

Energy challenges for Europe to 2010 and beyond according to the IEA

Fatih Birol

Head of the Economic Analysis Division IEA²², Paris, France

The European Union is likely to face great challenges over energy security and rising carbon dioxide emissions over the coming years. This article discusses energy market trends and prospects for the European Union, based on the IEA's 2004 *World Energy Outlook*. It analyses the underlying market conditions and the general energy-policy framework and presents an outlook for energy demand and supply as a whole under a Reference Scenario. It then analyses the impact of new policies on energy markets and looks at how policymakers can address these challenges. Further, it discusses in detail the region's natural gas prospects, and natural gas production in Russia, which is set to become a major exporter to Europe.

A message that arises from our analysis of trends to 2010 and 2030 is that today's challenges over security of supply and emission reduction will persist in the near future. The very long life of power plants, buildings and even cars limits the rate at which more efficient technology can be deployed. In the long term, however, energy policies can be very effective in addressing these challenges.

1. Current Trends

The European Union's primary energy demand has continued to edge higher since 2000. Demand dipped in 2002, largely because of mild winter weather, but rebounded by almost 2% in 2003, according to preliminary data. Recently, some power producers have switched back to coal from natural gas, which has proven to be much more expensive because of its *de facto* indexation to oil. Oil remains the predominant energy source, although

²² International Energy Agency/OECD, Paris
Tel: +33 (0) 1 40 57 66 70
Fax: +33 (0) 1 40 57 66 59
fatih.birol@iea.org

its share in total primary energy use has declined since the 1970s.

Economic growth in the European Union remains sluggish in major countries, though the pace of recovery has picked up in some countries, notably Spain and the United Kingdom. Overall, EU's GDP grew by only 1.1% in 2004. The economies of the main euro-zone countries – France, Germany and Italy – continue to lag. Unemployment remains stubbornly high, averaging nearly 9% across the region in August 2004, and consumer demand is weak. A sharp appreciation in the euro against most leading currencies has depressed exports and undermined industrial production but it has also shielded European consumers from some of the pain of high dollar-denominated oil prices.

Near-term economic prospects are nonetheless improving. Growth is expected to average over 2% in 2004 and above 2.6% in 2005. Over the period 2002-2010, growth is assumed to average 2.3%. It then slows to 2.1% from 2010 to 2020 and to 1.7% from 2020 to 2030. The differences in growth rates among countries are expected to shrink with the macroeconomic convergence that should result from economic and monetary integration. The European population is assumed to remain broadly unchanged over the projection period, rising very gradually through to the mid-2010s and falling back very slowly thereafter. As a result, GDP per capita will be 75% higher by 2030 than in 2002.

New EU directives on electricity and gas and a regulation on cross-border electricity exchanges entered into force in July 2004. Under the new directives, all energy users will have the right to choose their electricity and gas supplier by July 2007. The directives also require the legal unbundling of network activities from generation and supply, and the setting up of a regulator with well-defined functions. Network operators must publish tariffs for third parties wishing to make use of their grids and their public-service obligations are reinforced, especially for the most vulnerable customers. The regulation establishes common rules for cross-border trade in electricity. These moves, together with national initiatives, are expected to accelerate the opening of energy markets to competition, a trend which will ultimately lead to more rational investment in infrastructure and, in some cases, to lower costs to customers. This will partly offset the effect of other factors that are expected to drive prices up during the second and third decades of the projection period.

In 2003, the European Union adopted an emissions-trading directive that requires all member states to set limits on CO₂ emissions from energy-intensive plants by allocating them emission allowances. Trading started in

February 2005 with more than 12 000 plants falling under the scope of the directive. Most countries will, however, need to rely on additional measures if their national emission-reduction targets under the Kyoto Protocol are to be met.

2. The reference scenario projections

Europe's primary energy demand is projected to grow by 1.1% per year over 2002-2010 slowing to 0.7% per year in the period to 2030. The pattern of energy use will change over time (Figure 1). Consumption of coal will remain almost stable to 2010 and will drop by 10% by 2030. Coal's share in total primary energy use will decline from 18% in 2002 to 17% in 2010 to 13% in 2030. The share of nuclear power is also expected to fall sharply, especially during the second half of the *Outlook* period. At 7% in 2030, it will be less than half of that in 2002. The share of gas will increase, from 23% now to 25% in 2010 and 32% in 2030, mainly because most new fossil-fuel power plants will be gas-fired. The share of non-hydro renewables will also rise sharply, overtaking nuclear power early in the 2020s. Most renewables will be used to generate electricity. Primary energy intensity is projected to fall by 1.1% per year over 2002-2010 and somewhat faster after 2010, averaging 1.3% per year over the period 2002-2030. Energy intensity will continue to decline because of energy-efficiency gains and a continuing structural shift of the EU economy away from energy-intensive activities.

