Energy Policy 36 (2008) 1622–1641
ENERGY POLICY
www.elsevier.com/locate/enpol

Future European gas supply in the resource triangle of the Former Soviet Union, the Middle East and Northern Africa

Uwe Remme*, Markus Blesl, Ulrich Fahl

Institute of Energy Economics and the Rational Use of Energy, Universität Stuttgart, Hessbruehlstrasse 49a, 70565 Stuttgart, Germany

Received 8 November 2006; accepted 10 January 2008
Available online 4 March 2008

Abstract

A steady increase of natural gas demand can be observed in Europe over the last decades. Due to the European obligation to reduce greenhouse gas emissions in the framework of the Kyoto Protocol, the trend toward natural gas is expected to continue in the future. The increased consumption is faced by comparably low indigenous gas resources within Europe, so that the dependency of Europe on gas imports from abroad will rise in the future. In addition to the existing supply sources Russia and Algeria, gas resources from the Middle East and the Caspian and the Central Asian regions may be supply options to cover Europe's gas demand in the future. Against this background, possible natural gas supply options as well as the transport infrastructure to and within Europe are discussed regarding their technical capacity and their costs. With the help of a cost-minimization model of the European gas supply system, the gas flows and the infrastructure capacity development up to the year 2030 are analyzed. In a sensitivity analysis, the impacts of demand variations on the choice of supply sources are studied.

Keywords: Natural gas; Europe; Security of supply

1. Introduction

Historically, gas consumption of Europe[1] has been rising from 324 bcm in 1990 to 555 bcm in 2004[2] (IEA, 2005; BP, 2005a) corresponding to an annual growth rate of 2.2%. The lower specific CO_2 emissions of natural gas compared with other fossil fuels may further accelerate the trend to natural gas in the future. Indigenous production for natural gas has covered 59% or 330 bcm of European gas consumption in 2004, mainly from the UK (101 bcm), the Netherlands (86 bcm) and Norway (82 bcm). In 2004, with gas exports of 149 bcm to Europe Russia was by far the largest gas supplier for Europe. Second major supplier is Algeria with exports of 53 bcm to Europe in 2004. The import dependency for natural gas has been 41% in 2004 for Europe as a whole, the dependency on imports from abroad differs, however, significantly between countries (Table 1).

On a global level, conventional gas resources are unequally distributed. The largest gas reserves are located in the Russian Federation (48,000 bcm proven reserves in 2004), followed by Iran and Qatar with 28,000 and 26,000 bcm, respectively (BP, 2005a). These three countries alone account already for 58% of global proven gas reserves of 180,000 bcm. Assuming the gas consumption of 2004 being constant for the future, global proven reserves would last for 67 years. Taking into account additional conventional resources of 204,500 bcm, the static lifetime increases to 152 years (BP, 2005a).

New emerging economies, especially India and China, which have been beginning to secure their need for energy

*Corresponding author. Tel.: +49 711 685 87846; fax: +49 711 685 87873.
E-mail address: Uwe.Remme@ier.uni-stuttgart.de (U. Remme).

[1]Europe is defined in this article as the member states of the European Union (Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, The Netherlands and the UK) plus Bosnia-Herzegovina, Croatia, Macedonia, Norway, Serbia and Montenegro, Switzerland and Turkey.

[2]In the gas industry standard cubic meters are typically used to measure the amount of gas. The volume refers to conditions of 1.01325 bar and 15 °C. 1 bcm equals 1 billion standard cubic meters of natural gas.

0301-4215/$ - see front matter
doi:10.1016/j.enpol.2008.01.017

Table 1
Import dependency for gas in Europe in 2004 (own calculations based on BP, 2005a; IEA, 2005)

	Share of supply source (%)														Gas consumption (bcm)
	Domestic	Algeria	Denmark	Germany	Iran	Kazakhstan	Libya	Netherlands	Norway	Russia	Turkmenistan	United Kingdom	Uzbekistan	LNG	
Austria	25	0		12					9	54					8
Belgium		0		6				39	37	1		1		15	19
Czech Republic	2	0							26	71					10
Denmark	100														5
Finland										100					4
France	3	0						23	36	17		2		19	41
Germany	21	0	3					17	26	31		2			99
Hungary	23	0		6						71					13
Ireland	19											81			5
Italy	15	28					1	11	8	30				7	83
Netherlands	100														46
Norway	100														6
Poland	29	0		3		7			3	59	4		1		15
Romania	78	0								22					17
Slovakia	3									97					7
Spain	1	27							8					63	28
Turkey	3	0			16					63				19	23
United Kingdom	96	0							4						100
Remaining Europe	8	11	4	8				4	0	58				7	26
Total Europe	60	6			0.6	0.2	0.1			26	0.1		0.0	7	559

by investing in the exploration and production projects for oil and gas abroad, are becoming competitors with Europe for oil and gas on the global level. Hence, security of energy supply has become a major issue on the political agenda in Europe. Not only because of the finiteness of fossil resources, but also because of the need to ensure stable gas supply and transit conditions.

The need for such conditions has become apparent, also for a broader public, in the gas dispute between Russia and the Ukraine at the end of 2005 as well as in the supply shortages due to the extreme cold in Russia at the beginning of 2006. These events have highlighted that in addition to the gas reserves the infrastructure to transport natural gas is a critical factor in the context of security of gas supply.

Natural gas can be transported in pressurized form via pipeline or in liquefied form as LNG by ship. Imports via pipeline, mainly from Russia and Algeria, have accounted for 170 bcm of total imports from outside OECD Europe, while LNG imports have been around 40 bcm (BP, 2005a). Investments for both transport options are capital intensive and, hence, require long investment lead times. In case of pipelines, the negotiations for transit rights might lengthen the planning process further. Therefore, investment decisions for gas infrastructure projects have to be taken early enough. In addition, the liberalization of gas markets in the European Union raises the question, whether the markets will signal the investment needs in infrastructure timely enough.

In the face of these issues, the purpose of this paper is the analysis of future gas supply options for Europe. In the first part, the current gas transport infrastructure for Europe and the supply options within and from outside Europe are presented. In the second part, the costs for gas supply to Europe are discussed, before this information is used in a following analysis of a future development in the gas sector up to the year 2030 based on a cost-minimizing model of the gas supply system for Europe.

2. Situation of the European gas supply system

The European gas sector evolved in the 1950s and 1960s of the last century with the development of the oil and gas fields in Italy, the North Sea and the Netherlands. While at the beginning natural gas was only a by-product of oil production, which was vented or flared, high oil prices in the 1970s encouraged the widespread use of natural gas as energy carrier to reduce the dependency on oil. European LNG imports started in 1964 with first cargos of Algerian LNG shipped to the UK. With the construction of the Brotherhood pipeline through Czechoslovakia to Austria in 1969, Western European countries began to import natural gas from the Soviet Union.

2.1. Gas resources within Europe

The largest proven gas reserves in Europe, status of 2004, are located in Norway (2386 bcm), the Netherlands (1357 bcm) and the UK (531 bcm). The reserve situation, the production and consumption levels for the individual European countries are summarized in Table 2. Additional resources, which under current market conditions cannot be produced economically, account for 9416 bcm of conventional gas in Europe.

2.1.1. Norway

Gas resources of Norway are located on the Norwegian Continental Shelf in the North Sea. Production in 2004 amounted to 78.5 bcm (BP, 2005a). Major producing fields are the Troll and Sleipner fields, the Åsgard field in the Halten/Norldand area and the Staffjord and Gulfaks fields in the Tampen area. Norwegian gas production costs are around 21 US$/1000 m^3 (Statoil, 2005a). In the Barents Sea, the first European export facility for LNG (5.7 bcm/yr) fed by the Snøvhit gas field is currently under construction. Harsh Arctic climate conditions aggravated the construction process, so that first gas deliveries are not expected to start before the end of 2007 (Statoil, 2005b). Assuming current production levels, the proven Norwegian gas reserves can last for 30 years.

2.1.2. The Netherlands

In 2004, the Dutch gas production has been reported to be 69 bcm (BP, 2005a). Gas reserves have been estimated to be around 1357 bcm at the beginning of 2004 (TNO-NITG, 2004) with the majority located in the large onshore Groningen field (1103 bcm). To sustain the resource base, the Dutch government has set an upper limit for the production of natural gas in the Natural Gas Act. For the period from 2003 to 2007, the average upper production limit is 73 bcm, while in the consecutive period 2008–2012 the average annual production is restricted to 67 bcm (TNO-NITG, 2004). The so-called "small field policy" of the Dutch government aims in the same direction of preserving the reserves of the large Groningen field by preferentially producing from smaller fields. In the context of this policy, the Groningen field has evolved as a swing producer in the European gas market. Based on this restrictive production policy, the present known proven reserves may last for 20 years.

2.1.3. United Kingdom

Gas production in the UK amounted to 96 bcm in 2004 (IEA, 2005). British gas occurrences, mainly located in the North Sea, have been estimated to be 1681 bcm at the end of 2004, of which 531 bcm are categorized as proven, 295 bcm as probable reserves and 855 bcm as resources (DTI, 2005). A drastic increase in the gas consumption has been observed in the UK in the 1990s driven by a switch from coal to gas in electricity generation. This shift was on the one hand triggered by cost decreases for combined cycle power plants and on the other hand by the availability of cheap associated gas from oil production. In contrast to Norway and the Netherlands, the static lifetime of British gas reserves is with only 6 years

Table 2
European gas balance for 2004 (BP, 2005a; BGR, 2006; IEA, 2005; TNO-NITG, 2004)

	Proven reserves (bcm)	Additional conventional resources (bcm)	Production (bcm)	Net imports (bcm)	Net exports (bcm)	Consumption (bcm)	Static lifetime of proven reserves (years)
Austria	15	50	2.0	7.1		8	8
Belgium				15.1		19	
Czech Republic	4	10	0.2	8.8		10	20
Denmark	132	100	9.4		4.4	5	14
Finland				4.4		4	
France	13	300	1.3	39.7		41	10
Germany	270	200	20.6	78.4		99	13
Hungary	69	80	3.0	11.4		13	23
Ireland	20	50	0.9	4.1		5	22
Italy	227	500	13.0	70.0		83	17
Netherlands	1357	200	68.8		22.8	46	20
Norway	2386	3200	78.5		71.5	6	30
Poland	165	150	4.4	10.6		15	38
Romania	310	400	13.2	3.8		17	23
Slovakia	15	15	0.2	6.8		7	75
Spain	3	500	0.4	27.6		28	8
Turkey	8	20	0.7	22.3		23	11
United Kingdom	531	1150	95.9	4.1		100	6
Remaining Europe	80	2491	21.5	4.1		26	4
Total Europe	5605	9416	334	318.3	98.7	555	17

significantly lower, so that the UK is expected to become a major importer of natural gas in the future. Already in 2004, UK's gas imports were exceeding its exports (Table 2).

2.2. Gas resources outside of Europe

Although Europe's gas resources are not sufficient to cover its demand, large gas deposits are located in neighboring regions, namely, in the Former Soviet Union, Northern Africa and the Middle East (Table 3).

2.2.1. Former Soviet Union

The Russian Federation possesses with around 48,000 bcm the largest proven gas reserves in the world. Further notable proven gas reserves are found in Kazakhstan (2000 bcm), Turkmenistan (2850 bcm), Uzbekistan (1875 bcm) and Azerbaijan (1000 bcm) (BP, 2005a).

The largest part of the Russian gas reserves is located with 35,600 bcm in West Siberia in the Ural Federal District (FD) (Rezunenko et al., 2001). Russian gas production was 589 bcm in 2004, of which 507 bcm or 86% have been produced by the Russian gas company Gazprom (Gazprom, 2004). In the past, Russian gas production primarily relied on the three super-giant gas fields Urengoy, Yamburg and Medvezhye (355 bcm in 2002 (Rencap, 2004)). The production from these three fields is, however, already at a decline.

