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

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Supply shocks in the global gas market might affect countries differently since the market is regionally interlinked but not perfectly integrated. Additionally, high supply side concentration might expose countries to market power in different ways. To evaluate the strategic position of importing countries concerning gas supplies we disentangle import prices to price increasing and decreasing factors. Since the interrelations on the global gas market are complex 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 side. We find that Japan faces the most severe price increases as it completely relies on LNG supply. In contrast, European countries like the UK benefit from a good interconnection to the continental pipeline system and significant domestic price-taking production, both of which help to mitigate an increase in physical costs of supply as well as the exercise of market power.

Keywords: Natural gas market, security of supply, international trade, mixed complementarity problem
JEL classification: C61, L72, Q34, Q41

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1. Introduction

International resource markets more and more intermesh the world's economies. But as interdependencies increase, regional supply shocks, such as disruptions of trade flows caused by e.g. geopolitical conflicts, might get a global relevance. The global oil market, for example, has seen several of such supply shocks in history: among the most prominent conflicts, the First Gulf War in 1991 as well as the Iraq War in 2003 had significant influence on oil prices. As the global oil market is highly integrated, these regional conflicts caused global price shocks affecting countries all over the world.

A notable example for a resource market which is not highly integrated on a global scale is the one for natural gas. 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 might be globally disperse, as different world regions have different supply structures: domestic resources, the extent of import diversification, trade relations with small fringe producers or contractual supply agreements might be factors limiting price shocks.

One recent example of a supply shock was the Russian-Ukrainian gas crisis in 2009. Whereas European gas prices significantly increased during the crisis, e.g. US gas prices were not affected at all. Apart from the higher maturity of global oil trade, the main reason for the lower level of global natural gas market integration is that LNG transport including liquefaction and regasification is comparably complex and costly compared to 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 as well of being exposed to increasing market power during the shock.

Regional differences in supply structures and demand flexibility are important in the global natural gas market. The US has become almost independent of gas imports because of rising shale gas production, for example, while Japan relies solely on LNG imports. Additionally, Japanese natural gas demand has become more and more inflexible as the post-Fukushima outages of nuclear power generation are compensated by higher utilisation of remaining coal and natural gas fired power plants during the last couple of years. This reduces the fuel-switching potential in the Japanese electricity sector to a minimum. Also, 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 needs specific infrastructure to be transported, either via pipelines or the LNG value chain. Since gas is sometimes transported thousands of kilometres, thereby transiting different countries or crucial waterways, trade flows are highly vulnerable to be disrupted: As mentioned, the Ukrainian gas crisis in 2009 had only a regional effect on European gas prices. One example for a gas supply disruption that might have a global relevance is a potential blockage of the Strait of Hormuz.

The Strait of Hormuz is a 21 nautical miles wide passage connecting the Persian Gulf with the Indian Ocean. In 2011, 17 million barrels of oil per day or 20% of global trade volumes were shipped through this channel. What is often left out in public debate is the fact that the Strait of Hormuz has a 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). And in contrast to the transport of oil there is no opportunity to bypass the crucial waterway by means of pipeline transport. Consequently, LNG volumes shipped through the Hormuz Strait are important already and are likely to increase considerably in future years as gas demand in Asia is expected to increase strongly: the International Energy Agency (IEA) projects a doubling of 2011 gas demand in China and India until 2017. The world's two largest LNG importers Korea and Japan - both satisfying national gas demand by more than 95% with LNG - will presumably increase their gas consumption as well. Although demand is not predicted to rise in Europe, decreasing indigenous production will foster imports there as well (ENTSOG, 2011).

Given the regional differences in supply structure and demand flexibility as well as the supply side concentration, a potential Hormuz Strait blockage can therefore be broken down to the economic problem of 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 major factors influencing the magnitude of price effects in globally disperse demand regions. We therefore develop a model to disentangle import prices into decreasing and increasing drivers 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 on the global gas market are more complex due to e.g. seasonal demand patterns, capacity constraints and spatial supply cost differences, we use a worldwide gas market simulation model (Hecking and Panke, 2012). It is a spatial partial equilibrium model accounting for 87 countries, comprising the major national producers and importers as well as the relevant gas infrastructure like 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, it 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 on the global gas market within a consistent framework and identify regional price and welfare effects. Third and central point 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 the price increasing impacts of marginal transport and production costs, scarcity rents of transport and production capacity as well as the exploitable oligopoly mark-up. We are also able to identify price decreasing impacts such as trade relations to price-taking fringe suppliers or secured deliveries by long-term supply contracts.

We apply this approach to simulate a disruption of Hormuz Strait. Although such a disruption is fictitious, its consequences are interesting from an economic as well as a geopolitical point of view since Qatar's LNG exports supply countries all over the world. We simulate a 6-months lasting blockage thereby focusing on three countries USA, the UK and Japan which serve as prominent examples for a distinct supply structure each. We observe the strongest price reactions in Asia, prices in Japan rise from an already high level (505 USD/kcm) by up to 171 USD/kcm during a 6-months disruption. While US gas prices hardly change at all, European gas prices are also 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.

Besides the US American import independency, we identify and quantify three factors which 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 with price-taking indigenous production and storage capacity explain its higher exposure to changes in supply costs as well as increasing exertion of market power. Thirdly, as Qatar is an important source of Japan's contracted LNG import volumes, the price decreasing effects of Japan's LTCs is reduced in comparison to the reference scenario. Consequently, Japan's gas price increase is 92 USD/kcm higher than the one in the UK.

Our research is related to literature on quantitative analyses of security of gas supply based on numerical simulations of spatial Cournot oligopolies in resource markets.

In particular 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 which extent.

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 impact of new pipeline corridors to Europe and new LNG ports on security of supply. Papers of simulation based analyses of the effects of (geo-) political conflicts or the likes on the natural gas market are also rare and also concentrate on Europe only. Bettzüge and Lochner (2009) or 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. Firstly, we develop a framework for analysing regional price reactions after a trade disruption in a spatial oligopoly by disentangling prices into its increasing and decreasing factors. Secondly, we assess the strategic position of gas importing countries during a trade disruption by applying our methodology. Thirdly, in contrast to most studies on security of gas supply our model covers the worldwide natural gas market, thus we are able to analyse the consequences of a regional (geo-) political conflict on a global scale.

The remainder of this paper is structured as follows. The paper's methodology is described in section 2. We derive the spatial oligopoly simulation model and develop an approach to disentangle prices using the model results. Section 3 describes the data, main parameter assumptions and the scenario setting. The results are presented in section 4. In particular, we focus on the price difference between Japan and the UK, identify the major price drivers and provide an in-depth analysis of both countries' supply situation. Section 5 concludes.

