GAS
Medium-Term Market Report 2012

Market Trends and Projections to 2017

International Energy Agency

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FOREWORD

The IEA has decided to create a series of medium-term reports for the four main primary energy sources: oil, gas, coal and renewable energy, and this *Medium-Term Gas Market Report* is the first edition for the gas market. Special attention has been paid to ensure the consistency of the projections regarding supply and demand trends, while specific issues like the competition of coal and gas in North America or the impact of renewable policies on gas demand are covered in topical focuses.

Overall, global gas demand expanded by 60 billion cubic meters (bcm) in 2011, equivalent to roughly three-quarters of the Dutch production. In Europe, the combination of weak macroeconomics and rapidly growing renewable energy were detrimental to gas demand, despite the nuclear moratorium in Germany. Consequently, EU gas demand was below the level of the 2009 recession. In Japan, energy conservation and expanding utilisation of gas- and oil-fired power generation compensated for the loss of nuclear power generation, turning Japan into one of the main growth regions for gas demand. China and the Middle East continued their unfettered demand growth, as did the United States, on the back of extremely low gas prices.

Global gas demand is expected to grow by around 580 bcm over 2011-17, representing almost 90% of the current Russian production, and to reach close to 3 940 bcm by 2017. Demand growth continues to be driven by non-OECD countries, especially the Middle East. The OECD region is also marked by sea changes on the supply side: Australia is emerging as an LNG export giant rivalling Qatar itself. The unconventional revolution in the United States is projected to continue in full swing. US domestic production continues to grow, and by the end of the projection period, the first LNG export projects will see the light of day. This is a welcome addition to a market which is expected to become increasingly tight over 2012-14. The continued boom in unconventional gas in the United States may even herald the end of the hundred-year dominance of coal in US power generation. In 2005, when the first shale well was fractured, coal produced almost three times as much power in the United States as gas; by 2017, the race will be almost even.

In Europe, the twin characteristics of 2011 – macroeconomic weakness and further increase in renewable-based electricity – are likely to persist and will constrain gas demand. In addition, expensive oil-indexed prices will severely limit the competitiveness of gas. Ironically, coal has become the most profitable source of power generation in Europe.

The most important event in the year 2011 which will affect the medium-term outlook in several countries is the Fukushima accident in Japan and its consequences for the future of nuclear energy. Due to the project lead time of nuclear construction, decisions on nuclear investment will have an impact beyond the time horizon of this *Medium-Term Gas Market Report*, but the decline in nuclear production in Japan and Germany has already had and will continue to have a significant impact on electricity and thus on gas markets. Although there is considerable uncertainty over the nuclear production of Japan, it seems safe to predict that it will not return to the pre-Fukushima baseline and gas will play a major role in bridging the gap.

On the production side, the most important is the event that did not happen. 2011 was not the year when low gas prices finally stopped the growth of unconventional production in North America. In fact, the United States added the equivalent of half of Qatar's LNG exports to its gas production, representing half of the global production increase. As a result, the idea of US LNG exports jumped from being inconceivable to being inevitable; the first export terminal received approval to export LNG just months after the last import terminal finished construction.

Looking ahead, there are plentiful gas resources underground, but very large investments will be needed to deliver it to consumers. Some of the projects that supply growth depend on, including floating LNG, arctic field development in Russia, as well as field developments in complex geologies, which represent huge technical and project management challenges. Consequently, the risk of project delays and cost overruns is real. The projection horizon will witness the beginning of commercial scale shale gas production in both Poland and China, but it remains to be seen at what pace and at which costs it will be possible to develop shale gas resources outside North America. In any case, the United States will continue to reap the benefits of cheap gas at least in the next five years, which will have far-reaching consequences for the competitiveness of its gas intensive industries.

Natural gas is the most important commodity that does not have a proper global market with global prices. On the contrary, the year 2011 has been marked by increasingly diverging gas prices in Asia, Europe and North America. And while gas markets are becoming more flexible and transparent, this is a journey only half completed. The IEA hopes that this yearly *Medium-Term Gas Market Report* published for the first time in the framework of a new series of Medium-Term Energy Market Reports will provide useful analysis for all stakeholders and contribute to enhancing transparency and efficiency of the gas market.

This report is published under my authority as Executive Director of the IEA.

Maria van der Hoeven

ACKNOWLEDGEMENTS

This *Medium-Term Gas Market Report* was prepared by the Gas, Coal and Power Division (GCP) of the International Energy Agency (IEA). The analysis was led and coordinated by Anne-Sophie Corbeau, senior gas expert, with significant contributions from the GCP gas team: Alexander Antonyuk, Ichiro Fukuda, Hideomi Ito and Warner ten Kate.

Significant contributions were made from other colleagues, particularly Laszlo Varro, Steve MacMillan and Michael Cohen. Valuable comments and feedback were received within the IEA, from Didier Houssin, Manuel Baritaud, Marco Baroni, Doug Cooke, Laura Cozzi, Ian Cronshaw, Zuzana Dobrotkova, Carlos Fernández Alvarez, Paolo Frankl, David Fyfe, Cuauhtemoc Lopez-Bassols, Isabel Murray, Christopher Segar, Johannes Trüby, Aad van Bohemen, and Michael Waldron.

Timely and comprehensive data from Ana Luisa Sao-Marcos, Robert Powell and Karen Treanton were fundamental to the Report.

A special thank goes to Janet Pape for editing the report.

Muriel Custodio, Rebecca Gaghen, Angela Gosmann and Bertrand Sadin provided essential support to the report’s production and launch.

The review was made possible by assistance from GasTerra B.V. and Tokyo Gas.

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EXECUTIVE SUMMARY

World natural gas demand climbed to an estimated 3 361 billion cubic meters (bcm) in 2011, translating into an annual growth rate of 2%, much lower than the 7% recorded in 2010. This growth does not quite put natural gas demand back on its pre-crisis track, when natural gas demand was growing at 3% per year. Natural gas demand increased in all regions; in particular, China's gas demand increased by 21%, reaching 130 bcm. However, it collapsed in Europe, where it plummeted by 9% to levels even lower than in 2009. The correction, which had been predicted in the *Medium-Term Oil and Gas Markets Report 2011*, can be attributed to a mixture of low economic growth and higher gas prices and was exacerbated by mild weather. In particular, gas-fired plants have been affected by sluggish European power demand and the strong growth of renewables, as well as increasing difficulties competing against coal-fired plants due to both relatively high gas prices and extremely low CO_2 prices. Even the decommissioning of a number of German nuclear power plants in early 2011 did not translate into increasing gas demand in the German power sector. The OECD Americas region benefitted from low gas prices, which boosted the share of gas in the power generation and industrial sectors, notably in the United States. In OECD Asia Oceania, additional demand mostly originated from Japan, as the country replaced missing nuclear generation partly by gas-fired generation, following the earthquake and tsunami and the subsequent incidents at the Fukushima Daichi plant. Higher consumption in non-OECD regions was driven by economic growth and increasing needs in both the power and industrial sectors. Gas markets grew strongly in Asia, the Middle East and in Africa, but more moderately in Latin America and Former Soviet Union (FSU)/Non-OECD Europe.

Global gas supply increased by 3% in 2011, reaching 3 375 bcm. The 93 bcm increase was almost entirely from three countries: the United States, Russia and Qatar. Global gas supply increased actually faster than demand, as additional gas was needed to replenish gas storage facilities in Europe, which were below normal levels in early 2011, while the United States faced an unprecedented surplus of gas in its storage facilities at end-2011. From a regional perspective, gas production increased significantly in OECD Americas, the FSU/Non-OECD Europe and the Middle East, but quite marginally in Latin America, and OECD Asia Oceania. However, European gas production declined sharply by 9.3% from 2010.

The situation in 2011 was nothing like "business as usual" on the supply side, given the unrest in North Africa and the Middle East. Although attention was very much on oil following the disruption of 1.5 million barrels per day (mb/d) of Libyan oil, some shortages were also observed on the gas side. In particular, gas production dropped sharply in Libya and Syria, resulting in Libyan supplies to Italy being disrupted during several months in 2011. Meanwhile, the repeated bombing of the Arab Gas Pipeline linking Egypt to Israel, Jordan, Syria and Lebanon deprived these countries of part of their natural gas imports, which in some cases constituted most of their gas supplies.

Unconventional gas represented 16% of global gas production as of 2011. Despite the growing interest in shale gas, half of unconventional gas production consisted actually of tight gas. Production increases in 2011 came mostly from North America, where shale gas continues to boom despite record low gas prices and the reduction in the number of rigs. In addition to shale gas and tight gas, associated gas from light tight oil plays is also growing in importance. Together, production from these three sources now more than compensates for the decline in US conventional gas production. Over the medium term, unconventional gas production is expected to continue to expand, again coming primarily from North America, where US shale gas production continues to boom. Outside this region, tight gas and coalbed methane (CBM) will be the largest contributors to incremental production. In the Middle East, Africa and Latin America, tight gas could complement existing conventional gas, while CBM is projected to increase markedly in China and Australia. Other countries with significant shale gas potential face a number of challenges in addition to environmental issues, such as pricing, lack of transport infrastructure, upstream competition or the more active presence of a mature service industry. Consequently, new shale gas production developments are projected to be somewhat limited over the next five years, with the most likely developments taking place in China and Poland.

The global trade balance is visibly shifting to Asia, which is now not only attracting increasing flows of liquefied natural gas (LNG), but also of pipeline gas. Global LNG trade increased by 9.4% to reach 327 bcm in 2011, which represents a significant slowdown compared to the record 21% increase in 2010. The reason behind this slowdown is that only a single new liquefaction plant came on line in 2011, in Qatar, but additional LNG was still being produced from those started in 2010 and progressively reaching plateau during 2011. Nevertheless, LNG trade was still increasing faster than global gas demand. The bulk of these additional LNG supplies went to the hungry Asian markets, notably to Japan, which needed to import more LNG as nuclear generation steadily collapsed in that country following Fukushima. Meanwhile, the United States imported even lower LNG volumes and European LNG imports remained flat. This stability is actually remarkable considering the collapse of European demand and of its import requirements. On the pipeline side, Turkmenistan's exports to China more than tripled from 2010 levels following the expansion of the Central Asia Gas Pipeline.

Regional gas prices continued to drift further apart, as Henry Hub (HH) gas prices reached levels below USD 2 per million British thermal units (MBtu) – the lowest prices in a decade, while European spot and contract gas prices stabilised at between USD 8 and USD 10/MBtu and average import prices in Japan reached USD 17/MBtu during the second half of 2011. The gap between Japanese LNG prices and HH prices actually widened, from around USD 7/MBtu in January 2011 to over USD 14/MBtu in March 2012. Regional prices are increasingly determined by their respective regional dynamics. Although oil and gas prices are no longer as correlated as before 2009, European gas prices continue to be influenced by oil price movements. The weaker influence of oil prices reflects an increase in both volumes sold at the different continental spot markets and spot indexation in some long-term supply contracts. Despite the increasing LNG volumes available on global markets, the prospect of a global gas price not only did not materialise, but also looks increasingly less plausible. The North American gas market is expected to remain disconnected from other regional markets, while Asia still needs to develop a true market price, reflecting natural gas supply/demand balances rather than the fundamentals of the oil market.

Volumes of natural gas traded on European spot markets increased markedly in 2011, driven by the price differential between oil-indexed gas and gas traded on hubs and regulatory developments, which continued to facilitate hub trading. In 2011, physical volumes traded on the European continent grew by 8%, reaching 162 bcm, while traded volumes jumped by around a third to 542 bcm – a level higher than total European gas demand. Despite these positive developments, most European spot markets still lack liquidity. The National Balancing Point (NBP) is the only truly liquid spot market. Meanwhile, continental European spot markets have generally low churn rates and an insufficient number of products that can be traded.

Global gas demand is projected to reach 3 937 bcm by 2017, 576 bcm higher than today. These forecasts for natural gas demand over 2011-17 reflect three significant expected developments:

- **Gas demand surges in the United States, increasing by around 90 bcm, with the power generation sector being the primary driver contributing to nearly three-quarters of this growth.** In the power sector, gas benefits from low gas prices to increase its market share at the expense of coal. There are still a certain number of factors limiting the growth of gas within this sector, including the amount of switchable capacity, low prices of Powder River Basin's coal, coal contracts, and technology factors, but the push towards more gas seems inevitable. The US industry takes advantage of low US gas prices, notably in the petrochemical sector and for fertiliser producers. A wild card remains the penetration of gas in the transport sector for heavy-duty vehicles.
- **China remains the fastest growing market as its gas consumption doubles from 130 bcm in 2011 to 273 bcm in 2017, translating into an annual growth rate of 13% per year.** Gas demand increases in all sectors except for use by fertiliser producers. To reach these levels, there are certain key policy issues regarding pricing and regulation that China is assumed to have tackled. In particular, the power generation sector is key and gas-fired plants need to be more competitive against coal-fired plants.
- **There is no "Golden Age of Gas" in Europe, as gas demand remains below 2010 levels during the whole projection period.** Gas consumption is hit by the triple whammy of 1) low economic growth translating into slow power demand increases and sluggish development of the industrial sector, 2) high gas prices, notably over the coming two years, and 3) the strong growth of renewables. Corrected from weather conditions, residential gas demand will recover after the very mild 2011. The industrial sector struggles amid prices three to four times higher than in the United States, which becomes a new competitor for European-based petrochemical and fertiliser industries. Unlike their US counterparts, European industrials will not see any benefits of lower gas prices induced by shale gas developments. In the power generation sector, the boom of renewable energy sources actually results in declining generation by combustible fuels, whereby gas has to compete against coal. In the absence of a higher CO_2 price, gas-fired plants are projected to struggle, especially over the coming few years.

Many Asian, Middle Eastern, African and Latin American countries share the potential risk that, given low domestic gas prices and in some cases, more difficult fields to develop, domestic gas supply does not increase sufficiently to meet their potential gas demand. This leaves them with two options, besides fixing their gas policies: either curb gas demand or import (often more expensive) gas. Over the coming five years, many South Asian countries will become LNG importers, including current exporters such as Malaysia and Indonesia. More than half the Middle Eastern countries are importing or will import natural gas, either from outside the region through LNG or via pipeline from Egypt, Turkmenistan, or from the region, *i.e.* from Qatar, the only country able to handle increasing domestic and export demand. Middle Eastern demand grows faster than production over the medium term. Rapidly increasing domestic gas demand also leaves very little room for additional exports from Algeria and Egypt, while Latin American countries have to import increasing amounts of LNG.

On the production side, the FSU/Non-OECD Europe and OECD Americas regions will be the most important providers of additional gas supplies, as they represent 43% of the additional production reaching markets during 2011-17. Russia is projected to start major projects such as the Yamal Peninsula, although it has yet to take Final Investment Decisions (FIDs) on the next projects. Given the gloomy demand perspectives in Europe, Russia's main export market, the country is likely to turn more proactively to other export possibilities, namely LNG and Asian markets. Despite the record low gas prices and number of rigs, US gas production growth has been accelerating, boosted by the development of light tight oil, a trend that is expected to continue over the coming five years, putting the United States slightly ahead of Russia in terms of natural gas production in 2017. While Middle Eastern gas production is projected to grow significantly, there are still considerable uncertainties, notably concerning developments in Iraq and Iran. Over the coming years, there will be increasing interest in the development of the next new promising production centre – the African East coast.

Global LNG trade will slow down considerably over the coming three years before abruptly accelerating again in 2015, as both the new wave of Australian LNG and exports from the United States are projected to come on line. This slowdown is due to limited new LNG capacity (25 bcm) starting over 2012-13. There are 13 LNG projects amounting to 114 bcm/y currently under construction worldwide (or already started in 2012), which are expected to be operational by 2017. In addition, new LNG capacity will start in North America, notably the Sabine Pass project, which received authorisation from the Federal Energy Regulatory Commission (FERC) in April 2012. Most of these new projects will not be cheap, with construction costs anticipated to be twice as high as those for plants which came online over 2009-11. Most will sell gas at oil-indexed prices. The exception, both in terms of capital costs and indexation, is the US gas project, because its pricing formula is based on HH gas prices. This makes this gas relatively competitive against oil-indexed gas in Asia, unless HH gas prices quadruple. Australia is set to become the new Qatar, with one plant started in May 2012, seven plants currently under construction and many others close to reaching FID. However, these projects are likely to face many challenges, including higher capital costs and workforce shortages; they are expected to come on line later than announced. Indeed, four of these projects are first-of-a-kind, including three CBM-to-LNG projects and a floating LNG plant. Despite an impressive list of planned LNG liquefaction projects, it remains to be seen which projects will ultimately take FID.

The next five years will see growing needs to import gas in Asia and Europe, and in a more limited way, in the Middle East and Latin America. The main suppliers for these needs will be LNG, which will increase by one-third to 426 bcm by 2017, but also FSU pipeline exports, while exports from the Middle East are expected to remain flat. This requires in some cases building new interregional transport capacity comprised of both pipeline and LNG regasification terminals. At present, over 120 bcm of new regasification capacity is under construction as of early 2012, two-thirds of which is concentrated in Asia, notably China and India. Meanwhile, only three pipelines are under construction: the second part of the Nord Stream pipeline between Russia and Germany, the Central Asia Gas Pipeline between several Caspian countries and China, as well as the Myanmar to China pipeline. While China appears as a major centre for new imports, it also represents a major uncertainty for future investors if the shale gas revolution also takes place in China and reduces import needs over the longer term.

DEMAND

Summary

- Growth in world gas demand slowed significantly in 2011, increasing by only 2% year-on-year to reach around 3 361 bcm. In contrast, gas demand grew by 7% in 2010. Despite this slowdown, world gas demand is almost back to the growth path observed over the past decade. However, not all regional markets experienced growth in 2011. While gas demand increased in all non-OECD regions, OECD Americas and OECD Asia Oceania regions, gas consumption plummeted in Europe to below levels attained during the global financial crisis in 2009. The correction, already forecasted in the *Medium-Term Oil and Gas Markets Report 2011*, was driven by a mixture of continuing low economic growth, higher gas prices and relatively mild winter weather.
- Global gas demand is expected to continue to increase at a rather healthy pace, reaching 3 937 bcm by 2017, 576 bcm or 17% higher than in 2011.
- Non-OECD markets are forecast to generate 69% of incremental demand growth to 2017. Asia will be by far the fastest growing region, driven primarily by China which will emerge as the third largest gas user by 2013. The region's gas demand is projected to grow from 424 bcm to 634 bcm over 2011-17, a 50% increase. OECD Americas will be the second largest growing market in terms of incremental consumption. Meanwhile, the Middle East region will be the third largest growing region, taking advantage of huge regional gas resources, but this growth of 79 bcm (or 20%) will be very much contingent on the successful development of new and more expensive gas fields.
- Demand growth trends in other non-OECD regions such as Latin America and Africa are likely to exhibit wide disparities among the different countries. The FSU/Non-OECD Europe region is a relatively mature market and is forecast to continue to experience moderate demand growth of 0.7% per year in comparison to the emerging economies over 2011-17.
- OECD regions follow widely divergent paths. OECD Americas enjoys low gas prices, which provide considerable economic benefits reflected in a surge of gas demand in different sectors, notably power generation and industry. As a consequence, gas demand surges by 108 bcm or 12% over 2011-17. The Asia Oceania region's future gas demand is mainly determined by its largest consumer, Japan, and in particular, by policy and market responses to Fukushima.
- However, Europe is unlikely to experience a "Golden Age of Gas" over the period. Industrial gas demand is projected to decline over the next few years before recovering, while demand in the residential and commercial sectors is forecast to remain moderate after recovering from the mild weather conditions in 2011. The most dramatic change may occur in the power generation sector, where production from gas-fired power plants is being increasingly displaced by renewables. Even if nuclear power plants are phased out over 2012-17, generation from combustible fuels declines and gas-coal competition becomes the key determinant of gas demand in this sector.
- Future outcomes will be greatly affected by a range of uncertainties. In particular, the rate of economic growth will be a key determinant of natural gas demand over 2011-17, with any substantial reduction in economic activity likely to decrease gas consumption, especially in the power generation sector. The future evolution of natural gas prices, compared to coal and CO_2 prices (where these exist), will also impact gas demand in the power sector. Similarly, lower than expected expansion of renewables or an accelerated decommissioning of nuclear plants could be expected to have a positive effect on demand for gas. In the non-OECD region, future demand depends very much on the development of new local gas resources. If these move forward at a slower pace than anticipated, then regional gas demand will also be negatively affected.

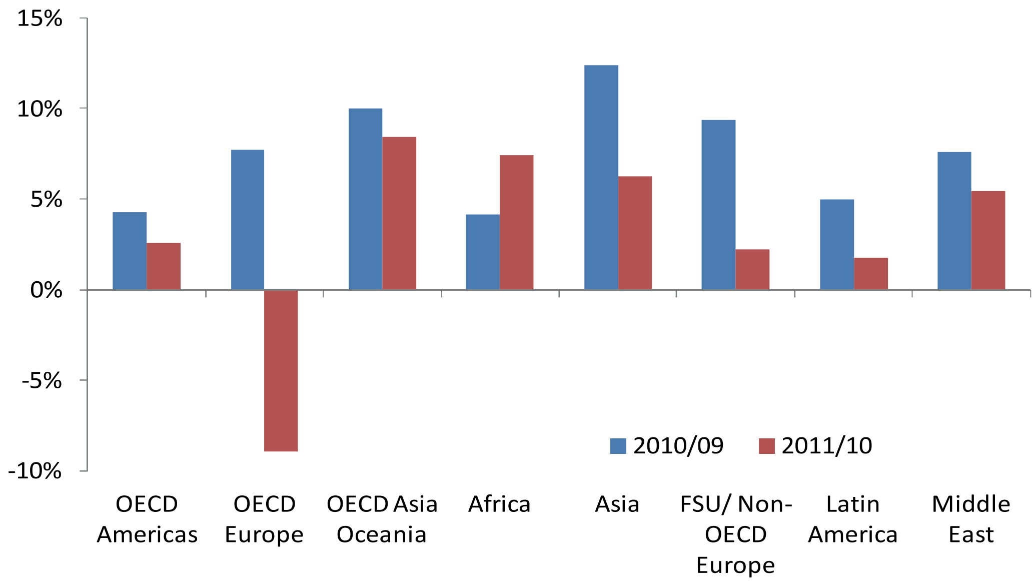
Recent trends

World gas demand is not quite back on its previous growth track

Global gas consumption is estimated to have increased by around 2% in 2011, reaching 3 361 bcm, a much lower increase than the record 7% growth seen in the previous year. While world gas demand continued to grow in 2011, there were slightly different drivers. Unlike in 2010, where the growth was split two-thirds/one-third in favour of the non-OECD region, this time, non-OECD markets grew faster than the world at 4%, reaching 1 768 bcm. Meanwhile, OECD gas demand dropped to 1 593 bcm. All regions recorded yearly growth rates lower than in 2010, except Africa, but Europe was the only one to witness a sharp drop in its consumption (see Figure 1).

China has been by far the fastest growing gas market in 2011, with 21% growth; consequently natural gas consumption in the entire Asian region increased by 6% in 2011. In contrast, many other Asian countries had their demand growth constrained by the lack of supply, this was especially the case in India where production declined sharply. Despite the unrest in many Middle Eastern and North African countries, both regions' gas consumption increased, at 5% and 7% respectively, but with wide divergence among individual countries within each region. Meanwhile Latin America increased modestly by 2%, a growth rate comparable to that of the FSU/Non-OECD Europe region, where consumption was driven by strong demand in Russia.

Figure 1 Relative annual variations in gas demand by region



Source: Unless otherwise indicated, all material for figures and tables derives from IEA data and analysis.