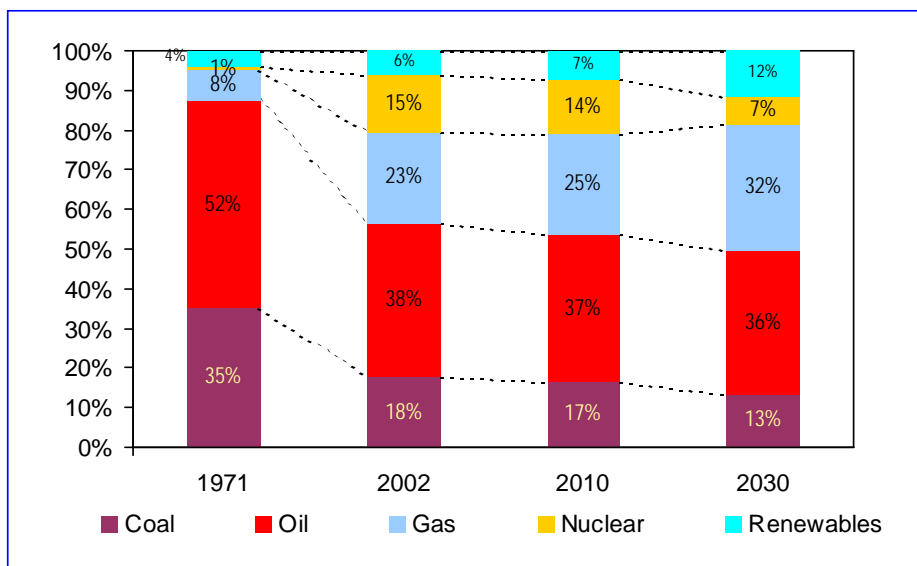
In the transport sector, where oil use is increasingly concentrated, the pace of demand growth will slow. Saturation effects and major improvements in the fuel efficiency of new cars and trucks will largely cancel out the effect of rising incomes on personal mobility and freight. Alternative transport fuels, including natural gas, will also displace oil-based fuels. Electricity will take a growing share of final energy use. It will increase by 1.7% per year up to 2010 and, on average, by 1.4% per year over the period to 2030. The increase in electricity consumption will come mainly from homes and offices. Most of the end-use increase in gas use will come from two areas: industry and space and water heating for households.

Table 1: Primary Energy Demand in the European Union (Mtoe)

	1971	2002	2010	2030	2002-2030*
Coal	426	303	307	274	-0.4%
Oil	633	648	687	743	0.5%
Gas	93	389	468	649	1.8%
Nuclear	13	251	251	146	-1.9%
Hydro	20	26	30	33	0.8%
Biomass and waste	25	65	84	147	3.0%
Other renewables	2	8	21	57	7.2%
Total	1 211	1 690	1 848	2 048	0.7%

Average annual rate of growth.

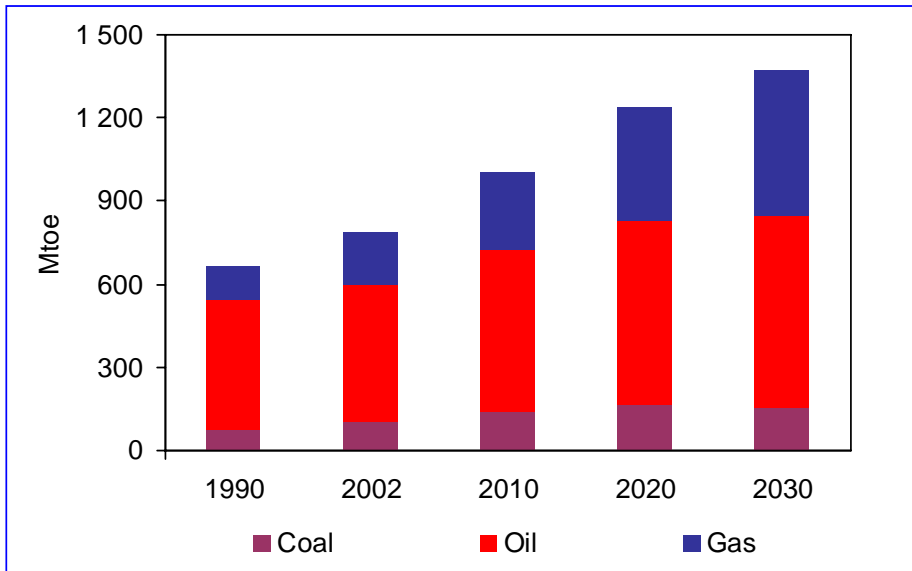
Figure 1: Fuel Shares in Primary Energy Demand in the European Union



The European Union's imports of fossil fuels will increase substantially as indigenous production dwindles and demand edges up (Figure 2). Imports already meet 76% of EU primary oil demand, and this share will grow to 85% in 2010 and to 94% by 2030. Production from the North Sea, the main source of indigenous supply, has already peaked. Its decline – led by production from the United Kingdom – is expected to accelerate over the

