THE WESTERN EUROPEAN GAS MARKET

Future Gas Infrastructure in Western Europe

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Summary

The purpose of this paper is to assess the needs for long distance gas transport infrastructure investment in western Europe (i.e. the European Union, Norway and Switzerland). The analysis of eastern European markets is limited to their impact on western European gas markets. The main conclusions are:

The increase in gas demand during the next 10 to 15 years will be met entirely from imports

- Gas demand will continue to grow relatively fast. Western European gas demand could expand from 330 bcm currently to about 390 bcm in 2000 and 410-450 bcm in 2010. Demand from the power sector will grow faster than demand in other sectors, although its growth rate will decrease over time. The residential sector will also contribute signficantly to overall gas demand growth.

- The growing demand will require more gas imports, given the expected stagnation (or decline) of domestic gas production in Europe around the present level of 200 bcm per year. As a result, western Europe's outside dependence will increase from about 30% at present to about 40% in 2005.

- Algeria, Russia and Norway can cover the gap between western European demand and production, up to and beyond 2010. Alternative sources are not necessary although Europe might call upon long distance suppliers to diversify supply sources. New sources (Qatar, Iran, Abu Dhabi, Trinidad, etc.) could possibly supply up to 100 bcm per year to Europe. However, in most cases, long distance gas delivered to Europe is more expensive than gas transported to Europe from Algeria, Russia or Norway.

- These forecasts assume that current energy policy options will be maintained. However, around 2010, major decisions will have to be made on Europe's long term energy policy (especially the replacement of new nuclear plants). If major policy changes took place (e.g. early nuclear decommissioning), this could increase long term future gas demand substantially.

Investment requirements will remain high

- Current import capacity (about 200 bcm of pipelines and over 40 bcm of LNG) would not be sufficient to meet western and eastern Europe's growing needs for imports. New gas infrastructure investments are needed between now and 2005.

- **Algeria**'s official export target of 60 bcm per year is consistent with its current investment programme consisting of the capacity increase of the pipeline to Italy (Transmed), the completion of the pipeline to Spain (GME) and the upgrades of Algeria's LNG facilities (all projects to be completed in 1996-97). Upgrade of the GME pipeline could be implemented if Algeria decided to increase its exports, although there is no plan to do so in the immediate future.

- **Norway**'s gas exports (30 bcm) could more than double in ten years. This will require additional transport capacity. Norway is about to start the construction of a new pipeline to France (NorFra) and then intends to build a new pipeline to Germany

(Europipe II). The next step, if required, would be to upgrade an existing pipeline (possibly Zeepipe).

- **Russia**'s expected sales to eastern and western Europe should be above 125 bcm in 2000, which exceeds Russia's existing transportation capacity to Europe. Full upgrading of the existing pipeline system (to 140 bcm) might just enable the fulfilment of eastern Europe's expected demand and western Europe's signed contracts with Russia up to 2005. However, new contracts between western Europe and Russia will require a new trunk pipeline.

- There are firm plans to build a new gas pipeline to link Russia to Germany through Poland and Belarus (**Yamal** pipeline). The full cost of this project (ie the full pipeline from Germany to the Yamal peninsula) is estimated at around USD 30 bn. The first phase of the project (from Germany to Torzhok between Moscow and St Petersburg) is likely to be under USD 10 bn. So far, financing has not been arranged and there are serious doubts whether Belarus and Russia will be able to finance their part of the pipeline (without which the German and Polish parts of the project would be useless).

A temporary excess of supply is possible in the medium run

- On the basis of contracts either existing or under negotiation, there may be a potential for excess supply until 2000, that could be accomodated either by variations of gas quantities taken around quantities contracted (swing or take-or-pay) or by a reduction in domestic gas production from the most flexible fields (especially Groningen in the Netherlands). If this short run excess supply materialises, it could lead to a fall in prices at a time when new gas infrastructure investments need to be built. The mechanisms for such a fall in prices could be exports of British gas through the UK-Continent interconnector or aggressive marketing by Russia's Gazprom.

Competition is likely to develop

- There seems to be an increasing tendency for competition to develop in the European gas market. A full scale market liberalisation, including vertical disintegration and the creation of gas spot markets, is currently taking place in the UK. In Germany, competing gas networks are under completion. More recently, tentative projects, challenging existing monopolies, were put under study in Italy, in the Netherlands and in Spain.

- Competition could increase infrastructure requirements and impose adjustment costs on existing gas companies. At the same time, competition should reduce sales prices (compared to prices set by monopolies). This will require productivity improvements or lead to a squeeze in profits (or both).

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1. Introduction[1]

The focus of this paper is to assess the needs for long distance gas transport infrastructure investment in western Europe (defined here as the European Union, Norway and Switzerland). The analysis of eastern European markets is limited to their impact on western European gas markets. The paper presents demand forecasts for western Europe up to 2010. Then, it considers how demand can be expected to be covered by existing and potential contracts. For each large supply source, it compares Europe's supply requirements with existing and planned gas transportation infrastructure. Finally, it describes the development of competition in European gas markets and its consequences for investment. It concludes with a review of the main risks that an investor faces in the European gas market.

The impact of competition in gas networks is examined in some detail because it emerges as the main structural change currently at work in the gas market. The 1960s saw the massive expansion of natural gas consumption in parallel with the development of onshore dry gas fields (Groningen, Lacq, Po Valley,...). The 1970s saw the expansion of offshore exploration and production (North Sea). The 1980s were first a period of slow growth (second oil shock) and then saw the development of gas for electricity generation in some big markets (the UK, Italy), a trend that is continuing at least for the next few years. The 1990s saw the first signs of gas market liberalisation in the UK and the introduction of competition in Germany. If this extends to other countries, as is likely, the introduction of competition will affect the investment level and generally the organisation of the industry.

1 The paper expresses the views of its author, not necessarily those of the EIB.

2. Gas Demand Until 2010

2.1. A bottom-up approach

There are two alternative ways of forecasting gas demand. First, there is the top-down approach, which is essentially macro-econometric: one forecasts a GDP growth rate, then derives a growth rate for energy demand as a whole, then estimates the share of gas in total energy demand. It has two major drawbacks. First, it is not adapted to situations of structural changes, such as those encountered in energy markets and especially in gas markets in the 1990s. Second, such models, based on estimates of elasticities, are only valid when the model's parameters take their values within a limited range; models sometimes over-react when parameters are set outside that initial parameter range.

The alternative is an eclectic bottom-up approach. It aggregates market forecasts prepared on the basis of information provided by the main market participants. It presents the advantage of taking full account of the gas and electricity companies' strategies and of integrating as much as possible the effects of structural changes. Its drawback is that there can be less macroeconomic consistency between the various components of the forecast. We have adopted the second approach but then checked for consistency with the macroeconomic approach. More specifically, we estimated future demand by sector (electricity sector, industry, residential and commercial) for Belgium, France, Germany, Italy, the Netherlands, Portugal, Spain and the UK. Demand in these countries represents 95% of total western European gas demand. Less detailed forecasts have been made for the other western European countries. The situation is summarised in the next paragraphs.

2.2. *Gas demand: prospects by sector*

2.2.1. Power sector

Gas demand in the electricity sector in western Europe reached 57 bcm in 1993. Gas can penetrate the electricity market in three different ways:

- Gas is the most economic fuel to use in the new combined cycle gas turbines (CCGTs)[2] which are more efficient than traditional plants[3]. New CCGTs are built mainly in the UK and in Italy.

- Gas replaces alternative fuels in existing power stations. Some countries (e.g. Italy) have dual-fired power stations, using for instance oil or gas. Some other countries (e.g. Spain, Italy) convert oil plants to gas, mainly for environmental reasons (Italy). Use of gas in existing power stations could increase gas consumption by 6 bcm in Italy and by 4 bcm in Spain, mainly to replace fuel oil[4].

- Gas is the preferred fuel in cogeneration (heat and power production) projects so far. Cogeneration developed rapidly in Eastern Germany, in the Netherlands, in Italy, in Spain and to a limited extent in the UK. However, in some cases (France, Austria), the potential for cogeneration is high and yet untapped[5].

In new supply areas (e.g. Portugal, Greece), conversion of power stations to gas provides a strong initial customer base for further development of the gas market. Gas-fired electricity generation cannot develop in Austria, France, Norway, Sweden or Switzerland because these countries experience excess capacity in electricity generation and use mainly

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2 LPG is an expensive alternative to natural gas in CCGTs.

3 Currently, the thermal efficiency of CCGTs usually exceeds 50%, compared to around 40% for coal or oil plants.

4 In general, conversion of coal plants to gas is not very economic, although this obviously depends on relative *prices of coal and gas; in the UK, Didcot is being converted to dual-fuel.*

5 France plans to develop 1 GW of cogeneration before the year 2000.

hydro or nuclear power stations[6]. In spite of excess capacity and adequate anti-pollution devices in existing plants in Germany, there are plans to increase gas-fired generation (less than 5 bcm between 1995 and 2000). Such plans however may not be implemented.

There is a general tendency at present to delay construction programmes. Spain, for instance, delayed 2 GW of CCGTs included in the 1991 National Energy Plan and, for the time being, will use gas in converted oil power stations only. In the Netherlands, cogeneration projects have been blocked to avoid over-capacity appearing. In the UK, many CCGT projects have been cancelled or delayed. In Italy, 3.5 GW of gas plant should be repowered against a programme of 7.5 GW a few years ago. In western Germany, the 2 GW programme of new gas plant before 2000 could well be revised downward. In most cases, boosted construction plans were meant to frighten off competition by overestimating new capacity. They were later revised considering what the competition had started to build.