To partially compensate for this decrease, the Zapolyarnoye field has been brought on-stream in 2001. It reached its design capacity of 100 bcm/yr in 2004. In addition, smaller gas fields in the vicinity of the large fields have been developed in the Ural FD (Pestsovoye, Vyngayakhinskoye and Etypuroskoye fields). Larger gas fields outside the Ural FD are the Orenburgskoye field (proven reserves 826 bcm end of 2002) in the Volga–Ural region and the Astrakhanskoye field (proven reserves 2531 bcm end of 2002) in the Southern FD of Russia. Large explored gas reserves are sited on the Yamal Peninsula with over 10,000 bcm found primarily in the Bovanenkovskoye, Kharasaveiskoye and Kruzenshternovskoye fields. Due to the permafrost conditions in this area production costs are estimated to be so high, that production is not expected to start before 2015. Another large, so far undeveloped, gas field is the Shtokmanovskoye gas condensate field in the arctic Barents Sea with proven reserves of around 3000 bcm.

With a Russian gas consumption of 393 bcm in 2004, more than two-thirds of the produced gas in Russia has been consumed to cover domestic needs. Due to low domestic gas tariffs set by the state,[3] natural gas is the most important primary energy carrier in Russia. For industrial consumers, prices for gas are ca. 38% below coal prices on an energy equivalent basis. This distortion makes the electricity sector with a share of 40% in total gas consumption the key gas consumer in Russia. Projections for Russian domestic gas consumption in 2020 range from 405 to 552 bcm (IEA, 2004). The lower value refers to the energy strategy of the Russian government until 2020 and stipulates that the share of gas in the power sector can be

[3]Average industry and household tariff was 30 US$/1000 m^3 in 2004 compared with export prices for Western Europe of 75–200 US$/1000 m^3.

Table 3
Gas balance for the FSU, Africa and the Middle East in 2004 (BP, 2005a; BGR, 2006; Rencap, 2004)

	Proven reserves (bcm)	Additional conventional resources (bcm)	Production (bcm)	Net imports (bcm)	Net exports (bcm)	Consumption (bcm)	Static lifetime of proven reserves (years)
Azerbaijan	1000	1900	4.6	3.9		8.5	217
Kazakhstan	2000	2500	18.5		2.7	15.2	108
Russia	47,578	83,000	589.1		195.7	393.4	81
Turkmenistan	2850	6000	54.6		39.1	15.5	52
Uzbekistan	1875	1500	55.8		6.5	49.3	34
Other FSU	1144	1160	20.3	75.7		95.9	56
Total FSU	56,477	96,060	742.9		165.1	577.8	76
Iran	27,550	11,000	85.5	1.6		87.1	322
Kuwait	1572	500	9.7			9.7	162
Oman	829	900	17.6		11.6	6.0	4
Qatar	25,771	2500	39.2		27.0	12.2	657
Saudi Arabia	6655	11,000	64.0		3.9	60.1	104
United Arab Emirates	6007	1500	45.8		7.9	37.9	131
Other Middle East	4057	5590	18.1		0.2	17.9	224
Total Middle East	72,441	32,990	279.9		37.7	242.2	259
Algeria	4545	1500	82.0		60.8	21.2	55
Egypt	1869	1000	26.8		2.2	24.6	70
Libya	1473	600	7.0		1.8	5.2	210
Nigeria	5296	3500	20.6		14.6	6.0	257
Other Africa	823	4144	8.7	1		9.7	95
Total Africa	14,063	10,744	145.1		78.4	66.7	97

reduced by coal, nuclear and hydro-based generation. To fulfill future export commitments and cover at the same time the domestic gas demand, in addition to the mentioned development activities, further investments in the development of new fields are crucial. The shutdown of gas power plants due to gas shortages in the summer 2006 demonstrated the tight supply situation existing today. Since typical time lags between the beginning of development work and production start are between 5 and 7 years, the situation will probably further aggravate. Increased Russian gas imports from the former Soviet states Kazakhstan, Turkmenistan or Azerbaijan may partially soothe supply shortages.

The major part of the explored reserves of Kazakhstans's gas is located in the Karachagankskoye oil and gas liquids field (1300 bcm). Kazakhan gas production has more than tripled over the last 10 years reaching 18.5 bcm in 2004 (BP, 2005a), so that Kazakhstan has become a net exporter of natural gas opposed to previous years. The majority of the gas fields are found in the Western part of the country, from where it is exported to the Orenburg gas processing plant in Russia and from there piped through the Soyuz pipeline westwards.

In 2004, Turkmenistan produced 55 bcm of natural gas, of which 39 bcm have been exported through the Central-Asia-Center (CAC) pipeline to Russia and the Ukraine. A small amount of 5 bcm has been exported to Iran. The largest gas field in Turkmenistan is the Dauletabad-Domez field in the Southern part with reserves of 1300 bcm.

Gas production in Azerbaijan was around 5 bcm in 2004 (Azstat, 2004), mainly for domestic use. The largest gas field, Shah Deniz in the Caspian Sea, has estimated reserves of around 625 bcm being equivalent to 63% of Azerbaijan's proven gas reserves (BP, 2005b). Production of this field is expected to start in 2006 with an annual production of 8.4 bcm.

2.2.2. Northern Africa

Notable gas reserves in Africa have been found in Algeria (proven reserves 4545 bcm at the end of 2004 (BP, 2005a)), Egypt (1869 bcm), Libya (1473 bcm) and Nigeria (5296 bcm).

Algeria is the largest gas producer on the African continent with a production of 82 bcm in 2004, of which 61 bcm have been exported to Europe. The largest Algerian gas field is the Hassi R'Mel with proven reserves of around 2400 bcm. Algerian gas is either exported as pipeline gas to Italy and Spain or is shipped as LNG (liquefaction capacity of 32 bcm/yr) to Europe.

Despite gas reserves of 1473 bcm, Libyan natural gas production is with 7 bcm in 2004 still comparably low (BP, 2005a), but might grow substantially over the next years, if foreign capital for production and transportation can be attracted. An example is the Green Stream offshore pipeline (capacity 9 bcm/yr) linking Libya with Sicily, which has started its operation in 2004 and is presently the only export option for Libyan gas.

Egyptian gas reserves are located in the Nile Delta, offshore from the Nile Delta and in the Western Desert. In

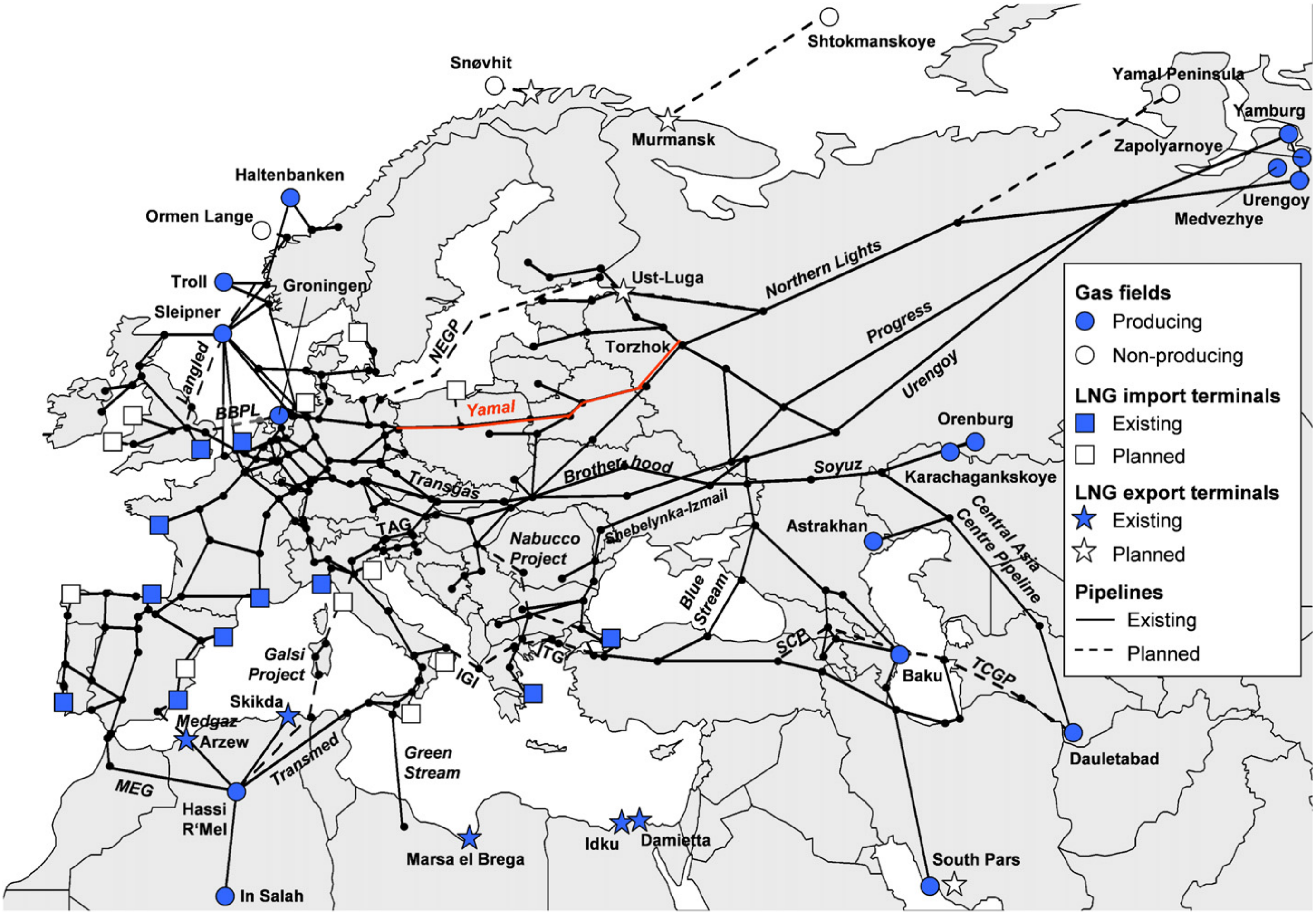

Fig. 1. Gas infrastructure in Europe (Wingas GmbH, 2003; GLE, 2005; CGES, 2003).

2004, Egypt produced 27 bcm of gas, which was nearly entirely consumed domestically.[4] The construction of two LNG export terminals with a combined capacity of 17 bcm/yr was finished in 2005 to export LNG to Spain, France, the US and Italy.

Nigeria exported 12.6 bcm of LNG, mainly to Europe (11.8 bcm), but also small amounts to the USA (0.3 bcm) and Asia (0.5 bcm). The LNG export capacity comprises 3 trains with a total capacity of 13 bcm/yr.

2.2.3. Middle East

With Iran and Qatar, the countries with the second (28,000 bcm) and third (26,000 bcm) largest proven gas reserves, respectively, after Russia are found in the Middle East (BP, 2005a). Iran's largest gas field is the offshore South Pars field with estimated reserves of 7900 bcm (EIA, 2005). Its development is currently underway, but was delayed because of technical, contractual and political issues. Iran was with 86 bcm in 2004 also the largest gas producer in the region, but its production is nearly entirely dedicated for domestic consumption. In 2004, Iran was even a net importer of natural gas: while 3.6 bcm have been exported to Turkey, 5 bcm have been imported from Turkmenistan. Several export projects to utilize Iran's huge reserves are being under discussion.

The majority of Qatar's gas reserves are sited in the offshore North Field geologically connected with Iran's South Pars field. In 2004, Qatar exported 24 bcm of LNG, mainly to Asian countries. Qatar's LNG export capacity accounts for 35 bcm/yr, projects to increase its capacity by 43 bcm/yr until the year 2012 have been proposed.