2. Methodology

We argue that international gas trade is best represented by a Cournot oligopoly with a competitive fringe since on the one hand large state-owned companies such as Gazprom, Sonatrach, Qatargas or Statoil control significant export volumes. On the other hand also a large number of companies with little annual production operate on the supply side, most of them providing no significant export volumes and thus representing a competitive fringe.[1]

In order to disentangle natural gas import prices into its components, 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 though. Since international gas trade is characterised by spatially distributed demand and supply plus a complex network of pipelines and LNG infrastructure, it is secondly necessary to develop a numerical spatial oligopoly model to simulate the market. Thirdly, we apply the price determination from the simple Cournot oligopoly model to the numerical oligopoly model 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 commence by deriving the optimal supply Q^* in a Cournot oligopoly with N asymetric players, i.e. players have 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 price determination in an oligopoly.

[1] We provide modelling results for the international gas market in 2010 assuming perfect competition in Appendix C. We find that modelling results do not match actual market results well. Consequently, we choose to model the global gas market as a Cournot oligopoly with a competitive fringe. We model the 8 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 in common that almost all of their exports are coordinated by one firm or consortium. Appendix C also contains the model results for our Cournot setting. Comparing them to actual market results, a better match than for the perfect competition setting is found.

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

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

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

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

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

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

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

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

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

Inserting equation 4 into the linear inverse demand function yields:

$$P^*(Q^*) = A - BQ^* \tag{6}$$

$$= \frac{1}{N+1}A + \frac{1}{N+1}\sum_{i=1}^{N} msc_i \tag{7}$$

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

Consequently in a Cournot oligopoly with asymetric players the equilibrium price equals the average marginal supply costs plus an average mark-up which 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 up to their maximum capacity and the oligopolistic players maximise their profit over the residual demand function.[2]

2.2. A spatial equilibrium model of the global gas market

Although we derived the formula for a simplified market, price determination is essentially the same in a set-up with multiple, interconnected markets and time periods (because of e.g. the possibility of storing a commodity) as it is the case with the global natural gas market. The main difference is that scarcity rents of production and infrastructure capacity are affected by the interrelation of all markets and time periods. Therefore, we develop a numerical spatial oligopoly model to simulate international gas trade next.

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 are essential to accurately model the natural gas market.[3] Figure 1 illustrates the logical structure of our model.

Exporters are vertically integrated with one or multiple 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 node.[4] Exporters compete with each other for the demand, thereby acting as Cournot players or competitively. 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. the costs associated with the physical realisation of the trades, vary depending on the location of production nodes and demand nodes. Each exporter's marginal supply costs consist

[2] 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 the focus on a zero-cost competitive fringe with a binding capacity constraint. Our application therefore follows the approach chosen in Borenstein and Bushnell (1999).

[3] Haftendorn (2012) stresses the point that when modelling a Cournot oligopoly with a competitive fringe with non-binding capacity constraints using a conjectural variation like ours model the resulting market equilibrium might leave the oligopoly players with lower profits compared to a setting where they price their sales with marginal supply costs, i.e. act as price takers. However, this objection is of no concern in our analyses since the competitve fringe in the reference scenario, and hence also in the scenario with a blockage of the Strait of Hormuz, faces binding capacity constraints.

[4] For more details on how the demand functions are determined, please refer to section 3.1.

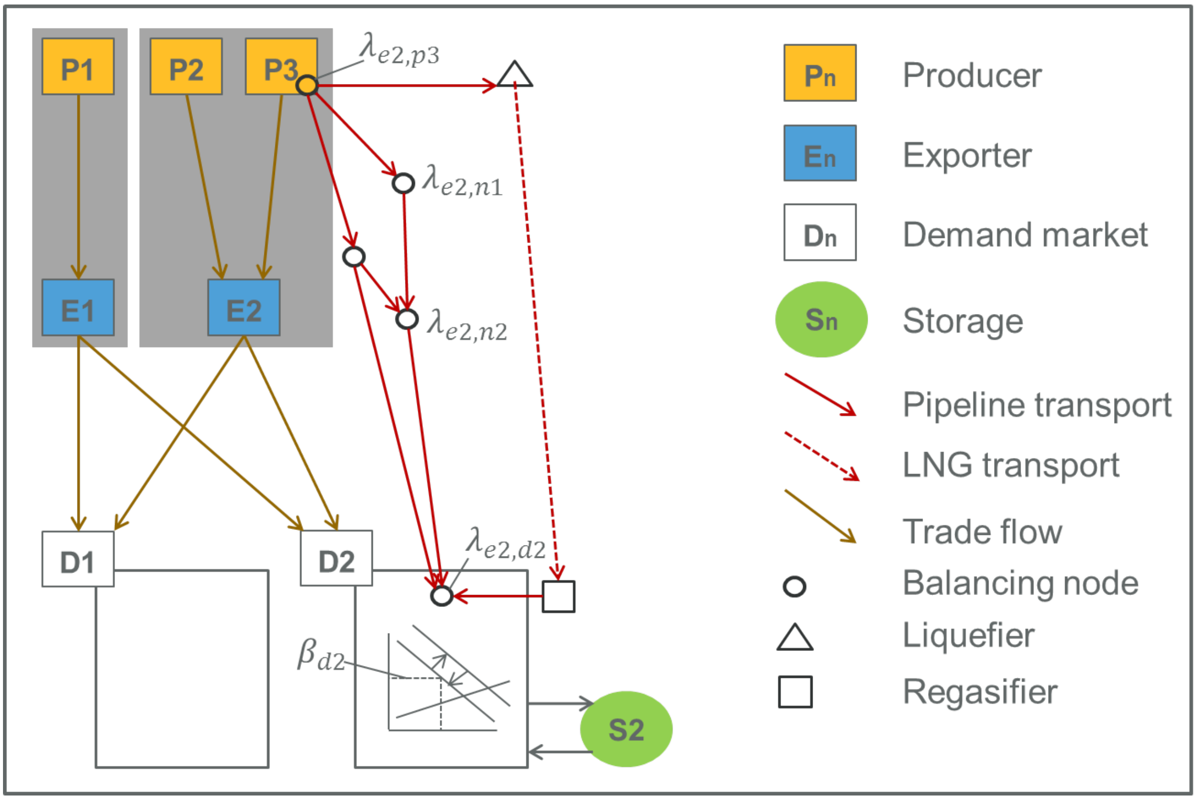

Figure 1: Logical structure of the gas market model

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 might want to use the same pipeline to deliver gas to a demand node, financial trades of one exporter influence the costs of other exporter's physical transports.

We start out by developing the optimisation problems of the different players in our model and derive an exemplary corresponding first-order optimality conditions for one player. The first-order conditions combined with the market clearing conditions constitute our partial equilibrium model of the global gas market. The vector of variables in parentheses on the right-hand side of each constraint are the Lagrange multipliers used when developing the first-order conditions (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 here 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 they were able to exercise market power.

