

# Supply disruptions and regional price effects in a spatial oligopoly - an application to the global gas market

## AUTHORS

**Christian Growitsch**  
**Harald Hecking**  
**Timo Panke**

EWI Working Paper No. 13/08

June 2013

**Institute of Energy Economics  
at the University of Cologne (EWI)**

Alte Wagenfabrik  
Vogelsanger Str. 321  
50827 Cologne

Tel.: +49 (0) 221 277 29-100  
Fax: +49 (0) 221 277 29-400  
[www.ewi.uni-koeln.de](http://www.ewi.uni-koeln.de)

## Corresponding Author

**Harald Hecking**

Institute of Energy Economics at the University of Cologne (EWI)  
Tel.: +49 (0) 221 277 29-221  
Fax: +49 (0) 221 277 29-400  
[harald.hecking@ewi.uni-koeln.de](mailto:harald.hecking@ewi.uni-koeln.de)

ISSN: 1862-3808

The responsibility for the working papers lies solely with the authors. Any views expressed are those of the authors and do not necessarily represent those of the EWI.

# Supply disruptions and regional price effects in a spatial oligopoly - an application to the global gas market

Christian Growitsch\*

Harald Hecking\*

Timo Panke\*

June 7, 2013

Supply shocks in the global gas market may affect countries differently, as the market is regionally interlinked but not perfectly integrated. Additionally, high supply-side concentration may expose countries to market power in different ways. To evaluate the strategic position of importing countries with regard to gas supplies, we disentangle import price components into increasing and decreasing factors. Due to the complexity of the interrelations in the global gas market, we use an equilibrium model programmed as a mixed complementarity problem (MCP) and simulate the blockage of LNG flows through the Strait of Hormuz. This enables us to account for the oligopolistic nature and the asymmetry of the gas supply. We find that Japan faces the most severe price increases, as the Japanese gas demand completely relies on LNG supply. In contrast, European countries such as the UK benefit from good interconnection to the continental pipeline system and domestic price-taking production, both of which help to mitigate an increase in physical costs of supply as well as in the exercise of market power.

*Keywords:* Natural gas market, security of supply, international trade, mixed complementarity problem

*JEL classification:* C61, L72, Q34, Q41

---

\* Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321, 50827 Cologne, Germany. E-mail: harald.hecking@ewi.uni-koeln.de.

We would like to thank Felix Höffler and Johannes Trüby for their helpful comments and suggestions.

## 1. Introduction

International resource markets link more and more of the world's economies. As interdependence increases, regional supply shocks, such as disruptions of trade flows caused by, e.g., geopolitical conflicts, may be of global relevance. The global oil market, for example, has seen several of such supply shocks in history, among the most prominent conflicts being the First Gulf War in 1991 as well as the Iraq War in 2003, which have had a significant influence on oil prices. Due to the high level of integration within the global oil market, these regional conflicts caused global price shocks that affected countries all over the world.

A notable example of a resource market that is not highly integrated on a global scale is the natural gas market. Imperfect global integration is indicated by high regional price differences, e.g., between Asia and the United States. In a partially integrated market, price effects may be globally dispersed, as different regions of the world have different supply structures. In particular, domestic resources, import diversification, trade relations with small fringe producers and contractual supply agreements may be factors limiting price shocks.

One recent example of such a supply shock was the Russian-Ukrainian gas crisis in 2009. Whereas European gas prices significantly increased during the crisis, US gas prices, for example, were not affected at all. Apart from the longer existence of the global oil trade, the main reason for the lower level of global natural gas market integration is that transport of LNG, including liquefaction and regasification, is more complex and costly compared to that of crude oil. However, imperfect regional price arbitrage is not the only issue influencing the economic effects of supply shocks. Additionally, the supply side of the global gas market is characterised by high market concentration. Thus, the demand side does not only face the risk of rising prices due to a supply shock, but also may be exposed to increasing market power during the shock.

Regional differences in supply structures and demand flexibility are important in the global natural gas market. For example, the US has become almost independent of gas imports because of rising shale gas production, while Japan continues to rely solely on LNG imports. Additionally, Japanese natural gas demand has become more and more inflexible as the post-Fukushima reduction in nuclear power generation is compensated by higher utilisation of remaining coal and natural gas-fired power plants. This reduces the fuel-switching potential of the Japanese electricity sector to a minimum. Another important feature of the global gas market is that the supply side of international gas

trade is rather concentrated, as large state-owned companies such as Gazprom (Russia), Sonatrach (Algeria), Statoil (Norway) or Qatargas (Qatar) control significant export volumes. Moreover, natural gas requires a specific infrastructure to be transported, either via pipelines or the LNG value chain. Since gas is sometimes transported thousands of kilometres, often crossing different countries or crucial waterways, trade flows are highly vulnerable to be disrupted. As previously mentioned, the Ukrainian gas crisis in 2009 had only a regional effect on European gas prices. One example for a gas supply disruption that could have a global relevance is a potential blockage of the Strait of Hormuz.

The Strait of Hormuz is a passage, 21 nautical miles wide, connecting the Persian Gulf with the Indian Ocean. In 2011, 17 million barrels of oil or 20% of global trade volumes were shipped through this channel per day. What is often left out in public debate is the fact that the Strait of Hormuz is of crucial geostrategic significance, not only for the crude oil market but for the global trade of liquefied natural gas (LNG) as well. LNG exports from the Persian Gulf, i.e., from Qatar (77.4 bcm) and the United Arab Emirates (7.8 bcm), accounted for 29% of worldwide LNG trades in 2010 (IEA, 2011a). Moreover, in contrast to oil transport, there is no opportunity to bypass the crucial waterway by means of pipeline transport. Consequently, LNG volumes shipped through the Hormuz Strait are already critical and their importance is likely to increase considerably in upcoming years as gas demand in Asia is expected to strongly increase. In fact, the International Energy Agency (IEA) projects a doubling of gas demand based on 2011 values in China and India by 2017. The world's two largest LNG importers are Korea and Japan - both satisfying more than 95% of national gas demand with LNG - and will presumably continue to increase their gas consumption as well. Although demand is not predicted to rise in Europe, decreasing indigenous production will also foster imports into the European market as well (ENTSOG, 2011). Given the regional differences in supply structure, demand flexibility and the supply-side concentration, a potential blockage of the Strait of Hormuz could therefore be interpreted as a supply shock in a spatial oligopoly with a competitive fringe and asymmetric players.

With respect to the supply shock caused by the blockage of the Strait of Hormuz, our paper aims at identifying and quantifying the major factors influencing the magnitude of price effects in globally disperse demand regions. We therefore develop a model to distinguish import price components into decreasing and increasing factors, such as production and transport costs, scarcity rents of production and infrastructure, oligopoly mark-ups, supplies of competitive fringe and long-term contracts.

Our methodology to analyse regional price drivers in a spatial oligopoly is structured in three steps. First, we illustrate the price formation in a simple asymmetric Cournot oligopoly. Second, since the interrelations of the global gas market are more complex due to, e.g., seasonal demand patterns, capacity constraints and spatial supply cost differences, we use a global gas market simulation model (Hecking and Panke, 2012). The spatial partial equilibrium model accounts for 87 countries, comprising the major national producers and importers, as well as the relevant gas infrastructure such as pipelines, LNG terminals and storages. In order to accurately simulate the global gas market, i.e., incorporate demand reactions and the possibilities of strategic behaviour, the model is programmed as a mixed complementarity problem (MCP). The flexibility and the high level of detail of the model allow us to simulate the interrelations of the global gas market within a consistent framework and to identify regional price and welfare effects. The third and central step of our approach to identify and quantify region-specific price drivers is to combine the price formation from the simple Cournot model with the gas market simulation model. By using the dual variables from the simulation, we are able to quantify to what extent marginal transport and production costs, scarcity rents of transport and production capacity as well as the exploitable oligopoly mark-up cause prices to increase. We are also able to identify factors that may result in decreasing prices such as trade relations to price-taking fringe suppliers and secured deliveries by long-term supply contracts.

Although a disruption of the Strait of Hormuz is fictitious, its consequences are interesting from an economic as well as a geopolitical point of view, especially since Qatar's LNG exports supply countries all over the world. We simulate a blockage lasting 6 months and focus on the United States, the UK and Japan, each serving as a prominent example of a distinct supply structure. We observe the strongest price reactions in Asia, with prices in Japan rising from an already high level (505 USD/kcm) by 171 USD/kcm during the 6-month disruption. While US gas prices hardly change at all, European gas prices are significantly affected during the disruption, albeit to a lesser extent than in Japan, as, e.g., gas prices in UK increase by up to 79 USD/kcm.

We identify and quantify three other factors to explain the difference in price changes between the UK and Japan. First, Japan is fully dependent on imports from the disturbed LNG market, whereas the UK has alternative supply opportunities from the European pipeline grid. Second, Japan's lower endowment of price-taking indigenous production and storage capacity explains its higher exposure to changes in supply costs as well as increased exertion of market power. Third, as Qatar is an important source of

Japan's contracted LNG import volumes, the price decreasing effects of Japan's LTCs are reduced in comparison to the reference scenario. Consequently, Japan's gas price increase is 92 USD/kcm higher than any increase seen in the UK.

Our research is related to literature on quantitative analyses of security of gas supply with particular attention to numerical simulations of spatial Cournot oligopolies in resource markets. During the last decade, building on the seminal paper by Takayama and Judge (1964), as well as on Harker (1986) and Yang et al. (2002), a variety of research has been made on spatial Cournot oligopolies and MCP models in resource markets (see for example Haftendorn and Holz (2010), Paulus and Trüby (2011) or Trüby (2013)). Applications of MCP models to natural gas markets are, e.g., Boots et al. (2004), Gabriel et al. (2005), Holz et al. (2008) and Egging et al. (2010). Yet to our knowledge, none of the existing papers applying MCP models to natural gas markets tries to identify which factors influence price changes during a supply shock and to what extent prices may be affected.

Quantitative research on security of supply is rather scarce and solely concentrates on Europe. Three of the few examples are Lise and Hobbs (2008), Lise et al. (2008) and Dieckhöner (2012), who measure the impacts of new pipeline corridors to Europe and of new LNG ports on security of supply. Papers on simulation-based analyses of the effects of (geo-) political conflicts on the natural gas market are also rare and concentrate on Europe only. Bettzüge and Lochner (2009) and Egging et al. (2008) analyse the impact of disruptions on Ukrainian gas flows and short-run marginal supply costs. Lochner and Dieckhöner (2011) analyse the effects of a civil unrest in North Africa on European security of natural gas supply.

We contribute to the existing literature on security of supply and spatial oligopolies in energy markets in three ways. First, we develop a framework for analysing regional price reactions after a trade disruption in a spatial oligopoly by separating price components into increasing and decreasing factors. Second, we assess the strategic position of gas importing countries during a trade disruption by applying our methodology. Third, as opposed to most studies on security of gas supply, our model covers the global natural gas market, thus allowing us to analyse the consequences of a regional (geo-) political conflict across the world.

The remainder of this paper is structured as follows. The methodology is described in Section 2, in which we derive the spatial oligopoly simulation model and develop an approach to distinguish price components using the model results. Section 3 describes the data, main parameter assumptions and the scenario setting. The results are presented

in Section 4, with particular focus on analysing the price difference between Japan and the UK, identifying the major price drivers and providing an in-depth analysis of both countries' supply situations. Section 5 concludes.

## 2. Methodology

We argue that international gas trade is best represented by a Cournot oligopoly with a competitive fringe: On the one hand, large state-owned companies such as Gazprom, Sonatrach, Qatargas or Statoil account for a significant share of global export volumes. On the other, a large number of companies with little annual production operate on the supply side, most of them providing no significant export volumes – thus representing a competitive fringe.<sup>1</sup>

In order to separate natural gas import price components into increasing and decreasing factors, we first provide a theoretical foundation of how prices are determined in a Cournot oligopoly with a competitive fringe. The natural gas market is more complex than a simple Cournot oligopoly. Since international gas trade is characterised by spatially distributed demand and supply plus a complex network of pipelines and LNG infrastructure, it is necessary to develop a numerical spatial oligopoly model to simulate the market. Next, we apply the price formula from the simple Cournot oligopoly model to the numerical oligopoly model in order to identify factors that increase and decrease import prices.

### 2.1. Oligopoly pricing

We start out by quickly recalling how the price in a Cournot oligopoly with a competitive fringe is determined (see also Tirole (1988)), which provides us with a theoretical foundation for our analysis. We begin by deriving the optimal supply  $Q^*$  in a Cournot oligopoly with  $N$  asymmetric players, i.e., players having differing marginal cost functions. In a second step, we derive the resulting price formula in such a market and elaborate on how a competitive fringe changes the way prices are determined in an oligopoly.

