story is a bit different compared to the provision of primary balancing power because in the case of positive secondary balancing power there is a larger proportion of active power plants that could potentially provide balancing power. The respective RSI^{-1} indicates that the market is not too concentrated because the providing power plants could be replaced by the provision from power plants that are currently not delivering balancing power (the histogram for the RSI^{-1} can be found in the Appendix). Therefore, the market can be considered as not as concentrated compared to the primary balancing power market. When the provision duration is lowered to an hourly level, the average modeled market concentration based on the RSI^{-1} is further reduced. In the case of the HHI, there is, however, no clear evidence for a reduction in average market concentration by reducing provision durations. There are single hours with very high modeled market concentrations in the hourly case.

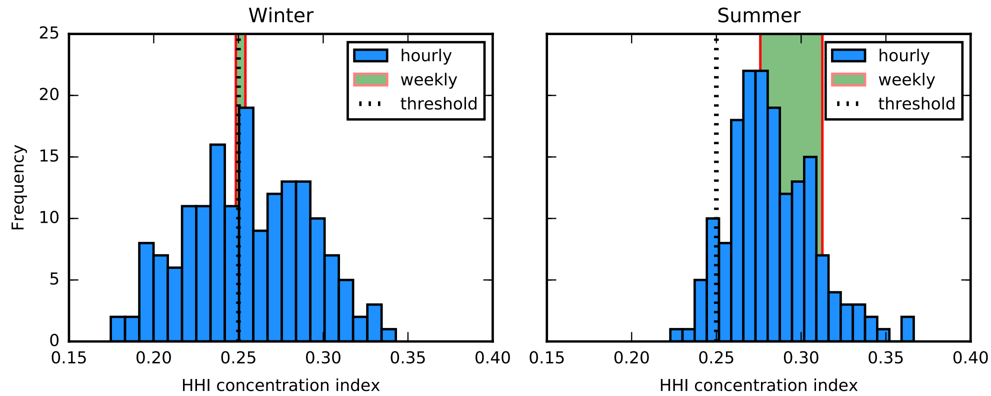


Figure 5.9: Histogram of the hourly HHI values for positive secondary balancing power in winter week (left) and summer week (right)

Market Concentration for Secondary Negative Balancing Power Provision

The HHI values for secondary negative balancing power that can be seen in Figure 5.10 have similar characteristics as the values for the positive secondary balancing power. Nevertheless, in the negative secondary balancing power market, we would expect no abuse of market power even with a high market concentration. The rationale for this is as follows: As to Section 5.2, the costs for capacity bids for balancing power are driven by opportunity cost compared to the spot market. Thus, for one hour, all operating power plants have zero costs for offering negative balancing power. For a longer provision duration, the costs would increase if the power plant would not be inframarginal all the time. However, due to pooling effects, operators can choose power plants which are operating in a specific situation. Therefore, the opportunity costs for each provider can be assumed to be (almost) zero. Many fringe operators can potentially participate in the auction since e.g. wind producers could also provide negative balancing power. This means that the resulting supply curve for negative balancing power is very flat. If operators would try to withhold quantities in an attempt to increase prices, fringe operators with similar small costs would provide the balancing power. Hence, prices of (almost) zero for negative balancing power should be the consequence. Note that in reality, there is uncertainty (e.g. power plant outages) which leads to slightly positive capacity bids. With our model, we can find the cost minimal provision of balancing power but we would expect fierce competition. Therefore, even high shares of market concentration that can be observed in the model results should not lead to the abuse of market power because all providers face the same low level of opportunity costs. This argumentation is supported by the results on the RSI concentration index for negative balancing power (cf. Appendix 5.6.4, Figure 5.18), where most situations point to sufficient available active capacities to mitigate market concentration.