2.3. Gas transport infrastructure for Europe

In the following, an overview of the present status of the gas pipeline and LNG supply system in Europe as well as of planned or proposed infrastructure projects is given (Fig. 1).

2.3.1. Existing pipeline system

The pipeline infrastructure of Europe's gas supply is characterized by the location of the main gas reserves, which are the Norwegian and British gas fields in the North Sea, the gas fields in Russia and the gas reserves in Northern Africa. Accordingly the main pipeline axes are composed of a North–South route running from the North

[4] 1 bcm have been exported via gas pipeline to Jordan in 2004.

Sea to the UK and the European continent, a South–North route from Northern Africa to Spain and Italy as well as an East–West route from West Siberia through Belarus and the Ukraine to Western and Southeast Europe.

2.3.1.1. Northern axis. Norwegian gas is exported by pipelines to the UK and continental Europe. Major export pipelines are the Vesterled pipeline to St. Fergus in Scotland, the Franpipe to Dunkerque in France, the Zeepipe to Zeebrugge in Belgium as well as the Norpipe and the Europipe I and II to Dornum/Emden in Germany. Norwegian gas is further exported from France and Germany via Switzerland to Italy.

2.3.1.2. Southern axis. Three pipeline connections exist between Northern Africa and Europe. From Algeria gas is transported through Morocco via the Maghreb-Europe-Gaspipeline (MEG; capacity 11 bcm/yr) to Spain and through Tunisia via the Transmediterranean Gaspipeline (Transmed; capacity 28 bcm/yr) to Sicily, Italy. The third pipeline connection is the offshore Green Stream pipeline from Libya to Sicily with a capacity of 9 bcm/yr.

2.3.1.3. Eastern axis. Important pipelines from the FSU to Europe are the Brotherhood, the Soyuz and the Yamal pipeline. The Brotherhood and Soyuz pipelines run from Russia, where they are fed by the Progress, Urengoy, Northern Lights pipelines as well as the Russian part of the Soyuz pipeline, through the Ukraine to Slovakia. From Slovakia the pipeline splits in two branches. A smaller branch runs through Austria to Southern Germany (WAG pipeline) and Italy (Trans Austria Gas pipeline (TAG)), while the larger part of the pipeline continues to the Czech Republic, where it enters Germany at Olbernhau and Waidhaus. From Germany the MIDAL pipeline is running further West to France. The Yamal pipeline runs from Russia via Belarus to Poland, from where the Yamal pipeline continues further westwards entering Germany near Frankfurt (Oder). From the Brotherhood pipeline also a branch separates to supply in Southeast Europe (Romania, Bulgaria, Greece, Turkey, Serbia, Macedonia and Bosnia) with Russian gas. Turkey is also directly linked to Russia by the offshore Blue Stream pipeline, which crosses the Black Sea and started its operation in 2002.

Over the last years it can be observed, that Gazprom tries to reduce the transit risks associated with the pipeline routes through Ukraine and Belarus by diversifying export routes. The Blue Stream pipeline, avoiding in contrast to the previous solely existing export route the transit through Moldova, Bulgaria and Romania, is an example for such a strategy. Another example for such a diversification strategy of transit routes represents the 1200 km long Northern European Gas Pipeline (NEGP) project, which is planned to run from Gryazovets in Russia to Vyborg and from there through the Baltic Sea to Germany. Despite higher offshore construction costs compared with a second Yamal pipeline through Belarus and Poland, Gazprom together with its two German partners, Wingas and E.ON Ruhrgas, preferred this route probably because of disputes with Belarus and the Ukraine during the 1990s about illegal gas withdrawals and delayed payments.

At the same time Gazprom tries to gain control over the transit pipelines in Belarus and Ukraine, as could be seen in the negotiations of gas deliveries to Belarus and Ukraine in 2005. While Belarus had to pay only 46 US$/1000 m^3 for Russian gas and in return for this low price signed over the property rights of the Belarus part of the Yamal pipeline to Gazprom, the Ukraine initially was supposed to pay 230 US$/1000 m^3 leading to a dispute between Gazprom and the Ukrainian government.[5] The gas dispute highlighted Europe's dependency on Russian gas and the possible risks associated with supply disruptions. In the aftermath of the conflict, several European countries announced efforts to diversify their gas supply, e.g. Poland and Germany by proposing the construction of LNG import terminals.

Gas from the Central Asian states Turkmenistan, Kazakhstan and Uzbekistan can be exported currently only via the CAC pipeline system to Russia. The CAC was built in the 1960s, but is today under poor condition. Upgrading of the CAC began in 2005, the capacity of the pipeline is planned to be incrementally increased from 55 bcm in 2005 to 80 bcm by 2010 (OGV, 2005).

The construction of the 690 km long South Caucasus Pipeline (SCP), which will transport the gas from Shah Deniz through Azerbaijan and Georgia to Turkey, was nearly finished at the end of 2005. It will represent the first pipeline link from Central Asia states with Europe avoiding the transit through Russia for exports. At present, Turkmenistan, Kazakhstan and Uzbekistan are only exporting their gas to Russia or other FSU states.[6] Selling gas to the West would offer, however, due to the higher gas prices, larger revenues. Such plans are opposed by Gazprom's strategy to gain control over the gas reserves in these FSU countries to buy and resell it to Europe. Thus, Gazprom could to some extent alleviate the need for exploring new fields in order to compensate for the declining production from the super-giant fields in West Siberia.

2.3.2. New pipeline projects

Several pipeline projects are currently in the construction or planning phase (Table 4). The pipeline projects can be distinguished in pipelines enhancing the gas transit within Europe and pipelines providing an increased import capacity from outside Europe.

Examples for the first group of projects are the Balgzand Bacton Pipeline, which is built from the Netherlands to the

[5] The dispute was settled by an agreement, in which the Ukraine payed an average price of 95 US$/1000 m^3 for a mixture of gas from Russia, Turkmenistan and Kazakhstan.

[6] The only exception is a gas amount of 1 bcm sold by Kazakhstan to Poland (PGI, 2005).

Table 4
Planned or proposed pipeline projects relevant for Europe (ENI, 2006; Interconnector Limited, 2005; OGV, 2005; BP, 2005b; BBL Company, 2006; Facts, 2005; Gallistl, 2004; EC, 2004)

Status	Pipeline	From		To		Distance (km)	Diameter (mm)	Capacity (bcm)	Start-up
		Place	Country	Place	Country				
Upgrade	Trans Austria Gaspipeline (TAG)	Baumgarten	Austria	Tarvisio	Italy	375	1×915, 1×1020,	41.0	2007
							1×1070	44.2	2008
								47.5	2009
	Transmediterranean Pipeline (Transmed)	Hassi R'Mel	Algeria	Mazarro del Vallo	Italy	920 onshore	2×1220	31.4	2008
						150 offshore	3×510, 2×660	34.7	2009
	Interconnector	Zeebrugge	Belgium	Bacton	UK	183		Import for UK 16.5	End 2005
								Import for UK 23.5	End 2006
	Central Asia Centre (CAC) Pipeline	Ilyaly	Turkmenistan	Aleksandrov Gay	Russia	1264	1×1020, 2×1220 2×1420	Upgrade from 55 to 80 bcm	2005–2010
Under construction	South Caucasus Pipeline (SCP)	Baku	Azerbaijan	Horasan	Turkey	690	1070	6.6	2006
	Interconnection Turkey–Greece (ITG)	Karaceby	Turkey	Komotini	Greece	200 in Turkey	915	11	2007
	Balgzand Bacton Pipeline (BBP)	Balgzand	Netherlands	Bacton	UK	230 offshore	915	17.5	2006
	Langled	Ormen Lange gas field	Norway	Easington	UK	1200 offshore	1070-1120	29	2007
	North European Gas Pipeline (NEGP)	Gryazovets	Russia	Greifswald	Germany	917 onshore 1198 offshore	1220	27.5	2010
Proposed	Nabucco pipeline	Erzurum	Turkey	Baumgarten	Austria	2841	1420	25.5–31	2010
	Trans-Caspian Gas Pipeline (TCGP)	Dauletabad	Turkmenistan	Erzurum	Turkey	266 offshore 1600 onshore	1220	30	–
	Interconnection Greece–Italy (IGI)	Komotini	Greece	Brindisi	Italy	595 onshore	915		2010
						212 offshore	820		
	Galsi Project	Hassi R'Mel	Algeria	Pesacaia	Italy	300 Algeria to Sardinia	610	9–10	2008
						330 on Sardinia	1070		
						270 Sardinia to Italy	710		
	Medgaz Pipeline	Beni Saf	Algeria	Almeria	Spain	200 offshore	610	8	2009
	Yamal Europe II	Kondratki	Poland	Frankfurt a. d. Oder	Germany	680	1420	32	2008–2010
	Greifswald to Balgzand	Greifswald	Germany	Balgzand	Netherlands	630			

Table 5
European LNG import capacities and global export capacities (GLE, 2005; IJ, 2005, company web sites)

Import to Europe				Global export			
Import countries	Import capacity		LNG Imports 2004 (bcm)	Export countries	Export capacity		LNG exports to Europe 2004 (bcm)
	2005 (bcm/yr)	2010 (planned) (bcm/yr)			2005 (bcm/yr)	2010 (planned) (bcm/yr)	
Belgium	4.5	9.0	2.9	Algeria	31.9	37.4	22.0
Cyprus		0.7		Angola		6.8	
Spain	33.6	53.3	17.5	Australia	20.3	72.7	
France	15.5	23.8	7.6	Brunei	9.9	15.5	
Germany		10.0		Egypt[a]	16.8	28.7	
Greece	2.6	4.5	0.6	Equatorial Guinea		4.7	
Italy	3.3	42.1	5.9	Indonesia	40.6	63.5	
Netherlands		8.0		Iran		49.7	
Poland				Libya	0.5	0.5	0.6
Portugal	5.5	8.5	1.3	Malaysia	25.9	27.7	0.2
Sweden		1.5		Norway		5.7	
Turkey	5.2	11.2	4.3	Nigeria	13.1	68.7	11.8
UK	4.4	54.4		Oman	14.6	14.6	1.3
				Qatar	35.2	78.3	3.9
				Russia		27.6	
				Trinidad & Tobago	20.4	20.4	
				United Arab Emirates	7.9	7.9	0.2
				USA	1.9	1.9	
				Yemen		9.2	
Total	74.6	227.0	40.0	Total	239.1	541.5	40.0

[a]The construction of the first two LNG terminals in Egypt has been completed in 2005; hence, no Egyptian LNG flows for the year 2004.

UK with a capacity of 17.5 bcm and should start its operation at the end of 2006 (BBL Company, 2006) or the upgrading of the Interconnector pipeline between Belgium and the UK, which currently exports British gas to the continent, but should transport gas also in the opposite direction with a final capacity of 23.5 bcm by the end of 2006. The capacity increase of the TAG pipeline delivering Russian gas from the Slovakian border across Austria to Italy is a further project eliminating a capacity bottleneck in the Italian gas supply. To the second group of projects belongs the North European Gas Pipeline (NEGP), which will create, by crossing the Baltic Sea, a direct connection between Russia and Western Europe.

Several projects have been proposed to explore the gas reserves in the Central Asian region (Azerbaijan, Turkmenistan) for Europe through pipeline routes avoiding gas transit through Russia. An example for such a pipeline is the currently built South Caucasus Pipeline (SCP) running in parallel to the Baku–Tiblisi–Ceyhan (BTC) oil pipeline from Baku to Erzurum in Turkey. Turkey will not be the final consumer but a transit country for transporting Caspian or Iranian gas further to the West as via the currently constructed Interconnector between Turkey and Greece (ITG), which might be extended to Italy in the future (Interconncector Greece–Italy project). The Nabucco pipeline, which is at present in the planning phase, is another project for delivering Central Asian or Iranian gas via Turkey to South East and Western Europe. The Nabucco pipeline is planned to run from Turkey via Bulgaria, Romania and Hungary to Austria.