Overall, a net addition of 15 to 20 GW of gas-fired capacity[7] should be brought on-line in western Europe before 2000, which represents an additional gas consumption of more than 20 and less than 30 bcm if these plants are all used base-load[8]. Gas demand in the electricity sector in Belgium, France, Germany, Italy, the Netherlands, Portugal, Spain and the UK should grow from about 40 bcm in 1995 to about 70 bcm in 2000. This represents a growth of about 10% a year until 2000. After 2000, the increase in gas-fired capacity should be moderate, given that European electricity markets are expected to grow at a very slow pace[9], that technological improvement in plant efficiency reduces fuel requirements, especially for gas plant, and that substitution of other fossil plants should slow down. Demand in the electricity sector could increase by less than 10 bcm between 2000 and 2005, which would yield a growth rate of less than 3% per year. Beyond 2005, the expansion of gas-fired generation will depend crucially on whether nuclear power policies in Europe will become more restrictive. The European Union current nuclear production represents more than 200 million tonnes of oil equivalent. Therefore, any reduction in the role of nuclear power could open up a very significant market for alternative fuels and for gas in particular.

2.2.2. Residential demand

There are significant differences between residential markets in Northern Europe, where most of the gas is used for heating, and the markets of Southern Europe where gas use is more balanced between space heating, cooking and water heating. Differences can be marked also within a country. These differences have an impact on the value of gas in residential markets, because gas replaces mainly LPG or electricity for cooking, electricity (mainly) for water heating and gasoil (mainly) for heating.

Residential gas consumption per inhabitant varies widely across Europe. The share of gas in residential energy demand ranges from 80% in the Netherlands and 65% in the UK to about 30% in France or Germany and around 10% in Spain or in Ireland. Therefore, there is still scope for further development of gas residential consumption in many European countries. In particular, fuel substitution can still take place not only in countries where gas has recently been introduced but also in Belgium and Germany, given their high gasoil consumption for space heating.

Residential demand depends on three key factors. First, it depends on the increase in the number and the size of dwellings. There is an increase in the number of separate dwellings and flats and houses tend to get bigger over time. Second, it depends on the level of house insulation and energy efficiency which also tends to improve over time. Third, it is heavily dependent on the gas companies' marketing and development strategies. The key corporate decisions are network extensions (substantial extensions in Italy, Spain, Germany,

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6 See Alario *The West European Electricity Sector* Cahiers BEI May 1994 and Alario *Gas Penetration in West European Power Generation Markets* 13 July 1995.

7 Italy 6.5 GW, UK 4 GW, Germany 4 GW, Portugal 0.9 GW, Ireland 0.5 GW, Greece around 0.6 GW.

8 i.e. 6000 to 7000 hours per year.

9 Alario *The West European Electricity Sector* Cahiers BEI May 1994

Greece, Portugal) and pricing especially with reference to competing energies. In Belgium, France, Italy, the Netherlands, Portugal, Spain, the UK and Germany, residential demand as a whole should increase by 15 bcm between 1995 and 2000, which is equivalent to a growth of about 2% per year and a share of about 45% of total demand for the sector.

Network extensions will attract new customers essentially in eastern Germany in Italy, in Spain, in Greece and in Portugal. In the other countries, new connections usually result from the connection of new houses to existing networks. The proportion of new houses connected to gas usually depends on national energy policies: connection is almost systematic in the Netherlands, it is frequent in the UK, it is more limited in France.

2.2.3. Industrial demand

Industry was the first gas market to develop because industrial customers (who take large quantities of gas directly from the high pressure grid) are the easiest to serve (and sometimes the most profitable). As a result, it is also the most mature segment of the market. Network extensions will attract new industrial customers essentially in eastern Germany, in Greece, in Italy, in Portugal and in Spain. Penetration rates will differ by fuel (for instance high prices of LPG lead to faster replacement by natural gas) and by country. Gas will replace petroleum products in all countries, and, in Germany (especially eastern Germany), gas will also replace coal and lignite.

Gas penetration also varies across sectors. In Europe[10], the share of gas in total energy consumption is around 40% for the chemical industry and the food industry. It is around 30% in most industries. It is only about 20% for iron, steel and metal industry. It is less than 10% in ore extraction.

In existing supply areas, a frequent hypothesis is that energy efficiency improvements should at least compensate the limited increase in the number of customers and in quantities consumed by each customer, so that consumption should remain stable. If anything, this assumption could overestimate future industrial demand in existing markets, especially in the event of a relocation of industries outside Europe (to benefit from lower wages or energy prices). Overall, in Belgium, France, Germany, Italy, the Netherlands, Portugal, Spain and the UK, industrial gas demand in new and existing supply areas would increase by about 10 bcm between 1995 and 2005.

2.3. Total gas demand forecast

Putting together the sectoral forecasts outlined above and global forecasts for smaller markets (OECD/IEA forecasts in several cases), gas demand in western Europe should increase by over 50 bcm between 1995 and 2000 and by about 30 bcm between 2000 and 2005. Western European gas demand should be about 385 bcm in the year 2000 and 415 bcm in 2005. At horizon 2010, demand should reach 445 bcm if the growth trends expected between 2000 and 2005 continue until 2010. These forecasts mean that demand could grow by about 3% per year until 2000 and then by less than 2% a year until 2010. However, if environment policies become tighter, energy demand will decrease while the share of gas will increase (as gas is less polluting than other fuels). The net effect could be that demand would stabilise, i.e. stay around 410 bcm.

2.4. Gas and total energy demand

Total primary energy supply in OECD Europe has grown by less than 1.5% per year since 1979. This is due to increasing energy efficiency of the economy: the ratio [Primary energy]/[GDP] has consistently decreased over the last twenty years[11]. In this context, gas

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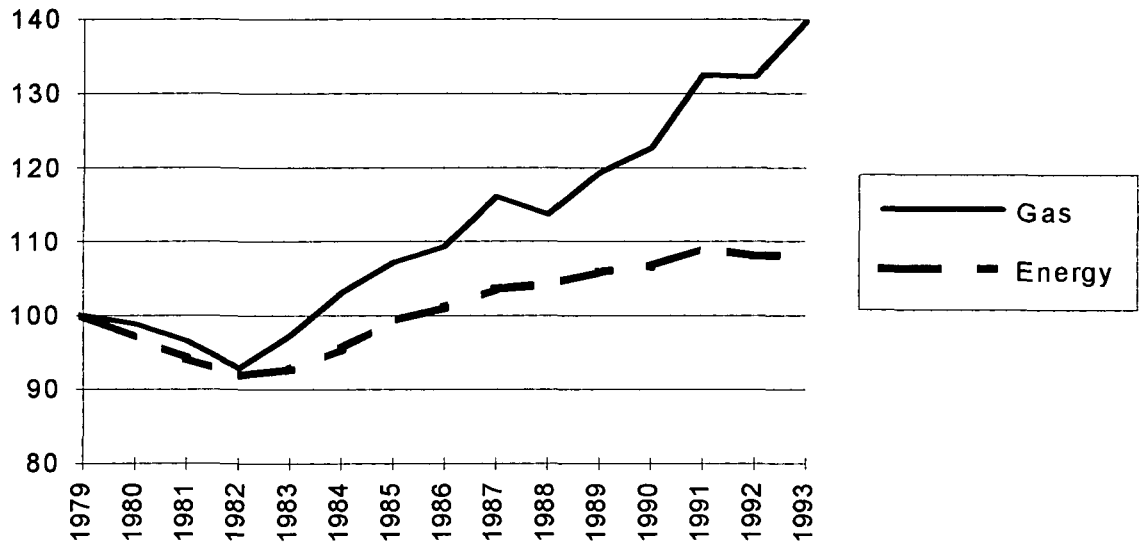
10 Eurostat 1992 figures for EU 12.

11 From 0.253 Mtoe/USD bn in 1973 to 0.211 in 1983 and 0.196 in 1993.

nearly doubled its share of the energy market in twenty years. It represented 18% of primary energy sources in OECD Europe in 1993. Gas demand has grown faster than global energy demand in all sectors (except transport where gas is little used) but at different rates, however. Gas has essentially gained market share in the residential and commercial sector (30% market share[12]). In industry gas has a 25% share of the market for energy destined for industry. Gas use for electricity generation is still limited (8% market share) although increasing rapidly. The OECD/IEA scenarios expect gas to account for 20% of primary energy sources in OECD Europe in 2000, and for 20%-24% of primary energy in 2010, but this assumes a GDP growth rate of about 3% which is probably too high.

Comparison of gas and total energy demand growth since 1979



Source: OECD/IEA

2.5. The environmental advantage of gas

One of the reasons for the expected increase in natural gas consumption is that gas, when burnt, presents important environmental advantages compared to other fuels. In order to produce the same amount of energy, gas combustion releases 25% less carbon dioxide (CO_2) than oil and 40% less carbon dioxide than solid fuels[13]. In addition, gas combustion releases hardly any SO_2, NO_x and particles.

Gas does present environmental drawbacks. The main constituent of natural gas is methane which is a greenhouse gas. Therefore, natural gas, when leaked, contributes to global warming. Leaks cannot be avoided even in well-maintained production and transportation facilities using the best available technology. Methane emissions from natural gas systems should not be over-estimated, however. They represent possibly about 10% of total methane emissions at world level, i.e. significantly less than methane emissions from natural ecosystems (ruminants, paddy fields, swamps, lakes and oceans) and about as much as what is released from coal mining. In addition, the warming power of methane, although twenty times higher than that of carbon dioxide, is more than ten times lower than that of nitrous oxide (N_2O) and well over 150 times lower than the less harmful of chlorofluorocarbons (CFCs)[14]. On balance, natural gas therefore deserves its reputation as an environmentally friendly fuel as its advantages, when burnt, outweigh its disadvantages when leaked.

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12 Gas represents 31% of final energy consumption in the residential sector.
13 See IEA *Greenhouse Gas Emissions, the Energy Dimension* OECD Paris 1991.

2.6. Eastern Europe

Since 1989, Eastern European countries have been undergoing radical political and economic changes. As a result, forecasting gas demand comes across three major difficulties:

- Future GDP growth is still extremely uncertain. Transition to market economies initially led to a recession but should eventually lead to stronger economic growth. A resumption of economic growth was observed in 1994 in all countries but many structural imbalances still need to be corrected and this could affect growth.

