Europe's energy future: natural gas supply between geopolitics and the markets: Work package I - The future role of natural gas - trends and projections for demand and supply in 2030

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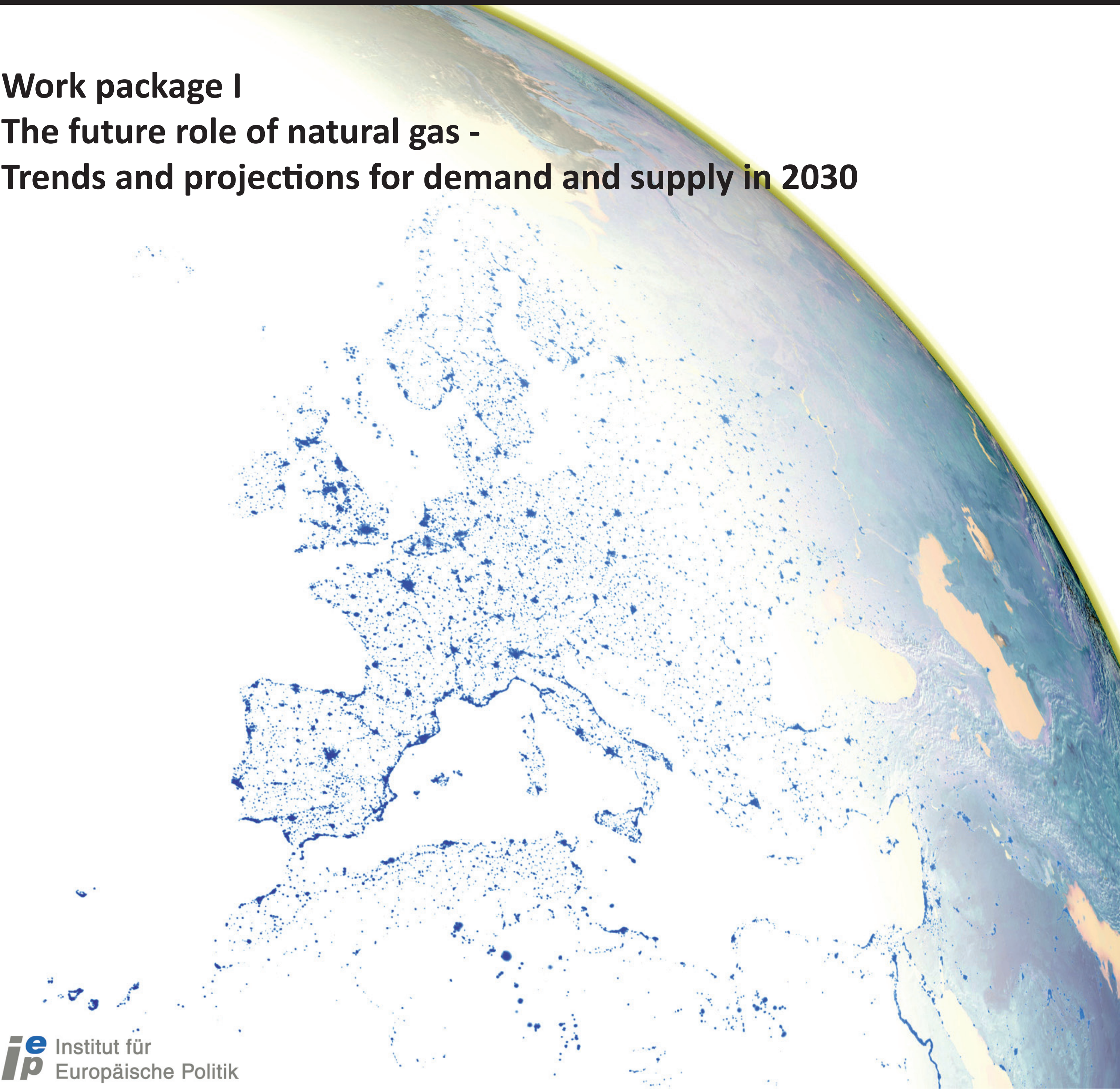
Europe´s Energy Future: Natural Gas Supply between Geopolitics and the Markets

Work package I
The future role of natural gas - Trends and projections for demand and supply in 2030



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List of Abbreviations

AGP	Arab Gas Pipeline
AIOC	Azerbaijan International Operating Company
Bcm	Billion cubic metres
BP	British Petroleum
CARA	Circum-Arctic Resource Appraisal
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CERA	Cambridge Energy Research Associates
CHP	Combined Heat and Power
CIS	Commonwealth of Independent States
CO_2	Carbon dioxide
DG ENER	Directorate-General for Energy
EGAS	Egyptian Natural Gas Holding Company
EIA	United States Energy Information Administration
EU	European Union
EU ETS	European Union Emissions Trading System
EUROGAS	European Union of the Natural Gas Industry
GDP	Gross Domestic Product
GEM	General Equilibrium Model
GHG	Greenhouse Gas
GTL	Gas-to-liquids
GWOB	Generate World Oil Balance
IEA	International Energy Agency
IEO	International Energy Outlook
IMF	International Monetary Fund
INGM	International Natural Gas Model
LNG	Liquefied Natural Gas
Mtoe	Million tonnes of oil equivalent
NGVs	Natural Gas Vehicles
NNPC	Nigerian National Petroleum Corporation
OECD	Organisation for Economic Co-operation and Development
p.a.	per annum
RES	Renewable Energy Sources
SOCAR	State Oil Company of Azerbaijan Republic
Tcm	Trillion cubic metres
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
US	United States
USGS	United States Geological Survey
WEM	World Energy Model
WEO	World Energy Outlook
WEPS+	World Energy Projections Plus

Executive Summary

The European Union (EU) is the world's second largest natural gas consumer market, with a natural gas demand of more than 550 bcm in 2009. Due to the fact that domestic gas production is relatively small, roughly 60 percent of the EU's annual gas consumption must be satisfied by external suppliers. What is more, this import dependence is set to increase over the next few decades, as Europe's own gas resources are depleting.

The aim of this report is to draw a comprehensive picture of future developments in the EU natural gas market. It seeks to establish whether natural gas will play a significant role in the EU over the next two decades and, if so, from where the EU may obtain the required volumes. More specifically, the study asks: First, how will the EU's demand for natural gas develop? Second, to what extent will domestic demand be covered by domestic production and how much gas will the EU need to import? And finally, which regions and individual countries will be in a position to supply the EU with the required amounts of natural gas?

These questions are examined on the basis of natural gas demand and supply scenarios compiled by the International Energy Agency (IEA), the United States Energy Information Administration (EIA), the European Commission's Directorate-General for Energy (DG ENER), the European Union of the Natural Gas Industry (Eurogas), and the consultancy firm Mott MacDonald. While the chapter following the introduction deals with the *current* role of natural gas in the EU, the two main chapters of the report shed light on the *future* development of EU natural gas demand and supply.

The demand side analysis identifies five factors to be the main determinants of natural gas demand: EU GDP growth, fuel price developments, energy and climate policies, and technology. Of the scenarios considered in this report, the ones assuming high economic growth, limited deployment of low-carbon technologies and slack climate policies forecast EU gas demand to grow consistently over the next two decades. By contrast, the scenarios featuring ambitious RES policies, a recovery of nuclear energy and high CO_2 and oil prices predict gas demand to decline substantially. Based on the scenario forecasts, this report estimates the EU's natural gas demand to range between 470 and 650 bcm in 2030.

The first question to be addressed in the supply side chapter, then, concerns the extent to which the EU will be able to cover such levels of consumption with domestically produced gas. The scenarios suggest that domestic production will stand at 70 to 100 bcm in 2030, thereby covering less than 20% of the EU's projected gas consumption. Accordingly, the EU's import requirements are likely to reach a level of 370 to 580 bcm by the end of the projection period. Against this background, the chapter examines selected regions and countries outside the EU with regard to their potential to supply the EU with the required amounts of gas. The report finds that Russia, Norway, Algeria, Azerbaijan, Turkmenistan, Qatar, and to a lesser extent Nigeria, are likely to serve as the EU's main suppliers throughout the projection period. The production and export forecasts for these countries suggest that, when combined, they will be able to cover most of the EU's projected additional import requirements.

1 Introduction

The EU, with a domestic natural gas demand of more than 550 bcm in 2009, is the world's second largest natural gas consumer market. As domestic production in the EU does not suffice to cover such high levels of demand, approximately 60 percent of the gas consumed each year has to be imported. Over the next few decades, the EU is expected to become even more dependent on external suppliers, as Europe's own gas resources - located mainly in the North Sea region - are depleting.

The aim of this report is to draw a comprehensive picture of future developments in the EU natural gas market. In the first part, the study therefore compares estimates of future EU natural gas demand; in the second part it turns to analyzing the gas supply potential of the EU and third countries. The central questions addressed in this study are: How will the EU's demand for natural gas develop? To what extent will domestic demand be covered by domestic production? Meaning, what are the EU's future import-requirements? And finally, which regions and individual countries will be in a position to supply the EU with sufficient amounts of natural gas?

These questions are answered on the basis of a variety of statistical data-sets compiled by the International Energy Agency (IEA), the United States Energy Information Administration (EIA), and the European Commission's Directorate General for Energy and Transport (DG TREN). Additionally, the report uses data-sets provided by the European Union of the Natural Gas Industry (Eurogas) and the consultancy firm Mott MacDonald, which comprise different scenarios forecasting future levels of natural gas demand and supply. The objective is to gain insight into the EU's future gas demand and supply by analysing and comparing these scenarios. The study is confined to a projection period that covers the next two decades, ending with the year 2030.

Following an introduction outlining the current role of natural gas in the EU, the report conducts a methodological overview of each energy model included in the analysis. Subsequently, it identifies major drivers of natural gas demand and presents the main scenario assumptions and variables employed by the EU ('EU Energy Trends to 2030'), the IEA ('World Energy Outlook'), the EIA ('International Energy Outlook') and Eurogas ('Long-term Outlook for Natural Gas Demand and Supply'). Ultimately, the study compares the natural gas demand forecasts compiled by the above-mentioned organisations.

Using the findings of the demand side analysis, the study then turns to examining the supply side. To begin with, the analysis considers the EU's own potential to produce gas throughout the projection period. By contrasting the likely future levels of domestic production with estimated gas demand, it reveals Europe's future gas import requirements.

Based on this, the study aims at highlighting the extent to which selected regions and countries outside Europe are endowed with natural gas resources and proved reserves and able to meet the EU's rising import needs. In so doing, the report will not only consider the EU's current major suppliers - Russia, Norway and Algeria -, but also take into account other regions and countries that have the potential to remain or become important gas suppliers to the EU in the foreseeable future. Among them are the Caspian region, notably Azerbaijan and Turkmenistan; the Middle East, particularly Qatar and, to a lesser extent, Iran; a few African countries, namely Egypt, Libya and Nigeria; and the Arctic. After having examined their resource bases, these regions and countries are scrutinized with regard to the state of their gas industry, notably with regard to current and potential future levels of gas production, existing and planned transport facilities and export capacities. Here, the study once more draws upon the scenarios provided by the IEA, EIA, and MacDonald.

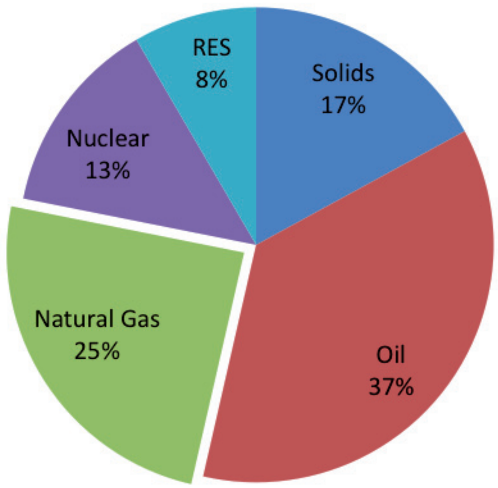
The analysis of projections of the EU's natural gas demand and supply in this work package serves as a basis for the analyses of policy measures in work packages II and III.

2 The role of natural gas in the EU - status quo

Natural gas plays a crucial role in the EU's present energy mix. Until the mid-1970s, however, the potential of this energy carrier was largely underestimated. Only the 1973/74 and 1979/80 oil price shocks raised the attractiveness of gas, as it qualified as a substitute for oil products, particularly in the residential, commercial and industry sectors.[1] As a consequence, the following years saw the emergence of gas markets in Europe and technological innovations such as the highly efficient combined cycle gas turbine (CCGT), which transformed gas into a prominent fuel in electric power generation.

Against this background, the following section addresses some general questions regarding the role of gas in the EU energy mix, its main uses as well as other characteristics of gas as an energy carrier or natural resource. Figure 1 displays the overall distribution of primary energy consumption in the EU by selected fuels.

Figure 1: EU Gross Inland Consumption (2008)



Source: Author's illustration based on Eurostat (2011). *Gross inland consumption, by fuel* [tsdcc320].

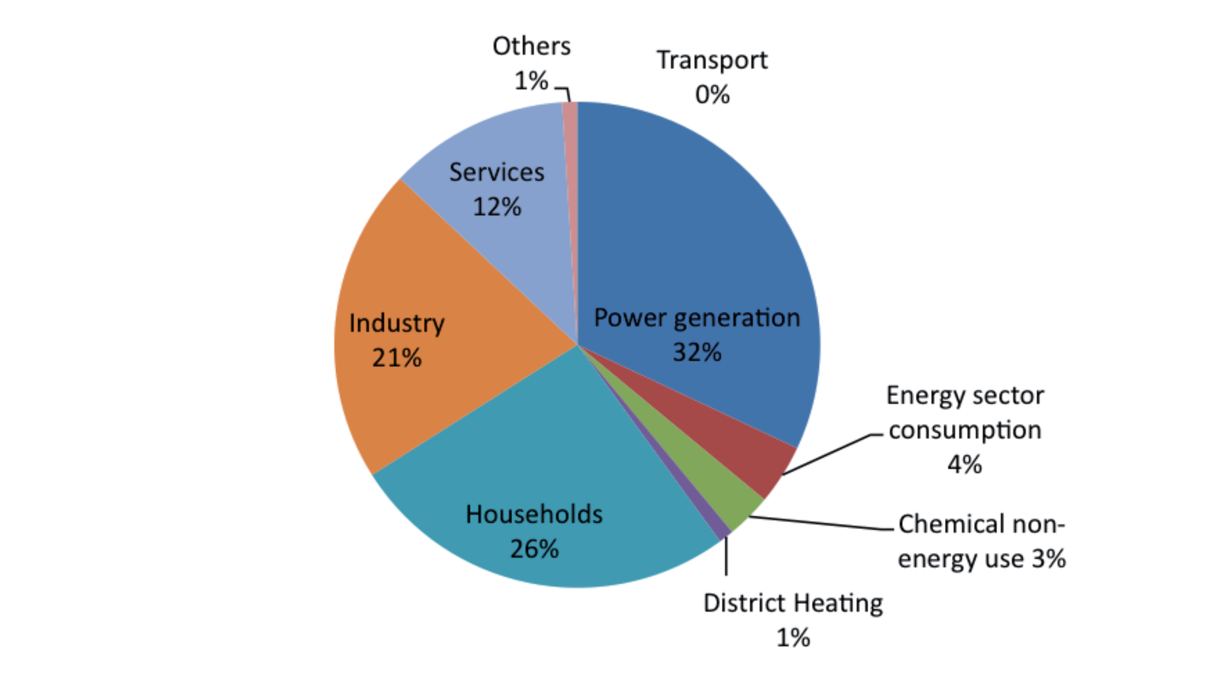
As the chart shows, oil still dominates Europe's energy mix, although demand has slightly declined in recent years. Natural gas ranked second among all primary fuels in 2008 with an estimated share of 25%, featuring significant growth rates since 1990. Similarly, renewables have gained a remarkable share in the fuel mix over the past twenty years, reaching 8% in 2008. Nuclear energy, on the other hand, has grown only by moderate 1.9% annually in the 1990s and experienced a period of stagnation in the last decade. Despite solid fuels still occupying the third position in the primary fuel mix, recent European Commission figures[2] suggest that the share of hard coal and lignite are set to deteriorate over time.

Today, natural gas serves various purposes depending on the respective sectoral application. Generally, one may discern three major areas of gas use: first, gas is a prominent fuel for space and water heating in the residential and commercial sectors; second, industries use natural gas for the production

1 Honoré, A.; Stern, J. (2007). *A constrained future for gas in Europe?*, In: Helm, D. (ed.): The New Energy Paradigm, Oxford University Press, p. 223.

2 European Commission (2010). *EU energy trends to 2030 - update 2009*. Luxemburg.

Figure 2: Use of natural gas in the EU by sector (2007)



Source: Author's illustration based on data obtained from Jean-Arnold Vinois, DG Energy (2010), EU Energy Policy on Natural Gas, Presentation held at the OLF Energy Dialogue, Brussels 14 April 2010.

of steam and process heat or as feedstock; third, natural gas is a prominent fuel in electric power generation, albeit of differing relevance in individual member states.

Figure 2 shows that the power sector contributes the largest share to overall EU gas consumption, closely followed by households and industry. By comparing the composite share of the heat sector (residential/services) to that of the power segment, data reveals that the former exceeds the latter as it accounts for roughly 38% of total EU gas consumption. According to the chart, the role of gas in transport is negligible, given its share of less than 1%.

In absolute terms, the EU's 2009 primary natural gas demand amounted to roughly 550[3] bcm, having increased by some 50% over the past twenty years. The sharpest increment in consumption of some 2.9 % p.a. was seen in the course of the 1990s, but demand growth has gradually dwindled to rates of only 1.5% p.a. in the past decade.[4] Nevertheless, in the EU gas power generation capacity has experienced a tremendous expansion over the past decade, amounting to roughly 120 GW - This is more than for any other energy source in the respective period.[5]

As this high level of consumption must be met by sufficient supplies, the EU is under enormous pressure to purchase gas from elsewhere, especially since EU gas production has undergone an adverse evolution compared to its gas demand. While production was at a constant rise between the late 1980s and 2002, where it reached its peak at 250 bcm, it has found itself at a steady decline ever since, with current EU production volumes of around 200 bcm per year. Obviously, this discrepancy creates a vast supply gap that has to be met by external sources. Most notably, the two main internal suppliers of natural gas, the Netherlands and the United Kingdom, have seen production declining considerably for several years and this trend cannot be offset by other, significantly smaller gas producers such as

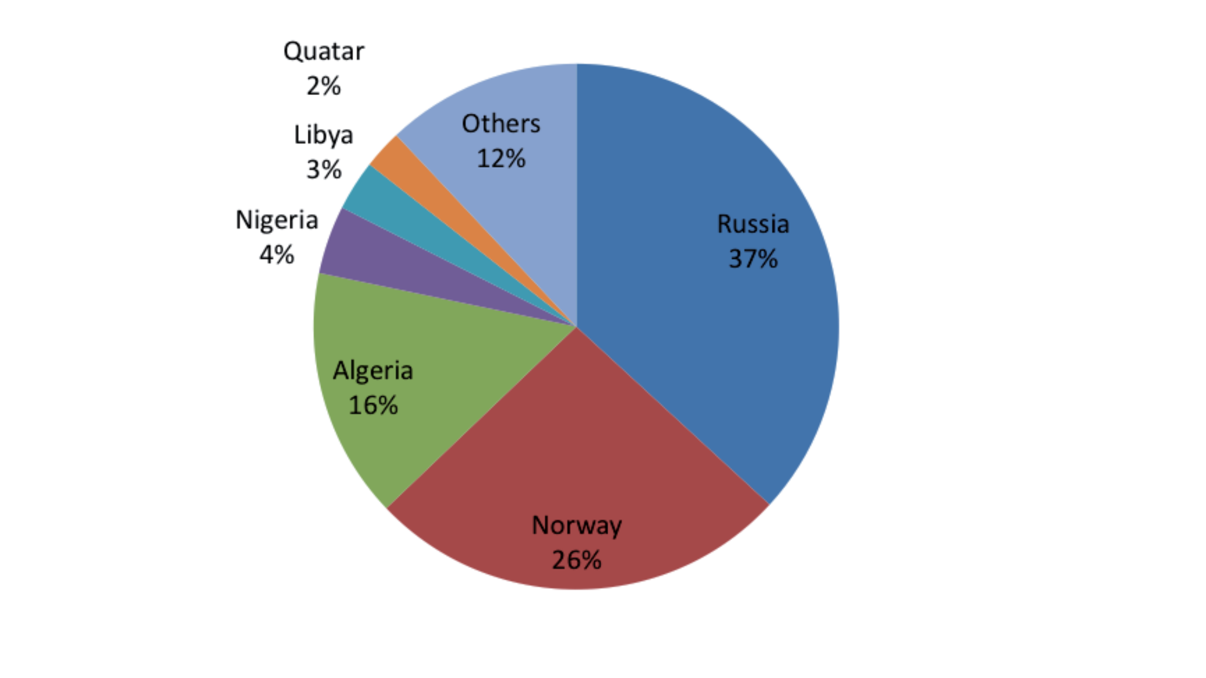
3 Eurostat (2010). *Statistical aspects of the natural gas economy in 2009*. Data in focus 20/2010.
4 European Commission (2010). *EU Energy trends to 2030 - update 2009*.
5 EWEA 2011. Wind in power. 2010 European statistics.

Germany, Italy, Denmark and Poland.

Unsurprisingly, the progressive depletion of existing European gas fields alongside increasing demand has tremendous consequences on EU import requirements. These have more than doubled since 1990, when imports accounted for approximately 160 bcm. In 2010, EU import needs have amounted to as much as 350[6] bcm, which means the EU gas import dependence has reached more than 60%.

The majority of the EU's imports are obtained from three major producing countries. In 2008, Russia (37%), Norway (26%) and Algeria (16%) together accounted for roughly 80% of total imports. While being fairly reliable external suppliers over the past decades, the regular occurrence of gas disputes between Russia, the EU's largest supplier, and important transit countries Ukraine and Belarus has fueled doubts regarding the security of gas supply to the EU.

Figure 3: EU natural gas imports (2008)



Source: Eurostat (2010). Data in focus 20/2010.

Hence, the European Commission has put diversification of energy supplies and supply routes on top of its energy security[7] agenda. Specifically, the "Second Strategic Energy Review" (2008) and the EU's new Energy Strategy "Energy 2020 - A strategy for competitive, sustainable and secure energy" (2010) have highlighted the need to expand infrastructural links inside and outside the EU. Such efforts shall help diversify external suppliers and routes of transportation. Two of the most prominent European natural gas projects currently under way are *Nord Stream* and the *Nabucco* pipeline. The former link, with a projected annual design capacity of 55 bcm, will deliver Russian gas to Germany by 2011/12. The latter project is expected to carry natural gas from the Caspian region, Central Asia and the Middle East to Europe. However, the Nabucco consortium has thus far struggled to procure sufficient volumes of gas to feed the 31 bcm pipeline, thereby fueling doubts regarding the line's planned completion in

6 Ibid.
7 It seems important to emphase at this point that security of supply is a multi-dimensional concept, in which exporting countries have a similar desire for demand security as consumers do for security of supply.

2016. One of the main hindrances to its breakthrough is the existence of a multitude of competing pipeline projects for the Southern Gas Corridor, such as the Russian-led South Stream Initiative, Italy-Greece Interconnector, Trans-Adriatic Pipeline, Azerbaijan-Georgia-Romania Interconnector and White Stream.[8] A joint declaration on the Southern Gas Corridor signed by the European Commission and the Azeri government on 13 January 2011 may increase the likelihood of Nabucco's eventual implementation. Aside from the mentioned pipelines, two other projects will contribute to meeting the EU's security of supply objectives, namely the two 8 bcm/y Galsi and Medgaz pipelines linking North Africa to the EU.[9]

In addition to the construction of new pipelines, a second mode of gas trade has taken a prominent role in recent years, namely that with liquefied natural gas (LNG). As an alternative form of natural gas, it implies a more flexible way of delivering the commodity from producers to consumers via sea routes and is particularly attractive to gas reserve holders lacking the ability to physically link up to consumer markets. Natural gas is liquefied subsequent to production, stored and then shipped from the supplier to the consumer market. Once at its destination, re-gasification terminals transform LNG into its original state of aggregation, so that it can be transported to final consumers via pipeline.[10]

Since 2000, LNG has experienced sustained growth in Europe and currently accounts for around 14%[11] of EU gas consumption. As projections forecast LNG markets to experience rapid growth in the upcoming decades, the share of LNG might eventually be pushed to 25-30%[12]. This swift evolution was not only favoured by the decreasing marginal cost of production at simultaneously high gas prices, but is also owed to the inherent advantages of LNG over traditional gas trade. Compared to pipeline gas, LNG trade can help increase competition and make gas available at relatively short notice. In addition, it contributes to diversifying transport routes and suppliers as well as to reducing risks associated with cross-border transit by land. Nonetheless, just as with pipeline gas, LNG trade may be threatened in the event of politically motivated blockades of major sea routes or hijacking of LNG vessels.[13] With regards to marketing, LNG allows for both long-term contracting and short-term spot trade and thus may help to improve the functioning of European gas markets when it comes to supply competition.

Until recently, high gas prices have further boosted the expansion of LNG capacity, not least on the assumption of future surges in US gas import needs. LNG as a flexibly tradable commodity has also started to serve arbitration purposes, reacting on price signals on either side of the Atlantic or the Pacific. As the share of short-term traded LNG has risen relative to the still dominant long-term contracts, price competition between US, European and Asian markets has started to emerge in recent years.[14]

The previous elaborations have shed light on various characteristics of natural gas. Besides this, aspects such as the current state of European natural gas markets in the light of ceasing economic recession, technological advances, and climate policy initiatives appear relevant as points of reference for the analyses.

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8 Euractiv (2010). *Europe's southern gas corridor: The great pipeline race*. Available online at: http://www.euractiv.com/en/energy/europes-southern-gas-corridor-great-pipeline-race-linksdossier-498558 (last accessed: 02.02.2011).

9 A detailed overview of existing and planned pipeline projects across Europe will be presented in chapter 4.

10 Thorndike, V. L. (2007). *LNG - A level-headed look at the liquefied natural gas controversy*. Versa Press: East Peoria.

11 Link, R. (2010). *Erdgasperspektiven in Zeiten sich wandelnder Märkte*. Presentation held at the 16th annual Euroforum Meeting, Berlin October 26th, 2010 ; BP *Statisitcal Review of World Energy 2010*.

12 Behrens, A. (2010). *Europas Gasmärkte im Wandel: Welche Rolle spielt unkonventionelles Erdgas?* In: Energiewirtschaftliche Tagesfragen, 11/2010, p. 14-16.

13 It is important to note in this context that the global LNG market is highly concentrated.

14 Clingendael International Energy Programme (2008). *The geopolitics of EU gas supply. The role of LNG in the EU gas market*.