2.3.3. *Liquefied natural gas (LNG)*

For distances longer than 3000–5000 km (depending on the transport volume) the transport of natural gas in liquefied form is generally more economic compared with pipeline transport (depending on the pipeline diameter and pressure). The global LNG trade can be divided in two market areas: the Pacific basin with South Korea and Japan as major LNG buyers and the Atlantic basin with the USA and Europe as consumers. Major LNG producing countries for the Pacific Basin are Australia, Brunei, Indonesia, Malaysia, Oman, Qatar and the United Arab Emirates (UAE), while Europe in the Atlantic basin at present mainly receives LNG from Algeria, Egypt, Nigeria and also the Middle East. At the end of 2005, LNG regasification facilities with a total import capacity of around 75 bcm existed in Europe (see Table 5).

Technological progress and economies of scale led to a decline of LNG supply costs. For the liquefaction part, investment costs have dropped from 550 US$/(t/a)[7] in the 1960s under 200 US$/(t/a) in 2003 (Cornot-Gandolphe et al., 2003). Due to this cost decrease several new LNG projects or the expansion of existing facilities are under construction or have been proposed in Europe. In the UK,

[7]1 metric ton of LNG corresponds to 1322 m^3 of natural gas.

two additional LNG import terminals to the existing one on the Isle of Grain are under construction. New LNG terminals are also discussed in Italy in addition to the existing one in Panigaglia. Germany, Sweden and Poland are considering entering the LNG market in order to diversify their gas supply. Gazprom has proposed to build LNG terminals in Murmansk at the Barents Sea and in Ust-Luga near St. Petersburg at the Baltic Sea. With these terminals Gazprom intends to provide the North American market with natural gas.

Due to its favorable geographic location and huge gas reserves, the Middle East region may become in the future a more important supplier for LNG, supplying both the Atlantic and the Pacific basin. Europe may find itself in the future in the position to compete for gas with countries in the Pacific region (e.g. China and India). A similar competition of Europe with North America could develop in the Atlantic basin for the gas resources in West Africa. Rising gas prices over the last years made LNG imports to the US competitive, so that a large number of LNG regasification facilities for the American market are currently on the drawing board, but it is unclear how many of these projects will be realized.

3. Model-based analysis of the gas supply system

In the following, a model-based analysis of the European gas supply system is presented. The analysis focuses on the future development of the gas infrastructure until the year 2030 including a sensitivity analysis concerning the impact of European demand variations on gas supply.

3.1. Structure and assumptions of the gas supply model

To build a model of the European gas supply system the energy system model generator TIMES has been utilized (Loulou et al., 2005), for which an overview of its principles is given in Appendix A. The model used in this analysis covers the natural gas system of the member states of the European Union plus Algeria, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Croatia, Georgia, Iran, Kazakhstan, Macedonia, Norway, Russia, Serbia and Montenegro, Switzerland, Turkey, Turkmenistan, and Ukraine. In addition, Egypt, Libya, Nigeria, Oman, Qatar and the UAE have been considered as LNG exporters in the model.[8] For a given demand vector of natural gas in the different countries and given capacity values for pipelines and LNG facilities, the model determines the flows within the gas system in such a way that the total discounted system costs are minimized. To study the future development of the gas supply system up to the year 2030, in a second analysis the model has been given the possibility to invest in pipeline and LNG infrastructure.

[8]For Libya, also the offshore Green Stream pipeline between Libya and Italy has been taken into account.

The European gas infrastructure is depicted in the model geographic nodes, which are linked by pipeline sections. In addition, the nodes can represent locations of gas fields, demand centers, LNG terminals or gas storages. The different pipeline sections shown in Fig. 1 are depicted in the model as processes with capacity data, losses as well as variable and fixed costs. To keep the model linear the capacities of the existing pipelines have been calculated based on pipeline length and diameter for fixed inlet and outlet pressures (Cerbe, 1999). Data on the pipeline diameters, lengths and pressures have been taken mainly from CGES (2003), Wingas GmbH (2003) and information from individual gas distribution companies. Pipeline diameters typically vary between 510 and 1420 mm. The inlet pressure of onshore pipelines is today between 80 and 100 bar, while for offshore pipeline, if no specific information was available, a value of 150 bar has been assumed.

The different geographical nodes are presented as different gas commodities in the model, which enter or leave the pipeline sections. Since information on the geographical distribution of domestic gas demand within the countries is difficult to obtain, it has been assumed here that domestic gas demand is equally distributed among the nodes within a country. Similar assumptions apply for the domestic gas production with the exception of Algeria, Azerbaijan, Iran, Kazakhstan, the Netherlands, Norway, Russia and Turkmenistan, where gas reserves or fields are directly assigned to individual nodes. To reflect seasonal variations in gas demand throughout the year, the gas system is modeled on a monthly level. Gas storages have been modeled on an aggregated domestic level, i.e. from each node the aggregated domestic storage capacity may be accessed. Data on the existing storages (working gas volume, maximum injection/withdrawal rate) have been taken from IGU (2003).

3.2. European supply cost curve for natural gas

To illustrate the costs and potential quantities of gas supply for Europe, a gas supply cost curve has been constructed taking into account the current infrastructure as well as the projects being currently under construction or being announced for the future. Production costs for natural gas vary significantly between different gas fields. Lowest production costs are stated in the literature for the Groningen field with approximate 4 €/1000 m^3, while the highest costs with 43 €/1000 m^3 are observed for the Norwegian Snøvhit field in the Barents Sea (Dahl and Gjelsvik, 1993; Van Oostvoorn et al., 1999; OME, 2001). For LNG, liquefaction capacity in the possible producing regions for exports to Europe has been exogenously assigned based either on the historic trade share of Europe or on available information on long-term LNG contracts. To compare LNG supply costs to Europe, transportation costs from various export ports have been calculated with Barcelona in Spain as destination port. Investment costs for pipelines are based on cost estimations for several realized and proposed pipeline projects described in Zhao (2000) and PGJ (2004).

Based on these assumptions the supply cost curve shown in Fig. 2 has been constructed. The lowest costs can be observed with 34 €/1000 m^3 for the pipeline transport of Algerian gas to Spain or Italy.

From the Former Soviet Union, the transport of gas from the Volga/Ural area (with the gas fields Orenburg in Russia or the nearby Karachagankskoye field in Kazakhstan) to Slovakia or Romania leads to supply costs of around 50 €/1000 m^3. The supply of West Siberian gas (e.g. from the fields Urengoy, Yamburg or Medvezhye) to Poland or Slovakia costs around 50 or 57 €/1000 m^3, respectively. The largest costs for pipeline gas occur with 91 €/1000 m^3 for gas being produced under Permafrost conditions on the Yamal Peninsula and being transported to Germany by the proposed NEGP offshore pipeline across the Baltic Sea. Due to offshore production in the Barents Sea also Norwegian LNG has similar high supply costs of 97 €/1000 m^3. Among the LNG supply options, LNG from Northern Africa has due to the proximity to Europe the lowest costs (Libya 60 €/1000 m^3, Algeria 65 €/1000 m^3). One should, however, note that for Northern African gas the alternative transport by pipeline, with supply costs in the range of 32–45 €/1000 m^3, is the more cost-effective choice. LNG from the Middle East (Qatar and Iran) has the second lowest costs with 67 €/1000 m^3. For transporting Middle East gas to Europe, LNG is the more economic choice with supply costs of 74 €/1000 m^3 compared with pipeline transport having supply costs of ca. 90 €/1000 m^3 (e.g. Germany via the proposed Nabucco pipeline). Maximum external gas supply for Europe based on the existing infrastructure is ca. 310 bcm/yr. Taking into account the infrastructure projects being under construction or planned, the total maximum external annual gas supply could increase to ca. 635 bcm by 2015–2020.

3.3. Analysis of current gas transit flows

Natural gas statistics as from BP (2005a) or IEA (2005) balance for countries the import and export of natural gas by its origin and destination. Information on pipeline gas transit between countries, however, is not reported in these statistics. Based on the existing pipeline capacities, the gas demand and production by country in 2004, the TIMES model of the European gas supply system has been used to simulate the physical gas flows for the year 2004. The resulting gas transit flows together with the existing exchange capacities reveal, which pipeline connections are utilized to a high degree and might be potential bottlenecks in the future system (Fig. 3).

The analysis shows that in 2004 the transit route through the Ukraine was by far the most important transit route for Russian gas to Europe with 116 bcm of gas entering Europe. The entry capacity at the Slovakian border was already utilized by around 75%. Other trans-border pipelines being used to a high degree were the pipeline between Slovakia and Austria, the connection between France and Spain, the pipelines between Portugal and Spain, the link between France and Switzerland, the Zeepipe and Franpipe pipeline running from Norway to Belgium and France, respectively, as well as the pipeline connections from Algeria to Italy and Spain.

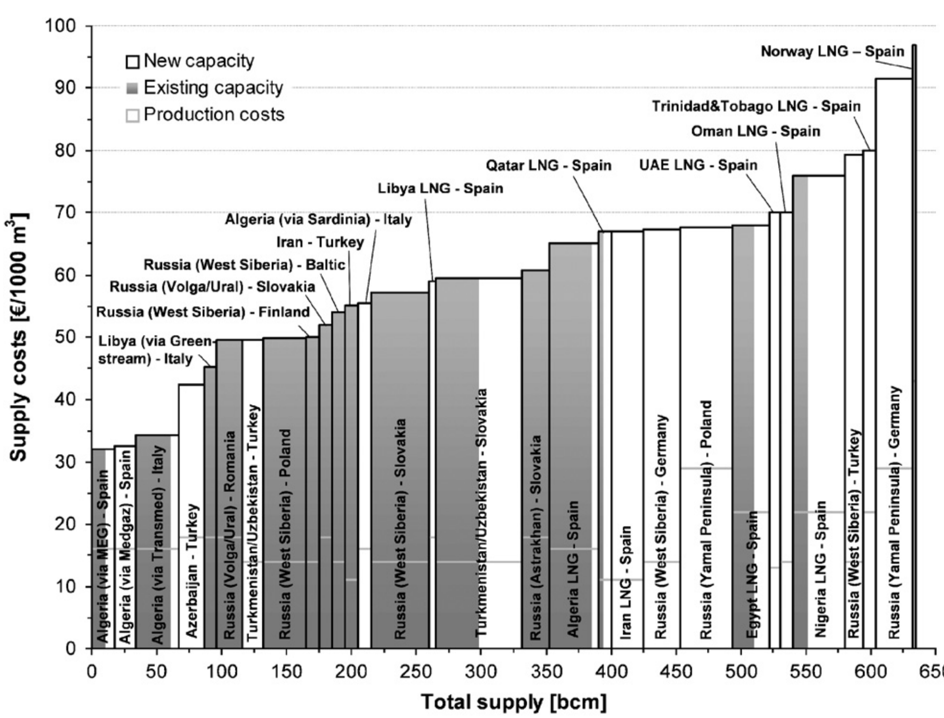

Fig. 2. Supply cost curve for natural gas to Europe (own calculations).

