Gazdálkodáskari Doktori Iskola

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From unilateral import dependence to competition on the Hungarian natural gas market

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Introduction[1]

This thesis summarises what I, in the last 10 years, have learned about the origins of and the potentially efficient ways to address one of the critical energy policy issue in Hungary (and in some aspects the wider Central and South East European region), that is unilateral import dependence and wholesale market inefficiencies in the natural gas sector.

The roots of present natural gas sector vulnerabilities go back to Soviet times, when the combination of major government funded infrastructure investments and very low gas product prices created fast increasing demand for natural gas in Hungary. After the commissioning of the once Russia-Hungary (today Ukraine – Hungary) gas interconnector in 1974, a wave of centrally subsidised gas distribution network development took place in the country. Industrial and household customers also invested huge amounts into switching their industrial, heating and cooking technologies from wood, coal and oil to natural gas. Finally, the share of natural gas based electricity generation grew far the largest among new EU member states in Hungary by 2005, the top year for its natural gas consumption. Figures 1–3 illustrate the penetration of gas infrastructure and consumption in the last four decades.

[1] For the references in this section, see the list after the final new study.

Figure 1. Primary fuel structure of Hungary, 1965–2013. – development of the share of gas

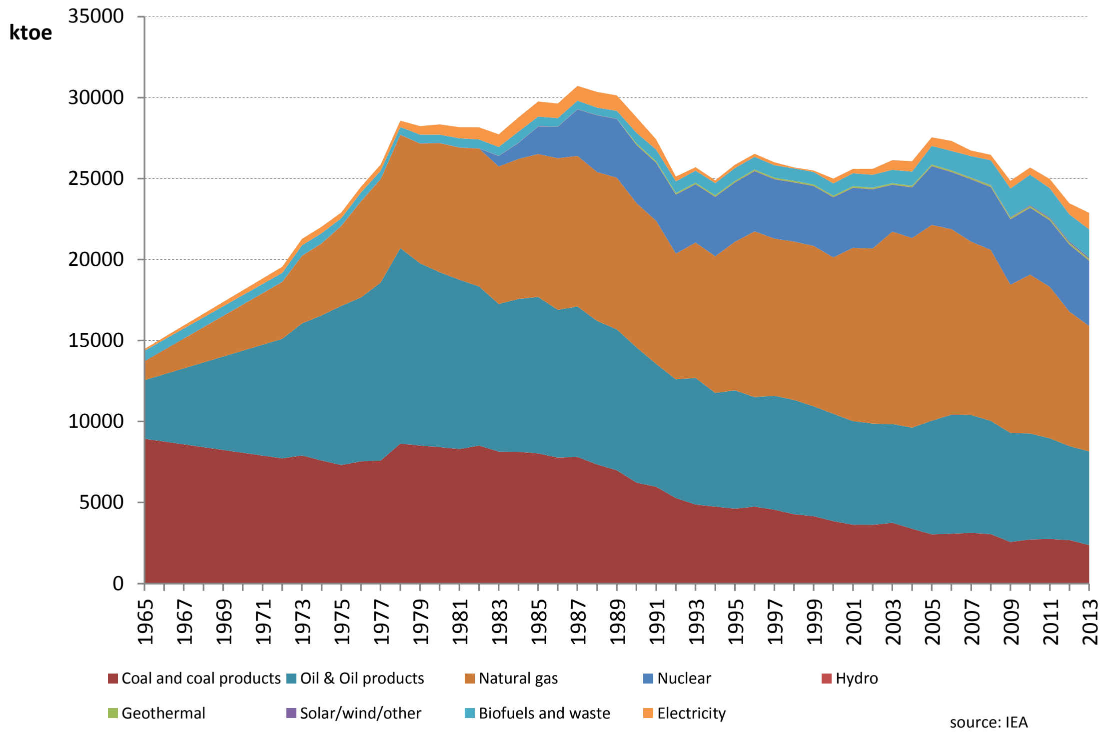


Figure 2. Development of domestic gas consumption, production, import (left axis) and the length of the gas distribution network (right axis) of Hungary, 1970–2013.

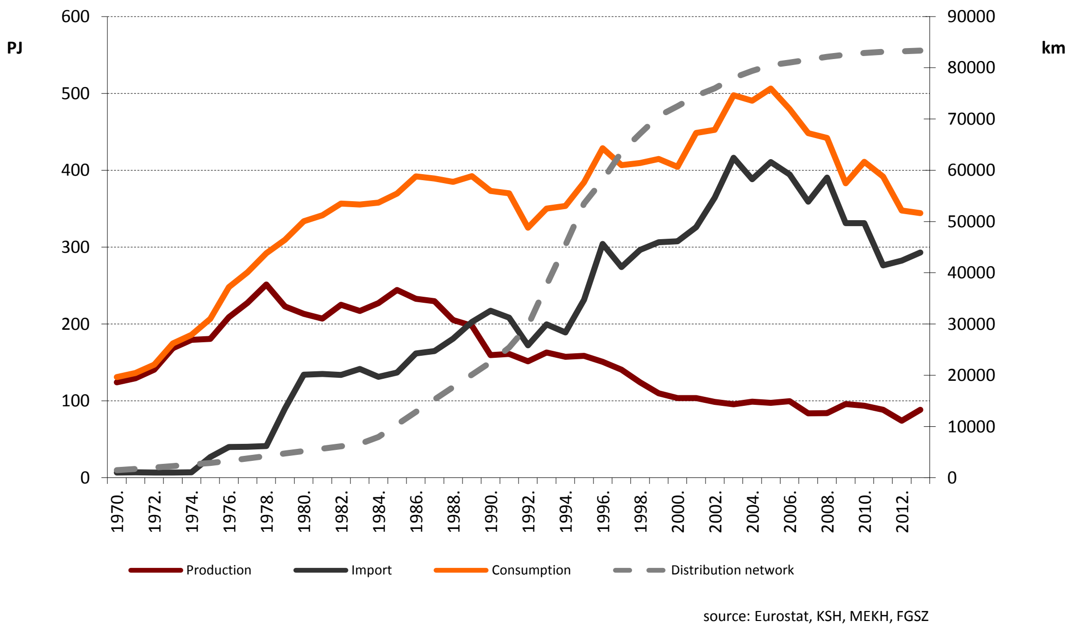
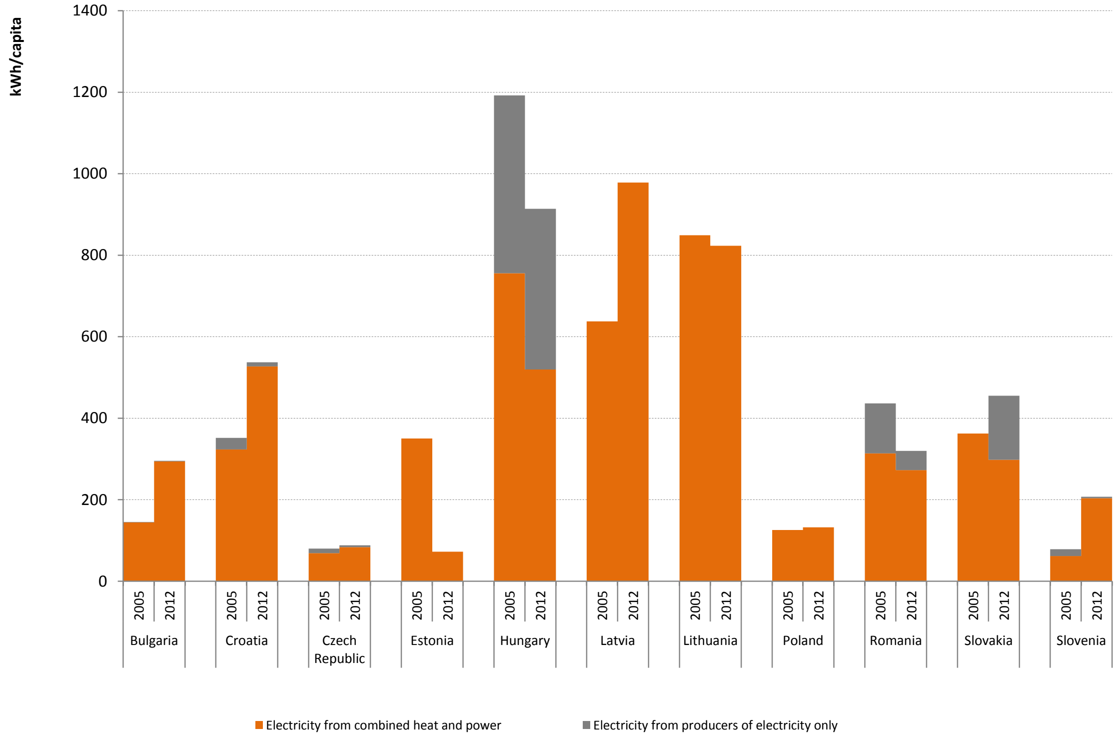


Figure 3. Per capita natural gas based electricity generation in new EU member states



Source: own calculations based on Eurostat

While the environmental benefits of a fuel switch from oil and coal to gas are unquestionable and the comfort of gas usage is also superior to its alternatives, natural gas penetration has perhaps gone too far in Hungary. When its gas consumption reached historic high in 2005, in Europe it was Hungary that relied most on natural gas to serve its primary energy demand. By 2011, the percentage of households with natural gas reached almost 90% in Hungary, the second highest behind The Netherlands with 93% (See ACER 2013). The key difference in the development of their natural gas markets for these two "gas addict" countries is that while The Netherlands is the largest natural gas net exporting country (the only other is Denmark) in the EU, domestic gas production could not serve more than 30% of consumption in case of Hungary since 1999. The rest had, and still has to be made up from imports.

The lack of import supplier, alternative to Russia, made import driven gas market development risky in two major ways for Hungary.

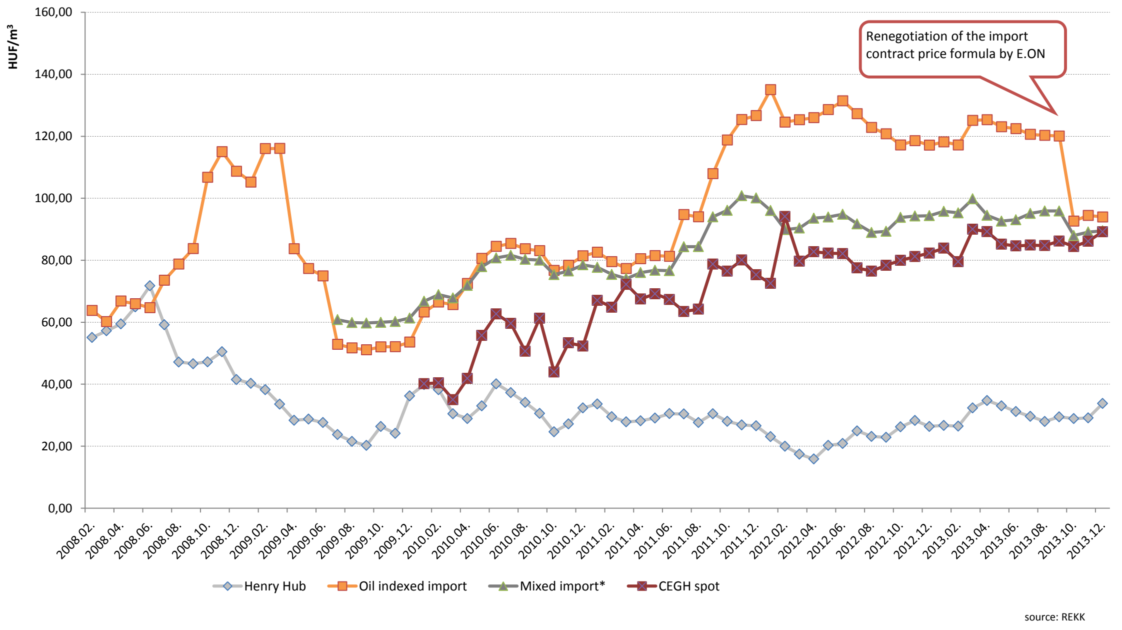
Unilateral gas import dependence on Russia first created a *price risk*, inherent in such a market setting with a monopolistic supply side. This price risk was managed by intergovernmental price agreements during Soviet times, and even after the collapse of the Soviet Union until 1996.[2] That year MOL, the Hungarian Oil and Gas Company entered into a long term gas purchase contract (in the followings: LTC) with Gazprom. This contract included a gas pricing formula that established a starting gas price for the two partners and then linked the change in gas price to price changes of oil products with transparent market prices.[3] Given the lack of transparent gas wholesale markets in Europe, this pricing method provided for a certain level of transparency and predictability for the contracting parties. However, they obscured the relationship between gas purchase costs for MOL (that is Hungarian customers) and the cost of Gazprom to supply gas for the Hungarian market. Prices were not based on the interplay of demand and supply but on prices of substitutes for natural gas.

To get an idea of the magnitude of monopolistic rents the Russian supplier has recently gained from oil-indexed gas sales to Hungary, we can compare oil-indexed and European spot gas prices depicted on Figure 4. As for an example, between October 2012 and September 2013 the Russian supplier sold 5 Billion cubic meters (Bcm) of natural gas on LTC basis to its Hungarian partner. Assuming a 100% oil indexed price for this amount of gas, the Russian supplier might had realized an average HUF 36/m^3 rent on these sales compared to the situation if it had to sell this amount at European gas hubs (e,g, the Central European Gas Hub at Baumgarten, Austria). Thus the annual amount of rent from oil indexed sales to Hungary can be estimated at around HUF 180 Billion, or € 600 million.

[2] In 1958 the so called "Bucharest price formula" was introduced in the Soviet bloc, according to which trading prices were fixed for 5 years, based on the average global market prices of the preceding five-year period. This system was, however, revised after the oil crisis of 1973. As the Soviet Union wanted to profit from increasing hydrocarbon prices, in 1975 it introduced a new sliding price formation practice with yearly price corrections. (Stern, 2012, p. 63)

[3] According to the 2005/2006 energy sector inquiry of the European Commission, light fuel oil and gasoil, and heavy fuel oil had a combined weight of more than 95% in the indexation of long-term contracts for gas supply to Eastern Europe. (EC, 2007, p. 104).

Figure 4. The development of oil-indexed, spot, and mixed natural gas prices, January 2008 – December 2013.



Source: REKK analysis

High relative gas wholesale prices combined with the almost universal use of gas by households for heating and cooking purposes created a case for chronic high level policy struggle around gas prices during, at least, the last three election campaigns. Arguments and government decisions about end customer gas price changes (increases or decreases) for household customers became a priority battle ground in the fight for votes (Kaderják, 2005a; REKK 2013a, 2014).

Beyond price risk, the lack, up to the commissioning of the Hungarian-Austrian Gas Pipeline (in the followings: HAG) in 1994, and later the limited capacity of alternative supply infrastructure to ship natural gas imports created serious gas *supply security risk* for the country. This risk manifested in more than 310 million m^3 of non-served gas during the 2009 January gas crisis. The present (winter of 2014-15) gas supply security risk for Hungary, posed by the unfolding political and military conflict between Russia and Ukraine is also largely due to import driven gas market development and the lack of sufficient infrastructure diversification for the country[4].

In the last decade the most significant motivation for change on the Hungarian gas market has been the EU policy drive towards opening up national natural gas markets

[4] For a preliminary quantitative analysis on the potential impacts of the Russia-Ukraine conflict on CEE gas supply security see Kaderják et al. (2014).

and integrating them into a single European one. It is not by chance that the history of competition on the Hungarian natural gas market dates back to the first half of 2004 when the country joined the EU. Since then for Hungary (and for many other new member states) the energy policy dilemma has been, and still is, how to combine competition and (price) regulation under highly concentrated supply side conditions to get the best social outcome when implementing EU gas market rules.

This thesis contains three of my former publications, some with co-authors, and an additional new study. What links these four studies together is their strive to understand the vulnerabilities of the Hungarian gas market in a wider, regional context, to identify policy options available for addressing those vulnerabilities and to offer a consistent methodology to support the economic analyses and evaluation of those policy options.

A. Vulnerabilities of the 2004 new member states' gas markets, including Hungary

The first paper included in this thesis (Kaderják et al. 2007a; in Hungarian: Kaderják et al. 2007b), published in the second volume of the *European Review of Energy Markets*, was motivated by a larger study for the European Commission to answer the question, what specific risks the 2004 EU enlargement brought about for the EU energy sector.[5] The major conclusion of the study was that, by that time, unilateral gas import dependence on Russia had become the number one energy security issue for the continental 2004 new Member States and this would be a new issue for EU energy policy to deal with in the future. The paper included in this thesis further elaborate on gas (and also electricity) sector related supply security issues of 2004 new member states. By applying different measures of natural gas dependency and natural gas import dependency, it provides specific conclusions on natural gas sector related vulnerabilities of our region as follows.

- Natural gas dependency of continental 2004 new member states is significantly higher than the EU average.
- Hungary and Latvia have a combined issue of high gas dependence for electricity generation and high economic dependence on gas.
- Natural gas import dependency is significantly higher in new member states than in the old ones.

[5] The full study was published by REKK in Kaderják and La Belle (2008).

- Diversification of sources of gas imports is much less for new than for old member states.
- A combined result is a high level and unilateral natural gas import dependency on Russia of the continental new EU member states.[6]
- The dominance of joint ventures of Russian Gazprom with German companies (particularly E.ON Ruhrgas) in the ownership of gas sector assets adds to the dominance of Russia in gas supplies throughout the Central and East European region and the Baltic states.

At the time of the publication of the study the legitimacy of its imbalanced concern for the vulnerabilities of new member states' gas industries was quite unclear for some of my Western colleagues. Russia was perceived as a long standing and all time reliable gas supplier to Europe. But soon after the publication of the paper, unfortunate real life developments started to confirm its conclusions. Since the early 2006 Russia-Ukraine gas dispute natural gas started to play an important role in energy supply security related discussions and policy decisions in the EU. Skyrocketing oil and related natural gas prices before the outbreak of the 2008 economic crisis made EU institutions increasingly aware of the vulnerability of the community to growing oil and natural gas imports from third countries. But since the January 2009 gas crisis natural gas has clearly dominated the energy policy debate in the EU, as far as supply security is concerned.

B. Lessons from a real-life experiment

The up to date largest-ever real life experiment to test the vulnerabilities of enlarged Europe's natural gas market took place between 7th and 19th January, 2009. During these days the transit of Russian gas to Europe through the Ukraine was halted. This was the most serious European gas crisis to have happened since the start of Russian gas transmission to Europe decades earlier. A daily average of 380 million cubic meter (Mcm) or a total of 5 billion cubic meter (Bcm) of Russian gas delivery through Ukraine to the EU and South East Europe was lost during these days.[7] Gas industries and customers of Central and South East Europe (CSEE), including many of the new

[6] From the 2007 accession countries Romania is an exception to this conclusion, due to its significant local natural gas production. However, the statement is valid for Bulgaria.
[7] Simpson, J. (2009), *January 2009 – Russia – Ukraine gas dispute*. IEA presentation for the Gas Coordination Group, February 23.

member states of the EU, were hit particularly strong by the crisis. The share of lost gas supply for the countries of the region from Austria to Greece due to the gas cut accounted for 50-100% (except for Poland and Romania). Several countries had to introduce forced load shedding measures. The official economic loss estimate from lost load was close to 2 billion Euros for the most affected countries. If the crisis did not coincide with a major economic recession, the economic loss it caused could have been significantly larger.

Originally I prepared the second paper that is included in this thesis (Kaderják, 2011b) as a chapter for a book that was edited by the then head of unit for energy supply security of DG Energy of the European Commission. Although the book was published only in 2011, Monsieur Jean-Arnold Vinois and E-Control, the Austrian energy regulatory agency together organized a workshop already on April 3, 2009 in Vienna to start reconstructing what exactly happened during those two dramatic weeks and to start understanding the lessons from it for EU energy policy purposes. I was asked to make a presentation at this workshop about the impacts of the crisis on the most affected countries of CSEE. This original motivation encouraged me and my colleagues to start work on better understanding the causes of differences in the success of managing the gas crisis and minimizing the damage to final customers in the most affected countries.

The paper is about the lessons I learned, by the comparison of country experiences with the January 2009 crisis, about the nature and vulnerability of the new member states' gas markets. It also provides an assessment of the policy reactions at the EU and member states' level to the crisis that, since then, have paved the development of the EU's renewed gas supply security (and market integration) policy. The most important lessons were the followings.

- EU market integration and supply security in natural gas are twin developments. Liquid gas wholesale markets can be successful in managing crisis situations as supply shocks through price adjustments up to a given point.[8] The more the new member states' gas markets integrate with the Western European markets, the higher level supply security they will enjoy. Diversification of supply sources and routes are key for the success of the market integration process.

[8] A later event, the supply shock caused by a cold spell in the winter of 2012 confirmed this conclusion (see Henderson and Heather, 2012)

- The use of *existing* EU natural gas infrastructure was inefficient during the crisis. However, the EU gas industry discovered the possibility of bi-directional use of some existing pipelines and interconnectors during the crisis. The implementation of physical bi-directional operation (or reverse flow) capabilities on all major gas interconnectors in the EU could extremely improve the efficiency in the use of the existing gas infrastructure – at a very low cost (GTE+, 2009). This lesson was transformed into a very important obligation by the recent gas supply security regulation of the EU (Regulation 994/2010/EC).
- The efficiency in the use of the existing gas infrastructure was further decreased by regulatory problems, like discriminative access rules to interconnection or gas storage capacities.
- The crisis also revealed the insufficient physical interconnectivity of the new member states' natural gas systems and the consequent lack of gas market cooperation among them. The new EU infrastructure regulation (Regulation 347/2013/EC) clearly acknowledges this problem and calls for the identification and implementation of missing gas infrastructures in the Eastern new member states.

Apparently the discussions following the 2009 January gas crisis resulted in a deeper EU-wide understanding of specific problems the natural gas industries of some new member states were, and still, facing. Recent EU level legislation to increase gas supply security and market integration, plans to further develop critical EU energy infrastructures, and the process establishing a gas target model reflect a proper policy response to those concerns.[9]

C. *Economic analysis of a proposed policy option to improve market integration in new member states: new infrastructure*

While the former two papers are about diagnosis, the third former publication included in this thesis (Kaderják et al., 2013) is about methodology and policy analysis to support answering the following question: What can we tell about the relative efficiency of

[9] Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks; Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009; Commission Decision on amending Annex I to Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks (2012/490/EU); Guidance on best practices for congestion management procedures in natural gas transmission networks [SWD (2014) 250]; CEER Vision for a European Gas Target Model. Conclusion Paper (1 December 2011).

proposed new gas infrastructure investments in promoting gas market integration in the Central and South East European region? The paper introduces the Danube Region Gas Market Model (DRGMM), a network and contract constrained multi-country competitive equilibrium model that had been developed by a team of REKK researchers, including myself.[10] The paper applies the DRGMM to estimate the impacts of new gas infrastructure investments on market integration, social welfare and supply security in the countries of Central and South East Europe. Individual projects, project packages (e.g. the North-South gas corridor for Central and Eastern Europe as proposed by the European Commission) and international pipeline projects (like Nabucco West) are evaluated according to a market integration measure introduced by the paper, called the Regional Cost Convergence Index (RCCI). Estimates on price spill-over effects of new infrastructures are also presented. The model can support cost benefit analyses required by the new EU infrastructure regulation (Regulation 347/2013/EC) to identify EU projects of common interest.[11]

D. From oil-indexed to hub-based gas wholesale pricing in Hungary

While in the three former analytical publications included in this thesis the focus of analyses was regional, the final new study concentrates on the Hungarian natural gas wholesale market. The primary objective of the study is to identify the principal conditions for a transition from monopolistic (oil-indexed) natural gas wholesale pricing to hub-based pricing in Hungary. The major hypothesis of the paper is that the major obstacles to efficient gas wholesale competition and related pricing to develop are (i) the exclusive control over a pivotal infrastructure (namely the Ukraine-Hungary interconnector), (ii) high level market concentration and (iii) the foreclosure of the Hungarian gas wholesale market by blocking interconnection capacities with regulated third party access.

The paper introduces the leverage function to support the consistent analysis of available government measures to undermine dominant market positions based on the control of pivotal infrastructures. It is also about simulating the wholesale price impacts

[10] The principal author of the model is András Kis.
[11] The model has been used for policy purposes in this regard. The energy priority area of the Danube Region Strategy used the presented modelling results to establish priorities in new gas infrastructure investments for the Danube Region and also published the paper *The Danube Region Gas Market Model and its Application to Identifying Natural Gas Infrastructure Priorities for the Region* (www.rekk.eu). Later the model was used for cost benefit analyses by the Energy Community to identify Projects of Energy Community Interest (PECIs) in the gas sector of South East Europe (Energy Community, 2013).

of policy measures to remove the obstacles to efficient gas wholesale competition in the country. In order to assess the efficiency of available supply side, production and infrastructure development related policy measures t, controlled experiments or simulations are carried out with a contract and infrastructure constrained perfect competition gas market model, the European Gas Market Model.

The simulation results provide strong support for the research hypotheses. They could reproduce the hypothetic functional form between leverage and related gas wholesale price outcomes. It was found that under contract and infrastructure constrained perfect competition those policies resulting in a leverage value at around –0.2 are sufficient to manage an almost full transition from oil-indexed to hub based gas wholesale pricing in Hungary. To encourage domestic production and the implementation of the Slovakia-Hungary interconnector seem to be the most effective policies to arrive at hub-based wholesale prices. Simulations also confirmed that a market and regulatory setting characterised with strong leverage, low market concentration and no cross border capacity blocking results in a gas wholesale price closest to hub-based prices. The results of the paper provide the basis for well-founded policy recommendations to manage a successful transition to market based gas wholesale pricing in Hungary.

Unilateral natural gas import dependence: A new supply security issue for Europe[1]

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1 Abstract

This paper considers security of supply of energy and how the EU enlargement in 2004 affected security of supply for the EU. Security of supply depends on accessibility to primary energy sources, on system adequacy and on market adequacy. We concentrate on the longer term aspects of supply security, namely access to primary fuels and system adequacy in the gas sector and we consider some statistical measures. Regarding import fuel dependency, we conclude that the 2004 enlargement brought abundant local solid fuel sources into the EU; and brought in two completely import oil dependent nations, Cyprus and Malta. Regarding gas dependency, we conclude that natural gas

[1] This research was supported by the EU Commission DG TREN under the contract "The Impact of the 2004 Enlargement of the European Union in the Area of Energy". Originally published in the second volume of the *European Review of Energy Markets, 2007, pp. 57–92.*
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dependency of continental 2004 new member states are significantly higher than the EU average; Hungary and Latvia have a combined issue of high gas dependence for electricity generation and high economic dependence on gas; that gas import dependency is significantly higher in new member states than in the old ones; and that diversification of sources of gas imports is much less for new than for old member states. Natural gas import dependency is a major energy policy issue for continental new EU members. We consider the asset and supply ownerships for gas markets in the region. A key issue also is the dominance of joint ventures of Russian Gazprom with German companies (particularly E.ON Ruhrgas) in the ownership of gas assets and in gas supplies throughout the central and east European region.

2 Introduction

Since the oil market crisis of the 1970's, energy supply security has always been a key energy policy issue to discuss and, to a limited extent, act on at a European level. The recent proposal of the European Commission [1] identifies the continent's increasing dependence on imported hydrocarbons, the insufficient mechanisms to ensure solidarity between Member States in the event of an energy crisis and the still missing predictability and efficiency of the internal energy and gas markets to host the necessary future investments as the three major security of supply challenges for Europe. Regarding the first two issues, the Commission also acknowledges that 'several Member States are largely or completely dependent on one single gas supplier.' This 'single gas supplier' refers largely to Russia and we can suspect that among the 'several' Member States there are many from those ten which joined the European Union in 2004. Indeed it seems to be the 2004 enlargement that brought the issue of unilateral natural gas import dependence onto the supply security agenda of the EU.

Security of supply depends on accessibility to primary energy sources, on system adequacy and on market adequacy. In turn, system adequacy includes both production and network adequacy. In the following analyses we concentrate on the longer term aspects of supply security, namely access to primary fuels and system adequacy in the gas sector. We provide an assessment of how the primary energy import dependency of the 2004 new member states compares to that of the old members. Special attention is paid to comparing the characteristics of gas import dependency of the old 15 member states to that of the relevant continental new ones.[2]

We can differentiate three sub-groups of 2004 new member states along technical or operational lines:

- the CENTREL group (Poland, Czech Republic, Slovakia, Hungary) and Slovenia, who have strong interconnections to continental western Europe in electricity and gas; sometimes referred to as the EU-5 group,
- the Baltic states (Estonia, Latvia, Lithuania), having no direct interconnections to UCTE countries; sometimes referred to as the EU-3 group, and
- Cyprus and Malta, being isolated systems; sometimes referred to as the EU-2 group.

EU-5 and EU-3 together are sometimes referred to as EU-8, and old member states are referred to as EU-15.

We will rely on two simple (although disputable) assumptions throughout this paper. Regarding primary energy sources, we assume that *ceteris paribus* less reliance on imported fuel and more diversity in fuel sourcing will increase supply security. For infrastructure, we associate higher capacity or capacity reserves with a higher level of supply security. We disregard the cost efficiency aspect of supply security throughout this paper.

First we assess and compare the new and old member states with regard to their primary energy balances and to the diversity in meeting their fuel demand. Special attention is paid to a deeper analysis of gas (import) dependency by country groups. Then gas infrastructure adequacy is analysed. Next a review of initiatives to improve supply security in new member states is provided. We conclude with a summary evaluation of the impact of the 2004 enlargement on EU wide energy security with regard to the aspects under investigation.

[2] Cyprus and Malta do not have natural gas sectors.

3 Access to primary energy sources

We start with examining the primary energy mix of the different country groups of the EU-25 (all members, old and new). Five main primary energy sources are considered: solid fuels, oil, natural gas, nuclear and renewable energy sources. The following characteristics are compared for EU-15 (old members), EU-5 (Central European), EU-3 (Baltic States), and EU-2 (isolated systems: Cyprus and Malta):[3]

(1) gross inland consumption (sometimes used as primary energy supply),
(2) domestic energy production,
(3) net imports, and
(4) fuel structure for electricity generation.

3.1 Gross inland consumption of primary energy sources

The left axis of Figure 1 below depicts the share of different primary energy sources in gross inland consumption, while the right axis shows the change in gross inland energy consumption from 1990 base values for the different country groups (1990 = 1.00).

The gross inland energy consumption of the old member states plus Cyprus and Malta has been steadily increasing. Cyprus and Malta together produced by far the largest increase in consumption among the groups under investigation: an almost 60% increase in the period under investigation.

Oil is the most important fuel source for these countries. In fact, Cyprus and Malta are almost 100% dependent on imported oil to serve their energy needs. It is worth mentioning that for EU-15 the share of oil and solid fuels in primary energy consumption has decreased in the last 15 years while the share of natural gas has increased from 17% to about 25%. The popularity of gas based electricity generation[4] plays a crucial role here.

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[3] The source of the data and of the concept definitions is, unless otherwise stated, EUROSTAT and the European Commission's Statistical Pocketbook (2006).

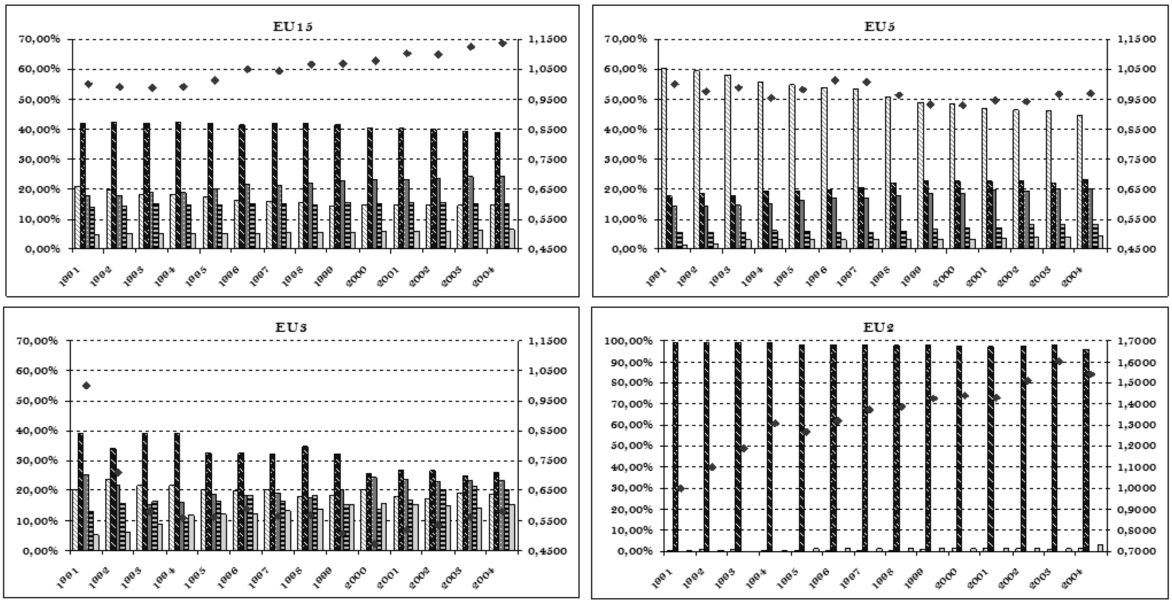
[4] Gas based electricity generation has become more important in the last decade for at least two reasons: first, changes in efficient plant size in electricity generation (and reductions in unit cost) and second, to help meet CO_2 standards.

On the contrary, gross inland energy consumption has decreased in both the EU-5 and EU-3 countries in the last 15 years. While this decrease is modest in the case of EU-5, the consumption of the Baltic countries sharply dropped between 1991 and 1992 and continued to decrease until 2000, when gross inland consumption was only 45% of 1990 consumption. Since then demand has started to recover.

For EU-5 the most important primary energy source is solid fuels, that is mostly domestically produced coal and lignite in Poland and the Czech Republic. However, the share of solid fuels has decreased from 60% in 1990 to approximately 45% recently, while both oil, natural gas and nuclear have increased their share in gross final consumption.

The primary fuel mix of the Baltic States (EU-3) seems to be the most balanced. It can be noted that regarding the EU-8, the level of penetration of nuclear fuel in EU-8 is similar to that in EU-15, and the importance of gas in the primary fuel mix of EU-15 and EU-8 is almost identical.

Figure 1. Gross inland energy consumption



3.2 Domestic production

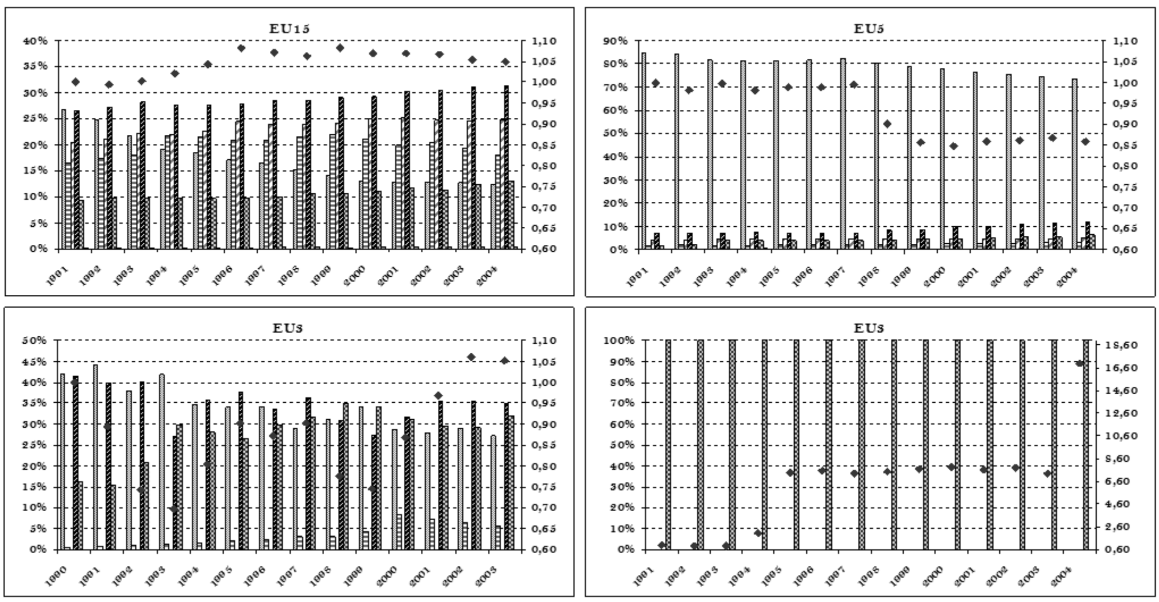
Figure 2 summarizes the trends of primary energy production for the four country groups. The left hand axis depicts the share of the five primary energy sources in total production, while the right hand axis shows the change in total production from 1990 base values (1990 = 1.00).

It can be seen that both the composition of fuels and the trend in production differ considerably between the country groups. Primary energy production of EU-15 countries increased by approximately 10% between 1993 and 1996, but has decreased moderately since then. The importance of solid fuels was decreasing in the past decade, and has been replaced mostly with nuclear and gas.

Solid fuel Czech and Polish coal mining dominate the fuel production of the EU-5 countries, while solid fuel (Estonian oil shale) and nuclear are typical for the EU-3. Malta and Cyprus have only renewable local primary energy sources to rely on.

In the Baltic countries we can see significant changes over the period. There is no domestic gas production. Their solid fuel production has been partly replaced by nuclear and renewable sources, and the share of renewable sources has increased from 15% to more than 30%.

Figure 2. Domestic production of primary energy



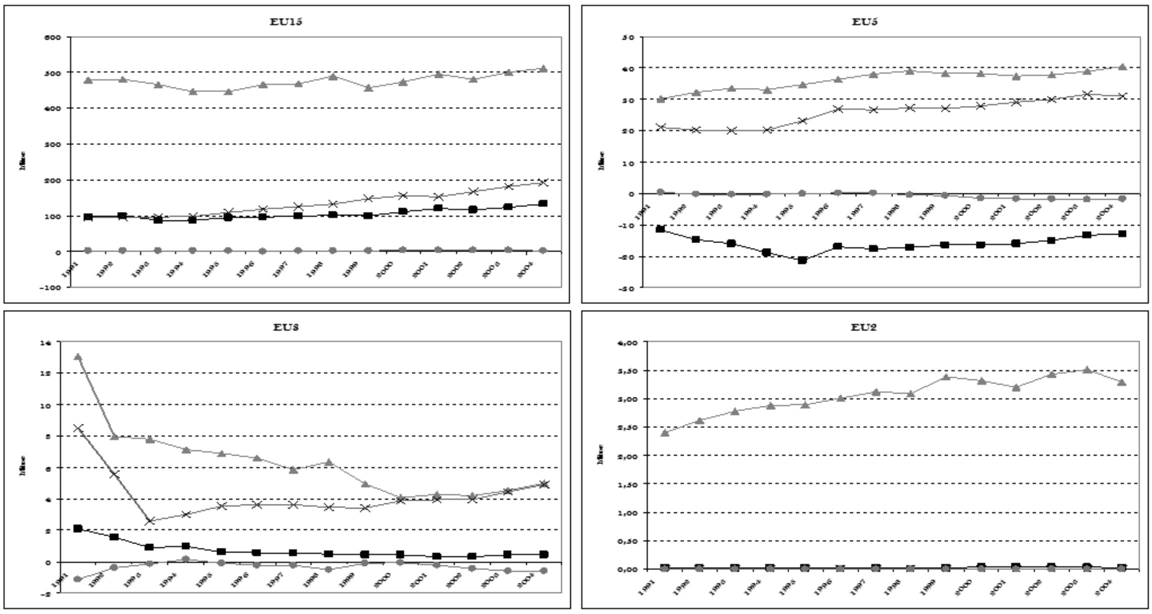
3.3 Net imports

After domestic production, we now look at the net import characteristics of the country groups. Figure 3 below indicates that for all the country groups except for the Baltic States, oil accounts for the largest amount of net imports. Since 1995 natural gas imports show the largest increase: approximately 100% increase for the EU-15, 50% for EU-5 and 25% increase for the Baltic States (EU-3).

