NATURAL GAS MARKET REVIEW

2009

INTERNATIONAL ENERGY AGENCY

2009

NATURAL GAS
MARKET REVIEW

The global economic crisis has not spared the gas sector. Over the past year, we have moved from a tight supply and demand balance with extremely high gas prices to an easing one with plummeting gas prices. Since the last quarter of 2008, demand has been declining dramatically, essentially because of the global recession. Yet significant new volumes of liquefied natural gas will come on stream within the next few years, and the United States' unconventional gas production has risen rapidly, with global consequences. It remains to be seen how these demand and supply pressures will play out, particularly in the pivotal power sector, in both OECD and non-OECD countries.

Meanwhile, the security of gas supplies has once again become a critical issue, in particular in Europe after it experienced its worst supply disruption during the Russian-Ukraine crisis in January 2009.

Moreover, the current market climate of weakening demand, lower prices and regulatory uncertainties added to the tough financial environment are likely to jeopardise investments, in particular in capital-intensive projects, further undermining long-term energy security in the most fundamental way when economies recover.

The *Natural Gas Market Review 2009* looks at these and other major developments and challenges in the different parts of the gas value chain in a selection of IEA countries – the United States, Canada, Spain, Norway, the Netherlands, and Turkey – as well as in non-IEA member countries in the Middle East, North Africa, Southeast Asia, and China.

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-eight of the thirty OECD member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions.
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations.
- To operate a permanent information system on international oil markets.
- To provide data on other aspects of international energy markets.
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use.
- To promote international collaboration on energy technology.
- To assist in the integration of environmental and energy policies, including relating to climate change.

35 years 1974•2009

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The European Commission also participates in the work of the IEA.

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

International Energy Agency (IEA)
9 rue de la Fédération, 75739 Paris Cedex 15, France

FOREWORD

2008 was a year split almost neatly in two in the energy world - prices and demand rose inexorably into early July 2008, only to see dramatic falls as the depth and spread of the global recession became apparent. The gas industry was not immune from these pressures, and gas markets have seen arguably greater price falls than oil, continuing well into 2009.

As in previous *Natural Gas Market Reviews*, we remain concerned from a long-term perspective about investment throughout the gas value chain, in upstream production, processing, liquefaction, pipeline transport and interconnection, and storage. While 2008 saw some progress in all areas, and a major expansion of LNG capacity is underway globally, overall investment continues to be inadequate, and the next years promise to be especially difficult, with falling demand and prices weakening all producers' cash flows, and financing conditions becoming tougher in both debt and equity markets. Regulatory uncertainties continue to slow investment.

Early 2009 also saw Europe's biggest gas crisis. Gas security has been high on the IEA agenda for some years, following Ministers' instructions in 2005 and 2007, to report more closely on gas market developments and to bring forward concrete proposals on gas security for consideration by IEA member governments. We anticipate that Ministers will indeed consider a set of principles and an action plan to enhance gas security at their next meeting in October 2009. The Russia-Ukraine crisis has given added momentum to this work.

One cornerstone of our efforts on gas security is the importance of fully functioning markets. Such markets can deliver flexible supply and demand responses quickly and efficiently, as we saw during the hurricane-related gas shortages in North America in 2008 and before that in 2005. But the strong price signals that markets deliver also encourage timely and adequate investment essential for long-term security of affordable gas supplies. This is particularly important in European markets, where although encouraging progress was made in a number of areas, market functioning remains weak.

As we have learnt from oil markets, greater transparency is an important first step to improved market functioning, as well as assessing and managing energy emergencies. We will continue to work with market players and member governments, and co-operatively with the EU and other organisations, in the important task of ensuring the market is well supplied with timely, accurate and harmonised data. While this will inevitably entail additional effort by companies, governments and organisations to collect and disseminate such data, I believe the time has come to make the efforts needed to raise the quality and timeliness of gas data.

Growing interconnections among energy markets make dialogue between IEA member countries and other major economies more important than ever. Such dialogue is most beneficial when grounded in areas of mutual interest. In this context our on-going dialogue with Russia and its largest gas company Gazprom, are I believe, especially important.

This is the fourth *Natural Gas Market Review*. In conjunction with its sister publication the *Medium-Term Oil Market Review*, it represents an important part of our response to provide more medium term analysis of oil and gas markets. As in previous editions, we welcome feedback. Gas issues will also be featured prominently in *World Energy Outlook 2009*, to be published in November this year.

This review is published under my authority as Executive Director of the International Energy Agency.

Nobuo Tanaka

ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

Strong demand in the first half of 2008 reverses dramatically later in the year and into 2009

The first half of 2008 saw strong gas demand growth in most IEA regions of up to 10% in some countries. This began to slow in mid year, then to reverse dramatically late in 2008, and continue to fall into 2009, as the global recession hit gas hard. The industrial sector was especially hit, as cold weather kept domestic and commercial heating demand strong. Demand for gas-fired power slumped, as industrial power demand fell in line with the economic downturn, and as gas-fired power is generally the most expensive in the mix of power sources, notwithstanding very marked price falls which accompanied weakening demand.

Gas prices peaked in mid 2008 at levels over USD 13 per MBtu in the United States for example, but have since dropped to around USD 3.50 per MBtu in April 2009. British prices have fallen from similar highs to around USD 4 per MBtu. Oil-based prices in Japan and Continental Europe, with their in built time lags, continued to rise through most of 2008, but with the fall in oil prices can be expected to decline through 2009 to average around USD 7-8 per MBtu in the case of Europe. Plentiful gas supply is also playing a strong role in markets where gas-on-gas or gas-on-coal competition can be seen.

Gas supply grows strongly

Of particular note is the continuing growth in unconventional gas production in the United States. Gas production in 2008 showed a near 8% increase over a year earlier, despite destructive hurricanes in the late summer, and has continued to show around 4% increases in the early months of 2009. Growth at these levels represents a major turnaround from the production declines of about 2% per year observed earlier in the decade, challenging the wisdom that United States production would inevitably decline, increasing the need for large-scale LNG and pipeline imports. Indeed LNG imports in 2008, at less than 10 bcm, were less than half the level of 2007. LNG was thus freed up for other markets, and over the course of 2008, some 20 bcm of "Atlantic" LNG was shipped to Pacific markets, double the levels of 2007, in response to the strong demand in those regions in the first half of 2008. Hence United States unconventional gas production is of global significance. However, low gas prices have reduced the gas rig count by nearly half in April 2009 compared to the year before, and it seems inevitable that growth in output will slow. The future of United States gas output remains one of the major uncertainties in global gas markets.

Globally, LNG capacity continued to grow, although various problems restricted output, so actual production grew only modestly to 240 bcm in 2008. However, a massive increase in new LNG capacity is already underway in 2009, and the next three years will see capacity grow to at least 370 bcm, an astonishing increase, without precedent in the LNG world. Thus, 2009 and 2010 will test the flexibility and resilience of the global LNG market. Norway also continued its export led expansion, with gas output in 2008 growing by 10% to almost 100 bcm. Growth will continue into 2009, and is set to rise to beyond

120 bcm in coming years, making Norway the largest IEA gas exporter.

Investment outlook weakens

Falling gas prices and volumes have taken a heavy toll on all producers' cash flows, adding to the already serious problems in gas investment throughout the value chain identified in earlier *Natural Gas Market Reviews*. Large investments continue to be needed to meet growing demand in the medium to longer term, and to offset falling output in many consumer countries. For example, UK gas output in 2008 was two thirds of 2003 levels, and declines at the end of 2008 and early 2009 were around 10%. While some relief can be expected from the high engineering, procurement and construction costs that were a feature of hydrocarbon developments from 2004 to late 2008, financing problems are likely to bedevil all new construction projects in 2009 and even into 2010, especially for the long lead time, high capital intensity projects found in many parts of the gas sector. Regulatory uncertainties remain as a barrier to investment, and any rise in gas demand will await economic recovery, likely at best to be sluggish and uncertain, further complicating investors' decision making.

In the LNG sector, notwithstanding the massive increases in capacity that will be seen in the next few years from projects under construction, very few new projects have been sanctioned in recent years. Unless 2009 and 2010 see a number of new project approvals, there will be a dearth of new capacity in the period after 2012. Financing problems, plus uncertain demand growth will impact such approvals adversely, although these projects are to meet medium to long-term demand. Globally there is nearly twice as much regasification capacity operating or well under construction, compared to liquefaction capacity. This imbalance is likely to remain an ongoing feature of the LNG trade well into the medium term.

The world's largest producer, Russia, faces considerable challenges, both financial and technical. Gazprom, accounting for around 80-85% of Russian gas output, will see prices for western European exports fall from USD 12 per MBtu in 2008 to USD 7-8 per MBtu in 2009, and has also seen volumes fall sharply in the first quarter of 2009. Gazprom has wisely prioritised its capital expenditure, to focus on upstream in established and new areas (Yamal), on the pipeline infrastructure to support these, as well as the Nord Stream project, linking Russia directly to Germany via the Baltic Sea. Price reform continues in Russia, which should drive greater efficiency in gas use, notably in the power sector.

Power sector demand likely to drop sharply

While gas demand for power was strong in the first half of 2008 in many IEA countries, again the collapse of industrial output in the final quarter of 2008 and into 2009 saw industrial power demand drop by up to 10% in many countries, both in and outside the IEA. While this translates into total electricity demand declines of around 4%, falls in gas-fired power are likely to be around double these levels, given the position of gas in the merit order, as seen in some countries in the early months of 2009. Hence, gas demand from the power sector through 2009 is likely to be weak, although the outlook in the medium term remains strong. Most power plants under construction and planned in OECD countries are gas-fired. Gas power has shorter lead times, lower capital cost, a smaller footprint and the lowest carbon emissions of any fossil fuel. New gas-fired capacity is also being developed in many non-OECD countries, although generally coal remains the dominant fuel in the power sector there. Current investment and financing uncertainty may actually favour gas further, with its smaller unit size and shorter lead times responding to an uncertain demand recovery path. Greater deployment of renewables over the medium term may also enhance the role of gas to balance intermittent sources such as wind.

Europe's biggest gas security crisis

The beginning of 2009 saw Europe's most serious gas security crisis, with nearly 7 bcm of gas not delivered to Europe and Ukraine over the first three weeks of the year. While some additional Russian gas supplies were available through Yamal and Blue Stream pipelines, as well as some spot LNG in southern Europe, the bulk of the European response was through rapid storage drawdown. Countries lacking adequate storage (chiefly in eastern and southern Europe) suffered supply shortfalls, since the crisis again demonstrated that gas cannot flow easily across borders in Europe. This is because there is a lack of physical interconnection capacity, capable of reversing the flow of gas from west to east, or the market mechanisms that enable gas to be redirected speedily and efficiently are not present in some areas. Only one major cross-border movement of gas was seen throughout the crisis, that of gas flowing out of the United Kingdom to Europe, although the United Kingdom suffered no loss of supply, since it imports no Russian gas. Encouraging progress has been made in enhancing market flexibility in Europe, such as greater hub trading and other improvements in market transparency. But, clearly more needs to be done urgently to make Europe's gas market work better. In the medium to longer term, Europe also needs greater investment in more varied sources and routes for gas supply, enhanced gas storage, and much more diversity in its electricity sector, embracing renewables, nuclear and coal, with improved environmental performance.

Non-OECD gas use grows fast

Many gas producers are consuming more gas in their own domestic markets, notably Iran and other Middle Eastern countries. Iran, as the second biggest gas reserve holder, seems unlikely to be a significant exporter before 2015, at the earliest. Other gas suppliers such as Qatar are imposing moratoria on further gas development. Both China and India are emerging as major gas users, although their energy mixes seem certain to be dominated by coal for the foreseeable future. Both countries will be able to import around 30 bcm of LNG within the next few years on the basis of regasification terminals being built and contracts concluded, and both could exceed 100 bcm of annual gas consumption in the near to medium term, bigger than any OECD European or Pacific gas user.

RECENT EVENTS

Gas in an era of global recession

- **During 2008, natural gas moved from a relatively tight supply and demand balance to an easing one. This will accelerate during 2009 as new supply capacity comes on line.**
- **Overall there was a 1% annual increase in OECD countries in 2008: gas demand rose strongly in the first half of 2008, but declined over the last quarter and fell even more rapidly in early 2009.**
- **For 2009, we anticipate demand to decline, especially in the industrial sector. Gas demand in the power generation sector will be affected differently in each region depending on the relative gas and coal prices.**
- **Demand is expected to rebound in the medium term driven by the power generation sector.**

OECD demand trends over 2008 and early 2009

Gas demand in OECD countries increased by 1% in 2008 from 1 507 bcm to 1 522 bcm. Growth has varied markedly across regions and countries, from Japan which was up 4.6% to 100 bcm to OECD Europe up by 2.8% to the United States which increased by less than 1%. This growth has happened despite a high price environment and negative economic growth towards the end of the year. But the year 2008 was very much a tale of two distinct time periods.

Gas demand continued to grow strongly by 5% during the first half of 2008. The growth was particularly significant during the January-April period but slowed afterwards. This was partly driven by a rebound of European residential demand as winter 2007-08 was colder than the previous one. Furthermore, additional gas-fired capacity coming on line in many OECD countries supported gas use in the power generation sector. Gas demand in the industrial sector was not yet affected by the economic crisis or higher prices.

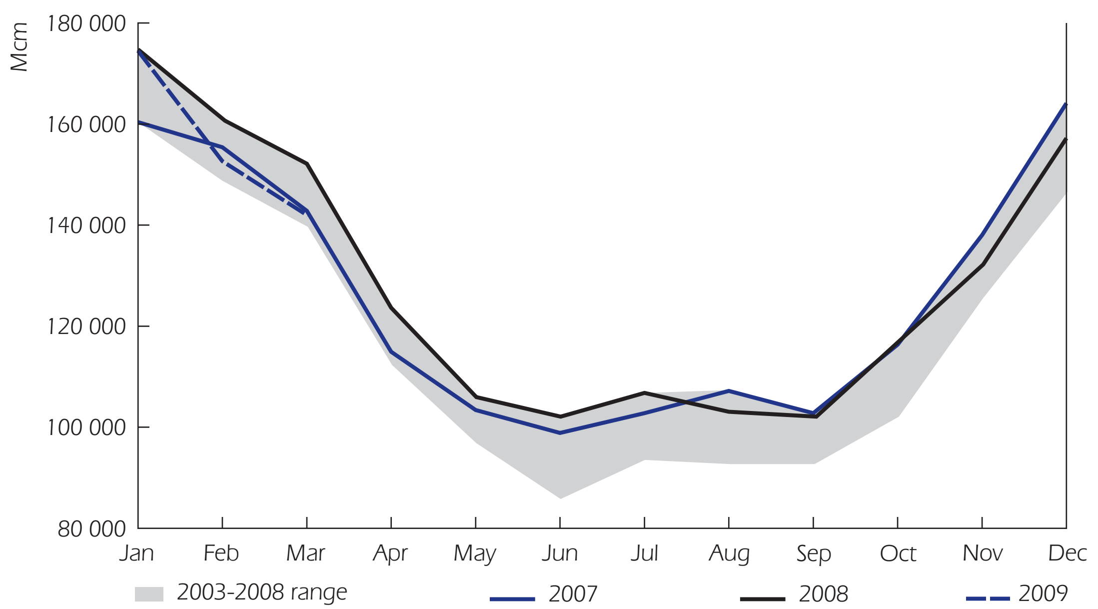
Demand trends changed substantially during the second half of 2008 and in particular during the last quarter. The combined impact of a sharp economic downturn and relatively high oil-linked gas prices in some markets, notably Continental Europe, **resulted in a 3.7% decline of gas demand during that period.** Rising gas procurement prices translated into higher energy bills for residential users while the recession caused energy costs to represent a higher share of households' disposable income. This is likely to have resulted in residential users starting their boilers later and lowering the thermostat. Many factories were closed during an extensive period over Christmas and well into 2009. In particular fertilizer plants closed down or halved their production. In the United States, industrial demand was 5% lower than 2008 during the fourth quarter but the decline continued to accelerate from 4% in November to 15% in February 2009. Industrial gas use shows a similar pattern in Japan, with January and February 2009 dramatically lower than the same period in 2008. Gas use in the power generation sector has been also affected: while coal prices have plummeted from around USD 200 per tonne mid-2008 to around USD 60 per tonne in May 2009 and CO_2 prices have collapsed to around EUR 10 per tonne, oil-linked gas prices at around USD 10-11 per MBtu have put gas-fired power at a disadvantage in the merit order, especially in Continental Europe.

Demand grew during 2008 quite strongly – by over 5% – in a number of countries such as Japan, Finland, Ireland, the Netherlands, Switzerland and the United Kingdom, each of them for different reasons. Demand was strong in Japan partly due to continued outage of the Kashiwazaki-Kariwa nuclear power plant while, in the United Kingdom, growth was due to a combination of higher residential demand during the first quarter and a preferential dispatch of gas-fired plants over coal-fired plants. A colder winter in 2007-08 drove the increase in Dutch demand. On the other hand, demand fell by more than 5% in Australia. Overall, for 2008, given the speed, breath and depth of the recession, gas demand held up reasonably well.

Demand expectations in the short and medium term

We expect the declining consumption trend to continue well into 2009 as the economic recession spreads and deepens in OECD countries. The OECD projects economies to contract by 4.3% in its 30 member countries in 2009 before a policy-induced recovery gradually builds momentum through 2010. In January

Figure 1 **Demand trends in OECD Europe**



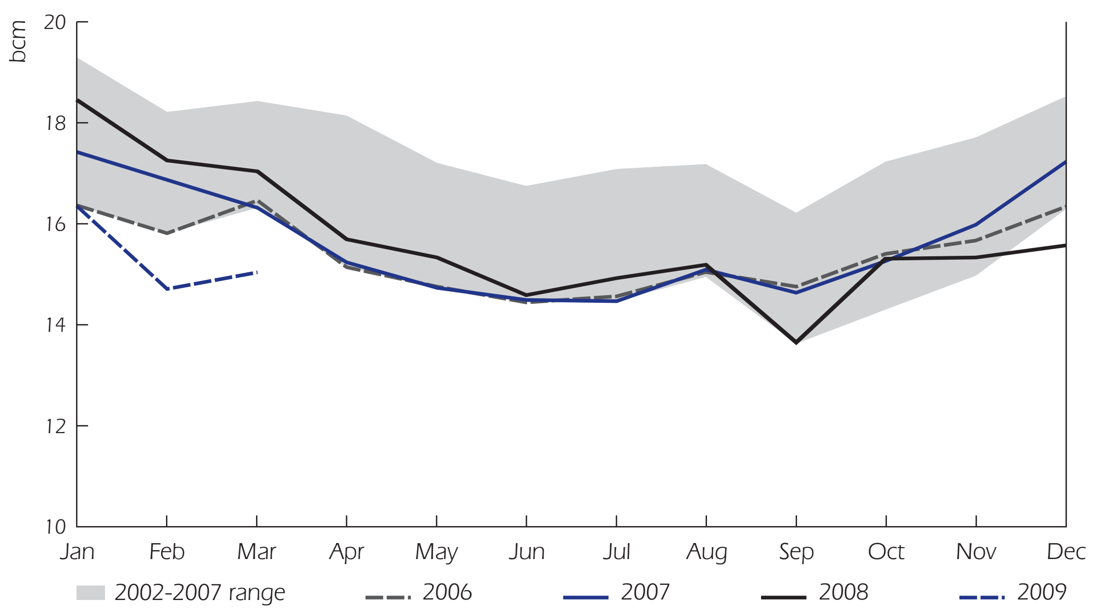
Key point: Strong growth in the first half, declines in the second half

Source: IEA.

2009, demand declined by 6% in Japan and 0.5% in the United States. This decline accelerated in February to 18% in Japan and 7% in the United States. The relatively low decline in the United States in January is mainly due to higher demand in the residential and commercial sectors due to cold weather while demand in the industrial and power generation sector has declined substantially compared to 2008. In January 2009, only extreme cold weather in Europe (100 Heating Degree days (HDD) colder than normal) and in the United States (35 HDD colder than normal and 70 colder than 2008) prevented demand from weakening substantially. In March 2009, gas demand declined by 7% in OECD countries (-3% in OECD North America, -13% in OECD Europe, and stable in OECD Pacific).

Assuming normal weather conditions, we expect the economic downturn to impact demand across all sectors: factories' closure or the reduction of their production will impact their energy – and gas – consumption. The trend observed in the United States is likely to be similar in other countries. In Spain, demand declined by 17% during the first quarter 2009 (with an impressive 31% decline from the power sector and 9% decline from other sectors including industry), while in Turkey, demand fell by 10% during the first quarter – with a 24% decline in the industrial sector.

Figure 2 **Industrial demand trends in the United States**



Key point: Dramatic fall at the end of 2008 and early 2009

Source: IEA.

Electricity demand is also likely to be lower in 2009 as it usually follows GDP growth closely. As gas prices will remain relatively high in the first part of 2009 in Continental Europe and OECD Pacific, gas-fired plants will usually be at the margin and generally the first to be affected by lower power demand. Gas demand from the power generation sector will be less affected in countries with spot prices, which were half oil-linked prices prevailing in Continental Europe and elsewhere in early 2009. As oil-linked gas prices decline over the course of the year, we expect gas to be in a better position to compete against coal in the power generation sector. Furthermore, around 17 GW of gas-fired capacity is expected to be added in 2009 in OECD countries. Finally, residential users can be expected to pay careful attention to their heating bills and reduce their consumption during the first spring months: although gas companies have started to pass through lower procurement costs in early 2009, end-user prices remain relatively high.

In the medium term we expect demand to rebound as the fundamental drivers behind gas demand growth are still present: new power plants under construction in OECD countries are predominantly gas-fired. The current difficult investment environment is likely to favour gas as gas-fired plants benefit from quicker construction times, are less subject to public resistance than coal and less politically sensitive than nuclear. Furthermore many non-OECD countries also favour gas: in particular Middle East countries are replacing their oil-fired capacity with new capacity fed with domestic gas.

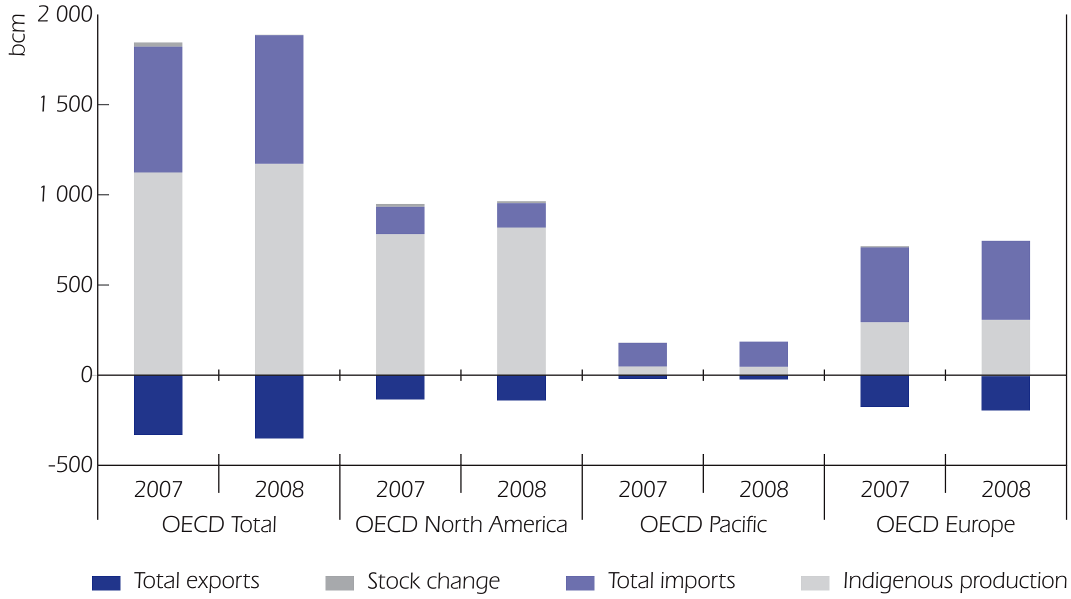
OECD supply trends over 2008

All OECD regions are dependent on imports, the least dependent being North America. Indigenous gas production in OECD countries increased by 4% or 47 bcm between 2007 and 2008 to reach 1 171 bcm. Almost all this was accounted for by the United States with a 42 bcm increase. OECD imports grew by 2% to 712 bcm, again showing more than 10% growth in the first four months of the year but falling later in the year by nearly 8%, while exports increased by 7% to 352 bcm. Exports are mainly via pipeline (three quarters from Canada, Norway and the Netherlands). Australia, Norway and the United States are the only LNG exporters in the OECD region.

In North America, domestic production increased by 36 bcm, falls in Canada offsetting some astonishing gains in the United States. Rising unconventional gas production has quite substantially affected the supply picture so that LNG import requirements have been scaled down in 2008 to less than half 2007 levels. Pipeline imports were also slightly lower, but their relative share of total imports for this region increased.

OECD Europe's production increased by 13 bcm, but this was essentially due to two countries **– Norway** and to a lesser extent the Netherlands. Most other OECD European countries saw their domestic production decline. Norwegian production grew by 9 bcm as the recent start in 2007 of Ormen Lange and Snøhvit enabled these two fields to add 14 bcm of incremental production, compensating for the decline of other fields. Dutch production – still a

Figure 3 **Supply balances in OECD regions**



Key point: All regions import

Source: IEA.

source of seasonal swing – reflects the colder winter in early 2008. Some months in early 2008 showed a 50% increase over the corresponding month in 2007. Very few countries are likely to see their domestic production increasing over the next few years. Imports increased faster than production, in particular imports from non-OECD. Exports were predominantly for OECD Europe, but for the first time in history, a European country (Norway) exported to other OECD regions via LNG.

In OECD Pacific, domestic production declined by 2 bcm as Australian gas production declined. The region remains completely dependent on LNG imports, the bulk of which originate from non-OECD countries and the rest from Australia. Although some LNG producers from the Atlantic basin increased their deliveries to this region significantly totalling more than 20 bcm or 8% of global LNG production, Pacific and Middle East producers hold the lion's share of LNG imports. Australia exports predominantly to Japan.

Supply expectations in the short and medium term

Despite lower demand in the fourth quarter of 2008 and early January 2009, OECD domestic gas production remained strong. **Production was still on an upward trend in OECD North America despite lower prices**. It remained stable in the Pacific and declined slightly in OECD Europe. Imports have been declining except in OECD Pacific. The drop has been particularly sharp in OECD Europe and affected both pipeline and LNG exporters, especially those selling on still high oil-based prices.

In the short term, we anticipate the most expensive sources of gas to be affected by the collapse of demand. In particular, buyers will try to run their contracts at the minimum levels using the embedded flexibility, opting to reduce their supplies to the minimum allowed in the contract. This will affect both pipeline and LNG contracts based on oil prices as the lag time in the formulas means that the oil-linked gas prices are still relatively high over the first half of 2009. Cheaper spot pipeline or LNG based on National Balancing Point (NBP) or Henry Hub (HH) prices will compete actively against these sources of gas. In spring 2009, spot prices were less than half oil-linked contract prices.

As new LNG liquefaction terminals are expected to come on line in 2009, the question is how the market will adjust, in a context of declining demand. If they follow the previous years' patterns, some terminals may start later than expected. One major uncertainty for 2009 is around unconventional gas production in North America: already the number of rigs has halved between October 2008 and May 2009. The question is whether unconventional gas production in North America can remain robust at prices below USD 4 per MBtu.

The evolution of gas prices

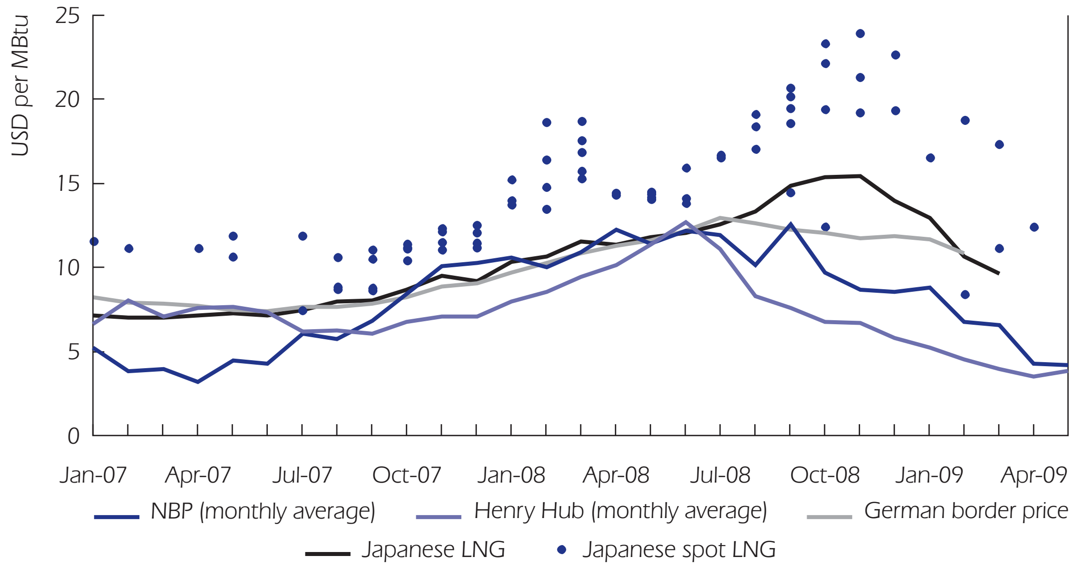
- **Gas prices in key liberalised markets in the United States and the United Kingdom fell from USD 13-14 per MBtu in mid-2008, to at or below USD 4 per MBtu in April 2009. Unlike oil, where prices have stabilised, prices in these markets have continued to fall sharply over the early months of 2009.**
- **Prices in markets linked to oil, such as Japan and Continental Europe, were slower to fall from their peaks approaching USD 15 per MBtu, as these prices typically have three- to six-month lags. Over the course of 2009, they are expected to fall to around USD 6-7 per MBtu.**
- **International prices are showing a degree of convergence, as greater LNG trade links regions more closely.**

Price convergence and divergence

Unsurprisingly, the price story in 2008-09 resembles demand, in that it consists of two distinct periods. All regional gas prices continued to increase up to mid-2008 to USD 12-13 per MBtu on the back of increasing oil prices, and a tightening supply and demand balance. The trend completely reversed from the second half of 2008, as spot prices started to steadily decline first in the United States and later in the United Kingdom.

However oil-linked gas prices in Japan continued to increase further to above USD 15 per MBtu bearing the legacy of the above USD 100 oil prices seen up to

Figure 4 **International gas prices 2007-2009**



Key point: Gas prices fall, but at different rates in different regions

Source: Bundesamt für Wirtschaft und Ausfuhrkontrolle (BAFA), ICIS Heren, ICE, Trade Statistics of Japan (Ministry of Finance), European Central Bank, Federal Reserve.

July 2008 while Continental European gas prices flattened above USD 12 per MBtu during the second half of 2008[1]. They started to decline only in late 2008 due to the time lags embedded in the long-term contracts' formulas. Prices have continued to fall in 2009, with prices in the United States and the United Kingdom now in the range of USD 3.5-4 per MBtu respectively, less than half the price of oil on an energy content basis.

Part of the fall in prices is due to the general collapse of energy prices – either through formal linkages or through inter-fuel competition in the end-user market. But the fundamental reason is an easing of the supply and demand balance on gas markets, as demand weakens while substantial LNG, and in North America, unconventional gas supplies, come on stream, leaving some LNG cargos struggling to find a home. Increasingly the US and UK markets are starting to be more closely linked through global LNG markets with a convergence of spot prices on both sides of the Atlantic.

1. The German border price expressed in Euros continued to increase up to November 2008. The German and Japanese prices expressed in Euros and Yen are converted into prices in US Dollars using the exchange rate of the month. This does not reflect the complexity of the long-term formulas and the lags, but these cannot be adequately quantified as all suppliers' contract terms differ.

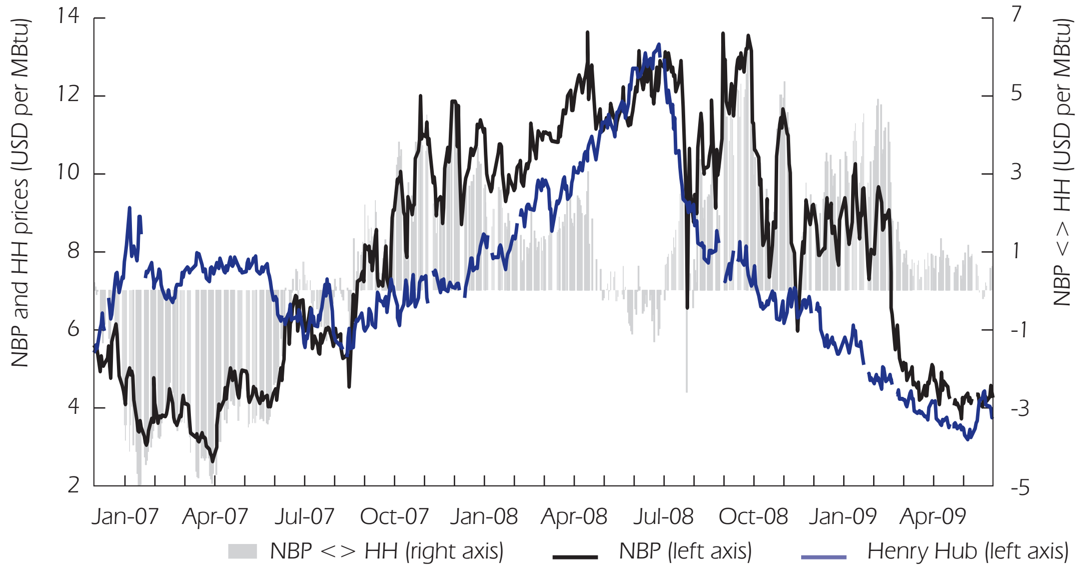
The two main spot markets in the United States and the United Kingdom had been until late 2008 mostly disconnected. Although prices have been following the same increasing pattern since September 2007 due to the overall rise of all energy prices, there were only a few periods with some convergence – usually during the lower demand summer periods. Global gas markets were relatively tight up to mid-2008 due to increasing demand and relatively small additional volumes of LNG coming on line. Strong demand for LNG in Asia – with some Japanese spot prices bidding above oil parity – led to more supply tightness in the Atlantic basin. The UK market was quite volatile with Continental European prices having a major influence due to increasing import dependency while the Henry Hub price (HH) was set by the marginal supplier – either unconventional gas or LNG. The spread between HH and NBP averaged USD 2 per MBtu over September 2007-April 2009, above but not significantly higher than transport cost differential of LNG from the Middle East or North Africa.

Since late 2008, spot prices have started to converge, showing similar declining trends reflecting the impact on spot prices of plentiful LNG supply on international gas markets and of increasing global exchange of gas between different regions. This has weighed down on the HH and NBP prices leading to a collapse of both prices to around or below USD 4 per MBtu in April 2009 while the spread between both prices halved. Such convergence has been made possible due to the coincidental weakening of demand in most LNG-importing countries combined with the arrival – or expectations of arrivals – of additional LNG supplies. Weakening LNG demand in Asia is resulting in an oversupply of flexible short-term LNG in the Atlantic basin, free to target either the United States or the United Kingdom (or displace some more expensive pipeline gas in Europe). With this additional LNG added to traditional supplies, the United Kingdom became very well supplied with gas and the linkage to continental oil-linked prices seen in 2007-08 was severed leading towards a convergence to Henry Hub price levels.

Meanwhile oil-linked prices in Europe and Japan remained very high in much of 2008 with falls only seen from late 2008-early 2009, reflecting the divergence of pricing systems within each region and different lags of price rises and falls relative to oil.

The price differential has created significant arbitrage opportunities as LNG regasification is being expanded both in the United States and in the United Kingdom – the only really liquid market in Europe. During the winter (November 2008-January 2009), the spread between European contract prices and the NBP or Henry Hub respectively averaged USD 4.7 and 7.4 per MBtu. For a 150 000 m^3 cargo, this means a gain of between USD 16 and 25 million. This notably resulted in the Interconnector between the United Kingdom and Belgium, flowing in export mode from the United Kingdom to Europe almost constantly since December 2008. This completely different pattern from historical trends, was exacerbated by the Russia-Ukraine crisis; in January 2009, some 0.8 bcm of gas was exported from the United Kingdom. **This has continued into 2009 making the United Kingdom a**

Figure 5 NBP and HH day-ahead prices and differential



Key point: Spot prices start to converge in 2009

Source: ICIS Heren, ICE, European Central Bank.

transit country. Furthermore, European players are now keen to use the flexibility in their contracts to import less oil-priced contracted gas and buy more spot LNG – as is the case in Spain (see below).

Regional analysis

European prices

The European markets are more than ever characterized by the duality between oil-linked gas prices on the Continent and NBP spot prices in the United Kingdom. However Continental spot markets such as Zeebrugge and the Title Transfer Facility (TTF) have gained in liquidity and are usually tracking NBP prices.

NBP prices rose from USD 3-5 per MBtu to USD 10.7 per MBtu on average in 2008 with spikes up to USD 14 per MBtu, partly linked to changing supply fundamentals. Until mid-2008, NBP prices were mostly influenced by continental oil-linked gas prices for two reasons:

- **Competition with European continental markets**. With production falling by 8% per year since 2004, the United Kingdom has become increasingly dependent on imports. During the winter, oil-linked European prices have been setting a floor to winter NBP prices – unless demand is exceptionally weak as was the case in winter 2007-08 or since the end of summer 2008. The United Kingdom has become a net importer of gas even during summer. Since the Langeled pipeline came on line, Norwegian gas has become more important for the United Kingdom's supply and demand balance, but at the same time, it can be dispatched to Continental markets if NBP prices are too cheap. The same applies to LNG in the Atlantic basin which can equally target Continental Europe or the United Kingdom markets.

- **Storage refilling**. The United Kingdom needed to refill its 4 bcm storage during summer mostly with Continental gas flowing through the Interconnector between the United Kingdom and Belgium. This required NBP prices during the winter to be at a premium over expectations about the next summer continental gas price to provide the incentive to withdraw gas from storage.

Up to end-2008, NBP prices have been supported by still increasing oil-linked European gas prices, production difficulties as well as uncertainties about Norwegian and LNG supply. But as supply confidence increased with the arrival of LNG cargoes to the expanded Isle of Grain terminal and demand weakened further, they came down sharply to USD 7 per MBtu after the Russia-Ukraine crisis and USD 4 per MBtu in April 2009.

Two radical changes have happened over the past year on the United Kingdom market: through the expansion of its regasification capacity from 8 to 34 bcm coupled with ample global LNG supply, the United Kingdom has become a transit market for LNG – and probably Norwegian gas as well – to the Continent. **This will continue as long as oil-linked prices remain above prices LNG producers are prepared to accept, bringing a degree of gas-to-gas competition to Europe**. Furthermore, the extreme volatility of contract prices has broken up the traditional seasonality of NBP prices. Since late 2006, winter prices have always been lower or equal to the following summer prices meaning a more expensive refilling. In early 2008, storage players kept gas in store and started injections earlier. While during winter 2007-08 they were able to resell gas in store at higher prices on the United Kingdom market, some of the stored gas was shipped to Continental markets and sold at advantageous contract prices during winter 2008-09. This year, players will be able to refill depleted storage at lower prices.

In Continental Europe, links to oil in contract prices prevail despite increased hub trading. Contract prices increased from an average of USD 7 per MBtu in 2007 to around USD 13 per MBtu in August 2008 before starting to come down significantly in late 2008. They are expected to go down further in 2009 to reach USD 6-7 per MBtu by mid-2009 and then stabilise, in line with oil prices observed in the first months of 2009.

Continental spot prices on the Dutch hub (TTF) and Zeebrugge are now closely linked to the NBP. Zeebrugge moves are tracking almost exactly the moves on NBP; some disparities exist with TTF reflecting different supply and demand dynamics as well as some transport constraints. One important question is how the prices on the other hubs – PEG, EGT and PSV[2] – will

2. PEG, Point d'échange de gaz (France) ; EGT: E.ON Gas Transport (Germany) and PSV: Punto di Scambio Virtuale (Italy).

evolve as supply in these markets remains dominated by long-term contracts.

Spain is a perfect example of this European price duality: on one side, most established players buy pipeline gas as well as some LNG under long-term contracts with an oil-price indexation. But Spain is now more exposed to global LNG markets through its 58 bcm regasification capacity – compared to 14 bcm of pipeline. Even given its 11% growth through 2008, Spain is only a 40 bcm market, so most of these terminals are underutilised making it possible to use the spare capacity to import spot LNG at international prices. Since early 2009, Spanish LNG prices have been at a discount to the NBP, rather than a premium to it, reflecting a 20% drop of demand during the first quarter. There are limits in the amount that companies can source on the hubs because of minimum take-or-pay commitments under long-term contracted gas. Some companies already face difficulties in meeting their commitments. On the back of higher contract gas prices, those companies with ability to import LNG have been increasing their short-term purchases of LNG and reducing contracted delivery of pipeline gas, anticipating much lower contracted prices later in the year.

North American prices

In North America, prices rose in 2008 based also on strong demand, lower inventories, and cold weather, from around USD 7 per MBtu to peak at USD 13.50 per MBtu in late June 2008. Then prices collapsed, falling further and faster than oil. Even the September 2008 hurricanes in the Gulf of Mexico didn't increase prices significantly, as a well-balanced and efficient gas market prevented a price hike. Prices fell to USD 7 per MBtu in October and to less than USD 4 per MBtu in April 2009 for the first time since September 2006 on plummeting industrial demand. Furthermore storage levels are relatively high in the United States compared with the previous years and the injection period started in early April with storage levels more than 12 bcm higher than 2008. This factor, added to depressed demand and the fact that the United States is often considered as the residual market for LNG, could push prices further down until they reach a floor at which significant switching occurs in the power generation sector, unconventional or other domestic gas production is reduced, or, (least likely) if LNG producers decide to shut in or postpone new liquefaction trains.

Asian prices

In the Asian Pacific region, markets have seen a significant growth in LNG spot and short-term trading over the past year. A large portion of those cargoes are priced differently from those under long-term contracts. A significant spread between prices for short-term and spot cargoes (USD 15 - 25 per MBtu) and long-term import prices has been observed. Even among long-term contracted volumes, there were significant divergences in prices from USD 7.5 to USD 13 per MBtu on average by source in 2008. Long-term oil-linked contract prices have started to come down on the back of declining oil prices but only from December 2008. Similarly to European prices they are expected to come down to around USD 6-7 per MBtu over 2009. Furthermore demand for LNG cargoes is likely to be much lower this year. In January 2009 there were no Japanese imports from Algeria or Egypt. Many Japanese companies have been using the downward quantity tolerance (usually 10%) or even tried to negotiate down their contractual obligations for this year. This is likely to put pressure on LNG producers and therefore weigh down on LNG spot prices which may re-align with the Atlantic ones – taking the transport differential into account.

Trading developments in Western Europe

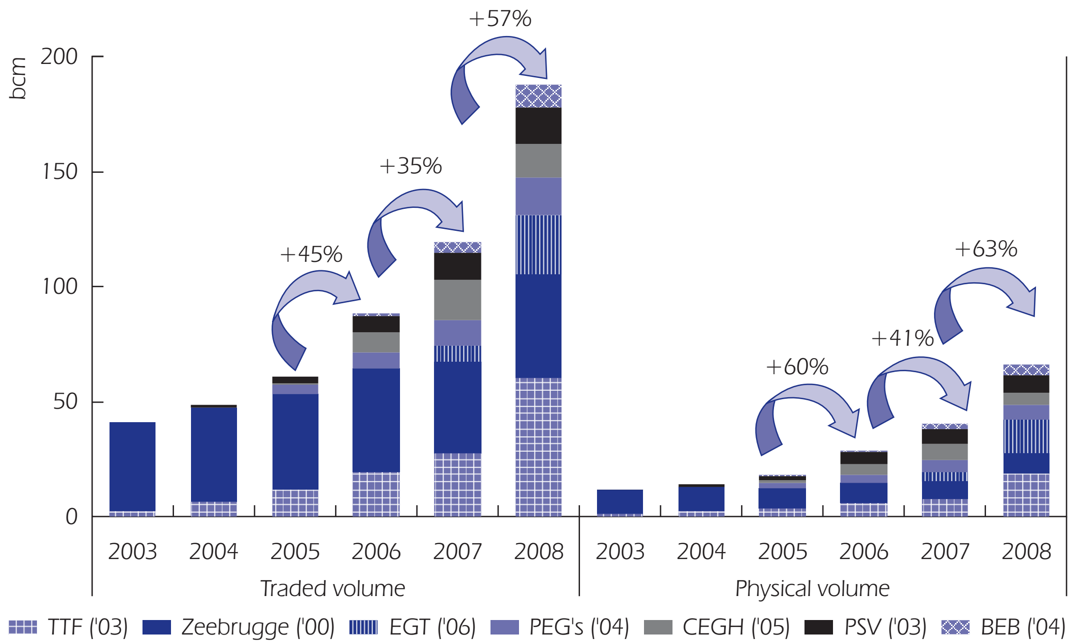
- **Overall traded volumes of gas increased markedly on Western European markets in 2008, compared to 2007.**
- **Greater regulatory activity was critical in opening up cross-border activity.**
- **Progress was uneven, being especially marked in Germany and Belgium, but weaker in Italy and Austria.**
- **Improvements in hub trading are important because they improve price discovery, ensuring competitively priced gas, but also improve energy security by allowing gas to move more freely to areas where gas supply might be disrupted. They also give producers confidence that they can access and market new production volumes.**
- **Greater flexibility provided by this growth is essential in responding to supply interruptions, such as January 2009.**

In 2008 traded volumes on Western European hubs increased by an impressive 57% to 188 bcm and physical volumes by an estimated 63% to 66 bcm – around 10% of OECD Europe's gas demand. So clearly progress is being made in the creation of liquid trading hubs to support the development of a more competitive European gas market.

Remarkable, besides the growth of the established trading hubs such as the National Balancing Point (NBP), Title Transfer Facility (TTF) and Zeebrugge, is the rapid development of the other Western European hubs, especially the German hubs. Four factors have played a role in this development:

- **Simplification of transport systems.** In Germany and in France the reduction in the number of entry-exit zones (market areas) improved the ease in which gas can be moved between markets. The result is clearly visible in Germany with volumes rapidly approaching those of the TTF and Zeebrugge hubs (4-5 bcm traded per month). Further reduction in market areas expected in Germany is likely to result in increased hub volumes.
- **Simplification of balancing rules**. In Germany, a new model came into effect from 1 October 2008 and developments in other countries are progressing. In the Netherlands, a new balancing model is planned from September 2010. The balancing would be more market-based and more closely tied to the TTF, reducing the risks and costs associated with imbalances, similar to the model implemented in other European markets.

Figure 6 **Developments on European Continental Hubs**



Key point: Strong growth continues, giving more flexibility to Europe

Source: Gas Transport Services, Huberator, GRTgaz, TIGF, CEGH, E.ON Gas Transport, Snam, Gasunie Deutschland.
Note: Volume weighted average over all continental hubs. Some of the churn ratios were based on an assessment.

- **Trading platform developments.** Most of the hub areas are supported by an electronic gas exchange platform where standard products can be traded, or are in the process of establishing such an exchange (for example in Italy and Austria). The range of traded products is often expanded in countries with an already established exchange. Providing reference prices is important to improve liquidity.

- **Access to cross-border capacity.** There are some promising developments such as EUCABO[3] and trac-x. In order to improve access to cross-border capacity in the short term, the Dutch TSO GTS (Gas Transport Services) started its EUCABO platform aiming to improve access to cross-border capacity and enable market participants to take advantage of price arbitrage between markets.

Despite this progress, improving the interaction between market zones remains a major challenge that needs to be tackled fully by regulators and governments.

3. EUCABO or European Capacity Booking is a platform developed by the Dutch TSO Gas Transport Services and the German Gasunie Deutschland (GUD) to contract cross border day-ahead capacities between the two transmission systems for both H-gas and L-gas.

In particular, access to cross-border capacity is a complex problem that is not easily nor simply solved, and demands close consultation between the involved stakeholders. Some positive steps have been made but a more comprehensive solution has not been found yet. Work on this subject is one of the main priorities of the Gas Regional Initiative (GRI) promoted by the European Regulators' Group for Electricity and Gas (ERGEG). As the events of January 2009 demonstrated again, the difficulty of moving gas across borders reduces Europe's gas security quite markedly.

United Kingdom

In 2008 for the first time in the history of the NBP the physical volumes remained stable – at 66.6 bcm. However traded volumes increased by 6% to 961 bcm; with a record churn factor of 14.4, the NBP remains by far the most liquid trading hub in Europe.

The strong decline in domestic production and hence increase in import dependency, combined with a relative low storage capacity makes the **United Kingdom dependent on price and demand developments in Continental Europe and on international gas markets**. The presence of sufficient import capacity without long-term contracts does not guarantee the availability of gas; although for the short to medium term, international markets appear well supplied, the United Kingdom market will remain relatively volatile.

Netherlands

Volumes have increased rapidly on the TTF over the past two years: **traded volumes**

Table 1 Traded and physical volumes at European hubs

bcm per year		NBP ('96)	Zeebrugge ('00)	TTF ('03)	PSV ('03)	PEG's ('04)	BEB ('04)	CEGH ('05)	EGT ('06)
Traded volume	2003	611.0	38.6	2.3	0.1				
	2004	551.9	41.1	6.2	1.1	0.3	0.0		
	2005	500.1	41.7	11.6	2.6	4.0	0.4	0.8	
	2006	615.2	45.1	19.1	7.1	7.0	1.2	8.9	0.2
	2007	902.6	40.2	27.3	11.5	11.1	4.8	17.7	6.6
	2008	960.8	45.4	60.2	15.6	16.5	9.7	14.9	25.3
Physical volume	2003	52.5	10.2	1.3	n/a				
	2004	53.2	10.6	2.3	n/a	n/a	n/a		
	2005	53.7	8.4	3.8	n/a	n/a	n/a	n/a	
	2006	60.6	8.6	5.9	n/a	n/a	n/a	n/a	0.1
	2007	66.8	7.9	7.4	6.8	n/a	n/a	6.9	4.1
	2008	66.6	9.1	18.7	7.7	n/a	n/a	5.2	14.4

Source: Gas Transport Services, Huberator, GRTgaz, TIGF, CEGH, E.ON Gas Transport, Snam, Gasunie Deutschland.

increased in 2008 by 120% to 60 bcm and the physical volumes by 152% to 18.7 bcm. In parallel, the number of active players on the TTF rose from 40 to 60 in 2008. However, the churn rate in 2008 decreased from 3.7 to 3.2. This downward trend in re-trading started around September 2008 and continues to fall in the first months of 2009 to even below 3, similar to levels seen in 2004. This might be caused by the tightened credit market resulting in lower credit lines and reduced activity of financial players but also to the difficult access to cross-border capacity as most is contracted under long-term supply contracts.