Global as well as European gas markets are currently experiencing what the International Energy Agency has called a "glut of global gas-supply capacity"[15]. The economic downturn, which has manifested itself in reduced economic activity, was certainly one main driver of this trend of slackening industrial gas demand in the past two to three years. The development of alternative power generation technologies and reduced primary fossil fuel input for climate policy purposes have contributed to lowering demand for gas in Europe. Almost simultaneously, however, and primarily triggered by a period of high prices in previous years, there has been a marked expansion of investment activity in the global gas industry, particularly in LNG infrastructure. On top of that, a massive surge in unconventional gas production in the US has added to the oversupply of natural gas.[16] This causes tremendous effects as low-priced LNG is being diverted to European markets, thereby rendering natural gas a more affordable and cost-competitive energy source in the EU. Declining gas prices at European spot markets have reflected this trend. Moreover, the prospect of having an emissions trading scheme effectively operating in the EU, has encouraged investments in the gas sector, as it raised hopes that the competitiveness of natural gas vis-à-vis other fossil fuels would be improved due to its relatively low carbon-impact.[17]

In short, the expansion of global gas supplies on the one hand and declining gas demand on the other have created a natural gas glut.[18] How the current situation in Europe will evolve remains to be seen. The subsequent analysis of various projections of natural gas demand and supply may help to gain a better understanding of possible future developments.

Aside from issues associated with the current gas glut, the specific nature of gas in terms of its role in a low-carbon economy has to be taken into account. Next to oil and coal, gas ranks among the fossil fuels that have dominated Europe's energy mix for the past decades. As gas is closely associated with a fossil energy system, it appears a crafty task to create awareness for its potential as a bridging or transition fuel towards a more sustainable energy system. Yet, there is reason believe that natural gas can contribute to decarbonizing the EU's energy system. Specifically, in the power sector, replacing coal by gas would reduce CO_2 emissions per kWh by around 50 to 60%. A fuel substitution of this kind may in fact become economically viable, if gas prices continue to decouple from those of oil. Ultimately, it remains to be seen whether the image of natural gas as a relic of the past or a necessary prerequisite for a low-carbon energy future will prevail.

Bearing these factors in mind, this report aims to give insight into the possible evolution of EU natural gas demand over the next two decades. Simultaneously, it seeks to highlight the potential role of individual suppliers and supplier regions with a view to their contribution to Europe's gas supply security up to the year 2030.

15 International Energy Agency (2010). *World Energy Outlook 2010*, Paris, p. 179.
16 see also Link, R. (2010) and Behrens, A. (2010).
17 Deutsche Bank Research (2010). *Gasschwemme erreicht Europa. Starke Effekte auf Preise, Sicherheit und Marktstruktur*. Beiträge zur europäischen Integration, EU-Monitor 75, 27.05.2010.
18 DB Research (2010). *Gasschwemme erreicht Europa*.

3 Natural gas demand forecasts

This chapter aims to give an overview of EU natural gas demand scenarios including projections until 2030. To this end, it distinguishes the main methodological assumptions underlying the energy market models provided by the European Commission, the International Energy Agency, the United States Energy Information Administration and others. Based on this, the different energy demand projections are compared and analyzed with regard to the future role of natural gas in the EU. In order for the reader to properly interpret the data presented, the following sections will briefly outline the main methodological characteristics and basic assumptions of each study.

3.1 Data composition and methodology

EU Energy trends to 2030 (2007 and 2009 updates)

The European Commission conducts research to assess the possible evolution of EU energy markets on a regular basis. The latest two editions of the "EU energy trends to 2030" were published in early 2008 (prior to the economic crisis) and in September 2010. Both studies follow the same methodology: historical data on energy prices, macroeconomic as well as sectoral activities and technology are drawn from EU and external databases.[19] Energy and climate policy assumptions are also included in the dataset, representing a crucial feature of the EU projections.

Scenario construction within the "EU Energy Trends to 2030" is effectuated by means of the PRIMES model. This is a partial equilibrium model of the EU Energy System providing medium- and long term projections.[20] PRIMES quantifies future EU energy demand and supply by simulating a market equilibrium solution. Equilibrium is determined by the level of energy prices necessary to ensure that future energy production matches consumption at a given point in time. Hence, the model equilibrium is price driven and static for each time period. The modular structure of the PRIMES model (see Figure 4) combined with its iterative modeling processes, however, also accounts for dynamic relationships and interactions between different market segments over the entire projection period.

As the model assumes a distributed decision-making process among energy system agents, energy demand and supply as well as technology choice are considered to be subject to rational economic behaviour. Agents' decisions are influenced by considerations of policies (taxes, subsidies, regulation), market economics and industry structures. At the end of this price formation process, the PRIMES model anticipates market clearing (equilibrium), where the quantity supplied equals the quantity demanded.

With regard to the quantification of its scenarios, the PRIMES model is comprised of a broad range of variables. On the one hand, available demand and supply technologies and international fuel prices are assumed to be influenced exogenously. On the other, the model ensures that energy demand and supply behaviour, energy prices and investment in new fixed assets (i.e. plant/equipment/other infrastructure) are determined endogenously. What is more, potential future cost structures and technological progress are simulated by incorporating indicators such as expected fuel prices, discount

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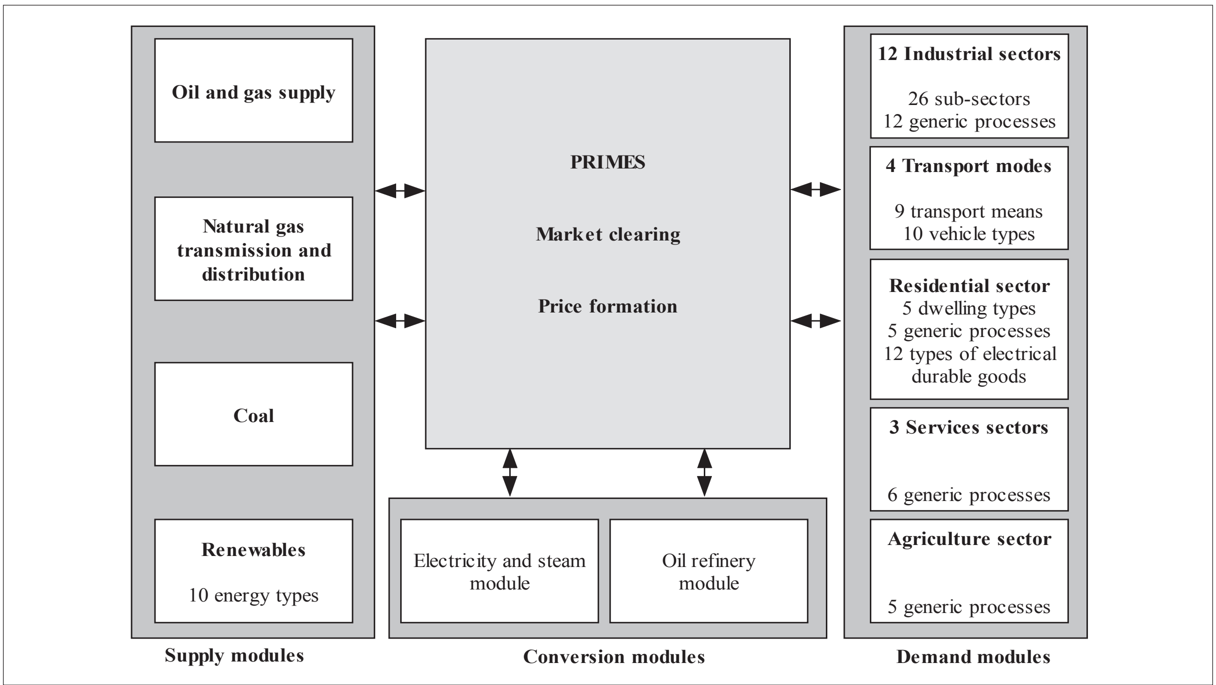
19 Primarily these data are obtained from the Eurostat Energy Balances, IEA and other institutions. Supply side information has been obtained from various databases, amongst others from EASAP SA, the Admire-Rebus database and figures from DG research as well as from the EEA. Information on energy supply and power generation technologies is taken from the TechPol database, the Zero Emission Technology Platform and the VGB database.

20 PRIMES is complemented amongst others by the POLES world energy model and the GEM-E3 macroeconomic model or the PROMETHEUS model respectively.

rates and information on plant closure as well as production trajectories of EU member states.

The PRIMES model is organized around three main components: fuel supply, energy conversion and sectoral demand. More specifically, it covers data on twelve industrial sectors, various transport modes, dwelling types, fossil fuels and energy carriers for each EU member state. In addition, a clearly defined set of policies is integrated into PRIMES. Overall, it can be regarded as a general purpose model, serving as a tool for scenario construction and policy impact assessments. The "EU Trends to 2030" set up one *Baseline scenario in 2007*[21] and two scenarios in the 2009 update, namely a *Baseline 2009* and a *2010 Reference case*[22]. While the baseline scenarios refer to a continuation of current trends and policies (at the time of scenario construction), the 2010 Reference projections rest upon more ambitious climate and energy policy assumptions.

Figure 4: PRIMES modular structure



Source: EU Commission (2008). *Europe's current and future energy position. Demand- resources -investments*, SEC(2008) 2871, p. 56.

IEA World Energy Outlook (2008, 2009 and 2010)

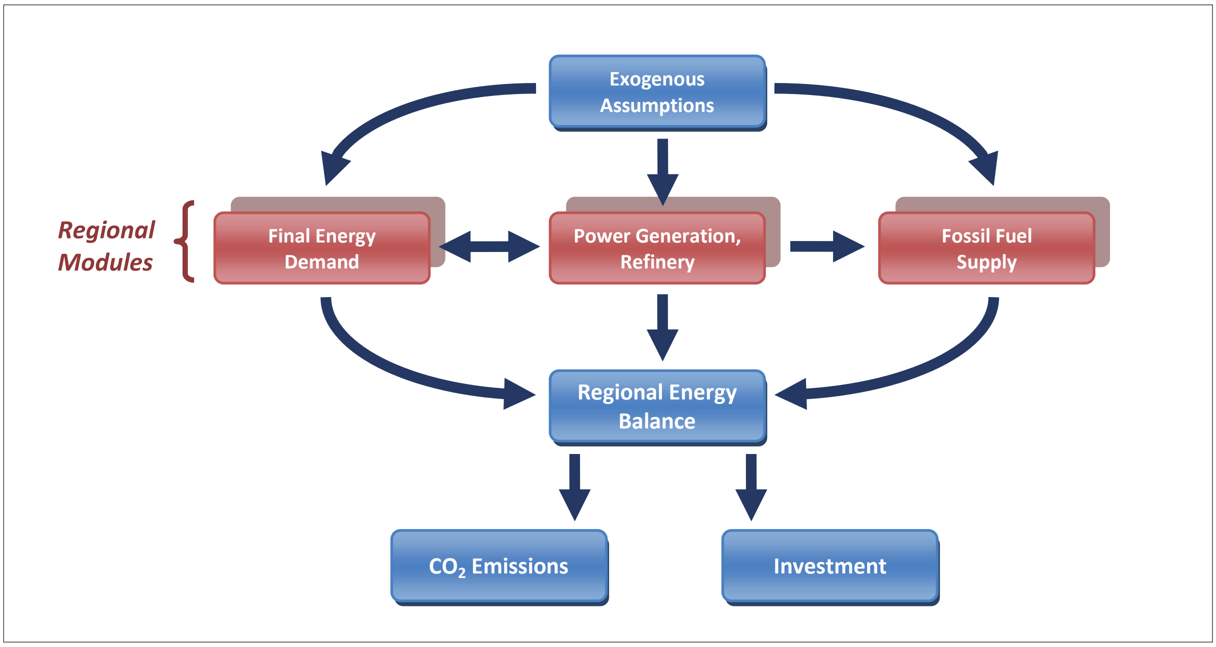
The International Energy Agency (IEA) provides global energy market projections in its annual publication, the World Energy Outlook (WEO). Historical data for the compilation of these studies is mainly drawn from the organization's own energy and economic statistics databases and in some cases additional information is obtained from other sources such as the OECD, IMF, World Bank, BP and the Oil and Gas Journal.

To quantify the WEO energy market projections, the World Energy Model (WEM) is used. The WEM is a large scale mathematical, partial equilibrium model that generates detailed sectoral energy projections on a global and regional scale (Figure 5). Similar to PRIMES, the WEM features a modular

21 Baseline 2007 is based on statistical data that was available until June 2007. However, the main source, the Eurostat Energy Balances, cover only the period from 1990 to 2005. Information on energy prices contains figures up to 2006.
22 Baseline 2009 was finalized in December 2009 and the Reference 2010 in April 2010.

structure to mirror essential energy market components. It is comprised of six distinct modules: final energy demand (including sectoral sub-models); power generation and heat; refinery and other transformation; fossil fuel supply; CO_2 emissions and investment. These variables are assumed to be determined endogenously at the regional level. As far as exogenous assumptions are concerned, the model takes into account economic growth, demographic development, international fossil fuel prices and technological progress. Fuel price trajectories are determined on the basis of the level of prices "needed to encourage sufficient investment in supply to meet projected demand"[23].

Figure 5: World Energy Model structure



IEA (2010). *World Energy Model - Methodology and Assumptions*, p. 5.

Beginning with the WEO 2007, the IEA started combining a General equilibrium model (GEM) with the partial equilibrium WEM model in order to further improve forecasts on interactions between energy markets and macroeconomic developments.[24]

The 2009 edition of the WEO is based on comprehensive historical data up to 2007 and complemented by some preliminary data for 2008. Notably, the power generation and gas-supply modules have been overhauled for this edition and the regional granulation extended to 24 units compared to 21 in WEO 2008. As with previous editions, WEO 2009 uses a scenario approach comprising a Reference Scenario and a 450 Scenario. While the former reflects a business-as-usual case, the latter caters to the notion of decarbonization and climate change mitigation, implying a limitation of the concentration of GHG in the atmosphere, to 450 parts per million CO_2-equivalent. WEO 2010 draws upon the same methodology and comprises three scenarios: a Current Policies Scenario, which resembles the previous Reference case; a New Policies Scenario implying relatively ambitious renewable energy targets and emission reductions; and an updated version of the 450 Scenario.

23 International Energy Agency (2009). *World Energy Outlook 2009*. Paris.
24 International Energy Agency (2010). *World Energy Model. Methodology and Assumptions*. Available online at: http://www.iea.org/weo/model.asp (last accessed: 03.02.2011).

Energy Information Administration - International Energy Outlook 2010

The United States Energy Information Administration (EIA) provides projections on world energy demand and supply in its annual International Energy Outlook (IEO). Data underlying its energy scenarios is predominantly derived from the EIA's International Energy Statistics database and other EIA publications. In some cases additional information is obtained from external sources such as IHS Global Insight and the Oil and Gas Journal, among others.

To generate energy market projections the EIA uses the World Energy Projections Plus (WEPS+) model. As the two mathematic models that were previously presented, WEPS+ features a modular structure with several sub-modules, namely a multi-sectoral end-use consumption module, an intermediate consumption module (electricity and heat generation) and supply modules projecting fuel supply and wholesale prices. Moreover, the IEO 2010 features a new electric power generation module that incorporates technology choice in a stock/flow model and a new linkage to the EIA's International Natural Gas Model (INGM). Similar to PRIMES, WEPS+ assumes an iterative process of market clearance where price formation is a function of market equilibrium at a given time. Thus, the model is price driven and static for a single time period but takes into account dynamic market interactions over the entire projection period.

Overall, the IEO 2010 generates five scenarios: a Reference Case, a Low and High Oil Price Scenario, and a Low and High Growth Scenario. The IEO's projections on global natural gas markets are derived from the INGM, while world liquids supply is simulated by means of the Generate World Oil Balance (GWOB).

Eurogas – Long-term Outlook for Natural Gas Demand and Supply 2010

A rather different approach to energy scenario construction was applied by the *European Union of the Natural Gas Industry (Eurogas)*. Instead of using mathematical models like the EU, IEA and EIA, this organization conducted a standardized survey among the experts of Eurogas member organizations. The figures provided by large member organizations are, in fact, often based on mathematical models. Many of the smaller organizations, however, are only able to provide qualitative estimates.

On the basis of two sets of assumptions, *Eurogas* created two scenarios: a Base Case, reflecting current trends and policies, and an Environmental Scenario, assuming a more sustainable energy supply in which natural gas plays a crucial role.

Taking the methodological assumptions of the different scenarios into account, the following chapter will highlight essential drivers of natural gas demand. Six major variables will be explored in detail in order to facilitate the comparison of the presented energy models.

3.2 Factors influencing natural gas demand and main scenario assumptions

Drivers of Natural Gas Demand

Due to varying assumptions, the energy scenarios analyzed in this report have projected EU natural gas demand to take rather different directions. While this is hardly surprising, the report seeks to explain discrepancies by disassembling energy models into their most relevant components. In order to expound the existence of dissimilar expectations regarding the prospects of natural gas in Europe, the following section takes a closer look at the main factors influencing gas demand and at the way in which these are assumed to interact in individual scenarios. This chapter not only identifies the main drivers of natural gas demand, but also indicates the basic assumptions underlying each of the EU, IEA, EIA and Eurogas projections.

The academic literature suggests that there is a wide range of factors stimulating or diminishing demand for natural gas. Some variables primarily have short-term effects, while others influence gas demand in the long-term. For the purpose of this report, long-term drivers are particularly relevant. Most energy market models consider economic activity or growth, generally measured in Gross Domestic Product (GDP), to be the most significant explanatory variable. Absolute and relative fuel prices are regarded as a second fundamental determinant of natural gas demand. In recent years, energy market modeling has also increasingly acknowledged the role of energy and climate policies and their impact on fossil fuel consumption. In addition, available technologies, their respective cost structures, efficiency levels and carbon intensity are assumed to influence investment decisions of market actors and to have a considerable impact on fuel choices.[25]

GDP growth

As opposed to other variables, the causal linkage between GDP growth and primary energy or natural gas consumption is fairly obvious. High economic growth indicates increased economic activity and hence more economic output. Not surprisingly, the IEA considers GDP growth "the principal driver of demand for energy services"[26]. This is particularly true regarding the natural gas demand of industrial consumers. In times of economic expansion, industrial sectors usually show rising production rates as well as higher energy and natural gas consumption, specifically where gas is needed for process heat and steam-raising. In turn, the recent economic crisis has caused energy intensive industries' production as well as their primary energy and electricity demand to plunge.[27] As a result, the overall gas demand has suffered notably. This development was further aggravated by a sharp decline in electricity demand in the power generation sector, complemented by a deterioration of the inter-fuel competitiveness of gas, resulting from sustained high gas prices and a simultaneous drop in coal prices. As GDP growth is highly correlated with electricity demand, its role as a driver of natural gas demand must not be underestimated.[28]

Apart from the power sector, the correlation of GDP growth and gas demand is also relevant in the residential sector, where higher household incomes[29] cause the average size of homes per capita to grow, leading to increased expenditure on heating and cooling. However, while this holds true in economic theory, the IMF posits that "the effect of income […] on gas demand in the household sector is unlikely to be significant since the fuel is an essential good, the demand for which does not vary much with income levels" [30].

The EIA 2010 Low Growth and High Growth Scenarios support the expected correlation between GDP and gas demand growth across sectors (see Figure 9). The "EU Energy Trends to 2030 - update 2009", however, forecasts that GDP growth and primary energy demand are set to further decouple in the future as a result of energy efficiency improvements, energy savings and a shift towards less energy intensive production. Be that as it may, the global economic crisis has shown that negative

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25 Other factors such as population growth, weather conditions and demographic development are also correlated with energy consumption. However, as the EU's future population is projected to remain fairly stable over the next decades and only annual figures are compared in this report (offsetting seasonal demand variations) these variables are neglected in the analysis. As far as other demographics are concerned, particularly the slight increase in the number of households in Europe may have an influence on residential gas consumption. Nevertheless, compared to the previously introduced main drivers of gas demand the impact of household numbers is considered negligible for the purpose of this study.

26 IEA (2009). *WEO*, p. 58.

27 European Commission (2010). *Energy Trends to 2030- update 2009*.

28 IHS CERA (2009). *Europe. Providing a home for global gas supplies?*, European Gas Watch, March 2009, p. 6.

29 Measured in GDP per capita.

30 International Monetary Fund (2002). *Issues in global natural gas: a primer and analysis*. IMF Working Paper 02/40, p. 23.

GDP rates of 4 to 5% may cause natural gas consumption to stagnate or even drop, which could be seen especially in 2009[31]. This clearly indicates the sensitivity of energy consumption to economic booms or recessions. The extent to which natural gas consumption will be affected by macroeconomic developments depends on how rapidly GDP growth is decoupled from primary energy demand.

Scenario assumptions

GDP growth assumptions, as the ones contained in the scenarios to be analyzed in this report, constitute one main variable explaining the deviations of energy market projections. The pre-crisis projections of the EU (dating back to 2007) assumed an average annual EU GDP growth rate of 2.2% up to 2030, whereas the 2009 EU Baseline and 2010 Reference Scenarios revised this figure to a mere 1.95% for the 2010 to 2030 period. Compared to its 2008 Reference Scenario, which was based on the assumption of an average GDP growth of 1.8% p.a., the IEA 2009 has recently been more cautious in its forecast, only estimating an annual growth rate of 1.5% up to 2030 in both the 2009 Reference and the 450 Scenarios. Similarly, the updated WEO 2010 implies a compound average annual growth rate of 1.6%. Although tailored for OECD Europe and, due to its geographic scope, not directly comparable to the previous figures, the EIA energy projections are based on the expectation of a 1.7% GDP growth p.a. in the Reference, High Oil and Low Oil Price Scenarios. The EIA's High and Low Growth cases reflect a variance of 0.5% above and below this growth figure respectively.

Fossil fuel prices

Another prominent factor explaining changes in natural gas consumption are fossil fuel prices. Before addressing this point, the following paragraph briefly refers back to the main natural gas consuming industry sectors. This serves as a starting point for analyzing the potential of inter-fuel competition between gas and other energy sources.

As mentioned above, EU gas consumption is primarily distributed among the residential, commercial, industry and power generation sectors. Electric power generation currently ranks as the single largest consuming sector and is widely perceived to be the main driver of EU gas demand in the coming years.[32] In industry, gas is used for the generation of process heat or steam and in some cases as feedstock. In the residential and services sectors, it features prominently in space and water heating. In transportation, on the other hand, gas plays and is projected to play a negligible role.

To what extent fossil fuel price fluctuations and relative price differences between gas and residual fuels affect actual demand for natural gas in the *short term*, primarily depends on the fuel-switching capabilities of each sector. Gas price peaks will only cause demand-side adjustments if gas can be appropriately substituted by another, more economically viable energy carrier. This inter-fuel substitutability particularly applies to industry and electric power generation. In the residential and commercial sectors, the short-term responsiveness of demand to changes in the gas price is rather limited. As the IMF ascertained, "capital investment for gas usage in homes is usually long term" and "the same argument applies to commercial establishments"[33]. Conversely, industry often uses multi-fuel energy systems, which allows it to switch to alternative fuels even at short notice. In economic terms, price elasticity of natural gas demand is rather low in the residential and commercial sectors,

31 IHS CERA (2009), *Europe. Providing a home for global gas supplies?*, p. 7.
32 IEA (2010). *WEO*, p. 183.
33 IMF (2002). *Issues in global natural gas*, p. 23.

while power generation and industry show higher elasticity as a result of their fuel-switching capabilities.

As previously elaborated, both absolute and relative price differences between fossil fuels are crucial when assessing inter-fuel competition. It is interesting to note in this regard that natural gas competes with different fuels and energy carriers depending on the respective sector. In power generation, natural gas-fired plants are primarily competing with coal-fired and in some cases with nuclear power plants. In the industrial, residential and services sectors, on the other hand, natural gas faces competition with electricity[34] and, to some extent, petroleum products.[35]

Generally, high (oil-indexed[36]) gas prices decrease total primary demand for natural gas because the use of alternative fuels becomes more economically viable.[37] This effect is most visible in the power sector. *In the short-term*, rising gas prices deteriorate the competitiveness of gas vis-à-vis coal, since variable costs (notably fuel) account for roughly two-thirds of total marginal costs of power generation in Combined Cycle Gas Turbines (CCGT).[38] Plants with a higher proportion of fixed costs, such as those based on hard coal, lignite and nuclear power, are less vulnerable to fuel price fluctuations. Consequently, at times of high gas prices relative to coal, the capacity utilization of CCGT plants is reduced, as cost considerations determine, which type of plant is to dispatch electricity.[39]

In the medium or long term, the gas to coal price ratio crucially determines investment decisions in electricity supply infrastructure.[40] A high gas to coal price ratio has a negative impact on the share of natural gas in installed power generation capacity, as it may induce more investment in coal-fired or other plant types and less in gas turbines.

Additionally, the level of CO_2 prices arising from the EU Emission Trading Scheme (EU ETS) affects marginal cost and hence fuel choice in power generation.[41] Carbon prices exert a two-pronged effect in the power sector: firstly, they influence short term marginal cost of power generation and thus determine the actual dispatch of electricity from individual power plants; secondly, they are a crucial determinant of long-term investment in power generation capacity. However, prices - though vital - are not the only determinants in this context. Other factors defining the relative financial attractiveness of gas vis-à-vis other fuels (plant efficiency, capacity factors, investment/operating/maintenance cost, construction lead times and plant life) are similarly relevant.

In order to quantify some of the above-stated assumptions, the different oil and gas price trajectories as well as expected gas to coal price ratios inherent to the projections under investigation are illustrated below.

34 European Commission (2008). *EU Energy and Transport. Trends to 2030 - update 2007*, Luxemburg. Note: Electricity ranks among secondary energy carriers and may be generated by various primary energy sources.

35 Brown, S.; Yücel, M. (2007). *What drives natural gas prices?* Federal Reserve Bank of Dallas, Working Paper 0703, p. 12.

36 The gas price is generally indexed to the development of the oil price. This is reflected, most significantly, in gas purchases based on long-term contracts, which predetermine the price of internationally traded gas relative to the average oil price. However, in regions where gas spot markets have evolved, this close oil/gas-linkage is gradually diminishing. Since 2008, slackening global gas demand alongside increased supply capacity, particularly LNG infrastructure and unconventional gas in the US, have caused gas prices to remain relatively low compared to that of oil (IEA (2010). *WEO*, p. 196; DB Research 2010, p . 4-6).

37 Fahl, U. et al. (2010). *Energieprognose 2009: Die Entwicklung der Energiemärkte bis 2030*. In: Energiewirtschaftliche Tagesfragen, 9/2009, p. 30-34, here p. 34.

38 Honoré, A. (2006). *Future natural gas demand in Europe. The importance of the power sector*. Oxford Institute for Energy Studies, Natural Gas Research Programme; IEA (2009). *WEO*, p. 382.

39 In spite of gas prices being significantly higher than those of coal, gas remains an attractive fuel in the power sector due to lower investment cost of CCGT plants compared to coal-fired plants, higher conversion efficiencies and more flexible dispatch (Honoré, A. (2006). Future natural gas demand in Europe, p. 28).

40 EU Commission (2010). EU Energy trends to 2030 - update 2009, p. 16.

41 The price of CO_2 allowances thereby progressively impinges on investment decisions and dispatching in the energy sector. As the IEA (2009, 477) posits, "clear signals for carbon prices coming from the EU Emissions Trading System can […] improve the position of gas versus coal, since coal-fired generation produces around twice the amount of CO_2 per unit of electricity generated". Please find additional information on this issue in the "climate policy" section.

Table 1: Fossil fuel price assumption in various scenarios

	Oil price ($/boe)		**Gas price**[42] ($/boe)		**Gas to coal price ratio**[43]
	2020	**2030**	**2020**	**2030**	**2030**
EU Baseline 2007*	61	63	46	48	3.2
EU Baseline 2009***	88	106	62	77	2.6
EU Reference 2010***	88	106	62	77	2.6
IEA Reference 2008**	110	122	74	82	3.6
IEA Reference 2009***	100	115	70	81	3.6
IEA 450 2009***	90	90	64	64	4.8
IEA New Policies 2010****	99	110	67	75	3.5
IEA Current Policies 2010****	110	130	70	81	3.5
IEA 450 2010****	90	90	62	63	4.7
EIA Reference 2010***	108	124	n.a.	n.a.	n.a.