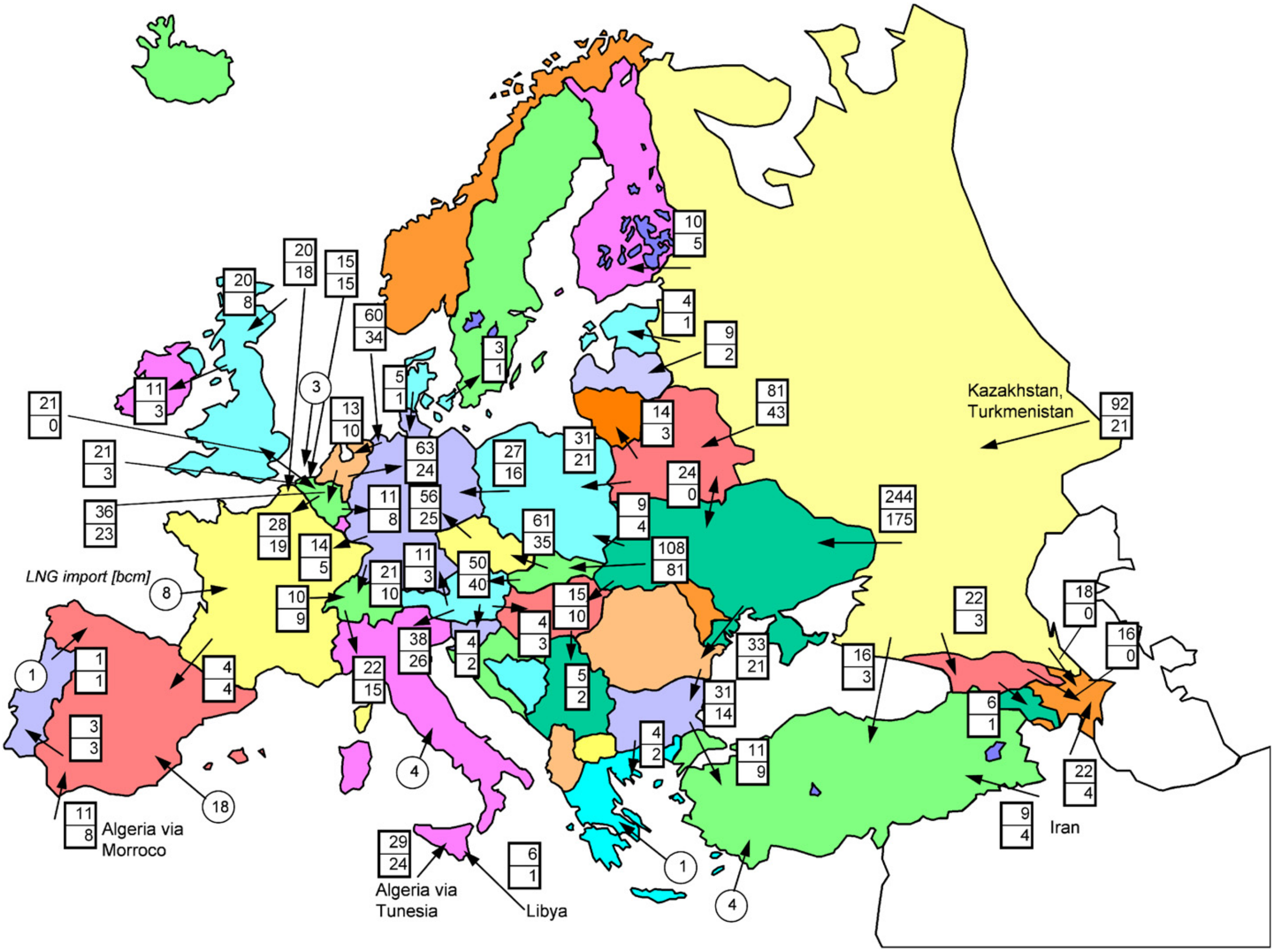

Fig. 3. Existing pipeline transit capacities in bcm/yr (above) and net transit gas flows in bcm (below) in 2004 (own calculations).

Depending on the development of gas demand in the individual countries, the pipeline with scarce capacity might be candidates for future expansions. To better study this question, in Section 3.4 a scenario for the future gas supply up to the year 2030 will be analyzed using the European gas supply model extended by the option to invest in new capacities for pipelines and LNG facilities.

3.4. Future development of the gas supply system

For this scenario analysis, the European gas supply system has been studied for the gas demand development displayed in Fig. 4, which is based on gas demand projections in the literature for the individual countries (EC, 2003; IEA, 2004; Botas, 2006). In the considered time horizon from 2004 to 2030 European gas consumption (excluding FSU) is assumed to be growing at an average annual rate of 1.6% compared with 3.5% between 1990 and 2004. The impact of the gas demand on the gas supply is studied in a sensitivity analysis in Section 3.5.

In addition to the planned pipeline and LNG expansions, the model has the freedom to increase the capacity of the pipeline sections by adding parallel pipes or to build pipelines along new routes. For onshore pipelines annualized investment costs of 0.15 € cent/($m^3 \times 100$ km) have been taken in this analysis,[9] while for offshore pipelines because of the more elaborate pipe laying process twice as high investment costs have been assumed (Zhao, 2000; PGJ, 2004). Future pipeline investment costs are influenced besides geographic conditions by factors as economies of scale and technological learning. To keep the model formulation linear, the specific pipeline investment costs are assumed to be independent of the pipeline diameter and hence capacity, so that economies of scale are not reflected in the analysis.[10] Due to this simplification, the model may—depending on the added capacity—over or under-estimates the real investment costs. Therefore, the model results should be considered as an indicator, where

[9]Based on a discount rate of 6% and a technical lifetime of 20 years.

[10]Consideration of economies of scale in the specific investment costs leads to a mixed integer programming (MIP) formulation of the optimization problem with associated solution difficulties for larger problems. Therefore, by neglecting the scale effects a linear programming (LP) formulation has been chosen here.

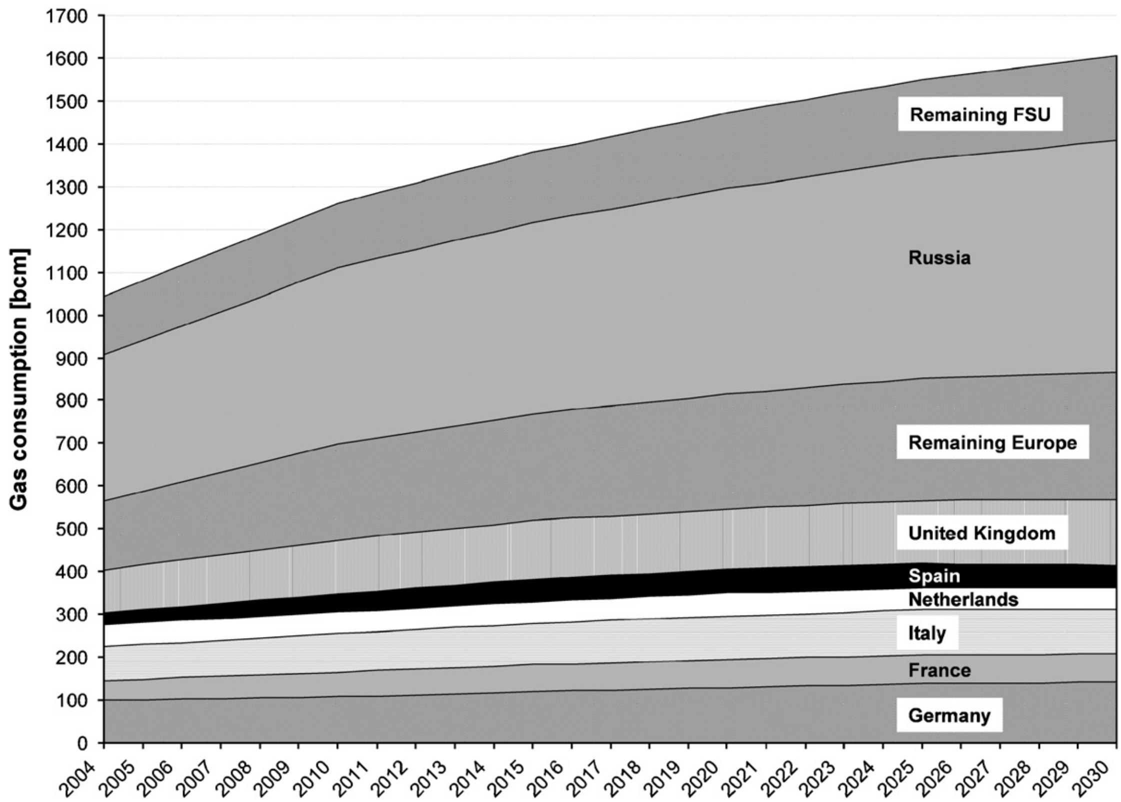

Fig. 4. Projection for European gas demand (EC, 2003; IEA, 2004; Botas, 2006, own assumptions).

expansions in the pipeline grid are necessary in the future, rather than an exact prediction of necessary capacity additions and their related costs. Regarding technological learning Zhao (2000) observed in an analysis of historic cost data for US onshore pipelines only small cost reductions due to learning suggesting that onshore pipelines are a mature technology without much potential for further cost improvements, while for offshore pipelines a learning rate of 24% could be derived.[11] In this analysis, it has been assumed that investment costs decline for onshore pipelines with a rate of 0.5% per year and for offshore pipelines with an annual rate of 1%.

Technological progress in oil and gas exploration and development, as better computer technology or drilling technology, has lead to significant cost reductions in the past. On the other hand, moving to gas production under more difficult geologic and climatic conditions, e.g. on the Arctic Yamal Peninsula, may be a factor increasing production costs. Based on Rogner (1997), it has been assumed here that in the future technological innovation leads to a reduction of the gas production costs shown in Fig. 2 decline at a rate of 1% per year after 2004. For LNG liquefaction plants, from Wene (2003) an annual reduction of specific investment costs of ca. 8% between 1986 and 2001 can be derived. It is, however, questionable, whether this high cost reduction observed in the 1990s will persist also in the future. Therefore, annual cost reductions of only 2% for the specific investment costs of liquefaction plants have been assumed in this analysis. For regasification plants, technology and efficiency gains in the past have been offset by a trend to larger storage volumes, so that here annual cost reductions 1% have been stipulated for the future.

The resulting pipeline capacities and gas flows in the year 2030 are shown in Fig. 5. The Ukraine will remain the country with the largest gas transit volume. In 2030, 143 bcm of gas are shipped from Russia through the Ukraine to Europe compared with 116 bcm in 2004 (see Fig. 3). Further major import routes from Russia to Europe are the expanded Yamal pipeline with 44 bcm of gas entering Poland and Lithuania as well as the NEGP pipeline with 27 bcm of gas flowing to Germany in 2030. To export a total volume of 356 bcm in 2030 (188 bcm in 2004), Russia does not solely rely on domestic production (total production for export and domestic consumption 711 bcm), but imports gas from Kazakhstan and Turkmenistan (172 bcm) via the expanded Central Asia Centre pipeline as well as from Azerbaijan and Iran (65 bcm) through the Caucasus. With supply costs of 46 and 36 €/1000 m^3, the gas from Central Asia and Azerbaijan, respectively, is more economic compared with the development of new gas fields on the Yamal Peninsula (supply costs of 53 €/1000 m^3), where only 16 bcm of gas are produced in 2003. Central Asian and Caspian gas is not only used by Russia for further exports to Europe, but is

[11]The learning rate describes the specific cost reduction achieved with each doubling of the cumulative installed capacity of a technology.