---

<sup>1</sup> We provide model results for the international gas market in 2010 (assuming perfect competition) in Appendix C. We find that the model results do not match actual market results. Consequently, we choose to model the global gas market as a Cournot oligopoly with a competitive fringe. We model the eight most important LNG exporting countries and the three most important pipeline exporters as Cournot players. The countries able to exercise market power are Australia, Algeria, Egypt, Indonesia, Malaysia, Nigeria, the Netherlands, Norway, Qatar, Russia and Trinidad and Tobago. All countries have almost all of their exports coordinated by one firm or consortium. Appendix C also contains the model results for our Cournot setting. By comparing these to actual market results, a better match is found than under the perfect competition setting.

Initially, we assume that  $N$  players maximise their profits by setting their optimal supply to a single end user market ( $q_i$ ). Each player  $i \in N$  has individual marginal costs of supply,  $msc_i$ , that are assumed to be constant and positive. Furthermore, we assume a linear inverse demand function, where the price  $P(Q)$  decreases with the total quantity  $Q = \sum_{i=1}^N q_i$  supplied to the market, i.e.,

$$P(Q) = A - BQ \quad \text{with } A, B > 0. \quad (1)$$

For a player  $i$ , the first order condition for sales is as follows:

$$\frac{\partial \pi_i}{\partial q_i} = P(Q) - Bq_i - msc_i = 0 \quad \forall i \quad (2)$$

with  $\pi_i$  representing the profit of player  $i$ . Substituting the wholesale price  $P(Q)$  by the linear inverse demand function yields:

$$\frac{\partial \pi_i}{\partial q_i} = A - B \sum_{i=1}^N q_i - Bq_i - msc_i = 0 \quad \forall i. \quad (3)$$

Consequently, the profit-maximising total supply to the wholesale market,  $Q^*$ , is determined by the following equation:

$$\sum_{i=1}^N \frac{\partial \pi_i}{\partial q_i} = N(A - BQ^*) - BQ^* - \sum_{i=1}^N msc_i = 0 \quad (4)$$

$$\Leftrightarrow Q^* = \frac{NA - \sum_{i=1}^N msc_i}{B(N+1)}. \quad (5)$$

Inserting Equation 4 into the linear inverse demand function yields:

$$P^*(Q^*) = A - BQ^* \quad (6)$$

$$= \frac{1}{N+1}A + \frac{1}{N+1} \sum_{i=1}^N msc_i \quad (7)$$

$$= \frac{BQ^*}{N} + \frac{\sum_{i=1}^N msc_i}{N}. \quad (8)$$

Consequently, in a Cournot oligopoly with asymmetric players, the equilibrium price equals the average marginal supply costs plus an average mark-up that depends on the slope of the demand function and total supply to the market.

The existence of a zero-cost competitive fringe with a binding capacity constraint ( $q_{cf}^{max}$ ) simply leads to a reduction of the mark-up by  $\frac{Bq_{cf}^{max}}{N}$ , as the competitive fringe produces its maximum capacity and the oligopolistic players maximise profit over the residual demand function.<sup>2</sup>

## 2.2. A spatial equilibrium model of the global gas market

Although we derive the formula for a simplified market, the method to determine the price is essentially the same as in a set-up with multiple interconnected markets and time periods (due to, e.g., the possibility of storing a commodity). The main difference between the simplified and complex formula is that scarcity rents of production and infrastructure capacity are affected by the interrelation of all markets and time periods. Due to the size of the problem at hand (high number of players, markets and time periods), deriving an equilibrium solution is challenging. Therefore, we develop a numerical spatial oligopoly model to simulate international gas trade.

The spatial equilibrium model is formulated as a mixed complementarity problem. This method allows us to make use of elastic demand functions as well as simulate strategic behaviour in international gas trade. As we argue that the natural gas market is best represented by a Cournot oligopoly with a competitive fringe, both aspects (elastic demand and strategic behaviour) are essential to accurately model the natural gas market.<sup>3</sup> Figure 1 illustrates the logical structure of our model.

Exporters are vertically integrated with one or more production nodes and trade gas with the buyers located at the demand nodes. We use a linear function to represent total demand at each of the demand nodes.<sup>4</sup> Exporters compete with each other in satisfying the demand, thereby acting as Cournot players or in a competitive manner. Therefore, at each demand node, all exporters form an oligopoly with a competitive fringe. The oligopoly is spatial and asymmetric, as each exporter's marginal supply costs ( $\lambda_{e,d,t}$ ), i.e.,

---

<sup>2</sup> In the natural gas market, short-run marginal costs of price-taking fringe players are substantially lower than actual market prices. In addition, capacity of the competitive fringe is low compared to overall market size. This justifies why we focus on a zero-cost competitive fringe with a binding capacity constraint. Our application therefore follows the approach chosen in Borenstein and Bushnell (1999).

<sup>3</sup> Haftendorn (2012) stresses the point that when modelling a Cournot oligopoly with a competitive fringe with non-binding capacity constraints using conjectural variation models, the resulting market equilibrium may yield the oligopoly players lower profits compared to a setting in which they set prices equal to marginal supply costs, i.e., act as price takers. However, this objection is of no concern to our analyses since the competitive fringe in the reference scenario, and hence also in the scenario with a blockage of the Strait of Hormuz, faces binding capacity constraints.

<sup>4</sup> For more details on how the demand functions are determined, please refer to Section 3.1.

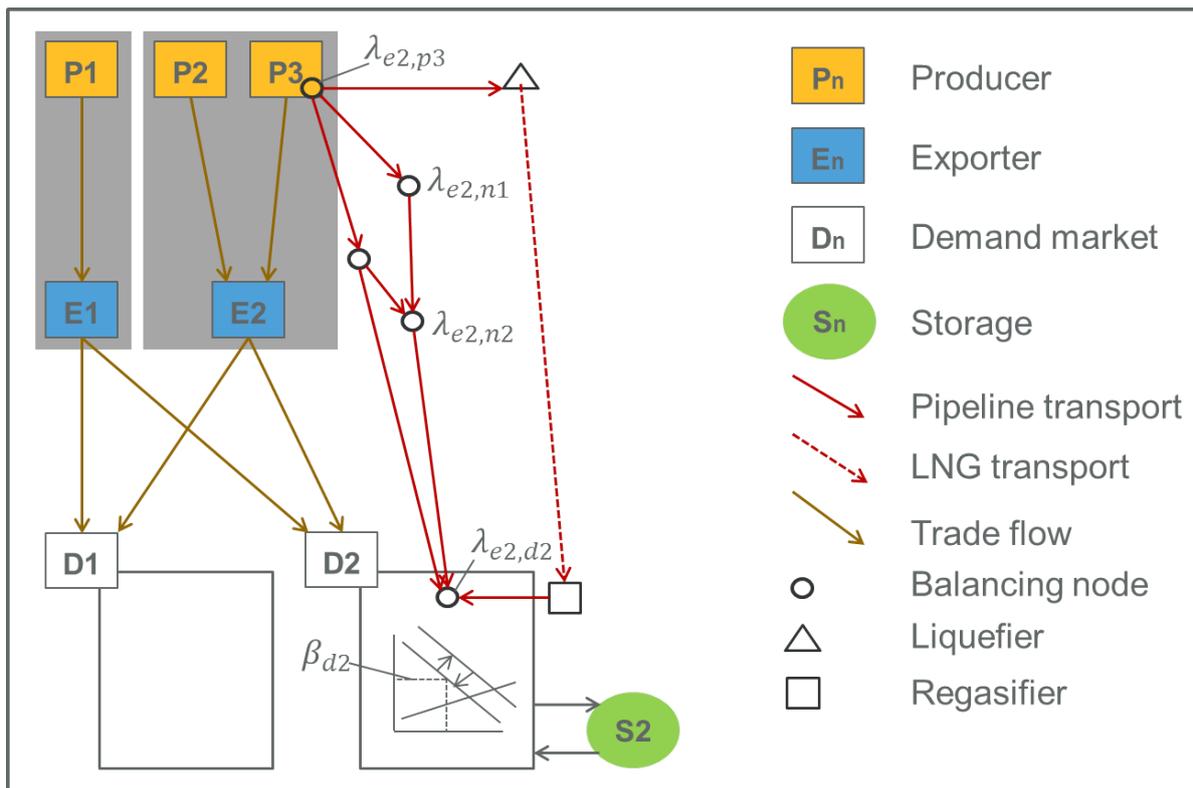


Figure 1: Logical structure of the gas market model

the costs associated with the physical realisation of the trades, vary depending on the location of production and demand nodes. Each exporter's marginal supply costs consist of marginal production and transport costs, including the scarcity rent for production and transport capacity. As different exporters compete for transport capacity, e.g., two exporters may want to use the same pipeline to deliver gas to a demand node, trades of one exporter influence the costs of another exporter's physical transports.

We start out by developing the optimisation problems of the different players in our model and derive the corresponding first-order optimality conditions for one player. The first-order conditions combined with the market clearing conditions constitute our partial equilibrium model for the global gas market. The vector of variables in parentheses on the right-hand side of each constraint are the Lagrange multipliers used in developing the first-order (Karush-Kuhn-Tucker (KKT)) conditions. The complementary slackness condition is indicated by the perpendicular sign,  $\perp$ , with  $0 \leq x \perp y \geq 0 \Leftrightarrow x^t y = 0$  for vectors  $x$  and  $y$ .

### 2.2.1. The Exporter's Problem

The exporter  $e \in E$  is defined as a trading unit of a vertically integrated firm owning one or more production regions  $p \in P_e$ . The exporters earn revenues by selling gas ( $tr_{e,d,t}$ ) on the wholesale markets of the importing regions  $d \in D$ . Each exporter  $e$  maximises its profits, i.e., revenues from sales minus costs of supply over all modelled time periods  $t \in T$  and all importing regions  $d$ . Exporters may behave as price-takers in the market, but can alternatively be modelled as if able to exercise market power.

The profit function  $\Pi_{eI}(tr_{e,d,t})$  is defined as<sup>5</sup>

$$\max_{tr_{e,d,t}} \Pi_{eI}(tr_{e,d,t}) = \sum_{t \in T} \sum_{d \in D} (\beta_{d,t} - \lambda_{e,d,t}) * tr_{e,d,t} \quad (9)$$

where  $\beta_{d,t}$  is the market clearing price in importing region  $d$ ,  $tr_{e,d,t}$  is the quantity that trader  $e$  sold to region  $d$  at time  $t$  and  $\lambda_{e,d,t}$  corresponds to the exporter's costs of physical gas delivered to demand node  $d$ . Long-term contracts (LTC) play a significant role in natural gas markets. Therefore, some of the trade flows between the exporters and importing regions have a lower bound, i.e., a minimal delivery obligation  $mdo_{e,d,t}$ .<sup>6</sup> Thus, LTCs are taken into account by incorporating the following constraint:

$$\sum_{t \in T} tr_{e,d,t} - mdo_{e,d,t} \geq 0 \quad \forall e, d, t \quad (\chi_{e,d,t}). \quad (10)$$

The Lagrange of the exporter's optimisation problem is defined by Inequality 10 and Equation 9. Taking its first partial derivative with respect to the decision variable  $tr_{e,d,t}$  gives us the first-order condition (FOC) for trade between exporter  $e$  and demand node  $d$ :

$$\frac{\partial L_{eI}}{\partial tr_{e,d,t}} = -\beta_{d,t} + cv_e * slope_{d,t} * tr_{e,d,t} - \chi_{e,d,t} + \lambda_{e,d,t} \geq 0 \quad \perp \quad tr_{e,d,t} \geq 0 \quad \forall e, d, t. \quad (11)$$

The variable  $slope_{d,t}$  is the slope of the linear demand function in node  $d$ . The term  $cv_e$  is the conjectural variation of exporter  $e$  and is a binary variable indicating whether ( $cv_e = 1$ ) or not ( $cv_e = 0$ ) the trader is able to exercise market power.

<sup>5</sup> In order to keep the formulae as simple as possible, no discount factor is included.

<sup>6</sup> To limit complexity, we exclude the possibility of reshipping contracted LNG to other countries, as observed in the last couple of years in the USA. Volumes however are rather small.