*2005 prices; **2007 prices; ***2008 prices; **** 2009 prices

Energy policy

EU Energy Policy has undergone quite an impressive evolution in recent years. While in the 1990s a common energy policy was far from existent, the situation gradually changed over the past decade with the adoption of various policy measures and the formal codification of an EU Energy Policy in the Lisbon Treaty (2009). Acknowledging the strong impact of European policies on energy markets, the following section aims to illustrate the potential effects of EU energy legislation on natural gas demand. The focus will be on legislation referring to the promotion of renewable energy sources (RES), energy efficiency[42] and energy savings.

As previously discussed, the residential, commercial, industrial and power generation sectors are the main gas consuming sectors in the EU. All of these sectors will be affected by the EU's renewable energy and energy efficiency legislation[43], which targets reductions in the overall consumption of energy, notably of fossil fuels, and promotes the use of alternative energy sources. Key factors include savings from better thermal insulation of buildings, efficiency improvements in household and office lighting, ecological product labeling, the promotion of cogeneration and the use of renewable energy sources in power generation and heating.

Especially in the power sector, the anticipated strong market penetration of wind, solar, biomass, geothermal and hydro power is likely to challenge the role of natural gas. With regard to the heat market, improved efficiency of buildings and a shift towards environmentally sound heating systems may imply considerable cuts in residential and commercial gas consumption. However, given the sluggish progress of efficiency improvements, a transformation in the heat market is only expected to occur in the long term. The impact of renewable energy policies on the power sector, on the other hand, will become visible in the short to medium term. In effect, the expansion of RES complemented by ambitious efficiency policies will gradually lead to cuts in gas and electricity consumption. To what extent individual fossil fuels will be affected by energy policies, however, remains to be seen. After all, climate policy measures and the economic viability of emission abatement technologies will also play a role.

42 Energy efficiency as used in this report, is defined according to the IEA: "Something is more energy efficient if it delivers more services at the same energy input". Available online at: http://www.iea.org/efficiency/whatisee.asp (last accessed: 02.02.2011).
43 A list of relevant policy measures can be found in "EU Energy trends to 2030 - update 2009", p. 17.

A decline in gas demand is likely to cause natural gas prices to fall, provided that price formation is based on market principles.[44] For the EU, the latter would require a completion of the internal gas market, accompanied by larger volumes of gas being traded at European spot markets. In effect, a well functioning internal market subject to some sort of LNG-driven intercontinental price competition would translate demand-cuts into lower spot gas prices, reduce variable costs of gas-fired plants and thus stimulate their load factors in future power generation.

At the same time, owing to the chemical characteristics of gas and the technological features of CCGT plants, the decarbonisation of the EU energy system may be seen as an opportunity for natural gas, rather than a risk. Increasing shares of RES in the electricity generation mix will require flexible conventional power plants that are able to cope with rising volumes of intermittent renewable energy supply. Gas-fired plants meet these requirements due to their inherent flexibility and quick responsiveness to balancing needs in the power system. Unlike coal-fired plants, gas could take over the role of such a complementary fuel in the future EU energy mix.[45]

The future role of nuclear energy as a low emission technology, which will primarily be shaped by political decisions, is also a key determinant of investment in power generation technologies such as CCGT. Surprisingly, despite nuclear energy's alleged technical incompatibility with high shares of RES in power generation[46], the EIA (2010) and the EU (2010) expect this technology to regain significance in Europe, whereas the IEA (2009) considers the role of nuclear power to diminish gradually. Obviously, the prospects for individual power generation modes are evaluated differently. Yet, if there is a future for nuclear power in Europe, it will increase the competitive pressure on natural gas in power generation, specifically in the light of rising gas import prices.

Alternatively, the promotion of cogeneration in the power sector may scale up natural gas demand, provided that sufficient gas is available at moderate prices. Gas currently makes up 40% of the total energy produced in this segment[47]. Due to the low environmental impact and high conversion efficiencies of CCGT plants[48], an expansion of Combined Heat and Power (CHP) technologies may possibly trigger gas demand. For example, this could translate into an increase in gas-based district heating.

A brief account of the scenarios' energy policy assumptions will be provided at the end of the subsequent climate policy section.

Climate policy

The impact of EU climate policy on natural gas demand is best illustrated on the basis of the EU ETS, as carbon pricing has strong repercussions on demand for fossil fuels. Yet, it is important to note that emission trading has a significantly stronger impact on the use of natural gas in electric power generation than it does on industry and the residential/commercial sectors. In electric power generation, the competition between natural gas and hard coal/lignite[49] on the one hand and nuclear energy as a low-

44 Wiser, R.; Bolinger, M.; St. Clair, M. (2005). *Easing the natural gas crisis: Reducing natural gas prices through increased deployment if renewable energy and energy efficiency*. Lawrence Berkeley National Laboratory, p. 3.

45 European Commission (2010). *EU Energy trends to 2030 - update 2009*, p. 29.

46 Due to technical constraints, nuclear power plants are not able to flexibly adapt to intermittent RES supply.

47 Euractiv (2010): *Europe switches to gas*. Available at: http://www.euractiv.com/en/energy/europe-switches-gas-linksdossier-259905 (last accessed: 03.02.2011).

48 As with other infrastructural investments "the boundary conditions like the availability of fuel […], fuel prices, power and heat demand curve define the power generation technology", also for cogeneration (Dichtl, H. (2005). *CHP plants for cities and industries – beneficial for the economy and the environment*, Siemens Power Generation, n. pag.).

49 The CO_2 emission factors (in tCO_2/toe) of hard coal and lignite amount to approximately 4.00 and 4.70 respectively, whereas that of natural gas is only 2.37 (Schiffer, H. (2008). *Deutscher Energiemarkt 2007*, In: Energiemarkt Tagesfragen 3/2008, p. 47).

emission technology on the other is severely influenced by the price of CO_2. Therefore, this section attempts to illustrate interdependencies between CO_2 allowance prices and the use of individual fuels for electricity and heat production.[50]

In theory, it is assumed that "high CO_2 prices tend to favour gas and low CO_2 prices to favour coal"[51]. It is the higher carbon intensity of coal that places it at a competitive disadvantage vis-à-vis gas in times of high CO_2 prices. This circumstance is expected to generate an increase in the load factor of gas plants in the future, provided that gas prices are relatively moderate.

At the same time, high CO_2 allowance prices may render other low-emission technologies such as nuclear power or Carbon Capture and Storage-based fossil fuel combustion a cost-effective alternative even to gas.[52] Several governments have recently dissociated themselves from previous nuclear phase-out plans,[53] which will curb the construction of new gas-fired plants.[54] Also, high CO_2 prices may induce investment in CCS technology, which reduces emissions of coal-fired plants below those of gas without Carbon Capture and Storage (CCS).[55] This could critically determine future fossil fuel choices given that power sector investment decisions primarily depend on "projected relative prices between coal and gas [...] which need to include CO_2 emission prices"[56].

Referring back to the previous section on energy policy instruments, it seems necessary to acknowledge that there is a link between RES and climate policies on the one hand and CO_2 price developments on the other. As the EU 2010 Reference Scenario shows, ambitious climate policies may induce industrial consumers and power generators covered by the EU ETS to alleviate their carbon emissions. Furthermore, privileged grid access for RES and the preservation of incentive schemes for the promotion of RES in the power sector may foster the expansion of these zero-emission technologies. As a result, the demand for emission allowances in the EU ETS is set to decline and so are CO_2 prices. Paradoxically, this correlation may have unintended repercussions on the power sector, as the cost of carbon intensive power generation would in fact fall. While this is hypothetical, an adequate reduction of the total volume of allowances under the EU ETS would cause emission certificates to remain scarce, and thus ensure stable or surging CO_2 prices.

Scenario assumptions

With respect to the individual energy scenarios under consideration in this report, the following differences can be discerned: The EU Baseline 2007 takes into account all EU energy and climate policy measures that have been implemented at the national level until December 2006. The successive EU 2009 Baseline covers policies implemented in the member states until April 2009 and some policies adopted by then. In addition to these policy assumptions, the EU 2010 Reference scenario encompasses legislation that has been adopted between April and December 2009 and assumes that the EU's RES and GHG emissions targets will be attained by 2020.

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50 One must not forget that apart from carbon prices, the total amount of allowances as well as the mode of allocation/auctioning, have a significant impact on investment decisions in power technologies. This aspect, however, will not be covered in this report.

51 Honoré, A. (2006). *Future of natural gas in Europe*, p. 29.

52 Gas price volatility may easily offset competitive gains from high CO_2 prices.

53 Sweden, Italy, Belgium, Germany.

54 Honoré, A. (2006). *Future of natural gas in Europe*, p. 33.

55 European Commission (2010). *EU Energy Trends to 2030 - update 2009*, p. 29; Hobohm, J. (2008). *Mehr Erdgas für den Klimaschutz? Chancen und Risiken einer erweiterten Gasstrategie für die europäische Energieversorgung*. SWP Studie S 32, November 2008, p. 10.

56 Honoré, A. (2006). *Future of natural gas in Europe*, p. 28.

In both the 2009 Reference and 450 Scenarios the IEA includes energy and climate policies implemented until 2008, while excluding policy targets and any intentions not backed by implementation measures. By contrast, the IEA 2010 New Policies Scenario takes into account policy commitments made by mid-2010, even where they are not yet backed by implementation measures. More specifically, this scenario assumes a 25% reduction in GHG emission by 2020. By comparison, the IEA 2010 450 Scenario expects cuts of as much as 30% in the respective period. Apart from that, this case broadly corresponds to the policy assumptions stipulated in the 2009 450 Scenario. As far as the IEA 2010 business-as-usual case is concerned, the WEO 2010 has replaced the previously used term "Reference Scenario" with the term "Current Policies Scenario". The latter incorporates measures adopted by June 2010 and does not cover any commitments or policy targets where formal adoption or full implementation are absent.

The EIA policy assumptions are fairly vague, but they account for energy and climate policies adopted until 2009 across OECD Europe. It is assumed that not all of the EU's RES targets will be met, but that renewable power will make up a considerable share of the future power generation mix. In contrast to the IEO 2009, this year's projections take into account the renewed interest in nuclear energy.

Eurogas established its Base Case scenario on the basis of policies in place until spring 2010 and on a business-as-usual outlook regarding nuclear energy. The Environmental Case reflects a more favourable policy towards natural gas.

Technology

The evolution of energy sector technologies is another key factor influencing European energy demand, fuel choices, CO_2 emissions and investment decisions in the future. Some considerations regarding technologies have already been dealt with in previous paragraphs. Therefore, this section offers only a brief overview of potential technologies affecting demand-side trajectories. Technology investment is a function of rational economic behaviour and projected returns on capital investment. Accordingly, politically and economically determined circumstances will inform investment decisions and influence technology expectations of each energy market model.

Among the most prominent technological innovations is the use of CCS in power generation. Its effect on natural gas demand would be considerable, provided that economic parameters allow for its commercial deployment. Based on the assumption of a relatively low coal price (compared to gas price levels) and at least moderate CO_2 prices, CCS would, in fact, increase the competitiveness of coal vis-à-vis gas by offsetting structural advantages of natural gas such as low investment costs, lower carbon intensity and high operational flexibility.[57] Under certain circumstances, however, it is also conceivable that gas-fired power plants could be equipped with CCS. This, of course, requires relatively low gas prices, the technical breakthrough in CCS, coupled with a change in public acceptance of this technology. If all this were to be met, gas+CCS could possibly be cost-competitive with coal+CCS in power production, not least due to the fact that gas emits 50-60% less CO_2 per kWh produced than coal.[58] Moreover, it is worth noting, that in the long-term, CCS processes may also be integrated into industry processes for emission abatement purposes, in both ETS and non-ETS sectors. The EU expects CCS to be commercially available post-2020. Therefore, in both the IEA 2009 Baseline and 2010 Reference Scenarios, CCS is listed in the technology portfolio. The IEA estimates CCS to become a

57 International Energy Agency (2010). Projected Costs of Generating Electricity, 2010 edition, OECD/IEA 2010: Paris.

58 There would hence be less CO2 to be captured, transported and stored in the case of gas-fired power plants when compared to coal-fired plants.

crucial technology in its 450 Scenarios, but projects only limited market penetration in the Reference cases. The EIA does not elaborate on the prospects of CCS in the EU.

The prospects for the future share of RES in power generation and total final energy consumption depend on the policy assumptions underlying each scenario. Assuming a strong market penetration of RES, complementary fuels capable of flexibly responding to intermittent energy supply are required. As mentioned above, gas could excellently perform this task, although high and volatile gas prices may temper future investment in gas fired-plants and their use. At the same time, there are other ways of dealing with inconsistencies in the supply of RES. The expansion of large pumped hydropower plants or electricity storage facilities, for instance, may contribute to balancing out immediate shortages of RES supply and thus become alternative balancing technologies. On top of that, sophisticated forecasting technologies, demand response mechanisms as well as smart grids may help to cope with the variability of renewables in the coming years.[59]

Finally, the exploration of unconventional gas in Europe has raised hopes as to the potential contribution of these resources to EU domestic gas supplies. In fact, a commercially viable extraction of shale and tight gas inside the EU may - to a certain extent - change the structure of the European gas market. With reference to previous elaborations on the impact of gas prices on gas consumption, it is worth noting that additional gas supplies would reduce spot market prices for the commodity, thereby increasing its cross-sectoral competitiveness. However, bearing in mind that shale or tight gas deposits are located in lower geological formations and much harder to reach than conventional gas fields, much will depend on the availability of technologies able to exploit those resources on an economically viable basis and on the stringency of environmental legislation in member states. In this context, it is nevertheless worth mentioning that unconventional gas production outside the EU may trigger substantial shifts in the global availability of gas supplies. Additional gas supplies would imply the afore-mentioned price dampening effects and maintain or improve the cost-competitiveness of natural gas vis-a-vis other fuels.

Overall, it seems important to note that among all drivers of natural gas demand presented in this chapter, technological development is by far the most difficult to quantify and forecast. Moreover, it is assumed that the impact of this variable on gas demand is much lower than that of the previously mentioned variables.

Scenario assumptions

As far as the EU's scenarios are concerned, all three cases assume a strong role of renewable energy technologies. While the 2007 Baseline does not include CCS as an available technology over the projection period, the 2009 Baseline and 2010 Reference projections predict CCS to play a moderate role post-2020.

Except for the IEA 2009 and 2010 450 cases, all other IEA scenarios under consideration in this report expect CCS to only marginally impact Europe's energy system. Only the IEA 450 scenarios project a strong market penetration of this technology alongside increasing use of second generation biofuels.

As for the IEA 2010 projections, only a vague distinction in terms of technological assumptions was made, namely between a slow (Current Policies Scenario), intermediate (New Policies Scenario) and fast pace of technological innovation (450 Scenario).

59 IEA (2010). *WEO*, p. 327.

Concluding remarks

In sum, the previous elaborations have highlighted that certain factors significantly impact the demand for natural gas. Of the five driving or, respectively, dampening factors that have been identified above, one may distinguish GDP growth and fuel price developments as baring the strongest weight overall. This is specifically true for power generation and industry gas consumption. The other three items vary more markedly regarding their effect on sectoral gas demand.

While GDP growth structurally determines energy consumption relative to economic output, absolute and relative fuel prices decisively inform short-term dispatching of electricity by plant type and long-term investment decisions in generation capacity. Energy and climate policy decisions, on the other hand, have gained significant leverage in affecting cost structures, thereby influencing gas demand in power generation as well as in the industrial, residential and services sectors. Energy policy decisions exert a significant influence on the power sector, notably as regards the choice of generation technology and the overall fuel mix. As to the sectors covered by the EU ETS, the introduction and tightening of Europe's emissions trading scheme already has and will continue to trigger changes in energy consumption and technology choices. The residential and services sectors are predicted to experience less intrusive repercussions by climate policies, but are, in turn, more directly affected by energy efficiency and renewable energy policy measures. In addition, technology is an important factor regarding the future energy mix. However, much uncertainty remains as to which technologies will be commercially deployed by 2020 or 2030. If CCS is to become economically viable in the future, this will certainly redefine the use of individual fuels, particularly in the power sector.

Table 2: Factors influencing natural gas demand by sector[60]

	GDP growth	Fossil fuel prices	Energy Policy	Climate policy	Technology
Power generation	+++	+++	+++	++	++
Industry	+++	++	+	++	+
Residential/ Commercial	+	+	++	+	+

3.3 EU primary energy and gas demand scenarios to 2030

With a view to the previously presented driving factors of natural gas demand and the basic assumptions underlying each scenario, this section seeks to highlight and compare the main findings of the EU, IEA, EIA and Eurogas energy demand forecasts. A proper understanding of the data requires the reader to acknowledge that considerable uncertainties are associated with key energy market, macroeconomic and policy assumptions underlying the studies.

60 The symbol "+" only indicates the estimated strength of the effect, but does not per se imply an increase of gas demand.

Table 3: Overview of basic scenario assumptions

2030	GDP growth until 2030 p.a. in %	Oil Price $/bbl	Energy Policy	Climate Policy (CO_2 price in €/t)	Technology
EU Base 2007	2.2	62.8	Implemented until Dec '06	Implemented by Dec '06 (24)	Strong RES + CHP/ limited nuclear/ no CCS
EU Base 2009	1.95	106	Implemented until April '09 / nuclear recovery	Implemented by April '09 / (39)	Strong RES + efficiency/CCS
EU Ref 2010	1.95	106	Adopted until Dec '09 / Plus 20% RES 2020 / nuclear recovery	Implemented by April '09 + Adopted by Dec '09 / 20% GHG target (19)	Strong RES + efficiency/CO_2 abatement/CCS
IEA Ref 2008	1.8	122	Implemented until mid '08	See energy policy	Limited CCS post 2020
IEA Ref 2009	1.5	115	Implemented until mid '09	see energy policy (37)[63]	Limited CCS post-2020
IEA 450 2009	1.5	90	New policies consistent with climate goals	see energy policy (44)[64]	Strong CCS / strong biofuels
IEA New Pol 2010	1.6	110	Adopted until mid '10 / plus 20% RES in 2020 / nuclear recovery	25% GHG reductions to 2020 (33)[65]	Intermediate pace of tech development[66]
IEA Cur Pol 2010	1.6	130	Adopted until mid '10, no targets	see energy policy (27)[67]	Slow pace of tech development
IEA 450 2010	1.6	90	New policies consistent with climate goals	30% GHG reductions to 2020 (76)[68]	Fast pace of tech development

Projected EU primary energy demand to 2030

Comparing the pre- and post-crisis projections, Figure 6 clearly confirms the expected strong impact of economic growth rates on primary energy demand: The EU Baseline 2007 and IEA Reference 2008 cases, which have been compiled on the basis of pre-crisis data, estimate the EU's energy needs to increase steadily over the projection period, to about 2,000 and 1,900 Mtoe in 2030, respectively; the more recently published scenarios, on the other hand, indicate a stagnation or a slight decline of energy demand to around 1,807 to 1,781 Mtoe.

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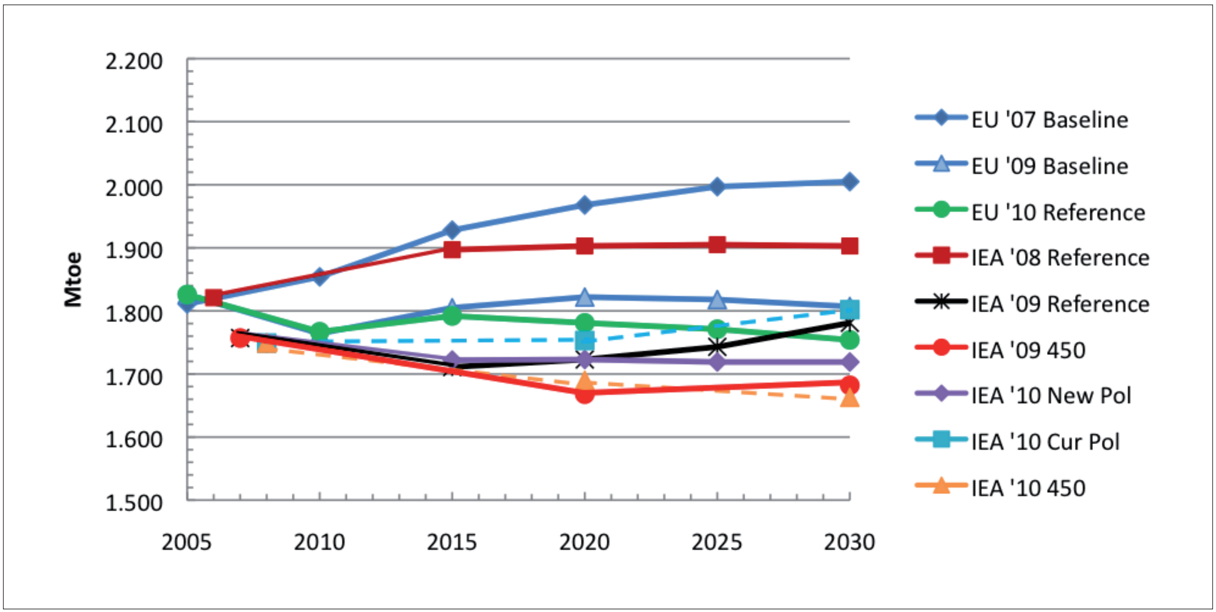
61 Converted from \$54/t CO_2 (2008 dollars) at an average exchange rate of 0.683.
62 Converted from \$65/t CO_2 (2008 dollars) at an average exchange rate of 0.683.
63 Converted from \$45/t CO_2 (2009 dollars) at an average exchange rate of 0.719.
64 This implies all currently available categories of technologies.
65 Converted from \$37/t CO_2 (2009 dollars) at an average exchange rate of 0.719.
66 Converted from \$105/t CO_2 (2009 dollars) at an average exchange rate of 0.719.

Figure 6: EU primary energy demand



Interestingly, the EU and IEA 2009 "business-as-usual" scenarios predict a similar level of demand for 2030, while displaying different trajectories. The EU Baseline Scenario forecasts energy demand to pick up slightly between 2010 and 2020 and to decline between 2020 and 2030. Meanwhile, the IEA 2009 Reference case projects primary energy demand to develop reversely. This may partially be explained by differences in economic parameters and fossil fuel price assumptions as well as by expectations relating to the market penetration of certain technologies.

The EU 2010 Reference Scenario (which makes the same macroeconomic assumptions as EU 2009 Baseline case, but features significantly stricter energy and climate policies) projects primary energy consumption to start falling from 2015 onwards, reaching a demand level that is 3% below that of the Baseline forecast in 2030 (1,750 Mtoe). A similar view is shared by the 2010 IEA Current and New Policies Scenarios. The former predicts demand to stagnate at approximately 1,750 Mtoe annually until 2020 and to marginally rise thereafter, to about 1,800 Mtoe in 2030. The IEA 2010 New Policies Scenario, on the other hand, forecasts energy demand to level out at 1,720 for the next two decades. In sum, the four examples of the EU and IEA 2009 and 2010 scenarios show that renewable energy and energy efficiency measures alongside binding GHG reduction targets, which are assumed to become relevant factors in the coming years, evoke a dampening effect on the EU's future primary energy demand.

The 2009 and 2010 IEA 450 Scenarios imply the most stringent climate policy assumptions of all scenarios under investigation and hence display the trajectory with the lowest energy demand levels until 2030. Both forecast a steady deterioration of demand until 2020, to a level of merely 1,670 to 1,690 Mtoe. While the 2009 Scenario subsequently expects demand to slightly pick up to roughly 1,680 Mtoe, the 2010 case assumes the downward trend to continue, with demand falling to 1,660 Mtoe by 2030. Both IEA 450 cases project a decline in EU total primary energy demand of more than 4% over the projection period.

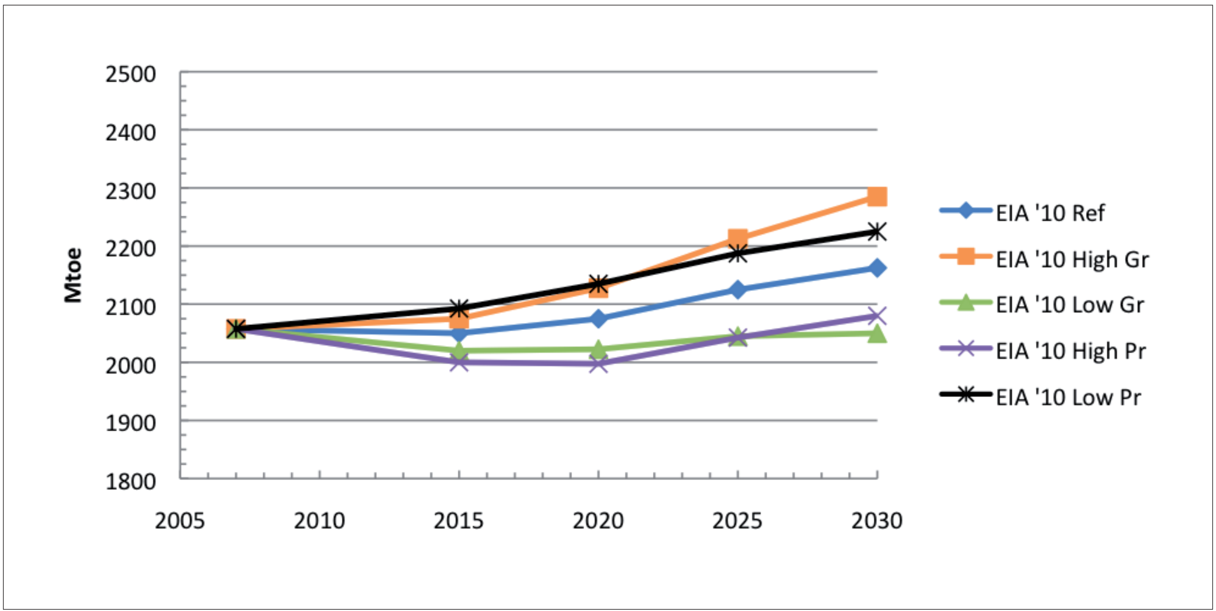
Overall, all of the most recent projections (regardless of individual model assumptions) suggest that EU primary energy demand will level out at around 1,700 to 1,800 Mtoe per year over the next two decades. Only the scenarios published prior to the economic recession expect these figures to be substantially higher.

Projected OECD Europe primary energy demand to 2030

As a result of the dissimilar geographical granulation of the EIA's International Energy Outlook 2010 (data refers to OECD Europe), their energy market forecasts cannot be compared alongside EU and IEA data. Nonetheless, the variation among the five EIA scenarios[67] further indicates to what extent macroeconomic and fuel price assumptions determine energy demand projections.

Figure 7 suggests that economic growth has a visible impact on primary energy consumption, with demand rising steadily in all scenarios except for the High Oil Price and Low Growth cases. This is supported by the fact that the High Growth Scenario implies the strongest surge in demand over the projection period, whereas low economic growth seems to curb demand.

Figure 7: OECD Europe primary energy demand



In sum, the EIA projects absolute levels of OECD Europe's primary energy demand to range between 2,000 and 2,100 Mtoe in 2020. In the second half of the projection period, all EIA trajectories suggest an upward trend, with consumption rising to nearly 2,300 Mtoe in the High Growth Scenario.

