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Identification of congestion and valuation of transport infrastructures in the European natural gas market

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ABSTRACT

Rising import dependency, increasing market liberalization and cross-border trade and security of supply fears facilitate investments in natural gas supply infrastructures in Europe. In order to ensure an efficient allocation of capital resources, it is important to identify congestion in the existing system and investment requirements based on economic principles. This paper first outlines an analytical framework for the identification of bottlenecks and the evaluation of transport capacities and the cost of congestion based on nodal prices. Secondly, an infrastructure model of the European gas market with high temporal and spatial granularity which exhibits the characteristics of the theoretical model is introduced. Parameterizing the model with the existing infrastructure and applying a demand and supply scenario for the year 2015, congestion mark-ups between countries in Europe are estimated. This approach indicates potential bottlenecks which might arise within the next five years and quantifies their economic costs. With only some temporary congestion, physical market integration is found to be high in Western Europe. In Eastern Europe, severe bottlenecks are identified and discussed. Implications for efficient investment decisions arising from the findings are examined in the context of the theoretical considerations.

1. Introduction

The European Union's rising import dependency on natural gas requires additional investments in import infrastructure and natural gas storages. At the same time, the Third Energy Package addresses, amongst other things, the strengthening of the single European market and the facilitation of cross-border energy trade which implies increased and better coordinated investments in gas transportation capacities between member states. Additionally, security of supply concerns in the aftermath of prolonged disruptions of gas supply following a dispute between Russia and Ukraine triggered a number of possible investment projects enhancing market integration and enabling reverse gas flows.

In practice, however, the identification and realization of investment projects, which are actually efficient, is difficult. For investors, which are not necessarily unbundled TSOs (transmission system operators) in the European gas market, it effectively depends on imposed third party access requirements and the rate-of-return for infrastructure investments set by regulators. Although the conduction of open season exercises helps to identify actual market demand, the results of this procedure may be distorted: liquid gas trading points sending price signals to market participants do not exist in all countries and the existing infrastructure capacities are not necessarily allocated efficiently. Instead, they might be blocked contractually by incumbents and not available to other companies - although they are actually not used. Therefore, open season exercises, for instance recently in Germany, tend to identify significant investment requirements when the market is asked to indicate its needs in a first step. Commitments to bookings of new capacities are, however, usually much lower. Further distortions to investment decisions arise from European Union subsidies for selected projects and the separate optimization of networks by TSOs which may neglect potential synergies arising from joint operation and optimization. Thus, the questions where actual physical, as opposed to the aforementioned contractual, bottlenecks exist and which investments in natural gas infrastructure may be efficient, is not yet answered in a comprehensive and encompassing approach.

Therefore, this article outlines an economic framework for the identification of transport infrastructure bottlenecks and their valuation as well as the valuation of (additional) infrastructure

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capacities. The existing literature and the microeconomic foundations of the approach applied in this paper are discussed in the next section. In Section 3, we develop an infrastructure model of the European gas market with high temporal and areal granularity which calculates physical gas flows and location- and time specific marginal supply costs. These can be interpreted as wholesale gas prices in a competitive market. The results of our simulations are presented in Section 4. Thereby, we investigate the European gas market in a scenario with the existing 2010 infrastructure and a supply and demand projection for the year 2015. Hence, results with respect to physical market integration indicate where additional investments might be necessary in the next five years. The model-based analysis allows a quantification of the economic costs of arising bottlenecks and the value of additional infrastructure investments.[2] Section 5 offers some concluding remarks.

2. Theoretical background

The existing literature on price formation, the economic valuation of transport and storage capacity, and the value of system bottlenecks in natural gas markets – which regards those factors simultaneously – is limited.

All articles considering grid-related issues are thereby to some extent inspired by and yield similar results than analyses on the economic valuation of transmission capacity in electricity markets. With the exception that large-scale storages do not (yet) play an important role in electricity markets, and are therefore mostly neglected in theoretic considerations, the two goods do exhibit similarities with respect to grid-boundedness and the natural monopoly character of their transmission.[3] Overviews of investment in and the economic valuation of transmission capacity in electricity markets are, for instance, provided by Hogan [2] and Stoft [3].

The most common approach is thereby based on locational marginal pricing which assigns each node, i.e. a system connection, entry or exit point, an individual competitive locational price. Assuming a competitive market, this price equals the total system marginal costs of supplying one additional unit of energy at the respective location and the marginal value of this unit to consumers – hence, the term LMP (locational marginal price). The concept was first introduced by Schweppe et al. [4] and was developed further by Hogan [5] and Hogan [2] with the latter work summarizing intermediate enhancements to the LMP framework by the author. A critical discussion of the LMP concept with respect to its application in congestion pricing is provided by Rosenberg [6].

Taking these LMPs, the value of a transportation service of energy from one location to another is then determined by the difference in the respective LMPs. I.e. the value of a transmission service from location 1 to 2 equals $p_2 - p_1$ in equilibrium. $p_2 - p_1$ also represents the per-unit-and-time-period economic value of the transmission asset and first-best transmission charge. According to economic theory, this value should also equal the variable cost of transmission from 1 to 2 if the line from 1 to 2 is not congested: If the LMP difference exceeds variable transmission costs albeit capacity being available, the no-arbitrage assumption would be violated as additional arbitrage could take place until prices only differ by the variable transport costs between the nodes. If, on the other hand, the line is congested, full arbitrage cannot take place. Then, prices are not determined by total system supply and demand but by residual supply and demand at the respective location (node). Consequently, the existence of congestion on a line between two locations is defined as the LMP difference between these nodes exceeding variable transport costs between the nodes [3].

The application of the LMP method to theoretically value transmission assets in gas markets was pioneered by Laffont [7] and Cremer et al. [8]. They provide a normative benchmark for the theoretically optimal gas transportation charges in a network by determining prices for each node in the system.