- Future energy demand is difficult to predict. Eastern European economies are reducing their energy intensity, both as a result of structural changes in their economies (e.g. closing down some industries) and as a result of more modern production technologies being introduced. In parallel, residential prices have increased significantly and more increases are expected (to bring prices in line with costs). It is very uncertain by how much this will reduce demand.

- The development of the share of gas in total energy demand is uncertain. Eastern Europe faces such serious pollution problems that gas is replacing coal, lignite and petroleum products. This substitution is likely to continue but the pace at which it will take place is difficult to forecast. For instance, there is serious uncertainty as to how long eastern European nuclear power stations can be kept in operation under reasonable safety standards.

We have based our forecast on various sources including information published by gas companies. On this basis, three countries could see a significant increase in demand over the next ten years. Poland's gas consumption could at least double (from under 10 bcm currently). the Czech Republic could also more than double its demand. According to Romanian sources, Romania could increase its consumption by 5 bcm in ten years. All other countries should experience moderate growth or a stability in their consumption. However the demand structure will change: the share of industry in total gas consumption will reduce while residential and possibly electricity sector demands will increase their market shares. As a result, total demand will become peakier, requiring more transportation and storage capacity. From approximately 70 bcm in 1995, demand could grow to 100 bcm in 2005. In 2010 demand could be between 80 bcm (low case) and 135 bcm (high case) and probably around 110 bcm (central scenario).

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14 Ibid.

3. Gas Supply

3.1. Gas reserves

3.1.1. Reserves in Europe

Western Europe holds less than 5% of the world gas reserves. Most of these reserves are located in Norway (2800 bcm), in the Netherlands (1900 bcm), in the UK (600bcm) and in Italy (400 bcm)[15]. Most of the reserves in Norway, the UK, Denmark and Italy are located offshore. Most Dutch gas reserves are onshore and therefore much cheaper to extract. The characteristics of Dutch gas reservoirs (especially Groningen) also allow more variations in daily produced quantities than any other fields in Europe.

Norway's reserves nearly doubled in 1979 when the Troll field (1300 bcm) was discovered. Troll will commence production in 1996[16]. In the Norwegian North Sea, all large fields will then be under production. In future, more marginal fields are likely to be developed in the North Sea, at a higher unit cost than that of large fields. Most large Norwegian fields in the less accessible areas of Haltenbanken (less than 400 bcm) and the Barents Sea (300 bcm) have not yet been developed.

Gas production will decrease substantially in France, Germany and probably in the UK. France's main field in Lacq is reducing production and should cease operations within ten years. Germany is closing down the eastern German production of low quality gas and production will decrease in western Germany after 2000. The UK's annual production is about 12% of its reserves, which is a particularly high ratio. The UK production will rise in the next five years or so, as a result of current field developments, but it is likely to decrease significantly afterwards. Some forecasters expect a steady increase in production beyond 2000 because yet undiscovered UK reserves are estimated at 1300-1500 bcm and because discoveries have so far enabled the UK to maintain its reserve level over the last ten years or so. However, estimates of potential reserves are fraught with considerable uncertainty; in addition, it is difficult to know how much of these reserves (probably located North and West of Scotland) could be produced at a cost comparable to the production cost of other new gas developments in or around Europe. On the basis of what has been discovered to date, UK production should decrease after the year 2000.

All other western European countries should be able to keep their gas production close to current level at least until 2010, except Denmark where production should double over the period. Overall, western Europe's production (excluding Norway) should be close to 200 bcm in 1995, could rise to 215 bcm in 2000 (increase due to Denmark and the UK) and is then likely to decrease, perhaps to 195 in 2005 and possibly to 175 bcm in 2010, although there is very little detailed information about the decreasing path of domestic western European supply. A breakdown of these figures is presented in the following table:

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15 Figures rounded to the nearest 100 bcm.

16 However, deliveries under the "Troll contract" started in 1993 with gas coming from the Sleipner fields.

Western European Gas Production (in bcm)

	Estimate 1995	Forecast 2000	Forecast 2005	Projection 2010
Austria	1	1	1	1
Denmark	5	8	9	10
France	4	4	0	0
Germany	18	18	9-18	0-12
Ireland	3	3	3	3
Italy	18	18	18	16-18
Netherlands	85	85	85	85
Norway	37	52	70-75	70-90
United Kingdom	69	80	70-80	60-70
Western Europe	**239**	**268**	**265-291**	**245-389**
Western Europe without Norway	**202**	**216**	**195-216**	**175-199**

Source: IEA, CEDIGAZ, Gas companies' published forecasts, Governments' forecasts, EIB estimates.

3.1.2. Additional sources of gas for Europe

World gas reserves have about doubled in twenty years and represent 68 years of current consumption. By comparison, oil reserves are slightly more abundant in energy terms but only represent 43 years of oil consumption. (Reserve production ratios are presented in Appendix 1).

The former Soviet Union holds about 40% of world gas proven and possible reserves, equivalent to about 70 years of production at current level. Russia holds 85% of these reserves (48 900 bcm in 1995[17]). Potential, possible and proven reserves could be as high as 216 000 bcm (i.e. 150% of current proven and possible world reserves). About 70% of Russian production come from two enormous Arctic fields (Urengoy and Yamburg) which can produce for more than 25 years at current production rates. Two Russian gas regions are yet undeveloped: the Yamal peninsula (10 200 bcm of proven and possible reserves) and the Barents Sea (11 500 bcm of reserves, 2 500 bcm of which are concentrated in the giant field of Shtoktmanovskoye). If these fields were exploited so as to produce at a constant rate for 50 years, they could produce 435 bcm per year. Clearly, Russia has abundant gas reserves. The question is whether the Russian gas companies have the financial resources to explore and develop the reserves and whether transportation can be arranged at reasonable cost. Rosshelf, the company that develops Shtoktmanovshoye, estimates at around USD 5 bn the development cost of this giant field. Gazprom reckons that the Yamal development will require about USD 40 bn, of which USD 10-12 bn will be devoted to developing gas production and around USD 30 bn will be spent on the pipeline[18].

Algeria holds 3 700 bcm of gas reserves. This is sufficient to guarantee present production levels for more than 25 years. In addition, reserves are expected to increase in the coming years as about a third of the country is being explored. Exploration is hindered by the political situation however.

Clearly, in pure quantity terms, Europe faces no gas shortage. Most of the world's gas reserves are within a 6 000km radius around Europe. As shown in Appendix 1, Europe's potential new suppliers (Iran with 20 000 bcm of reserves, Qatar with 7 000 bcm of reserves, Nigeria with 3 400 bcm of reserves,...) might be able to produce an additional 100 bcm in the medium term, although some of this would be diverted away from Europe (to the US and the Far East).

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17 In 1994 reserves went down from 49,500 to 48,900 bcm. This only reflects problems in financing and organising exploration in Russia.

18 Gazprom publication: *The Yamal Europe Project* 1995.

3.1.3. Gas costs

Gas costs have two key components: the cost of producing gas and the cost of transporting gas. There are many different ways of computing these costs and this does not contribute to the clarity of the debate: should capital cost be evaluated on the basis of historic costs or of replacement costs? Are costs already sunk included in the cost of new projects? etc. Many authors of cost comparison do not state clearly their positions on such issues and comparability of studies is therefore limited. All the costs mentioned below are notional and details of the calculation are not available.

According to a recent study[19], onshore production cost would be about 0.50 USD/MMBTU in Algeria, Russia, the Netherlands or Libya for existing fields[20]. Offshore production would cost about 1 USD/MMBTU[21], i.e. twice as much as onshore production. There are considerable differences between fields, however[22].

According to the same study[23], the production cost in Russia's Yamal peninsula could be 0.75 USD/MMBTU while the production cost in the Russian Barents Sea would reach 1.50 USD/MMBTU. However, according to another recent survey, developing the giant field of the Barents Sea (Shtoktmanovskoye) would be cheaper than developing Yamal[24].

Transport costs are significant, of the order of 0.30 USD/MMBTU/1000km for onshore pipelines, of 0.50 USD/MMBTU/1000km for offshore pipelines and at least 1.50 USD/MMBTU for LNG travelling over 1000 km (0.2 USD/MMBTU/1000km for transportation and 1.3 USD/MMBTU for liquefaction and regasification[25]). They vary both with volume and distance. There are economies of scale, both for pipeline and LNG transportation, with respect to the volume transported[26], and LNG shipping costs increase less with distance than pipeline costs. As a result, LNG becomes the cheaper option to transport 15 bcm/year when gas has to be transported over 5000 km.

Tentative cost estimates for marginal gas sources available to Europe have been compiled from available published sources and are presented in the following table (Transportation to nearest European Union border, assuming 10% rate of return on transport facilities):

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19 Pauwels *Géopolitique de l'approvisionnement énergétique de l'Union Européenne au XXIe siècle* Bruylant Brussels 1994. This study also forms the basis of the OECD/IEA computations of costs and prices.

20 The main exception being the giant field of Groningen where gas would only cost 0.10 USD/MMBTU to produce.

21 This figure appears rather low, especially for the North Sea where the futurte average unit gas production cost for newly discovered fields was estimated at 2.2 USD/MMBTU in the 1993 Brown Book.

22 For instance, the 28 bcm of production expected at Troll from 1996 could cost about 1.20 USD/MMBTU while the 6 to 13 bcm of production at another Norwegian gas field, Sleipner West, could cost 2.20 USD/MMBTU.

23 Pauwels Op. cit. This study also forms the basis of the OECD/IEA computations of costs and prices.

24 J. Grace *Cost Russia's biggest challenge is maintaining gas supplies* Oil and Gas Journal February 13, 1995. J. Grace provided estimates of marginal costs of Russian fields, taking Urengoy I as a basis for comparison. Developing Shtoktmanovskoye would be four times as expensive for production alone, and five times when transport is included. Developing Yamal's production would be five times as expensive as Urengoye I and seven times as expensive once transport costs are included.