OECD: Japan LNG imports surged; UK demand dropped even more

Natural gas demand in the OECD region dropped in 2011 by 0.8% to 1 593 bcm. The surprise in 2011 came from the collapse of European gas consumption, which was higher than the combined increase in the OECD Americas and OECD Asia Oceania regions. It is therefore fair to say that regional OECD markets profoundly diverged in 2011. This evolution was already highlighted in the previous *Medium-Term Oil and Gas Markets Report 2011*, which described the gas demand growth in Europe as "an illusion". Indeed, half of it was actually driven by the cold weather in 2010. While the focus has been on Japan's LNG imports' dramatic rise by over 12 bcm this year, the decline in individual countries such as Germany or the United Kingdom was actually at least higher than the surge in Japan's LNG imports. German and UK gas demand dropped by 13 bcm and 16 bcm, respectively.

The differences between the three OECD regions are quite striking when one looks at the countries individually. In the OECD Asia Oceania region, all countries but New Zealand had demand growth. In OECD Americas, gas consumption increased (boosted by low gas prices) in the United States, Chile and Canada. In absolute terms, the largest increase of over 17 bcm was actually observed in the United States, accounting for 43% of OECD gas use, which dwarfs other gas users. In contrast, a decline in demand occurred in most European countries, with a few notable exceptions: Greece, Poland, Portugal, Slovakia and Turkey. The highest relative increases were, quite surprisingly, Greece (+24%) driven by new gas-fired generation, and Turkey, where demand grew in all sectors. Growth rates in the other countries were relatively modest, below 2%. Meanwhile, all other countries witnessed a drop – sometimes a collapse – in their consumption. Among the largest drops in 2011 was Sweden.

Table 1 Gas demand by OECD country, 2011 and 2010 (bcm)

	2010	2011*		2010	2011*
Europe	570.4	519.5	*Slovakia*	6.1	6.2
Austria	9.5	9.0	*Slovenia*	1.1	0.9
Belgium	19.8	16.9	*Spain*	35.8	33.6
Czech Republic	9.3	8.9	*Sweden*	1.5	1.2
Denmark	5.0	4.2	*Switzerland*	3.7	3.2
Estonia	0.7	0.6	*Turkey*	38.1	44.7
Finland	4.7	4.0	*United Kingdom*	98.9	82.7
France	49.1	42.1	Asia Oceania	195.4	211.9
*Germany***	97.9	85.3	*Australia*	33.4	34.8
Greece	3.9	4.8	*Israel****	5.3	5.0
Hungary	12.1	11.3	*Japan*	109.0	121.3
Iceland	0.0	0.0	*Korea*	43.2	46.4
Ireland	5.5	4.9	*New Zealand*	4.5	4.2
Italy	83.1	77.9	Americas	839.9	861.6
Luxembourg	1.4	1.2	*Canada*	96.8	104.0
Netherlands	54.8	47.9	*Chile*	5.3	6.2
Norway	6.1	5.8	*Mexico*	64.7	61.4
Poland	17.2	17.2	*United States*	673.1	690.0
Portugal	5.1	5.2	OECD	1605.7	1593.0

* 2011 data are estimates as of April 2012.

** Due to revisions by the German government, Germany's data for 2010 and 2011 are estimated based on historical data.

*** The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

OECD American gas demand is boosted by low gas prices

The OECD Americas region's gas consumption increased from 840 bcm in 2010 to 862 bcm in 2011. The bulk of this incremental consumption came from the United States, but larger percentage increases were seen in Canada and Chile. US gas demand increased in all sectors, except the residential sector. In particular, the power generation sector remains a key driver behind the increase with gas-fired plants gaining a larger share in the power mix at the expense of coal.

Industrial gas demand is also recovering, driven more by low gas prices than by healthy economic growth. It is already higher than levels seen in 2005, but has not recovered to those of the early 2000s. Despite higher LNG deliveries, gas consumption in Chile remains well below the pre-2006 levels, when the country still benefitted from ample supplies from Argentina. In Canada, a much colder year compared to the extremely mild 2010 boosted natural gas demand for heating.

OECD Asia Oceania: the impact of the Fukushima accident

Japan was the driver behind the region's demand increase from 195 bcm to 212 bcm. As a result of the accident at Fukushima, gas demand in the power generation sector increased by around 11 bcm over April 2011-December 2011 compared to the same period in 2010. Both oil- and gas-fired generation contributed to replacing missing nuclear generation, not only the plants which had to be shut down due to heavy damage, but also those that were progressively taken off-line. As of early May 2012, no nuclear power plant is operating. Before Fukushima, the country had 54 reactors, which amounted to 49 Gigawatts (GW), and produced around 280 Terawatt-hours (TWh) in 2010. The cumulative missing nuclear generation since the accident amounted to 114 TWh over April-December 2011. Power demand was reduced by 51 TWh compared to the same period in 2010 due to lower demand in the industrial sector and power restraint measures. It has to be noted that 2010 was very hot, resulting in remarkable power demand over the summer. The missing generation came from oil and gas. An additional 145 thousand barrels per day (kb/d) of oil was consumed in Japan's power plants in 2011. Some coal-fired plants were damaged by the earthquake, so that they were unable to contribute to replacing nuclear. In addition, coal-fired capacity was already running at a high load factor before the earthquake, due to its low marginal cost, so there was less room for expansion.

Elsewhere in the region, Korea consumed an additional 3 bcm, taking demand levels to 46 bcm. Korea's GDP growth remained high in 2011, close to 4%, twice that of Australia and New Zealand. Meanwhile, New Zealand's gas demand dropped slightly. Israeli gas demand also dropped following the disruptions of the Arab Gas Pipeline throughout 2011 and 2012. Domestic production was not sufficient to compensate for the reduction by two thirds of Egyptian gas pipeline supplies. Without these disruptions, Israeli gas consumption would have increased following the country's plans to switch oil-fired plants to gas.

How low can European gas consumption drop?

European gas consumption outbid the very low performance of the European economy in 2011. Indeed, European gas demand collapsed by 8.9%, to reach 520 bcm against 570 bcm in 2010. This demand level is actually 10 bcm lower than the *annus horribilis*, 2009. The reasons, extremely mild weather combined with weak economic growth and high gas prices, managed to erase in a single blow the growth that occured in 2010. While in 2010, very cold weather resulted in a rapid demand recovery, this time, OECD Europe gas demand plummeted when the weather component disappeared. Out of the 51 bcm drop, it is estimated that 60% is due to weather, 10% to weak economic growth impacting industrial gas demand and 30% to the power sector, where oil-indexed gas is simply uncompetitive. Conventional power generation dropped even more rapidly than power demand, while rapidly increasing renewables, as well as higher output from French nuclear power plants compensated for the German phase-out. Within conventional power generation, gas rapidly lost its competitiveness due to a combination of high gas and low carbon quota prices. The collapse of gas consumption was particularly noteworthy, considering that Europe's largest gas consumers, namely, the United Kingdom, Germany, the Netherlands and France, tend to have a high share of residential consumption.

UK gas demand reached its lowest point since 1995 with a record drop of 16%. The United Kingdom illustrates perfectly what happened in Europe in 2011: residential-commercial gas demand dropped by an estimated 8 bcm, industry used less gas owing to a combination of high gas prices and low GDP growth, while gas use in the power sector declined by around 17%, notably during the first half of the year and the fourth quarter. In Germany, where gas demand dropped by 13%, total primary energy demand dropped by 5% and reached its lowest point since 1991, even lower than in 2009. Without the weather effect, it would have remained constant. Even the decision taken in March 2011 to decommission eight nuclear power plants following the accident at Fukushima neither reversed the trend nor resulted in an increase in gas consumption by power generators (see Box 2).

France had a similar situation with its 14% drop of its consumption, exacerbated by a 21.6% collapse of consumption from users connected to the distribution network, most of which are households. The year 2011 was the warmest in France since 1900. According to the Ministry of Industry, seasonally-adjusted French gas demand was actually stable, but the increase from large users such as new gas-fired plants coming on line recently compensated for the 3.2% drop from small users. In that respect, France is different from other European countries where gas is competing against renewables and coal. Italy, the third largest gas user in Europe, recorded a 6% drop due to a lower residential gas demand combined with lower gas use in the power sector. Adjusted for the weather effect, natural gas demand decreased by approximately 3% compared with 2010.

There are a few exceptions to this trend, some of which are relatively unexpected. Greece, despite its dire economic situation, consumed roughly one-fourth more gas than in 2010. Meanwhile, Turkish gas demand increased in most sectors, driven by one of the highest rates of GDP growth in Europe.

Figure 2 Seasonally-adjusted gas demand in Europe

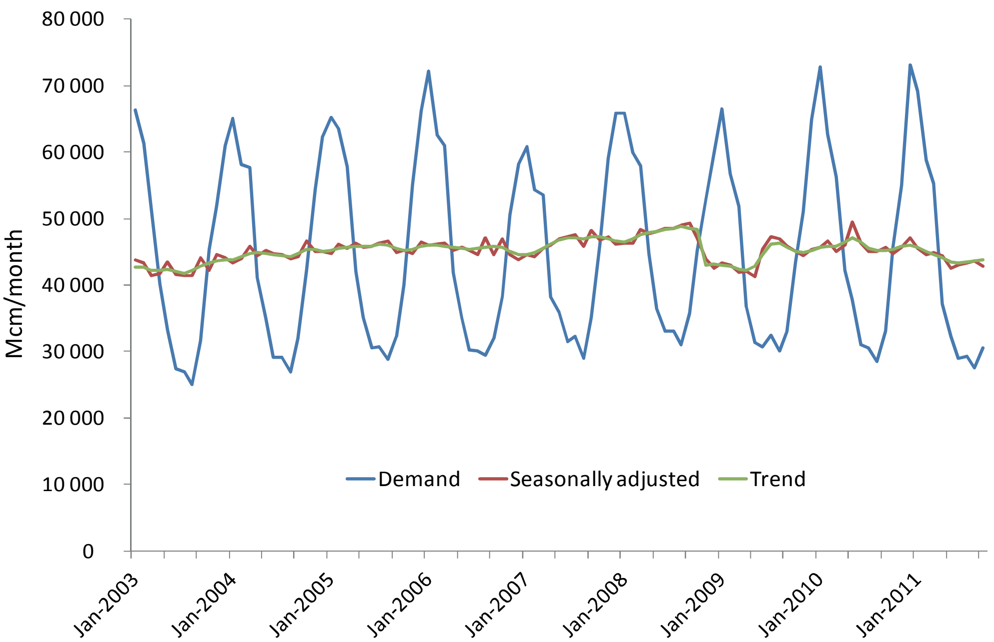


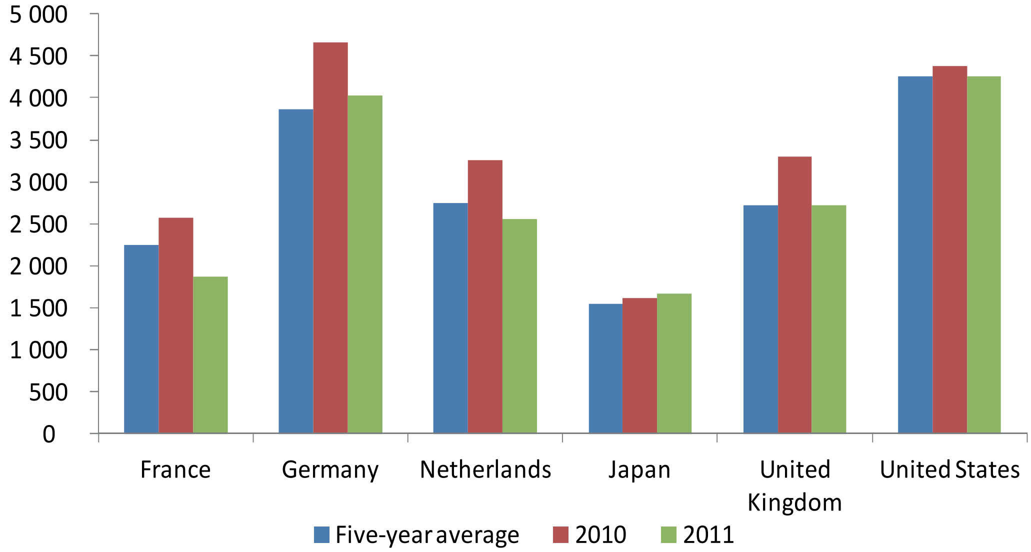
Figure 2 illustrates how seasonally-adjusted European gas consumption has been evolving. Based on the red line representing seasonally-adjusted demand and its trend in green, European gas demand has actually been going down since mid-2010. Although some recovery was perceptible from early 2009 to mid-2010, this was largely driven by low gas prices remaining below USD 5/MBtu until late 2009. The sharp increase of National Balancing Point (NBP) prices during the second half of 2010 and their stabilisation at around USD 8/MBtu since then gave a fatal blow to gas use by power generators. Gas-fired plants have been hit by the triple whammy of low electricity demand growth, a still strong push from renewables and tough competition from coal-fired plants, advantaged by low CO_2 prices. After reaching its lowest levels since 2003 in May 2009, seasonally-adjusted gas demand recovered and actually peaked in December 2010, but then started to drop again and lost 10% in nine months, so that demand in late 2011 was just at the levels it had in 2004.

Residential and commercial sector

This sector is very dependent on temperature changes, which have been fluctuating between extremes over the past few years. A very mild winter in 2011 in Europe and in the Northeast United States contrasts sharply with the cold spells in Europe in 2010 and in early 2012. Looking at heating degree days (HDD), the year 2011 was certainly milder in some countries such as France or the Netherlands, but HDD were at the same level as the five-year average in the United Kingdom and slightly higher in Germany. However, HDD in 2011 were significantly lower than in 2010 in most OECD countries, except in Japan, Greece and Turkey.

Consequently, residential gas demand dropped in 2011 in many European countries, as well as in the United States. In the United Kingdom, residential demand dropped by 23% in 2011. In particular, the consumption of residential UK gas users was 34% lower during the fourth quarter. Total French gas demand dropped from 49 bcm to 42 bcm, exacerbated by a 21.6% collapse of consumption from retail customers. In the Netherlands, gas delivered to the regional grid plummeted by 19%, while in Italy, the Transmission System Operator (TSO), Snam Rete Gas reported an 8.2% drop in the residential and tertiary sector. Data from the US Energy Information Administration (EIA) show that residential gas demand declined by 1% in that country.

Figure 3 HDD in selected countries



Box 1 The February 2012 demand shock in Europe

Europe had a short cold spell in late January/early February 2012, which contrasted sharply with mild temperatures in the preceding four months. On 1 February 2012, it became apparent that natural gas volumes transported to Europe through Belarus and Ukraine started to fall short of volumes nominated by customers. After several companies' deliveries fell short, the following day, alarm bells rang out across Europe. The immediate shortfall was a consequence of a demand shock spanning the Eurasian continent. Russia, the various transit countries and the European countries were experiencing an abnormal spike in residential demand due to a spell of extremely cold weather.

The extreme cold spell increased European natural gas demand by an estimated 11% compared with the daily average for the month of February, or about 1.5-2 bcm more in the first eight days of February for OECD Europe. Russian gas production in February increased to 60.1 bcm (including one extra day). This represents a total increase of 1% in daily production over that of February 2011 (based on 28 days). However, this increase in domestic production was mainly due to an increase in Novatek's production, as well as in associated gas production by oil companies, while Gazprom's production decreased by 0.14% y-o-y. In any case, the increase in domestic production was immediately absorbed by a 2.74% increase in Russian domestic demand, leaving about 9% (1 bcm) less volume available for exports to the European Union (EU) compared to February 2011.

Faced with higher demand from its customers, Gazprom was forced to deliver below nominated volumes. Gazprom has since then admitted that delivered volumes were 10% below nominated volumes for several days, with the effects of these shortfalls felt throughout the European gas supply system. Reported national shortages varied between 8% and 50% of nominated volumes. Total shortfall of Russian exports is estimated at 1 bcm, so the market faced a 2.5-3 bcm supply/demand disruption from the combination of extreme demand and reduced Russian supply.

The shortfall in Russian deliveries to Europe created a three-tier market response:

- **Storage withdrawal**: Storage levels across Europe were very high due to the mild onset of winter. On 1 February, storages were around 64% full, much higher than similar periods in 2010 and 2011. However, increased withdrawal rapidly brought storage levels in line with former years. Nearly 6.8 bcm was withdrawn from storages in the following eight days (compared to 2.1 bcm and 4.8 bcm at the corresponding time in 2011 and 2010, respectively). These withdrawals substantially alleviated the pressure coming from higher gas demand and reduced Russian supply.

- **Rising spot market prices**: A shortage in delivered volumes from Russia resulted in spot prices rising rapidly to levels unseen since 2006, with daily prices rising sharply to above USD 15/MBtu. However, as temperatures returned to normal, price levels came down just as quickly, settling to near before crisis levels within four trading days after the price peak. Spot market prices exceeded oil-indexed long-term prices for only two days during the cold spell (see Figure 5). The spot market price developments show the responsiveness of natural gas markets to eventualities, allowing market parties to adjust their behaviour accordingly.

- **Market-based demand mitigating measures**: Market measures in most affected countries mitigated the effects of the shortfall in Russian supplies by invoking interruptible contracts and allowing limited gas-to-oil switching (in Italy). Market-based emergency measures in Poland, Greece, Germany and Italy adequately addressed local shortfalls.

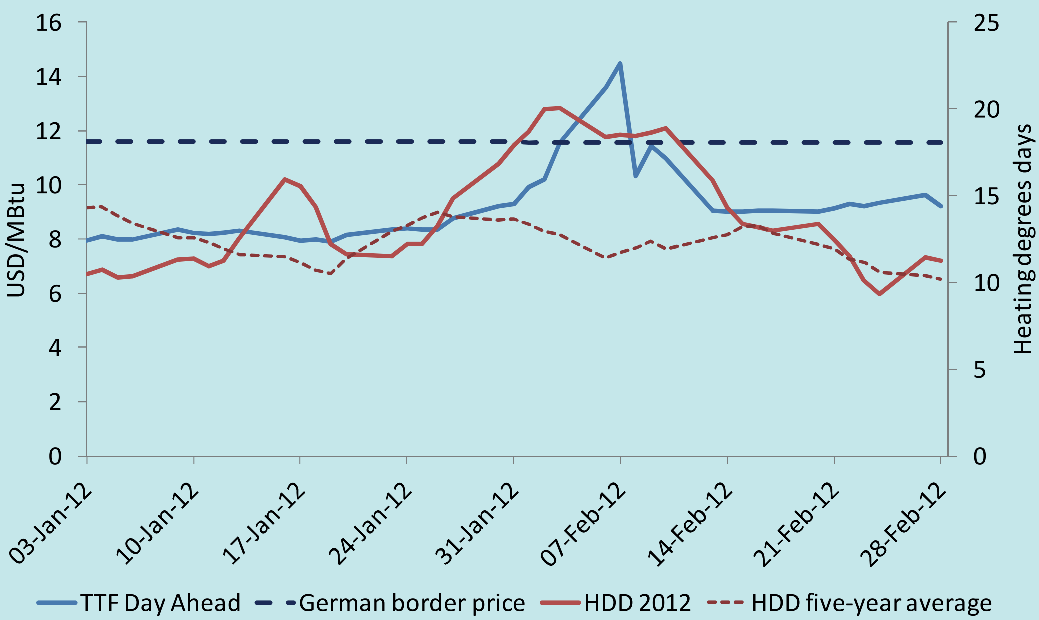
The European natural gas supply system therefore responded robustly faced with a set of extreme conditions. Nevertheless, it is also worth keeping in mind that since peak storage withdrawal rate declines with withdrawal, the situation would have been less comfortable without the previous extremely weak demand, and thus high storage levels at the onset, or if such circumstances had occurred later in the winter, when storage levels are generally much lower.

Box 1 The February 2012 demand shock in Europe (continued)

Figure 4 Storage levels in Europe in 2010, 2011, and 2012

On 20 February 2012, Gazprom announced that deliveries were back to normal. However, in Europe, emergency measures in place in Poland, Italy and Greece had generally been lifted earlier.

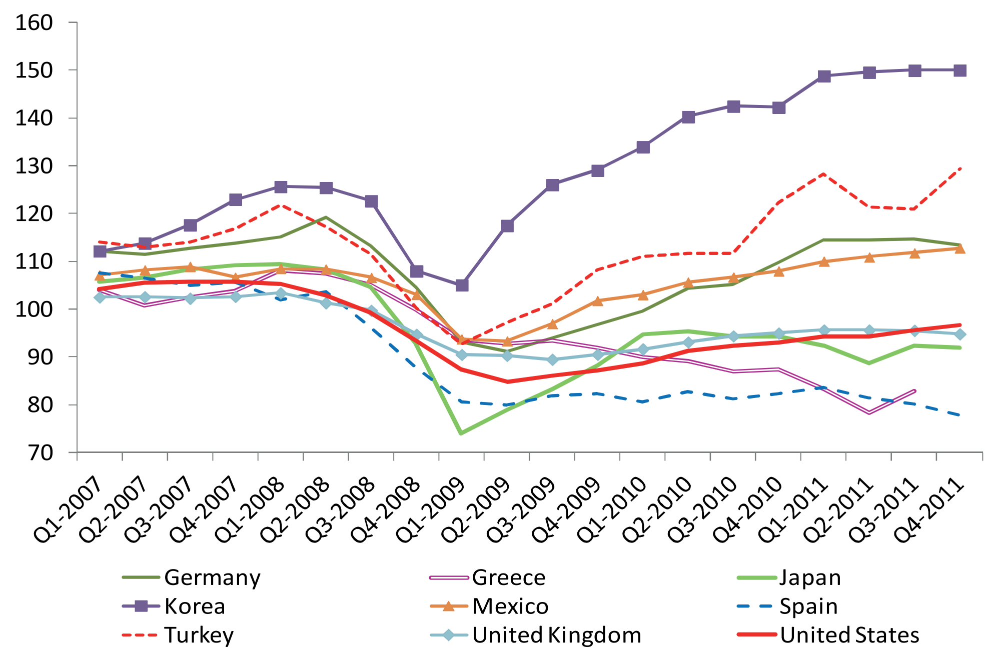
Figure 5 Heating degree days and European gas prices (Jan-Feb 2012)



The industrial sector

There are now wide divergences between OECD regions, not only in economic growth but also in energy prices. These are among the key parameters influencing industrial gas demand. Looking at the indices for production of the manufacturing industry, it is evident that some countries have recovered from the economic crisis in 2009, while others are far below their pre-crisis levels. Among European countries, only Poland, Slovakia and Turkey had higher indices for the fourth quarter of 2011 than their pre-crisis ones (dating from the second quarter of 2008). Most other European countries are around 10% below their pre-crisis production levels. Korea is by far the best performer, showing a 20% increase between those two dates. These indices are only one out of many indicators for the performance of the industrial sector. Although US industry has not quite yet recovered to its pre-crisis level, its gas demand in 2011 was actually higher than in 2008. Indeed, despite a relative weak economy, the US industry is living a honeymoon with gas because gas prices continue to stay at record low levels; industrial gas demand increased by 3.9% in 2011. This is an opportunity for US industries to improve competitiveness over their OECD European or OECD Asia Oceania counterparts. US gas prices averaged USD 4/MBtu in 2011, 9% lower than in 2010, and even dropped below USD 2/MBtu in early April 2012. The petrochemical industry and fertiliser producers are therefore considering not only restarting some mothballed facilities, but also building new ones, such as ethylene crackers.

Figure 6 Indices for manufacturing industry (2005 = 100)



Source: OECD.