In addition to the LTC constraint, each exporter also faces an individual market clearing condition that has to be fulfilled for every model node in which an exporter is active ( $n \in N_e$ ):

$$pr_{e,p,t} - tr_{e,d,t} + \sum_{n1 \in A_{.,n}} fl_{e,n1,n,t} - \sum_{n1 \in A_{n,.}} fl_{e,n,n1,t} = 0 \quad \perp \quad \lambda_{e,n,t} \text{ free} \quad \forall e, n, t \quad (12)$$

with  $A_{.,n}$  a set including all transport routes leading to node  $n$ . Variables  $pr_{e,p,t}$  and  $fl_{e,n,n1,t}$  denote produced gas volumes in production region  $p(n) \in P_e$  and physical transport volumes between node  $n$  and  $n1$ , respectively. Therefore, the corresponding dual variable  $\lambda_{e,n,t}$  equals the exporter's costs of physical supply to node  $n$ . If we consider a demand node  $d(n) \in D_e$ , market clearing condition 12 simplifies to<sup>7</sup>

$$\sum_{n1 \in A_{.,d}} fl_{e,n1,d,t} - tr_{e,d,t} = 0 \quad \perp \quad \lambda_{e,d,t} \text{ free} \quad \forall e, d, t. \quad (13)$$

Hence, Equation 12 ensures that the gas volumes, which exporter  $e$  sold on the wholesale market of demand node  $d$ , are actually physically transported to the node. If we consider a production node  $p$ , market clearing condition 12 collapses to:

$$pr_{e,p,t} - \sum_{n1 \in A_{p,.}} fl_{e,p,n1,t} = 0 \quad \perp \quad \lambda_{e,p,t} \text{ free} \quad \forall e, p, t. \quad (14)$$

Thus, the gas volumes produced have to match the physical flows out of node  $p$ . Production costs are represented by a production function, as used in Golombek et al. (1995, 1998). The corresponding marginal production cost function  $mprc_{e,p,t}(pr_{e,p,t})$  takes the form:  $mprc_{p,t}(pr_{e,p,t}) = a + b * pr_{e,p,t} - c * \ln(1 - \frac{pr_{e,p,t}}{cap_{e,p,t}})$ . Since trader  $e$  and its associated production regions  $P_e$  are considered to be part of a vertically integrated firm, profit maximisation dictates that either the production entity or the trading entity sell their product at marginal costs, while the other entity exercises market power. In our setting, the trading units are modelled as oligopoly players while production is priced at marginal costs. Hence, the corresponding dual variable  $\lambda_{e,p,t}$  to Equation 14 represents marginal production costs. Production in production region  $p$  is subject to a production constraint:

$$cap_{e,p,t} - pr_{e,p,t} \geq 0 \quad \forall e, p, t \quad (\mu_{e,p,t}). \quad (15)$$

---

<sup>7</sup> Equation 13 holds true if the demand node has no further connections, i.e., is a no-transit country. In case of a country such as Poland, physical flows of the Russian exporter to Poland have to equal the volumes sold to Poland plus all transit volumes.

Equations 13 and 14 also ensure that  $\sum_{p \in P_e} pr_{e,p,t} = \sum_{d \in D_e} tr_{e,d,t}$ , i.e., total production equals total trade volume for every exporter  $e$  in each time period  $t$ . As trade flows are linked to physical flows, each exporter also faces the problem of how to minimise transport costs by choosing the cost-minimal transport flows  $fl_{e,n,n1,t}$ . In our model, this is implicitly accounted for by a separate optimisation problem of the following form:

$$\max_{fl_{e,n,n1,t}} \Pi_{eII}(fl_{e,n,n1,t}) = \sum_{t \in T} (\lambda_{e,n1,t} - \lambda_{e,n,t} - trc_{n,n1,t} - opc_{n,t}) * fl_{e,n,n1,t} \quad (16)$$

where  $opc_{n,t}$  is defined as the operating costs at node  $n$  in month  $t$  and  $trc_{n,n1,t}$  as the cost associated with transporting gas from node  $n$  to node  $n1$ . Therefore, if  $n$  is a liquefaction node  $l(n)$ ,  $opc_{n,t}$  would reflect the costs of liquefying a unit of natural gas. If  $n$  is a liquefaction node then  $n1$  has to be a regasification node, thus  $trc_{n,n1,t}$  would be the short-run marginal LNG transport costs from node  $n$  to node  $n1$ . The optimisation problem is subject to some physical transport constraints such as the pipeline capacity:

$$cap_{n,n1,t} - \sum_{e \in E} fl_{e,n,n1,t} \geq 0 \quad \forall n, n1, t \quad (\phi_{n,n1,t}). \quad (17)$$

Thus, the sum over all transport flows (decided on by the traders) through the pipeline between nodes  $n$  and  $n1$  has to be lower than the respective pipeline capacity  $cap_{n,n1,t}$ . The dual variable  $\phi_{n,n1,t}$  represents the value of an additional unit of pipeline capacity. Along the lines of Inequality 17, we also account for capacity constraints on liquefied ( $\zeta_{l,t}$  being the corresponding dual variable) and regasified volumes ( $\gamma_{r,t}$ ), as well as LNG transport levels ( $\iota_t$ ).<sup>8</sup>

This optimisation problem may also be interpreted as a cost minimisation problem assuming a benevolent planner, since in equilibrium there will be gas flows between two nodes  $n$  and  $n1$  until the absolute difference of the dual variables associated with the physical market clearing constraint (Equation 12) of the two nodes ( $\lambda_{e,n1,t} - \lambda_{e,n,t}$ ) equals the costs of transporting gas from node  $n$  to node  $n1$ . Hence,  $\lambda_{e,n,t}$  can be interpreted as the exporter's marginal costs of supplying natural gas (including production costs  $\lambda_{e,p,t}$ ) to node  $n$ , as shown in Equation 9.

---

<sup>8</sup> The interested reader is referred to Appendix A for a detailed description of the omitted capacity constraints.

### 2.2.2. The Storage Operator's Problem

Each storage facility is operated by one storage operator  $s \in S$ . The storage facilities are assumed to be located in the importing regions. The storage operator maximises its revenues by buying gas during months with low prices and reselling gas during months with high prices. In our model, we assume storage operators are price takers<sup>9</sup> and, due to the nature of our modelling approach, also have perfect foresight.<sup>10</sup> Each storage operator faces a dynamic optimisation problem of the following form:

$$\max_{si_{s,t}, sd_{s,t}} \Pi_s(si_{s,t}, sd_{s,t}) = \sum_{t \in T} \beta_{d,t} (sd_{s,t} - si_{s,t}). \quad (18)$$

Using injection  $si_{s,t}$  as well as depletion  $sd_{s,t}$  in month  $t$ , we can define the motion of gas stock ( $st_{s,t}$ ), i.e., the change in stored gas volumes, as:

$$\Delta st_{s,t} = st_{s,t+1} - st_{s,t} = si_{s,t} - sd_{s,t} \quad \forall s, t \quad (\sigma_{s,t}). \quad (19)$$

Additionally, the maximisation problem of the storage operator is subject to some capacity constraints:

$$cap_{s,t} - st_{s,t} \geq 0 \quad \forall s, t \quad (\epsilon_{s,t}) \quad (20)$$

$$cf_s * cap_{s,t} - si_{s,t} \geq 0 \quad \forall s, t \quad (\rho_{s,t}) \quad (21)$$

$$cf_s * cap_{s,t} - sd_{s,t} \geq 0 \quad \forall s, t \quad (\theta_{s,t}). \quad (22)$$

Hence, we assume that storage capacity can be linearly transferred (by use of the parameter  $cf_s$ ) to the restriction on maximum injection ( $si_{s,t}$ ) and depletion ( $sd_{s,t}$ ).

---

<sup>9</sup> This assumption must be made in order to reduce model complexity and ensure solvability. Yet, the direction of the identified effects remains unchanged if storage operators are modelled as Cournot players.

<sup>10</sup> When analysing a supply disruption, this assumption may overestimate the price decreasing effect of storage. For a description of how we handled this issue, see Section 3.3.

### 2.2.3. Price determination

The equilibrium problem comprises the first-order conditions derived from the different optimisation problems as well as the market clearing conditions previously discussed. In addition, we have to include one last market clearing condition:

$$\sum_{e \in E} tr_{e,d,t} + sd_{s,t} - si_{s,t} = \frac{int_{d,t} - \beta_{d,t}}{slope_{d,t}} \perp \beta_{d,t} \text{ free} \quad \forall d, t. \quad (23)$$

The last market clearing condition (Equation 23) states that the final demand for natural gas, represented by a linear demand function (where  $int_{d,t}$  and  $slope_{d,t}$  represent its intercept and slope, respectively), and the gas volumes injected ( $si_{s,t}$ ) into the storage facility at node  $s(d)$  are met by the sum over all gas volumes sold on the wholesale market by traders  $e$  and gas volumes depleted ( $sd_{s,t}$ ) from storage facility  $s$ . Thus, the dual variable associated with Equation 23 ( $\beta_{d,t}$ ) represents the wholesale price in demand node  $d$  in month  $t$ .

Our model of the global gas market is defined by the stated market clearing conditions and capacity constraints, as well as the first-order conditions (FOC) of the respective maximisation problems.<sup>11</sup> The model is programmed in GAMS as a mixed complementarity problem (MCP) and solved using the PATH solver (Dirkse and Ferris, 1995; Ferris and Munson, 2000).

### 2.3. Disentangling prices in a spatial equilibrium model

Figure 2 illustrates our methodology to disentangle prices in order to later evaluate a certain import country's strategic position in the global gas market. In Section 2.1, we discuss a simple oligopoly model with a single market, asymmetric players and a competitive fringe. Here, natural gas prices equal the sum of an average oligopoly mark-up and average marginal supply costs of the Cournot players. In contrast, the model presented in Section 2.2 allows us to incorporate more complex market settings, such as additional import regions, long-term supply contracts as well as production and transport capacity constraints. As a result of the added complexity, price influencing factors are more diverse.

As seen in the exporter's FOC for optimal trade to demand node  $d$  (see Inequality 11), the exporter is willing to trade with demand node  $d$  as long as the price  $\beta_d$  covers his supply costs  $\lambda_{e,d}$  and his individual oligopoly mark-up  $cv_e * slope_d * tr_{e,d}$ . If an exporter

---

<sup>11</sup>See Inequality 11 and Appendix A for the remaining FOCs of our model.

is obliged to deliver LTC volumes to a certain import node, he may even be willing to accept a  $\beta_d$  that is smaller than the sum of supply costs and oligopoly mark-ups. This economic disadvantage for the exporter is denoted by  $\chi_{e,d}$  in the model.

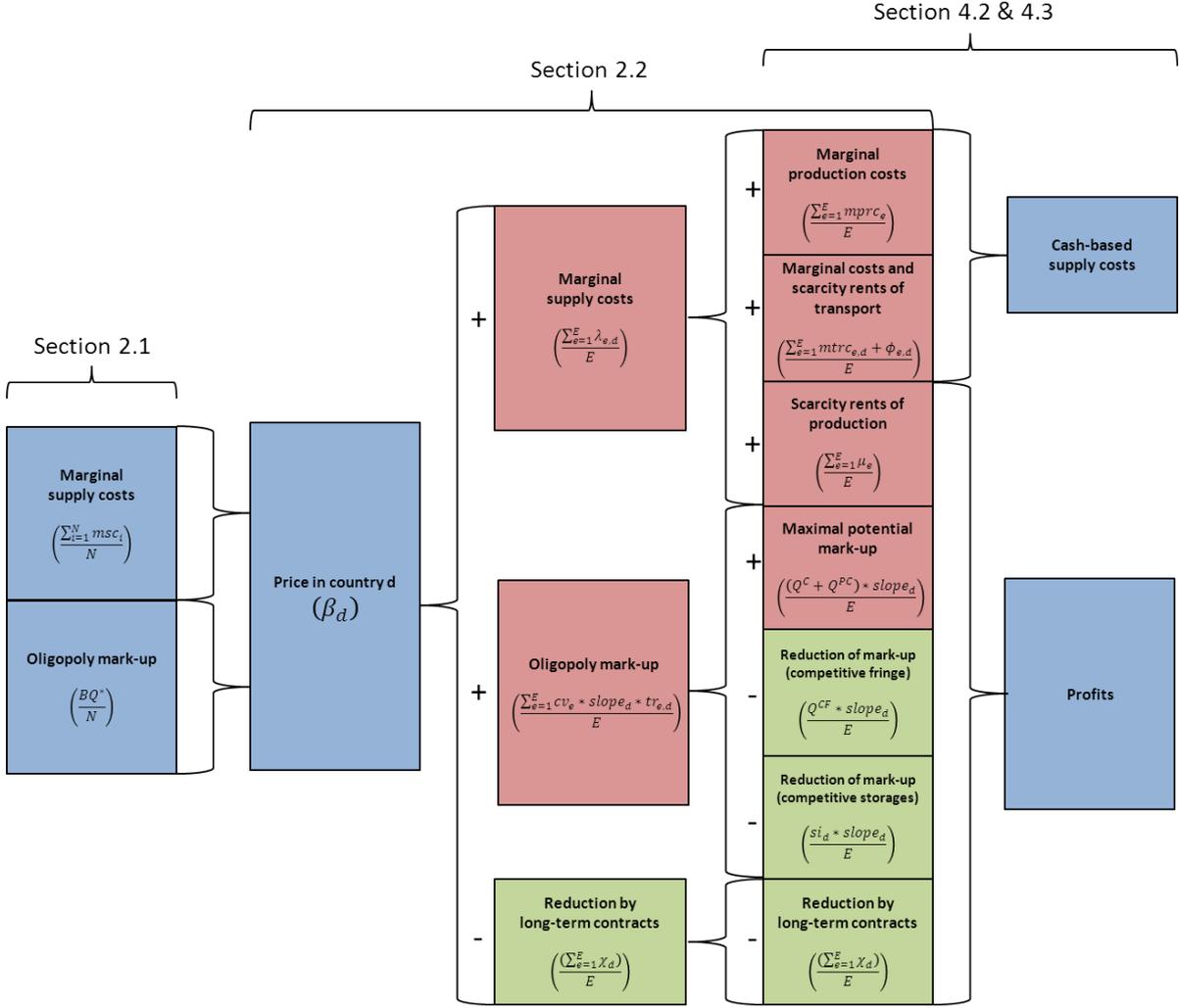


Figure 2: Disentangling prices in a spatial equilibrium model

According to the oligopoly pricing formula deduced in Section 2.1, we are now able to identify to which extent marginal supply costs and oligopoly mark-ups explain the different market prices  $\beta_d$ . The influence of marginal supply costs equals the average of all Cournot player's  $\lambda_{e,d}$ . Each  $\lambda_{e,d}$  can be further subdivided into production costs, transport costs and scarcity rents for transport and production infrastructure. Therefore, by taking the average of all aforementioned supply cost components, we can identify to what extent these components explain prices.