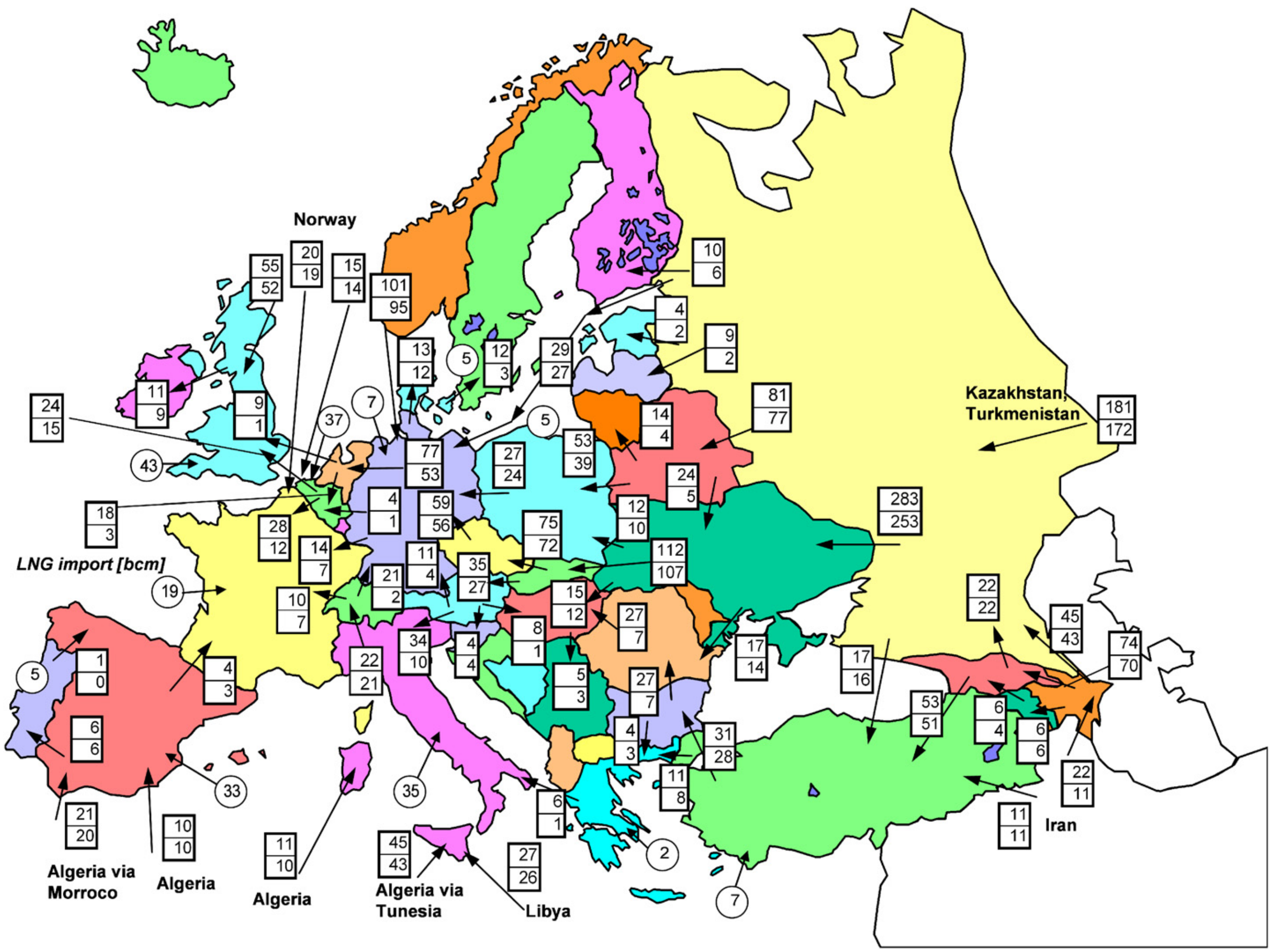

Fig. 5. Pipeline transit capacities in bcm/yr (above) and net transit gas flows in bcm (below) in 2030 (own calculations).

also required to cover the assumed increasing domestic gas demand (543 bcm) in 2030.

For gas imports from Azerbaijan and Iran to Russia, part of the existing pipeline capacity could be used, however, in reverse flow direction. In addition, gas from Iran (11 bcm), Azerbaijan (51 bcm) is exported to Turkey. From there, part of it is shipped via the Nabucco pipeline to South East Europe (28 bcm in 2030) as well as via the planned ITG and IGI pipelines to Greece (7 bcm) and Italy (1 bcm). Due to its close location to Europe and thus low gas transportation costs, Algeria, which already plays a important role as a gas supplier for Europe today, could expand its supply further. In 2030, 83 bcm of pipeline gas (32 bcm in 2004) are exported from Algeria to Spain and Italy. In contrast to the present situation, where Algerian gas is mainly targeting the Spanish, Portuguese and Italian market, in 2030 Algerian gas is further transported to Switzerland, France and Germany. Within Europe the gas reserves in the UK and the Netherlands have been nearly exhausted by the year 2030. The UK relies on gas imports from Continental Europe (16 bcm), Norway (52 bcm) and LNG imports (43 bcm) to cover its growing gas demand. Total European LNG imports quintuple from 40 bcm in 2004 to 198 bcm in 2030 with Italy (35 bcm), the UK (43 bcm) and Spain (33 bcm) being the three largest importers. Major LNG supplier is Iran with 130 bcm due its low supply costs, followed by Northern Africa (Algeria, Egypt and Libya).

In addition to the planned or proposed pipeline projects listed in Table 4, the pipeline capacities outside and within Europe have to be expanded as response to the increased gas demand until 2030. Main expansions in the FSU are necessary to transport Central Asian gas from Kazakhstan and Turkmenistan to Russia (+88 bcm/yr in 2030 compared with 2004) as well as for the export of Azeri gas to Russia and Turkey (+74 bcm/yr). The capacities of the pipelines from the Russia to the Ukraine are increased by 39 bcm/yr, while the Brotherhood pipeline to Slovakia needs only additional capacity of by 4 bcm/yr due to existing spare capacity. Pipeline capacity from Northern Africa is increased by 68 bcm/yr until 2030. Within Europe increased Norwegian gas production for the UK and

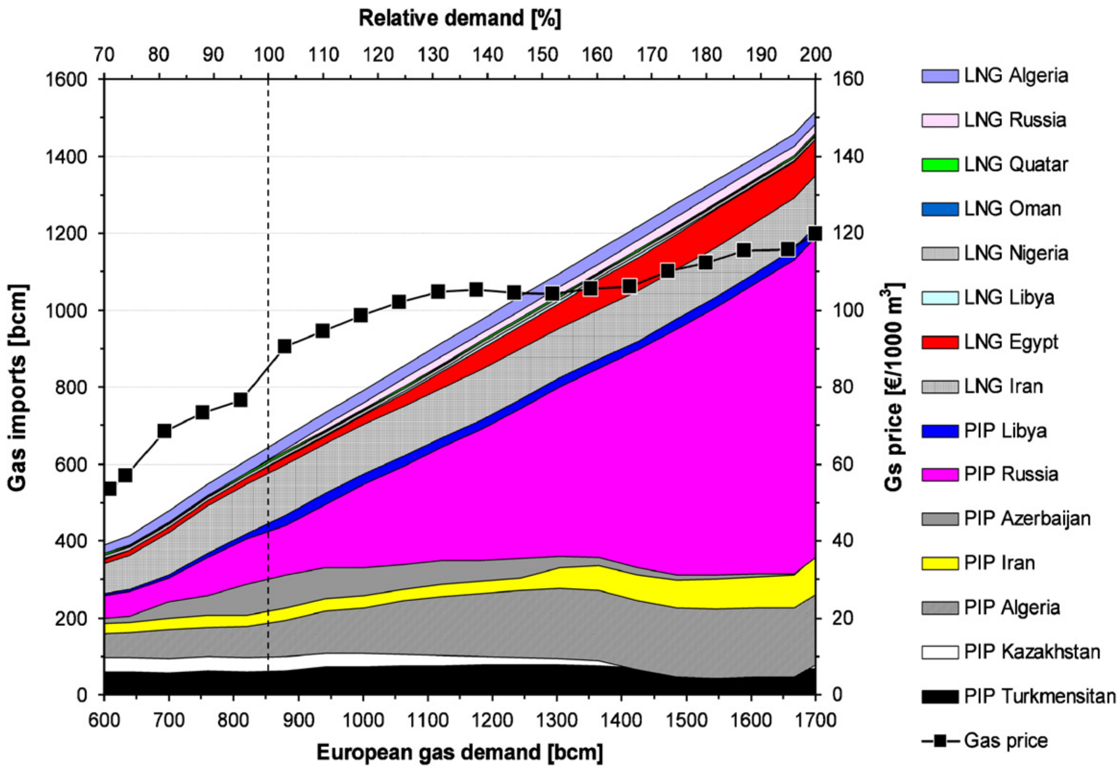

Fig. 6. Gas imports and gas price (average price in Germany) as function of European gas demand in 2030 (own calculations).

Continental Europe necessitates capacity expansions of 35 and 41 bcm/yr, respectively, by 2030.

Overall, in the considered scenario Europe imports 383 bcm of gas by pipeline and 198 bcm by LNG in 2030. This corresponds to an increase in the import dependency from 40% in 2004 (Table 1) to 68% in 2030. Thus, the dependency on imports as a whole is increasing, but the dependency on single suppliers can be reduced by diversifying the supply countries. While in 2004 around 63% of the imported gas came from Russia, the share of gas coming from Russia (including transits from Central Asia) can be reduced in 2030 to 36% by increased imports from Northern Africa (22% of total imports), the Caucasus (9%) and, especially, the new LNG supplier Iran (24%). It must be noted, however, that the Russian gas supply strongly relies on gas imports of 237 bcm from Central Asia (Azerbaijan, Kazakhstan and Turkmenistan) along the CAC pipeline, which due to lack of maintenance in the past is in a poor condition. Refurbishment and expansion of the CAC system from its current capacity of ca. 55 bcm/yr to its original design capacity of 90 bcm/yr are expected to cost 4.6 billion Euro. Hence, new export routes for Central Asian and Iranian gas via Turkey, as the proposed Nabucco pipeline, can be an alternative, which is with estimated 4.4 billion Euro for an import capacity of 20 bcm/yr more expensive than the refurbishment of the CAC pipeline, but reduces the dependency on Russia. The gas supply from Central Asia along the new routes also bears risks, but these are mainly associated with the political instability in the Central Asian and Middle East supply regions and with a complicated planning and construction process due to the large number of transit countries, while risks of disruptions in pipeline operation can be regarded as low, since the pipeline would mainly run through countries being members or associated with the EU as Turkey.

3.5. Sensitivity analysis on gas demand

Projections on future gas demand depend on various factors, as economic development, energy policies regarding CO_2 mitigation, the technological and economic development of technologies using gas as well as of competing substitute technologies using other fuels than gas. Since these projections therefore bear a high degree of uncertainty, in a sensitivity analysis the domestic gas demand of the European countries has been proportionally varied in a range from −40% to 200% for the years 2015–2030 with the gas demand shown in Fig. 4 corresponding to the 100% case. The resulting pipeline gas and LNG exports as well as the gas price, for which the average German price has been chosen to illustrate the price development,[12] are shown for 2030 in Fig. 6. Starting at the 65% demand level value, an increasing gas demand is initially mainly covered by higher pipeline gas imports from Azerbaijan and Russia (65–100%) and LNG form Iran accompanied by a rise in gas price from 50 to

[12]The average price for gas imports to Germany including royalties and producer rents was around 153 €/1000 m³ in 2004 (BMWI, 2006).