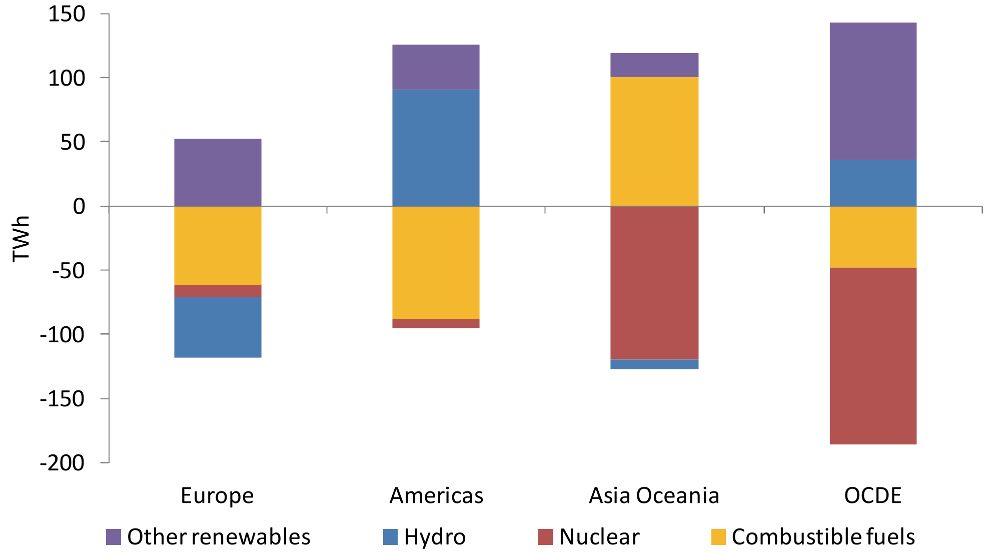
The picture is considerably different on the other side of the Atlantic, where not only the economy – and therefore the state of the manufacturing sector – is gloomy, but European gas prices have been at USD 8 to USD 10/MBtu, at least twice as high as the average Henry Hub gas price in 2011. Apart from a few exceptions highlighted before, industry is struggling in most European countries. The combination of weak economies and high gas prices is putting European industry at a disadvantage, not only against developing countries, but also now against North America. In the United Kingdom, gas demand in this sector receded 11% in 2011. Industrial gas demand during the fourth quarter actually reached its lowest level ever over the past 14 years for this time of the year. The consumption of Dutch gas users connected to the transmission grid (excluding power plants), most of which are industrials, dropped by over 2%. However, this trend is not uniform in Europe, as the Polish gas company PGNiG reported higher sales to both fertiliser producers and other industrials.

The power generation sector

Gas demand in the power generation sector remains extremely sensitive to anything involving other fuels and electricity demand in general. There were significant changes in 2011 for the role of natural gas-fired generation related to unexpected events, such as the Fukushima accident and the phase-out of nuclear power plants in Germany, as well as the evolution of the competitiveness of natural gas, notably versus coal. Overall, according to IEA *Monthly Electricity Statistics*, OECD electricity supplied is estimated to have slightly dropped in 2011 by 0.6%, or 60 TWh. Actually, European electricity supplied lost 90 TWh, partly due to mild weather conditions, while in Asia Oceania it lost 8 TWh and in the OECD Americas region, it gained around 40 TWh. Taking into account imports and exports, the decline in OECD generation is actually slightly lower, at around 40 TWh.

Overall, nuclear output in OECD countries declined by over 6%, or some 140 TWh, most of which can be attributed to Japan and Germany, where combined nuclear output lost over 150 TWh, or more than the total loss in the OECD region. This was balanced by some countries where nuclear generation improved, notably France, which had underperformed in 2010. Nuclear output was also weaker in the United States, with a 2.1% loss. The strong performance of renewable energy sources, which are estimated to have gained 143 TWh, is more than the loss in nuclear. Indeed, renewables excluding hydro expanded by one-third, or almost 110 TWh, for the whole OECD region. Hydro generation in OECD countries grew, as the strong increase of hydro in Canada and the United States more than made up for the losses in Europe and Asia Oceania.

Figure 7 Incremental electricity output by source and region, 2011 compared to 2010



Based on Figure 7, the implications for fossil fuels (*i.e.* natural gas, coal and oil) are therefore as follows: generation in the OECD region from these sources declined by around 50 TWh in 2011, of which the Americas region dropped by around 90 TWh, the Europe region over 60 TWh, while Asia-Oceania gained 100 TWh due mostly to Japan replacing nuclear with oil and gas. In the United States and Canada, natural gas benefitted from lower gas prices, improving the competitiveness of natural gas over coal, so that natural gas demand is expected to have increased (see the sectoral focus on the United States later in this chapter). In Chile, despite a relative slow increase in power demand, both coal and gas increased at the expense of oil-fired generation, whose share in the power mix dropped from 21% to 12%.

In Europe, the situation was the exact opposite from North America: despite a drop in both nuclear and hydro, combustible fuels still generated some 60 TWh less than in 2010. Among combustible fuels, gas has been struggling against coal in most countries, in many cases resulting in significant losses. In the United Kingdom, the decline in combustible fuel generation was entirely attributable to gas, while coal-fired generation marginally increased. The very same phenomenon was observed in Austria, Hungary, and Ireland. In Italy, Snam Rete Gas reported a 6.9% drop in gas use in the power sector. In contrast, in Spain, the output from combustible fuels was actually higher than in 2010, due to a much lower output from hydro generation (*i.e.* one-third less) compared to the record in 2010. This did not help gas-fired generation at all: it dropped while coal-fired generation increased in an impressive manner. Both coal and gas-fired outputs receded in the Netherlands, Belgium, and Finland, whereas Poland's strong economic growth resulted in higher power demand and there, gas benefitted. In Turkey, however, the increase in electricity demand was sufficient to drive both coal and natural gas-fired generation upwards, albeit with an advantage to coal.

Box 2 Does a reduction in nuclear output lead to an increase in gas demand?

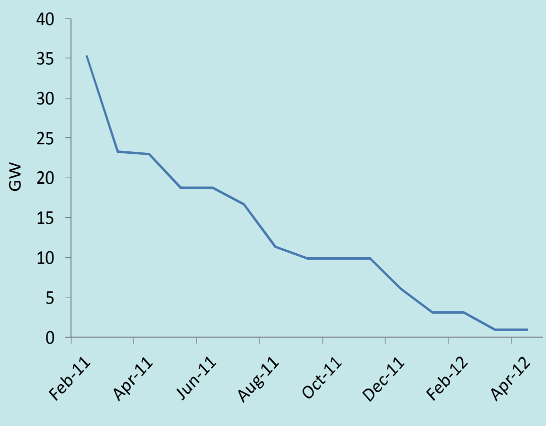
The answer is "not always", quite surprisingly, as shown in the reactions of Japan and Germany to the withdrawal of large parts of their nuclear capacity. Obviously, their situations are quite different. While nuclear represented around 28% of Japan's total electricity generation in 2010, and 23% in Germany, the nuclear output in Japan in 2010 (278 TWh) was twice that of Germany. Additionally, Germany is interconnected to the wider European power network, whereas Japan cannot rely on any import of power. In Japan, the closure of the nuclear power plants resulted in more gas (and oil) being burned. In Germany, lower power demand, more renewable energy and more electricity imports (despite Germany still being a net exporter) reduced the call for gas-fired plants.

In March 2011, an earthquake and tsunami hit Japan resulting in massive damage and a high death toll. On the energy supply side, power, oil and gas supplies were gravely disrupted. The most visible example, the Fukushima nuclear power plant, was severely damaged. Four units will be decommissioned and the others have been in cold shut-down since then. Around 40 GW of capacity were damaged in the Tokyo Electric power company (TEPCO) and Tohoku Electric Power Company areas, not only nuclear, but also coal-fired plants. Over the following months, nuclear power plants remaining online have been progressively shut down month after month, as they were put in scheduled maintenance. Two units, Hamaoka 2 and 3, were shut down following a decision by the government. Maintenance is a normal feature of the nuclear industry, as fuel needs to be replaced, but nuclear power plants usually come back online after a few days or weeks. This has not happened in Japan. Before the earthquake, as of end February 2011, some 35 GW of nuclear energy were operational, due to maintenance or some units still not operational after the 2007 earthquake. Capacity then dropped to 23 GW after Fukushima, before all were taken off-line by early May 2012.

Box 2 Does a reduction in nuclear output lead to an increase in gas demand? (continued)

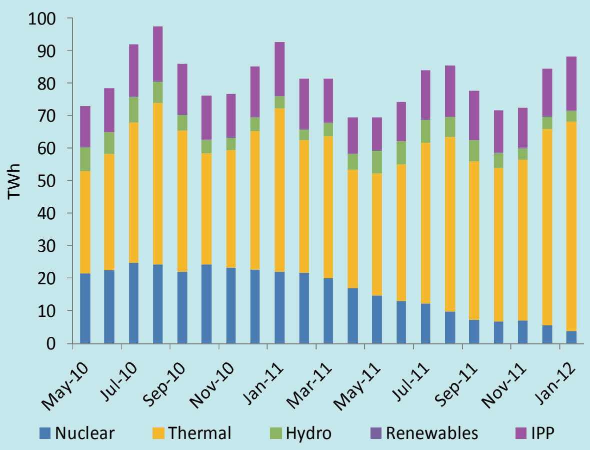
The output from nuclear power plants dropped from 278 TWh in 2010 to 157 TWh in 2011, while electricity sold fell by 4.7% to 937 TWh. During the critical period of April-December 2011, reduction of electricity demand helped to replace 44% of the missing nuclear generation. Power demand was even 12% lower in August, although it has to be noted that power demand in August 2010 had been at a record high due to hot weather. This still left Japan with 64 TWh of electricity to replace during that period. This came from oil and gas-fired plants. Indeed, data from the Federation of Electric Power Companies (FEPC) of Japan (the ten largest power utilities in Japan) show that their coal consumption dropped slightly by 3%. Accordingly, additional fossil fuel demand for power generation was distributed as follows: gas (56%), direct crude burning (27%) and residual fuel oil (20%).

Figure 8 Nuclear capacity in Japan



Note: Nuclear capacity at the end of the month.

Figure 9 Electricity generation in Japan



The ongoing closures in the Japanese nuclear sector supported demand for natural gas, fuel oil and "other products" (which includes crude oil for direct burn), to serve as replacement fuels in the electricity sector. The additional natural gas demand is estimated to have been 11 bcm, while an additional 145 kb/d of fuel oil and other products were used.

The key uncertainty is what will happen to the nuclear power plants which are currently under maintenance. They represent some 35 GW of capacity, which could generate 280 TWh if used at 8 000 hours per year. The Japanese government will formulate its new energy strategy during summer 2012. The previous pre-earthquake policy foresaw the construction of several new nuclear power plants and an increase in the share of nuclear energy in power generation to over 40%.

Whatever decisions are made, it is quite unlikely that nuclear will play as prominent a role as planned, and it is questionable that it will return to its historical levels, due to rising public opposition, preventing plants from re-opening at the local level. The coming summer will provide a test case, as during this period, electricity demand often peaks (*e.g.* 95 TWh in August 2010). Japan's strategy is likely to be based on ongoing energy efficiency efforts, combined with a strong push for renewables, but natural gas can be expected to play a more prominent role in the years to come. However, LNG's role may be limited by some regional constraints such as insufficient local LNG import capacity, lack of interconnections between regional gas grids and the existence of two power systems at different frequencies with limited interconnections. In the medium term, nuclear power plants able to restart will need to be reviewed by the regulatory body (NISA), authorised by the Nuclear Safety Commission and secure the local approval.

Box 2 Does a reduction in nuclear output lead to an increase in gas demand? (continued)

The case of Germany is quite different. In March 2011, the government decided to decommission eight nuclear reactors representing an annual production of 60 TWh (Germany's total annual nuclear production in 2010 was 140 TWh) and to decommission all the remaining ones by 2022. This corresponds to the initial plan put in place by the Schröder government in 2000. While some may have thought that such a move would be advantageous for gas, it appears that this is far from being the case. The loss of nuclear (around 32 TWh, because the moratorium came only in March) actually matched the drop in power demand; in addition, the combination of a surge of renewable output (+21 TWh) combined with lower net exports of electricity (-16 TWh) also matched the lower nuclear generation, resulting in a lower use of coal-, oil- and gas-fired plants. While coal-, oil- and gas-fired plants all produced less, it is obvious that the economics do not favour natural gas-fired plants because CO_2 prices are at record low levels. In 2012, there will be a further reduction of German nuclear production as the moratorium will have been in force for the full year.

Looking forward, the government's strategy is to decrease electricity demand by 10% by 2020 compared to 2008 and increase the share of renewable energy to 35%. The demand reduction target is ambitious, and if one assumes healthy GDP growth, it will require considerably more rapid improvement of energy efficiency than what was observed in the decade preceding the financial crisis. The ramp up of renewable production is in line with existing policies, although it may be hampered by slow construction of the transmission network. Considering the developments of wind and solar energy over the past few years, there is clearly a potential to replace the plants recently shut down by using renewables. According to the forthcoming IEA *Medium-Term Renewable Energy Market Report 2012*, Germany's annual renewable generation is projected to increase by about 80% between 2010 and 2017. If such a development continues up to 2022, the incremental electricity generated by all renewable energy sources will match and potentially exceed the 140 TWh of nuclear generation to be replaced. Demand for German electricity exports decreased in 2011, indicating that the moratorium did indeed increase conventional power generation outside of Germany. This demand would have fallen even more in the absence of a moratorium.

This strategy may not enable Germany to reach its CO_2 targets by 2020, unless the proper price signals are in place. Indeed, while sharply boosting renewables, Germany replaces a non-CO_2 emitting electricity source by another, resulting in limited gains in terms of CO_2 emissions reduction. In order to reach the 2020 objectives, Germany needs additional carbon gains, including switching from coal to gas. The quantity of coal-fired generation to be switched to natural gas by 2020 amounts to around 180 TWh, or 16 bcm of additional gas demand. Current CO_2 prices are far from giving the appropriate signals to achieve this goal, considering the relative coal and gas prices.

Non-OECD gas demand

Natural gas consumption increased in all non-OECD regions in 2011, but in many cases with a considerable slowdown compared to 2010. It is nevertheless worth noting that non-OECD accounted for almost all the world's incremental gas demand growth in 2011, increasing from 1 698 bcm to 1 768 bcm, a 4.2% annual growth which is exactly in line with gas demand growth during the previous decade. Rising demand is driven by drivers such as a stronger economic growth, at over 6% for non-OECD countries, resulting in higher needs in the industrial and power generation sectors. In many countries, gas demand continues to be boosted by subsidised gas prices.

As in 2010, China remained by far the fastest growing market, with demand increasing by 21% to reach around 130 bcm, reinforcing its position as the fourth-largest gas user in the world. It is just a question of one or two years before China becomes the third-largest user ahead of Iran. The Chinese government is keen to dramatically increase the share of gas in the energy mix over 2011-15 from 4.4% in 2010 to 8.6% in 2015, but for the moment natural gas consumption is constrained by the supply side, that is, domestic production, pipeline, as well as LNG imports. Although supply increased remarkably in 2011 – imports jumped from 17 bcm to 31 bcm and domestic production by 5% – other factors limited the increase: import capacity both on the pipeline and LNG side, and that these new imports are generally much more expensive than domestic production. The competitiveness of gas in the power sector depends crucially on gas prices relative to coal prices.

Elsewhere in Asia, gas consumption is estimated to have marginally increased by 1%. Here, too, the issue of supply constraints affects demand in these countries. Demand is estimated to have slightly increased in India, where massive LNG imports compensated for the significant drop of domestic gas production. The lower output from domestic fields caught most market participants off guard, so that they had to rely on additional spot LNG cargoes. Demand is also expected to have increased in Thailand (which started to import LNG in June 2011), Vietnam, Singapore, Chinese Taipei and Myanmar. In contrast, first estimates indicate a drop in consumption in Indonesia, Malaysia and Brunei.

The FSU/Non-OECD Europe region remains the largest non-OECD gas consumer, with around 705 bcm consumed in 2011, 2% higher than in 2010. This was essentially driven by a 2.3% increase in Russia. Unlike in 2010, where the weather (cold winter and hot summer) played a strong role in the demand increase, there were no such weather components in 2011. However, as a general factor affecting gas demand, the Russian economy grew by 4.3% in 2011. Electricity generation and gas used for generation grew more modestly (1.5% and 1.9% accordingly), so the rest of growth is probably attributed to the factors discussed in the Russian supply section. Detailed consumption data is not available yet, but one of those growth factors could be the reduction of flaring and a better utilisation of associated gas in West Siberia, which intensified in 2011. Meanwhile, Turkmenistan, Azerbaijan and Uzbekistan had almost flat gas consumption.

Middle Eastern gas demand gained an additional 6%, in line with previous years. This was largely driven by domestic production increases, although these also provided limitations as a few countries were struggling to ramp up their production. Two Middle Eastern countries, Kuwait and Dubai, imported a total of 4 bcm of LNG compared with 2.9 bcm in 2010. The largest demand increase came from Qatar, where the Pearl GTL project started in 2011. The only exceptions to these growth trends are Syria and Jordan, the first due to the civil war and the second due to lower imports from Egypt.

In Africa, gas demand is estimated to have increased from 103 bcm in 2010 to 111 bcm in 2011. Two different trends appeared. The largest gas users, Algeria and Egypt, gave priority to their domestic consumption, even at the expense of exports of pipeline gas or LNG. Nigeria also had a recovery of its demand, albeit not quite at the peak levels of 2008. Meanwhile, Libya's gas consumption dropped following the civil war, which lasted most of the year. Demand increases in the other countries were marginal, and these other countries represent only 15% of Africa's gas consumption.

In Latin America, individual countries' demand varied widely, but aggregated demand is estimated to have increased by around 3 bcm, reaching 139 bcm. While Brazil was the driver behind most of the incremental growth in 2010, its demand slightly declined in 2011 due to higher hydro levels. As domestic output increased while Bolivian imports increased, this sharply reduced LNG imports. These imports doubled in price between March 2011 and December 2011 (from USD 8/MBtu to above

USD 15/MBtu). Demand for gas in the power generation sector therefore dropped, but much less than in 2009, when consumption in this sector lost 65%. In 2011, demand only dropped by one-third. This illustrates the high variability of Brazilian gas consumption for power generators. Meanwhile, sales to distributors were also slightly reduced, while consumption from refineries gained almost 25%.

Demand in Bolivia rose by over 10%, benefitting from higher domestic production. The fastest growing sector was power generation. Argentinean gas consumption surged amid lower gas production and higher LNG imports. Gas consumption increased in all sectors, notably by 10% in the power sector, which became the largest consuming sector ahead of industry. Peru continues to benefit from the coming online of the new liquefaction plant. Meanwhile, both Colombia and Trinidad and Tobago's demand is estimated to have dropped in 2011.

Medium-term gas demand forecasts: growing amid uncertainties

Assumptions

The one major uncertainty concerning future energy demand is the economic outlook, that is, whether the world will enter into a double-dip recession over the next few years. This publication's forecasts are based on IMF GDP forecasts from January 2012, which are reasonably optimistic with the world's economy growing at around 4.5% over 2012-17. Europe's current worries about the financial stability of Greece, Spain, Italy and Ireland, together with questions regarding the sustainability of the growth in China, make predicting future economic growth challenging. OECD GDP growth was 1.7% in 2011, and it is projected to rise slightly to 1.9% in 2012 before exceeding 2.4% in 2013, to reach around 2.7% for the rest of the projection period. Obviously, there are significant differences among the OECD regions: forecasts for the OECD Americas show faster growth, at around 3.0% over 2012-17, which is 1 percentage point above Europe, where the economy remains sluggish. The OECD Asia Oceania region is between the two at 2.5% on average. In particular, Japan is expected to recover quicker in 2012-13, as its GDP will decline later on. In Europe, some key countries such as Germany, Italy and Spain are below the European average.

GDP growth will be on average 6.6% in non-OECD countries. The fastest growing country by far is China, at 9.4% on average, followed by the other Asian countries at 6.7%. At 5%, Africa is growing slower than the non-OECD average, while the Middle East's economies are projected to grow at 4.5%, followed by FSU at 4.2% and the Latin American region at 4.1%. The slowest growing region would be non-OECD Europe, where economic growth is projected to average 3.7%, which is still higher than any OECD region. Projections are for annual GDP growth to continuously increase year after year in most regions, with the exception of the FSU region, where it would slightly decline.

Fuel price assumptions serve as input to our model and are usually derived from the forward curve. They do not in any manner represent IEA forecasts. Oil price assumptions are consistent with those from the *Oil Market Report* of April 2012 (*OMR* April 2012), and are based on the prevailing futures strip at that time. Nominal oil prices reached USD 108 per barrel (bbl) in 2011, and will increase to USD 112/bbl in 2012, before progressively declining towards USD 90/bbl (USD 73/bbl real USD 2010) in 2017. Coal prices[1] are a key input for gas competitiveness in the power generation sector:

[1] Coal prices are real (USD 2011) prices for delivery at power plants for steam coal (6 000 kcal/tonne).

in Continental Europe, steam coal prices would decrease from USD 116/t in 2011 to USD 110/t by 2017, while Japanese coal prices decline from USD 131/t to USD 115/t over 2011-17. Chinese domestic coal prices would progressively increase from USD 85/t to USD 115/t.

Gas price assumptions are based on 15-day averages of the forward curves as of late March-early April 2012. Gas prices continue to reflect today's situation, with a strong regional divergence between European, Asian and US gas prices; there is a continuous disconnection between the US gas market and other regions. Henry Hub (HH) gas prices are expected to stay relatively low, despite a progressive increase, with HH gas prices increasing from USD 4/MBtu in 2011 to USD 4.7/MBtu by 2017. In contrast, prices in the OECD Asia Oceania region (in particular, in Japan and Korea) are expected to be driven by oil prices, as the relationship between oil prices and gas prices is maintained (see section the potential to develop a spot price in Asia in the Trade chapter). Therefore, LNG import prices are expected to remain relatively high over the whole projection period, with an average of USD 13.2/MBtu. Meanwhile, European prices fall between these two extremes. In particular, NBP gas prices will remain at a large premium over HH gas prices at an average of USD 10.5/MBtu over 2012-17, compared with USD 9/MBtu in 2011 (EUR 22.1/MWh). European gas prices in Continental Europe reflect the duality of price formation with a mix of oil linkage and spot price elements (based on NBP).

World gas demand reaches new highs

Global gas demand is projected to grow relatively fast over 2011-17, at 2.7% per year, which is comparable to the growth observed over the last decade. Gas demand in 2017 is 3 937 bcm, 576 bcm higher than 2011 levels. Non-OECD countries will represent 69% of the incremental growth, while OECD Americas will contribute to the bulk of the demand growth in the OECD region. Compared to the *Medium-Term Oil and Gas Markets Report 2011*, a fundamental change is the rapid growth of gas consumption in the United States, which is primarily driven by continued low prices (especially compared to other fossil fuels) and their consequences in key sectors such as the industrial and power generation sectors.

The fastest growing country is by far China, where natural gas consumption doubles over 2011-17, following the implementation of the 12th Five Year Plan (FYP), which promotes the use of natural gas within the energy mix. This results in an impressive annual growth rate of 13% per year, which is still below the 20% observed over the past three years. Africa is the second fastest growing region, with an annual growth rate of 5% per year. Natural gas demand in Asia increases also rapidly, although there will be competition in many countries on resources for exports and for the domestic market.

The Middle East, which had been historically one of the fastest growing markets, slows down, although regional gas demand still gains 79 bcm. Natural gas demand grows more rapidly than internal production (+72 bcm), forcing countries to import either LNG or pipeline gas from other regions. In a few countries, gas demand has therefore to be curtailed, a trend which is also observed in a few Asian countries, such as India, or Latin American countries. Natural gas consumption in the former Soviet Union and non-OECD Europe region grows very slowly at 0.7% per year, given the maturity of the market. Europe is also underperforming, with an average annual growth of 1.3% per year, due to the combination of high gas prices, low economic growth and significant growth of renewable energy sources.

