Accepted at Energy Policy, January 2008

A Complementarity Model for the European Natural Gas Market *

Ruud Egging[a], Steven A. Gabriel[b], Franziska Holz[c], Jifang Zhuang[d]

[a]Department of Civil and Environmental Engineering, University of Maryland College Park, Maryland 20742 USA, regging"at"umd.edu

[b]Department of Civil and Environmental Engineering, Applied Mathematics and Scientific Computation Program, University of Maryland College Park, Maryland 20742 USA, sgabriel"at"umd.edu

[c]DIW Berlin, Mohrenstraße 58, D-10117 Berlin, Germany, fholz"at"diw.de

[d]Chevron USA, Houston, TX 77401 USA, zhuang"at"umd.edu

In this paper, we present a detailed and comprehensive complementarity model for computing market equilibrium values in the European natural gas system. Market players include producers and their marketing arms which we call "transmitters", pipeline and storage operators, marketers, LNG liquefiers, regasifiers, tankers, and three end-use consumption sectors. The economic behavior of producers, transmitters, pipeline and storage operators, liquefiers and regasifiers is modeled via optimization problems whose Karush-Kuhn-Tucker (KKT) optimality conditions in combination with market-clearing conditions form the complementarity system. The LNG tankers, marketers and consumption sectors are modeled implicitly via appropriate cost functions, aggregate demand curves, and *ex-post* calculations, respectively. The model is run on several case studies that highlight its capabilities, including a simulation of a disruption of Russian supplies via Ukraine.

Keywords: European Natural Gas Market, Global LNG market, Mixed Complementarity Problem

1. Introduction

Many European countries have only limited domestic reserves of natural gas, and are therefore dependent on a small number of pipeline exporters to secure their supplies via pipeline. This situation enables strategic producers to exert market power resulting in higher prices for a variety of consumers downstream, as was already analyzed in [51]. The dependence of importing countries on one or a few suppliers was in evidence in January of 2006 when Gazprom, the large Russian gas and oil company shut down gas flowing to Ukraine due to contractual disputes ([52]-[62]; [69] provide an in-depth analysis).

*This paper is based upon work supported by the National Science Foundation under grant DMS 0408943 for co-authors one, two, and four. The third co-author was supported by the German Academic Exchange Service (DAAD) for a visiting stay at the University of Maryland in 2006.

Accepted at Energy Policy, January 2008

By no means is strategic power of the producers limited to Gazprom. Other examples include the Algerian Sonatrach that supplies a large share of natural gas to Southern Europe (Italy, Spain), and the Norwegian gas export consortium Petoro (selling the gas produced by Statoil and Hydro) that supplies large parts of Northern Europe including Germany, France, Belgium and the UK. In addition to issues of supply security for the EU there are questions of power sector environmental constraints which generally favor natural gas over other fossil fuels, such as coal or oil.

The situation in the European natural gas market has changed considerably over the last few years with the advent of the technology of liquefaction of natural gas and the possibility to import large amounts of Liquefied Natural Gas (LNG) by tanker to Europe. Although LNG has been used since the 1960s as a way to transport natural gas over long distances to isolated marketplaces, its utilization until the end of the 1990s was mainly limited to supply Japan and South Korea. Several reasons explain the recent strong development of LNG in the Atlantic basin. Political and economic considerations of supply security favor diversification to decrease dependency on single (or few) external suppliers. Importing LNG is a way to diversify gas supplies away from pipelines and create more supply options. Another reason for the attractiveness of LNG are the still increasing economies of scale for LNG equipment ([8], [18]) that allow for increasingly cheaper long-distance transports. LNG also is an alternative to domestic production and pipeline imports in times of growing demand for natural gas and anticipated depletion of domestic resources either voluntarily (e.g., the Netherlands) or involuntarily (e.g., Canada). In the former case, the Netherlands has voluntarily chosen a production cap that sustains domestic independence for a longer period but limits the possibility for neighboring countries to import. Thus, while natural gas markets previously were continental (Europe, North America) due to accessibility of pipelines, the rise of LNG is creating one global market with, for example, the East Coast of the United States and Europe competing for LNG in the Atlantic Basin.

Consistent with the trend towards increasing reliance on LNG, many countries have policies in place which should stimulate the development of LNG infrastructure. Several of the European Commission's (EC) priority projects in the Trans-European Energy Networks are LNG-related [14], [16], [17]. Figure 1 shows the anticipated increase in LNG import capacity by country expressed in billions of cubic meters (bcm) per year.[2] Major increases will be seen in the United Kingdom (+39 bcm), Italy (+20 bcm), Spain (+17.5 bcm) and France (+16.5 bcm).

The United States has traditionally relied on natural gas imports by pipeline from Canada, in addition to its domestic production. But LNG constitutes an increasing share. The U.S. imported 17.87 bcm of LNG in 2005, almost three times as much as the LNG imports in 2000 ([5], [7]). Declining domestic production in the United States and Canada will need to be replaced, and the U.S. will increasingly rely on LNG to fill the gap [19]. With several provisions in the Energy Policy Act of 2005 [21] the United

[2]The current five year horizon is 2006-2011. Aggregate capacity is shown for terminals for which construction has started, or is expected to begin by 2008. Data are from several sources, including [47], [65].

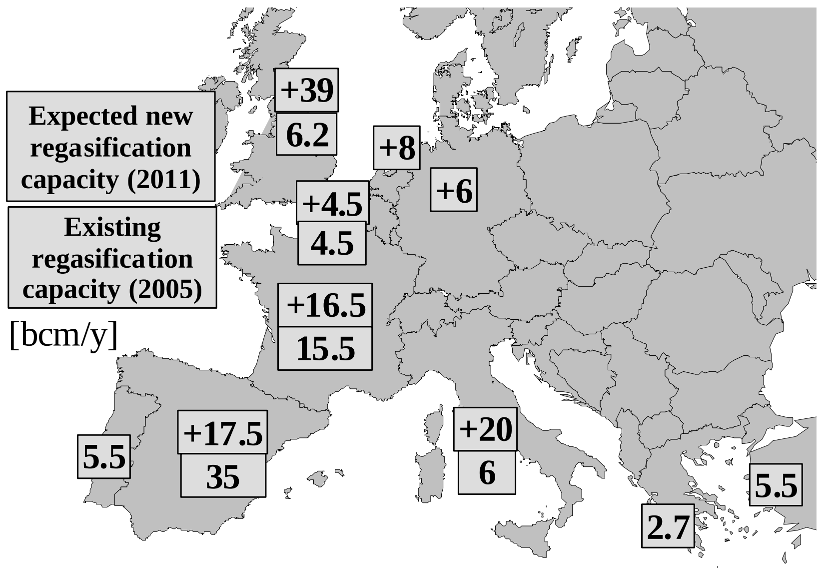

Figure 1. Existing and anticipated LNG import capacities in Europe [bcm/year]

States aims to encourage the development of the domestic infrastructure for importing LNG. Currently, the U.S. has five regasification terminals in place with total regasification capacity of 52 bcm/year; soon there will be eight. According to the U.S. Federal Energy Regulatory Commission (FERC) [24], there are plans for 31 more, not all of which may be built though due to strong societal opposition.

Besides natural gas importing countries, exporting countries also have clear incentives to increase the share of LNG in their natural gas portfolio, seeking demand security and benefiting from the potential high profits in the LNG supply chains [18]. Between 1997 and 2002 the number of LNG exporting countries rose from nine to 12, and total shipped volumes increased by more than 40% in that period. Egypt started LNG exports in 2002, Norway and Russia are expected to start exporting LNG exports in short term, possibly soon making a total of 15 LNG exporting countries.

Figure 2 shows that between 2000 and 2005 world wide natural gas consumption increased by 13% ([5], [7]). In the same period, the share of internationally traded gas in total consumption rose from 21.6% to 26.2%. Natural gas trade by pipeline increased by 37%, LNG trade by 38%. In the years to come, LNG is expected to outpace the growth in pipeline trade by far, accounting for possibly more than half of interregional gas trade by 2030 [46].

In this paper, we present a new, detailed model of the European natural gas market which accounts for the issues of market power of exporters and of globalizing natural gas markets with LNG trade. Besides a disaggregated representation of the European market, we cover all relevant pipeline exporters to Europe (Russia, Caspian Region, North Africa, Middle East) and all LNG exporters globally (North and Sub-Saharan Africa, Middle East, South-East Asia, Australia and Latin America) as well as all other LNG importing regions

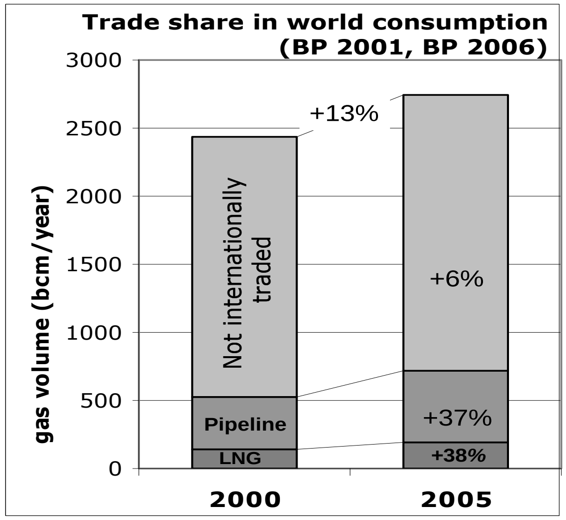

Figure 2. Global natural gas consumption and trade in 2000 and 2005 [bcm/year]

in the world. This allows us to analyze possible substitution effects between pipeline and LNG exporters on the one hand, and competition of demand between different LNG importing countries on the other hand.

The market participants being modeled include: producers and their marketing and trading arms which we call "traders", [3] pipeline and storage operators, LNG liquefiers, regasifiers, tankers, marketers (implicitly), and consumers in three sectors (residential/commercial, industrial, and power generation) via their aggregate inverse demand functions. These players, except for LNG tankers, marketers and consumers, are modeled via convex optimization problems, whose Karush-Kuhn-Tucker (KKT) optimality conditions [2] are both necessary and sufficient for global optimality. Necessity follows due to the polyhedrality of the feasible regions and sufficiency due to the convexity of the objective functions and the polyhedral feasible regions. Collecting these KKT conditions for all the players and combining them with market-clearing conditions constitutes an instance of a nonlinear complementarity problem (NCP) or variational inequality problem (VI) referred to as complementarity problem [23]. The optimization problems of the players are typically profit maximization objectives subject to operational constraints, e.g., production rates. In all cases, except for the traders, players are price-takers in the production, transportation, LNG, and storage markets.

Only the traders, being the pipeline sales end of the production companies that interface with downstream markets, can exert market power. They are modeled as being able to behave strategically in multiple countries accessible by pipeline from the producing country (possibly via transit countries). Modeling the traders as separate entities can be seen as anticipating European Commission decisions striving for legal unbundling of

[3] Transmitters do not take care of pipeline or other gas transportation issues. Their function is to market the gas produced by their production company counterparts.

Accepted at Energy Policy, January 2008

the various parts in the natural gas supply chain. This is a change compared to [13] where the production companies were modeled as vertically integrated comprising both production and sales functions.[4] However, it is important to note that the model set-up presented allows for representing vertically integrated production and trading companies where the latter are (legally) unbundled from the former. Lastly, the traders are a convenient mechanism that allows for proper accounting of transportation charges instead of using aggregate pipelines between production and consumption markets with no transit nodes as was the case in [29]. LNG tankers and consumers are modeled implicitly by cost and aggregate inverse demand functions, respectively.

To our knowledge, the concept of international traders operating separately from producers has not been used in other natural gas market models. (For an electricity market application refer to [67]) Modeling traders as separate players increases model transparency by clearly separating the production and the sales/export operations via pipeline of the production companies which are characterized by different operational costs and constraints. These players can be seen in the actual market: for example, the trading business of gas companies like Gazprom or GasTerra (Netherlands) is done by separate affiliates from the production companies; by Gazexport in the Russian case, by GasTerra in the Dutch case. Especially in the European Union, legal requirements have led to the separation (unbundling) of production and trade operations of companies. Although these separate units may still belong to the same holding company, each affiliate has its own operations and optimization problem under different constraints. We take account of the fact that the production and the trade operations could be part of the same company by not modeling any strategic behavior or bargaining between these two operations. The producer sells natural gas to the trader at a competitive (marginal cost) price. On the other hand the trader, the player operating in international natural gas markets, may behave strategically vis-à-vis its competitors, the other traders.

A similar rationale of modeling an activity separately that may be executed within the same company is generally applied to the pipeline operation that is done by an independent but perfectly competitive pipeline operator. Traditionally, in Europe the pipeline grid belonged to integrated production or wholesale trade companies. But the recent liberalization efforts of the European Commission have led to separation (unbundling) of the pipeline operation from production and/or trade. The interaction between the traders and the pipeline operators is such that the pipeline operators allocate transport capacity to traders that need to transport gas to their consumer markets.

While complementarity models of natural gas markets have been formulated and developed with real or realistic data before, e.g.,[13], [37], [34], [1], [26], [29], [4], [50], [38], the one presented in this paper distinguishes itself by its level of detail relative to the number and variety of players, the number of seasons (three seasons: low demand, high demand, and peak), as well as the number of countries modeled (52). In this respect, the model we present is approaching the level of detail of the Rice University World Gas Trade model

[4]Other major changes are the detailed representation of all agents in the LNG supply chain, the incorporation of all countries in the world involved in LNG imports and exports and a thorough update of the input database.

Accepted at Energy Policy, January 2008

[36], or the Gas Systems Analysis Model (GSAM) for North America ([28], [27]). This level of detail with a representation of the global LNG market and combined with the strategic behavior of the producers (via their traders) is unique and represents the main contribution of this work. The second contribution is the use of this model to analyze a series of geopolitical and market-based cases. One scenario involves the curtailment of gas supplies to Ukraine by Gazprom motivated by actual events in January, 2006. The other cases include: a perfect competition relaxation for the producers (traders), a shut-off of the relatively inexpensive gas that comes from Algeria, and a case relating to capacity expansions in LNG and pipeline capacity corresponding approximately to the year 2011. [5] Lastly, the base year of the simulations was taken as 2004.

The rest of this paper is organized as follows: in Section 2 we describe the complementarity model derived from the optimization problems and market-clearing conditions; in Section 3 we discuss the numerical results of the case studies, Section 4 provides conclusions, and lastly, an Appendix provides key data and modeling details.

2. Model Formulation

The economic behavior of the market participants in the natural gas sector is modeled by optimization problems for each of the players and market-clearing conditions linking them. The players are: producers, traders, liquefiers, regasifiers, storage operators, marketer/shippers (hereafter referred to as marketers and implicitly modeled), and consumers in three sectors (residential/commercial, industrial, and electric power generation). A schematic overview of the gas network and market participants is depicted in Figure 3. The countries (or nodes) are the ovals surrounding the players for that node. Also, the consumption sectors are shown as a triangle. In this figure, the following players can be distinguished:

- Producers (C_1, C_3) located at a production node (could be more than one per country)
- traders (T_1, T_3) operating at production, transit and consumption nodes (one per producer)
- LNG Liquefiers (L_1) (could be more than one per country)

The following players are active at the consumption nodes only:

- LNG Regasifiers (R_3) (could be more than one per country)
- Storage operators (S_1, S_3) (could be more than one per country)
- Marketers (M_1, M_3)(one per country)
- Consumers ($K_1, K_2, K_3,$) respectively, for the residential/commercial, industrial, and electric power sectors .

[5]The scenarios involving disruptions for Ukraine or Algeria have also been analyzed in [71], for the year 2030. However, the current model has a greater level of detail and includes seasonality aspects, in comparison with [71].