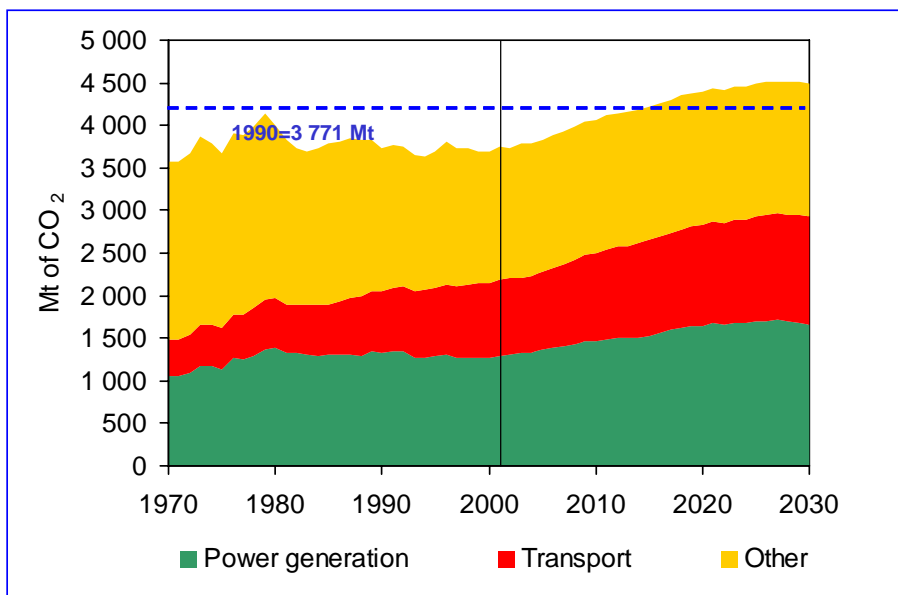
coming years. Total EU oil production is projected to fall from 3.2 mb/d in 2002 to 2.2 mb/d in 2010 and to 0.9 mb/d in 2030. The increase in Europe's gas imports will also be pronounced. The gap between production and demand will continue to widen, implying an increase in EU gas-import dependence from 49% in 2002 to 60% in 2010 and to 81% in 2030. A growing share of EU gas imports will be shipped as liquefied natural gas (LNG). Coal imports will also grow, mainly due to further closures of unprofitable mines in those countries which still have them: the Czech Republic, Germany, Greece, Poland, Spain and the United Kingdom.

Figure 2: Fossil Fuel Net Imports in the European Union



Energy-related CO₂ emissions in the European Union will rise as fast as primary energy demand. By 2030, emissions will reach 4 488 Mt, 20% above the 2002 level (Figure 3). Power generation will remain the single biggest CO₂-emitting sector in 2030. Its share will increase from 35% in 2002 to 36% in 2010 and to 37% in 2030. The share of transport jumps from 24% to 25% in 2010 and to 28% in 2030.

Figure 3: Energy-related CO₂ Emissions in the European Union



The Reference Scenario projections show the European Union as failing to meet its commitment under the Kyoto Protocol to cut greenhouse-gas emissions to 8% below their 1990 level by the period 2008-2012. The Europeans could only do so if additional EU measures were imposed or if they bought emission credits from non-EU countries. Europe's energy-related CO₂ emissions are expected to be 9% higher in 2010 than in 1990.

3. An Alternative Policy Scenario for the European Union

The Reference Scenario presented above takes into account all government policies and measures that had been adopted by mid-2004. It does *not* include policy initiatives that might be adopted in the future. Energy markets will very probably evolve in different ways from those depicted in this scenario, because the policy landscape will change.

In the Reference Scenario, energy use and carbon dioxide emissions continue to grow rapidly and fossil fuels continue to dominate the energy mix. The Alternative Scenario analyses how energy markets could evolve were countries to adopt a set of policies and measures that they are either currently considering or that they might reasonably be expected to implement over the projection period.

The impact of energy-saving policies on energy demand grows throughout the projection period, as the stock of energy capital is gradually replaced and new measures are introduced. Energy savings achieved by 2010 are only 1%.

In the Alternative Scenario, primary energy demand in the European Union reaches 1 870 Mtoe in 2030 – about 180 Mtoe, or 9%, lower than in the Reference Scenario. By 2030, the fuel mix in the Alternative Scenario looks very different from that in the Reference Scenario. Fossil fuels in aggregate account for 74% of primary energy demand, compared with 81% in the Reference Scenario. Coal consumption falls most. Renewables are 50 Mtoe higher, or 25%. In the Alternative Scenario, Europe's primary oil savings are bigger than in other OECD regions. This reflects policies to improve vehicle fuel efficiency, to promote biofuels and to encourage mass transit. By 2030, demand for oil is cut by more than 100 Mtoe, or 14%, compared with the Reference Scenario. These results grow out of a combination of policies, most of which have been aimed at reaching the EU's Kyoto commitment.

The European Commission is promoting the use of renewables in power generation, in the transport sector (biofuels) and in buildings (solar heaters). A number of new measures in these areas have been taken into account in the Alternative Scenario (Table 2). The emission-trading scheme has been included in this Scenario. The scheme will allow European companies to buy or sell emission allowances. Carbon-dioxide emissions in Europe will peak at around 3 900 Mt in 2020, and then start to fall. In 2030, they will be 850 Mt, or 19%, lower than in the Reference Scenario. Emissions in 2010 would be some 450 Mt, or 13%, above the Kyoto target.²³ In the Reference Scenario, they are 18% higher.

²³ The target date for the 8% emissions-reductions under the Kyoto Protocol is the period 2008-2012.

Table 2: Main Policies Considered in the Alternative Scenario in the European Union

Sector	Programme/measure	Impact
Power and heat	Renewable energy directive and extension	Renewables-based generation increases
	Policies to promote combined heat and power	Increased share of electricity generation from CHP plants
	Support for faster technology deployment	Faster deployment of renewables and fuel cells
	Extension of the life of nuclear plants in France and Sweden	More nuclear power production
Transport	Extended voluntary agreements with car manufacturers	New car and light-truck efficiency improves
	Increased support for alternative fuels	Increased use of biofuels
	White Paper on package of transport policies	Slower growth in passenger and freight transport and modal shift from road and aviation to rail and bus
Industry	Standards for new motor systems	Improved efficiency of new motor systems
	New voluntary programmes covering; -Information on and assistance in retrofitting, replacing and operating process equipment -Energy auditing, target setting and monitoring.	Improved efficiency of new technologies and accelerated deployment. Improved efficiency of energy use in factory buildings