Table 2 Gas demand, 2000-17 (bcm)

	2000	2010	2011	2013	2015	2017
Europe	474	570	520	529	547	561
*G4**	300	329	288	296	302	303
Americas	794	840	862	909	941	969
United States	661	673	690	728	754	779
Asia Oceania	131	195	212	211	227	241
Japan	83	109	121	121	126	129
Latin America	95	136	139	152	163	179
Africa	59	103	111	125	139	149
Middle East	179	369	389	427	444	468
FSU/Non-OECD Europe	597	690	705	722	731	735
Russia	391	473	483	493	499	501
Asia	180	399	424	489	564	634
*China***	28	110	132	176	226	276
OECD	1 400	1 606	1 593	1 649	1 715	1 771
Non OECD	1 111	1 698	1 768	1 915	2 041	2 166
EU-27	477	545	489	497	508	515
Total	2 510	3 303	3 361	3 564	3 757	3 937

Note: detailed demand by country and by sector are available in Table 28 and 29 in the chapter "The Essentials" at the end of this publication.
* G4: France, Germany, Italy and the United Kingdom.
** China includes Hong Kong.

OECD region: Europe looks for a floor and Americas for a ceiling

OECD gas demand is projected to grow from 1 593 bcm in 2011 to 1 771 bcm by 2017, translating into a 1.8% per year increase over 2011-17. This relatively bright outlook is based on widely different perspectives for the three OECD regions: Europe's recovery in gas demand is partly driven by a return to normal weather conditions, while there is genuine gas demand growth driven notably by the power generation and industrial sectors in the two other regions.

Table 3 OECD demand by sector (bcm)

	2010	2011	2013	2015	2017
Residential	534	506	519	521	525
Industry	341	341	361	379	393
Fertiliser	37	37	40	43	44
Power generation	570	585	602	636	662
Others	161	162	167	179	191
Energy industry	129	129	134	144	155
Total	1 606	1 593	1 649	1 715	1 771

The year 2011 could have been a bad year quickly forgotten by the European gas industry. However, between weak economic perspectives, high gas prices relative to coal, competition from industrials in other regions and moderate growth in the residential sector, the question is no longer by how much European gas demand would increase, but whether it would not decline altogether, taking into account the weather adjustments.

This contrasts very much with the situation in the OECD Americas region where industry and power generators will continue to enjoy relatively low gas prices in comparison to the other OECD regions, so that natural gas is projected to represent a growing share in these two sectors. Meanwhile, demand will grow in all OECD Asia Oceania countries, except New Zealand, albeit countries here have different drivers. In all cases, the power sector will be a major factor for growth, as can be seen in Table 3.

European gas demand in 2017 remains below 2010 levels

European gas demand is projected to increase progressively from 520 bcm in 2011 to 561 bcm by 2017, still below 2010 levels. With the recent debate on nuclear following Fukushima, one would have thought that the outlook for natural gas would finally brighten from a political angle. But from a market perspective, most power generators now look defiantly at gas-fired power plants, as these are currently struggling against coal-fired plants, and trying to find some room between the slowly increasing power demand and booming renewable energy generation.

Generation from renewable sources is strongly supported in Europe, as highlighted in the forthcoming IEA *Medium-Term Renewable Energy Market Report 2012,* to be issued in July 2012. In particular, generation from wind and solar sources is expected to more than double, from 179 TWh in 2010. Germany is by far the leader, followed by the United Kingdom, Italy and France. The output from other renewables (*e.g.* bioenergy, geothermal and ocean) will grow more modestly by about 50% over 2010-17.

Although hydro generation is more mature, its output is also increasing, notably in Turkey. Moreover, European nuclear generation will hold up reasonably well until 2016, receding from 916 TWh in 2010 to 880 TWh in 2016, then declining more substantially in 2017 to 848 TWh as additional nuclear power plants are decommissioned. The second stage of the German phase-out comes into force at the end of the decade, when additional nuclear power plants are expected to be decommissioned elsewhere, for example in the United Kingdom. There will be a few capacity additions, in Finland (2013), Slovakia (2013-14) and France (2016). As a result, the output from combustible fuels will decline by over 70 TWh over the projection period. This leaves very little room for growth in gas demand, although the output from oil-fired plants halves over 2010-17. The competitiveness of gas-fired plants improves over 2011-17 as gas prices slowly decline. After a drop in 2012, gas demand in the power generation sector therefore increases slowly over 2012-17, but never comes back to 2010 levels.

Obviously, the residential sector is not going to save European gas demand, considering the maturity of the markets. While there are still new users being connected, residential gas use per HDD per household is declining in most countries due to the use of alternative heating sources such as heat pumps, replacement of old boilers by more efficient condensation boilers and, in some cases, insulation improvements or norms being put in place for new households to promote the construction of more efficient houses. Residential gas demand was extremely high in 2010, reaching 230 bcm; according to the IEA's estimates, it decreased to 200 bcm in 2011 as HDD dropped by an impressive 17%. Assuming a return to normal weather (the five-year average over 2005-09), OECD Europe's residential-commercial gas demand is projected to recover in 2012 to 220 bcm and then slowly increase over the 2013-17 timeframe to 228 bcm. Residential gas use in mature markets such as Germany, the United Kingdom and the Netherlands will decline, while it would still be slightly increasing in France, and show positive trends in less mature markets such as Turkey and Greece.

To add to these cloudy perspectives, even the industrial sector can be expected to have a hard time recovering due to low economic growth and high gas prices relative to competitors in developing countries and now in North America. The industrial sector (excluding fertiliser producers) no longer uses as much gas as before 2005. Already, since 2000, there has been a declining trend, resulting from heavy industry moving offshore and industry making significant improvements in energy efficiency to keep energy costs down as they were facing rising gas prices. European industrial gas demand lost more than 20 bcm over the decade 2000-10, dropping to 117 bcm. It is projected to go down to even lower levels over the next couple of years due to a mixture of low GDP growth and higher gas prices, before starting to pick up and recovering to levels slightly above those of 2010 by 2014-15. While there will be some exceptions where industrial demand is still growing, such as Turkey, Greece or Poland, industrial gas demand will struggle to recover to 2010 levels in most countries. If Turkey is excluded, industrial gas demand in the other European countries recovers to 2010 levels only by 2017. One of the drivers enabling gas demand to recover is the assumption of declining gas prices after 2013. If gas prices remain stable at the high levels of 2013, even this slight recovery may be compromised.

Within the industrial sector, fertiliser producers will also use lower volumes: their gas consumption declines by less than 1 bcm over 2010-17, due to high gas prices and no new capacity to produce ammonia being added, with the exception of Poland and idle capacity coming back in Turkey. Additionally, some countries such as France and the United Kingdom still bear the impact of the closure of facilities over the past five years. Meanwhile, many producers face high gas prices compared with other regions and will reduce their use.

Gas use by the energy industry drops by 11% over 2010-17, driven by lower oil and gas production in key countries such as the United Kingdom and the Netherlands. In contrast, gas use in the transport sector, including both pipeline transport and use by natural gas vehicles (NGVs), increases by two-thirds, driven mostly by the road sector. The use by NGVs remains nevertheless modest, with less than 4 bcm consumed in 2017, not even 1% of OECD Europe's gas consumption.

OECD Americas' gas demand: the sky is the limit

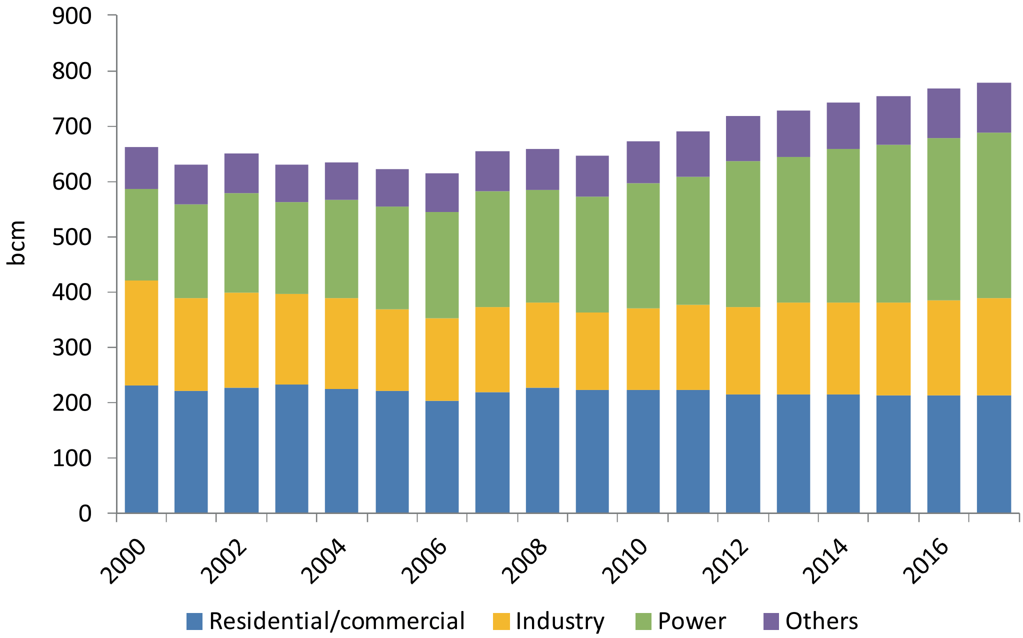
The outlook seems certainly brighter in the OECD Americas region, especially with Canada and the United States enjoying low gas prices. The picture is slightly different in Chile and Mexico, where the latter faces slightly declining gas production; both must rely on LNG and pipeline imports to meet their rapidly growing demand. OECD Americas' gas demand rises from 862 bcm in 2011 to 969 bcm in 2017, mostly driven by the power generation sector, but other sectors – industry and transport, are also showing healthy trends. US gas demand rises from an estimated 690 bcm in 2011 to 779 bcm in 2017; all sectors, except the residential-commercial sector, contribute to this growth.

Residential-commercial gas demand is one of the few sectors where demand is going down, as the two dominant markets – the United States and Canada – are showing a decline in gas use per HDD per connected household. This drop is nevertheless limited from 255 bcm in 2011 to 245 bcm in 2017, whereby residential-commercial use in the United States drops, while it remains relatively stable in Canada and increases slightly in Mexico and Chile.

Gas use in the industrial sector benefits from the relatively low gas prices that North America will enjoy over the projection period, remaining below USD 5/MBtu. The progressive increase in gas prices will stabilise the growth of industrial gas demand after 2015, but gas use in this region will gain some 32 bcm over 2011-17. Most of this incremental demand originates from the United States, and is driven partly by an increased competitiveness of the US industrial sector, with the reopening of mothballed plants as well as new petrochemical industries opening later in the projection period. The spread between oil products prices and natural gas prices also favours some switching in this sector. In 2010, the consumption of oil products in the industrial sector represented 90% of the gas consumption in the same sector, on an energy basis, so that there is switching potential. Mexico's gas demand also grows since the industry is still developing and GDP is projected to increase at over 3.5% on average.

Within the industrial sector, fertiliser producers are to benefit from low gas prices in North America, resulting in new facilities being built and idle facilities coming back to the market, notably in the United States. As a result, gas use by the fertiliser producers increases by 35% over 2011-17, with consumption coming back to pre-2005 levels. The largest driver is the United States, where new facilities start in the early part of the projection period and idle facilities re-open. There are also significant additions of new ammonia producing facilities in Mexico.

Figure 10 US gas demand, 2000-17



The power generation sector will represent 66% of the region's gas demand growth (71 bcm). In the United States, gas-fired plants benefit from low gas prices, enabling them to increase their share in the power generation mix over coal-fired plants (see the sectoral focus at the end of this chapter). Even with renewable energy sources increasing by over one-third from 461 TWh in 2011, generation from combustible fuels continues to increase. Despite the numerous obstacles, which have until now limited an important switch from coal to gas, sustained low gas prices over 2012-13 induce significant coal replacement, while new investment is dominated by combined-cycle gas turbines (CCGTs), even in the traditionally coal-heavy Midwestern states. Gas demand in the power generation sector in the other countries also rises, but modestly.

The energy industry's gas consumption is projected to grow by 14% or 13 bcm, reaching 109 bcm by 2017. The main driver will be its use for oil and gas production in the United States and Canada. OECD Americas represented 73% of the 129 bcm consumed in this sector in the OECD region in 2010. The region's share versus OECD energy industry gas demand is expected to remain constant over the next five years. Meanwhile, gas use in the transport sector increases from 23 bcm to 26 bcm; this increase comes to a large extent from increased use by NGVs in the United States, where the gap between oil and gas prices steers many companies to switch from gasoline-powered trucks or buses to ones using LNG.

Asia Oceania: all eyes are on Japan's power sector

While gas consumption in the OECD Asia Oceania is projected to increase over 2010-17 from 195 bcm to 241 bcm, the largest driver (and uncertainty) is by far the power generation sector and in particular, the future of nuclear energy in Japan. The other sectors are showing more modest evolutions. The power sector represented an estimated 56% of the region's total demand in 2011. At the country level, Japan remains by far the largest consumer (and LNG importer) of the region, followed by Korea. Meanwhile, with a doubling of gas consumption over 2010-17, Israel is the fastest growing consumer, owing to the rapid development of its domestic gas production (see Supply chapter). Australia is the second fastest growing market, benefitting from the development of domestic gas production. Only in New Zealand does gas demand decline over time, as the country can only rely on its domestic production, which is set to decline over time.

In Japan, some nuclear power plants are expected to restart after this summer, as discussed in the *OMR* April 2012 scenario "some nuclear". These nuclear reactors would come back starting in August 2012. The most likely ones to start would be reactors 3 and 4 of Ohi and the reactor 3 of Ikata, which passed stress tests in March 2012 and have been authorised by the Nuclear Safety Commission. These reactors are located in the southern region of Japan, where electricity demand is most needed by a dense network of industry and households. Under this scenario, the reactors which will be authorised to restart will represent slightly less than half of the historical nuclear production (around 280 TWh in 2010); no new nuclear power plant currently under construction is scheduled to start before 2018. To compensate for this loss of nuclear, the country relies primarily on energy savings. Despite higher increases in power demand in 2013-14, driven notably by the industrial sector, total electricity supplied in 2017 is still 3% lower than 2010 levels. Furthermore, renewable energy generation will increase by around 50% from 2010 levels. Gas is given a more prominent role, also due to its flexibility, lower CO_2 emissions than fossil fuel alternatives, the start of new CCGTs over 2011-17, and the availability of LNG on global gas markets. As a result, gas demand in Japan reaches 129 bcm, with most of the incremental gas demand coming from the power generation sector.

The residential-commercial sector represents a small share in the region's total gas consumption, and its growth will therefore remain extremely limited, with consumption increasing from 50 bcm to 52 bcm. In contrast, gas use in the industrial sector increases significantly by 26% over 2010-17, although this represents only 7 bcm in absolute terms. Korea's use in this sector is the fastest growing, with an additional 2 bcm. Israel's industrial gas use also increases to close to 1 bcm following the start of the Tamar field in 2013. Some industrials such as Hadera Paper have already signed long-term contracts for Tamar's gas. Gas use by fertiliser producers is limited in Asia Oceania, because neither Israel nor Korea is using gas for this purpose. Nevertheless, gas consumption in this sector is expected to increase by 44%, driven essentially by Australia, where new units to produce ammonia are expected to come on line over the coming five years. As a result, fertiliser producers' gas consumption increases from 2 bcm in 2010 to 3 bcm by 2017.

The largest relative increase takes place in the energy industry own use, where gas consumption increases by 88%, from 13 bcm to 24 bcm, driven by Australia, where not only use for oil and gas production surges, but also use in liquefaction plants. Gas consumption by the energy industry also increases in Japan and Korea, due to higher needs of regasification plants.

Sectoral focus: why is switching from coal to gas not occurring on a much larger scale in the United States?

In 2011, electricity generated from gas-fired plants exceeded the 1 000 TWh mark for the first time in US history. This was a 2.9% increase over the previous year, or some 29 TWh. At the same time, coal-fired generation dropped by 113 TWh, or 6.1%. Displacement of coal by gas in the US power mix is ongoing: since the shale gas revolution started around 2006, gas-fired generation has increased by 200 TWh, while coal has receded by 256 TWh. The US market is so oversupplied with gas that prices have collapsed even below the USD 2/MBtu line, but coal remains THE primary source of power supply. Coal still generated 70% more electricity than gas in 2011, and non-lignite coal plants were used at 62% capacity, while gas-fired capacity was used at 46.4%,[2] raising the imperative question: why is switching not occurring on a larger scale? Gas resources are ample. If gas were to replace nuclear plus coal generation over the coming 25 years, generating an additional 3 000 TWh per year, this would require around 550 bcm more gas per year. Added to the average gas demand forecasted in the *World Energy Outlook 2011*, this would mean an average annual US demand of 1250 bcm or over 31 trillion cubic meters (tcm) of gas over 25 years, compared to recoverable shale gas resources of 24 tcm. This example just shows that there is ample room for gas demand to increase. As gas prices are cut by one-third every passing year, why is gas not taking more market share from coal?

The dash for gas

The process of liberalising the US power sector accelerated in the 1990s. By this time, the United States had developed a well-functioning gas market and CCGTs became technologically mature. It is also worth noting that in the 1970s and 1980s, US energy policy restricted the use of gas in power generation (gas was considered a premium, scarce resource), so its share was artificially low. During this period and well into 2000s, CCGT technology was considered as an investment of choice by new entrants. A true boom in gas capacity construction occurred in the last two decades when 184 GW of gas-fired plants were built between 1990 and 2010, with a record of 36 GW of CCGTs added at the peak of the boom in 2002, or 57 GW including open-cycle. Some observers argue that too much capacity was built, which led to its underutilisation later in the 2000s. Although low gas prices below USD 2/MBtu in the 1990s are often referred to as one of the main reasons for the surge in gas generation investments, coal prices also dropped during this period, so that there is no direct correlation between low gas prices and high gas-fired capacity additions.

Many traditional levelised cost studies actually showed coal and nuclear as more competitive at that time. However, gas-fired plants offer certain advantages, including high efficiency, lower CO_2 emissions, relatively quick and cheap construction, modularity, and small scale, which contrast with

[2] There is considerable variation among states, however, with utilisation aggregates in some states below 10% (Nebraska, Iowa) and others over 80% (Connecticut, Alaska).

difficulties faced by coal plants on siting and licensing. Moreover, when the distinctive economic and financial characteristics of CCGTs are taken into account, they reveal their critical advantages for new entrants in liberalised markets. Indeed, a high degree of correlation between gas and electricity prices makes CCGTs "self-hedged" (Roques, 2007). All these considerations can be translated into an assumption that CCGT plant investments can take place with a lower cost of capital than coal or nuclear plants.

Gas price fluctuations and the dramatic but short-lived surge in gas capacity investments contrast with the gradual and steady increase of gas share in thermal generation and generation from coal- and gas-fired plants (see Figures 11 and 12). The graphics illustrate the competition between coal and gas. In absolute volumes, generation from gas doubled since the late-1990s and reached about 1 017 TWh in 2011, whereas coal generation hovered around the same level of 2 000 TWh until 2008, before dropping continuously since then to reach 1 734 TWh in 2011. It appears that during most of these 20 years, gas has actually filled the gap created by incremental power demand (+500 TWh) rather than displacing coal. Real competition between coal- and gas-fired plants started in the past few years, prompted by low gas prices. This took place in a context of stagnating power demand.

There are several factors which can hinder the penetration of gas in the power sector. Previous expectations of a US carbon pricing regime that would have enhanced the competitiveness of gas have not materialised. In addition, one must keep in mind that non-conventional technology transforming gas into a cheap domestic energy resource is relatively recent; these factors arose in the context of macroeconomic difficulties and weak demand. Furthermore, there are market and infrastructure factors which can explain the current situation and the limitations of gas-fired generation. These are discussed in detail in the following sections.

Figure 11 Coal and gas shares in thermal generation

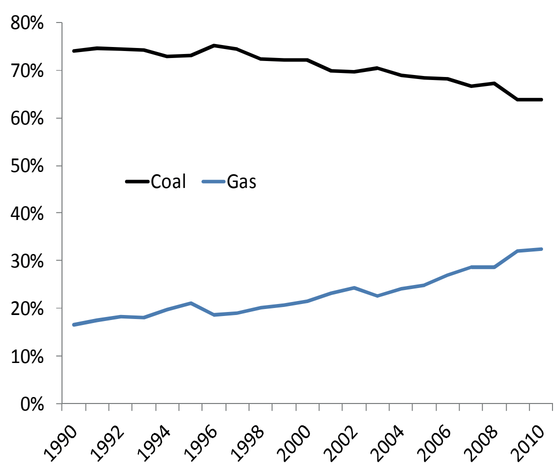
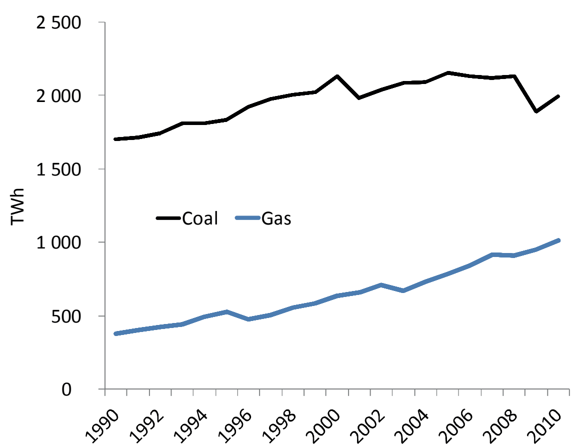


Figure 12 US coal and gas generation

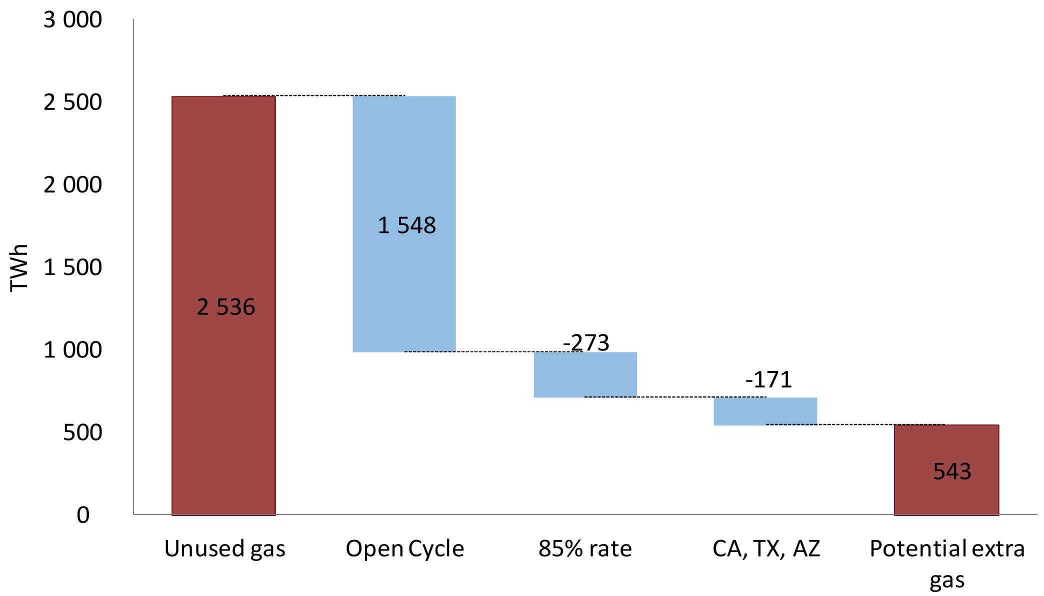


Potentially switchable gas capacity

First, it is crucial to understand to what extent gas-fired capacity could compete with coal-fired capacity. The United States had 405 GW of gas-fired capacity in 2010, compared with around 315 GW of coal-fired capacity. However, because as much as 197 GW of the total gas-fired capacity actually comes from open-cycle plants, which, due to their lower efficiency, are not as competitive as CCGTs, gas is therefore unlikely to substitute for coal even at prices in the range of USD 2.50 to USD 4/MBtu. This leaves 208 GW of CCGT capacity. Figure 13 shows the additional energy that could be delivered based on combined and open cycle nameplate capacity.