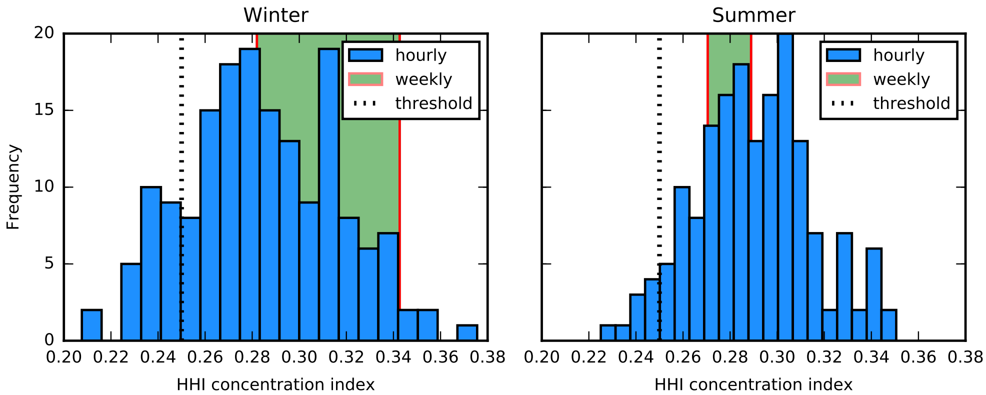


Figure 5.10: Histogram of the hourly HHI values for negative secondary balancing power in winter week (left) and summer week (right)

5.4.4 Influence of additional Demand Response on the Market Concentration

A shortened provision duration relaxes the provision duration constraint and potentially leads to dynamic market entries, e.g. by demand response technologies. The participation of demand response in US real-time balancing markets is well investigated, see for instance Heffner (2008), Vlachos and Biskas (2013) or Wang et al. (2015). In order to gain insights into the role of additional demand response technologies in our case, we model a sensitivity with additional 2.000 MW of pump storage. In the model rationale, pump storage capacity has the same features as flexible demand response processes or local storage applications. We model the capacity belonging to the fringe operators which reflects the assumption of competitively acting small operators. As expected, the average market concentration in the hourly market design is reduced in the sensitivity compared to the corresponding case without the additional capacity. However, the main observation of the market concentration analysis is found in the sensitivity as well, i.e. that there are hours with higher market concentration in the hourly market design compared to the weekly market design. This holds true for primary balancing power as well as for secondary balancing power.

5.5 Conclusion

Currently, the German primary and secondary balancing power markets have a weekly tender frequency. In a weekly market design, large power plant operators make use of pooling within their portfolio in order to provide balancing power. Fringe operators, however, do not have pooling options and need to withhold the capacity of their plants from the spot market for a whole week to provide balancing power which can lead to inefficiencies. Hence, fringe operators could potentially benefit from a shortened provision duration. The analysis at hand focuses on (1) efficiency gains from a shorter provision duration in primary and secondary balancing power markets, and (2) market concentration in market designs with different provision duration. Since it is known from the literature that simultaneous equilibria in spot and balancing power markets are efficient and unique (Richter, 2012), our methodology is based on a cost minimizing unit-commitment model for the electricity market in which we account for the ownership of power plants.

We quantify the efficiency gain from allowing pooling in a weekly market design to be EUR 1.033m in a winter week and EUR 0.319m in a summer week. Compared to this, the further efficiency gains that can be realized by shortening the provision duration from a week to an hour are small. An hourly market design would lower the costs of balancing power provision by EUR 222k in a winter week and EUR 96k in a summer week. Relative to the total simulated cost of balancing power provision in the weekly market design with pooling, the efficiency gain is 17% in the winter week, and 14% in the summer week.

Besides the efficiency gains, we identify effects on the market concentration. Here, we investigate the HHI and RSI^{-1} indices, which are based on the market share and the residual supply, respectively. According to the model results, we see the potential for high market concentration in the primary balancing power market due to the technical requirements power plants need to fulfill in order to participate in this market. In the market for positive secondary balancing power, the model results indicate less concentration because there is more available capacity that could potentially replace the providing power plants. For the negative secondary balancing power, our results are quantitatively similar to the other products. However, we consider concentration in the market for negative balancing power not to be an issue due to the low opportunity costs for providing negative balancing power. Based on the model results, we find a higher market concentration in the summer than in the winter in all considered markets. The higher market concentration in the summer is driven by a lower level of demand, which reduces the number of active power plants and also the number of operators that are providing balancing power.

Our results reveal a tendency towards decreasing average market concentration by shortening the provision duration. However, the market concentration indices take on a broader range of values in the case of a shorter provision duration depending on the residual demand level and its volatility. There are single provision periods with a very high market concentration in the hourly market design that could favor the potential for market power abuse.

Although market concentration can be an indicator for market power, it does not necessarily identify market power. The characteristics of the supply curve for balancing power determine the potential for market power abuse. If high market concentration is found in a flat segment of the supply curve, prices cannot be raised significantly. The goal of further research should be to comprehensively understand market imperfections in balancing power markets which is a prerequisite for conducting a comprehensive cost-benefit analysis for changes in market design like shortening of provision periods. Besides market concentration, aspects like e.g. strategic bidding between capacity and energy bid and uncertainty about the renewable feed-in or demand should be considered.