The profit function $\Pi_{eI}(tr_{e,d,t})$ is defined as[5]

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

where $\beta_{d,t}$ is the market clearing price in importing region d, $tr_{e,d,t}$ is the quantity trader e sold to region d at time t and $\lambda_{e,d,t}$ corresponds to the exporter's costs of physical gas delivery 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 $mdo_{e,d,t}$.[6] Thus, LTCs are taken into account by incorporating the following constraint:

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

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:

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

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

5 In order to keep the formulae as simple as possible no discount factor is included in the following.

6 To limit complexity, we exclude the possibility of reshipping contracted LNG to other countries. This can be 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 a individual market clearing condition which has to be fulfilled for every model node in which an exporter is active $n \in N_e$:

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

with $A_{\cdot,n}$ being a set which includes all transport routes leading to node n. $pr_{e,p,t}$ 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 physcial supply to node n. If we consider a demand node $d(n) \in D_e$, market clearing condition 12 simplifies to[7]

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

Hence, equation 12 also assures that the gas volumes, which exporter e sold at the wholesale market of demand node d, are actually physically transported there. If we consider a production node p, market clearing condition 12 collapses to:

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

Thus, the gas volumes produced have to match the physical flows out of node p. Thereby, 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 as being 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 being oligopoly players while production is priced at marginal costs. Hence, the corresponding dual variable $\lambda_{e,p,t}$ to equation 14

[7] Equation 13 holds true if the demand node has no further connections, i.e. is no transit country. In case of a country like Poland physical flows of e.g. the Russian exporter to Poland have to equal volumes sold to Poland plus all transit volumes.

represents marginal production costs. Production in production region p is subject to a production constraint:

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

Equations 13 and 14 also make sure 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 physcial 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:

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

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 regasification node,$r(n)$, $opc_{n,t}$ would reflect the costs of regasifying a unit of natural gas. If $r(n)$ then $n1$ has to be a liquefaction 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 like e.g. the pipeline capacity:

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

Thus, the sum over all transport flows (decided on by the traders) through the pipeline between node 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), regasified ($\gamma_{r,t}$) as well as LNG transport volumes (ι_t).[8]

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

[8] The interested reader is refered to Appendix A for a detailed description of the omitted capacity constraints.

the exporter's marginal costs of supplying natural gas (including production costs $\lambda_{e,p,t}$) to node n as it has been done in equation 9.

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 in months with low prices and reselling it in months with high prices. In our model, we assume storage operators are price takers[9] and due to the nature of our modelling approach they also have perfect foresight.[10] Each storage operator faces a dynamic optimisation problem of the following form:

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

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:

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

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

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

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

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

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

[9] This assumption had to be made in order to reduce model complexity and ensure solvability. Yet the direction of identified effects remains unchanged if storage operators are modelled as Cournot players.

[10] When analysing a supply disruption, this assumption might overestimate the price decreasing effect of storages. For a description of how we handled the assumption in our paper, 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 respective market clearing conditions discussed previously. In addition, we have to include one last market clearing condition:

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

The last market clearing condition (equation 23) states that final customer's 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 gas volumes injected ($si_{s,t}$) into the storage facility at node $s(d)$ is met by the sum over all gas volumes sold at the wholesale market by traders e and gas volumes depleted ($sd_{s,t}$) from storage facility s. Thus, the dual 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.[11] 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 of average marginal supply costs of the Cournot players. In contrast, the model presented in section 2.2 allows to incorporate more complex market settings. As a result of added complexity, like additional import regions, long-term supply contracts as well as production and transport capacity constraints, 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, if the price β_d covers his supply costs $\lambda_{e,d}$ and his individual oligopoly mark-up $cv_e * slope_d * tr_{e,d}$. If an exporter is obliged

[11] See inequality 11 and appendix A for the remaining FOC of our model.