25 For a 1000-km pipeline of 15 bcm of capacity, the transport cost could be 0.30 USD/MMBTU for an onshore pipeline and 0.50 USD/MMBTU for an offshore pipeline. LNG transport of 12 bcm/year over 1000 km would cost 1.50 to 1.80 USD/MMBTU. See OECD/IEA *Oil, Gas and Coal* Paris 1995.

26 Transport cost in a 5 bcm/year pipeline would be more than twice that of a 15 bcm pipeline; 6 bcm/year LNG transport facilities could be 20% more expensive than a 12 bcm/year facility.

Comparison of estimated border supply costs of marginal sources for given levels of production

Note: Production levels do not represent maximum production levels

Field	Country	Costs 1993 USD/MMBTU	Corresponding quantities produced (bcm/year)
Troll	Norway	2.3-2.6	40-50
Sleipner West	Norway	2.2-2.7	6-13
Haltenbanken	Norway	2.7-3.3	0-15
Yamal	Russia	2.6-3.4	0-25
Barents Sea	Russia	3.8-4.5	0-5
LNG to Italy	Nigeria	3.1-3.4	0-9
LNG to Italy	Qatar	3.0-3.5	0-20
pipeline to Italy	Qatar	3.6-4.7	0-20
Iran-Turkey LNG to Italy	Iran	2.8-4.1	0-20
Pipeline to Italy	Turkmenistan	3.7-4.5	0-10
LNG	Venezuela	3.3-3.8	0-8

Sources: Pauwels et al. (1994) *Géopolitique de l'approvisionnement énergétique de l'Union Européenne au XXIe siècle* Bruylant, Brussels, and published estimates from SNAM, OME, IEA.

Long distance gas appears to have little merits on the grounds of cost. Given high transportation costs for gas, location probably still gives a decisive advantage to Europe's traditional suppliers against potential long-distance gas suppliers. Western European countries are therefore likely to call upon long distance gas either to support a policy of diversification of supply or to take advantage of good opportunities (given the current excess capacity[27] in the world LNG market).

3.2. Matching supply and demand

3.2.1. Western Europe

As domestic production will stay almost constant while demand will increase, western Europe will become even more dependent on external gas sources. On the basis of existing contracts, the situation is as follows:

Supply and Demand in Western Europe on the basis of existing contracts (in bcm)

	1995	2000	2005	2010
Western Europe (domestic production)*	200	215	195-215	175-195
Norway's contracts to rest of western Europe	30	45	55	60
Russia's contracts to western Europe	70	75	75	45
Algeria's contracts to Europe	30	50	50	50
Others	5	5	5	5
Total	335	390	380-400	335-355
Demand in Western Europe	335	385	415	410-445
Extra supply needed	0	0	15-35	55-110

*Excluding Norway

Source: own elaboration from miscellaneous sources (figures rounded to the nearest 5 bcm)

Existing supply contracts signed with traditional gas suppliers (Norway, Algeria, Russia) and expected domestic production in Europe will be sufficient to meet demand in

27 Excess capacity in the world LNG market is addressed in S. Cornot-Gandolphe and M.-F. Chabrelle *Natural Gas in the World* CEDIGAZ Paris,1995.

2000. With a rather pessimistic view about domestic production potential, about 35 bcm of additional gas supplies could be needed in 2005, i.e. roughly 8% of total demand and roughly what is under negotiation with Norway (possibly about 10 bcm), Russia (possibly about 15 bcm) and LNG producers (Trinidad, Nigeria, etc.). With more optimistic expectations on western European gas production, quantities yet to be contracted would be only 15 bcm, which is within the margin of uncertainty of the demand forecast. Clearly, on the basis of contracts either existing or under negotiation, there is no gas supply shortage within the next ten years. There is even a potential excess supply in the next few years, that will be compensated either by variations of gas quantities taken around quantities contracted (swing or take-or-pay[28]) or by a reduction in domestic gas production from the most flexible fields (especially the Netherlands[29]).

At horizon 2010, existing contracts and expected domestic production should cover at least 70% of demand. Quantities yet to be contracted for 2010 are likely to be 55 to 110 bcm. If, as is likely, existing Russian contracts are renewed, quantities to be contracted would be 25 to 80 bcm. This is within the additional production possibilities of the traditional suppliers of Europe (Algeria, Russia, Norway). In addition, the 15-35 bcm of additional gas quantities required for 2005 are expected to be purchased on the basis of long-term contracts that would therefore still be in force in 2010. Then, Europe would need to contract additional quantities between 0 and 65 bcm *after* 2005. Although Europe's traditional suppliers could provide such quantities, gas producers located further away from Europe (Abu Dhabi, Oman, Qatar, Nigeria, Trinidad, Venezuela,...) expect to sell to Europe eventually and could also supply this amount. Their share will depend on Europe's willingness to diversify supply.

3.2.2. Eastern Europe

Domestic gas production is expected to fall in eastern Europe, from about 30 bcm in 1995 to roughly 25 bcm in 2005. Given the expected increase in demand, eastern Europe will therefore need to import about 40 bcm in 1995, all of it from Russia, and possibly 70 bcm in 2005, most of which will come from Russia. Only about 5 bcm would come from Norway on the basis of on-going negotiations and of transportation capacity from the North Sea to eastern Europe (although the situation can evolve rapidly). There are also plans to import 10 bcm of long-distance LNG via Croatia (isle of Krk) but this is still a very hypothetical project. So, Russia could supply to eastern Europe about 40 bcm in 1995 and more than 65 bcm in 2005.

Long term contracts are under negotiation between Russian and many eastern European companies. Up to now, gas trade in the East was based on inter-State agreements, with actual gas quantities sold and gas prices being set on an annual basis. Gas companies in Russia and eastern Europe are now negotiating long term commercial contracts probably similar to those signed between Gazprom and western European gas companies. Progress appears to be slow however. These negotiations cast some doubt on the *intentions* of eastern European countries with regard to Norwegian supplies: are eastern European countries negotiating with Norway to obtain more favourable conditions from Russia, with the intention of getting all the gas from Russia (the cheaper source)? Or are eastern European countries really intending to diversify supplies, even if Norwegian gas is more expensive? This is, so far, an open question.

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28 Depending on contracts, the swing factor allows to take daily 10% to 70% above or below the quantities contracted at contract price, i.e. without financial penalties. There is, however a minimum bill quantity which has to be paid, whether it is taken or not (take-or-pay clause). This quantity varies with contracts but is usually around 80%.

29 The Netherlands are keen to protect their reserves for as long as possible. It is therefore likely that the Netherlands would accept to dampen the flucturations in supply on the Continental western European market. This also appears to be consistent with the contracts signed between the Netherlands and neighbouring countries.

3.3. Security of Supply

This paragraph does not intend to replicate the recent Commission and OECD/IEA studies on security of supply[30], and simply sets out the main issues.

3.3.1. Operational and strategic security of supply

Security of supply is both an operational and a strategic concept. There is an operational requirement for gas supply to meet demand on a daily basis, in spite of the demand fluctuations due essentially to weather variations. On an annual basis also, demand may be much higher when winter is cold. Contracts signed with gas producers are somewhat flexible and allow for daily and annual variations in quantities taken (see below). Storage and interruptible contracts reinforce this flexibility. Gas storage provides additional flexibility to the gas system; it increases demand in summer when storage sites are being filled and contributes to meeting demand at peak, in winter. Gas storage therefore flattens the profile of gas takes from fields across the year, making it easier to increase gas production from fields to meet unexpected variations in demand. Finally, some large industrial customers conclude interruptible contracts with gas companies: these customers accept the risk of being interrupted at peak (if there is not enough gas available to meet total demand on a day) and pay a much lower price for gas in return[31].

Operational security of supply is a well-established requirement, met by all Western European gas systems. However, more storage will be required in future for operational reasons as the Groningen field in the Netherlands will no longer provide flexible supply after 2007[32]. According to Gasunie, Europe will need 20 bcm of new storage in the next twenty years, but we have no detail of this calculation[33].

There is also a strategic aspect to security of supply that derives from Europe's dependence on a small number of key suppliers (Gazprom for Russian gas, Sonatrach for Algerian gas, etc.). There are two main issues about strategic security of supply. One issue is whether a supplier has the ability to corner the market and extract monopoly rents. The second issue is how politically stable Europe's suppliers are.

3.3.2. Market power

In 1995 Algeria and Norway will each provide about 10% of western Europe's total demand. Russia will supply about 20% of the gas consumed in western Europe and nearly 35% of (eastern and western) European gas demand. This could prove sufficient for Russia to prompt a moderate increase in prices.

In the immediate future Russia has an incentive to push prices up as negotiations are about to start on the renewal of about 30 bcm of supply contracts with western Europe, and as eastern European countries are currently discussing long term contracts with Russia. So far, rather than forcing prices up, Russia has preferred to negotiate side deals (e.g. the construction of a pipeline or a power plant, as in Greece) or to require direct foreign investment in the sector (this seems to be the starting basis for negotiation on the Yamal gas). But there should come a point when Gazprom becomes more interested in higher

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30 *The IEA Natural Gas Security Study*, OECD Paris, 1995 and Commission communication *European Community, Gas Supply and Prospects* Brussels 18.10.95. COM(95) 478 final.

31 Interruptible contracts vary from one country to the next. In some cases "interruptible" contracts are concluded with large customers on the understanding that they will never be interrupted. Interruptible contracts are then a means to price-discriminate in favour of very large customers.

32 Freeflow pressure (230 bar in 1963 and 40 bar in 1995) will have virtually disappeared in 2007. In order to preserve flexibility, about 600 MW of compression will be installed on the Groningen field between 2000 and 2007.

33 Based on Sybe Visser's communication on *Gas storage as a business* at Gas Strategies's European Autumn Gas Conference, Venice 7-8 November 1995.

profits in the gas industry than in higher currency revenues for the Russian State, an evolution that the on-going privatisation of Gazprom could speed up.