In its ambition to create a gas roundabout, (see section on the Netherlands), the creation of a liquid open market is essential. Efforts for improvement are therefore ongoing. Around mid-2009, quality conversion is expected to be made available as a system service, creating a single market for natural gas in the Netherlands by eliminating the existence of a L-gas and H-gas system[4] . A positive impact on liquidity is expected since market players will no longer have to worry about the availability of quality conversion. Furthermore the discussions between the BBL Company and Ofgem on the offering of interruptible reverse flow services are ongoing. After a first rejection by Ofgem of the proposed tariff methodology, the BBL Company announced that it expects a decision to be taken before summer 2009. The possibility of interruptible reverse flow could improve liquidity on the TTF by enabling traders to optimise between the NBP and TTF prices, similar to the operation of the Interconnector between the United Kingdom and Belgium.

Belgium

In 2007 the Zeebrugge hub was the only trading hub in Western Europe which showed a decline in traded and physical volumes, and some even questioned the need of the hub so close to the NBP and the TTF. However 2008 saw a remarkable reversal: traded volumes were up by 13% to 45.4 bcm and the physical volumes were up by 14% to 9.1 bcm. The increase was especially large during the fourth quarter of 2008 and first quarter of 2009 with respective increases by 37% and 45% compared to the same period the year before. The following elements have contributed to this development:

- The introduction by Huberator of the full ZEE Platform Service in February 2008 which offers unlimited transfer of capacity between the four entry points of the Zeebrugge area, a service which was limited before. The Full ZEE Platform Service removed this barrier between the four entry points. Zeebrugge LNG terminal's capacity doubled in April 2008. Since July 2008, shippers have the possibility of re-loading LNG at Zeebrugge; this option has already been used at least six times.

- Fluxys started to offer interruptible transit services and thereby increased the available transit capacity.

- New operating rules on the Inter-connector came into practice reducing

4. L = low calorific, H = high calorific

the number of flow transitions between Belgium and the United Kingdom.

In order to further improve the liquidity of the Zeebrugge hub, Fluxys, the network operator, has substantial investment plans to increase the East-West and the North-South transport capacities. However, issues surrounding gas quality specifications between the continent and the United Kingdom need to be addressed in the near future.

Germany

At the beginning of 2007 the German gas market was fragmented and still consisted of 19 market areas, making gas transportation across Germany difficult. In order to stimulate hub trading this number was reduced to 14 on October 2007 under pressure from the German regulator. Together with the introduction of an entry-and-exit system, this simplification boosted the physical and traded volumes on the EGT-VP and the BEB-VP[5] ; the two most liquid trading hubs in Germany. Further mergers of market areas were expected to take place in October 2008 but most were postponed. Only E.ON Gas Transport and Bayerngas merged their H-gas zones forming a new company, NetConnect Germany. Although the German regulator had hoped to see greater simplification of the transport system, **this reduction to 12 zones combined to a new regulated daily balancing model (Gabigas) significantly boosted trading in October 2008**. Finally, the three L-gas market areas of GUD, EGMT and EWE Netz merged in April 2009 creating a new company called Aequamus.

On the whole, traded volumes in 2008 rose by an impressive 203% to 35 bcm and physical volumes rose by an estimated 201% to 19 bcm, putting the German hubs close to Zeebrugge and TTF in absolute, if not relative size.

Other measures are expected to improve liquidity and lower the entry barriers for new suppliers to small consumers. The trac-x platform which was established in 2005 for secondary trading of transmission capacity has increased trading possibilities. Meanwhile, the EEX announced that it is considering the introduction of an intraday pricing window to establish a reference price.

The expected further reduction of market areas in Germany is likely to provide a further boost for market liquidity. The H-gas areas – Wingas Transport, ONTRAS-VNG and GUD – plan to merge in October 2009. The two other L-gas areas of RWE Transportnetz Gas and E.ON Gastransport are expected to merge or join Aequamus, while another transmission operator – either Gaz de France Deutschland or Gasversorgung Süddeutschland/ENI Deutschland – could join NetConnect Germany. If all these mergers happen, this would reduce the number of market areas in Germany to four H-gas and one L-gas areas.

France

The traded volumes on the France Points d’Echange de Gaz (PEGs) continued to increase by 48% to 16.5 bcm. **Since October 2008, the volumes have increased at a more rapid pace than in previous**

5. E.ON Gas Transport Virtual Point and BEB Virtual Point.

Table 2 Evolution of the number of gas market areas

<table>
<tr><th></th><th>October 2006
19 zones</th><th>April 2007
18 zones</th><th>October 2007
14 zones</th><th>October 2008
12 zones</th><th>April 2009
10 zones</th><th>October 2009**
7 zones</th></tr>
<tr><td rowspan="14">H-Gas</td><td>ONTRAS</td><td>ONTRAS</td><td>ONTRAS</td><td>ONTRAS</td><td>ONTRAS</td><td rowspan="5">GASPOOL</td></tr>
<tr><td>BEB</td><td>BEB</td><td>BEB</td><td>GUD*</td><td>GUD*</td></tr>
<tr><td>Wingas I</td><td>Wingas I</td><td>Wingas I</td><td rowspan="3">Wingas</td><td rowspan="3">Wingas</td></tr>
<tr><td>Wingas II</td><td>Wingas II</td><td>Wingas II</td></tr>
<tr><td>Wingas III</td><td>Wingas III</td><td>Wingas III</td></tr>
<tr><td>EGT Nord</td><td>EGT Nord</td><td rowspan="3">EGT</td><td rowspan="4">NetConnect Germany</td><td rowspan="4">NetConnect Germany</td><td rowspan="4">NetConnect Germany</td></tr>
<tr><td>EGT Mitte</td><td>EGT Mitte</td></tr>
<tr><td>EGT Süd</td><td>EGT Süd</td></tr>
<tr><td>Bayernnets</td><td>Bayernnets</td><td>Bayernnets</td></tr>
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<tr><td>GVS-ENI</td><td>GVS-ENI</td><td>GVS-ENI</td><td>GVS-ENI</td><td>GVS-ENI</td><td>GVS-ENI</td></tr>
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<tr><td>RWE Sud</td></tr>
<tr><td>Gas-Union</td><td>Gas-Union</td><td>Gas-Union</td><td></td><td></td><td></td></tr>
<tr><td rowspan="5">L-Gas</td><td>BEB</td><td>BEB</td><td>BEB</td><td>GUD*</td><td rowspan="3">Aequamus</td><td rowspan="3">Aequamus</td></tr>
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<tr><td>EWE</td><td>EWE</td><td>EWE</td><td>EWE</td></tr>
<tr><td>RWE West</td><td>RWE West</td><td>RWE West</td><td>RWE West</td><td>RWE West</td><td rowspan="2">L-Gas 2</td></tr>
<tr><td>EGT</td><td>EGT</td><td>EGT</td><td>EGT</td><td>EGT</td></tr>
</table>

Source: IEA analysis, based on public sources.

Notes: * Gasunie bought BEB's network end 2007.

** In Italic, expected mergers by October 2009.

years. Almost the whole of this growth is due to increasing volumes on PEG Nord and to a lesser extent on PEG Est. The other trading hubs show a relatively stable flat development pattern.

Several positive developments support the growth of trading. The number of active shippers on the French network is increasing steadily. On 1 December 2008, Powernext started an electronic spot and futures exchange, which contributed to greater trading on the exchange but also increased the liquidity on the OTC markets by providing more price transparency.

On 1 January 2009 the three Northern market areas (North, West and East) of GRTgaz merged into one Northern market area. This has increased entry and exit possibilities, especially to the South, and also resulting in greater arbitrage opportunities with neighbouring countries. **However the Southern market areas in France remain relatively isolated** and dominated by the incumbents Total and GDF SUEZ who own most of the capacity in the Fos LNG terminal.

In the short term several elements are expected to contribute to an improvement in market liquidity such as the start of Fos Cavaou LNG terminal in 2009 providing more entry capacity in the south to other players, additional capacity between market areas and change of allocation rules, and additional gas-fired capacity coming on line: Poweo's Pont sur Chambre starting this summer and 5.4 GW planned by 2013.

In the longer term, the interconnection between the TIGF zone and the Spanish market could further boost trading with a link to the Iberian market.

Austria

Unlike most other Western European gas hubs, the traded volumes on **the Central European Gas Hub (CEGH) decreased in 2008 by 16% to 14.9 bcm** and the physical volumes by 25% to 5.2 bcm despite the sixth gas release by EconGas. However the churn rate increased slightly from 2.6 to 3. Since the CEGH depends almost entirely on Russian gas volumes the hub was heavily affected by the January dispute between Ukraine and Russia, and traded and physical volumes were down more than 40% compared to the previous month.

For nearly two years, discussions have been ongoing between the hub and the five bordering transmission operators on the signing of an operational balancing agreement based on the Austrian hub. These discussions finally led to an agreement being signed in February 2009 with an expected implementation in about six months. This should improve liquidity at the hub and simplify operations. In addition, in cooperation with the Wiener Börse, the CEGH aims to offer an electronic gas exchange for spot products from September 2009 and other futures products at some later stage.

Italy

In Italy traded volumes rose by 36% in 2008 to 15.6 bcm and physical volumes also rose by 14% to 7.7 bcm. Measures taken by the Italian regulator AEEG such as the compulsory gas releases by ENI and the selling obligation by Italian gas producers on the Punto di Scambio Virtuale (PSV), are likely to have contributed to PSV volume increases. The AEEG determined that from 1 October 2008 market participants who conclude new non-EU entry contracts are obliged to auction a certain volume (at least 15% or 30% depending on the total contracted volume) as month and season products on the PSV. However the first auction was quite unsuccessful and almost none of the auctioned gas lots were sold. The reason was that the decision taken well before the auction to base minimum prices on oil-linked import prices which were much higher than market prices when the auction took place resulted in bids under the minimum prices. Despite the AEEG decision to determine prices in a time frame closer to the auction, this did not prove successful during the last summer auction.

The major stumbling block for the development of the PSV remains the difficulty in obtaining entry capacity since most is booked under long-term agreements. The major capacity expansions that are planned to come in operation from 2009 onwards could increase the liquidity on the PSV by providing market participants easier excess to the market. Also the proposed gas exchange, intended to be operated by GME (current operator of the electricity exchange), could boost the liquidity on the PSV, but no start-up date has been announced.

The 2009 Russia – Ukraine gas dispute

- **Interruption of Russian gas flows transiting Ukraine in January 2009 at a time of very high demand triggered Europe's biggest gas crisis, indeed the worst gas crisis in IEA history.**
- **Europe responded with a mixture of storage draws, demand side measures, plus extra supply was obtained from other pipeline routes from Russia, other producers and LNG.**
- **Most responses were at a national level. Except for flows from the United Kingdom, cross-border flows within Europe were very small and slow to arrive.**
- **Hence countries poorly equipped with storage and other emergency arrangements (notably in Eastern Europe) were much more heavily affected.**

The lead-up to the 2008/2009 dispute

Russian gas imports account for about one quarter of Europe's gas needs. About 80% comes via pipeline transiting Ukraine; most of the balance coming via Belarus into Poland. Finland and Turkey receive gas directly from Russia. Ukraine imports gas from Russia and Turkmenistan via Russia, accounting for three quarters of its gas needs.

The gas crisis between Ukraine and Russia has a long history, which dates back to the break-up of the former Soviet Union in 1991. At that time, Ukraine stopped buying gas directly from Gazprom, and instead purchased it from Ukrgazprom, a jointly-owned intermediary. Although various interruptions, resulting from non-payment, occurred almost immediately, a more long lasting agreement was reached after Leonid Kuchma came to power in 1994[6]. However, as described in more depth in the *Natural Gas Market Review 2006*, after the Orange revolution a dispute between the pro-western Yushchenko government and Russia emerged over the price for gas. In 2008, a recurring feature of recent years, Ukraine's inability or unwillingness to pay for its gas on time, resulted in progressive debt and penalties accumulation. In February 2008,

6. Gazprom as a Predictable Partner: *Another Reading of the Russian-Ukrainian and Russian-Belarusian Energy Crises,* Jérôme Guillet, March 2007, Russia/NIS Center, IFRI.

the Ukrainian debt supposedly amounted to over USD 1.5 billion for 2007 supplies. After numerous contradictory statements from both parties, Gazprom briefly halved supplies in March 2008, and supplies only returned to normal levels when Naftogaz agreed to repay the debt. 2008 prices rose to USD 180 per mcm in Ukraine. While a considerable increase on 2005 prices (USD 50 per mcm), this was still only about half of Western European prices.

In early October 2008, Prime Ministers Tymoshenko and Vladimir Putin signed a memorandum that stipulated that Ukraine would pay a market price within three years after gradual rises, and that supply intermediaries like RosUkrEnergo would be removed. Another condition was that Ukraine would pay all outstanding debts and penalties before the end of the year. This seemed to provide some hope of a negotiated settlement for late 2008.

In the last months of 2008, talks between Naftogaz and Gazprom were ongoing, but final agreement appeared elusive, foundering on both price escalation and debt issues. Rapidly deteriorating economic circumstances in Ukraine (and indeed in Russia), and the prospect of a rapid fall in Gazprom's cash flow and revenues hardened the negotiating position of both sides. However, both parties emphasised that European customers would receive undisrupted deliveries.

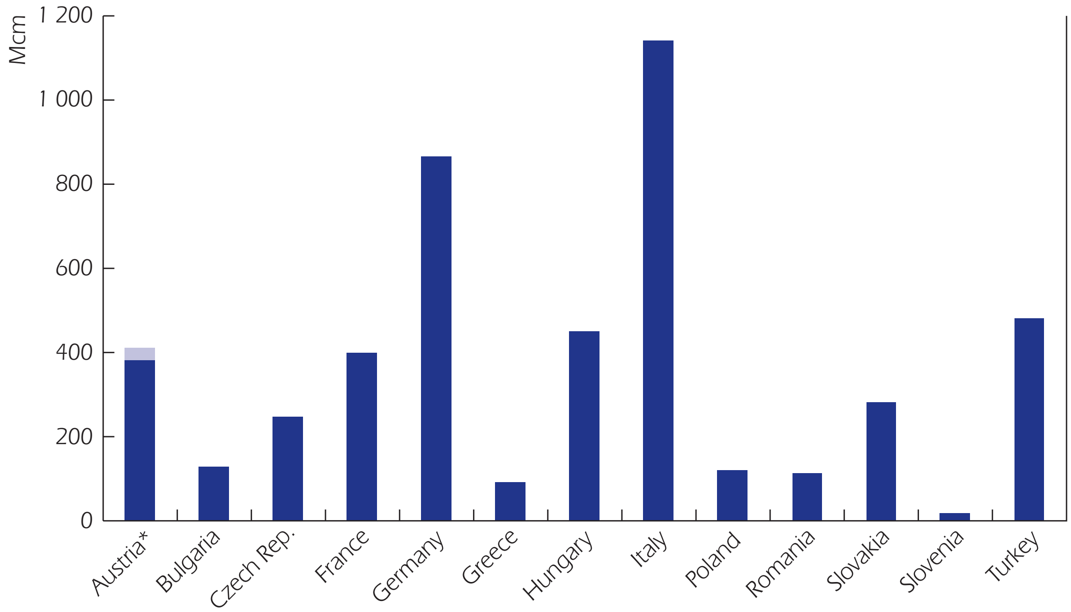
Both parties failed to reach agreement before the New Year. Gazprom wanted to raise the price from USD 180 per mcm to USD 250 per mcm. Ukraine said it was prepared to pay a price of USD 201 per mcm and wanted to raise the transit fees. Negotiations were blocked on this last point, because the transit was already settled in a separate contract which Gazprom claimed was valid until 2010. Another major stumbling block was the size of the outstanding Ukrainian debt, and the additional fines for late payments that were demanded by Russia.

The 2008-09 dispute

Starting on 1 January 2009, some 110 Mcm per day of Ukrainian supply was interrupted, along with small volumes to countries further west. On 5 January, supplies were further reduced, and all transit through the Ukrainian network was halted on 7 January and from that day some **300-350 Mcm per day of transit gas was disrupted**. This came at a time of very high peak gas demand in Western and Central Europe, with the coldest weather in two decades, but this was somewhat offset by sharply weakening industrial and commercial energy and power demand. **When flows were restored on 20 January, some 5 bcm of transit gas supplies had not been delivered over a two-week period, plus around 2 bcm of Ukrainian supplies.**

By comparison, the gas supply disruptions in the United States in 2005 due to hurricanes led to peak supply disruptions of 250-300 Mcm per day (in the week following Katrina), totalling about 10 bcm over two months (although production did not return to normal until 2006). Furthermore, disruptions in the United States did not occur at a time of peak demand. Gazprom's lost gas-sale revenues amounted to roughly USD 2 billion as of 20 January, although some (indeed most) of this may be recouped at a later date.

Figure 7 Russian volumes lost during the January 2009 disruption



Key point: Volumes missing amounted to 5 bcm

Source: IEA.

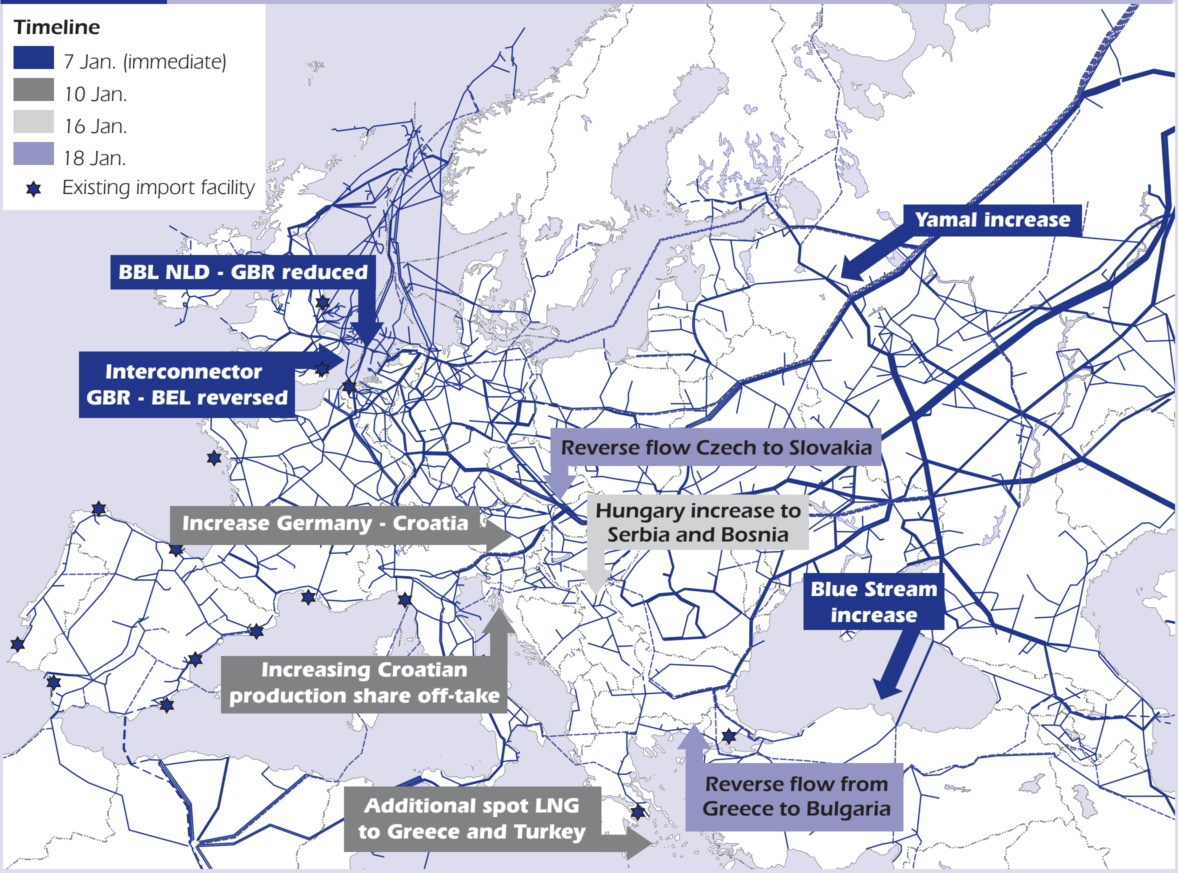
Note: Austria estimated.

How Europe dealt with the dispute

The cut-off of Russian gas supplies affected countries differently, although fortunately for most countries, Western European storage was effectively full as of the beginning of December 2008. Surprisingly on an aggregated level, Europe was able to cope with the supply disruption relatively well. However the biggest problem appeared to be moving gas to the places where it was most needed. The countries that were affected most had no access to LNG, did not have sufficient storage (or had storage in the wrong places) and lacked efficient interconnections with neighbouring countries (among these are Bulgaria, Romania, Slovakia, Moldova and Serbia). However, most other countries were able to substitute the Russian gas lost (at least in the short term) through a variety of mechanisms, including increased supply from other countries, stock drawdown, voluntary and involuntary demand reductions in industry and consumer sectors, and fuel switching in the power sector. Diversion of gas from relatively well-off areas to poorly supplied regions was slow and limited in the first half of January, (*e.g.* a few Mcm per day) but appears to have grown in scope and volume as the dispute continued. These arrangements were generally commercial ones, with some governments intervening to initiate these commercial arrangements.

Especially in Western Europe the flexible and rapid functioning of a traded market proved its importance. Within a very short period, price signals on the different hubs directed gas flows from west to east were the gas was most needed. The Interconnector between the United Kingdom and Belgium, and flows in the BBL pipeline between the United Kingdom and the Netherlands were reduced/reversed, contrary to what was expected in a normal winter. The net impact of these flows out of the United Kingdom may have been as high as 0.8 bcm, mostly coming out of storage in that country. IEA data shows exports in January up 0.73 bcm with LNG imports up by 0.25 bcm. Although the access to sufficient border capacity was challenging and could have posed difficulties, gas reached surrounding Western European markets, including Belgium, Germany, and France, and may well have reached Italy and Austria, at least indirectly. However, beyond the German borders, especially in the South Eastern part of Europe, these market mechanisms were generally unavailable because of the lack of proper market structures. Here it took weeks, and

Map 1 European response to the gas dispute between Russia and Ukraine



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Source: IEA.

Table 3 Summary of responses by European countries

	Austria	Bulgaria	Czech Republic	France	Germany	Greece	Hungary	Italy	Poland	Slovakia	Slovenia	Turkey
Alternative Russian supplies	✓	×	✓	×	✓	×	×	×	✓	×	×	✓
Supplies (increase existing)	✓	×	✓	✓	✓	✓	×	×	×	×	✓	✓
Supplies (reverse flow)	×	✓	×	×	×	×	×	×	×	✓	×	×
LNG	×	×	×	✓	×	✓	×	×	×	×	×	✓
Domestic production	×	×	×	×	×	×	✓	×	×	×	×	×
Storage	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	×	✓

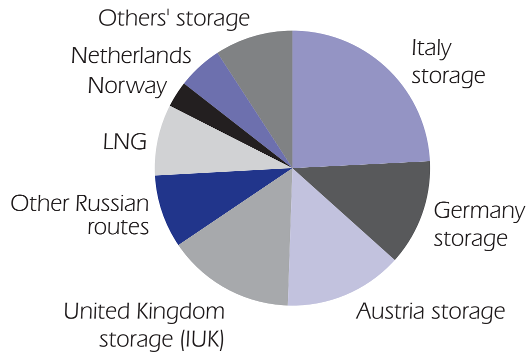
Source: IEA.

sometimes even government intervention, to direct gas flows to the areas of greatest need.

The conflict highlighted again that the first and most important defence against supply disruptions is a well functioning market that is able to respond quickly, preferably within hours rather than days, to changing market circumstances, and is based on demand and supply fundamentals. Beyond that, there is an urgent need to diversify and expand gas supply sources, and improve both the physical interconnection of countries in Europe (including the ability to move gas in the reverse direction to normal trade flows) and the market mechanisms that could underpin a speedy movement of gas supplies as demand and supply change. This need is particularly marked in Eastern European countries. None of this is new; both the European Commission and the IEA have made these observations repeatedly in recent years. Yet we have learnt from this experience, especially on possible flexibilities between neighbouring countries.

Another important mechanism in the response was storage drawdown, although estimating the extent of this is difficult, since stocks would have been under heavy pressure because of the very cold weather. For example, in France, demand was up 15% in January because of the very cold weather. Germany had a similar increase. January in OECD Europe was overall 100 HDDs colder than normal. Nonetheless, some exceptionally large stock draws can be seen in Italy, Germany and France, in each case more than 1 bcm higher than the previous January. In Austria, 1 724 Mcm were withdrawn during January compared to around 600 Mcm the previous years. In Italy, storage draw appears to have been the major response, accounting for around 1.2 bcm of extra supply. Germany was able to benefit from increased flows through the Yamal pipeline coming from Russia through Belarus and Poland. In the case of Greece and Turkey, spot LNG supplies made up about 400 Mcm of extra supply, and Turkey was able to source some 100 Mcm of extra supply from Russia via Blue Stream under the Black Sea. In most major economies of Western Europe, all demand was able to be met without interruptions to users, either industrial or domestic. However, in Central and Eastern Europe this was not the case, with industrial supplies interrupted in several countries and households as well. Interruption in some cases was planned, and part of contractual arrangements; in other cases it was unplanned. Responses of affected countries are summarised in Table 3, with cross border flows shown in Map 1. With the exception of UK-Belgium, these cross-border flows were quite small. The need for Eastern European countries to diversify gas supply sources is seen in recent moves (April-May 2009) for Poland to import Qatari LNG and Bulgaria to buy LNG, possibly importing via Greece.

Figure 8 **Replacing the missing Russian volumes**



Key point: Storage the key response

Source: IEA estimates.

The Russia-Ukraine settlement

The main components of the deal were a 10-year agreement by Ukraine to pay 80% of the netback EU price (around USD 360 per mcm in the first quarter of 2009), moving to 100% in 2010, and which is to be adjusted on a quarterly basis. The parties agreed on deliveries to Ukraine for 2009 of some 40 bcm, moving to 52 bcm from 2010 onwards (within the contract period).

In a new transit agreement signed on the same day, transit fees appear to have remained at 2008 levels in 2009. Thereafter, transit fees are set to rise upon expiration of the existing agreement (2010), in line with inflation and gas supply prices (USD 2.60 per mcm per 100 km), still well below EU levels (USD 4-5 per mcm per 100 km). Intermediaries (namely RosUkrEnergo) will be removed. Indeed, moving to 100% of the EU price, with a higher transit price, will make them essentially irrelevant.

Based on the 10-year supply agreement, Gazprom is allowed to halt gas deliveries to Ukraine if a new situation of non-payment arises, thus representing a risk for new gas supply cut-offs. On 19 February, Naftogaz released a statement in which it indicated that it might have problems making future payment to Gazprom for the gas, declaring that "this situation in terms of paying Gazprom could worsen because of the catastrophic rise in debts of regional utility companies". According to the Naftogaz statement, the total amount of outstanding debt stood at USD 570 million. A potential new dispute shall, if not solved within 30 days, be settled in accordance with the Charter of the Arbitration Institute of the Chamber of Commerce of Stockholm, in Sweden. Notwithstanding the ongoing difficulties of debt collection in Ukraine, and the sharply deteriorating economic situation, Ukraine's April gas payment was made in full at the beginning of May. However the financial situation of Naftogaz remains an unstable element to the new deal.

The parties have also agreed to sign a long-term gas supply contract[7] which will give Gazprom the right to deliver gas directly to Ukrainian industries, which alone account for 25% of annual gas imports and represent the most profitable share of the market.

Outstanding issues

After the resumption of the Russian gas deliveries to Europe and the signing of the new 10-Year Transit and Supply Contracts between Gazprom and Naftogaz (resulting in the elimination of the trader intermediary RosUkrEnergo from the transit through Ukraine), one of the key outstanding issues remains RosUkrEnergo's unfulfilled contractual obligations from cross-border trade via Ukraine. This intermediary concluded contracts for deliveries of a total amount of 7 bcm per year with companies in Poland, Hungary and Romania. The fate of RosUkrEnergo will be decided in accordance with Swiss law, though it seems to be already clear that, having lost its sources of gas in Russia, Central Asia and Kazakhstan, RosUkrEnergo will not be able to honour its contractual obligations. Other issues include the relatively low level of transit tariffs after 2010.

Gas Exporting Countries Forum

- **After seven years' existence as an informal grouping, a ministerial meeting of the Gas Exporting Countries Forum (GECF) decided in December 2008 to transform the Forum into a fully-fledged international organisation.**
- **Eleven countries, including the world's largest gas reserve holders Russia, Qatar and Iran, signed an agreement in Moscow creating the GECF and confirming its statute.**
- **It is too early to predict the likely direction of the GECF or its influence over gas markets. There are big structural differences between oil and gas markets, and, although tagged as a potential 'Gas OPEC', the organisation as it stands is not recognisable as a cartel.**

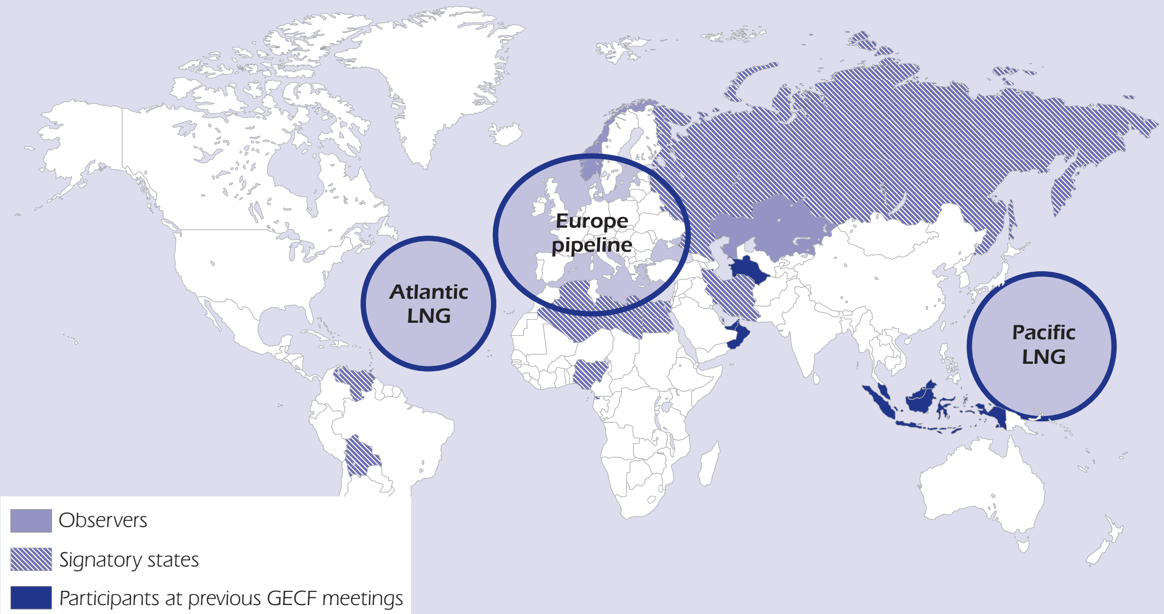
The signatory states[8] of the GECF together hold around two-thirds of global gas reserves. They accounted for 36% of global gas production in 2007 but 47% of exports. According to projections from the IEA *World Energy Outlook 2008* Reference Scenario, their share of global gas production will rise to 42% by 2030.

The list of signatories to the Moscow agreement suggests a shift in the GECF centre of gravity towards Europe and the Atlantic LNG market. Nine of the eleven signatories – all except Venezuela and Bolivia – are actual or realistic future

7. From 1 January 2009 to 31 December 2019

8. Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad & Tobago, Venezuela.

Map 2 **Gas Exporting Countries Forum's participants**



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Source: IEA.

suppliers to the European gas market. None of the three Pacific LNG suppliers that had been represented at previous meetings (Brunei, Indonesia and Malaysia) was present in Moscow. Caspian countries apart from Russia and Iran were also under-represented; Kazakhstan, a marginal net exporter, was the only presence from this region and attended as an observer.

Despite being tagged as a potential 'Gas OPEC' the role of the GECF is still loosely defined, reflecting a variety of views among participating states as to its purpose. The Forum's founding documents steer clear of contentious issues, and the stated objectives of the Forum are expressed in very general terms: to "support the sovereign rights of member countries over their natural gas resources and their abilities to independently plan and manage the sustainable, efficient and environmentally conscious development, use and conservation of natural gas resources for the benefit of their peoples."

GECF member countries have agreed to promote these objectives through "exchange of experience, views, information, and coordination" in areas such as exploration, the supply-demand balance, gas technologies, the structure and development of gas markets, and transportation. As it stands, the organisation is not recognisable as an OPEC-style cartel: the words "price" and "pricing" are not mentioned in the organisation's statute.

The deterioration in gas market conditions since mid-2008 undoubtedly played its part in helping gas exporters find common cause. Shared concerns about price levels and the possibility of "oversupply" may now be exacerbated by the large number of new LNG projects coming on stream in 2009-12. However, it will be difficult for GECF members to act to improve their market position in the short term. With the current structure of gas markets, producers' market power is limited *de facto* by the predominance of long-term gas supply contracts. Although wary of concluding new export contracts at times of low prices, there are few benefits to holding back incremental supplies from the market as the high costs of LNG infrastructure and storage create strong incentives to generate cash flow as soon as possible.

A more likely focus for GECF deliberations is the changing structure and supply of gas markets over a ten- or fifteen-year horizon, *i.e.* towards 2020 and beyond. Algerian Oil Minister Chakib Khelil emphasised this point when commenting on the differences between the Forum and OPEC: "OPEC looks at today, what happens on the market and makes the decision. The Forum ... it's more forward looking. It cannot control the volumes and price for the next ten years because it's locked into long-term contracts and also the price of gas is locked into oil."

Over this period, gas production is likely to become more concentrated in a smaller number of reserve-holding countries and national oil and gas companies. The structure of gas markets is also set to change, becoming more interlinked by trade in LNG and less tied to oil markets. While the imperative to keep gas competitive with other fuels would still provide a formidable obstacle to any short-term market manipulation, the GECF could look to coordinate medium-term investment plans among its member countries. The latter objective would appear to coincide with the view of Gazprom CEO Alexei Miller, who characterised the primary task of the Forum as "to jointly analyze and form the global gas balance, as well as consider the issues with regard to production volumes so as to avoid oversupply of gas to the market."

For the moment, though, it is too early to make predictions about the likely direction of the GECF: on the one hand, it could become a vehicle for debate, information-sharing and dialogue with transit and importing countries; on the other, it could look at some point to exert greater control over the gas market through actions that could constrain supplies. The "gas troika" of Russia, Iran and Qatar is likely to have a strong influence over the path that the Forum will follow only from a political point of view as Iran is not going to become a significant gas exporter for many years; this group has agreed to meet regularly following an October 2008 meeting in Tehran, and, along with Algeria, forms the political core of the GECF.

In defining a direction for the Forum, producers will have to be wary of the fact that gas – unlike oil – can more easily be substituted by other fuels, making the scope for a response by consumers to cartel-like behaviour much larger in the gas sector than in the case of oil. In this sense, there are risks associated with pursuit of a vision of the GECF as a potential market manipulator; instead of increased revenues and influence, producers may eventually end up simply with a constrained market for their exports.

INVESTMENTS

Introduction

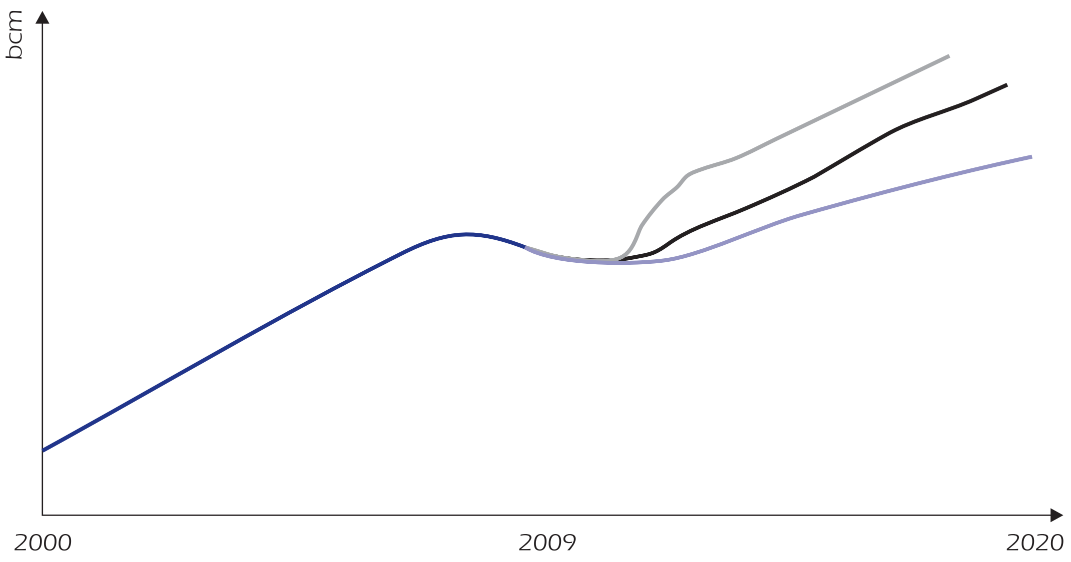
- **Investments are needed in all parts of the gas value chain to meet future demand needs.**
- **Given the uncertainties on demand and the current economic conditions, there is a risk that some investments might be postponed. This could potentially lead to a tight market as gas demand has the potential to rebound quickly while investments on the supply side are constrained by long lead times.**
- **Capital intensive projects expected to make FIDs in 2009-10 will be the most affected by the current market conditions.**

World gas demand is expected to increase by over half by 2030 according to the Reference Scenario of the *World Energy Outlook 2008*. Despite the maturity of their markets, **OECD countries** are still expected to see demand increasing. As their domestic production is expected to decline simultaneously, they **will become increasingly import dependent and are already looking at building new pipeline and LNG terminal infrastructure for their supply needs**. But demand will also be growing in non-OECD countries, in particular in countries such as China and India – which are expected to show the highest gas demand growth rates – but also in producing countries in the Middle East or North Africa. These latter countries tend to look increasingly at their own markets, which are growing rapidly due to an increased use of gas in the power generation sector and the development of gas grids. Some exporting countries such as Oman will turn into net importers within a few years.

In order to meet future demand needs across the world, each part of the gas value chain must be developed in a timely manner: upstream reserves that would feed both domestic and export markets; the liquefaction plants and regasification terminals if the reserves are developed as LNG plays or the long-distance pipelines and finally the storage infrastructure to make sure that not only annual but also seasonal and short-term demand variations are met. However, the **recent financial crisis seems to have aggravated and reinforced pre-existing uncertainties which were already hampering gas investments:**

Uncertainties about future demand and import requirements. Producing countries as well as sponsors of major new supply projects are increasingly worried about the future. This is not only about the length of the current crisis – or how long gas demand might stay depressed – but also about future demand paths. Will demand recover at a slower growth rate if the recent high price environment and concerns about climate change lead to more energy efficiency and non-CO_2 emitting technologies? Will demand recover with the same business-as-usual path and will gas remain the fuel of choice? Or will the slowdown of investments in the power generation sector translate into more gas-fired plants having to be built when electricity demand recovers translating into demand rebounding more quickly than expected?

Figure 9 Possible future gas demand trends



Key point: Demand: a key uncertainty for future investments

Source: IEA.

Regulatory uncertainties. Investors seek a stable regulatory framework whether they are investing into regasification, pipeline or storage infrastructure. Lengthy planning process coupled with heterogeneous regulatory systems for pipelines crossing several countries are discouraging.

Financial uncertainties. Companies and the infrastructure projects they support will be affected by the financial crisis as they look for more certainty before making the final investment decisions. Large-scale, long lead time projects are especially vulnerable in the current economic climate. In some cases, the completion of a project might require government backing.

A question of choice. Companies involved in many projects either on the same part of the gas value chain or in various parts will reassess priorities. The companies with the strongest balance sheets may prefer to absorb existing and smaller companies rather than investing in new projects.

The danger about investments not being made on time is the asymmetry between construction times on the demand and on the supply side, even not taking into account the permitting process and the search for partners and for funds which increases with the complexity and the size of the project. Only a couple of years are needed to build new gas-fired power plants or new intra-regional gas grid connections. But it would require as long as four to five years for new greenfield gas developments (depending on location); four years are now necessary to build a liquefaction terminal. Most transnational major pipelines can be built within three years, but it would take more time depending on the onshore/offshore requirements and the difficulty of the terrain. Major new LNG plants can take years to come to fruition – Pluto trying to prove otherwise. Due to the lag times in the development of new gas supplies, demand could return before adequate capacity has been added, leading potentially to a tighter market.

Supply investments in major producing regions

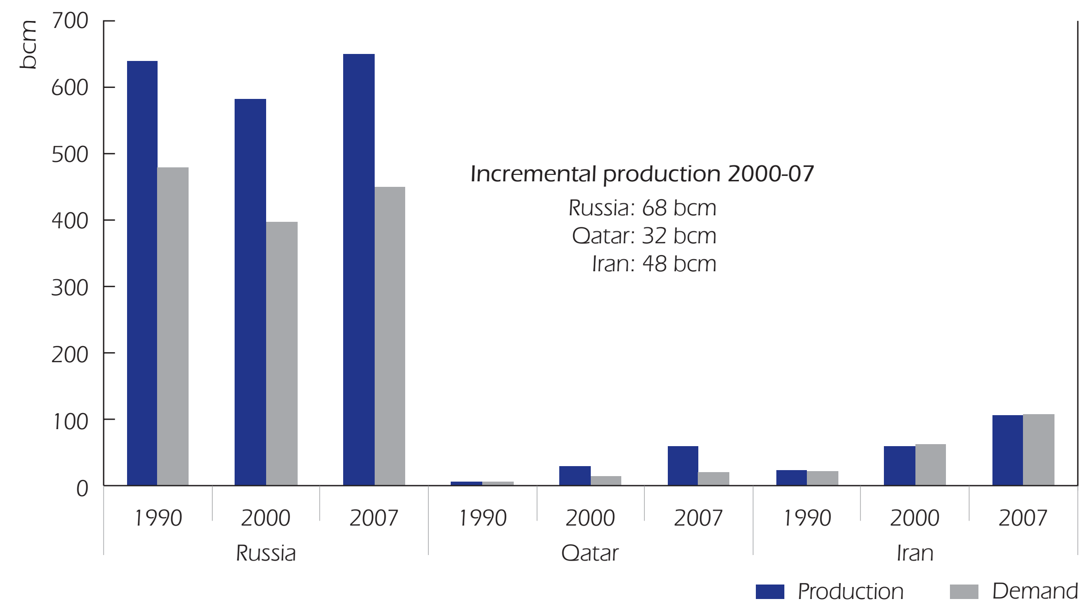
- **The slow pace of upstream gas development has been identified in previous *Natural Gas Market Reviews* as a concern, prior to the current financial crisis.**
- **Current global economic developments will sharply lower producer cash flows, while making demand growth more uncertain, slowing upstream development further.**
- **For Russia, the world's largest gas reserve holder, the new production area of Yamal will be crucial to maintaining or expanding production and exports; other major new fields, like Shtokman, now look unlikely before 2015.**
- **Qatar is dramatically expanding its gas exports, but its self-imposed moratorium looks set to limit new growth in output until 2015, or even later.**
- **Iran is a very large gas producer and user, but production increments look set to meet growing domestic demand. Significant exports by pipeline or LNG before 2015 look unlikely.**

Most producing countries face major challenges concerning the development of future resources. Even prior to the current financial crisis, gas development was slowing: high costs affected remote gas deposit development, producer governments' policies moved to "reserve" gas for local use rather than export, technical problems plus "Not in My Backyard" (NIMBY) and regulatory issues all contributed to slowed gas development. While surprisingly few project delays or cancellations have been formally announced, the current financial environment is likely to have consequences on how quickly new final investments decisions (FIDs) are made and what priorities are chosen. Most producers are likely to see demand falling in their core export markets this year, have markedly weaker cash flows and face much tougher financing conditions. **Demand uncertainty has become a major concern** – when will gas demand recover and at what pace is one side of the problem; political messages from markets concerning diversification of import sources, the scale of their import requirements is another, more subtle but of concern to producers. With the globalisation of gas markets, each producer's decision will be influenced by the others'.

Russia, Qatar and Iran are the three most important reserve holders in the world. Together they represent more than half of total proven gas reserves, but so far they account for only 27% of world production and consume 19%. These countries are very different:

- Russia and Iran are respectively the second and third largest gas consumers

Figure 10 **Gas production and consumption in the "Big 3"**



Key point: Promising potential in Qatar and Iran based on proven reserves

Source: *Natural Gas Information 2008*, IEA.

Table 4 **Production and capacity additions during 2000-15 by Qatar, Iran and Russia**

	Qatar	Iran	Russia
Production			
2000-07	32 bcm	48 bcm (South Pars 1-5)	68 bcm (NPT)
Production target 2015	175 bcm	146 bcm (South Pars 1-14) 80 bcm (South Pars 15-24) 21 bcm (Bidboland-II)	781-845 bcm (incremental production from Bovanenkovo, Kharasavey)
Capacity (post 2008: under construction and planned)			
2000-07	19 bcm (LNG)		20 bcm (EuRoPol)
2008-11	64 bcm (mega trains)		40 bcm (Sakhalin 2, Nord Stream)
2012-15		80 bcm (LNG) 120 bcm (pipes)	85 bcm (Shtokman, Nord Stream, South Stream)

Source: IEA.

Note: Capacity additions post-2012 are planned only.

in the world. Iran gas demand almost doubled over the 2000-07 period. Qatar demand amounts to only 20 bcm.

- Russia and Qatar are net exporters, while Iranian production struggles to meet demand.
- Qatar is predominantly an LNG exporter, while both Russia and Iran are currently predominantly pipeline exporters which plan to get increasingly involved in the LNG business.

One aspect of the significant gas production increase in Iran and Qatar is the target for condensate, GTL and LPG production. This could have a potentially big impact on oil markets. In particular, the huge LPG expansion should have a significant effect on the global LPG markets, especially in Asia, with secondary impact on the gas markets as LPG is competing with gas in Asia.

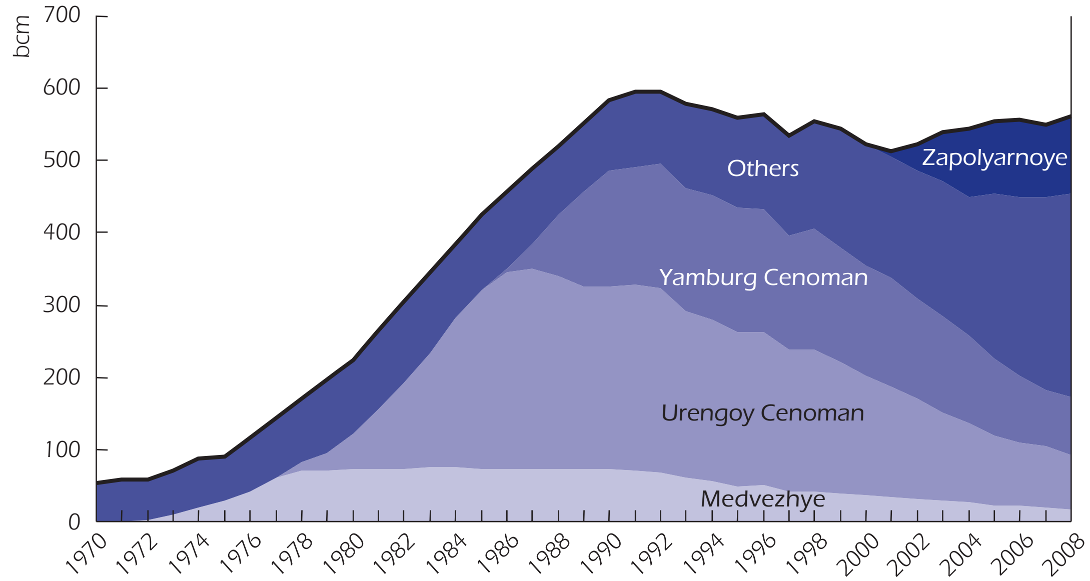
Russia

Russia has the largest proven gas reserves in the world – around 45 tcm. However there are increasing worries about whether Russia will be able to meet both rising domestic demand as well as export obligations. On the Russian side, producers worry about the security of demand: how will the market recover from the current crisis and what will be the impact of climate change and other major policy developments.

Gazprom is the largest gas utility in the world producing 551 bcm in 2008 or about 85% of total Russian gas output. Until recently, it had developed its business based on three super-giant gas fields in Western Siberia: Urengoy, Medvezhye, and Yamburg. But their production has been declining rapidly at around 20 bcm per year. In order to meet both domestic demand and export commitments, Gazprom has been relying on three factors: increasing imports of Central Asian gas; incremental production from the independents reaching over 100 bcm in 2008; and the development of new fields – in particular in the Nadym Pur Taz (NPT) region. This last item enabled Gazprom to keep a relatively stable production over the past five years, despite the steady decline of the three super-giants. Several fields such as Kharvutinskaya, Yety-Purovskoye, Petsovoyea or South Russkoye have been commissioned over the 2003-08 period while production of existing developments such as Zapolyarnoye (which started producing in 2001) has been further increased; these fields would represent a peak production of over 150 bcm.

But this strategy is reaching its limits. In particular, Central Asian imports have become more expensive – Turkmen gas prices have increased from USD 50 to 300 per mcm between 2005 and early 2009, reflecting Turkmen demands for pricing based on Russian netbacks from European sales. Independents remain effectively excluded from the export market by Gazprom's monopoly on export sales. Facing these issues, Gazprom is developing new gas fields which will be more technically challenging, more remote and more expensive to develop than the first generation of Russian gas. However, over the past five years Gazprom has also been focusing on investments in the European market – either in new pipelines avoiding

Figure 11 **Gazprom's gas production**



Key point: New fields are critical

Source: Gazprom.

transit risks such as Nord Stream or gas storage facilities such as Haidach. It has also been active within Russia acquiring controlling stakes in companies: the attempt to acquire coal producer SUEK failed, but Gazprom became active in the power sector and acquired some of RAO UES assets so that the generation capacity controlled by Gazprom increased from 12.7 GW in 2007 to 35.4 GW in 2008[1]. In April 2009, Gazprom bought ENI's 20% stake in Gazprom Neft for USD 4.2 billion. Although these activities may make sound corporate sense, as Gazprom positions itself to benefit from increasing domestic electricity prices and seeks to gain more control of various parts of the value chain down to domestic and foreign consumers, it raises questions in the minds of consumers as to whether these activities will not compromise **the very significant new investment needed upstream to ensure adequate and timely natural gas supplies**. The focus is therefore on the next generation of gas fields: in the West, on the Yamal peninsula and Shtokman, and in the East at Kovytka, Sakhalin and Chayandinskoye.