The price influence of the exporters’ oligopoly mark-ups is defined as the average of each Cournot player’s mark-up. For our analysis, we also need to identify the price-reducing effects of competitive fringe players. We therefore introduce the so-called “maximal oligopoly mark-up”, which is the hypothetical mark-up that Cournot oligopolists could realise at a demand node if there were no gas volumes from a competitive fringe available. Thus, as stated in Section 2.1, the fringe producers reduce the maximal oligopoly mark-up by  $slope_d * tr_d^{CF}$  and the fringe storages by  $slope_d * sd_d$ . Besides fringe suppliers, LTC’s may also have a price decreasing effect that can be identified by taking the average LTC opportunity costs of all Cournot players,  $\chi_{e,d}$ .

Now, as we are able to disentangle the import price components simulated by the equilibrium model into price increasing and decreasing factors, we use this approach in Chapter 4 to evaluate the market position of different countries during a supply crisis. There we will distinguish between “cash-based supply costs” and exporters’ “profits”. We define “cash-based supply costs” as monetary costs for using transport infrastructure (marginal costs and scarcity rent) and gas production. The scarcity rent of production and the oligopoly mark-up may both be interpreted as monetary profit for the exporter.

### 3. Data, assumptions and scenario setting

In this section, the data used in our global gas market model as well as the scenario settings of our analysis are described. This section’s description focuses on the demand side and the role of long-term contracts in the global gas market. In addition to the information provided in this section, we list details on data used for production capacities, costs, infrastructure capacities and transports costs in Appendix B.

#### 3.1. Demand

To study the economics of a disruption of the Strait of Hormuz and the effects on regional import prices with a high level of detail, we put a special focus on the demand data. In particular, monthly demand functions must be derived.

The total gas demand of a country and its sensitivity to prices are heavily affected by the sectors in which the gas is consumed. Gas consumption in the heating sector mainly depends on temperature and therefore has a seasonal pattern. On the other hand, gas consumption in industry has no seasonal and temperature-dependent demand pattern, making demand rather constant. Concerning price sensitivity, it is fair to assume that gas demand in the heating sector is rather insensitive to prices, since the gas price does

not strongly change the heating behaviour and since the heating technology is fixed in the short term. On the contrary, in power generation, the gas-to-coal spread has a higher impact on gas demand, implying high price sensitivity. Moreover, price sensitivities may also vary by country: It is reasonable to assume that, e.g., Japan (due to its tight generation capacity situation) is less price sensitive in power generation than Germany.

To derive a country's gas demand function, we have to account not only for the aforementioned aspects, but for the different sectoral shares of total demand as well. In addition, due to different seasonal demand patterns of each sector, the sectoral share of total demand may vary by month. If, for example, heating demand takes a large share of some country's total gas demand in January, then the corresponding demand function would be rather price insensitive. On the contrary, if in July, gas is mainly used in power-generation, the demand function would be rather price sensitive.

Our aim is to consistently derive country-specific monthly linear demand functions accounting for sectoral shares, seasonalities and price sensitivities. In the following, we outline our approach to determine these functions and the accompanying data sources.

First, we use country-specific annual demand data for the years 2010 and 2012. Demand data per country for those years is taken from IEA (2011a), IEA (2011) and (ENTSOG, 2011). IEA (2011a) provides consumption data on a country by country basis for the year 2010. For natural gas demand in 2012, we rely on forecasts from IEA (2011) and ENTSOG (2011).

In a second step, annual demand is split into monthly demand, using historical monthly consumption data provided by, e.g., IEA (2011a), 3E Information Development & Consultants (2009) and FGE (2010). Concerning the linear demand functions, sufficient data is only available for 27 nodes representing China, India and most of the OECD countries. For the other countries, we assume monthly demand to be inelastic and exhibit no seasonality.

Next, we distinguish two groups of sectors: We assume "industry and power (IP)" to have a higher price sensitivity than "heating and miscellaneous (HM)". IEA (2011a) provides sectoral shares of gas demand in industry, heat and power generation on an annual basis. For the heating sector, we derive monthly demand data from heating degree days provided by, e.g., Eurostat (European countries) or National Resources Canada (Canada)<sup>12</sup>. We further assume miscellaneous gas demand to exhibit no seasonal fluctuation. We derive the monthly demand for "industry and power generation" as a residual of total demand minus heating demand and minus miscellaneous demand. The

---

<sup>12</sup><http://www.nrcan.gc.ca/energy/sources/natural-gas/monthly-market-update/1173>

monthly demand for both groups, IP and HM, serves as a reference demand with which linear demand curves for each group may be derived.

Monthly reference prices are provided by IEA (2011a) for the majority of countries. We add monthly price information from the spot indices Henry Hub, Title Transfer Facility (TTF) and National Balancing Point (NBP). For all European countries where no data is publicly available, we use the European average gas price provided by IEA (2011a).

Having set up reference price-volume combinations, we still have to determine the monthly price sensitivities in the relevant countries for both demand groups IP and HM to derive specific linear demand functions. We thereby stick to an approach that is commonly used in modelling literature (e.g., Holz et al. (2008), Egging et al. (2010) or Trüby (2013)) by assuming point elasticities in the reference point. While we assume the demand elasticity of the HM group to be approximately -0.1 in all countries with a price sensitive demand function, we differentiate within the IP group. Due to the high degree of oil-price indexation as well as the tight capacity supply in Japan, we assume natural gas demand of the Asian countries to be less price sensitive than the other countries (-0.1 vs. -0.4).<sup>13</sup> These elasticity assumptions are in line with, e.g., Neumann et al. (2009) and Bauer et al. (2011) who assume a price elasticity of -0.3, or Egging et al. (2010) who assume price elasticities between -0.25 and -0.75.

Having derived monthly country-specific demand curves for IP and HM with different price sensitivities, we aggregate both demand functions horizontally. The resulting demand functions account for different seasonal demand patterns, different sectoral shares of total demand and different price sensitivities, therefore varying by month and country.<sup>14</sup>

Overall, the model covers a gas demand of 3267 bcm for 2010 and 3426 bcm in 2012. This equals 99% of both global gas consumption in 2010 reported by the IEA (2011a) and global gas demand in 2012 as forecasted in IEA's Medium-Term Oil and Gas Markets report (IEA, 2011). We model 49% of total global demand to be price sensitive and 51% to be inelastic. In Asia/Oceania, 379 of 645 bcm of total demand is elastic (59%), whereas in Europe and North America, more than 90% of total demand is modelled

---

<sup>13</sup>These elasticity values provide the best fit with actual market outcomes in 2010. Please refer to Appendix D for information on how prices in select countries change when the assumed elasticity is varied.

<sup>14</sup>Horizontal aggregation of two linear demand functions leads to a kinked demand function. Our modelling approach is only able to handle differentiable functions. After having checked all equilibrium price/quantity combinations, we can exclude the market outcomes in the steeper part of the kinked demand function. Therefore, we only use the less steep part in our analysis.

as elastic demand functions. The comparably low share of Asian elastic demand is acceptable for our study because most of the Asian countries with inelastic demand are gas producers and are therefore import independent (e.g., Malaysia, Indonesia or Australia).

### 3.2. Long-term contracts in the global gas market

Long-term contracts still play a significant role in the natural gas market, in particular in Europe and Asia. Therefore, our model also accounts for long-term supply contracts (LTC). For Europe, data on LTCs are based on information provided by Gas Matters<sup>15</sup>. LTCs are also important for LNG deliveries: In 2010, about 60 bcm were traded on a spot and short-term basis<sup>16</sup> (GIIGNL, 2010). Of the total LNG trades that occurred in 2010 (300 bcm), 80% were carried out as a result of long-term contracts.

As precise information on actual LTCs is not widely available, we model long-term contracts as a minimal delivery per annum from an exporting to an importing country, e.g., 6.4 bcm have to be shipped from Qatar to Italy over the course of the year. In other words, because the annual natural gas imports can be flexibly optimised during a year, we can neglect monthly minimal deliveries. Since our study focuses on security of supply effects during a disruption, we focus on the minimal deliveries instead of take-or-pay volumes, which serve as a means to guarantee “security of demand” for certain exporters.

Long-term contracts are often oil price indexed. This holds true in particular for the Asian LNG importers (Japan Crude Cocktail). However, our model derives prices endogenously, thus allowing the LTC reference prices to be determined via implicit modelling.<sup>17</sup> Our analysis focuses on a short time frame, i.e., one year.

---

<sup>15</sup><http://www.gasstrategies.com/home>

<sup>16</sup> GIIGNL defines short-term contracts as contracts with a duration of less than 4 years. Since our analysis focuses on the effects of an LNG disruption, it is necessary to include LNG long-term contracts in the model. Neglecting that fact would presumably overestimate the flexibility of LNG trade and therefore underestimate the severity of a disruption of the Strait of Hormuz. Since we lack more detailed data and do not have information about potential flexibilities (neither in long- nor in short-term contracts), we stick to an amount of 240 bcm contracted in the long term. We further assume this to be the contracted volume for 2012 as well.

<sup>17</sup> It is unclear how prices in an oil-price indexed LTC would react to a blockage of the Strait of Hormuz, as this depends on the specific contract structure as well as the change in the oil price. Therefore, the approach used in this paper is, in our view, only tractable in a partial equilibrium analysis such as the one presented.

### 3.3. Scenario setting

In our study, we simulate two scenarios: In the reference scenario, gas flows between November 2012 and October 2013 are computed assuming no disruption of the Strait of Hormuz. In the other scenario, we simulate a six-month blockage of the Strait of Hormuz beginning in November. As our model is non-stochastic, we fix storage levels in November based on the results from the reference scenarios. Otherwise, market players would anticipate the blockage and fill the storages in advance (perfect foresight assumption). We, however, implicitly assume that storage operators have information about the length of the disruption. Concerning LNG long-term contracts, we proportionately diminish the annual minimum take/delivery quantity to match the length of the disruption (i.e., a 12 bcm contract is reduced to 6 bcm). This is in line with a reference LNG contract provided by GIIGNL (2011), according to which a blockage is a force majeure and relieves the contracting parties from the take/delivery obligation.

## 4. Results

### 4.1. Prices

To analyse the fundamental price effects of a disruption of the Hormuz Strait, Figure 3 gives the monthly gas prices for Japan, the UK and the US in both scenarios (no disruption and 6-month disruption).<sup>18</sup>

First, we observe rather identical price curves for the US: In our simulations, the USA neither import nor export significant amounts of LNG in 2012. Therefore, US gas prices are not affected by the blockage of the Strait of Hormuz.

Second, it can be seen that UK's natural gas price is connected to and affected by incidents on the global LNG market.<sup>19</sup> Whereas in the reference run the gas price varies between 220 USD/kcm in summer and 250 USD/kcm in winter, we observe an increase in the gas price when simulating a 6-month long blockage. Once the disruption starts, the UK gas price immediately increase by up to 31% in the winter months (328 USD/kcm in January).

Third, we notice that Japan, which relies solely on LNG imports, is most affected by the disruption of Qatar's and United Arab Emirates' LNG exports. The monthly gas

---

<sup>18</sup>We use the market clearing price of the US southern demand node as a proxy for the monthly price of the United States.