The net imports of oil of the Baltic countries show an almost 50% fall in the early nineties. The same also applies to natural gas net imports, but the latter recovered more quickly. We can say that the recent increase in demand for primary fuel imports was supplied largely by oil and natural gas.

The two islands are totally import dependent on oil. Their net imports are around 3-3.5 Mtoe recently, which is approximately 30% more than in 1991.

Figure 3. Net imports of energy sources



3.4 Fuel structure of electricity generation

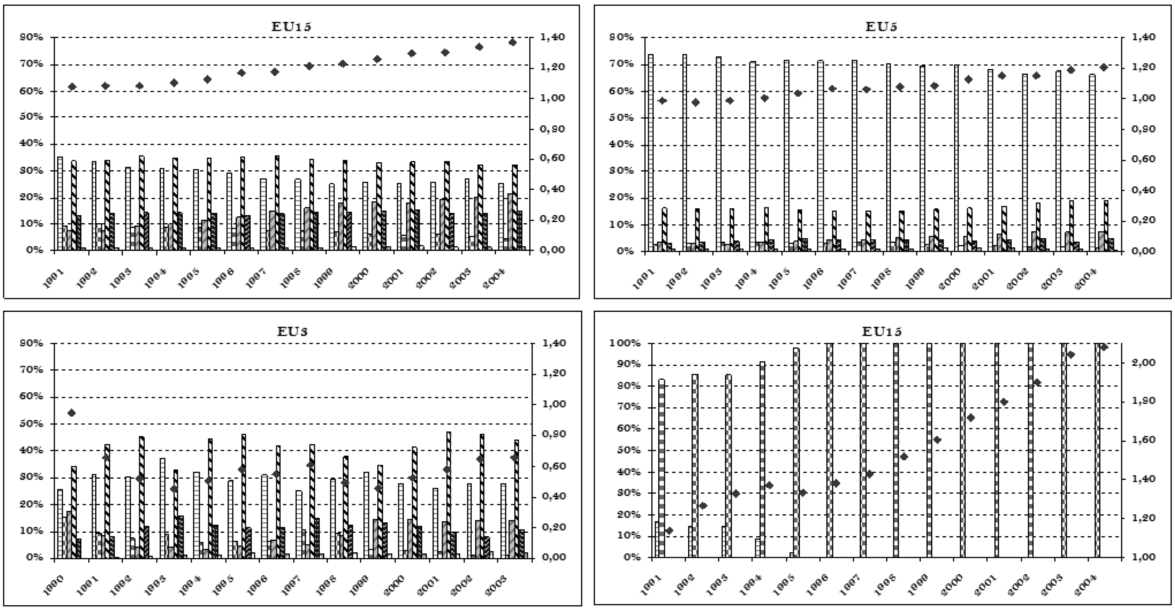
The fuel structure for electricity generation has a special relevance for energy supply security, since the availability of and secure sourcing of the different fuels significantly affect security of supply and the cost of generation. With the increasing reliance of Europe on natural gas as a fuel for electricity generation the security issues of the natural gas and electricity industries become very integrated.

How did the 2004 enlargement change the European situation in this respect? Before turning to the more in-depth analyses on fuel import dependency, let us briefly review the relevant basic statistics for the EU-25.

Regarding the fuel structure of generation, the striking feature of Figure 4 below is that while the dominant fuels in the EU-15 and the EU-3 are coal and nuclear, solid fuels play a much more prominent role in Central and Eastern Europe: while decreasing slightly over time, solid fuels are still the basis for almost 70% of generated electricity. Given that the bulk of the coal used is produced locally, the import dependency of EU-5 generation as compared to EU-15 seems less of a problem than at first sight. This picture is further strengthened by the fact that gas based generation in old member states (EU-15) on average has risen to 21% while its share in EU-5 is only around 8% and in EU-3 is 14%.

Dependency on nuclear generation is highest in the Baltic States (or more precisely, in Lithuania). Given that a precondition of EU enlargement was to gradually phase out the only major nuclear plant of the Baltic (the 1300 MW capacity of the Ignalina nuclear power plant in Lithuania), this issue is very relevant from a security of electricity supply perspective.

Figure 4. Electricity generation by fuel types



3.5 Aggregate measures of diversity in meeting fuel demand

We sum up the previous sections by providing aggregate measures to compare the diversity of meeting fuel demand for the country groups under investigation.

Diversity in meeting the fuel demand of a country or a country group, including imports, is the principal element of supply security. Diversity itself is made up of at least three subordinate properties [2].

- *Variety* refers to the number of different types of fuel to meet gross fuel demand.
- *Balance* refers to the pattern in the apportionment (spread) of that quantity across the relevant fuel categories.
- *Disparity* refers to the nature and degree to which the categories themselves are different from each other (substitution).

We calculate two versions of the *Shannon-Wiener index* (henceforth ‘Shannon index’) to measure the diversity of meeting fuel use for the regions under investigation.

The Shannon index is similar to the Hirschman-Herfindahl index, but, as Stirling demonstrates, it is not sensitive to the applied logarithm and it is also more robust, because it holds the additivity property [2]. The general form of the Shannon index is as follows:

$$SI = -\sum_{i=1}^{n} p_i ln p_i$$

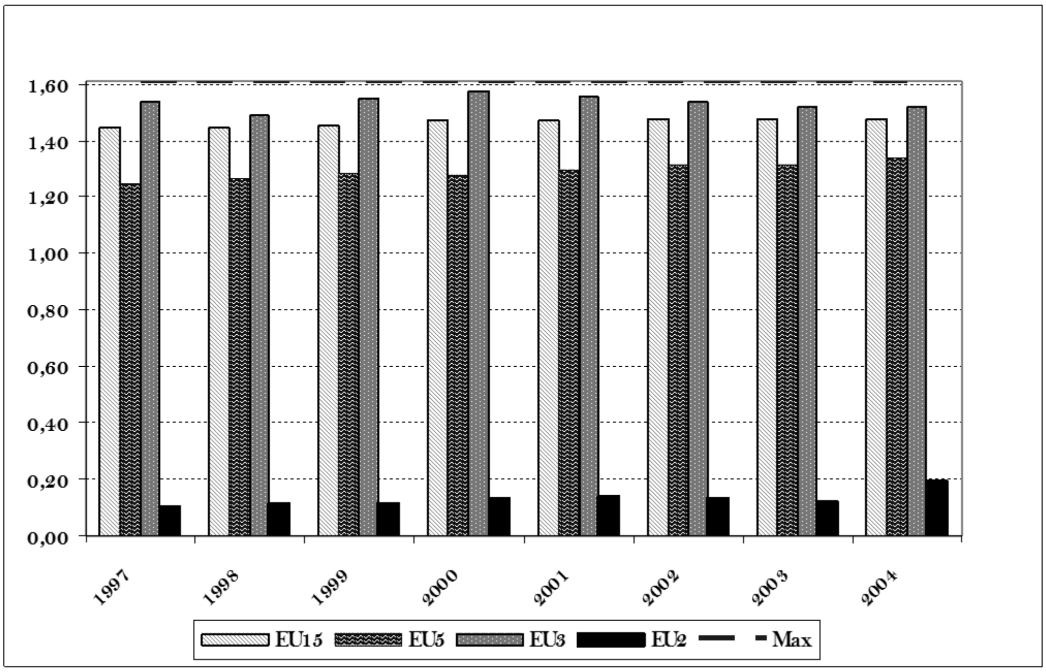
where p_i is the share of fuel type i in gross inland fuel consumption and n is the number of different fuels used.

Figure 5 depicts the Shannon index for the four country groups under investigation. The dotted (red) line above indicates the maximum value for the index in the case of five different fuel types (solid fuels, oil, gas, nuclear, renewable energy sources).[1]

The higher the value of the Shannon index, the higher the diversification in meeting fuel consumption. It can be seen that the diversification is highest in the EU-3 region, which has been at almost the maximum value in the last few years. For the period under investigation the value of the index for old member states remained high and stable. Diversification of the EU-5 countries has been steadily improving and in 2004 it almost reached the level typical for the EU-15 group. Naturally, Malta and Cyprus are the least diversified countries with respect to their fuel imports. We can conclude that the general Shannon index indicates no significant difference in the fuel diversity of EU-8 and old member states (EU-15), thus we can conclude that in the aspect of fuel diversity the 2004 EU enlargement did not significantly change the security of supply situation of the EU.

[1] In the case of five alternative primary energy sources, the maximum value of the Shannon index is $s_{max} = -ln\left(\frac{1}{5}\right) \approx 1.6$.

Figure 5. Shannon index



Beyond diversity, import dependence is also a major determinant of supply security. The general form of the Shannon index is unable to account for the extent of as well as the diversity in imports to meet local demand. In order to account for that, we followed the proposal of *Hirschhausen*, and *Jansen* calculated an enhanced version of the Shannon index [3][4]. The idea behind this index is that supply security is affected not only by the share of net imports in the final consumption of fuels, but also by the diversification of import sources. Hence, in the case of this index the higher the number of sources of imports at a given import rate, the higher the diversification of fuel supply. Formally, the index takes the following form:

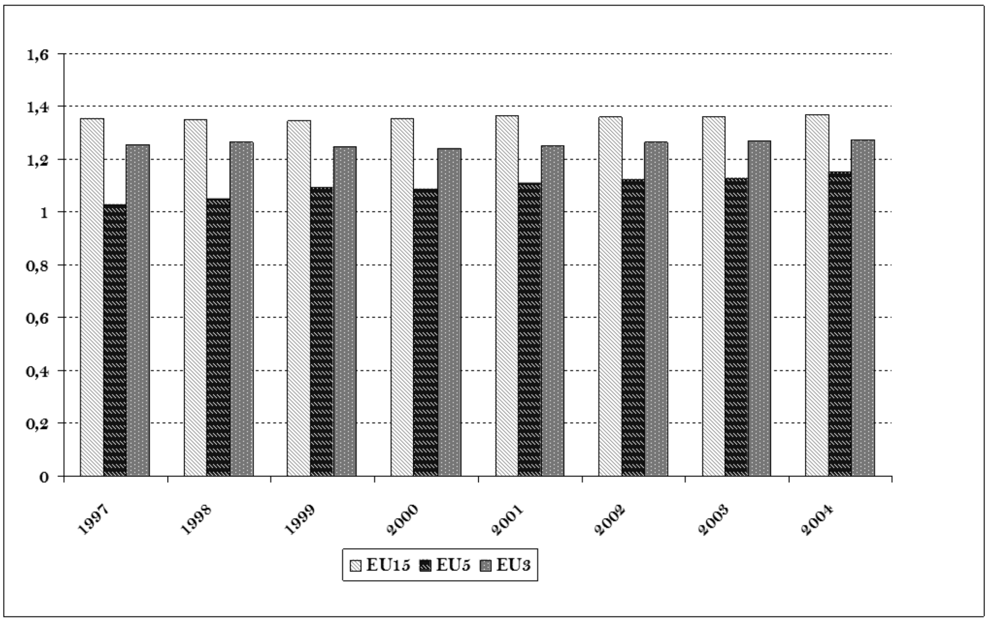
$$I = -\sum_{i=1}^{n} c_i p_i ln p_i$$

where c_i is a correction factor for each type of primary energy source. The correction factor takes into account the share of net imports in the total consumption of a given energy source, and the rate of diversification of the import sources.

For the calculation we assume that the world markets for solid fuels, oil and nuclear fuel are highly competitive since there are a number of alternative sources as well as transportation routes available for customers. Trading in gas however is more limited by the physical infrastructure. In the case of renewable sources, the level of international trading is very low, so we disregard the potential for diversification in this regard.

Due to the above reasons, the correction factors of solid fuels, oil, nuclear and renewable sources are set equal to 1, and the correction factor of natural gas only is calculated in the following way: $c_{gas} = 1 - m_{gas}\left(1 - \frac{S_{gas}}{S^{max}}\right)$, where m_{gas} is the share of net imports in gas consumption, S_{gas} is the Shannon index of gas import flows, S^{max} is the maximum of the Shannon index, and $S_{gas} = -\sum_{i=1}^{n} m_{gasj} ln m_{gasj}$, where m_{gasj} is the share of imports of gas from region j in the total imported gas for the given country group.[2] Figure 6 contains the results for the period 1997-2004.

Figure 6. Import corrected Shannon index



It seems apparent that the index value for the old member states (EU-15) is more resistant to the inclusion of the gas import issue into the index calculation. On the other hand EU-3 and EU-5 Shannon index values drop significantly. This is mainly the result of the fact that the gas import diversity of the EU-5 member states is much lower than that of the old member states. They have only five big trading partners, of which the

[2] The following exporting countries were considered: Belgium, Denmark, Germany, France, Italy, Netherlands, Slovakia, the United Kingdom, Croatia, Norway, Serbia and Montenegro, the Russian Federation, Ukraine, Algeria, Egypt, Libya, Nigeria, Trinidad and Tobago, Malaysia, United Arab Emirates, Iran, Oman and Qatar.

share of the Russian Federation is very high. On the other hand, old member states have significant inland sources of gas (imports from EU member states, in particular the Netherlands and the UK). Furthermore, their imports from outside the EU come mostly from three different regions: Norway, the Russian Federation and Algeria. Supplies from these three account for approximately 80% of EU-15 total net gas imports.

The drop in the Shannon index for EU-8 indicates the issue of their very high gas import dependency on Russian gas supplies. Since we consider this as the single most important supply security issue that the 2004 enlargement of the EU brought to the EU, we further analyse it at the country level in the next section.

3.6 Measuring import dependency on natural gas

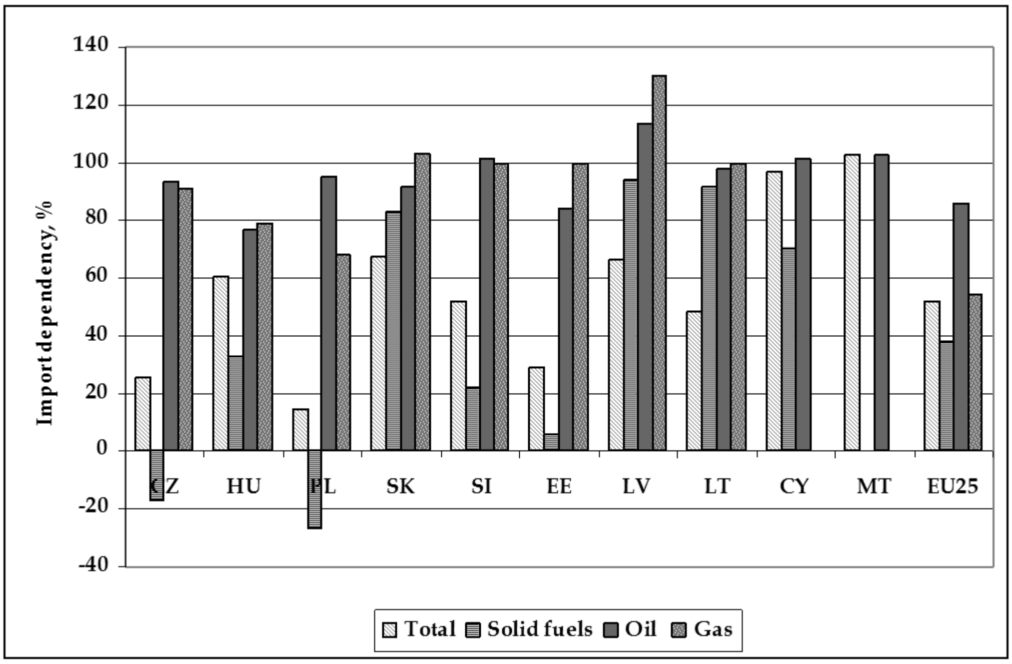
The natural gas industry is young in continental Europe. Its history goes back only four decades with the development of the major physical infrastructure linking production sites and consumption centres. Infrastructure development has traditionally been based on long term contracts for gas delivery. In this period the inland gas production of some EU-15 countries was significant. Gas supply has gradually been diversifying for old member states (Netherlands, Norway, UK, North Africa, LNG etc). In sharp contrast to that, for new Member States the development of the natural gas industry, including the physical infrastructure, was completely based on cooperation with the Soviet Union and within the COMECON block.

In a subsequent section, we discuss network operation and adequacy, and in this section, we analyze gas import dependency. First we consider more systematically the fuel import dependency of new member states compared to old ones. From a security of supply point of view, increased reliance on and decreased diversity in fuel imports poses a higher risk.

Figure 7 indicates the status of new member states' fuel import dependency. Import dependency from gas is higher than the EU-25 average for all those new members that use natural gas. This also applies to oil with the exception of Hungary and Estonia. The bulk of oil and gas imports for EU-5 and EU-3 countries are provided by Russia through pipeline systems. Taking all types of fuels into account, only Poland, the Czech

Republic, Estonia (because of their solid fuel sources) and Lithuania (because of its nuclear energy) perform better than the EU average for measures of import dependency.

Figure 7. Net imports / total consumption* in new members, 2004



* Definition: Import Dependency = Net Imports / (Bunkers + Gross Inland Consumption). Source: Commission Pocketbook (2006).

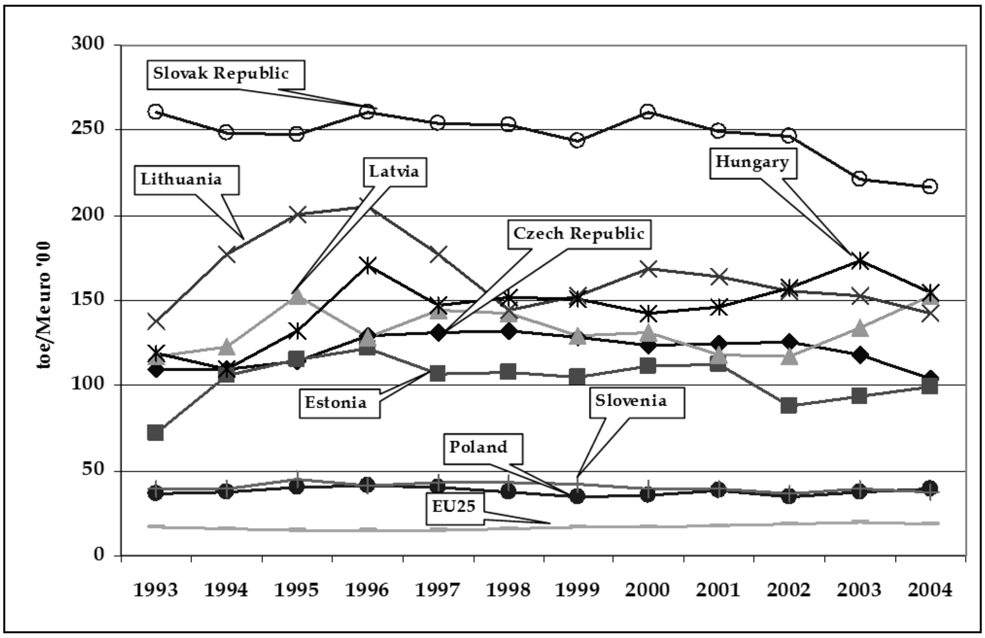
Note: A simplified formula, not taking bunkers into account, is used occasionally. This variant gives higher values for import dependency by overlooking maritime transport. Negative numbers indicate that the country is a net exporter. Values over 100 % are possible due to changes in stocks.

Next we apply a measure that is generally used to measure the oil dependency of national economies [5]. This index is a combined one, and it can be expressed as follows:

*(net gas import/total GDP) = (net gas imports/total gas used) * (total gas used/total energy consumption) * (total energy consumption/total GDP).*

Therefore, it is a combination of import dependency, gas dependency and energy intensity. Figure 8 depicts the development of these values for the new member states and compares it to the EU-25 average.

Figure 8. Natural gas dependency of the economies of new Member States*

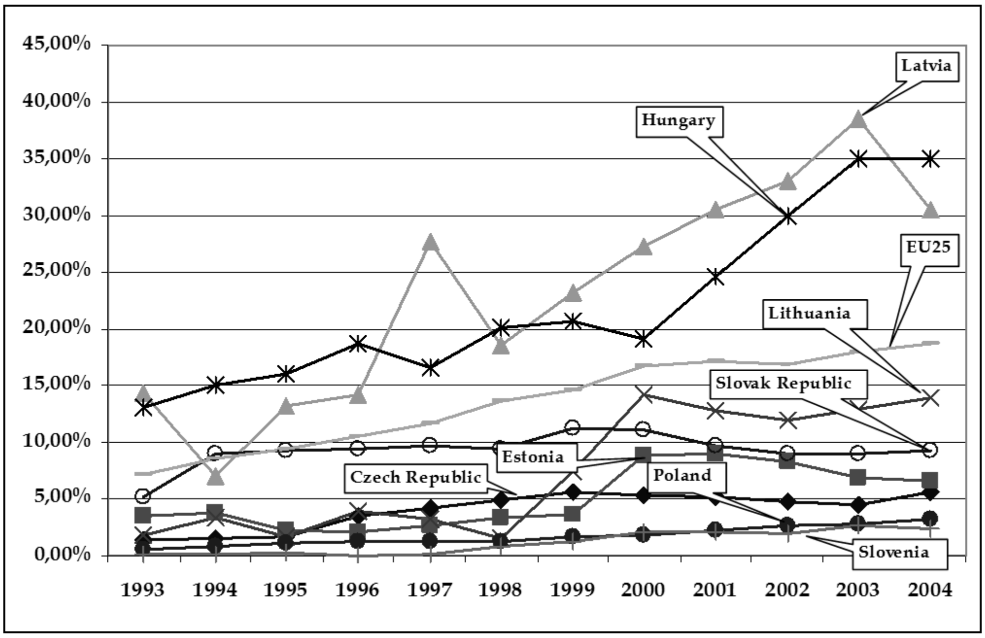


*in year 2000 euro

The message of Figure 8 is that gas dependency of the economies of continental new member states is higher than that of the old member states by orders of magnitude. The Slovakian, Hungarian, Latvian and Lithuanian economies use 15-25 times more gas to produce a unit of GDP than the rest of EU members. On the other end, Poland and Slovenia are the least dependent economies on gas from the continental new member states group (but still more dependent than the EU average).

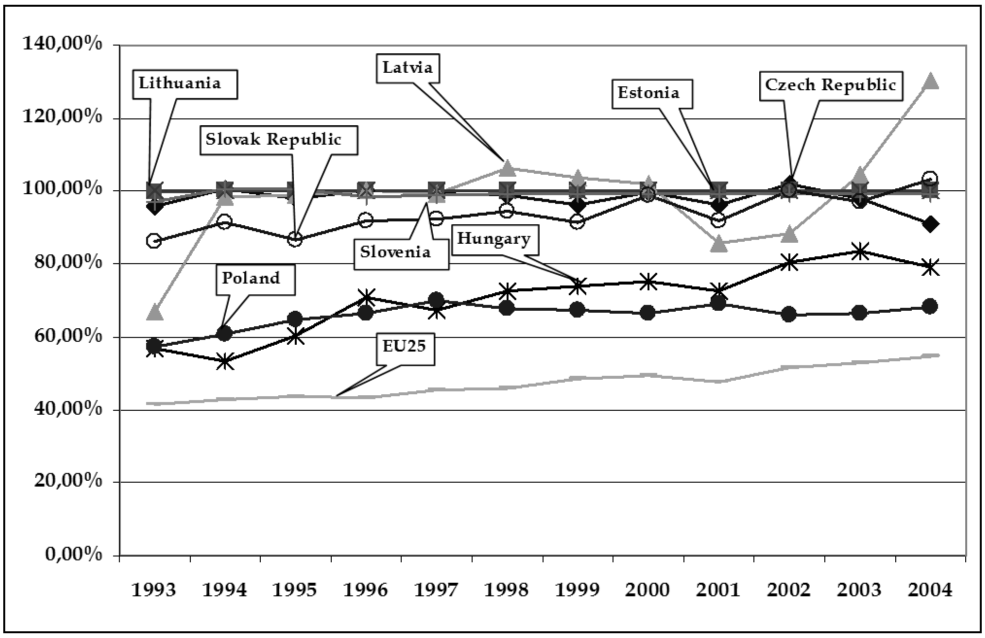
It is also worth having a look on the importance of gas in electricity generation by new member states. Figure 9 below shows that the combined issue of gas dependency of the economy and of electricity production is most apparent in Hungary and Latvia, and has become increasingly so over the period. The importance of gas in electricity generation for the rest of new members is below the EU-25 average.

Figure 9. The share of gas in electricity generation by new Member States



Finally, the level of net gas imports to total gas consumption is depicted on Figure 10. Here we can see that the gas import dependency of the new member states is well above the average for the whole EU (EU-25).

Figure 10. Net gas imports to total gas consumption



Note: Values over 100 % are possible due to changes in stocks

Table 1. Central and Eastern European new Member States' pipeline gas imports 2006 (bcm/%)

Country	PIPELINE GAS IMPORTS 2006 (bcm / year)						
	Algeria	**France**	**Germany**	**Norway**	**Russia**	**Other**	**Total**
Czech Republic				2.9 (30%)	6.8 (70%)		**9.7 (100%)**
Estonia					1 (100%)		**1 (100%)**
Hungary			0.8 (8%)		7.7 (75%)	1.8 (17%)	**10.3 (100%)**
Latvia					1.5 (100%)		**1.5 (100%)**
Lithuania					3.3 (100%)		**3.3 (100%)**
Poland			0.4 (4%)	0.4 (4%)	5.4 (61%)	2.7 (30%)	**8.9 (100%)**
Slovakia					6.4 (100%)		**6.4 (100%)**
Slovenia	0.4 (36%)				0.6 (55%)	0.1 (9%)	**1.1 (100%)**
EU-10	**0.4 (1%)**	**0 (0%)**	**1.2 (3%)**	**3.3 (8%)**	**32.7 (77%)**	**4.6 (11%)**	**42.2 (100%)**

Source: IEA, BP, Other

Although in terms of the gas molecules all imported gas supplies to all east and central European countries come from Russia, in commercial terms, some countries have managed to diversify some of their gas imports. For the group under investigation gas imports from Russia have reduced from 86% of all their gas imports in 1999 to 77% in 2006.

Even though it lies on the route of the Brotherhood Pipeline from Russia via Ukraine, and all gas flows are in an east-west direction, the Czech Republic has nevertheless been able to diversify some of its gas imports. From taking 82% of its gas from Russia in 1999, the Czech Republic in 2006 had reduced that to 70% and took 30% of its gas supply from Norway. Hungary, Poland and Slovenia have also diversified some of their gas supplies.

The three Baltic Republics of Estonia, Latvia, Lithuania, plus Slovakia (lying right next to Ukraine) in 2006 still took 100% of their gas supplies from Russia.

In summary, of the group of 2004 new member states gas import dependency seems to create the least problems for Poland. At the other end, Hungary and Latvia seem to be the most exposed economies regarding security of gas supply.

Regarding import fuel dependency, we can conclude that the 2004 enlargement:

- Brought the EU-5 region with abundant local solid fuel sources into the European Union;
- It brought two completely import oil dependent nations, Cyprus and Malta into the Union.

With regard to gas dependency, we can conclude that:

- Natural gas dependency of the economies of continental 2004 new member states (EU-8) are significantly higher than the EU average.
- Hungary and Latvia have a combined issue of high gas dependence for electricity generation and high economic dependence on gas.
- Gas import dependency is significantly higher in new member states than in the old ones.
- Diversification of sources of gas imports is much less for new than for old member states.

As a result of the above combination of factors, gas import dependence on Russia has become the number one energy security issue for the continental 2004 new member states.

4 Gas network adequacy and future investment plans

The physical structure of the gas networks together with the fact that Russia has not implemented a regulated third party access regime to its gas transmission networks (which would allow gas transits through Russia, Ukraine or Belarus) partly explains the restricted possibilities for diversification of sources of gas imports for EU-8.

Gas networks in continental new member states reflect the East-West gas transmission routes connecting major Russian gas fields to markets in central and western Europe (Germany, Italy and points further west). North-South connections and consequent cooperation across these member states are essentially missing. The current physical gas infrastructure in the new EU-8 does not allow for much diversity of sources of gas supply.[3]

From a security of supply perspective, there are at least three aspects of the infrastructure that have to be investigated. First, whether the capacity of the current infrastructure is sufficient to serve present and forecast demand. Second, how future investment plans might change the capacity as well as the ability of the infrastructure to support diversification. Since the owners of gas TSOs have a decisive say over their willingness to enter into new gas infrastructure development projects, our third aspect relates to the ownership structure of gas TSOs in EU-8.

4.1 Gas network adequacy

This section provides an assessment of gas transport and storage capacity for EU-8 and considers some basic conditions for diversifying into bringing LNG into the region.

4.1.1 Gas transport capacity at the end of 2005

The capacities of the main international gas pipelines at the border points of EU-8

[3] Note also that for EU-5 new member states there is a fundamental difference between how the operations of their electricity as opposed to the gas systems changed as a result of the reorientation process from Russia to the EU. While, as a consequence of UCTE harmonization, the cooperation of the electricity system of EU-5 essentially halted with Russia back in the middle of the 1990s, in the case of gas the political changes had in fact no effect on how the gas transmission system has been operated since then.

countires are shown in the following table.

Table 2. Capacities at EU-10 Cross Border Nodes (End 2005)

Pipeline	Location	From	To	Max Flow rate	
				mcm/ hour	bcm/ year
Gasum Oy	Imatra	Russia	Finland	0.80	7.0
LV-LT	Kiemenai	Latvia	Lithuania	0.22	1.9
Bel-Lit	Kotlovka	Belarus	Lithuania	1.20	10.5
Yamal	Kondratki	Belarus	Poland	3.72	32.6
EuRoPol	Mallnow	Poland	Germany	3.00	26.3
Brotherhood	Velke Kapusany	Ukraine	Slovakia	12.75	111.7
Brotherhood	Drozdowicze	Ukraine	Poland	0.70	6.1
Brotherhood	Beregdaroc	Ukraine	Hungary	1.72	15.1
Stegal	Lanzhot	Slovakia	Czech	6.50	56.9
Stegal	Hora Svate Kateriny	Czech	Germany	1.83	16.0
Megal	Waidhaus	Czech	Germany	3.97	34.8
TAG, HAG	Baumgarten	Slovakia	Austria	6.00	52.6
HAG	Mosonmagyarovar	Austria	Hungary	0.50	4.4
SOL	Murfeld	Austria	Slovenia	0.42	3.7
SOL	Rogatec	Slovenia	Hungary	0.20	1.8
TAG	Gorizia	Slovenia	Italy	0.19	1.7

Source: Mercados

These various pipeline systems are the main transit pipelines to western Europe: Brotherhood from Russia through Ukraine to the Slovak Republic and its various offshoots (STEGAL and MEGAL through the Slovak and Czech Republics, TAG and WAG through Slovak Republic to Austria, HAG from Austria to Hungary) and Yamal from Russia via Poland to Germany. There are some direct pipeline routes to Finland and to Baltic countries.

These pipeline routes were established in Soviet times and the main Brotherhood and offshoot pipelines date from the mid 1980s. The pipeline system is therefore approximately 20 years old now. More recent developments have been the Yamal pipeline but Yamal II is now in doubt because of the forthcoming Baltic sea pipeline route connecting Russia directly with Germany.

In terms of network adequacy, the Brotherhood pipeline operated in 2005 at about 70% load factor. With a capacity of 111.7 bcm a year and gas flows of 81.3 bcm on the Brotherhood pipeline at the Ukraine – Slovak Republic border, there was an average load factor in 2005 of 73%. This is a well used pipeline but there is sufficient spare capacity now to cope with any demand spikes.

4.1.2 Storage

An important way of balancing gas supplies and also in reducing reliance on a single source of piped natural gas is through using gas storage. The following table shows working gas capacity for the EU-15 and EU-8 countries for three spot years. They show that while the EU-8 countries have been increasing their gas storage, it has been more or less in line with EU-15 storage increases and in line with the growth in domestic demand.

Table 3. European Gas Storage

Country	Working Capacity (mmcm) End 1998	Working Capacity (mmcm) End 2002	Working Capacity (mmcm) End 2005
Austria	2,630	3,020	2,820
Belgium	854	636	655
Denmark	770	700	810
France	10,490	10,800	10,800
Germany	15,450	18,830	18,934
Italy	9,110	12,747	12,792
Netherlands	72	2,478	2,478

Spain	1,274	1,414	2,366
UK	3,114	3,645	3,759
Total EU15	**43,764**	**54,270**	**55,414**
Czech Republic	1,700	2,059	2,285
Slovak Republic	1,700	2,740	2,740
Hungary	3,200	3,340	3,400
Poland	1,100	1,460	1,795
Total EU10	**7,700**	**9,599**	**10,220**

Source: IEA; EU-8 1998, Cedigaz

The conclusion is that EU-8 member states have not fundamentally increased gas storage capacity as a response to the EU enlargement process, or for any other reason except as a balancing tool to manage domestic demand.

The ownership unbundling of gas storage from the transportation assets has recently been completed in Slovakia and Hungary, which might come to allow an increased competition in gas storage, to set against the massive gas storage in Ukraine.

The gas storage capacity in the EU-8 countries, and indeed in the whole EU25, is dwarfed by that of Ukraine. Against the approximately 50 bcm of working gas capacity in the EU25 in 1998, Ukraine alone had 36 bcm, and half of that in one storage field.

4.1.3 LNG

None of the EU-8 countries currently have any LNG import terminals.

LNG terminals for EU-8 countries have to be on the Baltic coast (so only Poland and the three Baltic Republics could be LNG importers). The problem that all these countries face is that LNG cargoes will have to pass through the Skagerrak (the straits between Denmark and Sweden). These straits are very narrow and congested. They also pass by very populated areas (Copenhagen, the capital of Denmark, and Malmö, a major city in Sweden), and at the narrowest point (some four km) they pass by the towns of Helsingor and Helsingborg. As well as congestion through the straits the Danish Government in particular wants to keep the transport of dangerous highly inflammable liquids (oil and LNG) to a minimum.

4.2 Future investments – The fight over controlling the gas infrastructure

EU-25 demand for natural gas is increasing strongly and new gas supplies and pipeline capacity is needed. On the other hand, new member states' companies and national governments have initiated several projects with the aim of having physical infrastructure in place to support gas import diversification. These two factors combined have led to a considerable amount of activity now in developing new gas pipeline and storage projects.

Indeed, what we see is a developing sharp competition over new infrastructure development opportunities and for control over the existing strategic assets. Russia is playing a leading role in this race. Russia wishes to secure its future market share in Europe partly through participating in infrastructure development projects. Control over strategic infrastructure (present and future) is perceived as a way to manage gas supplies to the developing European gas retail markets, Russia wishes to ensure that its gas supplies can reach profitable western European markets without being diverted en-route. Control over key transit infrastructure can also serve Russian interests in channelling Central Asian, Middle East and Caucasian gas supplies to western Europe through Russian Gazprom-controlled pipelines. The maintenance of gas import dependency of the EU-8 on Russian (or Russian controlled) supplies can provide a profitable quasi-monopoly position for Russia in the region. Finally it may help to re-vitalize or maintain Russian political influence in this part of the former Soviet block [6] [7].

The means that Russia employs to reach its strategic goals are diverse. They include proposing and developing new major pipeline routes (e.g. North European Baltic Sea pipeline project: NEBP) and the upgrading of existing ones (e.g. upgrading Brotherhood pipeline); the takeover, mostly in tandem with Eon-Ruhrgas, of significant stakes in EU-8 gas infrastructure (see later); and blocking non-Russian initiatives diversification projects by putting forward alternative 'phantom' proposals (e.g. Blue Stream 2).

4.2.1 Initiatives to increase security of supply in new Member States

In this section we discuss briefly those major initiatives that EU-8 member companies and / or governments (in cooperation with other partners) have been proposing to improve their access to external natural gas sources and thus to improve their security of supply.[4]

4.2.1.1 Nabucco gas pipeline

The most ambitious gas infrastructure project with a potential major positive impact on the diversity of new member states' gas infrastructure and security of supply is the well-known EU top priority NABUCCO pipeline project. If realised, this pipeline could bring an additional 30 Bcm/year of natural gas to the European market at Baumgarten in Austria.

It is important to emphasize that this project could serve several EU-level policy goals at the same time. It could provide Europe with direct physical access to vast Middle East, Central Asian and Caucasus gas reserves; it could fundamentally change gas-to-gas competition on new member states' gas markets; and it could contribute to increased cooperation of the EU with the supply countries.

4.2.1.2 Adria LNG

The idea of building an LNG re-gasification terminal at Krk island close to the Adriatic coast of Croatia and supply this gas to the Croatian, Italian, Austrian and Hungarian markets has a history of 10 years. Due to gas market developments the activity of the project company Adria LNG has been re-vitalized recently. If completed, the project could bring 8-14 Bcm/year additional gas to the region by 2011.

The Adria LNG Study Company is a joint venture by OMV, Total, RWE Transgas, and

[4] We do not cover the efforts for contractual diversification. See preliminary results of these efforts in Table 1.

INA to set up an LNG terminal in Croatia. Adria LNG also signed an alliance agreement with EON Ruhrgas in 2006. Due to the current state ownership in INA and OMV, government support from Austria, Croatia and also from Hungary seems vital for accomplishing this project. The Croatian and Hungarian governments have recently expressed their support for the project several times.

4.2.1.3 LNG in Poland[5]

The Polish oil and gas company PGNiG (Polskie Górnictwo Naftowe i Gazownictwo) and a consulting consortium are working on a detailed feasibility study and technical and economic assumptions for imports of liquefied natural gas (LNG) to Poland. The purpose of the study is to develop a comprehensive concept for LNG supply to Poland.

One of the key elements of the study is to verify the profitability of LNG terminal construction in the Polish Coast. The expected throughput capacity of the terminal is 3-5 Bcm with an option of further expansion.

The broad range of topics covered by the study includes a number of detailed analyses to be undertaken by PGNiG together with the consulting consortium. The specific topics will include gas demand, LNG sourcing capabilities, transportation options, potential terminal locations in Poland and technical concepts for the terminal. The feasibility study will also comprise an economic part in the form of a detailed financial model, as well as organizational and socio-economic analyses.

At the beginning of 2006 PGNiG signed letters of intent with the ports in Gdansk and Swinoujscie with a view to cooperation in location studies.

4.2.1.4 Polish – Norwegian - Danish gas cooperation[6]

In June 2007, Polish and Norwegian authorities are reported to have agreed on the financial terms for a pipeline to channel natural gas from Norway's offshore fields to

[5] Source: PGNiG homepage: http://www.en.pgnig.pl/firma/1865.htm. Downloaded: August 11, 2007
[6] Source: http://www.polandbusinessnetwork.pl/news/index.php?contentid=143568. Downloaded: August 11, 2007

Poland, which is trying to lessen its reliance on Russian energy. The commercial terms of the proposed plan are still to be agreed on. The planned gas pipeline from Norway to Poland is due to run via Denmark.

In May 2007, the Polish gas company PGNiG reached a deal on the pipeline with Denmark's Energinet.dk. In March, as part of the project, PGNiG also agreed with ExxonMobil to purchase a 15% stake in three Norwegian offshore gas exploration and production licences.