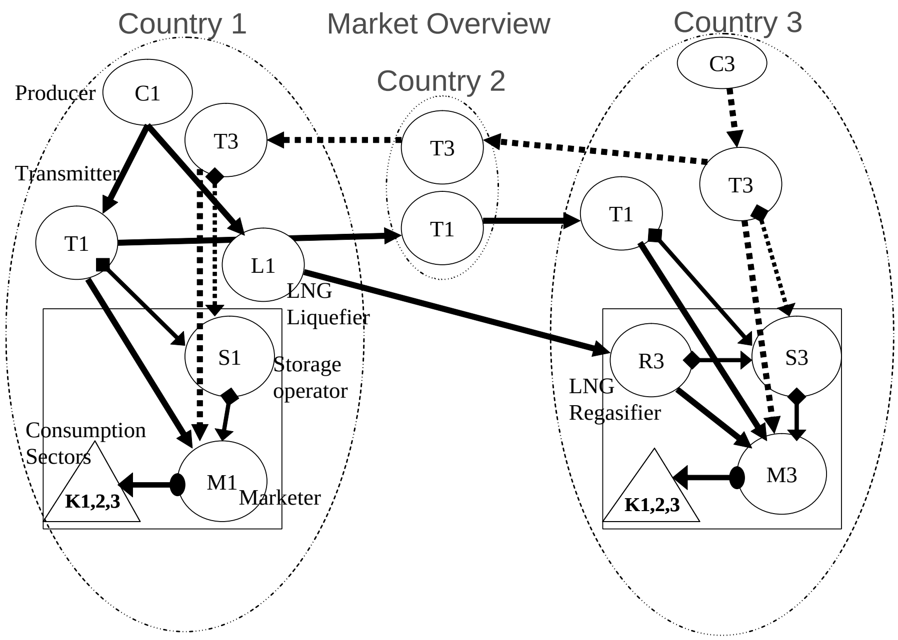

Figure 3. Overview Natural Gas Market Players

International pipeline flows are depicted via inter-country arcs whereas LNG tankers routes are described by arcs between liquefiers and regasifiers. At the production nodes, there is local gas transport from the producers to their trader and, possibly, to any liquefier. For example, in Figure 3, all flows originating from C1 are depicted as solid lines, flows from C3 as dashed lines. At the consumption nodes, gas flows from the traders to the storage operators and marketers, where transportation is defined to be on the local (i.e., national grid). Flows into and from storage are indicated with a diamond shape at the start of the arrow. The marketers are the only interface with the three consumption sectors and receive gas from producers via the traders (using pipelines) or via the regasifiers in each of the three seasons, and from the storage operators in the withdrawal seasons (2 and 3, for high and peak demand, respectively). Flows to final consumption sectors are indicated with an oval shape at the start of the arrow. traders or regasifiers supply storage operators in the low demand season (1) when there is injection into storage. In what follows, volumes are generally denoted in kcm, or 1000 m^3, and prices are in €/kcm. The general notation with respect to nodes and time periods is:

- Y is the set of years, $y \in Y$
- D is the set of seasons, $d \in D$
- $days_d$ is the number of days in season d
- N is the set of nodes, $n \in N$

where $|Y| = 1$ for this paper unless otherwise stated. The number of days per season and set of seasons are user-defined (see Appendix C), and the set of nodes includes all countries of the European pipeline and the global LNG market (see Appendix A). We next describe the specific optimization problems faced by the market participants and the complementarity problem that results.

2.1. Producers

Each production company located at a node is modeled as choosing gas production rates so as to maximize its net profit over the time horizon. The net profit is the difference between seasonal revenue and seasonal costs, summed over all seasons and years. This objective is subject to constraints on production rates, total production volume, and nonnegativity of the quantity produced. This is an approximation to the very complicated spatial and temporal dependencies that can exist. In particular, as described in [27] and [28], one would need to take into account reservoir variables such as porosity, permeability, thickness, production in previous time periods, rig movements between regions, etc.; see [9] for a discussion of relevant petroleum engineering principles. The total cost function takes into account all the expenses associated with producing at a given rate. As producing at a higher rate should require more resources (machines, personnel, etc.) it is reasonable to assume this function to be non-decreasing and convex. The producers are modeled as price-takers in a perfectly competitive environment. The complete optimization problem for producer p is thus:

$$\max_{SALES^P_{pdy}} \quad \sum_{y\in Y}\sum_{d\in D} days_d \left[\left(\pi^P_{n(p)dy}\right) SALES^P_{pdy} - c^P_p\left(SALES^P_{pdy}\right)\right] \tag{1}$$

$$s.t. \quad SALES^P_{pdy} \leq \overline{PR}^P_p \qquad \forall d,y \quad \left(\alpha^P_{pdy}\right) \tag{2}$$

$$\sum_{y\in Y}\sum_{d\in D} days_d SALES^P_{pdy} \leq \overline{PROD}_p \qquad \left(\beta^P_p\right) \tag{3}$$

$$SALES^P_{pdy} \geq 0 \qquad \forall d,y \tag{4}$$

where

- the "P" superscript means for all producers, not for a specific one (similar notational concepts for other players)
- P is the set of all producers in the network, $p \in P$
- $P(n)$ is the set of producers located at node n
- $n(p)$ is the node where producer p is located
- $c^P_p(SALES^P_{pdy})$ is the production cost function for producer p, following [34],[4], and [13] (€/volume/day)
- $\overline{PR}^P_p$ is the upper bound on the production rate for producer p (volume/day)

- $\overline{PROD}_p$ is the total production forecast for the time horizon (volume)
- $\pi^P_{n(p)dy}$ is the selling price of gas for producer p in season d and year y (€/volume) (exogenous to producers but a variable in the overall complementarity system)
- $SALES^P_{pdy}$ is the decision variable for the rate of gas sold by producer p to the trader at the same node in season d and year y (volume/day)[6]

Note that the Greek letters shown in parentheses besides the constraints are the associated dual variables (Lagrange multipliers). The dual variables associated with inequalities (hence nonnegative in sign) will be α, β, or γ with appropriate super- and subscripts. By contrast, free variables associated with equality constraints to an objective function (see for example in the traders problem in (10)) will be denoted as ϕ with appropriate super- and subscripts. Lastly, all prices that are determined by market-clearing conditions outside of the individual optimization problems (hence, exogenous to these problems) will be denoted as π with appropriate super- and subscripts except for the inverse demand function π^W_{ndy}, which is under the strategic influence of the traders. Since the well-head prices are exogenous to the producers, the producer problem (1)-(4) is a convex program as long as the cost function is convex, which, as stated above is a reasonable approximation to reality. As such, the KKT conditions are both necessary and sufficient for optimality.

These conditions are shown below but for ease of presentation have been divided by period lengths ($days_d$), resulting in a more compact formulation but not affecting the numerical results, except for a scaling factor for the duals in question. For example, consider the following two inequalities providing the same restriction on the daily sales rate, but with different scales for the dual variable α_{pdy}. Consider first what is stated above, i.e., $SALES^P_{pdy} \leq \overline{PR}^P_p$. This constraint, scaled with the period lengths becomes $(days_d)\left(SALES^P_{pdy}\right) \leq (days_d)\left(\overline{PR}^P_p\right)$.The dual variable α_{pdy} for this latter equation expresses the marginal value of an extra unit in production rate for the whole period, whereas the dual variable α_{pdy} of the previous expression gives the marginal value of an extra unit in production rate for every day in the period. A similar reasoning applies to the KKT conditions for the other parts of the overall complementarity system. Thus, the KKT conditions for the producers are the following:

$$0 \leq \left[-\left(\pi^P_{n(p)dy}\right) + \frac{dc^P_p\left(SALES^P_{pdy}\right)}{dSALES^P_{pdy}} + \alpha^P_{pdy} + \beta^P_p\right] \perp SALES^P_{pdy} \geq 0 \;\; \forall d, y \tag{5}$$

$$0 \leq \overline{PR}^P_p - SALES^P_{pdy} \quad \perp \alpha^P_{pdy} \geq 0 \;\; \forall d, y \tag{6}$$

$$0 \leq \overline{PROD}_p - \sum_{y \in Y}\sum_{d \in D} days_d SALES^P_{pdy} \quad \perp \beta^P_p \geq 0 \tag{7}$$

[6]Note that LNG liquefiers buy directly from the producers and that the market-clearing condition for production includes a term denoting the purchases by the liquefier from the producer at the same node.

In addition, one must consider market-clearing conditions that state that the supply of gas for a production region equals the demand for gas being sent to the trader and/or the LNG liquefier. The associated dual variables are the wellhead prices.

$$0 = SALES^P_{pdy} - PURCH^{T\leftarrow P}_{t(p)n(p)dy} - \sum_{l\in L(p)} PURCH^{L\leftarrow P}_{ldy}, \pi^P_{pdy}(\text{free}) \quad \forall d, p, y \tag{8}$$

where

- $PURCH^{T\leftarrow P}_{t(p)n(p)dy}$ is the is the decision variable for purchases by the trader from the producer (volume/day)
- $PURCH^{L\leftarrow P}_{ldy}$ is the is the decision variable for purchases by the liquefiers from their producer (volume/day)

2.2. traders

A trader operates for one producer and represents the gas trading arm of the production company. This approach is consistent with having production and trading carried out by separate parts of the same overall organization or by legally separate entities. In any event, each trader is dedicated to a producer and a trader purchases gas only from its own producer and then sells the gas, possibly by exporting the gas to other countries. We distinguish two types of traders:

1. traders operating only at the domestic node of the producer, in case it is a small producer and doesn't export any gas. Previous papers usually refer to this production as exogenous production, e.g., [4].
2. traders that can operate at any consumption node that can be reached via pipelines through transit nodes from their own producer's node. An example is Norway, both a gas producing and exporting country. The trader associated with the Norwegian producer will be present in European consuming countries such as the Netherlands, the United Kingdom, Belgium, France, Germany, Poland, Austria, Italy, etc., but will not be present in:
   a. Algeria, because Algeria is not a consumption node in the model
   b. Japan, because Japan can't be reached by pipeline from Norway
   c. Tunisia, because Tunisia is only a relevant transit country from Algeria into Europe.

The trader is modeled as maximizing its net profit subject to balance equations (flow conservation constraints in each node) as well as nonnegativity constraints on its variables. The revenues are derived from the sales to marketers ($SALES^{T\rightarrow M}_{tndy}$) and to storage operators ($SALES^{T\rightarrow S}_{tny}$). To determine the revenues, the sales to the storage operators are multiplied by the market-clearing price π^T_{ndy}. The sales to the marketers are multiplied by a convex combination of the price determined by the inverse demand function $\Pi^{W(T)}_{ndy}(\cdot)$ or by the market-clearing wholesale price π^W_{ndy} if no market power is exerted.

This convex combination of the price is determined by the market power constant for the trader t, $\delta^C_t \in [0,1]$ where $\delta^C_t = 0$ means no market power and $\delta^C_t = 1$ means that the trader is a full Cournot player. Since traders in the natural gas market can and may exert different levels of market power, not captured by the theoretical concepts of perfect competition or Cournot behavior, other values for δ^C_t are allowed. Although market power values between 0 and 1 have been used before (in [72] it is called *degree of competition*) there is no literature describing the precise meaning of other values than 0 or 1 for the market power constant. To prevent discussion about arbitrary values with several digits, we limited ourselves to a small yet representative set of values: $\{0, 0.25, 0.5, 0.75, 1\}$ and determined the actual values during the model calibration.

The costs to the trader include purchasing the gas from the producer $(\pi^P_{n(p(t))dy} PURCH^{T\leftarrow P}_{tndy})$ as well as the transportation charges given by $\sum_{(n,m)\in A(t)}(\tau^A_{nmdy} + \tau^{Reg}_{nmdy})FLOW^T_{tnmdy}$ where

- $FLOW^T_{tnmdy}$ is the decision variable for the rate of gas transported by trader t from node n to neighboring node m in season d and year y (volume/day)
- τ^A_{nmdy} is the congestion fee of the arc (n,m) in season d and year y (€/volume), determined by the pipeline operator's problem
- τ^{Reg}_{nmdy} is the regulated pipeline transportation costs for the arc a from n to m in season d and year y (€/volume)
- $A(t)$ is the set of arcs (n,m) that trader t could use. $A(t) := \{(n,m) : t \in T(n,m)\}$ [7]
- $loss_{nm}$ is the loss factor for the arc a from n to m

Anticipating EU regulations, we assume complete Third Party Access to the international pipeline network. Hence, any trader can contract transmission capacity with any pipeline. To introduce seasonality of storage use, an indicator δ^{low}_d is used. $\delta^{low}_d = 1$ if $d = '1'$, the low-demand season (injection into storage), and 0 otherwise.

[7] Here, arc (n,m) is the unique link between one node and another one, for notatinal simplicity, we use a to denote arcs when interpretation is unambiguous.

Thus, the optimization problem for trader t is as follows:

$$\max_{SALES^{T\to M}_{tndy}, SALES^{T\to S}_{tny}, FLOW^{T}_{tnmdy}, PURCH^{T\leftarrow P}_{tndy}} \sum_{y\in Y}\sum_{d\in D}\sum_{n\in N(t)} days_d$$
$$\left[\begin{array}{c} \left(\delta^C_t \cdot \Pi^{W(T)}_{ndy}(\cdot) + (1-\delta^C_t)\pi^W_{ndy}\right)\cdot SALES^{T\to M}_{tndy} \\ +\delta^{low}_d \cdot \pi^T_{ndy} SALES^{T\to S}_{tny} - \pi^P_{n(p(t))dy} PURCH^{T\leftarrow P}_{tndy} \end{array}\right]$$
$$-\sum_{y\in Y}\sum_{d\in D} days_d \left[\sum_{(n,m)\in A(t)} (\tau^A_{nmdy} + \tau^{Reg}_{nmdy}) FLOW^T_{tnmdy}\right] \tag{9}$$

$s.t.$

$$\left[\begin{array}{c} \delta^{low}_d \cdot SALES^{T\to S}_{tny} + SALES^{T\to M}_{tndy} \\ +\sum_{m\in N} FLOW^T_{tnmdy} \end{array}\right] - \left[\begin{array}{c} PURCH^{T\leftarrow P}_{tndy} \\ -\sum_{m\in N}(1-loss_{mn}) FLOW^T_{tmndy} \end{array}\right] = 0$$
$$\forall n \in N(t), d, y \quad \left(\phi^T_{tndy}\right) \tag{10}$$

$$SALES^{T\to M}_{tndy} \geq 0 \qquad \forall n, d, y \tag{11}$$
$$SALES^{T\to S}_{tny} \geq 0 \qquad \forall n, y \tag{12}$$
$$PURCH^{T\leftarrow P}_{tndy} \geq 0 \qquad \forall n = n(p(t)), d, y \tag{13}$$
$$FLOW^T_{tnmdy} \geq 0 \qquad \forall (n,m) \in A(t), d, y \tag{14}$$

with the additional definitions that:

- T is the set of traders, $t \in T$
- $p(t)$ is the producer for which trader t is the trading agent
- $N(t)$ is the set of nodes where trader t is present
- $T(n)$ is the set of traders t present at node n
- $T(n,m)$ is the set of traders t that can use arc (n,m), $T(n,m) := \{t \in (T(n) \cap T(m)\}$
- $PURCH^{T\leftarrow P}_{tndy}$ is the decision variable for the rate of gas bought by trader t from its producer $p(t)$ located at node $n \in (N(t) \cap N(p))$ in season d and year y (volume/day)

By influencing the inverse demand function $\Pi^{W(T)}_{ndy}(\cdot)$ the producer via its trader, can exert market power by withholding supplies to downstream customers. In particular, we posit that this inverse demand function is linear and has the following form:

$$\Pi^{W(T)}_{ndy} = INT^M_{ndy} - SLP^M_{ndy} \cdot$$
$$\left(\begin{array}{c} SALES^{T\to M}_{tndy} + \sum_{t'\in T(n):t'\neq t} SALES^{T\to M}_{t'ndy} \\ +\sum_{r\in R(n)} SALES^{R\to M}_{rndy} + \left(1-\delta^{low}_d\right)\sum_{s\in S(n)} SALES^{S\to M}_{sndy} \end{array}\right) \tag{15}$$

where INT^M_{ndy} and SLP^M_{ndy} are the intercept and slope constants for this linear function and $\left(\begin{array}{c} SALES^{T\to M}_{tndy} + \sum_{t'\in T(n):t'\neq t} SALES^{T\to M}_{t'ndy} \\ +\sum_{r\in R(n)} SALES^{R\to M}_{rndy} + \left(1-\delta^{low}_d\right)\sum_{s\in S(n)} SALES^{S\to M}_{sndy} \end{array}\right)$ represents the total sales from the trader and other traders to the marketers as well as sales coming from the regasifiers and storage operators, respectively. Only the sales from the trader, $SALES^{T \to M}_{ndy}$, are variables in the trader's optimization problem above. The other variables are treated as exogenous by the trader.