The 315 GW of coal-fired capacity is fuelled by a mixture of lignite, bituminous and sub-bituminous coal. Out of 16 GW of lignite-fired capacity in the United States, the majority is concentrated in the states of Texas and North Dakota, with some capacity in Louisiana, Mississippi and Montana. As lignite is a very low-cost fuel source, generally consumed close to the mine, it is unlikely that CCGT capacity could compete with lignite even at current gas prices. Generation from lignite capacity in Texas has been subtracted from the remaining potential generation from CCGT in Texas. Likewise, Arizona has relatively more expensive gas, long-term coal contracts and less efficient combined cycle plants, making switching less economical in that state. Therefore, the potential additional generation from CCGT capacity in Arizona has also been subtracted. Lastly, although California stands out as a state with a largely underutilised gas capacity, with no coal capacity to displace it, gas has no switchable potential. This leaves 543 TWh maximum to compete with coal, based on these considerations. This figure represents the ceiling of possible switching and does not denote an actual switchable amount.

Figure 13 Potential for gas to coal fuel switching, 2011



Factors affecting the utilisation of the switchable capacity

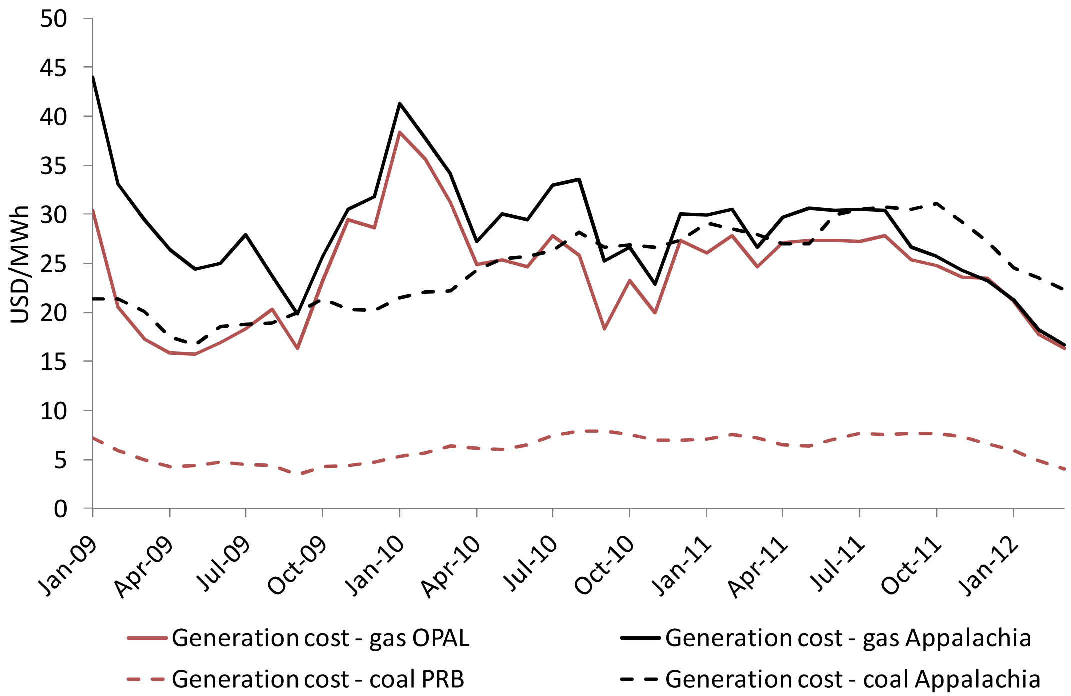
Many factors can affect how this switchable capacity is used. These include the relative fuel prices, the variability in plant level efficiency, contracts between coal producers and power producers, as well as some technical factors. They are examined in the following sections.

Fuel prices: the picture is not that simple

Fuel prices are probably the first factor which will come to mind when looking at coal versus gas. First, gas prices have fluctuated considerably over the past three years, making it hard for power generators to predict how they would evolve. Additionally, there is also greater variability at the state level, and even among plants. Looking at the spread between HH and regional indices from January 2011 to January 2012, the greatest variation occurs in winter months, with New England and New York experiencing significantly higher gas prices than the rest of the country due to lack of gas storage and transportation congestion. Florida also has more expensive gas prices.

This results in considerable differences in competitiveness between coal and gas across the United States. Figure 14 shows the generation costs from coal mined in the Appalachian basin and put on a rail car, compared with those from gas delivered on the Columbia Gas Appalachian hub. If both are used for power generation (NB: 50% efficiency assumed for gas-fired plants and 36% for coal-fired plants), natural gas was on par with coal on a monthly basis in the first half of 2011 for base-load power generation. However, in September 2011, gas prices dropped further and gained a competitive edge over coal in base-load power generation. The figure also shows the picture of a different US coal-producing region, the Western United States. There, the competitiveness of gas is not improving, even with local gas prices delivered at the OPAL hub in Wyoming well below HH levels (on average USD 0.25/MBtu lower in 2011). Considerably lower coal prices (averaging USD 0.75/MBtu in 2011) for coal produced in the Powder River Basin region make it nearly impossible for gas to be competitive in base-load power generation in this region, resulting in a continuous price differential in favour of coal between the fuels. In 2011, the differential averaged USD 5.5/MBtu, or around seven times the average Powder River Basin coal price that year. At the level of regional prices (and based on available data), substitution would therefore seem most likely to occur in the Eastern United States.

Figure 14 US regional power generation cost: Appalachia, Powder River Basin, 2009-12



Sources: ICE, Bloomberg.

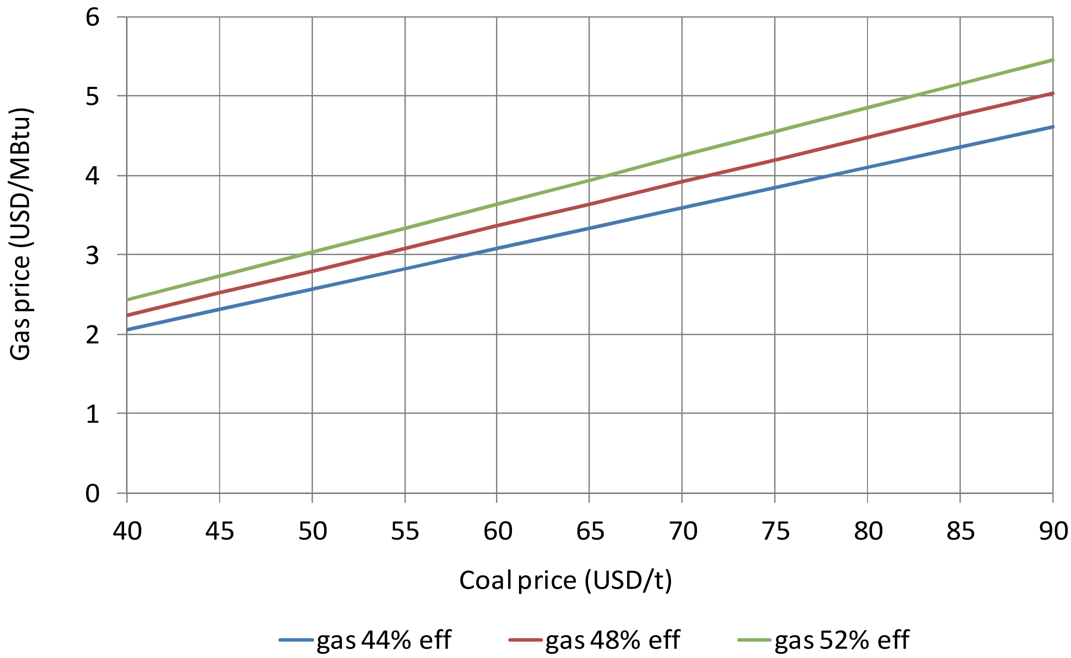
The efficiency of CCGTs is far from the theoretical maximum of 60%

The relative value of natural gas and coal to electric generators cannot be compared solely on a Btu basis, since the kilowatt-hours generated vary by facility. US non-lignite coal plants range in age from one to 88 years, with an average age of 38 years.[3] Due to depreciation and changes in technology, the efficiency of these plants varies considerably, with most falling in the range of 22% to 35%. Likewise, while the CCGT fleet is much younger, with an average age of 12.5 years, there is still considerable variance in efficiency, with the bulk of the fleet ranging from 40% to 50%, since the first generation of CCGT plants had considerably lower efficiencies.

There is no single, definitive source on the distribution of efficiencies in the two sets of generators, and available data can deliver different results. A study by the California Energy Commission in 2011 examined the falling heat rate of CCGT plants in California over 2000-10. Analysing data of state regulatory agencies, the study found the average heat rate of new CCGT plants in California to be around 48% in 2010. Aggregate calculations from EIA 2010 data support this finding; however, EIA data show considerably less efficient CCGT plants in Texas, with an average below 44%. Texas and California have respectively the largest and third-largest CCGT fleets.

Besides this uncertainty, it appears that, somewhat surprisingly, CCGT efficiencies can vary significantly. This can have far-reaching implications in some regions; in Texas, lignite and cheaper coal are available, despite the largest (but apparently less efficient) gas capacity. As a purely theoretical but indicative exercise, Figure 15 shows the "switching gas price" depending on the price of coal and the CCGT thermal efficiency. The coal-fired plant has an efficiency of 36%. A change of efficiency from 52% to 44% requires a gas price USD 0.60/MBtu cheaper (for a coal price of USD 65/t).

Figure 15 Gas switch price at different coal prices



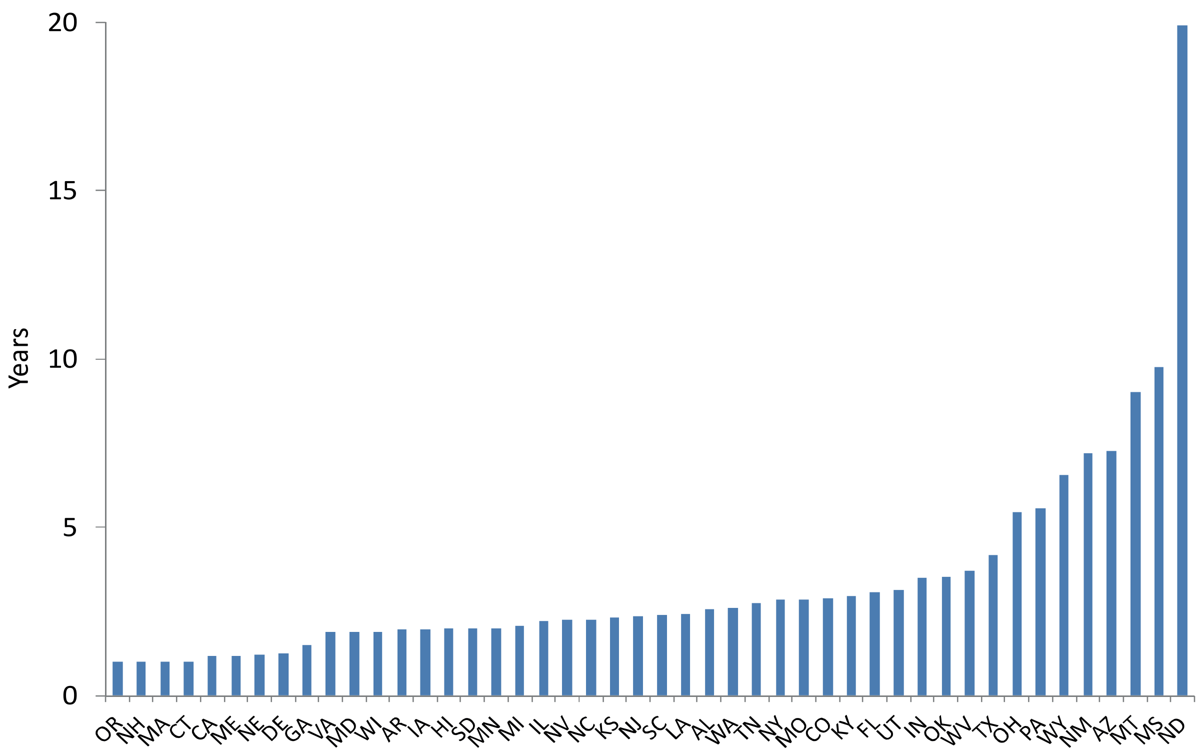
[3] Age weighted for MW capacity, EIA data.

Contracts: how coal producers maintain their share in the power sector

The terms and conditions of coal contracts influence the choice of fuel for electricity generation in the United States, as a larger proportion of the coal is purchased on a contractual basis, compared to purchase practices regarding natural gas. For reference, 93% of the coal consumed for electricity generation in the United States in 2011 was purchased via contracts, compared with 44% of the natural gas.

While the exact conditions attached to these contracts are not public, anecdotal evidence suggests that many have firm take-and-pay clauses, with the result that power producers have frequently committed to consuming a given amount of coal for several years into the future. Additionally, even until 2010, many analysts expected gas prices to increase back to at least USD 6/MBtu in the medium term, so that the confidence to switch and abandon coal was not yet there. EIA data shows that most contracts have less than five years to run. However, of the 15 states with the longest average remaining contract terms, some are those with a CCGT potential above 8 GW, such as Texas, Florida, Arizona, Pennsylvania, Oklahoma and Mississippi. Thus, how coal-to-gas competition will unfold in those locations is of particular interest. Market information suggests that utilities have started to reduce offtake commitments when rolling over coal contracts.

Figure 16 Average age of coal contracts for power generation, United States, by state



When the technology also plays an important role

Limitations of coal and CCGT technologies are also likely to play a role in the choice between these two fuels. The US power load has become more peaky in recent years, restricting the dispatch between coal- and gas-fired plants. Where a power producer might otherwise switch from coal to gas for base load and utilise coal for intermediate demand, technology may limit this, for the following reasons:

- Operating range and minimum output: the existing coal and CCGT fleets have different optimal capacity factors and the relationship between utilisation and efficiency differs. The existing US coal fleet may be less well-suited to meeting peak demand because its optimal utilisation falls in a smaller range. The level of optimal utilisation for a given plant depends on a range of factors, notably its age and its design. New coal and CCGT plants have similar ranges and can generally operate optimally at between 70% and 90%, and sub-optimally at between 40% and 70% with moderate losses in efficiency. For older plants, the loss of efficiency at lower levels of utilisation tends to be higher (IEA, 2010). As coal plants are on average 25 years older than CCGT plants, the efficiency losses associated with sub-optimal load factors are greater on average.
- Start-up rates: the start-up rates for coal-fired boilers and the steam component of CCGT plants are in the range of 8-48 hours, whereas the gas turbine components of CCGT plants have start-up rates below one hour (AEMO, 2010). This allows CCGTs to respond to rapid changes in demand, albeit at the efficiency level of an open cycle plant in the early stages.
- Ramp-up rates: the ramp-up rates of US coal-fired plants depend largely on their vintage. The range for plants of the 1960 vintage (the average age for a US coal plant being 38 years) is around 3 megawatts (MW) per minute for a 500 MW unit. This compares with average CCGT ramp-up rates of around 15-25 MW per minute, which is roughly similar to the ramp-up rates for coal plants built since 2000. As is the case with the operating range above, while ramp-up rates are similar for coal and CCGT plants of similar vintage, the average age of coal plants is much higher than that of CCGT plants, making coal plants more costly to run at intermediate load.

Understanding the specificities of the US power sector

Besides the considerations regarding switchable capacity and limitations on this, some specificities of the US power sector also come into play. Power sector reform is at different stages across the United States. Electricity prices are a key factor when considering electricity market reform. In some regulated states (in the Southeast), due to already relatively lower electricity prices, there might be less pressure to reduce prices further by switching to cheaper fuels. Although there might be some discontent about higher end-user prices in the liberalised Northeastern states, economic and market design factors play a key role. These states sometimes also have higher fuel prices.

In competitive markets, such as the Pennsylvania-New Jersey-Maryland (PJM) market, the design and structure are potentially a significant factor in coal-to-gas competition. Indeed, capacity payments mechanisms exist in most liberalised US markets and constitute a significant share of gas plants' revenues. For example, in 2010, CCGT plants in the PJM market received around 30% of net revenues from capacity payments (Potomac Economics, 2010). Purely from a microeconomic profit maximisation theory, this fixed stream of revenues should not affect decisions to run gas installations. However, the reduced risk of making a loss on gas installations thanks to capacity payments might affect the way market actors make decisions (utility functions depend on attitude to risk), especially when the same owner also has coal plants.

Some power producers, whose revenues are regulated, face weaker incentives to depart from existing practice in response to changes in relative coal and gas prices. In many cases, increases in cost are directly passed on to customers, meaning that a utility can maintain much or all of its margin, even when costs increase. In other cases, the basis for calculating revenues is not altered until a rate case is initiated, and this is usually done by the utility itself. In these latter cases, a regulated entity is still likely to seek to maximise margins by reducing costs as prices and revenues remain constant. In

2011, 75% of US coal-fired plants were in the regulated sector, against 36.5% in combined cycle gas. Nevertheless, some of the most intensive fuel switching took place in Florida, a regulated state, suggesting that public utility regulation does not necessarily dampen economic incentives.

In states where conditions are otherwise favourable to fuel switching, the electricity grid may limit switching. Specifically, there is very little trade between the three main interconnections in the coterminous American states (Western, Eastern and ERCOT) and within these interconnections, there is limited long-distance transmission capacity. This means that for fuel switching to occur, a CCGT plant needs to be not too distant from a load served by a coal-fired plant. Meanwhile, where transmission is theoretically available to transport a load, congestion on the transmission network may constrain the dispatch of generating units and limit the coal to gas switch in certain regions, in particular, where the location of gas-fired plants differs significantly from the location of coal-fired plants. Finally, in states where coal-fired generation serves as the primary base-load energy source, the geographic distribution of plants is relevant to the task of maintaining grid stability. In those states, it may be difficult to switch to base-load power fueled by CCGT if the geographic distribution of CCGT plants is not comparable.

The US Congressional Research Service (Stan Mark Kaplan, 2010) conducted a high-level analysis to identify all major coal plants with one or more existing CCGT plants within a ten-mile radius, reasoning that these CCGT plants would be best placed to displace coal within the constraints of the transmission network. The hypothetical surplus generation for each CCGT within the ten-mile radius was calculated and assumed to displace generation from the coal plant. The study found that "existing CGGTs plants near coal plants may be able to account for something on the order of 30% or less of the displaceable coal-fired generation and CO_2 emissions. Greater displacement of coal by existing CCGTs plants would depend on more distant CCGTs plants, which would be less clearly transmission interchangeable with coal plants. This emphasises the importance that the configuration and capacity of the transmission system will likely play in determining the actual potential for displacing coal with power from existing CCGT plants" (Stan Mark Kaplan, 2010).

Looking forward to retirement, coal plants?

Retiring coal plants as the result of more stringent environmental regulations may open up opportunities for fuel switching in the medium term, where it might not otherwise be economically viable. Permitting and licensing of new coal-fired plants has indeed become more challenging in the United States, partially due to the opposition to the construction of new plants.

Of the 299 GW of coal-fired capacity as of 2010, around 110 GW did not have emission control equipment (desulfurisation units) or firm plans to fit this equipment. Around 55 GW was found in plants with efficiency below the average and older than the average of 38 years. These plants are relatively less likely to justify the necessary investment to meet increasingly rigorous emissions control requirements and around 36 GW of this capacity is concentrated in the mid-western and southern states (Illinois, Indiana, Michigan, Wisconsin, Alabama, Mississippi, Tennessee and Kentucky).

Non-OECD region

Non-OECD gas demand is projected to grow from 1 768 bcm in 2011 to 2 166 bcm by 2017. The region represents 69% of the world's incremental gas demand over 2011-17, reflecting stronger economic growth, and in some cases, the availability of domestic gas resources at cheaper prices as is the case in the Middle East and FSU. The fastest growing region is Asia, and in particular China, where gas demand is projected to more than double over the next five years.

In all regions, the power generation sector is the key driver behind this rapid gas demand growth, although it faces competition from other energy sources, notably coal, in many Asian countries. The industry is also a strong driver for additional gas demand, as industrial output growth remains strong. Gas use in the residential-commercial sector is limited in non-OECD countries. Most of gas use in this sector is currently concentrated in the Former Soviet Union. However, it already plays a significant role in China and that country is projected to be the major driver behind the expansion of gas use in the residential-commercial sector for non-OECD countries.

Table 4 Non-OECD demand by sector (bcm)

	2010	2011	2013	2015	2017
Residential-commercial	249	252	274	292	306
Industry	416	431	473	512	544
Fertiliser	157	156	172	182	189
Power generation	761	799	854	908	971
Others	269	285	313	329	344
Energy industry	181	193	209	214	218
Non-OECD	1 698	1 768	1 915	2 041	2 166

Note: Detailed demand by country and by sector are available in Tables 28 and 29 in the chapter "The Essentials".

The Middle East

The Middle East was the fastest growing region over the last decade, as its demand increased by 8% per year, resulting in a doubling of natural gas consumption from 179 bcm in 2000 to 369 bcm in 2010. This exponential growth is expected to slow down over the next five years, to 3.1% per year over 2011-17. This results in Middle Eastern gas consumption reaching 468 bcm by 2017. The single biggest uncertainty for this growth is the successful ramp-up of gas production across the Middle East. As highlighted in the Supply chapter, a few countries are experiencing difficulties in ramping up production. Furthermore, developing additional gas import infrastructure, either pipeline from neighbouring countries or LNG import terminals, can be challenging. Besides the existing LNG import terminals, only an additional one will be built in Bahrain, enabling the country to compensate for the production drop in the latter part of the projection period.

Saudi Arabia is one of the fastest growing markets, benefitting from the development of its domestic gas production, which reaches 112 bcm by 2017. The country neither imports nor exports natural gas over 2011-17, but increased gas output displaces oil in the power sector. Significant growth is also projected in Iran, although this is a market with high uncertainty due to the political climate and its potential impact on the development of new gas production in this country. Iraq and Qatar both see their natural gas consumption increasing by around 11 bcm and 18 bcm, respectively. This represents a real recovery for Iraq, which entirely depends on the successful development of domestic gas production. If this fails, Iraq's consumption will certainly be much lower. Due to the challenges highlighted above, Bahrain and Oman will see a small increase in their domestic gas use. Lebanon remains the smallest regional market with 0.3 bcm consumed in 2017, as the country relies entirely on Egyptian gas supplies. Syria is projected to slowly recover from the drop in natural gas demand due to the war, but it will no longer get Egyptian pipeline gas supplies.