Similar to the EIA, the IEA[68] conducted a sensitivity analysis to test the impact of varying GDP growth rates and fossil fuel prices on world primary energy demand. In line with the EIA 2010 forecasts, the findings indicate that economic growth does indeed affect energy consumption more significantly than fluctuating fuel prices.

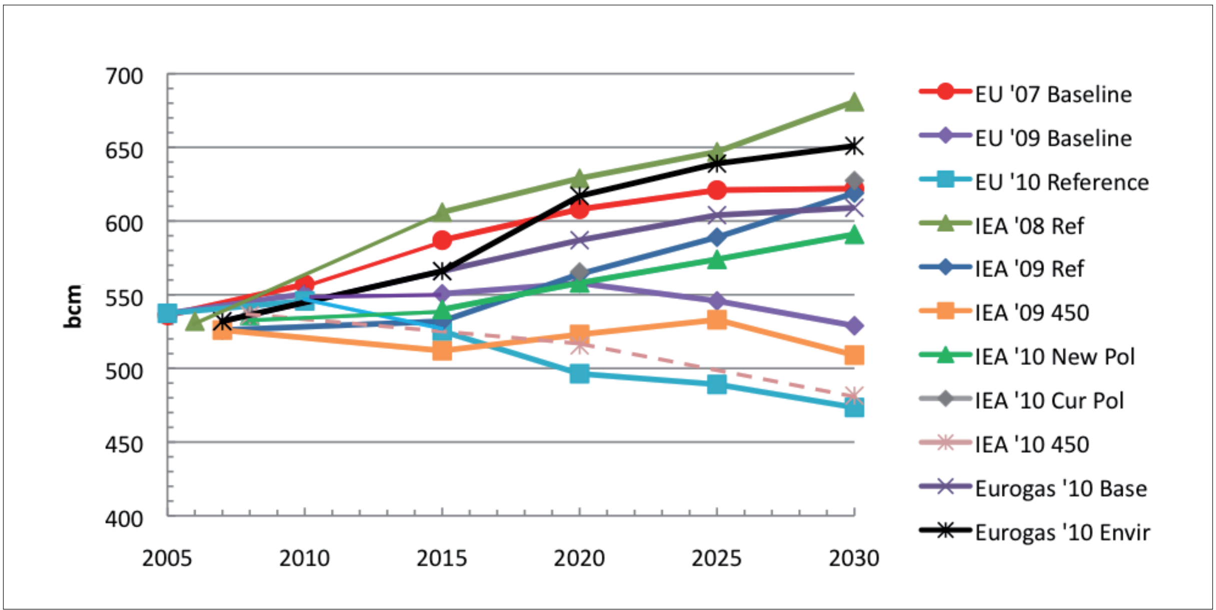
Projected EU primary natural gas demand to 2030

Figure 8 displays natural gas demand forecasts up to the year 2030 provided by the EU, IEA and Eurogas. What the graph illustrates is, that the projected demand curves essentially form two groups, pointing

67 Reference case, high and low Growth scenarios, high and low Oil Price scenarios.
68 IEA (2009). WEO, p. 659-663.

in opposite directions. A number of forecasts, some of which draw on pre-crisis data, indicate a steady or swift increase in gas consumption, notably from 2015 onwards. On the other hand, a second group of trajectories, particularly those that imply ambitious RES and climate policies, expect natural gas demand in Europe to dwindle markedly, albeit to varying extents.

Figure 8: EU primary natural gas demand



The EU 2007 Baseline and IEA 2008 Reference cases rank among the most optimistic outlooks, projecting gas demand to rise significantly, to as much as 620 and 680 bcm[69] in 2030, respectively. It is important to note that these scenarios are based on fairly optimistic macroeconomic estimates and do not take into account the impact of the recent economic crisis. Similar optimism as to future EU gas demand is reflected in the Eurogas 2010 Scenarios, both of which predict fairly high levels of gas demand for 2030. More specifically, the Eurogas 2010 Base Case follows a moderate upward trajectory, which flattens towards the end of the projection period, reaching slightly more than 600 bcm by 2030. The Environmental case, on the other hand, projects natural gas consumption to rise by astonishing 22% over the next 20 years, with the sharpest growth of 9% set to occur between 2015 and 2020. In total, this amounts to demand levels of 650 bcm by 2030.

Meanwhile, the fairly steep and linear increase of gas demand after 2015 forecast by the IEA 2009 Reference Scenario seems puzzling. As illustrated in Tables 1 and 3, the price, policy and economic assumptions underlying the IEA scenario are fairly moderate and prudent compared to the EU 2009 Baseline Scenario. Nevertheless, the IEA's Reference Scenario projects gas demand to reach a level of 620 bcm in 2030, which is roughly 15% (90 bcm) higher than the EU 2009 Baseline estimate of 530 bcm for the same year. The main reason for this vast gap between the two scenarios are inconsistent technology expectations. In the 2009 Reference case, the IEA casts doubt as to the quick and large-scale commercialization of low-carbon technologies in the EU, particularly in power generation. This has strong repercussions on projected gas use in the power sector, which is perceived as the "single largest driver of gas demand"[70]. By contrast, the EU 2009 Baseline - to the detriment of natural gas

69 The IEA converts Mtoe to bcm at factor 1.21; IEP conversion of EU and other data from Mtoe in bcm at factor 1.205.
70 IEA (2009). *WEO*, p. 365.

- assumes a strong presence of low-carbon technologies such as RES and CCS as well as a recovery of nuclear energy in the EU generation mix by 2030. As the IEA and EU scenario assumptions vary markedly only in terms of technological parameters, the degree of market penetration of low or zero-carbon technologies seem to critically affect natural gas demand in the EU.

The EU 2010 Reference case provides the lowest natural gas demand trajectory of all scenarios contained in this report. EU gas consumption was forecasted to increase slightly until 2010, but to plunge continuously between 2010 and 2030, by roughly 14%. In absolute terms, this corresponds to a decline of 70 bcm over the respective period, pushing the gas demand projected for 2030 down to 470 bcm. Interestingly, the sharpest demand cut, of 5%, is expected to occur in the period from 2015 to 2020. This may be due to the expectation that in the respective time period gas demand will suffer from additional efforts undertaken by the EU to meet its "20-20-20 to 2020" objectives. From 2020 onwards, the negative trend is forecast to become less marked.

The recent WEO 2010 did not differ much from the WEO 2009 in terms of the general prospects for EU gas demand, but it comprised two new types of scenarios, the Current Policies Scenario and the New Policies Scenario. The former, which assumes gas demand to climb to 630 bcm by 2030, resembles a "business-as-usual" scenario similar to the IEA 2009 Reference case. The New Policies Scenario, on the other hand, features more ambitious policy assumptions and thus predicts a slightly lower curve. In absolute terms, it projects demand to stagnate at 540 bcm until 2015 and to moderately augment thereafter, to 590 bcm by 2030. What is striking, however, is the IEA 2010 450 Scenario, as it implies a further reduction of natural gas consumption of 30 bcm compared to the IEA 2009 450 Scenario. Whereas a slight recovery of gas demand between 2015 and 2020 was forecasted in the 2009 trajectory, the 2010 case predicts a constant decline in gas demand over the entire projection period, to around 480 bcm in 2030.

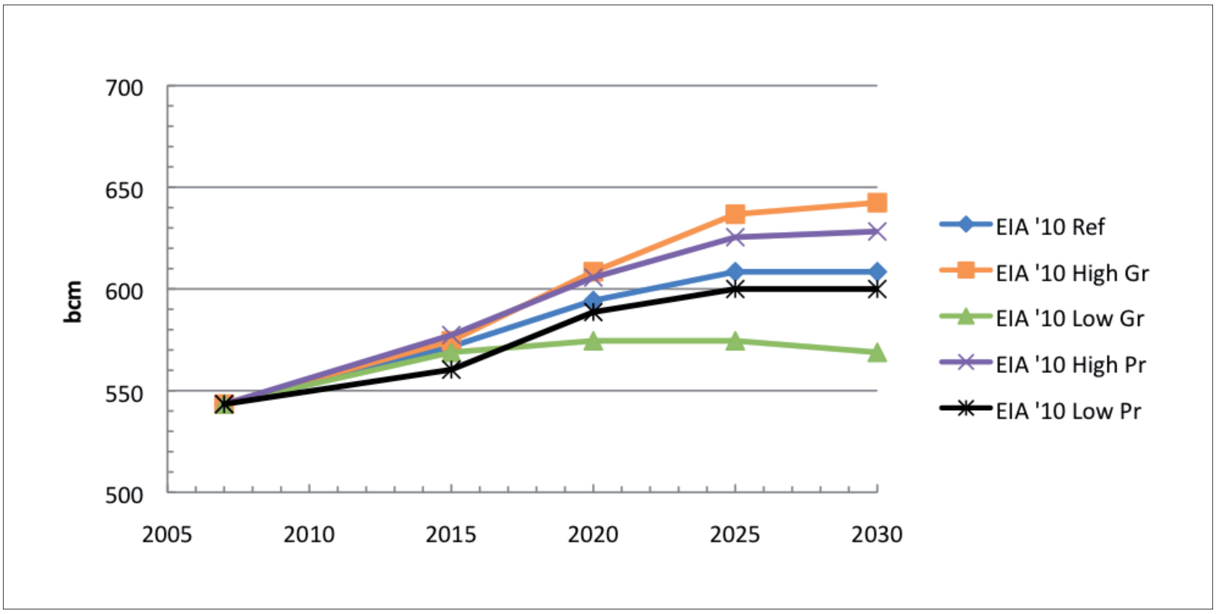
Overall, the presented natural gas demand projections suggest a likely level of consumption ranging between 470 and 650 bcm in 2030[71]. It is important to emphasize that from 2020 onwards the projections point in essentially two directions: either to a 2030 consumption level of 590 bcm and above; or to one of less than 530 bcm. In line with the theoretical assumptions stated above, economic growth, market deployment of low-carbon technologies as well as energy and climate policy action will become key factors determining the EU's future natural gas demand. Moreover, the presented scenarios suggest that high shares of renewable energy and nuclear power in the European energy mix, alongside high CO_2 prices, will cause tremendous cuts in gas demand across sectors, but most significantly in the power sector.

Projected OECD Europe natural gas demand

As illustrated in Figure 9, the EIA 2010 projects OECD natural gas demand in all cases to rise. Since the pace of demand growth varies considerably, the EIA's figures for gas demand in 2030 to range between 570 and 649 bcm. Aside from absolute figures, which are hardly comparable to those shown for the EU-27, the EIA trajectories further affirm the theoretical assumptions stipulated in chapter 3.2. They also display a very close interdependence of economic growth and gas demand. Accordingly, the High Growth case displays the steepest of all EIA trajectories, with demand projected to amount to 643 bcm in 2030. The Low Growth scenario, on the other hand, presents by far the lowest demand curve.

71 This excludes the IEA 2008 Reference Scenario estimates.

Figure 9: OECD Europe natural gas demand



While the EIA Reference case again ranks third among the five trajectories, the High Oil Price Scenario shows a rather surprising curve shape. Contrary to the EU, the EIA (2010) in fact expects high oil prices to trigger natural gas demand rather than to dampen it. Paradoxically, this is based on the assumption that higher oil prices would reduce demand for liquid fossil fuels to the benefit of other resources such as coal, natural gas and renewable energies. However, bearing in mind that gas today hardly competes with oil in Europe, it remains disputable to what extent and in which sectors gas can actually substitute oil in the event of (consistently) high oil prices.

Overall, the EIA 2010 scenarios estimate OECD Europe's natural gas demand to evolve in a fairly similar way until 2020, to between 570 and 610 bcm. By contrast, in the second half of the projection period trajectories are slightly more dispersed, covering an array of 570 to 640 bcm in 2030.

Concluding remarks

What we have learned by looking at the demand side may be synthesized in essentially three findings: First, there remains ambiguity regarding EU gas demand between 2010 and 2030. Particularly those scenarios assuming optimistic economic growth, limited progress with regards to the deployment of low-carbon technologies and relatively loose climate policies, forecast EU gas demand to grow consistently over the next two decades, to around 590 - 650 bcm in 2030. On the other hand, those scenarios featuring ambitious RES policies, a recovery of nuclear energy, and relatively high CO_2 and oil prices predict gas demand to take an adverse path, namely a decline to 530 - 470 bcm per year by 2030. Overall, existing forecasts predict gas demand to range between 470 and more than 650 bcm in 2030. Simply put, the uncertainty associated with the future evolution of EU gas demand amounts to as much as 180 bcm. In spite of the unclear picture concerning the EU's future natural gas demand, demand growth in Asia will turn out to become an important factor. GDP growth and climate policy in Asia, and China in particular, will have significant consequences regarding the availability of gas, also for European gas markets.

4 Natural gas supply forecasts

Complementary to the in-depth analysis of the EU´s current and projected natural gas demand, this chapter will offer perspectives on the future gas production inside and outside the EU. By gathering statistical information from a wide range of sources, a broad view on the supply potential of individual countries and regions is generated.

To begin with, this chapter will examine to what extent EU gas demand will be covered by domestic production throughout the projection period and, on this basis, highlight the bloc’s future gas import requirements. In the second part of this chapter, the analysis devotes attention to different regions and countries in the EU’s neighbourhood with regard to their future gas supply potential. In so doing, this chapter will not only cover data on proven natural gas reserves, potential resources and likely production capacities of external suppliers on a regional and country-specific basis; it will also take account of existing infrastructure, as well as planned additional pipeline links and LNG facilities that may contribute to meeting the EU’s natural gas import needs until 2030. In addition, issues related to political stability, economic viability and reliability of supply will - to a certain extent - be considered in the analysis in order to highlight certain prioritized producer regions and transport corridors.

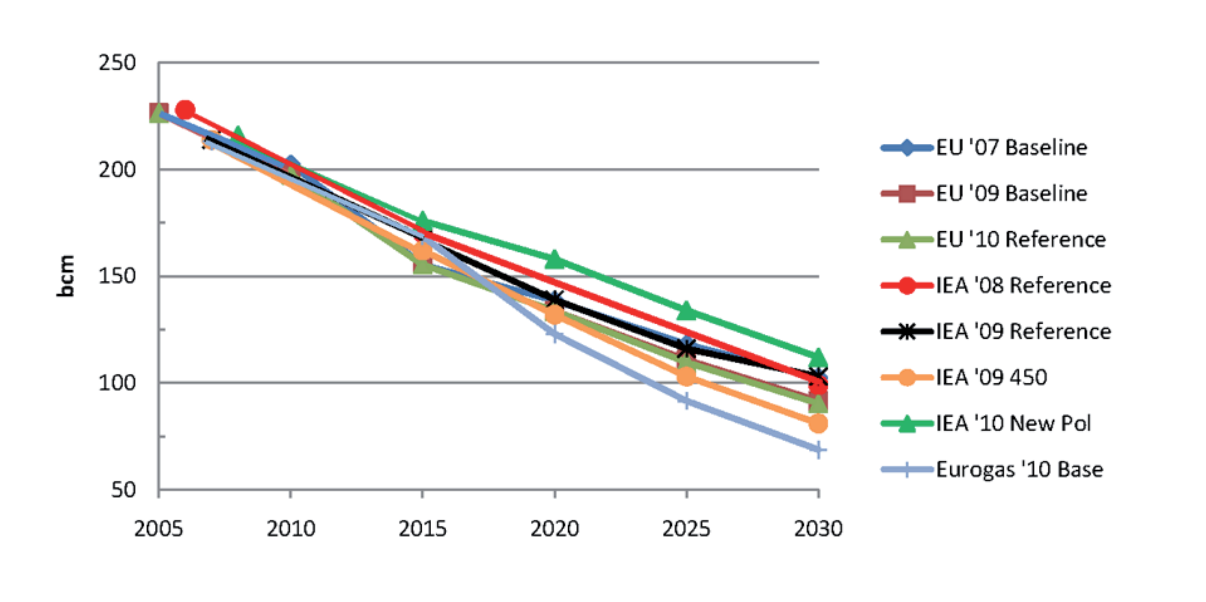
4.1 EU natural gas production and import requirements

Projected domestic gas production in the EU

After having analyzed the EU’s future natural gas demand, it is critical to take into account domestic production as an indicator for potential import needs. Therefore, this section will briefly outline the likely evolution of natural gas supply originating from the EU itself. Subsequently, forecasts of EU gas import requirements up to the year 2030 will be subject to analysis.

As illustrated in Figure 10, the EU’s production of natural gas is on a steady decline path. Resources are depleting and this trend is not expected to be offset by increasing recovery rates at existing fields or new conventional and unconventional gas discoveries. EU gas production is hence projected to be

Figure 10: EU natural gas production



roughly 60% lower in 2030 compared to its peak in 2001[72]. While Norway[73], as an OECD European supplier, is expected to expand its natural gas production from 92 bcm in 2007 to 129 bcm in 2025[74], this will not suffice to balance out the considerable cuts in production in the Netherlands and United Kingdom (UK), the EU's two major internal gas suppliers. Additional gas supplies from outside the EU will therefore become crucial for the EU's security of gas supply in the mid to long term. According to the IEA 2009 Reference scenario, current Dutch and British gas production of 102 and 74 bcm will plummet steadily, by rates of -2.5% p.a. and -6% p. a., respectively, until 2030. By the end of the projection period, net production of the two countries will amount to only 43 and 19 bcm, or, as IHS CERA[75] predicts, to as little as 18 bcm in the Netherlands and 15bcm in the UK.

However, the decline in EU conventional gas production may, at least temporarily, be compensated for by hitherto untouched resources of unconventional gas. The IEA estimates that Europe's total resources of unconventional gas amount to 35[76] tcm, of which 45% are shale gas, 33% tight gas and 22% coalbed methane.[77] Shale gas is expected to be found in seven EU member states, namely Germany, Poland, Sweden, France, Austria, Hungary and the UK.

The development of this new source of energy is still at an early stage. Whether or not unconventional gas will play a significant role in the EU's future domestic energy production depends on factors such as geology, access, environmental concerns, public acceptance, availability of the necessary technology, and economic profitability.[78] To this date, each of these factors requires further investigation. The Commission's Directorate-General for Energy has therefore stated that "it may take several years before sufficient data is available to draw conclusions on the proportion of the resources that can be turned into usable reserves"[79].

The current state of knowledge suggests that the production of unconventional gas will be less successful in Europe than it has been in North America. Not only are Europe's resources about seven times smaller than those of North America; there is also a significant lack of knowledge concerning the geology of unconventional gas at this stage. Moreover, access to resources is assumed to be more problematic in Europe as population density is high and environmental concerns carry more weight.[80]

Bearing these factors in mind, the Cambridge Energy Research Associates (CERA) predict that Europe's production of unconventional gas will reach no more than 10 to 15 bcm per year from 2020 onwards[81]; similarly, the IEA expects production to attain a level of 15 bcm per year by 2030[82]. Compared to the EU's future natural gas demand, the expected yield from indigenous unconventional gas resources is marginal. As mentioned above, natural gas demand trajectories suggest a likely level of consumption between 470 and 650 bcm in 2030. In the short- to mid-term, the exploitation of unconventional gas

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72 European Commission (2008). *EU energy and transport. Trends to 2030 - update 2007*.
73 Norway is no EU member, but its second largest supplier of natural gas.
74 IEA 2009 Reference Scenario projects Norway's natural gas production to peak at 129 bcm in 2025 and fall slightly thereafter.
75 IHS CERA (2010). *Long-term supply and demand Outlooks to 2035*, October 2010.
76 IEA (2009). *WEO*.
77 European Commission (2010). *Quarterly Report on European Gas Markets*. Market Observatory for Energy. Volume 2, issue 4: October 2009 - December 2009, p.21.
78 Korn, A. (2010). *Prospects for unconventional gas in Europe*. E.on presentation, February 5th 2010, p. 9.
79 European Commission (2010). *Quarterly Report on European Gas Markets*. Market Observatory for Energy. Volume 2, issue 4: October 2009 - December 2009, p. 21.
80 Korn, A. (2010). *Prospects for unconventional gas in Europe*, p. 12.
To illustrate the issue of environmental concerns, it seems important to note that in the US, the technology of hydraulic fracturing has been exempted from the "Safe Drinking Water Act", meaning that it is no longer under supervision of the US Environmental Protection Agency. In the EU, on the other hand, strict environmental regulations apply and are not expected to become subject relaxation in the future (Behrens, A. (2010). *Europas Gasmärkte im Wandel: Welche Rolle spielt unkonventionelles Gas?* In: Energiewirtschaftliche Tagesfragen, 11/2010, p. 11).
81 See Korn, A. (2010). *Prospects for unconventional gas in Europe*, p. 11.
82 IEA (2009). *WEO*.

resources will thus hardly help to reduce the EU's import needs.

As reliable data on the future exploitation of unconventional gas resources in the EU are yet to be delivered, the production trajectories presented in Figure 10 only take into account conventional gas reserves. In contrast to demand projections, the scenarios under investigation predict fairly identical production trajectories. As illustrated below, the scenarios, starting at a level of approximately 200 bcm in 2010, mostly display a sharp and linear decline of EU domestic gas production, expected to bottom out at 80 to 100 bcm in 2030. This corresponds to a rate of decline of as much as 50% over the next two decades. The Eurogas 2010 Base Case estimates production to contract even more severely, reaching only 70 bcm in 2030.

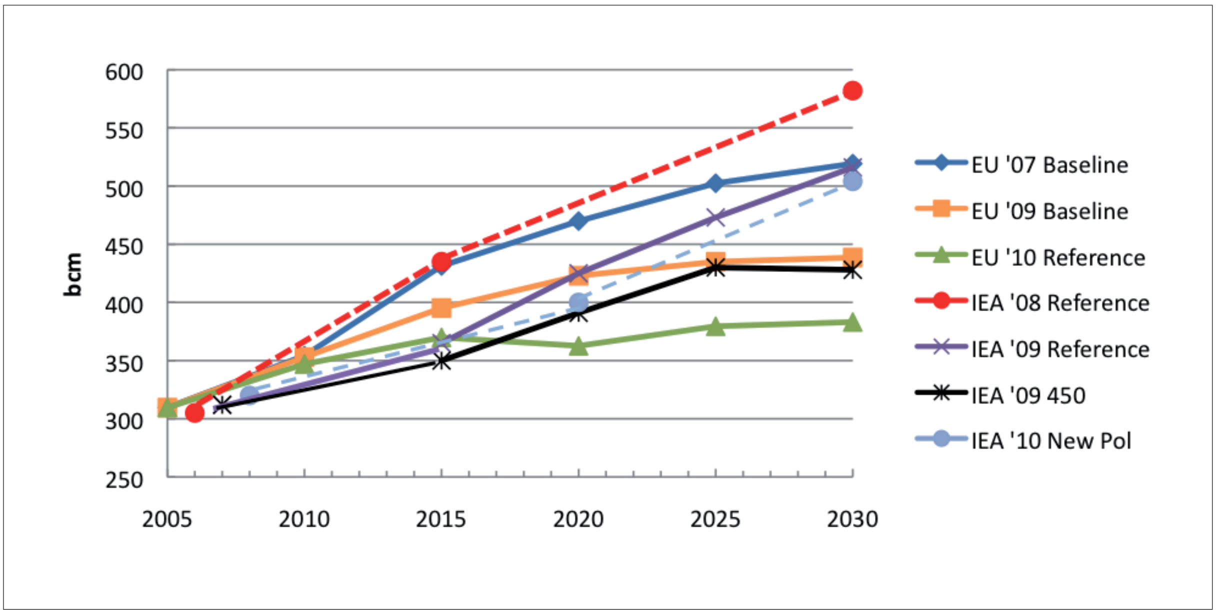
Projected EU natural gas import requirements

The described deterioration of EU gas production will pose immense risks to Europe's gas supply security in the future. Particularly towards the end of the projection period, with internal production contributing less than one quarter to meeting the EU's projected total demand, massive volumes of natural gas imports will be required. A closer look at import forecasts shall clarify to what extent additional gas needs to be procured by the EU in the mid to long term.

Given a projected natural gas demand of 470 to 650 bcm in 2030 and a projected domestic gas production of less than 100 bcm in 2030, increasing amounts of gas will need to be imported from third countries. Figure 11 provides an overview of possible EU import scenarios up to the year 2030.

All trajectories displayed below suggest that the EU's gas imports will rise continuously until 2030. As imports are a function of the respective EU primary gas demand and production, these forecasts are not surprising at all. With production set to bottom out at around 100 bcm or less in 2030, and a gas demand of at least 470 bcm, additional gas imports of 20 bcm or more compared to 2009 net import levels (approx. 350 bcm) will be required in 2030. Alternatively, assuming high gas demand growth in the coming years, supplementary imports of more than 170 bcm per year may be necessary to meet the EU's needs at the end of the projection period. Therefore, a more thorough comparison of import scenarios is deemed necessary.

Figure 11: EU net natural gas imports



The IEA 2008 Reference Scenario projects the steepest increase in natural gas imports over the projection period, reaching volumes of 580 bcm in 2030. This case reflects the most extreme evolution of domestic demand relative to production as it projects an annual consumption of around 650 bcm in 2030 and a collapse of domestic production to 70 - 80 bcm/y. Similarly, the EU 2007 Baseline curve forecasts a rapid average import growth of 3.9% p.a. between 2005 and 2015. In contrast to the IEA 2008 Reference case, however, it expects growth to slow down to 1.4% p.a. thereafter and for the rest of the projection period, with estimated imports of 520 bcm in 2030. In sum, the trajectories would require around 90% or 70% of additional gas imports by 2030 compared to 2005, respectively.

Although pre-crisis forecasts generally differ markedly from more recent forecasts, the IEA 2009 Reference Scenario predicts a level of natural gas imports to the EU in 2030 that is almost identical to the EU 2007 Baseline case. Contrary to the latter, it takes into account the dampening effect of the economic crisis and therefore projects only limited import growth until 2015. Subsequently, this situation is expected to change, with gas imports set to pick up sharply to 516 bcm in 2030. Similarly, the IEA 2010 New Policy Scenario expects gas imports to rise only moderately in the near term, but to rise swiftly from 2020 onwards, reaching import volumes of above 500 bcm by 2030.

The three residual scenarios (EU 2009 Baseline, IEA 2009 450, EU 2010 Reference) display the most moderate of all import projections. Although based on dissimilar model assumptions, each of these cases generally estimates gas to play a subordinate role in the EU's future energy mix. Comparing present[83] and projected import levels, the EU 2009 Baseline and the IEA 2009 450 Scenario forecast a rise in gas imports of as much as 40%, and the EU 2010 Reference Scenario of about 25% until 2030. This illustrates that, regardless of the exact development of EU gas demand, natural gas imports are likely to surge by rates of 25% to 90% over the upcoming two decades.

Concluding remarks

To sum up, these figures reveal an unambiguous trend for EU gas production to decrease by more than 50% or, in absolute terms, from 200 bcm today to less than 100 bcm at the end of the projection period. As this negative trend is due to the depletion of gas fields in Europe, EU import needs will inevitably augment. Meanwhile, the evolution of domestic gas demand will determine the pace of gas import growth. In absolute terms, EU and IEA scenarios[84] forecast import requirements to increase markedly, to levels of 370 to 580 bcm by 2030. As a result, the EU's gas import dependence is likely to reach more than 80%. Overall, estimates reveal that, even in the event of a sharp decline in gas demand across the EU, its imports will continue to rise. In order to meet these requirements by sufficient external supplies, producing countries need clear political commitments by the EU and individual member states concerning the future gas consumption. If this fails to appear, investments in projects able to supply the EU with gas will potentially struggle to go forward.