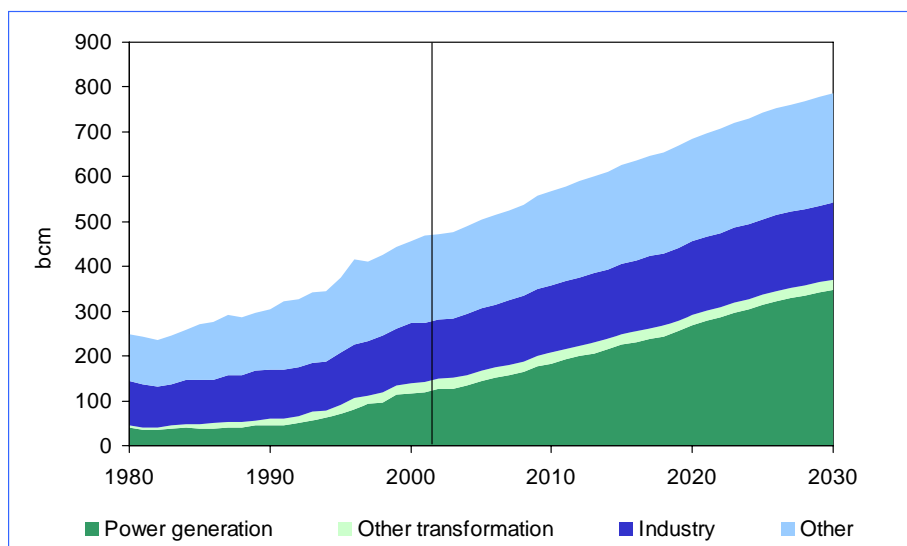
	Tax incentives and low-interest loans for investment in new efficient technologies	Accelerated deployment of new boilers, machine drives, and process-heat equipment
	Increased funding to R&D and demonstration programmes	Improved efficiency of new equipment entering the market after 2015
Residential and commercial	Efficiency standards for lighting ballasts	More efficient lighting
	Voluntary agreements on equipment and measures to reduce the standby power of appliances	More efficient equipment and appliances
	Updated energy labels for washing machines and dishwashers	More efficient equipment
	More “whole-building” R&D	More efficient buildings
	Full implementation of the Energy Performance in Buildings Directive	More efficient buildings

4. European Natural Gas Supply Challenges

Natural gas demand in the European Union will grow substantially. It is projected to increase by an average 2.3% per year in the current decade – the most rapid growth rate of any fuel other than non-hydro renewables. Growth will slow somewhat after 2010 and will average 1.8% over the entire projection period. The share of gas in total primary demand will continue to rise, from 23% at present to 25% in 2010 and 32% in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period (Figure 4). Gas is expected to account for the bulk of incremental power generation. The share of gas in power production is projected to surge from 15% in 2002 to 20% in 2010 and to over 35% in 2030. The EU power sector’s use of gas will increase by 3.7% per year.

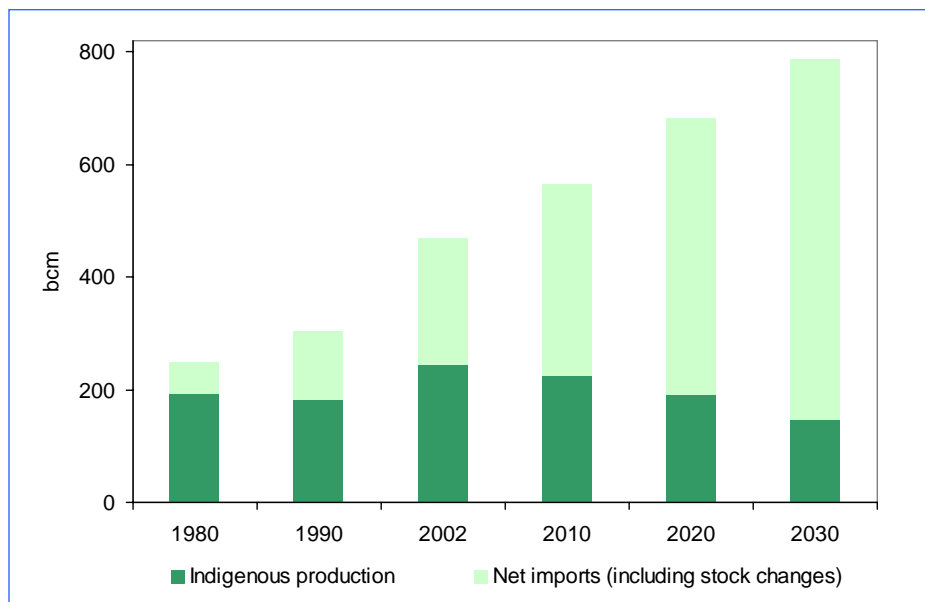
Demand in all other end-use sectors will also increase steadily: by around 0.9% per year in the residential and services sectors and by 1% per year in industry.

Figure 4: Gas Demand in the European Union by Sector



EU gas production amounted to around 240 bcm in 2003. Two producers – the United Kingdom (108 bcm) and the Netherlands (73 bcm) – accounted for 79% of the total, mostly from offshore fields in the North Sea, a mature producing region. Germany, Italy, Denmark and Poland are the only other significant producers. There is limited potential for increasing gas production in the region as resources are small. Proven reserves are less than 3.4 tcm, or 2% of the world’s total. Production from the North Sea is expected to decline steadily over the projection period. The United Kingdom will become a major net importer of gas before the end of the current decade. Production in the Netherlands is also expected to continue to fall gradually, but the country will remain a net exporter of gas. Total EU gas production is projected to decline over the projection period, down to 225 bcm in 2010 and 147 bcm in 2030 (Figure 5).