Figure 17 Gas use in the Middle East by country, 2000-17

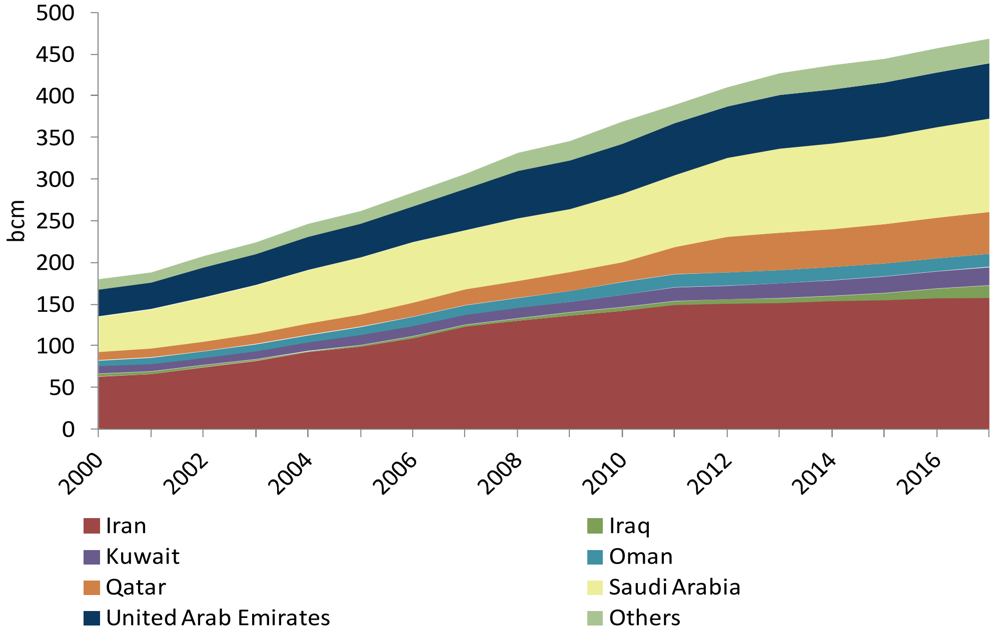
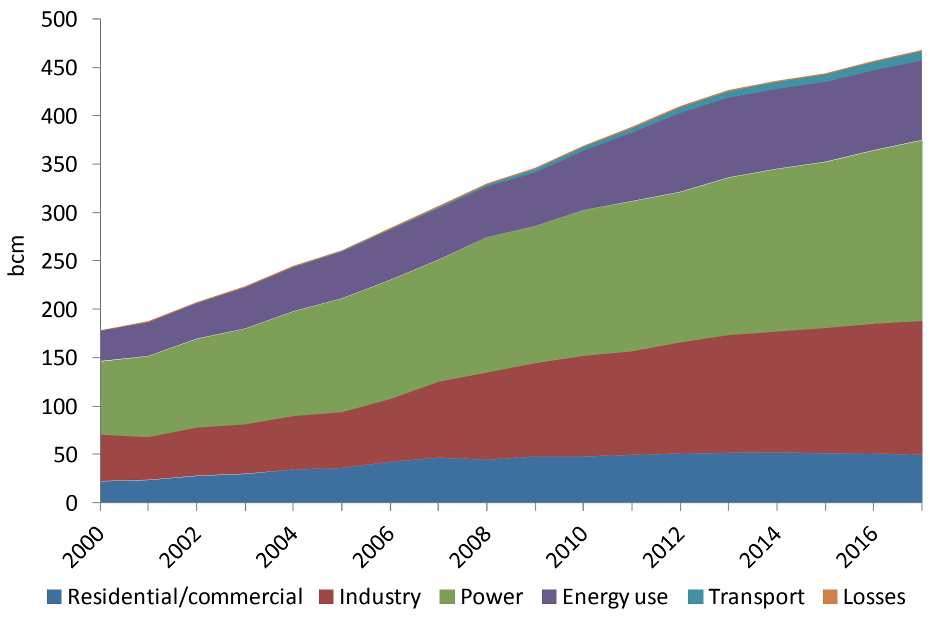


Figure 18 Sectoral gas use in the Middle East, 2000-17



In this region as well, power generators consume half of total gas demand, and their consumption is projected to grow at 3.2% per year, slightly faster than the region's total demand growth. While both gas and oil play a prominent role in the power generation sector, given the current oil prices, many countries prefer to export their oil rather than to use it for producing electricity. Over 2000-09, the region's electricity consumption increased at 6% per year, or over 27 TWh per year, while at the same time, gas use by power producers increased from 75 bcm to 141 bcm. This suggests that most of the incremental electricity was actually met by natural gas. Such a trend is expected to continue over the next five years. Even if this growth slows down, there will still be significant power demand needs, most of which will be met by gas-fired plants, even if oil use in this sector remains high.

With a 11% market share in 2017, the residential sector remains a small part of total gas demand. Gas use in this sector is mostly limited to Iran, where it should stabilise, provided that the country pursues the announced rises in domestic tariffs. Industrial gas consumption rises from 107 bcm in 2011 to 139 bcm in 2017, as many countries take advantage of the gas resource base to develop industries such as petrochemical or fertiliser. In particular, the consumption by fertiliser producers is expected to increase markedly in Saudi Arabia and Qatar.

Gas use in the transport sector remains limited to NGVs in Iran, where the number is expected to continue to rise. Iran has witnessed an exponential growth in these vehicles over the past five years, as the number of NGVs increased from almost none to two million, although they represent only 12.6% of the total number of vehicles.

Africa

Africa is expected to expand its gas use by 35% over 2011-17, reaching 149 bcm from an estimated 111 bcm in 2011. Algeria and Egypt, which already account for 71% of African gas demand, are projected to contribute around an additional 22 bcm, or around 56% of the incremental gas demand. In both countries, this substantial growth will compete against potential increases of gas exports. Other countries, such as Nigeria, Angola, Libya, and Tanzania, will also contribute to Africa's gas demand growth, but in a more limited way. Assuming the development of its national gas market based on the government's Master Plan, Nigeria increases its gas demand by almost two-thirds. Libya is assumed to recover from civil war and to resume its plans to develop gas use in the industry and power generation sectors, albeit with many delays. Angola's gas sector benefits from the start of the new LNG liquefaction plant in mid-2012.

In most countries, natural gas demand increase is limited by upstream developments, or in some cases, those of neighbouring countries. This is the case for many countries in the Sub-Saharan region, such as Senegal, Cameroon, the Congo and the Ivory Coast, which can only rely on their own gas production. Meanwhile, Togo, Benin and Ghana rely on the limited deliveries from Nigeria through the West Africa Gas Pipeline, feeding mostly power plants. South Africa's natural gas demand depends almost entirely on production developments in Mozambique.

The main driver behind Africa's almost 40 bcm gas demand growth is the power generation sector, which contributes to 53% of the incremental gas consumption. The second largest contributor is industry, with an additional 12 bcm consumed. These two sectors are the priorities in Africa, due to the needs for more power plants and to develop domestic industry. These users are also easier to connect than retail users in countries where the gas transmission network remains extremely limited. Within the industrial sector, an important gas user is the fertiliser industry, where gas use is projected to rise by almost 4 bcm over the projection period. Again, these developments are concentrated in two countries, mostly Algeria and to some extent, Egypt.

Figure 19 Gas use in Africa by country, 2000-17

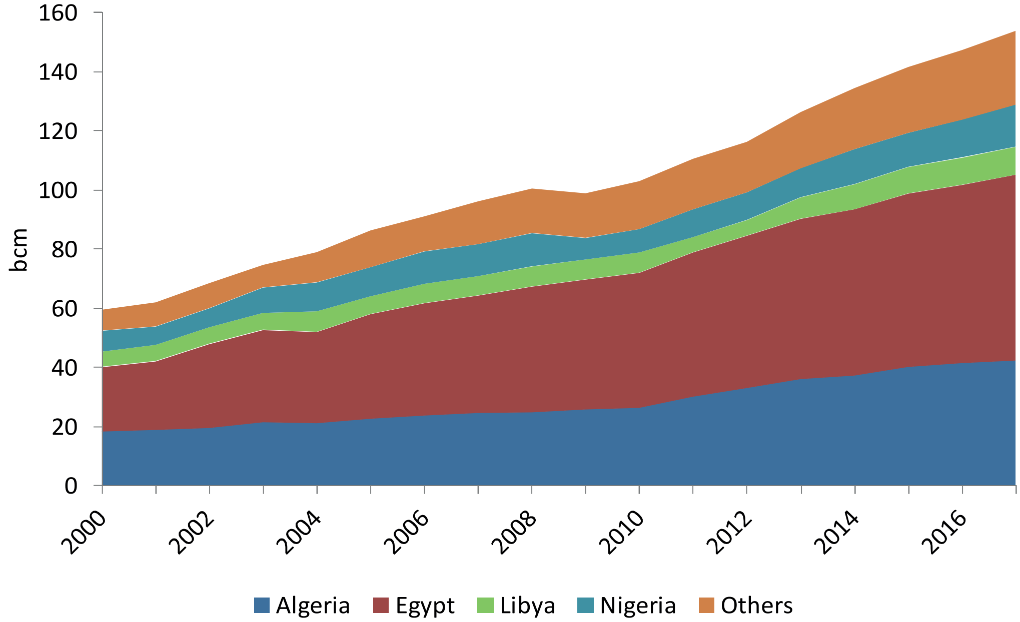
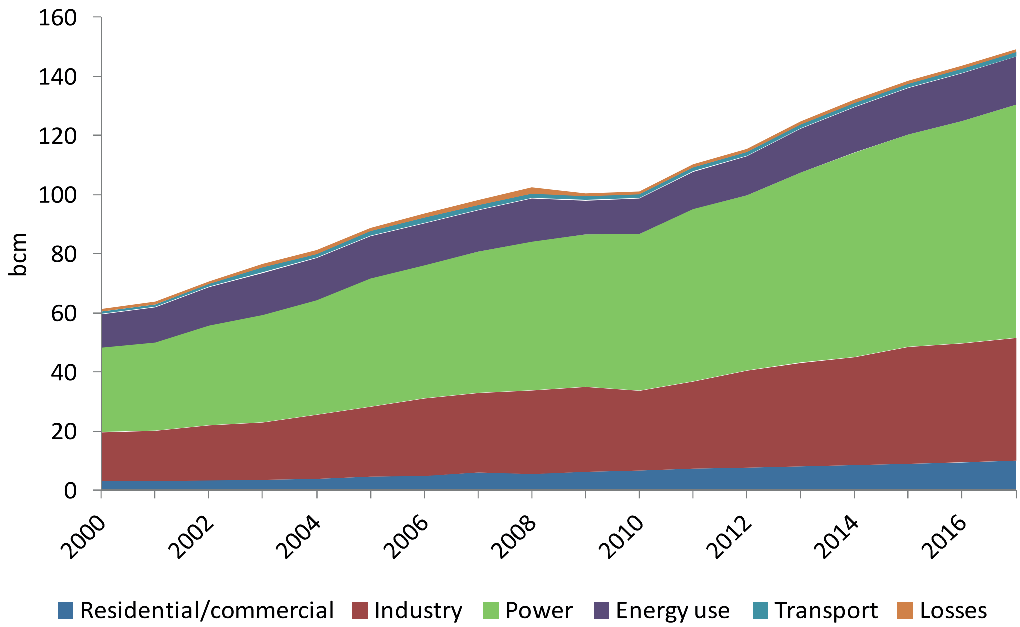


Figure 20 Sectoral gas use in Africa, 2000-17

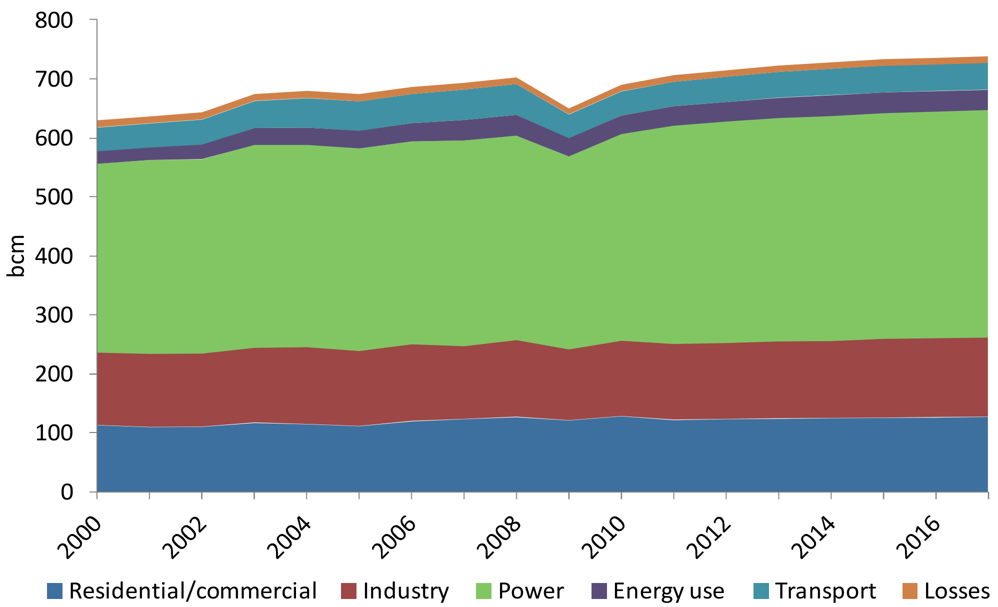


Gas use in the residential-commercial sector still increases by some 3 bcm, although it remains entirely concentrated in North Africa, mainly Algeria, Egypt, Morocco and Tunisia. The Algerian regulator CREG plans an additional 240 000 users to be connected every year over 2010-15. The development of such gas use in other African countries is doubtful on account of the limited needs for heating in other parts of Africa and the absence of distribution networks. Finally, gas use by the energy industry gains another 4 bcm: this sector's needs are driven by rising oil and gas production, the construction of new liquefaction plants, as well as the input to oil refineries. In contrast, gas use in the transport sector remains negligible, with most of the interest in NGVs concentrated in Egypt.

The Former Soviet Union and Non-OECD Europe

Even though the Former Soviet Union and Non-OECD Europe region is a relatively mature market, demand nevertheless rises modestly from 705 bcm in 2011 to 735 bcm in 2017, which is equivalent to an annual growth rate of 0.7% per year. Regional natural gas demand is dominated by Russia, with its consumption representing 68% of the region's gas consumption. Following its 2.3% growth in 2011, Russian gas consumption continues to grow, albeit slowly (0.5% per year), reaching a level of 501 bcm by 2017. The Caspian region is also an important centre of gas consumption, with 111 bcm consumed in 2011. The region's gas demand reaches 120 bcm by 2017. Non-OECD Europe remains a modest consumer of natural gas, as the region tries to limit its dependency on Russia. Moreover, no additional supply coming from either the Caspian region or global LNG markets reaches these markets due to the lack of new import infrastructure.

Figure 21 Sectoral gas use in FSU and Non-OECD Europe, 2000-17



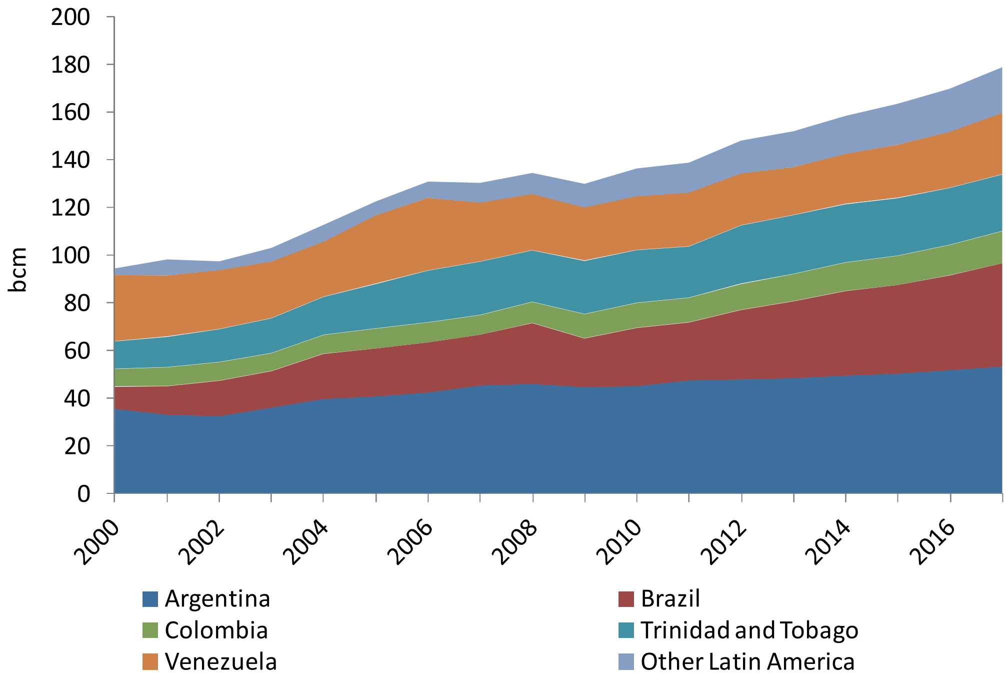
Representing half of total natural gas demand as of 2011, power generation is expected to increase at 0.6% per year, adding some 16 bcm of incremental gas demand (+4% over 2011-17). The second largest contributor to the demand increase is the industry sector, where consumption grows by 6 bcm (+4%). This includes fertiliser producers, which contribute to two thirds of the industrial sector's incremental gas demand.

Demand in the residential-commercial sector remains stable over 2011-17. This sector represents one-sixth of total demand, due to the region's important needs for heating. Demand for households barely increases, given the maturity of this sector and the considerable room for energy efficiency improvements, which happen in a very limited way. Gas tariffs for households increase in some FSU countries, but they remain very low compared to European levels. Gas use in the transport sector also increases by 4 bcm, albeit this additional demand comes primarily from higher needs to transport the gas to export markets (despite an expected decline in transit countries such as Ukraine and Belarus), as well as CNG bus programmes in Russia, Uzbekistan, and Kazakhstan.

Latin America

Latin America's gas demand is projected to increase by 29% over 2011-17, from 139 bcm in 2011 to 179 bcm in 2017. As of 2010, four countries represented over 80% of regional gas consumption: Argentina, Venezuela, Brazil, and Trinidad and Tobago. However, among these four countries, gas consumption has only been increasing in Argentina and Brazil since 2005, while it has been stable in Trinidad and Tobago and declining in Venezuela. Brazil represents half of the additional gas demand over 2011-17. Argentina has the second largest growth in demand, owing more to additional LNG imports than to increases in domestic gas production.

Figure 22 Gas demand in Latin America by country, 2000-17

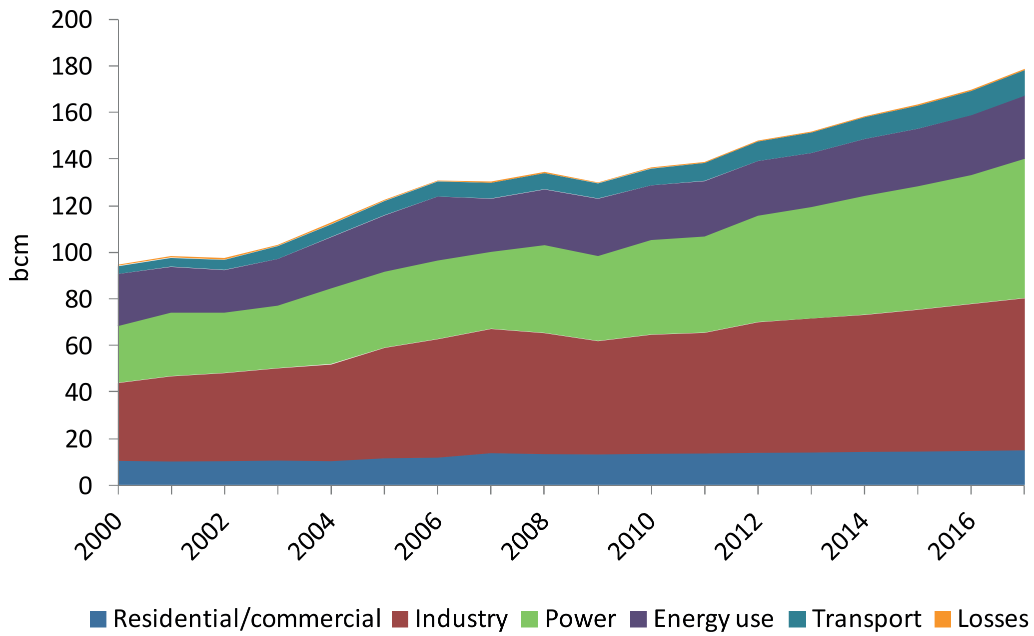


Demand increases in a more limited way in Venezuela and Trinidad and Tobago. Meanwhile, Peru benefits from the development of the fields linked to the liquefaction plant. Gas consumption also increases in Bolivia and Colombia, as the growth of domestic production also benefits these countries. There is limited growth in other Latin American countries, where gas is not used in most cases, due to either lack of such resources or import infrastructure.

As in Africa, the main drivers behind gas demand increase are the power generation and industry sectors, contributing to half of the incremental gas consumption. The additional consumption from power generators amounts to 19 bcm, against 13 bcm for industry. Many Latin American countries still suffer from lack of electricity generation, and although they are developing alternative generation sources, gas-fired plants are an important source of additional power. Fertiliser producers contribute to an additional 5 bcm of gas demand, with additional ammonia plants planned in Argentina, Brazil, Peru and Venezuela. Trinidad and Tobago remains the largest ammonia producer, but no expansion is planned as reserves dwindle, thus diminishing future gas demand.

Additional gas use in the residential-commercial sector contributes only 4% of the incremental gas demand. Meanwhile, the transport sector remains quite popular with NGVs representing 20% of total cars in Colombia and 15% in Argentina. There are already over 1.6 million NGVs in Brazil, although they represent only 3.4% of the total number of vehicles. Additional gas demand in this sector represents 4 bcm. Finally, due to growing gas production, gas use by the energy industry increases also by 4 bcm.

Figure 23 Sectoral gas demand in Latin America, 2000-17

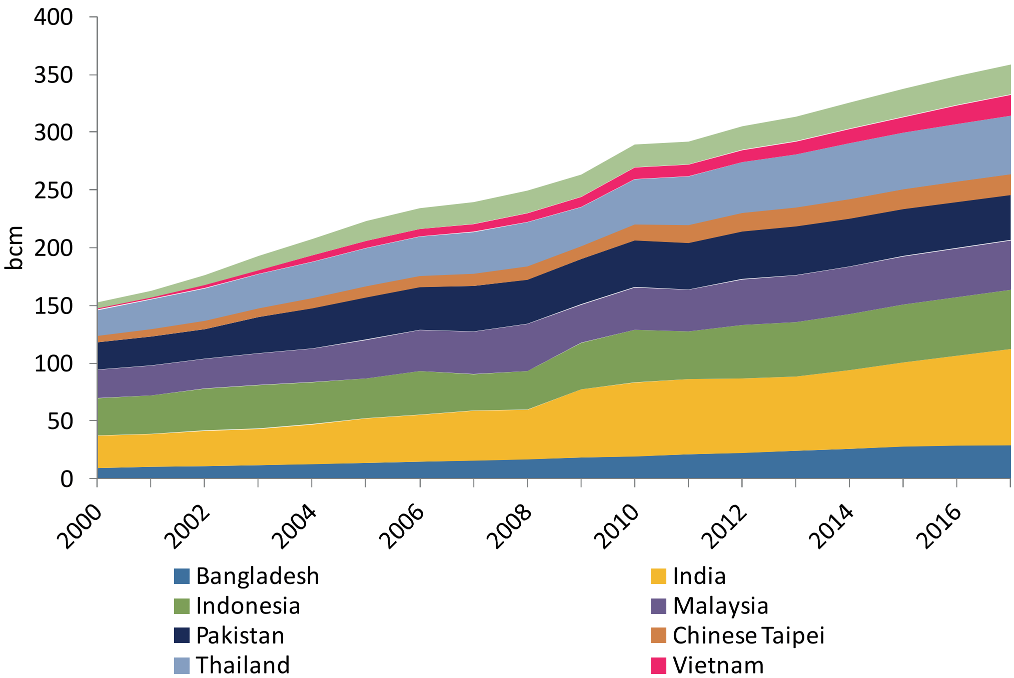


Asia (excluding China)

The Asia region is one of the fastest demand centres, even if one excludes China. Indeed, gas consumption is projected to grow from 292 bcm in 2011 to 358 bcm in 2017, or at 3.5% per year. Although this additional gas demand may sound impressive, Asian gas consumption remains limited by low production growth and the inability of some countries to attract the external supplies required to fill their needs. While the region greatly benefits from its large resource base to support rapidly growing gas consumption, this is insufficient because production remains constrained in a certain number of countries (see Supply chapter). Therefore, over 2011-17, some countries must turn to LNG imports to be able to meet rapidly increasing demand for natural gas. This is notably the case for Thailand, Vietnam, Indonesia, Malaysia and Singapore, although it should be emphasised that both Indonesia and Malaysia remain net exporters of gas.