4.2.1.5 Security gas storage development in Hungary

In order to decrease gas supply security risks, especially in winter peak load periods, the Hungarian Parliament has passed legislation that requires the Hungarian Hydrocarbon Storage Association to build a security gas storage facility with a minimum of 1.2 Bcm annual working gas capacity and a daily 20 million cubic metres (Mcm) off-take capacity. The estimated project cost is €400 million. MOL, the major Hungarian oil and gas company, won the investment tender. The storage facility should be operational by 2010. Conditions and pricing of access to this specific storage facility will be regulated by the Minister for economy and transport.

4.2.2 Russian initiatives

Regarding gas from Russia, there are two major existing pipeline routes. For a number of years now it has been increasingly realised that there is room for a North European Baltic Sea pipeline route of some form. Of the various projects under consideration, the NEGP has won out and is now the project under development.

The other North European supply route was pioneered by Yamal I, from the Yamal field in western Siberia in Russia through Poland to Germany. Yamal I is in operation and Yamal II can now be developed. Because of the NEGP Baltic Sea project though, Yamal II is now on hold.

Plans for diversification of gas infrastructure of new member states face some opposition from Russia which is obviously keen to protect its own supply monopoly for the region. These efforts have been supported by acquisitions of strategic gas assets in the region.

4.2.2.1 Changing ownership of EU8 gas infrastructure

In 1990, in the former Soviet system, the central and east European region could be described as being dominated by national single vertically integrated gas companies (as in much of western Europe), but in central and eastern Europe, national gas companies were under a strong degree of control by Soviet Gazprom. During the 1990s and still continuing now (2007), the region has seen a wide transfer of ownership of these previous national companies. The following table shows in a summary form the main players and owners in the gas industries of each of the EU8 member states. It shows the result of 15 years of activity and privatisation.

Table 4. Summary of EU-10 Gas Industry Structure (2006)

Country	National Gas Company	Ownership	Amount of Unbundling	New Entrants	Gas Supply 2006
Estonia	Eesti Gaas	Gazprom (37%) E.ON (33%) Fortum (17%) Others (13%)	Võrguteenus (TSO and DSO) 24 smaller DSOs (DSO, supply)	None	Russia-100%
Latvia	Latvijas Gaze	Gazprom E.ON	None	None	Russia-100%
Lithuania	Lietuvos Dujos AB Dujotekana UAB	Gazprom E.ON State Property Fund	Lietuvos Dujos AB (TSO, DSO, supply) Dujotekana UAB (supply) 6 local DSOs	None	Russia-100%
Czech Republic	RWE Transgas Net	RWE	RWE Transgas Net (TSO)	Wingas (one consumer)	Russia-70% Norway-30%

			8 DSOs (6 RWE, 2 E.ON) 105 small DSOs		
Slovak Republic	Slovensky Plynarensky Priemysel (SPP)	State (51%) E.ON (24.5%) GdF (24.5%) Option to Gazprom	None	None	Russia-100%
Hungary	MOL Földgázszállító Rt	MOL (100%)	MOL Földgázszállító Rt (TSO) E.ON (storage, wholesale trading; a pending asset swap with Gazprom) 6 regional DSOs (Budapest Municipality, Italgas, Gaz de France x 2, Bayernwerk, E.ON) 5 small DSOs 14 other suppliers	Panrusgaz (E.ON 50%, Gazprom 50%) EMFESZ (Russian, Ukrainian) 14 licensed suppliers	Russia-75% Germany-8% Others-17%
Poland	PGNiG	PGNiG (Polish State)	None	None	Russia-61% Germany-4% Norway-4% Others-30%
Slovenia	Geoplin	Geoplin (Slovenian)	None	None	Algeria-36% Russia-55% Others-9%

Source: Mercados

Note: TSO = Transmission System Operator, DSO = Distribution System Operator

It can be seen that many gas companies of the new member states are owned by joint ventures of Russian Gazprom and German E.ON Ruhrgas in joint ventures, or with other German companies (RWE, Wingas and Bayernwerk). There is also a small influence by Gaz de France and Italgas in the region. Of the whole region, every country that has allowed in foreign participation (which is every country except for Poland and Slovenia) has resulted in an E.ON Ruhrgas ownership of gas assets. Of these countries E.ON Ruhrgas made acquisitions in partnership with Gazprom in every country except for the Czech Republic (where another German company, RWE, has a 100% ownership of the gas transport company and six of the eight distribution companies, the other two being owned by E.ON). It could be said that the region has exchanged Soviet dominance for combined German and Russian dominance of their gas industries.

5 Conclusions

Natural gas import dependency has been identified as a major energy policy issue for those continental new EU members who joined the European Union in 2004. We have concentrated on an assessment of one component of the security of supply issue (namely the lack of diversification in sources of supply). It was demonstrated that the natural gas economies of old member states are significantly more diversified, and the security of supply issue has been increased and brought to the forefront of the EU's energy policy agenda by the 2004 enlargement.

A key issue also is the dominance of joint ventures of Russian Gazprom with German companies (particularly E.ON Ruhrgas) in the ownership of gas assets and in gas supplies throughout the EU-8 region.

Without strong efforts to introduce effective competition, an area where European Commission regulation could be very important, the dominance of the region by Russian and German companies (that is to say, by joint ventures of E.ON and Gazprom) is likely to continue. Efforts to promote competition could, among others include: (1) ownership unbundling of gas TSOs; (2) unbundling gas storage from gas transmission and providing effective independent storage; (3) unbundling gas supply from asset ownership; (4) introducing effective regulated third party access within the EU-8; (5)

reaching agreement with Russia and with transit countries for the provision of regulated third party access to their gas transmission grids; and (6) promoting key diversification projects (such as Nabucco, LNG, gas storage projects).

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The January 2009 gas crisis in Central Eastern and South-East Europe[1]

Péter Kaderják[2]

1 Introduction

Between January 7th and 19th of 2009 the transit of Russian gas to Europe through the Ukraine was halted. This was the most serious European gas crisis to have happened since the start of Russian gas transmission to Europe decades earlier. A daily average of 380 million cubic meter (Mcm) or a total of 5 billion cubic meter (Bcm) of Russian gas delivery through Ukraine to the EU and South East Europe was lost during these days.[3] Gas industries and customers of Central Eastern and South-East Europe (CSEE), including many of the new member states of the EU, were hit particularly strong by the crisis. The share of lost gas supply for the countries of the region from Austria to Greece due to the gas cut accounted for 50-100% (except for Poland and Romania). Several countries had to introduce forced load shedding measures. The official economic loss estimate from lost load is close to 2 billion Euros for the most affected countries. If the crisis did not coincide with a major economic recession, the economic loss it caused could have been significantly larger.

Retrospectively, the January 2009 gas crisis can be viewed as an unprecedented short run supply security experiment that tested the vulnerability of the EU's gas industry and, in particular, helped to detect the strengths and weaknesses of the gas industries of the CSEE region.

There are some positive lessons of this experiment from a regional perspective. The discovery of the reverse flow capabilities of the European gas transmission grid opened

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[1] Some parts of this paper rely heavily on Kaderjak, P. (ed) (2011), *Security of energy supply in Central and South-East Europe,* pp 234-257. Corvinus University of Budapest, REKK. Originally published in Vinois, J.A. (ed), The Security of Energy Supply in the European Union, pp. 193-219. Claeys and Casteels, 2011

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up formerly unproved supply diversification opportunities for the region through a better utilization of the existing infrastructure. Those countries with sufficient physical connections to the relatively liquid gas markets of Austria and Germany (Czech Republic and Slovenia) or to the LNG receiving terminal of Greece (Bulgaria) enjoyed the advantage of receiving reverse gas flows from these directions. It is also largely due to the accomplishment of reverse flows that despite former scepticism (*"at the end, all molecules in the region come from Russia"*), contractual diversification delivered during the crisis.

The crisis also confirmed that gas market development and supply security goes hand in hand. The Austrian case illustrated how a well functioning gas market could mitigate a major supply shock in a fast and efficient manner. Moreover, those countries from CEE with a strong physical link to the German and Austrian gas markets (Czech Republic and Slovenia) could manage the crisis without customer restrictions.

However, the crisis also revealed the asymmetries of the European gas industry as well as the most important weaknesses of the CSEE gas sector. While the gas transmission network of old EU members are relatively well interconnected, the current physical gas infrastructure of the CSEE countries does not allow for much diversity in gas supply sourcing. North-South interconnections and consequent cooperation across the region's gas markets were missing at the time of the crisis and this made it impossible to help each other when it happened. There were also serious problems encountered in the regional utilization of existing underground gas storage assets to ease the supply shock of the crisis. Finally, crisis related planning, regulation and preparedness was insufficient in the rest of the countries.

The purpose of this paper is to sum up the most important lessons from the 2009 gas crisis in CSEE and assess how the after crisis-efforts, both at the EU and at the national level, address the diagnosis that the crisis provided about the most important problems of the CEE gas markets. It comments on how the implementation of the new gas supply security regulation 994/2010 (Regulation) and some more recent initiatives at the EU level could improve the situation in CSEE. For this purpose, Section 2 provides a brief background on the gas industries of the most affected countries from Central Eastern and South-East Europe: Austria, Bosnia and Herzegovina, Bulgaria, Croatia, the Czech

Republic, Greece, Hungary, Romania, Serbia, Slovakia and Slovenia.[4] Section 3 provides major regulatory lessons from the crisis. Section 4 assesses to what extent the problems revealed by the crisis are addressed by EU and national level actions and Section 5 concludes.

2 CSEE natural gas industry background

The natural gas industry of the EU is characterized by important regional asymmetries. Among them the asymmetries in network topology and in gas supply sourcing between CEE new member states and Energy Community members on the Balkans *versus* the continental 'old' member states are important to understand for the study of the 2009 gas crisis.[5]

The gas transmission networks of old members are relatively well interconnected. Pipeline connections to all the three major supplying regions (Russia, Norway, North Africa) as well as a fast developing LNG infrastructure are available for them. This topology supports gas sector cooperation across member states and allows for a substantial diversification in supply sourcing. On the contrary, the gas transmission network topology in the Visegrad 4 continental new member states (Poland, Czech Republic, Slovakia and Hungary) reflect the East-West gas transmission routes connecting major Russian gas fields to markets in Central and South Europe (Germany, Italy) and points of delivery further to the West. North-South connections and consequent cooperation across these member states are missing. With regard to South East Europe, interconnections among the three different routes[6] that provide Russian gas supplies to these countries were also missing at the time of the crisis.[7] In sum, the current physical gas infrastructure of the Central and Southern East European (CSEE) countries does not allow for much diversity in gas supply sourcing.

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[4] We exclude Poland and the Baltic states from the analysis since increased supplies through the Yamal pipeline system during the crisis prevented these countries from the worst of it.

[5] See Kaderják, P., Cameron, P. and Tóth, A. I. (2007): *Unilateral natural gas import dependence: a new supply security risk for Europe*, in: European Review of Energy Markets, Volume 2, 57-92; and Pierre Noel. (2008). *Beyond dependence: how to deal with Russian gas*. European Council on Foreign Relations.

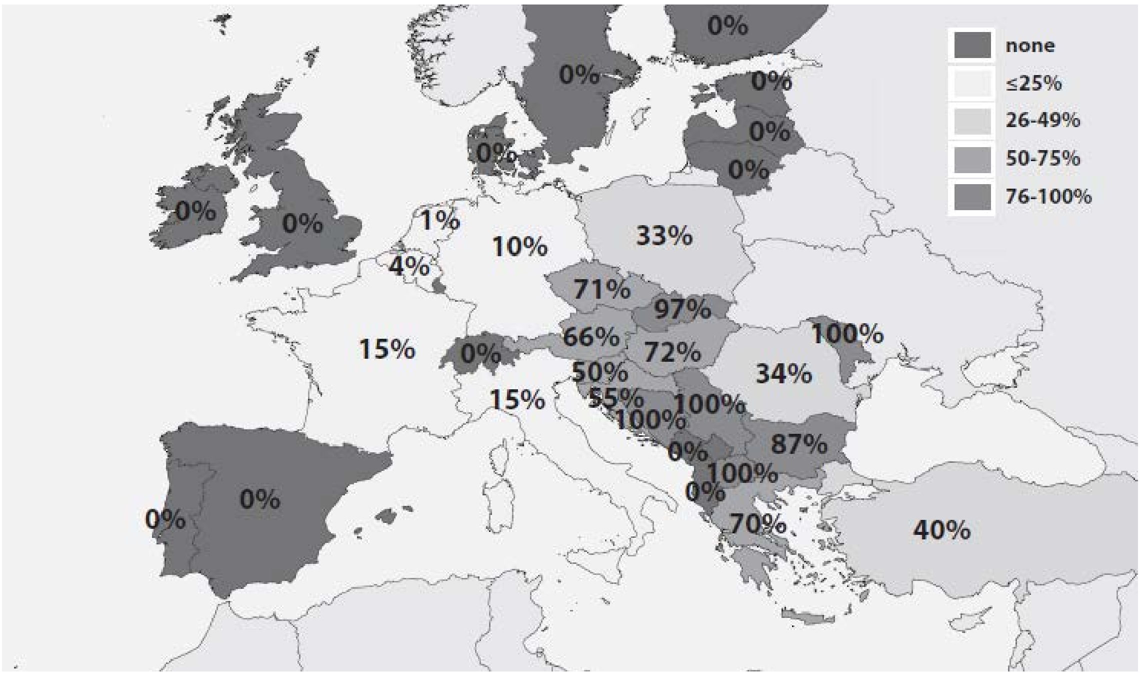
[6] 1) Russia-Ukraine-Romania-Moldova-Bulgaria-FYR of Macedonia; 2) Russia-Ukraine-Hungary-Serbia-Bosnia and Herzegovina; 3) Russia-Ukraine-Slovakia-Austria-Slovenia-Croatia.

[7] The first exceptions to this rule are the 4.5 mcm/day interconnector between Hungary and Romania that was commissioned in October 2010 and the 18 mcm/day interconnector between Hungary and Croatia commissioned in December 2010. However, these pipelines do not yet provide reverse flows.

A high level of unilateral gas import dependence on Russia is the other important characteristics of the CSEE gas sectors. While in 2006 the share of Russian gas in the primary gas supply of EU15 was an average of 20%, the same share for nine out of the ten[8] Eastern European member states was above 50%, and for six above 80%.

Due mostly to the asymmetries in network topology and gas supply sourcing, the 2009 gas crisis had also a highly asymmetric impact on the EU gas economies as illustrated by Figure 1.

Figure 1. Reduction in gas supply (imports + domestic production) on January 7, 2009



Source: The presentation of Walter Boltz at REKK's 1st workshop on Security of Supply in CSEE titled 'Regulatory reactions to the 2009 January gas crisis and the coming winter'. October 29, 2009. Budapest. www.rekk.eu/sos.

Table 1 provides before-crisis data on the annual balance of gas consumption and supply sources for the most affected CSEE countries. Note that the aggregate size of the gas markets under study equals only about 70% of the German gas market. As we can see, natural gas based electricity generation accounts for more than 30% of gas consumption in Hungary and Austria, while gas consumption for industrial purposes plays a dominant role in Slovenia (57%) and Serbia (54%) and its share is over 30% in

[8] The exception is Romania, due to its significant domestic gas production.

Austria, Bulgaria and the Czech Republic. Short-term fuel substitution in electricity generation or load shedding in the case of the rest of industrial activities is relatively easy and can be mandated by the gas TSOs or energy regulators. To apply demand side measures is more complicated in case of direct household gas use. Household consumption is dominant in the Czech Republic (42%) and Slovakia (44%) but its share is close to 30% in Hungary, Croatia, Serbia and Romania.

Table 1. Annual gas supply and demand data for the countries under study, 2007

	Share of natural gas in primary energy use (%)	Domestic produc–tion Bcm/year	Import Bcm/year Per source			Working gas storage capacity Bcm/year	Annual gas consumption Bcm/year			
			Russian	Other	Total		House –holds	Electri–city and heat	Industry	Total
Austria	23	1.8	4.2	2.4	6.6	4.2	2.2	2.6	2.7	8.4
Bulgaria	14	0.4	3	0	3	0.6	0.8	0.44	1.11	3.4
Bosnia and Herzegovina	6	0	0.32	0	0.32	0	0.1	0	0.2	0.3
Czech Republic	16	0.09	6.75	2.25	9	2.90	3.8	0.45	3	9
Croatia	26	2.9	1.05 (export 0.75)	0	1.05 (export 0.75)	0.62 (10% is rented by Slovenia)	1.08	0.4	0.72	3.3
Greece	12	0.03	3.15	0.95	4.1	0.08 (LNG)	0.22	3.05	0.5	3.8
Hungary	43	2.5	7.9 (East)	2.6 (West)	10.5	3.8	4	4.3	1.5	13
Romania	36	11.3	5.7	0	5.7	2.8	4.7	3	4.3	17
Serbia	13	0.25	2.14	0	2.14	0	0.65	~0.45	1.3	2.4
Slovakia	31	0	9	0	9	2.8	4	0.4	1.8	9
Slovenia	14	0	0.66	0.54	1.12	0.11 (rented)	0.17	0.11	0.68	1.2

Sources: IEA, Eurostat, Statistical Offices of Austria and the Republic of Slovenia, Srbijagas

Table 2 presents the availability of the three most important supply side options that were available for the CSEE countries to replace imported Russian gas during the crisis. These are a) alternative (non Russia contracted) imports; b) domestic production; and c) increased withdrawal from gas storage or an LNG receiving terminal.

Table 2. Availability of supply side options for SOS countries to replace Russia contracted gas imports (based on 2007 data)

	IMPORT DIVERSIFICATION (Non-Russia contracted import /total import, annual)	DOMESTIC PRODUCTION (production/winter peak load)	STORAGE/LNG (withdrawal capacity /winter peak load)
Austria	36%	16%	104%
Bosnia-Herzegovina	0%	0%	0%
Bulgaria	0%	8%	35%
Czech Republic	25%	0%	96%
Croatia	0%	38%	45%
Greece	23%	0%	110%*
Hungary	25%	13%	69%
Romania	0%	54%	43%
Serbia	0%	6%	0%
Slovakia	0%	0%	73%
Slovenia	48%	0%	n.d.

*LNG receiving capacity

Source: own calculations

As it seems apparent, underground storage withdrawal is the most robust option for the rest of the countries, most prominently Austria, the Czech Republic, Slovakia and Hungary. In addition, Greece has an LNG receiving capacity that exceeds its daily winter peak load. Domestic production is the most significant for Romania and Croatia. Short run 'in-house' resources, that is withdrawal capacity and domestic production together is enough to serve peak load of Austria for some time and enough to serve 97% of peak load in Romania, 96% in the Czech Republic, 83% in Croatia, 82% in Hungary and 73% in Slovakia given that those facilities operate at their peak capacity. On the difficult side are Bulgaria, Bosnia and Herzegovina, Serbia and Slovenia. Five out of the

11countries had managed to reach a certain level of contractual diversification away from Russia in their gas sourcing. Alternative partners for them come from Norway (Austria, Czech Republic), Germany (Austria, Hungary), France (Hungary) Algeria (Slovenia) and LNG (Greece).

3 The crises and major lessons from it

Following a sharp debate between Russia and Ukraine in the fall of 2008 about the terms and conditions of gas transactions between the two countries[1], including transit shipments of Russian gas through the Ukrainian pipeline system to the EU, the transit was halted between January 7th and 19th of 2009. A total of 5 Bcm of Russian gas delivery through Ukraine to the EU and South East Europe was lost during these days. While the below average temperatures during the rest of the crisis days had an upward pressure on the daily gas load, this effect was mitigated by a significant drop in the non-household gas demand implied by the economic recession. Also, the weather in December 2008 was milder than the average and resulted in an oversupply of stored working gas on the European market during the crisis. Less favourable demand and storage supply conditions or a longer crisis could have had a much more detrimental impact on customers than what they experienced in January 2009. As a leading European energy regulator stated, "Europe did not have a shortage in gas when the crisis hit but instead had a difficult time to get the gas from where it was to places where it was needed".[2]

The European gas industry put enormous efforts into mitigating the impacts of this unprecedented supply shock and to minimize the impact of the cut on final customers. At the continental scale, the most important developments were the followings. Already at around January 7, the flow of the UK-Holland interconnector was reversed. In order to replace missing EU supplies through Ukraine, Russia increased gas shipments through the Yamal and Blue Stream pipelines. Three days later Germany increased gas

[1] About the chronology of the unfolding commercial and political dispute between Russia and Ukraine, the involvement and role of EU institutions and companies in resolving the problem as well as the details of the new long term agreement between Russia and Ukraine see Pirani, S., Stern, J. and Yafimava, K. (2009), *The Russo-Ukrainan gas dispute of January 2009: a* comprehensive *assessment.* Oxford Institute for Energy Studies, February 2009, NG27.

[2] Boltz, W. (2009), *Regulatory reactions to the 2009 January gas crisis and the coming winter.* In: Security of gas and electricity supply in Central and South-East Europe, Summary of the presentations of the first workshop, p. 14. www.rekk.eu/sos.

shipments to Croatia and additional spot LNG cargoes became available for Greece and Turkey. At around January 9, Hungary started to increase gas shipments for Serbia and Bosnia and Herzegovina. Finally, just before the restoration of gas shipments through Ukraine, reverse flow was made possible to bring additional gas from the Czech Republic to Slovakia and from Greece to Bulgaria.[3]

Table 3 presents country level data on how the different CSEE countries offset, if they could, the amount of missing Russian shipments by supply and demand side adjustments during the crisis. We find that a combination of transparent market transactions, in-house transactions of multinational gas companies, extraordinary nominations of TSOs (for which the right was provided by crisis action plans) and demand side regulatory measures like the implementation of forced load shedding for end customers made up the mix of institutional reactions that ensured the balance between load and supply during crisis days. We find a wide variation of the above measures across the region depending on the level of gas market development and crisis preparedness.

Austria is the obvious example where the rest of the crisis management job was done by its well functioning balancing gas market. Its mechanism allowed replacing missing Russian imports very quickly 100%. The *daily* traded volume on the market during the crisis reached the average *monthly* volumes of 2008. A notable balancing gas price increase sent the appropriate signal for suppliers (i.e. storage operators, importers and electricity producers) to increase their market participation. In addition, cheap fuel oil prices relative to gas product prices prompted gas fired power plants to voluntarily switch from gas to fuel oil during crisis days.[4] A well functioning LNG market helped Greece to manage its crisis situation since there were available additional LNG cargoes to contract during the crisis.

[3] Simpson, J. (2009), *January 2009 – Russia – Ukraine gas dispute*. IEA presentation for the Gas Coordination Group, February 23.

[4] Boltz, W. (2009), *Management of the gas supply disruption in Austria, January 2009 – experience and lessons learned.* Presentation prepared at E-Control, January 21, pp 20-22.

Table 3. Adjustments to missing Russian shipments by supply and demand side measures during the crisis

	Missing Russian import Mcm/day	Additional supply (physical replacement)			Customer restriction			Official damage estimate (million Euro)
		Local production	Storage	Alternative import	Fuel switch	Industrial customers	Household / Protected customers	
Austria	10	0	10 (Germany)		yes	no	no	-
Bulgaria	7-9	0.2	1	2 (Greece) *	Yes, 6-7 mcm/day			225
Bosnia-Herzegovina	1,8	0	0	1.5-1.9** (Austria-Hungary)	Yes, until January 12			n.a.
Czech Republic	15	0,25	5-10	10 (Germany)	no	no	no	-
Croatia	4	5,7			yes	yes	no	270
Greece	9.8	0	9.8 (LNG)	LNG	yes	no	no	-
Hungary	24	3	21	transit	yes – 7	yes – 2	no	80
Romania	8-10	1	29	not possible	yes	reduced demand due to recession	no	-
Serbia	10	0,7	0	4,7 (Austria-Hungary)	yes	yes	yes	50
Slovakia	17-20	not possible	14-16	3 – 4	yes	yes	no	1000***
Slovenia	0.9-1.2	not possible	1 (Austria)	0.5-1	n.a.	no	no	-

*from January 19; **from January 9; ***possibly overestimated

Source: own calculations

Market and price mechanisms played a substantially less prominent role in other countries of the region to manage the crisis. This is mostly due to either the complete lack (e.g. Serbia, Bosnia-Herzegovina and Croatia) or the poor functioning of gas markets. However, intra-company transactions proved to be partially successful substitutes for liquid markets in some cases. The prominent example was provided by E.ON. This company has gas industry assets in a number of the affected CSEE countries (Czech Republic, Slovakia, Hungary) and could manage, in cooperation with the Austrian and Hungarian TSOs, to contract and ship additional gas for Hungary and the most exposed markets of Serbia and Bosnia-Herzegovina (see Figure 2.) after January 9. E.ON reports that the price of these additional shipments was the same as for its 'normal' commercial transactions with these countries and thus the whole arrangement can be considered as a case for solidarity. [1]

Figure 2. Additional EON-arranged supplies to the region from January 9, 2009.

Source: GTE and the presentation of Matthias Keuchel at a DEMOS workshop titled 'The 2009 January gas crisis and a complex approach to supply security'. February 19, 2009. Budapest.

Another example is that of RWE (see Figure 3). This German giant is having gas industry assets around the region including the gas transmission company of the Czech Republic (RWE Transgas Net at the time of the crisis). RWE Transgas managed to ship additional 10 Mcm/day of gas from its European portfolio compared to pre-crisis levels for the Czech (7 Mcm) and the Slovak (3 Mcm) markets from the peak of the crisis (January 12). On January 19 they could even manage to reverse the flow on the Slovak-

[1] Preparations for a possible crisis with a significant impact on the CSEE markets were already started in the Essen centre of E.ON in December 2008. See: E.ON (2009), *Mentőöv nyugatról*. In: Földgáz Magazin, issue 2009/1, pp. 4-10. Budapest.

Czech interconnector and ship 4 Mcm into the Slovak market. These companies claim with good reason that strong energy companies (instead of liquid local markets) secured gas deliveries to the region during the crisis.

Figure 3. Additional RWE-arranged supplies to the region from January 12, 2009.

Source: GTE and the presentation of Thomas Kleefuss at the Conference on Energy Economics and Technology titled 'Lessons learnt from the Ukrainian gas crisis: Diversification of supplies through Central European gas infrastructure'. April 3, 2009. Dresden.

Finally, when markets and intra-company transactions are not present and/ or are not sufficient to manage a supply shock, extraordinary rights for the TSO can be provided by e.g. a crisis management action plan to balance demand and supply by the application of non-market based nominations. However, serious concerns were raised with regard to the application of this measure in some cases in January 2009. For example, during the entire crisis period the Hungarian government refrained from officially announcing a crisis situation and thus providing the extra nomination rights for the TSO. The reason was a fear from the potential of litigations that might have emerged from TSO decisions that overruled commercial contracts. This example

highlights the importance of establishing *ex ante* rules for liabilities and commercial settlements with regard to TSO decisions during crisis situations.
It is also the TSO that is best positioned to manage customer restriction regulations. There have been reports from Hungary and Croatia about the partial malfunctioning of customer restriction regulations during the crisis. TSOs had limited access to the actual consumption data of restricted customers and thus had problems with enforcing demand side measures. Austria, on the other hand, had developed a detailed crisis management plan after the 2006 gas crisis and did manage the January 2009 crisis properly.

We can also observe from Table 4 that in order to offset missing Russian gas and keep supply and load in balance during the crisis days, various demand side measures with various durations for different customer groups were put in place in the region. Fuel switching (from gas to oil) in electricity generation and gas based district heating was a commonly applied measure, in some cases on a voluntary basis (Austria) while in some others as part of the implementation of forced load shedding regulation (Hungary). Interruptible contracts of industrial customers also helped to reduce gas demand in Slovakia, Romania and Slovenia. Forced load shedding was limited to industrial users in Croatia, Hungary and Slovakia while in Bulgaria, Bosnia-Herzegovina and Serbia household customers and public institutions were also restricted in their gas use for some time. Note that certain countries were successful in fully mitigating the shutoff for their customers (Austria, Czech Republic, Greece, Romania and Slovenia), while Croatia's customers suffered a significant load shedding despite the availability of additional local production possibilities. The effects of the cut-off of deliveries were the most severe in the case of Bulgaria, Serbia and Bosnia-Herzegovina.

3.1. Lessons learnt

Early studies of the 2009 gas crisis already emphasized the primary importance of the European gas infrastructure in responding to supply security situations of this sort by improving the efficiency in using existing and by building some missing pieces of it. Pirani and his colleagues claimed that Europe needed to react in terms of new gas infrastructure developments, concentrating in the short-term on CSEE providing '...additional interconnection with neighbouring countries, North-West Europe and

Southern European countries with the capacity to import additional LNG supplies from existing terminals, plus additional storage close to these markets'.[2]

The first assessment of the impacts of the gas crisis on South-East European countries by Kovacevic concluded that '…in South Eastern Europe the crisis [...] defined an energy efficiency and energy interconnection agenda for European utility stakeholders and policymakers'.[3]

In its analysis the Regional Centre for Energy Policy Research focused on identifying the most important components of relative success of the different CSEE countries in crisis management in order to identify policy and regulatory lessons from it.[4] Success was associated with avoiding customer restrictions and the associated economic value of lost load. They claim that the reasons for successfully weathering the supply disruption in the case of Austria, the Czech Republic, Greece, Slovenia and Romania were the followings:

- *Efficient market mechanisms.* There was a sufficient amount of bids during the crisis on the Austrian balancing gas market to replace missing Russian supply. In addition, significant industrial consumers in Austria voluntarily switched from using gas. This prevented any regulatory intervention and helped to manage the situations in Austria and Slovenia. Also Slovenia could get access to its gas stored in Austrian facilities thanks to the fact that cross border access conditions between the two countries proved to work. Finally, the availability of the LNG market helped Greece to manage its own situation and to help Bulgaria at the very end of the crisis.
- *Import diversification*. The share of gas imported from non-Russian sources was 48% in Slovenia, 36% in Austria and 25% in the Czech Republic at the time of the crisis. Although a majority of these are traditionally regarded as (only) 'contractual' diversification (in other words, contracts concluded with a party other than Russia are generally also fulfilled with gas from a Russian source), the crisis revealed that

[2] Pirani, S., Stern, J. and Yafimava, K. (2009), *The Russo-Ukrainan gas dispute of January 2009: a comprehensive assessment.* Oxford Institute for Energy Studies, February 2009, NG27, p. 58.
[3] Kovacevic, A. (2009), *The Impact of the Russia–Ukraine Gas Crisis in South Eastern Europe.* Oxford Institute for Energy Studies, March 2009, NG 29.
[4] Kaderjak, P. (2009), *The January 2009 gas crisis: what happened in Central and South East Europe?* Presentation at the ERGEG Gas Regional Initiative SSE meeting, Budapest, April 16. A more comprehensive report is provided in Kaderjak, P. (ed) (2011), *Security of energy supply in Central and South-East Europe,* pp 234-257. Corvinus University of Budapest, REKK.

the contracting parties were able to fulfil and in several cases temporarily even increase their deliveries beyond contracted amounts. The three countries have appropriate physical interconnections in the Austrian-German direction.

- *Successful reorientation of the typical flow directions and the establishment of technical conditions for West/East flows.* The performance of the Austrian, German, Czech, Slovak and Hungarian TSOs in establishing West/East gas deliveries proved to be a crucial component to successfully replacing missing Russian supply. The management in these companies proved to be outstanding. The increased imports from the West played an important mitigating role in the January crisis because of this reorientation of gas supplies.
- *Sufficient domestic storage capacity, production and access to LNG.* The ratio of domestic production to winter peak consumption, from amongst the studied countries, is the highest in Romania. This production and the availability of significant storage capacity prevented Romania from implementing restrictions on consumers. Storage capacity played a key role also in managing the crisis in Austria and the Czech Republic. Greece could manage the crisis by relying on its LNG stocks and on contracting additional spot LNG.

On the opposite, the gas industries of the countries suffering the highest consumer damages (Bulgaria, Serbia, Bosnia and Herzegovina) are far from the relatively liquid German/Austrian markets, lack domestic gas production and if they have any at all, their gas storage capacity is limited. They import exclusively Russian gas and the total consumption is supplied through a one-directional transit pipeline. These countries were prepared for a crisis only at a minimum level: they lacked alternative fuel stocks or if they had any, these were difficult to mobilise. Affected consumers often replaced the missing gas used for heating or district heating with electric heating.

The crisis also revealed several regulatory problems with regard to gas supply security preparedness in the CSEE countries. Since regulatory fine tuning and a better utilization of demand side measures to offset gas supply shocks might be much cheaper supply security measures than infrastructure development, it worth to get improvement in the following areas:

- *Fuel switching* provided the most immediate demand side option during the crisis. The exceptional situation that fuel oil prices were below natural gas prices during the crisis period resulted in massive voluntary fuel switching in Austria. It also helped the easy enforcement of fuel switch regulation[5] for electricity generation in Hungary. However, in Bosnia and Herzegovina, Serbia and Bulgaria alternative fuel 3 for weeks was available but logistic problems permitted fast switching.[6]

- *Interruptible contracts* were not reported to play a significant role in crisis management. This might partly due to the lack of efficiently functioning gas markets where a shortage in supply would be reflected in sufficiently high market prices to encourage customers to sell their ability to be interrupted for suppliers. Other regulatory types of incentives are mostly lacking around the region.
- *There were shortcomings reported about the enforceability of forced load shedding for industrial customers* in Croatia, Hungary and Slovakia. While the TSOs were responsible to enforce curtailments, they had no direct access to consumption data but only the DSOs. The TSOs did not have sufficient powers to punish non compliance of customers. Another piece of the problem was that the restriction decision had no relation to the cost the curtailment imposed on the customer. A consequence was that large industrial customers started to lobby immediately at the responsible ministries to get exemptions from the curtailment and many were indeed provided by it.
- *Financial liabilities* from emergency situation TSO nominations hurting private contracts were not well defined. The litigation risks emerging from this uncertainty unnecessarily limited the pace of action of the TSO.
- *The rules for cross border access to gas storage facilities* in crisis situations might be restrictive in certain instances. For example, the access to the strategic gas storage site of Hungary might be limited by the responsible minister.
- *Data availability and transparency* regarding almost all the aspects of gas market functioning was insufficient at the time of the crisis all over CSEE.

We conclude that the gas crisis revealed at least six major areas where action is needed to mitigate the serious gas supply security risk from lacking physical and market integration in CSEE. First, the efficiency in using existing gas infrastructure can and should be improved by establishing clear cross border and storage access rules, operable

[5] In Hungary gas based electricity generation companies are obliged to hold 8 days of fuel oil reserves on their sites and another 8 days close to their sites.
[6] Kovacevic, A. (2009), *The Impact of the Russia–Ukraine Gas Crisis in South Eastern Europe.* Oxford Institute for Energy Studies, March 2009, NG 29, p. 14.

also during crisis periods, and by utilizing reverse flow capabilities of transmission pipeline systems. Second, crisis preparedness is to be improved in the form of better crisis prevention and management planning and regulation, including in particular the definition of TSO rights and responsibilities and according liability rules for crisis situations. Third, incentive schemes should be applied and invented to encourage as much voluntary fuel switching as possible in order to minimize enforced customer load shedding during a crisis. Fourth, gas market data availability should be improved. Fifth, improving the interconnectivity of the gas infrastructure of CSEE seems to be unavoidable in order to improve supply security and also the integration of the internal EU gas market. Finally, the crisis also revealed the shortcomings of missing regional cooperation in energy security matters.

4 EU level efforts to address the problems revealed by the crisis

The 2009 January gas crisis and the follow up discussions and analyses of those events at different European institutions clearly resulted in an understanding and recognition of the gas industry related problems of the new EU member states and the wider CSEE region. To the benefit of these countries, the crisis implied a strong, coordinated and exceptionally fast reaction from the responsible EU institutions.[7] A prominent outcome of this reaction is the new gas supply security regulation 994/2010 of the EU that is discussed in detail by Vinois and Beyer in this volume. But beyond the Regulation, more recent initiatives, especially those with relevance to the future development of the gas infrastructure of the EU,[8] seem to recognize the supply security concerns of CSEE and put forward meaningful obligations and proposals to accomplish the gas grid and

[7] The staff of the European Commission completed an assessment of the crisis as early as mid summer of 2009 with a focus on the lessons from the crisis for European policy. This assessment was the basis for promulgating the proposal for the new gas supply security regulation. It put the emphasis on identifying means by which emergency preparedness and crisis response mechanisms could be improved at the Community level. The paper recognised the asymmetric impact of the crisis on Central and Eastern European member states and some Energy Community members and made efforts to draw the lessons from the experience of the most affected countries. It identified the most important elements of a reinforced future gas supply security policy as the follows: the strengthening of the internal gas market mechanism; improved market transparency; a reinforced European gas infrastructure with special reference to constraints, missing interconnections and the need for reverse flows; national action to enhance demand response measures; contractual diversification; improved cross border cooperation in times of crisis situations; and a reinforced role for the Commission to coordinate action to prevent and respond to gas crises.

[8] *Energy infrastructure priorities for 2020 and beyond* – a Blueprint for an integrated European energy network. European Commission, November 2010. Also see the Chapters by Catharina Sikow-Magny and Brendan Devlin in this volume.

market integration of the countries of this region. It seems that ten years after the successful integration of the electricity grid of CSEE into the European grid (UCTE), the integration of the gas grid of the region into the European system is now on the agenda of the Union. And it is difficult to overestimate the importance and relevance of such a policy for those member states which are struggling with all the supply security and price risks stemming from their unilateral gas import dependence on a single supplier. The rest of this section provides some specific comments how Regulation 994/2010 and other recent initiatives could bring about an improved supply security situation for CSEE.

4.1 Regulation 994/2010

Gas supply security and gas market development and integration are twin issues for the CSEE countries and, to a great extent, both of them seem to boil down to versions of gas infrastructure reinforcement plans representing, in turn, specific gas supply entry point and capacity combinations for the region. The different infrastructure patterns create alternatives for the improvement of gas market liquidity and gas-to-gas competition through opening up diversification opportunities.[9] This is why for CSEE the potentially most beneficial measures of Regulation 994/2010 are exactly those that put forward infrastructure standards for member states to meet.

Reverse flows - Paragraphs 5-6 of Article 6 oblige TSOs to enable permanent bi-directional capacity on all cross-border interconnections between Member States and to adapt the functioning of their transmission systems so as to enable physical gas flows in both directions on cross-border interconnections. Section 3.1 concluded that it was exactly the implementation of reverse flow possibilities that helped the most affected CSEE countries, except for Romania, to mitigate the adverse effects of the gas cut. A recent quantitative modelling study reports that even the present CSEE gas infrastructure, given its limited bi-directional flow possibilities, prohibits significant resilience against disturbances of the 2009 January kind, except for the East Balkan

[9] See Kaderjak, P. (ed) (2011), *Security of energy supply in Central and South-East Europe,* pp 258-281. Corvinus University of Budapest, REKK.

states.[10] This outcome could improve considerably if the referred modelling took into consideration the effects of more fundamental reverse flow possibilities for the region foreseen by the new Regulation. Especially, the availability of Italian shipments (including LNG) and increased bi-directional capacities between Germany, the Czech Republic, Slovakia and Austria could improve the utilization of existing infrastructure for the benefit of both supply security and market liquidity for the rest of the countries. The only concern to rise regarding the related pieces of the Regulation is that it provides TSOs with rather easy conditions to get, from any of the affected national authorities, an exemption to implement reverse flows (Article 7). Since rejecting to offer bi-directional cross border capacities has partly been a mean of integrated companies to protect their national markets, it is difficult to rule out this consideration to play a role in future decisions by national bodies, even in the light of future gas crisis risks.

The N-1infrastructure standard - Paragraph 1 of Article 6 requires each member state to upgrade its gas infrastructure so that the capacity of remaining infrastructure should guarantee a predefined level of service in the case of the fall out of the single largest gas infrastructure at a very high level of demand. Although a similar N-1 supply security principle has long been applied in the case of the electricity sector, the proposal to meet such a requirement in the case of the gas sector was opposed by many stakeholders in the course of discussions about the draft Regulation, mostly referring to the high costs of the needed upgrade.