A relevant difference between gas and electricity markets is the possibility to store gas in large-scale storage systems enabling demand balancing and intertemporal arbitrage. Hence, storages are an important component of the infrastructure system, which can possibly constitute an infrastructure bottleneck as well and which impact competitive locational prices and therefore the value of transmission assets. The optimal value and investment in gas storages is, for example, explored by Chaton et al. [9] without considering interaction with the grid. With a system perspective and appreciating the important role of storages in natural gas markets, Lochner [10] extends the simplified gas network model by Cremer and Laffont [7] by including storages and intertemporality. The concept of multiple time periods is thereby complementary to LMPs: After all, a storage is just a transmission asset between two time periods and can therefore be treated similar to a pipeline (which enables transmission between two locations). Hence, the simple model by Lochner [10] can be used to illustrate the relevant interdependencies between the gas infrastructures with respect to the valuation of congestion and capacities.

With respect to the general economic dynamics, gas markets thereby do not differ generally from electricity markets – or any other market for that matter: In the short-term, infrastructure capacities are set and cannot be changed quickly; demand and supply are much less elastic than in the long-run. Hence, while infrastructure bottlenecks can be eliminated in the long-term and are therefore less relevant for price formation than the overall supply and demand situation [11], this is not true in the short-term. When the infrastructure is fixed, prices in a competitive market might differ regionally as the scarce transport infrastructure can constitute a physical impediment which limits trade. Hence, due to the costly and limited infrastructure (pipeline grid), supply and demand might differ between geographically separated locations leading to different competitive locational prices, which are determined by supply and demand at the respective node. Supply thereby encompasses all available gas volumes at the respective point including local production, supply from past time periods[4] and potential transports to the node from all other natural gas sources on all available routes. Accordingly, the node's demand curve is made up by present consumption with the marginal willingness to pay differing between consumers, future consumption for which gas can be injected into the local storage and potential demand from other markets provided there is transport capacity available to get the gas to the alternative market. As in electricity markets, if transmission capacity between nodes is not constrained, arbitrage causes LMPs to equalize (apart from differences resulting from transport costs). Scarcity of capacity, on the other hand, may cause the residual supply and demand functions in the separate markets to differ resulting in different prices. The difference between LMPs is the cost of congestion and the economic value of transmission assets between the respective markets. The same

[2] Selected assumptions, the general model-based approach and some of the supply and demand scenarios presented in this article are based on a study by the Institute of Energy Economics at the University of Cologne (EWI) which was commissioned by the European Regulators' Group for Electricity and Gas, see EWI [1]. Results of this study and the ones presented in this paper are thereby the sole responsibility of the author and do not necessarily reflect the opinion of ERGEG.

[3] With the exception of sea transportation of natural gas as LNG (liquefied natural gas).

[4] Presuming there is a storage at this location and gas was previously stocked there.

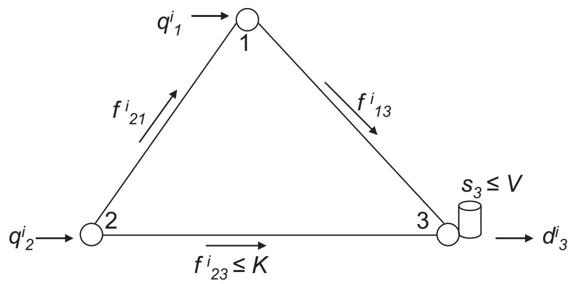

Fig. 1. Simple pipeline network with storage.

logic applies to storages: If storage capacity is unconstrained, arbitrage over time is possible and price differences should not exceed variable storage costs (in a microeconomic analytical framework with perfect foresight, such as the one presented in this paper); without storages, price formation between time periods is independent from each other.

To clarify the approach for identifying bottlenecks in this study, consider the simple pipeline network from Lochner [10], which is based on Cremer and Laffont [7] extended by a second period and a storage, in Fig. 1.

The grid consists of three nodes 1, 2 and 3 with production taking place at node 1 and 2 (q_1^t and q_2^t for all time periods $t = 0, 1$) and demand d_3^t being located at node 3. The nodes are connected with pipelines with f_{21}^t, f_{13}^t and f_{23}^t being the flows in t on the pipeline between 2 and 1, 1 and 3, and 2 and 3 respectively. As we abstract from period duration,[5] storage injection in period 0 equals the withdrawal in 1 and is denoted as s_3. V represents the storage working gas volume and K the pipeline capacity on pipeline from 2 to 3; the other routes are unconstrained. A functioning market (or a benevolent planer) would maximize social welfare SW:

$$\begin{aligned} SW = \sum_{t=0}^{1} \frac{1}{(1+i)} \Big[&+ \left(S^t\left(d_3^t\right) - p_3^t\left(d_3^t\right)d_3^t\right) + \left(p_3^t\left(d_3^t\right)d_3^t \right. \\ &- p_1\left(q_1^t\right)q_1^t - p_2\left(q_2^t\right)q_2^t - c_{13}\left(f_{13}^t\right)l_{13} - c_{21}\left(f_{21}^t\right)l_{21} \\ &\left. - c_{23}\left(f_{23}^t\right)l_{23}\right) + \left(p_1\left(q_1^t\right)q_1^t - C_1\left(q_1^t\right) + p_2\left(q_2^t\right)q_2^t \right. \\ &\left. - C_2\left(q_2^t\right)\right)\Big] - c_{\text{storage}}(s_3) - G - H \end{aligned} \tag{1}$$

G and H represent the capital costs for pipelines and storages. Variable transport cost and length of the pipeline are denoted as c_{ij} and l_{ij} for $ij = (2,1),(1,3),(2,3) S^t(d_3^t)$ denotes gross consumers surplus at node 3 and $C_i(q_i^t)$ the production cost function at node $i = 1, 2$ (the cost function does not differ between periods). Assuming a competitive market structure, the price at 3 equals the marginal willingness to pay by consumers ($S't(d_3^t) = p_3^t(d_3^t)$) and firms sell at marginal cost at node i for $i = 1, 2 (C_i'(q_i^t) = p_i^t)$.