As a policy implication, we recommend to monitor market concentration and price levels carefully after a change of the market design in the balancing power market. In specific situations, single operators may have a cost advantage compared to their competitors.

5.6 Appendix

5.6.1 Input Data for Modeling

Since we model the year 2014, we are able to use realistic data according to publicly available sources. Assumptions that are made are in line with typical assumptions for modeling the electricity market in Germany. The installed power plant capacities of different fuel types are shown in Table 5.4 and are based on Bundesnetzagentur (2015).[26] Additionally, Table 5.4 shows the assumed fuel costs and the CO_2 emission coefficients by fuel. We assume those costs to be static over the whole year. The CO_2 emission certificates are assumed to have a price of 6.2 EUR/t CO_2. The fuel costs of pumped storage are based on opportunity costs.

Table 5.4: Model inputs: Installed capacity in Germany for 2014, fuel costs, costs for CO_2 emissions certificates, and CO_2 emission coefficients

	Capacity [GW]	Fuel Costs [EUR/MWh$_{therm}$]	CO_2 Emission Coefficient [t CO_2 / MWh$_{therm}$]
Nuclear	12.1	3.6	0
Lignite	21.3	1.5	0.404
Coal	25.5	13.2	0.399
Gas	26.9	22.8	0.202
Oil	2.4	49.4	0.281
Pumped Storage	6.4	(opportunity costs)	0
Others	1	22.8	0.202
PV	32.7	0	0
Wind onshore	31.4	0	0
Wind offshore	0.4	0	0
Biomass	7.5	31.8	0
Hydro	4.4	0	0

Table 5.5 shows the assumed technical power plant parameters (particularly dependent on the year of construction).

[26] The actual input of installed capacities is further separated as to the year of construction: This gives further technical characteristics and parameters like full load and part load efficiency. The newer a power plant, the better are its technical parameters.

Table 5.5: Techno-economic parameters for conventional power plants

	Net efficiency full-load [%]	Fixed operating and maintenance costs [EUR/kW/a]	Availability [%]	Start-up time [h]	Minimum part-load [%]
Coal	37 - 46	36 - 54	84	4 - 7	27 -40
Lignite	32 - 47	43 - 65	86	7 - 11	30 - 60
CCGT	40 - 60	28	86	2 - 3	40 - 70
OCGT	28 - 40	17	86	0.25	40 - 50
Nuclear	33	97	92	24	45
Biomass	30	165	85	1	30

5.6.2 Robustness Checks

As a robustness check, a model run is considered in which the values of renewable feed-in is doubled. Table 5.6 gives an overview of the total system costs, and Figure 5.11 illustrated the costs for providing primary and secondary balancing power compared to a model run without balancing power provision.

Table 5.6: Total system cost in scenario with doubled renewable feed-in in million Euros

in mio. Euro	no provision	hourly	daily	weekly	weekly (no pooling)
Winter	131.6	132.8	132.9	133.0	134.1
Summer	102.4	103.5	103.5	103.6	104.3

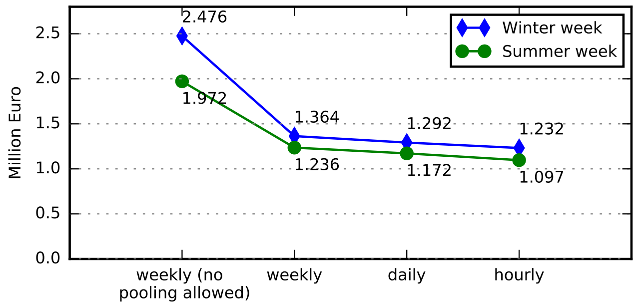
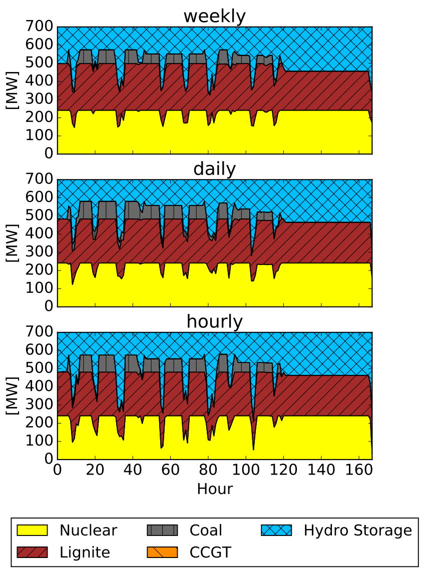