Unfortunately, the necessity of making huge investments coincides with the financial crisis and an expected major

1. Source: Gazprom Investor day, February 2009.

drop in revenues in 2009 for Gazprom on the back of lower oil and gas prices and lower offtake from European buyers and domestic users. Average prices for gas exports to Europe are likely to decline from USD 12 per MBtu in 2008 to USD 8 per MBtu in 2009. Russian production has been declining since the last quarter of 2008, with a year-on-year decline reaching 15% during the first quarter of 2009. This has been essentially due to plummeting demand both in Russia and in Europe, but the fact is that most of the decline has been attributed to Gazprom's subsidiaries, whose production declined by 18%. There are many uncertainties on the Russian gas demand outlook in 2009. It declined substantially during the last quarter of 2008 (by 15.0% in November and 10.3% in December), and the decline continued at 8.4% in January 2009. Nearly half of Russian power is gas-fired, and more than half of Russian gas demand comes from this sector, so the sharp drop in power use is also likely to heavily impact gas demand. An additional complicating factor is that the planned increases of residential and industrial tariffs, which could further reduce demand by improving efficiency, notably in the power sector, may be postponed due to the economic downturn. At the same time, the fall in export prices may make price reform more feasible. Wholesale prices were scheduled to increase by 25% over the course of 2009, with further increases in 2010, with obvious benefits to producers' cash flows.

Gazprom's board has already revised down their planned investment from RUB 920 billion announced in December 2008 to RUB 827 billion in April 2009 as they expect to save money by cutting capex and renegotiating contractor charges. It is not clear what would happen to the previous investments plans published late 2008 which envisaged an increase in annual production to 876-981 bcm in 2030[2], up from 665 bcm in 2008. Total exports were expected to rise to 415-440 bcm and domestic demand to 550-613 bcm. Total investments would amount to USD 545 and 645 billion over 2007-30. Although Gazprom has not announced any change in the development of the different projects, all the production targets look very ambitious, not only because the technological challenges are often higher compared to the previous generation of supergiant gas fields, but also because of questions about Gazprom's ability to focus on all projects simultaneously while the company still has a heavy debt. Although debt levels were reduced during 2008, most debt is in US dollars or euros, and the rouble has depreciated heavily against these currencies.

The possible deceleration reflected by recent announcements does not mean a cancellation of any of the large upstream projects, but the output is likely to be lower than what has been announced until recently. Therefore Gazprom may be tempted to reduce investments and reassess priorities, especially in the light of falling demand and uncertainties about future needs of export markets. **Gazprom has already indicated clear priorities on both production and transport**. On

2. Outlook for the natural gas industry, IFP, December 2008.

Map 3 Demand trends in OECD Europe

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

production, priority is being given to Zapolyarnoye (Valanginian deposits), Bovanenkovo (Yamal), Urengoy, and Shtokman. On transport, top priority is being given to Nord Stream, followed by Pochinki-Gryazovets (linking the two major export systems) and the Yamal pipeline delivery system.

Another solution would be to work on reducing Russian energy demand: more efficient gas turbines could easily save 20 bcm per year while better insulation in the residential and commercial sector could save another 70 bcm per year[3]. But the promised price rises, which would help drive these savings, may be especially difficult to pursue, given the economic and social impacts of the current recession.

The Yamal Peninsula

The Yamal Peninsula is critical to replace declining production in Western Siberia. Put simply, no bridging solution can replace these volumes that Gazprom expects to reach 310-360 bcm by 2030. Gazprom has a very ambitious plan for the Yamal Peninsula with the development of two fields Bovanenkovo and Kharasavey. By 2011, Yamal is expected to produce 8 bcm per year from the Bovanenkovo field. Gazprom expects to produce 115 bcm to be increased to 140 bcm in the long term. Kharasavey would start in 2014 bringing the combined production to 180 bcm – one-third of Gazprom's production today.

3. Source: Gazprom.

The challenges to develop the Yamal Peninsula are above all logistical: the construction material needs to be transported there and pipelines have to be built, notably a 1 100 km gas pipeline between Bovanenkovo and Ukhta to transport the gas back to the unified gas supply system (UGSS). Drilling and other equipment material will be mainly transported by railroad, and not by sea or by river which can be used only for one-third of the year. Gas pipelines have to be built in permanent permafrost conditions; even though this particular environment has been studied for decades, recent warmer conditions have to be taken into account. Such challenges are susceptible to causing delays for the project timeline. The most difficult section is the underwater crossing of Baidarata bay where the danger of icebergs requires trenched pipelines. In 2008, Gazprom made a significant investment of around USD 4 billion on the Bovanenkovo field and so far has laid 37.7 km of the pipeline across the bay. Nevertheless, given these added difficulties and the sheer scale of the project, the time frame of 2011 production start-up looks ambitious.

Shtokman

Shtokman is probably one of the most challenging gas projects to develop due to the difficult arctic conditions. Discovered in 1988, the field is estimated to contain 3.8 tcm of gas. It represents the first major offshore development for the Russian gas industry. Over the past decade, the Shtokman project has moved from a pipeline project to an LNG project and back to a project based on a mix of pipelines and LNG. Domestic politics, the increasing attractiveness of the LNG business and changing diplomatic relationships with European and the American governments respectively have been the major drivers behind these changes of directions.

According to the current plans, the field's output will be almost evenly split between pipeline and LNG and developed in three phases of 24 bcm each; the LNG share of the project will reach 40 bcm (30 Mtpa). A fourth phase bringing total production to 95 bcm is possible. During the first phase, the field will be developed by the Shtokman Development Company (Gazprom 51%, Total 25% and StatoilHydro 24%). The gas would be transported to Murmansk, and then either by pipeline to Europe through the Nord Stream pipeline or by LNG to the Atlantic region. No final investment decision (FID) has yet been taken. **If FID is made soon, Gazprom expects first gas in 2014 – a timeframe now considered as very ambitious by most observers** (see the LNG section for more details).

Developments in the East: Kovykta and Chayandinskoye

Developments in the Far East region are even more challenging due to the absence of export infrastructure – apart from Sakhalin 2 – and of gas pipe export agreements. Eastern Siberian gas may have missed a window of opportunity in Asian markets and now faces competition from other domestic production, LNG and Turkmen gas. Contracts with these markets will be difficult to conclude in the short term due to pricing and policy issues in China and competition from other LNG sources in Japan and South Korea.

The Kovykta field is located in the Northern part of the Irkutsk region in Eastern Siberia close to China and Korea. Reserves are close to 2 tcm. Since 1992, it had been developed by RUSIA Petroleum in which TNK-BP had a majority shareholding. The development of the field had two main objectives: supply to the small regional market – up to 4 bcm for industries and CHP – and future exports to China and South Korea – up to 20 bcm to China by 2014 and 10 bcm to South Korea by 2011. Although Eastern markets were more logical, a Western route was not entirely excluded. Exports to China and Korea failed due to disagreements on pricing and the sheer size of the development. But in 2007, after the repeated warnings of license cancellation by Russia's Ministry of Natural Resources, Gazprom and TNK-BP signed an agreement to sell TNK-BP's 63% stake to Gazprom. So far the deal has not been completed and may now be a lesser priority.

Gazprom also acquired a development license for the giant Chayandinskoye field (1.2 tcm reserves) in the eastern republic of Sakha. The development plan calls for a gas pipeline to deliver supplies from the field eastward, scheduled to come on line by 2016. The line would run from Yakutia to Khabarovsk and Vladivostok along the Pacific Coast.

Qatar

Qatar is one of the leading performers in terms of new gas development in the world. Qatar ranks third in terms of proven gas reserves with 26 tcm as of end 2007. Its production gains have been the fifth largest in the 21st century after Russia, Iran, China and Norway. Qatar has very ambitious export plans with LNG export capacity to increase from 52 bcm early 2009 to 105 bcm by 2011 with the addition of five LNG trains of 10.5 bcm each. These export projects have been or are being developed through a partnership between Qatar Petroleum and foreign partners (ExxonMobil, Shell or ConocoPhillips). Although all the liquefaction facilities may start operations by 2011, the maximum capacity is likely to be reached only in 2013 as Qatar has been facing project implementation delays. Meanwhile domestic demand has almost doubled between 2000 and 2007 to reach 20 bcm. There is a strong potential growth in the power generation, desalination and industry sectors. Therefore Qatar is likely to maintain a desire to balance exports (pipeline and LNG) and domestic market needs, but also export products – GTL, LNG or pipeline gas to the UAE as well as a variety of export markets. Originally, a wellhead gas production of 238 bcm[4] per year including 175 bcm of dry gas was planned from projects approved before the moratorium.

The main uncertainty for the country's future production is due to the moratorium on new export projects imposed in 2005. The objective for Qatar is to study the effect of the existing project production on North Field reservoirs. There are concerns about the pressure and the effect that

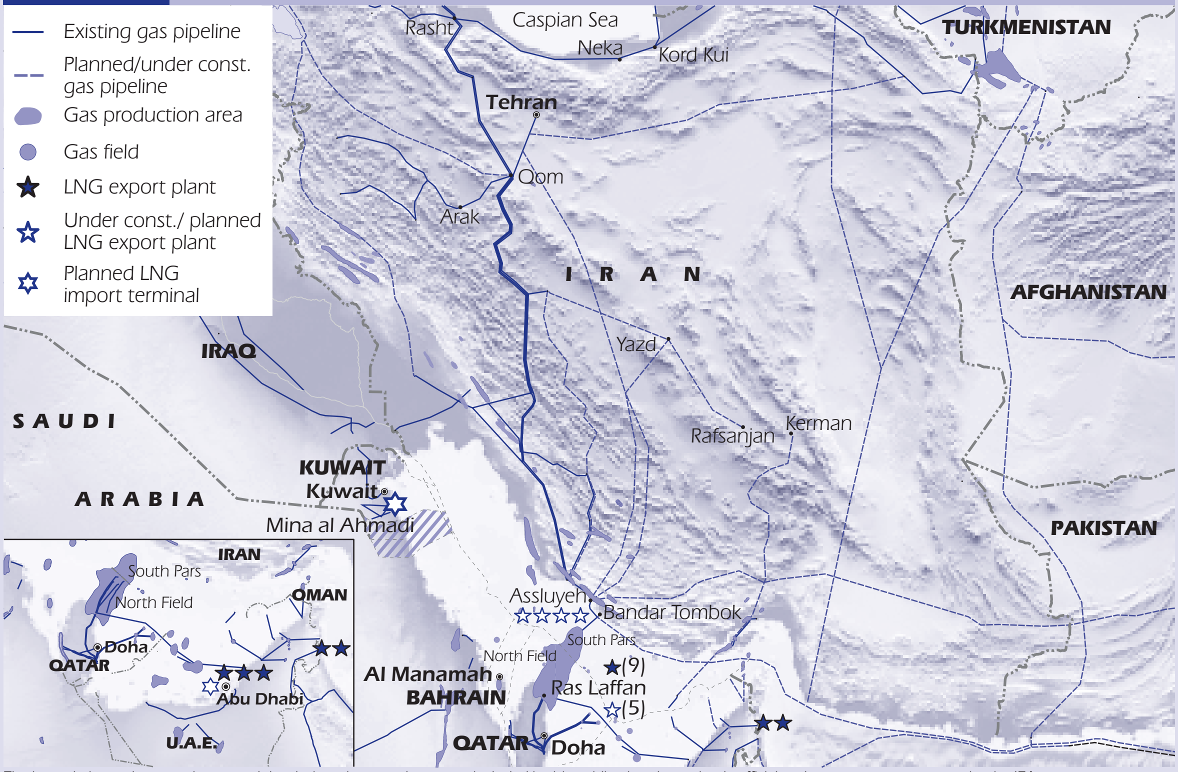
4. Including 700 000 – 800 000 b/d of condensate, 14 Mtpa of LPG, and 250 000 b/d of GTL production. Dry gas production is estimated to be 175 bcm per year (including LNG, pipeline exports, and domestic use).

further development would have on the field structure. Originally taken for three years, the moratorium was extended to 2010 later and there is no certainty about when it would be lifted. The moratorium is likely to stay in place until all the planned trains currently under construction have been brought fully onstream which would be in 2013 or a little later according to recent declarations of Saad al Kaabi, Qatar Petroleum gas development manager. Furthermore the study on the North Field is now expected to be completed only by 2012.

Given the scale of the reserves of the North Field and its strategic importance, it is understandable that the Qatari authorities have put the sustainability of the productive life of the North Field as a key national priority. As in some other producing countries such as Norway, sustaining production for a long time in order to create a legacy for future generations is particularly important. If the study proves satisfactory for the field's life, there could be a debottlenecking of the existing facilities, an increase of pipeline capacity or an expansion of GTL facilities. Alternatives could include exploration at different depths in the North Field area.

Furthermore Qatar may reassign gas production to domestic users – a pattern

Map 4 **Iranian and Qatari gas infrastructure**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA.

that is being seen in other Middle East and African countries such as Egypt or Libya. For example, the Barzan project between ExxonMobil and Qatar Petroleum has been reassigned to serve domestic users. However this project has been delayed by up to one year due to high current costs. The project sponsors announced they would use this delay to source gas from a new structure in Qatar's North Field.

Iran

Industry observers tend to think Iran has been lagging behind Qatar in developing gas reserves from the same geographical structure (North Field in Qatar and South Pars in Iran). **However, since 2000, the incremental production capacity at South Pars has been larger than that of North Field.** South Pars Phases 1-5, totalling 45 bcm per year, compares with Qatar's incremental production over the same period of 28 bcm per year.

But the medium-term developments appear more challenging due to the difficult equation between the use of gas for domestic industry, power, oilfield reinjection and export projects on one side **and production and imports on the other**. Currently Iran is – marginally – a net importer of gas. While the country has exported about 4.5-6 bcm per year to Turkey since 2003, Iran has been importing about 6.5-8 bcm per year from Turkmenistan – principally to supply industry and domestic consumers in the North East. The balance is particularly tight during peak winter periods. During the winter of 2007-08, Turkmen gas supplies of up to 23 Mcm per day were cut until April 2008 which had a ripple effect on exports to Turkey.

The development and marketing of gas on the world market is central in the government's 20-year strategic plan. Nevertheless, the continuous delays in the development projects undertaken and the weight of financial sanctions raise doubts about whether the country will be able to reach that goal. The government has envisaged a production of 292 bcm per year in 2010[5], a huge increase in output from 146 bcm per year[6] today.

Whereas a massive expansion of LNG production (+64 bcm per year from 2009-13) is underway at Qatar's North Field, incremental production at South Pars is currently limited to another 45 bcm in Phases 6-10 from 2008-10 and up to 20% or 9 bcm of incremental production from the existing Phases. Commissioning of Phases 6-8 sour gas production started in summer 2008 and the 504 km IGAT-5 sour-gas pipeline from the Assaluyeh processing complex to the giant Aghajari oil field was opened soon after. Phases 9-10 were officially inaugurated in March 2009 and is expected to ramp up production toward the end of the year.

5. Commercial gas production excluding reinjection is expected to be 195 bcm, according to the National Iranian Gas Company (NIGC).
6. Including volumes reinjected into oil fields. Commercial production was 107 bcm in 2007, according to *Natural Gas Information 2008*, IEA.

Table 5 South Pars development phases

Phase	Upstream partners (awarded)	Target Actual	Gas production* Condensate	Note
1	Petropars (NIOC subsidiary) Sep-97	2001 Nov-04	9 bcm 40 000 b/d	
2/3	Total; Gazprom; Petronas Sep-97	2001 2002	18 bcm 80 000 b/d	
4/5	ENI; Petropars; Naftiran	2004	18 bcm	
6/7/8	Jul-00 Petropars; StatoilHydro Oct-02	Apr-05 2004 2008-09	80 000 b/d 27 bcm** 120 000 b/d	Sour gas Reinjection
9/10	Iran's Oil Industries Engineering and Construction Company (OIEC) and Iranian Offshore Engineering and Construction Company (IOEC), plus South Korea's LG Sep-02	2007 2009	18 bcm 80 000 b/d	
	Capacity added 2002-07		45 bcm 200 000 b/d	
	Capacity added 2008-10		45 bcm 200 000 b/d	
11	Total, Petronas			Pars LNG
12	Petropars			Iran LNG
13/14	Shell, Repsol			Persian LNG
15/16	Ghararagah Khatam-ol-Anbia (Iranian Revolutionary Guard)			
17/18	Pars Oil and Gas Co. (POGC); National Iranian Drilling Co. (NIDC)			
19-21	To be awarded			
22-24	To be awarded			

Source: South Pars Gas Complex Company, media reports.

Note: *bcm per year.

**Initially sour gas. To be switched to sweet gas in two years.

The slow pace and impasse of project development for the South Pars Phases assigned to LNG projects and new upstream awards since 2004, due to changes in political priorities and international isolation, means that production growth is likely to slow significantly for the first part of the next decade, with later increments dependent on a resurgence in awards in the next couple of years. The use of domestic contractors with low levels of expertise, inspired by political rather than economic motives, also explains delays.

Additional development plans will continue to be constrained by international sanctions and western pressure. **Iran has signed up to extensive long-term commitments to supply LNG, but without western participation in the installation of the LNG trains, these are now most unlikely to be met before 2015.**

These upstream problems, added to a rapidly increasing domestic demand, are likely to mean further delays to planned capital intensive gas export initiatives. In this respect, short-distance pipelines or increments through existing infrastructure are likely to be the first solution chosen for any surplus gas.

In mid-2008, Iran officially postponed two of its three LNG developments focused on South Pars for the 2010-13 period leaving only the LNG project wholly-owned by NIOC in place. Partners Shell and Total may switch to later phases of the South Pars field for their LNG development. Other foreign companies, including the Chinese, have held intermittent talks on LNG development of other fields[7]. In addition, prolonged negotiations for gas deliveries to the Iran-Pakistan-India (IPI) pipeline mean that this project is unlikely to be operational at least until 2013 or beyond.

Caspian region

The Caspian region[8] holds significant proven reserves of 7.6 tcm; albeit lower than the three countries described above, they promise to grow substantially as new discoveries are confirmed – notably in Turkmenistan. The region's central geographical position gives it the unique capability to supply pipeline gas to Russia, Europe, Asia and the Middle East. So far gas is mainly exported to Russia; however competition for access to Caspian gas supplies has been intensifying over the past year. Total production reached 172 bcm in 2008 from 161.5 bcm in 2007. This compares to a domestic consumption of around 90 bcm, with power generation, industry and the residential sector all taking a significant share of demand.

Turkmenistan is the main gas producer and exporter in the Caspian region and figures for 2008 put annual gas production at 70.4 bcm, down from 72.3 bcm in 2007, compared to domestic demand of around 20 bcm. Turkmenistan has announced its intention to bring production to over 75.8 bcm in 2009, with an intensive

7. In March 2009, Iran's Oil Minister said that Iran signed a deal with China National Offshore Oil Corp. (CNOOC) to develop the North Pars gas field as an LNG export project.
8. Although Russia and Iran are also Caspian littoral states, the 'Caspian region' is used here to cover Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan.

program of drilling to bring a new field on stream at Gurrukbil-Garabil near the Dauletabad field that is the main source of current gas output. Among the other gas producers, production was up slightly in Uzbekistan and there were more substantial increases in both Azerbaijan and Kazakhstan: in Azerbaijan, phase I of the offshore Shah Deniz field pushed annual output up to 16.3 bcm (up from 11 bcm in 2007); in Kazakhstan, total gas production reached 33 bcm, of which 17.5 bcm was commercial or "sales" gas.

A major upstream development in 2008 was the international audit conducted on gas reserves at two fields in Turkmenistan. Provisional findings were announced in October and, while more appraisal work is necessary, the results were impressive. The best estimate of gas-initially-in-place at the vast South Yolotan-Osman field (this is now considered a single structure) was 6 tcm of gas, within a range from 4 tcm to a high of 14 tcm; the best estimate for the nearby Yashlar field was 0.7 tcm. These figures suggest that Turkmenistan is destined to join the small world elite of gas reserve-holders, with reserves far greater than the 2.7-2.8 tcm currently listed as proven.

Confirmation of these major onshore reserves has intensified competition for exploration and development rights in Turkmenistan and a succession of governmental and commercial delegations have received varying degrees of encouragement from the Turkmen side. Russia and China are well placed; China National Petroleum Corporation (CNPC) has been drilling exploration wells at the South Yolotan field since 2007 and continuing work on a gas pipeline link from the Turkmenistan sector of the Amu Darya basin (where it has a production sharing agreement (PSA)) eastwards to China. Iran is also in the picture following the signature of a memorandum of gas cooperation with Turkmenistan during a meeting of Presidents Berdymukhammedov and Ahmadinejad in February 2009. Interest from IOCs has been held back by the continued insistence on the Turkmen side that their role in onshore gas development is limited to service contracts[9]. **Turkmenistan's export commitments to Russia, China and Iran are well above current production levels, and this, along with increasing interest from other potential buyers, calls for production to increase.**

Alongside the above-ground risks affecting gas production in Turkmenistan, there are likely to be significant development challenges with the next generation of gas production, since it is deep, high pressure and high temperature (HPHT), and sour. The Turkmenistan side expects first gas from South Yolotan-Osman already in 2011, with successive development phases of 10 bcm per year after this date up to a total of 40 bcm for the initial phase; given declines in existing fields, the South Yolotan-Osman development is essential to Turkmenistan's ambitions to increase gas production (the official forecast sees

9. Investment opportunities in the Turkmenistan sector of the Caspian Sea remain open, as witnessed by a memorandum of understanding concluded by the Turkmenistan authorities with Germany's RWE in April 2009 that could lead to development rights for an offshore block.

Map 5 **Caspian gas infrastructure**

Only major trunk lines (mostly trans-national) are shown.
The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA.

production of 250 bcm by 2030), and to sustain multiple export routes.

Russia remains the main export market for all the East Caspian gas producers, *i.e.* Turkmenistan, Uzbekistan and Kazakhstan, and a major change in the politics and economics of East Caspian gas was the move from January 2009 to a "European" netback price for export along this route (see Box 1). Gazprom had previously used its near monopoly over export routes to claim a slice of the exporters' resource rent, but since 2006 has been forced to give ground, at least in part in order to deter the development of alternative routes to market.

While the new price offered to Turkmenistan and Uzbekistan seems to be considerably more than the one offered in 2008, it is not yet possible to examine how a "European" netback price is calculated, nor to predict how – and how fast – these export prices will react to declining European border prices in 2009. Moreover, as well as transmitting prices to Central Asia in 2009, Gazprom has been faced with lower demand for its own gas exports and this has also been felt by Gazprom's suppliers in the Caspian. It is not clear how much flexibility there is in the existing contractual arrangements, but Gazprom has been interested in limiting its take from the region as long as European gas demand remains weak.

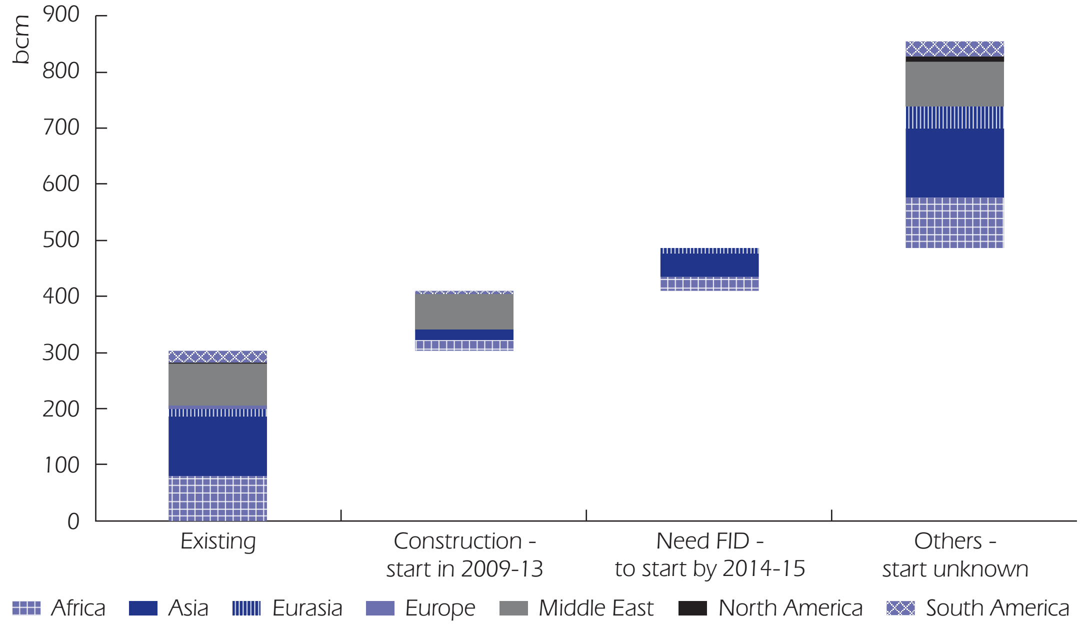
As of late 2009 or early 2010, Turkmenistan will no longer be as reliant on export routes to Russia with the scheduled opening of a large-volume export route to China in addition to the existing smaller-capacity link to Iran. The policy of pursuing multiple export options has brought dividends in recent years and increased Turkmenistan's leverage with potential and actual buyers of gas. This policy also appears to be the driver behind Ashgabat's proposal for a domestic East-West pipeline bringing gas from new production areas around South Yolotan-Osman westwards towards the Caspian coast (rather than linking to the existing main lines of the Central-Asia Centre system to Russia and/or the new Turkmenistan-China pipeline). The domestic pipeline could still serve as an export route to Russia through a connection to the Caspian Coastal Pipeline (although this is yet to be built), but it opens up the possibility of additional deliveries to Iran as well as – potentially – to a future Trans-Caspian line.

Investment in liquefaction capacity

- **Project delays (implementation and decision making) are common in the LNG liquefaction sector due to skilled labour shortages and higher material and engineering costs, as well as market uncertainty.**
- **Only five projects have advanced to FIDs since mid-2005.**
- **While engineering, procurement and construction (EPC) prices may come down somewhat, more reductions seem likely, and this may take more time to assess, causing some additional delays in decision making.**
- **There are signs of changing contracting, business models and corporate structures of LNG liquefaction projects, reflecting more difficult resources and higher risks.**

With regard to liquefaction, the next big questions are on where the next generation of LNG projects are coming from after 2012 and what the potential of slippage of new projects is. After only three FIDs in 2007 (Pluto LNG in Australia, the Skikda replacement train in Algeria, and Angola LNG), there was only one in 2008 (Gassi Touil). Several projects did not reach FIDs in 2008, as previously targeted (*e.g.* Gorgon and Ichthys, Australia, Nigeria LNG Seven Plus, Brass LNG, and a Flex LNG project, Nigeria). Thus expansion post-2012 already looks slower than previously thought, as recently as in 2008.

Figure 12 **LNG liquefaction, existing, planned and under construction**



Key point: A vast expansion, but FID needed soon for new projects

Source: IEA.

As of May 2009, there is 303 bcm of existing liquefaction capacity, 35% of which is in Asia, 25% in Africa and 26% in the Middle East. 103 bcm – one-third of the existing capacity – is under construction and expected to start between mid-2009 and 2013, with the majority located in Qatar (see section on Qatar in Development in the LNG markets). Uncertainty concerns investment in other projects – a total of 445 bcm which are currently at various stages of planning development. In this section, we will focus on the challenges faced by some LNG projects in particular, representing a total of around 80 bcm. These are the projects which we believe are most likely to reach FID within the next two years, which should enable them to start operating by 2014-15. This does not mean that no FID could be taken on the other projects or that other projects could not start by 2014-15.

Increasing challenges

With increasing indications of project delays (implementation delays and decision making delays) across the industry, the expansion of the liquefaction sector seems unlikely to be implemented as planned for the following reasons:

- uncertainty over material and engineering costs
- skilled labour shortages
- more market uncertainty, particularly lack of long-term sales commitment.

Completion times have escalated. In 2005 and 2006, plants such as Darwin LNG or Qalhat LNG were completed in less than three years. The projects starting exports in 2009 are taking more time. It is, for example, already more than 50 months since the EPC contract was awarded for the first of Qatar's mega-trains.

A tight EPC market

The tight EPC market which persisted until late 2008 has not only resulted in increasing costs but also project delays. While capital costs of liquefaction plants had plummeted from USD 600 per tonne per year of installed capacity to USD 200 over the ten years to 2005, they increased back to around USD 1 000 or even more for new plants seeking FID[10] in recent years. There are uncertainties on the evolution of costs for planned projects and for the ones under construction. Some industry experts argue that costs will come down as materials' costs are going down and contractors will compete against each other as the current generation of projects is completed, and fewer new ones emerge, but the timing and extent of cost falls remains unknown. Others argue that EPC costs will come down only after the beginning of 2010, because contractors still have backlogs.

One major factor has been sharp material cost escalation in the middle of the decade, affecting steel, cement, and other raw materials. The current wave of cost escalation started around the beginning of 2005, although the issue was widely recognised by LNG project sponsors only in 2006. While steel and other prices have fallen sharply since late 2008 and into 2009, the translation of these falls into actual project cost reductions has yet to be seen, and decision making could be delayed further while project sponsors wait to see the extent of reductions. Furthermore, the next generation of gas reserves is expected to be more difficult and complicated, so that environmental concerns concerning CO_2 and sour components of feedgas streams are also adding pressures.

Finally, the escalation of EPC costs has affected the nature of contracting. Before the cost increase, EPC contracts for LNG plants were awarded on a "lump-sum turn-key" (LSTK) basis. The potential cost increases after the contract was awarded were traditionally borne by the contractor, although part of these increases could be passed onto the clients depending on the contract clauses. However, the higher than anticipated cost increases resulted in some EPC contractors offering higher contracting prices for future projects.

While the LSTK approach is more difficult, it remains the preferred approach for the majority of contractors to keep discipline in their project implementation with some flexibility added ("open book estimation", "re-inverse & lead items", or "modular construction"). While these changes reduce risks for contractors, they may discourage project promoters from making commitments due to additional risks of cost increases.

10. It should be also noted that USD per tonne figures are highly dependent on site specific factors. Some cited figures include jetties and some utility facility costs, while others do not.

Limited human resources

Another challenge is limited human resources, not only in terms of skilled labour force – engineers, experts in complex project management – but also in terms of engineering companies. Such an issue is common to the whole E&P industry, not specifically to LNG projects. The existing workforce working in the E&P industry has been stretched as they face new, technically challenging projects. Skilled labour forces in subcontracting are also scarce for construction and commissioning during the latter stages of a project.

A small number of companies dominate recently completed LNG plants (grouped according to the proprietary liquefaction process used). These companies are JGC Corporation and Chiyoda Corporation, both of Japan; KBR, Bechtel as well as Foster Wheeler and Chicago Bridge and Iron of the United States; Snamprogretti of Italy; and Technip of France.

Over the past few years, the existing and increasing shortfall of skilled engineers has often been discussed within the global geoscience and engineering community. This does not mean that the few engineering companies can easily expand their employee bases. Firstly, future opportunities are uncertain. Furthermore, there may be a limit to the number of projects (including refineries and petrochemical complexes, as well as LNG) that can be undertaken globally simultaneously. EPC companies need to have both their workforce and the material arriving on the site at the same time. If projects are undertaken at the same time, EPC contractors are likely to have difficulties finding the necessary skilled workforce even if they use subcontractors.

More difficult projects in the future

Yet another factor is rather simple to describe: **projects are becoming more difficult**. There are much bigger, more difficult, and more remote projects – complex technically and engineering-wise. Project sponsor companies are more diversified, which requires EPC contractors to educate sponsors. In other words, there is lack of human resources in the project sponsor side. Not only national oil and gas companies (NOCs), but some of big international oil and gas companies (IOCs) may need additional skilled human resources.

Project ownership structures sometimes make projects difficult. If the project is integrated with the upstream development, it is generally simpler. If the upstream venture has a separate organisation or sponsors, more co-ordination is required. If the feedgas is supplied by third parties, transactions and transfers of feedgas tend to be more complicated. The same feedgas sources may sometimes have to supply to alternative markets (often quickly growing domestic markets). Clear frameworks are needed to make decision making easier.

A possible solution is smaller-scale LNG projects, including those using floating liquefaction vessels. There are many technical barriers to overcome for such floating LNG (FLNG), notably differing gas composition and associated liquid contents at relatively small gas fields targeted for those projects, preventing easy application of standardised liquefaction facilities. Having said that, established players in the LNG industry have expressed interest in this new segment and at least a few projects may advance. In particular, the Canadian shipping company, Teekay, and Merrill Lynch agreed in March 2009 to convert an 87 500 m^3 LNG carrier, Arctic Spirit, currently transporting LNG from Alaska, to Tokyo, into a floating liquefaction vessel and use it at a pier near Kitimat, British Columbia. The FLNG vessel would produce 680 Mcm (500 000 tonnes per year) of LNG, and could commence operations in 2012. This would make Canada the fourth LNG exporting country among the OECD members.

The next generation of LNG supply – a critical question in 2009 and 2010

With the challenges and uncertainties described above, the current financial crisis is making it even more difficult for these large capital intensive projects to move forward. Currently more than 10 projects in the world are looking to start operations in 2014 or 2015. But if sponsors want to capture this potential market window, FIDs need to be made in 2009 or 2010. This section looks in detail at the challenges faced by these projects. Project sponsors must recalculate their project economics at much lower energy prices. LNG buyers are more hesitant to make long-term offtake commitments due to the uncertainty of their market demand. Only a few liquefaction projects have been concluded without long-term sales contracts and they were only possible due to a sponsor with an already established market portfolio (for example Algeria). Firm sales commitments are increasingly more important to decision making.

PNG LNG, Papua New Guinea

Competitive front-end engineering and design (FEED) works are underway on the ExxonMobil-led PNG LNG project. In addition to ExxonMobil's 41.5%, other shareholders in the venture include Papua New Guinea's Oil Search (34%), Australia's Santos (17.7%), Japan's Nippon Oil (5.4%), the state-owned Mineral Resources Development Company (MRDC) (1.2%) and Eda oil (0.2%). These shares will change when the Papua New Guinea government exercises its option to purchase a 19.4% stake in the project.

The project has submitted an environmental impact statement (EIS) to the Department of Environment and Conservation. In addition to a liquefaction plant to be located 20 km northwest of the capital Port Moresby, the project involves the development of gas fields in the Highlands region along with a processing plant, and a pipeline which will run 311 km from the processing plant to the coast and 400 km offshore to the liquefaction plant site.

PNG LNG will have a capacity of about 8.6 bcm (6.3 million tonnes per year (Mtpa)). An FID is scheduled by the end of 2009 with start-up in late 2013 or early 2014. Before reaching the FID, the venture will have to line up marketing arrangements. In April 2009 Oil Search claimed that a "major Asian customer" has agreed to buy 2.7 bcm (2 Mtpa).

Table 6 LNG export projects nearing final investment decisions (FIDs) in 2009 and 2010

Production target	Project (sponsors), capacity, FEED	FID target
Late 2013 or early 2014	PNG LNG, Papua New Guinea (ExxonMobil, others) 8.6 bcm per year (2 trains) Competitive FEED underway (JGC/KBR, Bechtel)	End 2009
Late 2014 or early 2015	Ichthys, Northern Australia (Inpex, Total) 10.9 bcm per year (2 Trains) FEED awarded January 2009 to Chiyoda, JGC and KBR,	End 2009 or early 2010
2014	Gorgon, Western Australia (Chevron, Shell, ExxonMobil) 20.4 bcm per year (3 Trains) FEED underway on 3 train basis by KBR and JGC	End 2009
2014	Shtokman, Russia (Gazprom, Total, StatoilHydro) 10.2 bcm per year (1 or 2 Trains) FEED underway by Technip	Early 2010 (delayed)
2013	Donggi-Senoro LNG, Central Sulawesi, Indonesia (Mitsubishi, Pertamina, Medco) 2.7 bcm per year (1 Train)	2009
2014	Nigeria LNG Train 7, Nigeria (NNPC, Shell, Total, ENI) 10.9 bcm per year	First half 2010
2014	Brass LNG, Nigeria (NNPC, ConocoPhillips, ENI, Total) 13.6 bcm per year	First half 2010
2014 or 2015	One of the proposed CBM-to-LNG projects in Australia	2010

Source: IEA, company information.

Ichthys, Australia

In early 2008, the operator Inpex indicated that it wanted to make the project's FID late 2008 or early 2009, while official start-up was scheduled for late 2012. But it was only in January 2009 that Inpex awarded a FEED contract based on a liquefaction plant in Darwin in the Northern Territory, Australia, to a consortium grouping Chiyoda, JGC and KBR, after deciding to move the potential site from Western Australia. Now the FID is scheduled by early 2010 with the first shipment of LNG in late 2014 or early 2015.

The project will initially produce 10.9 bcm (8 Mtpa) of LNG, 1.6 Mtpa of LPG, and 100 000 b/d of condensate. The project is estimated to cost over USD 20 billion. Obviously reducing the cost is one of the primary purposes of the work in 2009.

Feedgas will come from the Ichthys field in the Browse Basin offshore Western Australia via a 850 km subsea pipeline to Darwin. A separate FEED contract for the project's offshore facilities has yet to be awarded.

Inpex said in December 2008 that it could sell part of its stake in the project to Japanese utilities. Inpex currently holds 76% while Total holds the remaining 24%. The project will be the first to be operated by the Japanese company and its primary marketing target is Japan.

Gorgon, Australia

In Northwest Australia, the three partners in Gorgon LNG – Chevron, Shell, and ExxonMobil – hope to complete FEED on an enlarged phase one conducted by the KBR/JGC joint venture **in 2009 and make a FID soon after**. The operator Chevron admits that Gorgon would be a very costly project and that Chevron was continuing to do what it could to reduce costs.

The project currently has government approval to build two trains of 6.8 bcm (5 Mtpa) capacity each on Barrow Island, and is seeking permission to build a third. The project's costs are currently estimated to be more than USD 20 billion. Chevron has emphasised that construction costs would fall in the current economic crisis.

Chevron expected to sign further initial agreements for the sale of its share of Gorgon's output before it takes FID. Chevron holds 50% of Gorgon's equity, with Shell and Exxon each holding 25%. The partners have already signed up with buyers in Japan and China for some of the output from the project: 5.7 bcm (4.2 Mtpa) for Japanese utilities from Chevron; and 2.7 bcm (2 Mtpa) each by Shell and ExxonMobil for PetroChina. Shell is also expected to bring some volumes to its Mexican and Indian terminals.

Other projects in Western Australia and Northern Territory

There are several other LNG project proposals in Australia. Chevron intends to go ahead with Wheatstone as a stand-alone LNG plant at Onslow. Recent drilling on the Iago field was successful and Chevron is considering a multi-train project. The target for start-up of the first two trains is 2015. In addition to a second train at the Pluto project, Woodside is leading two other projects in Australia – Browse LNG in Western Australia and Greater Sunrise (via a floating or Darwin onshore plant). A second train at Darwin LNG also has been mooted.

The Western Australian state government selected a site in December 2008 for an LNG hub in the Kimberley region to receive gas from the offshore Browse basin – James Price Point, 60 km from Broome, as it could meet environmental requirements and accommodate several projects. It also had no settlements within 20 km.

CBM-to-LNG projects in Queensland

Meanwhile, four projects in Queensland on the east coast of Australia have either entered or about to launch the FEED stage. All are based on the state's coalbed methane (CBM) reserves and the three largest ones are backed by well established industry players (BG, Petronas, and ConocoPhillips). Some form of project consolidation looks inevitable. Players recognise other

Table 7 Australia's coalbed methane/coal seam methane race

Production target	Project (sponsors), capacity, FEED	FID target
2014	Curtis LNG (BG, Queensland Gas Co) 9.5 bcm = 7 Mtpa FEED underway by Bechtel	End 2009
2014	Gladstone LNG (Santos, Petronas) 4.8 bcm = 3.5 Mtpa FEED underway by Bechtel	Mid-2010
2015	Australia Pacific LNG (ConocoPhillips, Origin) 9.5 bcm = 7 Mtpa FEED expected in 2009 likely by Bechtel	Late 2010 (T1) Early 2011 (T2)
2012	Gladstone LNG (LNGL, Golar LNG, Arrow Energy) 2.0 bcm = 1.5 Mtpa	Late 2009
	Shell, Arrow Energy 4.8 bcm = 3.5 Mtpa	
	Southern Cross LNG (LNG Impel (Galveston LNG)) 1.4 bcm = 1 Mtpa	

Source: IEA, company information.

challenges of CBM-based projects: access to land (the number of wells required would be larger); water disposal; heating value (5%-7% less than traditional Asia Pacific LNG); and management of longer and slower ramp up of gas production.

Donggi-Senoro LNG, Central Sulawesi, Indonesia

The relatively small size of Donggi-Senoro LNG project of 2.7 bcm (2 Mtpa) in Central Sulawesi, Indonesia, may give some advantages to the sponsors in terms of marketing and finance – the operator Mitusbishi (51%), state-owned Pertamina (29%), and the privately owned Indonesian company Medco Energi (20%). In January 2009, the liquefaction venture signed 15-year contracts with Pertamina and Medco Energi for the feedgas gas supply to the plant. The start of LNG production could come as early as 2013 if a FID comes in early 2009. Japan's electric power companies[11] may agree to take all of the output from the project.

NLNG Seven Plus and Brass LNG Nigeria

Both final investment decisions on Nigeria LNG Train 7 (NLNG Seven Plus) and Brass

11. These could include Chubu and Kansai, who already import a lot of LNG from Indonesia.

LNG slipped from 2008 into 2009. Both projects have been proposed for many years, but face delays mainly due to security concerns in the Niger Delta and uncertainty over the government's policy (see section on Nigeria). Still the partners hope that NLNG Seven Plus and Brass LNG will make FIDs by the first half of 2010.

Prospects for NLNG Seven Plus have improved now that a new inlet gas price for the entire NLNG complex has been agreed with state-owned Nigerian National Petroleum Corporation (NNPC). A super-mega train of 10.9 bcm (8 Mtpa) – even larger than the Qatari mega trains – is envisaged for this project. The partners of NLNG include NNPC (49%), Shell (25.6%), Total (15%) and ENI (10.4%).

Brass LNG has also secured marketing agreements with global portfolio players including BG, GDF SUEZ, BP, ConocoPhillips, and ENI for more than three years and partners are eager to start the project as soon as possible. Total replaced Chevron in 2006 to join the project, which plans to have capacity of 13.6 bcm (10 Mtpa) from two trains. The ownership of the project is NNPC (49%), ConocoPhillips (17%), ENI (17%) and Total (17%). The project awarded Bechtel the FEED contract in November 2004 and the construction contract in June 2007.

Shtokman, Russia

Front-end engineering design works for the offshore elements, liquefaction plant, and pipelines are due to be completed by mid-2009. Although the FID has slipped into 2010, the partners maintain that the project should see the first LNG shipment in 2014. The joint venture plans to invest around USD 15 billion in total for the first phase of the project. Construction is expected to begin in 2010, with first pipeline gas in 2013. LNG production is planned at a rate of around 10.2 bcm (7.5 Mtpa) from 2014. While the Shtokman Development Company is controlled by Gazprom (51%) and its partners are Total (25%) and StatoilHydro (24%), all the hydrocarbons will be owned and marketed by Gazprom. Thus a question remains regarding how Total and StatoilHydro book any reserves from the project.

Investments in regasification and pipelines

- **Growing demand expected in all markets means that increased investment in infrastructure, notably long-distance pipelines and/or LNG terminals, is needed, in particular in regions with falling production such as Europe.**

- **While current economic conditions will slow demand growth, the lead times for these investments are generally long, and a number of projects are pushing ahead, while others are likely to languish or be cancelled outright.**

- **Rising costs, regulatory issues, geopolitical risks and NIMBY issues all add to the problems created by the current financial crisis; innovation may offer one means to overcome these barriers through, for example, small scale or floating LNG regasification vessels.**

New supply infrastructure will be needed to face increasing demand – be it the increasing gas import dependency of OECD countries or growing needs from non-OECD markets such as China or India. These markets are increasingly competing for the same gas resources – be it transported by LNG or by pipeline. Until recently regional or long-distance pipelines were the traditional way to transport gas to markets, but LNG has been gaining momentum with an increase of LNG global trade from 169 bcm to 233 bcm between 2003 and 2007 while total international imports increased from 807 to 899 bcm. Many gas producers now hesitate between the LNG and the pipeline exporting options – betting sometimes on both as we have seen in Russia or Iran as they wish to diversify demand, transit and pricing risks. LNG and pipelines are therefore competing against each other in particular in OECD Europe and, to a lesser extent, in North America, but both have been also considered in China, India, and Latin America.

While both options ultimately depend on upstream developments, utilisation of LNG regasification also depends on the future developments of liquefaction – the perspective of under-utilisation of terminals may deter investments in regasification if the investor is not pursuing arbitrage or an integrated LNG supply chain strategy. Both supply options have differing strengths and weaknesses for project sponsors and the buyers:

Costs. Pipelines are capital intensive projects with high upfront costs requiring investments of several billion Euros (see table 10). A regasification terminal project would typically cost EUR 0.4-1.1 billion (USD 0.5-1.5 billion) for a 7-11 bcm (5-8 Mtpa) terminal. Offshore regasification has even lower capital costs[12]. From the buyer's point of view, costs to deliver gas to the market by pipeline have to be compared with those of liquefaction, shipping and regasification together. An investor will base its choice also on its LNG strategy – integrated approach, arbitrage or stand-alone investment – and may choose to invest in regasification only – this would be the case of GATE or Isle of Grain where companies other than the project sponsors have taken long-term capacity commitments.

Transit and policy issues. Pipelines can be affected by political issues as seen during the Russia-Ukraine crisis, but can also benefit from inter-governmental backing to improve or strengthen political relationships. The Arab pipeline between Egypt, Jordan, Lebanon and Syria or the Dolphin gas project between Qatar, the UAE, and Oman are such examples. Furthermore, project sponsors would seek long-term visibility on regulatory rules – a multinational pipeline would see regulatory difficulties increasing with the number of countries crossed, unless harmonisation can be achieved.

Flexibility. Pipelines tend to be dedicated to a market or a region which limits supply

12. The most recent example is Nynashamn in Sweden by AGA Gas (0.4-0.5 bcm) per year. The project cost is said to be around USD 33 million. While capital costs are lower due to lower capacity, this would not be obvious per ton of LNG. Another disadvantage is the fact that special tankers may need to be ordered for these terminals.

flexibility, but also opportunities for the supplier to divert gas to other markets. LNG terminals bring more flexibility to the market, but this could be seen either as an advantage or a disadvantage from a security of supply point of view: if LNG markets are tight, consumers would have to pay a premium to attract LNG supplies, but it can be a way to attract gas quickly to meet shortfalls as Greece and Turkey did in January 2009.

Construction times. Most LNG terminals can be built within two to three years, while for a pipeline the duration depends on the length and the complexity of the ground (or the water depth if it is offshore). However, the past years have seen many emerging economies adopting LNG as an easy fix for their energy shortages, while innovative solutions such as onboard regasification and floating storage are helping countries to develop regasification capacity quicker[13].

NIMBY/safety perceptions. Both LNG and pipelines are subject to opposition from local population, although the perception of problems appears to be more acute with LNG tankers.

In a context of tougher financial conditions, capital intensive projects may have more difficulties attracting financing, especially when added to uncertainties on demand, upstream developments or regulation. The Skanled pipeline project between Norway, Sweden, Denmark and (potentially) Poland was suspended in April 2009 due to the current economic environment, subsequent uncertainties related to timing of new field developments offshore Norway, and uncertainties on demand. Another question will be how projects will be financed. Financing terms are generally expected to be tougher, and political risks and sales agreements will come under intense scrutiny. For any lender, the key is the cash flow generated by the project itself. Depending on the project, this might be based on long-term sales and purchase agreements or income based expectations on tariffs and annual booking of the infrastructure. Flexible marketing arrangements may not be viewed as advantages, as they do not necessarily guarantee stable cash flows.

Regasification developments in the world

Looking at regasification investments worldwide, around 210 bcm of capacity are currently under construction and expected to start by 2012 – with around one-third in the United States and 25% for Asia and Europe respectively. This will increase global regasification capacity by around one-third, but this also means that regasification capacity will still be at least double that of liquefaction capacity.

The uncertainties lie around how much of the 531 bcm capacity currently planned will actually move forward. This will depend first of all on future developments of liquefaction capacity, of regional/national import requirements but also

13. There are already six operating onboard regasification LNG receiving terminals in the world. At least one more is expected to open in 2009.