The first order conditions of optimizing the social welfare function (equation (2)) with respect to the dispatch (i.e. the flow and storage) variables yield the aforementioned result that the value of a transmission asset as defined by the difference in prices between the respective nodes is determined by transport costs and the cost of congestion (here denoted as η^t):

$$p_3^t - p_2^t = c_{23}' l_{23} + \eta^t \tag{2}$$

Hence, without congestion ($\eta^t = 0$), prices only differ by marginal transport cost on the pipeline. According to Stoft [3], congestion is present when the price difference is larger, i.e. $\eta^t = p_3^t - p_2^t - c_{23}' l_{23} > 0$.

The cost of congestion can be described as follows in the model:

$$\eta^t = c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23} \tag{3}$$

$$\text{or } \eta^1 = \frac{i}{1+i}\left(p_2 + c_{23}' l_{23}\right) + c_{23}' l_{23} + \lambda \tag{4}$$

I.e. The cost of congestion cannot exceed transport cost of the unconstrained alternative (longer) transport route via node 1 and, in $t = 1$, the cost of delivery in the previous period plus incurred marginal storage costs with storage also being associated with a shadow cost in case of congestion of the storage facility. For a more detailed discussion of the value of the storage and the cost of the storage constraint, see Lochner [10]; this paper focuses on the identification of pipeline congestion in gas market simulations. As equation (3) shows, an approach to do so is an estimation of η^t. In reality, η^t is determined by additional factors such as supply and demand side elasticity.[6] In Section 4 of this paper, we therefore focus on prices and transport costs to check if the absolute price difference between two nodes is less than or equal to the transport costs between them. In the literature on market integration, this price difference is referred to as the parity bound [13]. If the price difference exceeds the parity bound, the markets at the nodes are not integrated (temporarily) due an impediment to trade, i.e. in the context of this paper an infrastructure bottleneck. If the price difference does not exceed the parity bound, η^t is less than or equal to zero and there is no congestions. The markets can be considered to be integrated (See the discussion in De Vany and Walls [14].) In order to be able to do an analysis of infrastructure bottlenecks in the European gas market based on this theoretical background, it is necessary to set up a model of the market to compute the LMPs at each node. Our model is described in the next section.

3. Modeling approach

Models computing nodal prices in natural gas markets are only available to a limited extent in the literature and usually differ with respect to their definition of a node. Models focusing on long-term developments such as Seeliger [15], Lochner and Bothe [16] and Möst and Perlwitz [17] usually define a whole country as a node implying that there are no bottlenecks within each country's national grid. This appears to be an appropriate assumption as the models analyze investments in gas production and cross-border transportation assets (and the electricity sector in the case of Möst and Perlwitz [17]). In the long-term, the other infrastructures can then be presumed to be expanded to suit the requirements of these developments. While both models compute nodal prices internally, they are not discussed specifically as investment decisions are endogenous. The same holds true for the models by Holz et al. [18] and Lise and Hobbs [19], the latter of which even aggregates Europe to just five nodes (regions) and, hence, fully abstracts from potential congestion between countries on the continent. However, this may be appropriate as both papers focus on the implications of (upstream) market power instead of infrastructure investments. In this context, Holz et al. [18] actually compute prices under different assumptions with their game-theoretic model. Although these are not nodal prices in the sense of competitive locational prices as in Stoft [3] (apart from one simulation assuming a competitive market), they indicate the value of additional supply at each node (= country) and, therefore, allow implicit conclusions on the value of assets on an aggregated basis.

[5] This could be included with a period duration factor along the lines of Gravelle [12].

[6] Which the simple model abstracts from.

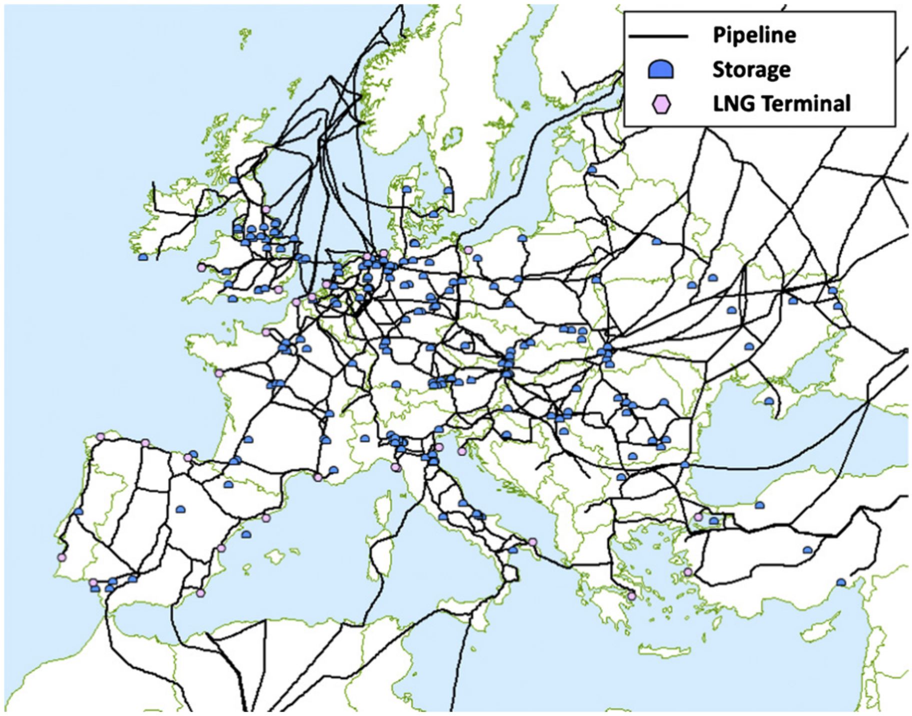

Fig. 2. Modeled Gas Supply Infrastructure System of the European Gas Market.