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

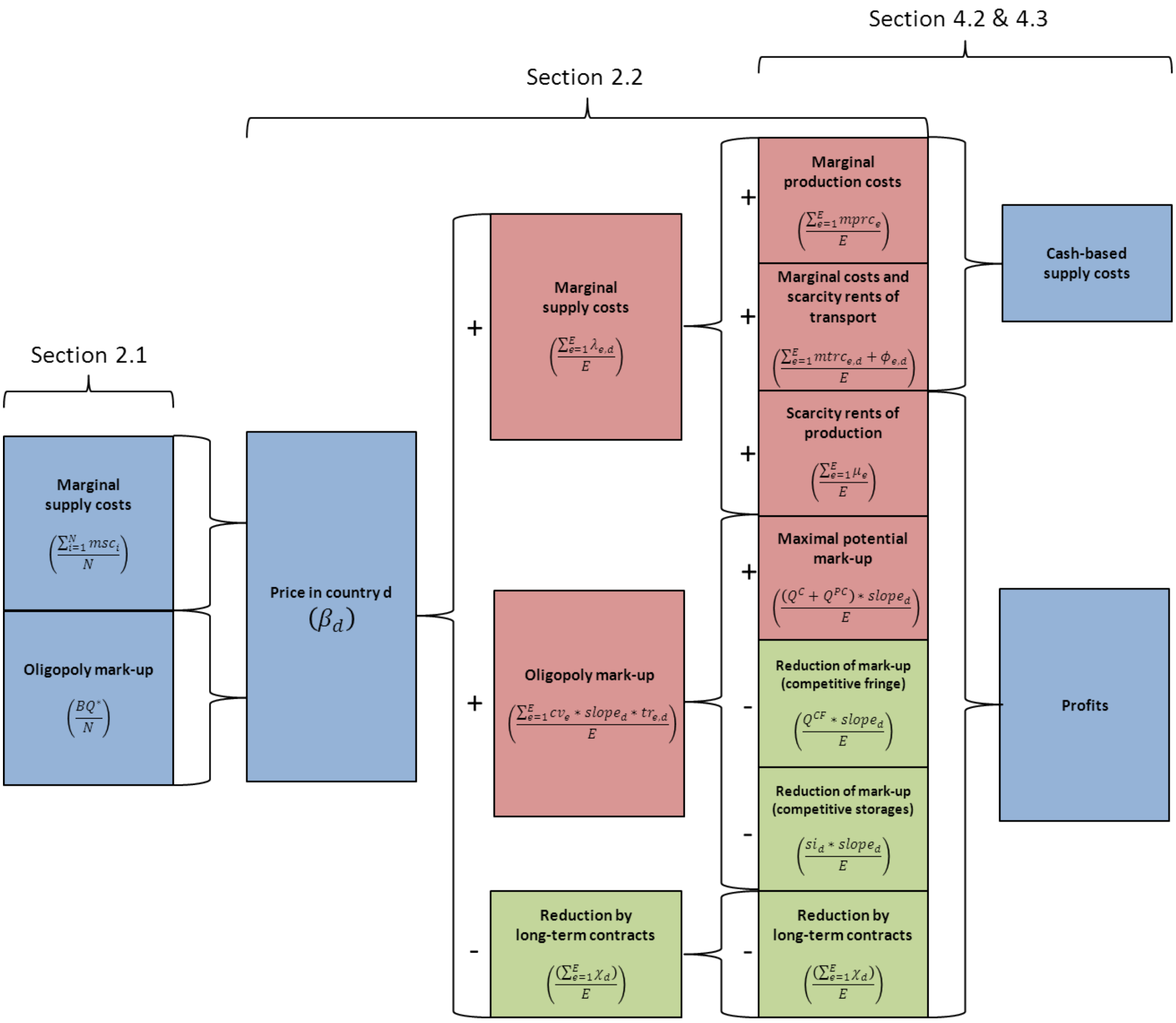

Figure 2: Disentangling prices in a spatial equilibrium model

According to the oligopoly pricing formula deduced in section 2.1, we are now able to identify to which extend marginal supply costs respectively oligopoly mark-ups explain the different market prices β_d. The influence of marginal supply costs is derived as 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 how much they explain prices.

The price influence of the exporters' oligopoly mark-ups is derived as the average over all Cournot players as well. For our analysis it is however necessary 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 demand node if there was 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 might also have a price decreasing effect. To identify it, we take the average over all Cournot player's LTC opportunity costs $\chi_{e,d}$.

Now as we are able to disentangle the import prices 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 in fact is monetary profit for an exporter as well as the oligopoly mark-up is.

3. Data, assumptions and scenario setting

In this section the data used in our global gas market as well as the scenarios setting of our analysis are described. This section's description focuses on the demand side and 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 and costs as well as infrastructure capacities and transports costs in Appendix B.

3.1. Demand

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

The total gas demand of a country and its sensitivity to prices is 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-depending demand pattern, but is 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 the heating technology is fixed in the short term. Contrary, in power generation the gas-to-coal spread has a higher impact on gas demand, implying high price sensitivity. Moreover, price sensitivities might 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 for example Germany.

To derive a country's gas demand function, we have to account not only for the aforementioned aspects, but for different sectoral shares of total demand as well. And due to different seasonal demand patterns of each sector, the sectoral share of total demand might vary by month. If for example heating demand takes a large share of some country's total gas demand in January, the corresponding demand function is rather price insensitive. Contrary, if e.g. in July, gas is mainly used in power-generation, the demand function is 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 therefore outline our approach to determine these functions and the underlying 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 2010 consumption data on a country by country basis. For natural gas demand in 2012, we rely on forecasts from IEA (2011) and ENTSOG (2011).

In a second step, annual demand is split up 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)[12]. We further assume miscellaneous gas demand to exhibit no seasonal fluctuation. We derive the monthly demand for "industry and power generation" as a

[12] http://www.nrcan.gc.ca/energy/sources/natural-gas/monthly-market-update/1173

residual of total demand minus heating demand minus miscellaneous demand. The monthly demand for both groups, IP and HM, serves as reference demand for the linear demand curves to be derived.

Monthly reference prices are provided by IEA (2011a) for the majority of countries. We further add monthly price information of the spot indices Henry Hub, Title Transfer Facility (TTF) and National Balancing Point (NBP), whereas 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 amount to -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 accounted for in our model to be less price sensitive than the other countries (-0.1 vs. -0.4).[13] These elasticity assumptions are basically 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 add both demand function horizontally. The resulting demand functions account for different seasonal demand patterns, different sectoral shares of total demand and different price sensitivities and therefore vary by month and country.[14]

Overall, the model covers a gas demand of 3267 bcm for 2010 and 3426 bcm in 2012. This equals 99% of global gas consumption in 2010 reported in IEA (2011a) respectively in 2012 forecasted in IEA's Medium-Term Oil and Gas Markets report (IEA, 2011). Thereby, we model 49% of total global demand to be price sensitive whereas 51% is assumed to be inelastic. In Asia/Oceania, 379 of 645 bcm total demand is elastic (59%),

[13] These elasticity values provided the best fit with actual market outcomes in 2010. Please refer to Appendix D for information on how prices in selected countries change when assumed elasticity are varied.

[14] 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 for our analyses.

whereas in Europe and North America more than 90% of total demand is modelled 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 therefore import independent (like 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[15]. LTCs are also important for LNG deliveries: In 2010, only round about 60 bcm were traded on a spot and short term basis[16] (GIIGNL, 2010). 80% out of 300 bcm of total LNG trades in 2010 were carried out based on long-term contracts.

As precise information on actual LTCs is hardly 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 whole year. In other words, the annual natural gas imports can be flexibly optimised during a year, we thus 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 would be rather a mean 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). In contrast, our model derives prices endogenously, we thus implicitly model the determination of the reference prices in the LTC.[17] In addition, our analysis focuses on a short time frame, i.e. one year.

[15] http://www.gasstrategies.com/home

[16] GIIGNL defines short term contracts as contracts with duration of less than 4 years. Since our analysis focuses on the effects of an LNG disruption, we thus necessarily have to include LNG long-term contracts into the model. Neglecting that fact would presumably overestimate the flexibility of LNG trade and therefore underestimate the severity of a Hormuz Strait disruption. Since we lack more detailed data and we 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.

[17] 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 the only tractable in a partial equilibrium analysis like ours.

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 Hormuz Strait. In the other scenario, we simulate a six-months blockage of the Strait of Hormuz, with the blockage starting in November. As our model is non-stochastic, we fix storage levels in November to the results from the reference scenarios. Market players would otherwise 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 diminish the annual minimum take/delivery-quantity proportionately to 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 Hormuz Strait disruption, Figure 3 depicts the monthly gas prices for Japan, the UK and the USA in both scenarios (no disruption and 6-months disruption).[18]

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

The UK's natural gas price is connected to and affected by incidents on the global LNG market.[19] 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 of gas prices when simulating a 6-months Hormuz blockage. When the disruption starts UK gas prices immediately increase by up to 31% in the winter months (328 USD/kcm in January).

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 price in Japan varies between 467 USD/kcm and 505 USD/kcm in the reference case. A 6-months lasting blockage of

[18] We use the market clearing price of the US southern demand node as a proxy for the monthly price of the United States.