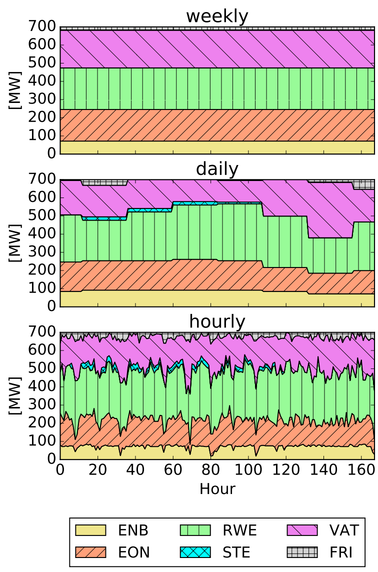
Figure 5.11: Costs of primary and secondary balancing power (compared to no provision) in scenario with doubled renewable feed-in

5.6.3 Balancing Power Provision by Technologies and Operators

The following diagrams are the illustrations analogous to Figure 5.6 for the primary balancing power in the summer and winter week, positive secondary balancing power in the summer week and negative balancing power in the summer and winter week.

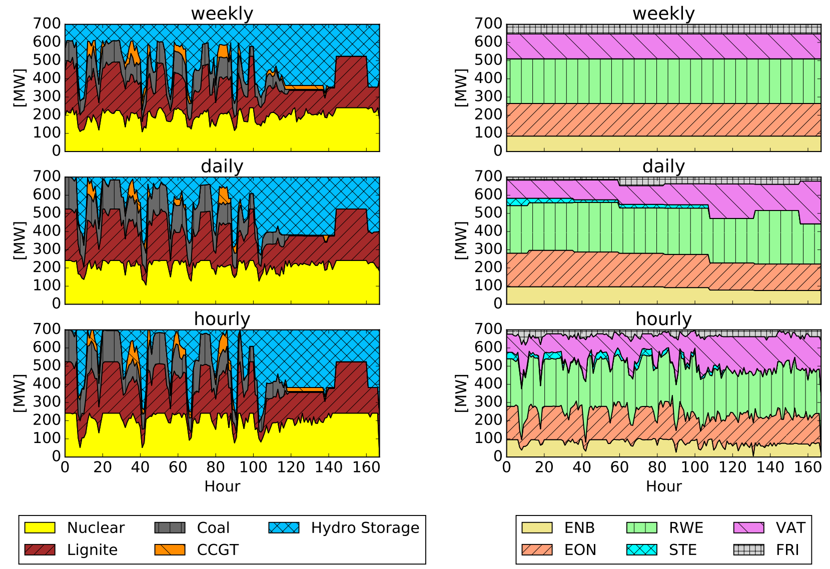


(i) Provision by technology



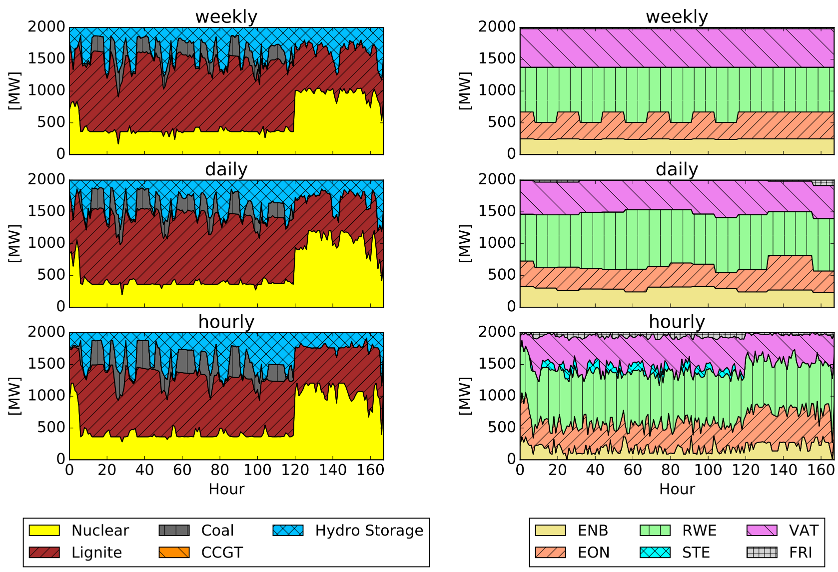
(ii) Provision by operator

Figure 5.12: Comparison of the technologies (left) and operators (right) providing primary balancing power for the weekly, daily and hourly provision duration in the summer week (model results)