Short-term considerations of the European gas grid with higher temporal and areal granularity are provided by Lochner and Bothe [20], Neumann et al. [21] and Monforti and Szikszaia [22]. Lochner and Bothe [20] develop the so-called TIGER model, an enhanced version of which is used in this paper. While they do not compute nodal prices, they provide a network flow model of the European gas market with over 500 nodes covering all major long-distance transmission pipelines individually. A similar linear optimization approach is used by Neumann et al. [21]. Instead of the minimization of commodity and dispatch costs given a fixed demand [20], they maximize social welfare by including an estimated demand elasticity and compute nodal prices. Bottlenecks between nodes are then identified by considering congestion mark-ups and the utilization of assets. However, their areal granularity of one node representing one country does not allow them to consider specific assets individually; the temporal granularity of one month might underestimate the strain on the systems on individual high (peak) demand days. The model by Monforti and Szikszaia [22] was set up to investigate system resilience in the light of security of supply stress situations rather than physical market integration. It abstracts from modeling storage operations explicitly but alters the amount of gas available from storages through Monte-Carlo simulations. With the same regional resolution as Neumann et al. [21], they cover a wider geographical area (EU-27 plus Norway and Switzerland). Although it is also a network model consisting of edges and nodes, gas dispatch is not based on costs or prices but certain "rules"[7] disabling the computation of competitive locational prices.

Our model is a linear optimization model minimizing the total cost of gas supply in the European gas market taking into account the relevant technical constraints of the infrastructure and assuming an efficient utilization of infrastructure assets. While it is based on Lochner and Bothe [20], the version applied in this paper is enhanced with respect to temporal granularity (daily) and geographic coverage (Europe plus surrounding gas production countries).

The mathematical formulations of the model is as follows: The objective function minimizes total costs TC, i.e. full commodity plus all variable costs incurred in the supply process[8]:

$$\begin{aligned}\min \mathrm{TC} = & \sum_{t,i} \mathit{commoditycost}_i \times \mathrm{SUPPLY}_{t,i} \\ & + \sum_{t,i,j} \mathit{transportcost}_{i,j} \times \mathrm{FLOW}_{t,i,j} \\ & + \sum_{t,i} \mathit{storagecost}_i \times \mathrm{STORAGELEVEL}_{t,i} \\ & + \sum_{t,i} \mathit{regasificationtariff}_i \times \mathrm{LNGIMPORTS}_{t,i} \\ & + \sum_{t,i} \mathit{voll} \times \mathrm{DEMANDREDUCTION}_{t,i} \end{aligned} \tag{5}$$

for all nodes i, all pipelines from nodes i to j, the respective storages and LNG terminals located at nodes i and all time periods t. Time periods t, thereby, equal one day, i.e. $t = 1, \ldots, 365$ in the annual simulation. A representation of all nodes and pipelines is pictured in Fig. 2.

The optimization of this objective function is subject to a number of technical restrictions arising from production, transport pipelines, storages and LNG terminals.

Production is aggregated to production regions but assigned for individual nodes. Both have to adhere to the following constraints (only depicted for nodes for simplicity):

[7] Domestic demand is first covered from domestic sources such as local production and storages; then, gas volumes flow in from neighboring countries or even from further upstream, if possible.

[8] To improve readability, endogenous variables are depicted in CAPITAL letters, exogenous input parameters in lower case.

$$\mathrm{SUPPLY}_{t,i} \leq peaksupplycapacity_{t,i}$$
$$\sum_{t \in \mathrm{year}} \mathrm{SUPPLY}_{t,i} \leq annualsupplycapacity_{\mathrm{year},i}$$

The only restriction for transport pipelines is its capacity (which depends on t as it may change over time):

$$\mathrm{FLOW}_{t,i,j} \leq pipelinecapacity_{t,i,j}$$

For all combinations of nodes i,j where there is no pipeline, $pipelinecapacity_{i,j}$ is zero implying that the flow on the pipeline has to be zero, too. Pipeline directionality is taken into account by differentiating capacities between i and j and between j and i.

Storages are constrained by a working gas volume (*wgv)* and maximum injection and withdrawal rates (*STORAGEIN* and *STORAGEOUT)* which are a function of the current storage level as they change with the pressure inside the storage. Furthermore, storages need to adhere to a balance constraint ensuring that injections and withdrawals (and the resulting storage level) are in equilibrium over time:

$$\mathrm{STORAGELEVEL}_{t,i} = \mathrm{STORAGELEVEL}_{t-1,i} + \mathrm{STORAGEIN}_{t,i} - \mathrm{STORAGEOUT}_{t,i}$$
$$\mathrm{STORAGELEVEL}_{t,i} \leq \mathrm{wgv}_{t,i}$$
$$\mathrm{STORAGEIN}_{t,i} \leq f(maxInjection_{t,i}, \mathrm{STORAGELEVEL}_{t,i})$$
$$\mathrm{STORAGEOUT}_{t,i} \leq f(maxWithdrawal_{t,i}, \mathrm{STORAGELEVEL}_{t,i})$$

Similar to production facilities, LNG import terminals are subject to maximum output rates and annual nominal import capacities (LNG storages are included in the same fashion as regular natural gas storages):

$$\mathrm{LNGIMPORTS}_{t,i} \leq peakregasificationcapacity_{t,i}$$
$$\sum_{t \in \mathrm{year}} \mathrm{LNGIMPORTS}_{t,i} \leq annualimportcapacity_{\mathrm{year},i}$$

In addition to these technical constraints, an energy balance constraint ensures that the market clears. For all nodes i and time periods t it needs to be true that the sum of gas volumes *entering* a node equals the sum of all flows *leaving* it:

$$\mathrm{SUPPLY}_{t,i} + \sum_j \mathrm{FLOW}_{t,j,i} + \mathrm{STORAGEOUT}_{t,i} + \mathrm{LNGIMPORTS}_{t,i} = \sum_j \mathrm{FLOW}_{t,i,j} + \mathrm{STORAGEIN}_{t,i} + demand_{t,i} - \mathrm{DEMANDREDUCTION}_{t,i} \quad (6)$$

As this condition needs to be true for all nodes i and all time periods t, it also ensures that the system as a whole is in equilibrium in each time period and over time.