Figure 5: Gas Supply Balance in the European Union



Rising demand and stagnating production will result in a surge in net imports, from 233 bcm in 2002 to 342 bcm in 2010 and 639 bcm in 2030. The bulk of this gas will go to meet new power-sector needs. The share of imports in the region's total gas demand will rise from 49% in 2002 to 60% in 2010. It will reach 81% by the end of the projection period. Incremental imports are expected to come from the Union's three main current suppliers, Russia, Norway and Algeria. Production in Norway, all of which is exported to the European Union, is expected to continue to grow, from 77 bcm in 2003 to 94 bcm in 2010 and 135 bcm in 2030. Most of the increase will come from the Norwegian Sea and the Norwegian sector of the Barents Sea.

Europe will also import a mixture of piped gas and LNG from other African and former Soviet Union countries, the Middle East and Latin America. Russia will remain the largest single supplier in 2030, exporting around 155 bcm compared with 105 bcm in 2002. But the biggest increase in supplies will be from the Middle East, mostly in the form of LNG, although increasing quantities of gas are expected to be transported to Europe by pipeline from Iran and possibly Iraq towards the end of the projection period. Imports of LNG from Trinidad and Tobago and from Nigeria are set to rise. Other new sources of gas are expected to include the

Caspian region (by pipeline), Libya (via under-sea pipeline), Egypt and Qatar (both as LNG). Venezuela could also emerge as an LNG supplier in the long term. Spot shipments from other LNG exporters in the Middle East, Latin America and Africa and possibly further afield could play an increasingly important role if a global short-term market in LNG develops. Turkey, which has over-contracted for gas supplies for the next several years, is expected to sell its surplus volumes to EU countries once a pipeline link has been built.

Progress in liberalising EU gas markets varies markedly among member states (Table 3). The implementation of a second EU gas directive, adopted in 2003, should give impetus to the development of competition in several countries. The directive allows all industrial and commercial consumers to choose their supplier starting in July 2004 and all other consumers to do so by July 2007. It also requires vertically integrated gas utilities to unbundle their transmission operations by July 2004 and their distribution operations by July 2007. According to a recent European Commission report, the main obstacles to the achievement of a truly competitive EU gas market are delays in opening up retail markets, ineffective regulation of network services and the concentration of market power in a small number of large companies (EC, 2004). The Commission has proposed a new regulation, similar to one already adopted for electricity, to promote cross-border trade.

Table 3: Status of Gas Market Liberalisation in the European Union

	Declared retail market opening (%)	Size of open retail market (bcm)	Switching from initial supplier, 2002 (%)		Concentration in wholesale market
			Large eligible industrial users	Small commercial and domestic users	
Austria	100	8	6	0	Yes
Belgium	83	9	Not known	Not applicable	Yes
Denmark	100	5	17	Not applicable	Yes
France	37	15	20	Not applicable	Moderate
Germany	100	90	5	<2	Moderate
Ireland	85	4	100	Not applicable	No
Italy	100	69	10	0	Yes
Luxembourg	72	<1	0	Not applicable	Yes
Netherlands	60	25	15	Not applicable	Moderate
Spain	100	20	38	1	Yes
Sweden	51	<1	0	Not applicable	Yes
United Kingdom	100	105	16	19	No
Estonia	80	<1	0	Not applicable	Yes
Latvia	0	0	0	Not applicable	Yes
Lithuania	80	2	0	Not applicable	Moderate
Poland	34	4	0	Not	Yes

Czech Republic	0	0	0	applicable	Yes
Slovak Republic	33	2	<5	Not applicable	Yes
Hungary	0	0	Not known	Not applicable	Yes
Slovenia	50	<1	0	Not applicable	Yes

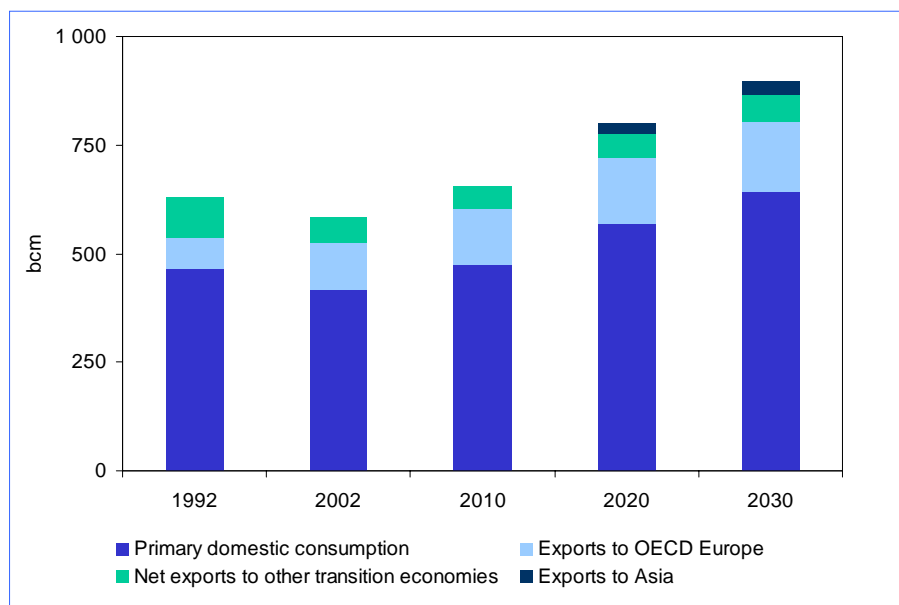
Source: EC (2004).