Some countries will not see any import infrastructure being built, despite pipeline and LNG import terminal projects; as a result, they will have to rely entirely on their domestic production. This is the case for Bangladesh, Pakistan and the Philippines. India has to rely on increasing volumes of LNG to face demand needs from the power generation sector, but given the high price of LNG on global gas markets, India's ability to import as much as it needs is limited, leaving still substantial volumes of unmet demand. Finally, Myanmar and Brunei have a relatively slowly growing domestic demand, which enables them to remain exporters of pipeline gas and LNG, respectively.

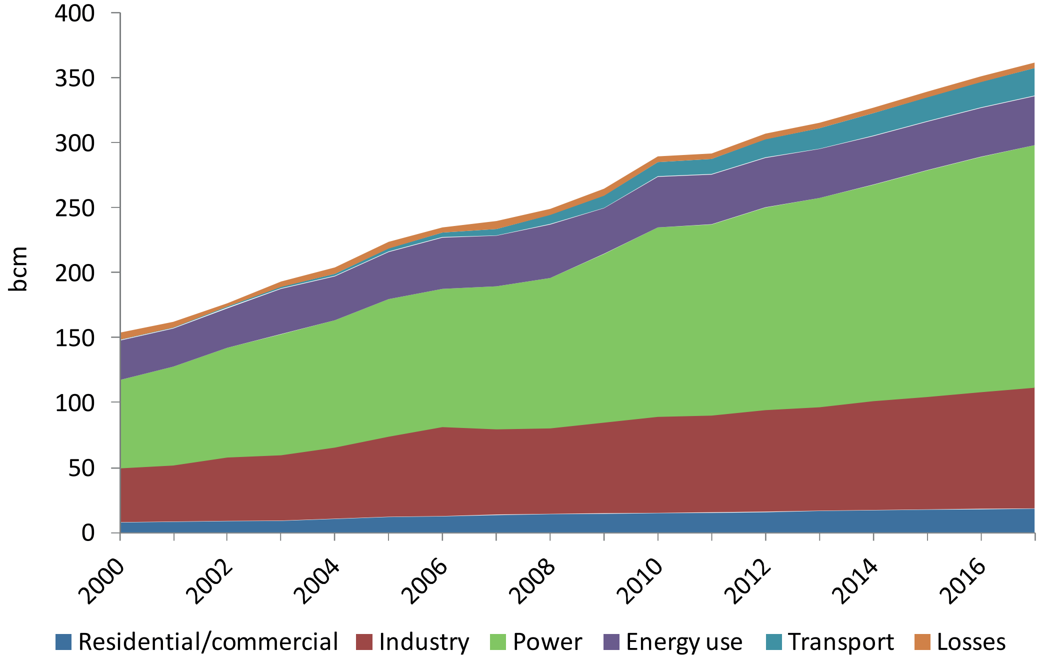
Figure 24 Gas demand in Asia (excluding China) by country, 2000-17



The transport sector is the fastest growing in Asia, increasing 10% annually, admittedly from a small base. Many countries are developing NGVs and encouraging the use of gas in the transport sector. This is notably the case in Pakistan, the world's leader in terms of the number of NGVs with 2.7 million representing 61% of the vehicle fleet. India, with over 1 million NGVs as of 2010, shows an impressive growth of this type of vehicle which considerably improves the quality of air in the big cities. Gas use in the transport sector nevertheless represents a small share of total demand as consumption reaches only 21 bcm in 2017. Most of the other sectors grow at 3% to 4% per year, in line with the region's average annual growth rate.

Power generation represents just over the half of total natural gas demand as of 2017, reaching 183 bcm, 38 bcm higher than in 2011. Gas is facing competition from coal in many Asian countries, notably in India and Indonesia. In India, gas demand in the power sector grows more slowly than what could have been expected two years ago, due to the failure of gas production to recover rapidly (see Supply chapter). In Indonesia, the second fast-track programme to build new power generation capacity gives a stronger role to coal. Gas nevertheless makes some breakthroughs in parts of the country, where a new LNG terminal will start operation (West Java). In Brunei, the government aims at diversifying the power generation mix away from gas, while in Thailand, the share of gas in the power mix remains high. Gas use in the industry reaches 92 bcm by 2017, from 75 bcm in 2011. Gas use by fertiliser producers contributes to 40% of the industrial sector additional consumption. The residential sector maintains a limited role as its contribution to total gas demand does not exceed 5%.

Figure 25 Sectoral gas demand in Asia (excluding China), 2000-17



Regional focus: what Chinese[4] gas demand of 273 bcm in 2017 means for the world

How fast Chinese gas demand will increase over the coming years is one of the hardest questions faced by the global gas industry in early 2012, due to the uncertainty about future imports to China. Indeed, there are no doubts that China will become a major importer of gas. It already is, with an estimated 31 bcm imported in 2011, and contracts already signed for significant additional pipeline and LNG imports. The question for external suppliers is how much pipeline gas and LNG China will need in five or ten years. For domestic companies, it is how to source the gas and also in which sectors demand will be growing, as they need to develop the necessary infrastructure to bring gas to future consumers.

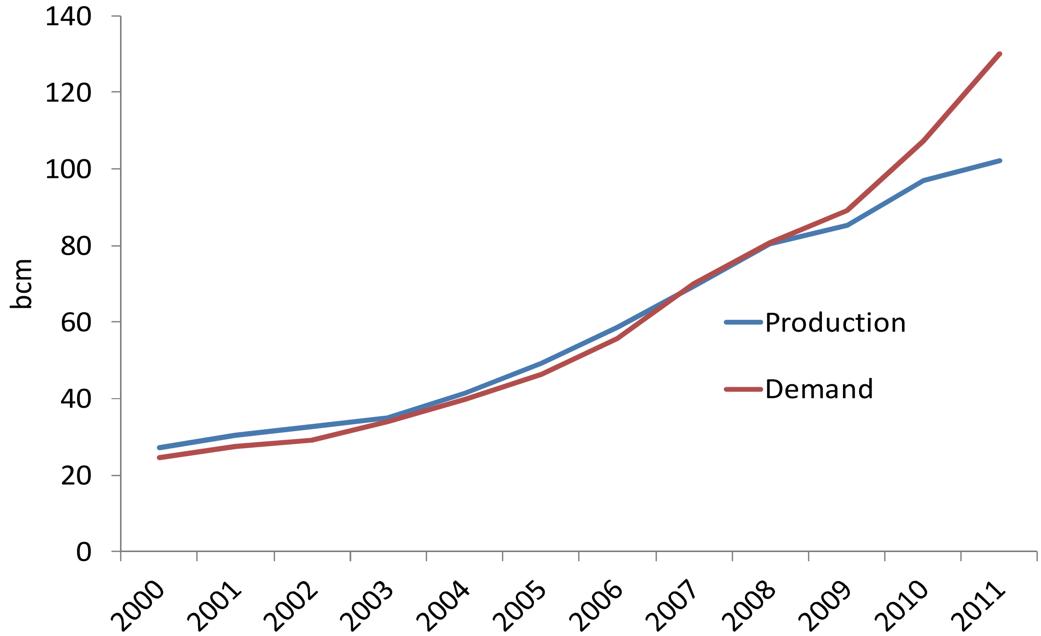
China is the fourth largest gas user in the world

As of 2011, China's natural gas demand reached 130 bcm, which represents an estimated 4.8% of the country's total energy demand. The 12th FYP foresees a doubling of the natural gas share in the primary energy mix to 8.6% over the period 2011-15, which would translate into a gas demand of 260 bcm by 2015. This appears to be extremely ambitious, even in the eyes of Chinese stakeholders. The consensus regarding gas demand by 2015 among Chinese experts is closer to 230 bcm. Gas demand in early 2012 was growing at 15% on a monthly basis, slightly slower than during the two previous years. In terms of sectoral gas demand, the residential-commercial sector represents

[4] In this subsection, China does not include Hong Kong; consequently, numbers differ from those of Table 2, Table 28 and Table 29.

around one-third of total gas demand, ahead of the power generation and industrial sector, accounting for roughly 20 bcm. Gas use for power generation increased markedly, almost doubling from 2008 to 2010, although still only a little over 2% of total power generation.

Figure 26 China's widening production-demand gap, 2000-11



Note: China does not include Hong Kong; consequently, the country appears as slightly exporting during the first years.

The Chinese National Petroleum Corporation (CNPC) projects gas consumption to increase to 230 bcm by 2015 and to 500 bcm by 2030 in a "regular policy scenario", and to 260 bcm by 2015 and 550 bcm by 2030 in a scenario where natural gas would benefit from strong policy support. In the regular policy scenario, 42.2% of gas would be used for urban consumption, 25.2% in industry, 21.1% for power generation and 11.4% for the chemical industry. As China imports increasing volumes of LNG – around 50 bcm by 2015, it will impact the world's gas trade significantly. Depending on whether there is any decision on future pipeline supplies from Russia in the coming years, these LNG supplies could evolve in a different manner after 2017. Russia is unlikely to commit to either the development of new green fields in the Far East or Eastern Siberia or the corresponding pipeline infrastructure to Chinese borders, without being sure that the volumes will be significant, even if the ramp-up takes time. While it is not expected that Russian supplies to China will be in place before 2017, they are nonetheless expected to represent a significant part of Chinese gas imports in the longer term … unless China rapidly develops such shale gas production volumes that importing Russian gas becomes unnecessary. This is precisely the uncertainty faced by many suppliers looking at China.

The Chinese gas market faces many issues, many of which are not new. However, as China is currently the world's fourth largest gas user, these issues have become more acute and could represent a hindrance towards the path of doubling gas demand in four years. Sufficient import infrastructure must be built in an efficient manner in coordination with domestic transmission, distribution and storage infrastructure. Moreover, sufficient supply needs to be available to feed into this new infrastructure, which implies that wholesale and end-user gas prices need to be high enough to attract more expensive supplies, notably from global LNG markets.

The most important issue faced by China is pricing. This is not only a question of absolute price level, which is frequently quoted as a key issue, but also of the structure of the pricing system itself. The reforms, which started a decade ago, aiming to create a more market-oriented oil and gas sector, including the reform of the state-owned companies, have to date failed to introduce a market-based gas pricing system. Besides, the gas market still has a monopolistic structure with three big players dominating most parts of the gas value chain.

Understanding China's pricing issue

The pricing level issue includes notably the growing divergence between the different gas streams reaching city gate, the fact that regulated residential gas prices are kept low, and the competitiveness of gas-fired plants in the power sector. As China has become increasingly import dependent, a widening gap has appeared between city gate prices from different sources. This is particularly striking when one compares the price of cheaper domestically produced gas to that of more expensive Turkmen pipeline gas and LNG. Turkmen pipeline gas imports accounted for an estimated 14 bcm in 2011 (compared to 4 bcm in 2010) and are expected to further increase over the coming years. The current contract states that Turkmen gas supplies will reach 40 bcm, and volumes up to 65 bcm are even under discussion, although it would certainly take more than five years to reach such levels. Supplies from Uzbekistan started in April 2012.

Meanwhile, CNPC has been losing money on Turkmen imports (CNY 1/m^3 according to press reports, which would equate to CNY 14 billion [or USD 2.2 billion] for the year 2011) resulting in the central government granting tax rebates for import prices exceeding wholesale gas prices for a period of ten years (2011-20). Meanwhile, the average price of LNG imports almost doubled between 2009 and mid-2011 to around USD 8/MBtu, which is much cheaper than what Japan pays but represents a dramatic increase against the price of the first LNG contract (USD 3/MBtu). Spot LNG has also become very expensive due to a combination of increasing oil prices and LNG markets having tightened after Fukushima. As a result, city gate prices at Shanghai are estimated to range between USD 8/MBtu (for gas from domestic sources transported through the first West-East pipeline) and USD 13/MBtu (for Turkmen gas imports) and even USD 17 to USD 18/MBtu for spot LNG imports as of end-2011.

This situation is expected to worsen over the next four years, as China is projected to import increasing volumes of gas (109 bcm by 2017). Meanwhile, new sources of LNG such as Australian LNG starting in 2014-15 are unlikely to be cheap, given the high capital costs of these projects and the fact that the pricing structure is thought to be based on oil formulas with at least a 12% slope. Keeping city-gate gas prices low will maintain the distortion between the different sources of gas and could create a discrepancy between artificially inflated demand and low supply, which must be resolved by administrative allocation.

Regarding the domestic gas pricing structure, tariffs are currently based on a cost-plus approach, with prices for wellhead and pipeline transport determined by the central government. The ex-plant (wellhead) price, based principally on the production cost of natural gas, is proposed by the project developer and adjusted by the central government. This price is a baseline, and producer and buyer can negotiate up to 10% above it. Transport tariffs depend on each pipeline and are determined based on the pipeline construction and operation costs plus a margin.

Tariffs vary with the transport distance from each gas source to each city gate. Therefore, the transport tariff depends both on the different consuming regions and the diameter and length of the pipelines. The internal rate of return (IRR) is standardised for all pipelines by the government at 12%, accompanied by very short depreciation periods of 10 years. This high IRR is required to compensate for losses at the production, imports and sales sides, where capped prices usually lie below the real production and sales costs. This generally leads to a competitive advantage of the integrated companies compared to non-integrated exploration and/or supply companies without their own transportation capacities. In addition, pipeline access is negotiated because there is no regulatory obligation for third-party access.

The end-user price varies depending on the type of end user: fertiliser producer, industrial users (direct supply), city gas (industrial or non industrial). The reform currently being started in the Guangdong and Guangxi regions would result in one maximum single price at the city gate independent from the gas source, which would streamline the whole pricing system (see Box 5). Even if the reform is extended nationwide by 2015, it is uncertain whether it would have an impact on production by then, given the lead times to bring new green fields to production. The effects would appear on a longer-term basis, but are still essential for the future of the Chinese domestic gas production sector.

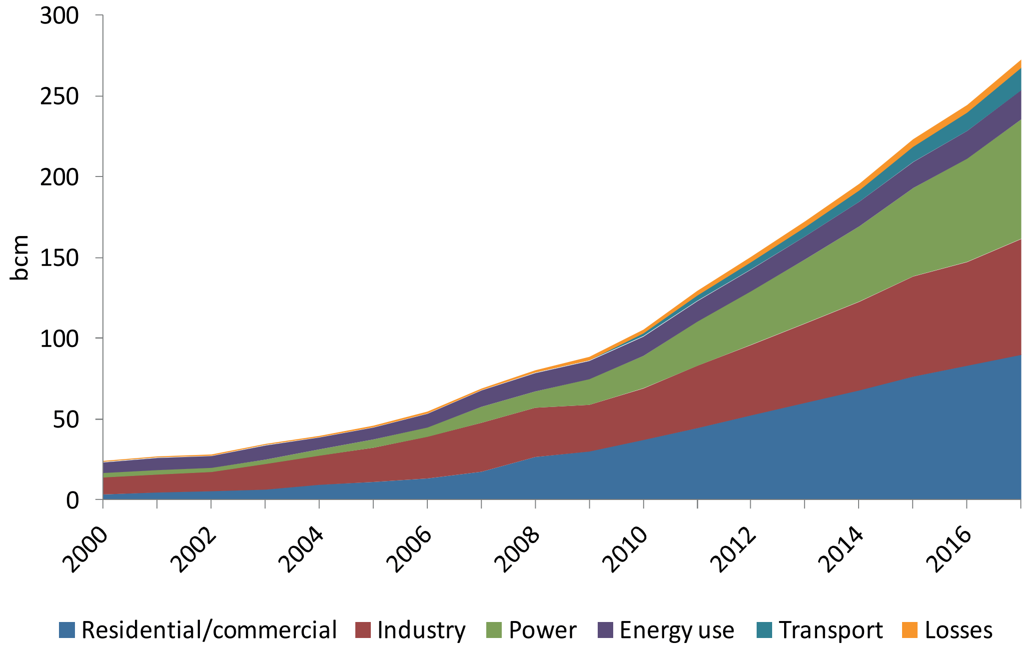
Attracting sufficient supply is also a question of infrastructure

Prices are not the only issue. Obstacles towards rapid development of Chinese gas demand also include the need for a rapid expansion of gas infrastructure at all levels, the lack of access for small, medium-sized and foreign companies to existing import and pipeline infrastructure, a lack of a clear, efficient and transparent regulatory framework and diffuse and overlapping regulatory authorities regarding energy markets. Having enough import infrastructure is an essential condition to meet high demand levels, given the constraints on domestic gas production. As of early 2012, Chinese LNG import capacity amounts to 29 bcm, while another 26 bcm is under construction. The capacity of the Central Asia Gas Pipeline from Turkmenistan is announced to reach to 55-60 bcm/year by 2015, which seems optimistic, while the 12 bcm Myanmar-China pipeline will start in 2013. However, capacity does not translate into supply. Although China could theoretically import around 120 bcm of gas by 2015 based on infrastructure, imports are projected to reach 85 bcm. Therefore, in order to meet the FYP target, attracting more supplies will be needed.

Gas demand increases at 13% per year

China's gas demand is projected to increase from 130 bcm in 2011 to reach 273 bcm by 2017, which implies an annual growth rate of 13% per year. This represents a very rapid growth, albeit not quite as rapid as foreseen in the 12th FYP, due to constraints on the supply side. By 2015, China's gas consumption is projected to reach 223 bcm and it will need to import 85 bcm, comprised of 35 bcm of Central Asian gas, 3 bcm from Myanmar and around 47 bcm of LNG. Gas demand will increase in all sectors, except in the non-energy use category (use by fertiliser producers), where it remains almost stable.

Figure 27 Evolution of Chinese gas demand, 2000-17



Power generation

The key sector for future gas demand is power generation. So far, the role of gas in China's total power generation has been extremely limited, as gas accounted for a very limited share of total power capacity until now. Natural gas is currently dwarfed by coal, a trend that is not expected to change over the coming five years, even if the share of gas in the primary energy mix increases. However, the FYP's target to increase the share of natural gas will influence coal and gas use in this sector. In particular, according to the 12th FYP, the share of coal in primary energy consumption will drop from 70% to 63%, or around 2 650 million tonnes of coal equivalent (Mtce) in 2015. Whether these ambitious objectives are reached or not, this will certainly contribute to slow down coal demand growth. In the IEA *Medium-Term Coal Market Report* issued in December 2011, coal demand in China was projected to increase from 2 517 Mtce in 2010 to 3 123 Mtce in 2016, with coal use in the power sector increasing at 5.2% per year.

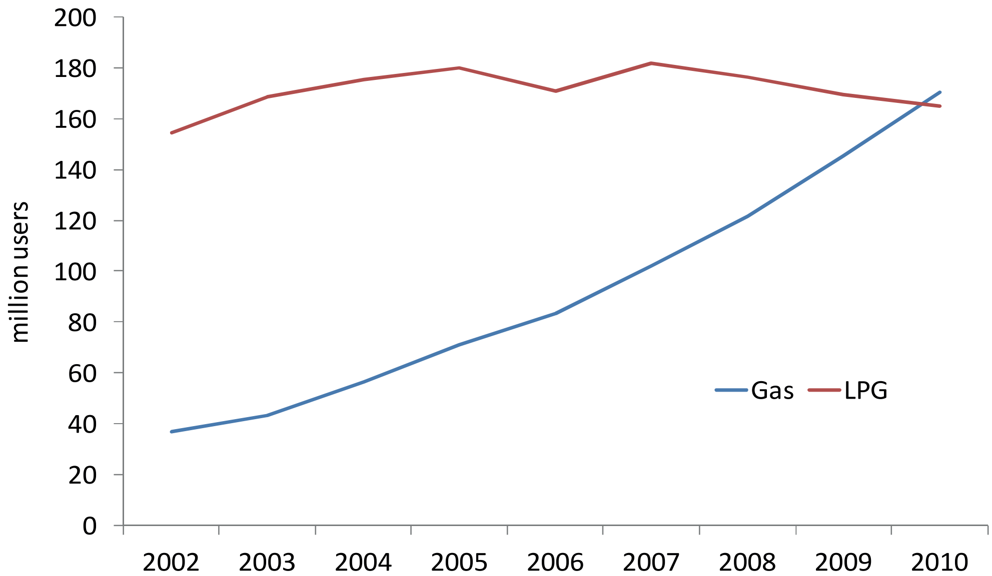
Over the past years, power capacity in China increased from 520 GW in 2005 to around 910 GW in 2010; coal-fired plants contributed most of this expansion. As of 2010, gas-fired capacity amounted to only 26 GW. The FYP foresees an increase of this capacity to 60 GW by 2015. While this target is likely to be reached, there is considerable uncertainty regarding the future load factor of gas-fired plants. Indeed, regulated and capped electricity prices make it difficult to pass through high gas prices unless there are regional shortages. This is a key issue for gas demand to increase in this sector and to play out its often favourable performance for meeting both the flexible- and peak-times of electricity demand, in addition to curbing coal demand growth. This will also require infrastructure and markets to be flexible to accommodate such demand fluctuations. The environmental benefits of gas, as well as its flexibility, should be recognised in the pricing system, which therefore imposes reforms in the electricity sector to be performed in parallel.

Gas demand in the power sector is projected to increase in line with the addition of new gas-fired capacity reaching 74 bcm by 2017; nevertheless, this capacity is never used base-load, but rather mid-merit at 5 000 hours per year on average towards 2015-16. This assumes that policy developments are happening, which make the use of gas more profitable for power generators.

Residential-commercial sector

The residential sector has been highlighted as a priority by the government in terms of natural gas development. It has also been one of the fastest growing, with the number of gas users increasing from 37 million in 2002 to 170 million in 2010 (see Figure 28).

Figure 28 Number of gas and LPG users in China, 2002-10



Source: CNPC.

Natural gas competes with LPG, but the number of LPG users has been lessening ever since 2005. New households are connected to gas, driven by policy support and by the attractiveness of gas versus LPG. Furthermore, gas use is also increasing in the commercial sector, which benefits from the availability of the distribution network. Gas use in the residential-commercial sector is projected to increase to 90 bcm by 2017.

This sector nevertheless faces potential increases in gas prices. Prices for the commercial sector are already very high compared to other sectors, so that households are the sector facing higher prices. Indeed, regulated residential gas prices are often kept low compared to industrial or commercial gas prices. Some regional residential prices are also lower than the corresponding price of imports, creating losses along the gas value chain. To increase residential gas prices, one must go through public hearings on a local basis, so that reforms decided by the central government could potentially fail to be implemented locally. Nevertheless, this has been changing since late 2011/early 2012 as some cities are taking advantage of recent lower inflation rates to gradually increase residential gas prices. These cities, which often own the distribution gas companies, also face higher procurement costs, so that there have recently been price increases of 30% to 40% in many cities across China.

Table 5 End-user prices in selected Chinese cities, 2011

	Residential		Industry		Power		NGVs	
	CNY/m^3	USD/MBtu	CNY/m^3	USD/MBtu	CNY/m^3	USD/MBtu	CNY/m^3	USD/MBtu
Beijing	2.05	9.01	2.84	12.48	2.84	12.48	4.73	20.79
Tianjin	2.20	9.67	3.15	13.85	3.15	13.85	3.95	17.36
Shanghai	2.50	10.99	3.69	16.22	3.89	17.10	4.70	20.66
Guangxi	4.37	19.21	5.73	25.19	5.73	25.19	4.95	21.76

Source: CNPC.

Is the transport sector a new wild card?