This model set up thereby makes the following assumptions: On the upstream side, it is assumed that gas is sold at price-inelastic commodity costs which is compatible with the assumptions of the theoretical model presented in Section 2 (Prices for short-term LNG cargos are presumed to form in the global market with Europe being a price-taker; commodity prices in long-term import contracts are supposed to be fixed by price-indexation to substitutes and therefore not a function of gas market supply and demand.) With respect to demand, the model does not incorporate a price elasticity in the short-term apart from a threshold price indicating a value of lost load (*voll)*. Above this threshold consumers are assumed to reduce consumption. Regarding market structure, the cost minimization presumes an effective regulation of the natural monopoly pipeline infrastructure and either a competitive storage market or its effective regulation (Depending on whether storage is regulated or not, which differs between countries.) The same holds true for LNG import facilities. The system optimization approach further presumes that all efficient swaps are realized by TSOs. Hence, as in Section 2, we consider a normative model describing the optimal dispatch in the gas market.

With respect to coverage and granularity, our model is one of the European gas market as represented in Fig. 2 consisting of 750 pipelines, 200 storages, 22 LNG import terminals and 500 nodes (which are omitted in Fig. 2).

The input parameters are based on the following sources:

- Lochner and Bothe [16] for supply costs ($commoditycost_i$),
- OME [23] for $transportcost_{i,j}$ and $regasificationtariff_i$,
- United Nations [24] for $storagecost_i$,
- ENTSOG [25] and EWI [1] for $demand_{t,i}$, $peaksupplycapacity_{t,i}$ and $annualsupplycapacity_{year,i}$,
- and UKERC [26] for the value of lost load (*voll)*.
- The parameters characterizing the specific infrastructure elements, $pipelinecapacity_{t,i,j}$, $wgv_{t,i}$, $maxInjection_{t,i}$, $maxWithdrawal_{t,i}$ and $annualimportcapacity_{year,i}$ and $peakregasificationcapacity_{t,i}$, are based on publicly available sources from the various LNG terminal, pipeline and storage operators as well as their industry associations' databases (GLE, GTE, GSE), see EWI [1] and EWI [27] for a disclosure of all sources. In the simulation, projects scheduled to be completed until the end of 2010 (according to ENTSOG [25]) are included. The major pipeline and LNG import terminal projects have typically longer lead times. Thus, we additionally include all projects under construction as these are quite certain to be available in 2015. These encompass three LNG terminals (Rotterdam (Netherlands), Gijon (Spain), and Toscana offshore terminal (Italy)) and the first stage of the Nord Stream pipeline from Russia to Germany (and the corresponding onshore connections).
- The typical injection and withdrawal profiles for storages as a function of storage type, level of gas in the storage, and maximum nominal injections and withdrawal rates were developed with storage operators and are discussed in EWI [27].

See Table 1 for the major numerical assumptions on supply and demand and EWI [1, Appendix] for the existing infrastructure at the end of the year 2009.

The optimization of equation (5) (minimization of *TC)* subject to all constraints does not only provide results for all optimization variables, but also allows an interpretation of the shadow costs (Lagrange multipliers) of the restrictions. The shadow cost of the energy balance constraint (equation (6)), thereby, indicate the total system cost of supplying one additional unit of gas at the respective node and the respective time. These can, hence, be interpreted as location- and time specific marginal costs, which constitute nodal prices in a competitive market. Knowing the transport costs between nodes ($transportcost_{i,j}$) then allows to estimate the congestion mark-up η from equation (2) as it has to equal the price difference minus transport costs. If the congestion mark-up is greater than zero, an infrastructure bottleneck on the pipeline exists. $\eta \leq 0$, on the other hand, implies that the price difference is within the parity bounds and the market is integrated in terms of prices [13].

3.1. Model validation

The model described in this section has been validated as part of its application in the context of the study EWI [1]. Thereby, the model was parameterized for the year 2008 and simulated gas flows were compared with actual gas flows in 2008 as far as data was available.[9] The numerical results can be retrieved from EWI

[9] Not all network operators in Europe do yet provide data on actual physical gas flows on their pipelines.

Table 1
Supply and demand assumptions for 2015.

Country	Demand [bcm/year]	Peak Day Demand [mcm/day]	Supply Capacity [bcm/year]
Austria	11	79	2
Belgium	25	176	0
Bulgaria	3	15	0
Croatia	6	34	2
Czech Republic	12	71	0
Denmark	4	26	4
Estonia	1	3	0
Finland	5	24	0
France	52	417	0
Germany	81	500	15
Greece	6	33	0
Hungary	20	128	1
Ireland	6	26	2
Italy	95	418	6
Latvia	2	7	0
Lithuania	3	14	0
Luxemburg	1	7	0
Netherlands	45	438	68
Norway	7	40	111
Poland	18	82	4
Portugal	7	28	0
Romania	12	90	12
Slovak Republic	6	40	0
Slovenia	2	8	0
Spain	53	279	0
Sweden	2	9	0
Switzerland	3	24	0
United Kingdom	90	471	38
Turkey	44	171	0
Algeria[a]			55
Azerbajian[a]			18
Iran[a]			16
Lybia[a]			9
Russia[a]			174

Source: Own assumptions based on ENTSOG [25] and EWI [1].
[a] Pipeline export capability to Europe.

[1, Chapter 5]. Generally, the findings yield that the model replicates gas flows in the European gas market rather well. However, there are some small absolute difference between actual and simulated gas flows. These are presumably due to contractual gas flows which are partially carried out in reality, although it would sometimes be more efficient to swap gas volumes where possible. The model, on the other hand, does find the optimal dispatch implementing all economically efficient gas swaps. Hence, gas flows in partially opposite directions, e.g. between Austria and Germany on the one hand, and from Norway to Switzerland via Southern Germany on the other hand, would be reduced as far as possible. However, this deviation of model results from reality does not limit the model's general suitability for the purpose of the investigation at hand. Firstly, the increasing efforts of regulators to reduce inefficiency in the European gas market will lead to a more efficient allocation of the scarce transport infrastructure assets – and hence bring reality closer to the model optimum in the investigated future time period. Secondly, additional congestion in reality (as compared to the model results) would indicate that there are inefficiencies arising from capacity allocation and system operation. Removing these through improving the efficiency in capacity allocation would most likely be less costly than additional investments. Hence, obtaining a view on the optimal market result as provided by the model is of additional value to regulators, investors and TSOs just because it would highlight differences from reality – not despite that.