The KKT conditions for the trader's problem as well as for the other players are presented in Appendix B. To determine the price π^T_{ndy}, market-clearing conditions are also included. It is only the storage operators in the low demand season that require a market-clearing condition (with the traders having market power over the marketers). For the storage market, in the low demand season, these market-clearing conditions take the form:

$$0 = \sum_{t \in T(n)} SALES^{T \to S}_{tny} - \sum_{s \in S(n)} PURCH^{S \leftarrow T}_{sy} \qquad \pi^T_{n1y} \quad \text{(free)} \ \forall n \in N(t), y \tag{16}$$

2.3. LNG Liquefiers

LNG liquefiers receive natural gas from the producers, liquefy the gas and then send it to downstream regasifiers by LNG tankers. The liquefiers maximize their net revenue by deciding on how much to sell to regasifiers ($SALES^L_{ldy}$) and how much to purchase from the producers ($PURCH^{L \leftarrow P}_{ldy}$). For a particular season and year, their revenue is given by the term $days_d \left(\pi^L_{n(l)dy} \right) SALES^L_{ldy}$ from which is subtracted their purchasing costs $\pi^P_{n(l)dy} PURCH^{L \leftarrow P}_{ldy}$, distribution costs $days_d u^{L \leftarrow P}_l PURCH^{L \leftarrow P}_{ldy}$ from the producer, as well as transmission costs using the tankers $c^L_l(SALES^L_{ldy})$ where

- L is the set of LNG liquefiers, $l \in L$
- $L(n)$ is the set of LNG liquefiers located at node n
- $L(p)$ is the set of LNG liquefiers buying from producer p
- $n(l)$ is the node where LNG liquefier l is located
- $p(l)$ is the producer p from which LNG liquefier l can buy
- $c^L_l(SALES^L_{ldy})$ is the liquefaction cost function of LNG liquefier l (€/volume/day)
- $u^{L \leftarrow P}_l$ are the unit distribution costs for producer p to LNG liquefier l (€/volume/day)

Note that both the selling price of gas, $\pi^L_{n(l)dy}$ as well as the buying price from the producer $\pi^P_{n(p(l))dy}$, are exogenous to the price-taking liquefier but are variables in the overall complementarity problem. $SALES^L_{ldy}$ and $PURCH^{L \leftarrow P}_{ldy}$ are the decision variables of the LNG liquefier. The optimization of net revenues is subject to liquefaction capacity constraints as well as balancing and nonnegativity restrictions. Consequently, the full problem can be stated as follows:

$$\max_{SALES^L_{ldy},PURCH^{L\leftarrow P}_{ldy}} \quad \sum_{y\in Y}\sum_{d\in D} days_d \left[\left(\pi^L_{n(l)dy}\right) SALES^L_{ldy} - \pi^P_{n(l)dy} PURCH^{L\leftarrow P}_{ldy}\right]$$

$$-\sum_{y\in Y}\sum_{d\in D} days_d u^{L\leftarrow P}_l PURCH^{L\leftarrow P}_{ldy} + c^L_l(SALES^L_{ldy}) \tag{17}$$

$$s.t. \quad SALES^L_{ldy} \leq \overline{LQF}^L_l \qquad \left(\alpha^L_{ldy}\right) \ \forall d, y \tag{18}$$

$$(1-loss_l)PURCH^{L\leftarrow P}_{ldy} - SALES^L_{ldy} = 0 \qquad \left(\phi^L_{ldy}\right) \ \forall d, y \tag{19}$$

$$SALES^L_{ldy} \geq 0 \qquad \forall d, y \tag{20}$$

$$PURCH^{L\leftarrow P}_{ldy} \geq 0 \qquad \forall d, y \tag{21}$$

where

- $\overline{LQF}^L_l$ is the upper bound on the LNG liquefaction rate for LNG liquefier l (volume/day)
- $loss_l$ is the liquefaction loss factor for LNG liquefier l (%)

In the liquefaction market, the total supply of liquefied gas at a node match the total demand by all regasifiers. This market-clearing condition is:

$$0 = \sum_{l\in L(n(l))} SALES^L_{ldy} - \sum_{b:n_s(b)=n(l)} PURCH^{R\leftarrow L}_{bdy} \quad \pi^L_{n(l)dy}(\text{free}) \quad \forall d, y \tag{22}$$

2.4. LNG Regasifiers

The modeling of the regasifiers is similar to the concept of the peak gas operator in the North American market as presented in [26] and [29]. There, the peak gas operators are modeled with production bounds and are active only in the peak demand season. We now take account of the new situation on the global natural gas markets where LNG has become part of the gas supply mix throughout the year. Hence, we model the regasifiers as being active in every season. They are the downstream interface with the liquefiers and are a new player compared to previous models ([26],[29],[4], [13],[38]). Modeling both types of players allows us to represent the entire LNG value chain, with the LNG tankers activity represented by the arcs between the liquefiers and the regasifiers.

The regasifiers maximize their net revenue by deciding how much re-gasified natural gas to sell to the storage operators $SALES^{R\rightarrow S}_{rdy}$ (in the low-demand season) and to the marketers $SALES^{R\rightarrow M}_{rdy}$ (in all seasons), and how much to purchase and transport from the liquefiers $PURCH^{R\leftarrow L}_{bdy}$. The regasifiers problem implicitly includes the LNG transportation problem of tanker utilization, which is subject to tanker operation costs $\left(u^{R\leftarrow L}_b\right)\left(PURCH^{R\leftarrow L}_{bdy}\right)$ and losses$(loss_b)\left(PURCH^{R\leftarrow L}_{bdy}\right)$. These and the other costs incurring from the LNG purchases $\left(\pi^L_{n_s(b)dy}\right)\left(PURCH^{R\leftarrow L}_{bdy}\right)$ and regasification operations

($c_r^R(SALES_{rdy}^R)$ are subtracted from the regasifier's revenue. We assume the regasification cost function to be convex, based on a somewhat similar argument made for the producers. The regasification operations are constrained by a limited regasification rate per day ($\overline{REG}_r^R$), and is subject to losses ($loss_r$). The sets and indices in this optimization problem are the following:

- B the set of boats (arcs), $b \in B$ [unlimited marine capacity and fixed distribution charges are assumed]
- $B(n)$ the set of boats shipping to node n
- $n_e(b)$ the destination (end) node of boat (arc) b
- $n_s(b)$ the origin (source) node of boat (arc) b
- $n(r)$ the node where LNG regasifier r is located;
- R the set of LNG regasifiers, $r \in R$
- $R(n)$ the set of LNG regasifiers located at node n.

Note that, here again, the selling prices of natural gas ($\pi_{n(r)dy}^W$ for the wholesale price and $\pi_{n(r)dy}^R$ for the price of sales to storage) as well as the buying price from the liquefiers ($\pi_{n_s(b)dy}^L$) are exogenous to the regasifiers optimization problems because they are determined in the market-clearing conditions with the players from the "adjacent" markets. The optimization problem for regasifier r involves choosing the values for $SALES_{rdy}^{R\to M}$, $SALES_{rdy}^{R\to S}$ and $PURCH_{bdy}^{R\leftarrow L}$ to maximize net profits subject to regasification rates, material balance, and nonnegativity constraint, that is:

$$\max \quad \sum_{y\in Y}\sum_{d\in D} days_d \begin{bmatrix} \pi_{n(r)dy}^W SALES_{rdy}^{R\to M} + \pi_{n(r)dy}^R SALES_{rdy}^{R\to S} \\ -\sum_{b:n_e(b)=n(r)} \left(\pi_{n_s(b)dy}^L + u_b^{R\leftarrow L}\right) PURCH_{bdy}^{R\leftarrow L} \\ -c_r^R\left(SALES_{rdy}^{R\to M} + SALES_{rdy}^{R\to S}\right) \end{bmatrix}$$

$$s.t. \quad SALES_{rdy}^{R\to M} + SALES_{rdy}^{R\to S} \le \overline{REG}_r^R \qquad \forall d,y \quad \left(\alpha_{rdy}^R\right) \tag{23}$$

$$\sum_{b:n_e(b)=n(r)} (1-loss_r)(1-loss_b)PURCH_{bdy}^{R\leftarrow L} - \left(SALES_{rdy}^{R\to M} + SALES_{rdy}^{R\to S}\right) = 0 \qquad \forall d,y \quad \left(\phi_{rdy}^R\right) \tag{24}$$

$$SALES_{rdy}^{R\to M} \ge 0 \qquad \forall d,y \tag{25}$$

$$SALES_{rdy}^{R\to S} \ge 0 \qquad \forall d=1,y \tag{26}$$

$$PURCH_{bdy}^{R\leftarrow L} \ge 0 \qquad \forall b: n_e(b)=n(r), d, y \tag{27}$$

The total supply for regasified natural gas must match the demand for it at each node. This equality is enforced by market-clearing conditions. As far as sales to marketers are

Accepted at Energy Policy, January 2008

concerned, this is taken care of in the inverse demand functions of the marketers. The market-clearing conditions between the regasifier and the storage operator in the low demand injection season are:

$$0 = \sum_{r \in R(n)} SALES^{R \to S}_{r1y} - \sum_{s \in S(n)} PURCH^{S \leftarrow R}_{sy} \qquad \pi^{R}_{n1y} \quad \text{(free)}\ \forall n, y \tag{28}$$

where $PURCH^{S \leftarrow R}_{sy}$ is the decision variable for the storage operator's purchases from the regasifier.

2.5. Storage Operators

The storage operators are modeled similarly to the equivalent players in [26] and [29] with the exception that they are now supplied by regasifiers, too. The storage operators buy gas from the traders ($PURCH^{S \leftarrow T}_{sy}$) or regasifiers ($PURCH^{S \leftarrow R}_{sy}$) and inject it into storage in the low demand season. They withdraw gas and sell it to the marketers ($SALES^{S \to M}_{sdy}$) in the two other, high demand seasons. This seasonal pattern of storage operation is a standard assumption in the modeling literature (e.g., [72]). The modeling of storage operators as actual natural gas traders, that are not only trading capacities but the gas itself, corresponds to the business model of many independent storage operators in Europe and especially in the UK. In our model, storage is used for the inter-seasonal arbitrage of demand, which implies that all gas that is injected in the low-demand season is withdrawn in the high-demand seasons.

In each season, the storage operator maximizies its profit which is the sum of revenue from sales $\left(\pi^{W}_{n(s)dy}\right)\left(SALES^{S \to M}_{sdy}\right)$ subtracted from the total costs. Total costs include the costs of purchasing the gas $((\pi^{T}_{n(s)1y} + u^{S \leftarrow T}_{n}) PURCH^{S \leftarrow T}_{sy} + (\pi^{R}_{n(s)1y} + u^{S \leftarrow R}_{n}) PURCH^{S \leftarrow R}_{sy})$, the costs of operating the storage facility ($c^{S}_{s}(PURCH^{S \leftarrow T}_{sy} + PURCH^{S \leftarrow R}_{sy})$), assumed to be a convex function, and the costs of transporting the gas to the storage from the traders and from the regasifiers $\left(u^{S \leftarrow T}_{n}\right)\left(PURCH^{S \leftarrow T}_{sy}\right) + \left(u^{S \leftarrow R}_{n}\right)\left(PURCH^{S \leftarrow R}_{sy}\right)$. The storage operator's optimization problem is then to select values for the decision variables $PURCH^{S \leftarrow T}_{sy}$, $PURCH^{S \leftarrow R}_{sy}$ and $SALES^{S \to M}_{sdy}$ subject to a number of technical constraints, such as upper bounds on the daily injection rate ($\overline{INJ}^{S}_{s}$), on the daily withdrawal rate ($\overline{EXT}^{S}_{s}$) and on the working gas volume ($\overline{WRKG}^{S}_{s}$) which can be considered as the storage capacity[8]. The following sets and indices are used in the storage operator's optimization program:

- S the set of storage operators
- $S(n)$ the set of storage operators located at node n
- $n(s)$ the node where the storage operator s is located

[8]Working gas, as opposed to base gas, is the amount of gas that can be injected and withdrawn. A certain minimum amount of base gas is necessary to maintain a pressure level in the storage for normal operations. To inject the gas into the reservoir, a certain amount is needed to fuel the compressors effectively resulting in a loss ($loss_s$) of the original amount.

As the storage operators are assumed to behave competitively vis-à-vis their upstream and downstream markets, they are price-takers for the purchase prices ($\pi^R_{n(s)dy}$and π^T_{ndy}) and the selling prices to the marketers ($\pi^W_{n(s)dy}$). The interaction with the upstream and downstream markets is modeled in the market-clearing conditions with the regasifier, the trader and the marketers (28), (16), and (41), respectively.

The optimization problem for storage operator s therefore is to maximize its net profit by adjusting sales and purchases while taking into account injection, extraction, material balance, and volume constraints as well as nonnegativity conditions for the decision variables and is given as follows.

$$
\begin{aligned}
\max \quad & \sum_{y\in Y}\sum_{d=2,3} days_d \left(\pi^W_{n(s)dy}\right) SALES^{S\to M}_{sdy} \\
& -\sum_{y\in Y} days_1 \begin{bmatrix} (\pi^T_{n(s)1y} + u^{S\leftarrow T}_n) PURCH^{S\leftarrow T}_{sy} \\ +(\pi^R_{n(s)1y} + u^{S\leftarrow R}_n) PURCH^{S\leftarrow R}_{sy} \\ +c^S_s \left(PURCH^{S\leftarrow T}_{sy} + PURCH^{S\leftarrow R}_{sy}\right) \end{bmatrix} && (29) \\
s.t. \quad & PURCH^{S\leftarrow T}_{sy} + PURCH^{S\leftarrow R}_{sy} \leq \overline{INJ}^S_s \qquad \forall y \quad (\alpha^S_{sy}) && (30) \\
& SALES^{S\to M}_{sdy} \leq \ \overline{EXT}^S_s \qquad \forall d=2,3,y \quad (\beta^S_{sdy}) && (31) \\
& days_1(1-loss_s)\left(PURCH^{S\leftarrow T}_{sy} + PURCH^{S\leftarrow R}_{sy}\right) \\
- \ & \sum_{d=2,3} days_d SALES^{S\to M}_{sdy} = 0 \qquad \forall y \quad (\phi^S_{sy}) && (32) \\
& \sum_{d=2,3} days_d SALES^{S\to M}_{sdy} \leq \overline{WRKG}^S_s \qquad \forall y \quad (\gamma^S_{sy}) && (33) \\
& SALES^{S\to M}_{sdy} \geq 0 \qquad \forall d=2,3,y && (34) \\
& PURCH^{S\leftarrow T}_{sy} \geq 0 \qquad \forall y, t\in T(s(n)) && (35) \\
& PURCH^{S\leftarrow R}_{sy} \geq 0 \qquad \forall y && (36)
\end{aligned}
$$

2.6. Pipeline Operator

The pipeline operator's problem is similar to the one described in [26] and [29]. We consider a pipeline operator for each pipeline (n,m), $(n,m)\in A$ (with A the set of pipeline arcs). The pipeline operator is modeled as a regulated player in the natural gas market that, based on complete Third Party Access, allocates pipeline capacity to market players demanding transport capacity. This corresponds to the political willingness in Europe to restrict the, *a priori*, high monopolistic revenues of pipeline owners by regulating their prices or revenues. We assume the first case of price regulation, where the price paid for pipeline use (π^{Areg}_{nmdy}) is regulated and fixed. The total revenue of a pipeline operator is determined by the sum of its fixed price and the congestion price (τ^A_{nmdy}) income: $\sum_{y\in Y}\sum_{d\in D} days_d(\pi^{Areg}_{nmdy} + \tau^A_{nmdy}) SALES^A_{nmdy}$.