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

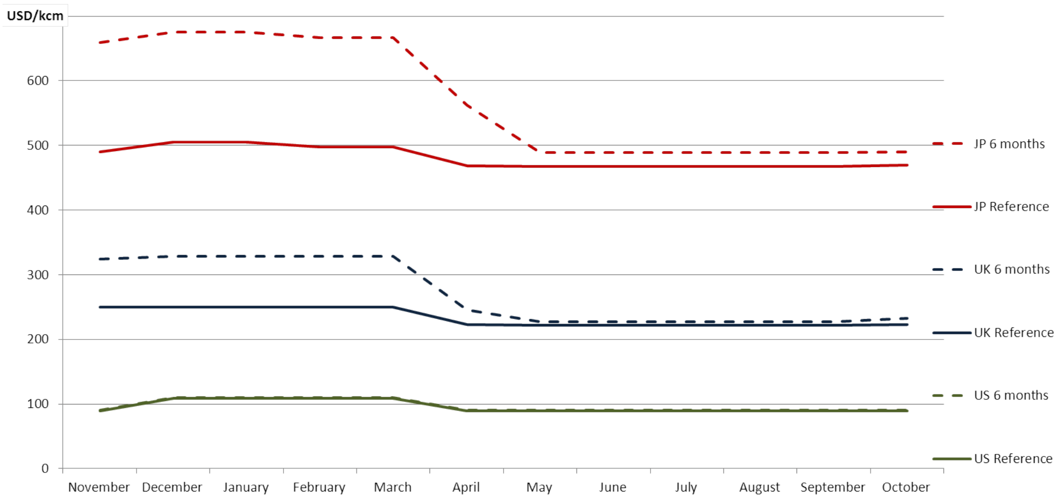

Figure 3: Price effects of Hormuz Strait disruption in three selected countries

Hormuz Strait increases the gas price in Japan by nearly 34% to more than 677 USD/kcm in January.

Thus, for both countries we observe increasing prices during the disruption. However, it remains unclear whether exporter's profits increase or higher supply costs drive the prices. As an example, Figures 4 and 5 therefore provide a closer insight at the formation of January prices in both scenarios for Japan and the UK, respectively. Both figures contain the country's January demand function and the cash-based supply cost curves of both scenarios.[20]

[20] 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.

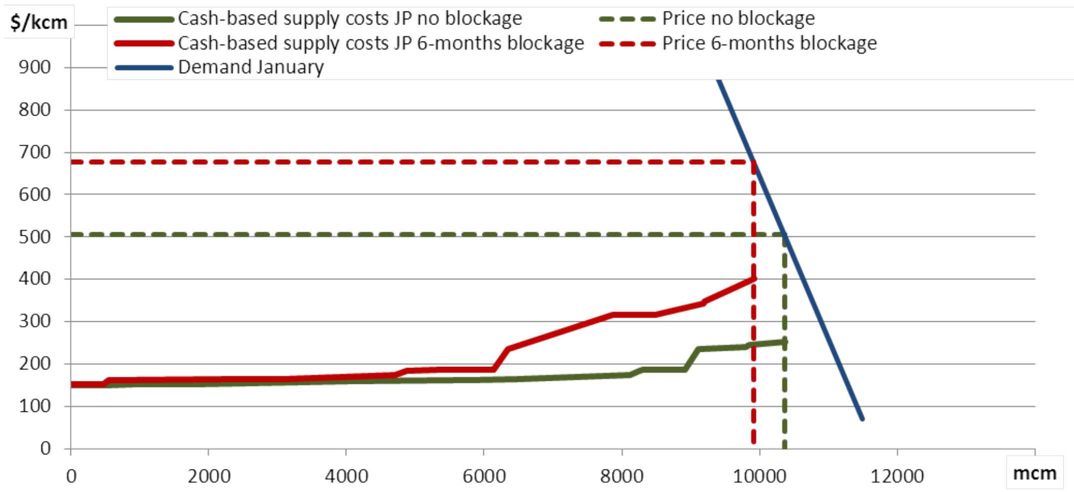

Figure 4: Changes in Japan's supply cost curve due to the Hormuz Strait disruption

Concerning Japanese supplies, we observe a remarkable increase of supply costs whereas in the UK, supply costs in both scenarios are nearly identical except for the very right part of the curve. Increasing prices however seem to be also driven by higher profits for the suppliers in both countries. Yet, both figures do not provide an indication what factors drive prices most.

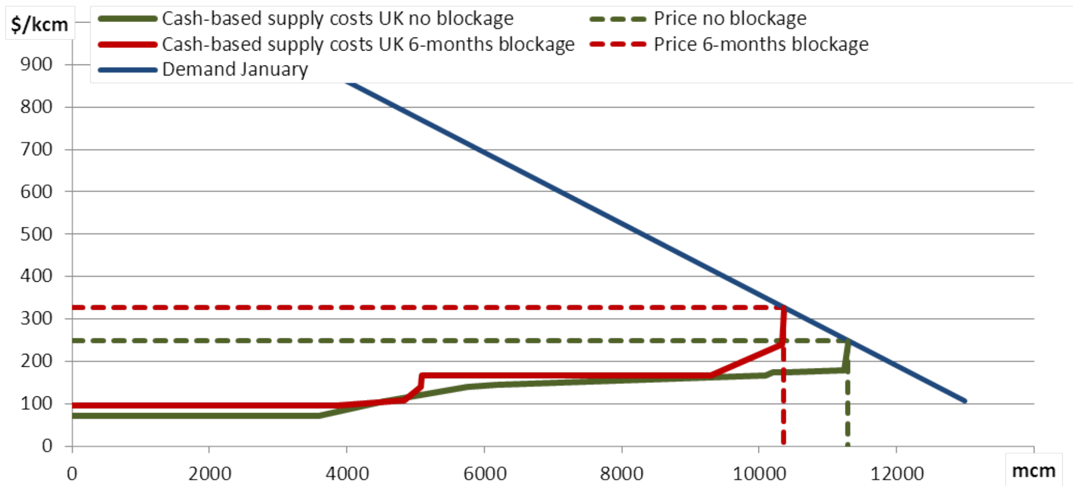

Figure 5: Changes in UK's supply cost curve due to the Hormuz Strait disruption

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 our approach introduced in section 2.3. Using the dual variables from our simulation model we are able to derive price components in order to evaluate the strategic market positions of different countries. As an exemplary 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.[21]

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 the exporter actually has to bear 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 terminus "maximal potential oligopoly mark-up" labels the mark-up that exporters could realise if the complete demand of a country were 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 the exporter has to bear (or vice versa a price advantage for the importer).

As Figure 6 reveals, the total January price difference between Japan and the UK is 255 USD/kcm, thereof 31 USD/kcm are 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 of the "profits". Compared to the UK, we assume the gas demand of Japan to be more inelastic. Thus, the high Japanese dependency of natural gas lets Cournot players realise higher mark-ups in Japan than in the UK.

[21] Concerning the US, the abundant domestic production makes the country become independent from imports. This does not only explain the low prices, but as well the insensitivity to prices during the global supply shock of a Hormuz Strait disruption.