Table 8 Investments in regasification terminals

Region	Country	Operation (bcm)	Construction (bcm)	Planned/proposed (bcm)	TOTAL (bcm)
Asia	China	8.5	22.4	27.5	**58**
	Chinese Taipei	28.4			**28**
	India	21.8	7.5	19.0	**48**
	Indonesia			6.3	**6**
	Japan	243.8	0.6	11.4	**256**
	Korea	90.3	18.6	11.3	**120**
	Pakistan			4.8	**5**
	Philippines			1.9	**2**
	Singapore			4.1	**4**
	Thailand		6.8		**7**
Asia total		**393**	**56**	**86**	**535**
Europe	Albania			8.0	**8**
	Belgium	9.0		9.0	**18**
	Croatia			10.0	**10**
	Cyprus			0.7	**1**
	France	17.0	8.3	35.5	**61**
	Germany			14.0	**14**
	Greece	5.2			**5**
	Ireland			4.1	**4**
	Italy	3.5	11.8	75.5	**91**
	Lithuania			2.0	**2**
	Netherlands		12.0	26.5	**39**
	Poland			2.5	**3**
	Portugal	5.5		2.5	**8**
	Romania			5.0	**5**
	Spain	57.9	8.1	8.7	**75**
	Turkey	12.5			**13**
	United Kingdom	28.6	16.6	41.3	**87**
	Sweden		0.3		**0**
Europe total		**139**	**57**	**245**	**442**
Middle East-Africa	Dubai			4.1	**4**
	Kuwait		3.0		**3**

Table 8 Investments in regasification terminals (continued)

Region	Country	Operation (bcm)	Construction (bcm)	Planned/proposed (bcm)	TOTAL (bcm)
	South Africa			1.9	**2**
Middle East-Africa total			**3**	**6**	**9**
North America	Canada (East)		10.3	20.7	**31**
	Canada (West)			5.2	**5**
	Dominican Republic	2.4			**2**
	Mexico (East)	5.2			**5**
	Mexico (West)	10.3	5.0	20.6	**36**
	Puerto Rico	4.0			**4**
	United States (East)	106.6	68.3	145.1	**320**
North America total		**129**	**84**	**192**	**404**
South Amercia	Argentina	1.5			**2**
	Brazil	6.8		2.2	**9**
	Chile		5.2		**5**
South America total		**8**	**5**	**2**	**16**
Grand total		**669**	**205**	**531**	**1 405**

Source: IEA, company information.

on regional dynamics. Developments in North America will be influenced mainly by unconventional gas production, in Europe or Northern Asia[14] by pipeline developments – in particular from Russia and the Caspian region (see below), in Latin America, Middle East and South Asia by intraregional pipelines from producing countries/subregions to demand centres.

The following sections focus on Europe and Latin America. Further discussion on pipeline developments in South Asia and Middle East regions can be found in the sections covering those regions.

Supply infrastructure developments in Europe and Eurasia

In the *World Energy Outlook 2008*, the Reference scenario estimated OECD Europe's gas import needs to reach 477 bcm by 2030, with a particularly sharp increase (50%) between 2006 and 2015. While the current economic conditions are moderating demand markedly, investments in both new pipeline and LNG terminals will remain essential. There are currently over 200 bcm of planned pipeline capacity targeting Europe (see

14. China, India, Korea, Japan.

Table 9 Regasification terminals under construction in Europe

Country	Terminal	Start up	Capacity (bcm)
United Kingdom	Dragon	Q3 2009	6
	South Hook Expansion	2009-10	10.5
Italy	Adriatic LNG (Rovigo)	Q3 2009	8
	Livorno	2011	3.8
France	Fos Cavaou	Summer 2009	8.25
Netherlands	GATE	2011	12
Spain	Musel	2011	6.8

Source: IEA, company information.

table 10) and 300 bcm of LNG planned regasification capacity. Obviously, not all this supply capacity will be built, as this would add to an existing 400 bcm of pipelines and 139 bcm of LNG regasification capacity[15]. But which project comes online will also depend on developments on interconnectors between the different markets as the pattern of flows will evolve as domestic production declines in the North. This is particularly important for the infrastructure targeting Spain (see chapter on Spain) or Italy.

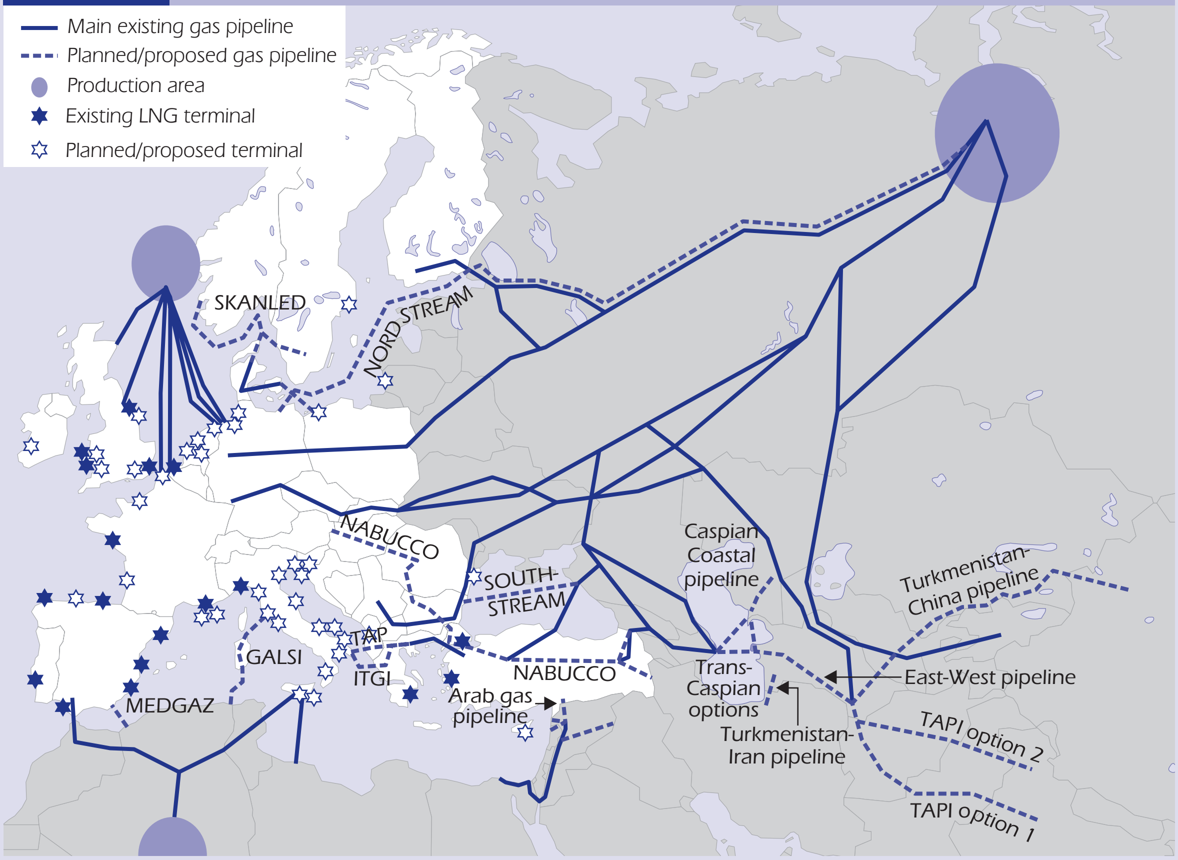
Only 57 bcm of regasification terminals are actually under construction – most of them have experienced repeated delays of up to two years such as Rovigo in Italy, Fos Cavaou in France or the two Welsh terminals South Hook (started operation in March 2009) and Dragon.

Among the pipelines under construction are the expansion of the Trans Tunisian Pipeline Company's (TTPC) section of the Transmed pipeline by 3 bcm and the 8 bcm Medgaz pipeline linking Algeria directly to Spain, expected by mid-2009.

Most other pipeline and regasification projects remain at various phases of the planning stage and are subject to delays, uncertainties about costs, financing and future demand as well as local opposition to construction. Competition between pipelines and LNG terminals will remain particularly tough over the coming years. As can be seen on Map 6, most LNG terminals are located in Western Europe where import requirements are expected to be the highest, while the political will to diversify supply might play in favour of LNG terminals in Croatia or Poland. Meanwhile, most additional pipeline projects are expected to come from the East as additional North African capacity aiming at Spain and Italy will face either a lack of interconnections to the wider European market or the need to convert Italy into a transit country.

15. Annual utilization rates typically vary between 70 and 90% for pipelines and between 50% and 90% for regasification terminals.

Map 6 **Main supply projects to Europe**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

Nord Stream pipeline

Nord Stream is the pipeline linking Vyborg in Russia to Greifswald in Germany. Consisting of two strings of 27.5 bcm each and bypassing any transit country, **the first string is expected to be commissioned end-2011 with the second starting in 2012**. Project shareholders are Gazprom (51%), E.ON Ruhrgas and Wintershall holding (20% each) and Gasunie (9%). However, E.ON Ruhrgas had been discussing selling 4.5% to GDF SUEZ. Costs have increased substantially compared to the first estimates and are now estimated at almost EUR 7.4 billion. The sheer size of the pipeline (one-tenth of the European gas consumption or one-third of current Russian exports to Europe) has the potential to change markedly the flow patterns in North-East Europe and result in lower utilisation of the existing pipelines through Slovakia or Poland – which depend on transit through either Ukraine or Belarus. Interconnections to the market have been planned with the construction of NEL to North-West Germany and OPAL to the Czech-German border. The main challenge in 2009 is to get the final environmental permits from the countries whose territorial waters and/or the Exclusive Economic Zones (EEZs) are crossed: Finland, Sweden, Denmark, and Germany.

Galsi pipeline

Originally planned to start in 2008, the Galsi pipeline linking Algeria to Italy through Sardinia got the go-ahead at the signing of an inter-governmental agreement by Rome and Algiers at the end of 2007. Galsi would be owned by Sonatrach (41.6%), Edison (20.8%), Enel (15.6%) and Hera Trading (10.4%), the rest being held by the Sardinian authorities. Although a FID was expected mid-2009, it has been postponed to mid-2010 which would further delay the pipeline from the 2012 expected start. Galsi had suffered from cost increases as well as difficult discussions about the route. EUR 120 million funding has been committed to the project, as part of the EU stimulus plan. According to the agreement of October 2008, Snam would be responsible for the 520 km-long Italian section and Galsi for the rest. The pipeline also depends on developments of upstream and transport infrastructure within Algeria as well as the competition from 86 bcm of LNG liquefaction capacity planned/under construction.

Nabucco

The consortium behind the 31 bcm pipeline (RWE, OMV, BOTAS, MOL, Transgaz, and Bulgargaz) is **expected to take a FID in 2009, but the project has been postponed several times since its conception and is now expected to start construction in 2011 with first gas in 2014**. The absence of an upstream player and a clearly identified supply source has been one of the major issues along with the difficulty of having different national regulatory regimes. Possible supply sources include Azerbaijan, Iran, Turkmenistan, Kazakhstan, Iraq, Egypt or Russia. As discussed in the Middle East section, Iran and Egypt are unlikely to be major contributors as pipeline export projects face competition from high domestic gas demand and LNG exports, while Russia supports the competing South Stream project. The most likely source in the short term would be the second phase of Shah Deniz field in Azerbaijan expected to provide between 8 and 16 bcm by 2014-15, but there is tough competition between several pipelines to get this gas – Nabucco, South Stream, and possibly ITGI, TAP and, less likely, White Stream. The project received support from the European Commission, which proposed the Caspian Development Corporation as a way to have a coordinated approach to buy Caspian gas, and agreed to commit EUR 200 million funding as part of the European Commission stimulus plan announced in April 2009. The Budapest conference on Nabucco in January 2009 set the goal of signing the Intergovernmental Agreement (IGA) and the Project Support Agreements (PSAs) by June 2009. This would enable the project to move forward on financing: the **EIB has already announced that they would finance 25% of the project – around EUR 2 billion, with the rest likely to be coming from the EBRD as well as other commercial banks and credit export agencies.**

South Stream

The 31 bcm pipeline linking Russia to Bulgaria has been gaining momentum

Table 10 Pipeline projects in Europe

Source	Pipeline	Completion	Transit/portion	Max offshore depth (m)	Length (km)	Maximum capacity (bcm/y)	Estimated cost (bn Euros)	Shareholders
Russia	Nord Stream 1	End 2011	Under Baltic Sea to Germany	200	1 200	27.5	8	Gazprom (51%), BASF, E.ON (20% each), Gasunie (9%)
	Nord Stream 2	2012				27.5		
	South Stream	2015	Under Black Sea to Bulgaria	2 200	900		4	Gazprom, ENI
			Bulgaria -Austria			31 10	15-20	Gazprom + country partner (50% each)
			Serbia (10 Bcm/y)					Gazprom
	South Stream exp	na		2 200		16		Gazprom
Caspian/Russia	Nabucco	2014	Ankara to Austria (Bulgaria, Romania, Hungary)		3 296	8	7.9	BOTAŞ, Bulgargaz, Transgaz, MOL, OMV, RWE
		End 2015	Georgia/Iran to Ankara			8		
		2019	Compression (Turkey - Austria)		3 296	15.5		
	ITGI	2007	Turkey-Greece		300	11.5	0.3	BOTAŞ in Turkey, DEPA in Greece
		2007-12	Greece		600	8-9	0.6	DEPA/Desfa
		End 2012	Under Adriatic Sea to Italy		215		0.4	Edison, DEPA
	White Stream (GUEU)	2015	Georgia - Crimea - Ukraine - Romania/Georgia - Romania	2 100	1 400/1 238	8	2.5	Pipeline Systems Engineering (PSE) Radon-Ishizumi
		2019				8		
		2024				16		
	TAP	2011	Greece-Albania		505	10	1.5	EGL, StatoilHydro
			Under Adriatic Sea to Italy	820	115			
			Ionian Adriatic Pipe (5 Bcm)		400		0.2	EGL, Plinacro, BH

Table 10 Pipeline projects in Europe (continued)

Source	Pipeline	Completion	Transit/portion	Max offshore depth (m)	Length (km)	Maximum capacity (bcm/y)	Estimated cost (bn Euros)	Shareholders
Algeria	Galsi	2012	Algeria		640	8	2	Sonatrach 41.6%, Edison 20.8%, Enel 15.6%, Sfirs 11.6%, Hera: 10.4%
			Algeria-Sardinia	2 800	280			
			Sardinia		300			
			Sardinia-Italy	1 300	250			
	Transmed	2009	Algeria -Tunisia	n/a	n/a	3.3		TTPC
	Medgaz	2009	Under Mediterranean Sea to Spain	2160	210	8	0.9	Sonatrach (36%), Cepsa (20%), Iberdrola (20%), Endesa and GDF SUEZ (12% each)
Libya	Green Stream exp	2012	Under Mediterranean Sea			3		ENI (75%)

Source: : IEA, project sponsors' information.

Box 1 *The southern corridor and the Georgian crisis*

Despite the apparent logic of a direct link between the gas-rich Caspian region and Middle East and the large and lucrative European market, the southern corridor for gas supply to Europe through Turkey has been slow to develop. Events in 2008-09 provided a good illustration both of the potential benefits of such a gas corridor in terms of Eurasian gas market diversity, and of the reasons why progress has been hard to come by.

The South Caucasus gas pipeline linking Baku in Azerbaijan to the Turkish grid in Erzurum, via Georgia, has been in operation since the end of 2006, bringing up to 7 bcm per year from the offshore Shah Deniz field in Azerbaijan to the Georgian and Turkish markets, with small volumes of gas re-exported from Turkey to Greece through the Turkey-Greece-Interconnector commissioned in November 2007. There are a number of other pipeline proposals that would greatly expand gas trade along the southern corridor, including the Nabucco project from Turkey through south-east Europe to Austria and two pipeline projects that would reach Italy across the Adriatic/Ionian Sea.

International focus on the South Caucasus was sharpened abruptly by the conflict in August 2008 between Russia and Georgia. Even though the actual disruption to gas transit flows through Georgia was minimal – a precautionary suspension of supply for two days from 12-14 August – the conflict was seen as having a broader impact on energy security[16]. Almost all current gas exports from the East Caspian go through Russia, and increased perceptions of political risk in the South Caucasus – alongside an increase in the perceived costs of disagreement with Russia – were seen as hindering the prospects for a new westward export route.

There is some evidence of this effect, for example in the reduced incidence of public support for trans-Caspian gas trade since August 2008 from major East Caspian producers such as Turkmenistan. However, the challenges facing the corridor are by no means limited to regional geopolitics; perhaps more significant are the generic difficulties involved in putting together any long-distance multi-country pipeline routes: how can the (often competing) interests of many different parties along a complex gas supply chain be aligned?

All the proposed pipeline routes along the southern corridor involve multiple jurisdictions, and include countries inside and outside the European Union. Securing agreement on uniform, stable conditions for natural gas transmission along the route has been complicated by concerns about security of gas supply in key transit countries, most notably in Turkey where gas demand has risen rapidly in recent years.

16. The European Council noted on 1 September 2008 how “recent events illustrate the need for Europe to intensify its efforts with regard to the security of energy supplies”.

Box 1 ***The southern corridor and the Georgian crisis (continued)***

The challenge remains to address Turkish concerns about future gas supply without creating obstacles to transit that could impede the development of the corridor.

Without transparent and efficient means of transmitting market signals back up the value chain, the attractions of European sales can look opaque to producers. This commercial challenge was reinforced with the move by Gazprom towards "European" netback pricing for East Caspian gas export from January 2009. Although the nature of the pricing formula used for this gas trade is not clear, the announcement implies parity with the price paid on the European market for Russian natural gas, minus the costs of transportation and storage – and a Gazprom margin – back to the relevant delivery point in Central Asia. The availability of a "European price" via Russia might not be sustained if the option of a southern corridor starts to fade, but for the moment it has eroded one of the route's major attractions for Caspian producers.

This shift in Gazprom's pricing strategy has also allowed Russia to enter the picture as a potential export route and market for Azerbaijan. The infrastructure for Russia-Azerbaijan gas trade already exists, since Russia was a supplier to Azerbaijan until 2007. These imports have been displaced by growing Azerbaijan gas production, and both Russia and Iran are competing with westward routes for incremental Azerbaijani output (see section on Caspian gas production). Gazprom signed a memorandum of understanding with SOCAR in March 2009 regarding the possibility of gas sales and purchase, including swap agreements.

However, if Gazprom hoped that its offer of a higher export price would delay the development of all new pipeline routes out of the Caspian then it reckoned without the determination of China to open up a new export route to the east. The Turkmenistan-China pipeline runs from south-east Turkmenistan via Uzbekistan and Kazakhstan, and construction began in 2007-08 on the different sections. Gas deliveries are scheduled to begin in the last quarter of 2009, although it may take some years before deliveries to China approach full design capacity of 40 bcm per year.

The Turkmenistan-China pipeline and a PSA for the China National Petroleum Corporation on the east bank of the Amu Darya river showed that rapid progress is possible in developing a gas relationship with Turkmenistan. Key elements of the Chinese approach were the long-term commitment to gas purchases as well as underwriting the construction of transportation infrastructure up to the delivery point in Turkmenistan.

Up until now, Europe's multiple states and competing private companies have not been well positioned to match China's determined pragmatic approach. However, Europe is now examining options for a more concerted response: the European

Box 1 The southern corridor and the Georgian crisis (continued)

Commission's Strategic Energy Review from November 2008 floated the idea of a consolidated gas purchasing mechanism for gas east of Baku, provisionally called a Caspian Development Corporation. Alongside clear conditions for gas marketing and transit west of Baku, such a mechanism could help to make Europe a more compelling competitor for East Caspian gas.

over the first half of 2009 through the signature of intergovernmental agreements with different European countries – Bulgaria, Hungary, Serbia, and Greece. Negotiations are underway with Austria and Slovenia. The pipeline consists of three main parts: the offshore part to Bulgaria which would cost over EUR 4 billion and be built by Gazprom-ENI, and two subsections amounting to EUR 15-20 billion. The offshore pipeline would cross Bulgaria East-West and then divide into the two parts, one going to Greece and the other to Serbia, Hungary, Austria and possibly Slovenia. Gazprom is likely to take a majority stake in the offshore section. An expansion to 47 bcm has been announced. Originally planned for 2013, the pipeline has been postponed to 2015. Among the issues faced by the pipeline are the ramping costs, some opposition from the European Commission eager to diversify supply, and finding supply – no dedicated supply source has been identified although it is likely to come from the Caspian region and therefore compete with Nabucco. Also the multi-national approach means that all countries have to find financing for the project to move forward.

Supply infrastructure developments in South America

Emerging markets are increasingly looking at LNG to fill gas demand despite the region's abundant resources. This is the case in Latin America, but also in the

Table 11 LNG regasification terminals in South America

Country	Terminal	Start up	Capacity (bcm)
Argentina	Bahía Blanca GasPort (South)	May 2008	1.5
Brazil	Pecém FSRU (North)	January 2009	2
	Guanabara Bay (Rio de Janeiro)	March 2009	4.8
	Tergas, Rio Grande	2013	2.2
Chile	Quintero (Central) (BG)	June 2009	3.4
	Mejillones (North) (GDF SUEZ)	2010	1.8

Source: IEA, company information.

Middle East, China and India (see separate chapters on China and India). Latin America is a net exporting region with 146 bcm produced and 129 bcm consumed in 2007. Excluding Trinidad and Tobago, the main consumers are Argentina, Venezuela and Brazil representing 80% of demand but representing only 75% of total production. Only Bolivia is a net exporter, whereas Argentina's surplus has been fading since 2000 due to a lack of incentive in upstream investments as prices to domestic producers have been historically low. Historically, the region has relied on production from Argentina and Bolivia and developed a network of pipelines between countries. Regional disputes, a surge in resource nationalism and frequent supply shortages have resulted in three countries – Argentina, Brazil and Chile – looking at LNG to diversify their supply sources and address these shortages instead of relying on neighbouring countries. In these aspects, developments in Latin America mirror those globally.

Although there are still a number of active pipeline projects in South America, many have been abandoned over the past years. The Gran Gasoducto del Sur linking most Latin American countries[17] between Venezuela and Argentina was put on hold in 2007 for example.

Brazil

While Brazil's significant gas resources are under development, the country continues to import gas both by pipeline through the Gasbol pipeline from Bolivia and more recently by LNG. Petrobras started commissioning the country's second LNG import facility at Guanabara Bay (4.8 bcm) in March 2009, with commercial operations expected in May. The Golar Spirit floating storage and regasification unit (FSRU) is being used after completing commissioning of the Pecém terminal in the northeast Brazilian state of Ceará. The Golar Winter, which is being converted to an FSRU in Keppel's Singapore shipyard, is to be used at the Guanabara Bay from May. Another 2.2 bcm terminal is proposed by Gas Energy to start by 2013. As the country focuses on developing domestic resources, expansions of existing pipelines or new pipelines are unlikely to be the first priority.

Argentina

Argentina has been suffering from supply shortages since 2004 and became a net importer in 2008. Supplies have been imported from Bolivia, but uncertainties on the development of Bolivian gas production and competition from Brazil for these resources have led Argentina to look at other possibilities. Regasification facilities are therefore seen as temporary measures to bridge gas shortages over the next several years until Argentina can increase its domestic gas production. State-owned Enarsa has an onshore terminal plan at Bahía Blanca with Petróleos de Venezuela, S.A. (PDVSA). Repsol's Argentine affiliate YPF is planning to import LNG again through onboard regasification vessels from May through September 2009. Enarsa will continue buying regasified LNG at international prices while reselling it to large users at below market rates

17. Venezuela, Brazil, Argentina, Bolivia, Paraguay and Uruguay.

– USD 2-2.50 per MBtu for industrial customers. The government plans to increase domestic prices by as much as 30%, which would have a positive impact on the upstream sector, in agreement with the Gas Plus Plan, which will allow domestic natural gas production from new fields to sell at higher prices than existing output. Despite uncertainties on Bolivia, there are still discussions on additional supplies from Bolivia under the 2006 agreement and importing more gas from Bolivia through the GNEA pipeline (North-eastern Argentina Gas Pipeline). The pipeline consists of a small section in Bolivia (17 km named the YABOG/GASYRG—GNEA Connector), a first Argentinean phase (97 km from the border to Mosconi) and a second Argentinean phase (from Mosconi to Coronda). According to Enarsa the basic engineering and the environmental analysis report on the GNEA pipeline have been completed in November 2008. The total capacity amounts to 10.1 bcm per year and the total investment costs are estimated at USD 1.8 billion.

Chile

Chile imports most of its gas from Argentina through the GASANDES pipeline and Gasoducto del Pacifico **but supply cuts have led the country to look at other supply sources**. The GNL Quintero receiving terminal in central Chile plans to open its fast-track phase in June 2009. This will involve discharging directly from the ship into the onshore vaporizers with only a very small 10 000 m^3 storage tank available as buffer. Two larger 160 000 m^3 tanks will be operational in the second quarter of 2010. Looming gas and energy supply problems forced the government to pursue the fast-track construction option, which was announced by state-owned ENAP in 2006. The terminal could be later expanded to 7 bcm. GNL Quintero has a contract to buy up to 2.3 bcm of LNG from BG Group's global portfolio.

The country's second import terminal, GNL Mejillones is also expected to open by the end of 2009. This terminal located in the country's northern electric power system (SING) is an urgent priority for the mining sector. The SING system is much more dependent on gas for lack of short-term alternatives. Gas imports from Argentina remain below contracted levels, and there are no interconnections between the two power grids. GNL Mejillones is expected to supply 1.8 bcm to four existing power plants totalling 1 100 MW. GDF SUEZ is expected to provide about 0.8 bcm of LNG for the first three years from its global portfolio, including Yemen LNG.

The issue for the development of LNG imports is the cost of LNG relative to other sources of power generation, in particular coal. Chilean gas consumers may agree to pay a premium for supply security, given the risk involved in Argentinian gas imports.

Investments in storage

- **Gas storage is an essential part of the gas value chain, helping to meet large seasonal and daily swings in demand, and providing security of supply against unanticipated supply interruptions.**
- **But gas storage is expensive, typically five to ten times more so than oil on an energy basis, and faces difficult regulatory, cost and market uncertainties.**
- **While Europe as a whole appears to have adequate storage capacity, it is not uniformly available across markets, and more must be done to encourage necessary investment, especially as gas production falls in many IEA countries.**

While attention tends to focus on major supply projects such as pipeline and LNG terminals, **investments in storage facilities are also crucial to meet seasonal, daily or extreme variations of gas demand and ensure adequate supplies to all users.** They are also a key element for security of gas supplies. The recent Russia-Ukraine crisis highlighted the importance of storage which enabled many countries to face unexpected supply disruptions and cold weather with limited/no interruptions of major consumers. On the other hand, the absence of storage in South Eastern European countries resulted in residential users and district heating being cut, while some of these countries managed to get gas from other countries' storage facilities. Geological structures are the most promising basis for storage facilities, such as the depleted gas fields of south west France or northern Italy. However, countries have different geological potential: some such as Latvia have a high potential but limited needs, others such as Belgium, Japan or Finland almost completely lack (additional) potential. Unfortunately storage remains a supply tool with a limited geographical range.

Uncertainties

A company looking at storage investments will compare the costs of a newly built facility to a long-term capacity booking to a storage operator based on its needs in terms of space and deliverability over a long period, which requires some predictability. Investments in storage are therefore challenging for the reasons which can be categorised as follows: regulation, demand and costs.

Regulatory challenges

New storage projects, in particular depleted fields or aquifers, can have **very long construction times** – from three up to ten years, not taking into account getting the necessary authorisations. In that respect, each country has specific processes regarding new storage facilities which, in some cases, require only the approval of the competent national authority, but in other cases also of different authorities or local councils. Having to deal with several stakeholders, results in increasing lead times – when the projects are not refused. This has been notably the case in the United Kingdom where planning application for Caythorpe and Welton facilities has been refused by local councils. Delays of up to four years due to disagreements on planning have been seen in the United Kingdom.

There is a **wide disparity in terms of tariffs and access**. Tariffs can be either regulated or negotiated – with sometimes the regulator comparing negotiated tariffs with a regional benchmark, as is the case in Austria. Seasonal storage will tend to be cheaper on a volume basis and short-range storage cheaper on a deliverability basis. Regulatory frameworks changing periodically can create uncertainty for project sponsors and users. Furthermore, companies building storage may not want to be restricted in terms of access and some have asked for third-party access exemptions, notably in the United Kingdom. However, in case a partial exemption is granted, it should be clear how anti-hoarding mechanisms would be applied to the exempted capacity. Finally, access to storage can be imposed due to the allocation of rights based on customers' portfolio as is the case in France, Spain or Italy.

Market needs uncertainties

The difficulty consists in assessing what type of storage a specific market needs: seasonal storage – usually depleted field or aquifer with lower withdrawal rates but higher working capacity – in order to meet seasonal variations between winter and summer, or short-range storage – usually salt caverns with a very high withdrawal rate – to meet peak demand such as from power generators or be used for trading opportunities. Most of the flexibility need – the difference between winter and summer demand – comes from the residential sector. The need for flexibility and therefore for seasonal storage can therefore be mostly derived from expectations on future residential gas demand and by deducting the flexibility embedded in long-term contracts or domestic production. Flexibility from domestic production provided by fields such as Morecambe in the United Kingdom or Groningen in the Netherlands is likely to decline in OECD countries, as production declines in general. However, the combination of worries about climate change, recent price spikes and focus on energy efficiency may very well result in lower winter peak demand. Furthermore, in some countries with a high wind potential, gas-fired plants will be increasingly used as reserve for wind generation requiring a rapid start and short-range flexibility. Due to the uncertainties on how much additional wind will be built and due to the specific wind seasonal patterns of each region, these requirements are relatively difficult to assess.

Costs uncertainties

The cost uncertainties are mainly on cushion gas and cost recovery. A 500 Mcm depleted field would need on average 500 Mcm of cushion gas. Based on 2008 prices, this would cost over EUR 150 million, 35% more than the previous year. This would be more expensive for aquifers but twice what is required for salt caverns. This represents a higher risk for depleted fields or aquifers due to very long lead times (over three years) and uncertainties on future prices at which the gas will be bought. Companies may therefore seek to conclude a partnership with a major supplier providing cushion gas below market prices. Existing producing fields with remaining gas also diminish these uncertainties.

Uncertainties on cost recovery will depend on two factors: the type of use of storage –

seasonal or not and whether the tariffs and the access are regulated or not. Seasonal storage is often valued based on the intrinsic value – by looking at the spread between future winter and summer prices, with the risk that the coming on line of new storage facilities reduces this spread. For salt caverns the extrinsic value is as, or even more, important than the intrinsic value, depending on the market liquidity. While regulation can to some extent mitigate risks on demand and on rate of returns, the latter have to be well adapted to all types of storage. Market-based prices can potentially result in higher return in particular for short-range storage taking opportunity of market volatility, but contain higher risks. Such considerations might lead to underinvestment in more seasonal storage.

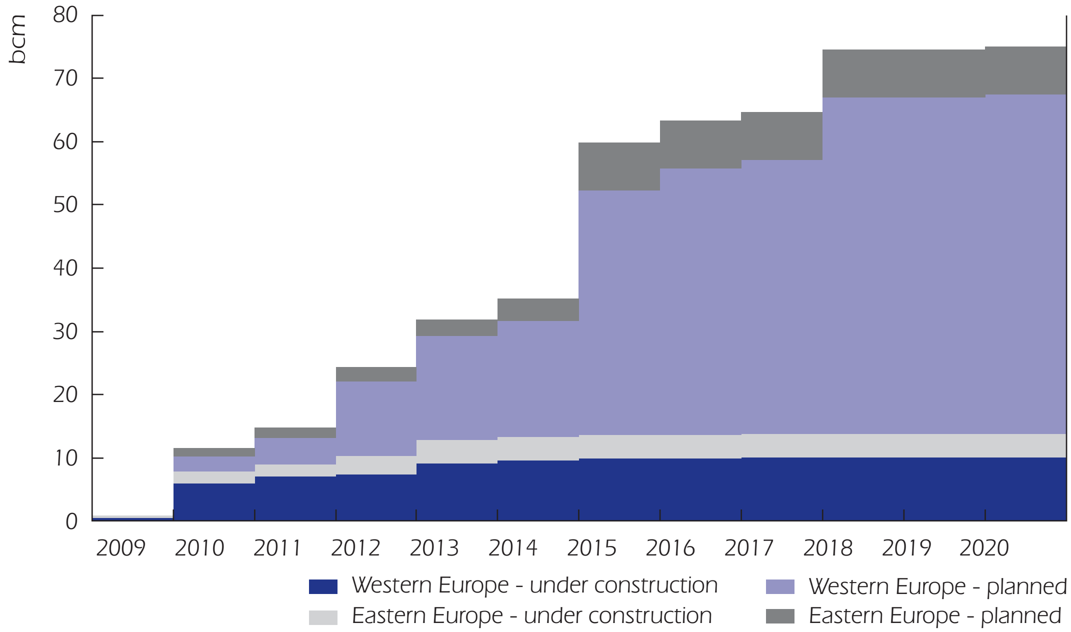
Under the current financial conditions, and with the existing challenges described above, investors may postpone their FIDs on storage or reassess their priorities in favour of other parts of the gas value chain. Typical capital costs for a 100 Mcm storage facility will vary between USD 30-100 million depending on the type of storage, with salt caverns usually more expensive. There has not been any real improvement on the regulatory issues, in particular to simplify the planning process or give better regulatory clarity on the longer term. Furthermore, recent market evolution seems to have complicated the assessments of market needs even further due to the growing share of renewables and potential impact of energy efficiency or climate change. The development of trading places in Continental Europe (see section on liquidity development) means that storage valuation in non-regulated markets is likely to be increasingly influenced by these hubs – which still need to develop in terms of liquidity. These last factors may lead to an increased focus on salt caverns which can be developed by phases with much shorter lead times and are therefore much less capital intensive than big depleted fields or aquifers. On the positive side, expectations of lower prices means that facilities under construction can hope to have access to cheaper cushion gas.

Europe

There is currently 82 bcm of working storage capacity operating in Europe[18] representing a deliverability of 1 510 Mcm per day[19] . Two-thirds are depleted oil or gas fields (55.5 bcm), the rest are aquifers (16.4 bcm) and salt caverns (10.1 bcm). Some countries such as France, Germany, or Austria have adequate storage capacity with the ratio between the working storage capacity and their gas demand higher than 20%. Austria is the highest with a ratio of 50%. However many countries such as Spain, Turkey, and the United Kingdom have very low ratios at around 5%, while some in particular in South Eastern Europe or Northern Europe have almost no storage capacity at all. The United Kingdom can still rely on domestic production to provide flexibility, but production is already a third lower than 2003, and the decline is expected to continue. Spain complements underground storage with LNG storage.

18. Europe includes OECD Europe as well as Eastern European non-OECD countries.
19. There is 76 bcm in OECD Europe with a deliverability of 1475 Mcm/d.

Figure 13 European storage capacities under construction and planned



Key point: Planned projects need move to construction stage

Source: IEA, regulators, project sponsors' information.

There are currently 13.8 bcm under construction in Europe, and again the majority of them (9.6 bcm) are depleted fields. Most are located in countries where there is already sufficient storage such as Italy or Germany, but there are also significant additions in Spain and in the United Kingdom. Around 7.9 bcm are expected to be operational by 2010 but due to the current economic difficulties, some projects may slip to 2011 or 2012. However a large number of projects (71.6 bcm) are still currently in the planning stage – although this includes projects committed which may just be delayed and projects whose viability is more problematic due to the reasons discussed above. It is unlikely that many of these projects would move quickly from the planning stage to construction in the current economic circumstances. Again depleted fields dominate the picture with 49.3 bcm planned, but there is a higher share of salt caverns (15.8 bcm) compared to the existing split. This is likely to be the result of the combination of two factors – the perception of increasing need for short-term flexibility as well as the development of hubs prompting companies to capture the value of flexibility, as 11.8 bcm are located in the United Kingdom and Germany. Figure 13 shows the development of storage capacity under construction and planned over the next decade. It has to be noted that around **11 bcm of planned capacity**

has no starting date; furthermore it is likely that the storage planned for 2010-11 will be delayed. Finally the quite significant jump in 2015 is more the result of three significant depleted field projects representing over 12 bcm than an investment surge. **Such large projects are also the most likely victims of investment difficulties and demand uncertainties.**

Other OECD countries

Underground storage capacity in other OECD countries amounts to 139 bcm and is mainly located in the United States, which holds around 117 bcm of storage, around 18% of demand. Other countries with storage are Canada (20.7 bcm) and Australia (1.3 bcm). New Zealand does not have any storage, while Japan and Korea have LNG storage. Depleted fields represent the majority of these projects with 123 bcm due to the history of oil and gas production in the three countries. In the United States, storage capacity is owned by interstate and intrastate transmission operators, local distribution companies (LDCs) and independent storage providers. The transmission system operators (TSOs) use part of the storage for transmission system management and lease the rest. The deregulation of storage, added to the growth of power generation and the presence of a liquid hub, has been the driver behind the development of salt caverns. The large majority of the 28 bcm capacity under construction or planned is salt caverns (17.5 bcm) as market players hope to take advantage of price changes and arbitrage opportunities. The average size of storage projects is therefore much lower than in Europe at 240 Mcm compared with Europe (580 Mcm) so that the majority of the projects under construction are expected to come on line by 2012. In the United States as well, around 3 bcm of projects expected to come on line between 2008 and 2012 have been cancelled or are on hold. In Canada, facilities in Western Canada are usually owned by transmission operators or producers while in Eastern Canada, they are owned by LDCs and serve to balance the need for substantial flexibility: during the core of the winter season, residential and commercial demand is typically five to six times higher than during the summer (on a monthly basis). There are very few new projects, but the country can also count on flexible production. This is also the case for Australia, where nothing has been planned beyond the small existing capacity.

Non-OECD countries

Storage is also planned in other non-OECD countries, although accurate information is not available. Many developments are planned in the Caspian region where a lot of potential exists due to the presence of depleted fields. The dynamics behind the construction of new storage projects in these countries is different from OECD countries. Companies are usually state-owned, often belong to the national (main) producer so that issues such as regulation or cushion gas are less important. Investments in new storage are often done in parallel with expanding gas export capacity but may be affected by lower cash flows in the next couple of years if companies have to choose between investing in production and storage.

Table 12 World underground gas storage* - capacity summary (working capacity)

	Existing (bcm)	Construction/planned (bcm)
Europe		
OECD Europe	76	70
Non-OECD Europe	3	14
Total Europe	**82**	**84**
Former Soviet Union		
Russia	60	na
Ukraine	34	na
Caspian Region	12	8
Total former Soviet Union	**106**	**8**
North America		
Canada	21	0
United States	117	28
Total North America	**138**	**28**
Middle East		
Iran	0	5
South America		
Argentina	0	0
Asia Pacific		
Australia	1	0
China	2	3
Total World	**330**	**123**

Source: IEA, regulators, project sponsors information.

Note: *Does not include "underground" LNG storage, or aboveground LNG storage.

For example, Kaztransgaz, has announced plans to upgrade and renovate Akyrtobe and Poltoratskoe. In Uzbekistan, there are plans to develop Gazli and Khodjaabad and add 1.3 bcm of capacity. In Azerbaijan, the two existing storage facilities could be upgraded to reach a total capacity of 8 bcm compared to the existing 1 bcm.

Iran is currently trying to develop storage capacity as the recent winters have highlighted the need for additional measures to meet peak demand. Three facilities are planned representing 5.4 bcm.

The impact of the financial crisis on gas project financing

- **Project financing is becoming more important for the long-term future of the gas industry, due to the continuing high capital intensity of most gas supply and infrastructure projects.**
- **As many projects are still waiting for investment, demand for finance is expected to be high in the next couple of years.**
- **However, there is a general reluctance in lending, and fewer financial institutions involved in the energy sector, in the wake of the global financial crisis, which will translate into higher costs and lowered availability of project finance from commercial banks.**
- **Export credit agencies (ECAs) are expected to have a more important role.**

Before the crisis: the expansion of project finance in gas projects

Before the financial crisis, particularly in the early 2000s, it was relatively easy for natural gas projects' sponsors to access funding thanks to strong energy demand, high oil and gas prices, and abundant liquidity in the global money market. International banks were quite aggressive in seeking to finance these projects, so that competition among banks reduced margins and the interest rate of lending. For example, banks' eagerness to lend to LNG projects led to squeezed lending margins from around 150 basis points (bp) in the mid-1990s to 55-75 bp in the mid-2000s which enabled project sponsors to reduce their debts despite increasing EPC costs. International banks could find few opportunities to finance upstream oil developments as most investments in upstream exploration and development were (and remain) based on Production Sharing Contracts (PSC), in which investors usually use equity. Both IOCs and NOCs had enough money at that time due to increasing oil prices.

The specificity of the natural gas business is that it generally requires long-term investments of multi-billions of dollars in upstream and supply infrastructure such as production facilities (increasingly in more difficult regions and locations), liquefaction, pipelines, and regasification terminals. These segments of the supply chain are usually out of the scope of PSC, and project sponsors (or sometime buyers) have to find external funding sources. Project finance, *i.e.* non-recourse or limited-recourse base finance was commonly used for financing these gas supply and infrastructure projects for several reasons. Generally, the natural gas business is composed of long-term and relatively stable value chains. Thus lenders (banks) can structure their repayment security primary on this value chain.

For lenders (banks), project finance lending is an attractive business if it is "well-structured" (see below), because generally the margin and the interest rate are rather high compared with simple lending such as corporate finance, reflecting the banks' risk taking, while these risks can be mitigated by the structuring of securities.

Most project sponsors prefer non-recourse or limited recourse borrowing because it is off-balance sheet and their financial obligations can be reduced. In the case of NOCs, the off-balance borrowing means that it does not affect the national budget and the official external debt of the country.

The core security of project finance is the cash flow generated by the project itself. In the case of a liquefaction plant, it is the cash flow of LNG sales income based on the long-term sales and purchase agreement, usually with take-or-pay clauses. Lenders can hedge the risk of income reduction caused by lower off take volume, but are exposed to the risks of lower prices. In the case of a pipeline and a receiving terminal, the core security can be the tariff income based on the long-term throughput agreement. In this case, lenders can avoid the risk of changing gas prices if tariffs are based on the throughput volumes. To ensure the core security, several back-up measures such as a completion guarantee, sponsors' cash injection under certain conditions, and insurance are required, and all related assets and rights of the project are assigned or mortgaged as collateral. Since large amounts and long-term lending are required to finance natural gas projects, international banks usually syndicate the consortium for lending project finance. The lending price (margin and interest) and security structures are negotiated between sponsors and the leading bank, which organises the banks participating in the (usually) syndicated loan.

Although not as large as liquefaction, project finance has been used for LNG receiving terminal projects in the United States, Spain, Portugal, the United Kingdom, Canada, China, and India. Pipeline project promoters, including Nord Stream, Nabucco, and Galsi, have been all advised by commercial banks and also approached by ECAs. Project finance has been used in the gas storage sector in the United States and Europe as well. As more gas storage projects may arise in Europe, there should be more room for project finance.

After many successful experiences of project finance for gas projects, lenders' appetite had become stronger and competition among lenders became acute. Particularly from 2005 to early 2007, many banks were eager to participate in project finance lending to natural gas projects, resulting in a reduction of the lending margins. For example, the spread on Libor for LNG project finance had been reduced from around 150 bp in the mid-1990s to less than 100 bp, or sometimes even as low as around 50 bp.

The mid-2007: The subprime loan crisis

The impact of the financial crisis on the financing of natural gas supply projects was deemed to be less serious than in other sectors in the first stage of the crisis – during the summer of 2007 and the first half of 2008. After the subprime loan crisis started in late 2007, the situation deteriorated sharply. The number of banks which could participate in syndicated loans declined and the lending price increased because of the sharp deterioration in banks' funding situation. The interest rate offered for new project finance jumped up over libor+200bp compared with rates less than libor+50 bp in 2006-07. At that time, however, several international banks deemed to be able to manage their funding were still eager to extend project finance to natural gas projects because the loan assets of project finance were categorised as better ones in their risk-return portfolio compared with other risk assets such as Asset Backed Securities (ABS), and Collateralised Debt Obligations (CDO). These banks were encouraged by the increase in prices – both of natural gas and the lending price for the project finance. Tight markets and high energy prices still encouraged new gas supply projects. Although EPC costs were increasing sharply, oil and gas producing countries were seeing increasing energy revenues.

This had consequences for energy markets. After August 2007, oil prices increased sharply despite the possible impact on energy demand of the then unfolding financial crisis. WTI jumped to USD 100 per barrel in October 2007, and continued to increase until the end of the first half of 2008. The analysis of money flows showed that a certain part of investment funds were changing their target from high risk securitised financial products and stocks to commodity markets such as oil or gold. The financial investment in future trade in oil markets by hedge funds and commodity index funds which had existed since early 2000s escalated under the expanding uncertainty of the financial crisis. Commodity markets were recognised by hedge funds as less linked to security or stock markets at that time, hence providing greater diversity of risk.

However by mid-2008 the situation had moved to a more gloomy stage.

Mid 2008: The financial crisis

In the spring of 2008, the impacts of the US recession were becoming more severe and obvious. Despite the serial reduction of interest rates by the Federal Reserve Board (FRB), the US financial market continued to deteriorate. After Lehman Brothers collapsed in mid-September 2008, fears of systematic failure of global financial markets grew. Global financial and equity markets weakened dramatically. This led to the intervention of the US, European and Japanese governments to save some banks and insurance companies and try to put in place plans to help the banks such as the Emergency Economic Stabilization Act adopted in October 2008 in the United States. The depth and breadth of global recession was becoming apparent. Commodity prices generally peaked in mid-2008, and fell steadily into 2009. In the case of gas prices in the United States, they fell by nearby three quarters from their peak in June 2008 to April 2009.

Together with the expanding financial crisis, the situation of financing for natural gas projects had dramatically changed as well. Early 2008, some banks were still willing to extend project finance, but recognised the structural defects of their business model. What has changed since then is as follows:

Difficulties for international banks. The basic business model of international banks contained the "exit strategy", meaning that selling their loan assets by means of securitisation methods in order to maintain their risk asset-equity balance. Even for project finance lending, most banks were intending to securitize, and then sell their loan assets. When the security market was active, there were differing types of risk appetite by differing funding sources. For example, pension funds preferred long-term, low-risk investment while private equity funds or hedge funds took high-risk but high-return assets. To meet this variety of appetites, banks securitised their loan assets, subdividing by risk-return variations. This structure of a loan asset sale was similar to mortgaged security sales. The sharp reduction in activity of this type of securities market due to the financial crisis has affected this strategy, in particular the collapse of investment funds, resulting in the near extinction of high-risk takers. Hence, banks have to hold these long-term loan assets after providing the loan. It is not easy for most banks to increase their risk assets, even though it is a "well-structured" project finance loan asset, while they are required to reduce their leverage (asset-equity ratio), and their write-downs in existing assets are expanding.

Recourse to official financial support by bilateral and multilateral financial institutions. These financial institutions play a significant role in project finance. Export Credit Agencies (ECAs) such as the US EXIM, JBIC, NEXI, ECGD, Coface, SACE, and KEXIM[20] have supported several natural gas supply projects by means of their loan and/or guarantee facilities, and are expected to be more active in providing finance to new projects. Multilateral Financial Institutions including Regional Institutions such as EIB, EBRD, ADB and IDB are supporting natural gas and related projects as well such as the Nabucco project. For private banks, these enhancements are advantageous because the loan asset covered by the guarantee facility of these public institutions is classified zero or 10% risk weight asset even in the Basel II regulations.

Review investments plans. Over the second half of 2008, investors behind natural gas supply projects faced a more serious situation that compounded the effects of the financial crisis. Gas prices declined rapidly while EPC costs remained at a high level. Investors have been forced to review the economics of their projects as natural gas demand is weakening, and growth is uncertain at best, due to weakening economic activity everywhere. Currently, these problems on the project side – the expanding uncertainty of natural gas price and demand – have become at least as critical as the financial issues, affecting big and small projects alike.

For the energy sector, three issues are particularly important:

- Funding strains persist and banks' access to longer-term funding is diminished. While in many jurisdictions, banks can now issue government-guaranteed, longer-term debt, their funding gap remains large. As a result, many

20. US EXIM: The Export-Import Bank of the United States, JBIC: The Japan Bank for International Cooperation, NEXI: Nippon Export and Investment Insurance, ECGD: The Export Credits Guarantee Department (United Kingdom), Coface: The export credit insurance company of France, SACE: The export credit agency of Italy, KEXIM: The Export-Import Bank of Korea.

corporations are unable to obtain bank supplied working capital and some are having difficulty raising longer-term debt, except at much more elevated yields.

- Lending costs are rising. Terms are generally expected to be tougher, as political risks and sales agreements will come under intense scrutiny. Flexible marketing arrangements may not be viewed as advantages, as they do not necessarily guarantee stable cash flows. Lenders may be less favourable to super-giant projects and unconventional technologies.

- The retrenchment from foreign markets is now outpacing the overall deleveraging process, with a sharp decline of cross-border funding intensifying the crisis in several emerging markets. The withdrawal of foreign investors and banks, together with the collapse in export markets, is creating funding pressures in these economies. Net private capital flows to emerging markets will be negative in 2009.

For gas-based investment, all these issues will be important. Projects that can reduce their scale relative to markets, and shorten lead times, are likely to face fewer financing hurdles. For some parts of the gas supply sector, this may encourage innovation, such as smaller production or terminal facilities.

DEVELOPMENTS IN THE LNG MARKETS

- **The year 2008 was marked by large regasification capacity expansions but saw little growth in LNG output due to many production problems.**

- **A massive expansion of global LNG liquefaction capacity is about to come over the period 2009-13, with some signs of further slight delays, while demand is slumping compared to one year ago.**

- **Demand is uncertain – a generally weakening trend, but could surge, depending on the timing and type of economic recovery. Other factors can easily affect short-term LNG demand – prices of other energy sources (coal, oil, and pipeline gas).**

- **2009 and 2010 will be a test of the flexibility and resilience of the global LNG market – can it balance?**

- **The same period (2009-10) will be a critical time for the next generation of LNG supply projects – final investment decisions (FID) will be needed in 2009 or 2010 if new gas is to come to market in 2014 or 2015.**

- **Only one new LNG FID was made in 2008. While regasification and shipping expanded rapidly, liquefaction is the limiting factor in global trade. Unless we see new FIDs in 2009-10, a hiatus in post 2012 output seems likely.**

An era of global projects begins

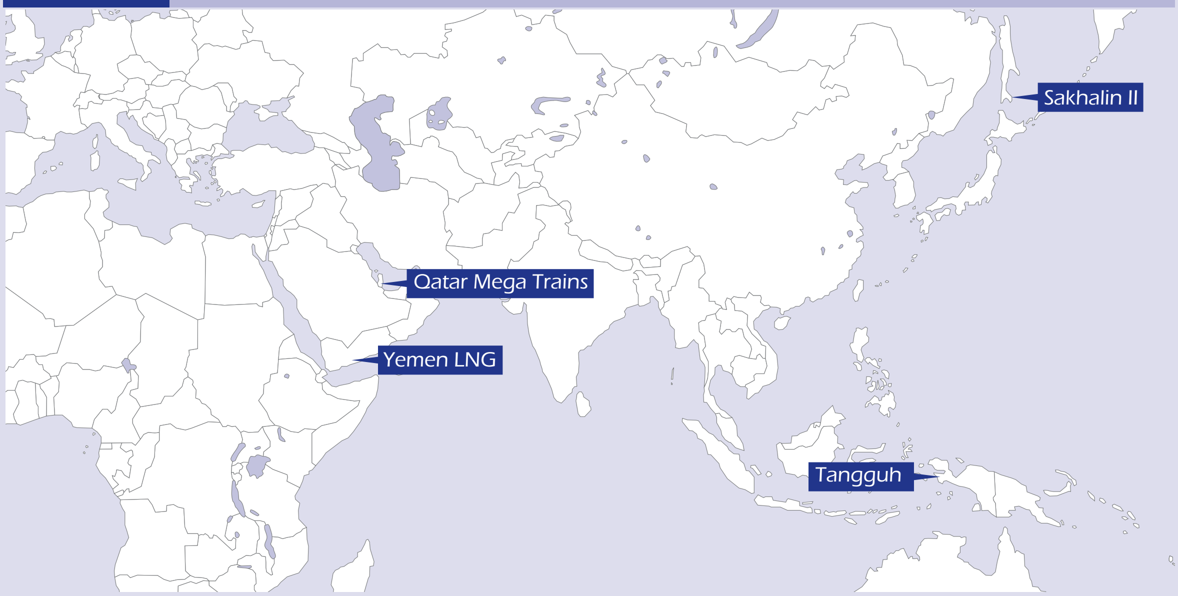
In the past couple of years, higher gas prices and tighter market balances accelerated global exchanges of LNG cargoes, notably from the Atlantic to the Asia-Pacific markets. The past issues of the *Natural Gas Market Review* argued that those inter-regional movements of LNG underpin the globalising trends of gas markets.