5. Russian Gas Supply Outlook

The countries of the European Union imported about 105 bcm of natural gas from Russia in 2002. To meet its rapidly growing demand, Europe will increase its imports from Russia in the future. European gas imports from Russia are expected to rise to 137 bcm in 2010 and to 155 bcm in 2030. Developments in Russia's gas sector will therefore be of crucial importance for the European gas sector. Russia's huge gas resources are expected to underpin a continued increase in production, to meet a gradual rebound in domestic demand and to provide increased exports to Europe as well as to new markets in the East.

We project production to rise from an estimated 608 bcm in 2003 to 655 bcm in 2010 and 898 bcm in 2030 (Figure 6). Net exports are expected to rise from 169 bcm in 2002 to 182 bcm in 2010 and 274 bcm in 2030. This projection takes account of increased imports from Central Asia, which will make possible higher exports to Europe. Russia will still be the world's biggest gas exporter at the end of the projection period. Higher production will, however, call for considerable investment in greenfield projects to replace declining output from super-giant fields that have been in production for decades. Securing the necessary financing will depend on market reforms, particularly the elimination of domestic price subsidies, and easier access for independent producers to the national transmission system operated by Gazprom, the dominant gas company (IEA, 2003).

Figure 6: Russian Gas Balance



Box 1: Profile of Gazprom

Gazprom is the world's largest gas company. It plays a central role in the Russian economy, providing up to a quarter of federal government tax revenues. It accounts for almost 90% of Russian gas production and owns and operates the national network of high-pressure inter-regional gas pipelines, which, at over 150 000 km, is the longest in the world. It is the sole owner of gas storage sites in Russia, operating 22 underground facilities. Gazprom's role in local distribution has risen markedly since the mid-1990s, as it acquired stakes in smaller companies facing financial difficulties. Gazprom has a monopoly on all gas exports outside the Commonwealth of Independent States (CIS) and holds a monopoly on gas processing in Russia, making it the sole buyer of the wet gas produced by Russian oil companies and independent gas producers. Over the years, the company has acquired a vast array of holdings in such sectors as banking, insurance, agriculture, media and construction. It is committed to disposing of many of its non-core assets, but this is proving a slow process.

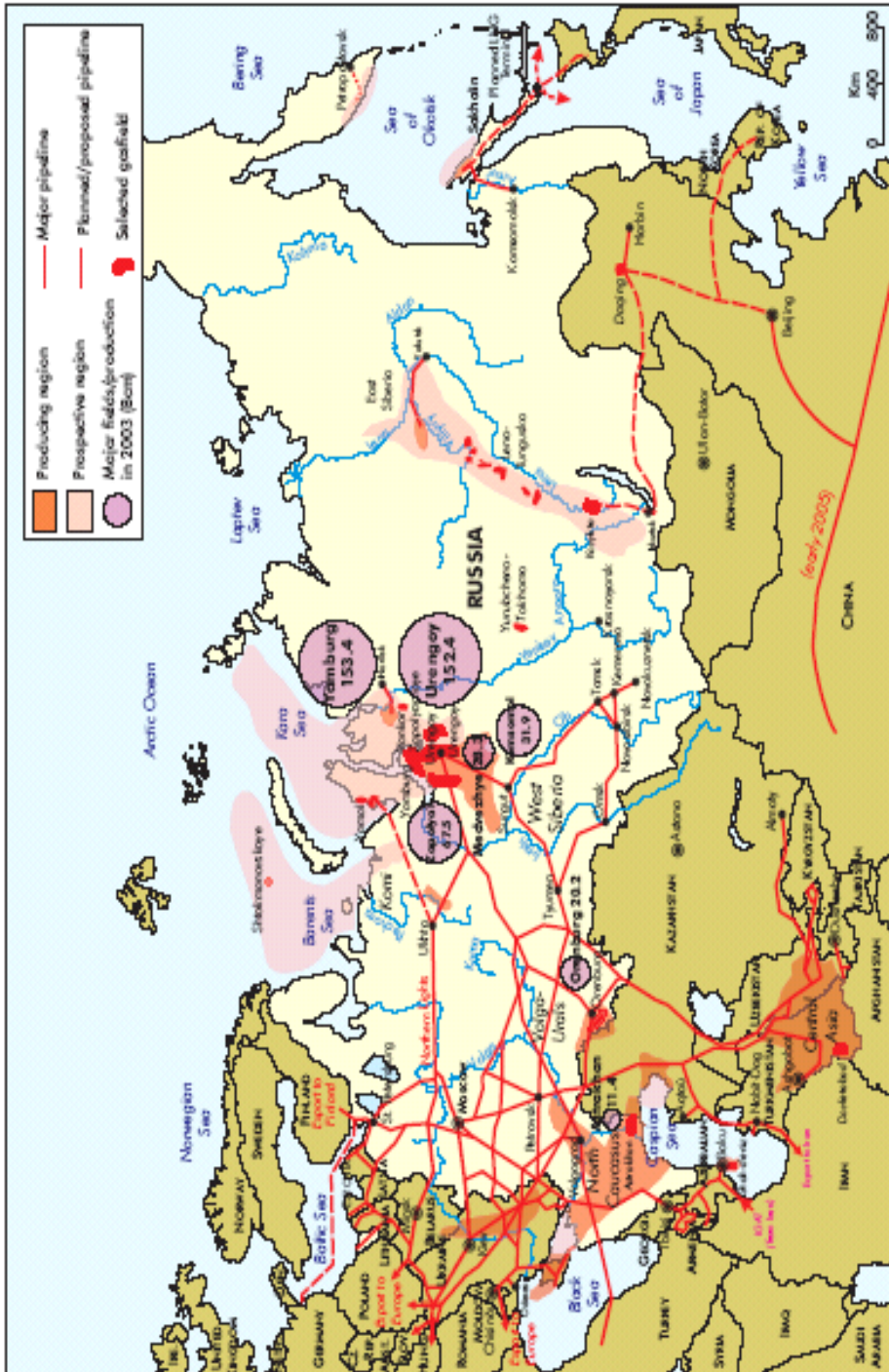
Though constituted as a joint-stock company, Gazprom operates in many ways as an arm of the state, combining commercial and regulatory functions and maintaining tight control over the sector's infrastructure and over