90 €/1000 m^3. One should note, that the gas prices reported here are marginal supply costs based on fundamental factors as production costs, transport costs and reserve limits, whereas observed market prices in reality are influenced by additional factors as the linkage of the gas to the oil price or market imperfections as supply or transport oligopolies. Increasing the gas demand in the range of 100–130% leads to higher pipeline gas imports from Algeria, Russia and LNG imports from Algeria and Egypt, while Azeri gas production in 2030 is decreasing again. The latter is caused by the fact that limited proven gas reserves in Azerbaijan are already exhausted in 2030 to match the increasing gas consumption in earlier years. For a gas demand higher than 100% the gas price initially approaches asymptotically a level of 105 €/1000 m^3 caused by a growing Russian gas supply. To cover demands higher than 150%, Iranian gas is exported via pipeline to Europe accompanied by an increase in gas prices reaching a level of 120 €/1000 m^3 for a demand level of 200%. The more cost-effective transport of Iranian gas in form of LNG to Europe has been limited here to 130 bcm in 2030, which corresponds to an already ambitious annual increase of Iran's LNG export capacity for Europe by 5 bcm/a (not considering possible capacity build-up for supplying other world regions). This LNG export potential is already fully exhausted at gas prices up to 73 €/1000 m^3. Algerian gas supply can only be slightly expanded in the range from 130–200%, since its cost-effective gas reserves are nearly exhausted.

4. Conclusions

Assuming an increasing gas demand in Europe in the future and diminishing indigenous gas resources, European gas supply will depend more strongly on gas imports in the future compared to today. At present, with a share of 80% in European gas imports, Russia is the main supplier for Europe. The scenario presented here shows that Russia will remain an important supplier for Europe. However, in the future the decline in gas production of the super-giant Russian fields Urengoy, Yamburg and Medvezhye, in combination with increasing domestic gas demand in Russia, will require investments for the development of new and more costly Russian gas fields. Furthermore, if the Altai gas pipeline project, which plans to transport Western Siberian gas to China, should be realized, Europe would find itself in a situation of directly competing with China for gas resources in Western Siberia.

The scenario analysis reveals that Europe's dependency on gas imports will increase indeed in the future, but cost-effective options exist to diversify its supply mix. For pipeline gas such policy strategies could be increased gas imports from Northern Africa, mainly from Algeria with supply costs in the range of 32–55 €/1000 m^3, and gas shipments from the Central Asian countries Azerbaijan, Kazakhstan and Turkmenistan (supply costs between 47 and 59 €/1000 m^3). In the latter option, the gas either has to be shipped through Russia, which means that the dependency on Russian gas supply is merely replaced by a dependency on the Russian pipeline infrastructure, or new pipelines via Turkey and South East Europe, as the suggested Nabucco pipeline have to be built. Despite higher costs, the Nabucco pipeline can reduce Europe's dependency from Russia and, therefore, may also strengthen the position of European countries in gas price negotiations with Russia. Besides this diversification of pipeline gas imports, LNG, being imported today only by a few countries in Europe, can be a strategy to be more seriously considered by other European countries, which currently solely rely on pipeline imports, to diversify their gas supply options. Apart from Northern Africa, LNG imports from the Middle East, especially Iran due to its second largest gas reserves in the world, could be a comparably cheap LNG supply source for Europe (estimated costs of 67 €/1000 m^3). Besides competition with Asian countries for these gas resources, recent political tensions in the relationship of the Iran and the West, however, may be an obstacle to follow such a strategy, so that projects with other LNG producers in the Middle East, e.g. Qatar, seem to be more realistic in the near term.

A sensitivity analysis on the European gas demand shows that in case of high demand growth over the next three decades (exceeding 1000 bcm in 2030), gas supplies from Algeria and Central Asia due to limited reserves in these regions, as far as known today, are not sufficient to cover this demand growth plus the domestic consumption in FSU, especially in Russia. Under these conditions much higher gas imports from Russia seem to be inevitable to fill the gap, which require, however, the timely investment in the development of new fields and the necessary infrastructure. Therefore, in addition to develop and strengthen alternative gas supply options to Russia (new pipeline routes and LNG import terminals), European policies should also aim at improving market conditions in the Russian upstream gas sector, e.g. giving oil companies, who are still flaring substantial amounts of associated gas, and independent producers more transparent and easier access to the transport infrastructure, in order to attract the necessary capital to invest in new gas fields and pipelines.

Appendix A. The TIMES model

The European gas sector model used in this analysis has been developed with the TIMES (The Integrated Markal Efom System) model generator. The TIMES modeling framework (Loulou et al., 2005) has been developed and is maintained by the Energy Technology System's Analysis Programme (ETSAP), an implementing agreement under the aegis of the International Energy Agency (IEA).

The TIMES model generator allows the optimization of a local, national or multi-regional energy system in a technology-rich manner over a time horizon of several years to decades taking into account technological, environmental and energy political constraints. Often, a

TIMES model describes the entire energy system from primary energy over conversion and transportation processes to end-use energy sectors and useful energy demand. The modeling framework, however, may also be used to analyze one sector of the energy system in more detail, as done here for the gas sector.

A.1. Structure of a TIMES model

In TIMES, the energy system is modeled by a network of processes, representing energy technologies, and commodities, depicting energy carriers, materials or emissions. Processes are linked to the commodities by input and output flows. The resulting network is referred to as reference energy system (RES). In case of the European gas sector model the processes depict pipeline sections, gas storages, LNG tankers, liquefaction plants or regasification terminals, while the commodities represent pipeline gas at different geographic locations, LNG or methane emissions. A simplified excerpt of the RES of the gas sector model is shown in Fig. 7. Processes are represented by boxes, commodities by vertical lines, both are linked by horizontal lines, the gas or LNG flows. Besides existing processes the RES may contain new technologies so far not utilized in the energy system. For the gas sector, this means that the RES contains for example new, not yet realized gas routes as options for future investments.

A TIMES model can consist of several regions, each of which described by its own distinct RES. The regions of the European gas sector model represent the 46 countries covered in the analysis and are connected by transit gas pipelines or LNG trade links. The specific topology of the gas grid and the options to process LNG are modeled in TIMES for each country through its own RES.

The operation and expansion of the energy system is driven by the need to cover exogenously given energy demands, which are specified in the gas model as gas demands at geographically different gas commodity nodes.

TIMES is a dynamic model, i.e. the time horizon considered in the model is divided into several periods. Decisions can be taken by the model in each period. The smallest possible period duration is 1 year. To reduce model size, a period, however, often represents several years. In the gas supply model, the first four years from 2004 to 2007 are modelled annualy and are followed by 5 year periods until 2030. Within a year, seasonal, weekly and daily time segments can be differentiated to account for example for demand fluctuation throughout the year.

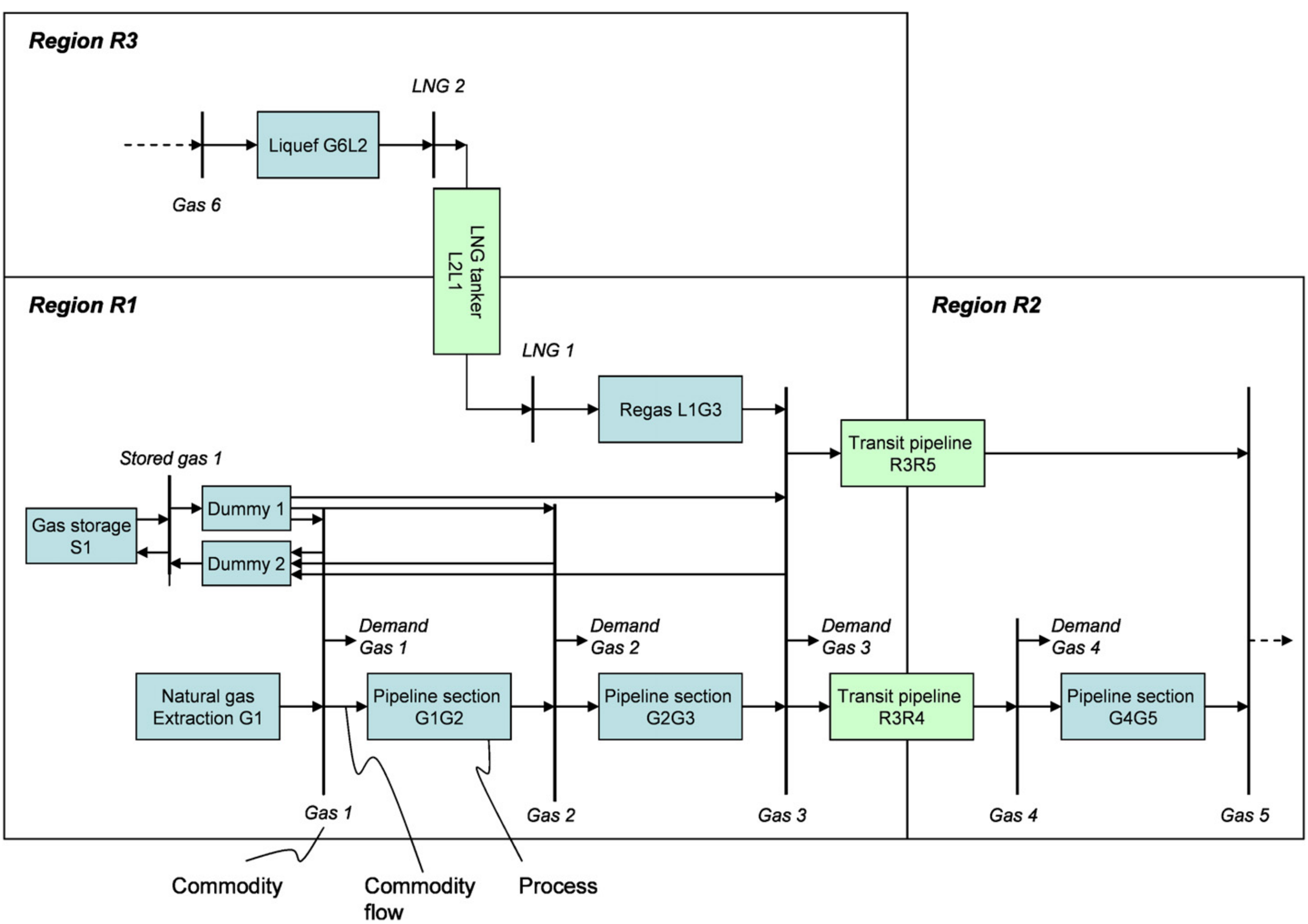

Fig. 7. Simplified example for a reference energy system (RES) in TIMES.

In the gas model used in this analysis, the year has been divided in 12 months to capture seasonal fluctuations in gas consumption.

A.2. Mathematical formulation of TIMES

As mentioned before TIMES is a model generator. This means that based on the topology information given in form of the RES and the time structure for a specific model an equation system for this model is automatically created. The purpose of a TIMES model run is to optimize the energy system with respect to an objective function, which typically equals the discounted sum of the costs of all considered regional energy systems over the entire model horizon. The main decision variables of a TIMES model are the operating levels of the processes (e.g. the input and output flows of a pipeline section), the trade flows between model regions and the investment decision for new capacity (e.g. expansion of a pipeline section).

In the standard formulation of TIMES, the model constraints and the objective function are of linear form and the decision variables are continuous, so that the resulting optimization model takes the general form of a Linear Programming (LP) problem as shown in Eq. (A.1).[13]

$$\begin{array}{ll} \text{Objective function} & \sum_{j=1}^{n} c_j x_j \\ \text{subject to the constraints} & \sum_{j=1}^{n} a_{ij} x_j \geqslant b_i, \quad i = 1 \ldots m \\ \text{with the variables} & x_j \geqslant 0, \quad j = 1 \ldots n, \end{array} \tag{A.1}$$

where i is the constraint index running from 1 to m, j is the variable index running from 1 to n, x_j is the decision variable, c_j is the cost coefficient of decision variable x_j, a_{ij} is the coefficient of decision variable x_j in constraint i and b_i is the right-hand side constant of constraint i.

Some of the basic constraints commonly used in a TIMES model are given in the following.