Some observers and industry experts have predicted that the next few years will see a return to "regional" markets along with the expected significant increase in both liquefaction and regasification capacity around the world, assuming that any extra regional requirements should be met by extra output within the regions. Particularly for the North American market, the increase in domestic gas production from unconventional sources has substantially weakened LNG demand.

However, the trends in the past couple of years have already transformed the business to an irreversible extent: the business model of multiple supply sources to support deals in multiple market outlets in different regions has many attractions to a number of large industry players. All LNG export projects that are going to start incremental and new production in 2009 have supply commitments in multiple OECD (and non-OECD) markets. But all of them have experienced delays in construction and commissioning.

2009 has been highlighted as a year when the global LNG markets will see an

Map 7 **Global LNG Projects Starting Exports in 2009**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

unprecedented expansion in liquefaction capacity, whereas the year 2008 saw little or no growth of LNG trade after years of substantial growth earlier in the decade.

2008 LNG markets : sharp contrast between the first and second halves

In parallel with general energy market trends, global LNG markets saw strong starts in the first half and bearish activities in the second half toward the end of 2008. **In the end, the year saw no growth in traded volumes**; this was the first year of no production growth in the 21st century. In 2008, North American LNG activities were notably smaller than 2007, as **imports into the United States fell by more than half** (less than 10 bcm in 2008 compared to 22 bcm in 2007). The reduced volumes of LNG in the United States were virtually distributed between Japan, Korea and Spain, particularly in the first half of 2008.

As a result, the **cargo movements from the Atlantic to Pacific regions increased to 20 bcm** in 2008, from 13 bcm in 2007 and 5 bcm in 2006. Some of them were called «diversions» as they moved to different destinations from originally anticipated ones. However, more recently, those transactions of relatively long distances are carried out on a short- and medium-term contract basis, rather than spot basis. Thus, the term "diversion" does not include all of the non-traditional cargo movements.

Europe increased LNG imports by 15% to 59 bcm in 2008, driven by increases in imports into Spain, France, and Italy, despite the continuing sluggish performance in the United Kingdom.

The year 2008 also saw many production problems and feedgas shortages. Some liquefaction facilities may have problems because they are getting older; similarly for older feedgas pipelines.

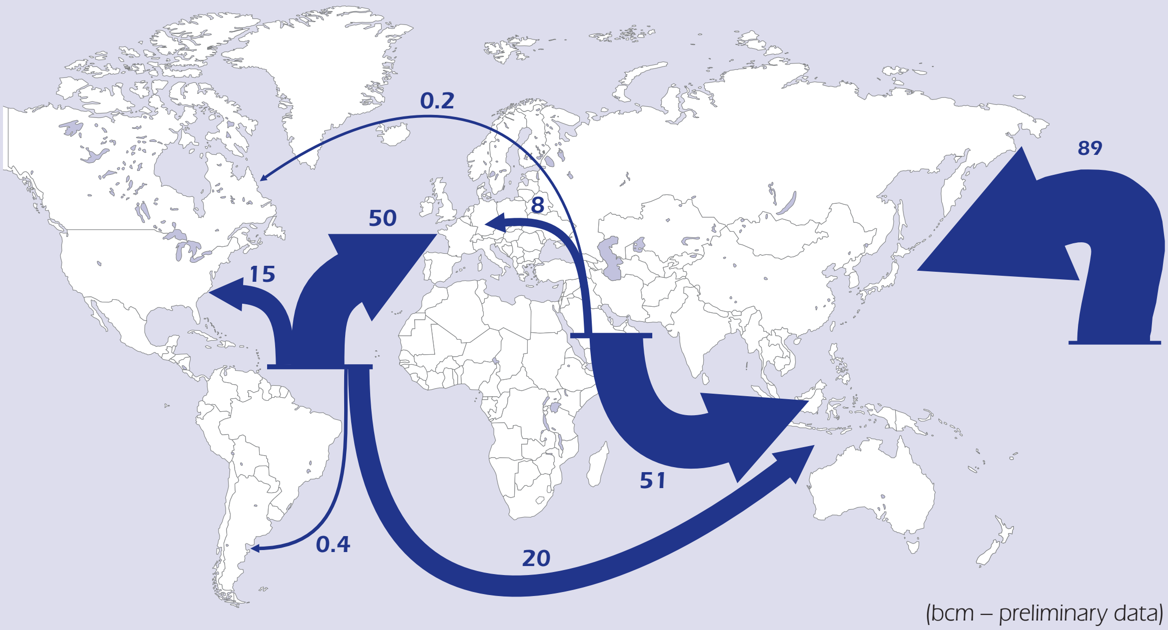
The year 2008 also saw a number of other firsts in the history of the LNG industry. Argentina, which is actually relatively rich in natural gas resources, became

Table 13 Recent LNG supply problems (force majeure) at a glance

LNG plant	Lost supply	Notes
NLNG, Nigeria	2.5 bcm in 4 months (December 2008 - March 2009)	Caused by numerous thefts from condensate pipeline Repair completed in March 2009. Operational status is uncertain as of June 2009
Qatargas I, Qatar	0.6 bcm in January 2009	Transformer problems Unusual to declare force majeure Return to 100% operations in February 2009
Arzew, Algeria	3 bcm in 6 months	Caused by corrosion of feedgas pipeline

Source: company information, media reports.

Map 8 Global LNG trade in 2008



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA.

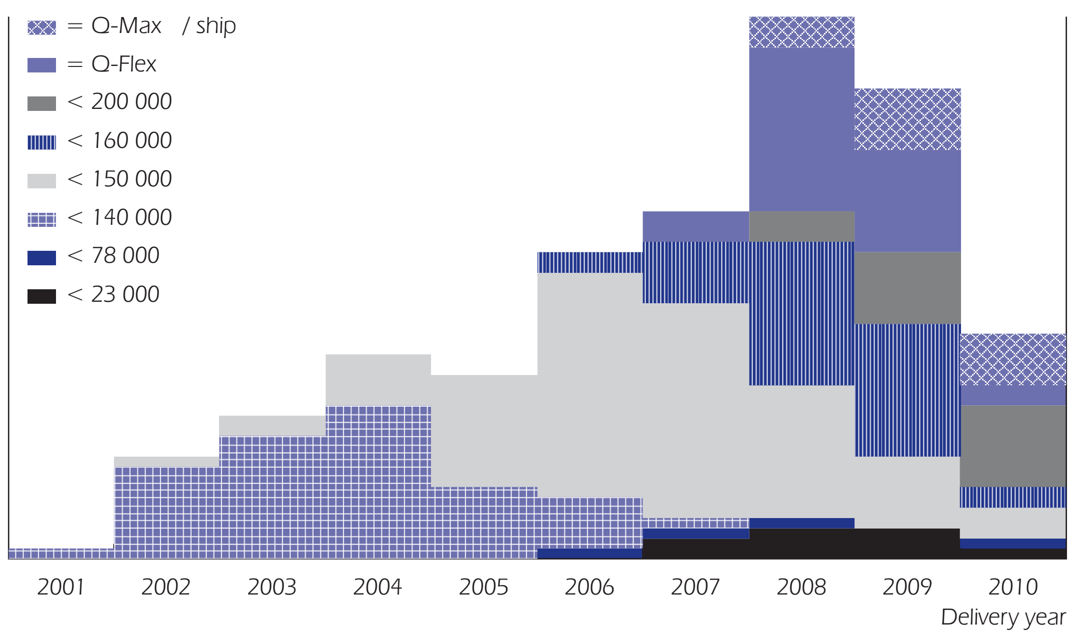
the first LNG importing country in South America, ahead of Brazil and Chile. Brazil also received its first LNG cargo in July 2008, although the unloading of the cargo was only completed in January 2009. Three large-scale receiving terminals were commissioned in North America, despite the decreasing need for imports, and one of them is the first LNG receiving terminal on the West Coast of the Americas – Costa Azul in Baja California, Mexico.

Another interesting point is the longer average shipping distance, 7 129 km in 2008, compared to 6 290 km in 2007 and 5 700 km in 2000 – another indication of the globalising trends.

The demand reduction in Asian LNG markets starting in the fourth quarter 2008 has been stark into 2009. Buyers in Japan, Korea, and Chinese Taipei are asking long-term sellers to reduce deliveries or defer cargoes even after annual delivery programs (ADPs) have been concluded earlier.

On the back of this static growth in 2008 in trade and the expected huge expansion of capacity in liquefaction and regasification, the LNG shipping fleet capacity is also steadily expanding. Another record-breaking 53 new-build ships came out of shipyards in 2008, surpassing the deliveries in 2006 (30) and 2007 (34) which

Figure 14 Expanding size of LNG new-build carrier ships



Key point: Record-breaking ship delivery continues in 2008

Source: IEA, LNG World Shipping, LNG Daily, GIIGNL.

were already at record-breaking levels. The 53 new ships represented a 25% increase in cargo capacity in a year of virtually no trade growth. A further 50 or so ships are expected to be delivered in 2009.

The size of individual LNG carrier ships is also expanding. Until 2001, the maximum size was less than 140 000 m³ for any new-build LNG carrier ships. Then 145 000 m³ became a standard around the middle of the decade. In parallel with slight upward movement to over-150 000 m³ for the industry standard, super-giant Q-Flex (209 000-217 000 m³ cargo capacity each) and Q-Max carriers (260 000-266 000 m³) are being built for Qatari expansion projects, as they are expected to ship cargoes to relatively distant markets. Q-Max carriers are said to be 40% more fuel efficient than existing vessels. Ships of another size between the current standard and the super-giant, 165 000-180 000 m³, began to be delivered in 2008.

LNG business outlook : 2009-13

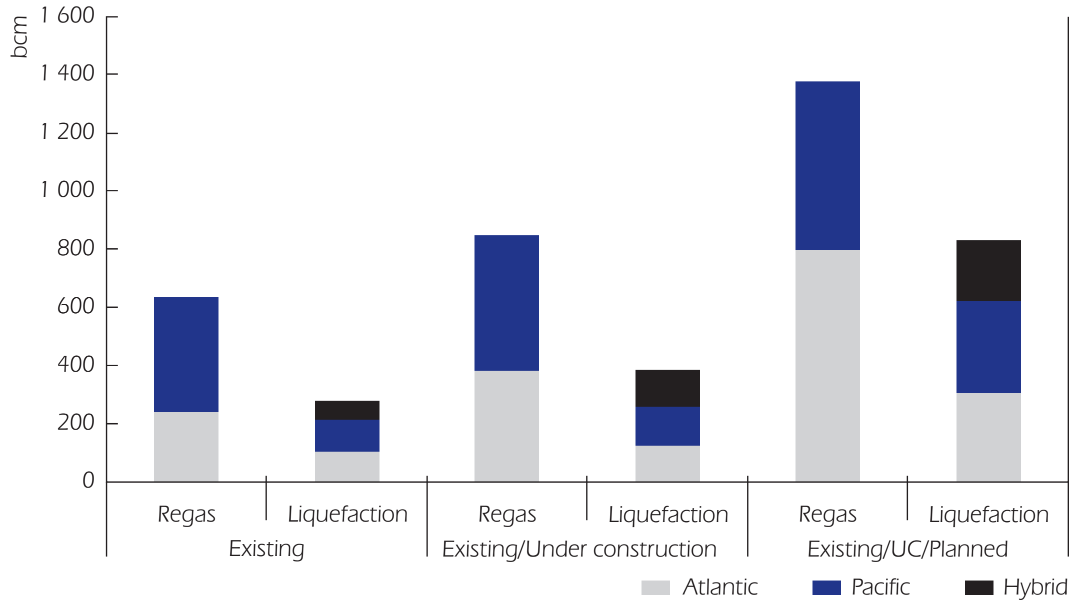
The LNG business is an integrated one, from production and liquefaction to shipping and regasification. Today more questions focus on the future developments of liquefaction capacity post-2013 while the shipping fleet capacity is steadily expanding and regasification far exceeds liquefaction capacity. There is also a large asymmetry on the length of time needed to develop integrated liquefaction projects compared to regasification terminals or building new ships.

To put things in context, **the 2009-13 period will see liquefaction capacity increase from 280 bcm as of end 2008 to 373 bcm by end 2010** and 410 bcm by end 2013, almost a 50% increase within five years. Although there might be some slippage in the commissioning dates, this capacity is already under construction and deemed to be commissioned (see details below in this section). In parallel, **regasification capacity will increase from 637 bcm as of end 2008** – already twice as much as liquefaction – **to 813 bcm by end 2010.**

Among the major changes to be noted are:

- The increase of the regasification capacity in the Atlantic basin rebalancing the share towards that area.
- A third of the incremental increase of regasification capacity expected by end-2010 will be located in the United States and might be relatively underutilised in the short term – or start operating later.
- Regasification surcapacity will continue to encourage short-term and spot trade as well as the growth of hybrid liquefaction capacity (which can target both Atlantic and Pacific markets). Unlike liquefaction, regasification capacity benefits from shorter lead times – usually three years or even shorter – and can increase much more quickly.
- Planned capacity has the potential to double both the liquefaction and the regasification capacity. Although some

Figure 15 **Liquefaction and regasification capacity, existing, under construction and planned**



Key point: Regasification capacity outpaces liquefaction

Source: IEA, company announcements.

projects are likely to be cancelled, a key question mark is how much planned liquefaction capacity will come on line post-2013 and what will be the evolution of the regasification capacity in the regional markets. These two issues are addressed in the investment section.

It is quite natural that there is more regasification capacity than liquefaction capacity, as under this circumstance LNG can play a balancing role between markets and enhance flexibility to cope with demand fluctuations, or even supply interruptions as seen in January 2009 in Greece and Turkey. There have always been concerns about under-utilisation of receiving terminals, particularly those in the United States. But at least for 2009 and 2010, the huge, relatively new, regasification capacity in that country is expected to play an important role in balancing global LNG markets, subject to availability of underground gas storage capacity.

While terminal regasification capacity continues to increase at a rapid pace, a large amount of new liquefaction capacity will be seeking markets, particularly from 2009-13. The LNG market is at the core of the fundamental uncertainties in global gas markets for the two years to come:

- How will the new liquefaction capacity coming on line and these potential major imbalances be addressed with the market weakening in 2009?

- What will be the influence on spot prices in the Atlantic basin and how will this affect unconventional gas production in the United States?
- Will non-OECD markets be more active?
- Will this mean more short-term trade, or more interest by sellers in medium- or longer-term deals?
- And crucially what will be the impact on the FIDs on liquefaction capacity this year and next?

New liquefaction under construction will come predominantly from Qatar, but there will be newcomers to the LNG scene in 2009 – Russia and Yemen, while other LNG exporters continue to build up their liquefaction capacity.

Qatar

The biggest expansion of liquefaction capacity is expected to come from Qatar, who has already been the biggest exporter of LNG in the world since 2006. **The size of expansion is enormous and unprecedented, from 41 bcm per year at the end of 2008 to 105 bcm** (77 Mtpa) when the additional six trains are all in operation **by 2013,** representing 27% of global capacity.

Partly due to the size of both the trains themselves and the expansion as a whole, the Qatargas and RasGas projects are not immune to the delays and cost overruns seen in the industry since at least 2005. The original start-up schedule for those trains was from 2007 to 2010 when FIDs were made in 2004 and 2005. All the construction and commissioning activities of those LNG projects, as well as one GTL (gas-to-liquid) plant and other projects, have been concentrated on the 106 km^2 Ras Laffan Industrial City, causing logistical nightmares. It is not just lack of human resources and materials, but also logistical constraints that have delayed project implementation.

At the beginning of 2008, sponsors still insisted that the first shipment from the first mega-train could start in the third quarter of 2008. The inauguration ceremony of the first of the mega trains was held on 6 April 2009, after initial production began in March. Ramping up to plateau capacity production is also expected to take more time than originally anticipated. Although all the liquefaction facilities may start up by 2011, full production capacity may not be reached until 2013.

Qatar's massive investments from 2009 can be summarised as follows:

- Six mega trains to add 64 bcm per year production by 2013 – need more time to ramp up.
- Three in 2009 (Qatargas 4 (March), Ras Gas 6 (June), Qatargas 5 (September)), two in 2010 (RasGas 7, Qatargas 6 (First half)), and one in 2011 (Qatargas 7 (maybe in 2010)) are to be commissioned.
- One began producing LNG in March 2009 (originally 2007) following a protracted testing and commissioning period.
- Diversification is a key in marketing.

In order to cover the expected needs of transportation (larger volumes and longer distances than in the past), super-giant LNG carrier ships are being delivered to the export ventures from Korean shipyards: 31 Q-Flex and 14 Q-Max ships.

Qatar has been expanding and diversifying its market reach since it started exporting LNG in 1997 to Japan. The current expansion phase was originally proposed to target markets in the United Kingdom and United States. But from 2006, the Qataris started to market part of the expected mega-train output to other regional markets on medium- and long-term basis. This has been a strategy to diversify its markets in terms of geographic spread, and liquid and traditional market (and different regional pricing) combinations. The targeted geographical distribution between Asia, Europe and North America has evolved from one-third each early 2008 to 40% in Asia, 35% in Europe, and 25% in North America early 2009[1].

Other projects in 2009

Three other new production projects are due to be on stream in 2009 – also behind schedule.

Sakhalin II, Russia

Russia's Sakhalin II project shipped its first LNG cargo from the first of two liquefaction trains in March 2009 to its long-term customers in Japan[2]. The second train is expected to start operations in the third quarter of 2009. The facilities are not expected to reach full capacity in the short-term due to constraints on the 800 km feedgas pipeline and are expected to produce 4-5 bcm (3-4 Mtpa) of LNG, or about 50 cargoes, in 2009, out of the 13 bcm (9.6 Mtpa) nameplate capacity.

The Sakhalin project is an example of the long lead times that a project may require before being completed. Exploration activities started around the island of Sakhalin 30 years ago, while the production sharing agreement (PSA)

Table 14 At a glance: other new liquefaction projects in 2009

Sakhalin II, Russia 13.1 bcm per year = 9.6 Mtpa	Gazprom's (and Russia's) entry into the Pacific gas market, and physically into LNG markets Importance for Asian importers (Japan and Korea) = diversification of supply sources in shorter distance A project with Japan's engineering and money Indication of time that a project may take - mid-term investment important
Yemen LNG 9.2 bcm per year = 6.8 Mtpa	The first project that Total takes the lead - there are only a dozen companies in the world that have actually operated LNG liquefaction plants
Tangguh, Indonesia	First increase in LNG production in this decade in the country

Source: company reports.

1. Ahmed al-Khulaifi, Chief Operating Officer of Qatargas, CERAWeek 2009, February 2009.
2. One off spec cargo ('Cargo 0') was sent to India prior to the first cargo, but is expected to reach the destination later in April 2009.

was signed 15 years ago between the Russian Federation, the Sakhalin Oblast Administration and the Sakhalin Energy Investment Company (SEIC). Despite some early marketing success with Japanese clients in 2003, the project operator Shell soon faced massive cost increases, and delays. This, added to the growing pressure from the Russian Federal Environmental Agency, led Shell and its existing partners in SEIC, Mitsui and Mitsubishi of Japan, to hand over a controlling 50%-plus-one-share stake in the export venture to Gazprom for USD 7.45 billion in 2007.

During 2008, it became apparent that the project would start exports in 2009, rather than in 2008. As the project's contractual commitments to some buyers commenced in 2008, the project had already started deliveries of replacement cargoes from other supply sources since summer 2008.

This project marks Gazprom's (and Russia's) entry into the Pacific gas market, and physically into LNG markets, giving the company significant diversification of its outlets. This is also important for Asian importers (Japan and Korea), as it represents diversification of supply sources from a shorter distance, with a project implemented with Japan's engineering and finance. The project has also demonstrated how many years may be required to be implemented, implying that medium- to longer-term investment is important to secure natural gas.

Table 15 ***Sakhalin II: 25 years in making***

1984-86	Lunskoye and Piltun-Astokhskoye fields are discovered.
1992	A feasibility study agreement by MMM (Marathon, McDermott and Mitsui) and Russian Federation.
	Shell and Mitsubishi join.
1994	Sakhalin II PSA by the Russian Federation, the Sakhalin Oblast Administration and Sakhalin Energy.
1997	McDermott withdraws.
1999	First oil production at Piltun-Astokhskoye: Russia's first offshore oil production.
2000	Marathon withdraws.
2001	Supervisory Board approves Phase 2.
2003	Sakhalin Energy signs sales with Japan's Tokyo Gas, Tepco, Kyushu Electric.
	Full development of both Piltun-Astokhskoye and Lunskoye fields starts.
2005	A major cost increase and project delay (from 2007 to 2008) is revealed.
December 2006	A protocol to bring Gazprom into the Sakhalin Energy as a leading shareholder.
April 2007	Gazprom acquires 50% plus 1 share and the leading role.
June 2008	Project financing deal with JBIC and other lenders.

Source: Sakhalin Energy website[3] and media reports.

3. Source: www.sakhalinenergy.com/en/aboutus.asp?p=key_milestones.

Yemen LNG, Yemen

Yemen LNG (YLNG) is to ship the first cargo from its first 4.6 bcm (3.4 Mtpa) train in the middle of 2009, a delay of more than six months. The second train is expected to begin operation several months later. As its FID was made in August 2005, and construction started in October that year, just before the global EPC market crunch began to plague the industry, the cost overrun for the project is thought to be smaller than those experienced recently at other LNG projects in the world.

The project is the first for France's Total as operator and for France's Technip to assume a lead contractor role. This French combination is also working on Russia's Shtokman project.

About one-third of the LNG is planned to go to Korea. The remaining volumes are contracted by Total and GDF SUEZ, both of which have multiple outlets for LNG.

Yemen's state-owned Safer Exploration and Production Company and YLNG signed an agreement securing gas supply from the Marib basin Block 18 for the LNG venture in January 2008. There had been concerns over gas availability and the sustainability of reservoirs on Block 18 since the control over the block was taken by Safer from Hunt Oil, one of the partners in YLNG, in November 2005. Total is providing Safer assistance in developing the block as a condition for project financing.

Tangguh, Indonesia

Start-up of the first of two trains of 10.3 bcm (7.6 Mtpa) BP-led Tangguh LNG project in Papua in Eastern Indonesia is expected in July 2009, again after a delay of more than six months. In March 2009, the country's energy minister said that one option for the reduced lifting by the long-term buyers from the Bontang venture in 2009 would be to sell the 12 cargoes to customers of the Tangguh project, which may fall further behind schedule. Indonesia is also considering a third train at the project, which may come on stream in 2014-15 with capacity of 5.2 bcm (3.8 Mtpa). The partners also say that they might be willing to reserve as much as 2.7 bcm (2 Mtpa) for the domestic sector, possibly through an import terminal proposed on the Island of Java.

The Tangguh venture has a contract of 3.5 bcm (2.6 Mtpa) with the promoters of China's Fujian terminal, which is still waiting for its commercial operation after receiving the first commissioning cargo in April 2008. Other long-term sales deals from the venture include two Korean sales, one Mexican and one Japanese. The Korean customers Posco and K-Power, which have contracted respectively 0.75 bcm and 0.82 bcm, are currently being supplied from other sources, notably Egypt. Sempra gets 5 bcm (3.7 Mtpa) for its Energia Costa Azul terminal in Mexico's Baja California. Up to half of the Sempra volume can be diverted to other markets, most likely in Asia, including Korea Gas Corporation (Kogas). Tohoku Electric, who currently buys 1.1 bcm (0.8 Mtpa) from Indonesia's Arun through 2009, signed, in May 2008, a purchase agreement for 0.16 bcm (0.12 Mtpa) from the Tangguh venture for a period of 15 years from 2010.

Other liquefaction projects under construction for 2010-13 starts

After the expected massive expansion of liquefaction capacity in 2009 and 2010, new supply additions scheduled between 2011 and 2013 are likely to be few, as under normal circumstances it takes a project around four years to be operational after receiving a FID and only five liquefaction trains are under construction for completion during the time frame.

Peru LNG, Peru

Peru LNG is one of the few LNG export projects in the world outside of Qatar due to come on stream in 2010, as it was the only project that made a FID in 2006. The project will be the first in Pacific South America.

The plant has a capacity of 6 bcm (4.4 Mtpa). The project sponsors are Hunt Oil (50%), SK Energy (30%) and Repsol YPF (20%). The gas is transported from the Camisea fields in the country's southeast rain forest through a 408 km pipeline to the terminal located 170 km south of Lima. Chicago Bridge & Iron won the EPC contract estimated at USD 1.5 billion for the liquefaction plant in January 2007.

The majority of the output from the plant is contracted to Mexico's planned Manzanillo terminal on the Pacific Coast through Repsol. Some volumes may be sold to Asian LNG buyers. As the Mexican terminal is due to be operational in July 2012, the initial volumes will go to other destinations, including the Canaport terminal in the Canada's Atlantic Coast operated by Repsol and due to open in 2009.

Pluto, Australia

Pluto has a planned capacity of 6.5 bcm (4.8 Mtpa). The Pluto field located in Western Australia was discovered in 2005. Along with the neighbouring Xena field, it holds reserves of 5 tcf (143 bcm). The FID was taken in August 2007. The project is underpinned by 15-year sales agreements with Kansai Electric and Tokyo Gas which have a 5% stake in the project each, the operator Woodside Petroleum holding the rest (90%). The partners now expect production to start late 2010. **This ambitious schedule would amount to one of the fastest LNG exporting projects ever developed**. The estimated cost stands at AUD 12 billion, including upstream development, almost doubling the original estimate made in 2005.

Woodside is retaining 0.6-1.3 bcm (0.5-1 Mtpa) of the project's output for flexible marketing. It was originally meant to sell in the West Coast of North America, but Woodside shelved its own LNG receiving terminal plan off the coast of California at the beginning of 2009.

Woodside continues to evaluate options for securing gas for a proposed second train expansion at Pluto LNG: further development of Woodside's existing reserves at the Pluto and Xena fields; gas from third-party sources; and gas from Woodside's future discoveries. The company indicated in February 2008 that it would like to reach a FID on Train 2 of the Pluto project in 2008, but drilling activities in the Cazadores and Bellicose license areas in 2008 failed to find enough gas.

Angola LNG, Angola

Angola LNG is a 7.1 bcm (5.2 Mtpa) liquefaction plant located near Soyo in the South of the Congo river. The project is now owned by Chevron (36%), state-owned Sonangol (Sociedade Nacional de Combustíveis de Angola) (23%), Total, BP and ENI 14% each. The FID was taken in December 2007 after being postponed several times and the project is now expected to start early 2012.

Sonangol has a 20% interest in the American Clean Energy LNG terminal located in Pascagoula, Mississippi and expected to start late 2011. It was the Angola LNG sponsors' preferred option, but given the growth in United States' gas production and low prices, the partners are re-evaluating their marketing strategy.

Given the current lack of local gas markets, LNG export was clearly the main option to make use of gas reserves. The project will use both associated and non-associated gas from several offshore fields. The project also has a plan to process and treat up to 3.5 Mcm per day of gas for the domestic market, which could stimulate market development. If successful, the project would provide a good example of an LNG project accompanied with domestic market development, satisfying both export and domestic needs, rather than a choice between the two. The process of developing a second train is already underway. When ENI joined the first train consortium in 2006, it signed a participation agreement to join a second train consortium, which would be led by Sonangol (40%).

Algeria (Skikda Replacement Train and Gassi Touil)

Algeria started exporting LNG in 1964 and has now an installed production capacity of 27.2 bcm (20 Mtpa) from 18 trains at Arzew and Skikda, excluding the three trains at the Skikda plant destroyed in an explosion in January 2004. The plants are all owned and operated by state-owned Sonatrach.

In July 2007, Sonatrach agreed with KBR[4] on a USD 2.88 billion EPC contract to build a replacement train at the Skikda complex. At that time the new train was to start operating in November 2011. The train will have 6.1 bcm (4.5 Mtpa) of nameplate capacity, greater than the three trains that were destroyed in the fatal explosion in January 2004. In March 2009, Algeria's oil minister revealed that the Skikda replacement train will not be completed until 2013, instead of 2011 as previously envisaged. A separate plant at Arzew, to process gas from Gassi Touil field, will start at about the same time as the Skikda train, also around a year later than previously planned.

The commencement of construction of the replacement plant after the accident was delayed by cost issues for almost three years. At that time, the FID of USD 2.88 billion, equated to USD 640 per

4. The company has an alliance with JGC on gas projects around the world. But for this project, KBR decided to undertake the task alone.

ton of installed capacity, compared to USD 270 of the Equatorial Guinea's first train also completed around the time (May 2007). But the Skikda complex, which also accommodates existing liquefaction trains, offers some cost savings in relation to marine infrastructure, pipelines and the upstream components, highlighting the price inflation in LNG liquefaction plant at that time.

The only FID on an LNG liquefaction project in the world in 2008 was on Algeria's other project, **a liquefaction train at Arzew for gas from Gassi Touil**. The EPC contact for the 6.5 bcm (4.7 Mtpa) train was awarded to a consortium of Snamprogetti and Chiyoda in July 2008, after Sonatrach cancelled its earlier award of an earlier EPC contract to Petrofac and IKPT[5]. Like the Skikda replacement train, the project is now targeted for 2013.

In March 2008, Sonatrach agreed with StatoilHydro to supply 3 bcm per year of LNG from 2009 to the Norwegian company's capacity at the Cove Point LNG terminal in the United States. This is in line with the Sonatrach's plan to expand gas sales to the United States. The company also has access to terminal capacities in the United Kingdom, France, and Spain[6] .

There are some challenges to meet Algeria's export target of 100 bcm per year by 2015. In addition to the LNG project delays, ageing domestic pipelines are another uncertain factor. In 2008, a declaration of force majeure of some LNG shipments from the country due to a feedgas pipeline problem in June from Arzew affected 20% of the capacity. In order to utilise the incremental export capacity of more than 30 bcm per year (the two LNG plants and two new pipelines [Medgaz and Galsi], as well as the Transmed expansion), significant enhancement of upstream gas production as well as modernising domestic pipeline infrastructure will be essential, given the fact that domestic gas demand is also growing strongly.

5. The combo had no experience in leading any LNG liquefaction projects and the industry observers doubted the viability of their undertaking.
6. Isle of Grain in the United Kingdom, Montoir in France and Mugardos (El Ferrol) in Spain.

MARKET DEVELOPMENTS

Gas for power

- **Gas-fired power has grown rapidly, especially in OECD countries, where it has provided four-fifths of incremental power since 2000, and is now the second most important source of power. Gas and electricity markets are now increasingly interconnected.**
- **In the short term, in the current recessionary environment, gas-fired power, with shorter lead times and lower capital cost, may well remain the favoured choice in OECD countries.**
- **Growing shares of intermittent renewable power, especially wind, seem likely to increase the demand for gas-fired power, backing out higher carbon options, notably coal.**

Gas: fuel of choice?

The power sector has been the main driver for incremental gas demand in the OECD in recent years and is expected to remain so well into the coming decade. Natural gas now accounts for 20% of global electricity production, second after coal at 41%.

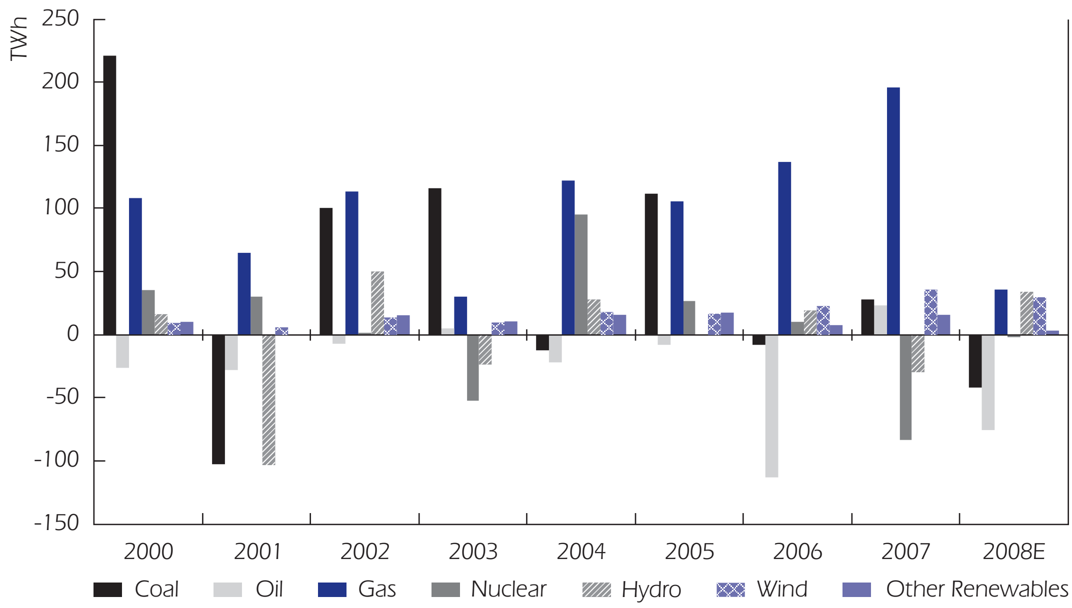
In 2008, 2343 TWh were generated by gas-fired plants in OECD countries, slightly up from 2 307 TWh in 2007; it represented 21% of total electricity generated against 37% for coal. In 2007, gas overtook nuclear as the second largest source of power. Wind represented 2% of total generation. Russia, the Middle East plus Egypt account for more than half non-OECD gas-fired power output.

The steadily increasing use of gas in power generation has resulted in a greater inter-dependence of the gas and electricity markets. Used mainly to satisfy intermediate and peak load, gas-fired generation is often the marginal source of electricity supply. As a result, electricity prices are largely influenced by those of natural gas. At the same time, power generation is becoming the fastest growing sector of gas demand. So spot gas prices are likely to be increasingly influenced by electricity markets. As the linkage between these two markets increases, reliability and operational issues in one can exacerbate the effects on supply and demand in the other.

Figure 16 shows the steady upward trend in gas used in power **in the OECD regions since 2000 despite a slow-down in 2008. Gas accounted for more than three-quarters of new electricity demand**. During this period, 288 GW of gas-fired plants came on line compared to 44 GW for coal and 59 GW for wind.

However, the global recession had a negative impact on the power sector in 2008, in particular on electricity demand. Based on preliminary estimates, generation in the OECD declined by 0.1% in 2008, in particular during the second half of the year. While the output from gas-fired plants slightly increased, electricity generated by coal-fired plants, oil-fired plants and other renewables declined. Hydroelectric generation increased by 3% while generation from wind power plants increased by 23% reflecting the addition of new capacity. Lower electricity demand has adversely affected gas demand by utilities. In many European countries,

Figure 16 **Changes in power generation by fuel source in OECD**



Key point: Gas has been the fuel of choice in 21st century but 2008 sees major changes

Source: IEA.

gas demand has been affected by higher short-run marginal costs for gas-fired plants compared to coal-fired plants during the second half of 2008 and early 2009. Furthermore CO_2 prices collapsed (high CO_2 prices favour gas over coal), weakening the competitive position of gas further. However, spot gas prices have fallen much faster in the United States and the United Kingdom, putting gas in a better competitive position relative to coal.

Regional analysis

Electricity generation in the United States declined by 1% during 2008, but this is deceptive as it fell by 3% during the second half of the year according to the Energy Information Administration (EIA). The EIA reported 188.5 bcm (6 654 bcf) of gas used for power in 2008, a decline of 5.3 bcm or 2.8% compared to the previous year. Electricity generated by gas-fired plants declined over the second half of the year, but this was a consequence of a cooler summer than in 2007. Meanwhile, electricity generated by coal plants declined by 1%. Electricity generation in the United States is expected to show slightly negative growth in 2009 and more destruction in gas or in electricity demand may continue in the remainder of 2009. First quarter power demand fell around 4%; gas-fired power declined by more than double that figure. The US Department of Energy (DOE) projects a decline in total electricity consumption of 1.7% this year followed by an increase of 1.2% in 2010 as a slowly improving economic climate contributes to a recovery in the sales of electricity.

In Europe, electricity generation has been falling at unprecedented speed, negatively affecting gas demand by utilities. In the United Kingdom, electricity consumption declined by 3% over the last months of 2008 and early 2009 on the back of falling industrial demand (-6%). National Grid expects this trend to continue and the recession to impact through the summer period (April-September) with demand on average reduced by 1.1 GW. **In 2008, Spanish power generators' demand for gas rose by 30%**. It was strong as combined-cycle gas generators stepped up production to offset the impact of persistent drought in early 2008. Slow utility demand coupled with a jump in hydroelectric generation and relatively high gas prices have contributed to weakening power sector demand for gas in 2009. **Enagas reported that the demand for gas in Spain fell by 30% during the first quarter 2009.** In particular, February 2009 recorded a 215% increase in hydroelectric generation and a substantial increase in generation from wind, both obviously due to favourable weather.

Japan has also seen a large fall in power demand, led by an unprecedented drop in industrial production, which is reported to have declined by 15-20% in late 2008 and by over 30% during the first months of 2009[1]. **Electricity sales by the ten main utilities in February 2009 declined by 16%** on the same month a year earlier to 75 TWh. As in Europe, the industrial sector a much stronger factor in determining electricity generation than are weather deviations or relative fuel prices. Utility LNG consumption fell 12% between January and February or 18% down from last February.

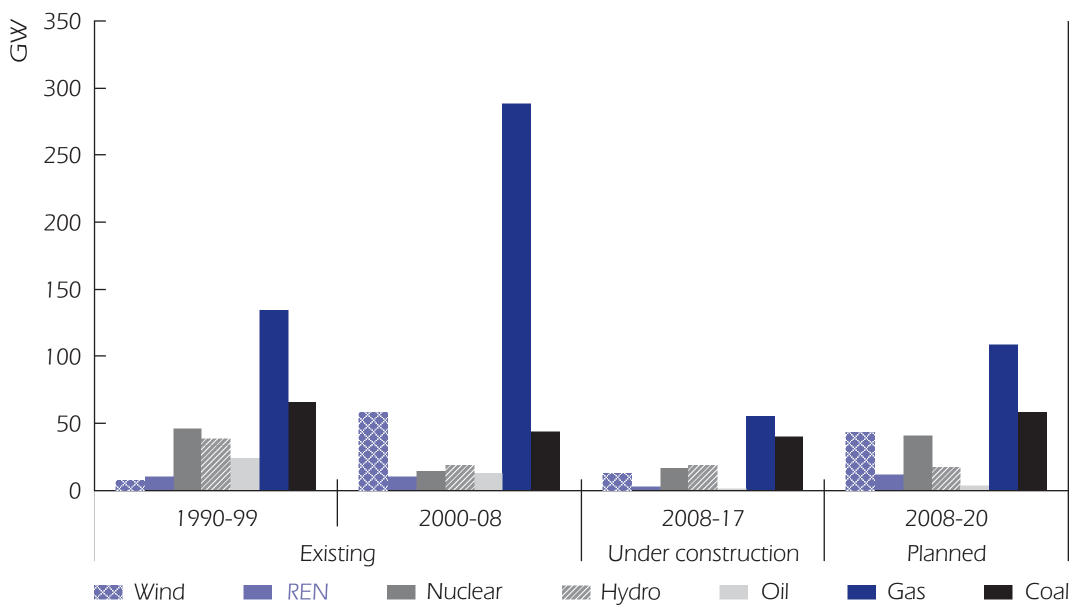
The relationship between power output and overall economic growth is even stronger in emerging markets than in the OECD countries. Since 2002, China alone generated almost half of the electricity demand growth in emerging markets, expanding output at a phenomenal double-digit rate per annum. In China, electricity output contracted at a 9% annual rate in November, as industrial users of energy, ranging from steel to auto to petrochemical producers continued to cut planned production. Indian electricity generation was also recently reported flat year-on-year, the lowest increase in three years, while power output was also hard hit in Singapore and Taiwan. While many of these markets are largely coal powered, other significant gas users also saw falling power output, notably Russia, where gas accounts for nearly half power output of 1 000 TWh.

Short to medium-term outlook

Overall, we expect a decline of gas demand in the power generation sector in early 2009 due to the overall decline of electricity demand in most countries. The decline will be accentuated in countries where gas prices are linked to oil prices and remain high during the first half of 2009. However, as gas prices are expected

1. METI, Indices for industrial production, production and shipments.

Figure 17 **OECD capacity expansion**



Key point: Gas still the option of choice

Source: Platts.

to converge to lower levels during the end of 2009, gas-fired plants will be in a better position to compete against coal-fired plants even if coal prices remain at around USD 60 per tonne. Gas-fired generation has a substantially higher fuel cost component than nuclear or coal. Its cost is therefore more sensitive to fuel cost variations than the other generation options. The declines in all gas prices expected in 2009 will improve the competitiveness of gas-fired generation, taking into account the higher efficiency of combined cycle gas turbines (CCGTs) (55%) relative to coal-fired power plants (40-42% and often less).

In the medium term however, natural gas demand for power generation is expected to increase both in OECD and non-OECD countries. Around 150 GW of new electricity generating capacity is under construction in OECD countries, with gas representing over 50 GW and coal around 40 GW. This compares to around 600 GW under construction worldwide, expected to start operations by 2015. Globally, gas only comes third behind coal (around 215 GW) and hydro (160 GW). China and India alone represent around two-thirds of new coal capacity and more than half of the new hydro capacity.

In OECD countries, gas-fired capacity is expected to continue to account for the bulk of capacity additions in the coming decade. Many factors play in favour of gas-fired investments, including the lower up-front investments, shorter construction lead times, more flexible operation and lower greenhouse gas (GHG) emissions compared to the coal option. Furthermore, gas is valued for its flexibility, and is expected to be the fuel of choice for power generation over the next decade due to the much lower lead times of alternative sources, except some renewables. Current difficulties in financial markets seem likely to favour new gas build, or at the very least, increase gas-fired plant load factors.

Over the past decade, natural gas has been competing fiercely with coal and has been the fastest growing fuel source in the Europe. This reflects in part tightening in CO_2 regulations and strong public opposition to coal-fired capacity. Public attitudes may be a key barrier to generation investment. In the United States, a strong anti-coal attitude has resulted in significant delays and cancellations of about half of coal-fired projects (noting of course that half of US power is coal-fired). In Canada, there is a policy commitment in Ontario to phase-out coal-fired power plants. The patterns of investment in the coming decade will depend on climate change and renewable energy policies.

While in Europe the Emission Trading Scheme (ETS) provides transparent signals for carbon prices, in other OECD jurisdictions, any new policies intended to curb GHG emissions will increase the total costs of fossil fuel for power generation through additional costs associated with cap-and-trade and/or carbon tax. This will likely alter the mix of new power plants and increase the demand for natural gas. Coal-fired generation, which produces about twice the CO_2 per MWh as gas-fired generation, is the most affected by the cap-and-trade and carbon tax plans. The impact on coal-fired generation will vary depending on specifics of the regional markets. Under many scenarios, the relative share of coal-fired generation in the power mix will likely diminish due to the retirement of existing units and/or the development of fewer new units. This could change in the longer term when, and if, coal with carbon capture and storage (CCS) becomes competitive.

A resurgence of nuclear power will meet some of the supply requirements as around 14 GW of nuclear capacity are under construction in OECD countries. Nuclear energy has been recognised by the European Commission as a way to curb CO_2 emissions but the decision to build new plants has been left to Member countries. However, there is great uncertainty about the timing of new nuclear reactors, in part reflecting challenges in their financing. Nevertheless, public opinion has eased somewhat in recent years and several utilities are now poised to submit applications to build new nuclear generating plants. Among the most advanced projects are the plants under construction at Olkiluoto in Finland and Flamanville in France expected to come on line in 2012-13. Other plants under construction are located in Japan, Korea and the United States. Only two new reactors were started in the OECD in 2008 and the first half of 2009, both in Korea.

Flexibility challenges in the power sector

Gas-fired generation could become the swing resource utilised to provide flexibility in power systems with large shares of intermittent renewable generation. Gas-fired capacity will increase while its overall load factor may be reduced in favour of renewable resources when available. This switching will have an impact on the profitability of new investments.

Over the last five years, wind power capacity in the OECD has increased by an average of 8 GW per year – much more in 2007 and 2008. Output doubled between 2005 and 2008. Wind output is highly variable and unpredictable, therefore wind turbines generally need backup power from hydro or fossil fuels to keep the electricity grid in balance. Gas turbines are able to respond quickly to provide the needed generation, and can be turned on and off quickly. They also have relatively low capital cost, making them a preferred choice to provide back-up capacity. Thus, as wind power capacity increases, the demand for gas-fired capacity also tends to increase.

Spain provides a good example of the interactions between wind-based and gas-fired generation. By the end of 2008, Spain had 21 GW of wind powered capacity, producing about 9% of the country's total power supplies. Most of these wind generators are located in scarcely populated areas, while major load centres are in urban areas, with high air-conditioner loads. Peak summer loads coincide with periods when there usually isn't much wind, while the opposite happens during winter meaning large differences in terms of gas-fired plant load: on 20 June 2008, Spain broke a record in terms of peak daily gas demand from the power sector with 64 Mcm per day representing an utilisation rate of 75% compared with 22 GWh per day for wind. On 20 December 2008, however, wind plants produced 67 GWh or 11% of total electricity generation; this impacted on the utilisation rate of gas-fired plants which declined to 18% – or a demand of 15 Mcm per day. Such fluctuations require heavy investments in gas storage, particularly of the type needed to respond quickly to large gas demand movements from power generators. Spain has recently set a new record for wind power generation with more than 40% of the country's energy needs being covered by wind turbines during periods of a few hours. On a cumulative basis, wind energy met 11.5% of demand up to April 2009, with production up by a third on last year. Renewable energy provided 31% of total electricity supply in Spain in February, partly due to heavy rainfall that enabled increased hydroelectric production.

As wind generation increases in Europe, there needs to be in the long term sufficient available capacity that is flexible enough to respond at all times to cover reliably such variations in output (as well as to digest surpluses). If this flexible response is provided by gas, as it is in Spain, then that increases the importance of storage and secure gas flows. Large shares of wind power are likely to encourage more investment in flexible capacity (such as gas) than in other thermal plants such as coal or nuclear, because those plants will no longer have the full load hours they could once have counted upon. Other methods of flexible response are available, being other types of flexible generation (pumped storage but new hydro developments are very limited in OECD countries), increased transmission interconnection, and demand side response (which remains a much discussed but much underutilised approach). It is likely that the gas system will be required to provide this flexibility and reliability.

Towards greater transparency

- **There have been improvements on gas data transparency in Europe, both on pipeline flows and storage levels.**
- **However, there remains much missing data in particular in Eastern Europe, as well as a lack of harmonisation between the different transmission system operators (TSOs).**
- **Lack of this data undermines Europe's security of gas supply, in the short term, as it impedes the ability of the market to move gas to where it may be needed and in the longer term through weakening essential market signals.**

In order to have a well-functioning gas market as well as increase gas security, transparency of information is critical (see "Development of Competitive Gas trading in Continental Europe" IEA 2008). **Timely and adequate price and other signals are essential if the investment on which long-term security of supply depends is to occur in the right place, time and is of the right type**. Such investments need to cover upstream gas development, long-distance pipelines, LNG regasification terminals, and storage, including a variety of drawdown rates, sensitive to market needs.

In North America, data transparency is quite advanced. Data on stocks are given by week by the Energy Information Administration (EIA) as well as monthly import and consumption data. The market is also well supplied with price data by time and location, plus flows and pipeline capacities. **In Europe however, there have been gaps** in terms of data on transport by pipeline and storage stocks. Under the pressure of the European Commission (EC) and national regulators, transmission systems operators (TSO) and storage system operators (SSO) have started publishing data. Improved data is a key element to improve trading, but also in case of disruption, it allows a better overview of flows and stocks and is therefore critical in order to get available gas volumes where they are needed.

Pipeline flows

At the 5th meeting of the Madrid Forum on February 2002, the Guidelines of Good Practice (GPP) were agreed, marking the start of the process aiming to improve transparency of gas data in Europe. In line with these aims, the European Regulators Group for Electricity and Gas (ERGEG) launched its Electricity and Gas Regional Initiatives (ERI and GRI) in spring 2006. These two initiatives were created to speed up the integration process of the different national energy markets. Subsequently the GRI created three regional gas markets in Europe (North-West, South South-East and South) as an interim step to create a single EU gas market. The regional areas have different priorities depending on how advanced liberalisation is. However the improvement of transparency is a priority in all three.

In the DG[2] Competition's energy sector inquiry published in 2007, the absence of sufficient and timely information was highlighted as one of the most serious shortcomings in the functioning of the internal market. This was also seen as a major stumbling block for the entry of new market players (especially in countries where the TSO is part of a vertically integrated company). In December 2007 as a reaction to these findings, the TSOs in the GRI North-West, in consultation with consumer groups, committed themselves to the implementation of the TSO Transmission Transparency project. The goal of this project is to publish information on capacity availability and gas flows at cross-border points in the North-West gas region. With regard to gas flows the 16 TSOs[3] committed to publish information on:

- Daily flows and interruptions
- Daily prompt allocations
- Daily aggregate day-ahead nominations
- Historic gas flows

The final deadline for implementation for the project was December 2008. Of course this initiative did not limit TSOs from publishing additional information. Since the start of the project significant progress has been made: data for 133 interconnection points was provided as of September 2008. However, though most TSOs provide information on at least the historic gas flows and the daily aggregated flows on a D-1 basis, further improvement is needed. Indeed there are significant variations in quality, completeness and timeliness between TSOs. Now, seven years after the start of the improvement process, it is still impossible to get an overview of the gas flows in large parts of Europe due to different data formats of reporting, the application of the 3-shipper rule (that suppresses data where there are too few shippers to protect company confidential data), but mostly due to the absence of data from many transmission operators (especially in Eastern Europe).