3.3.3. Political stability

There is also a risk that the political situation in Algeria or in Russia deteriorates so much that gas supplies would be fully or partially interrupted. Short term breakdowns in supply can be treated with the same instruments as short term increases in demand, essentially increasing the needs for storage capacity and for interruptible contracts. Long term interruptions require more specific solutions. In the short term, all countries claim they can face several months of supply interruption by Algeria or Russia and this is supported by the conclusions of the IEA and the Commission studies on security of supply. In the longer term, LNG/pipeline alternatives may exist for Algerian gas (for instance increasing deliveries from Russia and Norway with a complement of LNG from Latin America and Africa), although adapting or building the new facilities could take up to three years.

In any case, the Algerian risk should not be overestimated. In a recent report[34], the Observatoire Méditerranéen de l'Energie (OME) developed a possible scenario of FIS government in Algeria. The OME concludes "With such a scenario, we do not think that gas supplies would be interrupted" as gas exports are vital to the Algerian economy, as Algeria's islamists accept free trade and liberal principles and as the social base of the FIS would put pressure on an islamic government to see their economic condition improve. The risk is more of a progressive upheaval of the political, economic and social environment which would eventually affect the hydrocarbon sector.

In case of a long term complete supply interruption from Russia, there would be no alternative but to divert some of the gas demand to other fuels: there is not enough gas available at reasonable cost fully to replace Russian gas in Europe. The IEA estimates that demand for heavy fuel oil would then increase by 30%. Making scenarios on what would happen if only partial long term interruption took place is more difficult.

The issue of political stability does not necessarily play in favour of long distance gas. The more countries crossed by a pipeline, the less politically secure the gas deliveries at the end of the pipeline. This plays against Middle East gas pipeline development projects (e.g. the Iranian pipeline project through parts of the former Soviet Union and through eastern Europe).

3.3.4. Contract flexibility

Developing contract flexibility is probably the best response to the risk of long term interruption or sharp reduction in gas quantities supplied. Existing contracts already provide some flexibility: the maximum amount of gas that can be taken either on a daily or on an annual basis (maximum contracted quantity or MCQ) is usually much higher than the nominal quantity signed for in contracts (average contracted quantity)[35] and can even be increased further with the supplier making "best endeavours" to provide more gas (excess gas, sold at a much higher price). In addition, there exist emergency supply contracts, such as those concluded between the Netherlands and neighbouring countries (details of these contracts are kept confidential).

Expanding contract flexibility would require spare import capacity. In the case of pipeline gas, excess transportation capacity is needed. In the case of LNG, excess *export* capacity would be required to replace LNG from one source by LNG from another source[36]. In the short run, such excess capacity exists. Only long term emergency contracts with LNG

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34 OME *Future Natural Gas Supply for Europe, The Role of Transit Countries and Security of Supply* in *The IEA Natural Gas Security Study* OECD Paris 1995.

35 This is intended to dampen the effect of weather variations on gas quantities consumed.

36 As a breakdown in one source of supply would free import capacity. However, spare import and export LNG capacity would be required if emergency LNG imports were to replace pipeline gas.

exporting countries would ensure that this is also the case in the long run. So far, we have no evidence of such contracts being negotiated.

To a large extent, "excess capacity" in gas pipeline or LNG facility is the best response to the risk of long term supply breakdown. However, a significant transportation reserve margin (i.e. in effect idle capacity) is unlikely to be sustainable in a market environment without some form of public regulation[37]. The problem is how this spare transportation capacity should be enforced and financed; in particular, it is not clear whether the consumer or the gas companies (through a reduction in their profits) should pay for it.

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37 The most common way of ensuring revenues for spare pipeline capacity is some form of regulation of the split between capacity charge and commodity charges for pipeline use. This is the method used in the past in the US and in the UK.

4. Gas transportation

4.1. Gas transportation: existing infrastructure and projects

4.1.1. Pipelines to Europe

Europe imports gas from three main sources: Algeria, Norway and Russia.

Two pipelines connect Algeria to the Continent: one goes to Spain (GME, with a capacity of 8.5 bcm in 1997[38]) and one goes to Italy (Transmed, with a capacity of 16 bcm in 1995 and 24 bcm in 1997). Therefore Algeria's pipeline export capacity to Europe will be 32.5 bcm in 1997. Both pipelines could be upgraded (GME to 18 bcm[39] and Transmed to 30 bcm) which would raise Algeria's pipeline export capacity to 48 bcm. Pipeline upgrade would be achieved by installing additional compressors. This raises the operating costs of the pipelines but only requires limited additional investment.

Four pipelines connect Norway to Europe. Frigg (12 bcm) goes to the UK, Norpipe (21.5 bcm) and Europipe I (12.5 bcm) go to Germany, Zeepipe (12 bcm) goes to Belgium. This represents a total capacity of 58 bcm, with 46 bcm of capacity to Continental Europe. Two new pipelines are planned with construction about to start. NorFra (14 bcm) will go to France and Europipe II (12 bcm) will go to Germany. Upgrades of Frigg, Norpipe, Zeepipe and Europipe I are also technical possibilities, representing a potential of 30 to 40 bcm. In three years' time, Norway could technically wheel gas through Frigg, through the UK system and on to the UK-Continent Interconnector (20 bcm in 1998). But gas negotiations are deadlocked between the UK and Norway, especially on Frigg.

Russia exports gas to most of western Europe through a single large pipeline[40] (with a capacity of 75 bcm available to western Europe) which connects Russia to Germany and France through Ukraine, Slovakia and the Czech Republic. The export capacity to western Europe will increase to 90 bcm in 1998 when the Transgas pipeline has been upgraded in Slovakia. Russia's overall gas export capacity to eastern and western Europe is estimated at 105-117 bcm and could reach 130-140 bcm with the full upgrade of the existing pipelines, *although considerable uncertainty surrounds these figures*[41] as Russia may not have the financial resources to maintain (or perhaps even repair) the existing transportation facilities[42]. In addition, a pipeline is currently under construction in Poland and should eventually connect Russia to Germany through Belarus and Poland (This pipeline is called the "Yamal" pipeline, or the EuroPol gaz pipeline[43], or the Western Europe-Russia pipeline). It could add 70 bcm of capacity[44], eventually bringing Russia's transportation capacity to Europe to 200-210 bcm.

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38 Pipeline capacity is 9.5 bcm but 1 bcm of capacity is booked by Morocco.

39 Includes Morocco's share currently under discussion.

40 The two exceptions are Finland, which is directly connected to Russia, and Greece which will receive Russian gas through Bulgaria. In 2000, Finland is expected to consume about 4 bcm and Greece about 2 bcm.

41 Poor maintenance and problems with compression are sometimes mentioned about Russian pipelines, which would reduce available capacity.

42 Gazprom officially admits to having difficulties financing its investment:
"Practically all branches of the [Gazprom] complex are in deep financial crisis. For the lack of financial resources the enterprises of the complex postpone the realisation of a number of investment programmes" (extract from a paper presented by V.I. Rezounenko, Member of the board of RAO Gazprom and V.E. Bryanskikh, Head of the Department for Prospective Development, RAO Gazprom, Autumn European Gas Conference, Venice 7-8 November 1995).

43 Europol gaz is the name of the joint venture for the Polish part of the pipeline.

44 According to Gazprom, the Yamal pipeline would have a capacity of 83 bcm in Yamal, of 69 bcm in Belarus, of 67 bcm in Poland and of 52 bcm in Germany. Sales to Belarus, Poland and Germany are currently under negotiation (Poland, for instance is negotiating for 13.4 bcm) and could change in future. For instance, Poland or Belarus could resell some of their gas to other countries or allow the Russians to do so. Therefore, at present and in the absence of signed contracts, we can consider that the planned capacity of the Yamal pipeline in Europe is close to 70 bcm.

In total, Western Europe has the capacity to import 196 bcm of pipeline gas. Continental Europe[45] has the capacity to import 184 bcm of pipeline gas and this capacity should grow to about 260-275 bcm before the year 2000 with new committed projects. With all these projects and all potential upgrades of existing pipelines, capacity would reach 365 bcm.

4.1.2. LNG

Algeria has an LNG export capacity of 20 bcm, currently being upgraded to over 28 bcm. This is less than western Europe's LNG import capacity (19.5 bcm in France, 13.5 bcm in Spain, 6.5 bcm in Belgium, 4 bcm in Italy, i.e. a total capacity of 43.5 bcm). Algeria remains however the main source of long term LNG imports in Europe although Spain and Italy have limited LNG import contracts with Libya and Spain is currently concluding a contract with Trinidad and Tobago for about 2 bcm, mainly to diversify supply. Excess capacity in the world LNG market permitted spot imports of LNG (from Australia or Abu Dhabi to Belgium, France or Spain) in the last few years, but this is temporary. The development of pipeline gas, at lower costs, limits the development of LNG. Only two LNG projects are in advanced stages in Europe: Greece is building an LNG terminal to import less than 1 bcm per year of Algerian gas; Italy plans an LNG terminal to import, *inter alia*, 3.5 bcm of Nigerian gas per year (capacity of the project could be 12 bcm). Both projects have suffered considerable delays and further delay could well occur at least on the Italian project[46]. All other projects in Europe (e.g. in Spain, Portugal, the Netherlands or Ireland) are in a preliminary phase (feasibility studies). New European LNG imports are likely to come from Venezuela (4.6 bcm in 2002/2003), from the Middle East (Oman, Qatar, Iran, Yemen) and in the longer term from Norway (Northern fields, Haltenbanken) or Russia (project of 10 bcm LNG line between Mourmansk in the Barents Sea and Zeebrugge in Belgium).