However, if we have a quick look at the present infrastructure conditions of the most affected countries, we might suspect the cost issue to be less pressing for the rest of the countries. Figure 4 provides the values for a measure called Residual Supply Index (RSI) for the countries under study (except for Greece) for the years 2008 and 2015.[11] The calculation of the index is very similar to the N-1 criteria included in Appendix I (2) of the Regulation. The difference is that in the calculation of RSI it is assumed that the capacity of the single largest gas infrastructure (denoted by I_m in the Regulation) equals to the capacity of the largest import pipeline capacity. Also, RSI applies daily

[10] See Kaderjak, P. (ed) (2011), *Security of energy supply in Central and South-East Europe,* pp 140-142. Corvinus University of Budapest, REKK.

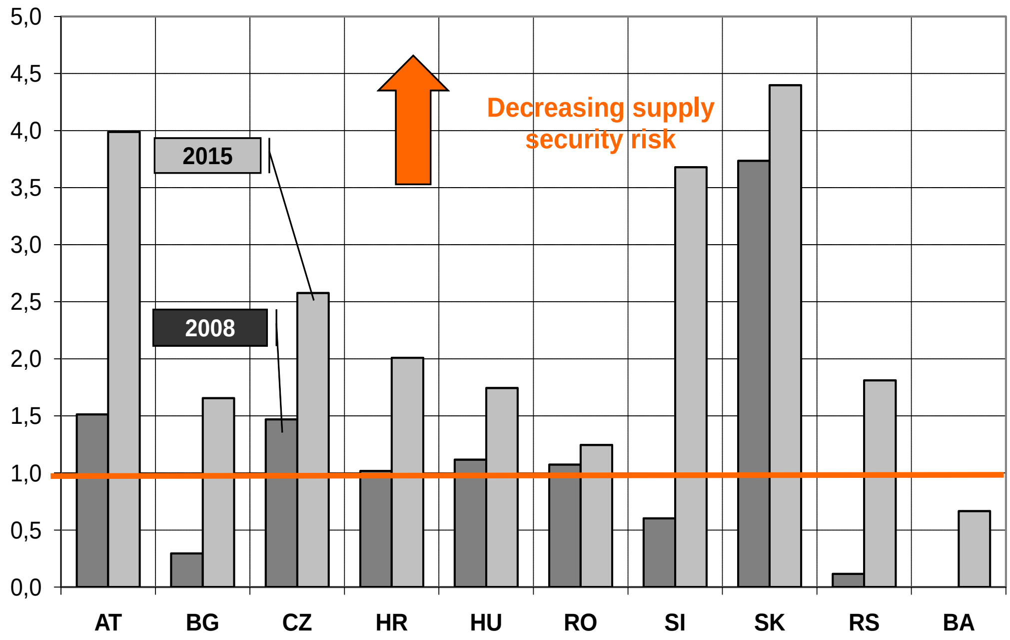
[11] For more elaborated discussion on gas supplysecurity indexes for the CSEE region see Kaderjak, P. (ed) (2011), *Security of energy supply in Central and South-East Europe,* pp 32-36. Corvinus University of Budapest, REKK.

average winter consumption in the denominator instead of the extremely high demand figure (D_{max}) required by the Regulation.[12] The formula for calculating the RSI is the following:

$$RSI = \frac{P_{dom} + S_{est} + L_{ext} + I_{total} - I_{largest}}{C_{peak}}$$

where C_{peak} is daily average winter consumption, P_{dom} is daily domestic production, S_{ext} is daily storage extraction, L_{ext} is daily LNG extraction, I_{total} is the total pipeline import capacity and $I_{largest}$ is the import capacity of the largest single pipeline.

Figure 4. Residual supply index, current and forecast



Source: Eurostat, ENTSO-G, IEA, REKK calculations

The results indicate that Austria, the Czech Republic and Slovakia could most probably meet the N-1 criteria already with their pre-crisis infrastructures, whereas Croatia, Hungary and Romania were quite on a narrow margin in 2008. To meet N-1 seems to be the most difficult – and probably costly – for Bosnia and Herzegovina, Bulgaria, Slovenia and Serbia. Figure 5 also shows the expected future improvements in the RSI value according to planned infrastructure upgrades, which are especially marked in the case of Austria, Bulgaria, the Czech Republic, Hungary, Croatia, Slovenia and Serbia.

[12] D_{max}: total daily gas demand (in mcm/d) of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.

The Regulation allows member states for meeting the N-1 criteria by including market-based demand-side measures as well as through international cooperation at the regional level. The 2009 January crisis demonstrated significant opportunities for the region in both regards. As it was pointed out, voluntary fuel switching, especially in the case of power generation and district heating units, was widespread in a number of countries. Better incentives and regulation could further improve the situation in this regard. On the other hand, the cross border cooperation of Slovenia and Austria and also Hungary and Serbia during the crisis clearly demonstrated the sizable benefits (cost savings) that a more conscious regional cooperation to utilize existing gas industry assets could bring in mitigating future gas crisis risks. The implementation of a low cost[13] reverse flow option from Greece to Bulgaria close to the end of the crisis was another promising example in this regard.

Nevertheless, the implementation of the N-1 standard makes it necessary that member states, after exhausting the opportunities in applying demand-side measures and regional cooperation, will have to upgrade their infrastructures to meet a minimum level of gas supply security. Paragraph 8 of Article 6 and Paragraph 2 of Article 7 describe what role upgrade costs should play in infrastructure standards related implementation and exemption procedures. Note that in CSEE parts of these upgrades have already been supported by EU funds from the European Energy Programme for Recovery. Cost efficiency in planning for such upgrades should be crucial, although evidence indicates that cost efficiency might play only a secondary role in government decisions in this regards.[14] This is why conditions in case of public (e.g. EU) support for such upgrades should contain cost-benefit and cost-efficiency measures. In sum, the Regulation, through the obligations of the N-1 standard and reverse flows, created very positive incentives for developing incentive-based demand-side regulations and for regional cooperation.

Preference for market-based solutions - The crisis related experience of the CSEE countries supports that feature of the Regulation to strictly prefer the application of

[13] See Silve, F. and Noel, P. (2010), *Cost Curves for Gas Supply Security: The Case of Bulgaria*, EPRG working paper 1031, September.

[14] See about the expensive choices of Bulgaria by Silve, F. and Noel, P. (2010), *Cost Curves for Gas Supply Security: The Case of Bulgaria*, EPRG working paper 1031, September. The cost-benefit valuation of the recently accomplished strategic underground gas storage site of Hungary is discussed in Kaderjak (2011), pp 86-93.

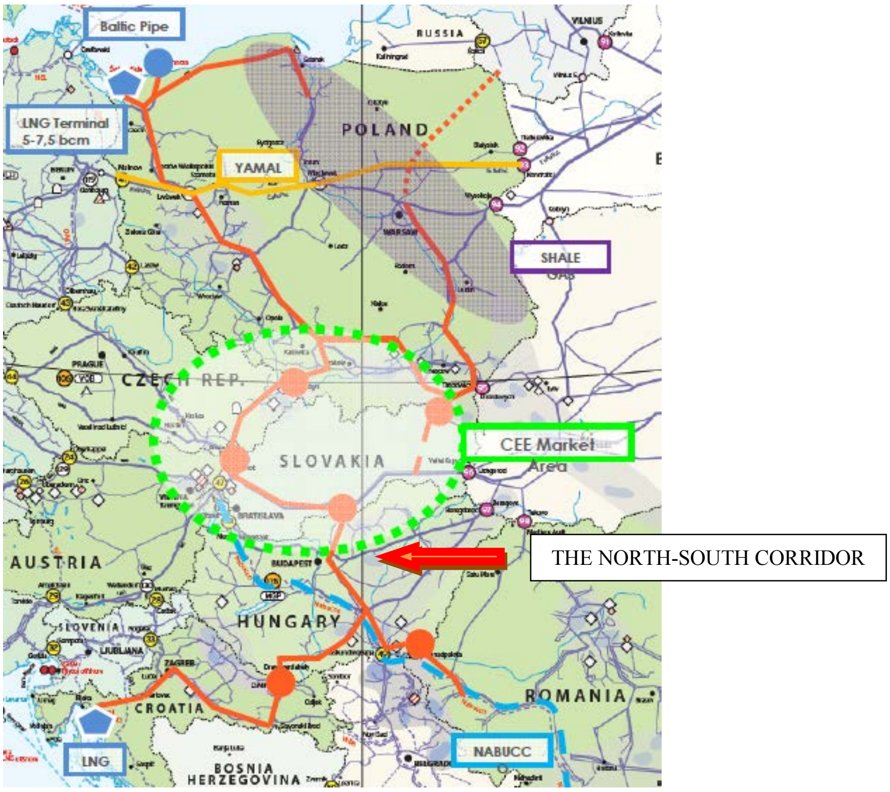
market-based demand and supply side measures to non-market based ones in crisis planning and mitigation.[15] While market-based supply side solutions were quick and successful in the case of Austria and Greece to mitigate the impacts of the gas cut, several problems occurred when applying non-market based measures in other cases. Examples are the problems encountered in enforcing firm load shedding regulations in Croatia and Hungary or in getting access to storage sites in Slovakia.

4.2 Other infrastructure related initiatives

The lessons from the 2009 gas crisis manifested in the European Commission's Communication "Energy infrastructure priorities for 2020 and beyond – a Blueprint for an integrated European energy network" adopted on 17 November, 2010. The initiative was warmly welcomed and supported by the Hungarian EU presidency and by the governments of CEE new member states early 2011. This is not by chance, since the Communication includes, among its proposed priority gas corridors, two significant projects that could significantly improve gas supply security and market liquidity in the region. The first is the Southern Corridor of the EU that would bring gas from the Caspian Basin, Central Asia and the Middle East to the EU by crossing CSEE countries and also bringing additional gas liquidity for these countries. The second is the North-South Corridor in CSEE that could create the missing interconnections among the Visegrad 4 countries (V4: Poland, the Czech Republic, Slovakia and Hungary) and Croatia and provide new LNG entry points at the Baltic and Adriatic coasts for the landlocked countries of the region (see Figure 5).

[15] See e.g. Paragraph 2 of Article 6 on the preference for market-based demand-side measures. Paragraph 7 of the same Article calls for a test of market demand first for new infrastructure investments and Article 10 provides details on how Emergency Plans should provide preference for market-based measures.

Figure 5. A CEE gas market concept



Source: The presentation of Rafal Wittmann at the 4th Central European Gas Congress titled 'Regional Gas Infrastructure in Central Europe', June 16, 2011. Budapest.

Work on the implementation of the North-South Corridor has already started. Following the cooperation of V4 and SEE countries (V4+) throughout 2010 on promoting regional gas infrastructure development plans and the adoption of the Energy Infrastructure Package of the EU in November 2010, a Gas Working Group of the High Level Group on North-South Energy Interconnections in Central-Eastern Europe was established in February 2011.

5 National level efforts to address the problems revealed by the crisis

The 2009 gas crisis resulted in fierce political reactions in the affected countries of the CSEE region and prompted intensive debate on the short and long term strategies for improving gas supply security. Much of the national level debate has been around various physical development projects to enhance supply side options. Table 4 provides an overview of recent infrastructure development related proposals, parts of which have been concluded in the course of 2010.

Table 4. Recently discussed gas supply security options in CSEE

Country	Proposals	Concluded since the crisis
Bulgaria	Reinforcement of the interconnections and development of bidirectional interconnections with Romania, Greece and Turkey; establishing projects for LNG import.	
Czech Republic	Extension of storage capacity; extension of the Western interconnection pipeline.	
Croatia	Acceleration of the KrK LNG project; establishment of a second storage facility; establishment of the Croatian-Hungarian gas pipeline connection.	Croatia – Hungary interconnection concluded in December 2010
Hungary	New interconnections with Slovakia and Slovenia; upgrading of the HAG connection with Austria.	Underground working gas storage capacity upgraded by 2.7 Bcm (from which 1.2 Bcm is strategic storage). Hungary-Romania interconnector concluded in October 2010. Hungary Croatia interconnector to be concluded in December 2010
Serbia	Development of natural gas storage capacity jointly with Gazprom; Bulgaria-Serbia interconnector.	
Slovakia	Establishing a wholesale and storage undertaking partly owned by the state; regional storage cooperation; nuclear power production; option of a strategic storage.	
Slovenia	Establishing a domestic gas storage facility; demand for further coal-based and nuclear power production.	

Source: Platts reports; Hungarian Energy Office

For example, gas infrastructure investments have already resulted in a significant upgrade in the import pipeline and gas storage capacities of Hungary (see Table 5).

Table 5. Capacity of the Hungarian gas system before and after the 2009 gas crisis

	Daily peak capacity, Mcm			Annual capacity (Bcm)		
	2008	2010	% change	2008	2010	% change
Underground storage	51	80,1	57%	3,72	6,13	65%
Domestic production	10,2	10,2	0%	2,8	2,8	0%
Import	42,1	72,1	71%	15,3	26,3	72%
Total	**103,3**	**162,4**	**57%**	**21,82**	**35,23**	**61%**
Transit	11,3	11,3	0%	4,1	4,1	0%

Source: FGSZ, REKK

But beyond infrastructure upgrades, gas crisis related regulations have also been amended in a number of countries. Taking again the Hungarian example, the government revised the country's gas market emergency regulation as a response to the 2009 January crisis. The revisions concentrated on re-defining customer categories for enforced firm load shedding. Also, the newly proposed long term energy strategy of the country considers gas infrastructure diversification as one of its key mid-term priorities.

6 Conclusion

The 2009 January gas crisis confirmed earlier warnings that the single important supply security risk that the enlargement of the EU in 2004 and 2007 brought about was the unilateral gas import dependence and insufficient gas infrastructure of the new member states.[16] The shock of the crisis helped to learn much about the vulnerability of the enlarged European gas industry and, in particular, that of the CSEE region. Since the crisis a number of developments seem to confirm that very important lessons from the crisis have been learnt at the European level. A new gas supply security regulation with

[16] Kaderjak, P and LaBelle, M (ed) (2008), *Impact of the 2004 Enlargement of the EU Energy Sector*. Study prepared for DG TREN. Published by the Regional Centre for Energy Policy Research, Budapest.

the right focus on customer protection, infrastructure upgrade and improved crisis preparedness had been adopted with fast speed. Also, an ambitious energy infrastructure development program, with a balanced focus on gas infrastructure problems in CSEE, is being formed right before the start of final preparations of the Union's next budget. Moreover, the crisis confirmed European policy makers in their former conviction that security in gas supply for the community would only come together with a physically sufficiently interconnected and efficiently operating internal gas market. Now, the real question today is to what extent the national governments, especially those of the most affected member states, learned the same lessons and, even more, whether they are ready to provide persistent attention to international cooperation and able to create a supporting regulatory environment for gas companies in order to fix their gas market problems in the coming decade. We will get a first impression about the answer to this question when the first national and, perhaps, joint Emergency Plans are published by the national Competent Authorities on December 3, 2012, the latest.

The Danube Region Gas Market Model and its application to identifying natural gas infrastructure priorities for the Region[1]

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1 Abstract

The paper introduces the Danube Region Gas Market Model, a network and contract constrained multi-country competitive equilibrium model and applies it to estimate the impacts of new gas infrastructure investments on market integration, social welfare and supply security in the countries of Central and South East Europe. Individual projects, project packages (e.g. the North-South gas corridor for Central and Eastern Europe) and international pipeline projects (like Nabucco West) are evaluated according to the Regional Cost Convergence Index. Estimates on price spill-over effects of new infrastructures are also presented. The model can support cost benefit analyses foreseen by the proposed European Infrastructure Package to identify EU projects of common interest.

[1] Originally published in *Competition and Regulation 2012*, pp. 256-282. MTA KRTK, Institute of Economics, Budapest

2 Introduction

New EU member states and the wider Central and Southeast European region (from this point forward the Danube Region or DR[2]) suffer from specific gas industry problems. The most serious of them is the lack of sufficient interconnectivity which impedes gas supply source diversification for the DR, reduces the scope for gas market integration and supply security improvements at the regional level.[3]

Since the shock of the 2009 January gas crisis, European energy policy has been attempting to remedy the above mentioned gas industry problems of the DR and Energy Community countries alike. A prominent example is the gas supply security regulation 994/2010 of the EU. The new European Infrastructure Package (EIP)[4] intends to identify and provide Union level support for gas infrastructure projects that will positively impact interconnectivity and market integration[5] in the region. The EIP identifies certain priority corridors, which in the case of gas includes linking the Baltic, Black, Adriatic and Aegean Seas. The development of north-south interconnections in Central and Eastern Europe and Southeast Europe forms an important element of this corridor. In 2011 the EC commissioned a "High Level Group"[6] with the mandate to devise an action plan for the development of interconnections in gas, electricity and oil by the end of 2011. The High Level Group published its action plan in December 2011. In 2012 this work continues with a similar High Level Group activity for the Energy Community countries.

Finally, in October 2011, the EU approved the European Union Strategy for the DR that foresees a strengthened cooperation in a wide range of areas, including energy policy.

[2] The 14 Danube Region countries are: Austria (AT), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), the Czech Republic (CZ), Germany (DE), Hungary (HU), Moldova (MV), Montenegro (MNE), Romania (RO), Serbia (SB), Slovakia (SK), Slovenia (SL) and Ukraine (UA).

[3] The price, supply security and political risks of a lock-in situation with dominant Russian import dependence for the DR are assessed by Kaderják (2011a and 2011b).

[4] COM(2011) 658 (in the followings: proposed Regulation), SEC(2011) 1233 and COM(2011) 665.

[5] Article 4 of the proposed infrastructure Regulation defines four criteria that will apply for the evaluation of gas projects of common interest; their impact on market integration, security of supply, competition and sustainability.

[6] The High Level Group on north-south interconnections is chaired by the EC and includes Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia as members, and Croatia as an observer. Austria, Germany and Slovenia also became members of this group. The High Level Group also established a "working group on natural gas" (GWG) consisting of representatives of the relevant ministries, regulatory authorities and transmission system operators (TSOs) in the participating countries, except for Austria and Germany.

Its Action Plan[7] states that for a secure and well-functioning natural gas market in the DR;

'…the interconnections between national markets have to be improved and countries in the region need to gain access to new external sources. Reinforcing gas transmission infrastructure will be key for preventing potential supply disruption in the future. Well-functioning networks, interconnections and interoperability are needed for energy security, diversification and effective energy operation.' (EC 2011, p. 18).

While an agreement seems to emerge that gas infrastructure development is the key to improve gas market integration and supply security for the DR, no solid methodology has yet been developed to assess the impacts of the proposed projects or project packages on regional gas market integration, security of supply, competition and sustainability. Moreover, while the proposed Regulation foresees the application of energy system-wide cost-benefit analysis for the evaluation of promoted projects, such a methodology is still to be developed – in the case of gas by the European Network of Transmission System Operators for Gas (ENTSO-G).

The study by Kantoor Management Consultants (2012) develops a methodology to establish priorities for regional gas infrastructure developments in support of the North-South gas working group, but the proposed methodology still leaves many problems unsolved. Its basis is a physical flow model, with country-level analysis, focusing mostly on security of supply issues. The gas market representation is rather simple and price formation modelling is neglected, leaving the explanation for how new infrastructure will impact market integration incomplete. On the whole, the Kantoor study provides important insights on how changes in infrastructures affect security of supply status of individual countries. However, the analysis does not specifically evaluate the impact of new infrastructure on prices, costs and benefits, or social welfare.

This paper reports on an alternative approach to the evaluation and ranking of new gas infrastructure projects in a regional gas market context. We introduce the Danube Region Gas Market Model (DRGMM) and illustrate how model simulations can be used to assess the impacts of new infrastructure or infrastructure packages on regional gas market integration and for system-wide cost-benefit and security of supply analysis. If extended to include all the EU27 gas markets, the model could help the

[7] Com(2010) 715 and SEC(2010) 1489, respectively.

implementation process of the proposed infrastructure Regulation. First, it could serve as a potential component of the cost-benefit methodology envisioned by the proposed Regulation.[8] Second, model estimates on the distribution of consumer and producer benefits from new infrastructure across impacted countries could also support the Agency for the Cooperation of Energy Regulators (ACER) in elaborating its decisions on cross border cost allocation for Projects of Common Interest (PCI) when national regulatory authorities could not reach an agreement.[9]

The structure of the paper is as follows: After a brief literature review on gas market modelling, we summarize the basic assumptions and characteristics of the DRGMM. Then we present several simulation results to illustrate the variety of analyses the model allows for, including market integration, cost-benefit, and security of supply analyses. Finally we reflect on the limitations of the model's present version and suggest areas for future research.

2 Literature review

Here we will provide a short review of commonly referenced, large-scale computational gas market models that have been used to analyze the security of gas supply and the impact of infrastructure developments in Europe.

The main focus of the EUGAS model (Perner and Seeliger, 2004) is to analyze the prospects of gas supplies to the European market in the coming decades. It assumes perfect competition among market players and contains an extensive infrastructure representation. The objective function and the constraints of this model are linear across a five year horizon, and the annual gas consumption is split seasonally into three different load periods.

Contrary to the EUGAS model, most of the gas simulation models depict the strategic interaction between the suppliers. The GASTALE model (Boots, 2004) was the first attempt to apply successive oligopoly conditions in natural gas production and trading in a large-scale simulation model. The model has a two-level structure, in which producers engage in competition *a la* Cournot, and each producer is a Stackelberg leader with respect to traders, who may be Cournot oligopolists or perfect competitors.

[8] See e.g. Article 12 of the proposed Regulation.
[9] See Article 13(6) on this matter.

The extended, dynamic versions of the GASTALE model (Lise and Hobbs, 2008 and 2009) include investments in scarce infrastructure (such as pipelines, storages and LNG infrastructure), but they assume market power only for producers.

GASMOD (Holz et al., 2008) is similar in spirit to GASTALE, similarly structuring the European natural gas market as a two-stage-game of successive oligopolies; imports to Europe (first stage, upstream) and trade within Europe (second stage, downstream). As the model's main focus is to examine the possible effects of liberalization on trade, the geographical coverage of the model is wide. On the demand side it includes all European markets and on the supply side it includes all major exporters to Europe.

Egging et al. (2008) presented a more detailed complementary model of the European natural gas market which accounts for the market power of exporters and of the globalization of natural gas markets with LNG trade. The market structure that their model constructs is different from that of GASMOD and the static GASTALE model, marked by the assumption that only traders can exert market power by playing the Cournot game against each other, with other players assumed to be price takers.

Based on their previous work (Gabriel et al. 2005a, b) Egging et al. (2010) presented the World Gas Model. It is a multi-period mixed complementarity model for the global natural gas market, which contains more than 80 countries and regions and covers 98% of worldwide natural gas production and consumption. It also includes a detailed representation of cross-border pipelines and constraints imposed by long-term contracts in the LNG market. The model operates with five year periods and two seasons (peak and off-peak). Similar to the previous models, it accounts for market power in the upstream market between traders using both pipelines and LNG deliveries. It allows for endogenous capacity expansions and seasonal arbitrage by storage operators.

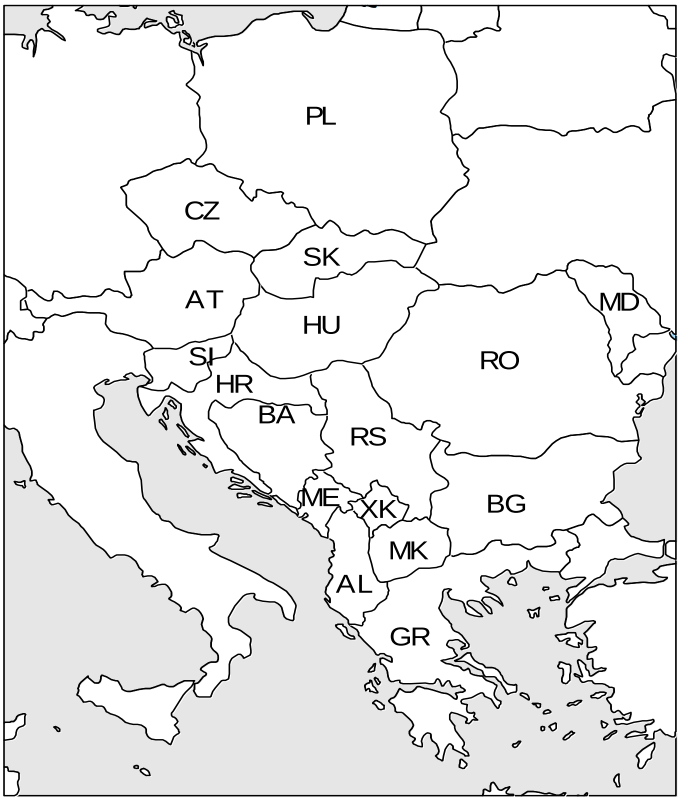
The NATGAS model (Mulder and Zwart, 2006) assumes an oligopolistic producer market where a small number of strategic natural gas producers are facing price-taking traders in the downstream market. The main focus of the model is to compute long-term effects of policy measures on future gas production and gas prices in Europe. It contains long-run projections of supply, transport, storage and consumption patterns in the model region, aggregated in 5-year periods, distinguishing two seasons (winter and summer).

Abada et al. (2012) developed a dynamic Generalized Nash–Cournot gas market model (GaMMES model). In the applied oligopolistic market structure they take into account long-term contracts in an endogenous way, which makes the model a Generalized Nash Equilibrium problem. Their demand representation is specific because it captures the possible fuel substitution that can be made between the consumption of oil, coal, and natural gas in the overall fossil energy consumption.

3 The Danube Region Gas Market Model

The Danube Region Gas Market Model has been developed by REKK to simulate the operation of an international wholesale natural gas market in the Central and South-East European (CSEE) region.[10] Figure 1 shows the geographical scope of the model. Country codes denote the countries for which we have explicitly included the demand and supply side of the local market, as well as gas storages. Large external markets, such as Germany, Italy or (indirectly) Russia, are represented by exogenously assumed market prices, long-term supply contracts and physical connections to the CSEE region.

Figure 1. The geographical scope of the Danube Region Gas Market Model



All map outlines are based on the maps of Daniel Dalet, source: http://d-maps.com/m/europemax/europemax09.svg

[10] For an initial description and application of REKK's Regional Gas Market Model see Kaderjak, P. 2011a, 121-147.

Given the input data and subject to constraints represented by the physical gas infrastructure and contractual arrangements specific for the Danube Region, the model calculates a dynamic competitive market equilibrium, resulting in the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions, and long-term contract deliveries.

Model calculations refer to 12 consecutive months, with a default setting of April to March.[11] Dynamic connection between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and long-term take-or-pay (TOP) contract constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

The Danube Region Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) TOP contracts; and (7) spot trading. We will describe each of them in detail below.

3.1 Local demand

Local *consumption* refers to the amount of gas consumed in each of the local markets in each month of the modelling year. It is, therefore, a quantity measure.[12] Local *demand*, on the other hand, is a functional relationship between the local market price and local consumption, similarly specified for each month of the modelling year.

Local demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 €/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example).

The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

[11] The start of the modelling year can be set to any other month.
[12] All quantities are measured in energy units within the model.

3.2 Local supply

Local *production* is a measure of quantity similar to local consumption, so the corresponding counterpart to local demand is local *supply*. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price.

In the model, each supply unit (company, field, or even well) has a constant marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, with the constraints being independent across months.[13] Therefore production decisions in October, for example, have no direct effect on production possibilities in any other month.

Any number of supply units can be defined for each month and each local market. As a result, local supply will be represented by an increasing step-function for which the number and size of steps can be chosen freely.

3.3 Gas storage

Gas storage facilities are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from or injected into storage. Each local market can contain any number of storage units (companies or fields).

Storage units have a constant marginal cost of injection and a separate cost of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There is no specific working gas fee, but the model contains a real interest rate for discounting the periods, which automatically ensures that foregone interest costs on working gas inventories are taken into account.

There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.

[13] Minimum production levels can be set to zero. If minimum levels are set too high, a market clearing equilibrium may require negative prices, but this practically never happens with realistic input data.

3.4 External markets and supply sources

Explicitly modelled local markets are limited to the countries of the CSEE region (including the DR), but their gas sectors are by no means closed to the outside world. There are comparatively large external markets and supply sources neighbouring the region, which can serve as import sources (e.g. Russia, LNG markets), export destinations, or both (e.g. Germany, Italy).

Prices for external markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. As a consequence, the price levels set for outside markets are important determinants of their trading direction with the CSEE region. When prices are set relatively low, CSEE countries are more likely to import from the outside markets, and vice versa.

3.5 Cross-border pipeline connections

Any two markets (local or outside) can be connected by any number of pipelines, which allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which corresponds to the presence of dedicated transit pipelines.

Cross-border pipelines are unidirectional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each pipeline has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.

Virtual reverse flow ("backhaul") on unidirectional pipelines can also be allowed or restricted for each connection and each month. The rationale for virtual reverse flow is the possibility to trade "against" the delivery of long-term TOP contracts, being that the reduction of pre-arranged gas flow can be considered the same type of commercial transaction as selling gas in the reverse direction.

We disregard from modelling the internal gas transmission systems of local and external markets.

3.6 Long-term take-or-pay (TOP) contracts

A TOP contract is an agreement between an outside supply source and a local market concerning the delivery of natural gas into the latter. The structure of a TOP contract is the following; each contract has monthly and annual minimum and maximum quantities, a delivery price, and a monthly proportional TOP-violation penalty. Maximum and minimum quantities (monthly or annual) cannot be breached. If the purchase of deliveries are below the monthly minimum, the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered.

Any number of TOP-contracts can be in force between any two source and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next.

The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract, but they can also be changed month to month. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions.

3.7 Spot trading

The final building block, spot trade, serves to arbitrage price differences across markets that are connected with a pipeline. Typically, if the price on the source-side of the pipeline exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the pipeline is reached.

Physical flows across a pipeline equal of the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become “negative” (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow on a pipeline.

3.8 Equilibrium

The DRGMM algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, adhering to all the constraints detailed above.

In short, the equilibrium state (the “result”) of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[14]

Local consumers decide about gas utilization based on the market price. This decision is governed entirely by the local demand functions we introduced earlier.

Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions.

Second, traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection, and working gas capacity as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[15,16]

Finally, traders also perform spot transactions based on relative prices in local and outside markets based on the available cross-border transmission capacities to and from those markets, including countries such as Russia, Germany, Italy, Turkey, or LNG markets which are not explicitly included in the supply-demand equalization.

[14] When assessing welfare effects, we omit storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

[15] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.

[16] A similar inter-temporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

4 Simulation results

This chapter presents an application of the DRGMM to assess the likely impact of all known gas infrastructure development project proposals[17] on regional gas market integration in the DR. The types of projects we analyse are inter-region pipelines (interconnectors, including reverse flow projects), underground storage sites, LNG terminals and international long distance pipelines providing new sources of gas supply for the DR.

For this purpose we create and run a reference scenario with 2011 input data and additional assumptions discussed below. Next we add, one by one, the proposed projects to the reference case infrastructure *ceteris paribus* and compare model outcomes to the reference case. Thus the outcome of regional gas trading and infrastructure operations can be measured according to the differences in outcomes from the 2011 reference case. When adding new infrastructure to the reference case, we disregard the cost and timing of infrastructure investment, so the model is established '*overnight*' and the tariffs paid by infrastructure users for transmission, storage or LNG terminal services remain unchanged. However, for the purpose of cost-benefit analysis we collected available project related investment cost data.

After analysing individual projects one by one, we repeat the same procedure for project packages like the proposed project list of the north-south gas working group. Finally, the likely impact of new long distance pipelines on the regional gas market is assessed in the context of a 2020 reference scenario.

4.1 Input data

Table 1 contains the dimension and sources of technical input data used for the simulations. In order to create the 2011 reference scenario, we used estimated data when 2011 data was still not available (e.g. consumption data due to delayed publication). The actual data used to create the 2011 and 2020 reference scenarios is summarized in the country profiles in Annex 1.

[17] Annex 1 contains the list of analysed projects.

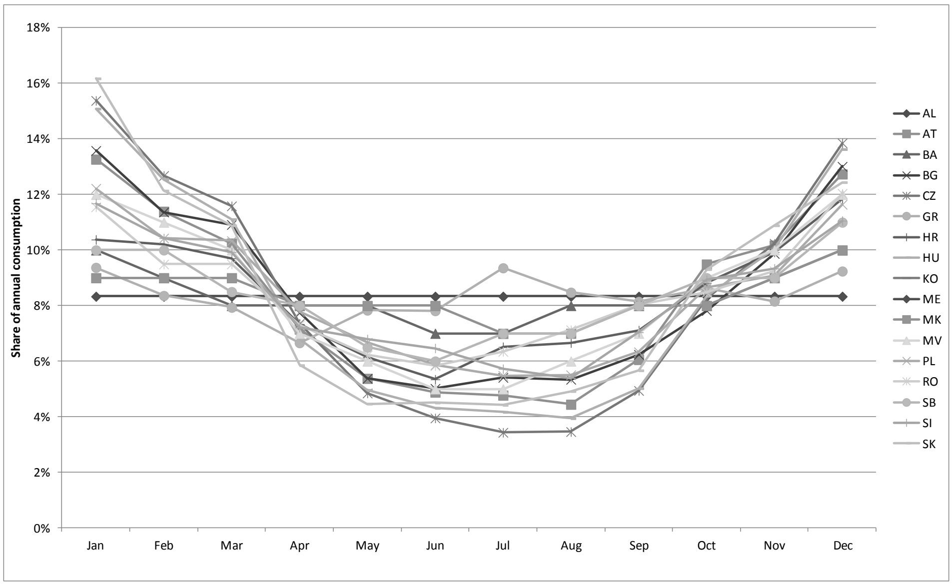
Table 1. Summary of input data structure and sources

Data		Source	
Category	Unit	Actual data	Forecast / Planned
Consumption	Annual Quantity (bcm) Monthly distribution (% of annual quantity)	Eurostat, EnC data	N-S study, EnC data, Eurostat, ENTSO-G, own estimation
Production	Minimum and maximum production (mcm/day)	EUROSTAT, EnC data	N-S countries: N-S study, EnC data, ENTSO-G GRIPs, TYNDP,
Infrastructure			
♦ Pipeline	daily maximum flow	ENTSO-G, EnC	TSOs, N-S action plan, TYNDP, GRIPs, EnC
♦ Storage	Injection (mcm/day), withdrawal (mcm/day), working gas capacity (mcm)	GSE	
♦ LNG	Capacity (mcm/day)	GLE	
TOP contracts	Yearly minimum maximum quantity (mcm/year) Seasonal minimum and maximum quantity (mcm/day),	Gazprom, National Regulators Annual reports, Platts	

EnC: Energy Community Regional Energy Strategy Task Force data; N-S Study: Kantor Management Consultants (2012)

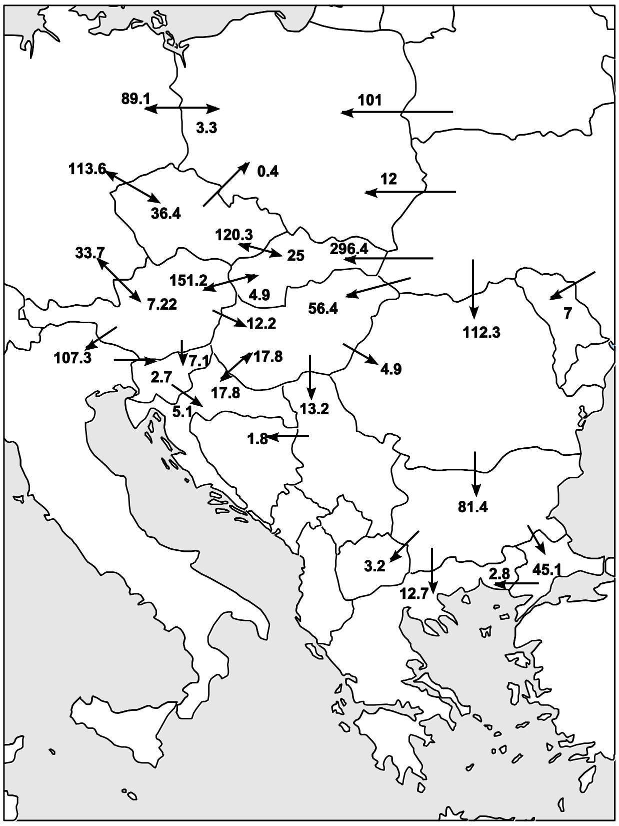
For the 2020 annual consumption and production forecast we rely on a critical review of the forecasts of institutions listed in Table 1. The monthly distribution of gas consumption for the analysed countries was estimated using historic data (see Figure 2).

Figure 2. Estimated monthly distribution of consumption in the modelled countries (% of annual consumption)



The pipeline infrastructure of the region for the 2011 reference scenario is depicted on Figure 3.

Figure 3. Interconnector topology used for the 2011 reference scenario. Arrows show the possible physical flow direction and the daily maximum capacity (mcm/day)



Finally, in order to run the model, we also have to assume TOP and spot prices for external markets and tariffs paid by infrastructure users for transmission and storage (injection and withdrawal).

Table 2 contains external gas product prices we use for simulation purposes in this paper. With regard to TOP contracts we assume a mixed pricing regime with a 20% weight for spot and 80% weight for oil indexed pricing, which reflects the European gas industry's ability to renegotiate Russian TOP contracts in recent years due to the economic crisis.[18] The assumed tolerance for TOP annual contracted quantity is ±15%. For the simulations with the 2020 reference scenario, we assume the renewal of the long term contracts expiring between 2011 and 2020, but also assume a 20% decrease in their annual contracted quantity.

Table 2. External market price assumptions (€/MWh)

Market	Price in €/MWh
Western Europe (TTF spot)	24.2
Russia (TOP)	34.2
Italy (spot)	28.0
Turkey (TOP)	31.6
LNG	24.2
LNG BG, RO	31.6

Transit contracts are taken into consideration only as far as they use infrastructure within the DR. In case of Germany and France we assume 50% of their Russian imports will come through Nord Stream from 2013, thus 2020 flows are reduced accordingly. Furthermore, in the case of Germany we assume that 50% of the transit requirements pass through the Yamal pipeline. For Turkey, we take into account only those Russian import contracts that are transmitted through Romania and Bulgaria. For Italy, Russian contracts go through Slovakia and Austria.

We do not have a realistic representation of local market transmission tariffs for the DRGMM, so we set them close to zero in this paper. We think that disregarding from transmission tariffs will not distort our conclusions because the unit transmission cost for a MWh of gas is negligible compared to its product price.[19] Another argument is that

[18] Note however that we assume no active *pricing behaviour* on external markets.
[19] REKK has recently carried out a survey of gas transmission tariffs for an 80 MW gas fired power plant for 10 of the modelled countries and found a € 1.87/MWh average value for this group. This is 5.5% of the oil indexed and 7.7% of the German spot price we use in this study.

although significant differences in transmission tariffs across the region might distort cross-border arbitrage opportunities, including the utilization of gas storage assets, the advancement of EU-wide gas market regulation and integration is expected to level-off transmission tariffs for the region. Nevertheless, this is a point for further model development.

Data on gas storage tariffs (injection and withdrawal fees) were gathered from storage owners or national energy regulators. Besides direct storage costs, we also account for the foregone interest costs on holding working gas inventories. The real interest rate for calculating the interest costs of gas inventories is set at 5%.