In November 2008, frustration with this slow progress resulted in the launch of a list of Minimum Requirements at the 15th Madrid Forum by network users, comprising industry groups such as EFET, Eurogas, Eurelectric, OGP, GEODE, CEDEC and (later) IFIEC. These parties also asked the EC to make these requirements binding. In response to this initiative GTE organised a workshop on 29 March 2009 to work on this request. However GTE members argued that they should be allowed to recover their associated costs. Concentrating particularly on gas flows, the following six improvements seem attainable:

Aggregation of publication: gas markets are increasingly difficult to examine

2. European Commission Directorate General for Competition
3. Swedegas, Gaslink, National Grid, Interconnector, Energinet, GTS, Fluxys, DEP, Gasunie Deutschland, E.ON Gastransport, RWE Transgas, Wingas Transport, Ontras, GdF Transport, GRT Gaz and BBL.

Table 16 Data published by Transmission Systems Operators

Country	Transmission operator	Historic gas flows	D-1 gas flows	D+1 gas flows	Real-time gas flows
Belgium	Fluxys	✓	✓	✓	×
Denmark	Energinet.dk	✓	✓	×	✓
Germany	E.ON Gastransport	✓	✓	✓	×
Ireland	Gaslink	✓	✓	✓	×
Netherlands	Gas Transport Services (GTS)	✓	✓	✓	✓
Spain	Enagas	✓	✓	✓	×
France	GRT Gaz	✓	✓	×	×
France	TIGF	✓	✓	×	×
Germany	RWE Transportnetz Gas	✓	✓	✓	×
Germany	Gasunie Deutschland (GUD)	✓	✓	×	×
Italy	Snam Rete Gas	✓	✓	×	×
United Kingdom	National Grid (NG)	✓	✓	×	✓
Austria	OMV Gas GmbH	✓	×	×	×
Austria	WAG	✓	×	×	×
Austria	TAG	✓	×	×	×
Germany	GdF DT	✓	×	×	×
Bosnia Herzegovina	BH-Gas	×	×	×	×
Bulgaria	Bulgargaz	×	×	×	×
Croatia	Plinacro	×	×	×	×
Czech Republic	RWE Transgas Net	×	×	×	×
Finland	Gasum	×	×	×	×
Germany	Wingas	×	×	×	×
Germany	Ontras	×	×	×	×
Germany	GVS/ENI	×	×	×	×
Greece	Desfa	×	×	×	×
Hungary	FGSZ Natural Gas Transmission	×	×	×	×
Luxembourg	SOTEG	×	×	×	×
Norway	Gassco	×	×	×	×
Poland	GAZ-SYSTEM S.A.	×	×	×	×
Poland	EuRoPol GAZ	×	×	×	×

Table 16	Data published by Transmission Systems Operators (continued)				
Country	**Transmission operator**	**Historic gas flows**	**D-1 gas flows**	**D+1 gas flows**	**Real-time gas flows**
Portugal	REN Gasodutos	×	×	×	×
Romania	Transgaz	×	×	×	×
Serbia	Srbijagas	×	×	×	×
Slovakia	Eustream	×	×	×	×
Slovenia	Geoplin plinovodi	×	×	×	×
Sweden	Swedegas	×	×	×	×
Switzerland	Swissgas	×	×	×	×
Turkey	BOTAŞ	×	×	×	×

Source: TSOs.

Note: In May 2009 some of the GTE members started uploading data on the transparency platform of GTE.

individually. However the data publication on cross-border flows, which by definition are supranational, is left to individual TSOs. This seems an obvious argument for an overarching international approach for publication. Such an approach also has the benefit of preventing, double-counting, and of reconciling often conflicting flow formats or even data[4].

Harmonisation of data formats: the bottom-up approach of the project resulted in different reporting units and frequency. Unlike storage, there is no European entity or TSO group publishing all the available information on gas flows in a consistent data format.

Inclusion of domestic production entry points: despite the fact that domestic European production is declining, it still represents a substantial share of the supply mix. Not every country currently publishes flows on the entry points for domestic production. The Netherlands and Germany do not publish such flow data.

Inclusion of all European countries (especially Eastern Europe): while there is still a lot of improvement needed in Western Europe, Eastern Europe is lagging even further behind. In most of these countries, the provision of information is very poor. The Russia-Ukraine gas dispute highlighted the importance of an adequate overview of gas flows. Timely availability of this data would allow market participants to make better and more efficient decisions on the allocation of their gas in the event of further emergencies, and to invest more effectively and efficiently.

Solution for the 3-shipper rule: currently in the GRI North-West Transparency project, 29 out of the 133 interconnection points are subject to the 3-shipper rule. This means that no flow information is published on roughly a quarter of the interconnection

4. Currently bordering TSOs both publish data on the same border points.

points. If Eastern European countries were to start publishing data, this number would probably rise due to the heavy dependence on one supplier. Taking into account the commercial interest of shippers, a more satisfactory solution is needed.

Real-time information: Following the example of National Grid (NG) of the United Kingdom, the first TSO publishing near real-time flow information, Gas Transport Services of the Netherlands also started publishing such information. Though on an aggregated level and therefore less detailed than NG it enables market players to base their actions on the actual situation. Such initiatives should improve the timeliness and effectiveness of market participants balancing demand and supply.

Storage levels

The second EU Gas Directive required storage operators to provide sufficient information for efficient and secure access to storage facilities[5] while the Guidelines for Good Practice for System Storage Operators (GGPSSO) provided guidance on the information to be published. However, in December 2006, an ERGEG monitoring report highlighted the shortcomings of this implementation. Information on storage capacity booked and available as well as easy access to storage tariffs and conditions is essential as well as historical operational data. One major issue for SSO was confidentiality, which allows them to publish no information if there are fewer than three users.

At the end of 2006, Gas Storage Europe (GSE) – a grouping of European SSOs – announced that they would publish on a weekly basis storage levels for selected regions. The aggregated storage inventory started early January 2007 with four geographical zones. Since October 2007, these regions have been linked to existing hubs or major trading points:

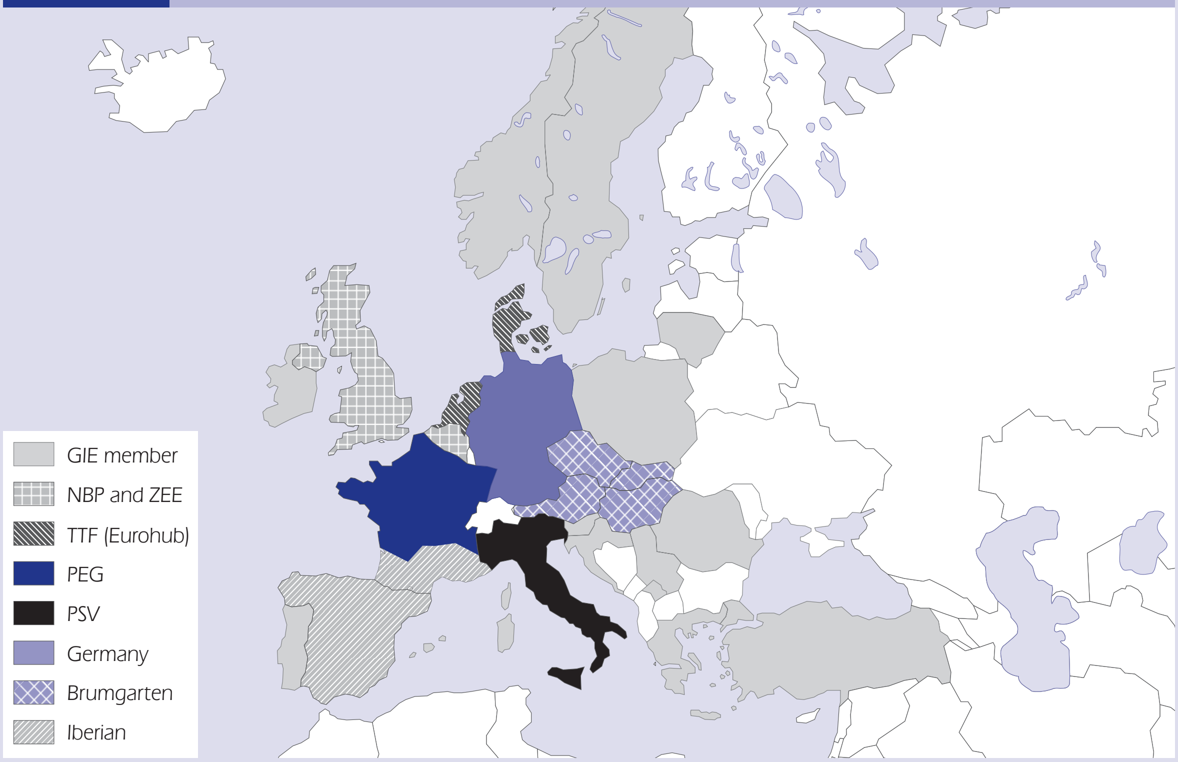
- NBP + Zeebrugge: facilities in Belgium and some in the United Kingdom[6]
- TTF: some facilities in the Netherlands and Denmark
- Baumgarten: some facilities in Austria, the Czech republic, Hungary and Slovakia
- PEG: facilities in Northern France
- Germany: some facilities in Germany
- PSV: facilities in Italy (excluding strategic storage)
- Iberia: facilities in Iberia and Southern France

Data on stock levels at the beginning of each calendar week for each of the different regions are usually available at the end of the week.

Despite the obvious progress that this transparency initiative represents, total working capacity covered by GSE amounts to 53 bcm compared to 82 bcm in Europe (including Turkey). Some countries

5. Article 8 of the second gas directive.
6. NBP and Zeebrugge are separated since 25 May 2009.

Map 9 Gas Storage Europe storage data coverage



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: GSE, http://transparency.gie.eu.com.

especially in Eastern Europe (Poland, Romania, Bulgaria) are not covered and there are still missing data within the regions covered as these regions do not include all storage operators. In particular Germany covers around 60% of the working capacity (90% since 25 May 2009), while in Baumgarten, half of the Austrian capacity is not covered and Italy does not include around 5 bcm of strategic storage. Furthermore the capacity increases that occur when new operators join the network or new facilities come on line are difficult to track.

In parallel, most of the SSOs participating to the aggregated storage inventory have started publishing data on their own websites. Again, data available is mainly in Western Europe. The quality of the data in terms of frequency and lag time between the day of the operation and the publication of the data varies considerably from one operator or country to another. In Austria and the Czech Republic, data are gathered by the regulator or the Ministry which allows a complete coverage of the facilities but at the expense of a certain delay in the publication. Furthermore, some operators do not keep historical data while the net injection/withdrawals are sometimes published instead of the absolute levels.

Table 17 Data published by Storage Systems Operators

Country	Entity	Frequency	Lag time	Comments
Austria	E-control	Monthly	2 months	Covers all facilities
Belgium	Fluxys	Weekly	1 week	
Czech Republic	Ministry[6]	Monthly	1 month	Covers all facilities; only net injection/withdrawal*
Denmark	DONG	Daily	Days	No data from Energinet.dk
France	Storengy	Daily	Days	Daily details disappear two weeks after, weekly available
	TIGF	Weekly	3 days	
Germany	Ministry	Monthly	2 months	Net injection/withdrawal
Hungary	E.ON Földgaz	Weekly	2 weeks	Disappears the week after
Italy	Stogit	Weekly	2 days	Disappears the week after, daily data available after several months
Slovakia	Pozagas	Weekly	1 week	Disappears the week after
	Nafta	Weekly	1 week	Disappears the week after
Spain	Enagas	Daily	Days	
United Kingdom	NG	Daily	Days	

Source: SSOs.

7. RWE Transgas publishes daily data on its storage facilities but they do not represent the total capacity.

NON-OECD COUNTRIES AND REGIONS

Non-OECD countries represent just under half of global gas use, but account for 63% of global gas output. The following section provides an overview of selected non-OECD consumers and producers. Note that Russia, the largest producer and second largest consumer, is discussed in the Investment section; Qatar developments can be found in the Investment and LNG sections.

China

- **Chinese gas use at near 80 bcm in 2008 is the third highest amongst non-OECD countries. However, this represents less than 4% of Chinese total energy supply, which is dominated by coal.**
- **China has ambitious plans to double domestic gas production to 160 bcm by 2015, and has in place agreements to import a minimum of 24 bcm of LNG by 2011.**
- **In addition, China will import up to 40 bcm of Turkmen gas by pipeline starting early in the next decade, marking the first physical link between East Asian and Eurasian gas markets. Other pipeline imports may be sourced from Kazakhstan and Myanmar.**
- **Even with these large supply additions, gas will remain a small part of China's energy supply.**
- **Price reform will be an important policy development, to ensure rational and efficient use and supply of gas in China.**

China's natural gas market has been expanding rapidly in recent years, particularly after the completion at the end of 2004 of the West-East Pipeline, which transports gas produced in the western part of China to eastern cities. **In 2007, China's natural gas consumption grew by 23.8% and attained 69.5 bcm,** making China one of the world's top 10 gas consuming countries. Despite the rapid increase in consumption, the share of natural gas in China's energy mix is still 3.5%, while coal dominates with nearly three quarters of energy supply. In particular, gas-fired power makes up only 1% of the power mix, almost exclusively in the South, including Hong Kong. In order to promote the use of this "clean energy" as a substitute fuel for oil and coal, the government aims at expanding the share of natural gas up to 10% by 2020, and has enhanced the development of the domestic gas market. The government has maintained a "cost-plus" based domestic price regime until now in order to promote gas use, resulting in relatively cheap prices compared to international levels. This price regime was sustained by controlled prices for domestic gas output, plus a very cheap LNG import contract (around USD 3 per MBtu) which started in 2006. However, this regime is now being challenged by the significant increase in higher priced gas imports in the near future.

Consumption

The growing urbanization, the expansion of industrial use, including the petrochemical industry and the power sector, have been the driving forces behind the recent high-paced increase in demand. Moreover, high oil prices until mid-2008 made residential and industrial consumers switch to gas as it was much cheaper than oil and LPG in China at that time. The differential between domestic prices of natural gas and international prices of alternative fuels caused several perverse situations in the country such as overproduction in some petrochemical plants using cheap gas. On the other hand, many gas-fired power plants were idle, faced with supply shortages of natural gas due to demand growth in other sectors. Confronted with these situations, the government issued a new priority sector policy in August 2007, which categorised city residential use and combined systems for heat and power as being the first priority and restricted industrial use. In November 2007, the government decided on a sharp increase in natural gas prices.

Since late 2008, in common with most markets, natural gas consumption growth slowed sharply, showing the effect of the global economic recession, but similar to the Chinese economy, still kept steady growth. According to provisional estimates, **in 2008, China's natural gas consumption grew by 11.8% to 77.7 bcm**. China's monthly merchandise exports have been decreasing since November 2008 in comparison to that for the previous year, and recorded a staggering fall of 25.7% in February 2009. In January 2009, the government announced a large-scale two-year "stimulus plan" amounting to CNY 4 trillion (USD 580 billion) in order to stimulate the economy and to maintain annual GDP growth above 8%. Although the precise measures are still not clear, public investment in infrastructure may be a pillar to expand domestic demand, which may have a positive effect on the natural gas market's growth.

Domestic production

China's natural gas production grew by an annual average rate of 15% from 2000 to 2007, amounting to 69.5 bcm in 2007, and it is estimated to have reached 79.3 bcm in 2008. China National Petroleum Corporation (CNPC) forecasts incorporate an aggressive production outlook, foreseeing that China can maintain the current high pace of increase in natural gas production, attaining 160-170 bcm by 2020. **In January 2009, the Ministry of Land and Resources announced a more ambitious target of 160 bcm by 2015**. As far as domestic gas reserves are concerned, China's latest national investigation in 2005 identified prospective resources amounting to 56 tcm while its recoverable resources were estimated to be 22 tcm. In 2008, CNPC announced that China's total proven reserves amounted to 5.94 tcm. More recently, in December 2008, CNPC announced the discovery of the large-scale gas field called Klameli in the Junggar Basin, in Xinjiang, with confirmed reserves of 100 bcm. In addition to this conventional gas, the potential of coalbed methane is estimated at 37 tcm of geological resources and 134.3 bcm of proven reserves.

LNG imports

The first LNG receiving terminal in Guangdong opened in June 2006. In 2008, this terminal received a total of 4 bcm of LNG based on the long-term contract with Australian North West Shelf (NWS) project. Faced with the strong demand in the Guangdong region in 2007 and 2008, China National Offshore Oil Corporation (CNOOC) procured additional spot LNG from Oman, Algeria, Nigeria, Egypt and Equatorial Guinea despite high prices at that time (USD 8.2-20.6 per MBtu). The second LNG terminal in Fujian was completed in 2008, and the first commercial cargo from Indonesia's Tangguh project is expected to be delivered mid-2009. The start of the third terminal in Shanghai was delayed, and is expected to occur later in 2009 or even 2010, with LNG supplies coming from Malaysia's Tiga project. Two additional terminals are now under construction in Jiangsu and Dalian initiated by CNPC and both of them are expected to open by 2011. In 2008, CNPC signed a sale and purchase agreement (SPA) with the seller of the Qatargas IV project, although it initially planned to import LNG from Gorgon or Browse projects in Australia. The price formula is said to be close to "oil parity", due to LNG market conditions at that time. In November 2008, CNPC signed another SPA with Shell: LNG may be supplied by Australia's Gorgon project and supplemented by additional LNG volumes from Shell's portfolio. On the other hand, CNOOC signed two more SPAs in 2008, one with the QatarGas II project and another with Total, probably intending to meet the increase in demand by the expansion of the Guangdong terminal and the start of another new terminal. **As a result of these procurement activities of LNG** by CNOOC, CNPC and Sinopec, **the total contracted volume on a long-term basis now totals around 33 bcm per annum**[1]**.**

Table 18 Existing long-term LNG sales and purchase agreements

Buyer	Supply source	Volume (bcm per year)	Term (years)	Signing date	Destination terminal /capacity (bcm)	First cargo
CNOOC	North West Shelf, Australia	4.5	25	December 2004	Guangdong (5.0)	June 2006
	Tangguh, Indonesia	3.5	25	September 2006	Fujian (3.5)	2009
	Malaysia LNG Tiga	4.1	25	July 2006	Shanghai (4.1)	4Q 2009
	Qatargas III	2.7	25	June 2008		4Q 2009
	Total	1.4	15	January 2009		2010
	Queensland Curtis LNG, Australia	5	20	May 2009		2014
CNPC	Qatargas IV	4.1	25	April 2008	Jiangsu (4.8)	2011
	Shell	2.7	20	November 2008	Dalian (4.1)	2011
	ExxonMobil	2,7	20	Pending		
Sinopec	PNG LNG	2,7		Pending		2014

Source: Company information, media reports.

1. In addition to these confirmed volumes, other non-confirmed agreements have been reported, such as the non-binding agreement between CNPC and Woodside (Browse, 2.0-3.0 Mtpa), the Head of Agreement between CNPC and Iran (South Pars, 2.0 Mtpa), and the Memorandum of Understanding between Sinopec and Iran (South Pars, 10 Mtpa).

Pipeline gas imports

Despite the many years of discussions between Russia and China on building a gas pipeline, no real progress has been observed until now. China changed its strategy to focus on Central Asia, and succeeded in securing a commitment to gas supply from Turkmenistan. In July 2007, CNPC and Turkmenistan signed two agreements; a production sharing agreement (PSA) for development of gas reserves on the right bank of the Amu Darya River in eastern Turkmenistan, and a 30-year SPA for 30 bcm per year of natural gas. **In August 2008, both parties agreed in principle to increase the sales volumes on the SPA to 40 bcm as offered by the Turkmen President Berdymukhammedov.**

To transport this gas back to the domestic market, China planned the Central Asia-China Pipeline via Uzbekistan and Kazakhstan, and rapidly obtained confirmation from these two transit countries of their co-operation for the pipeline. This cross-border pipeline will run around 2 000 km to the Chinese border, where it will connect to the second West-East pipeline. Construction of the Turkmenistan-China pipeline began in 2007 and the first phase with a capacity of 20 bcm per year is expected to be completed in 2010.

Around 13 bcm per year for this pipeline is foreseen to come from the Bagtyiarlyk gas field, which CNPC is developing in Turkmenistan based on the PSA; the remaining portion should be provided by Turkmengaz from the Malay and Uchaji fields. The parties have reportedly agreed an oil-based pricing formula. This project creates for the first time a pipeline link between the Chinese market and the European and Russian markets, and establishes Turkmenistan as an important pivot between western and eastern Eurasia.

CNPC is also actively exploring Aktyubinsk and Urikhtau in Kazakhstan, and the Aral Sea in Uzbekistan. In November 2008, CNPC and Kazmunaigaz signed a comprehensive agreement for co-operation on natural gas development, including another gas pipeline construction originating from Beineu in western Kazakhstan that will connect to the Turkmenistan-China Pipeline. However, there is little scope in the short term for either Uzbekistan or Kazakhstan to send significant volumes to China. Additional pipeline gas imports are being planned from Myanmar to the southern part of China. In December 2008, China and Myanmar signed an SPA for 10 bcm per year of natural gas with a planned 1 000 km pipeline.

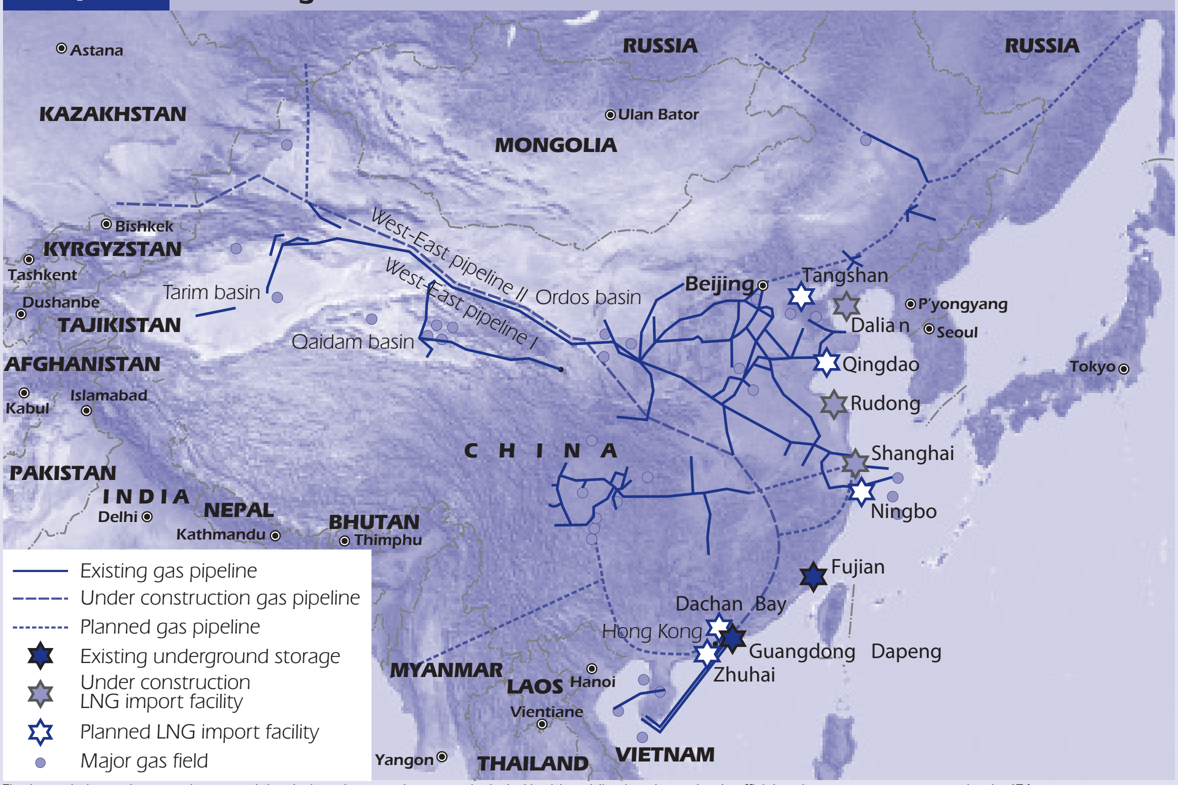
Infrastructure development

The second West-East pipeline was launched in February 2008, in order to transport natural gas from Turkmenistan. It will be built in two phases: the first phase is the western link from the border with Kazakhstan to Gansu, to be completed by the end of 2009. The second phase is the eastern leg, linking to markets in Shanghai, Guangdong and Hong Kong by 2012. Thus, the second West-East Pipeline will meet expanding demand in two major economic zones in the coastal area, *i.e.* the Yangtze River Delta and the Pearl River Delta. The total length of the main trunk line is 4 843 km, and the transport capacity will be 30 bcm per year. Three underground storages are planned to be built alongside the pipeline, which will have 2.5 bcm of total working gas capacity. CNPC announced a total investment cost of CNY 142 billion (USD 20 billion). Sinopec is planning to build two other inter-provincial pipelines, originating in Sichuan, to the Yangtze River Delta area (the Sichuan-East Pipeline) and to the Pearl River Delta (the Sichuan-South Pipeline). Additional LNG terminals are approved or under planning in many regions such as Zhejiang, Qingdao, Zhuhai, Shenzhen, Caofeidian, and Hainan.

Towards price reform

Natural gas prices have been under government control in China. The current price regime is composed of three elements; (i) ex-plant price, (ii) transportation tariff, and (iii) end-user price. (i) and (ii) are set by the central government principally based on the costs of production and transportation plus the appropriate margin. (iii) is determined by each provincial government based on distribution costs and the prices of alternative fuels. However, this regime contains a number of structural flaws, in particular concerning balancing the seasonal, regional and inter-sectoral

Map 10 Chinese gas infrastructure



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Source: Petroleum Economist, IEA, media reports.

gap of demand and supply. Gas inflows from multiple fields to the same pipeline distributing to multiple users are causing difficulties in identifying the gas source and the original cost. Moreover, the increase in imported natural gas with higher prices seems to have pushed the Chinese government towards reform of the natural gas price regime. The policy paper issued in 2007 was a step in that direction. The LNG price level in recent SPAs is likely to be close to "oil parity", which may be double or triple current domestic wholesale prices of natural gas in China. Turkmen gas could be expensive as well for users in eastern coastal cities in China, which have to pay transportation tariffs for the long distance of the second West-East Pipeline. Fortunately for China, the international gas price has been falling since late 2008.

Despite all the negative impacts of the world economic crisis, it has also brought several positive factors for the evolution of the market. Falling international gas prices and less concern over inflation in China have provided the opportunity for price reform in China. The revaluation of the Yuan, which appreciated 15% against the US dollar from 2006-08, has eased the impact of rising import prices. The government is said to have set up an expert working group to develop a reform plan for a natural gas pricing regime which may be implemented earlier than most people anticipate. Each stakeholder, including producers, local governments and the association of city gas and industrial users, has been consulted and proposed their respective ideas.

India

- **As in China, gas plays a small part in India's energy needs, barely 5% of total primary energy supply.**
- **But demand has been growing rapidly, despite being constrained by a lack of gas availability.**
- **Gas supplies look set to rise sharply in the next few years, with a near doubling of domestic output, and an increase in LNG import terminal capacity from 13 bcm in 2007 to 30 bcm by end-2009, potentially opening the way to a near doubling of gas use in India in the short term.**
- **Pipeline imports seem unlikely before 2015.**

Like China, India gas consumption remains relatively modest compared to its population. Primary energy demand is still largely dominated by coal (over 50%) but gas demand has the potential to grow substantially over the next decade. Since 2003, gas use has increased by more than 60%. Demand has nevertheless been constrained to levels around 40 bcm (44 bcm in 2007) by the lack of supplies which has affected the use of gas in the power sector and fertilizer production, (41% and 26% of use respectively), as well as the development of the transmission network. **Indigenous production at 32 bcm in 2007** is being supplemented by LNG imports. India has been importing gas through two LNG terminals, starting in 2003, and rising rapidly. **In 2007, imports totalled**

11.7 bcm, mostly from Qatar, but also Algeria, Nigeria and Trinidad and Tobago.

In 2008, India set up a gas utilisation policy to optimise the use of gas in a context of supply scarcity. The Model Production Sharing contract (MPSC) provides guidelines for the utilisation of gas in the different sectors. The 22 fertilizer plants have been given first priority. Some using naphtha or fuel oil and not connected to the grid will be connected by 2011. Liquefied petroleum gas (LPG), is the second priority. Gas-fired power plants rank third in the list as some plants are either not running or use refined products. Fertilizers based in Andhra Pradesh will be the first to benefit from the recent start in April 2009 of the Krishna-Godavari (KG) field whose production is expected to reach up to 30 bcm by 2011.

Consumption

Gas demand has been growing strongly over the 2000-07 period. The main consumers are the fertilizer industry as well as the power generation sector which represent more than two-thirds of total gas demand. Gas-fired power is a little below 10% of power output, which is dominated by coal (with two-thirds of generation). However, if the country was not suffering from a shortage of gas supplies, demand could be around 20 or even 30 bcm higher than it is. In the power generation sector, most of the 13 GW of installed gas-fired capacity are used at relatively low factors while power demand goes unmet in many areas. In addition, big cities such as Bangalore and Chennai have not yet been linked to the pipeline system, although such connections are planned. One specific use in India has been the development of natural gas vehicles (NGV) in Western and Northern India. Around 700 000 vehicles have been converted to natural gas, accounting for more than 3% of gas use.

Domestic production

Domestic production has been relatively stable over the past five years. Most of the gas has been produced by Oil and Natural Gas Corporation (ONGC), Oil India and Joint ventures of Tapti, Panna-Mukta and Ravva. Most of the output comes from Western offshore fields while some onshore fields are located in the Assam, Andhra Pradesh and Gujarat States. But gas production is expected to increase substantially in the short term, thanks to Reliance Industries' **giant field Krishna-Godavari, whose production is expected to add 30 bcm supply, doubling domestic gas production** over the next few years. Additional gas production is also expected from six fields under implementation by ONGC although no date has been announced so far. The government has also offered blocks under the New Exploration Licensing Policy (NELP) to private and public sector companies with the right to market gas at market determined prices. Over the past ten years, the government has awarded 212 oil and gas blocks but launched its biggest licensing round in April 2009, offering 70 blocks.

Supply and import infrastructure

As demand continued to grow, resulting in severe shortages, India started importing LNG in 2003. Total regasification capacity amounts to 21.8 bcm. In 2007, LNG represented around 28% of demand. So far, India has two LNG terminals located in the North-West of the country. The 8.9 bcm Dahej terminal, operated by Petronet, came on line in 2004 and was expanded to 17 bcm in 2009. The 3.7 bcm Hazira LNG terminal started operations in 2005; its capacity was increased to 4.9 bcm through debottlenecking in 2008. A third 7.5 bcm LNG terminal Ratnagiri in Dabhol is currently under construction and expected to be completed in 2009. Petronet plans to complete its second LNG terminal (3.4 bcm) in Kochi in the southern state of Kerala by 2011, while another terminal has been proposed by Gujarat State Petroleum Corp Ltd (GSPC) at Mundra Port. Petronet has secured supplies for its terminals with RasGas.

India has also been looking at importing gas by pipeline. Even though two projects are still under consideration, the Myanmar-Bangladesh-India pipeline project seems to have been cancelled.

- The Iran-Pakistan-India (IPI) pipeline: no real progress has been made so far. The main hurdles are disagreements over gas transit fees, tariffs, Indian concerns over pipeline security in Pakistan as well as the absence of a purchase deal between Delhi and Tehran.
- The Turkmenistan-Afghanistan Pakistan-India (TAPI) is also advancing slowly. Negotiations are still under way between the four countries. According to plans in 2008, construction was scheduled to begin in 2010 and operations to start in 2015; however Turkmenistan may have difficulties meeting all its export commitments. In April 2009, Turkmenistan offered gas from the Yasrak field to feed TAPI.

Transportation infrastructure

The existing pipeline network is essentially in the west and northern parts of the country, linking the terminals and the fields to major cities such as New Delhi. Until recently, the main transmission companies were GAIL and GSPL (Gujarat State Petronet). The development of the domestic production and the coming on line of LNG terminals will help GAIL develop the transmission network. Furthermore India's gas policy promotes private pipeline investment. As a result, Reliance Industries completed in 2008 the East-West pipeline linking the KG field in the East to its refinery in Gujarat. The 1 440 km pipeline is now the longest in India. Meanwhile GAIL plans to invest USD 4 billion over the next three years to double the length of its pipeline network to 13 000 km with the Dahej-Uran, the Dabhol-Panvel and the Jagoti-Pithampur pipelines. Furthermore GAIL plans to connect new cities such as Pune, Kota, Indore and Gwalior. GSPL plans to expand its transmission network from 1 130 km to 1 575 km.

Pricing issues

Pricing remains an issue in India which has been facing the rapid increase of international LNG prices since it started importing LNG in 2004. Prices for domestic production from state-owned companies were kept relatively low. Furthermore, Indian industrial users were not ready to accept rapidly increasing international prices. In September 2007, the government changed the pricing system for domestic production. The price for companies other than ONGC has been set between USD 4.22 and 5.76 per MBtu compared with

Map 11 *Indian gas infrastructure*

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Source: IEA, Petroleum Economist, media reports.

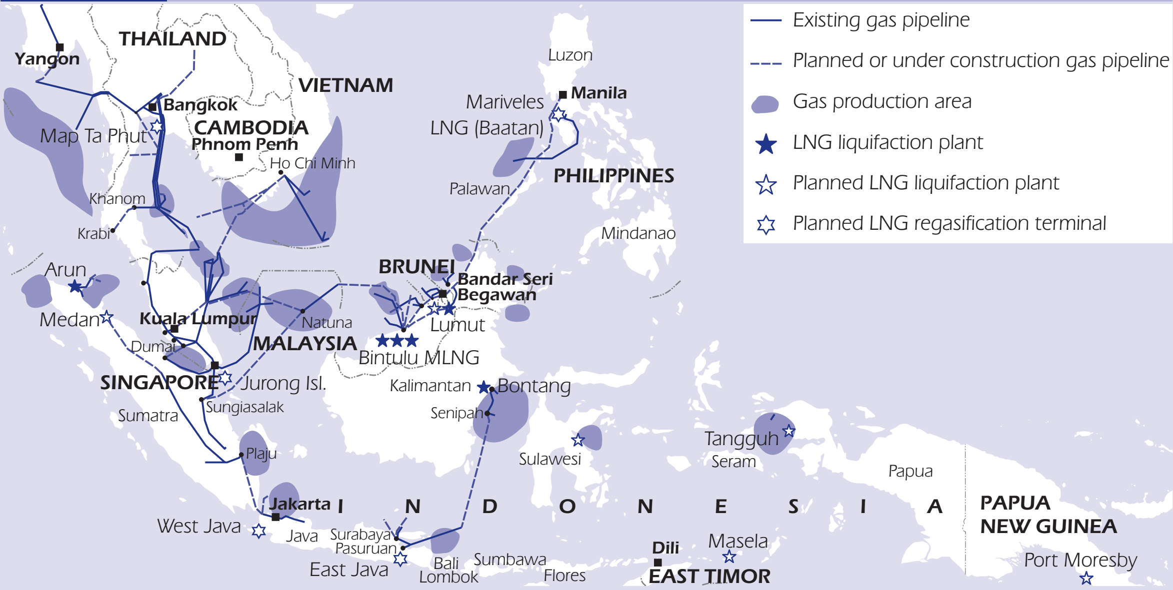
USD 2.02 per MBtu for ONGC. Although these prices were much lower than international LNG prices, which were above USD 10 per MBtu over 2008, the latter have already declined sharply in late 2008, and can be expected to decline further over the course of 2009.

Southeast Asia

- **Gas continues to be an important part of the region's energy mix despite the current economic downturn.**
- **The demand for gas is expected to increase while the investment in production, supply and transport infrastructure is continuing.**
- **Asia is a thriving market for LNG imports and exports due to distances between suppliers and consumers making pipelines too costly. The producing countries are conveniently located to supply LNG to the major markets in China, India, Korea and Japan.**

In early 2008, the outlook for Asia Pacific gas producing countries was buoyant with most countries expected to register strong economic growth. There was high demand for gas from within the region and outside the region. Even with the completion of a number of LNG projects, there was concern that not all demand for gas could be met. Gas prices peaked

Map 12 South East Asian gas infrastructure



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Source: Petroleum Economist, IEA.

during the period as most gas contracts in the region are pegged to oil. Negotiated contracts and on-going price negotiations were subjected to upwards review. However, rapidly falling oil prices in the second half of 2008 reversed these trends. Demand for energy also fell as countries experienced sharp economic slowdowns. Many countries have revised downward their short- to medium-term forecasts for economic growth. Further, the supply of LNG is expected to increase significantly in 2009 both globally and regionally, as large increments of new LNG production arrive on stream.

Brunei

Currently around 80% of Brunei's gas production (10 bcm out of 12 bcm per year) is exported as LNG to Japan and Korea. Gas is also consumed domestically in power generation, petrochemicals and other energy intensive industries. Almost 100% of electricity is gas-fired. Brunei has a very limited gas pipeline infrastructure, and there is no cross-border pipeline from Brunei to its neighbouring countries.

Oil and gas exports account for more than half of its GDP. Brunei is intensifying its efforts in the exploration and development of new fields, hoping to extend LNG sales contracts to Japan and Korea beyond their scheduled 2013 expiration. However, due to disputes with Malaysia over maritime boundaries, potential deepwater areas remain undeveloped.

Indonesia

Tangguh LNG project in West Papua has a capacity of 10.3 bcm, starting in 2009. This is the third LNG complex in Indonesia after

Bontang and Arun. Volumes are destined for export to the west coast of North America (5 bcm, half of which is subject to diversion), Fujian, China (3.5 bcm) and SK Power and POSCO, Korea (1.6 bcm). There are also plans to take uncommitted gas for Indonesia's domestic use.

Indonesia's NOC Pertamina is expected to decide on its partners to develop the giant Natuna D-Alpha gas block in the East China Sea in 2009, from the short-listed companies including Shell, StatoilHydro, China National Petroleum Corporation (CNPC), and ExxonMobil, the former operator of the block. More recently, Petronas, Malaysia's NOC, has been invited to partner with Pertamina in the venture. The field was discovered in 1973 and has estimated reserves of 54 tcf (1.5 tcm) of recoverable gas. The high CO_2 content of about 71% makes the development of the field difficult.

Indonesia is blessed with the largest gas reserves in the region (3 tcm). Pipeline systems in Sumatra and Java seek to overcome the geographical mismatch between the main demand centres in Indonesia (Java and Bali), and some of predominant supply sources in Natuna Island and South Sumatra. Other supply regions, such as Kalimantan and Papua, are not connected by pipelines with the largest consuming regions.

Due to this mismatch, LNG import terminals are being considered in East Java, West Java and North Sumatra to complement the existing and future pipelines. One of the terminals in West Java is currently planned to be operational in 2013, counting on supply from the Bontang LNG plant and Tangguh.

With the current emphasis on greater utilisation of gas for domestic consumption so as to reduce dependence on oil, the government has plans for more gas to be made available domestically. About a third of power use is oil-fired, with gas accounting for less than half this level. The largest users of gas in Indonesia are power plants, (about 20% of annual gas use of 36 bcm), followed by industrial users, fertiliser and petrochemical plants, *i.e.* those who use gas as feedstock. As the government is slowly reducing subsidies on oil for domestic use, more demand for gas is expected.

Malaysia

Based on the official Malaysian government figures, Malaysia's economy is predicted to slow down in 2009. However, analysts in the private sector expect the country to face recession in 2009. A decline in gas consumption has been observed as demand for gas by power plants declined about 5% in February this year. Around half of domestic natural gas use is in the power sector. Nevertheless, as gas prices are subsidised in Malaysia, demand is expected to be stable or decline only slightly.

Due to the economic crisis, the gas price has been reduced to assist businesses during this period. The gas price to be effective from 1 March 2009 is as follows:

Table 19 Gas prices in Malaysia (as of March 2009)

Sector	New price effective 1 March 2009 (MYR per MBtu)	Previous gas price (MYR per MBtu)
Power sector	10.7	14.31
Reticulation (residential/commercial)	15	22.06
Industry	15.35	23.88

Source: Economic Planning Unit, Prime Minister's Department, Malaysia.
Note: MYR: Malaysian Ringgit. 1 USD = 3.5 myr as of June 2009.

It was also decided that the gas price will be reviewed twice a year on 1 January and 1 July. Currently, the gas being subsidised by PETRONAS is around 50% of market price.

The debottlenecking of MLNG Dua facility is scheduled to be completed by the end of 2009[3]. Once completed, each of the three trains will be capable of producing 4.1 bcm per year, in total, an additional 1.5 bcm per year. With the debottlenecking exercise on MLNG Dua complete, the Bintulu complex's annual production capacity will rise to 33 bcm. The debottlenecking of MLNG Tiga depends on the economy and gas supply. The expansion, if undertaken, will increase the Bintulu complex's annual production capacity to 35.5 bcm. Additional supply of gas from Sabah via a 500 km pipeline is being planned to supplement the gas supply to the Bintulu complex. The main consumers for gas in Sarawak are LNG plants and a fertiliser plant.

On 11 December 2008, Kikeh field (offshore Sabah) commenced exporting gas to Labuan Gas Terminal (LGAST). The main customers for the gas are methanol plants.

Singapore

Singapore is constructing a 4.1 bcm LNG terminal on the industrial Jurong Island to be operational around 2011. Security of gas supply is the main driver for this development, to complement the current 8 bcm per year pipeline imports from Indonesia and Malaysia, which is used to generate 80% of the country's power supply. Gas demand is expected to rise as power generators switch from oil to gas; in addition, new petrochemical plants are planned.

Supported by the development of the LNG terminal and perhaps additional gas import capacity from West Natuna, the Gas Act 2008 will facilitate open access for gas importers and retailers in Singapore that will increase and expand gas market liquidity in this region. There is a potential availability of surplus gas that may be diverted towards spot trading.

Thailand

Thailand is a significant gas user, at 35 bcm per annum, two-thirds of which

3. Source : PETRONAS.

is used in the power sector. Nearly 70% of the country's 140 TWh annual power output is gas-fired. Thailand currently receives gas from several fields in the Gulf of Thailand, and the Yadana and Yetagun gas fields in Myanmar (about 10 bcm per year) as well as the Malaysia-Thailand Joint Development Area (JDA). In 2008 state-owned PTT started construction of a receiving terminal on the east coast of the country to be completed by June 2011. PTT has agreed to purchase 1.4 bcm per year of LNG from Qatar. Thailand's gas demand is forecast to rise to 52 bcm in 2011 and 72 bcm in 2021. Thailand wants LNG to diversify away from piped-gas from Myanmar, as domestic production seems likely to fall. Major potential users of regasified LNG include the state-owned Electricity Generating Authority (EGAT). The government is also promoting the use of natural gas powered vehicles (NGVs) for the transportation sector[4].

Vietnam

While power and gas use are currently low, Vietnam expects double-digit power demand growth, most of which would will be met by gas-fired power generation. In the Phu My area, new power plants will be supplied by gas from the Nam Con Son basin, while the South-West basin is being developed to supply projects in that area. Vietnam is also developing both hydro and coal-fired power projects.

The Philippines

Demand for natural gas in the country is expected to register a healthy growth in the next two decades, from the current low base of 4 bcm. Currently, gas is sourced from the Malampaya field which has limited reserves. Philippine National Oil Co. (PNOC) has a plan to build an LNG receiving terminal in Bataan. In 2007, Japan's Marubeni conducted a technical feasibility study on the terminal and associated gas-fired power plants with minimum capacity of 1 GW. Since then the plan has registered little progress.

Myanmar

The negotiation on gas sales for block M-9 is approaching its final stages. The Heads of Agreement (HoA) signed in June last year would form a basis for the final gas sales agreement. The HoA stated that 80% (6.8 Mcm per day) of the average volume of gas available will be exported to Thailand while the remainder will be for domestic consumption[5]. The project is targeted to be on stream by 2012.

On 24 December 2008, China and Myanmar signed an agreement for the sale of oil and gas for a 30 - year period. The agreement stated that the supply of gas will come from the Shwe field, with reserves of up to 170 bcm. It also includes the construction of oil and gas pipelines to Kunming in Yunnan Province. China is expected to start receiving gas from Myanmar via pipeline by 2013. Myanmar annual gas output can

4. The number of NGVs is expected to increase from about 51,000 in 2006 to more than 500,000 after 2010.
5. Source : Ministry of National Planning and Economic Development.

be expected to double from the current level of 12 bcm to around 25 bcm by 2015.

Since the discovery of hydrocarbons in the Bay of Bengal, the tension over maritime borders with Bangladesh has increased. Talks between the countries are on going.

Papua New Guinea

The front-end engineering and design (FEED) for PNG LNG project began in May 2008 after the partners in PNG LNG agreed to the fiscal terms with the Papua New Guinea government. The final investment decision (FID) on this project is expected to be taken by the end of 2009. The partners of this project are keen to secure long-term contracts with targeted buyers in Japan, China, Korea, Chinese Taipei and India for the whole volume of 8.6 bcm per year. The project is scheduled to start shipments in 2014. Gas is sourced from Hides, Juha, Angore, Kutubu, Agogo, Moran and Gobe fields with estimated reserves of 9 Tcf (255 bcm).

West Africa

- **Nigeria is a significant LNG exporter, with potential to provide significantly more.**
- **Domestic use is low, and much gas is flared, despite chronic power shortages.**
- **Other regional producers are entering the LNG market (Angola, Equatorial Guinea) and gas from Cameroon could be fed to Equatorial Guinea.**

Nigeria

Nigeria's gas reserves, estimated at around 5.2 tcm or 3% of global reserves, are the largest in Africa. Although a significant and growing LNG exporter (21 bcm in 2007), domestic gas use in this populous (145 million) country is low at 13 bcm, about a third being in the power sector, where it provides more than half the very low production of 23 TWh. The Nigerian government launched the gas master plan in 2008, which focused on exploiting the country's significant gas potential for economic development by prioritizing the domestic use of gas for power generation over export. To achieve this goal, the government has tried to attract investors in building three central gas gathering and processing facilities and three gas pipeline transmission systems. In March 2009, the government selected 15 companies for these investments, including IOCs as well as Gazprom. This development should give companies a clearer direction for their businesses including the planned LNG projects. The Nigerian National Petroleum Corporation (NNPC) announced in February 2009 that plans are in place to deliver around 20 bcm per year of gas to the domestic market by end-2009, although it is unclear if this has been adopted as a national policy by the government.

Nigeria flared 22 bcm of gas in 2007 according to OPEC data. The Nigerian government has taken a firm stance on gas flaring. It was announced that the government would not budge from the deadline of ending flaring by end-2008 and companies that continue to flare gas after the deadline would be heavily fined. However, the deadline passed without any serious repercussions for flaring companies and the government has proposed end-2010 as a new deadline. Nigeria hopes that the existing flared gas can be used as feedstock for LNG exports or domestically for power generation.

There have been a number of delays in commissioning the West Africa Gas Pipeline (WAGP) which will carry Nigerian gas to Ghana through Benin and Togo. The 678 km pipeline experienced a number of obstacles including operational problems, sabotage by militants in the Niger Delta, and other accidents. The project offers a potential to support regional development and cut spending on fuel product imports for power generation. For example, Ghana generates more than a third of its power from oil. The Takoradi power plant in Ghana will be the first beneficiary of the pipeline. First gas was brought to Ghana in December 2008. Since April 2009, gas is supplied at 30 Mcm per day to the power plant.

Since early 2008, Russia's Gazprom has been pressuring Nigeria to take part in its hydrocarbon projects. In September 2008, Gazprom signed an MOU with the NNPC to co-operate on oil and gas projects in Nigeria, though few details were disclosed. Gazprom also mentioned in February 2009 that it was interested in investing over USD 2.5 billion in Nigeria's gas infrastructure required by the gas master plan. In return, it is likely that Gazprom would like to be involved in not only LNG projects but also in the Trans-Sahara Gas pipeline (TSGP) project. TSGP would carry Nigerian gas for 4 200 km through Niger and Algeria to the Mediterranean. It is strategically important for the European Union, which wishes to diversify its gas supplies and increase energy security. Algeria is also interested in this project as it could help not only enhance its position as a key gas supplier to Europe, but also meet the country's own demand. Apart from Gazprom, Total has expressed its interest in taking a stake in TSGP in February 2009. This project is still at an early stage and a formal consortium to develop the pipeline is yet to emerge.

Equatorial Guinea

With the successful operation of the first LNG project (EGLNG), Equatorial Guinea hopes to establish itself as a hub for the aggregation of gas in the area. In January 2009, an MOU was signed between the national gas company (Sonagas), E.ON Ruhrgas, Union Fenosa Gas and Galp Energia for the creation of a company that will act as the owner of a gas-gathering system which will utilise gas that is currently being flared. The gas-gathering company, known as Consortium 3G, is currently drafting a gas master plan for Equatorial Guinea. The aim of the plan would be balancing the needs of LNG export with those of domestic gas use. Until recently, the country was an observer of the Gas Exporting Countries Forum (GECF), but became a formal member at the 7th Ministerial meeting in Moscow in December 2008.

The government's stance on gas flaring has become more assertive[6] than a few

6. The government announced in July 2008 that it will take a legal action over gas flaring by ExxonMobil, which contributes more than 70% of the gas being flared in the country.

years ago, as the country is keen to use its gas resources. While the second train of EGLNG has been planned, its final investment decision is complicated due to difficulties sourcing sufficient gas for the project. Although in 2006, Nigeria and Equatorial Guinea signed an agreement in which Nigeria was to supply gas feedstock for the second train of EGLNG, Nigeria has since planned new LNG projects and tried to reserve a large amount of gas for domestic use. On the other hand, co-operation with Cameroon is forthcoming, as its national hydrocarbon company (SNH) started discussions in early 2009 with counterparts of EGLNG to supply gas for the second train.