4.2. The needs for new gas transportation infrastructure in Western Europe

4.2.1. Extra investment is under way with Norway

Norway exports between 2 and 5 bcm of gas to the UK every year through the Frigg line and, given the relationships between the two countries, is only expected to export about 2 bcm per year in future. The Norwegians were keen to increase their exports and signed a contract with a UK power generator (National Power) for about 30 bcm over 14 years in 1991 but this contract has yet to be approved by the UK authorities. The British and Norwegian governments are negotiating an extension of the pipeline and production sharing agreements (e.g. Frigg) but negotiations are deadlocked. On the Continent, the situation is different. All governments are keen to see an increase in imports of Norwegian gas which is seen as a secure long term source of supply. On the basis of existing contracts and given the transportation facilities outlined above, the situation is as follows:

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45 Including eastern and westen European countries with the exception of Finland and the Baltic States which are supplied by direct pipeline from Russia.

46 The project is currently going through a redifinition phase.

Sales and Transport Capacity between Norway and the Continent (in bcm)

	1995	2000	2005	2010
Contracted sales	28	45	55	60
Transport capacity with 2 new pipelines*	46	72	72	72
Transport capacity with upgrades of existing pipelines	46	77-87	77-87	77-87

*NorFra to France, Europipe II to Germany

Source: Gas Matters, Euroil, Misc.

Existing contracts with Norway require either the construction of two new pipelines (one to France and one to Germany) or an upgrade of existing pipelines. The first solution has been adopted and the French pipeline (NorFra) has now been approved by the Norwegian Parliament with expected completion date in 1997-98 while the German pipeline is expected to be completed a few years later (2000?). The solution avoids difficult negotiations between partners of existing pipelines, it gives Norway more strategic possibilities in the dispatch of its gas, and it gives Europe spare import capacity of gas coming from a politically secure source of supply. It also satisfies France's desire to avoid paying transit fees to Belgium.

Several contracts are under negotiation. Spain could increase its purchases from 2 bcm to 4 bcm; Italy considers buying 3-4 bcm. Some of these quantities would transit through NorFra the future pipeline to the French coast which could then operate at full capacity (14 bcm) given that the French expect to transport 10 bcm per year for their own use. Germany could buy an additional 5 bcm per year from Norway and eastern Europe is negotiating for about 5 bcm as well (Czech Republic 1 bcm, Hungary 2 bcm, Poland 2 bcm), which would fill most of Europipe II, the new pipeline to Germany[47]. These contracts, if all signed, would bring Norway's exports to the Continent to about 65 bcm. This would mean that all pipelines except *one* would run close to full capacity throughout the year. Spare pipeline capacity could be needed however, to cater for possible increased variability in contracts So all the transport capacity to the Continent appears to have a role (being used either for base-load or peak deliveries). New contracts in addition to those mentioned would require additional pipeline capacity, e.g. the upgrade of the Belgian link Zeepipe.

4.2.2. Extra investment needed with Russia

As discussed earlier, with 35% of world reserves, gas production potential is not an issue for Russia. The only question is whether an increase in exports will require new field developments (Yamal) or whether higher exports will simply compensate the current fall in domestic Russian demand, especially if this demand reduction persists (Gazprom does not expect demand to pick up again before the year 2000). However, Russia does not currently have the transportation facilities to increase exports. On the basis of existing contracts and given the transportation facilities outlined above, the situation is as follows:

47 Additional purchases by Austria are also possible.

Sales and Transport Capacity between Russia and Europe (East and West) in bcm

	1995	2000	2005	2010
Contracted sales in the West, expected sales in the East*	105	125	140	130
Transportation capacity existing and under construction	105	120	120	120
Potential with upgrade of existing pipelines	105	130-140	130-140	130-140
Potential with "Yamal" pipeline	105	110-180	170-180	170-180
Contracts with western Europe	70	75	75	45
Transportation capacity of Transgas to western Europe	75	90	90	90

*Central scenario for eastern Europe. Numbers in this table are tentative estimates.

Russia's transportation capacity *needs upgrading by 2000* in order to supply what eastern Europe requires and what western Europe has *already contracted*. The upgraded capacity of *existing* pipelines (*probably* 140 bcm) should be just sufficient to supply demand in 2005. However, if existing contracts are renewed beyond 2005, which is likely, then contracted quantities would reach 155 bcm and a new link with Russia would be required. In any case, the Transgas pipeline to Western Europe operates at full capacity and any new contract with western Europe requires either an upgrade of the pipeline or a new pipeline. Both are under way. On the one hand, the Transgas pipeline is being upgraded to 90 bcm in 1998. On the other hand, the German/Russian joint-venture WINGAS plans to import additional quantities of Russian gas and is involved in the construction of a new pipeline between Russia and Germany through Poland and Belarus. This second pipeline to western Europe would therefore go through different eastern European countries than those crossed by the existing Transgas pipeline. Avoiding Ukraine is currently perceived as a very significant advantage of the new pipeline compared to the alternative which would consist of laying a new pipe along the existing Transgas line.

The new pipeline is being built from both ends, with first gas planned for 1998 in Yamal although transportation capacity to Europe may be required well before production capacity in Yamal. The 665 km through Poland and 575 km through Belarus are likely to be completed before the 2865 km through Russia. Initially, the pipeline may not need to reach Yamal for gas to be exported to Europe: the pipeline will be connected to the Russian grid in Torzhok (between Moscow and St Petersburg). This could reduce considerably the initial cost of the project as most of the obstacles (400 km of permafrost, 600 km of taiga, most of the 850 rivers and lakes to be crossed) are located in the eastern half of the pipeline. As the distance between Torzhok and the German border is about a third of the total distance, the cost of this first phase of the project is likely to be of the order of USD 10 bn (order of magnitude only on the basis of Gazprom's global description of the project). It must be pointed out that although the Yamal project and the full Transgas upgrade (to 140 bcm) are technically relatively well defined, their financing is not organised yet and Russia may face considerable difficulties finding the required financial resources. The German and Polish pipelines would then lay idle and this could create supply shortage in the European gas market.

If existing pipelines are upgraded and the full planned capacity of the Western Europe-Russia pipeline is built, Russia could double its transportation capacity from 105 bcm today to 200-210 bcm.

4.2.3. Capacity sufficient in Algeria

On the basis of existing contracts and given the existing and new transportation facilities outlined in paragraph 4.1 above, the situation is as follows:

Sales and Transport Capacity between Algeria and Europe (in bcm)

	1995	2000	2005	2010
Contracted sales of Algeria to Europe	30	50	50	50
Contracted sales of Algeria to the world	35	55	60	55
Transport capacity Algeria to the world*	36	60	60-80	60-80

* LNG and pipelines Source: Sonatrach

Algeria wants to limit exports so that reserves represent at least 25 years of production. Given the current level of reserves, this sets an export limit of 60 bcm per year, i.e. exactly what export capacity is likely to be in 1997 after completion of current work on the pipelines to Europe. However, there is a need for investment in local facilities (e.g. GR2 pipeline from south-eastern Algeria to Hassi R'Mel) effectively to maintain the 60 bcm capacity.

There is still scope for large reserve discoveries in Algeria. The Algerian company Sonatrach reckons the export limit could soon be raised and Algeria could export 80 bcm, i.e. the maximum that can be transported by fully upgraded pipelines and LNG facilities. For the time being, however, given the reserve/production ratio, there is no need for new export facilities in Algeria. But the export limit based on reserves is a political constraint that can be lifted at any time by the Algerian government. BP and Sonatrach recently signed an agreement for the exploration and expected development of the gas reserves of the In Salah region (1200 km south of Algiers). This investment is expected, eventually, to increase production by some 10 bcm per year, which could allow additional exports.

4.2.4. Spare capacity around the UK?

The UK is interconnected with the Norwegian sector of the North Sea (Frigg, 15.5 bcm) and with the Republic of Ireland (5 bcm). In 1998, it will be interconnected with the continent through the UK-Continent Interconnector. Bids for capacity by the shareholders have led to set the Interconnector's capacity at 20 bcm (from the UK to the Continent). The Interconnector can also function from the Continent to the UK with a smaller capacity (9 bcm). It is expected that the Interconnector will first ship gas from the UK to the Continent, and several years later, from the Continent to the UK. An interconnection between Scotland and Northern Ireland (2 bcm of capacity) is also under study and could even be completed by 1997.

There appears to be surplus gas in the UK at present. In 2000, the UK gas demand should be about 80 bcm and, according to official forecasts, the UK gas production should be between 80 and 110 bcm. Given that up to 4 bcm of Norwegian gas is exported to the UK, production would have to be at least 105 bcm for the Interconnector to be fully used and even more than 107 bcm if the Irish link were used to export about 2.5 bcm per year, as is forecast by the OECD/IEA. This would be close to the maximum production officially envisaged for 2000. For most of the year, a 20 bcm interconnector is unlikely to be used at full capacity. More fundamentally, our forecasts tend to show that there is no need for additional gas imports to the Continent in 2000: all the gas likely to be required is already contracted. In this context, the UK-Continent Interconnector is likely to have three roles:

- It will provide a hedging mechanisms which should lead to price harmonisation between the UK and the Continent; more specifically, it is likely to reduce prices on the Continent;

- The Continent will gain access to specific UK facilities, especially the spot market (the only gas spot market to exist in Europe so far) and possibly storage facilities;

- It will provide additional security of supply to the Continent (e.g. in 2000, the Interconnector's capacity will represent 40% of Algerian gas supplies to Europe).

It remains to be seen how important each of these roles will be in future and how they will contribute to the Interconnector's profits.

4.2.5. Projects of bigger links between or within national networks in western Europe

Many EU countries are reinforcing their interconnections:

- Portugal will receive Algerian gas through Spain (2.5 bcm per year);

- The link between Spain and France will be upgraded, possibly from 2 to 4 bcm per year;

- The link between Denmark and Germany (DEUDAN) is being upgraded to 2.5 bcm per year;

- The possibility of a new link between Germany and Italy (the link would be owned by a subsidiary of Gazprom, Wingas and Edison) is under study;

- The UK-Continent Interconnector could require an upgrade of the links between Belgium and neighbouring countries[48].

- Finland and Sweden and possibly the Haltenbanken field in Norway could become interconnected (through the Baltic Sea). A project has been under discussion for some years but is still at a very preliminary stage. The project appears to be required by Finland but to be premature for the Swedish gas grid.