4.2 Market integration measures

The first set of our project related analyses deals with regional gas market integration and the impact of new interconnectors or LNG stations.[20] Since market integration is a multi-dimension concept and difficult to measure *per se*, we have developed variations of a simple measure of market integration. Our *Regional Cost Convergence Index* (RCCI) is based on the assumption that an advance in market integration results in price convergence across the countries concerned *and* towards cheaper gas supply sources. Thereby in the 'Danube Region 2011' reference, a new piece of gas infrastructure will improve market integration by reducing local oil-indexed prices closer to continental spot price levels.

Formally,

$RCCI = \frac{\sum p_i \cdot q_i}{p_{spot} \cdot Q} - 1$, where

i is an index for the DR countries, $i = 1 \ldots k$;

p_i is the annual weighted average gas price on local market i, calculated by the model;

q_i is the annual gas consumption on local market i, calculated by the model;

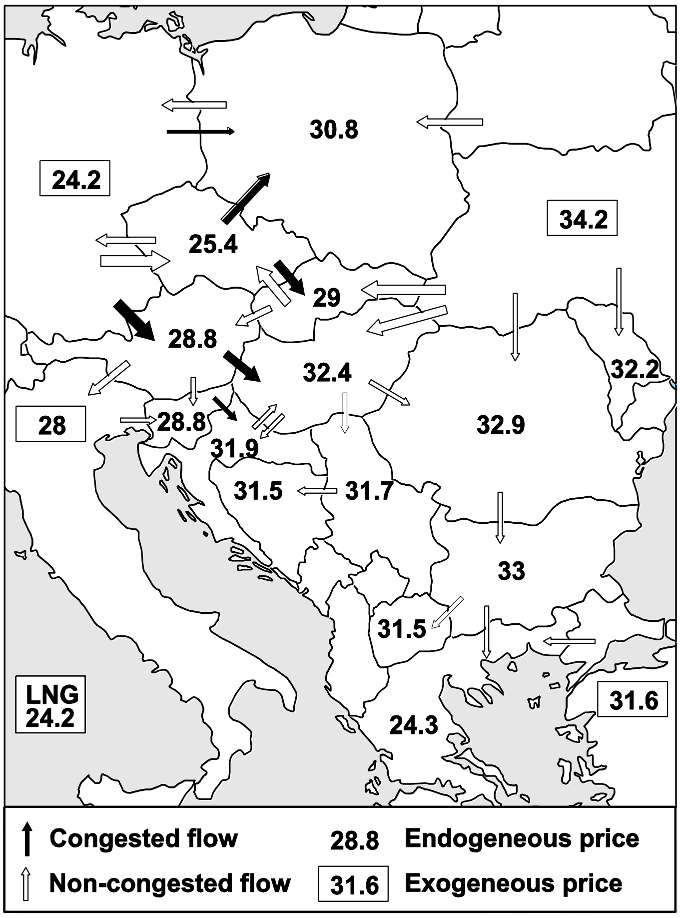
Q is the amount of DR gas consumption (sum of q_i over k), calculated by the model;

p_{spot} is the continental spot price.

[20] A positive impact on gas market integration is the singularly most important criterion a PCI should meet according to Article 4 of the proposed infrastructure Regulation.

The RCCI is the excess gas purchase cost (a percentage), which is the amount that the DR pays for its gas consumption over the same amount at a continental spot price. The RCCI for the 2011 reference scenario is 21.5%. Figure 4 shows the modelled 2011 reference scenario with local prices (€/MWh, white boxes) and trade flows (arrows), assuming external market prices (included in the grey boxes). White arrows represent non-congested and grey indicates congested interconnections.

Figure 4. Reference scenario: 2011 current infrastructure (RCCIref = 21.5%)



4.3 Analysis of individual projects case by case

To calculate the project RCCIs, we added the proposed gas infrastructure projects to the 2011 reference scenario one at a time, holding everything else constant. No single gas storage project had a significant regional market integration impact. Table 3 contains the pipeline simulations and Table 4 lists the LNG projects, in the order of increasing RCCI values. Those projects with lower RCCI save more gas purchase cost *for the region* than those with higher values, while the distribution across individual countries will vary. For example, in the 2011 reference scenario, consumers of the Danube

Region pay 4700 million € more than what they would pay for their consumption on a Western European spot market price.

We identified seven pipeline and five LNG projects which alone can have a significant and beneficial regional impact on gas prices and purchase costs. While the rest of the pipeline projects do not have a significant regional impact individually, there are some that actually result in *higher* RCCI values (that is, increasing gas purchase cost for the region). The latter results might seem counter-intuitive, but they are actually consistent with the workings of the market. The market equilibrium maximizes total welfare, i.e. the aggregate welfare of *all* market players, i.e. consumers, producers, storage and interconnector, operators etc. Therefore while the addition of a new infrastructure element will never decrease short-term social welfare, it may well result in a welfare loss for one or more groups of market players.

Table 3. Individual pipeline project ranking by RCCI

Pipeline	RCCI (ref:21,51%)	Pipeline	RCCI (ref:21,51%)
CZ-PL2	17,10%	PL-SK	21,51%
SK-HU	18,35%	BG-RO	21,51%
GR-BG	21,13%	PL-CZ	21,51%
TR-BG	21,29%	HR-IT	21,51%
RS-BG	21,39%	MK-GR	21,51%
RS-RO	21,42%	HR-HU2	21,51%
RO-MD	21,47%	RS-MK	21,51%
BA-RS	21,50%	RS-HR	21,52%
MK-AL	21,51%	BA-HR	21,52%
HR-RS	21,51%	MK-RS	21,55%
HR-BA	21,51%	RO-HU	21,56%
HU-SK	21,51%	BG-RS	21,56%
MK-XK	21,51%	RO-RS	21,56%
AT-CZ	21,51%	MK-BG	21,56%
HR-SI	21,51%	MD-RO	21,57%
RS-BA2	21,51%	SI-HU	21,67%
HU-SI	21,51%		

Table 4. Individual LNG project ranking by RCCI

	RCCI (ref:21,51%)
LNG-PL	16,94%
LNG-PL2	17,04%
LNG-HR	20,03%
LNG2-RO	20,40%
LNG2-BG	21,29%
LNG-GR2	21,51%

According to RCCI, the best ranking pipeline project for the region is an upgrade of the Czech-Polish interconnector from its present 0.4 mcm/day to 8.6 mcm/day capacity. A new Slovak-Hungarian interconnector ranks second, followed by three projects that reduce relatively high Bulgarian prices, and lastly an interconnection from Romania to Moldova. The best ranking LNG projects are on the Polish and the Croatian territories.

However, project ranking by RCCI alone can be misleading from a regional perspective since it is neutral with regard to the distribution of price changes and cost savings across the countries. Impacts of some projects might be limited within those parties that are directly involved while benefiting others across the region. Our *Regional Spill-over Index* (RSoI) measures by how much the addition of a new piece of infrastructure will change the 2011 reference RCCI when we exclude the countries directly affected by the new project[21] from the RCCI calculation. Table 5 contains the results for those interconnector projects that produce part of their cost reduction effects beyond the borders of the project countries.

Table 5. The reduction of regional gas purchase costs by individual pipeline projects in peripheral countries, %

Pipeline project	Reduction, %
SK-HU	1.59%
GR-BG	0.51%
RS-BG	0.11%
MD-RO	0.02%
TR-BG	0.01%

[21] One country in the case of LNG, and two in the case of a new interconnection

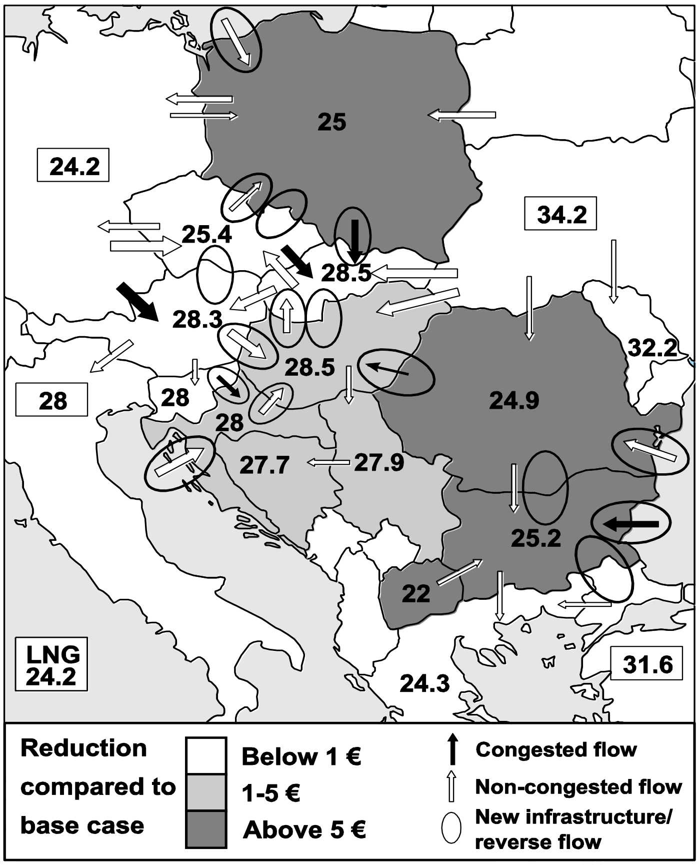
We can see that the impacts of two of the top ranking projects by RCCI, the Czech-Poland and the Serbia-Romania interconnectors (see Table 3), are strictly limited to the involved countries, (their RSoI is 0). In contrast, the majority of benefits are generated beyond the borders of the project countries (Slovakia-Hungary and Greece-Bulgaria). We can identify similar differences in the case of LNG projects. The benefits of a Polish LNG receiving terminal, without additional cross border pipelines put in place, is strictly limited to Poland itself. At the same time a Croatian LNG project could bring reduced prices and purchase costs not only for itself but also for Slovenia, Hungary, Serbia and Bosnia and Herzegovina without any supplemental infrastructure.

4.4 Analysis of project packages – the North-South gas corridor

The DRGMM model can also be used to carry out similar assessment of regional gas market integration for project packages. In recent years a number of proposals have been put forward to develop a set of infrastructure projects to improve gas market interconnectivity of the DR. The two prominent ones were the New Europe Transmission System (NETS) project (a European priority project under the EU's TEN-E program) and the recently developed North-South gas corridor for Central and Southeast Europe. Since the present status of the NETS project does not allow for the breakdown and identification of its individual infrastructure projects, we used the North-South corridor project list that was published by the Commission in December 2011 (EC, 2011).

Adding the 17 projects of the North-South corridor to the 2011 reference case lowers the RCCI index from 25.1% to 6.8%. This translates into an annual gas purchase cost savings of 2827 million € for the DR (see Figure 5).

Figure 5. The impacts of the North-South corridor (RCCIref = 21,5%)



All countries except for the Czech Republic seem to enjoy a significant drop in wholesale gas prices in the modelled countries. The implementation of the entire project seems to bring the Western part of the region very close to the German / Italian markets and the South-Eastern part to the Greek market, as four LNG terminals provide significant new supply sources for the region.

Second, the empty black circles on Figure 4 stand for projects that are built but not utilized by market participants according to the model. An interesting issue for future analysis is how the package could be reduced while still preserving its benefits for the region. This requires an in-depth analysis due to the abnormal trading patterns of the region that are a result of significant TOP obligations and spot trading opportunities supported by a robust infrastructure and new LNG supply sources. We can observe several trade flows from high to low priced countries (e.g. Bulgaria exporting to Greece or Hungary exporting to Serbia) or a lack of trade between countries with a price differential (e.g. an empty pipeline between Slovenia and Hungary).

4.5 The impacts of new international gas pipelines entering the region

Up to now we have investigated the impacts of intra-regional projects and project packages on market integration. However, in recent years discussions about how to increase gas supply source diversification of the DR have manifested in South Corridor gas pipeline project alternatives, e.g. Nabucco, Nabucco West, South Stream, TAP. Now we seek to analyse the potential impacts of new pipeline supply sources entering the DR according to the model.

For this analysis we first create a 2020 reference scenario. Compared to the 2011 reference case, three major changes are made to the model: first, only new infrastructure under construction in 2011 are added; second, load data is modified according to best available 2020 forecasts; third, we assume that TOP contracts expiring between 2011 and 2020 will all be extended again but at a reduced rate of annual contracted capacity (80% of the former contract). External price assumptions are unchanged compared to the 2011 reference scenario. The RCCI index for the 2020 reference case is 29.9%

New pipelines are represented schematically, by assuming that new gas entering the region is under a TOP regime. TOP is priced at Russian price minus 5%, with the Russian price 80% oil and 20% spot indexed.

We compare the impacts of two pipeline business models under two different intra-regional network configuration alternatives (four cases). The first pipeline brings 10 bcm to the Turkish-Bulgarian border and then ships all of it to Baumgarten via Bulgaria, Romania and Hungary. Spot trading of this gas is then allowed (Project 1). This pipeline business model considers the DR as primarily a transit area. Alternatively, Project 2 brings again 10 bcm to the Turkish-Bulgarian border but some of the gas is distributed along the way: 1 bcm for the Bulgarian and Romanian markets, 2 bcm for the Hungarian market, and the remaining 6 bcm reaches Baumgarten. Sufficient additional pipeline capacities are assumed to bring these amounts to the affected markets. We estimate the impacts of Projects 1 and 2 on RCCI both with the assumption of a complete and incomplete North-South corridor. The corresponding RCCI figures are summarised in Table 6.

Table 6. The impact of alternative 10 Bcm South Corridor projects on RCCI under alternative intra-regional network topology

	With North-South package	Without North-South package
2020 base scenario	19.16%	29.86%
V1 (10 bcm TOP to AT)	16.89%	29.54%
V2 (10 bcm distributed along the route)	16.73%	27.38%

We conclude that the bulk of the improvement in RCCI is due to improved intra-regional interconnectivity along with the addition of LNG sources to the DR – representing the implementation of the North-South corridor projects. The more regionally diversified pipeline business model performs slightly better than the transit model.

4.6 Allowing virtual reverse flow (backhaul) transactions on EU-EU borders of major transit pipelines

Because of the apparent counter-incentives of transit pipeline owners, in the foregoing we have disregarded from allowing backhaul transactions on all transit pipelines, shipping Russian gas to Western and South Europe crossing the DR. However, one might argue[22] that instead of building new infrastructure, the addition of a bi-directional component to existing infrastructure would significantly improve the integration of the DR with West European gas markets.

In order to estimate the potential impact of backhaul transactions on the DR's gas purchase costs, we allowed for virtual reverse flow transactions to happen at all EU-EU borders as – including Croatia[23] - along the transit pipelines. However, no backhaul transactions are allowed at EU-third country borders (EU-RU, EU-TR and EU-EnC[24]).

Table 7 contains the results of our simulations.

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[22] The authors thank Pierre Noel for raising their attention to this point.
[23] Croatia will be member of the EU from 01.07.2013
[24] Allowing backhaul transactions on the EU-EnC borders does not significantly change the result, RCCI would be 25,01%

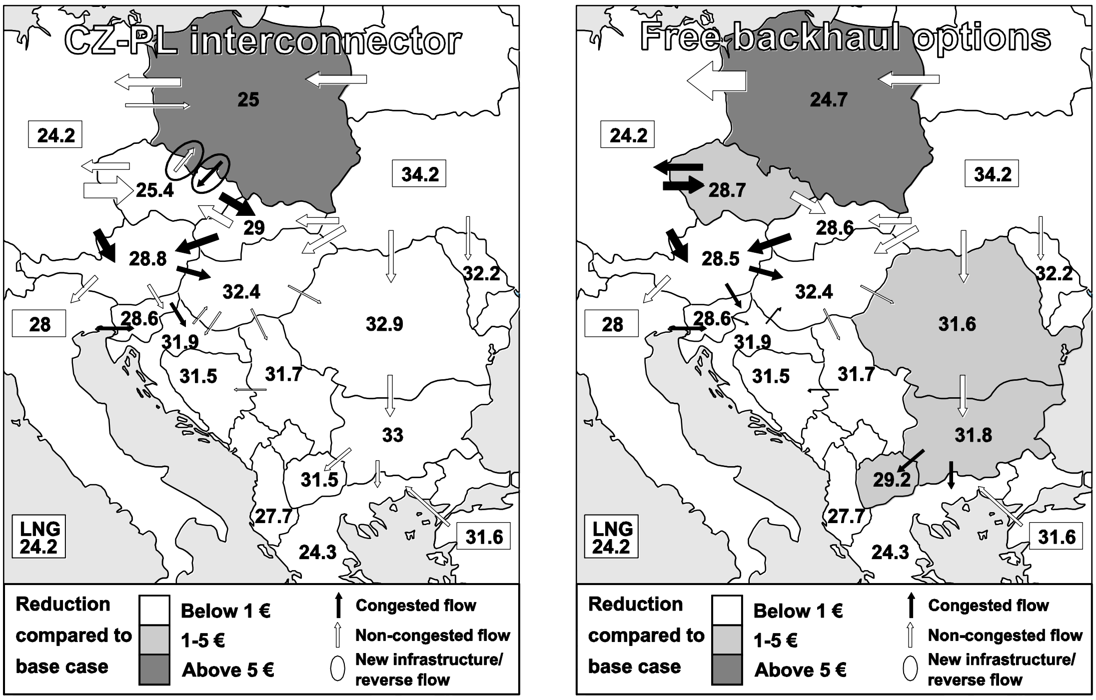
Table 7 The impacts of virtual reverse flow options on RCCI

Backhaul option	not allowed (base case)	allowed on all EU-EU borders	Annual savings on regions gas bill compared to base case
2011	21.51%	17.20%	823 million €
2020 base scenario	29.86%	25.13%	1181 million €

The figures in Table 7 lead can be used to calculate an annual savings of € 823 – 1181 million in gas purchase cost for the region.

The realization of a new Czech-Polish interconnector (map on the left) has very similar results on a regional scale to the free backhaul option (map on the right). However prices in the Czech Republic remain unchanged in the first case while they increase significantly in the second.

Figure 6. Effects of a new CZ-PL interconnector compared to free backhaul options



5 Using the model for cost-benefit analysis: an illustration

Up to this point we have concentrated on market integration and price impacts of projects and project packages and ignored project related costs. However, the consideration of project related investment cost coupled with calculated savings from the model allow for a more economically significant measurement and evaluation than the RCCI or the RSoI alone. Since the availability of investment cost data for future natural gas infrastructure projects is very limited,[25] we often used international benchmarks for this purpose. In this regard the following analyses is based on some cost estimations.

First we calculate a *regional payback period* for the projects by dividing the project related investment cost with the estimated annual purchase cost reduction. Table 8 contains the results of the calculations and also compares project rankings by RCCI against the payback period.

Table 8. Individual project ranking by RCCI and regional payback period

	Project	RCCI (ref:21.51%)	Annual saving on gas bill (million €)	Estimated investment cost (million €)	Pay-back period (year)
Individual pipeline	CZ-PL2	17.10%	841.75	28	0.03
	SK-HU	18.35%	598.51	150	0.25
	GR-BG	21.13%	73.49	160	2.18
	TR-BG	21.29%	41.77	75	1.80
	RS-BG	21.39%	22.98	95	4.13
	RO-MD	21.47%	7.73	50	6.46
LNG	LNG-PL	16.94%	872.30	470	0.54
	LNG-HR	20.03%	281.39	240	0.85
	LNG2-RO	20.40%	205.51	470	2.29
	LNG2-BG	21.29%	41.77	470	11.25

The results indicate that the four best pipeline projects could cover investment costs *for the region* within just 3 years, with the two best (CZ-PL and SK-HU) within a few months. The regional payback period for the Polish and Croatian LNG projects is also less than a year. Surprisingly, the differences in the regional payback period changes the RCCI ranking only slightly, e.g. the TR-BG project becomes more lucrative than the GR-BG pipeline.

[25] Investment costs are gathered from the project home page, from investors in the case of pipelines and a benchmark for LNG.

Thus the question is why these projects are not being built, or if they are planned why they proceed slowly when they are profitable and provide tangible benefits to the region? Part of the answer to this question relates to the positive network externalities of new interconnectors that are non-internalized because of the system of regulated third party access. The revenue from a new interconnector is based on investment and operation costs of the pipeline company. These costs are typically shared and paid by the consumers of those member states directly involved in the project through the regulated transmission tariffs. A new pipeline might include more dispersed additional costs and benefits for producers and consumers across a wider geographic area.[26]

We can illustrate this point by simulating the likely impacts of building one of the top ranking projects, the Greece-Bulgaria interconnector. This project ranks third in RCCI and its estimated cost is € 160 million. By adding this interconnector to the 2011 reference case, we can identify ten countries where the new line leads to a measurable change in annual weighted average wholesale gas prices and improvement in social welfare. Table 9 summarizes the results of this simulation.

Aggregate welfare rises by € 190 million annually, with Greece and Bulgaria the most significant beneficiaries. In the meantime, Romania and Hungary suffer sizeable welfare losses. With regard to market players, TSOs and consumers are the beneficiaries of the project while DR gas producers and TOP contract holders suffer losses. In this scenario, excess demand for the new pipeline capacity results in significant congestion revenues for the participating TSOs.. A gas price decrease, on the other hand, adversely affects local producers and TOP gas holders (TOP gas is crowded out by cheaper Greek LNG sources, leaving TOP holders with a significant loss in all countries except for Greece). Since gas prices increase in Greece relative to the reference case (cheaper LNG flowing now to the North), consumers suffer a significant welfare loss while producers and TOP traders make gains.

[26] Part of the benefits could be captured by tendering pipeline capacity, e.g. an open season procedure.

Table 9. Changes in welfare measures due from Greece – Bulgaria interconnector (million €)

	Net consumer surplus	Producer surplus	Storage operation profit	Net profit from long-term contracts	TSO auction revenues	Total social welfare
GR	-76.8	41.0	0.0	43.9	114.9	122.9
BG	60.3	-8.2	0.0	-46.7	103.8	109.2
RO	94.8	-98.8	0.0	-24.5	-7.5	-35.9
HU	1.7	-0.4	0.0	-1.2	-7.6	-7.5
MK	3.2	0.0	0.0	-2.6	0.0	0.6
SI	0.0	0.0	0.0	0.0	-0.1	-0.1
AT	0.0	0.0	0.0	0.0	-0.1	-0.1
HR	0.6	-0.4	0.0	-0.2	-0.1	0.0
RS	0.3	-0.1	0.0	-0.2	0.0	0.0
BA	0.1	0.0	0.0	0.0	0.0	0.0

We think that model simulations of this kind might help structure the debates surrounding new gas infrastructure projects for the DR by identifying their distributional impacts. Within the EU context, ACER could potentially make use of such results in preparing for its decisions on cross border investment cost allocation (see Article 13 of the proposed infrastructure Regulation).

6 Using the model for supply security analysis: another illustration

The DRGMM model can also support sophisticated gas supply security analyses at the regional level. As we have noted before, the DRGMM model uses a fully dynamic solution algorithm over 12 consecutive months, in which we assume that traders optimize their use of storage assets and the flexibility of the delivery of TOP contracts. As a result, the model produces monthly forward prices for the entire year, which are "right on the spot" in the sense that if there are no subsequent changes in the input data, then all the outcomes (including prices) will turn out as predicted as the year unfolds.

Of course, in reality, supply and demand conditions will deviate from forecasts throughout the year. To capture this, the model allows for the possibility of intra-year runs in which any input variable pertaining to the upcoming months can be changed.

Given that the gas year runs from April to March the initial model run will have to include forecasts for supply-demand conditions in each of the 12 months, otherwise it would be impossible to input optimal storage and contract delivery decisions in the beginning of the year.[27] Taking the forecast as given, we can then calculate how each of the 12 months will "play out".

Now let us suppose that a supply disruption occurs in January. For the sake of the example, it could be another gas dispute between Russia and Ukraine that results in zero Ukrainian transits through the whole of January. In the model, we would represent this incident by setting the maximum transport capacity of the pipelines through Ukraine (to Romania, Moldova, Hungary, and Slovakia) to zero for a month.

An important question is, in which month do market participants know that interconnectors crossing Ukraine will be unavailable in January? If they already know it in April, they will likely have enough time to stock up gas to better adjust to the crisis. But, if it takes them by surprise, the price effects will be much more severe.[28] One can therefore imagine that the actual effects will be highly dependent on the length of time that is available for preparation.

Fortunately, the DRGMM model allows for a full exploration of these issues. Taking the start-of-year run as a reference for how market events occur naturally, it is possible to "stop" the year in any month (e.g. just before January), re-set the input parameters of the model for the rest of the year (e.g. interconnector capacities in January, and probably also the yearly TOP minimum constraints), and re-run the optimization procedure while taking the outcomes of the past months (e.g. storage utilization from April to December) as already given. The model results will then reflect the consequences of regional market-based responses to the supply shock, including the spillover effects on countries not directly affected by the shut-down of the pipeline (Serbia or Bulgaria in this case).

[27] The key decision variables here are those with inter-temporal consequences.

[28] Since the model employs market mechanisms only, negative supply shocks will present themselves as price jumps in the affected areas.

Figure 7. The effect of an unexpected supply disruption of all pipelines

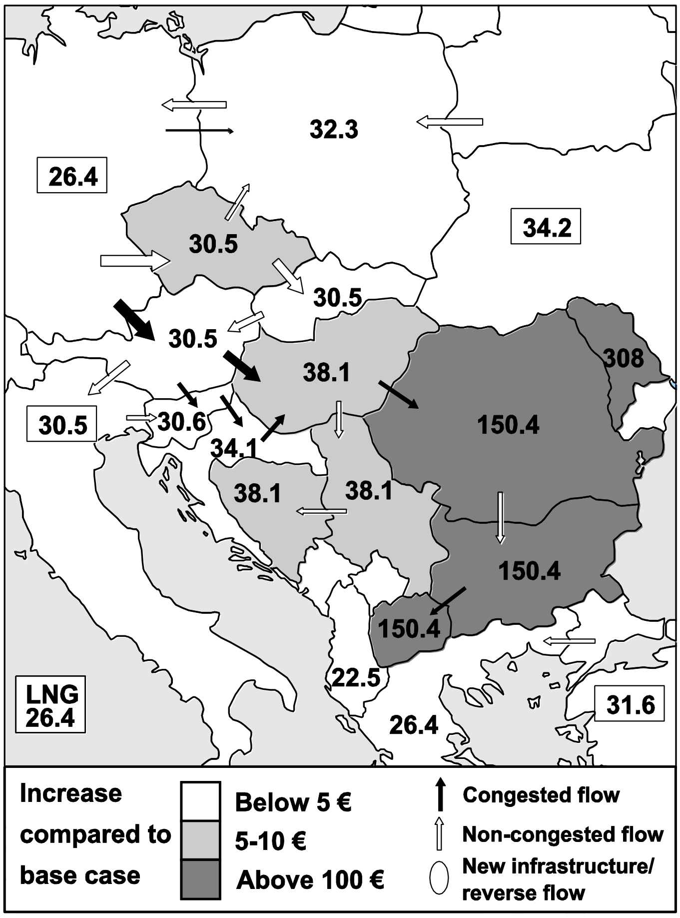


Figure 7 shows the results of the crisis situation that we outlined above. The coloring of the markets indicates the extent of the price rise in January and the seriousness of the supply disruption if the market equilibrium is restored via mandatory consumption cuts.

Light grey colored markets experience a price rise of about 4-5 €/MWh for the crisis month, whereas the dark grey colors indicate a price rise beyond 10 €/MWh. As the actual numbers show, the supply disruption is quite severe in the Eastern part of the Balkans, whereas it seems to be more manageable in Hungary, Serbia, and Bosnia and Herzegovina. Interestingly, the Czech Republic is also affected through the decrease in SK→CZ pipeline flows.[29]

As a final point, we note that the regional (and country-level) supply security effects of various policies and new infrastructure elements can also be assessed using this

[29] The same crisis situation turns out to be almost fully manageable (except in Moldova) when market players start preparing for it in April, instead of only reacting to the events as they take place in January.

methodology. One would simply carry out the supply shock analysis, such as the one above, with and without the policy or the new infrastructure and compare the outcomes.

7 Model limitations and future research directions

The DRGMM is a unique analytical tool that represents the natural gas industries of Central and South East Europe in a detailed and consistent manner. In this paper we have described the assumptions and logic of the model and presented several simulations to measure and analyse effects on market integration, cost-benefit, and security of supply. However, the model has limitations that need to be addressed.

The first of these limitations is the model geography. At present, only the 17 countries from Figure 1 are represented in detail as 'local' markets in the model, leaving a significant part of the EU labelled as an 'external' market. An extension of the model to present 'external' EU markets could result in a detailed representation of the entire interconnected EU natural gas wholesale market.

Second, the model lacks a sensible representation of the EU's outside suppliers' pricing behaviour. In its present form, the pricing of external markets to supply the DR is static; a combination of oil product price and spot price indexation by Russia, relative pricing from Turkey, and spot pricing in Germany, Italy and LNG. Yet in the last four years there were several instances of supply/demand shocks that shifted heavily oil-indexed contracts more towards spot price indexation (Stern and Rogers, 2011). We can also assume that a stronger internal and East-West integration of DR gas markets, promoted by a significant change in network topology in the DR, could create a basis for a more dynamic and market based gas pricing system in the region compared to a present, very rigid oil indexation. Thus, developing a more realistic representation of outside supplier pricing behaviour is a key future model development task.

Third, the representation of gas transmission and storage access prices and pricing in the model requires refinement. This is made difficult by the lack of a consistent data, particularly well-documented benchmarking of gas infrastructure access costs across Europe. Nevertheless, since the magnitude of transmission and storage access tariffs in comparison to product prices is marginal, we can argue that a more accurate and detailed representation of infrastructure access tariffs and rules are not likely to significantly change model results and in fact might disrupt model algorithms.

Finally, one could argue that the representation of the DR gas market as existing in perfect competition under network and TOP contractual constraints is an unrealistic assumption. Beyond TOP constraints, national gas wholesale markets are often dominated by players with significant market power. The assumption of efficient utilization of cross border pipeline capacities is somewhat flawed because existing capacity allocation rules are far from market based mechanisms (see REKK, 2011 on a Hungarian example). Nevertheless, the world represented by the model is the vision of the European Union, including its south-eastern region, for a restructured gas industry. The model thus provides for a normative reference case in a European spirit and allows for an important assessment of the impacts, changes and distortions of projects relative to a baseline case.

Annex 1: The list of the analysed projects

Cross-border interconnections

Pipeline	Maximum flow (mcm/day)	Estimated start-up
BG-RO	14.00	2012
RO-BG upgrade	4.11	2012
RO-HU	4.79	2013
BG-RO upgrade	4.11	2013
GR-BG	8.22	2014
TR-BG	13.70	2014
HU-SK	13.70	2015
SK-HU	13.70	2015
RS-BG	4.93	2015
PL-SK	13.70	2016
TR-BG upgrade	10.96	2017
CZ-PL upgrade	8.22	2017
PL-CZ	8.22	2017
AT-CZ	13.70	2017
HU-SI	3.56	2017
SI-HU	3.56	2017
HR-SI	31.78	2017
RS-BA upgrade	3.29	2018
HR-BA	6.85	2018
BA-HR	6.85	2018
HR-IT	41.10	2018
HR-RS	7.40	2018
RS-HR	7.40	2018
MK-BG	1.23	2018
MK-GR	2.74	2018
MK-AL	2.47	2018
MK-KO	1.37	2018
MK-RS	2.19	2018
RS-RO	4.38	2018
RO-RS	4.38	2018
BA-RS	3.29	2018
RS-MK	2.19	2018
MD-RO	2.74	2018
RO-MD	2.74	2018
GR-BG upgrade	5.45	2020
HR-HU upgrade	12.98	2020

Storage facilities

Market	Injection capacity (mcm/day)	Withdrawal capacity (mcm/day)	Working gas capacity (mcm)	Estimated start-up
CZ	3.9	3.9	290	2012
PL	0.54	2.36	180	2012
RS	10	10	350	2012
PL	5.7	5.7	150	2013
SK	3	2.5	250	2014
AT	1	1.2	84	2014
AT	5.71	8.57	685	2014
AT	2.9	2.9	100	2014
PL	0.28	0.41	35	2014
SK	3	2.5	250	2014
RO	15	15	1 600	2015
PL	7	10.8	675	2015
GR	5	4	360	2015
CZ	0.87	0.87	350	2016
HR	8.256	8.256	510	2017
CZ	1.7	1.7	195	2017
BG	10	10	550	2017
RO	4	4	300	2018
RO	2	2	250	2018
BG	9	9	600	2018
AT	2.8	2.8	225	2018
AT	17.3	17.3	900	2018
AT	24.5	24.5	1600	2018
RS	10	10	350	2018
PL	20.6	20.6	422	2020

LNG terminals

Country	Maximum flow (mcm/day)	Estimated Start-up
LNG-HR	16.44	2014
LNG-PL	13.7	2014
LNG2-RO	21.92	2015
LNG2-BG	6.85	2015
LNG-GR2	5.76	2015

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From oil-indexed to hub-based gas wholesale pricing in Hungary[1]

1 Introduction

In Hungary natural gas has been playing an outstanding role in meeting primary energy demand for a long time. In 2012, 34% of final energy demand was met by natural gas that is 12 percentage points over EU28 average.[2] In 2013 43% of installed electricity generation capacity was natural gas based[3], 88% of households were connected to the gas grid and 77% (in 2012) of district heating was produced by using natural gas. According to recent forecasts (REKK, 2011), the share of natural gas will remain significant in the fuel mix of the country in the longer term. Thus the efficiency of the natural gas market has a major impact on the competitiveness of gas-intensive manufacturing, gas based electricity generation and the welfare of household customers. In addition, a competitive natural gas market with high supply security standards is key for the transformation towards a low-carbon energy system in Hungary (EC 2011)[4].

Since the political system change of 1990 the Hungarian natural gas industry has gone through a tremendous transformation. Corporatization and unbundling of the former, vertically integrated and state owned Hungarian Oil and Gas Trust (OKGT) into six major regional gas distribution companies and the establishment of the National Oil and Gas Company (MOL Rt.) took place in the early 1990s. The 1994 Gas Act established a "single buyer" model for the industry and created a favourable regulatory framework for future privatization, the major wave of which took place between November 1995 and March 1998. By the end of the privatization process major international gas companies entered the Hungarian market and the only state ownership in the industry remained 25%+1 share in MOL. Between 1998 and 2004 the development of the

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[1] I would like to thank Adrienn Selei, Ákos Beöthy and Péter Kotek for their valuable assistance and comments that helped me preparing this Chapter. Certainly, all responsibilities with regard to the content of the Chapter remain with the author.
[2] Eurostat.
[3] A. Stróbl.
[4] The CO_2 emission intensity of natural gas based electricity generation compared to coal based generation might be 70% lower. Gas based generation, together with pump storage, is also key in providing system flexibility to balance intermittent renewable (wind and solar) generation. This is why natural gas is commonly considered as the fuel of transformation towards a low carbon electricity system. This pivotal role of natural gas for a low carbon Hungarian policy roadmap was confirmed by the joint study of REKK and KMPL prepared for the Hungarian Ministry of National Development: *A villamosenergia-termelés, valamint a lakossági és közületi hőfelhasználás dekarbonizációs lehetőségei Magyarországon. Háttértanulmány a Hazai Dekarbonizációs Útitervhez* (2012).

industry has largely been shaped by preparations to join the European Union and, since the accession on May 1, 2004, to fully implement a competitive gas market in accordance with EU rules.

1.1 The problem

Despite the long standing traditions of its oil and gas industry[5], favourable geological conditions and location, as well as its developed natural gas infrastructure, the Hungarian natural gas market is still in a fragile situation. This is reflected by the fact that natural gas has become the synonym of Russian dependence, high heating bills for households and – as a consequence of the 2009 January gas crisis and the present Russia-Ukraine conflict – energy supply security risk in recent years.

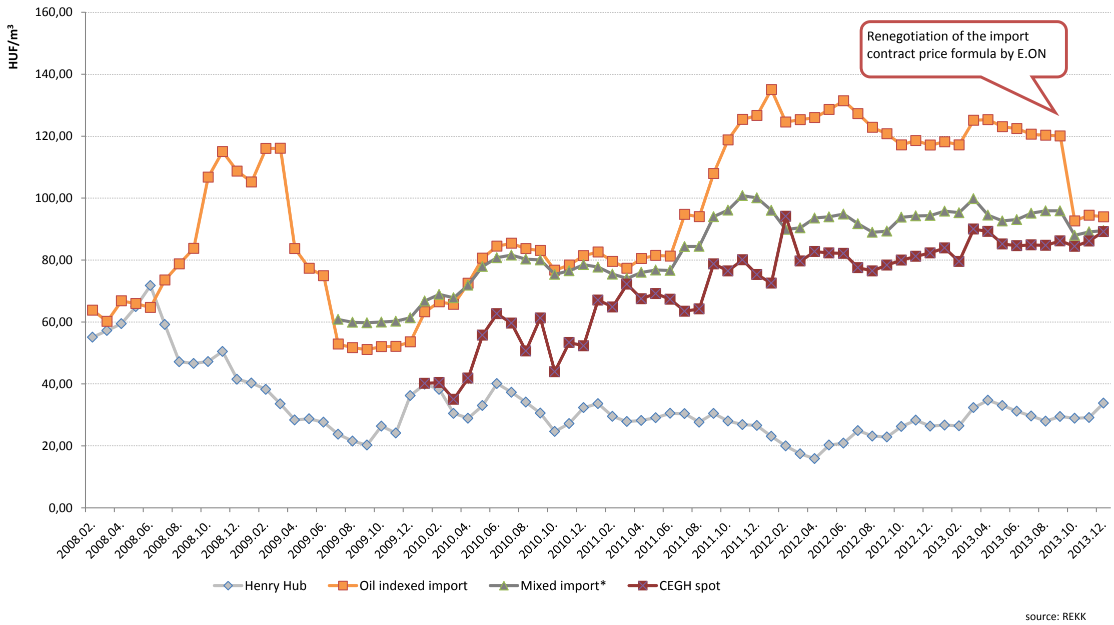
The performance of the Hungarian gas wholesale market in the five years between the fall of 2008 (the beginning of the last economic recession) and 2013 reflects its inefficiency. On the North-West European core markets oversupply and increased competition resulted in wholesale natural gas prices 20-40% below the oil-indexed price, which has been the benchmark for Hungary[6] (see Figure 1). In those five years Hungarian customers could benefit from favourable West-European market trends only due to regulatory intervention[7].

[5] See, for example, the documentary series *Olaj, olaj, olaj! Fejezetek a magyar kőolaj- és földgázipar történetéből.* KLT Kulturális Kft., 2007.

[6] This margin remained even in the period of increasing spot gas prices after the Fukushima nuclear disaster on March 11, 2011 and the follow-up demand shock caused by increased Japanese demand for liquified natural gas (LNG). From October 2013 Gazprom finally adjusted its supply price much closer to market levels for its Hungarian partners (E.ON and then MVM).

[7] Instead of allowing 100% recovery for oil indexed gas import cost in regulated Universal Service (US) prices for households, the regulator applied a '0,4*spot+0,6*oil indexed' formula from October 2010 and a '0,7*spot+0,3*oil indexed' formula from October 2011. This resulted in a 23% decrease in the allowed cost of gas for US customers until January 2013, compared to pre-2010 October levels. In addition, since January 2013 the Hungarian government implemented three subsequent US end customer gas price cuts (January 2013: -10%, September 2013: -11,1% and January 2014: -6,5%) that resulted in an overall 43% decrease in the allowed cost of gas for US customers compared to pre-2010 October levels (source: Hungarian Energy and Public Utilities Regulatory Authority: MEKH). In addition, those traders who got access to the Hungarian Austrian Gas Pipeline (HAG) to ship western priced natural gas to the country could offer below oil-indexed priced gas for free market customers.