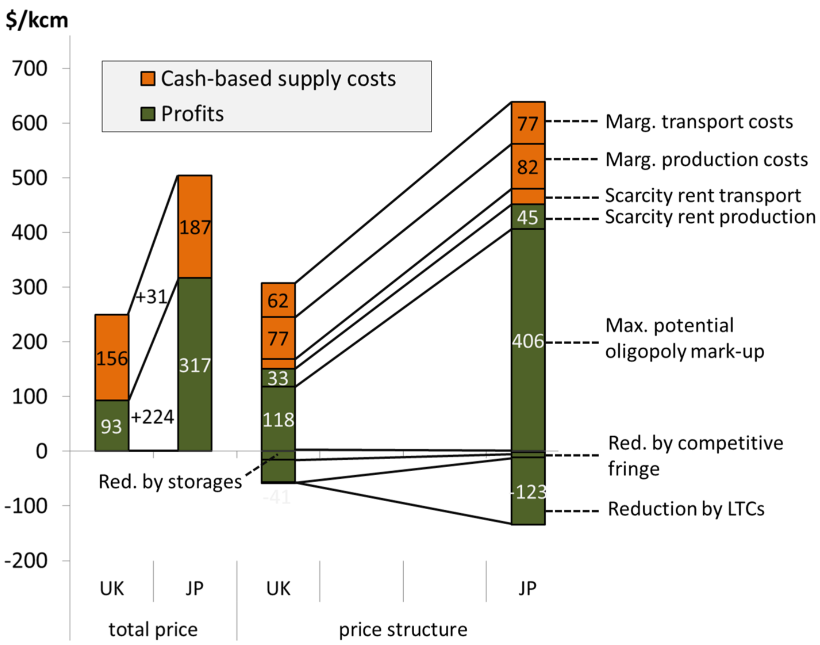

Figure 6: Price structure of the UK and Japan in the reference scenario

Yet, both countries are able to limit the oligopolistic mark-ups: the UK has a 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 such that those factors only reduce the gas price in total by 12 USD/kcm. Japan's trump card in limiting oligopoly mark-ups are 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 exploitable by its suppliers.

4.3. Structure of price reactions during a supply disruption

After having provided an insight into the price structure of both Japan and the UK in the reference scenario, we focus next on the price increase during a blockade of Hormuz Strait. Figure 7 illustrates the January price level in both countries without a disruption (topmost bar) and with a disruption of 6 months (lowest bar). Additionally, the middle bars of the Figure display what cost components lead to an increase respectively decrease of the gas price during the disruption.

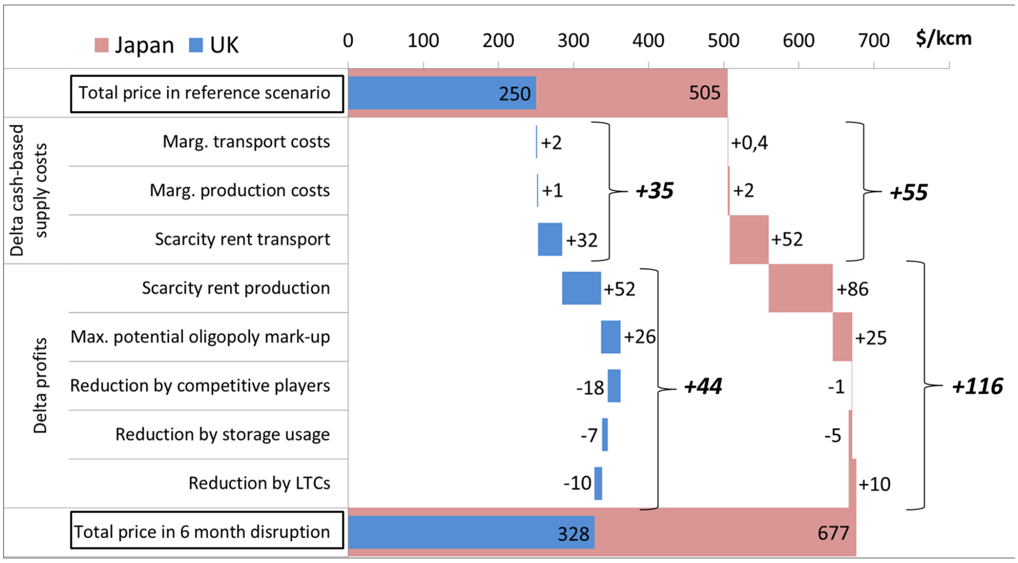

Figure 7: Structure of the import price increase during a 6-month Hormuz Strait disruption in Japan and the UK

Marginal transport and production costs: We observe a slight increase of those two cost components because gas has to be imported from more distant sources and gas production is intensified during the blockade. However, since both production and transport capacities already had high utilisation rates on 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: The blockage of Hormuz Strait implies an outage of ca. 30% of global LNG trade volumes. LNG importers therefore need to find alternative sources of supply which makes LNG liquefaction capacity (which we account to transport infrastructure) become scarce. Transport scarcity costs explain 52 USD/kcm of the total price increase in Japan, whereas in the UK it is only 32 USD/kcm. The difference can be explained by taking a closer look at both countries' market position. Japan is solely depending on LNG imports, price insensitive and competes for supply with countries such as South Korea being in the same situation. The UK however is more sensitive to prices and connected to the European pipeline grid and therefore 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 where prices are therefore high. Most of the increase of transport scarcity rent in the UK results from bottlenecks in the European pipeline grid especially on deliveries from Russia. Japan on the other hand has no alternative to the remaining LNG volumes on the world market. As Japan competes for LNG supplies and therefore also for LNG transport capacities with other LNG depending importers, the opportunity costs of the transport value chain to deliver LNG to Japan increase during the blockade.

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 Strait of Hormuz blockage, on a global scale, production capacity is more scarce than transport capacity. Japanese import prices are however more affected by scarcity of production capacity than the British ones. The reasoning for the difference is similar to 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 to produce gas for later selling to Japan therefore increase when the supply side becomes tighter due to the Hormuz Strait blockade.

Maximal potential oligopoly mark-up: On the one hand, countries reduce demand during the Hormuz Strait disruption which decreases the potential mark-up ceteris paribus. On the other hand as QA and 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 ca. 25 USD/kcm. Yet, both countries have different market positions to reduce price increases.

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 by domestic production. Therefore, its ability to reduce the import price increase during the Hormuz Strait blockage is limited.

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

Reduction by LTCs: The UK holds several LTCs, i.e. has secured deliveries from certain exporters. These LTCs lead to a reduction of the price increase of 10 USD/kcm during the disruption. Long term contracts and therefore contractual obligations for certain LNG exporters (Algeria, Nigeria and Trinidad) to deliver gas to the UK imply opportunity costs for the exporters. These costs can be interpreted as realization of their price risk. Concerning Japan, surprisingly LTCs explain 10 USD/kcm of the price increase during the Strait of Hormuz blockage. 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 of a 6-months disruption. This interesting observation can be explained with the fact that Qatar is one of the more important sources of contracted LNG volumes, which 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 six-month disruption.