We concentrate on the variable part of the revenue that the pipeline operator can influence in its optimization problem: the congestion revenue. This revenue, for each season, is based on multiplying the congestion rate τ^A_{nmdy} by the number of days in that season and then by the rate of gas sold (the pipeline operator's decision variable) for each arc (n,m) $(SALES^A_{nmdy})$.

The pipeline capacity of each pipeline arc (n,m) has a limit on its daily flows $(\overline{PL}^A_{nm})$. Capacity constraints of pipelines are an important characteristic of the natural gas market. A limited import capacity to a country can considerably influence the market situation in this country, as a possible oligopolistic player (trader) can exert more or less market power depending on the number of competitors that can enter this market. The pipeline operator's optimization problem therefore is:

$$\max \quad \sum_{y\in Y}\sum_{d\in D} days_d \tau^A_{nmdy} SALES^A_{nmdy} \tag{37}$$

$$s.t. \quad SALES^A_{nmdy} \leq \overline{PL}^A_{nm} \quad \forall d,y \quad \left(\alpha^A_{nmdy}\right) \tag{38}$$

$$SALES^A_{nmdy} \geq 0 \quad \forall d,y \tag{39}$$

Note that the congestion fee, τ^A_{nmdy}, is exogenous to the pipeline operator's optimization problem. His decision variables are the daily pipeline flows, $SALES^A_{nmdy}$. The market-clearing conditions for pipeline capacity ensures for each pipeline a the equality of flows operated by the pipeline operator $(SALES^A_{nmdy})$, and flows transported by the traders $(\sum_{t\in T((n,m))} FLOW^T_{tnmdy})$, with $T(n,m)$ the set of traders present in both the starting node and the end node of the arc.

$$0 = SALES^A_{nmdy} - \sum_{t\in T((n,m))} FLOW^T_{tnmdy}, \quad \tau^A_{nmdy}\text{ (free)} \quad \forall (n,m),d,y \tag{40}$$

2.7. Marketers

Marketers are the interface with the final demand for natural gas. As such, and as perfectly competitive players the marketers simply pass on the final demand to the upstream sector. Their inverse demand function $\Pi^{W(T)}_{ndy}(\cdot)$ is incorporated in the traders' optimization problem (9). The total purchases of the marketer will by definition equal the total sales of the other players (traders, regasifiers, and storage operators) to the marketer. The following conditions enforce the market clearing wholesale price, π^W_{ndy}, to match the inverse demand function at the equilibrium point.

$$0 = \pi^W_{ndy} - \left(INT^M_{ndy} - SLP^M_{ndy} \begin{bmatrix} \sum_{t\in T(n)} SALES^{T\to M}_{ndy} \\ +\sum_{r\in R(n)} SALES^{R\to M}_{ndy} \\ +\left(1-\delta^{low}_d\right)\sum_{s\in S(n)} SALES^{S\to M}_{ndy} \end{bmatrix} \right), \pi^W_{ndy}\text{(free)}, \forall n,d,y \tag{41}$$

Collecting the Karush-Kuhn-Tucker (KKT) optimality conditions of the players' optimization problems presented above and combining them with the mentioned market-clearing conditions constitutes an instance of a mixed complementarity problem (MCP) or variational inequality problem (VI) referred to as complementarity problem [23]. We ensure that the optimization problems are convex and that their Karush-Kuhn-Tucker optimality conditions are both necessary (due to polyhedrality of the feasible regions) and sufficient (due to the convexity of the objective functions and the polyhedral feasible regions) for global optimality of the solution [2].

The MCP model is programmed in GAMS using the PATH MCP solver [10]. The PATH solver iteratively solves a sequence of linear approximations to the model and avoids convergence to local non-optimal solutions. Model runs were performed on a computer with 3.2 Ghz clock speed, 2GB RAM and typically took about one minute to solve.

3. Numerical Results

This section presents results of using the complementarity system described above in four cases relative to the base case assumption of market power for the producers (traders). These other cases are: 1. if the traders were taken to be perfectly competitive; 2. the disruption of Russian exports via Ukraine; 3. a cutoff of the relatively inexpensive Algerian gas; and 4. capacity expansions in LNG and pipeline infrastructure corresponding to projections for the year 2011. (The first cases are simulated for the base year 2004.) The intention of running these scenarios was to show the breadth of the model capability as well as to indicate potential impacts on the global gas markets. These cases are abbreviated as follows: SBC (strategic base case), PCM (perfectly competitive market), UKR (Ukrainian gas curtailment), ALG (Algerian gas production cutoff), 2011 (capacity expansions for 2011).

Note that in this section, all volumes and capacities are in billions of cubic meters per year (bcm/y), costs and prices are in Euros per thousand cubic meters (€/kcm) with alll market players and the input data assumptions shown in detail in the Appendices. The model was first calibrated for the base case by allowing parameters such as production capacities, demand curve intercepts and slopes, and market power constants to vary so as to have outputs match historically reported values for the base year 2004. The market power constants for Algeria, the Netherlands, Norway and Russia were set to $\delta^C = 0.75$ and for the Caspian Sea region, Denmark and the United Kingdom the values were $\delta^C = 0.25$. For price elasticities we followed [13]: -0.25 for the residential/commercial sector, -0.4 for industrial demand and -0.75 for power generation. Based on [45] and [6] reference demand levels for 2004 were determined and the model was calibrated resulting in consumption levels within 1% for each country, except Japan at 1.3%. For separate seasons as well as separate sectors the calibrated outcomes were within 2% for each country, and within 1% for most. For "LNG demand only" countries (see Appendix), we have assumed that there is no seasonality of the demand and calibrated on their LNG imports in the base year for as far as these values were present [6]. The average wholesale price in Europe after calibration was 148 €/kcm, which compares favorably to reported selling prices of circa 127 €/kcm (Statoil, [70]), 139 €/kcm (GasTerra, [35]), and the USD figure 126 $/kcm [6].

3.1. Strategic Base Case versus Perfect Competitive Market

All players, except the traders, are assumed to be price-takers in all cases. To simulate a perfectly competitive market for the case PCM the market power constants for all traders δ_t^C are all set equal to 0. In the following paragraphs the results for the two cases SBC and PCM are compared to analyze how market power affects the market participants, consumed volumes, market prices and producer profits.

As can be expected, production and consumption are lower in the strategic base case as compared to a market with perfectly competitive producers. In the strategic scenario, the traders increase prices by withholding quantities. In particular, in the strategic base case, the total consumption of all included countries is 674 bcm (the calibration value for 2004) as compared to 731 bcm under a perfect competition assumption (see Figure 4). This means that about 8.4% more consumption occurs when the producers (via their traders) are perfectly competitive; a similar result for production occurs (779 bcm for PCM and 721 bcm for SBC, see Figure 5). Additionally, in perfect competition, most production and export capacities are binding.

Consistent with economic theory, higher prices ensue when the producers are allowed to exert market power via their traders. In particular, Europe sees 27% higher volume-weighted wholesale prices[9] (148 €/kcm vs. 116 €/kcm) as a result of market power; average worldwide prices are 21% higher. The higher price increase in Europe is due to the traders' market power supplying via pipelines to Europe. However, the global LNG market spreads the higher price level to other markets as well. As Figure 6 shows, the countries with relative price differences under SBC higher than the European average are the Netherlands, Hungary, Poland, Turkey, Romania and the United Kingdom with differences of 62%, 52%, 38%, 38%, 29%, and 28%, respectively. Countries with low import capacities (Netherlands, UK) or little diversification possibilities of pipeline or LNG imports (Eastern Europe) are impacted most.

Countries with relatively small price differences between SBC and PCM are Germany (13%), Spain (10%), France (7%), and Italy (9%). These countries largely depend on imports. They have access to LNG or have good access to many pipeline suppliers and thus have a diversified supply portfolio. They face higher than average prices in PCM, but suffer less from exertion of market power. Especially Spain, France and Italy benefit from their relatively large share of LNG imports and LNG import capacities, since we assume the LNG players to behave competitively in all cases.

Besides lower consumption and production levels in the strategic base case, the mix between LNG and pipeline gas is also different. In particular, under market power assumptions, Europe consumes overall less gas (521 vs. 575 bcm) but counts on a larger share of it being supplied by LNG (7.2% vs. 4.4%). Additionally, in the SBC, Europe

[9] All price and cost comparisons are volume-weighted averages over seasons and countries, unless stated otherwise.

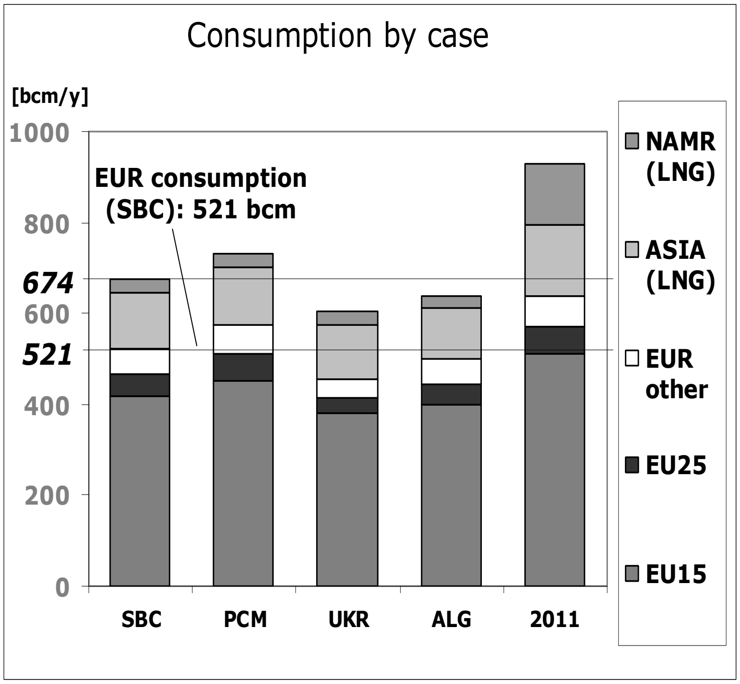

Figure 4. Consumption (bcm) in European countries in all five cases

counts on storage for 14.2% of total consumption but only 7.6% under perfect competition. This is a direct effect of the higher prices in a Cournot model which provide an incentive for higher cost suppliers (LNG, storage) to enter the market.

3.2. Disruption Ukrainian Pipelines versus Strategic Base Case

In the winter of 2005-2006, Gazprom decided to cut off its pipeline gas to Ukraine based on contractual disputes. According to the New York Times, a case was made as to the political nature of this curtailment [54]. Later in 2006, supply shortages of Russian gas affected Georgia ([63], [62], [64]). Gazprom in particular, and Russia in general holds a strategic advantage given its huge supply of natural gas. According to Stern [68], the proved gas reserves for Gazprom as of the end of 2004 were 16,357 bcm. The Russian reserves account for roughly one third of the global natural gas reserves, and its supply share in European gas consumption is about 30%. Moreover, in the next ten to fifteen years, the global influence of Russian gas may be even more felt via LNG to Asia and North America and pipeline gas to Asia [68]. Thus, to represent the case of Russia exerting market power in the production market, we have designed a case corresponding to a disruption of pipeline gas to Europe via Ukraine.

To simulate the impact on the European gas market of disrupted Ukrainian pipeline transit the capacities of all Ukrainian outgoing pipelines (a total capacity of 171 bcm per

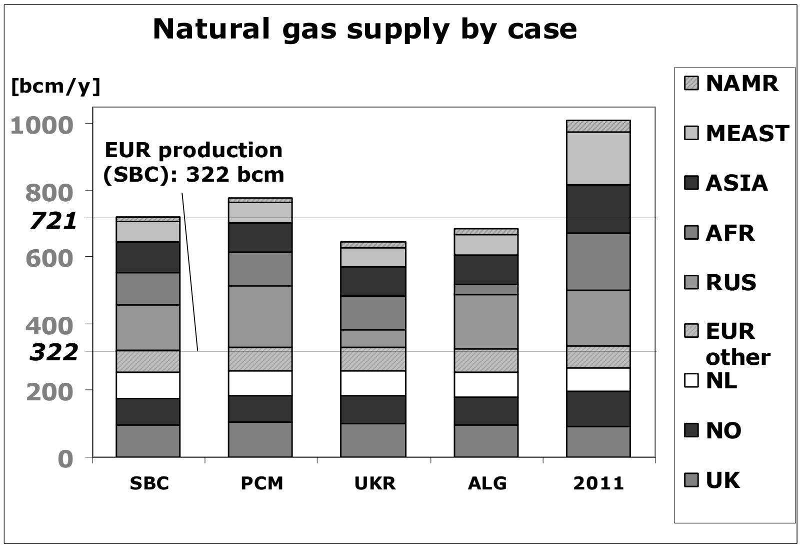

Figure 5. Natural Gas Supply by Geographic Area (bcm)

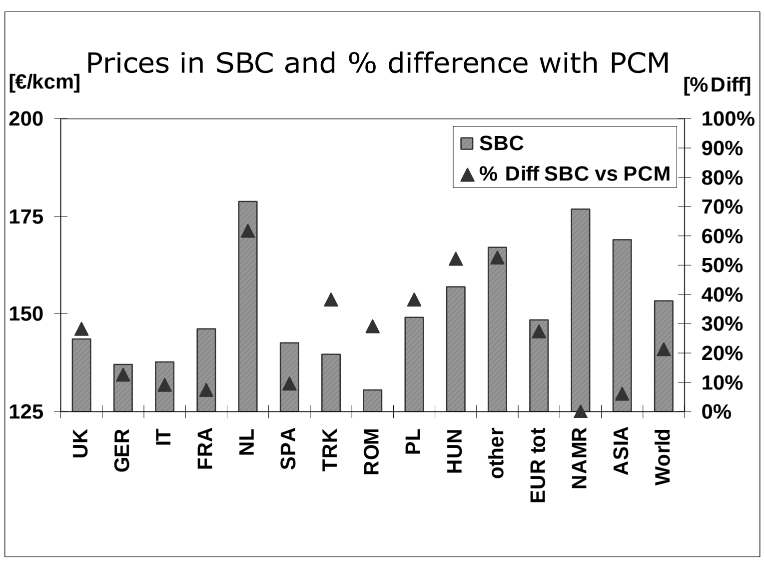

Figure 6. Prices in SBC and PCM

Accepted at Energy Policy, January 2008

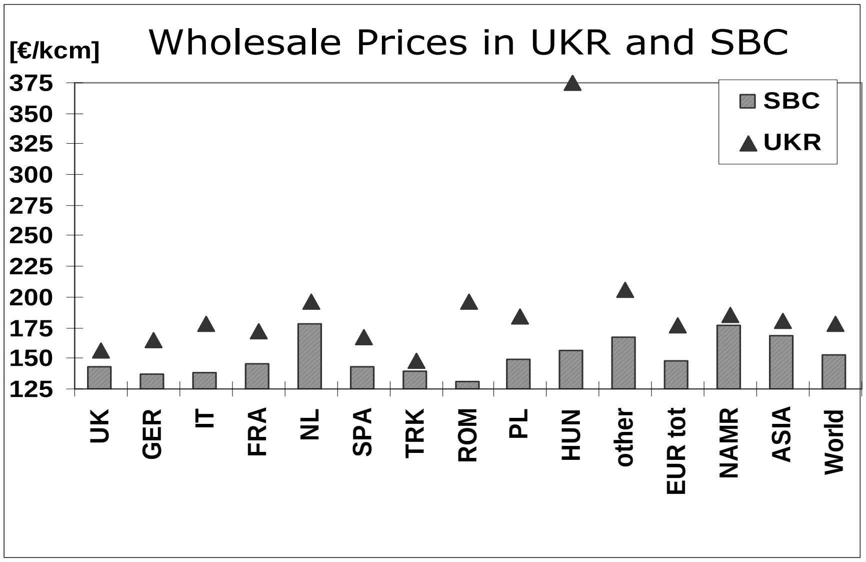

Figure 7. Prices disrupted Ukraine versus SBC

year) are set to zero.[10] The following paragraphs compare the results for the cases UKR (Ukrainian gas curtailment) and SBC (strategic base case).[11]

Disruption of Ukrainian supplies leads to a model-wide gas consumption of 604 bcm, 11% lower than the SBC consumption level. European consumption decreases by over 12% to 456 bcm, the LNG supply increases to 42 bcm. The average worldwide wholesale price level increases by 16% to 178 €/kcm, and the European price level by 19% to 177 €/kcm. Storage supplies 59 bcm, 13% of total European consumption, however 15 bcm lower than in the SBC. Storage cannot play a bigger role mainly due to lack of supply in the low demand period and resulting higher price levels, especially in Eastern and Central European countries. Figure 7 shows that Hungary suffers from the largest increase in wholesale prices, from 157 to 375 €/kcm, due to 80% of its total import capacity being shut off with the Ukrainian curtailment.