4. Results

Based on the demand, supply and infrastructure assumptions, the model yields the optimized gas dispatch. Due to the increase in demand and the decline in domestic production, imports increase significantly relative to the current (2010) situation. From the pipeline gas sources, imports from Russian and Norway increase up to the exogenous limits set for 2015 (see Table 1). Algerian pipeline imports increase up to the capacity limit of the pipelines in place and amount to 51.6 bcm in 2015. LNG with its relatively higher costs constitutes the marginal supplier delivering 105 billion cubic meters (bcm) of LNG to the European market in 2015. Generally, the higher amount of gas flows, transits and deliveries over longer distances (imports) implies an increase in the utilization of infrastructure assets.

While analyzing pipeline utilizations would already indicate potential bottlenecks, they can only be identified by the approach described in Sections 2 and 3. Therefore, we consider the system marginal cost of supplying one additional cubic meter (m^3) of natural gas at each point in the system and at each time period provided by the model, which allows an investigation of the shadow cost of the capacity restriction on each pipeline. For our analysis, we focus on cross-border connections. Therefore, we select representative nodes in each country and compare the differences in marginal supply costs to the variable transport costs of transporting gas from one node to the other on the route with the lowest transport costs. The connections where congestion is identified ($\eta > 0$) by the model are depicted in Fig. 3. The arrows in Fig. 3 point in the direction of the congestion; the color implies its frequency as a percentage of the year 2015. The width of the respective arrow indicates the aggregated cost of the congestion from small to large (log-scale) with the values presented in Table 2.

Generally, it can be noted that the larger and darker colored arrows can be found in Eastern Europe, with the exception of a bottleneck between Germany and Denmark. The major issue appears to be import capacity into Hungary, which is always congested with a high cost of congestion. In Western Europe, congestion is usually only temporary and the costs of the respective bottlenecks are generally rather low.

4.1. Estimation of congestion mark-ups

The calculated congestion mark-ups for all investigated country pairs are presented in Table 2. The table includes the share of the year when congestion occurs, the average mark-up η (over all days where $\eta > 0$) as defined in equation (1), i.e. the cost of not having one additional cubic meter of capacity per day, as well as the aggregated congestion cost over the whole year. These are relevant for the estimating the welfare effects of investments.

The data confirms the previously discussed findings. The bottlenecks with the highest economic costs are the ones between Germany and Denmark, into Hungary from Romania, the Slovak Republic and Austria and between Slovenia and Croatia. The constraints in Western Europe are associated with relatively low shadow costs. On the one hand, this is due to their low frequency as they only occur in selected winter days with (extremely) high demand. On the other hand, due to the relatively high physical market integration in Western Europe, there are usually multiple options/transport routes for supplying gas. So even if a pipeline is congested, the other options do not cause significant extra costs which means price spreads between countries do not get large reducing the cost of congestion.

The aggregated annual cost of congestion on a route in Euro (EUR) per cubic meter daily capacity thereby indicate the economic efficiency of capacity expansion on the route: If the annualized marginal capacity cost is lower than the annual cost of the constraint, adding capacity is beneficial from a welfare point of view until the marginal capacity cost equals the cost of congestion in equilibrium. In the numerical example, this implies that

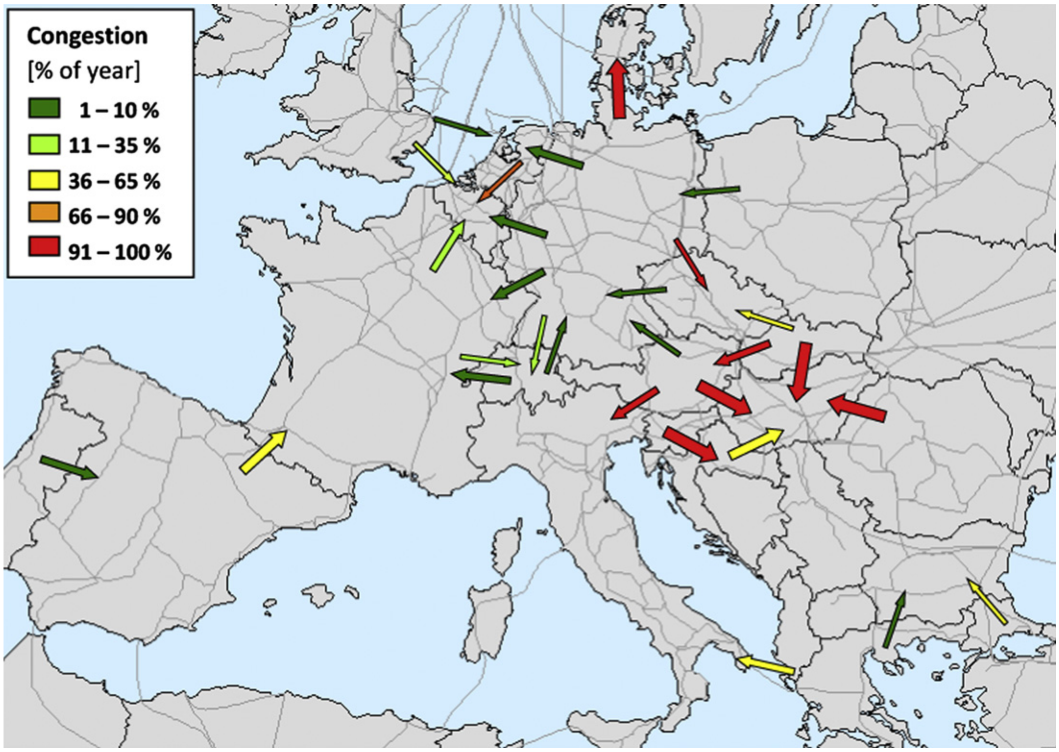

Fig. 3. Identified bottlenecks in 2015.