information flows within it. A majority of the shares in the company was sold to private investors in the 1990s. But the state still holds 38% directly and another 16.6% indirectly, giving it majority control of the board.

6. Russian Natural Gas Resources and Production Trends

Russia's gas resources are huge. It has 47 trillion cubic metres of proven natural gas reserves, 26% of the world total (Cedigaz, 2004). Gazprom holds the licences to fields holding 55% of these reserves; other producers hold 28%, while 17% are unallocated. Three-quarters of Russian gas reserves – and a similar share of current production – are in West Siberia, and most of these are in the Nadym-Pur-Taz region (Figure 7). European Russia (including the Barents Sea shelf) accounts for 16% and East Siberia and the Far East together for the remaining 9%. Some 20 giant fields have been discovered, each with more than 500 bcm in reserves, making up three-quarters of total Russian reserves. Only seven of these fields have been brought into production. Reserves are equivalent to about 81 years of production at current rates. In addition to proven reserves, there are an estimated 33 tcm of undiscovered gas resources (USGS, 2000).

Figure 7: Major Gas Reserves and Supply Infrastructure in Russia



Russian gas production fell sharply in the 1990s in response to the collapse in domestic demand following the break-up of the Soviet Union, from a peak of 632 bcm in 1991 to a trough of 561 bcm in 1997. Production has since recovered, largely thanks to rising exports. Output amounted to an estimated 608 bcm in 2003, of which Gazprom produced 540 bcm. The bulk of Russian gas production comes from three super-giant fields in Nadym-Pur-Taz that have been in production for many years and are now in decline: Medvezhye, Yamburg and Urengoye. Rising output from a fourth super-giant field, Zapolyarnoye, which started producing in 2001, is expected to compensate for much of the decline in production at the other super-giant fields over the next few years. Sustainable peak production of around 100 bcm from Zapolyarnoye is expected to be reached in 2008, once a third gas-processing plant is brought on stream.

In the next few years, Gazprom and independent producers will need to bring several new fields on stream in existing producing areas to stem the decline from the three old super-giants. Gazprom expects production from those fields to fall by 7% to 8% per year over the rest of the current decade. If this forecast proves accurate and decline rates remain the same beyond 2010, their combined output would fall from 334 bcm in 2003 to about 200 bcm in 2010 and less than 100 bcm in 2020. Gazprom prefers investing more in new fields rather than trying to sustain production levels at the super-giants – despite the success of past efforts to slow the rate of production decline at the Medvezhye field. The company is giving priority to developing a number of smaller fields in the vicinity of the super-giants which will be able to use spare capacity in the pipeline system running from Nadym-Pur-Taz. These include Pestsovoye, Yen-Yakhinskoye, Yuzhno-Russkoye and shallow-water fields in the Ob-Taz Gulfs. Yuzhno-Russkoye is ear-marked to fill the planned North European Pipeline to Germany and beyond, Gazprom plans to invest over \$7 billion in 2004, rising to \$9 billion in 2006, most of it in upstream projects.²⁴

Contrary to earlier official expectations, there is unlikely to be a need for Gazprom to bring new fields on the Yamal Peninsula into production before the beginning of the next decade and possibly not before the middle of the decade. The timing of these developments will depend partly on Gazprom's imports of Central Asian gas. Yamal's reserves exceed 10 tcm, but the climate and terrain are harsh, and development costs are high (IEA, 2001). New pipelines would need to be built, but costs could be minimised

²⁴ The Ministry of Economic Development and Trade (MEDT) is critical of Gazprom's investment plans. The ministry wants Gazprom to reduce investments and adopt a balanced budget, probably on the grounds that Gazprom's upstream investments are less efficient than those of independent producers.

by connecting the fields to the existing pipeline system to the south. The first Yamal fields to be developed will probably be Bovanenkovskoye and Kharasavey, with the potential to produce a total of 150 to 180 bcm a year at plateau. Gazprom is also planning to develop, with foreign partners, the Shtokmanovskoye field in the Barents Sea, which holds 2.5 tcm of proven reserves. Peak production from this field, which may be used for LNG exports, is estimated at 70 bcm a year. But development costs are very high, possibly exceeding \$20 billion. We do not expect first gas before 2020, even though production is officially expected to begin in 2010.