To sum up, we have identified three factors which explain why the Hormuz Strait blockage affects 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 augment 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 which 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 only 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 again exacerbating since the beginning of 2012 when Iran has threatened to block the Strait of Hormuz, the world's most important LNG choke point. Since regional security of supply depends on the individual supply structure, a potential blockage would differently affect gas supplies in different world regions: do regions have local production, do they mainly rely on pipeline imports or do they fully depend on LNG imports?

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

We find that gas price increases most in Japan. We also observe gas price increases in the UK, however significantly lower than in Japan. US gas prices are hardly affected as the country is rather independent from global gas trade. We identify three reasons why a Hormuz Strait blockage affects the Japanese import price much more than the British one.

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 like Russia or Norway. Thus, the UK faces an alternative market that – in opposite to the LNG market – is only accessed by European and not global competition. In turn, Japan has to compete globally for LNG supplies. This translates in higher scarcity rents which Japan has to pay to attract LNG volumes.

Second, the UK is less exploited to market power than Japan. In opposite to Japan, UK profits from price-taking domestic production and underground long term storages which act as a competitive fringe, thereby decreasing mark-up rents of oligopolistic players.

Third, LTCs limit the price increase in the UK since they secure gas volumes which otherwise would have been sold to the UK only at higher prices. In opposite, the price decreasing effect of LTCs diminishes in Japan: the blockage of Hormuz Strait also 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 attracted by comparably higher prices.

This study investigates the regional disperse price effects following a supply shock in the natural gas market. Yet we had to make some simplifying assumptions in our analysis, mainly because of computational issues. First, we assume perfect foresight which might be a strong simplification, in particular for storage operators. Second, we model storage operators as price takers despite the fact that a supply shock might allow them to maximise profits by initially refraining from storage depletion, thereby further increasing gas market prices. Third, we use a partial equilibrium model of the global gas market, we thus do not consider e.g. the interdependencies between the oil and gas market. The interaction of substitutive fuels, such as oil and gas, could differently affect regional prices during a supply shock and is currently open for further research.

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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, for example. 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 the user can customize it, 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 A.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. Therefore, they are listed in the following.

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

Along the lines of inequality 17, this inequality 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. The same holds true for the restriction of gas volumes which are regasified and then transported to a demand node d in month t

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

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

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

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 which delivers gas to a regasification terminal has to drive back to a liquefaction terminal in order to load new LNG volumes. Thereby, we simplify 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:

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

Production

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

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

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:

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

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:

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

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

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

Table 1: Model sets, variables and parameters

Sets	
$n \in N$	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
Primal Variables	
$pr_{e,p,t}$	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
Dual Variables	
$\lambda_{e,n,t}$	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
ι_t	marginal benefit of an additional unit of LNG transport capacity
$\gamma_{r,t}$	marginal benefit of an additional unit of regasification capacity
$\zeta_{l,t}$	marginal benefit of an additional unit of liquefaction capacity
$\chi_{e,n,y}$	marginal costs of delivery obligation
Parameter	
$cap_{n,t/n,n1,t}$	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

	Total number of nodes	Number of countries	Countries with more than one node	Countries aggregated to one node
Demand	84	87	Russia and the United States	Baltic countries and former Yugoslavian republics
Production	43	36	China, Norway, Russia and the United States	-
Liquefaction	24	24	-	-
Regasification	27	25	-	-
Storages	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 we fix production volumes to limit model complexity. Concerning endogenous production we face the problem that there is only data on historical production (i.e. from IEA (2011a), but no single source which provides information about historical or current production capacities. We collect information from various sources listed in table B.2. For the major LNG exporters Qatar and Australia, we derive possible production capacities from their domestic demand assumptions and liquefaction capacities. In total, we assume a global production capacity of 3542 bcm in 2010 and 3744 bcm in 2012. 12 to 13% 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).[22] For the exporting countries, we estimate Golombek production functions by OLS regression, using various data sources like Seeliger (2006), OME (2001) or information on costs published in the *Oil and Gas Journal*.

[22] Please refer to subsection 2.2 for more details on the Golombek production function, in particular on its first derivative, the marginal cost function, which is used in our model.

Table 3: Assumptions and data sources for production

	Assumptions	Sources
Production	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)
	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 that pipeline capacity to one large pipeline Russia-Ukraine. The Institute of Energy Economics at the University's (EWI) own extensive pipeline database 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[23].

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 B.3 the distance break-even between onshore-pipeline and LNG transport is 4000 km, whereas it is around 2400 km for offshore-pipelines[24]. This is in line with Jensen (2004) and Rempel (2002).

[23] Please refer to http://www.searates.com/reference/portdistance/

[24] We assume that a typical LNG vessel's average speed amounts to 19 knots and that its average capacity lies at circa 145 000 cbm.

Table 4: tab:Assumptions and data sources for infrastructure

	Assumptions	Sources
Infrastructure	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 underpin our choice of modelling the gas market as an oligopoly. Therefore we compare two market settings – perfect competition and Cournot competition with a competitive fringe – with respect to their fit to 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 hand 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 contrasts 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 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. Thereby, the deviation is shown in per cent 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 realised demand in 2010 by 3.7% and 9.7%, respectively. In contrast, simulated demand in North America resembles the actual demand quite well.

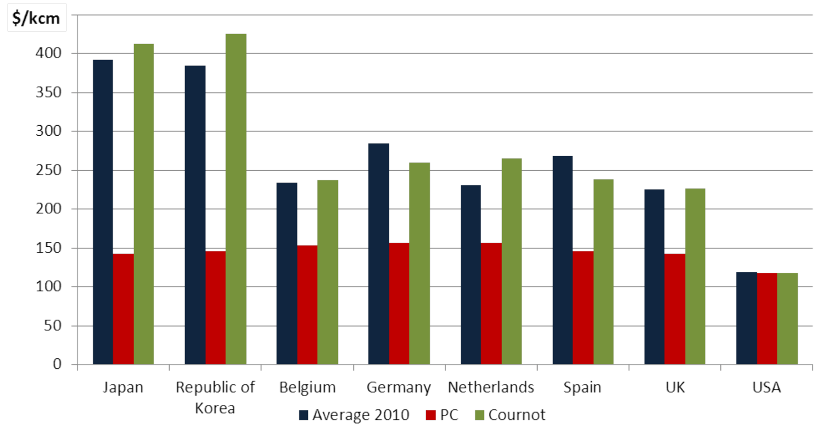

Figure 8: Actual and simulated average prices (in USD/kcm)