Table 2
Congestion mark-ups for all investigate country pairs.

Inter-connection points	Days with congestion mark-up > 0 [% of year]	Average congestion mark-up [EUR/m^3/day]	Aggregated congestion mark-up [EUR/m^3/day/year]
AT → DE	0.3%	0.016	0.016
AT ← SK	91.1%	0.003	0.887
AT → HU	100.0%	1.707	614.675
AT → IT	90.6%	0.006	1.877
AT → SI	100.0%	0.008	2.936
BE ← DE	0.6%	0.872	1.743
BE ← NL	85.0%	0.001	0.361
BE ← GB	14.4%	0.001	0.037
BE → FR	15.8%	0.001	0.067
BG—RO	0.0%	0.000	0.000
BG ← TR	60.3%	0.002	0.433
BG ← GR	9.7%	0.001	0.031
CH ↔ DE	27.2%	0.002	0.202
CH—IT	0.0%	0.000	0.000
CH ↔ FR	11.7%	0.031	1.476
CZ → DE-S	0.8%	0.006	0.018
CZ ← DE-E	96.9%	0.001	0.404
CZ ← SK	38.6%	0.001	0.091
DE → DK	100.0%	1.682	605.613
DE ← PL	9.7%	0.001	0.026
DE → FR	0.3%	1.721	1.721
DE → NL	0.8%	0.586	1.757
ES → FR	39.7%	0.005	0.783
ES ← PT	0.3%	1.658	1.658
GB—IE	0.0%	0.000	0.000
GB → NL	0.8%	0.002	0.005
GR—TR	0.0%	0.000	0.000
GR → IT	40.6%	0.008	1.211
HR ← HU	43.6%	0.112	17.596
HR ← SI	100.0%	1.748	629.238
HU ← RO	100.0%	1.712	616.203
HU ← SK	100.0%	1.710	615.562
IT—SI	0.0%	0.000	0.000

Germany to Denmark capacities would be beneficial to expand if the cost for one billion cubic meter of annual capacity is 15.6 billion EUR or less.[10] The costs of expanding the existing pipeline or building a new one on this route may very likely be below this threshold. Hence, investment should take place (and is already being prepared by the relevant TSOs). On the other hand, for capacity between, for instance, Greece and Italy, the capacity cost for one billion cubic meter per year should not exceed 31 million EUR. As the proposed interconnector projects between these two countries may be significantly more costly, investment in capacity may not be economically efficient.[11]

To demonstrate the estimation of the costs of these bottlenecks with our approach, two of these bottlenecks are discussed in detail in the following:

4.2. Selected country analysis

Figs. 4 and 5, therefore, display the difference in marginal supply costs for the respective locations over the course of the year, the relevant variable costs for transport of gas between these nodes, and the aggregated cost of congestion between the two as the area between them if the (absolute) marginal supply cost difference exceeds the transport costs (i.e. η is greater than zero).

The difference in locational marginal supply costs between Belgium and the United Kingdom in Fig. 4 displays a clear seasonal

[10] For simplicity only considering congestion costs of the year 2015 and assuming a rate-of-return of 9.5 percent and an economic lifetime of pipeline capacity of 30 years for the annualized capacity costs.

[11] For illustrative purposes, this paragraph scaled capacity expansion costs to units of one billion cubic meter annual capacity (from m^3 daily capacity in Table 2). As the previous considerations and the methodological framework focused on marginal congestion costs, these should only be applied in the evaluation of marginal capacity costs (and not the capacity costs of a one billion cubic meter pipeline). A full analysis of discrete investment decisions requires an extended theoretical and modeling framework, see further remarks in Section 5.

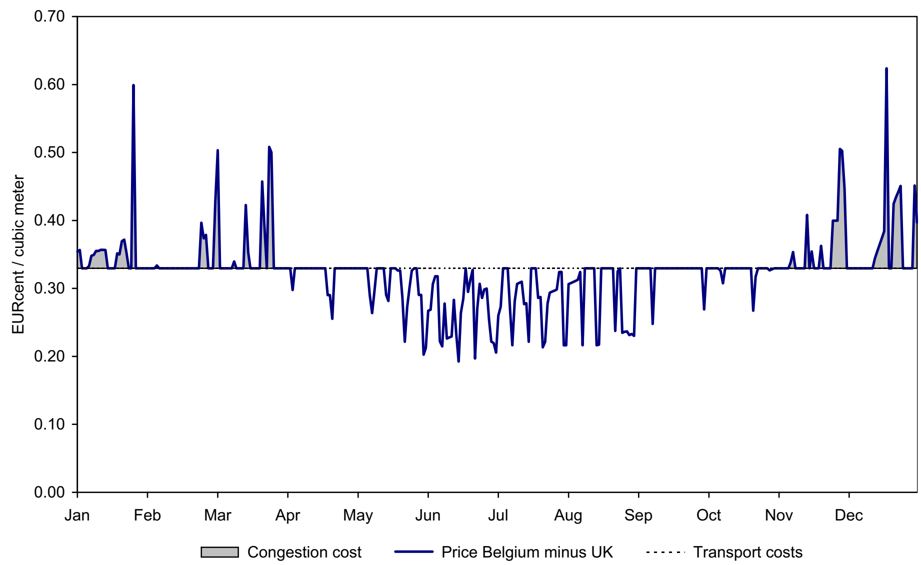

Fig. 4. Marginal supply costs and transport differences between Belgium and the UK.

pattern: congestion takes mainly place in winter on days with rather high demand; there is no congestion in summer as the price difference from April to November is always below transport costs. Generally, prices in Belgium are higher than in the UK which is a results of the scenario assumptions with relatively low additional pipeline import capacity to the continent but the existing high LNG import capacities in the UK. Hence, a lot of LNG is imported in Europe, especially the UK, and the flow direction on the interconnector is predominately from the UK to the continent.