Angola

The Angolan government encourages investment in exploring for natural gas, in order to utilise gas for domestic electricity supply and diversify its generation mix which depends mostly on hydropower[7]. In March 2009, Angola's parliament decided to exempt gas exploring companies from paying taxes. Angola has little infrastructure in place to utilise its gas reserves that are currently flared[8], and needs to install new gas-gathering facilities and upgrade power generation infrastructure. The Angola LNG project (ALNG) has made progress since receiving its final investment decision in December 2007, and appears to be on schedule with the first LNG expected in 2012. ALNG plans to provide the domestic market with up to 1.3 bcm of gas for increasing electricity supply and creating a petrochemicals industry. In this regard, Angola's LNG project contributes to the development of the domestic market, rather than competing with it.

Middle East and North Africa

- **Middle East and North Africa (MENA) countries hold almost half of global gas reserves, and are both significant gas users and exporters.**
- **Rapidly growing domestic power and industrial demand growth will reduce export availability in the absence of new gas developments, and the right policies to underpin them.**
- **Iran, the world's second largest gas reserve holder, is now the world's third largest gas user; a third of gas is used in the power sector. Despite its vast reserves, it is a net gas importer.**

The Middle East and North Africa countries hold around 80 tcm or 46% of proven global gas reserves. The region has seen domestic gas demand increase significantly in recent years. **Between 2000 and 2007, domestic consumption grew by 48% in the North African countries while there was an increase of 56% in the Middle East**. This is a trend that is set to continue, although not at the same pace. Even though the Gulf region has vast gas reserves, most Gulf countries are heading

7. Hydropower accounts for 90% of total power generation in Angola.
8. Angola flared 7.3 bcm of natural gas in 2007, according to OPEC data.

Map 13 African gas infrastructure

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA.

towards gas shortfalls. This is the case for Kuwait, Dubai, Saudi Arabia, United Arab Emirates (UAE) and Oman. In particular, Kuwait and Dubai are turning to LNG imports with Kuwait starting imports in 2009. Also Egypt is facing a balancing act between domestic gas use and exports, and a moratorium on new export projects until 2010 was introduced in 2008. The increases in gas demand are and will continue to be mainly driven by power generation and industry, such as petrochemicals and desalination. Significant gas resources are also reinjected into oil fields.

North Africa exports both LNG and pipeline gas, mainly to Europe. The region has currently a pipeline export capacity of about 50 bcm, to Spain and Italy. This capacity will increase by the end of 2009, when the 8 bcm Medgaz pipeline from Algeria to Spain starts operating. Further pipelines are planned such as the 8 bcm Galsi pipeline, going from Algeria to Italy (via Sardinia) expected in 2012-13 or the expansion of Green Stream by 3 bcm. As for LNG, there are currently 45 bcm of liquefaction capacity in North Africa and 75 bcm in Middle East. Significant capacity additions are coming on stream in the MENA region in the short term (see section on the Developments in the LNG markets), at a time when the global gas market is experiencing a downturn in demand. Most European countries, for instance, saw slowdowns in their gas demand in the last quarter of 2008 and the first quarter of 2009, as gas consumption in the industrial sector dropped following the economic slowdown.

Gas supplies from the MENA region are a priority for European consumers, as they seek to diversify their imports. This will require investments in cross border capacity (France-Spain, potential reversal of TENP pipeline linking the Netherlands to Italy) and transmission capacity in order to bring these volumes to the core European markets. Spain is already suffering from potential over-supply as total import capacity is roughly twice demand and Italy is likely to have overcapacity if other projects such as additional LNG terminals (beyond Rovigo) and pipelines (Turkey-Greece-Italy) are completed as well. Italy probably needs to become a transit country for additional North African gas to reach other markets.

Algeria

Algeria has the eighth largest reserves of natural gas and is the sixth largest natural gas producer worldwide. Their production in 2007 was 90 bcm, of which 63 bcm was exported and the remaining 27 bcm consumed domestically. It exports both pipeline gas and LNG to Europe as well as to North America and Asia. Algerian supplies to OECD Europe have been quite stable over past years, varying between 50 and 60 bcm. Due to the delays in LNG projects (see section on LNG markets), as well as potential delays of pipeline projects, **Sonatrach postponed meeting its long touted 2010 gas export targets of 85 bcm per year until 2012, with an increase to 100 bcm by 2015**. After the announcement of the new targeted completion dates of 2013 for the two LNG projects, the 85 bcm target also looks more likely to be reached only after 2013. In March 2009, however, the country's energy minister reasserted the export target of 100 bcm per year by 2015, and confirmed plans to spend

USD 63.5 billion in the energy sector up until 2013, claiming that oil prices of USD 40-50 per barrel were sufficient to sustain this. There are some hurdles to this target though: project delays, an ageing infrastructure and a reserve squeeze as domestic demand is increasing.

Algeria is currently modernising its 16 200 km pipeline infrastructure (some of which is 40 years old) and extending it by 5 300 km. Domestic demand comes mainly from the power generation sector which represents just over 40% of total demand followed by 27% used by industrial customers directly supplied by Sonatrach. According to the long-term forecasts of the regulator *Commission de Régulation de l'électricité et du gaz* (CREG) issued in 2008, **demand is expected to increase to 55 bcm by 2017** under a base case scenario (67 bcm and 49 bcm under a high and low case scenario respectively). Major drivers for this demand growth would be the power sector and new major industrials such as Ammoniac SBGH in 2011 or Aluminium Beni Saf in 2012. In the power sector, the majority of the new capacity is gas-fired (see table below). Going forward, to succeed with their export target as well as to satisfy the rapidly increasing domestic demand, new production capacity needs to come on line.

Beyond Gassi Touil expected for 2012 (discussed further in section on Developments in the LNG markets), development of some gas fields led by Sonatrach needs to move forward, as well as Timimoun with Total, Touat with GDF SUEZ, Reggane with Repsol. As for future supplies, international companies need the

Table 20 New power plants in Algeria 2008-12 (planned and under construction)

Plant	Type	Capacity (MW)	Expected online date
Oran Est	Gas turbine	75	Mar-08
Relizane	Gas turbine	465	May-July 2009
Arbaâ	Gas turbine	560	February-October 2009
Alger Port	Gas turbine	71	April-May 2009
M'sila	Gas turbine	430	June-August 2009
Annaba	Gas turbine	71	Mar-09
Batna	Gas turbine	254	April-May 2009
Hadjiret Ennous	CCGT	1 200	2009
Terga	CCGT	1 200	2012
K. Edraouch	CCGT	1 200	2012
Hassi R'mel	Hybrid (solar/gas)	150 (30 solar)	2010

Source: CREG, programme indicatif des besoins en moyens de production d'électricité 2008-17.

Note : most plants have several turbines, which come on line at different dates.

right incentive to go ahead with exploration activities, especially in a time of economic downturn. Algerian Minister of Energy and Mining Chakib Khelil announced that Algeria will consider making changes to their upcoming oil and gas licensing round after a weak response in the most recent round, held in December 2008. Of the 70 international oil companies that showed interest in the licensing round, only nine submitted bids. This round was the first to be held under a 2006 amendment of the hydrocarbon law, which gives Sonatrach a minimum 51% share in all oil and gas exploration agreements made with foreign companies.

Egypt

There has been a rapid rise in domestic gas consumption over the last 20 years. More recently, **from 2000-07, gas consumption increased by close to 70% in just seven years up to 37 bcm**, roughly equalling that of Spain. The single most important demand driver of gas consumption in Egypt has been power generation which has been and will continue to be the largest gas consumer in the country, accounting for about 60% of total gas utilised.

Egypt is facing a tough choice between domestic gas use and exports as it intends to extend the Arab Gas Pipeline all the way to European markets as well as adding new LNG trains to existing projects (see section on the Developments in the LNG markets). The Arab Gas Pipeline transports gas from Egypt, through Jordan into Syria and Lebanon. Egypt also exports gas to Israel, after signing a contract for delivering 1.7 bcm per year (with an option to take up to 2.1 bcm per year). The opposition criticised the government for securing low prices when domestic gas demand is rapidly increasing, and the export contract went to court, as it was not approved by the parliament. Although contested, the country's Higher Administrative Court ruled, in February 2009, that the exports could continue.

As the government of Egypt decided to prioritise supplies to its domestic market first, a moratorium on new export contracts until 2010 was introduced. The dilemma is that the state wants gas for the domestic market, but the international players might choose to hold off on development of deepwater gas if Egyptian authorities do not agree to a higher domestic price, or to release some of this output to supply new export projects (*e.g.* a new LNG train). For example, the first train at Damietta has not run at full capacity due to a shortage of feedgas. Still, compromises can also be made, as shown by the long-term gas sales deal that Germany's RWE Dea struck with the Egyptian government for the gas from its offshore North Idku gas field in the first half of 2008. RWE had slowed its development plans for this offshore field since 2006, as it was not allowed to develop this gas for LNG exports. This put strong pressure on the Egyptian state, knowing that it needed gas to satisfy the domestic market. RWE was thus able to get a much higher price for its expensive deepwater gas, even though they were not allowed to export their production.

In general, IOCs are required to sell about two thirds of their production to the Egyptian state. This gas will then be sold to the domestic market at low prices given the high levels of energy subsidies.

Plans to phase out such subsidies are being discussed, but this is politically very difficult. This is an issue that needs to be dealt with as current domestic prices by no means reflect the spiralling exploration and development costs seen in the deepwater offshore areas. Meanwhile, the price at which EGAS will buy gas developed by IOCs is now negotiated on a case-by-case basis. In the context of the 2008 licensing round it was reported that the buy-in prices ranged between USD 3.70 and USD 4.70 per MBtu depending on the location of the concession – figures seen quite favourably by the industry, and significantly higher than in some other major producing countries.

The past year has seen some significant additional gas discoveries both on- and off-shore. The Egyptian Ministry of Petroleum is now said to be more confident of increasing proved reserves and supplying more gas both domestically and for export. They have given BP and ENI authorisations for the additional 7 bcm LNG train at Damietta, though financial constraints may now force the companies to delay. Meanwhile, an agreement is said to have been reached for a significant increase in the price of gas for Israel, which would open the way for a resumption of deliveries at full volume.

Libya

Expansion of natural gas production is a high priority for Libya as it aims to use natural gas instead of oil domestically for power generation and industrial activities, freeing up more oil for export. Between 2000 and 2007 natural gas production increased by 180% to reach about 30 bcm per year. Libya is also seeking to increase its natural gas exports, particularly to Europe. Their current export projects consist of the expansion of the existing 8 bcm Green Stream pipeline to Italy by 3 bcm and the expansion of the Marsa El Brega LNG plant. The LNG plant currently has an output level of 1 bcm (0.7 Mtpa), significant below the design capacity of 4.4 bcm (3.2 Mtpa). Sirte Oil Co. (SOC) entered a rejuvenation agreement with Shell in 2005, to redevelop and upgrade the plant, but the work is moving very slowly. Libya has succeeded in attracting foreign investors, both upstream and downstream. Companies like BP, Shell and Exxon are looking for potentially exportable gas. And ENI, the major international player in Libya, is teaming up with Gazprom. For Gazprom, this will be an important step to diversify its supplies and gain more access to European markets. However, exploration in the last year has been disappointing particularly compared with Egypt or Algeria; and without significant new discoveries, growing domestic demand is soon likely to put pressure on volumes available for export.

Domestic consumption, estimated in 2008 at 10 bcm, is forecast to increase to around 30 bcm by 2012. It will mainly be driven by the industrial sector and power generation where gas usage is strongly encouraged by the government. A substantial number of new gas-fired plants are planned, most of them located along the coast. To achieve this, pipeline capacity is being expanded both in the West around Tripoli and in the East beyond Benghazi. A pipeline link between Alexandria and the most eastern city of Tobruk in Libya is also under consideration. As an example on the industrial side, Yara International completed a 50% joint venture with the National Oil Corporation of Libya (NOC) and Libyan Investment Authority (LIA) when they signed the final agreement, in February 2009, to create the fertilizer joint venture Libyan Norwegian Fertilizer Company (Lifeco) that will own and operate the fertilizer facilities at Marsa El Brega. NOC will supply natural gas to Lifeco under a long-term agreement with a price linked to fertilizer product prices.

Iran

Domestic demand for natural gas in Iran is rising steeply. **Consumption grew at an annual average of 8% from 2000 to 2007 reaching 107 bcm in 2007**. The National Iranian Gas Company (NIGC) forecasts a doubling of commercial gas delivery by 2012, equating to a 16% per year growth. This is partly due to heavy subsidies on the domestic market, as well as a desire to reduce dependence on imported gasoline, through gas use in vehicles. The need to reform gas pricing is well recognised in the country. In addition, the ambitious plans for expansion in the petrochemical sector will require large volumes of gas.

Furthermore, the need for reinjection in Iran's maturing oil fields is about to increase sharply. **Currently 30-40 bcm per year of gas is reinjected, possibly growing to more than 100 bcm in 2015**[9]. There are nevertheless disagreements between different governmental bodies on how national gas resources should be used.

Imports

Currently, Iran is a net importer of gas. Tehran receives 9 bcm per year[10] from Turkmenistan through the pipeline that runs from the Turkmen Korpedzhe field to Kurt-Kui on the Iranian side. The gas is mainly consumed by Iranians in the north-eastern corner of the country. The Turkmen supply has been interrupted several times amid price disputes. When deliveries resumed in 2008, Iranian authorities would not disclose how much they were paying. For 2009, it is reported that Iran has agreed to pay USD 350 per mcm. This is at or above the European price, and will require Iranian government subsidies of close to USD 1.5 billion to underwrite the low domestic price level. Capacity for imports from Turkmenistan is likely to be expanded from 8 to 13 bcm per year in the period to 2012. Iran has further signed a deal with Azerbaijan for gas import from the Shah Deniz offshore gas field post 2012, through the spur of the South Caucasus Pipeline (SCP) leading to Turkey via Georgia already extending into Iran, but not being used.

Export pipeline commitments

Meanwhile, Iran has signed a variety of contracts and Memorandums of Understanding to supply gas, mainly to its regional neighbours, few of which have yet been implemented.

Iran is committed to supply Turkey with 10 bcm per year, but there have been several interruptions in Iranian delivery and the

9. Facts Global Energy.
10. The figure is not actual but on contract basis.

average supply since 2003 has been lower at 4-5 bcm per year. Since around 63% of Turkey's current gas demand is met by Gazprom, additional Iranian supplies would significantly reduce Turkey's dependence on Russian supplies. In September 2007, state-owned Turkish petroleum company TPAO signed a preliminary deal to develop three phases of South Pars, and has the option to transport the Iranian gas back to Turkey. The agreement includes plans for two pipelines that would eventually be connected to the Nabucco pipeline in Erzurum. The pipelines' capacity will be 30 bcm per year and will be linked to the Iranian east-west pipeline system. This would allow Turkmen gas to be shipped to Europe through Iranian territory, if Turkmen production is substantial enough.

In October 2008, Iran said it would supply neighbouring Armenia with 1 bcm per year. The amount of gas may expand to 3 bcm later. In exchange, Armenia will supply Iran with electricity (3 kWh per cubic meter gas). Gazprom is to contribute USD 200 million to the cost of the Iranian-Armenian pipeline. Some commentators have suggested that this would relieve the Russians of the need to supply Armenia via Georgia. In March 2009 Armenia announced the completion of the line, but no date for deliveries has been set.

Iran signed a contract in early 2008 with Oman for the transfer of 10 bcm per year by pipeline. The deal implies that Oman and Iran will jointly develop the Kish gas field in the Gulf as well as the Hengam gas field. Oman has been short of gas for its Qalhat LNG plant, but may receive enough from the planned extension to Qatar's Dolphin pipeline via Abu Dhabi.

Iran has not resolved a long-standing dispute with Crescent Petroleum of the United Arab Emirates (UAE) for the supply of 6 bcm per year of associated gas from the offshore Salman field. There are also other potential deals with Bahrain and Kuwait. All these plans are vulnerable to disputes over prices.

The Swiss energy company Elektrizitäts-Gesellschaft Laufenburg AG (EGL) signed in March 2008 a 25-year contract for delivery of gas to its power stations in Italy via a pipeline scheduled to be completed in 2012 (the Trans-Adriatic pipeline, TAP). The contract implies that Iran would sell 5.5 bcm per year through the existing Iran-Turkey link for 25 years.

The long-planned Iran-Pakistan-India Pipeline (IPI) is intended to carry 60 Mcm per day, shared equally by India and Pakistan. But India and Iran have not been able to agree on pricing or on the delivery point for the gas. India has now virtually withdrawn from the project since the terror attacks in Mumbai in November 2008. Without participation by India, it is obviously more difficult for Pakistan to agree on terms and conditions with Iran.

Export LNG commitments

In March 2009, Iran's Oil Minister said that the country has signed a deal with China National Offshore Oil Corp. (CNOOC) to develop the North Pars gas field as an LNG export project. CNOOC plans to invest USD 5 billion in upstream and USD 11 billion in LNG facilities, in exchange for 50% of the production of the field. Russia has also shown interest in developing the South Pars field.

With LNG projects based on South Pars gas reserves involving Total/Petronas and Shell/Repsol on hold for some time, only the Iran LNG project led by National Iranian Oil Corporation has begun site preparation works. No realistic completion date is in sight.

OECD COUNTRIES AND REGIONS

OECD countries account for half of gas use globally, and while many are significant producers, and even exporters, the OECD countries are net gas importers.

North America

- **Natural gas prices rose and fell dramatically, like oil prices, in 2008. However, unlike oil, they have continued to fall sharply well into 2009, to less than half the price of oil on an energy basis.**
- **Demand in the United States, Canada and Mexico also fell sharply late in 2008 and into 2009, notably in industrial and power generation use.**
- **The astonishing rise in unconventional gas production, of at least 50 bcm per annum, reversed the historical decline in United States gas output, and has global implications, through reducing United States demand for LNG.**
- **Whether these production levels can be maintained at prices below USD 4 per MBtu is one of the major uncertainties in the United States and indeed on global gas markets in 2009-10.**

Recent market evolution

In 2008, Henry Hub prices averaged USD 9 per MBtu, up from USD 7 per MBtu in 2007. Prices were particularly volatile, increasing from USD 7 per MBtu to more than USD 13 per MBtu in June 2008 due to increases in oil prices, continuing cold weather in the first quarter of 2008, lower inventories and increased demand (see section on gas prices). After that spike, they have been progressively declining to well below USD 4 per MBtu in March, April and May 2009 despite a colder than average winter season. This recent decline reflects fundamental adjustment to supply and demand conditions in North America as well as a drop in oil prices. Industrial gas demand in particular has fallen sharply, beginning in late 2008 and into 2009, so that in February 2009 industrial gas use was down 15% on a year earlier. At the same time, the conventional wisdom of plateauing or declining US gas production (backed up by around 1-2% per annum decline 2000-06) has been overturned by a sharp increase in unconventional gas production, so that gas output rose around 8% in 2008, continuing into 2009. One outcome has been high storage levels: 54.3 bcm as of early May 2009, 13.7 bcm higher than last year and 10.3 bcm above the 5-year average of 44 bcm. Demand for imported gas (from Canada and LNG) fell 14% in 2008, while LNG imports were down dramatically by more than half. In Canada, prices have followed a similar evolution with a steady increase from around USD 7 per MBtu first quarter of 2008 to USD 11 per MBtu in July before falling to USD 6 per MBtu in February 2009.

Demand

Canada's gas consumption has been relatively stable the last five years, at an average of 96 bcm. Around one-third of Canadian gas demand comes from the residential and commercial sector and is very seasonal. The industrial sector consumes less than one-third and the rest is consumed in the power generation sector. In particular, gas is used by the non-conventional oil industry in order to extract and process oil sands. Gas is used in co-generation processes to generate both electricity and steam. Canadian consumption increased by 4% to 100 bcm in 2008. Also exports saw a fall during 2008, down 6% year-on-year. Natural gas consumption in the **United States was up by 5 bcm in 2008 reaching 657 bcm, a more modest increase than the one seen in 2007 (+39 bcm)**. In 2007, the main drivers were power generation (up 10% year-on-year) and the residential sectors (up 8% year-on-year). In 2008, it was the residential and commercial sector that had the greatest increases, at around 3.5%. The economic slowdown hit particularly the industrial and power sectors, which account for almost 60% of the gas consumption in the United States. The severe economic slowdown has resulted in layoffs and plant

Map 14 **North American gas infrastructure**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA, media reports.

closures, while ammonia and ethanol producers have seen prices and output drop rapidly[1]. Also the steel industry in the United States has been hit hard with production levels down over 50% in January 2009 compared with the same month a year earlier. The drops in both sectors were particularly important during late 2008 and early 2009. In January 2009 and February 2009 industrial gas demand was down 12% and 15% respectively, well below the five-year average. Gas demand in the power generation sector dropped by 3% in 2008 due to a combination of a milder summer, lower prices during the first half of the year, and **lower electricity demand towards the end of 2008. Gas-fired power was down 4% in early 2009.** Still, the low gas prices also have the potential to mitigate some of the demand decline. The current prices have for instance enabled the restarting of some closed-down fertilizer or feedstock plants and gas-fired generation is displacing coal-fired generation in some regional markets, despite sharp coal price declines.

Demand in Mexico followed the pattern seen in many OECD countries. Strong growth in 2006 and 2007 (8-9% in Mexico's case) continued in the first half of 2008, only to be reversed sharply later in the year, with near double digit falls in the last quarter. Gas use in 2008, at 61 bcm, was only marginally up on 2007.

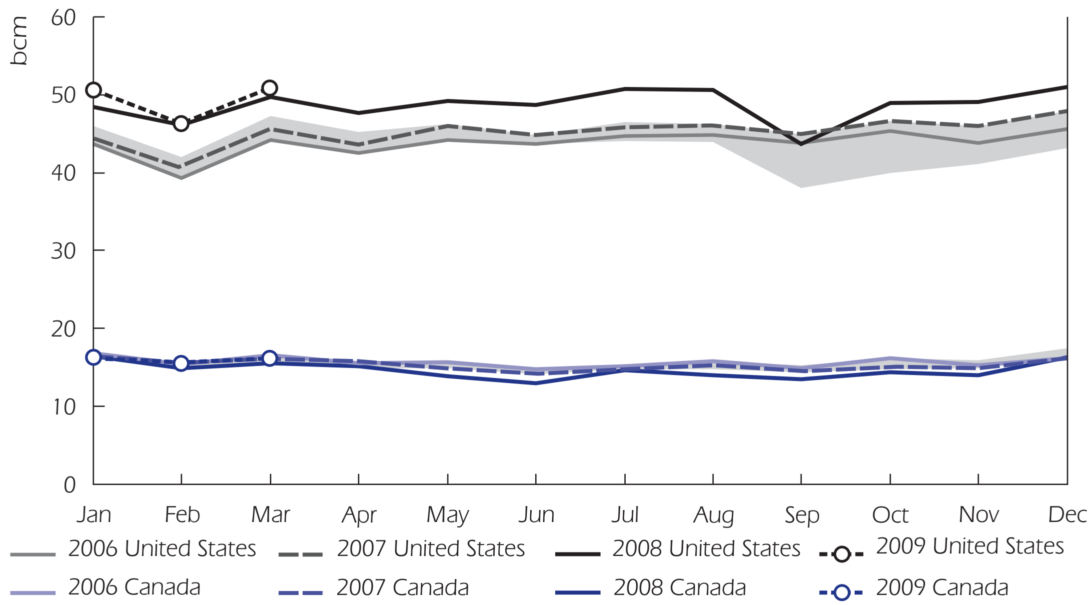
Domestic production

The average monthly year-on-year increase in **natural gas production in the United States for the first and second quarter of 2008 was around 9% compared to the same period in 2007.** The increase was led by the development of onshore fields, *e.g.* in Texas and Wyoming (supported by an increase in the average number of gas rigs in these regions). More than half of the increase in production between first quarter 2007 and first quarter 2008 came from Texas, where supplies increased by 15%. Wyoming followed closely with an increase of 9%, Oklahoma with 6% and in Louisiana with 4%. The production growth in the last two quarters slowed down to a level of around 4% due to hurricanes in September 2008 which reduced the production in the Gulf of Mexico by around 6 bcm. As much as 95% of the gas production in the Gulf of Mexico was shut-in at the start of September; full restoration is not expected until late May 2009.

The Western Canada Sedimentary Basin (WCSB) accounts for 98% of Canadian gas production, of which 80% comes from Alberta, 16% from British Columbia and the remaining 4% from Saskatchewan. **Throughout 2008 Canadian gas production was lower than in 2007, recording a near 5% fall for the year**. Around 57% of Canadian production was exported to the United States, with a drop by around 5% between 2007 and 2008. Canadian gas exports to the United States are likely to remain weak for the next couple of years due to increased United States domestic production and new infrastructure *(e.g.* Rockies Express Pipeline). **Canadian gas production is projected to peak in 2011 at**

1. *E.g.* several ethanol producers have filed for bankruptcy including VeraSun, the United States' second largest producer.

Figure 18 North American production



Key point: United States output grows strongly

Source: IEA.

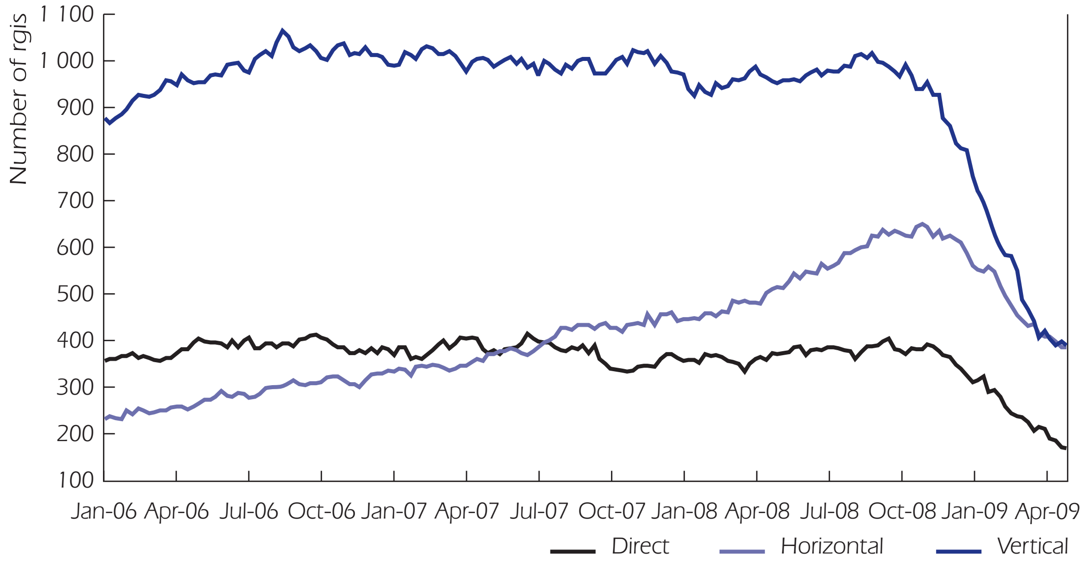
around 187 bcm, and then decline, but this will depend on the future development of the Mackenzie Delta and of coalbed methane production, both of which may become important supply sources.

In the United States, the recent production growth has been driven by unconventional gas. This development has been made possible due to high natural gas prices through most of 2008 and improved technology, especially in the area of shale gas. The high-price environment created the incentives for major investments in drilling programs and there was a significant increase in the number of horizontal rigs.

Low prices combined with the tightness in credit has and will continue to lead to reduced drilling activities. Still, some companies already have commitments for rigs, or there may be other factors preventing immediate shutdowns and cutbacks. According to data published by Baker Hughes[2], **the total number of rigs drilling for gas in the United States peaked at 1606 in September 2008 but was down to 711 end of May 2009**. In particular, North American demand for drilling more complex horizontal wells[3] soared 40% during 2008 peaking in October with a weekly number of 650 rigs. The number of rigs drilling horizontal wells started to decline in the last quarter of 2008 as the

2. US rig report for May 1, 2009. Current and historical data, Baker Hughes.

Figure 19 **Average weekly rigs in North America**



Key point: Low prices led to a significant fall of the number of rigs

Source: US Rig Report for May 1, 2009 - Current and historical data, Baker Hughes.

economic downturn and sharply decreased prices took their toll and was down to 375 in May 2009. The numbers for vertical rigs fell, for the first time, below the number for horizontal rigs as of end-March 2009. This is the result of producers shutting down the rigs drilling less economical, vertical wells first. Horizontal rigs are typically used to develop unconventional gas resources, where decline rates are steeper than for conventional gas, meaning that the producers have to keep drilling to maintain production levels.

Most of the growth in natural gas production in the United States will come from unconventional natural gas (tight gas, shale gas and coalbed methane), following the trend seen in recent years. This growth will be led by shale gas (*e.g.* from Barnett, Haynesville, Fayetteville and Marcellus). The share of unconventional natural gas in total natural gas production is set to increase. Many of the unconventional gas plays are commercially viable at prices of USD 4-5 per MBtu and in specific areas the threshold is estimated to be as low as USD 2-3 per MBtu. As noted above, there has been a steep reduction in the rig counts in early 2009, but the largest share of the reductions has been in the vertical rig count as producers have shut down the less efficient, more costly rigs in the less prospective areas first. This has to some extent, balanced the production picture as

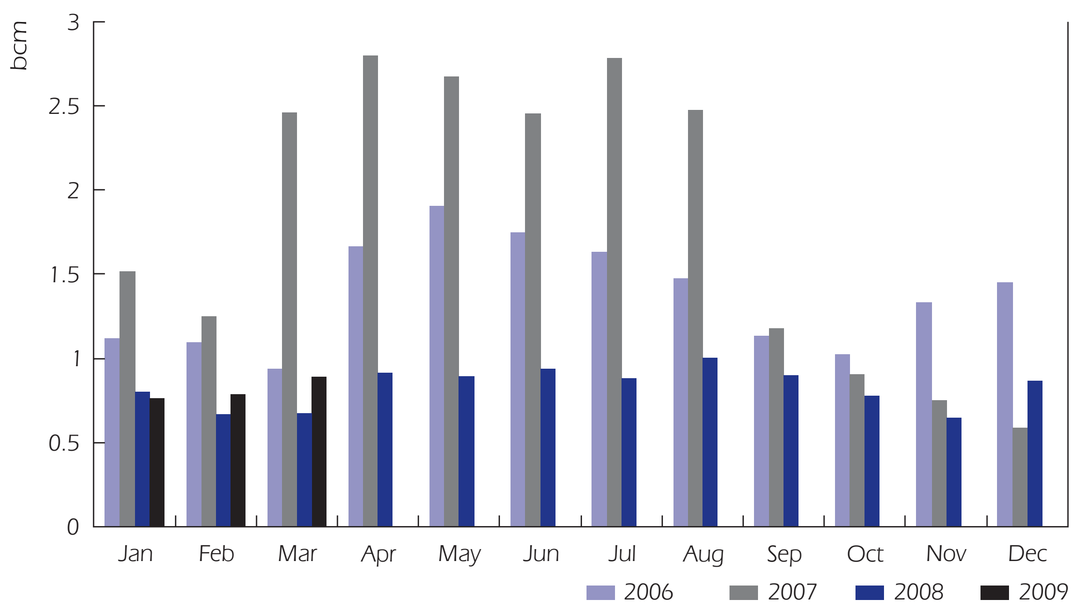
3. Both oil and gas drills.

the rigs kept in operation have a higher degree of efficiency in combination with being moved to areas with better prospects.

Notwithstanding these declines in drilling, gas output in early 2009 continued to increase by around 4%. Nonetheless, **it seems very likely that this fall in the rig count will lead to a slowdown in gas production**. The actual effect on the production level will depend on various factors making it hard to predict. A decline in production would normally push the price for natural gas upwards (assuming demand also recovers) and thus lead to an eventual recovery in drilling. The price picture will also be affected by external forces, through the LNG imports planned for the United States. A recovery of production, if it occurs, will thus depend on both national and international market forces. As noted above, some of the unconventional gas can survive prices down to USD 2-3 per MBtu, and is therefore able to compete with or reduce the levels of LNG that are potentially available to the US gas market (see section on the Development in the LNG markets).

The average weekly number of rigs drilling for gas in 2007 in Canada fell significantly from the 2006 numbers, ending at 215, down from 361 rigs, and increased only modestly in 2008 to 220. It has been down to 40-50 since late April 2009. Most of the drilling in Canada took place in Alberta, closely followed by British Colombia. The production of natural

Figure 20 **Annual LNG imports to the United States**



Key point: LNG imports divided by two between 2007 and 2008

Source: IEA.

gas in Canada declined from 188 bcm in 2006 to 175 bcm in 2008.

Again developments in Mexican gas output mirrored those seen in a number of producing countries. Growth was strong in 2006 and 2007, at double-digit rates, continuing into 2008. But falling prices have seen growth disappear, leaving output flat in the latter part of 2008 and early 2009 compared with a year earlier. Total output in 2008 was still up a healthy 4.4% over the previous year, at 58 bcm.

Supply balance

Total natural gas imports to the United States reached a record high of 130 bcm in 2007. The 2008 level is down by almost 14% compared to the 2007 level, at 113 bcm. Since March 2008, imports from Canada have been generally lower than 2007, culminating in December 2008 when they were 12% below December 2007. LNG imports in 2008 were particularly affected as they fell by 54% to just under 10 bcm compared with a record level of almost 22 bcm in 2007. The recent price situation together with the increase in domestic production in the United States has had global implications through the LNG trade; **LNG volumes previously planned to meet United States' needs are now available to other markets** (see section on the Development in the LNG markets). The United States is a net exporter to Mexico. Imports from the United States increased by 25% between 2007 and 2008 while exports declined by 20%.

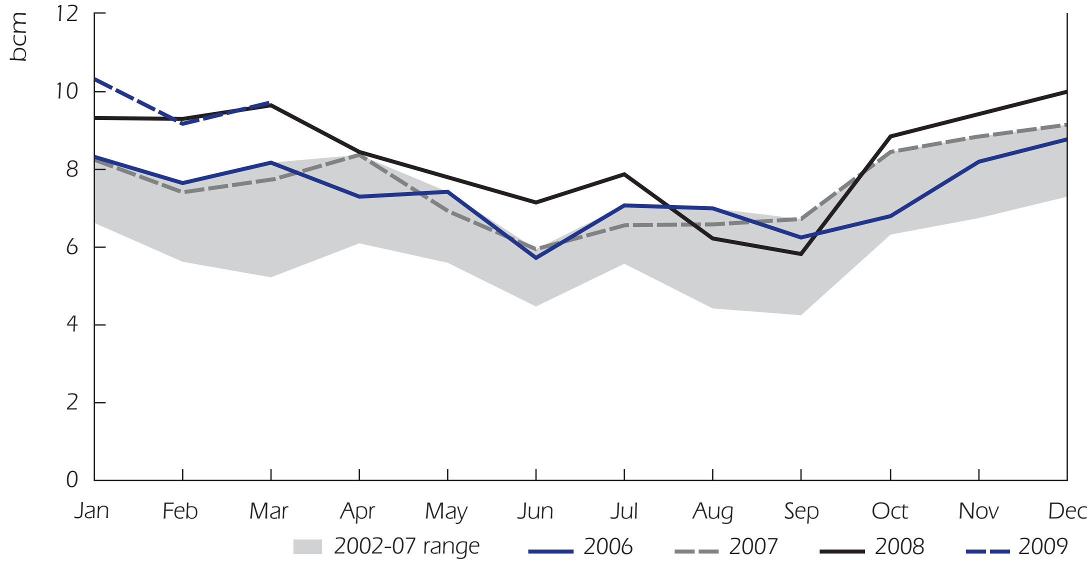
Norway

- **Norway is the IEA's second biggest gas exporter, 93 bcm by pipeline in 2008; in addition Norway will export 6 bcm per year of LNG from the Snøhvit facility when it reaches full production.**
- **Gas production at 100 bcm in 2008 is set to rise to between 115 and 140 bcm within the next decade.**
- **Acreage releases will be necessary to attain this production objective.**
- **Pipeline systems need to be expanded and extended if export goals are to be reached.**

Norway is the second biggest exporter of gas to Europe, behind Russia but ahead of Algeria. While oil production on the Norwegian Continental Shelf (NCS) has shown a falling trend, natural gas production has been increasing steadily from 77 bcm in 2003 to 100 bcm in 2008, a 10% increase over 2007, continuing this growth in 2009. 60 fields on the NCS are currently producing, 11 fields are under development and 73 discoveries await appraisal. During 2008, about every second exploration well resulted in a discovery and in total, 25 oil and gas discoveries (15 gas discoveries) were made on the NCS, resulting in a record year[4] adding 49-97 bcm of recoverable gas. The largest share of the gas discoveries were made in the Norwegian Sea.

4. To compare, 12 discoveries were made in 2007 (NPD).

Figure 21 **Norwegian gas production 2002-09**



Key point: Norwegian gas output increased strongly in 2008 and early 2009

Source: IEA.

Most exports are via pipeline to Europe but Norway started to export LNG in 2007 from the offshore arctic field of Snøhvit and can now reach the Asian and North American markets. The last major development in the Norwegian pipelines network was the 25 bcm Langeled pipeline to the United Kingdom which came on stream in October 2007. The 7 bcm Tampen Link connecting the Statfjord field with the existing Far North Liquids and Associated Gas System (FLAGS) was officially opened the same month.

StatoilHydro is the main player on the NCS. Petoro, a state-owned limited company, was established in 2001 to manage the state's direct financial interest (SDFI)[5]. Gassco operates the pipeline system from the fields to the European markets on behalf of the owners grouped in Gassled. Gassled was established in 2003 as a joint venture of oil and gas companies operating on the NCS. For 2008, the Ministry of Petroleum and Energy offered production licenses to 40 companies of which 26 were foreign. Of these 40 companies, 19 companies were offered operatorships, including 15 foreign[6].

5. In 1985 Statoil's NCS licenses were split in two. Statoil was allowed to keep one half and the SDFI was given the other half.
6. BG Norge AS, Centrica Resources Norge AS, ConocoPhillips Skandinavia AS, Dana Petroleum Norway AS, Dong E&P Norge AS, Eni Norge AS, Lotos E&P Norge AS, Lundin Norway AS, Maersk Oil Norway AS, Marathon Petroleum Norge AS, Nexen Exploration Norge, OMV Norge AS, Premier Oil Norge AS, Talisman Energy Norge AS and Wintershall Norge AS.

Gas sales

Gassco transported 93.3 bcm of Norwegian gas to European terminals during the gas year 2007-08, 9 bcm more than the previous gas year. StatoilHydro sold around 80 bcm during that period, including the group's own production (around 39 bcm), third-party gas and gas sold on behalf of the SDFI. **StatoilHydro is the second biggest gas supplier in Europe and the sixth biggest in the world[7].**

Norway's biggest markets are Germany, the United Kingdom and France. Domestic gas usage in Norway is insignificant compared to exports, at less than 7 bcm in 2008, up 26% from 2007[8]. The largest consumer of gas domestically is the Tjeldbergodden methanol plant. The 420 MW gas-fired power plant at Kårstø which started in November 2007 has hardly been used due to high short-run marginal costs and declining electricity prices. The low gas prices observed since early 2009 combined with the collapse of CO_2 prices resulted in a restart of the plant in February 2009.

Supply outlook and Infrastructure development

Norway is likely to continue to play an important role as a gas supplier to European gas markets as Europe is expected to become increasingly import dependent and aims to diversify gas supplies. Increased exploration for gas and the development of new fields such as Ormen Lange and Snøhvit is expected to continue. Although the Norwegian Ministry of Petroleum and Energy expects NCS oil and gas production to fall after 2015[9], gas should exceed falling oil production in 2013 and reach a production level between 115 and 140 bcm within the next decade.

Sustainability is an important issue in Norway. The emission level from gas production in Norway is lower than in other oil and gas producing countries. This has been achieved through innovative work such as removing CO_2 from gas produced in the Sleipner field and reinjecting it into a deep geological layer below the Sleipner platform. A CO_2 offshore tax was introduced in 1991, and currently amounts to USD 50 per tonne. Furthermore, the Norwegian government aims at increasing its effort regarding carbon capture and storage (CCS), in particular on the Kårstø power plant and Mongstad refinery.

Investment in exploration and production will be crucial to reach production targets. Statistics Norway (SSB) estimates **2009 total investments[10] for oil and gas production will amount to NOK 137.4 billion[11]**. Although they have been adjusted down from previous estimates due to tough economic conditions, they are **still higher than last year's investments of NOK 123.9 billion**.

7. The group sells gas to customers in Germany, France, Belgium, Italy, the Netherlands, the UK, the Czech Republic, Austria, Spain, Denmark, Ireland, Norway, Azerbaijan, Georgia, Turkey and the USA.
8. OECD data.
9. Development of production on the Norwegian Continental Shelf"; KonKraft report 2, December 2008.
10. First quarter 2009.
11. 1 USD = 6.5 NOK (May 2009).

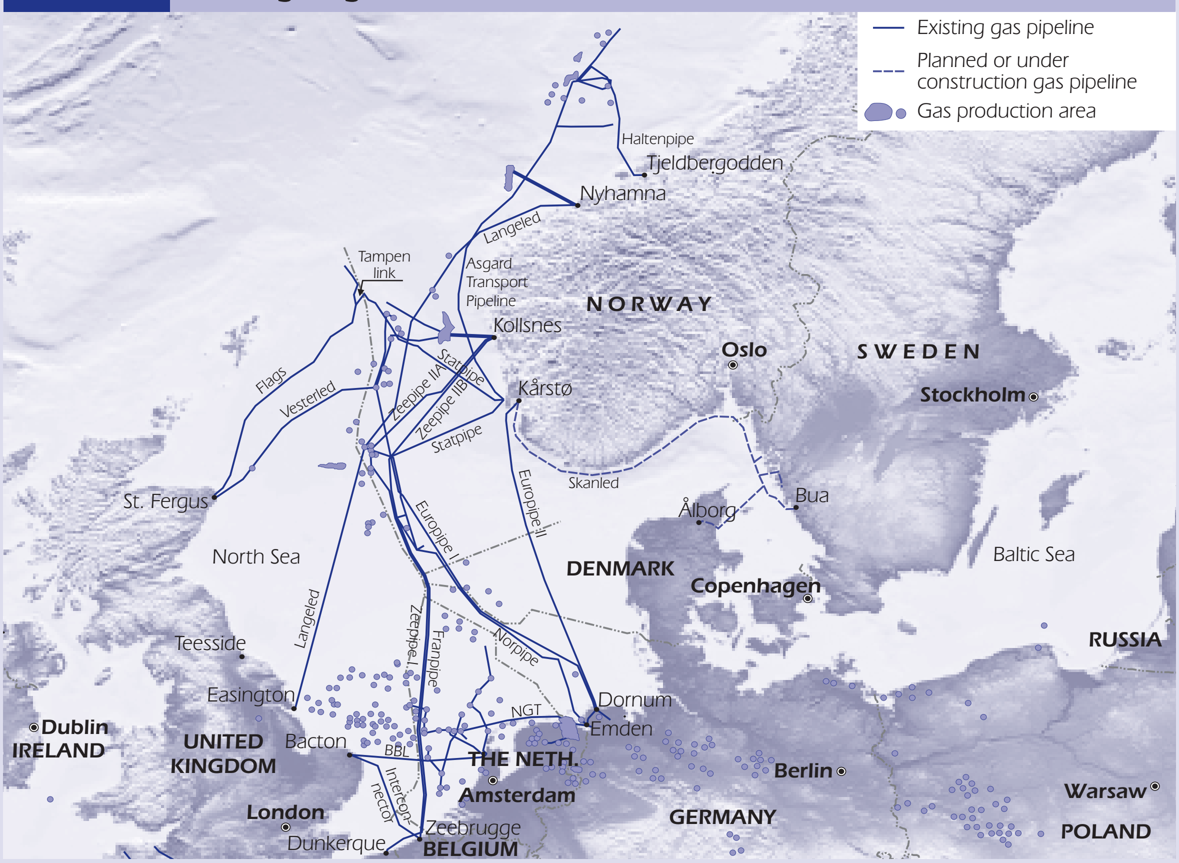
In 2009 investments in exploration (and concept studies) alone are expected to reach NOK 29.2 billion (EUR 3.3 billion).

Norway's long-term role as a major gas supplier to Europe will depend on two key factors:

- The potential opening of new areas on the NCS for oil and gas activity, in particular offshore Lofoten and Vesterålen which have been closed for exploration activity. The decision lies with the Norwegian Parliament (the Storting).
- The current export capacity stands at 120 bcm compared to a production level close to 100 bcm in 2008. Transportation capacity is thus a limitation for the new gas coming from the Norwegian Sea and needs to be debottlenecked.

The plan to build a pipeline from the Troll field to Europe was shelved in November 2007, when the Norwegian government announced that it would not support the

Map 15 **Norwegian gas infrastructure**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA, company announcements.

Troll Future Development plans to increase gas production from the field[12] due to a possible negative impact on future liquids production.

Norway has been considering a 843 km pipeline from Kårstø to Grenland and then to the Swedish west coast and to Denmark, the Skanled gas pipeline. It could be extended to Poland (the Baltic Pipe). The export capacity would be 24 Mcm per day up to Grenland and 20 Mcm per day afterwards. Bringing gas to Grenland has been favoured by politicians and industrials such as Yara International. In February 2009, Petoro reached an agreement on behalf of the Norwegian government to take up to 30% share in Skanled whereby Østfold Energi and Agder Energi would transfer their respective shares; while Skagerak Energi's stake would be reduced from 20 to 10%. Gasunie had agreed to join the project.

The Skanled Project Group decided in April 2009, to suspend the project, due to increased commercial risk combined with the global economic developments that have given an uncertain view on future gas demand. The project might be re-launched if the commercial conditions become more favourable in the future according to Gassco.

Netherlands

- **The Netherlands has the highest gas use of any IEA economy, as a percentage of total primary energy supply.**
- **Gas provides around 60% of the Netherlands power output, and in the short-term new gas-fired capacity is being constructed.**
- **The Netherlands remains a significant exporter of gas with an important ability to meet sharp demand swings.**

The discovery of the Groningen field 50 years ago enabled the Netherlands to move away an energy economy dominated by coal and oil. Within 10 years, three quarters of the population had been connected to gas, and within 20 years, 98% of the population and most commercial and industrial users burnt gas. **Gas now represents 40% of primary energy demand – the highest in the IEA**. The Netherlands is not only the fifth largest consumer of gas in OECD Europe; it is also a net exporter supplying pipeline gas to surrounding countries and a provider of swing capacity to cope with seasonal and other demand variations. However, the Netherlands is gradually entering a new period of development: as a result of the expected decline in production, it is expected to turn into a net importer within two decades. The Netherlands is seizing this opportunity to become a major transportation hub for the North West European region.

12. Holds about 10% of the oil and gas on the Norwegian Continental Shelf. By far the biggest Norwegian gas field – it is four times the size of Ormen Lange.

Recent market evolution

Since the liberalisation of the Dutch gas market in July 2004, the market has been increasingly dominated by large international players, mostly by means of acquisitions of smaller Dutch utility companies. In 2008-09, this trend of consolidation continued with the planned takeover of Essent by RWE and of NUON by Vattenfall. Only Eneco and Delta remain independent Dutch utility companies, while Gasunie took over BEB's transmission network creating the first supranational transmission company.

The Minister of Economics plans additional measures to further improve liquidity, among which are a simpler balancing regime, an improved access to cross-border capacity and the offering of quality conversion as a system service.

Demand

In 2008 total Dutch gas consumption totalled 50 bcm, some 7.9% higher than in 2007 due to a colder winter. The Netherlands has a mature natural gas market with the highest penetration rate in OECD Europe and as a result little room for expansion. Consequently the consumption of natural gas in the household, commercial and industrial sector has been gradually decreasing due to technology improvements and efficiency savings. An exception is power generation where close to 60% of power is gas-fired and is expected to grow.

Future gas consumption depends heavily on environmental policies as the Netherlands plans to reduce its GHG emissions by 2020 by 30% compared to 1990 levels and to improve energy efficiency levels by 2% annually (compared to 0.9% currently). These targets will tend to put downward pressure on gas demand in most sectors, but uncertainty prevails in the power sector.

In the household sector, the Energy Performance Coefficient for new build houses, improved insulation, and competition from all-electric houses in the new build segment will contribute to the declining trend. Demand in the commercial sector will be affected by boiler replacements, improved insulation and a decrease in the working population. Demand in the industrial sector is expected to remain rather stable or slightly decline due to increased energy efficiency.

In the power sector, between 16 GW and 17 GW of new capacity is planned, exceeding by far demand growth – noting that the Netherlands imports about one-fifth of its electricity needs. In the short term to 2011, most of the new capacity under construction is gas-fired – around 2.8 GW compared to total generating capacity of 20 GW. But there are also 2 GW of renewables, mainly wind and for the period 2011-14 around 5 GW of coal-fired capacity is planned. However, the economic recession, the tight credit market added to a strong opposition from environmental organisations might endanger the (timely) realisation of some of these projects.

Domestic production

On 1 January 2008, the remaining reserves in the Netherlands amounted to

Table 21 Power plant projects in the Netherlands

Location/Name	Company	Capacity (MW)	Primary fuel	Planned start-up	Status
Eemshaven/ Magnum	Nuon (1st unit)	350	Gas/coal	2011	Construction halted
Eemshaven/ Magnum	Nuon (2nd unit)	850/1 050	Gas/coal	2014	Permit
Borcele/ Sloecentrale	Delta	870	Gas	2009	Construction
Lelystad/ Flevocentrale	Electrabel	900	Gas	2009	Construction
MaasStroom/ Maasvlakte	Intergen	419	Gas	2010	Construction
Schoonebeek	NAM	130	Gas	2010	Construction
Maasvlakte	Unknown	600	Gas	2011	Unknown
Moerdijk	Essent	430	Gas	2011	Construction
Maasbracht/ Clauscentrale	Essent	640	Gas	2012	Construction
Maasvlakte	Enecogen	840	Gas	2012	Permit (FID Q2 2009)
Eemshaven	Advanced Power	1 200	Gas	2013	Permitting
Bergum	Electrabel	454	Gas	2014	Planned
Eemshaven	Electrabel	125	Gas	2008 (?)	Unknown
Amsterdam	Nuon	500	Gas	Unknown	Planned
Diemen	Nuon	500	Gas	Unknown	Planned
Maasvlakte	E.ON	1 050	Coal/biomass	2012	Construction
Maasvlakte	Electrabel	800	Coal/biomass	2012	Permit
Eemshaven	RWE (1st unit)	800	Coal/biomass	2013	Permit
Eemshaven	RWE (2nd unit)	800	Coal/biomass	2014	Permit
Geertruidenberg/ Amercentrale	Essent	800	Coal/biomass	2014	On hold
Sas van Gent	Delta	82	Biomass/gas	2010	Unknown
Delfzijl	Aldel	115	Biomass/gas	2014	Planned

Source: Tennet and companies websites.