Oil companies and independent gas producers, who hold around a third of gas reserves, are expected to make a growing contribution to Russian gas production in the coming decades. They already account for an estimated 13%, all of it sold to domestic customers. Several companies are seeking to boost production, much of it associated with oil. Company projections imply that total non-Gazprom output could reach 260 to 290 bcm by 2015 – about a quarter of total Russian gas production (Table 4). Such a big increase is, however, unlikely. The *Energy Strategy* projects non-Gazprom production at between 105 and 115 bcm in 2010 and between 140 and 160 bcm in 2020. The prospects for independent production depend critically on transparent and reliable access to Gazprom's gas-processing capacity and transmission system. Large volumes of gas produced by oil companies are still being flared because Gazprom declines to buy it or because the terms of access to processing plants and the network are uneconomic.

Table 4: Russian Gas Production of Non-Gazprom Companies (bcm)

	2003	Company expectations 2010-2015
Oil companies	40.4	215
Surgutneftegaz	13.9	25
TNK-BP	6.8	20-40
Rosneft	7.1	50
Yukos	5.7	50
Lukoil	4.7	50
Other	2.1	-
Independents*	35.9	75
Novatek	21.0	52
Nortgaz	5.0	11
PSAs (including Sakhalin)	0.2	12

Other	10.7	-
Total	76.3	260-290

* *Expectations of independents are all for 2010 (based on Energy Strategy).*

Sources: IEA estimates; company reports; Government of the Russian Federation (2003).

Central Asian gas is expected to play an increasingly important role in meeting Russia's domestic needs, as well as Gazprom's export commitments to Europe. Gazprom has signed deals with Turkmenistan, Kazakhstan and Uzbekistan to import gas. The most important of these deals, with Turkmenistan, provides for annual imports of 5 to 6 bcm in 2004, rising to a plateau of as much as 80 bcm over 2009-2029. The gas, priced at an estimated \$29 per thousand cubic metres, will be paid for in cash and in bartered gas equipment and services through to 2006. These arrangements will allow Gazprom to delay the development of its own expensive reserves in Yamal and Arctic regions. They will also reduce Gazprom's need to buy gas from independent Russian producers. Furthermore, they will effectively eliminate Central Asian producers as competitors for sales to Europe and other export markets, since most of their production will go to Russia. However, it is uncertain whether these deals will proceed as planned.

Export Prospects

Russian exports gas exclusively to other CIS countries and Europe. In 2003, Russia exported 119 bcm to OECD Europe. Gazexport, a wholly-owned subsidiary of Gazprom, is the sole exporter to Europe. Other non-Gazprom companies export Russian gas to other CIS countries. Rising gas demand in Europe is expected to remain the primary driver of Russian gas exports over the projection period, although Asia will emerge as an important new market. Exports to Europe are projected to climb to 137 bcm in 2010 and 155 bcm in 2030. Exports to Asia are expected to reach 30 bcm by 2030. These projections are extremely sensitive to the rate of growth in domestic gas demand.

Increased exports to Europe will require substantial additions to pipeline capacity. Existing capacity can meet projected export needs through to the end of the current decade and probably well beyond in the case of Turkey, where demand is growing much more slowly than was previously envisaged. Completion of the Yamal-Europe Pipeline by 2005 will increase capacity through Belarus and Poland to Germany, but plans for a parallel line have been put on hold. Bottlenecking could also delay the need for new projects. Gazprom and a number of international oil and gas companies are nonetheless considering building a 20-bcm/year North European pipeline,

which would run under the Baltic Sea from the Russian coast near Saint Petersburg to the German coast, and possibly on to the Netherlands and the United Kingdom. We do not expect the line, which will cost an estimated \$5.7 billion, to be built until after 2010.

Gazprom is also looking into the possibility of developing LNG exports based on reserves on the Yamal peninsula and in the Shtokman field in the Barents Sea. But the costs would be very high, because of the extremely harsh climate. For this reason, we have assumed that no LNG projects other than Sakhalin-2 proceed before 2030.

Gas exports to Asia in the form of LNG from Sakhalin-2 are due to start in 2007. The project, owned by a foreign consortium led by Shell, involves the development of an offshore gas field and the construction of a two-train liquefaction plant with a capacity of 9.6 million tonnes per year. Gas will also come from an adjacent oil and associated-gas field. Total investment will amount to around \$9 billion. We expect gas exports from the less advanced Sakhalin-1 project, led by Exxon-Mobil, to start in the 2010s.

Pipeline exports to Asia are expected to begin during the second decade of the projection period. Rusia Petroleum, owned by the TNK-BP joint venture²⁵, holds a licence to develop gas reserves at the Kovykta field near Irkutsk in East Siberia. It plans to develop the field and build a pipeline to export the gas to China and Korea. According to a feasibility study completed in late 2003, a 34-bcm/year pipeline system, with branches to Dalian and Beijing and an undersea line to South Korea, would cost in the region of \$12 billion and upstream development another \$5 billion to \$6 billion. Gazprom was appointed by the Russian government in 2001 to co-ordinate all East Siberian export projects. It has recently sought greater control over the Kovykta project and has proposed exporting gas from Chayandinskaya, another East Siberian field, if agreement on Gazprom's participation in the Kovykta project with Rusia Petroleum is not forthcoming.

²⁵ In 2003, BP announced an equity investment of \$6.75 billion in TNK, creating a new company, TNK-BP, Russia's third-largest oil company.

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