83 Referring to 2005, 2007 and 2005 levels, respectively.

84 The IEA 2008 Reference Scenario, which draws on pre-crisis data, should be considered with due care.

4.2 The global distribution of resources and proven reserves

In the light of rising import requirements, the question is which countries will be able to supply the EU with sufficient amounts of natural gas throughout the projection period. As a first approach to this question, Table 5 displays evidence as to the likely long-term gas supply potential of individual regions in the world. Data on global proven reserves suggests a distinction of essentially two types of regions: firstly, those endowed with the bulk of proven recoverable deposits of natural gas, namely the Middle Eastern countries and Russia; and secondly, regions accounting for medium-sized or relatively small volumes of gas reserves, such as Eastern Europe and large parts of Eurasia, the Asia-Pacific region, Africa, North America, Latin America as well as OECD Europe. It is interesting to note that IEA, BP and EIA use slightly different regional granulations in their studies, so that direct comparisons, notably for ultimately recoverable resources, are complicated. However, where regional definitions match, the resource and reserve estimates compiled by the three organizations are rather consistent, suggesting fairly reliable data.

Table 5: Global proved reserves and recoverable resources of natural gas

	Proved reserves (tcm)				Ultimately recoverable resources (tcm)	
Regions[87]	end-2007 IEA ’08	end-2008 IEA ‘09	end-2008 BP	end-2009 BP	end-2007 IEA ‘08	end-2008 IEA ‘09
Middle East	73.2	75.2	75.8	76.2	134.8	134.8
E. Europe/Eurasia	n.a.	54.9	n.a.	n.a.	n.a.	151.8
Former Soviet Union	53.8	n.a.	n.a.	n.a.	132.2	n.a.
Russia	n.a.	n.a.	43.3	44.4	n.a.	n.a.
Asia-Pacific	15.2	15.2	16	16.2	29.9	33.9
Africa	14.6	14.7	14.7	14.8	33.9	29.9
North America	8	9.5	9.2	9.2	62.5	68.8
Latin America	7.7	7.5	7.3	8.1	24.5	24.5
OECD Europe	6.2	5.4	n.a.	n.a.	25.5	27

Sources: Author´s illustration based on IEA 2008, 2009; BP 2009, 2010 and EIA 2009 ; available data on proven reserves does not cover unconventional gas reserves.

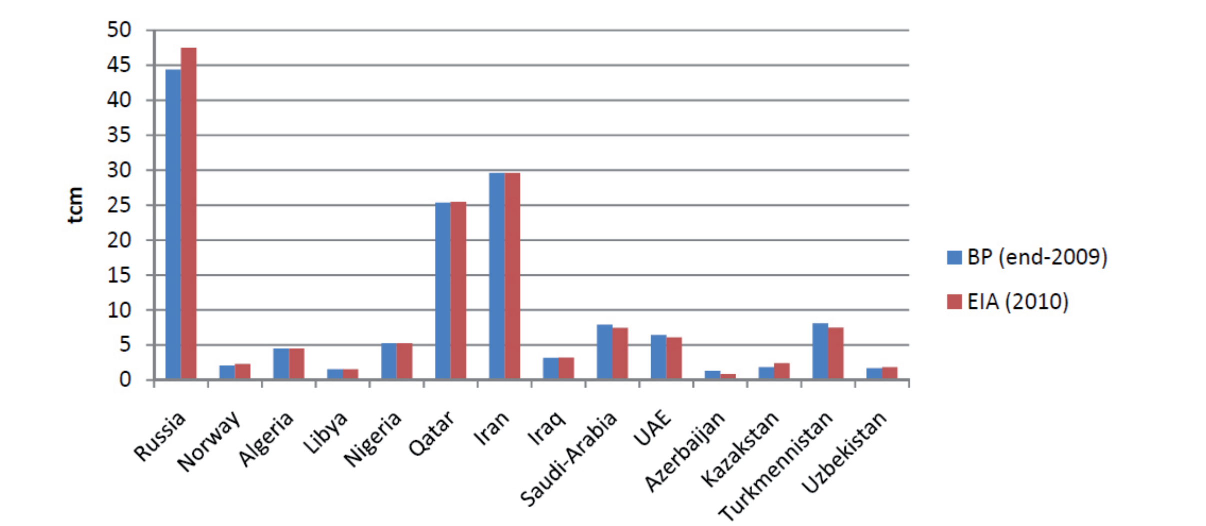
As some of the regions displayed above are far too distant to serve as EU suppliers, the following supply-side analysis will focus only on the bloc’s major current and potential future external gas suppliers. In doing so, it seeks to extract information on three aspects from historical data and projections: proven natural gas reserves, present and projected production and export capacity as well as available and planned transport infrastructure. Proven natural gas reserves will be discussed in the following.

Statistics[86] reveal that the EU’s major gas supplier, Russia, possesses the largest proved natural gas reserves in the world, some 44 to 48 tcm in 2009. Iran and Qatar rank second and third in this list, accounting for 28 to 30 and 25 tcm, respectively. By comparison, Norway, the EU’s second largest natural gas supplier, held reserves of slightly more than 2 tcm in 2009.

85 For definitions of regional and country grouping see *WEO* 2010, p. 708 ff.
86 The subsequent elaborations refer to data obtained from BP Statistical Review of World Energy 2010 and EIA International Energy Statistics database. The EIA database is available online at: http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm (last accessed: 07.02.2011).

Northern Africa is another crucial supply region for Europe. Particularly Algeria, which controls considerable amounts of natural gas reserves, equivalent to 4.5 tcm, and its neighbours Egypt and Libya, with roughly 1.7 and 1.5 tcm, respectively, substantially add to the resource-richness of the region. Nigeria, as a relatively remote African supplier, is estimated to control reserves of 5 to 5.5 tcm.

Figure 12: Proven natural gas reserves of current and potential future EU suppliers



Sources: Author's illustration based on BP 2010 Statistical Review of World Energy and EIA International Energy Statistics.

Besides this, Figure 12 highlights the fact that certain other countries, notably in the Caspian and Central Asian, but also in the Middle East, may become relevant natural gas suppliers to the EU in the near future. Certainly most striking are the estimated recoverable volumes of natural gas in Iran. For political reasons, however, it is rather unlikely that Iranian gas will be an option for the EU in the foreseeable future. Similarly, the chances of Iraqi pipeline gas being delivered to Europe is fairly small, at least in the short-term.[87] Qatar, in contrast, is already an important LNG supplier to the EU. In 2009, the UK (5.7 bcm), Belgium (5.6 bcm) and Spain (4.6 bcm) imported significant amounts of Qatari LNG[88]. Given its vast reserves of natural gas (25 tcm), one may speculate as to the possibility of enhanced natural gas imports in the future. Also, the littoral states of the Caspian Basin - particularly Azerbaijan, Kazakhstan and Turkmenistan - bear a considerable potential with a view to securing Europe's future gas supplies. While Azerbaijan and Kazakhstan hold proven reserves of 0.85 to 1.3 tcm and 1.8 to 2.4 tcm, respectively, Turkmenistan exceeds these volumes by far, with estimated reserves of 7.5 to 8.1 tcm.

While Europe's natural gas reserves are diminishing, the continent is surrounded by countries that are, in quantitative terms, capable of meeting its future gas import needs. Whether these supply potentials will be accessible for the EU in the near future will depend on the establishment of sufficient production capacities and transport infrastructure. For now, one may note that the well-established exporters of natural gas to the EU hold substantial, albeit strongly varying, shares of global proven gas reserves. As previously stated, Russia ranks first in terms of proven gas reserves in the world; Norway and Algeria, on the other hand, feature considerably smaller deposits. Bearing in mind the need to secure and diversify Europe's external energy supply, it is these individual countries' potential to create (additional) export capacities and infrastructural links in the coming years that will determine their attractiveness for closer energy relations with the EU.

87 Euractiv (2010). *Turkey brokers key gas supply deals for Nabucco*. Available online at: http://www.euractiv.com/en/energy/turkey-brokers-key-gas-supply-deals-nabucco-news-494988 (last accessed: 03.02.2011).

88 European Commission (2010). *Country file Qatar*, Market Observatory for Energy, May 2010.

Before tackling this issue, however, another geographically proximate source of natural gas, namely the Arctic, needs to be examined. Although less salient in public debates than the recent discoveries of unconventional gas in Europe, the huge resources assumed to be found in the high north may become an attractive alternative to traditional European gas supplies. Yet, this depends on the volumes of actually recoverable reserves and on practical issues regarding the cost of exploitation and the delivery of Arctic gas to European markets.

Arctic Natural Gas Potential

The Arctic, defined as the Northern hemisphere region located north of the Arctic Circle, is a region that is difficult to assess as far as natural gas resources are concerned. It is nevertheless increasingly seen as a valuable option for development, as exploration opportunities in other regions are declining and technological means improve.[89] The exploration of Arctic onshore areas is already underway and, by 2007, fields containing 32.2 tcm of natural gas had been developed. The Arctic continental shelves, on the other hand, have not yet been explored extensively, but, at least potentially, they constitute one of the world's largest areas for the future production of natural gas.[90]

In order to assess the Arctic's oil and gas resource potential, the U.S. Geological Survey (USGS) compiled a geologically based, probability study of the region entitled 'Circum-Arctic Resource Appraisal' (CARA). Employing a new map that differentiates between the sedimentary composition of individual areas, the Arctic was subdivided into 69 Assessment Units, 48 of which were quantitatively investigated. The USGS found that roughly 30% of the world's undiscovered gas may be located north of the Arctic Circle. More specifically, it states that there is a 95% chance that more than 21.8 tcm of natural gas can be found in this region, a 50% chance of there being more than 43.8 tcm, and a 5% chance that natural gas in the Arctic amounts to 84.6 tcm.[91] "Arctic Mean Estimated Undiscovered Technically Recoverable, Conventional Natural Gas Resources" according to the USGS amount to 47.2 tcm.[92] To compare: the world's annual gas consumption currently stands at 3.1 tcm.

The bulk of undiscovered gas resources - an estimated 23.3 tcm out of the total 47.2 tcm - are assumed to be located in Russia. The offshore part of the northern West Siberian Basin alone accounts for almost 39% of the Arctic's undiscovered gas resources, according to USGS estimates. Norway - another important supplier to the EU with access to Arctic resources - is assumed to hold a comparatively small contingent of 1.7 tcm. However, a considerable amount of 9.5 tcm is expected to be found in the Eurasia Basin and the East Barents Basin, which are partly attributed to Russia and partly to Norway.[93]

As far as the political framework for the exploration and extraction of Arctic gas is concerned, it is crucial to mention that the long-lasting dispute between Russia and Norway over the border-delineation in the potentially resource-rich Barents Sea has finally been settled in September 2010. An Arctic border agreement now allows for the region to be opened up to offshore exploration and it might enable Norway to use newly accessible resources as a compensation for declining reserves in the Norwegian Sea. Russia, on the other hand, is lacking the technology required to develop offshore gas fields and might be interested in cooperating with Norway and other foreign partners in this matter.

89 Gautier, D. L.; Klett, T. R. (2010). *U.S. Geological Survey - Oil and Gas Resource. Assessment of the Russian Arctic*. Final Report, July 2010, p. 4.

90 Gautier, D. L. et al. (2009). *Assessment of undiscovered oil and gas in the Arctic*. In: Science, Volume 324, p. 1175/1176.

91 Gautier et al. (2009). *Assessment of undiscovered oil and gas in the Arctic*, p. 1178.

92 Bird, K. J. et al. (2008). *Circum-Arctic resource appraisal: estimates of undiscovered oil and gas north of the Arctic Circle*. USGS Factsheet 2008-3049, p. 4.

93 Bird et al. (2008). *Circum-Arctic resource appraisal*, p. 4; Gautier et al. (2009). A*ssessment of undiscovered oil and gas in the Arctic*, p. 1178.

The Arctic certainly has the potential of becoming a significant source of natural gas, notably for continental Europe. However, current estimates of the amount of Arctic natural gas resources are subject to great uncertainty. Moreover, the extent to which the estimated undiscovered resources will in fact be exploitable depends, first and foremost, on technological and economic factors. Relieving the Arctic's gas resources is expected to be both difficult and expensive. Against this background, Norway's prime minister has stated just recently that "it would take years before the region is opened up for oil and gas activities"[94]. Accordingly, Arctic gas is unlikely to make a noteworthy contribution to the EU's gas supply before 2030.

The previous elaborations have illustrated the resource potential of individual countries and regions. In addition to offering promising data on the EU's traditional suppliers Russia, Norway, Algeria, the analysis has highlighted other regions such as the Caspian Basin, Central Asia and the Middle East as being potentially relevant for securing Europe's external gas supplies in the future. Whether and to what extent individual gas suppliers will in fact be able to deliver natural gas to Europe in the medium to long-term, will be the subject of analysis in the subsequent section.

4.3 Production and export capacity forecasts for selected countries and regions

In order to gain insight into how much natural gas will actually be available for exports to the EU, the following section will compare and interpret different production capacity scenarios for potential suppliers up to the year 2030 and examine their exsiting and planned gas transport infrastructure facilities. The analysis will be complemented by considerations on the economic viability and technical feasibility of infrastructure projects as well as on the risks of political instability.

4.3.1 Russia, Norway and the Arctic

Russia

Russia has been a reliable energy supplier to Western Europe for more than three decades. Certainly, the regular occurrence of political disputes between the Russian gas company Gazprom and the transit countries Ukraine and Belarus has unveiled Europe's vulnerability to pipeline gas supply disruptions. In view of the risks of third countries being able to jeopardize the EU's security of gas supply, a political debate has evolved, which culminated in the recent adoption of a security of gas supply regulation in the EU[95]. Steady gas supplies to the EU primarily depend on the maintenance of sufficient production and export capacities on the part of supplier countries. As far as Russia, the world's largest exporter of natural gas, is concerned, projections of future exploration, production and export capabilities seem to fluctuate significantly. In 2008, the country shipped roughly 243 bcm of gas to foreign consumers, conveying the impression of a flourishing Russian gas industry. However, this figure masks a de facto overall production decline from 662 bcm in 2008 to 583 bcm in 2009.[96]

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94 Euractiv (2010). *Norway, Russia seal Arctic border accord*. Available online at: http://www.euractiv.com/en/energy/norway-russia-seal-arctic-border-accord-news-497585 (last accessed: 10.12.2010).

95 Regulation (EU) No. 994/2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EU entered into force 2 December 2010.

96 EIA. *International Energy Statistics*; According to the recently updated EIA (2010): *Country Analysis Briefs Russia* (November 2010), production even stood at 546 bcm in 2009.
Note: All EIA data on proved reserves, production and transport capacities has been converted from cubic feet to cubic meters at factor 0.0283.

Siberia accounts for the bulk of the country's natural gas production, gathering resources from the three most profitable fields Yamburg, Urengoy and Medvezh'he. Yet, as these fields' output diminishes gradually, new upstream projects including those on the Yamal Peninsula and in the Barents Sea have been launched in recent years. The Yamal region has nearly 22 tcm of proved gas reserves and a further 16 tcm of preliminarily expected reserves, many of which are situated in the large Bovanenkovskoye field, featuring volumes of 4.9 tcm. According to Gazprom, gas production on the Yamal Peninsula is projected to start at 8 bcm in 2011 and to deliver up to 360 bcm by 2030. The Zapolyarnoye field, which is also situated in this resource-rich region just south of the Arctic Circle, has operated at a capacity of 100 bcm per year since 2004.[97] Russia's considerable gas deposits furthermore extend to the Arctic Sea, where specifically the Shtokman field, with estimated extractable reserves of 3.9 tcm, has attracted the attention of Russia's Gazprom subsidiary Neft Shelf. The field is currently being developed in cooperation with the French and Norwegian companies Total and Statoil. It is set to produce 24 bcm in phase I and 70 bcm when the project is completed.[98] Projected additional production sourced from new wells is expected to offset production declines at the previously mentioned three big gas fields that are currently delivering the bulk of Russian gas.[99]

Regarding the general structure of the sector, the Russian gas industry is dominated by the state-owned company Gazprom, which not only commands almost all upstream activities carried out in the country, but also holds all rights to market these products.[100] In addition, the right to export natural gas to foreign consumers solely rests on Gazprom or, more specifically, its subsidiary Gazexport. Of its total exports in 2009 (179 bcm)[101], Russia shipped approximately 129 bcm to Western and Eastern European markets. Much of its residual exports were destined for customers in the Commonwealth of Independent States (CIS).[102]

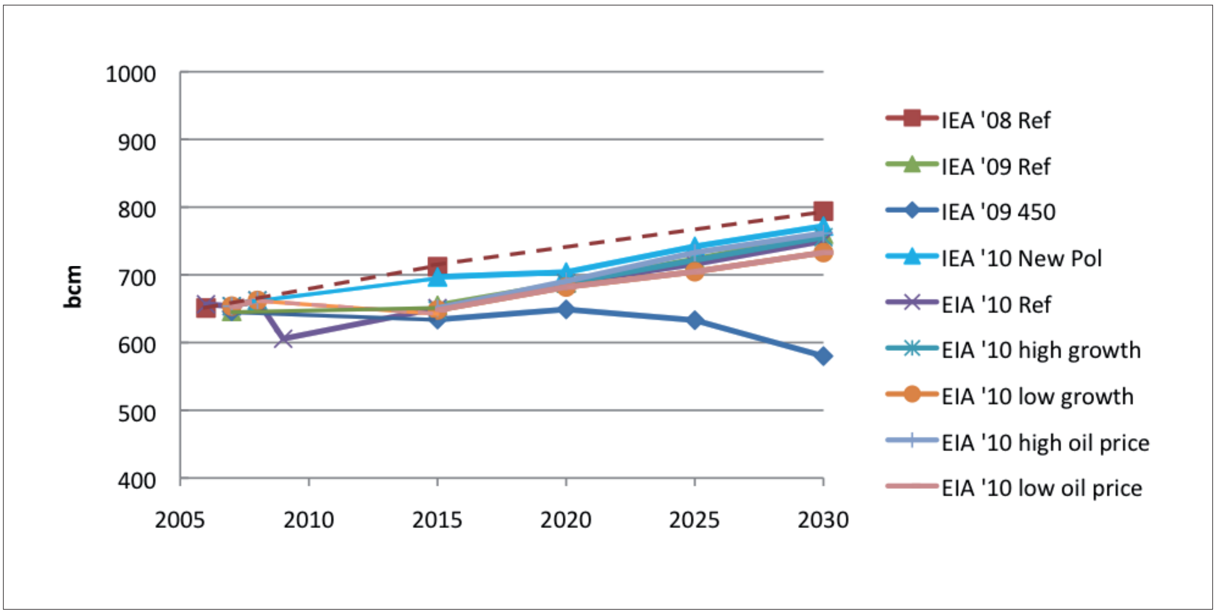
Bearing this empirical evidence of current developments in mind, the analysis will now address the likely evolution of Russian natural gas production under certain political and market conditions. The most optimistic trajectory of Russian gas production is shown in the IEA 2008 Reference case, indicating a constant upward trend to around 790 bcm in 2030. The IEA 2009 Reference scenario displays stagnating production levels in the first five years and significantly rising production levels post-2015. By contrast, the IEA 2009 450 case, with a view to decarbonisation and a lower fossil fuel demand, assumes a marginal reduction of Russian gas production until 2015. Subsequently, the curve picks up slightly, but plunges from 2020 onwards, reaching the lowest level of all scenarios of 580 bcm in 2030. The IEA 2010 New Policies Scenario, which features stable economic growth and fairly high oil and gas prices, draws a more optimistic picture of Russian gas production. Starting at 662 bcm in 2008, Russian production is forecasted to reach almost the levels projected by the IEA 2008 Reference Scenario by the end of the projection period, namely 770 bcm.

Strikingly, quite a large number of scenarios project a similar evolution of Russian natural gas production, notably in the period 2020 to 2030. Particulary the EIA scenarios diverge very little, each starting at roughly 650 bcm in 2008 and expecting a level of 730 to 760 bcm in 2030[103]. Despite the fact that most models provide quite similar figures, the graph illustrates the assumed dampening effect of lower GDP growth, lower energy demand and lower gas prices on investment in upstream activities. Overall, the presented scenarios project a likely range of gas production in Russia of 580 to 790 bcm in 2030.

97 Gazprom. *Yamal Megaproject*. Available online at: http://www.gazprom.com/production/projects/mega-yamal/ (last accessed: 15.12.2010).
98 Gazprom. *Shtokman*. Available online at: http://www.gazprom.com/production/projects/deposits/shp/ (last accessed: 15.12.2010).
99 International Energy Agency (2008). *WEO 2008*, p. 314; EIA (2010). *Country Analysis Briefs Russia*.
100 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Russia*, p. 14.
101 EIA. *International Energy Statistics*.
102 EIA (2010). *Country Analysis briefs Russia* (based on data provided by Eastern Bloc Research 2010).
103 For the period 2008 to 2010 detailed data is only available for the EIA 2010 Reference scenario.

When contrasting these projections with estimates of Russian domestic gas consumption - projected to rise from 470 bcm in 2015 to slightly less than 500 bcm in 2030[104] - some uncertainty remains as to Russia's future gas export potential. According to the IEA 2010 New Policies Scenario, the country's net exports will increase from 209 bcm in 2008 to 269 bcm in 2030. In the light of the mentioned production and consumption estimates, however, it seems possible that Russian export capacity reaches its limits during the projection period. This may be avoided if the country's production evolves according to the most optimistic scenarios presented above, climbing to around 750 bcm by 2030, and, if Russia continues to import increasing volumes of relatively cheap natural gas from Caspian and Central Asian suppliers to reconcile its domestic energy needs with rising exports to Europe. Alternatively, Russia could meet its rising export requirements by structurally reducing its domestic gas consumption.

Figure 13: Russia - natural gas production



An additional crucial factor determining Russia's gas export potential to the EU is the presence of an adequate pipeline system to link up Russian production facilities with the European market. Currently, Gazprom operates a large natural gas pipeline system consisting of nine major transmission lines, seven of which are meant for exports. Among those carrying gas to Western and Eastern European markets are the Yamal-Europe I pipeline, with a capacity of 33 bcm/y, which traverses Russia, Belarus, Poland and Germany;[105] Northern Lights, which runs alongside Yamal-Europe and establishes a parallel link to Minsk, Belarus, featuring an annual capacity of 14 to 25 bcm per year; the Soyuz pipeline, delivering some 30 bcm/y to Western Europe via Ukraine; and finally the northern part of the Brotherhood line, which transports roughly 30 bcm/y via Ukraine, Slovakia, the Czech Republic and Austria to Germany.[106]

Aside from the pipelines linking Russian gas fields to Western European consumers, a number of other lines ensure deliveries to Russia's southern and south eastern neighbours, notably Turkey and countries in the Caucasus and Central Asia. The Blue Stream (off-shore) pipeline is one of these links, delivering around 10 bcm of natural gas across the Black Sea to Turkey in 2009. Once completed it is designed to

104 EIA (2010). *International Energy Outlook 2010*, Reference case, p. 43.

105 Gazprom 2010: *Yamal-Europe*. Available online at: http://www.gazprom.com/production/projects/pipelines/yamal_evropa/ (last accessed: 07.02.2011).

106 Nies, S. (2008): *Oil and Gas Delivery to Europe. An Overview of existing and planned infrastructure*. Governance europeenne et geopolitique de l'energie. Ifri: Brussels, p. 65.

deliver as much as 16 bcm per year.[107]

With regard to expanding and diversifying gas deliveries from Russia to Western Europe, three other pipeline projects are currently at a planning stage or already under construction. First, the Yamal-Europe II pipeline, which is set to carry approximately 30 bcm/y of additional gas to Poland and Germany directly via Belarus. Second, the Nord Stream pipeline, which is designed to connect Russia and Germany, thereby bypassing traditional transit countries Ukraine, Belarus and Poland. It is scheduled to become partly operational by the end of 2011 with an initial capacity of 27.5 bcm and to reach its full capacity of 55 bcm by 2013.[108] A third planned link, and probably the most controversial one is South Stream, featuring a design capacity of 63 bcm/y. Its offshore section is meant to run some 900 kilometers under the Black Sea, connecting the Russian compressor station Berengoya to the Bulgarian coast. The onshore component of South Stream, thus far, is planned to either turn northwestwards, cutting across Serbia and Hungary or southwestwards through Greece and Albania.[109]

Overall, Russia theoretically holds sufficient natural gas reserves in the Barents Sea and on the Yamal Peninsula and already a fairly diversified transport infrastructure that is geared towards Western and Eastern Europe. Whether these huge gas deposits will in fact be developed in due time to compensate for the maturation of current fields and to meet projected rises in Russia´s domestic gas consumption will hinge on sufficient investment, (foreign) technical expertise as well as fuel price developments.