Tables 1 and 2 show the worldwide LNG shipments respectively for the SBC and UKR cases. In both cases most LNG liquefiers are producing at full capacity, except for Norway which is the most expensive hence the marginal LNG supply option. Algerian supplies

[10]Setting the transit capacity for the whole year equal to zero is an approximation of the January 2006 events, since the actual disruption lasted for a few days only. One must also keep in mind that the results of the complementarity model are long-term equilibrium values and do not take into account short term adjustments.

[11]The model was run with aggregate demand curves per country and the sector demands were calculated *ex-post* based on their actual demand curves. In some countries with low consumption the equilibrium prices in the UKR case are higher than the demand intercepts of the power generation sector, leading to some negative values (*ex post*). As aggregate country demand cannot be negative, and the negative volumes are small in magnitude (<0.5 bcm per case and 2.1 bcm aggregate) these outcomes were ignored.

Table 1
Wordwide LNG Shipments- Strategic Base Case

	NO	ALG	EGP	ARB	AUS	RUS	SEA	TRI	NIG	Total In
BE	0.6	0.2								0.8
UK	0.4	0.1								0.5
POR		2.5								2.5
SPA		17.4								17.4
FRA		3.3	8.5							11.9
IT			1.4							1.4
GR			0.8							0.8
TRK			2.4							2.4
IND				3.1						3.1
CHI				4.6						4.6
TW				10.4						10.4
KOR				21.6			10.6	0.9		33.0
JP					13.1	6.5	55.5			75.1
USA		7.3						12.3	0.9	20.5
CAN									10.6	10.6
Total Out	1.0	30.8	13.2	39.6	13.1	6.5	66.0	13.2	11.4	194.8

decrease by 1.1 bcm (30.8 to 29.7) and Norwegian LNG supplies decrease by 0.5 bcm (1.0 to 0.5) in the UKR case, presumably because there is less competition for Russian gas in the European market for their pipeline exports.

On the demand side, two countries import significantly more, and three countries import significantly less LNG. Italy and France have to replace the lost pipeline inflows of Russian gas and increase LNG imports by 4.5 bcm and 1.9 bcm. Japan, Turkey and South Korea import 3.8, 2.2 and 1.3 bcm less. Spain, which is a major LNG importer, sees LNG imports decrease only moderately.

The influence on international natural gas trade can be described as a "ripple-effect". In the SBC, European countries are only supplied by nearby regions: Norway and Mediterranean countries, especially Algeria and Egypt. But when Russian pipeline supplies are disrupted, the European demand for LNG rises and the Arabian LNG exporting countries shift some of their shipments to Europe, away from Asia. The U.S. receives less gas from Algeria and demands more from Trinidad & Tobago, which stops supplying to South Korea. South Korea and Japan compete for the South East Asian LNG supplies, and as a result both see prices increase by 13 €/kcm with lower supplies. The global LNG market provides an alternative gas source for affected European countries, and as a results global LNG prices rise. The average LNG selling price excluding transport increases by more than 13%, from 131 to 148 EUR/kcm.

Table 2
Wordwide LNG Shipments- Ukrainian Gas Interruption Case

	NO	ALG	EGP	ARB	AUS	RUS	SEA	TRI	NIG	Total In
BE	0.5	0.8								1.3
POR		2.3								2.3
SPA		16.7								16.7
FRA		4.0	6.8	3.0						13.8
IT			6.1							6.1
GR			0.2	1.2						1.4
TRK			0.0	0.1						0.1
IND				3.1						3.1
CHI				4.6						4.6
TW				10.4						10.4
KOR				17.3			14.4			31.7
JP					13.2	6.5	51.6			71.3
USA		5.8						13.2	1.1	20.1
CAN									10.3	10.3
Total Out	0.5	29.7	13.2	39.6	13.2	6.5	66.0	13.2	11.4	193.3

Under this scenario, while most countries face severe negative ramifications of the shut-off of gas through Ukraine, Turkey's total imports are hardly affected. Turkey faces a large decrease in LNG supplies because there is a strong demand for LNG in the rest of Europe (Figure 8). But it benefits from the availability of more pipeline gas from Russia through the "Blue Stream" pipeline in the Black Sea which compensates the LNG imports.

3.3. Disruption of Algerian Supplies versus Strategic Base Case

Algerian natural gas production is important for the European and global natural gas markets for a number of reasons. First, natural gas production costs in Algeria are relatively low, due to geographical and geological conditions. Second, Algerian natural gas can be exported to Europe via offshore pipeline through the Mediterranean Sea. Currently, there are two pipelines in use, one to Italy and one to Spain, with a total capacity of 34 bcm. Two more pipelines between Algeria and Europe will be on stream before 2011. Third, Algeria is an important exporter of LNG, being the first country to start LNG supplies in the 1960s, and currently having a combined liquefaction capacity of 30.8 bcm. Its geographic location allows Algeria to arbitrage between supplying Europe and North America with LNG. In the strategic base case results, 24% of the Algerian LNG goes to North America, the rest to Europe.

To simulate a curtailment of Algerian natural gas supplies, the production capacity of Algeria was set equal to zero. This disruption leads to a drop in model-wide consumption of 5.2%, from 674 bcm (SBC) to 639 bcm. The model-wide production level falls by 5.3% to 683 bcm. European consumption also decreases, by 4.5%, to 498 bcm, and LNG supplies to Europe fall by 14 bcm to 23 bcm. The shortage in natural gas and especially LNG supplies leads to a price level increase of 11% to 170 €/kcm globally, and an increase of 10% to 163 €/kcm in Europe. Storage supplies 69 bcm of European consumption, about

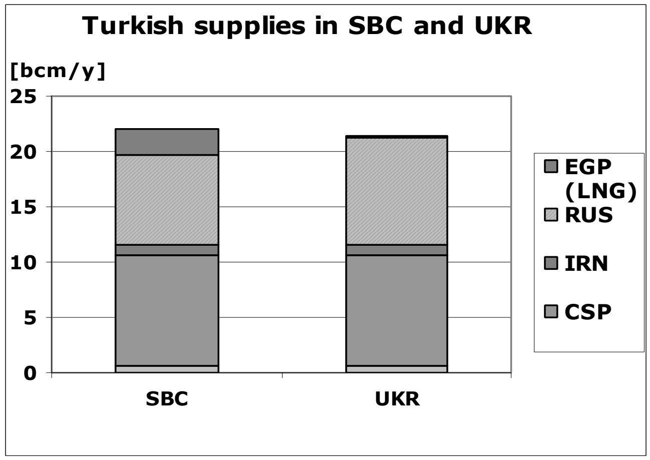

Figure 8. Decomposition of Turkish supplies in cases SBC and UKR

5 bcm less than in SBC.

Italy and Spain are the main importers of Algerian natural gas. The Mediterranean offshore pipelines land there and both countries are LNG importers. In the SBC, the Algerian supplies to Italy account for 27% of total Italian consumption; for Spain, Algeria contributes to even larger 88% of its total supplies. Figures 9 and 10 show the supply diversification of Italy and Spain in SBC and ALG. A main difference is that Italy receives its Algerian supplies by pipeline, whereas Spain receives about $\frac{3}{4}$of its Algerian supplies as LNG. When Algerian supplies are disrupted, both countries face a drop in consumption of roughly 10% of their consumption in SBC. Although Spain relies more on Algerian gas than Italy, in this crisis situation it is more flexible to find alternative gas suppliers by turning to the world-wide LNG market.

A closer look at the European market in Tables 3 and 4 shows that the falling Italian imports from Algeria are compensated by an increase of the pipeline imports from the Netherlands, Russia , and to a lesser extent from Norway. The Dutch exports to Italy reduce the German imports from the Netherlands, but Germany can compensate by raising its imports from Russia. Overall, Russia (+25.5 bcm/y) and the United Kingdom (+1.1 bcm/y, incorporated in category "other") are the only pipeline exporters that benefit from the disruption of Algerian supplies by exporting more gas at higher prices to Europe. All other (pipeline and LNG) suppliers operate close to or at their (production or transport) capacity limits and Russia is the only producer with significant spare capacity. Spain hardly compensates the lacking pipeline imports because of lacking pipeline connections with the rest of Europe. Spain is connected to the European mainland only via a small pipeline to its neighbor France, with an annual capacity of 3 bcm. However, Spain can compensate with LNG supplies from Egypt and the Middle East. Thus, the presence of pipeline capacity plays an important role in determining the alternative supply schemes of Spain, Italy and overall in Europe.

Accepted at Energy Policy, January 2008

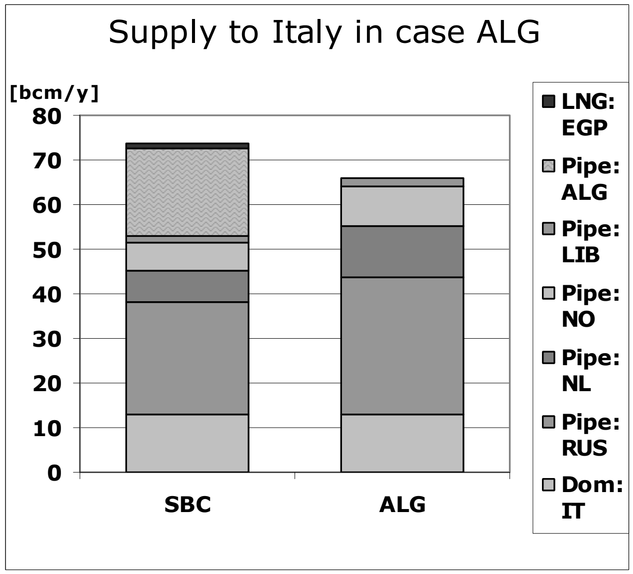

Figure 9. Gas supply to Italy in SBC and ALG

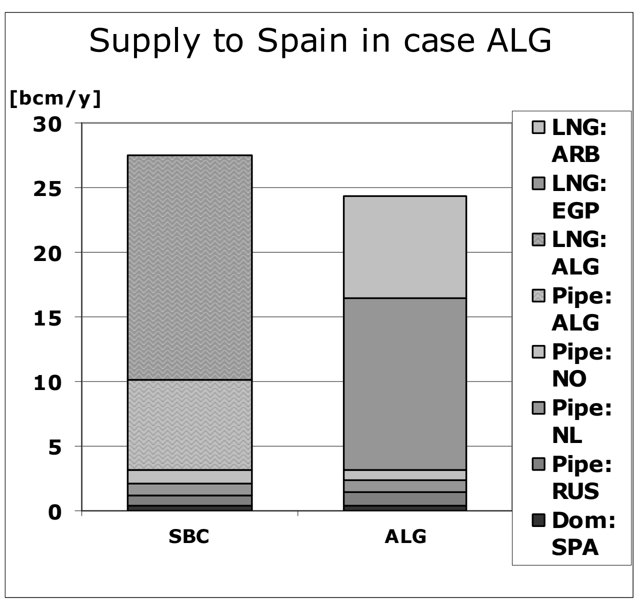

Figure 10. Gas supply to Spain in SBC and ALG

Pipeline Exports	TO	Italy	Spain	Germany	Rest Of Europe	Total
Algeria	SBC	19.6	6.9	0.5	4.5	31.5
	ALG					
Russia	SBC	25.0	0.8	17.6	73.3	116.7
	ALG	30.8	1.1	32.3	78.1	142.3
Netherlands	SBC	7.4	0.9	23.9	42.9	75.0
	ALG	11.3	0.9	16.8	45.9	74.9
Norway	SBC	6.0	1.1	20.5	51.5	79.2
	ALG	8.8	0.8	14.6	50.0	74.2
Other	SBC	14.5	0.4	23.7	144.5	183.1
	ALG	15.0	0.4	19.9	148.9	184.2
Total	SBC	72.5	10.1	86.2	316.8	485.6
	ALG	66.0	3.2	83.6	322.9	475.6

Table 3
Pipeline Flows in SBC and ALG

In the global LNG market, Algerian LNG supplies go to Europe (76%) and to North America (24%) in the base case scenario. In the Algeria disruption case, falling LNG supplies to North America are mostly compensated by higher LNG exports from Trinidad and Tobago and from Norway. While Norway is the marginal LNG supplier in the SBC, it increases its total LNG exports in the ALG case (which are now shipped to North America) and benefits from the scarceness of LNG in the global markets. There is a shift in Egyptian LNG supplies (from other European importers to Spain) and in Middle East exports (from Asia partly to Europe) but the binding liquefaction constraints do not allow for entirely compensating for the falling Algerian supplies in the global market. Italy does not import any LNG when Algerian supplies are disrupted, as all LNG imports are drawn by Spain. In essence, in both the pipeline and LNG markets, physical transport capacity is fundamental for determining the flows in the natural gas market.

3.4. Increased Transport Capacity in the Near Future (2011) versus Strategic Base Case

The current development towards an increasing importance of LNG in the world natural gas markets will continue at a rapid pace through 2011. The International Energy Agency predicts the share of LNG to double from 2006 to 2010, to approximately 11% of world natural gas consumption [47]. An increased capacity expansion case is used to analyze how a bigger supply and import potential of LNG influences the European natural gas market. For the expansion scenario to be realistic, pipeline and LNG projects that are known or expected to come on line by 2011 are used.[12] Predictions for a longer time horizon than the

[12]Data on pipeline and LNG projects are from different sources, such as the IEA [47], and gas sector journals [65].

LNG Exports		Spain	Other Europe	North America	Asia	Total
Algeria	SBC	17.4	6.1	7.3		30.8
	ALG					
Egypt	SBC		13.2			13.2
	ALG	13.2				13.2
Middle East	SBC				39.6	39.6
	ALG	7.9	2.3		29.4	39.6
Norway	SBC		1.0			1.0
	ALG			5.7		5.7
Trinidad	SBC			12.3	0.9	13.2
	ALG			13.2		13.2
Nigeria	SBC			11.4		11.4
	ALG		0.8	10.6		11.4
Other	SBC				85.6	85.6
	ALG				85.7	85.7
Total	SBC	17.4	20.3	31.1	126.1	194.8
	ALG	21.1	3.1	29.5	115.1	168.8

Table 4
LNG Flows in SBC and ALG

next five years are difficult because decisions on infrastructure and production expansions after 2011 are yet to be made.