<sup>19</sup>Around 14 bcm of the total LNG imports in 2010 (18,7 bcm) stem from long-term LNG contracts (GIIGNL, 2010).

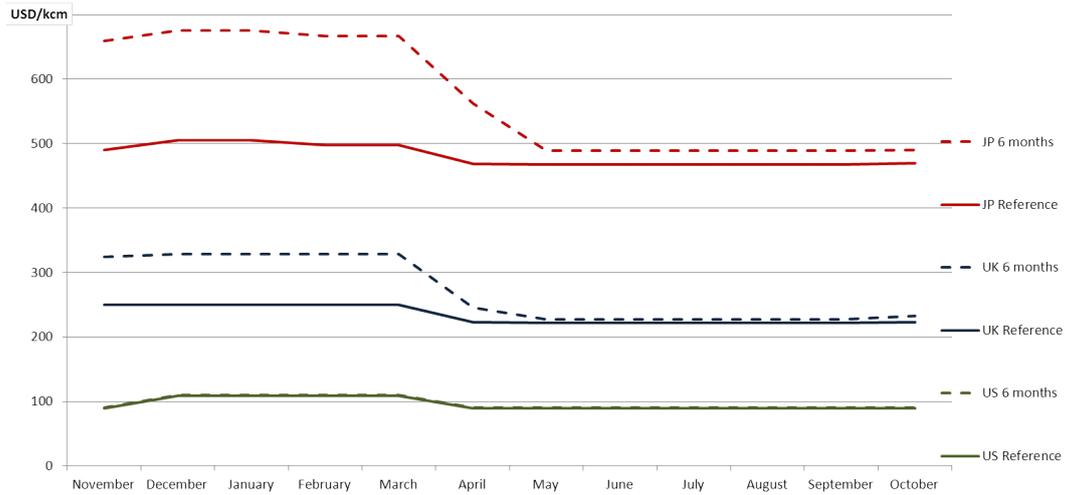


Figure 3: Price effects of a disruption of the Hormuz Strait in three selected countries

price in Japan varies between 467 USD/kcm and 505 USD/kcm in the reference case. A 6-month long blockage of Hormuz Strait increases the gas price in Japan by nearly 34% (to more than 677 USD/kcm in January).

Thus, for both countries (Japan and the UK), we observe increasing prices during the disruption. However, it remains unclear whether an exporter's profits increase or whether higher supply costs cause the increase in prices. As an example, Figures 4 and 5 provide closer insight into the formation of January prices in both scenarios for Japan and the UK, respectively. Both figures contain the respective country's January demand function and the cash-based supply cost curves for both scenarios.<sup>20</sup>

<sup>20</sup> According to the terminology used in Section 2.3, cash-based supply costs include marginal costs of production and transport plus a scarcity rent for transport infrastructure.

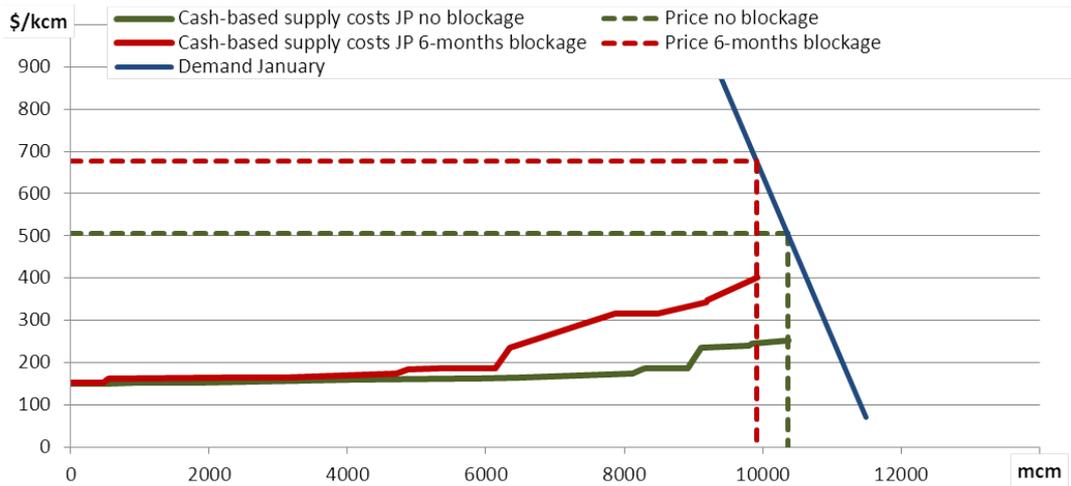


Figure 4: Changes in Japan's supply cost curve due to a disruption of the Hormuz Strait

Concerning Japanese supplies, we observe a remarkable increase in supply costs, whereas in the UK, supply costs in both scenarios are nearly identical except for the rightmost part of the curve. Increasing prices, however, seem to be also driven by higher profits for the suppliers in both countries. Yet, neither figure provides an indication as to what factors drive prices most.

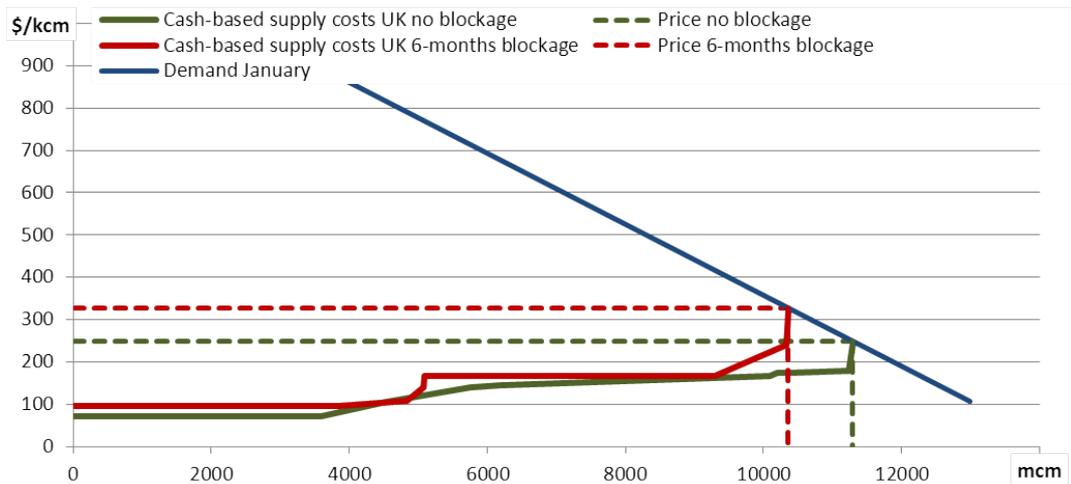


Figure 5: Changes in UK's supply cost curve due to a disruption of the Hormuz Strait

Therefore, the observed price effects raise two questions: Why does the import price level differ among different countries, even in the reference scenario? And what drivers explain the different price reactions after a supply shock? To answer these questions, we apply the approach introduced in Section 2.3. Using the dual variables from our simu-

lation model, we are able to derive price components in order to evaluate the strategic market positions of different countries. To give an application of our methodology, we next focus on the January prices of Japan and the UK in the reference scenario and during the supply shock.<sup>21</sup>

#### 4.2. Price structure in the reference scenario

To explain the price differences between Japan and the UK, we first take a look at Figure 6. The diagram illustrates the different components of Japanese and British import prices in January in the reference scenario (no disruption).

As stated in Section 2.3, we distinguish between “cash-based supply costs” and “profits”. We define “cash-based supply costs” as those costs that the exporter actually has to bear in order to deliver gas to an importing country (i.e., marginal costs of production and transport as well as congestion rents for transport infrastructure). The scarcity rent for production capacity is monetary profit for the exporter. Therefore, it is part of what we refer to as “profits”. Another component of the profits is the average mark-up, which oligopolistic players can realise in a certain import market. The term “maximal potential oligopoly mark-up” labels the mark-up that exporters could realise if the complete demand of a country was satisfied by Cournot players. However, gas purchases from price-taking players or depletion from storages lowers the “maximal potential mark-up”. In other words, the presence of a competitive fringe reduces the oligopoly rents. Last, LTCs have a decreasing effect on import prices and, in particular, the exporters’ margin. Since LTCs are modelled as minimal deliveries from an exporter to an import country, the LTC is a binding constraint for the exporter. This can be interpreted as an economic disadvantage that the exporter has to bear or, conversely, a price advantage for the importer.

As Figure 6 reveals, the total January price difference between Japan and the UK is 255 USD/kcm, yielding 31 USD/kcm to be explained by higher supply costs. The “profits” account for the major price difference (224 USD/kcm). Whereas the scarcity rent for production capacity has a similar impact on prices in both countries, the “maximal potential oligopoly mark-up” explains most of the differences between the “profits”. Compared to the UK, we assume the gas demand of Japan to be more inelastic. Thus,

---

<sup>21</sup> Concerning the US, the abundant domestic production makes the country independent from imports. This does not only explain the low prices, but also the insensitivity to prices during the global supply shock (disruption of the Strait of Hormuz).

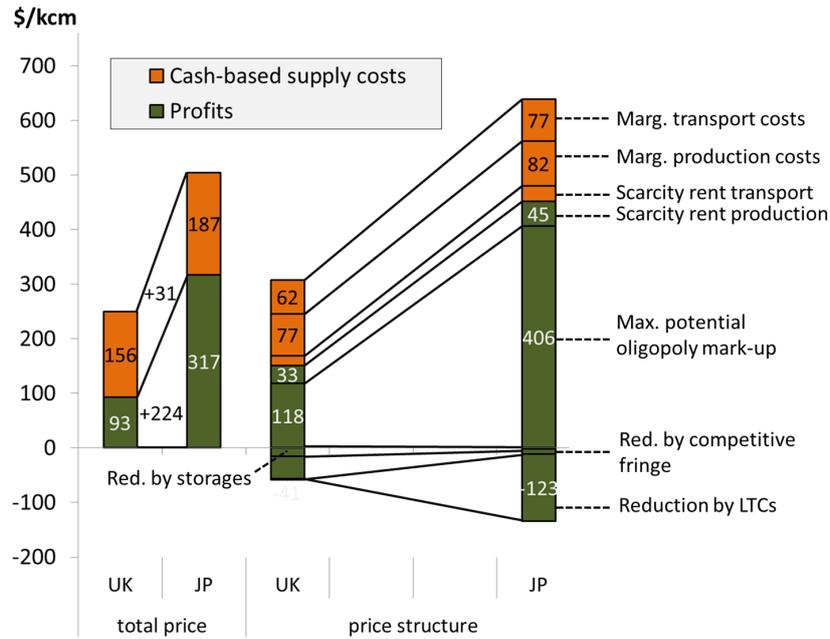


Figure 6: Price structure of the UK and Japan in the reference scenario

the high Japanese dependency on natural gas lets Cournot players realise higher mark-ups in Japan than in the UK.

Yet, both countries are able to limit the oligopolistic mark-ups: The UK has significant domestic production (which we assume to be provided by price-taking producers) and storage reserves that in total lead to a price reduction of 56 USD/kcm (-41 USD/kcm and -15 USD/kcm, respectively). Japan, on the other hand, only has small capacities of domestic natural gas production and seasonal underground gas storages, which only reduce the gas price in total by 12 USD/kcm. Japan’s key advantage in limiting oligopoly mark-ups is its access to long-term contracted LNG volumes. In our setting, the contracts lead to an import price reduction of 123 USD/kcm. In other words, without the secured deliveries by long-term contracts, Japan would be much more likely to be exploited by its suppliers.

### 4.3. Structure of price reactions during a supply disruption

After having provided insight into the price structure of both Japan and the UK in the reference scenario, we focus next on the price increase during a blockage of Hormuz Strait. Figure 7 illustrates the January price level in both countries without a disruption (topmost bar) and with a 6-month disruption (lowest bar). Additionally, the middle bars

of the figure display the cost components leading to an increase and decrease of the gas price during the disruption.