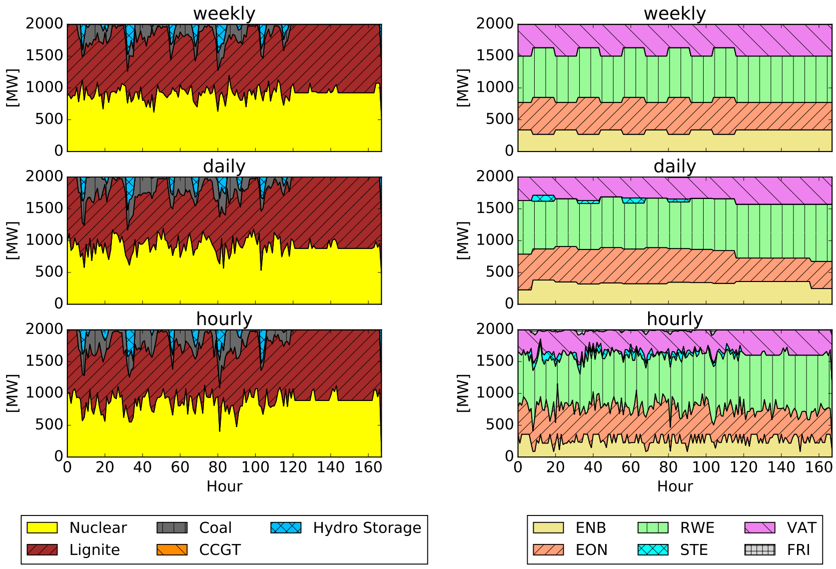
(i) Provision by technology (ii) Provision by operator

Figure 5.13: Comparison of the technologies (left) and operators (right) providing primary balancing power for the weekly, daily and hourly provision duration in the winter week (model results)



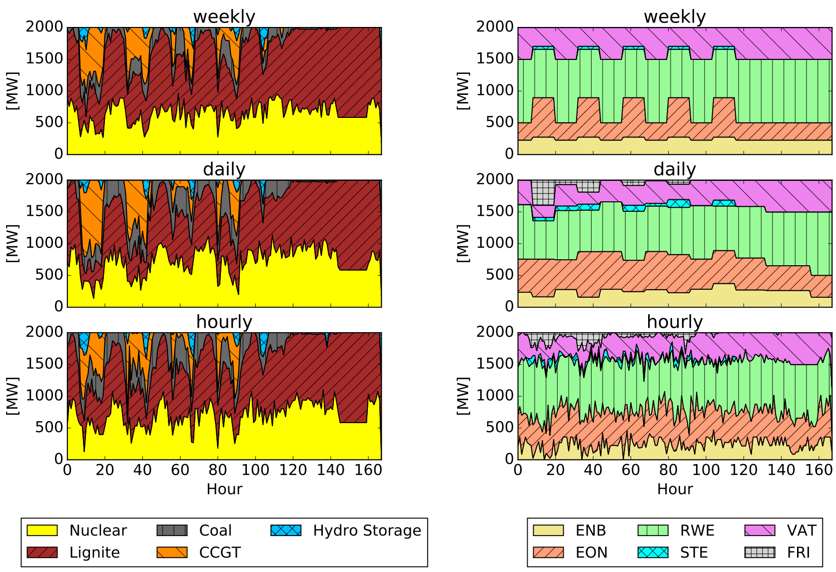
(i) Provision by technology (ii) Provision by operator

Figure 5.14: Comparison of the technologies (left) and operators (right) providing positive secondary balancing power for the weekly, daily and hourly provision duration in the summer week (model results)



(i) Provision by technology (ii) Provision by operator

Figure 5.15: Comparison of the technologies (left) and operators (right) providing negative secondary balancing power for the weekly, daily and hourly provision duration in the summer week (model results)



(i) Provision by technology (ii) Provision by operator

Figure 5.16: Comparison of the technologies (left) and operators (right) providing negative secondary balancing power for the weekly, daily and hourly provision duration in the winter week (model results)

5.6.4 RSI Concentration Index for Secondary Balancing Power

Figure 5.17 and 5.18 show the RSI^{-1} market concentration indices for secondary balancing power (positive and negative, respectively). Values above the threshold of 1.1 point to high market concentration situations in which one supplier might be pivotal. It becomes obvious that in most situations, enough (active) capacity is available. The situation is more critical in the modeled summer than winter week.