In particular, a number of regasification projects to come on line are assumed, in Europe (Germany, the Netherlands, the UK, see Figure 1), as well as in North America (the U.S., Canada and Mexico) and the rest of the world. Upstream, a considerable amount of additional liquefaction capacity is expected to become operational by 2011. The highest increases of total capacity will come from the Middle East (increase by a factor of three, to an annual capacity of 120 bcm), from West Africa (also by a factor of three, to 48 bcm) and from Australia and Southeast Asia (increase by 50% to 140 bcm together). The coverage of our model, which includes all LNG exporters and importers, allows analyzing questions such as the arbitrage of suppliers in the Atlantic basin between Europe and North America, and the arbitrage of the Middle East LNG exporters between the Atlantic and the Pacific basin.

There are less pipeline construction projects until 2011 than LNG projects. However, some significant pipeline projects are assumed to be built, such as: 1. the first line of the Nordstream pipeline from Russia to Germany through the Baltic Sea; 2. two pipelines in the Mediterranean Sea, from Algeria to Italy, and from Algeria to Spain.

To simulate the natural gas market in 2011, production capacities and reference consumption values in the demand function [15] were adjusted in addition to liquefaction, regasification and pipeline capacities. Given the considerable pipeline and LNG congestion in the base case scenario, one can expect an increase in natural gas trade, production, and consumption from the capacity expansion and higher demand. Indeed, Figure 5 shows a rise of model-wide production of natural gas by 40% under the capacity expansion case compared to the SBC scenario, to a total of 1009 bcm per year. European consumption

Table 5
LNG trade flows in 2011 [bcm]

From→	NO	ALG	EGP	ARB	AUS	RUS	SEA	TRI	LIB	NIG	Total
Europe	1.6		17.5	72.3							91.3
N-America		31.8		27.1				29.1	2.5	45.6	136.2
Asia				13.4	38.2	13.0	90.2				154.8
Total in	1.6	31.8	17.5	119.0	38.2	13.0	90.2	29.1	2.5	45.6	388.4

alone grows by 22% to 639 bcm. The share of LNG imports in Europe increases from 6% to 14.5% (92 bcm). With a projected demand increase in the period 2004-2011 of 123 bcm [15], and a model outcome of 117 bcm, the anticipated capacity expansions seem to somewhat accurately represent the increase in European gas demand for the period up to 2011.

A closer look at the details of LNG trade behind the values in Table 5 [13] shows that the U.S will draw most of the LNG in the Atlantic basin. North America as a whole receives 136.2 bcm of LNG imports compared to 91.3 bcm in Europe. In particular, the U.S. will be the exclusive importer of Algerian, Libyan, West African (Nigerian) and Trinidad and Tobago LNG. The Middle East LNG exports, however, are characterized by a large mix of receiving countries in North America (23% of the Middle East exports), Europe (59%) and Asia (16%). This indicates that while there is a clear result in favor of the U.S. of the arbitrage in the Atlantic basin, there is no apparent tendency of the arbitrage of the Middle East exporters between the Atlantic and Pacific basins. European LNG imports only come from Norway, Egypt, and the Middle East. The main reasons for the dominant importing position of the U.S. can be found in the demand function assumptions (high demand growth in the U.S.) and in the (production and transport) cost structure. Overall, in a competitive market for LNG, (production and) transport costs, and hence geography, would play an important role in determining the LNG trade relations. The Pacific and the Atlantic basins would mainly be supplied by exporters located in the same basin, with the Middle East providing swing supplies between the two basins. These results differ significantly from regional models of the European market which do not take into account demand for LNG in other world regions.In [38], for example, the authors find a larger diversity of European imports from all possible LNG sources and no cutoff of some sources.

For the pipeline market in Europe, the additional pipeline capacity leads to an increase of pipeline imports, providing some justification for the investments. Russia is able to increase its exports to Europe in 2011 to 142 bcm (compared to 117 bcm in 2011), and in particular to Germany, the destination of the Nordstream pipeline (from 17.6 bcm in the SBC scenario to 25.2 bcm in 2011). However, it must be noted that the current (2004) export capacity of pipelines from Russia to Europe already is of the order of 150 bcm,

[13] The LNG liquefaction capacity of Equatorial Guinea that is expected to come on-line in the next five years is for the case 2011 assigned to the LNG node Nigeria, which should be viewed more generally as "West Africa".

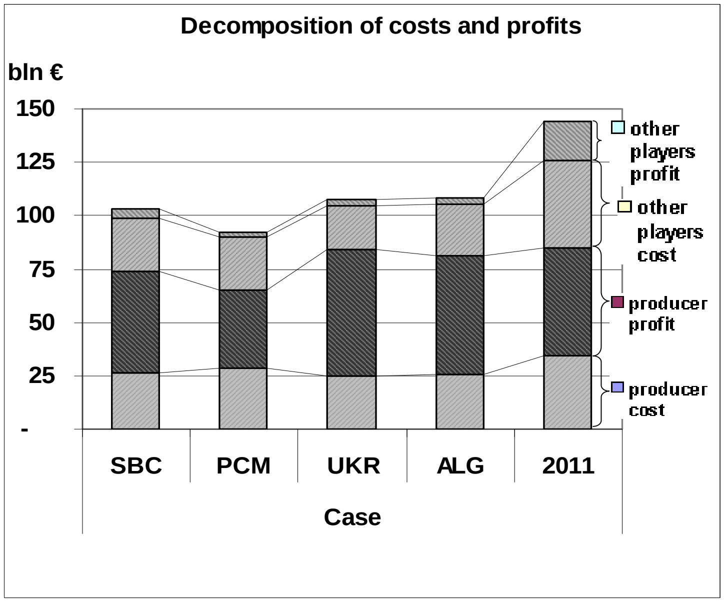

Figure 11. Decomposition of costs and profits among agents in the supply chain

and that in 2011 Russia would still not be exporting at its full capacity. The Nordstream pipeline project must rather be understood as a strategic option in the transit game with Ukraine and Belarus. Algeria's pipeline exports in the SBC scenario, however, are bound by the available pipeline capacity. The reason for this are the relatively cheap production costs of Algerian natural gas. Logically, the Algerian exports in 2011 will rise drastically after the construction of two new pipelines through the Mediterranean Sea, from 31.5 bcm in the base year to 49.2 bcm in 2011.

Storage delivers 11.5 % of the total natural gas consumption in Europe, and operates at its capacity limit.[14] Price levels in terms of €2004/kcm rise to 153 and 157 for Europe and the global LNG market, respectively; this is 2.1% and 1.6% higher than the 2004 levels. These numbers must be considered with caution as they are dependent on the different assumptions for 2011, especially with respect to demand elasticities and demand functions calibrations.

3.5. Decomposition of costs and profits in the supply chain

Between the gas well and the end user, several middlemen add value to the gas. One would expect that the more competitive the market and the more supply and transport capacity there is available, the lower the total profits would be as a percentage of the total added value (i.e., total consumer spending for this study).

Figure 11 supports this intuition. The lower parts are the producers' costs and profits (total of producers and traders); the upper parts the aggregate costs and profits of liquefiers, regasifiers and storage operators. Market power adds € 11 billion to total producer

[14]Note that the storage capacity was not changed in the model from 2004 to 2011.

profits (€33 billion in PCM vs. €44 billion in SBC). Alternatively, because of market power consumers pay €11 billion extra (€103 vs. €92 billion), for almost 8% less gas with the difference going to the producers (and traders).

As stated earlier, the disruption of the Ukraine transit has a higher impact on the total consumed volume than the disruption of the Algerian supplies. It is interesting to see that total consumer spending for both disruption cases is significantly higher than in the SBC, and between the two of them almost equal: €107.5 bln in UKR vs. €108.3 bln in ALG, for consumed volumes 604 vs. 640 bcm respectively. Especially in the UKR case, the producers benefit highly from the lack of alternative gas suppliers, and their profits add up to 50% of the total consumer spending. In 2011, producer profits go up a modest 3.2% relative to the SBC 2004. Liquefiers and regasifiers then benefit from playing a more significant role and see their added profits sextuple, while supplied volumes only about double.

4. Conclusions

In this paper, we have described a detailed and extensive model of the European natural gas market which includes 52 countries that produce, consume, or ship gas to Europe. The full supply chain is modeled, including producers and their marketing arms which we call "traders", pipeline and storage operators, marketers, liquefiers, regasifiers, LNG tankers and final consumption. The producers via their traders are modeled as strategic players with the possibility of market power; all other players are posited as price-takers. We chose this specification for two reasons. First, we are concentrating on international trade of natural gas where the market power possibility of the traders is the dominant characteristic. Second, modeling more than one type of player as strategic would give a more complex problem (in the complementarity framework, this would be an MPEC) that is hard to solve for a large-scale problem as ours.

The economic behavior of the players is characterized by solving appropriate optimization problems except for the LNG tankers and marketers which are implicitly modeled via cost and demand curves, respectively. Collecting the Karush-Kuhn-Tucker (KKT) optimality conditions for the players' optimization problems, and combining them with market-clearing conditions results in a complementarity system. The model is calibrated to market outcomes for the base year 2004. A series of cases is run to reveal insights about the European and worldwide natural gas market. The cases cover: a strategic base case in which the producers (traders) can exert market power, a case in which the traders are modeled as perfectly competitive, a disruption of Russian gas supplies through Ukraine, disruption of Algerian gas supplies, and a capacity expansion case for the year 2011, with the last three assuming strategic behavior on the part of the traders.

When looking at the case of perfect competition, the strategic base case, and the lessons learned from calibration, the low production and consumption levels when assuming full Cournot market power may indicate that the main players in Europe are either not fully Cournot players, or possibly that policy and old long term contracts in place prevents them from exerting full market power. However even with lower than full Cournot market power levels, average prices in Europe are as much as 27% higher than in a perfectly competitive market.

A disruption in Russian supplies to Europe through the Ukraine may cause a substitution effect with worldwide higher LNG consumption and prices. The curtailment of Algerian supplies shows that high import shares from a single supplier are by itself not a cause for concern; flexibility is key in managing dependency. A mature global LNG spot market could possibly provide such flexibility, at least for countries with significant LNG regasification capacity. For countries relying on the pipeline market, sufficient pipeline import capacity and a diverse supply portfolio is key for securing their imports. The capacity expansion case illustrates that LNG will be competitive with gas supplied by long-distance underwater pipelines. With the currently ongoing large investments in new LNG facilities in an increasing number of countries, a global LNG market is arising. The model provides insights in the future perspectives of LNG trade where Europe and North America will be in competition for LNG in the Atlantic basin, and model results indicate that North America could attract more LNG. Europe will continue to rely on its regional pipeline gas supplies to satisfy the majority of its demand (85% in the capacity expansion case), with LNG providing an element of supply security through diversification. The great detail of the model in terms of players and geographical coverage provides in-depth insight into the supply situation of each country.

Future work will be in three directions: extending this work to a more detailed representation of other regions beside Europe; allowing for stochasticity in the players problem to better reflect uncertainty in actual markets; and modeling of forward markets and capacity investments.

5. Acknowledgements

We would like to thank two anonymous reviewers for their insightful comments.

REFERENCES

1. F.R. Aune, R. Golombek, S.A.C. Kittelsen, K.E. Rosendahl, 2004. "Liberalizing the Energy Markets of Western Europe - A Computable Equilibrium Model Approach", *Applied Economics*, 36 (19), 2137-2149.
2. M.S. Bazaraa, H.D. Sherali, C.M. Shetty, 1993. *Nonlinear Programming Theory and Algorithms*, John Wiley & Sons, Inc., New York.
3. BG Group, 2006. "A Market Leader in Global LNG". Presentation. (http://ir.bg-group.com/bgir/presentations/2006-09-12/lng_analystpres.pdf)
4. M.Boots, F.A.M.Rijkers, B.F.Hobbs, 2004. "A Two-Level Oligopoly Analysis of the European Gas Market", *The Energy Journa*l, 25 (3), 73 - 102.
5. BP, 2001. *Statistical Review of World Energy.*
6. BP, 2005. *Statistical Review of World Energy.*
7. BP, 2006. *Statistical Review of World Energy.*
8. Cayrade, P. 2004, Investments in Gas Pipelines and Liquefied Natural Gas Infrastructure. What is the Impact on the Security of Supply? (www.feem.it/Feem/Pub/Publications/WPapers/default.htm)

Accepted at Energy Policy, January 2008

9. B.C. Craft, M.F. Hawkins, 1959. *Applied Petroleum Reservoir Engineering*. Prentice-Hall, Chemical Engineering Series, Englewood Cliffs, New Jersey.
10. S. P. Dirkse, M. C. Ferris. *The PATH solver: A non-monotone stabilization scheme for mixed complementarity problems*. Optimization Methods and Software, 5:123-156, 1995.
11. DONG, 2006. "Dok. INF-037714 1 003", www.dongenergy.com
12. Energy Bulletin 4170, April 2003.
13. R. Egging, S.A. Gabriel, 2006. "Examining Market Power in the European Natural Gas Market", *Energy Policy*, 34 (17), 2762-2778.
14. EC, 2000. The present list of projects of common interest is available in the annex of Commission Decision n° 761/2000/EC of 16 November 2000, setting out the specifications for projects of common interest (Decision C(2000) 2683).
15. DG-TREN January 2003, European Energy and Transport Trends to 2030.
16. EC, 2004. *Trans-European energy networks: TEN-E priority projects*, Luxembourg. Office for Official Publications of the European Communities.
17. EC, 2006. Decision 1364/2006/ec of the European Parliament and of the Council of 6 September 2006 laying down guidelines for Trans-European Energy Networks and repealing Dec. 96/391/EC and Dec.1229/2003/EC.
18. EIA DOE, 2003. *The Global Liquefied Natural Gas Market*.
19. EIA DOE, 2006. *International Energy Outlook 2006*.
20. www.eia.doe.gov/emeu/cabs
21. EPA, 2005. The Energy Policy Act of 2005, 109th Congress, U.S.A.
22. Eurogas, *Statistics 2004*, www.eurogas.org
23. F. Facchinei, J.-S. Pang, 2003. Finite-Dimensional Variational Inequalities and Complementarity Problems (Vol. 1), Springer, New York.
24. FERC, 2006. Existing and Proposed North American LNG Terminals, Oct 19, 2006, www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf
25. Fluxys, 2006. Fluxys natural gas storage services. Conditions and tariffs. www.fluxys.be/pdf/2006/20060921-Tarieven_Stock_2006_E.pdf
26. S.A. Gabriel, S. Kiet, 2005. J. Zhuang, "A Mixed Complementarity-Based Equilibrium Model of Natural Gas Markets", *Operations Research*, 53(5), 799-818.
27. S.A. Gabriel, J. Manik , S. Vikas, 2003. "Computational Experience with a Large-Scale, Multi-Period, Spatial Equilibrium Model of the North American Natural Gas System," *Networks and Spatial Economics*, 3, 97-122.
28. S. A. Gabriel, S. Vikas, D. M. Ribar, 2000. "Measuring the Influence of Canadian Carbon Stabilization Programs on Natural Gas Exports to the United States via a Bottom-Up Intertemporal Spatial Price Equilibrium Model," *Energy Economics*, 22, 497-525.
29. S.A. Gabriel, J. Zhuang, S. Kiet, 2005. "A Large-Scale Complementarity Model of the North American Natural Gas Market", *Energy Economics*, 27, 639-665.
30. Gaz de France, July 2004, *company brochure*: "Gaz de France, European leader in Liquefied Natural Gas (LNG)"
31. http://eng.gazpromquestions.ru/page8.shtml
32. Gas Infrastructure Europe, 2005. "LNG Map". (http://gie.waxinteractive3.com/download/gridmap/LNG_102.pdf)