Congestion is only detected for the high demand day when the nodal price difference exceeds transport costs. In this case, this is due to the relatively lower peak demand in the UK relative to the continent and the higher availability of withdrawal capacity, especially from LNG terminals, than in Belgium. (Note that this causes also congestion from Germany, the Netherlands and France into Belgium, which coincides with this high demand. See Table 2 and Fig. 3.) Although the congestion costs equals about 0.27 EUR-cent/m^3 at its maximum, the aggregated cost of congestion, i.e. the area between the price difference and transport cost curves in Fig. 4, is only 3.7 EUR-cent/m^3 daily capacity over the whole year. Scaling this figure up to 1 bcm annual capacity yields that the cost of congestion on the interconnector pipeline would be 100,807 EUR per bcm per year. I.e. the congestion should only be removed if the annualized capacity cost for the addition of 1 bcm of interconnector capacity does not exceed this figure.

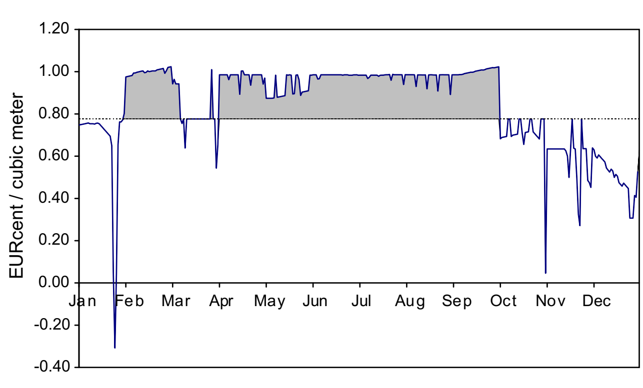

Fig. 5. Marginal supply costs and transport differences between Bulgaria and the Turkey.

Fig. 5 illustrates that the difference in locational marginal supply costs between Bulgaria and Turkey exceeds the transport costs for the larger part of the year. However, the seasonal pattern is reversed compared to the intuitive result, illustrated for instance in Fig. 4, one would expect: congestion in winter, capacity available in summer. This can be explained by Turkey's role as a potential transit country for gas flows from the Caspian region or the Middle East to Europe. The import capacities from the East into Turkey can bring high gas volumes into the country. In the summer, transporting these volumes further West congests the pipelines to Bulgaria leading to a separation of the price formation in the two countries. In winter, however, Turkish demand is higher than in summer: Less gas is available for transits further to the West. Capacity to Bulgaria would then still be available for additional transits. Hence, arbitrage possibilities lead to a convergence of marginal supply costs, the difference of which decreases to or below transport costs between the markets. On the peak demand winter day at the end of January, the price difference illustrated in Fig. 5 even becomes negative. Hence, prices are lower in Bulgaria than in Turkey which induces gas flows from Bulgaria to Turkey.

As in Fig. 4, the shaded area between the two curves in the summer months represents the aggregated shadow cost of the transport capacity constraint. Normalizing this figure to 1 bcm annual capacity yields that it would be profitable to expand capacity there if the annualized capital cost is not larger than 1.19 million EUR. Whether or not this is possible should be part of the decision regarding capacity expansion at this interconnection point.[12]

5. Conclusions

The approach outline in this paper can be used to identify congestion in the European gas market between countries but also on transport infrastructures within countries. By computing and

[12] In this illustrative example. Applying the method to quantification of congestion costs would further call for sensitivities or Monte-Carlo simulations producing expected shadow costs.

comparing locational marginal supply costs with transport costs, physical bottlenecks can be identified. Estimations of the congestion mark-ups allow evaluations of the values of additional capacities and the cost of the bottleneck. The general approach (without estimation of aggregated mark-ups) has for instance been applied in an in-depth analysis commissioned by ERGEG investigating the ten year network development plans of TSOs in Europe in twelve scenarios and various sensitivities [1]. In this context, it needs to be noted that the applied normative modeling framework only detects physical bottlenecks which would even occur in a fully functioning gas market. If the operation of the European gas grid is not completely efficient, which may be the case due to transaction costs, not fully harmonized operation and capacity booking rules, intransparency and a lack of liquid gas trading in some countries, and, most notably, the optimization of individual grids in each country instead of total system optimization, additional bottlenecks might become evident.

With respect to the general approach, it further needs to be noted – and was shown in the numerical example in the previous section – that congestion is not necessarily inefficient from an economic perspective: If the marginal cost of the congestion does not exceed the marginal capacity cost over the lifetime of the capacity asset, having price differences and, hence, an infrastructure bottleneck is efficient.[13]

Regarding the results presented this paper, this may be true for the congestion between the UK and Belgium. The aggregated annual congestion mark-up is rather low and may not justify capital expenditure to increase capacity on the pipeline. For the example of Bulgaria and Turkey, this area is significantly larger. The simplified calculations of the annualized congestion costs found the same to be true for other interconnections where investment may definitely be economically efficient. However, for a full calculation, an improved incorporation of demand elasticities in the modeling framework is required.

Three further issues arise:

(i) With discrete investment decisions (as in the reality of a gas market: building a pipeline with a non-infinitesimal capacity or not), the marginal units cannot be considered alone and volumes have to be further taken into account.
(ii) Additionally, Section 2 demonstrated that the valuation of pipeline capacities is impacted by storage investments (and vice versa). Again, in the Belgium-UK example, it might be that an investment in peak shaving storage capacity in Belgium is more efficient to remove the temporal bottleneck in transmission than an expansion of transport capacity.
(iii) This leads to a third implication: Interdependencies might also arise between one pipeline asset and another, as well as other infrastructures such as LNG terminals (and the aforementioned storages). Hence, even if a full assessment of investment costs and the discounted and aggregated congestion mark-ups on specific routes finds these investments to be economically beneficial, the simultaneous elimination of several bottlenecks may not be efficient as one is not unlikely to have an impact on the other.

Therefore, apart from improved demand side modeling, further research with respect to efficient investment will need to deal with the incorporation of discrete investment decisions in large-scale infrastructure models, as this would allow more sophisticated analysis of the efficient removal (or non-removal) of congestion.

[13] See also Lochner [10].

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