Norway

Norway is the second largest natural gas supplier to the EU and, at the same time, the second largest exporter of natural gas in the world, in both cases ranking behind Russia. Showing a steady output growth in previous years, the Scandinavian country's production amounted to roughly 103 bcm in 2009. Of these volumes, Norway exported approximately 99 bcm, leaving a marginal amount of roughly 4 bcm for domestic consumption.[110]

Norway's single largest gas field Troll, located in the southwestern part of the North Sea, accounts for roughly one-third of the country's entire gas output. It held recoverable reserves of 970.6 bcm at the end of 2009[111] and is projected to produce 31 bcm in 2010. The three largest gas fields, namely Troll, Ormen Lange in the Norwegian Sea (estimated production of 22 bcm in 2010) and Asgard (annual production of 11 to 12 bcm), currently make up 60% of Norway´s total gas production[112]. Of course, the maturation of these large deposits proceeds year after year. However, Norway and specifically Statoil have managed to develop a large number of alternative fields in the North Sea, the Norwegian Sea and since 2007 also in the Barents Sea. While Statoil undoubtedly dominates the upstream business on the Norwegian continental shelf, the company operates a considerable number of fields in cooperation with international partners such as ExxonMobile, Connoco Phillips, Total, Shell and Eni.[113]

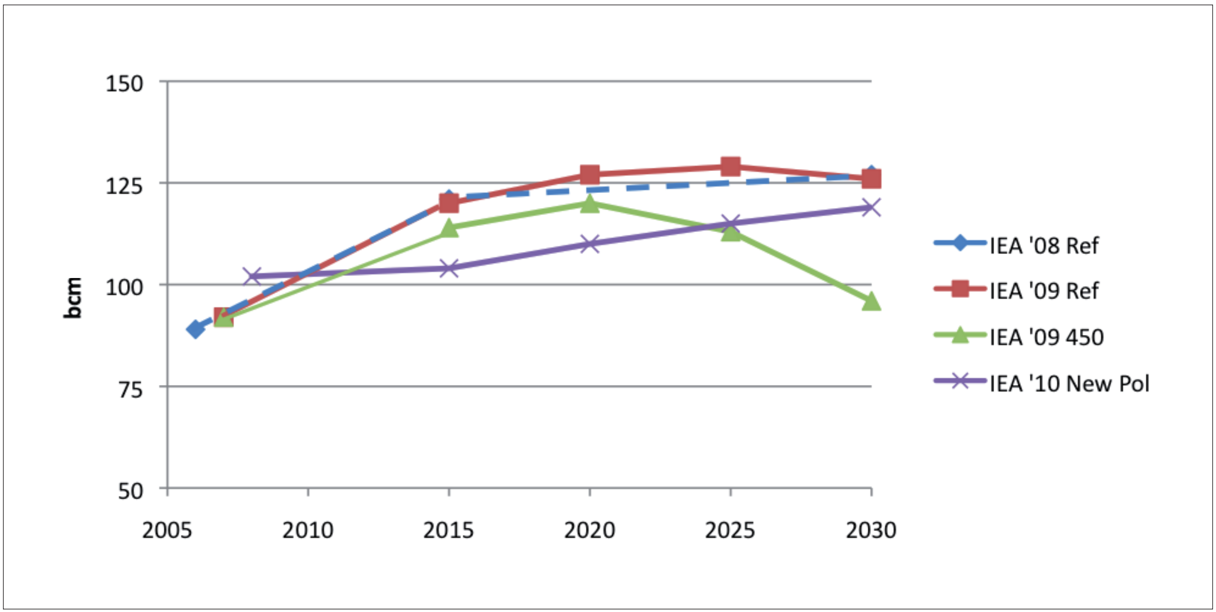
In order for Norway's natural gas to be exported to consumer markets, a diversified pipeline network is in place that allocates almost all Norwegian gas exports to the EU. Gassco, Norway's state-owned gas pipeline operator, administers a number of pipeline links directly connecting Norwegian upstream facilities to France and Germany, namely Franpipe (20 bcm/y), Europipe I and II (40 bcm/y) and Norpipe (16 bcm/y). Moreover, the network includes interconnections to the UK, i.e. Vesterled (13

107 Gazprom. *Blue Stream*. Available online at: http://www.gazprom.com/production/projects/pipelines/bs/ (last accessed: 07.02.2011).
108 EIA (2010). *Country Analysis Briefs Russia*.
109 South Stream website. Available online: http://south-stream.info/?L=1 (last accessed: 07.02.2011).
110 EIA. *International Energy Statistics*.
111 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Norway,* March 2010, p. 14.
112 EIA (2010). *Country analysis briefs Norway*; see also Statoil. *Norwegian continental shelf*. Available online at: http://www.statoil.com/en/OurOperations/ExplorationProd/ncs/Pages/default.aspx (last accessed: 10.01.2011).
113 Ibid.

bcm/y) and Langeled (25 bcm/y), and to Belgium through Zeepipe I, IIA and IIB (total of 68 bcm/y).[114]

Since 2007, Norway also commands a large-scale LNG liquification and export terminal at Melkoya, which is connected via pipeline to the Snohvit field, the first Norwegian venture in the Artic.[115] As the Melkoya terminal is currently operating at full capacity, plans have been unveiled to expand this project and to source additional gas from the nearby Askeladd field. Norwegian LNG production - primarily contracted to Spanish, French and UK importers - has recently grown markedly, from roughly 2 bcm in 2008 to above 3 bcm in 2009.[116]

Figure 14: Norway - natural gas production



Putting the afore-mentioned supply capacities in a longer-term perspective, the outlook for Norwegian gas production is fairly positive. As Figure 14 shows, the IEA 2008 and 2009 Reference Scenarios both predict a substantial increase in gas production until 2025, to 129 bcm, and marginally declining production levels afterwards, reaching approximately 126 bcm in 2030. While showing a similar trajectory until 2015, the IEA 2009 450 Scenario forecasts Norwegian production to peak already in 2020 and to drop considerably in the second half of the projection period, to a mere 96 bcm in 2030. As with the previous scenarios, this sharp decline may be attributed to the underlying scenario assumptions. By contrast, the IEA 2010 New Policies Scenario anticipates only a moderate expansion of production until 2015 and projects a consistent surge thereafter, from 104 bcm in 2015 to 120 bcm at the end of the projection period.

Overall, all four trajectories suggest a fairly similar evolution of production capacities in the Norwegian gas industry. In fact, the absolute difference between the most pessimistic and the most optimistic forecast for 2030 amounts to as little as 30 bcm. In other words, the trajectories indicate a rather stable development of production, likely to peak around 2020 or 2025 and to slightly decrease afterwards. Moreover, these figures reveal that Norway's production potential largely depends on the development and exploitation of new gas fields on the Norwegian continental shelf, in the high north and/or in the Barents Sea. If these fields yield little, which is not to be expected, Norway's role as a major exporter of

114 EIA (2010). *Country Analysis Briefs Norway*.
115 At the end of 2009 the Snohvit field held recoverable reserves of 155 bcm (The Economist Intelligence Unit 2010. *Norway*, p. 14).
116 EIA (2010). *Country Analysis Briefs Norway*.

natural gas may diminish in the long-term. Taking into account, however, that Statoil has been awarded new exploration acreage and production licenses in the North Sea, the Norwegian Sea and the Barents Sea in January 2011,[117] the prospects for the country's future natural gas production seem promising. Nevertheless, the level of gas production in Norway beyond 2020 very much depends on political decisions by the Norwegian government and Parliament concerning the opening up of new areas for exploration and production. This is notably the case for the Lofoten – Vesterålen region. Political and commercial commitments in the EU will also be of utmost importance when it comes to investments going forward or not.

4.3.2 The Caspian Basin and Central Asia

The Caspian region, comprising Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan, holds 7% (13 tcm) of the world total of proven natural gas reserves. In 2009, the region's total gas production of amounted to 159 bcm. [118]

As far as the EU is concerned, Azerbaijan and Turkmenistan are the "key potential individual supplier states" in the Caspian region.[119] Not only are these two countries (along with Kazakhstan) expected to be the region's main producers and exporters over the next few decades; they are also the countries that are best placed to maintain transport links to Europe.[120] Meanwhile, other Caspian countries have traditionally been more geared towards the east and are unlikely to supply Europe with any significant amount of gas in the projection period. Kazakhstan, producing 36 bcm of gas in 2009 and an estimated 61 bcm in 2030[121], may be one of the largest gas producers of the region, but is expected to export most of its gas to Russia and China. Uzbekistan has produced as much as 66 bcm in 2009 and is expected to have an output of about 69 bcm in 2030[122]. However, as in the case of Kazakhstan, exports are primarily directed at Russia, with future plans revolving around gas sales to China. The remaining Caspian countries, even when combined, hold only marginal gas resources. They have produced no more than 0.1 bcm in 2009 and are expected to produce roughly the same amount in 2030.[123] The following section shall therefore be confined to taking a closer look at Azerbaijan and Turkmenistan.

Azerbaijan

According to BP, EIA and IEA data, Azerbaijan's proven reserves amount to roughly 0.9 to 1.4 tcm. Gas production in 2009 stood at 16.5 bcm, more than one-third of which emanated from the Shah Deniz natural gas and condensate field. It was the start-up of that very field, which turned Azerbaijan into a net exporter of natural gas in 2007. Prior to that, the country had been an importer of Russian gas. By 2009, as domestic gas consumption amounted to 10.6 bcm, 5.9 bcm were available for exports. European markets were the main recipients.[124]

Azerbaijan's largest gas field is the aforementioned Shah Deniz field, which contains roughly 1 tcm of natural gas.[125] Its development is undertaken by a consortium consisting of Statoil and BP, and the

117 Statoil (2011). *New exploration acreage for Statoil*. Press release published 19.01.2011. Available online at: http://www.statoil.com/en/NewsAndMedia/News/2011/Pages/19Jan:TFO.aspx (last accessed: 25.01.2011).
118 IEA (2010). *WEO*, p. 524-525.
119 European Commission (2010). *Energy Infrastructure priorities for 2020 and beyond - A blueprint for an integrated European energy network*, COM (2010) 677 final, p. 32.
120 IEA (2010). *WEO*.
121 According to the IEA (2010) New Policies Scenario.
122 Ibid.
123 IEA (2010). *WEO*, p. 525.
124 EIA (2010). *Country Analysis Briefs Azerbaijan*; EIA. *International Energy Statistics*; IEA (2010). *WEO*, p. 527.
125 BP (2010). *Shah Deniz. One of the world's largest gas-condensate fields*. Available online at: http://www.bp.com/sectiongenericarticle.do?categoryId=9006668&contentId=7015092 (last accessed: 02.02.2011).

operators, SOCAR, Total, LUKoil, OIEC (Iran) and TPAO (Turkey). Gas production began in early 2007 and has increased rapidly since then, reaching 3.1 bcm in 2008 and about 7.1 bcm in 2009. Phase I production is expected to peak at 8.6 bcm in 2010. Phase II is estimated to reach a peak capacity of 19.8 bcm, but its completion had to be postponed to 2016 due to difficulties in reaching a transit agreement with Turkey. Aside from Shah Deniz, there are also significant gas resources in the Guneshli field, which is part of the ACG oil and gas field system. However, this field is currently providing associated gas for domestic use only.[126] Furthermore, exploration is underway at the Absheron field and drilling has been proposed at Nakhichevan.[127]

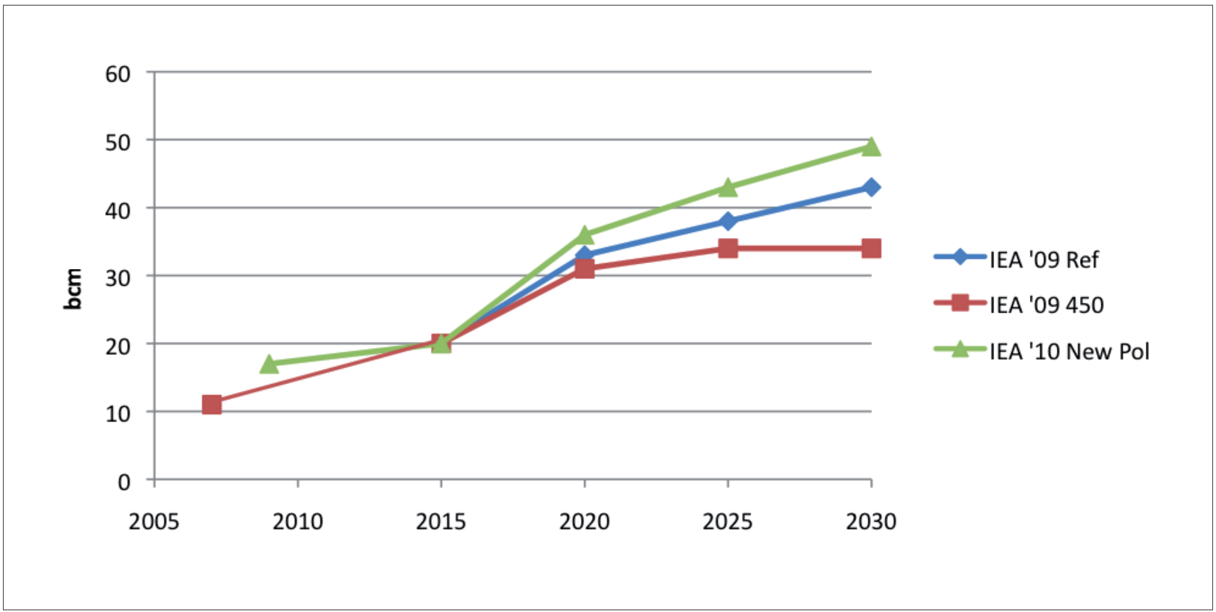
Azerbaijan's gas industry is dominated by the state-owned State Oil Company of Azerbaijan Republic (SOCAR). One of the SOCAR subsidiaries, Azerigaz, handles natural gas processing, transport, distribution, and storage, especially domestically. Another SOCAR subsidiary, Azneft, is in charge of the exploration, development and production of gas from older, SOCAR-owned onshore and offshore natural gas fields. Every international consortium seeking to develop gas in Azerbaijan must involve SOCAR. The most prominent international consortium currently active in Azerbaijan is AIOC (Azerbaijan International Operating Company), as it produces most of the country's output. AIOC is made up of 10 petroleum companies, each of which has concluded extraction agreements with Azerbaijan. Among those companies are BP, which is the largest foreign investor in Azerbaijan, the leader of the consortium and the technical operator of Shah Deniz, Chevron, Statoil, Turkiye Petrolleri, ExxonMobil, and SOCAR. AIOC has been involved in the development of the ACG fields as well as the Shah Deniz gas field.[128]

In 2009, the bulk of Azeri exports went via the South Caucasus Pipeline to Turkey[129], which is undoubtedly the 'key transit state' for exports from Azerbaijan to Europe. This pipeline, owned and operated by the Shah Deniz consortium, currently has the capacity to transport about 8 bcm of gas per year and may be expanded to around 20 bcm in the coming years.[130] Potential future transport routes to Europe may run through the Black Sea and the Eastern Mediterranean. Azerbaijan furthermore exports gas via the Gazi-Magomed-Mozdok pipeline to Russia and via the Baku-Astara pipeline to Iran.[131]

Agreements on gas trade with Europe will allow for a considerable expansion in production and export to commence in the mid-2010s. Out of the three available scenarios for Azerbaijani gas production, the IEA 2010 New Policies Scenario predicts the highest increase in production over the projection period (Figure 15). While it resembles the other two scenarios in projecting a modest increase in production to about 20 bcm until 2015, it differs from them in that it projects a steeper increase in production between 2015 and 2020. According to the IEA 2010 New Policies Scenario, the start of Phase II of the development of Shah Deniz in 2017 will raise total production to 36 bcm by 2020. By comparison, the IEA 2009 Reference and 450 Scenarios only expect an increase to 33 bcm and 31 bcm, respectively. Each of the scenarios projects that, throughout the 2020s, output increases steadily. However, the output projected for 2030 varies, amounting to 49 bcm in the IEA 2010 New Policies Scenario, 43 bcm in the IEA 2009 Reference Scenario, and 34 bcm in the IEA 2009 450 Scenario.

126 EIA (2010). *Country Analysis Briefs Azerbaijan*.
127 IEA (2010). *WEO*, p. 527.
128 EIA (2010). *Country Analysis Briefs Azerbaijan*.
129 Since 2007, the Shah Deniz consortium has been exporting gas through the South Caucasus Gas Pipeline to Turkey (The Economist Intelligence Unit Limited 2010. *Industry Report: Energy. Azerbaijan*, March 2010, p. 14)
130 IEA (2010). *WEO*, p. 530.
131 EIA (2010). *Country Analysis Briefs Azerbaijan*.

Figure 15: Azerbaijan - natural gas production



While domestic gas consumption is set to increase over the projection period to roughly 14.5 bcm in 2030[132], gas production is estimated to increase even faster, thereby making more gas available for exports.[133] In the IEA 2010 New Policies Scenario, Azeri net exports are projected to increase from 8 bcm in 2009 to about 35 bcm in 2030. However, whether and how these export volumes will reach Europe depends on actual production rates and the outcome of ongoing negotiations.

Three new major European pipeline projects are currently being discussed, all of which are trying to secure Azeri supplies for markets in southeast Europe.[134] Some West European companies, such as RWE and OMV, are trying to procure supplies for the long-discussed 3000 km Nabucco pipeline, which is also backed by the EU. Others, including Statoil, Elektrizitätsgesellschaft Laufenburg AG and E.on, support plans for a Trans-Adriatic Pipeline. Still others, notably Edision Spa and DEPA, advocate an Interconnector Greece-Italy.

The key supply source for each of these projects is Phase II of the development of Shah Deniz.[135] Consequently, the three projects have long been regarded as competing options. More recently, however, representatives of the EU and several companies have started discussing the possibility of combining Nabucco with the other European pipeline projects. The result of these discussions "might be the eventual construction of a smaller pipeline than Nabucco, with outlets both to Italy and to Central Europe"[136]. Another possibility not to be disregarded is that the gas produced in phase II might be sold to Russia, whose South Stream pipeline project, if carried out, has the potential to make the EU's pipeline projects redundant.[137]

The EU was able to take an important step forward in January 2011, when European Commission President Barroso and Azerbaijan's President Ilham Aliyev signed the 'Joint Declaration on the Southern

132 According to the IEA 2010 New Policies Scenario.
133 IEA (2010). *WEO*, p. 482 and 526-527.
134 IEA (2010). *WEO*, p. 529.
135 EIA (2010). *Country Analysis Briefs Azerbaijan*.
136 Torello. A. (2010). *Sale of gas field will test EU's pipeline strategy*. In: The Wall Street Journal online, 24 December 2010.
137 Euractiv (2011). *Barroso tops Azeri gas deal with visa facilitation*. Available online at: http://euractiv.com/en/energy/barroso-tops-azeri-gas-deal-with-visa-facilitation-news-501255 (last accessed: 22.01.2011).

Gas Corridor'[138], which states that the common aim is "to see the Southern Corridor established and operational as soon as possible and to establish the Republic of Azerbaijan as a substantial contributor to - and enabler of - the Southern Gas Corridor". The declaration enables Azerbaijan to diversify its list of clients, while allowing the EU to diversify its sources of supply. It is expected to bring 10 bcm of gas per year from the Shah Deniz II field to the EU, eventually.[139]

While no specification is made with regard to the companies that are to be commissioned to develop and transport the gas, the parties to the declaration urge "a swift allocation process for the available gas resources at the Shah Deniz II Project and other fields in Azerbaijan"[140]. Azerbaijan is in fact already negotiating with the Nabucco consortium, the representatives of the Interconnector Greece-Italy and the representatives of the Trans Adriatic Pipeline. The outcome of these negotiations will determine which one of the pipeline projects under discussion will eventually form the Southern Gas Corridor (although there still is a chance that Azerbaijan splits the gas among several bidders).

In this context, it is worth noting that the 10 bcm of gas that will be made available to the EU are not sufficient to fill the Nabucco pipeline, which is supposed to have a final capacity of 31 bcm. The Interconnector Greece-Italy and the Trans Adriatic Pipeline, on the other hand, each happen to have a planned capacity of exactly 10 bcm. However, the Nabucco consortium might be able to procure additional volumes from other countries in the region. Turkmenistan, for example, is currently engaged in negotiations with the EU.[141]

It is difficult to tell at this stage which one of these three projects is most likely to be realised. What seems to be clear, however, is that there is only room for one of them, at least in the period to 2025. Besides these pipeline projects, the possibility of bringing gas directly across the Black Sea by pipeline or in the form of liquefied or compressed natural gas to Romania or Bulgaria is also being discussed. Whatever transport route ends up being implemented, it is safe to say that "Azerbaijani gas, potentially joined by other sources of gas from the Caspian and Middle East, is set to open up a new corridor for gas supply to Europe over the next few years".[142]

Turkmenistan

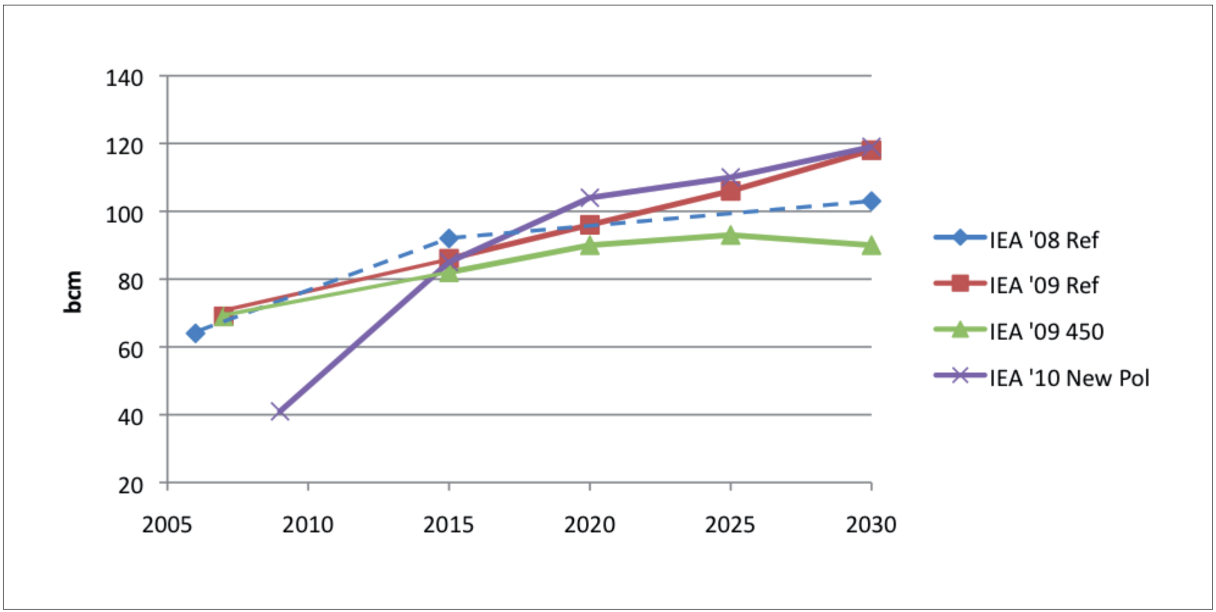
Turkmenistan, having 7.5 to 8.1 tcm of proven reserves at its disposal, is the largest gas resource holder in the Caspian region and one of the region's largest gas producers. However, production has fallen sharply - from 71 bcm in 2008 to about 38 bcm in 2009 - following an explosion on the major CAC export pipeline and the overall economic downturn.[143] Despite this, Turkmenistan has retained its position as the region's biggest gas-exporter. While most exports go to Russia, and increasingly China, the possibility of transporting gas from Turkmenistan to Europe is widely discussed.[144] However, as yet there are no transport links between Turkmenistan and the EU and none of Turkmenistan's gas is exported to the EU.[145]

Turkmenistan's main existing gas fields are Shatlyk and Dauletabad, but their output is in decline. The bulk of Turkmenistan's remaining gas resources are located in the onshore South Yolotan field in southeast Turkmenistan, discovered in 2006. The IEA expects first gas from South Yolotan in 2013, reaching 30

138 *Joint Declaration on the Southern Gas Corridor*, signed in Baku, 13 January 2011.
139 Euractiv (2011). *Barroso tops Azeri gas deal with visa facilitation*.
140 *Joint Declaration on the Southern Gas Corridor*.
141 Euractiv (2011). *Barroso tops Azeri gas deal with visa facilitation*.
142 IEA (2010). *WEO*, p. 528.
143 EIA. *International Energy Statistics*.
144 IEA (2010), *WEO*, p. 534 and 541.
145 EurActiv (2010). *Europe's southern gas corridor. The great pipeline race*. Available online at: http://www.euractiv.com/en/energy/europes-southern-gas-corridor-great-pipeline-race-linksdossier-498558 (last accessed: 25.01.2011).

bcm per year by 2020 and 60 bcm per year by 2025. Provided that a third development phase will be considered profitable, production levels might go up to as much as 90 bcm per year by the end of 2035. For the first phase of field development at South Yolotan, the country's authorities awarded contracts to the United Arab Emirates-based companies Petrofac and Gulf Oil & Gas, South Korea's LG and Hyundai, and CNPC. However, overall project management is in the hands of the state-owned company Turkmengaz. Turkmengaz effectively has a monopoly on all onshore developments, while international companies are confined to providing assistance on a contractual basis. Offshore developments, on the other hand, are open to the investment of international companies, but they contain a comparatively small amount of resources, which makes them less attractive.[146]

Figure 16: Turkmenistan - natural gas production



Turkmenistan's overall production of natural gas is expected to recover from the decline in 2009 and get back to 2008-levels within the first half of the 2010s. According to the IEA 2010 New Policies Scenario (Figure 16), output rises constantly, to 85 bcm in 2015, over 110 bcm in 2025 and 119 bcm in 2030. The IEA 2009 Reference Scenario is remarkably similar, predicting production to reach 118 bcm by 2030. Only the IEA 2009 450 Scenario deviates significantly in that it assumes, first, that production will grow at a slower pace and, second, that there will be a decline in production between 2025 and 2030. It estimates production levels to reach no more than 90 bcm by the end of the projection period.

According to IEA estimates, net exports increase from 17 bcm in 2009 to 55 bcm in 2015 and to 85 bcm at the end of the projection period, mainly due to the development of the South Yolotan field. However, there are two main issues that might lead to future levels of production and export being well below what would be possible given the country's resource base. The first issue concerns Turkmenistan's policy on upstream investment, whereby all onshore projects are automatically assigned to Turkmengas. This prevents international companies from investing and from bringing in their expertise and technology. The second issue concerns persisting difficulties with gaining access to major export markets caused by a lack of infrastructure. As Turkmenistan's government insists on selling the country's gas at its border, it is down to those buying the gas to set up the infrastructure that is needed outside the country. So far, only China has managed to put a new long-distance pipeline to Turkmenistan into action. It is questionable

146 IEA (2010). *WEO*, p. 536-537.

whether European customers will be able or willing to commit to an investment of this scale.[147]

The idea of transporting gas from Turkmenistan through a Southern Corridor to Europe is widely discussed.[148] In March 2010, RWE suggested that it expected Turkmenistan to agree to supplying 10 bcm of gas per year to the Nabucco project from 2015 onwards. However, there are doubts over how Turkmen gas is supposed to be delivered to Turkey, where Nabucco is meant to begin. The South Caucasus Pipeline is an option, but it might not have the capacity to carry additional volumes of gas and, so far, it does not even go all the way to Turkmenistan.[149]

Several suggestions have been made on how to transport Turkmen gas westward across or around the Caspian Sea, thereby connecting Turkmenistan to the existing transport links to Europe. These include, first, a sub-sea pipeline from shore to shore; second, a mid-Caspian interconnector tying offshore Turkmenistan production platforms to the existing Azerbaijani offshore infrastructure (which might be politically difficult to implement); third, exporting natural gas by tanker across the Caspian (which is technically unproven); and fourth, expanding exports to Iran or, respectively, creating a new pipeline connection around the southern Caspian through Iran (the latter possibility being currently disregarded for political reasons).[150]

Gas from Turkmenistan´s onshore fields is unlikely to be exported to the EU. However, the IEA assumes that up to 10 bcm of Turkmenistan's offshore gas, which is developed in the Caspian Sea and does not yet have an obvious route to market, will eventually be provided for exports to Turkey and the EU. Transports might start in the latter part of the 2010s.[151]

4.3.3 The Middle East

The Middle East[152] holds 75 tcm, or 41% of the world total, of proven reserves of natural gas. In 2008, the region's total production of natural gas amounted to 379 bcm.[153]

From a European perspective, Qatar and Iran seem to be the Middle East's most promosing supplier states. They share the world's largest gas field (North Field/South Pars) and hold about two-thirds of the Middle East's gas reserves. Furthermore, Qatar and Iran are expected to be the main contributors to the increase in gas production and exports that is assumed to occur in the Middle East over the projection period.[154]

Aside from Qatar and Iran, only Saudi Arabia, the United Arab Emirates (UAE) and Iraq possess significant proven gas reserves. They are unlikely, however, to serve as important suppliers to the EU. Saudi Arabia holds an impressive 7.5 to 7.9 tcm of proven gas reserves, but the country's gas production is insufficient to cover growing domestic demand, let alone exports.[155] Over the projection period, domestic gas demand is expected to more than double from 78 bcm in 2009 to about 150 bcm in 2030.[156] By comparison, production is expected to rise from 78 bcm in 2009[157] to 130 bcm (IEA 2009 450 Scenario)

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147 Ibid., p. 526 and 535.
148 Ibid., p. 536-541.
149 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Azerbaijan*, p. 12.
150 IEA (2010). *WEO*, p. 526.
151 Ibid., p. 542.
152 Bahrain, the Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, the United Arab Emirates and Yemen; it includes the neutral zone between Saudi Arabia and Iraq (IEA 2010, *WEO*, p. 709).
153 IEA (2009). *WEO*, p. 485.
154 Ibid., p. 485-486.
155 Ibid., p. 495.
156 EIA (2010). *Country Analysis Briefs Saudi Arabia*; EIA. *International Energy Statistics*.
157 EIA. *International Energy Statistics.*

or 149 bcm (IEA 2009 Refenrence Scenario) in 2030. Accordingly, the IEA assumes that all gas produced in Saudi Arabia over the projection period will be consumed domestically and that virtually nothing will be left for exports. The UAE, with proven reserves of about 6.1 to 6.5 tcm, find it equally difficult to produce volumes sufficient to cover both rising domestic gas demand and exports. As production levels are expected to rise but slowly, from 51 bcm in 2008 to 53 bcm in 2015 and 71 bcm in 2030[158], according to IEA 2009 Reference case, the country is expected to remain a net importer of gas throughout the projection period.[159]

In the case of Iraq, on the other hand, the biggest issue is that estimations for possible future production and export volumes are associated with a great amount of uncertainty. While Iraq holds proven natural gas reserves of 3.2 tcm, production only amounted to 2 bcm in 2008 and 1.2 bcm in 2009.[160] About 40% of the gas produced that year was flared as there is no infrastructure that would allow for the gas to be processed and transported to markets. Moreover, persistent security issues and an unstable regulatory regime discourage foreign investment. Nevertheless, Iraq has expressed an interest in export routes such as the proposed Nabucco pipeline through Turkey to Europe. In 2009, Prime Minister Nouri al-Malikie went as far as to suggest that Iraq could be exporting 15 bcm per year to Europe by 2015. Aside from Nabucco, there is the proposed Arab Gas Pipeline (AGP), which would allow for gas to be transported from Iraq's Akkas field to Turkey and then Europe, and the possible construction of LNG export facilities.[161] However, the IEA expects production to reach no more than 13 bcm by 2015 and 52 bcm by 2030, thereby putting the Prime Minister's plans into question. The overall situation in Iraq makes it highly uncertain whether Iraq will at any point become a noteworthy supplier to the EU. [162]

The proven reserves of the remaining eight countries of the Middle East only amount to about 3 tcm, which is a marginal amount compared to the Middle East total of 75 tcm or to Qatar and Iran's combined proven reserves of 55 tcm. The following section will therefore concentrate on the latter two as the most likely future suppliers to the EU.