Figure 1. The development of oil-indexed, spot, and mixed natural gas prices, January 2008 – December 2013



Source: REKK analysis

1.2 Study objective

The primary objective of this study is to identify the principal conditions for a transition from monopolistic (oil-indexed) natural gas wholesale pricing to hub-based pricing in Hungary.[8] It is also about simulating the wholesale price impacts of policy measures to remove the obstacles to efficient gas wholesale competition in the country.

The major hypothesis of the paper is that the major obstacles to efficient gas wholesale competition and related pricing to develop are the followings in Hungary:

(i) *Exclusive control over a pivotal infrastructure*, the (Russia-)Ukraine-Hungary interconnector (in the followings: UA-HU interconnector), that ensures a dominant market position for the Russian supplier.

- In the history of natural gas in Hungary annual gas import demand couldn't have been served without Russian supplies through the UA-HU

[8] According to Stern (2012, p.7.), oil-indexed gas pricing (or oil price escalation) is when the gas „price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil, and / or fuel oil." In case of hub-based gas wholesale pricing (alternatively spot or market pricing) „the price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different time periods (daily, monthly, annually or longer). Trading takes place at physical hubs (for example Henry Hub in the USA) or notional hubs (such as NBP in the UK). If there are longer term contracts, these will use gas price indices to determine the price. Spot LNG is also included in this category".

interconnector. Until 1996 when the Austrian-Hungarian gas pipeline (in the followings: HAG) was put in operation, Hungary received gas imports only through the UA-HU interconnector. Despite more recent investments into the diversification of the Hungarian gas transmission infrastructure, the annual import demand of the country was not possible to be fully met from non-Russian-Ukrainian directions even by mid-2014[9]. In sum, while the interconnection capacity of the Hungarian natural gas transmission system in the Russian / Ukrainian direction is abundant *relative* to the country's import demand, interconnection capacities in other directions used to fall well below the import demand of the country. The result has long prohibited the effective competition of non-Russia owned and priced gas to meet Hungarian gas demand.

- The present natural gas transmission topology with exclusive supplier control over the UA-HU interconnector in itself has long ensured market dominance for the Russian supplier in Hungary. Between 1996 and 2015, the duration of the present long term gas supply contract (in the followings: LTC[10]) between Gazprom and its Hungarian counterpart, market dominance manifested in a monopolistic oil-linked natural gas wholesale pricing regime.
- As long as the gas imported through the supplier controlled UA-HU interconnector remains pivotal in meeting Hungarian natural gas import needs, the Russian supplier will preserve a dominant wholesale market position even after the present LTC expires in 2015. *Capacity withholding* on the pivotal infrastructure can support monopolistic pricing by the Russian supplier even in the absence of a new LTC with monopolistic pricing arrangements (e.g. partial oil-indexed pricing). In this case the basis of market dominance for the Russian supplier is the *exclusive control over the use of capacity of a pivotal infrastructure*.

[9] The completion of new interconnections with Romania and Croatia by the Hungarian gas transmission system operator, FGSZ in 2010 and 2011 started to change this situation. The *„National Energy Strategy 2030 of Hungary"*, accepted in 2011, also put the emphasis on diversification of supply sources and the physical infrastructure in case of the natural gas sector. A flagship project of this strategy is the new Slovakia – Hungary interconnector that is expected to start commercial operations by January 2015 at the latest.

[10] In this study „LTC contract" will stand for long term (over 5 years) natural gas contracts with take-or-pay (TOP) obligation but with a certain level of flexibility in the quantity of the TOP obligation. Short term contracts without quantity flexibility are called „spot" contracts.

- In order to ensure the basis of its market dominance (control over a critical infrastructure) and related monopolistic rents, the Russian supplier will have an incentive to block or gain control over import capacities with regulated third party access and alternative to the UA-HU interconnector. For the worse, competitively priced spot gas that could enter the Hungarian market through import capacities with regulated third party access also presents a threat to the local counterparty of Gazprom. Both Gazprom and its Hungarian counterparty have a shared interest in blocking or gaining control over import capacities with regulated third party access, thus foreclosing their potential competitors.
- A final related hypothesis is that halting the pivotal nature of the UA-HU interconnector is a necessary but not sufficient condition to create efficient competition on the Hungarian gas wholesale market.

(ii) The present major Russian long term contract, held by a single Hungarian wholesaler, as a principal source of *wholesale market concentration.*

- MOL, then the single gas wholesaler of Hungary, entered into a major, 19 years duration LTC with its Russian partner in 1996. Since then this contract has served as the principal import supply source to meet Hungarian natural gas demand and, at the same time, has also guaranteed market dominance for its actual holder[11] on the Hungarian gas wholesale market. While the contract was fully compatible with the single buyer market model in place between 1994 and 2004, it was in conflict with the objective of creating efficient competition after the start of gas market liberalization on January 2004. However, even after 2004 subsequent gas market models were adjusted to the existence of the contract by introducing first the Public Utility (PU) market segment (2004-2009) and since then the Universal Service (US) market segment. The PU and US market segments have provided preferential sales concessions for the Russian LTC holder.
- The present LTC with Gazprom expires in 2015. Government decisions about the future structure of the natural gas wholesale market and related contractual arrangements will be crucial in determining the level of wholesale market concentration and related future gas pricing in Hungary. In

[11] 1996-2006: MOL; 2006-2013: E.ON owned EFT; since 2013: MVM owned MFGK.

particular, the price impact of the terms and conditions of a potential new LTC between the present dominant Hungarian gas wholesaler, MVM, and the Russian supplier will be key in this regard. This contractual arrangement will also be informative about the incentives for the contracting parties to gain control over interconnection capacities with regulated third party access.

(iii) *Regulatory constraints to market development*.

- Efficient gas wholesale market competition is also constrained by a number of anti-competitive regulatory measures that are in place in Hungary. The most important of these are:
    i. the discriminative allocation of cross border interconnection capacity at the Austrian – Hungarian (HAG) interconnector;
    ii. distortive end-customer price regulation in the US market segment;
    iii. system use charges for transmission, distribution and strategic storage differentiated by customer segments (US versus non-US);
    iv. sector specific extra taxes on natural gas trading and network related activities (transmission, distribution).
- This study will concentrate on identifying *potentially distortive access rules* to critical interconnectors, allowed by the present and upcoming EU regulations and favouring the Russian supplier and its Hungarian partner, and assessing their wholesale price impacts.

Table 1 below summarises the assumed relationship between the combinations of obstacles (i) and (ii) above to gas wholesale market competition and gas wholesale pricing regimes. Assuming that the policy objective is social welfare maximization through creating the conditions for competitive pricing to develop, we can derive a few preliminary policy hypotheses from the table. The first is that without undermining an existing dominant market position based on the exclusive control of a pivotal infrastructure there is no chance to move out of monopolistic pricing regimes. Even without an LTC, the market player with control over the pivotal infrastructure will play a dominant role in price determination. Second, it is the combination of an infrastructure topology with no pivotal component and low wholesale market concentration (e.g. by entering into no or just a relatively small sized LTC) that can bring about hub-based or competitive pricing. A proper infrastructure topology, combined with high market concentration through e.g. a relatively big sized LTC will not really lead out of the oil-indexed world. It will also invite incentives on the side of dominant players to manipulate open access rules to critical interconnectors.

Table 1. Assumed relationship between the combinations of obstacles to gas wholesale market competition and gas wholesale pricing regimes

		POSITION OF THE RUSSIAN SUPPLIER			
		Pivotal infrastructure		No pivotal infrastructure	
		With LTC	Without LTC	With LTC	Without LTC
MARKET CONCENTRATION	High market concentration level	Oil indexed	Monopolistic	Partially oil-indexed	Oligopolostic
	Low market concentration level	Partially oil-indexed	Dominant price leadership	Oligopolistic / Competitive	Competitive

In the followings I will first review potential policy options to remove the obstacles to efficient gas wholesale competition in the country. First I will define a dominant market position based on the exclusive control of a pivotal infrastructure. I will introduce the leverage function that can help the analysis of policy alternatives to undermine the pivotal nature of a critical infrastructure (in the Hungarian case the UA-HU interconnector) in an integrated manner. Next I will review alternative future wholesale market arrangements for Hungary and their relation to a possible future LTC between MVM and the Russian supplier. Finally, I will analyse cross border infrastructure access rules in force to identify potentially distortive capacity allocation rules that, while complying with the rules in force could ensure market dominance for powerful market participants.

After identifying some critical policy options that could bring Hungarian gas wholesale gas pricing close to hub-based pricing, I will translate some of these measures into modelling scenarios and will use for simulation purposes the European Gas Market Model to compare the wholesale price impacts of the different policy options.

2 From oil-linked to hub-based gas wholesale pricing in Hungary – a literature survey

There is a limited literature with relevance to the question, what are the principal conditions for a transition from monopolistic (oil-indexed) natural gas wholesale pricing to hub-based gas pricing in Hungary.

Soczó and Tarjáni (2007) discussed natural gas supply source diversification options for Hungary. Since alternative supply sources are expected to be owned and priced by new market participants, supply source diversification is clearly related to the wholesale pricing question, investigated by the present study.

Some other studies have put the emphasis on investigating the potential impact of expanded gas import capacities from non-Russian-Ukrainian directions on wholesale gas prices. An early study by REKK (2011a) introduced the concept of *leverage* (L) in the following manner:

$$L = \frac{C - P - I_w}{C} \tag{1}$$

when C is annual gross natural gas consumption, P is for annual maximum domestic natural gas production capacity and I_w indicates aggregate gas import capacity from non-Russia-Ukraine directions. Positive values of this indicator mean that (unconstrained) annual consumption can't be met from domestic production plus potentially non-Russia controlled import directions.[12] The paper argued that expanding import capacities from non-Russian directions (I_w) is *the* policy option to break down the dominant market position of the Russian supplier by improving the leverage on the Hungarian side. The study carried out a social cost-benefit analysis of infrastructure investment options proposed by the Hungarian gas transmission system operator, FGSZ in March, 2011 (see Table 4). It argued that the social cost of such investments are simply the investment costs (recovered by customers through increased transmissions charges) and the social benefits are due to increased consumer surplus from an *assumed* gas wholesale price decrease from oil-indexed to hub-based levels when the value of leverage becomes negative. The study further argued that expanded interconnections could invite additional transit shipments through the Hungarian gas transmission system providing for the opportunity to decrease transmission tariffs at a later stage. The study concluded that, by assuming a 5% social discount rate, the social net present value of new investments into expanded non-Russian import infrastructure is in the range of EUR 1.9 – 2.8 Billion, depending on the chosen future gas demand development

[12] Certainly, the source of natural gas imported from non-Russian direction can be Russia. It is the ownership and pricing control and not the physical origin that matters here.

scenario and the size of the investment program[13]. In order to avoid the uncertainty in assumed future oil-indexed and hub-based gas price patterns to derive social net present values, the authors also estimated the *minimum necessary discount* of hub-based gas price to the oil-indexed price to make the studied infrastructure investments paying back from a social welfare perspective. They found that in all scenarios this discount remained below 3%. The policy conclusion was that if decision makers expected wholesale gas prices to fall more than 3% as a result of investments into non-Russian import infrastructures, they had to go ahead with these investments. The huge potential of such a strategy is reflected by the fact that hub-based gas prices have been, on average, 30% below oil indexed gas prices since the completion of the study (April 2011; see also Figure 1).

However, this influential study by REKK[14] had serious shortcomings. First, it investigated only one potential option (new import infrastructure) to build up leverage with the objective of undermining oil indexed gas pricing and disregarded from demand side policy options and incentives for domestic gas production. Second, the study disregarded from critical preconditions that can make supplies *via* new import capacities from non-Russia-Ukraine directions real competitors to the Russian supplier. These preconditions include available supply at new entry points without Russian price control, the lack of Russian access to new capacities and access regulation to interconnectors that can prevent manipulation of these capacities by market participants, including the Russian supplier and its contracting European partners. Finally, the study only provided an intuition about the relationship of leverage values and wholesale gas price development.

[13] Social benefit estimates were based on consumer surplus increases due to gas wholesale price decreases resulting from new infrastructure investments between 2011 and 2030. Other potential benefits (e.g. from increased transit) were disregarded. The authors assumed that hub-based gas prices will remain 10% below oil-indexed levels in the forecasting period (the actual difference at the time of the completion of the study). Hungarian gas wholesale prices were assumed to switch from oil-indexed to hub-based once the value of leverage became negative.

[14] Following the recommendations of the study, the actual Hungarian energy strategy made gas infrastructure diversification one of its top priorities. By 2013 the expansion of HAG capacity by an annual 1.1 Bcm was completed. The new Slovakia-Hungary gas interconnector became a top priority investment project for the government and is supposed to start commercial operations by January 2015. Due to gas infrastructure developments between 2005 and 2012 regulated natural gas transmission tariffs doubled in nominal terms. Except for HAG with close to 100% capacity utilization, the rate of utilization of other interconnectors was still rather low in 2012: HU-CR 2%; HU-RO 23% and UKR-HU 18%.

The relationship between expanded natural gas import capacities from non-Russia-Ukraine directions and Hungarian gas wholesale prices was further investigated by András Kiss (2011). He assumes that the profit of the Russian supplier is determined by its own pricing strategy and the intensity of competition generated by expanding alternative import options on the Hungarian market. The Russian supplier can apply either an oil-indexed or a marginal cost based (competitive) pricing strategy. By the use of REKK's regional gas market model the author investigated the impact of eight infrastructure investment alternatives on the profitability of the Russian supplier. He found that competitive pricing became profitable for the Russian supplier as soon as non-Russian import capacities exceeded the difference of demand and domestic production (that is, the value of leverage became negative). In the rest of these scenarios oil-indexed pricing brought negative profitability for the Russian supplier. Thus this study, while based on a more explicit model of the Russian supplier's behaviour and by applying a more sophisticated simulation method, provided some support to the intuition of the REKK (2011a) study about the relationship of leverage, built up by infrastructure investments and the expected (rational) pricing pattern on the natural gas wholesale market. However, the pricing model of the Russian supplier is still quite simple in the paper (a simple choice between oil-indexed or marginal cost based pricing). Similar to the above referred REKK study, it also assumed perfect access to and competition through the alternative interconnectors to the UA-HU one with no manipulation by the Russian supplier and its contracting partners.

The role of new infrastructures[15] to enhance market integration and competition, and to undermine oil-indexed natural gas wholesale pricing in Central and South East Europe is in the focus of the study by Kaderják et al. (2013)[16]. Based on simulations by the regional gas market model of REKK, the study provided further support to the argument that certain new infrastructures might be key drivers toward more market based gas wholesale pricing in the region. In particular, it confirmed the new SK-HU interconnector's outstanding importance not just for the Hungarian market but for the region as a whole in this regard. Compared to a 2011 reference case, when Hungarian wholesale gas prices were modelled close to oil-indexed levels, the model forecasted a

[15] The investigated infrastructure options were those proposed by the European Commission to complete North-South energy interconnectors in Central-Eastern Europe (see EC, 2011).
[16] The paper is also included in this thesis.

10% wholesale price decrease as a result of the SK-HU investment. Moreover, the study concludes that the implementation of this interconnector with undistorted access to and perfect competition through it could *annually* save about 600 million Euro in purchasing natural gas for the so called Danube Region countries[17]. Given the project cost of 150 million Euro, its implementation pays back to the Region in a few months.

The present paper further investigates the most important conditions for a transition from monopolistic (oil-indexed) natural gas wholesale pricing to hub-based gas pricing in Hungary. Its novelty is that it further develops the concept of leverage introduced by REKK (2011a) into a leverage function. The leverage function allows for a consistent assessment of policy measures to enhance gas wholesale market competition under undistorted market and regulatory conditions. The paper also applies a simulation methodology to assess the wholesale price impacts of demand side, production and infrastructure related policy options under perfect competition as well as under distorted market and regulatory conditions. The latter refers to high level wholesale market concentration and distorted access to interconnections critical for competition to develop. Simulations are carried out by the European Gas Market Model of REKK.

3 Market dominance based on the exclusive control over a pivotal infrastructure

In case of network energy industries the efficiency of wholesale market competition is not only affected by market structure (demand characteristics, concentration of supply, institutions of trade, transaction costs) but the availability of and non-discriminatory access to fundamental industry infrastructure (sometimes called *essential facilities* for competition). In case of the natural gas industry the latter means the gas transmission system (including cross border pipelines, called interconnectors) and natural gas storage facilities. This explains the central role that EU gas market liberalization rules[18] put on *unbundling* transmission activities from competitive activities and introducing non-discriminatory, regulated third party access rules to their capacities.[19]

[17] The 14 Danube Region countries are: Austria (AT), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), the Czech Republic (CZ), Germany (DE), Hungary (HU), Moldova (MV), Montenegro (MNE), Romania (RO), Serbia (SB), Slovakia (SK), Slovenia (SL) and Ukraine (UA). Most important beneficiaries would be SB, HR, BA, SL, RO and BG.

[18] Directive 2009/73/EC on the common rules for the internal market in natural gas, and Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks.

[19] Natural gas storage is a potentially competitive activity. EU rules also require the unbundling of distribution from competitive activities, but this is not really relevant for wholesale competition that is the topic of this paper.

This paper argues that the lack of non-discriminative third party access to a natural gas infrastructure that is pivotal in supplying a given natural gas market can itself ensure market dominance and related oligopolistic pricing opportunities for the market participant with exclusive control over the capacity usage of the given infrastructure.

This section of the paper first provides a brief overview of the major characteristics of the Hungarian natural gas transmission and storage infrastructure. Next it defines what to mean under pivotal infrastructure and identifies it under the present Hungarian gas infrastructure topology. Finally it assesses policy options to undermine the pivotal position of a critical infrastructure.

3.1 Major characteristics of the Hungarian natural gas infrastructure

This section summarises the major characteristics of the Hungarian natural gas infrastructure (transmission and natural gas storage) in order to support identifying infrastructure components pivotal for wholesale market competition in the short (one-two weeks) and the long (annual) run. This is why the distribution infrastructure is not covered here.[20]

3.1.1 Transmission and cross border interconnections

The independent transmission operator (ITO) of the Hungarian gas sector is Földgázszállító Zrt (FGSZ Zrt.), the 100% subsidiary of MOL. It owns and operates a transmission network of 5,300 km length with five compressing stations. Tables 2 and 3 summarise the main characteristics of the cross border interconnectors of this transmission system between 2007 and 2013. By mid-2014 the interconnectors only support uni-directional physical operations except for the UA-HU interconnector, although the Hungary-Romania and Hungary-Croatia interconnectors, commissioned in 2010, were already designed to support bi-directional physical operations.[21]

[20] For additional information on Hungary's natural gas infrastructure the reader should consult with www.fgsz.hu.

[21] Making the HU-RO and HU-CR interconnectors bi-directional is required by Regulation 994/2010. Their implementation is also urged, as a short term measure, by the European Energy Security Strategy, recently proposed by the European Commission to the European Parliament and the Council (COM, 2014) as a response to the Russia-Ukraine conflict.

Table 2. Annual physical capacities of interconnectors between Hungary and its neighbours, Bcm / year

	IMPORT							EXPORT						
	2007	2008	2009	2010	2011	2012	2013	2007	2008	2009	2010	2011	2012	2013
Ukraine	10.9	10.9	21.9	21.9	26	26	26	-	-	-	-	-	1.7	6.1
Austria (HAG)	4.4	4.4	4.5	4.5	5.2	5.2	5.2	-	-	-	-	-	-	-
Croatia	-	-	-	-	(6.5)	(6.5)	(6.5)	-	-	-	-	6.5	6.5	6.5
Serbia (transit)	-	-	-	-	-	-	-	4.1	4.1	4.1	4.8	4.8	4.8	4.8
Romania*	-	-	-	(1.8)	(1.8)	(1.8)	(1.8)	-	-	-	1.7	1.7	1.7	1.7
TOTAL	15.3	15.3	26.4	26.4	31.2	31.2	31.2	4.1	4.1	4.1	6.5	13	14.7	19.1

* The first reverse gas flow happened to take place in the RO>HU direction in February 2014. After the test operation the Romanian TSO, Transgas, reported technical difficulties on the Romanian side and has halted capacity allocations since then. FGSZ is working on the significant expansion of the above capacity with its Romanian partner.

Source: Annual Reports of FGSZ

Table 3. Daily physical capacities of interconnectors between Hungary and its neighbours, Mcm / day

	IMPORT							EXPORT						
	2007	2008	2009	2010	2011	2012	2013	2007	2008	2009	2010	2011	2012	2013
Ukraine	30.0	30.0	60	60	71.3	71.3	71.3	-	-	-	-	-	4.8	16.8
Austria (HAG)	12.1	12.1	12.1	12.1	14.4	14.4	14.4	-	-	-	-	-	-	-
Croatia	-	-	-	-	(19.2)	(19.2)	(19.2)	-	-	-	-	19.2	19.2	19.2
Serbia (transit)	-	-	-	-	-	-	-	11.3	11.3	11.3	13.2	13.2	13.2	13.2
Romania*	-	-	-	(4.8)	(4.8)	(4.8)	(4.8)	-	-	-	4.8	4.8	4.8	4.8
TOTAL	42.1	42.1	72.1	72.1	85.7	85.7	85.7	11.3	11.3	11.3	18	37.2	42	54

Source: Annual Reports of FGSZ

Apparently the capacity of the Ukraine-Hungary interconnector far exceeds present and forecasted future natural gas import demand of Hungary.[22] However, import capacities from non-Russia-Ukraine directions (only HAG by mid-2014) are not sufficient to meet annual import demand.

In 2011 FGSZ proposed the further diversification of the Hungarian gas transmission system by implementing the investments described in Table 4.

[22] REKK (2011) forecasted natural gas import demand of the country to fall between 8 and 13.5 Bcm by 2030. The upgrade of the Ukraine-Hungary interconnector in 2009 was not motivated by expected fast increase of gas demand in Hungary but by gas transit plans in the Ukraine – South East Europe direction.

Table 4. Investment options proposed by FGSZ to increase natural gas import capacities from non-Russia-Ukraine directions. March, 2011.

	Estimated investment cost, Billion HUF					Expansion of import capacity, Bcm / year	Cost of an additional m^3 of import capacity, HUF	Year of commissioning
Investment options	2011	2012	2013	2016	2018			
(1) Upgrade of the Mosonmagyaróvár compressing station (HAG)	0.4					1.1	0.3	2011
(2) Slovakia – Hungary (Vecsés-Gödöllő-Balassagyarmat)*	1.9	19.2	26.9			4.0	9.2	2014/2015
(3) HAG upgrade				21.7	75.7	4.4	22.3	2018/2019

Source: Ten years network development plan, FGSZ (2011).

The most recent energy strategy of Hungary, *Energy Strategy 2030* (approved in 2011), made further gas market diversification an energy policy priority. As a follow up, the upgrade of the Mosonmagyaróvár compressing station was completed and resulted in an increase of the HAG import capacity from 4.4 to 5.2 BCM per year form 2011. Also, the new Slovakia – Hungary natural gas interconnector project got approval for a priority status by the government, in accordance with the *Energy Strategy 2030* economic impact assessment conclusions by REKK (2011a). However, on the Hungarian side this project is implemented by Hungarian Gas Transit Ltd. (Magyar Gáz Tranzit Rt: MGT), a subsidiary of MVM and the state owned Hungarian Development Bank, instead of FGSZ[23]. The new interconnector is already built and is under test operations by mid-2014. It is expected to start commercial operations by January 2015 by the latest, with an annual 4 Bcm capacity to the Hungarian and 1.6 Bcm to the Slovakian direction.

[23] Whether MGT is to gain the status of the second Hungarian natural gas transmission system operator from the European Commission is still unclear. In its decision adopted on 17th September 2013 (C(2013) 6159 final), the European Commission requested several amendments from the Hungarian Energy and Public Utility Authority regarding its decision on the exemption of the Slovakian-Hungarian natural gas interconnector from ownership unbundling rules in Article 9 of Directive 2009/73/EC.

3.1.2 Underground storage (UGS)[24]

Hungarian gas storage facilities have been created on depleted gas fields. By mid-2014 five commercial and one strategic gas storage facility is operational in the country, from which only a smaller one (Pusztaederics) is located in western Hungary. Table 5 summarises the major technical characteristics of the underground natural gas storage facilities.

Table 5. The technical features of Hungarian natural gas underground storage facilities

	Injection, mcm/day								Withdrawal, mcm/day								Working gas capacity, mcm							
	2003 - 2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2003-2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2003-2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Zsana	10.8	10.2	17	17	17	17	17	17	18	24	28	28	28	28	28	28	1300	1540	2170	2170	2170	2170	2170	2170
Puszta-ederics	2.2	2.15	2.5	2.5	2.5	2.9	2.9	2.9	2.5	2.9	2.9	2.9	2.9	3.1	3.1	3.1	330	330	340	340	340	340	340	340
Hajdú-szoboszló	16.8	10.3	10.3	10.3	10.3	11.5	11.5	11.5	19.2	19.7	20.2	20.2	20.2	20.8	20.8	20.8	1400	1440	1440	1440	1440	1640	1640	1640
Kardos-kút	2.2	1.92	2.2	2.2	2.2	2.35	2.35	2.35	2.3	2.9	2.9	2.9	2.9	3.2	3.2	3.2	180	280	280	280	280	280	280	280
Maros-1	1.1	1.3	1.2	1.2	1.2	-	-	-	2.2	1.5	1.2	1.2	1.2	-	-	-	150	130	110	110	110	-	-	-
Szőreg commercial	-	2.7	2.7	2.7	2.7	2.7	2.7	2.7	-	-	5	5	5	5	5	5	-	-	700	700	700	700	700	700
Szőreg strategic	-	10	10	10	10	10	10	10	-	20	20	20	20	20	20	20	-	1200	1200	1200	915	815	615	615
Szőreg US*	-	-	-	-					-	-	-	-					-	-	-	-	285	385	585	585
TOTAL	33.1	38.57	45.9	45.9	45.9	46.45	46.45	46.45	44.2	71	80.2	80.2	80.2	80.1	80.1	80.1	3360	4920	6240	6240	6240	6330	6330	6330

*Capacities made available to US providers from strategic stocks

Source: MEKH decisions

In 2012 the two players on the commercial UGS market were E.ON Földgáz Storage Zrt with the dominant market share (70% on working gas capacity basis) and the majority MOL owned MMBF Zrt (30%). Based on their share in annual withdrawal, they had similar shares.

The Hungarian strategic storage facility at Szőreg, together with its physically linked Szőreg commercial UGS facility was put into operation by MOL in 2009. The strategic storage facility with 1.2 Bcm working capacity was operated by MMBF, while the owner of

[24] For a detailed description of the Hungarian natural gas storage market, see the study by Tóth et al. (2009).

the gas was the Hungarian Hydrocarbon Storage Association (MSZKSZ). It is the minister responsible for energy to decide about the quantity and the usage of the strategic storage.
In the course of 2013 the state owned electricity company MVM purchased all the USG facilities from E.On Földgáz Storage, while the Hungarian Development Bank acquired majority ownership in MMBF.

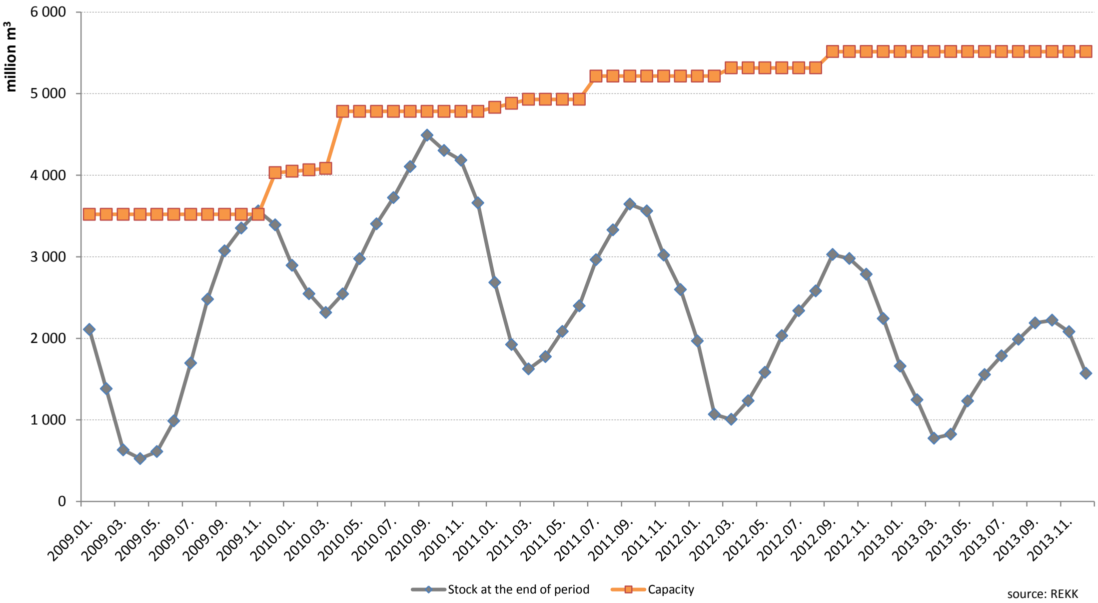
The above figures reflect that, due to significant investments by E.On Földgáz Storage and the completion of the combined strategic and commercial storage facility at Szőreg, the Hungarian UGS industry went through a significant expansion between late 2008 and 2012. Between the end of 2007 and 2012 working gas capacity increased by 88% (from 3360 mcm to 6330 mcm), from which commercial storage capacity increase accounted for 60% and the strategic storage for 40%. In the same time period the daily withdrawal capacity of the Hungarian UGS system increased by 81%.

The present 6330 mcm working gas capacity seems abundant to manage the seasonality of Hungarian gas demand. As a joint result of capacity increases and reduced demand for commercial UGS capacity, the annual average utilization of Hungarian UGS capacities has been decreasing since 2010 (Figure 2).[25]

The significant increase in the daily withdrawal capacity of the UGS system has increased short term gas supply security of the Hungarian gas market. The present 80 mcm withdrawal capacity in itself is sufficient to serve 100.2% of the daily peak consumption of 78.8 mcm of 2012.

[25] For a recent assessment of the Hungarian UGS market in a regional context see REKK (2013b).

Figure 2. Monthly commercial working gas storage capacity and working gas stock in Hungary, January 2009 – December 2013.



Source: REKK (2014)

3.1. The pivotal nature of the Russian supplier to meet natural gas demand in Hungary

In this section I first define the short- and long term measures to assess the pivotal nature of the UA-HU interconnector (the Hungarian natural gas infrastructure component with the largest capacity and lacking non-discriminatory third party access to its capacity) to meet Hungarian import demand. Exclusive control over the capacity of this infrastructure has long ensured market dominance for the Russian supplier in Hungary.

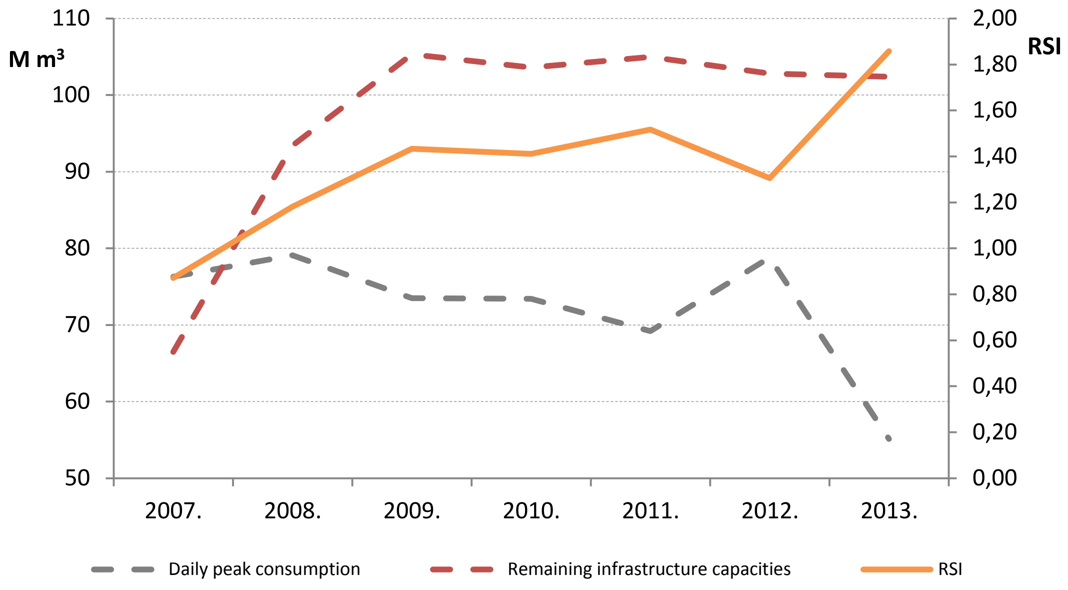
3.1.3 Pivotal position in the short term (1-2 weeks)

I use the slightly modified *Residual Supply Index*, proposed by the California Independent System Operator, to investigate the pivotal nature of the UA-HU interconnector and related Russian supplies in meeting short term peak demand in Hungary. The RSI index will indicate whether the remaining natural gas infrastructure will be able to meet winter peak demand in case of a shutdown of the UA-HU interconnector.[26] The RSI is calculated in the following way:

$$RSI = \frac{P_{dom}+S_{ext}+L_{ext}+I_{total}-I_{RU}}{C_{peak}} \quad (2)$$

where C_{peak} is winter daily peak consumption, P_{dom} is domestic daily peak production capacity, S_{ext} is daily peak underground storage withdrawal capacity, L_{ext} is daily peak LNG regasification capacity, I_{total} is total pipeline import capacity of the country and I_{RU} is the maximum import capacity of the UA-HU interconnector. RSI values greater than 1 indicate that the remaining infrastructure can potentially serve winter peak demand in case of the shutdown of the UA-HU interconnector. Figure 3 shows the development of winter peak demand, remaining infrastructure capacities and the RSI index between 2007 and 2013.

Figure 3. The development of winter peak demand, remaining infrastructure capacities and the RSI index between 2007 and 2013



source: own calculations based on FGSZ and MEKH data

The data indicate that infrastructure developments since 2007 undermined the pivotal nature of the UA-HU interconnector to meet winter peak demand, *given* that sufficient supply of natural gas is available to fill the capacities of the remaining infrastructure elements (storage, interconnectors and production wells) and that those capacities aren't

[26] Since the UA-HU interconnector is the piece of the Hungarian natural gas infrastructure with the largest capacity, the index also indicate whether Hungary complies with the N-1 standard prescribed by the 994/2010 gas supply security regulation.

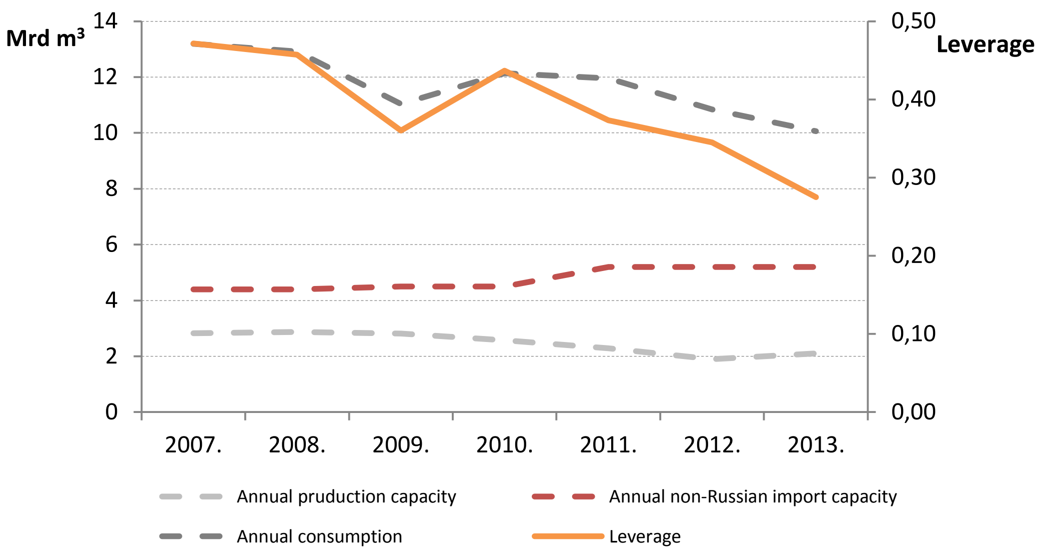
/ can’t be blocked by the Russian supplier. Both the decrease of winter peak demand (especially between 2008 and 2011 and in 2013) and increased capacities of the remaining infrastructure (in the period 2007-2009) contributed to this improvement.

3.1.4 Pivotal position on the long term (> year)

While in the short term lost Russian shipments through the UA-HU interconnector can be replaced by storage withdrawal, stored working gas can’t be considered as additional supply source on an annual or longer basis. Thus, when judging the pivotal nature of the UA-HU interconnector and related Russian supplies in meeting annual or longer term demand, I disregard from storage and, by following REKK (2011a), use formula (1) in section 2 of this paper.

Figure 4 indicate the development of the components of the leverage measure and its values for Hungary between 2007 and 2013.

Figure 4. The development of the components of the leverage (L) measure and its values for Hungary between 2007 and 2013



Source: own calculations based on FGSZ data

For the period 2011-2013 the values of the measure are 0.37, 0.35 and 0.27, respectively. This means that for these years 37%, 35% and 27% of annual natural gas consumption could only be covered from the UA-HU direction. For comparison, the share of imports through the UA-HU interconnector in annual consumption was 37%, 32% and 35% for these years. This indicates that recent gas infrastructure developments were less successful to undermine the longer term pivotal nature of the UA-HU interconnector and related Russian shipments.

This might change with the start of commercial operations of the new Slovakia-Hungary (SK-HU) interconnector. By recalculating the formula in (1) when adding the planned SK-HU import capacity, we arrive at a value of –0.21 for 2013.

3.2 The leverage function

For policy making a more dynamic and fruitful application of formula (1) is to consider it as an energy policy objective function. I call it the *leverage function*, where the policy objective is to undermine, at minimum cost, the pivotal nature of a critical infrastructure that ensures a dominant market position for a supplier with exclusive rights to use the given infrastructure.[27]

$$L(\psi, E, \tau, \sigma) = \frac{C(\psi(p,r,t),E) - P(p,\tau) - I_w(\sigma)}{C(\psi(p,r,t),E)} \qquad (3)$$

The pivotal position is undermined when the value of L reaches a non-marginal negative value, say -0.2. At that point the supplier will know, with a fair level of certainty, that the infrastructure it controls is not any more pivotal in serving a given market. This poses a credible threat that monopolistic (e.g. oil-indexed) priced supply through the pivotal infrastructure[28] will face effective competition from gas shipped to the market from alternative directions.

The domain of the L function is [-∞; 1] and its value depends on both demand and supply side variables.

First, it depends on the demand for natural gas (C), which in turn depends on the price of gas for end-customers (ψ) and the level of *exogenous* energy efficiency investments

[27] In the Hungarian context this is, of course, the UA-HU interconnector.

[28] When monopolistic pricing arrangements (e.g. oil-indexed pricing) cancel due to e.g. the termination of long term contracts, this can be replaced by monopolistic pricing based on capacity withholding on the pivotal infrastructure.

(E)[29] that result in reduced natural gas consumption. End customer natural gas price is composed of the wholesale price of gas (p), regulated gas price components (e.g. system use charges, denoted by r) and taxes (t). The partial derivatives of C with regard to both ψ and E are negative.

Second, the value of L depends on the level of domestic natural gas production. Within the constraints of principal gas reserves in a country, the level of production activity (P) will depend on the wholesale price of gas (p) in relation to production marginal cost and the level of government taxation on gas production (τ). The partial derivative of P with regard to p is non-negative, since increased gas prices will encourage increased exploration and production activities *ceteris paribus*, but the outcome of such activities is inherently uncertain. The partial derivative with regard to τ is negative.