1 390 bcm of which 1 075 bcm were from the Groningen field, 117 bcm from onshore small fields and 198 bcm from offshore small fields. The Netherlands produced 85.7 bcm in 2008, up by 11.8 % from 2007. 54% was produced by the Groningen field and 46% by the small fields. This represents 14% of OECD Europe supply. Since 1974, the government has applied a total production cap and the "small fields" policy in order to develop as many of the smaller gas fields as possible, given them priority over production from the Groningen field. This has contributed to a large increase in the

small fields' output and to the development of offshore gas. This policy proved highly successful since up to now around 36% (1.1 tcm) of all produced gas (3.0 tcm) in the Netherlands originated from fields other than Groningen. Exploration activity has been nevertheless declining in the Netherlands with only 12 wells drilled in 2008, although seven new gas fields started producing. Consolidation has also been taking place in the upstream sector: NUON acquired Conoco Phillips' Dutch subsidiary Burlington, GDF SUEZ took over a large part of NAM's assets in the Netherlands; and Total acquired Talisman's Dutch subsidiary Goal Petroleum Nederland B.V.

Dutch gas production is expected to start to decline in the next years, especially the production from the small fields. In the near term, this decline can be partly compensated by an increase in the production from the Groningen field. However, the speed of production decline will be partly determined by a successful continuation of the small fields policy. In particular, offshore production is time-constrained by the presence of the required offshore infrastructure and by the flexibility of the Groningen system for load factor conversion of the small fields' gas. If most of the infrastructure is dismantled in around 15-20 years, reserves have to be developed rapidly. Several measures are already being taken. One is the handling of the so-called "sleeping" concessions, where permit holders either perform exploration and production activities themselves or outsource them to third parties. Another includes fiscal measures to make the exploration and production of the marginal fields more attractive. Another challenge is the competition from offshore wind parks. Finally, compression work is being done on the Groningen field within the Groningen Long Term (GLT) project: in order to maintain reservoir pressure, a total of 460 MW of compression will be installed by end 2009.

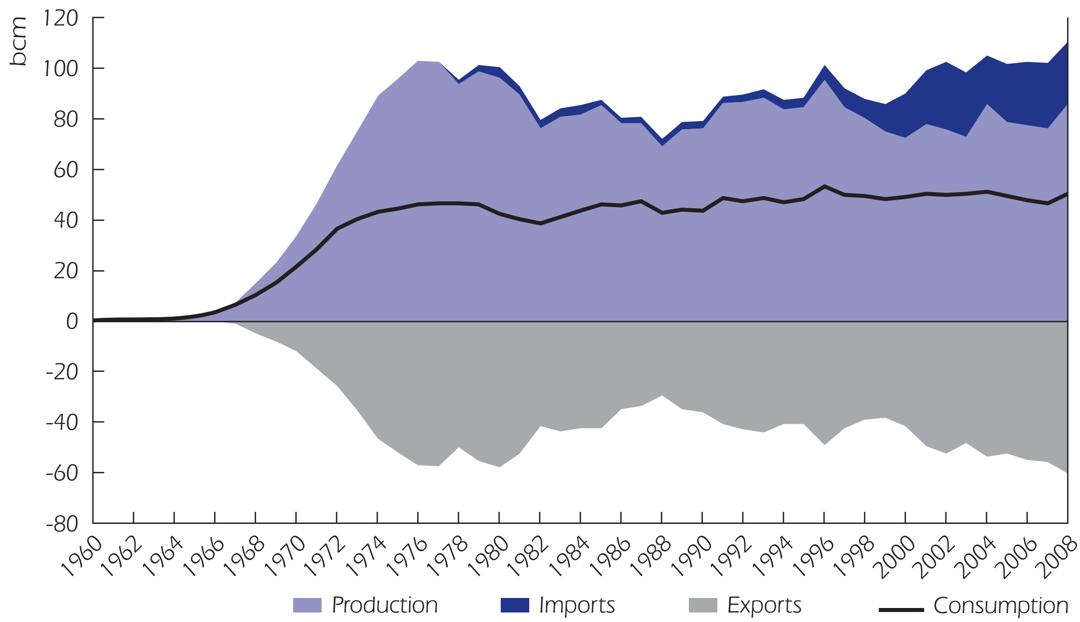
Supply balance

The Netherlands started exporting gas to Germany in 1964 and since then total exports have been increasing. Exports in 2008 increased by 8% to 60 bcm due to colder weather. Exports were sharply weaker in the last quarter of 2008 but showed **a sharp increase in January 2009 from colder weather and the disruption of Russian supplies. In January 2009, net exports were 40% higher than January 2008.**

The Netherlands now supply gas to Germany, Belgium, France, Switzerland, Italy and the United Kingdom on the basis of long-term contracts. With the contract between GasTerra and Centrica starting in December 2006, the Netherlands started exporting gas to the United Kingdom through a dedicated pipeline the Balgzand to Bacton pipeline (BBL). In 2008 GasTerra prolonged the existing long-term agreement with E.ON Ruhrgas until 2028, supplying an additional 60 bcm.

In parallel, the Netherlands started to import relative small volumes of pipeline gas since the mid-seventies, which increased significantly at the end of the nineties with the start of market liberalisation. The main exporters to the Netherlands are Norway, Russia, Germany and Denmark. **In 2008, imports reached**

Figure 22 Dutch gas balance 1960-2008



Key point: A major gas exporter but imports are increasing

Source: IEA.

25.3 bcm. As Gasunie is participating in the Nord Stream pipeline, additional Russian volumes could reach the Dutch market.

Infrastructure developments

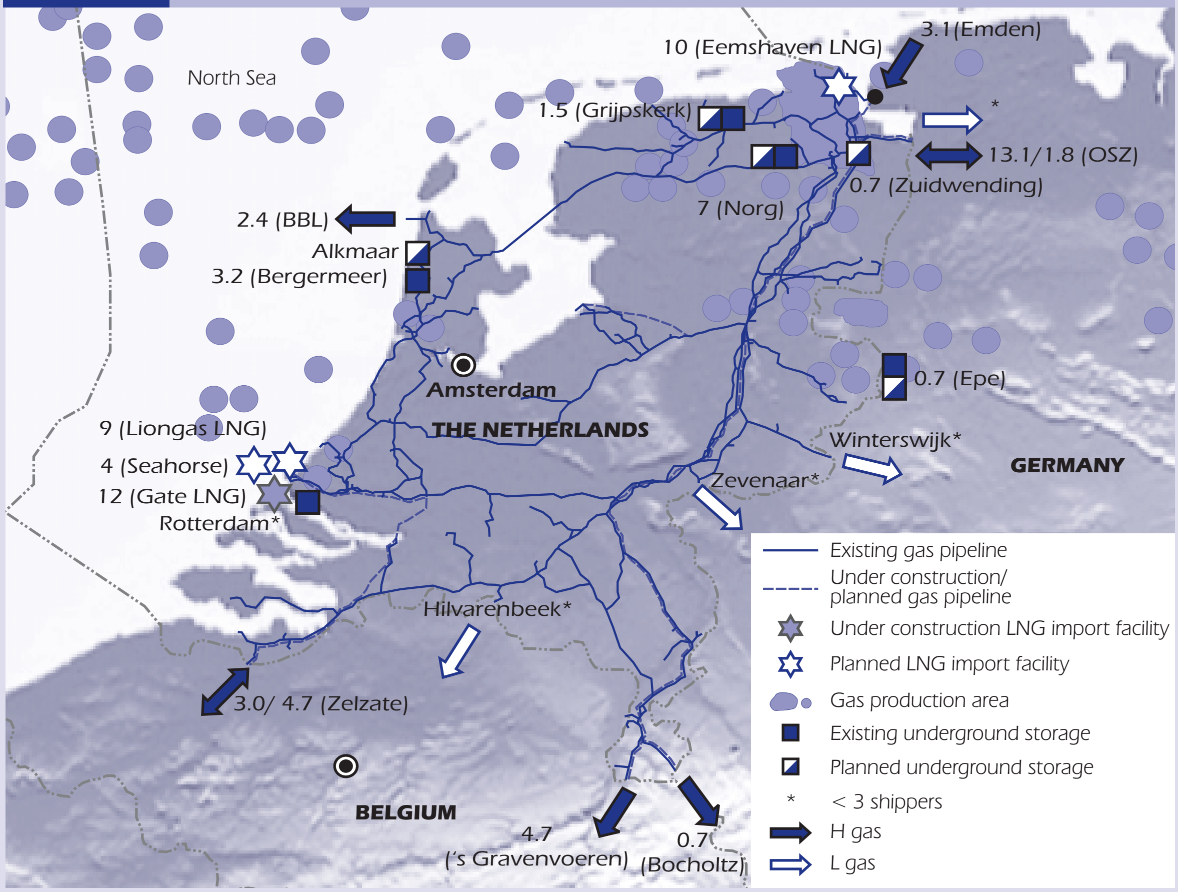
The Netherlands aims to become a European hub for gas based on its central geographical position in Northern Europe, the existing transport and storage infrastructure, and the plans to develop further import and transport infrastructure.

Four LNG terminals are planned, the most advanced being the GATE LNG terminal from Gasunie and Vopak. The terminal is under construction in Rotterdam and scheduled for completion in 2011. Two other LNG terminals are planned in Rotterdam by 4Gas and Taqa and another in Eemshaven by Essent, Gasunie and Vopak. It is likely that another terminal will be built.

In 2007 the high pressure transmission grid owned by Gasunie consisted of 12 050 km and the local distribution grid of 123 635 km. A major number of projects are currently under way, enabling the concept of a gas roundabout. Gasunie started in 2008 with the North-South project aiming at building 485 km of new pipelines by 2012.

Next to these pipeline expansions, multiple storage projects are underway, in various phases of development. Currently Gasunie and NUON are constructing four salt caverns at Zuidwending. Further

Map 16 **Gas infrastructure in the Netherlands**



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Source: Petroleum Economist, IEA.

expansion of the German Epe salt caverns is planned[13], as well as the expansion of the storages of Norg and Grijpskerk. Finally Taqa is preparing a final investment decision for a large new gas storage facility in the depleted gas field of Bergermeer.

Spain

- **Spain has seen a sharp increase in gas consumption of 65% over the period 2003-08.**
- **Gas-fired power has been a major factor, increasing five fold over the period 2000-08.**
- **Spain is the number three LNG consumer globally; this has been a major means of diversifying gas supply from more than 70% dependence on one supplier in 2000 to around 32% dependence in 2008.**

Spain is the sixth largest European gas consumer and has been one of the fastest growing gas markets in Europe. Natural

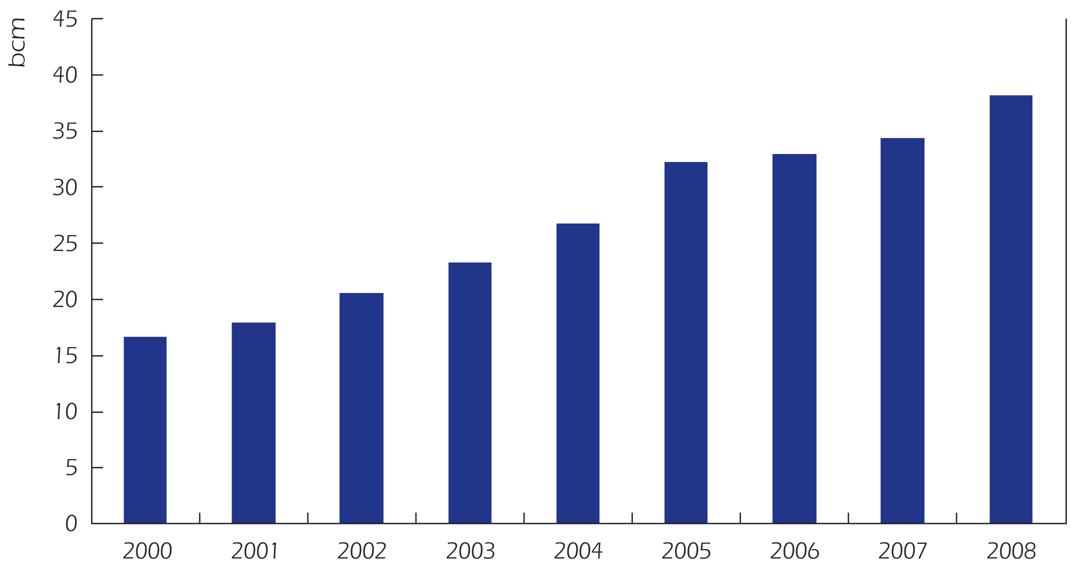
13. Basically Dutch storage, as it is only connected to Dutch grid.

gas' share in the country's Total Primary Energy Supply in 2007 was 21.8%, slightly below OECD countries' average. Gas demand increased from 23.2 bcm in 2003 to 38.2 bcm in 2008.

Spain has been very successful in diversifying its supply sources with LNG representing around two-thirds of total supplies. Six LNG terminals are now operational, representing a capacity of 58 bcm compared to 14 bcm for the two gas pipelines from Algeria and France. Spain is now looking at enhancing this supply capacity as well as reinforcing the interconnections with the wider European market. Since end-2007, Spain has been working with Portugal on building an Iberian gas market – MibGas.

The liberalisation of the gas market has been particularly impressive. In 2007, the liberalised market represented 88.5% of the total market compared with 11.5% for the regulated market. Many small users switched due to the progressive and planned disappearance of the regulated market (and tariffs) in July 2008. A new system of last resource tariff and defined time frame to 2010 for gradual reduction in the consumption threshold has been introduced for small users who had not switched after July 2008. Five last resort suppliers have been appointed by the Government: Gas Natural, Iberdrola, Endesa, Union Fenosa and Naturgas.

Figure 23 Spanish gas consumption 2000-08



Key point: one of the fastest growing markets in OECD Europe

Source: IEA.

Gas demand

Gas demand remains dominated by the industrial sector which accounts for 50% of total demand, compared with 35% for power generation and 14% for the residential and commercial sectors. But industrial demand has remained flat over the past years. **Demand growth was essentially driven by the power generation sector** – where gas has become the fuel of choice – and to a lesser extent by the residential sector. Gas penetration remains lower than in other countries with 6.8 million gas customers (out of a population of 44 million) but the connection of new households has been impressive increasing more than 60% since 2000. Between 2000 and 2007, gas-fired power increased nearly fivefold, from 20 TWh to 95 TWh, equal to almost all incremental power demand. During the past three years, total gas consumption increased at 6% per year on average, largely driven by the new CCGTs coming on line. Demand increased by 11% to 38 bcm in 2008, driven by record consumption from the power generation sector during the first quarter. Due to very low hydro levels during winter 2007-08, gas-fired plant utilisation increased substantially and peak daily gas demand broke several records.

However, **demand has considerably weakened during the last quarter of 2008, and especially the first quarter of 2009 according to the state-owned TSO Enagas, which reported a 31% consumption decline from power generators and a 9% decline from other sectors**, for a total demand decline of 17%.This is due to the economic crisis impacting industrial demand, and for the power sector, to a combination of weaker electricity demand, higher hydro levels and increased wind output. Furthermore gas-fired plants are higher on the merit curve than nuclear, hydro and wind, and for power generators with contracts with an oil linkage their plants are not competitive against coal.

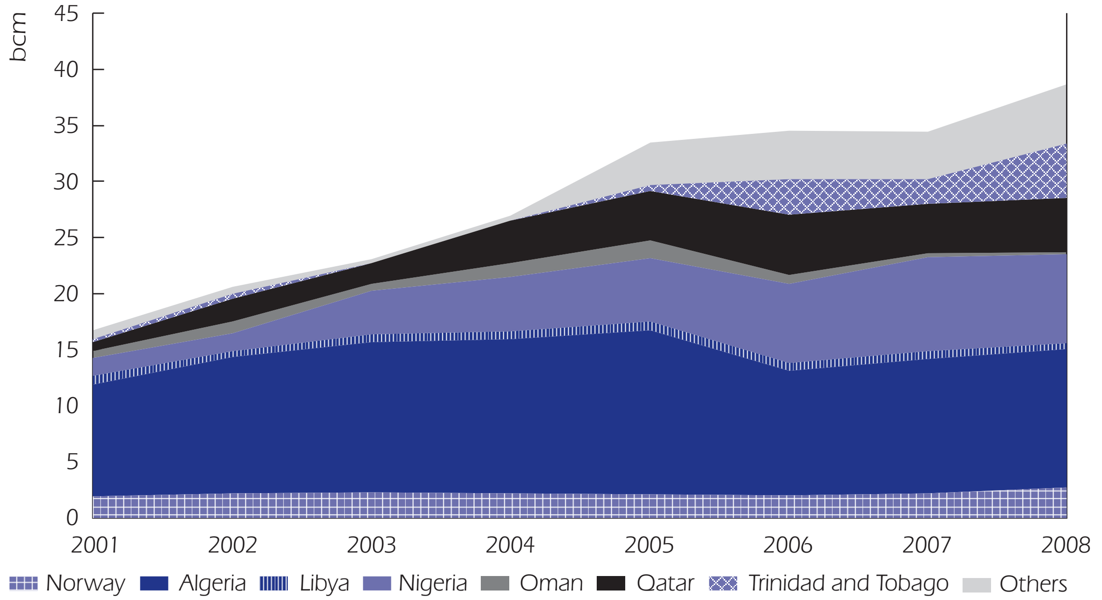
The power generation sector remains a key consumer with growing potential; gas-fired power was forecast to grow from 95 TWh in 2007 to 141 TWh by 2016. In 2007, 14 new CCGTs joined the system, totalling more than 5 GW of capacity and in 2008 0.6 GW. Although demand is likely to be weaker in 2009, most power plants under construction and planned are gas-fired or wind. Furthermore, Spain has indicated a desire to reduce the share of nuclear power in the mix, currently at around 20%.

Gas supply

Spain imports more than 99% of its gas needs and is the world's third-largest importer of LNG. Less than 80% of imports are based on long-term contracts indexed to oil prices. The ratio of piped natural gas to LNG deliveries has been declining from "50% LNG-50% piped gas" structure in 2000. A significant increase of LNG volumes was observed up to 2007, when 68% of total import was supplied as LNG, 32% as piped gas.

In 2008, 32% of gas was imported from Algeria – both pipeline and LNG, followed by Nigeria with 20%, Qatar with 13%, Trinidad and Tobago with 12% and Egypt with 11% and Norway with 7%. Norway started exporting LNG in 2008 but most supplies are still pipeline gas. Algeria's share

Figure 24 **Evolution of Spanish gas supply**



Key point: Rapid diversification of supply sources

Source: IEA.

has declined significantly from 70% in 2001 while Spain has remained the second largest market for Algerian gas. The arrival of gas from the Medgaz pipeline (8 bcm annually, by mid-2009) will raise this share, although some gas may also flow north into France, The Royal Decree 1766/2007 limits imports from one single country to a maximum of 50% compared to 60% in the previous Royal Decree 1716/2004.

Spain has been able to attract many spot LNG cargoes in the past due to TPA to key infrastructure. A quarter of the capacity of regasification, storage, transportation and distribution system intake installations is set aside for short-term contracts, less than two years long[14]. This often results in under-utilisation of the LNG terminals: the Barcelona, Huelva and Cartagena terminals operated by Enagas were used at 30-40% in 2008, compared with 50%-70% for the other LNG terminals Bahía de Bizkaia, Reganosa and Sagunto.

Infrastructure development

According to the Hydrocarbons Sector Law (1998), energy planning is mandatory for basic gas infrastructure. The last Strategic Plan 2008-16 was adopted in 2008 by the government to provide a

14. "The utilisation rate of the LNG terminals is low because they are designed to deal with the demand peaks of the Spanish Gas System, which is characterised by a highly seasonal demand." Source: country submission.

stable regulatory framework and secure enhanced investment in the development of the grid. Spain is keen to develop both additional LNG terminals and pipeline capacity. The last LNG terminal Reganosa started in 2007 and most of the existing six LNG terminals are expected to be expanded by 2013. A new LNG terminal El Musel on the Northern coast is planned by Enagas by 2011. Two additional LNG terminals would be located in the Canary Islands (Tenerife and Gran Canaria). Furthermore, the Medgaz pipeline is expected to be operational in 2009, rebalancing the LNG-pipeline capacity equilibrium.

Another key point is the **development of international pipeline connections, which remain weak**, with the exception of the Spanish-Portuguese interconnection and two existing connections with France at Larrau – the 2.6 bcm Lacal pipeline used for transit through France of Norwegian gas, and Biriatou – the 0.5 bcm Euskadour line linking the Bilbao terminal to the TIGF network. The capacity of these interconnections is expected to be enhanced in both directions and open seasons are currently being conducted. The enhanced co-operation of the French and Spanish TSOs has been promoted within the framework of ERGEG South Gas Regional Initiative. It has resulted in launching of a joint Open Season Period in November 2008 as a part of the commercialisation of the capacity

Map 17 Spanish gas infrastructure

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Petroleum Economist, IEA, company announcements.

in existing (after application of the TPA rules) and planned capacity. A third interconnection project to the eastern side in Catalonia (MidCat project) is at the planning stage and aims at building a 13.5 bcm bi-directional pipeline by 2015.

Spain also lacks underground storage with only two underground storage facilities, both depleted gas fields operated by Enagas, in Gaviota and Serrablo representing a total capacity of 2 166 Mcm – around 6% of annual demand, which is low compared to other countries. Shippers are therefore obliged to keep stocks of an amount equivalent to 20 days' of their sales/consumption. Therefore, new underground facilities are planned: Enagas has been awarded an administrative licence to convert a third depleted gas field, at Yela. Yela has a capacity of 1.05 bcm and should be operational by 2011. Three other projects Castor, Marismas and Reus are currently under development and will double storage capacity, up to 5.76 bcm by 2016, accordingly to the latest infrastructure plan.

This modest underground storage capacity necessitates using LNG storage at the terminals. This capacity is also to be expanded; for example Barcelona, Cartagena, Huelva, Sagunto Terminals are going to add storage tanks of 150 000 m^3 each.

Market developments

The Spanish market has witnessed major recent developments in terms of gas industry structure. First of all, liberalisation increased the number of active traders to 14: in 2007 the incumbents represented 61% of the liberalised market compared to 39% for new entrants. Gas Natural's share of the total gas market dropped from 64% in 2002 to 48% in 2007. **One of the main features was the gas-power convergence** with existing gas incumbents entering the electricity market through increased gas-fired fleet and vice-versa. Gas Natural has been the most successful entrant into the electricity sector.

Most of new entries to gas and electricity markets have taken place through mergers and acquisitions of existing companies. In 2004 EDP took over Hidrocantabrico; in 2007 – Enel and Acciona took over Endesa (after previous failed attempts by Gas Natural and E.ON). Gas Natural is acquiring the country's third biggest power group Union Fenosa. Due to increasing concerns on market concentration, the Spanish competition authority decided that Gas Natural must dispose of 600 000 small gas clients and sell 2 GW of gas-fired capacity. Gas Natural is also committed to selling its stake in Enagas and reducing its links to Cepsa by standing down from the oil group's board.

But liberalisation has also benefitted incumbent companies with well developed distribution networks. Around 70% of customers remained loyal to the retailer affiliated to the same vertically integrated group of the distributor. "Dual fuel" offers of combined electricity and gas deliveries, popularised by Gas Natural and electricity companies (Endesa, Iberdrola and Union Fenosa) have resulted in a limited rate (14%) of total deliveries supplied by the energy marketers.

Turkey

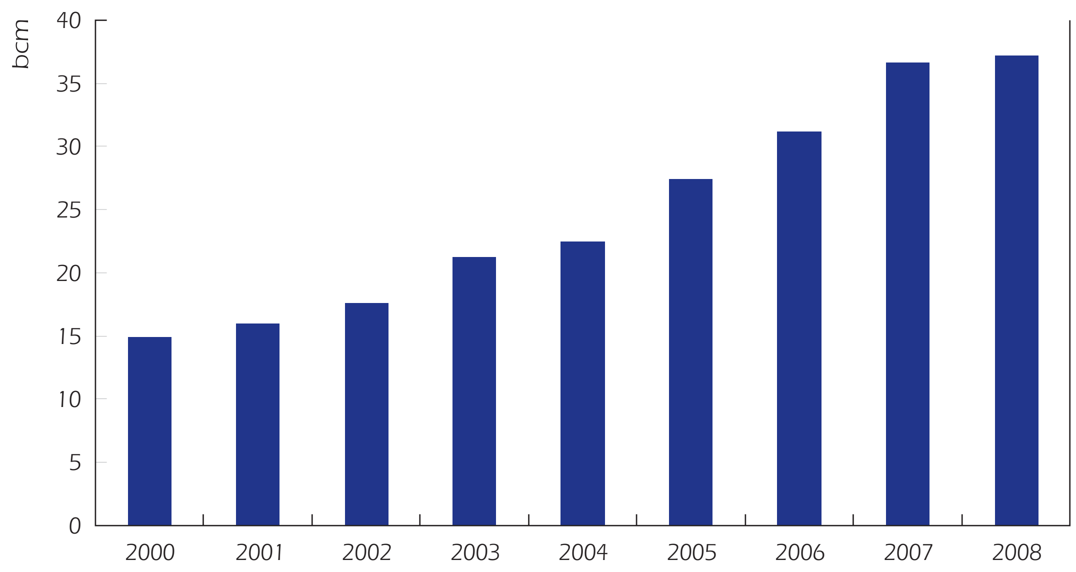
- **Turkish gas demand has grown at a rapid 63% in the period 2004-07, but in late 2008 demand declined sharply.**
- **Turkey has a high level of gas-fired power – more than half – and while there are major plans for a more diverse power mix, gas-fired power will still double in absolute terms over the next decade.**
- **More than 60% of Turkey's gas comes from Russia via two pipeline routes; diversification in new supply is highly desirable.**

Turkey is a rather atypical OECD member country, as it is currently undergoing a high economic growth and high industrialisation phase. Between 2000 and 2007, GDP grew by nearly 40%, even allowing for the banking crisis of 2001 when GDP declined 7.5%. Natural gas has met a major part of Turkey's rapidly growing energy needs, rising from 6% of supply in 1990 to more than 30% in 2007. Between 2000 and 2007, it doubled its share, representing in absolute terms a 150% increase, so that gas demand is now comparable with that of Spain.

Gas demand

In common with most OECD gas consuming countries, the first half of 2008 saw strong demand growth, (more than 11% in the first quarter) with growth levelling off in the summer, and demand contractions becoming marked late in the

Figure 25 Turkish annual gas use



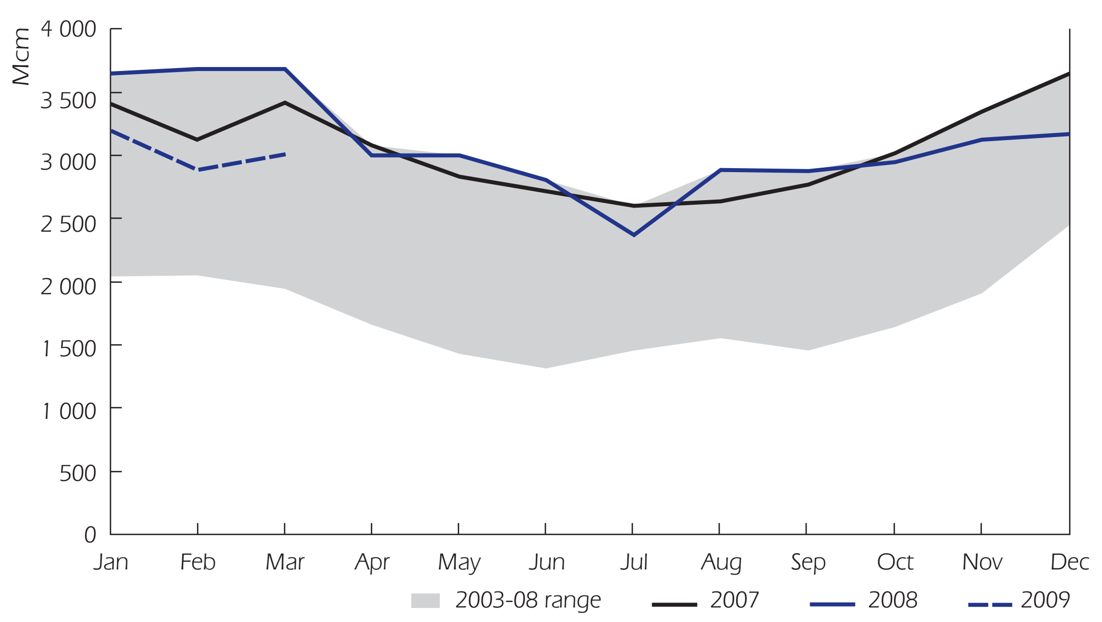
Key point: 63% growth over 2004-08

Source: IEA.

year, especially in industrial use. Demand levels in the three months ending January 2009 were down by nearly 11% from corresponding months a year earlier. Total demand growth was only 1.6% to a level of 37 bcm for 2008, marking an abrupt halt to the rapid growth that saw gas use rise 63% between 2004 and 2007. First quarter of 2009 demand fell 18%.

Gas has been especially important in the power sector, rising from barely one-sixth of generation in 1990 to half in 2007, in absolute terms a tenfold increase. In the residential and commercial sector, over the same period, gas went from zero to one-third of demand, mostly for heating due to the gasification program implemented by BOTAŞ. This has also benefitted industrial demand which has multiplied by four during 2000-08. With the fast growth of the Turkish economy, increasing population and rising living standards, electricity demand is growing at a high rate: electricity consumption increased by 50% over 2000-07. It is expected that the temporary decrease in consumption due to the economic downturn in 2008-09 will not change the long-term trend and that – **based on conservative projections – electricity consumption will double by 2020**. This will require at least doubling installed generation capacity which represents an unprecedented challenge among OECD member countries. While the share of gas-fired power is forecasted to decline, with more coal, hydro, wind and the introduction of nuclear in the mix,

Figure 26 Turkish gas use 2007-09



Key point: Sharp contractions at year's end continue in 2009

Source: IEA.

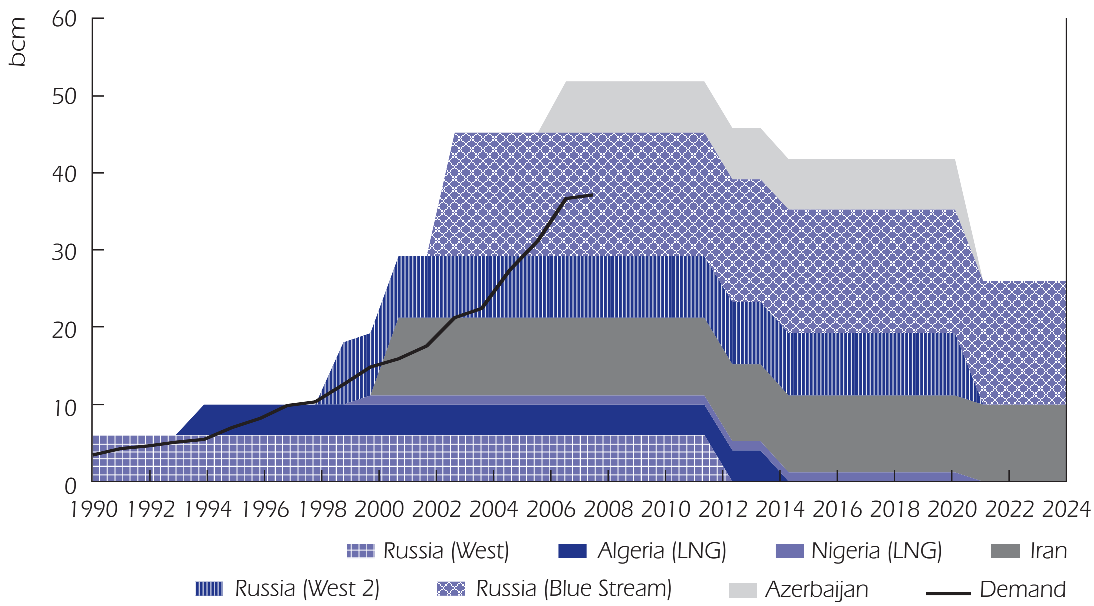
gas-fired power is still expected to nearly double in absolute terms over the period 2008-30[15]. Delays in any of the alternatives will exacerbate increases in gas-fired capacity, which is particularly favoured by private sector power generators.

Gas supply

Turkey has a high level of dependence on imported energy. Only lignite, some oil, and a very small amount of gas and hydro are domestically produced. Security of supply thus features highly in Turkey's energy policy priorities. Virtually all gas is imported, a circumstance unlikely to change over the forecast period. Given that **currently around two-thirds of gas supply comes from one supplier, Russia,** via only two pipeline routes, security of supply concerns dominate gas (and to a lesser extent electricity) policy thinking. **The Russia-Ukraine dispute in January 2009 exacerbated these concerns**. Other import infrastructure includes two LNG terminals, the 7 bcm South Caucasus pipeline which started delivering Azeri gas in 2007 and a 10 bcm pipeline from Iran.

In absolute terms, gas imports were multiplied by 2.5 from 2000 to 2008, and notwithstanding the current recession, energy demand is expected to grow strongly, and gas imports to double again

Figure 27 **Turkey's long-term contracts vs. demand**



Key point: New contracts or extension of the existing ones is needed

Source: BOTAŞ.

15. According to BOTAŞ' scenario.

between 2008 and 2030. Meeting this demand for imported gas to 2020 will require very heavy investment in additional pipeline and LNG terminal capacity, plus extra commercial storage. Current total storage amounts to only 1.6 bcm at two facilities, too small for current demand, let alone to meet the increase in the power sector, with its potentially sharp variations in demand. Even allowing for much slower growth over 2009 and into 2010, this **new supply infrastructure is still needed quite soon**, given the lead times in the sector. In addition, some existing supply contracts begin to expire in coming years, meaning new ones need to be concluded again in the next few years (see figure 27).

Fortunately, Turkey is well placed with respect to major gas reserves in Russia, Iran, Iraq, Egypt, the Caspian region (Azerbaijan) and Central Asia (Turkmenistan). LNG supplies are also potentially available, as a near 50% increase in global LNG output is anticipated in the next few years, notably from Qatar (and indeed spot LNG supplies were one important means used to alleviate the impact of the interruption to gas supplies in January 2009). Pipelines bringing gas from Middle East or Central Asian sources could be extended further, to meet growing demand in Eastern and Western Europe, and diversify supply sources for all countries concerned. Indeed Turkey is a logical, potentially very significant gas transit country. Gas from the Turkish grid already flows to Greece as of late 2007. Thus, looking at the Turkish gas scene, priority needs to be given to stimulating timely investment, from diverse supply sources, and from a diverse range of entities.

Turkey's gas sector is in the process of liberalisation, started in 2001. But progress remains very slow in contrast to the electricity sector, although there have been some recent important changes. While this may have been because of unrealistic goals in 2001, revitalised gas reform is now urgent if necessary investments are to be made and new gas supply secured. Progress has been made in allowing prices to move to more market-oriented levels, with prices rising in 2007, and increasing some 80% in 2008. BOTAŞ, the state-owned vertically integrated gas utility, continues to occupy a dominant position in the wholesale market, with at least 90% of the market. The situation has slightly improved with the removal of restrictions on importing LNG, effective use of the second LNG terminal (still underutilised), and allowing third parties to import into LNG terminals. These provisions were hurting security of supply; their removal is a positive step. But the market dominance of BOTAŞ, and in particular its *de facto* monopoly with regard to pipeline imports and its control over the transmission system, are likely to render these reforms insufficient. According to the 2001 law, BOTAŞ' share of imports was supposed to be limited to 20% by 2009, to be achieved through a gas release program. After the release which was postponed several times, to 2006, only 4 bcm (around 10% of the market) was released.

Fortunately, market circumstances present a major opportunity to press ahead, addressing market reform and security of supply concerns simultaneously. Growing demand, plus declining contracted import supplies, should allow large new market entrants, such as major Turkish industrial companies, international or national energy companies. There is some surplus capacity at existing LNG terminals, but terminal capacity would need to be expanded to realise the full diversity and security benefits that LNG could provide. **For any new entrants to appear, barriers to entry need to be reduced, and new entrants will need to have complete confidence in third-party access to an independently operated transmission network** (hitherto not available). This implies the full legal separation of BOTAŞ import and trading operations from its transmission/pipeline operations, a step envisaged in 2001, but yet to be enacted.

Leaving aside LNG imports, additional pipeline capacity will be necessary. Building large long distance pipelines is capital intensive, and requires long lead times. Such investment will obviously be difficult in the next few years in current financial circumstances. Attracting pipeline investment is most successful where gas regulations, laws and policies are stable, transparent, with the greatest degree of regulatory harmonisation along the pipeline route. This is especially true where pipelines cross multiple national frontiers (*e.g.* pipelines crossing Georgia or Syria) or those transiting to Greece, Bulgaria or further afield. Distortions between pipelines serving domestic needs and transit should be avoided. Pipeline tariffs need to be cost based, kept to a minimum, and third-party access available to facilitate multiple market-based entrants and users. In addition, Turkey has legitimate aspirations to create a liquid gas trading market, (supplementing its role in oil) with the flexibility and competitiveness benefits that that would entail. Such operations are most successful where the above trading conditions are met, namely multiple sources (including storage) and markets, easy access to transport, and low transaction costs, within a stable, non-discriminatory regulatory framework. In short, non-commercial risks must be minimised, and the differences between gas and oil clearly recognised.

Under these circumstances, it should be possible to address long-term security of supply in Turkey through the classical means of diversity of sources and routes; short-term security issues should be addressed through a suite of emergency style measures. Other OECD countries have utilised these approaches very successfully, such as Spain, limiting the market share of individual suppliers, and rapidly developing a diverse group of LNG suppliers and terminals, supplementing existing and expanded pipelines, giving a resilient, flexible, secure, competitive supply base. Incentives for LNG terminal development (possibly through the regulatory system) might assist this process in Turkey. Short-term loss of supply should be met through measures such as using the fuel switching flexibility in the power or industrial sector, or interruptible supplies, or spot LNG. Increased commercial storage could also be important here. Careful evaluation of the large-scale interruption in January 2009 would yield further insights into how Turkey might cope in the future. In particular, advance preparation by the government, large users (such as the power sector), distribution companies and all interested parties is an important lesson from January 2009. A flexible power sector which can switch fuel in response to market or other signals, is especially useful; thus Turkey's high level of gas-fired power can be turned from a vulnerability to an opportunity.

ANNEX 1: ABBREVIATIONS

ABS	Asset-backed securities
ADP	Annual delivery program
ALNG	Angola LNG project
AUD	Australian dollar
b/d	Barrels per day
BBL	Balgzand-Bacton Line
bbl	Barrel
bcf	Billion cubic feet
bcm	Billion cubic metres
boe	Barrels of oil equivalent
bp	Basis points
Btu	British thermal unit, 1 Btu =1 055 joule, 0.0002931 kWh
CBM	Coalbed methane
CCGT	Combined-cycle gas turbine
CCS	Coal capture and storage
CDO	Collateralized debt obligation
CEGH	Central European Gas Hub (virtual trading point in Austria)
CHP	Combined production of heat and power
CIF	Cost, insurance and freight: a term of sales where the selling price includes cost of goods, insurance and freight
CNG	Compressed natural gas
CNOOC	Chinese National Offshore Oil Corporation
CNPC	Chinese National Petroleum Corporation
CNY	Yuan (Currency of China)
CRE	La Commission de régulation de l'énergie = national energy regulator of France
CREG	Commission de Régulation de l'électricité et du gaz = national energy regulator of Algeria or national energy regulator of Belgium
CSM	Coal seam methane = CBM
DOE	Department of Energy (US)
E&P	Exploration and production
EBRD	European Bank for Reconstruction and Development
ECA	Export credit agency
EFET	European Federation of Energy Traders
EIA	Energy Information Administration, the United States
EPC	Engineering, procurement and construction
ERGEG	The European Regulators' Group for electricity and gas, set up by the European Commission
ETS	Emission Trading Scheme
EU	European Union
EUR	Euro
FEED	Front-end engineering and design
FERC	Federal Energy Regulatory Commission, the United States
FID	Final investment decision
FOB	Free-on-board: a term of sales where the selling price that does not include shipping, indicating the one at the loading port. Buyers arrange shipping transportation.
FSRU	Floating storage and regasification unit
FSU	Former Soviet Union
GBP	Pounds (Currency of the United Kingdom)
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GEODE	European independent distribution companies of gas and electricity
GHG	Greenhouse gas
GGP	Guidelines of Good Practice
GRI	Gas Regional Initiative

GSE	Gas Storage Europe
GTE	Gas Transmission Europe
GTL	Gas-to-liquids
GW	Gigawatt (10^9 watts)
GWh	Gigawatt hour
HDD	Heating degree-days
HOA	Heads of Agreement
IEA	International Energy Agency
IFIEC	International federation of industrial energy consumers
IOC	International oil company or Indian Oil Corporation
IOGC	International oil and gas company
IPE	International Petroleum Exchange, based in the United Kingdom
IPI	Iran-Pakistan-India Pipeline
IPP	Independent power producer
ISO	Independent system operator
IUK	Interconnector UK
JCC	Japan Crude Cocktail, the average price of crude oil imported into Japan
kb/d	Thousand barrels per day
kW	Kilowatt (10^3 watts)
kWh	Kilowatt hour
LDC	Local distribution company
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane, butane)
LSTK	lump-sum turn-key
mb/d	Million barrels per day
MBtu	Million British thermal units
Mcm	Million cubic meter
mcm	Thousand cubic meter
MENA	Middle East and North Africa
MJ	Megajoule
MOU	Memorandum of Understanding
MPSC	Model Production Sharing Contract
Mtoe	Million tonnes of oil equivalent
mtpa	Million tonnes per annum
MW	Megawatt (10^6 watts)
MWh	Megawatt hour
NBP	National Balancing Point (a virtual trading point for gas in the United Kingdom)
NCS	Norwegian Continental Shelf
NDRC	National Development and Reform Commission, China
NELP	New Exploration Licensing Policy
NGL	Natural gas liquid
NGV	Natural gas vehicle
NIGC	National Iranian Gas Company
NIMBY	Not in my backyard
NIOC	National Iranian Oil Company
NNPC	Nigerian National Oil Company
NOC	National oil company or Libya's National Oil Company
NOK	Norwegian Krone
NWS	North West Shelf (an Australian LNG venture)
NYMEX	New York Mercantile Exchange, in the United States
OCGT	Open-cycle gas turbine
OECD	Organisation for Economic Cooperation and Development
Ofgem	Office of Gas and Electricity Markets, the United Kingdom
OGP	International Association of Oil & Gas producers
OPEC	Organisation of Petroleum Exporting Countries
OTC	Over-the-counter
PEG	Point d'Echange de Gaz (French gas hub)
PNOC	Philippine National Oil Company
PSA	(PSC) Production Sharing Agreement (Contract)
PSV	Punto di Scambio Virtuale (Italian gas hub)
SCP	South Caucasus Pipeline

SDFI	State's direct financial interest
SEIC	Sakhalin Energy Investment Company
SPA	(SPC) Sale and Purchase Agreement (contract)
SSO	Storage system operator
TAP	Trans Adriatic Pipeline
TAPI	Turkmenistan Afghanistan Pakistan India Pipeline
Tcf	Trillion cubic feet
Tcm	Trillion cubic meters
TENP	Trans Europa Naturgas Pipeline
Toe	Tonne of oil equivalent
TPA	Third-party access
TPES	Total primary energy supply
TSGP	Trans Sahara Gas Pipeline
TSO	Transmission system operator
TTF	Title Transfer Facility
TWh	Terawatt hour
UAE	United Arab Emirates
USD	United States dollar
VP	Virtual point
WAGP	West African Gas Pipeline
WCSB	Western Canada Sedimentary Basin
WEO	*World Energy Outlook* (IEA publication)
WTI	West Texas Intermediate (benchmark crude oil in the United States)

ANNEX 2: GLOSSARY

Associated gas	Natural gas found mixed with oil in underground hydro-carbon reservoirs, released as a by-product of oil production.
Balancing	The requirement to equal supply and demand in a pipeline system over a certain period.
Base-load capacity	Capacity of liquefaction plant or regasification terminal that is expected to be processed in a year.
Base-load power	Power supplied by generation units that run continuously.
Brownfield project	Expansion project to an existing plant, or renewal project at existing plant.
City gate	The point at which a local distribution company (LDC) receives gas from a pipeline or transmission system.
Coalbed methane (CBM) or Coal seam methane	A type of unconventional natural gas, formed in the coalification process and found on the internal surfaces of the coal. To extract the gas water must be removed from the coalbed to reduce partial pressure. The large quantities of water, sometimes saline, produced from CBM wells pose an environmental risk if not disposed properly.
Combined Cycle Gas Turbine (CCGT)	A system to generate electric power through a combination of steam and gas turbines. It burns fuel gas in compressed air and runs gas turbines with the resulting high-temperature combustion. The very high temperature exhaust gas from the gas turbines is suitable for input into a heat-recovery boiler, which in turn provides steam to the steam turbines. A gas turbine can reach its full running capacity in ten minutes from ignition, whereas a simple steam turbine needs more time to reach required temperature from steam. By combining the two, the CCGT system can start operations quicker than a steam-turbine power generation plant.
Condensate	Light hydrocarbons existing as vapour in natural gas reservoirs that condense to liquid at normal temperature and pressure.
Cushion gas	Gas required in a storage facility to maintain sufficient pressure (sometimes: base gas).
Dry gas	Gas that does not contain heavier hydrocarbons or that has been treated to remove heavier hydrocarbons.

Greenfield project	Project constructed from the ground up, a brand-new project.
Feedstock gas	Gas used as raw material for petrochemical or fertiliser plants, or used to liquefy into LNG.
Flaring	Burning off unused natural gas, typically at an oil producing field where the associated gas cannot be economically utilised. Sometimes gas is flared as a safety measure to mitigate overpressure of other gas systems.
Heating Degree Day	The number of degree days for one day is the difference between 65°F (18.3°C) and the average daily temperature for this day. They are a measure of the energy needed to heat buildings and helps comparing how much colder/milder a period is compared to the previous years.
Henry Hub	Pipeline interconnection in Louisiana, the United States, where a number of pipelines meet, which is the standard delivery point for the NYMEX natural gas contracts in the United States, used as the benchmark price in the United States Gulf Coast for domestic and international gas transactions.
Hub	Physical or virtual location where multiple natural gas pipelines interconnect or natural gas is assumed to be delivered between multiple parties.
Indexation	Linking the gas price in a contract to published prices or other indicators.
Injection	The act of putting gas into a storage facility.
Long-term contract	A supply contract of gas deliveries lasting years, typically 20-25 years for LNG and international long-haul pipeline trades to support big investment and 2-5 years for domestic industrial-sector sales in certain countries.
Net-back price	The effective wellhead price to the producer of natural gas, *i.e.* the downstream market price less the charge for delivery.
Non-associated gas	Natural gas not in contact with crude oil in the reservoir.
Offtake	To take a delivery of gas or LNG at a certain point.

Open access	Natural gas transportation or LNG regasification service available to all shippers on a non-discriminatory basis.
Open season	A procedure conducted by an infrastructure facility (pipeline, storage, or LNG regasification terminal) owner to gauge potential users' financial interest in the capacity of the facility.
Peaking (or peakshaving)	The maximum capacity of power generation, storage withdrawal, capacity or LNG regasification send-out, during the highest daily, weekly, or seasonal demand period.
Play	A set of known or supposed accumulations of hydrocarbons sharing similar geologic properties, such as source rock, migration path, trapping mechanism, and hydrocarbon type.
Shale gas	Natural gas that is produced from reservoirs predominantly composed of shale (a fine-grained sedimentary rock), rather than from more conventional sandstone or limestone reservoirs.
S-curve	A pricing mechanism that uses a linkage to an indicator (typically seen in Asian LNG contracts using the JCC oil price as an indicator), where the rates of gas price increase or decrease compared to the indicator are slowed outside of a certain indicator range so that both buyers and sellers are partially protected from moves of the indicator outside a certain range.
Sour gas	Natural gas that contains significant amount of hydrogen sulphide.
Take-or-pay	A clause in a gas (or an LNG) supply contract that dictates the seller shall receive payments from a buyer for a minimum quantity of gas (or LNG), irrespective of whether the buyer takes delivery.
Unconventional gas	Unconventional gas is gas that is more technologically difficult or more expensive to produce than conventional gas. Unconventional gas resources can be divided into coalbed methane, tight gas, shale gas and methane hydrates.

ANNEX 3: CONVERSION FACTORS

Table 22 Conversion factors for natural gas price

From: / To:	USD /MBtu	USD /1 000 m^3	USD / tonne	USD / MWh	USD / TJ
USD /MBtu	1	37.912	51.56032	3.412	0.0009478
USD /1 000 m^3	0.02638	1	1.3600	0.09000	0.00002500
USD / tonne	0.01939	0.7350	1	0.06615	0.00001838
USD / MWh	0.2931	11.11	15.11	1	0.0002778
USD / TJ	1 055	40 000	54 400	3 600	1

Note: Based on gas with 40 MJ/m^3

Table 23 Conversion factors for natural gas volumes

From: / To: (multiply by:)	bcm per year	million tonnes per year	bcf/d	Tcf per year	PJ per year	TWh per year	MBtu per year	Mtoe per year
bcm per year	1	0.7350	0.09681	0.03534	40.00	11.11	3.7912×10^{7}	0.9554
million tonnes per year	1.360	1	0.1317	0.04808	54.40	15.11	5.16×10^{7}	1.299
bcf/d	10.33	7.595	1	0.3650	413.2	114.8	3.91×10^{8}	9.869
Tcf per year	28.30	20.81	2.740	1	1,132	314.5	1.07×10^{9}	27.04
PJ per year	0.02500	0.01838	0.002420	0.0008834	1	0.2778	9.47×10^{5}	0.02388
TWh per year	0.09000	0.06615	0.008713	0.003180	3.600	1	3.41×10^{6}	0.08598
MBtu per year	2.638×10^{-8}	1.939×10^{-8}	2.554×10^{-9}	9.32×10^{-10}	1.055×10^{-6}	2.93×10^{-7}	1	2.520×10^{-8}
Mtoe per year	1.047	0.7693	0.1013	0.03698	41.87	11.63	3.97×10^{7}	1

Note: Based on gas with 40 MJ/m^3.

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