Qatar

Qatar holds proven gas reserves of about 25 to 26 tcm and the country's gas production has increased rapidly over the previous two decades, reaching 77 bcm in 2008 and 89 bcm in 2009.[163] Qatar has been a net-exporter of natural gas since the mid-1990s and currently is the world's largest producer of LNG as well as of Gas-to-Liquids (GTL).[164] By 2009, as domestic gas demand stood at 21 bcm, the country's exports amounted to 68 bcm, roughly 70% of which was LNG. The main recipients of Qatari LNG were South Korea, Japan, India, Spain, Belgium and the UK.[165]

Of Qatar's proven reserves, 99% is located in the North Field. To begin with, the field was developed in order to cover domestic demand. Meanwhile, it also supplies two major LNG projects (Qatargas 1 and 2, and RasGas 1 and 2) and the Dolphin regional pipeline project. Further projects are near completion and about to start production, namely the Qatargas 3, Qatargas 4 and RasGas 3 LNG projects as well as the Pearl GTL project.[166] The rapid development of the North Field was only curtailed in 2005, when the

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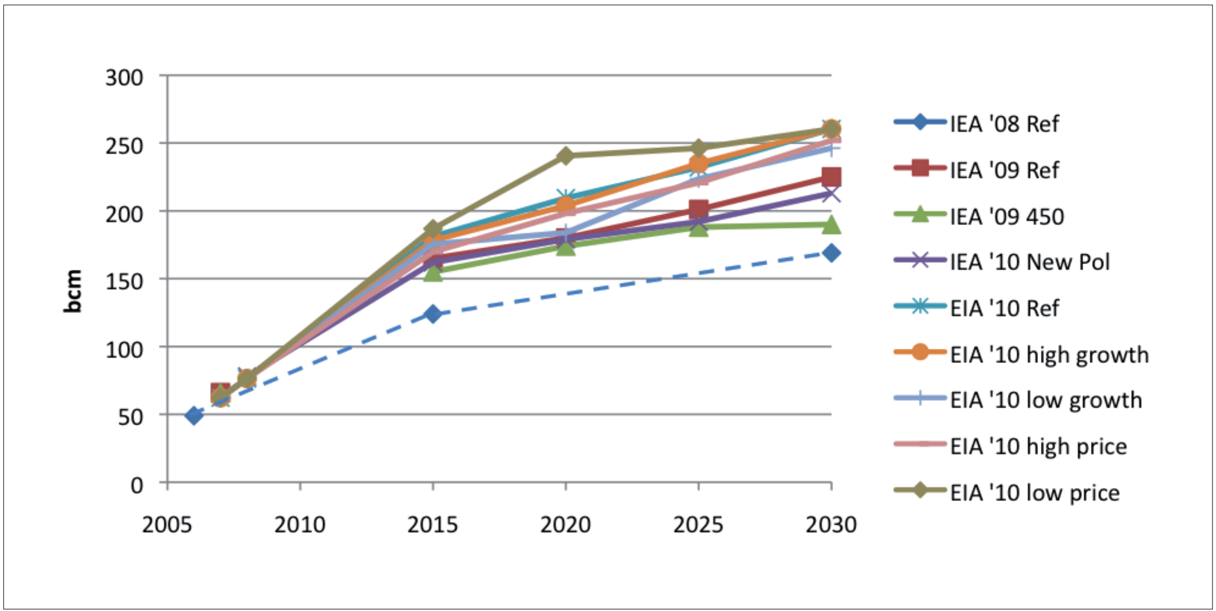
158 According to the IEA 2009 450 Scenario, output is to reach only 61 bcm in 2030.
159 IEA (2009). *WEO*, p. 495-496.
160 EIA. *International Energy Statistics*; see also IEA (2010). WEO, p. 191.
161 EIA (2010). *Country analysis briefs Iraq*.
162 IEA (2010). *WEO*, New Policies Scenario, p. 191.
163 IEA (2009). *WEO*, p. 191.
164 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Qatar*, April 2010, p. 13.
165 EIA (2010). *Country Analysis Briefs Qatar*; EIA. *International Energy Statistics*.
166 IEA (2009). *WEO*, p. 487.

Qatari government placed a moratorium on additional projects with the aim to find optimised ways of gas development before pressing ahead. As the moratorium did not affect projects already approved or underway, the growth in production volumes continues. A further expansion in the production of LNG is possible after the moratorium is lifted in 2013.[167]

Qatar's gas industry is dominated by the state-owned company Qatar Petroleum (QP), which manages upstream production and plays a significant role in downstream projects. In addition, Qatar collaborates with large international oil companies such as ExxonMobil, Shell, and Total in order to obtain the necessary technology and expertise. The LNG sector is mainly in the hands of Qatar LNG Company (Qatargas) and Ras Laffan LNG Company (RasGas). Together, they have 11 trains available and a total LNG liquefaction capacity of 76 bcm/y. Several of these trains are explicitly intended to supply European markets. [168] Qatar Petroleum, in cooperation with ExxonMobil, is actively seeking to gain access to European LNG markets by developing a new onshore LNG regasification terminal in the UK as well as the world's first offshore terminal off the north-eastern coast of Italy.[169]

Figure 17: Qatar - natural gas production



As Figure 17 illustrates, the available scenarios all assume Qatar's gas production to increase constantly throughout the projection period. Due to the moratorium, however, they diverge significantly in terms of the predicted growth rates. What is striking is that the IEA estimates a much lower rise in production than the EIA in each of its scenarios. The IEA 2009 450 Scenario projects the lowest growth, assuming gas production to reach no more than 190 bcm by 2030. The highest rate of growth is predicted by the EIA 2010 Reference Scenario, the EIA 2010 High Growth Scenario and the EIA 2010 Low Oil Price Scenario, all three of which assume production to reach 260 bcm by the end of the projection period.

While both demand (expected to grow by an average of 9.4% annually between 2010 and 2020[170]) and production are set to rise throughout the projection period, it is difficult to predict exact export figures. It is likely that Qatar will seek to increase its resource base through further exploration before

167 The Economist Intelligence Unit (2010). *Qatar*, p. 12.
168 EIA (2010). *Country analysis briefs Qatar*.
169 ExxonMobil (2008). *Qatar - North Field. Brochure*. Available online at: http://www.exxonmobil.com/Corporate/energy_project_qatar.aspx (last accessed: 03.02.2011).
170 The Economist Intelligence Unit (2010). *Qatar*, p. 10.

attempting to increase natural gas exports and that the country's priority will be on meeting domestic demand.[171] Nevertheless, it can be expected that significant volumes of Qatari gas will continue to be available for export. After all, each of the scenarios expects production levels to rise significantly over the projection period. Most gas will be sold in the form of LNG, as the country is expected to consolidate its position as the world's biggest LNG exporter.

Qatar has been supplying Europe with gas for a couple of years now. Given its massive resources and the sophisticated transport facilities, including the ones currently under construction, it can be expected that Qatar will consolidate and extend its position as an important supplier to Europe throughout the projection period.

Iran

With roughly 29 tcm, Iran has the world's second largest natural gas reserves at its disposal, after Russia. The country's largest natural gas fields are South and North Pars, Kish, and Kangan-Nar. Gas production has risen steeply over the last two decades, amounting to 116 bcm in 2008 and 131 bcm in 2009. However, as consumption has also gone up significantly, Iran has routinely been a net importer of gas. In 2008, with domestic consumption standing at 119 bcm, Iran had to import additional volumes from Turkmenistan.[172] The only gas that is actually exported is transported via pipeline to Turkey.[173]

The biggest gas field in Iran is the offshore South Pars field (called North Field in Qatar), which is assumed to hold 12 to 13 tcm of natural gas reserves.[174] Another large field is the offshore Kish field, which is estimated to contain reserves of 1.4 tcm. Further exploration is underway in the Fars province including the Varavi, Shanol, and Homa fields, as well as in the Persian Gulf Salman gas field.[175]

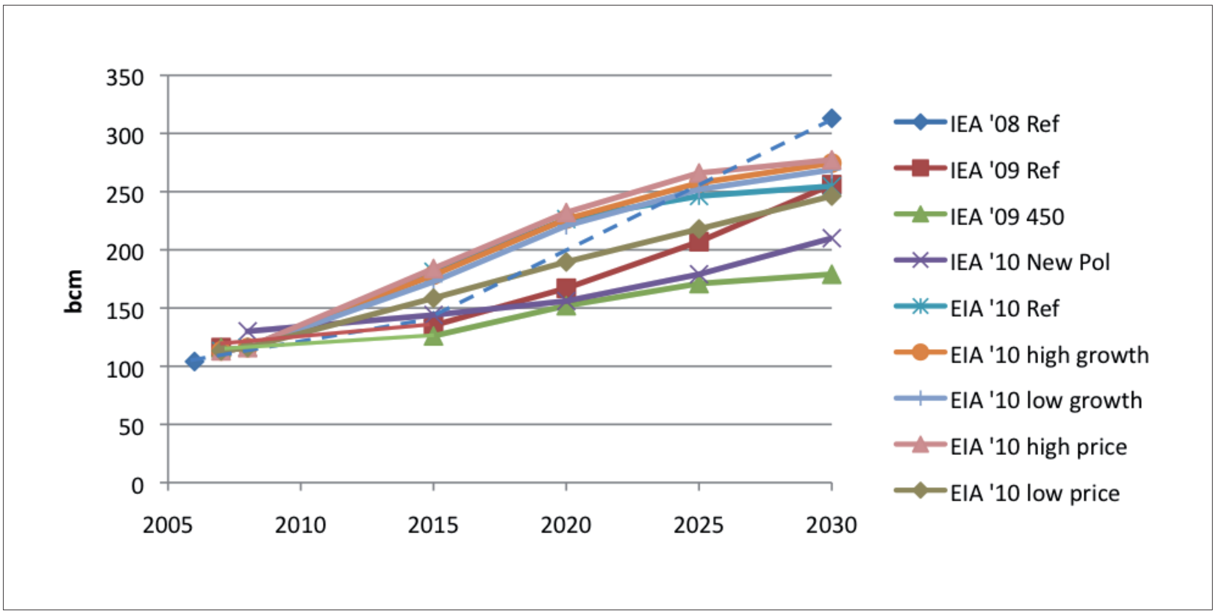
Iran's gas industry is dominated by the National Iranian Gas Company (NIGC). Its most significant subsidiary, the Pars Oil & Gas Company (PAGC), manages the South Pars project and is responsible for upstream LNG development. Downstream development is shared between several companies. Many international oil companies that used to be active in Iran have left the country due to poor investment climate and because operating in Iran is in many cases condemned by their home governments. Iran has therefore been trying to find new international partners, as their expertise is needed to tap the full LNG potential. As it is, the country's LNG projects are unable to compete with those in neighbouring Qatar.[176]

The available scenarios for Iran's future gas production (Figure 18) predict fairly similar levels of production for the year 2030, ranging from 246 bcm in the EIA 2010 Low Oil Price Scenario to 277 bcm in the EIA 2010 High Oil Price Scenario. Only the IEA 2009 450 Scenario and the IEA 2010 New Policies Scenario forecast significantly lower levels of production for 2030. Along with the other scenarios, they nevertheless assume that Iran's gas production will grow constantly throughout the projection period.

Iran's export capacities, however, are not expected to increase. One reason for this is the continued growth of domestic gas consumption, by an estimated 7 percent annually throughout the next decade. Domestic sales are heavily subsidised and the Iranian authorities seek to extend the use of gas in transportation as a means of reducing import dependencies. Moreover, the expected growth of the petrochemical sector will raise the demand for gas. Thus, Iran is likely to continue using the

171 IEA (2009). *WEO*, p. 488.
172 EIA. *International Energy Statistics*; EIA (2010). *Country Analysis Briefs Iran*; see also IEA (2009). WEO, p. 491.
173 The Economist Intelligence Unit Limited (2010). Industry Report: Energy. Iran, March 2010, p. 16.
174 It has been divided up for development in 25 phases, ten of which are currently online (EIA (2010). *Country Analysis Briefs Iran*).
175 EIA (2010). *Country Analysis Briefs Iran*.
176 The Economist Intelligence Unit (2010). *Iran*, p. 9.

Figure 18: Iran - natural gas production



vast majority of the gas produced for domestic consumption. Additional factors preventing Iran from becoming a major exporter are frequent delays to gas development and international sanctions.[177]

Nonetheless, Iran has expressed plans to export up to 35 bcm/y of gas to Turkey and other European markets, either through the planned Nabucco pipeline or via alternative routes. In order for these plans to become feasible, Iran would first have to improve the investment climate. Furthermore, the development of South Pars needs to be continued and the existing transport route linking southern Iran with Turkey must be expanded. As it is questionable whether these steps will be taken, the IEA expects no more than a slight increase in exports from Iran to Turkey and other European markets over the projection period.[178]

All in all, it is fairly unlikely for Iran to become a major supplier to the EU despite its massive gas reserves. The main reasons for this are, first, the fact that a large share of Iranian gas is consumed domestically, second, the uncertainty related to production prospects and, third, political reservations preventing a closer cooperation with European partners.

4.3.4 North Africa and Nigeria

In order to draw a comprehensive picture of EU external natural gas supply, it is important to include the countries south of the Mediterranean Sea in the analysis. North African countries as well as Nigeria might play an important role in diversifying Europes gas imports. As illustrated at the onset of this chapter, a number of African countries hold considerable shares of global proven gas reserves and, as a result of their geographic location, are predestined to contribute significantly to Europe's security of gas supply. Whether or not the region's major gas producers Algeria, Egypt, Libya and Nigeria will have sufficient export and transport capacities to cater to the EU's rising import needs is the subject of analysis in this section.

177 IEA (2009). *WEO*, p. 491.
178 Ibid., p. 494.

Algeria

Algeria stands out among Europe's African gas suppliers. Aside from holding the second largest gas reserves on the continent (roughly 4.5 tcm), the country's total gas production significantly exceeds that of its Mediterranean neighbours, amounting to nearly 86 bcm in 2008. Of this, less than one third was consumed domestically, and the remaining 58 bcm was shipped to foreign markets. In 2009, production stood at 81 bcm and exports marginally decreased to about 53 bcm, roughly 32 bcm of which were transported via pipeline gas and 21 bcm in the form of LNG.[179]

Algeria extracts its gas mainly from one large field, Hassi R'Mel, which holds proven reserves of 2.4 tcm. Although natural gas production in Algeria is dominated by state-owned Sonatrach, the country is presently working on a number of projects with the support of foreign investors. The Southwest Gas Project, for example, which covers new fields such as the Reggane Nord field is operated by Repsol at an annual capacity of 2.9 bcm. In addition, the Timimoun project is jointly developed by Total, Sonatrach and Cepsa and expected to deliver 1.6 bcm of gas per year in the near term. The Touat project, with a design capacity of 4.5 bcm/y, is set to be fully functional in 2013.[180] On top of that, Statoil and BP are the joint operators of the In Salah and In Amenas gas fields, which have an output of about 9 bcm per year.[181]

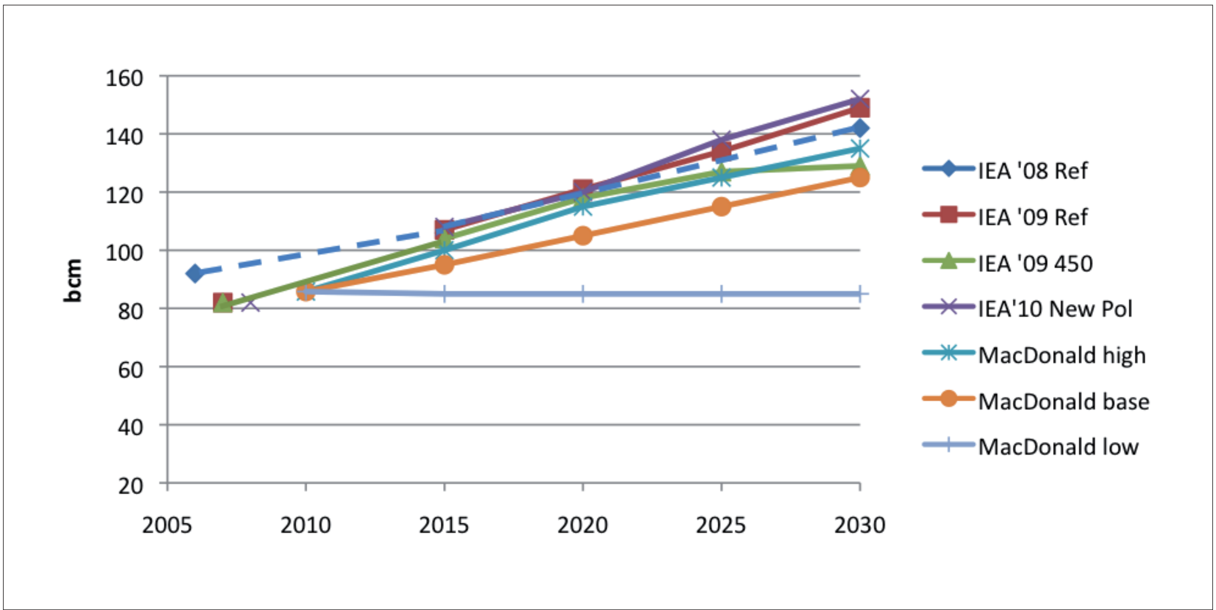
In terms of transport, Algeria commands a vast domestic pipeline network, which connects upstream projects in other regions of the country to the Hassi R'Mel gas field. In fact, all export pipelines to Europe as well as LNG export terminals are linked to Hassi R'Mel, making it the country's main internal and external gas hub.[182] Currently, Algerian gas is exported to Europe via two lines: the Enrico Mattei Gasline (EMG, also called Transmed), connecting Algeria to Tunisia and Italy with an upgraded capacity of 33.5 bcm/y; and the Pedro Duran Farell Gasline (PDFG, also Maghreb-Europe Gas pipeline) linking Algeria to Spain via Morocco. Since 2005, the pipeline delivers 11.5 bcm of gas per year and it may be expanded to 20 bcm in the future.[183]

In order to scale up exports to Europe three additional pipeline projects are currently under way. Medgaz, with a 8 bcm/y transmission capacity, aims at connecting Hassi R'Mel to the Spanish coast across the Mediterranean Sea and is set to be operational by 2011. Galsi, which features the same design capacity, will tie Algerian gas to the Italian transmission network in Tuscany. This link, however, has experienced delays in the authorization phase.[184] Finally, a new 4.400 km Trans-Saharan gas pipeline is currently in the planning phase, which might eventually transport gas from Nigeria via Algeria to Europe - the realization of the project, however, is uncertain.[185] Aside from pipeline gas, LNG makes up around one-third of Algeria's total gas exports. Four LNG plants, namely Arzew, Skikda, Bethioua and Gassi Touill have a combined capacity of 21 bcm per year. In the course of planned capacity expansions until 2013 this figure is estimated to nearly double. [186]

The evolution of Algeria's gas industry in recent years has been promising and the country's projected production and export capacities are of utmost relevance to European markets. Therefore, a thorough analysis of Algeria's future supply potential seems necessary.

179 EIA. *International Energy Statistics*; EIA (2010). *Country Analysis Briefs Algeria*.
180 EIA (2010). *Country Analysis Briefs Algeria*.
181 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Algeria*, March 2010, p. 12.
182 Ibid.
183 Mott MacDonald (2010). *Supplying the EU natural gas market*. Final Report. November 2010, p. 9.
184 The Economist Intelligence Unit (2010). *Algeria*, p. 12-13.
185 Ibid.
186 EIA (2010). *Country analysis briefs Algeria*.

Figure 19: Algeria - natural gas production



According to most of the scenarios displayed in Figure 19, Algeria is likely to produce roughly twice as much natural gas in 2030 as it does today. The rising trajectories, especially of the 2008 and 2009 IEA Reference cases and the IEA 2010 New Policies Scenario, suggest that, on the assumption of moderate economic growth and regardless of political decisions taken by the EU, Algeria will substantially strengthen its position as a global gas supplier. It is striking that even in the IEA 2009 450 Scenario, which implies significantly reduced gas consumption in Europe, Algeria will still expand its production by almost 60% between 2007 and 2030. Only the Mott MacDonald 2010 Low Case forecasts a stagnation of Algerian gas production over the projection period.

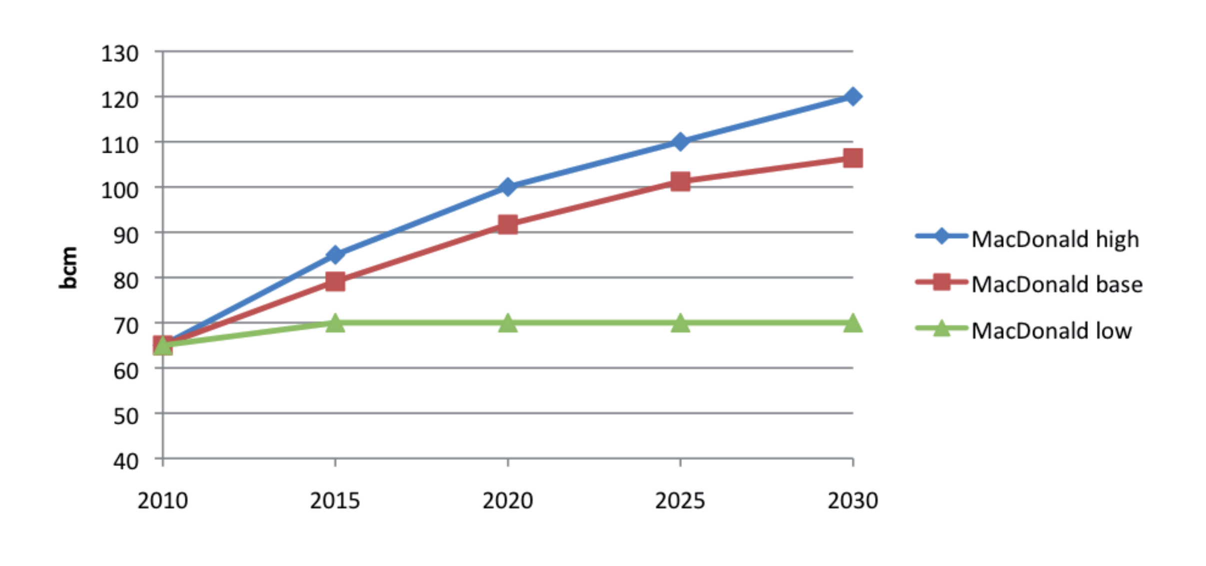
Provided that the planned transport infrastructure projects will be completed, Algeria has the potential to remain an essential gas supplier to the EU in the future. Not only is its gas production set to increase tremendously, it is also estimated that its export capacity may rise to as much as 90 bcm in 2030, according to Mott MacDonald's 2010 High Case. The moderate Base Case, on the other hand, expects exports to reach a level of 72 bcm in the same year. In the Low Case, domestic consumption surges to 65 bcm in 2030, thereby reducing Algeria's export capacity to a mere 20 bcm per annum. In sum, Algeria seems to be headed towards a prosperous energy future. With stable economic growth, the country will be capable of providing additional supplies, of approximately 10 bcm to 30 bcm, to Europe until 2030. Thanks to existing and planned pipeline and LNG infrastructure, Algeria is also endowed with the means to deliver these volumes across the Mediterranean Sea. Thus, Algeria is very likely to defend its prominent position among the EU's gas suppliers.

Egypt

Egypt holds the third largest proved natural gas reserves in Africa, after Nigeria and Algeria, and is the second largest producer (59 bcm in 2008 and 63 bcm in 2009) on the continent. In contrast to its western neighbor Algeria, however, it consumes around two-thirds of its total gas supplies domestically. While this deprives foreign consumers of access to a large share of Egyptian gas, the country is still a major gas exporter. Over the past ten years production has increased tremendously, nearly tripling since 1998, in 2009 Egyptian exports amounted to almost 20 bcm.[187]

This being said, the question is where Egyptian gas originates and how it reaches European markets. First of all, it is important to mention that the Egyptian gas sector is dominated by the state-owned General Petroleum Corporation, which controls upstream activities such as licensing, infrastructure and production. While no specific data is available for the size of individual gas fields, the lion share of the country's gas will probably continue to be sourced from fields in the Mediterranean Sea, the Nile Delta and the Western Desert.[188] Egypt holds proven reserves of approximately 1.7 to 2.2 tcm[189] and its gas production, which presently reaches roughly 60 bcm per year, is expected to increase steadily over the projection period. This, of course, is beneficial for European consumers, as the additional volumes of gas will most likely contribute to securing gas supply in the EU. However, the expansion of exports is expected to be limited by Egypt's surging domestic gas demand and political interference in the allocation of Egypt's gas reserves.[190]

Figure 20: Egypt - natural gas production



With regard to transport infrastructure, Egypt currently operates a relatively small pipeline network to connect production sites to foreign markets. This explains the fairly low share (30%) of pipeline gas in total exports. Major recipients of Egyptian pipe gas are its neighbours Lebanon, Jordan and Syria, which are connected to Egypt by the Arab Gas Pipeline (AGP). This link with a current throughput of 3.8 bcm/y and a design capacity of 10 bcm/y could eventually be expanded to Turkey.[191] Furthermore, the Arish-Ashkelon pipeline, which branches away from the AGP and physically links Egypt to Israel, transports for 1.7 bcm annually.[192]

The remaining 70% of Egyptian gas exports (approx. 13 bcm in 2009) are shipped to consumers in the form of LNG. Egypt's European consumers (e.g. France and Spain) play a considerable role, as do the US, Japan, India and South Korea. To make these amounts of LNG available to such remote markets, two LNG facilities are presently in place: an ELNG plant situated in Idku, comprising two trains with

187 EIA. *International Energy Statistics*; EIA (2010). *Country Analysis Briefs Egypt*.
188 EIA (2010). *Country Analysis Briefs Egypt*.
189 EIA. *International Energy Statistics;* BP (2010). *Statistical Review of World Energy*.
190 MacDonald (2010). *Supplying the EU natural gas market*, p. 10.
191 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Egypt*, July 2010, p. 14.
192 MacDonald (2010). *Supplying the EU natural gas market*, p. 11.

a composite capacity of 9.8 bcm per year and the SEGAS terminal at Diametta, which produces 6.5 bcm annually and is set to be upgraded by a second train in the near future.[193] While the LNG export capacity is 16 bcm, only 13 bcm were actually exported in 2009, 6.7 bcm of which were destined for European consumers. Interestingly, all LNG facilities are operated with the help of foreign investors, including Petronas, BG, EGAS and Gaz de France.[194]

The marked increase in Egyptian gas production in recent years is expected to continue, mainly thanks to offshore fields in the Mediterranean Sea. Therefore, all production forecasts of Mott MacDonald 2010 draw a rather optimistic picture (Figure 20). The High Case projects gas supply to double from current levels to 120 bcm in 2030, causing exports to climb to as much as 60 bcm/y. The Low Case, on the other hand, estimates production to increase but marginally, to no more than 70 bcm at the end of the projection period. Moreover, this case projects domestic demand to rise rather drastically to the point where Egyptian imports of 25 bcm may be required by 2030.[195] The Base Case shows an intermediate trajectory expecting gas production to rise steadily to 92 bcm in 2020 and 106 bcm in 2030 and exports to remain at current levels.