33. Gas Infrastructure Europe, 21 December 2005, The European Natural Gas Network (www.gte.be)
34. R. Golombek, E. Gjelsvik, 1995. "Effects of Liberalizing the Natural Gas Markets in Western Europe", *Energy Journal*, 16 (1), 85-111.
35. Gasunie Annual Report 2005, www.gasterra.nl
36. Hartley, P., Medlock, K.B., 2006. "The Baker Institute World Gas Trade Model", in: Victor, D.G., Jaffe, A.M., Hayes, M.H. (Eds.), *Natural Gas and Geopolitics: From 1970 to 2040*. Cambridge University Press, 357-406.
37. A. Haurie, G. Zaccour, J. Legrand, Y. Smeers, 1987. "A Stochastic Dynamic Nash Cournot Model for The European Gas Market". Tech. Report HEC Montreal.
38. Holz, F., Hirschhausen, C.v., Kemfert, C., forthcoming. "A Strategic Model of European Gas Supply (GASMOD)", *Energy Economics*.
39. IEA, 1994. *Natural Gas Transportation*. OECD/IEA, Paris.
40. IEA, 1998. *Natural Gas Distribution*. OECD/IEA, Paris.
41. IEA, 2002. *IEA Flexibility in Natural Gas*. OECD/IEA, Paris.
42. IEA, 2002. *Natural Gas Information 2002*. OECD/IEA, Paris.
43. IEA, 2003. *World Energy Investment Outlook - 2003 Insights*. OECD/IEA, Paris.
44. IEA, 2003. *Monthly Natural Gas Survey*. (http://www.iea.org/Textbase/stats/gasresult.asp)
45. IEA, 2004. *Monthly Natural Gas Survey*. (http://www.iea.org/Textbase/stats/surveys/archives.asp)
46. IEA, 2004. *World Energy Outlook 2004*.OECD/IEA, Paris.
47. IEA, 2006. Natural Gas Market Review. OECD/IEA, Paris.
48. http://www.inogate.org
49. Institute for Energy, Law & Enterprise, 2003. *Introduction to LNG*, University of Houston Law Center, www.energy.uh.edu
50. W. Lise, B.F. Hobbs, F.v. Oostvoorn, 2006. "Natural Gas Corridors Among the EU and its Main Suppliers: Simulation Results with the Dynamic GASTALE Model", *29th IAEE International Conference*. GEE, Potsdam, Germany.
51. Mathiesen, L., Roland, K. and K. Thonstad (1987), *The European Natural Gas Market: Degrees of Market Power on the Selling Side,* in Golombek, R., Hoel, M. and J. Vislie (eds.): Natural Gas Markets and Contracts, North-Holland.
52. "Dispute Over Natural Gas Prices in Ukraine, " *The New York Times*, December 16, 2005.
53. "Putin Offers 3-Month Extension of Ukraine's Gas Subsidy," *The New York Times*, December 31, 2005.
54. "Russia Cuts Off Gas to Ukraine in Cost Dispute," *The New York Times*, January 2, 2006.
55. "Russia Restores Most of Gas Cut to Ukraine Line," *The New York Times*, January 3, 2006.
56. "Russia and Ukraine Reach Compromise on Natural Gas," *The New York Times*, January 5, 2006.
57. "Envoys Say Gas Crisis Hurt West's Relations with Russia," *The New York Times*, January 5, 2006.
58. "Gas Halt may Produce Big Ripples in European Policy," *The New York Times*, January 3, 2006.
59. "Europe Comes to Terms with Need for Russian Gas," *The New York Times*, January

8, 2006.
60. "Ukraine is Increasingly Dependent on Gas From Turkmenistan," *The New York Times*, January 10, 2006.
61. "Gazprom Builds Wealth for Itself, but Anxiety for Others," *The New York Times*, January 13, 2006.
62. "Russia Gas Line Explosions Scare Europe," *The New York Times*, January 26, 2006.
63. "Explosions in Southern Russia Sever Gas Lines to Georgia," *The New York Times*, January 23, 2006.
64. "Georgia, Short of Gas, Is Hit With a Blackout," *The New York Times*, January 27, 2006.
65. Oil and Gas Journal, 2004-2006. Various Issues.
66. OME, 2003. *Medsupply: Development of Energy Supplies to Europe from the Southern and Eastern Mediterranean Countries.* Final Report.
67. Smeers, Y, *Do We Need a Power Exchange if There are Enough Power Marketers*, CORE Discussion Paper 9760, August 1997.
68. Stern, J., 2005. *The Future of Russian Gas and Gazprom.* Oxford Institute for Energy Studies, Oxford, 2005.
69. Stern, J., 2006. The Russian-Ukrainian Gas Crisis of January 2006, Oxford Institute for Energy Studies.
70. Statoil, Annual Report 2005, www.statoil.com
71. Van Oostvoorn, F., 2003. *Long-Term Gas Supply Security in an Enlarged Europe.* Final Report ENGAGED project.
72. Zwart, G., M. Mulder, 2006: NATGAS: A Model of the European Natural Gas Market. *CPB Memorandum*: 40 p. Centraal Planbureau: The Hague.

6. Appendix A: Country groups and abbreviations

The data set that we have used for running the model comprises of 52 countries. The following tables show the countries logically grouped according to their world regions, as well as the abbreviations used to refer to them in tables and figures.

7. Appendix B: Optimality Conditions of Players

This section presents the KKT conditions for the optimization problem of each player (see Section 1 for the optimization programs). The KKT conditions characterize the optimal solution of the players' programs. While the derivation of the KKT conditions of the producer were described in detail in Section 1.1, we are presenting here the KKT conditions of the traders, the LNG liquefiers and regasifiers, the storage operators and the pipeline operators.

Accepted at Energy Policy, January 2008

Table 6
European Countries and Abbreviations

Europe	**EUR**
Austria	**AT**
Belgium	**BE**
Bulgaria	**BG**
Croatia	**CRO**
Cyprus	**CYP**
Czech Rep	**CZ**
Denmark	**DK**
Estonia	**EST**
Finland	**FIN**
France	**FRA**
Germany	**GER**
Greece	**GR**
Hungary	**HUN**
Ireland	**IRE**
Italy	**IT**
Latvia	**LTV**
Lithuania	**LTH**
Luxembourg	**LUX**
Malta	**MLT**
Netherlands	**NL**
Norway	**NO**
Poland	**PL**
Portugal	**POR**
Romania	**ROM**
Slovakia	**SLK**
Slovenia	**SLV**
Spain	**SPA**
Sweden	**SWE**
Switzerland	**SWI**
Turkey	**TRK**
United Kingdom	**UK**
Belarus	**BLS**
Ukraine	**UKR**
Russia	**RUS**

Accepted at Energy Policy, January 2008

Table 7
African Countries and Abbreviations

Africa	**AFR**
Algeria	**ALG**
Egypt	**EGP**
Libya	**LIB**
Morocco	**MOR**
Nigeria	**NIG**
Tunisia	**TUN**

Table 8
Caspian Sea Countries

Caspian Region	**CSP**
Azerbaijan	
Kazakhstan	
Turkmenistan	
Uzbekistan	

Table 9
Middle East Area Abbreviations

Middle East	**MEAST**
Caspian	**CSP**
Iran	**IRN**
Arabian Peninsula	**ARB**

Table 10
Arabian Peninsula Countries

Arabian Peninsula	**ARB**
Oman	
Qatar	
UAE	

Table 11
Asia and Australia Country Abbreviations

Asia and Australia	**ASIA**
Australia	**AUS**
China	**CHI**
India	**IND**
Japan	**JP**
South East Asia	**SEA**
South Korea	**KOR**
Taiwan	**TW**

Table 12
Southeast Asia Countries

South East Asia	**SEA**
Indonesia	
Brunei	
Malaysia	

Table 13
NorthAmerican Country Abbreviations

North America	**NAMR**
Canada	**CAN**
Mexico	**MEX**
Trinidad & Tobago	**TRI**
United States	**USA**

7.1. B.1. trader

After taking derivatives of the optimization problem of the trader (9)-(14) and substituting the equilibrium price π^W_{ndy} for the inverse demand function Π^W_{ndy} (15) in the first set of KKT values, we have the corresponding KKT conditions as follows:

$$0 \leq -\left(\pi^W_{ndy} - \delta^C_t \cdot SLP^M_{ndy}(SALES^{T\to M}_{tndy})\right) + \phi^T_{tndy} \perp SALES^{T\to M}_{tndy} \geq 0, \forall t, n, d, y \quad (42)$$

$$0 \leq -\pi^T_{n1y} + \phi^T_{tn1y} \perp SALES^{T\to S}_{tny} \geq 0, \forall t, n, y \quad (43)$$

$$0 \leq \pi^P_{tndy} - \phi^T_{tndy} \perp PURCH^{T\leftarrow P}_{tndy} \geq 0 \ , \forall n \in N(p(t)), d, y \quad (44)$$

$$0 \leq \begin{bmatrix} (\tau^A_{nmdy} + \tau^{Reg}_{nmdy}) + \phi^T_{tndy} \\ -(1 - loss_{nm})\phi^T_{tmdy} \end{bmatrix} \perp FLOW^T_{tnmdy} \geq 0 \ \forall n, m, d, y \quad (45)$$

$$SALES^{T\to M}_{tndy} + \delta^{low}_d \cdot SALES^{T\to S}_{tny} + \sum_{m\in N} FLOW^T_{tnmdy} - PURCH^{T\leftarrow P}_{tndy}$$
$$- \sum_{m\in N}(1 - loss_{mn})FLOW^T_{tmndy} = 0, \forall t, n \in N(t), d, y \quad \left(\phi^T_{tndy}\right) \quad (46)$$

7.2. B.2 LNG Liquefier

As long as the cost function $c^L_l(SALES^L_{ldy})$ in the optimization problem of the LNG liquefier (17)-(21) is convex, the KKT conditions are both necessary and sufficient. These conditions are:

$$0 \leq -\left(\pi^L_{n(l)dy}\right) + \frac{dc^L_l(SALES^L_{ldy})}{dSALES^L_{ldy}} + \alpha^L_{ldy} + \phi^L_{ldy} \perp SALES^L_{ldy} \geq 0 \ \forall d, y \tag{47}$$

$$0 \leq \pi^P_{n(l)dy} + u^{L\leftarrow P}_l - (1 - loss_l)\phi^L_{ldy} \perp PURCH^{L\leftarrow P}_{ldy} \geq 0 \qquad \forall d, y \tag{48}$$

$$0 \leq \overline{LQF}^L_l - SALES^L_{ldy} \perp \alpha^L_{ldy} \geq 0 \qquad \forall d, y \tag{49}$$

$$0 = (1 - loss_l)PURCH^{L\leftarrow P}_{ldy} - SALES^L_{ldy} \ \ \phi^L_{ldy}(free) \qquad \forall d, y \tag{50}$$

7.3. B.3 LNG Regasifier

Similar to the case of the liquefier, the optimization problem of the regasifier (23)-(27) is convex assuming that the cost functions are convex. As this assumption is valid, the KKT conditions are both necessary and sufficient and are given as follows.

$$0 \leq -\pi^W_{n(r)dy} + \frac{dc^R_r(\cdot)}{dSALES^{R\rightarrow M}_{rdy}} + \alpha^R_{rdy} + \phi^R_{rdy} \perp SALES^{R\rightarrow M}_{rdy} \geq 0 \ \forall d, y \tag{51}$$

$$0 \leq -\pi^R_{n(r)dy} + \frac{dc^R_r(\cdot)}{dSALES^{R\rightarrow S}_{rdy}} + \alpha^R_{rdy} + \phi^R_{rdy} \perp SALES^{R\rightarrow S}_{rdy} \geq 0 \ \forall d = 1, y \tag{52}$$

$$0 \leq \pi^L_{n_s(b)dy} + u^{R\leftarrow L}_b - (1 - loss_r)(1 - loss_b)\phi^R_{rdy} \perp PURCH^{R\leftarrow L}_{bdy} \geq 0 \ \forall d, y \tag{53}$$

$$0 \leq \overline{REG}^R_r - SALES^{R\rightarrow M}_{rdy} - SALES^{R\rightarrow S}_{rdy} \qquad \perp \alpha^R_{rdy} \geq 0 \ \ \forall d, y \tag{54}$$

$$0 = \sum_{b:n_e(b)=n(r)} (1 - loss_r)(1 - loss_b)PURCH^{R\leftarrow L}_{bdy} - (SALES^{R\rightarrow M}_{rdy} + SALES^{R\rightarrow S}_{rdy}) \quad \phi^R_{rdy}(free) \ \forall d, y \tag{55}$$

7.4. B.4 Storage Operator

Assuming that the cost function of the storage operator is convex, its optimization problem (29)-(36) is a convex program for which the KKT conditions are both necessary and sufficient. These conditions are:

$$0 \leq \left(-\left(\pi^{W}_{n(s)dy}\right) + \beta^{S}_{sdy} - \phi^{S}_{sy} + \gamma^{S}_{sy}\right) \perp SALES^{S\to M}_{sdy} \geq 0, \forall d = 2,3,y \tag{56}$$

$$0 \leq \begin{bmatrix} (\pi^{T}_{n(s)dy} + u^{S\leftarrow T}_{n}) \\ +\frac{dc^{S}_{s}\left(PURCH^{S\leftarrow T}_{sy} + PURCH^{S\leftarrow R}_{sy}\right)}{dPURCH^{S\leftarrow T}_{sy}} \\ +\alpha^{S}_{sy} - (1 - loss_{s})\phi^{S}_{sy} \end{bmatrix} \perp PURCH^{S\leftarrow T}_{sy} \geq 0, \forall y \tag{57}$$

$$0 \leq \begin{bmatrix} (\pi^{R}_{n(s)dy} + u^{S\leftarrow R}_{n}) \\ +\frac{dc^{S}_{s}\left(PURCH^{S\leftarrow T}_{sy} + PURCH^{S\leftarrow R}_{sy}\right)}{dPURCH^{S\leftarrow R}_{sy}} \\ +\alpha^{S}_{sy} - (1 - loss_{s})\phi^{S}_{sy} \end{bmatrix} \perp PURCH^{S\leftarrow R}_{sy} \geq 0, \forall y \tag{58}$$

$$0 \leq \overline{INJ}^{S}_{s} - PURCH^{S\leftarrow T}_{sy} - PURCH^{S\leftarrow R}_{sy} \perp \alpha^{S}_{sy} \geq 0, \forall y \tag{59}$$

$$0 \leq \overline{EXT}^{S}_{s} - SALES^{S\to M}_{sdy} \perp \beta^{S}_{sdy} \geq 0, \forall d = 2,3,y \tag{60}$$

$$0 = \sum_{d=2,3} days_{d} SALES^{S\to M}_{sdy} - days_{1}(1 - loss_{s}) \begin{bmatrix} PURCH^{S\leftarrow T}_{sy} \\ +PURCH^{S\leftarrow R}_{sy} \end{bmatrix}$$

$$\phi^{S}_{sy}(free), \forall y \tag{61}$$

$$0 \leq \overline{WRKG}^{S}_{s} - \sum_{d=2,3} days_{d} SALES^{S\to M}_{sdy} \perp \gamma^{S}_{sy} \geq 0, \forall y \tag{62}$$

7.5. B.5 Pipeline Operator

Given that the pipeline operators optimization program (37)-(4) is linear, the KKT conditions are both necessary and sufficient for optimality and are given as follows.

$$0 \leq -\tau^{A}_{nmdy} + \alpha^{A}_{nmdy} \perp SALES^{A}_{nmdy} \geq 0, \forall d, y \tag{63}$$

$$0 \leq \overline{PL}^{A}_{nm} - SALES^{A}_{nmdy} \perp \alpha^{A}_{nmdy} \geq 0, \qquad \forall d, y \tag{64}$$

8. Appendix C: Input parameter details

This section describes some of the key inputs to the complementarity system decribed in the paper. Demand seasons are as follows: low={april-september}, a period of 183 days; peak={december,january}, 62 days; high={Feb,Mar,Oct,Nov}, 120 days. Note that in this section, all volumes and capacities are in millions of cubic meters per day (mcm/d), costs and prices are in Euros per thousand cubic meters (€/kcm).