Finally, an increase of gas import capacity from non-pivotal directions (I_W) will decrease the value of L. When gas transmission is a regulated business, which is the rule for the European Union, investments into additional natural gas transmission (including interconnectors) critically depend on the level of capital cost remuneration (e.g. weighted average cost of capital: WACC) provided through regulated transmission tariffs for the investors by the regulator (σ).

The leverage function clearly indicates those policy options and control variables that are available for a government[30] when it is to undermine dominant market positions based on the control of pivotal infrastructures.

The easier cases are for energy efficiency, domestic production and additional non-pivotal infrastructure capacities. It involves social welfare costs when the government decides to encourage additional investments into such assets and activities: the cost of

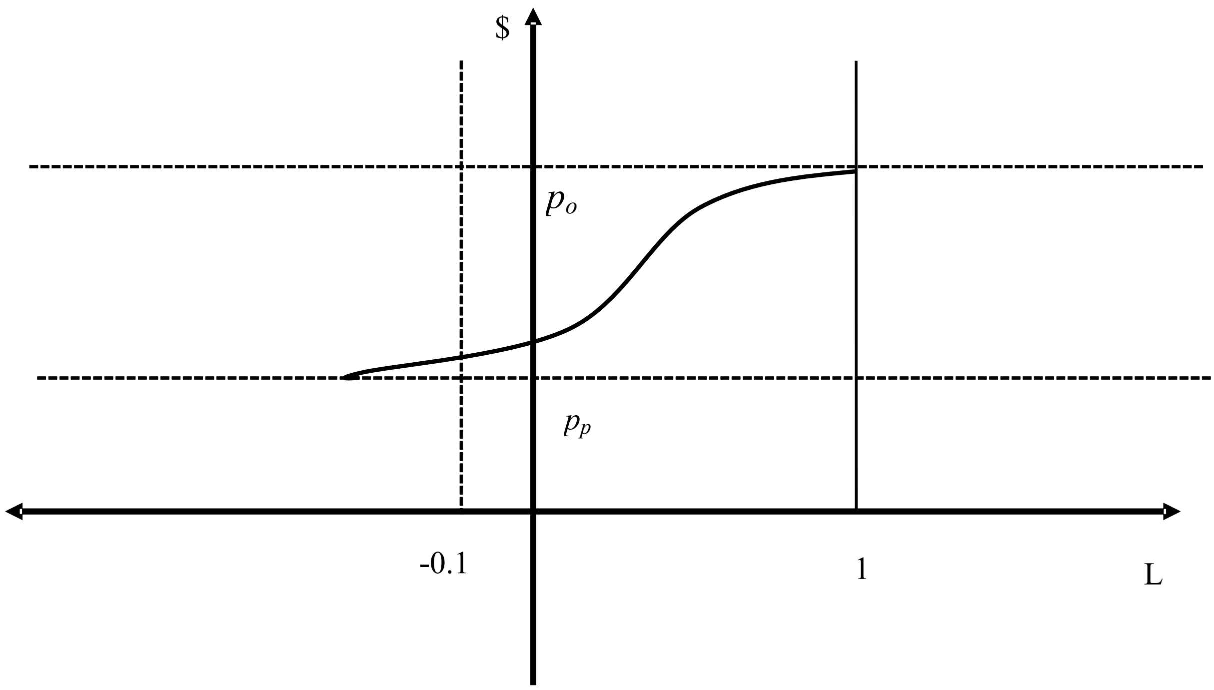
[29] An increase in relative gas prices will encourage an increase in energy efficiency investments by increasing their profitability. These investments will decrease gas demand *ceteris paribus* and will be reflected in empirical gas demand functions. I will call these investments *endogenous* energy efficiency investments because they are related to changes in end customer gas prices. *Exogenous* energy efficiency investments, on the other hand, are energy efficiency investments largely independent from changes in relative gas prices. Typical examples are government subsidised building refurbishments programs.

[30] For simplicity in the followings I mean government and regulatory measures together when I talk about „government measures", although important price regulatory decisions are in the authority of regulatory institutions largely independent from the government.

additional taxation to ensure subsidies for exogenous energy efficiency investments[31], potentially lost government revenues from exploration concessions or gas production excise taxes due to decreased production tax levels, and increased regulated natural gas transmission tariffs to ensure increased WACC for transmission investors.

The source of the social benefit to gain from incurring these costs is wholesale gas price decrease that a stronger leverage against a pivotal supplier (indicated by lower *L* values) can bring about. The *p(L)* function, denoted by Figure 5 illustrates the assumed relationship between *p* and *L*: the path stronger leverage can undermine monopolistic gas wholesale pricing (denoted by p_o: oil-indexed) and enforce market based gas prices (denoted by p_p: hub-based).

Figure 5. The assumed form of the wholesale price function, p(L)



We can see that the government has no direct influence on the *wholesale* gas price level: it is determined by demand and supply conditions, the latter having either a competitive (the case of p_p) or concentrated structure (the case of p_o). What the government has

[31] In a closed economy the marginal cost of public funds, λ is the cost of raising 1 unit of public fund. This cost includes in particular the deadweight loss caused by distortionary taxes. According to Laffont (2005, p.1-2.) the range of λ for developed countries is around 0.3, meaning that it costs for citizens 1.3 units of currency every time when the government raises 1 unit of tax revenue. In developing countries the range for the value of λ is estimated around 1.2 – 2.5. A special case is when a country can receive external funds to support such energy efficiency investments (e.g. European development fund sources for Hungary).

control over is to combine its powers over end-customer gas prices, energy efficiency subsidies, gas production related taxation and infrastructure investment related regulatory incentives so that their combined effect puts the pivotal supplier under competitive pressure.

Note that according to (3) the *partial impact of falling gas wholesale prices* will be decreased domestic production and exploration activity that will in turn weaken the leverage. Moreover, if falling wholesale price levels directly pass through to end customer prices, this impact is further enhanced by increased gas demand. A conclusion is that *to delink wholesale and end customer gas prices in times of falling wholesale prices might be a desirable temporary policy measure* to support the government objective to undermine a pivotal market position concerned by this study.

Indeed, the government has control over the difference between wholesale and end-customer prices by either direct end-customer price control[32], the regulation of system use charges and/or taxation. While distorted end customer prices or system use charges might be socially very costly policies to delink wholesale and end customer prices, extra taxation on wholesale gas transactions might be, from a social welfare point of view, a neutral supporting policy to undermine a pivotal market position.

For example, a coordinated end customer price regulation and taxation policy to support undermining a pivotal market position could be the following:

[1] $t = - dp$, when $dp < 0$; in this case $\psi_1 = p_1 + r + t = p_1 + r - dp = p_0 + r$

[2] $t = 0$, when $dp = 0$; in this case $\psi_1 = p_1 + r = p_0 + r$, and

[3] $t = dp$, that is a full pass through of wholesale price increase into end customer prices when $dp > 0$; in this case $\psi_1 = p_0 + r + dp = p_1 + r,$

where t is the (temporary) tax rate and $dp = p_1 - p_0$. Tax revenue in case [1] could compensate vulnerable customers. Such a policy could ensure that ψ becomes

32 While wholesale natural gas pricing is more and more market determined in the EU (See Stern and Rogers, 2012), government control over end customer gas prices are still overwhelming in the EU. According to ACER (2013), 15 member states still applied regulated retail natural gas prices for households, 11 member states for small and medium sized enterprises and 5 member states even for large industrial customers in 2012. We can add Croatia to all this, which was not yet an EU member at the time of the ACER survey but applies regulated end customer tariffs for natural gas.

independent from changes in p except for wholesale price increases. Certainly, the tax could be cancelled once the pivotal position is gone.

Furthermore, the government can fully separate the development of wholesale and end-customer prices by taxation. In this case t is set so that ψ becomes constant without regard to changes in p thus demand will only be affected by energy efficiency investments. The case is similar in case of production: while the government has no direct control over wholesale gas prices, it can compensate a decrease in wholesale prices with adjusting τ so that production activity remains unaffected. In order to make those variables under government control more explicit, we can reformulate (3) in the following way:

$$L(r,t,E,\tau,\sigma)=\frac{C(\psi(r,t),E)-P(\tau)-I_w(\sigma)}{C(\psi(r,t),E)} \tag{4}$$

4 Market dominance and wholesale market concentration

According to my hypothesis, in addition to the unfavourable topology of the natural gas transmission infrastructure, the second obstacle to the transition from monopolistic, oil-indexed to hub-based pricing is high level concentration of the gas wholesale market in Hungary.[33] High wholesale market concentration has long been caused by the combination of a very limited number of alternative supply sources, the terms of the major LTC and the gas wholesale market model applied by legislation.

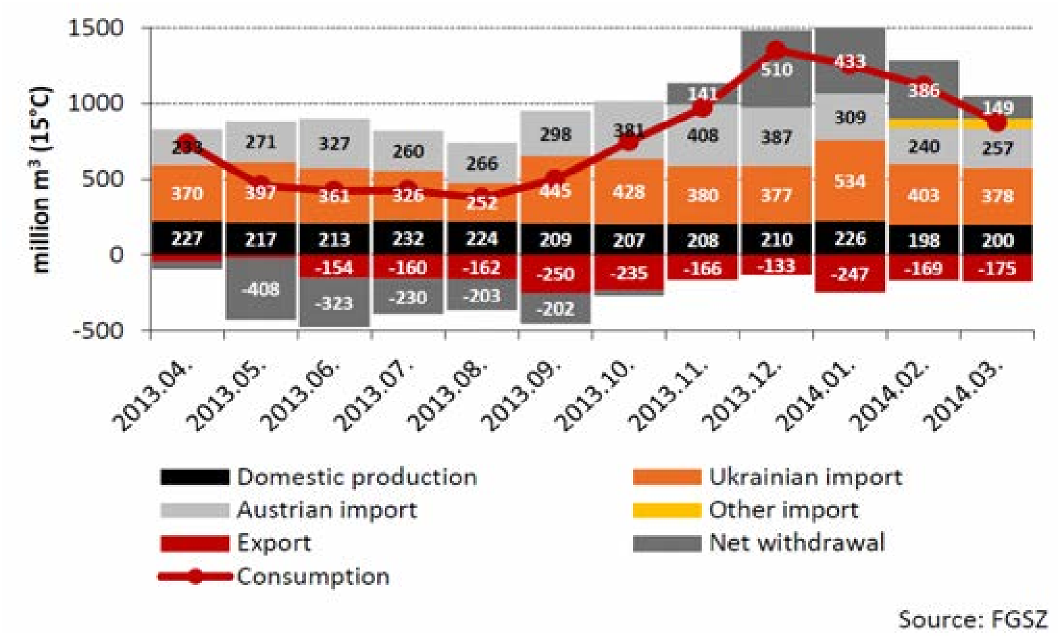
4.1 Major wholesale gas supply sources

Domestic production, Russian import and other imports are the gas supply sources available for meeting Hungarian gas demand. Figure 6 illustrates the recent monthly structure of gas supply to meet demand (including export demand)[34] in Hungary. In 2013 local production accounted for 27% of overall supply sources, Russian imports from Ukraine for 49% and imports from Austria for 24%.

[33] According to the definition of the Gas Act XL/2008 and the gas wholesale market analysis by the Hungarian Energy Office (MEH, 2010), gas wholesale includes those transactions when gas is sold for re-sellers and not for end users. In the Hungarian context this means that gas wholesale consists of transactions when gas is sold for re-sellers, including public utility or universal service suppliers.

[34] Export includes shipments to Serbia and Bosnia and Herzegovina, Romania and Ukraine.

Figure 6. The structure of monthly Hungarian gas supply, April 2013 – March 2014



Source: FGSZ, REKK Energy Market Report, 2014/2

4.1.1 Natural gas production

In terms of domestic production, MOL has long been the dominant market participant. In 2013 its market share in production was 96%. Since the mid-1990s some smaller independent producers have been active on the market with an aggregate market share below 10%. The government started tendering new exploration and production concessions for conventional natural gas by late 2013.

The Carpatian Basin (including Hungary) is also assumed to have significant non-conventional gas reserves, but according to the Energy Information Administration of the USA, the geological characteristics of the Pannonian-Transylvanian basin seems not to be favourable for significant future shale production.[74]

Table 6 contains available information about likely conventional gas reserves as well as on actual annual natural gas production activity in Hungary.

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http://www.eia.gov/analysis/studies/worldshalegas/pdf/chaptersviii_xiii.pdf

Table 6. Natural gas reserves and production in Hungary, 2007-2012, mcm

	2008	2009	2010	2011	2012
Proven and possible reserves	21,544	22,351	21,143	21,959	21,398
MOL production	2,620	2,751	2,679	2,179	1,907
Independent production	188	339	259	107	165
Total production	2,808	3,090	2,938	2,286	2,072

Sources: MOL Annual Reports 2008-2012, MEH

Recent estimates by ENTSO-G and REKK assumes a further decline in annual natural gas production in Hungary down to around 1 Bcm by 2020 and 0.3 – 0.8 Bcm by 2030 (REKK, 2011).

MOL's discretion over selling and pricing its own produced natural gas is limited by contracts and regulatory measures. When selling its gas wholesale and storage business to E.ON Ruhrgas International AG (ERI) in 2005-2006, MOL also contracted to sell its domestic production to ERI. However, as a precondition for agreeing to the MOL – ERI transaction, DG Competition obliged ERI to sell half of MOL's production (1-1.5 Bcm per year) through a *contract release program* in order to reduce its market dominance (see more details in section 4.2.) A result of the program was the entry of two active new wholesale market participants: ENI owned TIGÁZ and Budapest municipality majority owned FŐGÁZ. Both got access to about a quarter of MOL's annual gas production between July 1, 2007 and June 30, 2015.[75] The original objective of the contract release program was to increase diversity and liquidity on the free retail market segment.

Beginning from 2011, the pricing of domestic gas produced from wells opened before 1998 became regulated. Today MOL delivers (contract release) gas to TIGÁZ and FŐGÁZ, while the other two universal service suppliers (E.ON and GDF) receive domestic produced gas from MVM/MFGK at cost based regulated tariffs (about a third of import cost by the end of 2013).

[75] A detailed assessment of the MOL-ERI related contract and gas release programs can be found in Pató et al. (2008). For contract release see pp. 17-20.

4.1.2 Russian import

Russian import is based on a 'historic' or 'legacy' bilateral long term contract, including a take-or-pay (TOP) obligation with some flexibility for an annual contracted quantity (ACQ) to be purchased by the Hungarian partner. The quantities of the Hungarian contract is shown and compared to others in the region by Table 7. In 2013, annual contracted quantity accounted for 87% of annual gas consumption in Hungary. From September 30, 2013 the Hungarian counterpart to the Panrusgaz contract is Magyar Földgázkereskedő Zrt (MFGK), a 100% subsidiary of MVM.

Table 7. Long term contracts and some of their characteristics in selected CEE countries

	ACQ, mcm/year	Expiration	Annual consumption, 2013 (mcm/year)	ACQ/2013 cons.	Importer company	Majority owner
Bulgaria	2900	2022	3134	93%	Overgas	Gazprom[76]
Czech Republic	7500	2035	9138	82%	Wemex	Gazprom[77]
Poland	10250	2037	18731	55%	PGNIG, Europol (transit)	Polish state; Gazprom[78]
Hungary	9900	2015	11372	87%	Panrusgaz	Hungarian state/ Gazprom[79]
Romania	3500	2030	15321	23%	WIEE Romania	Romanian state/ Gazprom[80]
Slovakia	6500	2028	5855	111%	SPP	Slovakian state[81]
Slovenia	830	2018 (2035)	879	94%	Geoplin	Slovenian state[82]

Source: compiled by author

Historic long term contracts like the present Hungarian one have some common characteristics.

[76] Gazprom Export 49.51%, Gazprom 0.49%, DDI Holdings Ltd. 50% (possibly a Gazprom-owned company, registered in 1999 in London)
[77] Gazprom owns 50%; Centrex owns 33% (possibly a Gazprom-subsidiary)
[78] Gazprom owns 48% of shares in Europol and another 4% through Gas-Trading S.A. (possibly a Gazprom-subsidiary)
[79] Gazprom Export 40%, MVM 50%, Centrex 10% (possibly a Gazprom-subsidiary)
[80] Owned by WIEE (50% Gazprom, 50% BASF)
[81] 51% state, 49% E.On and GDF Suez
[82] Slovenian state 39.6%, Petrol Ljubjana 32%, others 28.4

- *Take-or-pay* (TOP) *obligations* define the minimum annual contracted quantity (ACQ) the buyer agrees to purchase and the seller is obliged to deliver in a given year. The parties also agree to the level of flexibility (e.g. ± 10%) they allowed to divert from ACQ without extra payments. However, if the purchased quantity falls below ACQ minus agreed flexibility, the buyer has to pay for that minimum quantity (ACQ-flex) anyway.
- LTCs also include *delivery clauses* that define the location where imported gas has to be delivered by the exporting country. Typically, these delivery locations used to be at the borders of the importing countries. In order for the exporter to get a certification of delivery to issue its bill, gas has to physically pass a metering point installed with an electronic meter. The ownership of gas changes only when the gas passed the meter.
- The *pricing formula* included in the Panrusgaz contract is a typical *oil product linked* one. Gas price depends on a starting price escalated by a weighted average of historic gasoline and fuel oil price changes.
- The typical contract used to restrict the buyer to re-sell LTC gas by applying so called *destination clauses*.

In the course of creating the EU internal market and fostering within-EU spot trading in gas, the EU prohibited the implementation of destination clauses by its Third Energy Package in 2009. However, TOP obligations, delivery clauses and a pricing formula is still part of legacy LTCs.

The present flexibility in the Hungarian contract is ± 15%. Due to decreasing demand and increased competition from spot priced gas through HAG the actual sales conditions for TOP gas have deteriorated dramatically since 2009. At the end of 2012 MVM estimated the amount of TOP gas that the dominant wholesaler (E.ON owned EFT and from late 2013 MVM owned MFGK) had to take over but could sell only at a loss being 18.4 Bcm between 2012 and 2015. That is, in these four years 46% of the ACQ (4.6 Bcm per year) would be sold at a 30% discount to the LTC purchase price.[83] The analysis estimated TOP related financial loss at a gigantic HUF 553 Billion ($ 2.5 Billion).[84] The purchase of these excess TOP quantities might have been agreed by the

[83] The estimated loss is 30,1 HUF/m^3.
[84] The MVM report is published at http://atlatszo.hu/wp-content/uploads/2014/08/08mell_osszefoglalas.pdf.

Russian partner to be realized only after the present contract expires in 2015. This might help the restructuring of, but not to avoid, expected financial losses of MFGK / MVM over time.

By mid-2014 MFGK was reported to have a 66% market share on the Hungarian gas wholesale market.[85] Its major portfolio elements are the Panrusgaz and E.ON (0.5 Bcm/year until 2015) legacy contracts, part of MOL domestic production and preferential access to a significant share of the HAG capacity.

At present the delivery point for 80% of the gas is the UA-HU border and for 20% the HAG. Access to the UA-HU interconnector is not open and also discriminatory. Temporary access to capacity at the UA-HU interconnector to ship gas to the Hungarian market for other than Gazprom has been provided only for a small number of selected market participants in an in-transparent manner. [86]

4.1.3 Alternative imports

By mid-2014 alternative gas imports can flow to the Hungarian market only through HAG.[87] The utilisation of HAG's AT>HU capacity has been among the highest in Europe in recent years, indicating the significant and permanent gas wholesale price difference between Western Europe and Hungary.

Beyond contract release gas for TIGAZ and FŐGÁZ, HAG import could, in principle, provide the only alternative supply source to promote the entry of wholesale market participants alternative to EFT and more recently MFGK.

However, access to the capacity of HAG is still discriminative. While according to the Business Code (ÜKSZ) of the gas system the rule for cross border gas transmission capacity allocation is auctioning in case of congestion, preferential access have been

[85] See slide 9 of the presentation by Kralik, G. L. (2014). http://www.magyarfoldgazkereskedo.hu/hu/tevekenysegunk/Documents/Napi%20Gazdas%C3%A1g%20Konferencia_Kr%C3%A1lik%20G%C3%A1bor.pdf

[86] These market participants were temporarily allowed to market alternative Russian (Turkmen, Kazakh) or Ukrainian gas in Hungary by using the UA-HU capacity (e.g. EMFESZ, Eurobridge).

[87] In recent years the Hungarian gas transmission system operator initiated and completed with its partner TSOs important new interconnections, which at the first time opened up possibilities for North-West South-East and North-South gas cooperation in the CEE region. The HU>RO (4.8 mcm/day) and HU>HR (19.2 mcm/day) interconnectors were commissioned in 2010. Both of these interconnectors were designed to provide bi-directional services. However, the implementation of these physical reverse flow projects is delayed.

provided for E.ON and MVM to the HAG capacity since 2011 by the government. For example, for the gas year 2011/12, 20,4% of HAG capacity was allocated on the basis of former long term capacity booking, 33-33% of HAG capacity was allocated for E.ON and MVM respectively at normal transmission capacity charges, 4% was put on an annual auction and 10% was reserved for monthly auctions. Note that the winners of the yearly auction paid 6 times the normal transmission capacity charge the regulation established for the preferred companies (REKK, Energy Market Report, 2011/3). Since April 2012 the relevant ministerial decree[88] kept the overall volume of preferential allocation for E.ON and MVM unchanged but modified their shares to 16.5% and 49.5% of overall HAG capacity, respectively.

Provided the above distortions in cross border capacity access, HAG's contribution to improve the efficiency of gas wholesale market competition falls much below its potential role at present in Hungary. Two third of its capacity provides access opportunity to alternative supply sources for the two largest wholesale market players, also controlling LTC quantities. Nevertheless, a limited auctioning has already allowed for the market entrance of alternative wholesalers (e.g. GDF Suez, MET, Global NRG, AXPO).[89] Due to the lack of market transparency, the impact of that limited competition on wholesale and retail prices is unclear.

4.2 Former gas market model characteristics

Former Hungarian gas market models had long managed the price risks inherent in the concentrated gas supply structure by creating monopoly or dominant gas wholesalers that fell under price regulation.

Up to 1991, natural gas production, transmission, storage and distribution were organized into a single state owned, *vertically integrated* company, OKGT.

Later distribution was unbundled from OKGT, organized into regional companies and privatised in 1995. The Gas Act of 1994 created a *single buyer market model*, when MOL got the exclusive right and obligation to supply gas distribution companies. MOL was also the single buyer of locally produced and imported gas. In 1996 MOL transformed former intergovernmental agreements into a LTC up to 2015 with Russia

[88] Ministerial Decree 13/2011/ NFM and its modifications.
[89] The entry of MET to the market was made possible by MVM allowing MET to use its pre-allocated HAG capacity rights at a suspiciously low price. see: http://index.hu/gazdasag/2014/01/27/mol/

(Panrusgaz of 9 bcm/year until 2015). It also concluded alternative, smaller Western LTCs; with E.ON Ruhrgas (0.5 bcm/y until 2015) and with Gaz de France (0.6 bcm/y until 2012). MOL sold gas to the regional distribution companies on a long term contract basis at regulated prices. Distribution companies served retail customers also at regulated prices (MEH, 2010).

The Gas Act of 2003 provided the framework for the first phase of gas market liberalisation in Hungary and replaced the single buyer model with a *hybrid market model*.[90] This model was based on the co-existence of the free and captive retail market segments. Eligible (mostly larger industrial) customers got the right to opt out from the incumbent supplier but also to get back under regulated tariffs at any time. In this model the dominant wholesale market player was called the Public Utility Wholesaler (PUW). It got the exclusive right and obligation to serve Public Utility Suppliers (PUS), which were obliged to serve the gas needs of captive retail customers. PUW and PUS sales prices were regulated. While the PUW was allowed to compete for eligible customers, free market traders were not allowed to enter the PUS market segment. Until the end of 2005 MOL was the PUW and also had exclusive control over gas supply sources.

In 2005 an E.ON-MOL transaction significantly reshaped the structure of the Hungarian gas market. As part of the deal, E.ON Ruhrgas International AG (ERI) purchased the gas wholesale business of MOL (later called E.ON Földgáz Trade Zrt; in the followings: EFT), 100% of MOL Földgáztároló Rt., the owner and operator of Hungarian underground gas storage assets and 50% of Panrusgaz, EFT's largest supplier. MOL retained the gas transmission system operator company FGSZ and its production activities. As a consequence of the transaction EFT became the dominant gas wholesaler company in Hungary. It took over the control of LTCs and also entered into a 10 years contract with MOL to purchase its domestically produced gas. The decision of the European Commission that allowed for the deal to happen[91] also put *gas and contract release obligations* on EFT to mitigate its dominant wholesale market position. Under the gas release program EFT had to offer 1 Bcm of its gas per year for alternative suppliers through an open, non-discriminatory auction between 2006 and 2013. Under the contract release program EFT had to re-contract 50% of its 10 years contract to

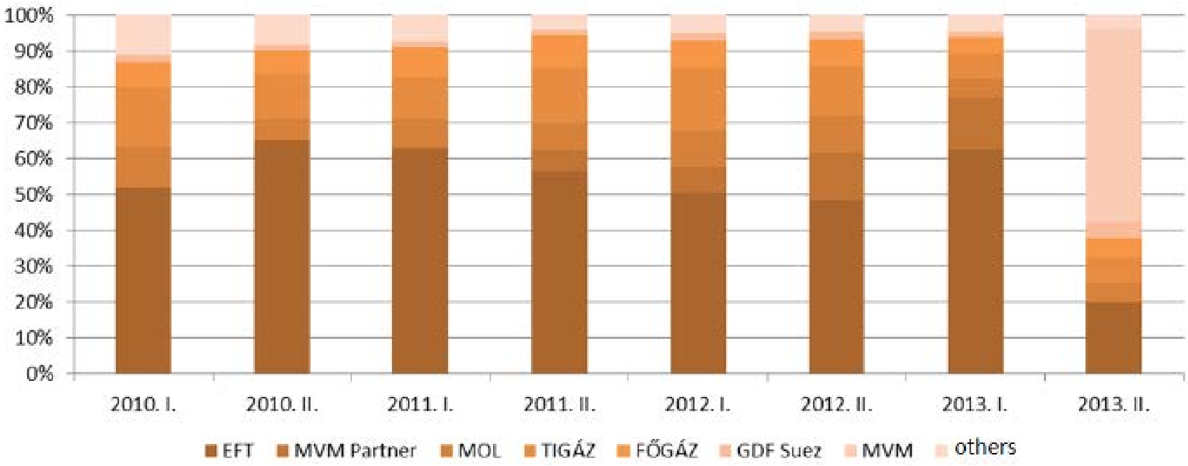
[90] For a review on the implementation details of the Second Energy Package under the Hungarian context, see Kaderják and Antall (2005).

[91] Decision of the European Commission No. 21/XII/2005 (December 21, 2005)

purchase MOL gas production. Under the two programs EFT provided an annual 2.2-2.4 Bcm gas from its portfolio to alternative market participants (see more details in Pató et al, 2008).

By implementing the EU Third Package requirements, the Gas Act of 2008[92] removed the remaining barriers from free market competition and retained the option to purchase gas at regulated prices only for a more limited group of retail customers (so called Universal Service or US customers). [93] However, the dominant wholesale position of EFT with 50-60% share in purchasing available supply sources has prevailed until the end of 2013, when MFGK (MVM) purchased its portfolio. Other significant wholesale market participants beyond EFT and MVM are MOL, TIGÁZ (ENI), FŐGÁZ and GDF-Suez (see Figure 7).

Figure 7. Market share of gas wholesale traders from purchased supply sources (production + import), 2010-2013*



*For 2010 II., the MVM figure involves MVM Partner and, from September 1 2013, also Magyar Földgázkereskedő Zrt (MFGK).

Source: MEKH (2014), p. 52

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[92] Act XL of 2008 about Gas Supply.

[93] As of August 2013, households, other consumers with a buying capacity not exceeding 20 m^3/hour, and municipalities up to the quantity of providing gas for those living in municipality-owned rentals were entitled to Universal Service. The quantity of natural gas sold under Universal Service was 3.7 billion m^3 in 2012, 34% of gross domestic consumption.

It seems apparent from the above brief assessment that the primary structural problem of the Hungarian gas wholesale market is related to the LTC with Russia that has been providing the majority of supply sources to the market since 1996. The Hungarian counterparty to this contract (MOL, then EFT and now MFGK) has always had a dominant (over 50%) wholesale market share. The subsequent market models that implemented the EU gas market liberalization rules under the Hungarian context have always been adjusted to acknowledge the existence of this LTC by first introducing the Public Utility market segment between 2004 and 2009 and then the Universal Service market segment. The LTC holder has always had a preferential supply right to serve these market segments.

A final note is that LTC pricing has always had a decisive impact on wholesale gas price development on both the regulated and the free market segments in Hungary. In the regulated Universal Service segment this influence is direct since the regulator has established the justified cost of gas for US customers on the basis of the Weighted Average Cost of Gas of the US wholesaler.[94] However, the LTC price also has a significant, though indirect influence on free market gas wholesale prices. The dominant market position of the LTC holder has long allowed oligopolistic pricing on this market segment. The marginal cost of the dominant wholesaler has also been determined by the LTC price. So free market gas price arrangements has long considered the (assumed) WACOG of the dominant wholesaler that is the oil indexed gas price as their starting point. It is just in the last 1-2 years that decreasing demand and increased spot imports started to undermine this traditional pricing regime on the free market.

4.3 Future scenarios for wholesale market arrangements

As we have seen, the combination of a pivotal infrastructure controlled by the Russian supplier, limited alternative supply sources, the features of the major Russian LTC, most notably its pricing regime and relative quantity-wise inflexibility (TOP clause) and the chosen gas wholesale market liberalization models has long ensured the dominance of oil-indexed gas pricing on the Hungarian gas wholesale market.

However, the breakdown of oil indexed gas pricing already started with increased short term trading through HAG. The change in the dominant pricing regime might further

[94] Since 2011 the regulator applies a mixed oil-indexed – spot price ratio to calculate justified WACOG from LTC purchases. The present mix is 0.7*spot + 0.3*oil indexed.

accelerate from 2015 due to at least two major developments. First, the present LTCs (both Panrusgaz and E.ON) expire in 2015. While it is assumed that 18.4 Bcm TOP gas will have to be purchased by MFGK after 2015 (see section 4.2), it is not clear under what kind of arrangement this will take place (time allowed for purchase; pricing conditions, etc). Second, the new Slovakia-Hungary interconnector will become commercially operational and thus the pivotal nature of the Ukraine-Hungary interconnector will be gone. I assume these developments create a unique opportunity to shift the nature of gas wholesale competition from an oligopolistic towards a more efficient one in Hungary. This could also mean a shift from oil-indexed dominated towards spot gas pricing.

Related to these developments, in the turn of 2012 and 2013 the Ministry of National Development carried out an analysis and conducted a related consultation with market participants about possible future gas wholesale market alternatives beyond 2015 for Hungary. The analysis and the conclusions of the consultation are reported in REKK (2013). The study compares three alternative futures for the Hungarian gas market. The major characteristics of the three high level models are summarized in Table 8. In terms of the wholesale market structure what makes the most significant difference among the investigated future options is the existence and volume of a potential future LTC. The Wholesale Competition model assumes no dedicated LTC to the Hungarian market after 2015, while the Universal Service + Competition and the Dominant Wholesaler models assume a smaller (2-3 Bcm/year) and larger (5-9 Bcm) contract, respectively. Since the study presents the up-to-date most comprehensive assessment of the relationship between future market models and related gas wholesale price developments, I use the REKK (2013) scenarios as in inspiration when formulating the policy simulation scenarios in Section 7 of this paper.

Table 8. Post-2015 gas wholesale market model scenarios by REKK (2013)

	MODEL NAME		
	WHOLESALE COMPETITION	UNIVERSAL SERVICE + COMPETITION	DOMINANT WHOLESALER
Wholesale market structure	No new LTC after the expiring of legacy LTCs in 2015. Demand is served by competing international and local gas companies from their international portfolios (LTC and spot). Well functioning market institutions.	Shares major features of the 'Wholesale competition' model but a special Universal Service market segment added.	Continuation of the pre-2015 market model. New and large sized (5-9 Bcm per year) LTC with Russia is concluded. A single wholesale market participant dominates the market. International companies are discouraged from the market. Small competitive fringe.
Universal service, domestic production	No US market segment retained. Retail customer price regulation cancelled. No regulatory constraint on the sale of domestic production.	US wholesaler allowed to enter into new LTC up to 50-60% of the demand of US customers (cc 3 Bcm). US wholesaler is appointed or selected on an open tender for 3-5 years. US wholesaler obliged to serve US supplier(s). Financial risk from changing US market size due to supplier switcing is on US customers. Domestic production from wells opened before 1998 can be chanelled into the US wholesaler's portfolio. US supplier is not allowed to directly participate the free market segment.	US market segment retained. Dominant wholesaler serves US supplier(s). US wholesaler is allowed to directly compete on the free market segment. Domestic production from wells opened before 1998 chanelled into the US wholesaler's portfolio.
Infrastructure access	Non-discriminatory rules for connection, capacity booking and congestion management. Market based capacity allocation.	Same as in 'Wholesale competition'	In order to reduce the financial risk from its large LTC protfolio, the US wholesaler is allowed to deliver LTC gas by booking cross border capacity on other than the Ukrainian interconnectors (HAG, SK-HU).
Supply security	Large number of active wholesale market participants bring supply and contractual diversification. HUB function strenghtened. Better utilization of infrastructure. Too much exposure to spot transactions is a risk.	Basic competitive feature of the wholesale market and resulting source and contractual diversification remains. Additional security is provided by the - limited size - LTC and the regulatory control over the US supply segment.	High level security in gas volumes terms. High risk of single supply source remains.
Regulatory environment	Ex post price control. Regulator respects rules, withholds from unexpected interventions (e.g. price caps)	Regulated US prices reflect the purchase cost of the US wholesaler and additional US costs.	Significant regulatory involvment in US price regulation due to potential cross financing between the US and free market segments. Regulation largely substitutes lacking market signals. Inherent incentives for 'market protection' type regulatory measures.
Likely market outcome	Move closer to European spot prices. Highly dependent on progress in regional supply source diversification efforts (e.g. Nabucco)	Efficient competition on wholesale level retained. Move closer to European spot prices. US wholesaler is under competition from free market traders for US customers.	Dominant wholesaler have price setting power. Free market wholesale price outcome less dependent on spot price signals but rather on LTC pricing conditions. Significant financial risk on dominant wholesaler.
Industry consultation conclusion	Supported by most as a long term objective. Risky in short term due to lack of diverse supply sources.	Most preferred short term option.	Opposed, except one respondent.

5 Distortive access rules to critical interconnectors

Cross border interconnection capacities with third party access are the single most serious threat to a dominant gas wholesaler under the market conditions prevailing in Hungary. Certainly, this threat translates to real competition only when competitively priced gas becomes available to be shipped to the market and access is allowed to cross border pipeline capacities.

It is the history of the company EMFESZ that best illustrates that competition can hit the dominant wholesaler even when competitors are granted *discriminatory access* to cross border capacities that are otherwise non accessible for third parties. Between 2005 and 2010 EMFESZ could import alternative Russian / Turkmen gas to Hungary through the UA>HU interconnector and gain about 10% of the Hungarian retail market predominantly on the basis of this supply source (MEKH 2014, p. 53). Since EMFESZ gas was competing with Gazprom LTC gas, marketed by EFT, this was the period of a strange Russian-Russian gas-to-gas competition in Hungary. However, the real and long-lasting competitive threat comes through cross border capacities that fall under *non-discriminatory regulated third party access* rules.

An underlying hypothesis of this study is that a major market precondition of moving from oil indexed to spot gas pricing in Hungary is improved liquidity and integration of our region's gas markets with those of North and South West Europe. This could ensure that the supply of spot priced gas becomes available in significant amounts West to our region. Without regard to whether it is of Russian origin or not, this creates the possibility to ship spot priced gas from Austria or Slovakia[95] to Hungary. From Croatia and Romania Hungary could get access to alternative supply sources once physical reverse flow capabilities are implemented on these interconnectors.

The regulatory precondition of moving towards spot pricing is to guarantee a transmission access regime in Hungary and the EU countries critical in supplying natural gas to Hungary (Austria, Czech Republic, Croatia, Germany, Italy, Slovakia and

[95] In June 2014 physical reverse flow capacity from Germany to the Czech Republic was 10 times, from the Czech Republic to Slovakia was 5 times the capacity of the SK>HU interconnection towards Hungary.

Slovenia) that does not allow for strategic booking or withholding of transmission capacities, including cross border capacities.

However, a dominant market player always has an incentive to keep competitors away. The import of competitively priced gas could impose significant financial losses on a LTC holding, incumbent dominant gas wholesaler due to TOP clauses (see discussion in section 4.2 on estimated losses for MFGK). In order to reduce its sales and financial risks from selling large LTC gas quantities, the dominant wholesaler might try to deliver LTC gas through interconnectors that fall under regulated third party access thus foreclosing competition from spot gas on the downstream market. The incumbent wholesaler also has an incentive to put pressure on the regulator to implement "market protection" measures of this kind in order to reduce quantity and price risks inherent in LTCs under competitive pressure.[96] The incumbent's pressure on the national regulator can be assumed more effective once the dominant wholesaler is state-owned.

The above risks hold under the Hungarian context. Gazprom and its local contracting partner (at present MFGK) have a shared interest in blocking non-Russian-Ukrainian cross border capacities thus reducing spot gas availability for the market. The government, as an owner of MFGK faces the dilemma of promoting the spread of spot pricing at the risk of significant financial losses on the side of MFGK or protecting the company by implementing "market protection" measures. Among the most effective of these measures is to distort cross border access conditions for independent market participants thus foreclosing competition.

The remaining of this section reviews cross border access rules in force in Hungary and the main provisions of Commission Regulation 984/2013 on establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems. It tries to identify the room existing and upcoming regulations might allow for *potentially distortive access* to critical interconnectors. In particular, the question is asked whether present and potential future Russian LTC holders (or their affiliates) could, within the EU regulatory framework, book significant amounts of interconnection capacities at EU-EU borders in order to foreclose competition on downstream markets.

[96] I owe this idea to my colleague Lajos Kerekes.

5.1 *Existing Hungarian access rules*

By mid-2014 no regulated third party access is provided to the UA-HU interconnector in the Hungarian direction. The implementation of EU gas market rules in Ukraine due to obligations under its Energy Community membership might change this situation in the future.

As discussed in section 4.2, access to HAG capacity is discriminative today. Although LTC holder Panrusgas and MFGK have full access to the UA>HU interconnector without regulated third party access, capacity is also booked on HAG for the delivery of 20% of the LTC quantity.

A recent incident illustrates that the competition for long term bookings on HAG already started, right before the upcoming EU Capacity Allocation Regulation for cross border interconnectors should come into force (see later in this section). In May 2014 FGSZ initiated a long term capacity allocation procedure for HAG capacities for gas years from 2015/16 up to 2024/25. The TSO's priority was for the longest and largest volume capacity booking needs. By its Decision 1993/2014 (May 12, 2014) the Hungarian regulator, MEKH obliged the TSO to immediately halt the procedure. It referred to Article 156 (1) of Government Decree 19/2009 about the implementation of the Gas Act. This Article states that up to March 15, 2015 cross border gas transmission capacity can only be booked until September 30, 2015. The exception to this rule of the Government Decree is only new infrastructure that applies for an exception to regulated third party access and related tariffs to the regulator. Neither HAG nor the new SK-HU interconnector belongs to the latter category. This means that the framework for future capacity allocation on HAG will be Regulation 984/2013.