In view of the positive overall trend in the Egyptian gas sector, one may assume that the relatively moderate supply to Europe of roughly 7 bcm in 2009 will be augmented according to scheduled capacity expansions. However, it is important to consider Egypt's domestic policies and consumption, as these factors will eventually determine whether the country will become a major exporter or a net importer of natural gas in the future.

Libya

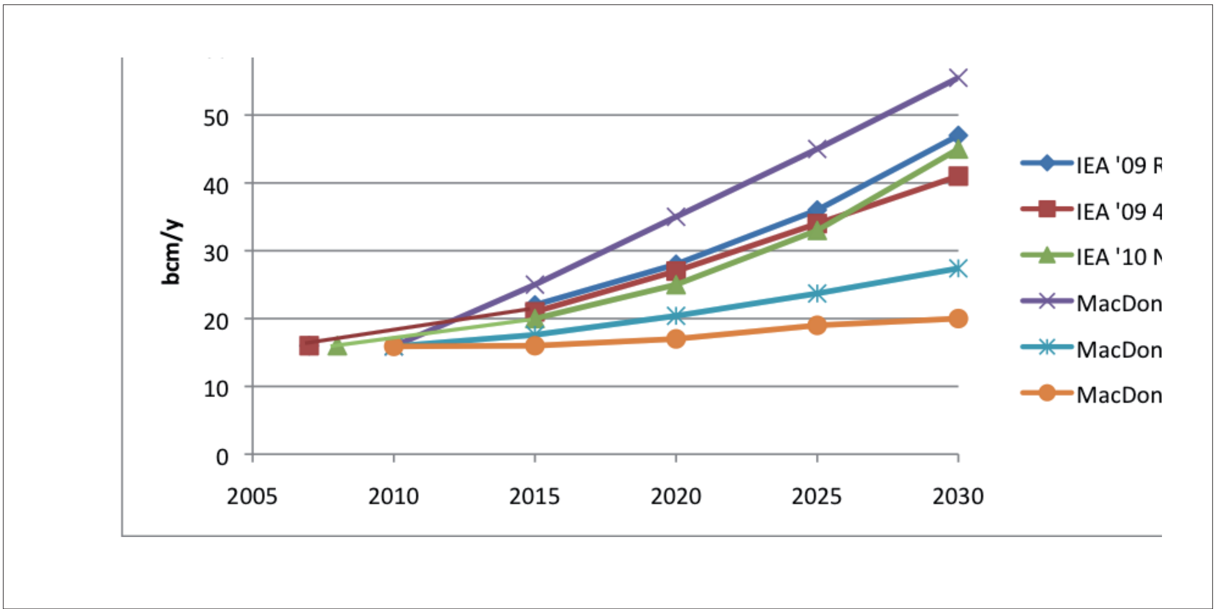
Compared to its North African neighbours, Libya is considered a minor gas supplier, although far from unimportant for Europe´s energy security. With exports of about 10 bcm per annum, it accounted for only 12% of the region's total exports in 2009, whereas Algeria accounted for 65% and Egypt for 24%.[196] Given proven natural gas reserves of 1.5 tcm, these relatively low export rates seem striking. Libya's overall gas production has risen sharply, from 6 bcm in 2003 to 11 bcm in 2005 and roughly 16 bcm in 2009, which is in line with the country's ambition to become an important gas supplier in the region. While the reserves-production ratio still exceeds factor 100, Libya's gas deposits promise great potential for future gas supplies. The most prominent fields, currently making up most of the country's production, are the onshore Al-Wafa and the offshore Bahr es Salam fields, which form part of the Eni-led West Libya Gas Project that has been fully operational since 2005.[197]

As mentioned above, Libya´s exports rose to roughly 10 bcm in 2009. More than 90% of exports were delivered by one single pipeline, Greenstream, which runs beneath the Mediterranean Sea from Mellitah to Sicily, Italy.[198] In order to increase exports to Europe there are plans to scale up Greenstream's capacity to 20 bcm in the near future. The remainder of exports is transported in the form of LNG, processed at a single LNG plant in Masra EL Brega, which is fed by six small fields in the Sirte Basin. From there, Libya's entire LNG production, which amounted to the small number of 0.5 bcm in 2008, is shipped to Spain.[199] Libya's fairly low gas production and export rates may be attributed to the fact that, in the past, political priorities have favoured the oil industry rather than

193 The Economist Intelligence Unit (2010). *Egypt*, p. 14.
194 EIA (2010). *Country Analysis Briefs Egypt*.
195 MacDonald (2010). *Supplying the EU natural gas market*, p. 10.
196 MacDonald (2010). *Supplying the EU natural gas market*, p. 9-12.
197 EIA (2010). Country Analysis Briefs Libya; EIA. *International Energy Statistics*.
198 MacDonald (2010). *Supplying the EU natural gas market*, p. 12.
199 Massaras, D. (2007). *Libya - Land of Emerging Opportunities*, IHS. Available online at: http://energy.ihs.com/News/published-articles/articles/libya-land-emerging-opportunities.htm (last accessed: 03.02.2011); EIA (2010). *Country Analysis Briefs Libya*.

the gas business. On top of that, for a long time UN sanctions have impeded an expansion of LNG production, as technical limitations could not be overcome without external assistance.[200] As this is about to change, a prosperous future for the gas sector might unfold, not least as a result of an expansion of gas-fired electricity generation.

Figure 21: Libya - natural gas production



According to most scenarios displayed in Figure 21, Libya's natural gas production will expand massively over the next two decades. All three IEA scenarios assume that current output will triple within the next twenty years to as much as 41 to 47 bcm by 2030. The MacDonald 2010 High Case provides an even more optimistic outlook, anticipating production to exceed 55 bcm by the end of the projection period. In contrast, the Mott MacDonald 2010 Base and Low Cases project a fairly moderate to pessimistic evolution of Libyan gas supply, which they forecast to reach 27 or 20 bcm in 2030, respectively.

Compared to production scenarios, export availability[201] forecasts seem somewhat bleak. This is due to an expected rise in domestic electricity demand and limited technical capacities to produce and transport additional volumes of gas. In order to make additional volumes available to foreign markets, Libya needs to lower the rates of gas flaring and increase investment in infrastructure.

Nigeria

The EU's fourth largest external gas supplier, Nigeria, is located further south on the African continent. While holding the largest proven gas reserves in Africa (5.2 tcm), its geographic location somewhat complicates pipeline deliveries to distant export markets such as those in Europe. Nevertheless, Nigeria has managed to supply large volumes of the commodity to a wide range of consumers across the globe, almost entirely through sea transport, in the form of LNG. It is striking that despite being the largest reserve holder in Africa, Nigeria´s annual gas production amounted to no more than 32.8 bcm in 2008 and 23.2 bcm in 2009, which is less than half of Algeria's output. As domestic consumption accounted

200 MacDonald (2010). *Supplying the EU natural gas market*, p. 12.
201 A function of total supply and domestic consumption.

for 12 bcm in 2008, 20.8 bcm were available for exports in the same year.[202]

Most of the country's gas reserves are situated in the Niger Delta, where security issues, sabotage and bunkering prevent the establishment of urgently needed infrastructure. This has an impact on the oil and gas business and causes the waste of associated gas through gas flaring. Moreover, political instability deters foreign investment, thereby preventing a modernization and expansion of upstream activities.

Nevertheless, in 2008 Nigeria supplied 14 bcm of LNG to foreign markets, most of which was shipped to destinations in Europe (9.3 bcm), the US (0.4 bcm), Mexico (2 bcm) and Asia (2 bcm). Compared to the previous year, however, LNG exports went down by 30%. According to the EIA 2010[203] this dramatic plunge was a consequence of technical difficulties obstructing one of the country's major LNG processing facilities. The bulk of Nigerian LNG is produced at the Nigeria Liquified Natural Gas facility on Bonny Island, jointly operated by NNPC, the Nigerian National Petroleum Corporation, Shell, Total and Agip.[204] The terminal utilizes six trains, with a composite capacity of more than 30 bcm per year. An additional train for this plant is scheduled to become operational in 2012. Moreover, three new LNG terminals are expected to commence operations in 2012[205]. The exact date depends heavily on potential investment and construction delays caused by security threats as well as LNG market developments.

Although most of Nigeria's exports are shipped in the form of LNG, since 2010 the country also supplies gas to its western neighbours Benin, Togo and Ghana via the West African Gas Pipeline. The main section of this link runs offshore along the coast, from where it branches off to all three partners. Its initial export capacity is 1,7 bcm/y, but eventually it will reach its design capacity of 5 bcm/y.[206] Moreover, as previously indicated, Nigeria and Algeria are in the process of discussing the feasibility of a Trans Saharan Gas Pipeline, reaching from the Niger Delta to the export terminal of Beni Saf on the Mediterranean Sea. Nigeria´s NNPC and Algeria's Sonatrach have signed a Memorandum of Understanding in 2009 to promote the further development of the project.[207] The project's realization, however, is complicated by the sheer length of the pipeline as well as by the risk of sabotage. Nevertheless, the prospects for Nigeria's gas industry have improved considerably in 2009, when the NNPC and Gazprom agreed to set up a new joint venture called Nigaz to develop the country's oil and gas sector.[208]

Forecasts of Nigeria´s natural gas production are limited to figures provided by The Economist Intelligence Unit (2010). Neither of the previously cited organizations, such as the IEA, EU, EIA and Mott MacDonald, provides gas supply forecasts for Nigeria. The Economist Intelligance Unit only considers the period between 2009 and 2020 and little information is avaible regarding underlying scenario assumptions.

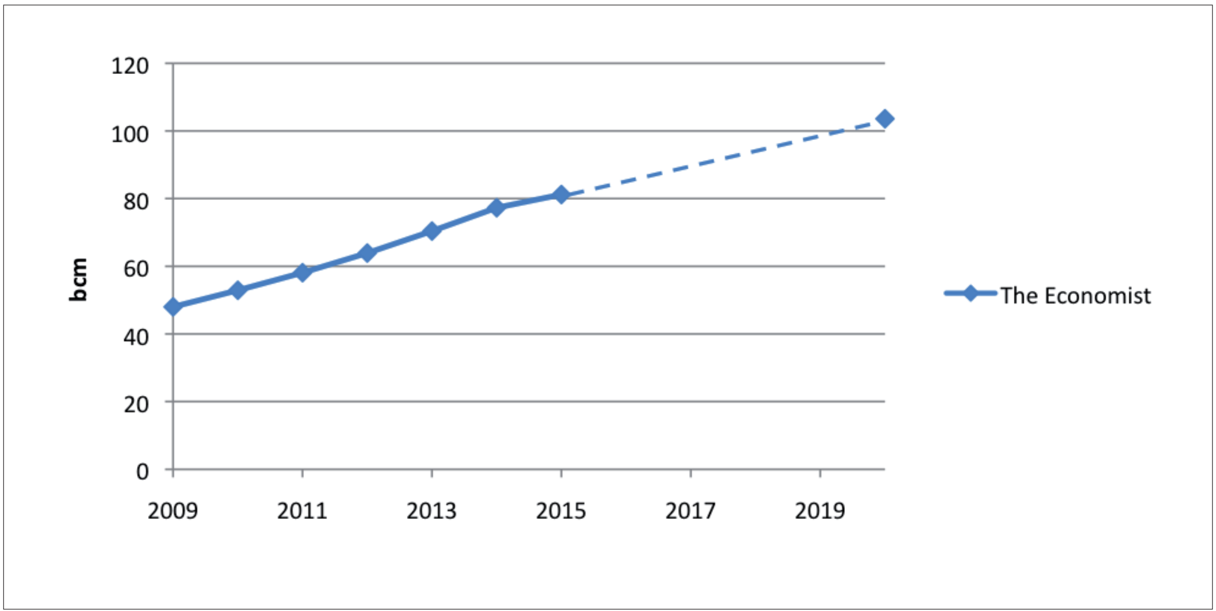
Figure 22 illustrates a clear trend regarding the future development of Nigeria's gas supplies. Starting at 48 bcm in 2009, the production curve is assumed to rise steadily over the next decade. By 2020, production is projected to more than double, reaching roughly 100 bcm. Due to the lack of alternative scenarios, however, it is difficult to estimate how changes in political or economic conditions would impact on Nigeria's gas supply. Moreover, the availability of gas exports might be curtailed by the

202 EIA (2010). *Country Analysis Briefs Nigeria*; EIA. *International Energy Statistics*.
203 EIA (2010). *Country Analysis Briefs Nigeria*.
204 The Economist Intelligence Unit Limited (2010). *Industry Report: Energy. Nigeria*, March 2010, p. 13.
205 EIA (2010). *Country Analysis Briefs Nigeria*.
206 West African Gas Pipeline Company. *About the pipeline*. Available online at: http://www.wagpco.com (last accessed: 03.02.2011).
207 EIA (2010). *Country Analysis Briefs Nigeria*.
208 The Economist Intelligence Unit (2010). *Nigeria*, p. 14.

country´s surging domestic gas consumption, which is projected to triple by 2020, to 39 bcm or more.[209] Therefore, much uncertainty remains as to Nigeria's likely export potential in the mid-term, and even more so in the long term.

Nigeria, in fact, holds considerable gas reserves and may expand its production swiftly in the coming years. Whether or not these additional capacities will translate into rising exports to European markets, however, will primarily hinge on the physical, legal and investment security as well as on Nigeria's domestic gas demand.

Figure 22: Nigeria - natural gas production



Concluding remarks

This chapter has shown that several regions and countries in the EU's immediate neighbourhood as well as further afield have the potential to contribute to the bloc's rising gas import needs in the future. The first part of the chapter has shown how proven reserves and ultimately recoverable resources are distributed across the globe. The findings suggest that the bulk of existing gas reserves are located within reach of the EU, namely in Russia and the Middle East, but also in North Africa and in the Caspian region. This is definitely a cause for optimism in terms of Europe's security of natural gas supply. Yet, a differentiated analysis of the current and likely future gas suppliers of the EU has yielded ambiguous results. Some countries have large resource bases, but lack the exploration, production and transport capacities necessary to tap the full potential of these resources. Others experience rising production rates, but their ability to export gas is diminished by a simultaneous and swift growth in domestic gas demand.

According to most scenarios, Russia, Europe's leading external natural gas supplier will expand output in the mid- to long-term, despite currently declining production rates. The pace of output growth, however, is critically dependent on the timely development of new gas fields in the Barents Sea and on the Yamal Peninsula. If there are delays in their development, the expected increase in domestic demand could jeopardize the availability of sufficient volumes of gas for exports. Norway, the EU's second largest gas supplier, is assumed to experience increasing production rates until 2020 or 2025

209 Ibid.

and declining rates thereafter. Its role as a major gas supplier may thus be threatened in the long term if new fields on the Norwegian continental shelf, in the Artic and in the Barents Sea are developed too sluggishly or if they yield too little to compensate for the depletion of other fields.

As far as the Caspian region and Central Asia are concerned, the analysis highlighted that two countries are particularly qualified to serve as future gas suppliers to the EU, namely Azerbaijan and Turkmenistan. While Azerbaijan's proven reserves are comparatively small, the development of the Shah Deniz field has turned the country into a net exporter of natural gas and the start of phase II of this project in 2017 is expected to increase Azerbaijan's exports substantially. The main concern regarding Azeri gas exports to Europe is the current lack of transport infrastructure. This puzzle needs to be resolved if Europe is to tap the country's supply potential and to diversify its gas imports. In addition, Turkmenistan may play a noticeable role with regard to Europe's gas supply, as it controls huge gas reserves and as it may more than quadruple its exports by 2030. Yet, the country's rigid policy on upstream investment may cause production and exports to grow much slower than desired. While gas from Turkmen onshore facilities is unlikely to be transported to the EU, offshore production may eventually provide 10 bcm/y of exports to Turkey and Europe.

The Middle Eastern countries constitute another group of gas suppliers, two of which were examined closer in this study, namely Qatar and Iran. Qatar is already among the EU's gas suppliers and contributes roughly 2% to Europe's overall gas imports. Moreover, due to its massive natural gas reserves and excellent upstream and transport infrastructure, the country is likely to consolidate or even expand this share in the coming decades. Since gas is exported solely in the form of LNG, however, Qatar's future role as a supplier to the EU will be determined by the availability of re-gasification infrastructure in the EU as well as by gas price developments in the three major regional gas markets, Europe, the US and Asia. At the same time it is rather unlikely that Iran, which holds the second largest gas reserves in the world, will become a major gas supplier to the EU. The main reasons for this are that a large share of Iranian gas is consumed domestically, that there is uncertainty related to production prospects, and that political reservations prevent a closer cooperation with European partners.

Finally, a number of African countries have been subject to analysis in this chapter, the majority of which are located in North Africa. Algeria is expected to retain or even expand its prominent position among EU gas suppliers in the future. Not only does it control massive natural gas reserves, it also has an elaborate pipeline and LNG infrastructure system at its disposal, which is set to be expanded further. By 2030, it may be able to supply around 10 to 30 bcm/y of additional gas to Europe. Egypt, on the other hand, is the third largest gas reserve holder in Africa, but, due to limited production and transport capacities, it is currently only exporting a small amount of natural gas to the EU. While Egyptian exports are expected to rise in the coming years as a result of capacity expansions, it is important to consider the country's domestic policies and rising consumption. These factors will eventually determine whether the country becomes a major exporter or a net importer of natural gas. Similar to Egypt, Libya's current gas production and exports are fairly limited. According to the presented scenarios, however, output may increase tremendously over the projection period. Yet, this will not necessarily be reflected in larger volumes of gas exports, since domestic demand is set to rise sharply and transport infrastructure will remain limited. The largest gas reserve holder in Africa and fourth largest external gas supplier to the EU, Nigeria, is situated relatively far from European gas markets. Compared to a country such as Algeria, Nigeria currently underperforms in terms of the ratio between production volumes and resource potential. Although Nigeria's gas production is predicted to increase significantly in the coming years, persisting security concerns may deter investment and rising domestic consumption may slow the growth in gas exports.

5 Conclusion

This report has provided an overview of the current role of natural gas in the EU and its potential evolution over the next two decades. First, the role of gas in the EU's current energy mix was presented, focusing on structural features of gas consumption in Europe and existing challenges to a sustained security of gas supply. Subsequently, the two main chapters of this report have attempted to shed light on the future development of EU natural gas demand and supply. To this end, a wide range of energy market scenarios compiled by the European Commission, the International Energy Agency, the U.S. Energy Information Administration and other organizations have been analyzed. Demand forecasts were analyzed first. In the next step, they were compared with EU production forecasts, which revealed that the EU will be increasingly dependent on imports. Against this background, the report examined which regions and countries will be able to supply the EU with the required amounts of gas throughout the projection period.

The question underlying the report as a whole is whether natural gas is going to play a significant role in the EU over the next two decades and, if so, from where the EU may obtain the required volumes. The first section of the report has shown that gas currently accounts for approximately 25% of EU Gross Inland Energy Consumption, being of particular importance in the residential and commercial sectors, in industries, and in power generation. At the same time, EU gas production is insufficient to cover domestic demand, which amounted to about 550 bcm in 2008. Each year, the EU needs to import large volumes of gas from third countries - particularly Russia, Norway and Algeria. In an attempt to diversify its suppliers and transit routes, the EU supports a number of new pipeline projects such as Nord Stream and Nabucco and seeks to intensify energy relations with natural gas producers in the Caspian Basin, Central Asia, the Middle East and North Africa. In addition, the EU supports the use of LNG as an alternative to traditional pipeline gas, which already covered 13 to 15% of the EU's gas consumption in 2008.

Future levels of EU import dependence are, to a great extent, a function of domestic demand. The first one of the two major sections of this work package has therefore dealt with EU gas demand forecasts up to the year 2030, examining a broad range of scenarios compiled by a number of renowned research organizations. To make each approach transparent, the report commenced by explaining the scenarios' respective data composition and methodology and by listing and explaining the variables employed and the assumptions made. Subsequently, a qualitative analysis of the main factors influencing gas demand was undertaken. EU GDP growth and fuel price developments were identified to have the strongest impact on gas demand. Their effects are particularly pronounced in the power and industrial sectors. In addition, energy and climate policies, affecting all sectors to a similar extent, seem to be important determinants of gas demand. The impact of technology, while being difficult to assess, is considered relevant as well.

Against this background, the report analyzed the natural gas demand forecasts. Their comparison revealed two possible trends: The scenarios assuming high economic growth, limited deployment of low-carbon technologies, and slack climate policies forecast gas demand to grow consistently over the next two decades, reaching 600 to 650 bcm by 2030. In contrast, the scenarios featuring ambitious RES policies, alongside a recovery of nuclear energy and relatively high CO_2 and oil prices, predict gas demand to decline to 470 to 530 bcm by the end of the projection period. Drawing on the different forecasts, the report concluded that the EU's natural gas demand is likely to reach a level of 470 to 650 bcm in 2030. This range, although wide, served as an important point of reference for the subsequent supply side analysis.

The first question to be answered in the supply side section, then, concerned the extent to which the EU will be able to cover such levels of consumption with domestically produced gas. According to all scenarios compared in this report, EU gas production declines by more than 50% over the next two decades due to the depletion of existing gas fields. The scenarios suggest that domestic production will stand at 70 to 100 bcm in 2030, thus covering a probable share of less than 20% of the EU's projected gas consumption. The remaining gas, 370 to 580 bcm, will have to be imported from third countries.

After having reached estimates of the EU's future import requirements, the report turned to examining the supply potential of selected regions and countries. Russia and the Middle East as well as North Africa and the Caspian Basin control the bulk of existing gas reserves. However, a detailed analysis of the EU's potential future suppliers has shown that other factors are often more important to consider. Some countries have large resource bases but lack the exploration, production and transport capacities necessary to tap the full potential of those resources. Others experience rising production rates, but their ability to export gas is diminished by a simultaneous growth in domestic demand.

The country analyses undertaken in this report suggest that Russia will remain the largest supplier to the EU throughout the projection period. According to the IEA 2010 New Policies Scenario, the country's net exports will increase from 209 bcm in 2008 to 269 bcm in 2030. Norway is currently the EU's second largest gas supplier and most of the 99 bcm of gas exported in 2009 went to European markets. Most production forecasts indicate that the country may be able to deliver an additional 20 to 25 bcm in the second half of the projection period. However, Norway will only be able to maintain a high level of exports under the condition that new fields on the Norwegian continental shelf, in the Artic and in the Barents Sea yield enough to compensate for the depletion of other fields.

In the Caspian region, two countries have proven to be particularly qualified to serve as future gas suppliers to the EU, namely Azerbaijan and Turkmenistan. Azerbaijan, although endowed with comparatively small resources, is expected to increase its exports considerably throughout the projection period. The IEA 2010 New Policies Scenario projects Azerbaijan´s net exports to reach 35 bcm by 2030. European markets are expected to be the main recipients. Turkmenistan, on the other hand, controls huge gas reserves and it may more than quadruple its exports throughout the projection period. The country's net exports may reach 85 bcm by 2030 and about 10 bcm of gas may eventually be exported to Turkey and Europe. Imports from Azerbaijan and Turkmenistan could make a major contribution to the EU's plans of diversifying its gas supplies via the Southern Corridor.

Of the Middle Eastern countries, the most promising future supplier to the EU is Qatar. The country already contributes more than 2% to Europe's overall gas imports and, due to its massive natural gas reserves and excellent upstream and transport infrastructure, this share might well increase throughout the projection period. Iran, on the other hand, is rather unlikely to become a major gas supplier to the EU despite holding the world's second largest gas reserves. A large share of Iranian gas is consumed domestically, production prospects are uncertain, and political reservations prevent closer cooperation with European partners.

Potentially important future gas suppliers can also be found on the African continent, particularly in the North. Algeria is expected to consolidate or even expand its prominent position among EU gas suppliers. Not only does it control massive natural gas reserves, the country is also planning on further extending its already elaborate network of pipeline and LNG infrastructure. By 2030, Algeria may be able to supply the EU with an additional 10 to 30 bcm of gas. Its total net exports may reach as much as 72 bcm by the end of the projection period according to the MacDonald 2010 Base Case. Egypt, on the other hand, only exports a small amount of natural gas to the EU despite being Africa's third largest gas reserve holder. At this stage, it is unclear whether the country will become a major exporter or a net importer of natural gas, although the MacDonald 2010 Base Case projects Egypt's net exports to amount to 20 bcm in 2030. Either way, the EU should not count on procuring any significant amounts of gas from Egypt throughout the projection period. Furthermore, this report analyzed Libya's and Nigeria's potential to supply the EU with natural gas, as both countries have significant resources at their disposal. While Libya is unlikely to become a relevant supplier to the EU before 2030, Nigeria has the potential to strengthen its position among EU suppliers over the next two decades. However, much will depend on issues such as political stability and investment security.

The country analyses have shown that Russia, Norway, Algeria, Azerbaijan, Turkmenistan, Qatar, and to a certain extent Nigeria, are likely to serve as the EU's main suppliers of natural gas throughout the projection period. Moreover, the production and export forecasts for these countries suggest that, when combined, they will be able to cover most of the EU's projected additional import requirements. However, future levels of gas production (beyond 2020) very much depend on political decisions. In producing countries, decisions about access to new areas and tax regimes will be most relevant. Moreover, without clear political commitments by the EU (EU institutions and member states) concerning the future gas consumption, investments in projects able to supply the EU with gas will struggle to go forward. Only if access is granted to new areas and prospects for gas consumption in Europe will be reasonably positive, can it be assumed that companies will make investment decisions to develop new projects.

This being said, it is equally important to underline that Europe is surrounded by abundant gas resources – but in order to make these accessible for Europe and ensure necessary investments, clear political signals from the EU are needed.