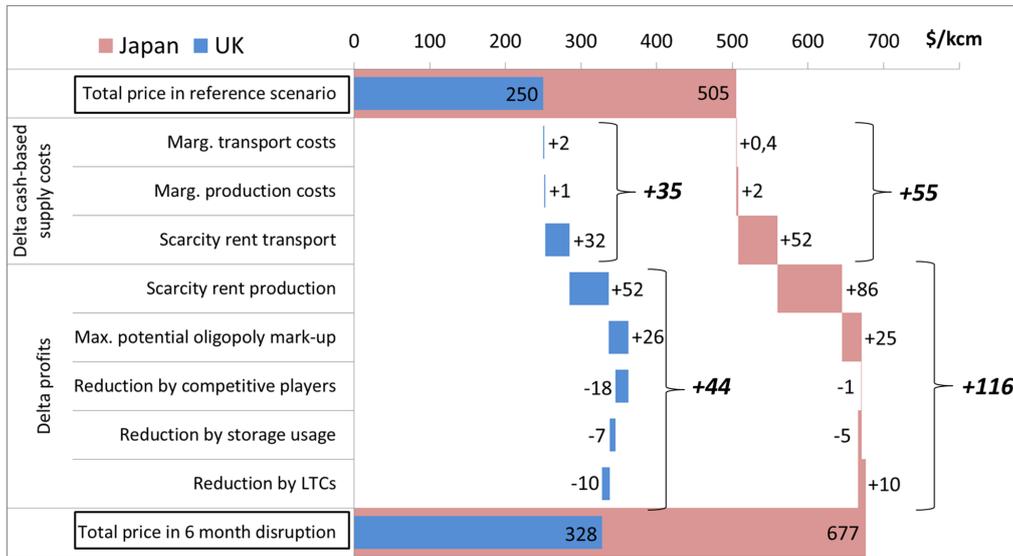


Figure 7: Structure of the import price increase during a 6-month disruption of the Hormuz Strait in Japan and the UK

**Marginal transport and production costs:** We observe a slight increase in those two cost components because gas must be imported from more distant sources and gas production is intensified during the blockage. However, since both production and transport capacities already have high utilisation rates (compared to the global average) in the reference scenario, marginal production and transport costs only explain a fraction of the total price increase in Japan and the UK.

**Scarcity rent of transport:** A blockage of the Hormuz Strait results in an outage of approximately 30% of global LNG trade volumes. LNG importers therefore need to find alternative sources of supply, which makes the available LNG liquefaction capacity (which we account to transport infrastructure) scarce. Costs resulting from transport scarcity explain 52 USD/kcm of the total price increase in Japan, but only 32 USD/kcm in the UK. The difference can be explained by taking a closer look at both countries' market positions: Japan depends solely on LNG imports, is price insensitive and competes for supply with other countries in the same situation (such as South Korea). The UK, however, is more sensitive to prices and, being connected to the European pipeline grid, is linked to producing countries such as Norway, the Netherlands and even Russia. Thus, the UK is less willing to buy gas from LNG terminals where capacity is scarce and prices are consequently high. Most of the increase in transport scarcity rent in the

UK results from bottlenecks in the European pipeline grid, especially during deliveries from Russia. Japan, on the other hand, has to rely on the LNG volumes still available to the global gas market during the blockage of the Hormuz Strait. As Japan competes for LNG supplies (and therefore also for LNG transport capacities) with other LNG-dependent importers, the opportunity costs of the transport value chain to deliver LNG to Japan increase during the blockage.

**Scarcity rent of production:** Production capacity costs explain the major part of the total price increase in Japan (86 USD/kcm) and in the UK (52 USD/kcm). The price increases induced by the scarcity rents of production are therefore higher than those induced by the transport scarcity rents. This indicates that given a blockage of the Strait of Hormuz, production capacity on a global scale is more scarce than transport capacity. Japanese import prices are, however, more affected by the scarcity of production capacity than are the British ones. The reason for the difference is similar to that of the transport scarcity rents. Whereas the UK has alternative sources of supply connected by pipelines, Japan competes with other LNG importers for the production volumes of LNG exporting countries. The opportunity costs of producing gas to sell to Japan at a later point in time therefore increase when the supply side becomes tighter due to a blockage of the Hormuz Strait.

**Maximal potential oligopoly mark-up:** On the one hand, countries reduce demand during a disruption of Hormuz Strait, which decreases the potential mark-up *ceteris paribus*. On the other, as Qatar (QA) and the United Arab Emirates (AE) are not able to export gas, the number of oligopoly players decreases, which in turn increases the potential mark-up. In our setting, we observe that in both Japan and the UK, the impact on the price increase is approximately 25 USD/kcm.

**Reduction by price-taking players:** During the disruption, the UK increases domestic and polypolistic production, which reduces the import price increase by 18 USD/kcm. Japan, on the other hand, covers only a small fraction of total gas supply with domestic production. Therefore, its ability to lessen the import price increase during a blockage of the Strait of Hormuz is limited.

**Reduction by storage usage:** The UK augments its storage depletion by 160 mcm during the disruption, leading to a decrease in the import price by 7 USD/kcm. Even though the storage usage in Japan is only increased by 100 mcm, we observe a reduction of 5 USD/kcm. This indicates that in improving a country's market position, storages increase in importance as countries grow more insensitive to prices.

**Reduction by LTCs:** The UK holds several LTCs, meaning it has secured deliveries from certain exporters. These LTCs lead to a reduction of the price increase by 10 USD/kcm during the disruption. Long-term contracts and the corresponding contractual obligations for certain LNG exporters (Algeria, Nigeria and Trinidad) to deliver gas to the UK result in opportunity costs for the exporters. These costs can be interpreted as a realisation of their price risk. Concerning Japan, LTCs explain a surprising 10 USD/kcm of the price increase during a blockage of the Strait of Hormuz. While LTCs lead to a price decrease of 123 USD/kcm in the reference scenario, LTCs only decrease the import price by 113 USD/kcm in the scenario with a 6-month disruption. This interesting observation can be explained by the fact that Qatar is one of the more important sources of contracted LNG volumes that, in the event of a blockage of the Strait of Hormuz, have to be substituted by non-contracted LNG volumes. Consequently, the price decreasing effect of Japanese LTCs is reduced in the case of a 6-month disruption.

To summarise, we have identified three factors that explain why a blockage of the Strait of Hormuz would affect the Japanese import price twice as much as the British one: First, Japan's import dependency on LNG forces Japan to compete for supplies in the disturbed LNG market. Therefore, scarcity rents for both transport and production are affected stronger than in the UK, where the connection to the European pipeline grid provides a viable alternative to LNG gas during the disruption. Second, during the crisis, the UK profits from price-taking domestic production and storage gas reserves that limit the mark-up rents for oligopolistic players. Japan, on the other hand, has only small capacities of domestic production and underground storage and is therefore more exposed to Cournot behaviour. Third, LTCs help the UK to decrease prices by securing gas deliveries that would normally be sold to the UK at higher price levels. Japan also has significant volumes of LTCs helping to overcome the crisis; however, since part of Japan's LNG long-term contracts are supplied by Qatar (and hence not available in case of a blockage of the Strait of Hormuz), the decreasing price effect in Japan is reduced in comparison to the reference scenario.

## 5. Conclusions

The political situation in the Persian Gulf is exacerbating: Since the beginning of 2012, Iran has threatened to block the Strait of Hormuz, the world's most important LNG choke point. Because regional security of supply depends on the individual supply

structure, a potential blockage would affect gas supplies differently depending on the region of the world.

In our paper, we raise the question in which regions would gas import prices be most affected by a blockage and why. For this purpose, we interpret the case of a blockage of the Strait of Hormuz as a supply shock in a spatial oligopoly. We analyse the compensation of missing Qatari gas supplies and compare regional price effects. Moreover, we develop a framework to disentangle regional price components into increasing and decreasing factors. Identifying the main price drivers allows us to quantify the supply situation in different regions.

We find that the gas price increases most in Japan. We also observe that gas price increases in the UK are significantly lower than those in Japan. US gas prices are hardly affected, as the country is rather independent from global gas trade.

We identify three reasons why a blockage of the Strait of Hormuz affects the import price in Japan much more than that in Britain. First, Japanese gas supplies fully depend on the disturbed LNG market. The UK, on the other hand, has access to the European pipeline grid, which is supplied by important producers such as Russia and Norway. Thus, the UK faces an alternative market that – as opposed to the LNG market – is only accessible by European (and not global) competitors. In turn, Japan has to compete globally for LNG supplies. This translates into higher scarcity rents that Japan has to pay in order to receive LNG volumes.

Second, the UK is less exposed to market power than Japan. Unlike in Japan, UK profits from price-taking domestic production and underground long-term storages (which act as a competitive fringe), thus decreasing mark-up rents of oligopolistic players.

Third, LTCs limit the price increase in the UK, since they secure gas volumes that otherwise would have been sold to the UK at higher prices. In contrast, the price decreasing effect of LTCs diminishes in Japan: The blockage of the Strait of Hormuz suspends LTCs between Qatar and Japan. Therefore, Japan loses its price advantage from the Qatari LTC volumes. In other words, during the disruption, the missing volumes have to be replaced at comparably higher prices.

This study investigates the regionally dispersed price effects following a supply shock in the natural gas market. However, mainly due to computational issues, some simplifying assumptions had to be made in our analysis. First, we assume perfect foresight, which may be a strong simplification, particularly for storage operators. Second, we model storage operators as price takers, despite the fact that a supply shock may allow them to maximise profits by initially refraining from storage depletion and thereby further

increasing gas market prices. Third, we use a partial equilibrium model of the global gas market, thus failing to consider, e.g., the interdependencies between the oil and gas market. The interaction of substitutive fuels, such as oil and gas, could affect regional prices differently during a supply shock. In particular, the analysis of global inter-fuel competition using a model that accounts for strategic behaviour in the respective markets is an interesting possibility for further research.

## References

- 3E Information Development & Consultants, June 2009. China Energy Monthly.
- Bauer, F., Bremberger, C., Kunz, F., 2011. Implementation of the hogan, rosellón, and vogelsang (hrv) incentive mechanism into the intragas model.
- Bettzüge, M. O., Lochner, S., 2009. Der russisch-ukrainische Gaskonflikt im Januar 2009 – eine modell-gestützte Analyse. *Energiewirtschaftliche Tagesfragen* 59 (7), 26–30.
- Boots, M., Rijkers, F., Hobbs, B., 2004. Trading in the downstream European gas market: a successive oligopoly approach. *The Energy Journal* 25 (3), 73–102.
- Borenstein, S., Bushnell, J., 1999. An empirical analysis of the potential for market power in California's electricity industry. *The Journal of Industrial Economics* 47 (3), 285–323.
- CEDIGAZ, 2009. Ugs worldwide data base. Tech. rep., CEDIGAZ.
- CIEP, 2008. The Geopolitics of EU Gas Supply – The role of LNG in the EU Gas Market. Tech. rep., Clingendael International Energy Programme, The Hague, Netherlands.
- Dieckhöner, C., 2012. Simulating security of supply effects of the nabucco and south stream projects for the european natural gas market. *The Energy Journal* 33 (3).
- Dirkse, S. P., Ferris, M. C., 1995. Mcplib: A collection of nonlinear mixed complementarity problems. *Optimization Methods and Software* 5 (4), 319–345.
- Drewry Maritime Research, June 2011. LNG Shipping Market 2011 - Annual Review and Forecast.
- Egging, R., Gabriel, S., Holz, F., Zhuang, J., 2008. A complementarity model for the European natural gas market. *Energy Policy* 36 (7), 2385–2414.
- Egging, R., Holz, F., Gabriel, S. A., 2010. The World Gas Model: A multi-period mixed complementarity model for the global natural gas market. *Energy* 35 (10), 4016 – 4029.
- ENTSO, 2011. European Ten Year Network Development Plan 2011 - 2020. European Network for Transmission System Operators for Gas (ENTSO), [http://www.entsog.eu/download/regional/ENTSO\\_TYNDR\\_MAIN\\_23dec2009.pdf](http://www.entsog.eu/download/regional/ENTSO_TYNDR_MAIN_23dec2009.pdf).
- Ferris, M. C., Munson, T. S., 2000. Complementarity problems in games and the path solver. *Journal of Economic Dynamics and Control* 24 (2), 165–188.
- FGE, December 2010. China Oil and Gas Monthly.
- Gabriel, S., Kiet, S., Zhuang, J., 2005. A mixed complementarity-based equilibrium model of natural gas markets. *Operations Research* 53 (5), 799.