Transformation equation for a process p:

$$\eta_{PRC,r,v,t,p,cgin,cgout,s} \sum_{cin \subset cgin} \eta_{FLO,r,v,t,p,cgin,cin,cgout,s} \cdot FLO_{r,v,t,p,cin,s} = \sum_{cout \subset cgout} FLO_{r,v,t,p,cout,s} \quad \forall r, v, t, p, cgin, cgout, s. \tag{A.2}$$

Commodity balance of a commodity c:

$$\sum_{p \subset topin_{r,p,c}} FLO_{r,v,t,p,c,s} + \sum_{p \subset exp_{r,p,c,rr}} EXP_{r,v,t,p,c,s,rr} + \sum_{p \subset pstor_c} STGIN_{r,v,t,p,c,s} + fr_{r,t,c,s}\, dem_{r,t,c}$$

$$\leqslant \left(\sum_{p \subset topout_{r,p,c}} FLO_{r,v,t,p,c,s} + \sum_{p \subset imp_{r,p,c,rr}} IMP_{r,v,t,p,c,s,rr} + \sum_{p \subset pstor_c} STGOUT_{r,v,t,p,c,s} \right) com\_eff_{r,t,c,s} \quad \forall r, t, c, s. \tag{A.3}$$

Capacity-activity constraint for a process p:

$$ACT_{r,v,t,p,s} \leqslant af_{r,v,p,s} \left(NCAP_{r,v,p} + pasti_{r,v,p} \right) \Delta_s \quad \forall r, v, t, p, s \tag{A.4}$$

with

- *cin*, *cout* input and output commodity index, respectively,
- *cgin*, *cgout* set of input commodities (*cin*) and output commodities (*cout*), respectively,
- *r*,*rr* regional indices,
- v vintage period index,
- t time period index,
- p process index,
- s sub-annual time segment index,
- $af_{r,v,p,s}$ availability factor of process p built in vintage period v in sub-annual time segment s,
- $com\_eff_{r,t,c,s}$ efficiency of commodity c in period t and sub-annual time segment s due to distribution and transportation losses not explicitly modeled as processes,
- $dem_{r,t,c}$ annual demand of commodity c in period t,
- $fr_{r,t,c,s}$ fraction of annual demand $dem_{r,t,c}$ occurring in sub-annual time segment s to define the load curve,
- $pasti_{r,v,p}$ old capacity of process p built in vintage year v already been built before the beginning of the model horizon,
- Δ_s duration of sub-annual time segment s expressed as fraction of a year,
- $\eta_{PRC,r,v,t,p,cgin,cgout,s}$ overall efficiency from the sum of input commodity flows in *cgin* to output flows in *cgout* in time period t and sub-annual time segment s for capacity of process p built in vintage period v,
- $\eta_{FLO,r,v,t,p,cgin,cin,cgout,s}$ flow specific coefficient of the input commodity flow *cin* belonging to the commodity group *cgin*,
- $\exp_{r,p,c,rr}$ set of exchange processes p exporting commodity c from region r into region rr,
- $imp_{r,p,c,rr}$ set of exchange processes p importing commodity c from region rr into region r,
- $topin_{r,p,c}$ set of processes p in region r with commodity c as input flow,
- $topout_{r,p,c}$ set of processes p in region r with commodity c as output flow,
- $pstor_c$ set of storage processes p for commodity c,
- $ACT_{r,v,t,p,s}$ activity variable describing the production level in period t and sub-annual time segment s of process p built in vintage period v,

[13] Variants of the TIMES model using binary variables (e.g. to describe blockwise capacity expansion) exist, leading to a mixed integer programming (MIP) optimization problem.

$FLO_{r,v,t,p,c,s}$ flow variable of commodity c in period t and sub-annual time segment s linked to capacity of process p built in vintage period v,

$IMP_{r,v,t,p,c,s,rr}$ import flow of commodity c from region rr into region r in period t via exchange process p built in vintage period v,

$EXP_{r,v,t,p,c,s,rr}$ export flow of commodity c from region r to region rr in period t via exchange process p built in vintage period v,

$NCAP_{r,v,p}$ new capacity of process p built in vintage period v,

$STGIN_{r,v,t,p,c,s}$ input flow of commodity c in period t and time segment s in storage process p built in vintage period v and

$STGOUT_{r,v,t,p,c,s}$ output flow of commodity c in period t and time segment s in storage process p built in vintage period v.

The transformation Eq. (A.2) describes the relationship between the input and output flow variables of a process taking into account losses associated with the transformation, e.g. auxiliary energy required to transform pipeline gas into LNG. Emissions linked to the use of a process, e.g. methane emissions of a pipeline section are also captured by this equation type. The commodity balance (A.3) guarantees that for each commodity at each point in time the sum of consumption from all processes cannot exceed the overall production of this commodity. The capacity–activity relationship (A.4) ensures that the production or activity of a process is limited by its available capacity. For a pipeline section in the gas model, this constraint limits the monthly maximum throughput depending on the available pipeline capacity.

Main cost components in the objective function are the costs (revenues) for energy imports (exports) with external regions (being outside of the geographic area covered in the model, e.g. LNG imports from Nigeria), variable operating costs, fixed operating and maintenance costs, as well as investment and decommissioning costs.

Input data of a TIMES model are the technical and economic characteristics (efficiency, availability, investment costs, etc.) of the processes, existing capacity stock, costs and potential of domestic energy resources, costs/revenues associated with exogenous energy imports/exports and the demand vector for energy or energy services (gas consumption in the different nodes in the gas model).

References

Azstat, 2004. State Statistical Committee of Azerbaijan: The Statistical Yearbook of 2004.

BBL Company, 2006. Information on company web site, 〈www.bbblcompany.com/en/offshore.html〉 (retrieved 06.02.2006).

BGR, 2006. Federal Institute for Geosciences and Natural Resources (BGR). Reserves, Resources and Availability of Energy Resources 2004, Brief Study, Hannover.

BMWI, 2006. Federal Ministry of Economics (BMWI). Monthly natural gas balance and development of cross-border prices, Status July 2006, web site 〈www.bmwi.de〉 (retrieved 01.07.2006).

Botas, 2006. Natural gas supply and demand scenarios, web site 〈www.botas.gov.tr/eng/naturalgas/ng_sup_dem.asp〉 (retrieved 06.02.2006).

British Petroleum (BP), 2005a. Statistical review of the world.

British Petroleum (BP) Azerbaijan, 2005b. Sustainability Report 2004, London.

Centre for Global Energy Studies (CGES), 2003. Gas Pipelines of the Former Soviet Union, London.

Cerbe, G., 1999. Grundlagen der Gastechnik: Gasbeschaffung, Gasverteilung und Gasverwendung. Carl Hanser Verlag, München.

Department of Trade and Industry (DTI), 2005. UK Gas Reserves and Ultimate Recovery 2005, web site 〈www.og.dti.gov.uk/information/bb_updates/chapters/Table4_4.htm〉 (retrieved 06.02.2006).

Dahl, C., Gjelsvik, E., 1993. European natural gas cost survey. Resources policy, September, pp. 185–204.

EC, 2003. European Commission: European Energy and Transport—Trends to 2030, Luxembourg.

EC, 2004. European Commission: Trans-European energy networks: TEN-E priority projects, Luxembourg.

Energy Information Administration (EIA), 2005. Kazakhstan Country Analysis Brief, web site 〈www.eia.doe.gov/emeu/cabs/kazak.html〉 (retrieved 06.02.2006).

ENI, 2006. ENI brings forward the expansion of TTPC and TAG. Press Release 12.01.2006.

Facts, 2005. Norwegian Ministry of Petroleum and Energy: Facts 2005: The Norwegian petroleum sector, web site 〈www.mpe.dep.no〉 (retrieved 06.02.2006).

Gallistl, J., 2004. Turkey–Austria pipeline (Nabucco project). In: Presentation at the IEA Seminar on Natural Gas in South East Europe: Investment, Transit, Trade, 5–6 May 2004, Istanbul, web site 〈www.iea.org〉 (retrieved 06.02.2006).

Cornot-Gandolphe, S., Appert, O., Dickel, R., Chabrelie, M. F., Rojey, A., 2003. The challenges for future cost reductions for new supply options (Pipeline, LNG, GTL). In: Paper Presented at the 22nd World Gas Conference, Tokyo, 1–5 June 2003.

Gas LNG Europe (GLE), 2005. LNG Map, web site 〈www.gte.be〉 (retrieved 10.01.2006).

Gazprom, 2004. Annual Report 2004, web site 〈www.gazprom.com〉, (retrieved 06.02.2006).

International Energy Agency (IEA), 2004. World Energy Outlook 2004, Paris.

International Energy Agency (IEA), 2005. Oil, Gas, Coal & Electricity: Quarterly Statistics, vol. 2005, issue 3, Paris.

Infrastructure Journal (IJ), 2005. LNG Project Table, web site 〈www.infrastructurejournal.com〉 (retrieved 06.02.206).

International Gas Union (IGU), 2003. Report of Working Committee 2: Underground gas storage. In: 22nd World Gas Conference, Tokyo, web site 〈www.igu.org〉 (retrieved 06.02.2006).

Interconnector Limited, 2005. Interconnector capacity enhancement, Media Release 28.10.2005, web site 〈www.interconnector.com〉, (retrieved 06.02.2006).

Loulou, R., Remme, U., Kanudia, A., Lehtilä, A., Goldstein, G., 2005. Documentation of the TIMES model, web site 〈www.etsap.org〉 (retrieved 06.02.2006).

Oil and Gas Vertical (OGV), 2005. Kazakhstan, Issue 13/2005, web site 〈www.ngv.ru〉 (retrieved 06.02.2006).

Observatoire Méditerranéen de l'Energie (OME), 2001. Assessment of internal and external gas supply options projects for the EU, evaluation of the supply costs of new natural gas supply projects to the EU and an investigation of related financial requirements and tools, study, web site 〈http://europa.eu.int/comm/energy/gas/publications/index_en.htm〉 (retrieved 06.02.2006).

Van Oostvoorn, F., Askounis, D., Aslanian, G., Makarov, A., Velthuijsen, J.W., 1999. Russian energy markets: current situation and opportunities for co-operation. Report ECN-C-99-027, Energy Research Centre of the Netherlands (ECN), 1999.

Polish Geological Institute (PGI), 2005. Mineral Resources of Natural Gas: Natural Gas, December 2005, web site ⟨www.pgi.gov.pl/mineral_resources/gas.htm⟩ (retrieved 06.02.2006).
Pipeline & Gas Journal (PGJ), 2004. Pipeline Construction Scorecard, August 2004.
Renaissance Capital (Rencap), 2004. Gazprom: Don't Miss it!, Moscow.
Rezunenko, V.I., Ponomarev, V.A., Zezimov, V.V., Staroselsky, V.I., 2001. The resource base of the gas industry in the Federal Districts of Russia, Mineral Resources of Russia: Economics and Management, 4/2001.
Rogner, H.-H., 1997. An assessment of world hydrocarbon resources. Annual Energy Review 22, 217–262.
Statoil, 2005a. Annual Report on Form 20-F 2004, web site ⟨www.statoil.com⟩, (retrieved 06.02.2006).
Statoil, 2005b. Increased costs and delayed start for Snøvhit, Company press release 16.09.2005, web site ⟨www.statoil.com⟩ (retrieved 06.02.2006).
TNO-NITG (Netherlands Institute of Applied Geosciences TNO), 2004. Oil and gas in the Netherlands, Annual review 2003 and prognosis 2004–2013, The Hague.
Wene, C.-O., 2003. Investments in the mid-stream LNG chain and technology learning, Report, web site ⟨www.wenergy.se⟩, (retrieved 06.02.2006).
Wingas GmbH, 2003. European Gas Pipeline System. Verlag Glückauf, Essen.
Zhao, J., 2000. Diffusion, costs and learning in the development of international gas transmission lines. Interim Report IR-00-054, IIASA, Laxenburg.