Production input parameters

The model data set includes 28 producers, 10 have access to the European market via pipelines (ALG, CSP, DK, EGP, IRN, LIB, NL, NO, RUS and UK), six only have export possibilities via LNG liquefaction (ARB, AUS, EGP, NIG, SEA and TRI)). The remaining 12 supply domestically only. We follow [34], [4], [13] for specifying the production cost functions. It takes a quadratic cost function as a starting point, and adds a log term to have a steeper increase in marginal production costs close to full production capacity.

The fixed production cost term is δ, α is the linear cost term, and β the quadratic cost term. $\gamma$is the scaling parameter for the log term. The convex cost functions are of the following form

$$c_p^P(SALES_{pdy}^P) = \delta_p^P + (\alpha_p^P - \gamma_p^P)(SALES_{pdy}^P) + \beta_p^P(SALES_{pdy}^P)^2 - \gamma(\overline{PR}_p^P - SALES_{pdy}^P)\ln(\frac{\overline{PR}_p^P - SALES_{pdy}^P}{SALES_{pdy}^P}), \alpha_p^P > 0, \beta_p^P \geq 0, \gamma_p^P \leq 0$$

The incorporated production cost functions need five parameters: capacity: $\overline{PR}_p^P$, $\alpha, \beta, \gamma, \delta$ which are listed by country in Table 14. Constant costs δ are assumed zero, as they disappear when taking derivatives and therefore don't influence the equilibrium computations

Precise production capacity information is very hard to obtain. As in recent years most producers have been producing close to full capacity, we have based the inputs on actual production volumes according to: [6] and [45]. For big producers and exporters we have added 10% to the maximum production levels in 2003 and 2004 of these two data sources to allow for some supply side flexibility. For smaller, producers only supplying to domestic markets we have taken just the maximum production levels of the two years. Capacity of producers for which that are not incorporated as consumers, like Russia and Algeria, is adjusted downward to reflect their own consumption. For production costs the most reliable source with the desired level of detail is [34]. However it is 10 years old and covers a small subset of countries only. Based on [34] [43], [66] we have categorized producers into inexpensive, intermediate and expensive categories and assumed values in a reasonable range given these data sources. Inexpensive producers' linear production cost term is 20 €/kcm, intermediate 40 and expensive 60. We have calculated β and γ to let different producers have maximum marginal production costs at maximum capacity of either 60, 66 or 90 €/kcm. These values are presented in the last column of table 14. For brevity category other in this table presents the total production capacity for AT, FRA, IRE, TRK, SPA, CZ, SLK, GR and their production cost parameters. Although each of them has very small production capacity, they are separately modeled.

Liquefaction input parameters

The model data includes 10 liquefiers, six of which are the only access option to the consumption markets for the producers they are affiliated with. The 10 liquefiers include Norway and Russia, anticipating their short term entry into the LNG market. Liquefaction capacities are aggregated by country and mainly based on: [6] Table 15 lists the parameter values used for the base year model runs. For existing producers we added 10% to the maximum production levels in 2003 and 2004. For liquefiers expected to get on line before 2008, we used [18], [32], [66] ,[43], [49], [3], [8]. α is the linear cost term in the quadratic liquefaction cost function, quadratic term β is determined in such a way that the marginal costs at full capacity is 1 €/kcm higher than liquefaction of the first unit of gas. Liquefaction losses: [30]

Table 14
Production Cost Parameters

Producer	Capacity [mcm/d]	α	β	γ	Max marg
RUS	548.0	20	0.004	-5.5	60
NL[15]	301.0	20	0.080	-6.7	90
UK	288.0	60	0.021	-3.5	90
NO	224.7	40	0.018	-6.7	90
SEA	205.5	20	0.010	-5.5	60
ALG	186.3	20	0.011	-5.5	60
CSP	150.7	20	0.013	-5.5	60
ARB	123.3	20	0.016	-5.5	60
GER	52.1	60	0.115	0.0	66
AUS	41.1	40	0.097	-6.7	90
EGP	41.1	20	0.049	-9.8	90
TRI	41.1	20	0.049	-5.5	60
ROM	36.2	60	0.166	0.0	66
IT	35.6	60	0.169	0.0	66
NIG	35.6	20	0.056	-5.5	60
DK	27.4	40	0.146	-6.7	90
PL	15.1	60	0.398	0.0	66
HUN	8.2	60	0.730	0.0	66
LIB	8.2	20	0.243	-5.5	60
IRN	2.7	20	0.730	-5.5	60
Other	15.7	60	0.115	0.0	66

Table 15
Liquefaction Parameters

Liquefier	Capacity [mcm/d]	Loss	α	β
ALG	84.4	12%	33	0.012
ARB	122.0	12%	40	0.008
AUS	36.7	12%	43	0.027
EGP	40.3	12%	33	0.025
LIB	2.3	12%	33	0.435
NIG	37.9	12%	37	0.026
NO	15.6	12%	43	0.064
RUS	17.8	12%	36	0.056
SEA	213.0	12%	29	0.005
TRI	42.2	12%	35	0.024

Accepted at Energy Policy, January 2008

Table 16
Regasification Parameters

Regasifier	Capacity [mcm/d]	Loss	α	β
BE	**12.3**	**1.4%**	**8**	**0.08**
CAN	**28.0**	**1.4%**	**8**	**0.04**
CHI	**12.2**	**1.4%**	**8**	**0.08**
FRA	**42.5**	**1.4%**	**8**	**0.02**
GR	**3.8**	**1.4%**	**8**	**0.26**
IND	**8.2**	**1.4%**	**8**	**0.12**
IT	**16.4**	**1.4%**	**8**	**0.06**
JP	**246.6**	**1.4%**	**8**	**0.00**
POR	**15.1**	**1.4%**	**8**	**0.07**
KOR	**95.9**	**1.4%**	**8**	**0.01**
SPA	**95.9**	**1.4%**	**8**	**0.01**
TW	**27.4**	**1.4%**	**8**	**0.04**
TRK	**15.1**	**1.4%**	**8**	**0.07**
UK	**17.0**	**1.4%**	**8**	**0.06**
USA	**54.8**	**1.4%**	**8**	**0.02**

Regasification input parameters

The model contains 15 regasifiers in the base year, 18 in the 2011 case, MEX, NL and GE being the ones coming on line in the mean time. Seven countries are represented in the model for their LNG demand only: CAN, CHI, IND, JP, KOR, TW, USA. Two of them, CAN and CHI in anticipation of regasification terminals that will come on line soon. Regasification capacities are aggregated by country and mainly based on: [32],[18], [6], [20] Regasification costs originate from [66], [43], [49], [3]. α is the linear cost term in the quadratic regasification cost function, of the form, quadratic: $c_r^R(SALES_{rdy}^R) = \overline{a}_r^R + \overline{b}_r^R$ $(SALES_{rdy}^R) + \overline{c}_r^R(SALES_{rdy}^R)^2$.The quadratic term β is determined in such a way that the marginal costs at full capacity is 1 €/kcm higher than regasification of the first unit of gas. Regasification losses are an average of the values in [3]. Table 16 lists the parameter values used for the base year model runs.

LNG shipment input parameters

Any liquefier can send LNG tankers to any regasifier in our model. For distances we took representative harbors in each country, and used www.distances.com to determine the distances between the harbors in sea miles, see table 17. We have assumed shipment losses to be signifacntly lower than pipeline losses, and have set them to: 0.4% per 1000 sea miles . For shipment costs we used 5 €/kcm/1000 sea miles, based on [8], [18], [49].

Table 17
LNG Shipment Distances [1000 sea miles]

	ALG	ARB	AUS	EGP	IRN	LIB	NIG	NO	RUS	SEA	TRI
BE	1.6	6.2	9.9	3.2	6	2.7	4.3	1.4	11.6	8.5	4.0
CAN	3.0	7.6	6.9	4.6	7.5	4.1	4.7	3.3	10.6	7.4	2.1
CHI	8.0	5.0	2.4	6.5	4.8	7.2	9.3	11.0	2.0	1.8	11.8
FRA	0.5	4.5	8.3	1.5	4.4	1.0	4.0	1.9	11.3	6.8	3.7
GR	0.9	3.6	7.3	0.6	3.4	0.5	4.8	4.1	9.0	5.9	3.7
IND	4.3	1.2	3.8	3.0	1.1	3.8	7.0	7.6	5.8	2.3	4.9
IT	0.5	4.4	8.1	1.3	4.2	1.0	4.2	3.5	9.7	2.7	4.3
JP	9.2	6.5	3.0	7.9	6.3	8.7	10.8	12.4	0.9	3.2	4.3
POR	0.6	5.2	9.0	2.2	5.1	1.7	3.3	2.4	10.6	7.5	3.3
KOR	9.2	6.1	3.1	7.6	5.9	8.3	10.4	12.1	1.2	2.9	3.3
SPA	0.3	4.6	8.3	1.5	4.4	1.2	3.3	2.0	10.4	6.9	3.4
TW	8.3	5.2	2.2	6.6	5	7.4	9.5	11.2	1.8	2.0	3.4
TRK	1.1	3.4	7.1	0.4	3.2	0.6	5.0	4.3	8.8	5.7	5.1
UK	1.3	6.0	9.7	2.9	5.9	2.5	4.1	1.4	11.4	8.3	5.1
USA	3.3	8.0	7.3	5.0	7.8	4.4	5.0	3.7	9.1	7.9	2.0
NL	1.7	6.3	10.0	3.3	6.1	2.8	4.4	1.3	11.6	8.6	4.1
GER	1.9	6.5	10.2	3.5	6.3	3.0	4.6	1.1	11.8	8.8	4.3
MEX	5.1	9.7	7.3	6.6	9.6	6.2	6.2	5.6	10.4	8.0	2.2

Pipeline input parameters.
Table 18 shows pipeline capacities are aggregated on country-to-country level. The basic source is : [33], complemented by various other sources for countries not covered by this main source.

The tariff schemes for pipeline transmission have become increasingly complex in recent years. Our regulated pipeline tariffs reflect a capacity usage component only, no capacity reservation component. We have assumed that so-called entry-exit tariffs apply everywhere. Based on [71], [4], [1],[31], [12] we have taken 10 €/kcm for pipelines over land, and 20 €/kcm for pipelines under sea. Two exceptions are made because of the extreme distances covered: Russia to Turkey 40 €/kcm and Russia to Ukraine 30 €/kcm. For pipeline losses we know a value of 0.22% per 100 km. Based on this figure loss rates have been applied between 0.5% and 5% depending on the length of the pipeline.

Consumption input parameters.
The model covers 36 consuming countries: AT, BE, BG, CAN, CHI, CRO, CZ, DK, EST, FIN, FRA, GER, GR, HUN, IND, IRE, IT, JP, KOR, LTH, LTV, LUX, NL, NO, PL, POR, ROM, SLK, SLV, SPA, SWE, SWI, TRK, TW, UK, USA. Five of these are considered only for their LNG consumption: CA,CHI,JP, TW,USA. The sector shares in natural gas consumption, also for the "LNG only countries" are based on [44]; for

Accepted at Energy Policy, January 2008

Table 18
Pipeline Parameters

FROM	TO	Capacity [bcm/y]	FROM	TO	Capacity [bcm/y
ALG	MOR	11.1	IRN	TRK	10.0
ALG	TUN	28.8	IT	AT	3.1
AT	GER	10.7	IT	SLV	1.5
AT	HUN	4.4	IT	SWI	1.8
AT	IT	34.2	LIB	IT	9.1
AT	SLV	3.7	LTV	LTH	1.9
BE	FRA	26.3	MOR	SPA	11.1
BE	GER	8.5	NL	BE	38.6
BE	LUX	2.2	NL	GER	72.7
BE	NL	10.5	NO	BE	14.0
BE	UK	8.8	NO	FRA	18.0
BG	GR	3.1	NO	GER	40.5
BG	TRK	14.0	NO	NL	13.1
BLS	LTH	10.5	NO	UK	22.5
BLS	PL	26.6	PL	GER	26.3
BLS	UKR	29.0	POR	SPA	0.4
CSP	IRN	5.2	ROM	BG	26.3
CSP	TRK	5.0	RUS	BLS	33.0
CSP	UKR	5.0	RUS	EST	3.7
CZ	GER	55.2	RUS	FIN	7.0
DK	GER	3.0	RUS	LTV	3.7
DK	NL	0.5	RUS	TRK	16.0
DK	SWE	2.6	RUS	UKR	155.0
EST	LTV	2.9	SLK	AT	52.6
FRA	SPA	2.9	SLK	CZ	56.9
FRA	SWI	7.4	SLV	CRO	1.8
GER	AT	0.9	SLV	IT	1.7
GER	BE	10.7	SPA	FRA	0.5
GER	CZ	10.5	SPA	POR	3.1
GER	DK	1.8	SWI	IT	21.8
GER	FRA	14.0	TUN	IT	28.8
GER	LUX	1.9	UK	BE	20.1
GER	NL	2.3	UK	IRE	10.9
GER	PL	3.4	UKR	HUN	15.1
GER	SWI	21.3	UKR	PL	6.1
HUN	CRO	1.8	UKR	ROM	38.4
IRE	UK	10.9	UKR	SLK	111.7

Accepted at Energy Policy, January 2008

Table 19
Storage Parameters

Storage	Working gas [mcm]	Injection capacity [mcm/d]	α	β
AT	**2,820**	**33.0**	**30**	**0.23**
BE	**712**	**22.0**	**30**	**0.34**
BG	**500**	**2.2**	**30**	**3.41**
CRO	**500**	**3.8**	**30**	**1.97**
CZ	**3,150**	**52.0**	**30**	**0.14**
DK	**810**	**24.0**	**30**	**0.31**
FRA	**10,490**	**219.0**	**30**	**0.03**
GER	**19,099**	**462.0**	**30**	**0.02**
GR	**750**	**5.0**	**30**	**1.50**
HUN	**3,610**	**46.6**	**30**	**0.16**
IT	**16,800**	**295.0**	**30**	**0.03**
EST	**300**	**0.6**	**30**	**12.50**
LTV	**700**	**1.2**	**30**	**6.25**
LTH	**1,200**	**2.4**	**30**	**3.13**
NL	**3,500**	**175.0**	**30**	**0.04**
PL	**1,365**	**26.0**	**30**	**0.29**
ROM	**1,568**	**10.5**	**30**	**0.71**
SLK	**2,740**	**33.0**	**30**	**0.23**
SPA	**1,500**	**12.0**	**30**	**0.63**
SWE	**10**	**1.0**	**30**	**7.50**
SWI	**72**	**2.0**	**30**	**3.75**
UK	**3,855**	**138.4**	**30**	**0.05**

India and Korea sector shares of $\frac{1}{3}$ have been used. For "LNG only countries" the sector shares have been applied to the total LNG imports. Note that sector shares affect the price elasticity of the aggregate demand curves that are used in the model. Seasonality patterns in demand levels are based on [45]. For countries only included as LNG importers we have assumed there are no seasonal variations in demand patterns. For case 2011 we adjust the reference demands for 2004 by applying seven times the growth rate of [15] for period 2000-2010.

Storage input parameters

For 22 European countries we have included storage operators. The main sources for capacities are:[42], [22],[48]. Table 19 presents working gas and injection capacities, and injection costs[16]. The extraction capacity is set equal to twice the injection capacity. Injection costs represent the total storage costs. Based on [11], [25], [39], [40], [41] we take linear costs α of 30 €/kcm and β is determined in such a way that the marginal costs when injecting at full capacity 25% higher than when injecting at minimum capacity. For injection loss we use 1.5% ([25]). All input data are listed in Table 19.

[16] Capacities of the Baltic States Estonia, Latvia, Lithuania have been adjusted in the calibration process.

Accepted at Energy Policy, January 2008