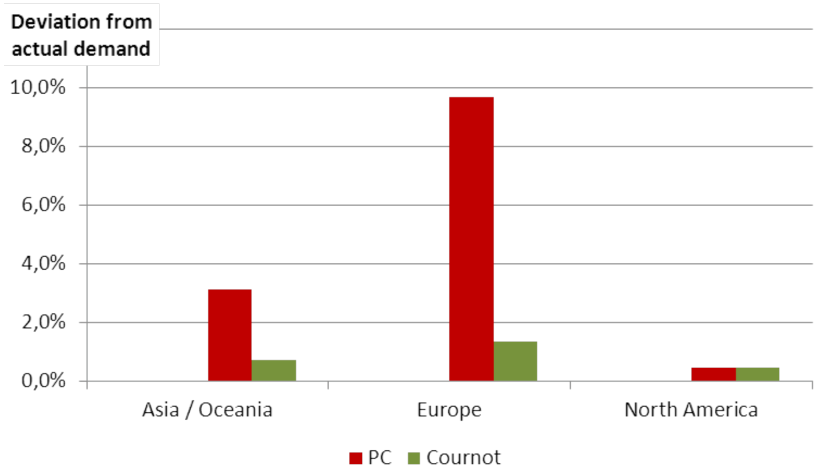

Figure 9: Deviation of demand under different settings (in % of actual demand in 2010)

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

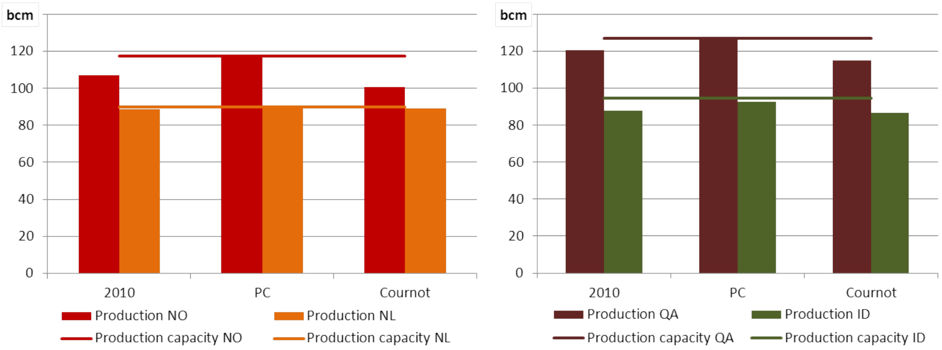

Figure 10: Annual production and capacities in four selected countries in the different market settings (in bcm)

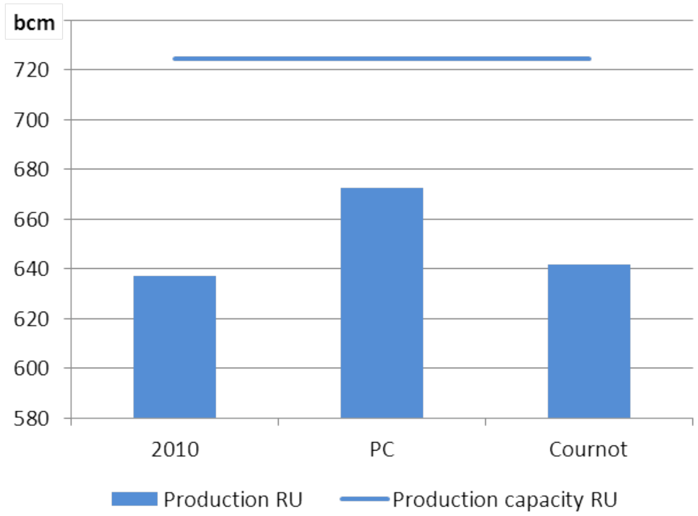

Figure 11: Annual Russian production and capacities in the different market settings (in bcm)

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

D. Sensitivity analysis

We analyse three alternative settings for the IP sector's demand elasticity since in almost all countries this elasticity assumption is the most important in determining overall demand elasticity in a countries: one in which the elasticity in all countries is 50%

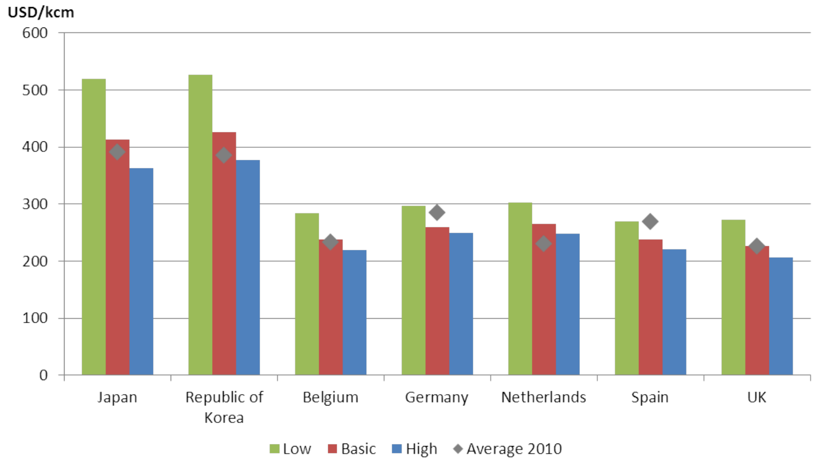

Figure 12: Sensitivity analysis I: Comparison of prices in selected countries with varying elasticity assumptions

higher (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

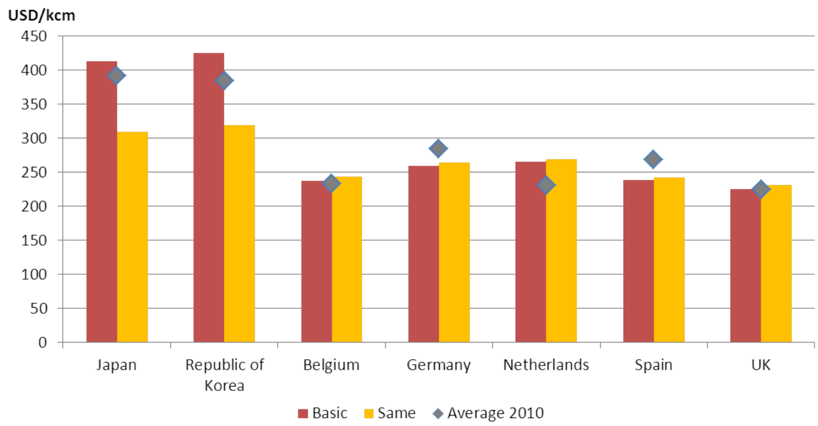

Figure 13: Sensitivity analysis II: Comparison of prices in selected countries with varying elasticity assumptions

that by assuming the same demand elasticity in all countries regional prices differences are much lower than in reality or in the scenario "Basic". We therefore conclude that the elasticity assumptions used in this paper provide a reasonably good fit with actual prices in 2010 which cannot be improved on a total level by a different combination of elasticities.