Then all neighbouring EU countries will be directly interconnected except France and Italy. There is no plan to build such an interconnection that has, so far, no economic justification.

Many EU countries are also reinforcing their national high pressure networks:

- The Spanish high pressure grid could double in length over the next ten years;
- Italy is reinforcing its network to accommodate additional gas pipeline deliveries from Algeria and Russia;
- Long distance gas pipelines are being built or upgraded between western and eastern Germany to transport Russian gas to the West (Jagal, Yamal pipeline, Stegal) or Norwegian gas to the East (Netra);
- The link between the Danish North Sea and the land will be used at full capacity (7.5 to 8.5 bcm[49]) around the year 2000 and could then require upgrading.
- High pressure pipelines are being laid for the first time in Portugal and in Greece;

In addition, most EU countries are building up storage facilities, especially Belgium, France, Germany, Italy, the Netherlands and Spain. This responds to operational requirements (more storage is needed to dampen the daily or seasonal variations of a growing demand). In many cases, it is also intended to improve the security of gas supply. In western Europe, Denmark, Ireland, the UK and the Netherlands are the only countries not to depend at all on Russia or Algeria for their supply. The other countries need some storage reserves to face possible unpredictable interruptions in supply.

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48 This depends on how much transit capacity will be freed by France with the use of NorFra in place of other Norwegian pipelines. Upgrade to Germany is likely.

49 The capacity of this line is expected to increase from 7.5 bcm to 8.5 bcm in 1997.

4.2.6. Little new LNG capacity

The traditional gas suppliers of Europe are able to produce all the gas needed for Europe up to 2010. We have outlined above the investment required for such gas quantities to be transported to Europe. This leaves little room for long-distance gas (LNG from beyond the Mediterranean). Long-distance gas can only develop at the expense of Norwegian, Algerian or Russian gas. In other words, any significant investment in LNG facilities to import long distance gas should be compensated by a reduction in the construction programme with the traditional suppliers of gas to Europe, unless it is accepted that spare LNG capacity is required to improve security of supply. But then, spare capacity should be coupled with emergency supply contracts signed with LNG producers.

In the short term, LNG investment (most likely the upgrade of existing facilities) should concentrate primarily in the Spain/Portugal peninsula: the two countries will get most of their gas from Algeria; their only European interconnection (with France) will have a capacity of 4 bcm at most; and they have little storage capacity (0.7 bcm -in Spain- at present). Therefore, in Spain and Portugal, security of supply could rely more than elsewhere on the development of non-Algerian LNG supplies. This may delay the potential upgrade of the Algerian pipeline.

5. Impact of competition

5.1. The introduction of competition

In the last five years or so, the European Commission has tried to impose a market reform of gas and electricity industries, including vertical disintegration of national monopolies (unbundling) and open access to existing gas and electricity transport infrastructure (third party access)[50]. Wheeling is widespread in the gas industry: Germany conveys Russian gas to France, Belgium takes Norwegian and Dutch gas to France, Luxembourg and Germany, France transports Norwegian gas to Spain, Germany transports Norwegian gas to Austria, etc. But these movements are based on the good will of the relevant gas companies, not on internationally established principles. Wheeling, as it exists, suffers two major restrictions:

- Gas companies have no automatic or guaranteed access to gas pipelines outside their country. Even if there is spare capacity on a pipeline, the only obligation of the operating company is to *negotiate* with some foreign companies and not necessarily to *grant access* (Transit Directive).

- Gas companies can get their gas to cross a country, but they can hardly ever sell some of this gas along the way before reaching the border of their own country. This is prevented by statutory import transportation and distribution monopolies granted to national companies. The completion of the Single Market for gas would require companies to be able to sell gas outside their national borders. This clearly requires the removal of statutory import monopolies. The question is whether it is also necessary to get rid of *de facto* or *de jure* transportation and distribution monopolies. The Commission thinks it is but this view is challenged by gas companies and some Member States.

Further, the Commission has recognised recently that the rules drawn up for the electricity sector may not be directly applicable to the gas sector. As negotiations take place first about electricity, the directive on liberalisation of the gas market may still be a few years away. However, under one form or another, competition is likely to become a lasting feature of most western European national gas markets because barriers to entry are getting eliminated as a result, in particular, of the liberalisation of the electricity sector. There are now enough very large customers to allow a new entrant to build a customer base and the resulting transportation network with only a handful of clients (what established companies criticise as cherry-picking). Then, given that the economic fundamentals already exist for a development of competition, the removal of remaining legal barriers to entry could be a matter of time. Competition is developing in the UK and, to a certain extent, in Germany, and could emerge in Italy, the Netherlands and Spain:

- The gas market in Great Britain (following the Monopolies and Mergers Commission gas inquiry of 1993-4) should be fully liberalised in stages over the next five years or so. The key aspects are the creation of a spot market (so far embryonic), the access to British Gas' storage for all independent traders and equal access for all to the transportation network.

- In parallel, Germany has allowed joint-ventures of the German gas producer Wintershall[51] and the Russian gas company Gazprom to enter the gas market as an importer and as a trader/transporter of gas (with its own gas transportation network). As an importer, Wintershall already has a 10% market share and expects 15% market share in 2003. As a trader, Wintershall has a 4% market share and should have a 10% market share in 2000.

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50 TPA is now being negotiated primarily in the electricity sector.
51 A BASF subsidiary.

- In Italy, the electricity company ENEL has started purchasing gas directly without help from the gas import and marketing company SNAM. Now the private company Edison is considering importing gas directly through a joint venture (Volta) with Gazprom and Wintershall which would build a pipeline from Germany to Italy to import Russian gas. This project is still at a very preliminary stage (feasibility study) although 1998 has been put forward as tentative completion date.

- In the Netherlands, a large Dutch energy distribution company (Enerco) has announced plans to build a 6-bcm LNG terminal in Rotterdam, which would end the quasi-monopoly of Gasunie. A large gas user (Finnish agrochemical producer Kemira) also takes part in the joint-venture[52]. The project is at a very preliminary stage. The government responds to such industry pressures: the December 1995 gas law allows limited third party access in the Netherlands.

- In Spain, the Basque gas company is seeking authorisation to build an LNG terminal so as to import gas directly rather than have to purchase from the Spanish gas company Gas Natural.

This is the situation so far, but there is little doubt that competition will further develop, although it is difficult to predict the forms that competition will take.

In parallel, the European Energy Charter, signed in December 1994, intends to create a level-playing field in the energy sector in Europe, by eventually providing investors the benefit of national treatment and liberalising market access. So far, national treatment will only apply to the post-investment phase (production) and not to the pre-investment phase (licensing, purchase of sites and equipment, etc.) although negotiations are taking place (probably until 1997) to extend the scope of the Charter. Contracting parties will also *facillitate* access to energy markets and transit of energy, which could eventually foster competition in energy markets in Europe. The Energy Charter is binding but it remains to be seen how enforceable it will be in practice.

5.2. Impact on the organisation of the sector

Two models have developed in parallel. The "British model" is based on vertical disintegration. There are now five distinct businesses in the UK gas industry: the gas producers, the gas traders (selling bulk quantities of gas), the gas distributors (bringing the gas to final customers), the gas transportation companies (responsible for high and medium pressure transportation) and the storage companies (several regulatory decisions tend to sever the link between transportation and storage). Ultimately, the final customer will have the choice of a gas supplier. Competition in gas distribution to residential customers is about to be tested in a few regions of the UK.

The "German model", is based on competing vertically integrated concerns: Wintershall, the challenger to Ruhrgas, is a producer, a transporter, a trader, a storage operator. The distribution companies have the choice of their supplier. However, the final customer has no direct say in the matter. It is still early days for competition in the European gas industry and it is not possible to provide an assessment of the two models or even to predict whether they will spread across Europe. The North American example tends to show that regulatory decisions are the real constraint on the type of competition that develops and therefore it would not be surprising if each EU country developed its own style of gas market liberalisation. In any case, the change in market organisation will require existing gas companies to change their practices or their structure and this will almost certainly impose adjustment costs.

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52 The US trading house Fathom Fuels is also a partner in the project.

5.3. Impact of competition on contracts

5.3.1. Impact of competition on negotiations

Gas price negotiations are changing. For the time being, this results in more frequent contract renegotiations where both the *starting level* and the *structure* of the price index formula are up for discussions. Contract renegotiation is now spreading to the UK where the practice was extremely rare. This is a recognition that long term contracts could need to adapt to on-going structural changes: so far, renegotiations have focused on prices but the development of competition has also led gas companies, especially British Gas, to ask for a renegotiation of the quantities contracted. British Gas has lost so much market share that the company seems unable to sell to final customers the quantities British Gas bought from North Sea producers under long term contracts. Many of the North Sea contracts were negotiated around 20 p/therm while the current spot price is closer to 10 p/therm. As a result, British Gas cannot sell gas to other traders except at a (significant) loss. The situation is complicated by the fact that British Gas may have contracted more than it could have sold even under the old monopoly system. The company is now trying to renegotiate downward the quantities bought under long term contract and, on this point, British Gas has received the support of both the Regulator (OFGAS) and the UK Government. British Gas potential market share loss is dramatic and requires rather exceptional treatment. However, an extended quantity renegotiation could create a precedent and affect gas contract security in Europe.

Under normal circumstances, quantities of gas sold by traders in a competitive market are likely to vary more than quantities sold by monopolies. Contracts will need to let traders' market share vary within reasonable limits. As a result, the swing (range of quantities that can be taken under a contract) should increase in contracts concluded between producers or importers and competing traders. The swing has a cost for the producer[53] and therefore competition is likely to make gas contract prices increase for otherwise similar conditions. It is also possible that larger nominal quantities will be contracted for, to signal to competitors an ambition to win market share: more than 100% of the market needs may be contracted and, as a result of take-or-pay clauses, some traders could have to pay for gas without taking it from the fields.