- GIIGNL, 2010. The LNG Industry.
- GIIGNL, 2011. Ex-ship master lng sale and purchase agreement - 2011version.  
 URL [http://www.giignl.org/fileadmin/user\\_upload/pdf/A\\_PUBLIC\\_INFORMATION/Publications/GIIGNL\\_DES\\_MSA2011\\_Final\\_.doc](http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/Publications/GIIGNL_DES_MSA2011_Final_.doc)
- Golombek, R., Gjelsvik, E., Rosendahl, K., 1995. Effects of liberalizing the natural gas markets in Western Europe. *The Energy Journal* 16 (1), 85–112.
- Golombek, R., Gjelsvik, E., Rosendahl, K., 1998. Increased competition on the supply side of the Western European natural gas market. *The Energy Journal* 19 (3), 1–18.
- Haftendorn, C., 2012. Evidence of market power in the atlantic steam coal market using oligopoly models with a competitive fringe.
- Haftendorn, C., Holz, F., 2010. Modeling and analysis of the international steam coal trade. *The Energy Journal* 31 (4), 205–229.
- Harker, P. T., 1986. Alternative models of spatial competition. *Operations Research* 34 (3), 410–425.
- Hecking, H., Panke, T., 2012. COLUMBUS - a global gas market model. EWI Working Paper 12/06.
- Holz, F., Von Hirschhausen, C., Kemfert, C., 2008. A strategic model of European gas supply (GASMOD). *Energy Economics* 30 (3), 766–788.
- IEA, 2011. Medium-Term Oil & Gas Markets 2011.
- IEA, 2011a. Natural Gas Information. Tech. rep., International Energy Agency.
- IEA, 2011b. World Energy Outlook 2011. International Energy Agency, Paris.
- IGU, 2003. ABCs of Underground Gas Storage. IGU WOC2 group for WGC 2003 in Tokyo.
- Jensen, J. T., 2004. *The Development of a Global LNG Market*. Alden Press, Oxford.
- Lise, W., Hobbs, B., 2008. Future evolution of the liberalised European gas market: Simulation results with a dynamic model. *Energy* 33 (7), 989–1004.
- Lise, W., Hobbs, B., Van Oostvoorn, F., 2008. Natural gas corridors between the EU and its main suppliers: Simulation results with the dynamic GASTALE model. *Energy Policy* 36 (6), 1890–1906.
- Lochner, S., Dieckhöner, C., 2011. Civil unrest in North Africa - Risks for natural gas supply? EWI Working Paper 11/1, Institute of Energy Economics at the University of Cologne (EWI).

- Neumann, A., Viehrig, N., Weigt, H., 2009. InTraGas - A Stylized Model of the European Natural Gas Network. Working Paper WP-RM-16, Dresden University of Technology.
- OME, 2001. Assessment of internal and external gas supply options projects for the EU, Evaluation of the Supply Costs of New Natural Gas Supply Projects to the EU and an Investigation of Related Financial Requirements and Tools. Chapter 3 - Assessment of Future Supply Costs to Europe, Observatoire Méditerranéen de l'Énergie.
- Paulus, M., Trüby, J., 2011. Coal lumps vs. electrons: How do chinese bulk energy transport decisions affect the global steam coal market? *Energy Economics* 33 (6), 1127–1137.
- Rempel, H., 2002. Natural gas for europe - present state and predictions for a stable supply in the future. *Energy Exploration & Exploitation* 20 (2&3), 219–237.
- Seeliger, A., 2006. Entwicklung des weltweiten Erdgasangebots bis 2030. No. 61 in *Schriften des Energiewirtschaftlichen Instituts*. Oldenbourg Industrieverlag, München.
- Söderbergh, B., Jakobsson, K., Aleklett, K., 2009. European energy security: The future of norwegian natural gas production. *Energy Policy* 37 (12), 5037–5055.
- Söderbergh, B., Jakobsson, K., Aleklett, K., 2010. European energy security: An analysis of future russian natural gas production and exports. *Energy Policy* 38 (12), 7827–7843.
- Takayama, T., Judge, G. G., 1964. Equilibrium among spatially separated markets: A reformulation. *Econometrica: Journal of the Econometric Society*, 510–524.
- Tirole, J., 1988. *The theory of industrial organization*. MIT press.
- Trüby, J., 2013. Strategic behaviour in international metallurgical coal markets. *Energy Economics* 36, 147–157.
- van Oostvoorn, F., 2003. Long-term gas supply security in an enlarged Europe: final report ENGAGED project. Tech. rep., Energy research Centre of the Netherlands ECN.
- Yang, C. W., Hwang, M. J., Sohng, S. N., 2002. The cournot competition in the spatial equilibrium model. *Energy Economics* 24 (2), 139–154.
- Yoshizaki, K., Sato, N., Fukagawa, H., Sugiyama, H., Takagi, G., Jono, T., 2009. Utilization of Underground Gas Storage (UGS) in Japan. 24th World Gas Conference 2009.
- Yuwen, Z., 2009. Study and Construction of underground gas storage facilities in China: Current status and its future. 24th World Gas Conference 2009.

## A. Details on the model

The model's spatial structure is formulated as a directed graph consisting of a set  $N$  of vertices and a set  $A \subset N \times N$  of edges. The set of vertices can be subdivided into sources and sinks, where gas production facilities are modeled as sources and importing regions as sinks. The model's time structure is represented by a set  $T \subset \mathbb{N}$  of points in time (months). This time structure is flexible and can be customized by the user, which means any year ( $y$ ) until 2050 can be simulated with up to twelve months per year. An overview of all sets, decision variables and parameters can be found in Table 1.

### Remaining capacity constraints

In Section 2.2, we skipped a few capacity constraints in order to keep the description of our model as brief as possible. These are listed in the following. Along the lines of Inequality 17, Inequality 24 states that the sum over all transport flows (decided on by the traders) through the liquefaction terminal, i.e., all natural gas that is liquefied, has to be lower than the respective liquefaction capacity.

$$cap_{l,t} - \sum_{e \in E} \sum_{n \in A_{.,l}} fl_{e,n,l,t} \geq 0 \quad \forall l, t \quad (\zeta_{l,t}). \quad (24)$$

The same holds true for the restriction of gas volumes that are regasified and then transported to a demand node  $d$  in month  $t$ :

$$cap_{r,t} - \sum_{e \in E} \sum_{d \in A_{r,.}} fl_{e,r,d,t} \geq 0 \quad \forall r, t \quad (\gamma_{r,t}). \quad (25)$$

Finally, we account for a limitation of available LNG tankers. Hence, the sum of all gas volumes transported between liquefaction terminal  $l$  and regasification terminal  $r$  in month  $t$  is restricted by the available LNG transport capacity:

$$(LNGcap) * 8760/12 * speed - \sum_{e \in E} \sum_{l \in L} \sum_{r \in R} 2 * (fl_{e,l,r,t} * dist_{n,n1}) \geq 0 \quad \forall t \quad (t_t) \quad (26)$$

where  $speed$  is defined as the average speed of a LNG tanker (km/h),  $dist_{n,n1}$  as the distance in km between node  $n$  and node  $n1$  and  $LNGcap$  as the number of existing LNG tankers times their average size in the initial model year. By using Inequality 26, we take into account that each LNG tanker that delivers gas to a regasification terminal has to drive back to a liquefaction terminal in order to load new LNG volumes. Therefore,

we simplify the model by assuming that each imaginary LNG tanker drives back to the liquefaction terminal from where it started.

## First-order conditions of the model

### Physical flows

Taking the first partial derivative of Equation 16 with respect to  $fl_{e,n,n1,t}$  and accounting for the Inequalities (capacity constraints) 17, 24, 25 and 26 results in:

$$\begin{aligned} \frac{\partial L_{eII}}{\partial fl_{e,n,n1,t}} = & -\lambda_{e,n1,t} + \lambda_{e,n,t} + trc_{n,n1,t} + opc_{n,t} \\ & + \phi_{n,n1,t} + \zeta_{l,t} + \gamma_{r,t} \\ & + \iota_t * 2 * dist_{l,r} \geq 0 \quad \perp \quad fl_{e,n,n1,t} \geq 0 \quad \forall e, n, n1, t. \end{aligned} \quad (27)$$

### Production

The first-order condition for production is derived from the payoff function  $\Pi_p(pr_{e,p,t})$  defined as

$$\max_{pr_{e,p,t}} \Pi_p(pr_{e,p,t}) = \sum_{t \in T} (\lambda_{e,p,t} * pr_{e,p,t} - prc_{e,p,t}(pr_{e,p,t})) \quad (28)$$

where  $pr_{e,p,t}$  is the corresponding decision vector of  $p$ . The set of feasible solutions for  $pr_{e,p,t}$  is restricted by the non-negativity constraint  $pr_{e,p,t} \geq 0$ . The first-order conditions of the producer's problem consists of Constraint 15 as well as the following partial derivative of the Lagrangian  $L_p$ :

$$\frac{\partial L_p}{\partial pr_{e,p,t}} = -\lambda_{e,p,t} + mprc_{e,p,t}(pr_{e,p,t}) + \mu_{e,p,t} \geq 0 \quad \perp \quad pr_{e,p,t} \geq 0 \quad \forall p, t \quad (29)$$

## Storage utilisation

The following derivatives derived from Equations 18 and 19 (as well as the respective capacity constraints) constitute the first-order conditions of the storage operator's optimisation problem:

$$\frac{\partial H_s}{\partial sd_{s,t}} = -\beta_{d,t} + \sigma_{s,t} + \theta_{s,t} \geq 0 \quad \perp \quad sd_{s,t} \geq 0 \quad \forall s, t \quad (30)$$

$$\frac{\partial H_s}{\partial si_{s,t}} = -\sigma_{s,t} + \beta_{d,t} + \rho_{s,t} \geq 0 \quad \perp \quad si_{s,t} \geq 0 \quad \forall s, t \quad (31)$$

$$-\frac{\partial H_s}{\partial st_{s,t}} = \epsilon_{s,t} = \Delta\sigma_{s,t} = \sigma_{s,t+1} - \sigma_{s,t} \leq 0 \quad \perp \quad st_{s,t} \leq 0 \quad \forall s, t. \quad (32)$$

Table 1: Model sets, variables and parameters

<b>Sets</b>	
$n \in N$	all model nodes
$t \in T$	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 / importing regions
$r \in R \in N$	regasifiers
$l \in L \in N$	liquefiers
$s \in S \in N$	storage operators
<b>Primal Variables</b>	
$pr_{e,p,t}$	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
$sd_{s,t}$	depleted gas volumes
<b>Dual Variables</b>	
$\lambda_{e,n,t}$	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
$\beta_{d,t}$	marginal costs / price in node $n$ in time period $t$
$\mu_{e,p,t}$	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
$\rho_{s,t}$	marginal benefit of an additional unit of storage injection capacity
$\theta_{s,t}$	marginal benefit of an additional unit of storage depletion capacity
$\iota_t$	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
$\chi_{e,n,y}$	marginal costs of delivery obligation
<b>Parameter</b>	
$cap_{n,t/n,n1,t}$	monthly infrastructure capacity
$trc_{n,n1,t}$	transport costs
$(m)prc_{n,t}$	(marginal) production costs
$opc_{n,t}$	operating costs
$mdo_{e,n,t}$	minimal delivery obligation of exporter $e$
$dist_{n,n1}$	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. & depl. capacity

## B. Data

Table 2: Nodes in the model

	<b>Total number of nodes</b>	<b>Number of countries</b>	<b>Countries with more than one node</b>	<b>Countries aggregated to one node</b>
<b>Demand</b>	84	87	Russia and the United States	Baltic countries and former Yugoslavian republics
<b>Production</b>	43	36	China, Norway, Russia and the United States	-
<b>Liquefaction</b>	24	24	-	-
<b>Regasification</b>	27	25	-	-
<b>Storages</b>	37	37	-	-

### Production

For the majority of nodes, we model gas production endogenously. Only for very small gas producing countries and those with little exports do we fix production volumes to limit model complexity. Concerning endogenous production, we face the problem that there are only sources with data on historical production (i.e., IEA (2011a)) but no single source that provides information about historical or current production capacities. We collect information from various sources listed in Table 3. For the major LNG exporters (Qatar and Australia), we derive possible production capacities from the domestic demand assumptions and liquefaction capacities. In total, we assume a global production capacity of 3542 bcm in 2010 and 3744 bcm in 2012. Twelve to thirteen percent of that capacity is assumed to be fixed production. The usage of the remaining production capacity (87%) is optimised within the model.

Concerning production costs, we follow an approach used in Golombek et al. (1995, 1998).<sup>22</sup> For the exporting countries, we estimate Golombek production functions by OLS regression, using various data sources such as Seeliger (2006) and OME (2001), or information on costs published in the *Oil and Gas Journal*.

<sup>22</sup>Please refer to Subsection 2.2 for more details on the Golombek production function, in particular on the marginal cost function (its first derivative) that is used in our model.

Table 3: Assumptions and data sources for production

	<b>Assumptions</b>	<b>Sources</b>
	Exogenous production of small countries in 2010	IEA (2011a)
	Forecast on exogenous production of small-scale producing countries	IEA (2011a,b); ENTSOG (2011)
	Estimates of future production capacity in the USA	IEA (2011)
<b>Production</b>	Development of production capacities in Norway and Russia	Söderbergh et al. (2009, 2010)
	Forecasts for Saudi-Arabia, China, India, Qatar and Iran	IEA (2011a)
	Information which allow us to get an idea of production capacities in Africa, Malaysia, Indonesia and Argentina	IEA (2011b)

## Infrastructure

We consider the global gas infrastructure data aggregated on a country level. To reduce complexity, we bundle LNG capacities to one representative LNG hub per country. The same applies for storages and pipelines: Although, e.g., Russia and the Ukraine are connected via multiple pipelines in reality, we bundle pipeline capacity into one large pipeline “Russia-Ukraine”. The Institute of Energy Economics at the University of Cologne (EWI) has its own extensive pipeline database that serves as the major source for current pipeline capacities and distances. New pipeline projects between 2010 and 2012 are based on publicly available data. The distances of the 196 LNG routes were measured using a port to port distance calculator<sup>23</sup>.