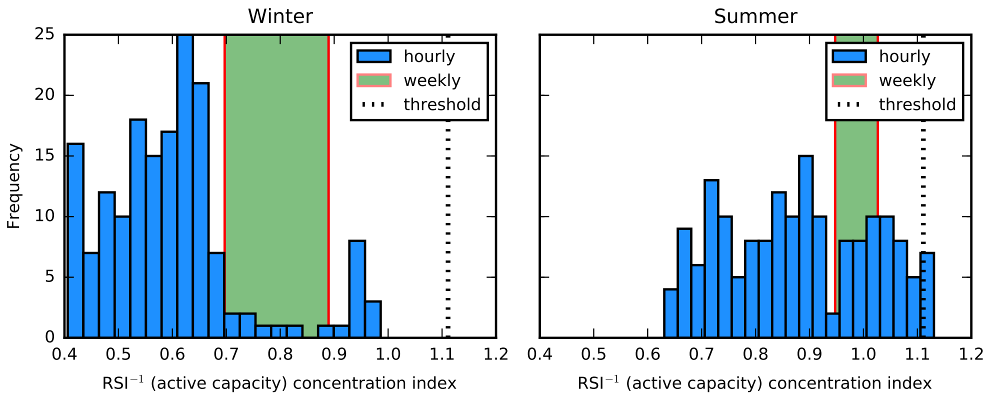


Figure 5.17: Histogram of the hourly concentration index RSI^{-1} for positive secondary balancing power in winter week (left) and summer week (right)

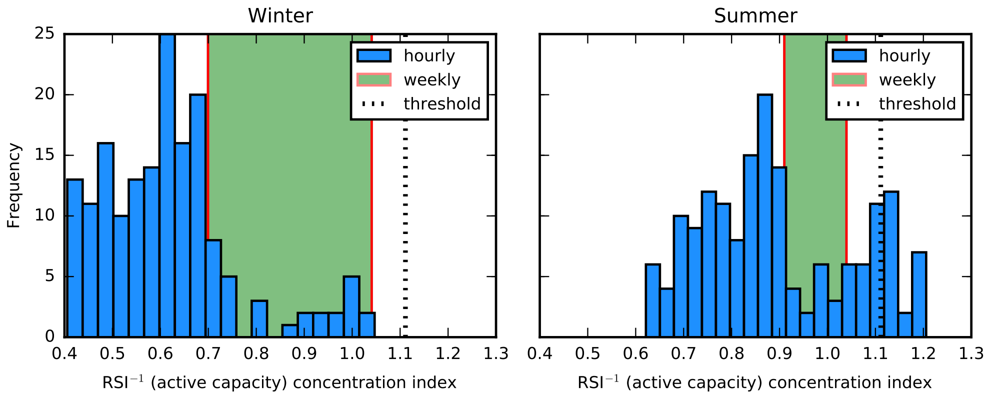


Figure 5.18: Histogram of the hourly concentration index RSI^{-1} for negative secondary balancing power in winter week (left) and summer week (right)

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- H. Hecking, C. John, F. Weiser (2015). An Embargo of Russian Gas and Security of Supply in Europe. *Zeitschrift für Energiewirtschaft*, 39:63–73. DOI 10.1007/s12398-014-0145-9.
- R. Kümmel, D. Lindenberger, F. Weiser (2015). The Economic Power of Energy and the Need to Integrate it with Energy Policy. *Energy Policy*, 86:833-843. DOI 10.1016/j.enpol.2015.07.026.

Working Papers:

- S. Schulte, F. Weiser (2017). Natural Gas Transits and Market Power – The Case of Turkey. *EWI Working Paper* 17/06.
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Conference Proceedings:

- M. Richter, F. Möllenbruck, F. Obermüller, A. Knaut, F. Weiser, H. Lens, D. Lehmann (2016), Flexibilization of Steam Power Plants as Partners for Renewable Energy Systems. *Conference Proceedings 20th Power Systems Computation Conference*.

Conference Presentations:

- Impacts of Nord Stream 2 on the EU natural gas market. *ENERGETIKA XXI: Economy, Policy, Ecology*. November 2017. Saint Petersburg, Russia.
- Natural Gas Transits and Market Power - The Case of Turkey. *40th IAEE International Conference*. June 2017. Singapore, Singapore.
- Tender Frequency and Market Concentration in Balancing Power Markets. *39th IAEE International Conference*. June 2016. Bergen, Norway.

JOURNAL REFEREE

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