5.3.2. Impact of competition on prices

There is no international spot market for gas comparable to Rotterdam's oil market. Gas prices are confidential and, even more so are the indexing clauses included in long term contracts. It is customary to price gas with reference to lagged prices of alternative fuels (essentially petroleum products and in a few cases, electricity and coal prices as well). The starting base for contract negotiations is the price of gas that makes the best available alternative exactly as competitive as gas (netback value). Past gas prices demonstrate an econometric correlation with petroleum product prices (linked, in turn, to crude oil prices). The strongest correlation exists with fuel oil prices, which reflects its dominant role in the price indexing clauses of existing contracts.

The development of competition is likely to lead to the creation of spot markets at least in some EU countries. These in turn will lead to the development of futures that are rapidly traded as financial instruments well outside the industry. This is happening to oil markets at present. It leads to rather erratic short term movements of spot and futures prices. Then, the link between spot petroleum product prices and spot gas prices would

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53 This can be seen on a numerical example. A producer has a maximum capacity of 100. He accepts to sell with a swing of 110%. He can therefore sell a quantity x such that 110%*x=100. If the swing becomes 130%, the producer can only sell a quantity z such that 130%*z=100. Clearly z<x.

become loose. Already, UK spot prices have dropped to about 1.50 USD/MMBTU, independently of petroleum product prices[54].

Both the US and the UK experienced a severe drop in prices almost as soon as spot markets were introduced. Prices have remained low since then. Three mechanisms can push prices down in a liberalised market. First, it becomes more difficult, in a competitive market, to make consumers pay for stranded assets (e.g. extra storage, unused pipelines, etc.). Second, market liberalisation makes it possible for consumers to choose their desired level of security of supply rather than have to live with the normally very high security imposed by gas monopolies[55]. This would in effect reassign some pipeline and storage capacity that would no longer qualified as reserve margin (for security of supply) but would become excess capacity available for use by new competitors. In a deregulated market, this would depress prices toward short term marginal cost. But the main mechanism towards lower prices is gas competing with gas (a situation that national gas monopolies avoid). This could take place under at least three circumstances in Europe. First, surplus gas from Britain could reach continental Europe via the UK-Continent Interconnector, thus spreading low UK prices to markets in mainland Europe. Second, supplies of Russian gas could increase significantly in an effort to increase market share. Third, regulatory changes could bring about a full liberalisation of the European gas markets, although this is unlikely in the short run.

5.4. Impact of competition on infrastructure investment

Competition requires more pipelines if regional networks compete, even though there are institutional ways (third party access, or "single buyer" system) of reducing the requirement for extra capacity[56]. To some extent, the increase in investment due to duplication of facilities will depend on the level of vertical integration to be maintained while competition is introduced. By and large, the more vertically integrated the industry when competition is introduced, the greater the need to duplicate investment. For instance, when completely separate networks coexist (as in Germany), all command and control facilities have to be duplicated.

Competition also requires more storage to adjust supply to weather and market conditions. Finally, competition requires more sales and marketing efforts. Overall, competition is likely to increase investment requirements in the sector.

It may be possible for the Regulator to influence the level of investment. The Regulator may act as a coordinator, an "auctioneer" on behalf of the industry. Projects then compete for regulatory approval before being built and no longer compete in the market once they are built. The form of profitability regulation (rate-of-return regulation, price-cap, etc.) also affects investment levels. There is a general belief, for instance, that rate-of-return regulation leads to high levels of investment. Finally, the Regulator may influence the investment level by setting or enforcing safety and quality standards either for gas deliveries or for services associated with them.

The consumer may also increasingly have a role in the definition of the suitable investment level. Gas which is distributed within a geographical area has very well defined technical characteristics. It is therefore not possible for a gas trader to introduce substantial variations in product quality. However, the distributor still has a choice between quality and

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54 This, however, is linked as much to regulatory changes as to the development of spot trading facilities.

55 This was most clearly illustrated in California where customers are divided into two categories: those who benefit from the level of security of supply chosen by the gas company (Core customers) and those who can choose to make their own arrangements for supply security (Non-core customers). This example was much debated during the liberalisation of the UK market.

56 This can be illustrated on a numerical example: in a market of 100 bcm of demand one company expects to sell, say, 80 to 100 bcm of gas and the other 0 to 20 bcm of gas and if there is not third party access, they will each build enough capacity to transport their maximum expected level of sales, i.e. 100 bcm and 20 bcm. Therefore, they will build 120 bcm of capacity. If there is third party access, they are more likely to build about 100 bcm of gas transportation capacity.

price: it is possible for the gas supplier either to increase the quality of its distribution network or to maintain a low but reasonable level of distribution quality and reduce gas prices as much as possible. If gas suppliers favour a quality distribution strategy, operations like billing or customer service will become more sophisticated and this is likely to require extra investment. Similarly, increased network reliability requires investment. On the contrary, if gas suppliers decide to compete in prices, they will be under pressure to reduce investment, for instance bringing safety standards to the minimum required by law or regulation. How far this process could go depends on whether "gold-plating" takes place in some parts of the industry and whether the exacting safety and quality standards encountered in the industry are required more by the consumers than by the authorities.

5.5. *Impact of competition on companies profit*

As mentioned above, competition could increase infrastructure requirements, increase gas purchase prices and impose adjustment costs to existing gas companies. At the same time, competition should reduce sales prices (compared to the prices set by monopolies). Clearly, this will require productivity improvements (e.g. British Gas is laying off 25% of its staff) or lead to a squeeze in profits (or both). Up to now, gas monopolies used their comfortable profits to finance a large share of their investment programmes. In future, gas companies could need more external financing as their profits may be reduced by competition.

6. Main Risks

The European gas market shows a potential for significant future growth that should warrant significant infrastructure investment in the sector. However, the investor in the gas market is faced with the following main risks:

- **Outside dependence, especially dependence on Russia:** Both Algeria and Russia constitute significant political risks and there is probably no alternative to Russian gas in Europe. Russia supplies about 20% of the western European gas market and is likely to supply more in future. Russia supplies nearly 60% of the eastern European gas market and this share is also likely to increase. Developing contract flexibility and increasing the number of suppliers are required to reduce this risk.

- **Russia's finance shortage:** Many investors are hesitant to finance large-scale projects in Russia. At the same time, a significant increase in Russia's gas transportation capacity to Europe is required. If Russia cannot receive the required funding, necessary transportation projects may be delayed. This could lead to temporary shortage on the western European gas market.

- **Demand in Eastern Europe:** Russia's export potential to western Europe is directly dependent on how much Russian gas gets taken in eastern Europe. However, the future level of eastern European gas demand is very uncertain.

- **Competition** could reduce profits in the gas industry. It could also lead to still largely unpredictable structural changes.

- **Future evolution of gas prices** is extremely uncertain. Field development and production costs are likely to increase (see paragraph 3.1.3) and new gas infrastructure requirements are significant (see parapgraph 4). These exert upward pressures on prices. However, in the short term, there might be a slight excess supply on the gas market (see parapgraph 3.2.1) which would tend to push prices down. Finally, the development of competition is likely to exert a downward pressure on prices, the timing and the extent of which is unknown. Competition is also loosening, at least for short term prices, the link between petroleum products and gas prices (see paragraph 5.3.2). The net effect of all this is uncertain. There is a real risk, however, that prices will be low in the short term while gas companies' investment in new infrastructure to meet future gas demand will be high.

Finally, this survey assumes that no technological breakthrough will take place in connection with the use of gas and that the current energy policy options will be maintained. Both hypotheses can be questioned. Gas is used marginally in the transport sector and in air conditioning. These constitute long term potential markets; they are environmentally-friendly but not economic options so far. Similarly, progress of coal gasification would influence the growth of the gas market. More fundamentally, major energy policy decisions have to be made before 2010 in Europe. In particular, many nuclear power stations will come to the end of their productive life around that date and will have to be replaced either by new nuclear plants or by alternatives such as gas-fired power stations. This could result in a substantial increase in gas demand. Tighter environmental policies are likely to increase the share of gas in a shrinking energy market, and their impact on gas consumption in absolute terms is therefore more ambiguous. Long term security of supply is heavily dependent on the evolution of the economic and political situation in Russia. A prolonged and substantial breakdown in Russian supplies would undermine the growth of the gas market. However, the opposite scenario (a substantial improvement of Russia's situation, leading to Russian gas supplies becoming almost as secure as, say, Norwegian supplies) could result in higher gas demand than expected. The future of nuclear, the progress of the environmental policy and the evolution of security of supply are decisive factors for Europe's choice of long term energy options around the year 2010.

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APPENDIX 1: Long Distance Gas

Hypothetical medium-term supply capacity to Europe(Bcm)

Country	Quantity
Abu Dhabi	10
Azerbaidjan	?
Egypt	?
Iran	25
Kazakhstan	10
Libya	3
Nigeria	5
Oman	6
Qatar	15
Trinidad	3
Turkmenistan	10
Venezuela	6
Total	93

Source: miscellaneous

Reserve Production Ratios
(Reserves and Production in billion cubic metres)

	1993 Output	1994 Reserves	Reserve/ production
Qatar	18.4	7079	385
Iran	60.0	20700	345
Abu Dhabi	18.9	5335	282
Libya	12.4	1299	105
Nigeria	36.8	3400	92
Saudi Arabia	67.3	5185	77
Former Soviet Union	778.1	57500	74
Norway	41.6	2805	67
Czechia & Slovakia	0.3	11	32
Denmark	6.7	215	32
Poland	5.0	155	31
Spain	0.6	18	29
Algeria	130.7	3700	28
Western Europe	254.8	6222	24
Eastern Europe	35.3	788	22
Netherlands	84.0	1875	22
Albania	0.0	2	22
Romania	21.5	445	21
Italy	19.4	360	19
Hungary	5.6	88	16
Austria	1.5	21	14
Ireland	2.7	31	12
Germany	19.4	198	10
United Kingdom	73.6	630	9
France	4.9	30	6
Turkey	0.2	25	119
Bulgaria	0.0	7	100
Greece	0.1	9	75

Source: Cedigaz

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