We account for LNG transport distances by LNG tanker freight rates of 78000 USD/day (Jensen, 2004; Drewry Maritime Research, 2011). Based on our costs assumptions shown in Table 4, the break-even distance between onshore pipelines and LNG transport is 4000 km, and around 2400 km for offshore pipelines<sup>24</sup>. This is in line with Jensen (2004) and Rempel (2002).

<sup>23</sup>Please refer to <http://www.searates.com/reference/portdistance/>

<sup>24</sup>We assume that the average speed of a typical LNG vessel amounts to 19 knots and that the average capacity lies at circa 145000 cbm.

Table 4: Assumptions and data sources for infrastructure

	<b>Assumptions</b>	<b>Sources</b>
<b>Infrastructure</b>	Current and future capacities of LNG terminals	GIIGNL (2010); IEA (2011b)
	National storage capacities (yearly working gas volumes)	IEA (2011a); CEDIGAZ (2009)
	Underground storage capacities of China, Japan and South Korea	Yuwen (2009); Yoshizaki et al. (2009); IGU (2003)
	Onshore / offshore pipelines transportation costs (16 USD/kcm/1000 km and 26 USD/kcm/1000 km)	Jensen (2004); van Oostvoorn (2003); Rempel (2002)
	LNG liquefaction and regasification costs add up to 59 USD/kcm	Jensen (2004)
	Variable operating costs for storage injection of 13 USD/kcm	CIEP (2008)

### C. Cournot setting vs. perfect competition

The objective of this section is to justify our decision to model the gas market as an oligopoly. Therefore, we compare two market settings – perfect competition and Cournot competition with a competitive fringe – with respect to how well these simulations fit to the actual market outcomes in 2010. These two settings were chosen because, on the one hand, global gas markets are characterised by a relatively high concentration on the supply side. On the other, due to cost decreases in the LNG value chain, regional arbitrage has become a viable option, thereby potentially constraining the exercise of market power.

We start out by analysing the model outcomes of the perfect competition scenario. Figure 8 compares the observed average prices in USD/kcm with the resulting average market clearing prices in the different market settings. Simulated prices in the perfect competition scenario are significantly lower than the actual prices in 2010 in almost every country depicted in Figure 8, except for the US.

Figure 9 displays the deviation of simulated total demand from actual demand realised in 2010 for the two different model settings. The deviation is shown as a percentage of the actual demand figures in 2010. Figure 9 shows that endogenous demand in the perfect competition scenario strongly deviates from reality. The largest deviations were observed for Asia/Oceania and Europe, where the modelled demand exceeds the actual

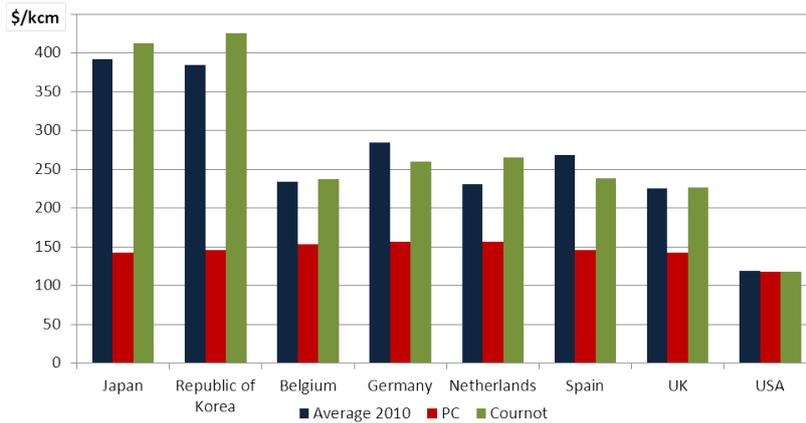


Figure 8: Actual and simulated average prices (in USD/kcm)

realised demand in 2010 by 3.7% and 9.7%, respectively. In contrast, simulated demand in North America resembles the actual demand quite well.

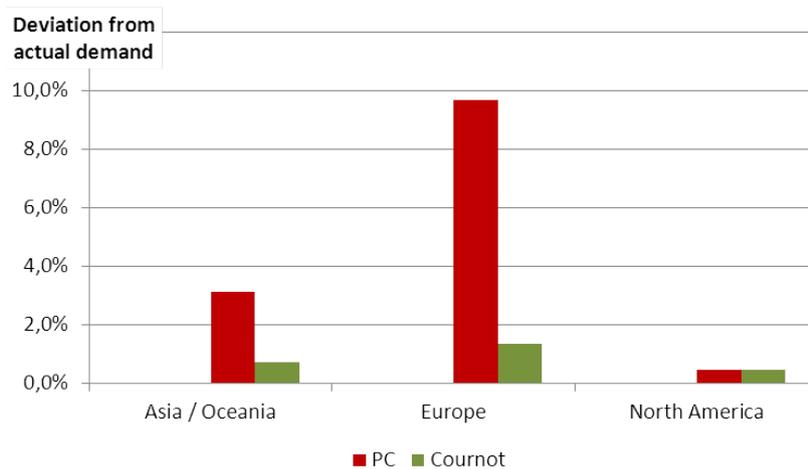


Figure 9: Deviation of demand under different settings (in % of actual demand in 2010)

Figures 10 and 11 display production capacity (indicated by the bars), simulated production volumes and actual production in 2010 for five selected countries. Concerning the perfect competition case, the simulated production of the five producing countries exceeds production volumes observed in 2010 (see Figures 10 and 11). From Figures 8 to 11, we conclude, that except for the North American natural gas market, the assumption of perfect competition does not fit well with actual market data. Therefore, we model the eight most important LNG exporting countries and the three most important pipeline exporters as Cournot players, thus allowing them to exercise market power by means of

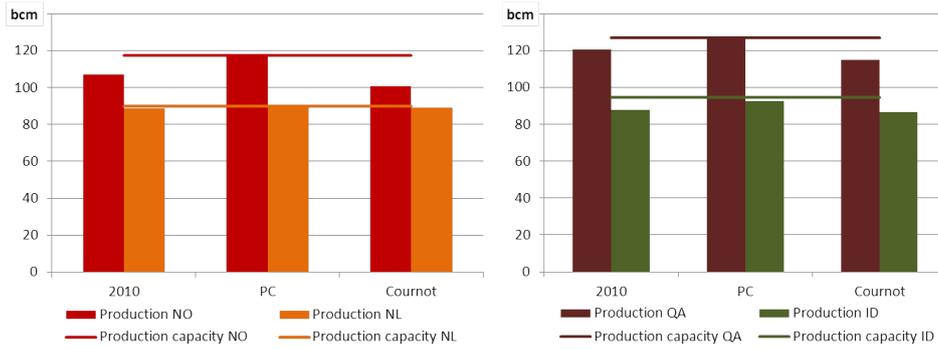


Figure 10: Annual production and capacities in four selected countries in the different market settings (in bcm)

production withholding. All countries have almost all of their exports coordinated by one firm or consortium, e.g., Gazprom (Russia), Statoil (Norway) or Sonatrach (Algeria).

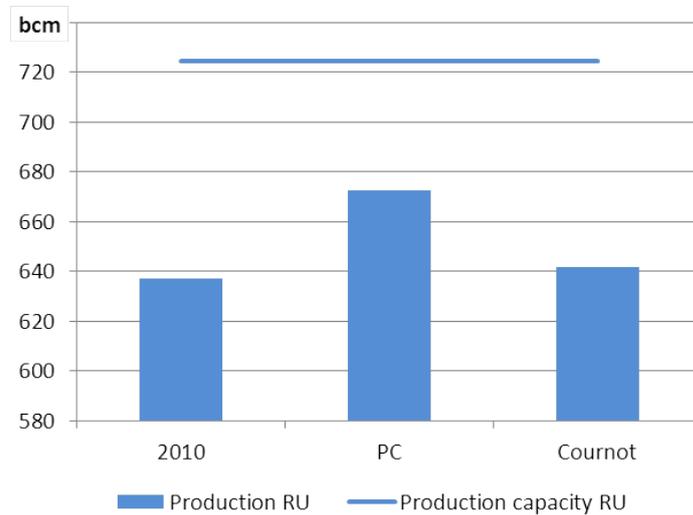


Figure 11: Annual Russian production and capacities in the different market settings (in bcm)

In comparison to the perfect competition setting, model results in the Cournot setting (i.e., demand, production and prices) seem to represent reality more accurately. Since the Cournot setting with a competitive fringe provides the closer fit to actual production, demand and price data such a setting is used for our analysis presented in Section 4.

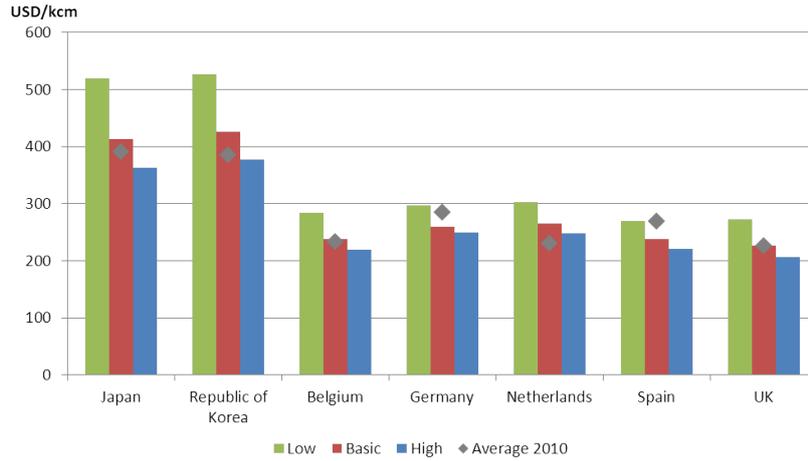


Figure 12: Sensitivity Analysis I: Comparison of prices in selected countries with varying elasticity assumptions

## D. Sensitivity analysis

We analyse three alternative settings for the IP sector’s demand elasticity, since this elasticity assumption is most important in determining overall demand elasticity in almost all countries. For example, we conduct one sensitivity analysis in which the elasticity in all countries is 50% higher (labeled “High”), i.e., -0.15 and -0.6 respectively, one in which it is 50% lower (“Low”) and one in which the IP sector’s demand elasticity is -0.4 in all countries (“Same”).

We find that elasticity assumptions (“Basic”) used in our analysis provide the best fit with actual data. While prices in the sensitivity scenario “Low” substantially exceed actual prices (see Figure 12, in particular in Japan and Korea), prices in the sensitivity scenario “High” undershoot prices in almost all countries (with the exceptions of Korea and the Netherlands). If we take a closer look at the scenario “Same” (Figure 13), we see that by assuming the same demand elasticity in all countries, regional price differences are much lower than in reality (or in the scenario “Basic”). Therefore, given the elasticity assumptions used in this paper, we are able to obtain a reasonably good fit to the actual prices in 2010 and conclude that no other combination of elasticities could improve the accuracy of our model.

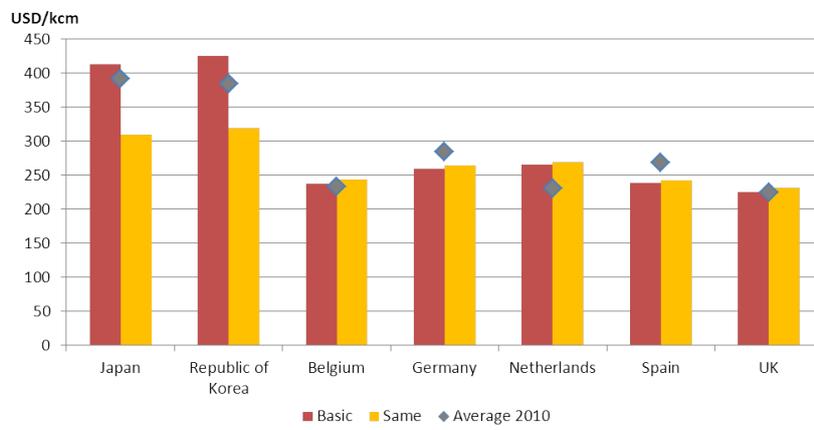


Figure 13: Sensitivity Analysis II: Comparison of prices in selected countries with varying elasticity assumptions