It is critical for gas wholesale market development in Hungary, but still unclear, what capacity allocation rules will apply to the new SK-HU interconnector. The project developing companies (MGT on the Hungarian and Eustream on the Slovakian side) did not apply for an exemption to third party access rules for this new infrastructure. According to non-official information, MGT plans for an open season type of capacity allocation round where bidders for the highest volumes and longest contracting periods would get preference in capacity booking. It is also unclear whether this would comply with present Hungarian regulations and the upcoming EU Capacity Allocation regulation.

5.2 Provisions of Regulations 715/2009 and 984/2013

Starting from 7 March, 2016 it will be Commission Regulation 984/2013 on establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (in the followings: CA Regulation) together with Regulation 715/2009 that will serve as an EU-wide framework for cross border transmission capacity allocation. The CA Regulation shall apply from 1 November 2015 and the first capacity auction will take place in early March 2016.

The main provisions of the CA Regulation is about to ensure that from early March 2016 available gas interconnection capacity products are better defined, as far as possible harmonized on the two sides of the interconnectors (bundled capacity products) and auctioned in a harmonized manner all across Europe. The CA regulation sets out the framework for capacity calculation and maximization by TSOs and defines yearly, quarterly, monthly, daily and intra-day auction methodologies, calendars and transparency requirements with regard to publishing their results.

However, the CA Regulation has not much to say about how to prevent capacity bookings to foreclose downstream markets. It makes an effort to oblige TSOs to reserve 20% of the technical capacity of interconnectors for shorter term bookings (10% for maximum 1, 10% for maximum 5 years)[97] and also puts a 15 years limit on the length of possible capacity booking on annual yearly auctions.[98] It urges national regulators to increase actual reserved capacities for shorter term bookings at certain critical interconnection points.[99] However, it also respects existing transport contracts, many of them based on LTCs and only push for that all transmission capacity related to the execution of LTCs "shall be bundled at the earliest opportunity".[100]

[97] Article 6 and 8 (6-8)

[98] Article 11 (3)

[99] „The exact proportion of capacity to be set aside in relation to paragraphs 6 and 8 shall be subject to a stakeholder consultation, alignment between transmission system operators and approval by national regulatory authorities at each interconnection point. National regulatory authorities shall in particular consider setting aside higher shares of capacity with a shorter duration to avoid foreclosure of downstream supply markets". Article 8 (9)

[100] Article 20 (5)

EU transmission access regulations are also very soft on how to manage contractual congestions. Regulation 715/2009 only requires that in the event of contractual congestion, the transmission system operator shall offer unused capacity on the primary market at least on a day-ahead and interruptible basis.[101] This is not of much help for shippers intended to enter a downstream market and to face competition from incumbent, dominant wholesalers.

It is paragraph 5 of Article 2 of the CA Regulation that is the most explicit on how to address the risk of foreclosure of downstream supply markets:

> *"In order to prevent foreclosure of downstream supply markets, competent national authorities may, after consulting network users, decide to take proportionate measures to limit up-front bidding for capacity by any single network user at interconnection points within a Member State."*

This section provides for a very broad authorization, but no obligation, for competent national authorities (mostly national regulatory authorities) to limit up-front the participation of certain network users in bidding for specific capacities or to limit the share of capacities a single network user might receive at the auctions. In case of those LTC holders that can deliver gas to a certain EU market through an interconnector for which EU-like regulated third party access rules do not apply, such limitation could be easily justified on the basis of reciprocity. This case clearly holds for any Russian LTC a Hungarian market participant might have until no regulated third party access rules implemented for the UA>HU interconnector. However, the CA Regulation delegates the full authority to establish any limitation of this kind to the competent national authority. Neither ACER nor the Commission has any authority in this regard.

[101] Article 13 (3)(a)

The conclusion of this brief regulatory review is that nothing in existing and upcoming transmission capacity allocation regulations explicitly rules out the possibility that Gazprom, its affiliates or their LTC holder incumbent partner book significant amounts of available capacity for long term (up to 15 years) on EU-EU interconnectors (including HAG and the SK-HU interconnector) in the course of the capacity auctions foreseen by the CA Regulation. Once this happens, gas wholesale competition was foreclosed on the Hungarian market. It is the Hungarian regulator, HEPURA that got a general authorization by the CA Regulation to limit such bookings up-front. However, it is early to tell to whether MEKH will use its powers in this regard.

6 Modelling methodology: the EGMM[102]

For the upcoming simulations in section 7 I will use the European Gas Market Model that has been developed by my colleagues and myself to simulate the operation of an international wholesale natural gas market in whole Europe. Figure 8 shows the geographical scope of the model. Country codes denote the countries for which we have explicitly included the demand and supply side of the local market, as well as gas storages. Large external markets, such as Russia, Turkey, Libya, Algeria and LNG exporters are represented by exogenously assumed market prices, long-term supply contracts and physical connections to Europe.

Figure 8. Post-2015 gas wholesale market model scenarios by REKK (2013)

[102] The following description was provided by the gas modelling team of REKK, composed of András Kiss (principal model author), Borbála Tóth (team leader), László Paizs, Adrienn Selei and Péter Kotek.

Given the input data, the model calculates a dynamic competitive market equilibrium for 35 European countries, and returns the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries.

Model calculations refer to 12 consecutive months, with a default setting of April-to-March.[103] Dynamic connections between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and TOP constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) long-term take-or-pay (TOP) contracts; and (7) spot trading. Each of them is described in detail below.

6.1 Local demand

Local *consumption* refers to the amount of gas consumed in each of the local markets in each month of the modeling year. It is, therefore, a quantity measure.[104] Local *demand*, on the other hand, is a functional relationship between the local market price and local consumption, similarly specified for each month of the modeling year.

Local demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 €/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example).

The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

[103] The start of the modeling year can be set to any other month.
[104] All quantities are measured in energy units within the model.

6.2 Local supply

Local *production* is a similar quantity measure as local consumption, so the corresponding counterpart to local demand is local *supply*. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price.

In the model, each supply unit (company, field, or even well) has either a constant, or a linearly increasing marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.[105]

Any number of supply units can be defined for each month and each local market. As a result, local supply will be represented by an increasing, stepwise linear function for which the number, size, and slope of steps can be chosen freely.

6.3 Gas storages

Gas storages are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from, or injected into, the storage. Each local market can contain any number of storage units (companies or fields).

Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There is no specific working gas fee, but the model contains a real interest rate for discounting the periods, which automatically ensures that foregone interest costs on working gas inventories are taken into account.

There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.

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[105] Minimum production levels can be set to zero. If minimum levels are set too high, a market clearing equilibrium may require negative prices, but this practically never happens with realistic input data.

6.4 External markets and supply sources

Prices for external markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. In case of LNG the price is derived from the forecasted Japanese spot gas price, taking into account the cost of transportation to any possible LNG import terminal. As a consequence, the price levels set for outside markets are important determinants of their trading direction with Europe. When prices are set relatively low, European countries are more likely to import from the outside markets, and vice versa.

6.5 Cross-border pipelines

Any two markets (local or outside) can be connected by any number of pipelines or LNG routes, which allow the transportation of natural gas from one market to the other. Connections between geographically non-neighboring countries are also possible, which corresponds to the presence of dedicated transit routes.

Cross-border linkages are directional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.

Virtual reverse flow ("backhaul") on unidirectional pipelines or LNG routes can also be allowed, or forbidden, separately for each connection and each month. The rationale for virtual reverse flow is the possibility to trade "against" the delivery of long-term take-or-pay contracts, by exploiting the fact that reducing a pre-arranged gas flow in the physical direction is the same commercial transaction as selling gas in the reverse direction.

Additional upper constraints can be placed on the sum of physical flows (or spot trading activity) of selected connections. This option is used, for example, to limit imports through LNG terminals, without specifying the source of the LNG shipment.

6.6 LNG infrastructure

LNG infrastructure in the model consist of LNG liquefaction plants of exporting countries, LNG regasification plants of importing countries and the "virtual pipelines" connecting them. "Virtual pipelines" are needed to define for each possible transport route a specific transport price. LNG terminals capacity is aggregated for each country, which differs from the pipeline setup, where capacity constraints are set for all individual pipeline. LNG capacity constraints are set as a limit for the set of "virtual pipelines" pointing from all exporting countries to a given importing country, and as a limit on the set of pipelines pointing from all importing countries to a given exporting country.

6.7 Long-term take-or-pay (TOP) contracts

A take-or-pay contract is an agreement between an outside supply source and a local market concerning the delivery of natural gas into the latter. The structure of a TOP contract is the following.

Each contract has monthly and yearly minimum and maximum quantities, a delivery price, and a monthly proportional TOP-violation penalty. Maximum quantities (monthly or yearly) cannot be breached, and neither can the yearly minimum quantity. Deliveries can be reduced below the monthly minimum, in which case the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered.

Any number of TOP-contracts can be in force between any two source and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next. Contract prices can be given exogenously, indexed to internal market prices, or set to a combination of the two options.

The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions, and routes can also be changed from one month to the next.

6.8 Spot trading

The final building block, spot trade, serves to arbitrage price differences across markets that are connected with a pipeline or an LNG route. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached.

Physical flows on pipelines and LNG routes equal the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become "negative" (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow of the connection.

6.9 Equilibrium

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time.[106] However, it is instructive to spell out this condition in terms of the behavior of market participants: consumers, producers and traders.[107]

Local consumers decide about gas utilization based on the market price. This decision is governed entirely by the local demand functions we introduced earlier.

Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then

[106] There is one, rather subtle, type of arbitrage which is treated as an externality, and hence not eliminated in the model. We assume that whenever long-term TOP contracts are (fully or partially) linked to an internal market price (such as the spot price in the Netherlands), the actors influencing that spot price have no regard to the effect of their behavior on the pricing of the TOP contract. In particular, reference market prices are not distorted downwards in order to cut the cost of long-term gas supplies from outside countries.

[107] We leave out storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.

producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions.

Second, traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection and working gas capacity, as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[108,109]

Finally, traders also perform spot transactions, based on prices in each local and outside market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Turkey, Libya, Algeria or LNG markets, which are not explicitly included.

[108] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.

[109] A similar intertemporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

Table 9. Summary of modelling input parameters and data sources

7 Category	Data Unit	Source
Consumption	Annual Quantity Monthly distribution (% of annual quantity)	Energy Community data, Eurostat, ENTSO-G
Production	Minimum and maximum production	Energy Community data, ENTSO-G
Pipeline infrastructures	Daily maximum flow	GIE, ENTSO-G, Energy Community data
Storage infrastructures	Injection, withdrawal, working gas capacity	GSE
LNG infrastructures	Capacity	GLE, GIIGNL
TOP contracts	Yearly minimum maximum quantity Seasonal minimum and maximum quantity	Gazprom, National Regulators Annual reports, Platts, Cedigaz

7 Simulation scenarios and results

This section defines the simulation tasks and scenarios to test my hypotheses by the use of the EGMM. Controlled experiments are executed so that hypothetic scenarios or market/policy settings for Hungary are developed and their wholesale price outcomes are derived in a European market context that best represent actual supply, demand, infrastructure and contractual conditions. The scenarios are built around changes in few policy variables that are assumed to have the most significant wholesale price impact while the rest of the variables are controlled (unchanged). The Hungarian scenarios are not intended to be 'realistic' in terms of representing actual market conditions. Their aim is to represent stylised, sometimes extreme market settings in order to test the responsiveness of wholesale pricing outcomes to changes in some critical policy variables.

7.1 Simulating the partial impacts of marginal policy changes on Leverage and gas wholesale prices under contract and infrastructure constrained perfect competition

Section 2 identified available government measures to undermine pivotal infrastructure positions. Demand side measures include those affecting end-customer prices (like the tax wedge between retail and wholesale gas prices or regulated tariff components) and exogenous energy efficiency investments. An important supply side measure is to encourage domestic gas production by a favourable investment environment, e.g. by setting low relative extraction taxes (royalty). An additional government measure is to encourage investment into gas import capacity from non-pivotal directions, e.g. by providing sufficiently high regulated return for such investments. According to the hypothesis, once the pivotal infrastructure position is undermined, oligopolistic (oil-linked) gas prices will also be undermined. This hypothesis assumes a functional relationship between the measure to identify a pivotal infrastructure, namely the Leverage index as defined in (1) and gas wholesale prices, ceteris paribus (see Figure 5).

One way to test the above hypothesis would be to carry out the econometric estimation of the invers of the leverage function in (4):[110]

$$p(L) = p\,(r, t, E, \tau, \sigma). \tag{5}$$

However, the lack of sufficient data prohibited to follow this way.

Instead, this section provides estimates on the functional relationship between p and L based on EGMM simulation values.

The process of simulation is as follows. I start to run the model with a Hungarian reference case with a relatively high L value. In the reference case 2012 consumption and production data and 2014 infrastructure and tariff data is used for all countries endogenously modelled by EGMM. In the reference case the value of L is 0.35 for Hungary, Russian LTC is 100% oil-indexed priced and no spot Russian gas is available for the market.[111]

[110] Note that in (4) t and τ helps to delink end-customer prices and production levels from wholesale gas price fluctuations respectively, thus resolving the endogenity of p and L apparent in (3).

[111] In light of recent Russian LTC renegotiations and the spreading practice of mixed spot-oil indexed LTC pricing the assumption of 100% oil indexed pricing by Russia might seem unrealistic. However, my objective here is to test the capacity of alternative policy measures to put pressure on oil indexed pricing. To develop a theory on Russian gas pricing under regulatory and competitive pressures is a topic for another study.

The hypothesis is that due to the high positive *L* value for the reference case, the modelled wholesale gas price for Hungary will be closer to the oil-linked price. Next I generate (*p;L*) value pairs or observations by introducing marginal changes in the determinants of the L function: gas demand, domestic gas production and aggregate gas import capacity from non-Russia-Ukraine directions. I derive the partial impact of marginal policy changes on *L* and *p* values as follows:

[1] From the reference case I start to reduce reference demand (110.75 TWh in 2012)[112] in marginal blocks (5 TWh) until the *L* value reaches -0.2, ceteris paribus and derive related wholesale price estimates.

[2] From the reference case (25.2 TWh annual maximum production capacity) I start to increase maximum capacity of domestic production in marginal blocks (5 TWh) until the *L* value reaches -0.2, ceteris paribus and derive related wholesale price estimates.

[3] From the reference case I start to increase import capacity from non-Russia-Ukraine directions in marginal blocks (5 TWh/year) until the *L* value reaches -0.2, ceteris paribus and derive related wholesale price estimates. Two alternative sub-scenarios have been developed to test the impact of alternative development options.

[3A] In the first case only the HAG capacity was expanded by marginal blocks (5 TWh/year) until *L* reached a sufficiently low value (< -0.2).

[3B] In the second case the SK-HU interconnector was implemented first in marginal blocks (5 TWh/year) until it reached the actual planned capacity (127 GWh/day SK-HU capacity) and then HAG expanded until *L* reached a sufficiently low value (< -0.2). To reach *L*= -0.2 ceteris paribus next to the SK-HU capacity an extension of AT-HU capacity with 40 GWh/day was also necessary.

The EGMM derives yearly average wholesale price estimates under contract (LTC) and infrastructure (interconnection capacity) constrained perfect competition. Thus the results of the above simulations will be informative on the partial wholesale price

[112] During the calculations it is assumed that 1 Bcm = 9.77 TWh

impacts of different policy measures to improve leverage for Hungary under the specific assumptions about contract and infrastructure constrained perfect competition inherent for the EGMM model.

7.1.1 Simulation results

Figures 9-12 summarise the results of the first simulation round. The results illuminate the capacity of policies discussed in the context of the Leverage function in (3) to undermine Russian oil-indexed gas pricing when Russia is not willing to adjust its pricing policy to apparent competitive pressure. Modelled German prices plus transmission tariffs from Germany to Hungary are used as an approximation for hub-based pricing.

Figure 9. Modelled impact of marginal demand reductions on leverage and gas wholesale prices

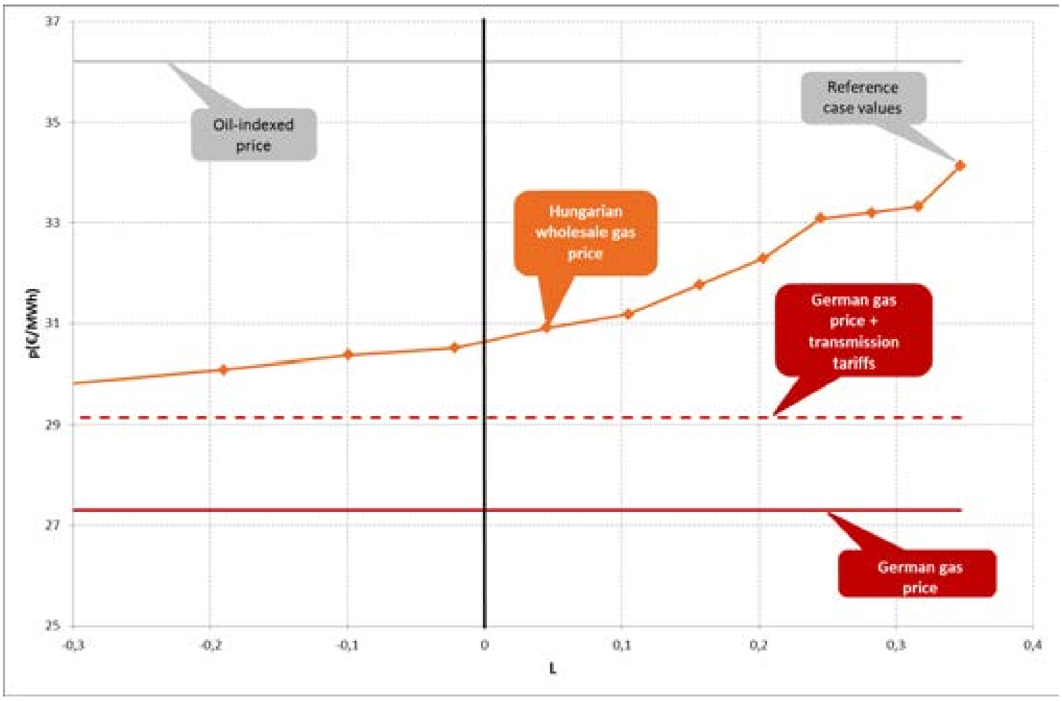


Figure 10. Modelled impact of marginal domestic production increases on leverage and gas wholesale prices

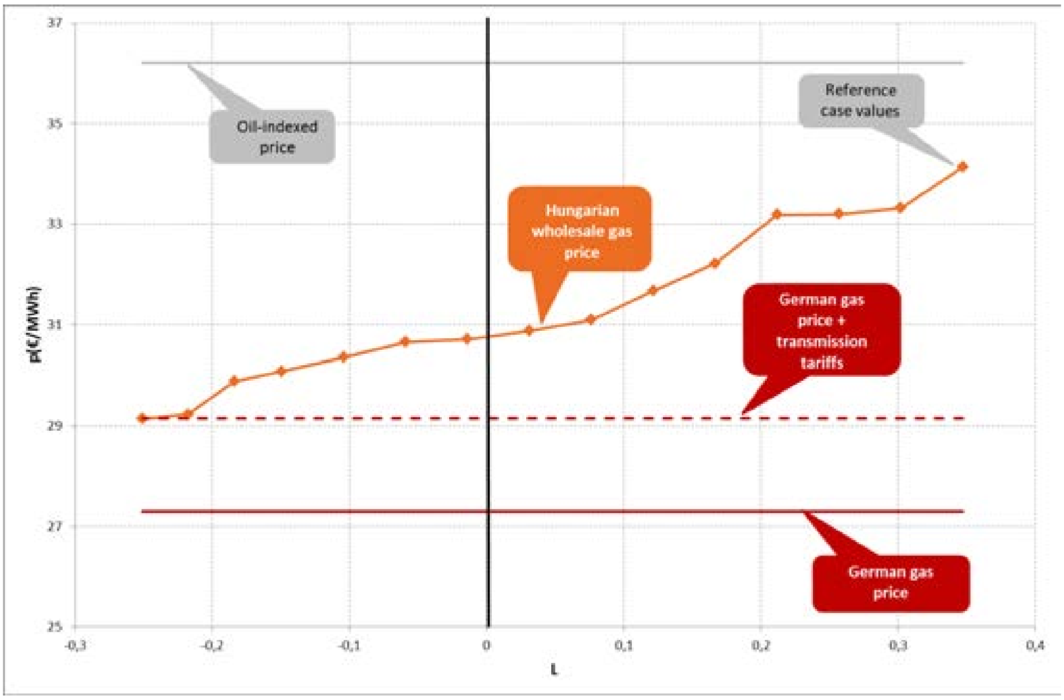


Figure 11. Modelled impact of marginal HAG capacity expansions on leverage and gas wholesale prices

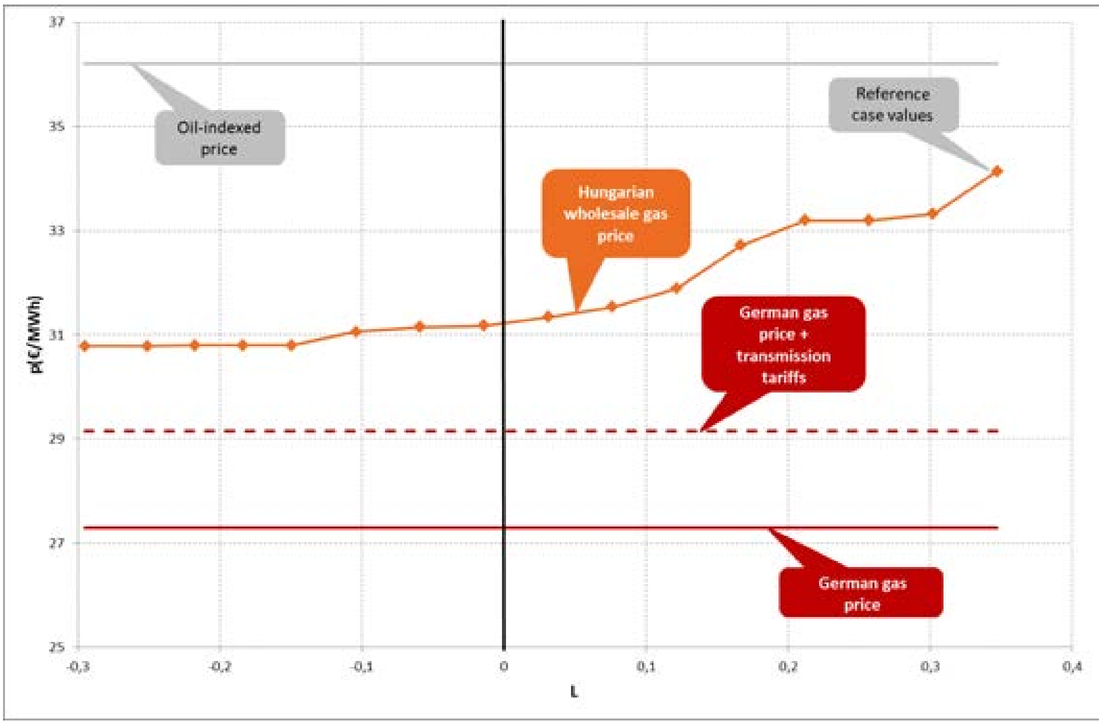
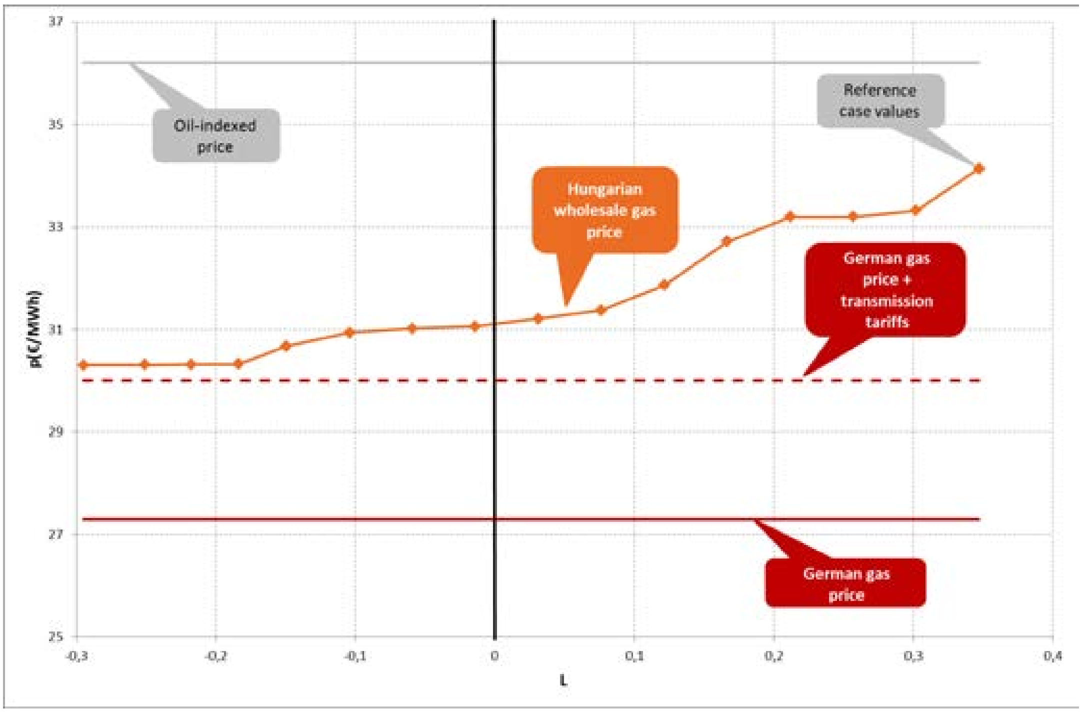


Figure 12. Modelled impact of marginal SK-HU and follow up HAG capacity expansions on leverage and gas wholesale prices



The following conclusions can be drawn from the above results.

- In the reference case the modelled Hungarian wholesale price (34.1 €/MWh) is only 6% below the oil-indexed price (36.2 €/MWh). The oil indexed price is 24%, the reference price is 17% over the hub-based price (29.2 €/MWh).
- The above simulation results reproduce the hypothetic functional form illustrated on Figure 5. All three policies by themselves (and most probably in combination) can lead to a gradual move from close-to oil-indexed to close-to hub-based gas wholesale pricing.
- At $L \approx 0$ values all partial policies result in 10% wholesale price decrease compared to the reference case.
- To encourage domestic production to increase and the implementation of the SK-HU interconnector seem to be the most efficient policies to arrive at hub-based wholesale prices at L values around -0.2.
- The least effective policy seems to be the expansion of only the HAG capacity due to congestion at the German Austrian interconnector.

An overall conclusion is that *under only contract and infrastructure constrained perfect competition*, policies that result in an L value ≈ -0.2 are sufficient to manage an almost full transition from oil-indexed to hub based gas wholesale pricing in Hungary. An exception is when only the HAG capacity is expanded. The partial impact of demand reduction policies seems to be a bit slower to produce close-to hub based gas wholesale prices.

7.2 Simulation of the impact of additional market and regulatory distortions on gas wholesale prices in Hungary

In the second round of simulations additional market and regulatory distortions are introduced and their impacts on gas wholesale price development investigated. The simulations are related to the testing of the hypothesis formulated in the Introduction about the major obstacles to moving from oil-indexed to spot gas wholesale pricing in Hungary. The existence of a pivotal infrastructure, gas wholesale market concentration and distortive cross border capacity access rules were assumed to be the most detrimental market characteristics for spot pricing to develop on the Hungarian market (see also Table 1 on the assumed relationship between the first two obstacles and likely gas wholesale pricing regimes).

For simulation purposes I define two possible, stylised states with regard to each of the three market/policy characteristics and thus create 8 possible market/policy scenarios for Hungary to compare. As in the case of previous simulations, the reference case includes 2012 consumption and production data and 2014 infrastructure and tariff data for all countries endogenously modelled by EGMM except for Hungary. For the Hungarian market I will control for demand, production and underground storage characteristics so that they will remain unchanged in all the subsequent simulations.

In the eight simulation scenarios the following alternative states will apply with regard to the investigated market/policy characteristics:

- *Pivotal infrastructure.* In the Hungarian context, the potential pivotal infrastructure is the UA>HU interconnector. I will represent the existence versus the lack of its pivotal position by two alternative infrastructure settings. The first will reflect interconnection conditions in the reference case with an L value of 0.35 (UA>HU is pivotal). In the alternative case L = -0.2 due to the implementation of the fully bi-directional SK>HU interconnector and further extension of HAG.

- *Market concentration.* The concentration of the Hungarian wholesale market is represented by two alternative LTC volumes. High concentration translates to a 8 Bcm (78.16 TWh)/year, 100% oil-indexed (36.2 €/MWh) LTC with ± 15% flexibility (see dominant wholesaler model in section 4.2). Low market concentration is represented by a 2 BCM (19.54 TWh)/year, 100% oil-indexed LTC with the same flexibility (see Universal Service + Competition scenario in the same section). Russian spot gas is not available in any of the two scenarios (having a very high price).

- *Distortive access to interconnectors.* With regard to capacity booking for LTC holders two alternatives are considered again. In the first type of scenario (see Scenarios 1, 2, 5 and 6 below) LTC gas can only be delivered to the Hungarian market through the UA>HU interconnector. This is the stylized case when the regulator prohibits capacity booking for LTC holders on interconnectors falling under regulated third party access rules (see discussion in section 4.2). In the second type of scenario regulated third party access interconnectors are used first for delivering LTC gas and if needed for larger contracts, the remaining amount flows to the Hungarian market through the UA>HU interconnector. More precisely, in Scenario 7 70% of contracted quantity is delivered through HAG (up to full capacity) and for the delivery of the remaining 30% UA>HU capacity is used. In Scenario 8 100% LTC gas flows on HAG, in Scenario 3, 55% flows on SK-HU (up to its full capacity) and the remaining 45% on HAG. Finally, in scenario 4 100% LTC gas flows on the SK-HU interconnector. Only remaining capacity, if any, is available for spot trading on these interconnectors in case of second type Scenarios.

Table 10 summarises the major characteristics of the simulation scenarios.

Since Scenario 2 is the closest to a competitive market/policy setting (strong leverage, low market concentration, no cross border capacity blocking), I expect this scenario to result in a gas wholesale price closest to hub-based prices (approximated by modelled German wholesale prices). On the other end, being the least competitive setting, I expect Scenario 7 (low leverage, high market concentration, cross-border capacity blocking) to result in closest to oil-indexed prices.

Table 10. Alternative market/policy setting simulation scenarios

Assumptions		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Leverage	L = 0,35 (2011)					x	x	x	x
	L = - 0,2	x	x	x	x				
Market concentration	LTC: 8 Bcm	x		x		x		x	
	LTC: 2 Bcm		x		x		x		x
Capacity blocking	UA>HU: 100%	x	x			x	x		
	UA>HU: 0%, SK>HU (HAG)			x	x			x	x

7.2.1 *Simulation results*

Tables 11 summarises the results of the second simulation round by individual scenarios. Hungarian and German wholesale prices and profits from LTC gas sales are indicated. Profit from LTC is the difference between the revenue of the LTC holder from selling the TOP (at least ACQ-flexibility) volume at equilibrium market price and the cost of purchasing it at 100% oil indexed prices.

Table 11. Wholesale prices and LTC profits in the different market/policy simulation Scenarios

	Scenario 1	Scenario 2	Scenario 3	8 Scenario 4	9 Scenario 5	10 Scenario 6	11 Scenario 7	12 Scenario 8
HU price (€/MWh)	30.7	30.2	31.8	31.6	30.8	31.0	34.9	35.0
DE price (€/MWh)	27.4	27.5	27.5	27.4	27.4	27.6	27.2	27.4
HU-DE price spread (€/MWh)	3.3	2.7	4.3	4.2	3.4	3.4	7.7	7.6
Annual profit from long-term contract (m€)	-574	-152	-267	-29	-580	-139	-297	-89

The following conclusions can be drawn from the results.

- All the scenarios result in negative profits for LTC contract holders. This indicates that 100% oil indexed gas is already under heavy competition in the EU and also the Hungarian market.
- As expected, Scenario 2 provides for the wholesale price closest to hub based pricing at moderate LTC loss.

- Scenario 4 is a version of Scenario 2 with distortive access of LTC holders to the SK-HU interconnector. The results indicate that distortive access in case of a small LTC and abundant interconnection capacity falling under regulated third party access rules results in minimum LTC related negative profits at moderate price increase compared to Scenario 2. Thus this could be considered as a loss minimization scenario.
- Scenarios 5 and 7 indicate that large volume LTCs produce the highest negative profits for LTC holders. As for Scenario 5, the combination of low leverage, high LTC volume and full spot competition through HAG creates the largest LTC related financial loss.
- The lesson from Scenario 7 is that the gigantic financial loss of Scenario 5 can be reduced by distortive access to HAG at the cost of a very high wholesale price increase on the Hungarian market. Scenario 7 indeed provides for the worst combination of market/policy conditions and indeed results in close to oil-indexed wholesale prices.
- Scenario 8 is a version of Scenario 7 with reduced LTC contract volume. While this scenario also results in a close to oil-indexed wholesale price, the reduced contract volume significantly decreases LTC related financial losses under conditions of low leverage and full spot competition through HAG.

Next we can compare the performance of Scenarios along the major investigated policy dimensions in terms of the average wholesale price and the average LTC profit they result in. Again, a few conclusions can be drawn from the data presented in Table 12.

Table 12. Wholesale prices and LTC profits in the different market/policy simulation Scenarios

Scenarios	Average price (€/MWh)	Average annual LTC profit (m€)
L = 0.35	32,9	-276,3
L = -0.2	31,1	-255,5
LTC = 8 Bcm	32,05	-429,5
LTC = 2 Bcm	31,95	-102,3
UA>HU 100%	30,7	-361,3
Distortive access	33,3	-170,5

First, there is a significant trade-off between wholesale price levels and the extent of distortive access to regulated third party access interconnectors. Distortive access moderates the financial loss of the LTC holder company at the cost of increasing wholesale prices. To the contrary, undistorted competition through regulated third party access interconnectors brings wholesale prices closest to hub-based levels at the cost of significant financial loss for the incumbent wholesaler.

Second, a small LTC seems to help minimizing LTC related losses while large LTC scenarios produce the highest financial losses for incumbents.

Finally, better leverage matters mostly pricewise. Scenarios with $L = -0.2$ value produced an average wholesale price being the second closest to the hub-based price.

8 Final conclusion and recommendations for future research

This study identified the principal obstacles to a transition from monopolistic (oil-indexed) natural gas wholesale pricing to hub-based pricing in Hungary as (i) the exclusive control over a pivotal infrastructure (namely the UA-HU interconnector), (ii) high level market concentration and (iii) the foreclosure of the Hungarian gas wholesale market by blocking capacities of regulated third party access interconnectors.

It introduced the leverage function to help the consistent analysis of available government measures to undermine dominant market positions based on the control of pivotal infrastructures. It also assumed a functional relationship between leverage and the prevailing gas wholesale price so that under contract and infrastructure constrained perfect competition a sufficiently low leverage value (<-0.2) would bring about close to hub-based gas wholesale prices. However, when high level market concentration and additional regulatory distortions in the form of distortive interconnection access spoil perfect competition, the relationship between leverage and the prevailing wholesale gas price becomes unclear.

In order to assess the efficiency of available supply side, production and infrastructure development related policy measures to undermine a dominant market position and to encourage a transition from oil-linked to hub-based gas pricing in Hungary, controlled experiments or simulations were carried out with a contract and infrastructure constrained perfect competition gas market model, the European Gas Market Model. Additional simulations tested the wholesale price impacts of 8 stylised market/policy settings for Hungary defined along the dimensions of leverage, wholesale market concentration and access rules to critical interconnectors.

The simulation results provided strong support for the research hypotheses. They could reproduce the hypothetic functional form between leverage and related gas wholesale price outcomes. It was found that under contract and infrastructure constrained perfect competition those policies resulting in a leverage value around -0.2 are sufficient to manage an almost full transition from oil-indexed to hub based gas wholesale pricing in Hungary. To encourage domestic production and the implementation of the SK-HU interconnector seem to be the most effective policies to arrive at hub-based wholesale prices.

Once the possibility of high level market concentration (in the form of a large volume LTC) and distortive access to non-Russian-Ukrainian interconnectors is introduced, the market/policy setting with strong leverage, low market concentration and no cross border capacity blocking results in a gas wholesale price closest to hub-based prices. The higher market concentration (i.e. the volume of a LTC) becomes, the higher the financial risk the LTC holding dominant gas wholesaler is facing. Simulations also found a significant trade-off between wholesale price levels and the extent of distortive access to regulated third party access interconnectors. Distortive access moderates the financial loss of the LTC holder company at the cost of increasing wholesale prices. To the contrary, undistorted competition through regulated third party access interconnectors brings wholesale prices closest to hub-based levels at the cost of significant financial loss for the incumbent wholesaler.

Finally, two future research tasks are proposed. The present paper lacks an explicit theory of Russian gas pricing and its transition as competitive pressure on monopolistic (oil-linked) gas pricing increases. Such a theory could significantly contribute to the forecasting of realistic market outcomes in terms of price and trade developments in the EU.

Second, the analysis of policy measures in the context of the leverage function could be expanded to include the assessment of the relevant marginal costs of the investigated policy measures. This could allow then for defining minimum cost policies to manage a transition from oil-linked to hub-based gas pricing in Hungary and elsewhere.

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List of Abbreviations

ACER: Agency for the Cooperation of Energy Regulators

ACQ: Annual Contracted Quantity

CEE: Central and Eastern Europe

CEER: Council of European Energy Regulators

CSEE: Central and South-East Europe

CA: Capacity Allocation

COMECON: Council for Mutual Economic Assistance

DR: Danube Region

DRGMM: Danube Region Gas Market Model

DSO: Distribution System Operator

EC: European Commission

EGMM: European Gas Market Model

EIP: European Infrastructure Package

EFT: E.ON Földgáz Trade Zrt

EnC: Energy Community

ENTSO-G: European Network of Transmission System Operators for Gas

ERI: E.ON Ruhrgas International AG

FGSZ: Natural Gas Transmission Company

GTE: Gas Transmission Europe

HAG: Hungarian-Austrian Gas Pipeline

IEA: International Energy Agency

ISO: Independent System Operator

ITO: Independent Transmission Operator

L: Leverage

LNG: Liquified Natural Gas

LTC: Long-term Contract

MEH: Hungarian Energy Office

MFB: Hungarian Development Bank

MFGK: Hungarian Natural Gas Trading Company

MGT: Hungarian Gas Transit Company

MOL: Hungarian Oil and Gas Company

MSZKSZ: Hungarian Hydrocarbon Storage Association

MVM: Hungarian Electricity Company
NEBP: North European Baltic Sea Pipeline
NEGP: North European Gas Pipeline
NETS: New Europe Transmission System
NFM: Ministry of National Development
NBP: National Balancing Point
OKGT: Hungarian Oil and Gas Trust
PCI: Projects of Common Interest
PECI: Projects of Energy Community Interest
PU: Public Utility
PUS: Public Utility Supplier
PUW: Public Utility Wholesaler
RCCI: Regional Cost Convergence Index
REKK: Regional Centre for Energy Policy Research
RSI: Residual Supply Index
RSoI: Regional Spill-over Index
TAG: The Trans Austria Gas pipeline
TAP: Trans Adriatic Pipeline
TEN-E: Trans-European Energy Networks
TOP: Take-or-Pay
TSO: Transmission System Operator
UCTE: Union for the Co-ordination of Transmission of Electricity
UGS: Underground Storage
US: Universal Service
USP: Universal Service Provider
WACC: Weighted Average Cost of Capital
WACOG: Weighted Average Cost of Gas