Another interesting development is the increasing number of small liquefaction plants supplying liquefied gas (LNG) to refilling stations. As of end-2011, 35 LNG stations were operational and able to process some 4 bcm (9.96 million cubic meters per day [Mcm/d]) of gas. CNPC owns around 25% of them and Xinjing Guanghai owns 15%. This gas is mostly used in the transport sector or in case of power outages. The number of NGVs has been growing fast in China, from 97 200 in 2005 to an estimated 450 000 in 2010, but it represents only 0.3% of the total number of cars in China. Given the speed at which the transport sector expands, there is ample margin for this number to increase. This increase in terms of NGVs is obviously matched by the development of refilling stations, which amounted to 1 350 as of 2010.

Looking forward, gas use in the transport sector is projected to increase four-fold to 14 bcm, or 5% of total gas consumption by 2017. Indeed, there is rising interest in using gas in the transport sector, in particular due to concerns over China's air pollution, which has sparked interest in cleaner LNG transportation, while oil prices are increasing at the same time. This is also driven by constraints in terms of pipeline capacity, which encourage the sale of the gas locally. Such a feature is certainly of interest for the small and medium-scale producers without access to pipelines. China is looking to construct up to 13 LNG terminals with a total capacity of 4 bcm/y (1 125 Mcm/d), doubling the current capacity. There are plans to increase the LNG production capacity to 14 bcm by 2015. This expansion will be matched by the rapid increase in the number of LNG or CNG refilling stations from 1 350 in 2010 to 5 000. For example, CNOOC plans to build 100 LNG vehicular refilling stations in Fujian by 2015. These stations would consume between 0.35 million tonnes per annum (mtpa) and 0.4 mtpa (between 476 Mcm and 544 Mcm). Hubei Province plans to build an additional 16 LNG refilling stations by end-2012, in order to reach 105 stations by end-2015. Gas prices for NGVs are also determined by the central and the local governments. In 2011, prices ranged from CNY 2.3/m^3 to CNY 4.95/m^3, with an average of CNY 4/m^3 (USD 18/MBtu).

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SUPPLY

Summary

- Global gas supply increased by 3% in 2011, reaching 3 375 bcm. The 93 bcm increase was largely supplied by three countries: the United States, Russia and Qatar. From a regional perspective, gas production increased significantly in OECD Americas, FSU countries and the Middle East. OECD Latin America and OECD Asia Oceania recorded marginal supply increases. Supply remained stable in Asia, while declining in Africa and in Europe. Global gas supply increased more rapidly than demand (2%), with the difference used to increase or refill storage.
- Unconventional gas represented 16% of global gas production as of 2011, with half from tight gas production despite the rapid growth and ever-increasing interest in shale gas. Production developments in 2011 were concentrated in North America. Unconventional gas production is expected to continue to expand over the medium term, led by developments in North America. Beyond this region, production growth will mostly come from tight gas and coalbed methane and from Asia Oceania, in particular, Australia, China, India and Indonesia. Shale gas developments in the medium term will be limited, with the most likely developments taking place in China and Poland. Countries with significant shale gas potential face a certain number of challenges on top of environmental issues, including pricing, infrastructure, and lack of upstream competition or an under-developed service industry.
- Global gas production is projected to increase by 562 bcm over 2011-17, in line with global gas demand. Gas production increases in all regions, except in Europe. OECD regions are expected to provide 30% of the growth in global production capacity over the projection period, changing the trend of the previous decade where non-OECD and especially Middle Eastern producers were the main incremental suppliers.
- The United States is forecast to be one of the largest sources of incremental supply to 2017, where gas production continues to boom despite a difficult gas pricing environment. High oil prices, driving the production of gas associated with light tight oil extraction, combined with substantial domestic consumption and new international opportunities, are expected to underpin continued expansion of US gas production over the period. Meanwhile, the fastest growing region in relative terms is OECD Asia Oceania, where natural gas output more than doubles, boosted by new LNG export plants in Australia and increasing production in Israel.
- Russia and the Caspian region remain important sources of incremental supply over 2011-17, as FSU/Non-OECD Europe's production increases by 129 bcm. However, moderate growth in domestic and European export markets, combined with limited access to alternative global markets, especially in North Asia, is likely to constrain production growth over the projection period. In the Caspian region, natural gas production in Turkmenistan, Uzbekistan and Kazakhstan benefits from its connection to China, unlike Azerbaijan, where the infrastructure needed to facilitate exports to Europe is not yet under construction.
- Natural gas production increases in the Middle East and Africa by 72 bcm and 57 bcm, respectively. While this enables Africa to increase its LNG exports, in the Middle East, this increase fails to meet incremental gas demand. There is growing interest in Mozambique and Tanzania, although this is unlikely to translate into increased production or exports in the medium term.
- Asia's gas output increases by 26% (111 bcm), with 61 bcm coming from China alone. In contrast, India struggles to restore its production to current levels. Meanwhile, Latin American gas production records the slowest rate of increase – only 15% (25 bcm) over 2011-17.

Recent trends

The United States leads 2011 global supply growth

Global gas supply increased by an estimated 3% in 2011, in line with the average growth rate observed over the last decade (2.8%). Global supply actually increased more than demand (2%), due to more gas being put in storage. The largest contributor to the 93 bcm of net supply increase was the United States, with an additional output of 49 bcm in 2011, largely ahead of Qatar (+26 bcm) and Russia (+22 bcm). Supply growth in 2011 came therefore from the three countries which either have been the fastest growing producers or have ample gas reserves, with relatively little additional supply coming from other countries. In particular, Qatar benefitted from the expansion of its LNG export capacity. In contrast, gas production dropped substantially in most European countries. It even dropped in Norway, where natural gas production had been continuously growing over the past decade.

From a regional point of view, OECD gas production contributed to 19 bcm, or 20% of global gas supply growth, with non-OECD countries supplying the rest. Among the OECD regions, Americas appears as the main driver behind OECD gas supply growth, with an additional 47 bcm produced, compensating for the sharp drop in Europe and stable gas production in OECD Asia Oceania. Non-OECD supply increased by 76 bcm, and this growth was based on the traditional sources of incremental supply: the FSU as well as the Middle East. There was limited additional supply coming from Latin America, while Asian production remained relatively stable and African gas production dropped due to the unrest in Libya.

Table 6 Regional production, 2010 and 2011* (bcm)

	2010	2011*	Growth rate (%)
OECD**	1 178	1 197	1.6
Americas	816	863	5.7
Europe	301	273	-9.3
Asia Oceania	61	61	0.3
Non OECD***	2 103	2 178	3.6
Africa	209	204	-2.4
Asia	432	431	-0.1
FSU/Non-OECD Europe	826	863	4.5
Latin America	161	164	1.8
Middle East	475	516	8.7
World	3 281	3 375	2.9

* 2011 data are estimates.

** 2010 data for OECD countries are based on revisions provided by OECD countries early 2012.

*** 2010 data for non-OECD countries are based on IEA *Natural Gas Information 2011*, with the exception of Iraq which has been revised.

This does not mean that the situation in 2011 was "business as usual". Attention has been very focused on the Middle East and Africa region due to the Arab Spring. While, with the disruption of 1.5 mb/d of Libyan oil, the focus was very much on oil, the gas supply side also witnessed a sharp drop in gas production in Libya and Syria, the repeated bombing of the Arab Gas Pipeline linking Egypt to Israel, Jordan, Syria and Lebanon, and sabotage in Yemen, albeit with limited effects on production or exports in 2011. In Yemen, a more significant disruption took place in April 2012. This happened at the same time as demand increased in Asia, notably after the Fukushima accident.

Box 3 The impact of the Arab Spring

The Arab Spring, which ignited in Tunisia in January 2011 and spread over North African and Middle Eastern countries, created uncertainty about its impact on oil and gas production. Egypt and Algeria are significant gas producers and exporters. Bahrain, Libya, Syria and Yemen are medium-sized producers, whereas only Libya and Yemen export gas. At the beginning of the unrest, LNG transit through the Suez Canal was closely monitored as it represents a key route for Qatar LNG; around 40 bcm (40% of Qatari LNG exports) passed through the Suez Canal in 2011. The most visible effects of the Arab Spring were seen in Libya (production and exports) and Egypt (exports). Egypt's and Algeria's upstream sectors were not affected by the unrest; their somewhat disappointing performances resulted from ongoing factors. In Syria and Libya, however, the upstream sector was affected.

Table 7 Disruption in MENA selected countries

	Production	Exports		Production	Exports
Bahrain	??	X	Algeria	None	None
Jordan	None	X	Egypt	None	+++ (pipe)
Lebanon	X	X	Libya	+++	++++
Oman	None	None	Morocco	None	X
Yemen	+	+	Tunisia	??	X
Syria	++	X			

Note: X = no exports or no production. None: no disruption. +: <10% disruption, ++: <50%, +++: <70%, ++++: >70%.

In Libya, the disruption upstream was mostly seen at the export level, but domestic gas demand was affected as well. Libya exported 9.4 bcm of pipeline gas to Italy in 2010 as well as 0.6 bcm of LNG, mostly to Spain. In 2011, pipeline supplies dropped to 2.3 bcm and LNG to 0.1 bcm. Libya started reducing its exports to Italy on 21 February 2011; the following day, supplies were interrupted. From March to October, Italy did not receive any gas from Libya. Demand dropped by 5 bcm, while higher deliveries from both Russia and Northern Europe (+7 bcm) compensated for these missing supplies. However, Algerian gas supplies to Italy dropped by 4.6 bcm due to rising domestic demand. LNG imports were stable from the previous year. As of early 2012, Libyan supplies are almost back to normal. Given the strong position of ENI in the Libyan upstream sector, the absence of any alternative outlet for Libyan gas and the revenues generated by gas exports (albeit much lower than oil), the supply contract is unlikely to be revised downwards.

Figure 29 Libyan gas exports to Italy, 2005-11

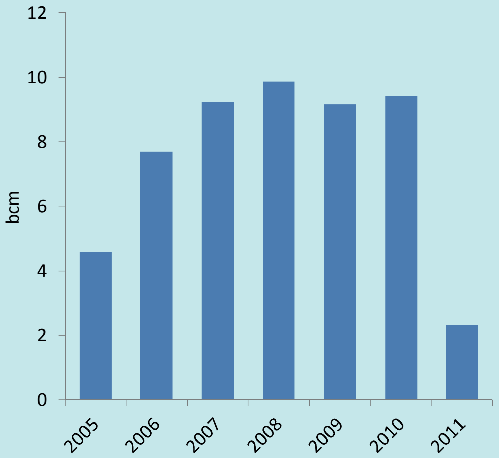
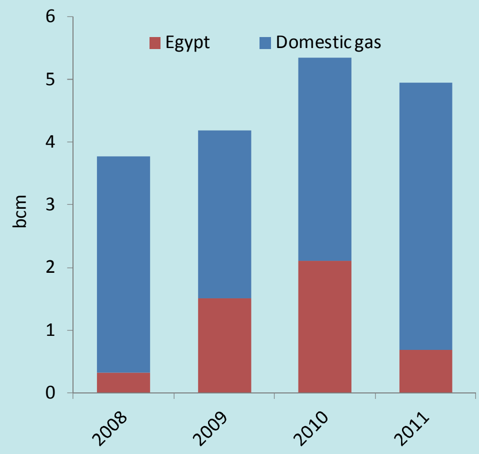


Figure 30 Israel's gas supply



Box 3 The impact of the Arab Spring (continued)

The Arab Gas Pipeline (AGP) from Egypt to Israel, Lebanon, Jordan and Syria was first attacked on 6 February 2011. The explosion took place south of the Gaza strip, on the AGP section running from the North of the Sinai (El Arish) to the south (Taba and Aqaba), where the AGP connects with Jordan. The pipeline section to Israel was not damaged, but it was closed as a precaution. The AGP was attacked 14 times in total over the following year. As a result, exports to Israel dropped by 1.4 bcm from 2.1 bcm in 2010. Israel increased its production, but this was insufficient and demand was curtailed, requiring Israel to use more expensive oil products. The country is already looking at importing LNG based on a floating storage and regasification unit (FSRU) to be built by end-2012, before Tamar comes on line in 2013. Jordan, which depends 80% on Egyptian gas, lost an estimated 2 bcm. It has renegotiated its contracts with Egypt, but has seen the gas prices doubling to USD 5/MBtu as a consequence.

OECD markets: plus, minus, equal

All OECD regions have widely divergent production trends. On the whole, OECD gas production increased by 19 bcm to 1 197 bcm in 2011. OECD Americas' gas production gained another 6%, while European gas output plummeted and gas production is OECD Asia Oceania was relatively stable.

Table 8 Gas production by OECD country, 2011 compared to 2010 (preliminary data, bcm)

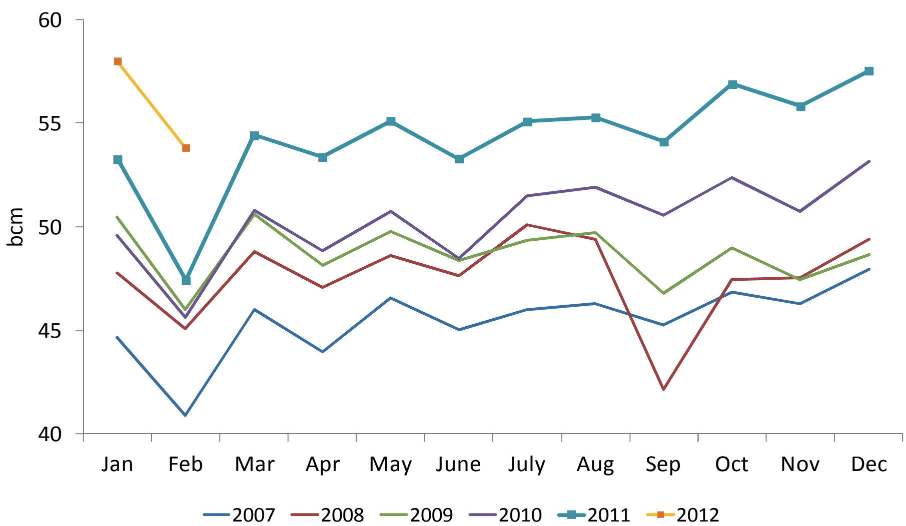
	2010	2011		2010	2011
OECD Europe	300.5	272.6	*Slovakia*	0.1	0.1
Austria	1.7	1.7	*Slovenia*	0	0
Belgium	0	0	*Spain*	0	0
Czech Republic	0.2	0.2	*Sweden*	0	0
Denmark	8.2	6.6	*Switzerland*	0	0
Estonia	0	0	*Turkey*	0.7	0.8
Finland	0	0	*United Kingdom*	59.8	47.2
France	0.7	0.6	OECD Asia Oceania	61.0	61.2
Germany	13.0	12.4	*Australia*	49.0	49.0
Greece	0.0	0.0	*Israel*	3.2	4.3
Hungary	2.8	2.8	*Japan*	3.3	3.2
Iceland	0	0	*Korea*	0.5	0.3
Ireland	0.5	0.3	*New Zealand*	4.8	4.4
Italy	8.4	8.3	OECD Americas	816.2	863.0
Luxembourg	0	0	*Canada*	159.9	161.3
Netherlands	88.5	80.7	*Chile*	1.8	1.8
Norway	109.7	104.6	*Mexico*	50.2	46.6
Poland	6.0	6.2	*United States*	604.3	653.3
Portugal	0	0	OECD	1 177.7	1 196.8

OECD Americas is looking for a ceiling, but is there one?

In 2011, US gas production increased by 8.1%, or 49 bcm. This incremental production over a single year is similar to the increase that took place over 2007-10. Without doubt, US gas production growth *is* accelerating. Monthly output was higher than the previous year's in every month of 2011. This has had obvious consequences, not only on prices – which collapsed (see section on prices in the Trade chapter), but also on intraregional trade. Net imports from Canada plummeted from 86 bcm in 2008 to 61 bcm in 2011 as pipeline imports dropped at the same time as exports increased. Meanwhile, net exports to Mexico increased from 9 bcm to 14 bcm, mostly due to the surge in gas exports. While the United States has yet to export LNG, it is already physically exporting its gas surplus to neighbouring countries, proving once again that the North American gas market is truly integrated. The competitiveness of US gas affects production of neighbouring countries: in Canada, production gained 0.9%, or 1.4 bcm, which represented only 20% of the domestic demand increase, while, in Mexico, it receded from 50.2 bcm to 46.6 bcm, a larger drop than that of Mexican gas demand. However, the US gas production increase may be reaching its limits due to constraints on import/export capacity and transmission bottlenecks.

Additionally, storage facilities have been breaking records in terms of filling rates over the past few years, but the recent warm weather during winter 2011/12 further deflated demand, which was not needed by an already oversupplied market. Working gas storage levels have been constantly above historical levels since December 2011. Storage levels reached their cyclical low point after winter 2011/12 in early March 2012, standing at 67 bcm (62% full). This level was the highest ever recorded for that time of the year and around 21 bcm higher than the five-year average. Consequently, there is a considerable supply surplus to use during the year 2012.

Figure 31 Monthly US gas production, 2008-12



OECD Asia Oceania: Australia prepares itself for the Great Leap Forward

Australia is expected to become the largest LNG producer by the end of the decade. Meanwhile, production is slowing and stagnated in 2011. With no new export projects starting in 2011, and existing LNG facilities at plateau, domestic production increases can only be driven by the domestic market. Although the start of 2011 showed some production increases, the second half of 2011 witnessed a reversal of the trend, so that 2011 gas output finished at the 2010 level – 49 bcm. Australian gas production is expected to increase after the Pluto LNG plant came online in May 2012.

In Europe, gas production is diving

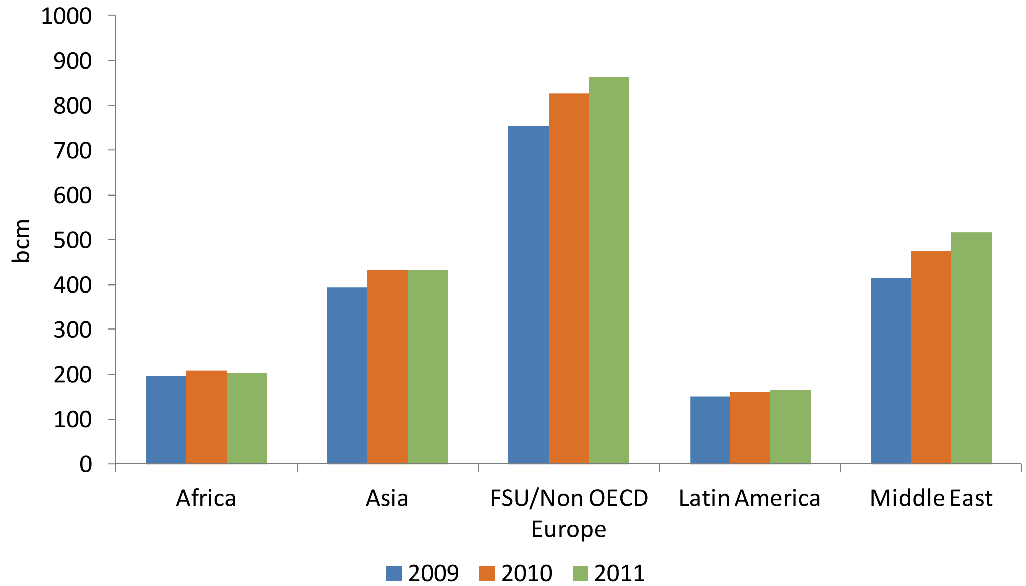
While 2010 offered the surprise of a small increase in European gas output, in 2011, production followed previous trends: it plummeted and lost almost 28 bcm in one year. As expected, the culprit is largely the United Kingdom, responsible for a 12.6 bcm drop. UK gas producers have been complaining about the instability of the fiscal regime, which in their view led to lower exploration and sluggish business confidence. But other countries contributed as well to the drop in production. The Netherlands lost almost 8 bcm of gas production, which given the collapse of European gas demand, was not unusual since the country often acts as a swing producer. Denmark lost 1.6 bcm and Germany 0.7 bcm. This represents the expected decline of mature production areas that nothing seems able to slow down.

More surprisingly, Norwegian gas production, which had been the constant driver of European gas production growth over the past ten years, slowed and lost around 5 bcm for good measure, largely due to Troll's production declining in 2011. Nothing in the fundamentals explains such a drop; apparently Norwegian gas producers avoided flooding the European gas market, to which they export around 95% of their gas, and tried to maximise the product "volumes - prices". In this very bleak environment, only Turkey and Poland saw a slight progression in their output.

Non-OECD Markets

The increase in gas production in the FSU region was to a large extent driven by Russia, where gas production increased by 3.5% to 659 bcm. This puts Russia at its highest production level recorded, above the peak of 2008 (651 bcm). The independent producers are the drivers of this growth, while Gazprom's gas production increased by a mere 0.2%, up to 509 bcm in 2011. The company enjoyed a very buoyant period in early 2011, with high demand for exports (notably due to storage refilling) and from the domestic market, but its production declined over the second half of the year amid lower European gas demand driven by exceptionally warm weather and competition on the Russian gas market. Russian gas production would actually have been higher if exports to Europe had not been constrained due to a sluggish gas demand.

Figure 32 Non-OECD gas production, 2009-11



The Caspian region gained some 15 bcm but saw widely divergent trends: Turkmenistan's gas production increased by a third, driven by exports to China. Kazakh production also rose by 11%. In contrast, Azerbaijan saw a slight production decline that is also reflected in lower exports to Europe, while Uzbek gas output also dropped by an estimated 4%. Production in other FSU and non-OECD European countries dropped slightly, the only exception to that trend being Bulgaria.

Middle Eastern gas supply increased by an estimated 41 bcm, largely driven by the final ramp-up phase of Qatar's production, following the start of its last two mega-trains. They began operations in November 2010 and February 2011, so that the corresponding production increase was seen mostly in 2011. Meanwhile, other trains rose to plateau, so that LNG exports increased from 77 bcm in 2010 to 100 bcm in 2011. Qatar also raised gas production to supply the Pearl GTL plant, which started in 2011 and which will consume up to 17 bcm when it reaches plateau end-2012. Yemen's gas production increased more modestly by 3 bcm due to LNG exports ramping up to maximum levels despite continuing political instability. Syrian gas production is estimated to have dropped by one-third, in line with its oil output.

Latin American gas production increased slightly from 161 bcm to 164 bcm in 2011, owing to increases in Brazil, Peru and Bolivia. Gas production in Brazil continued on its buoyant trend, increasing by an estimated 18% in 2011. According to Petrobras' statistics, most of the incremental production comes from offshore areas outside the Campos basin where production gained 44%; the Campos basin output receded by 10%. Onshore production represented only 28%. Bolivian gas production also resumed growth after the drop in 2009, with exports to Brazil recovering and combined with a new export contract signed with Argentina. Peruvian gas production gained around 4 bcm as the new LNG export plant rose to plateau. In contrast, Argentinean gas output continued on the downward trend observed since it peaked in 2004, dropping by an estimated 3%. Despite new discoveries, the investment climate is not brightening in Argentina. The relationship between the company YPF and the government has become strained over the past few months, and the company was partially nationalised in early 2012.

In Asia, production marginally dropped by 1 bcm in 2011. Two major developments took place. China's production increased by 5%, reaching 102 bcm. This marked the continuous expansion of fields such as CNPC's Changquing and Sinopec's Zhongyuan, as well as CNOOC's offshore production. CNPC still represents around 75% of Chinese gas production, with Sinopec and CNOOC representing around 13% to 14% each. The share of other producers is consequently extremely limited. China does not seem to have made substantial progress with coalbed methane (CBM) production in 2011; in contrast, the first tenders for shale gas were organised in June 2011. An unexpected development came from India, where much hope was placed on the Krishna Godavari KG-D6 field, which was expected to double India's gas production from 30 bcm to 60 bcm between 2008 and 2012. But production of KG-D6 was actually cut by half in 2011, leading to a 9% drop of Indian gas production because of technical issues with the field (the presence of water, potentially combined with difficult relationships between RIL and the government following the latter's decision that the allocation and the price of gas were to be decided by the government). This led India to massively increase LNG imports during 2011.

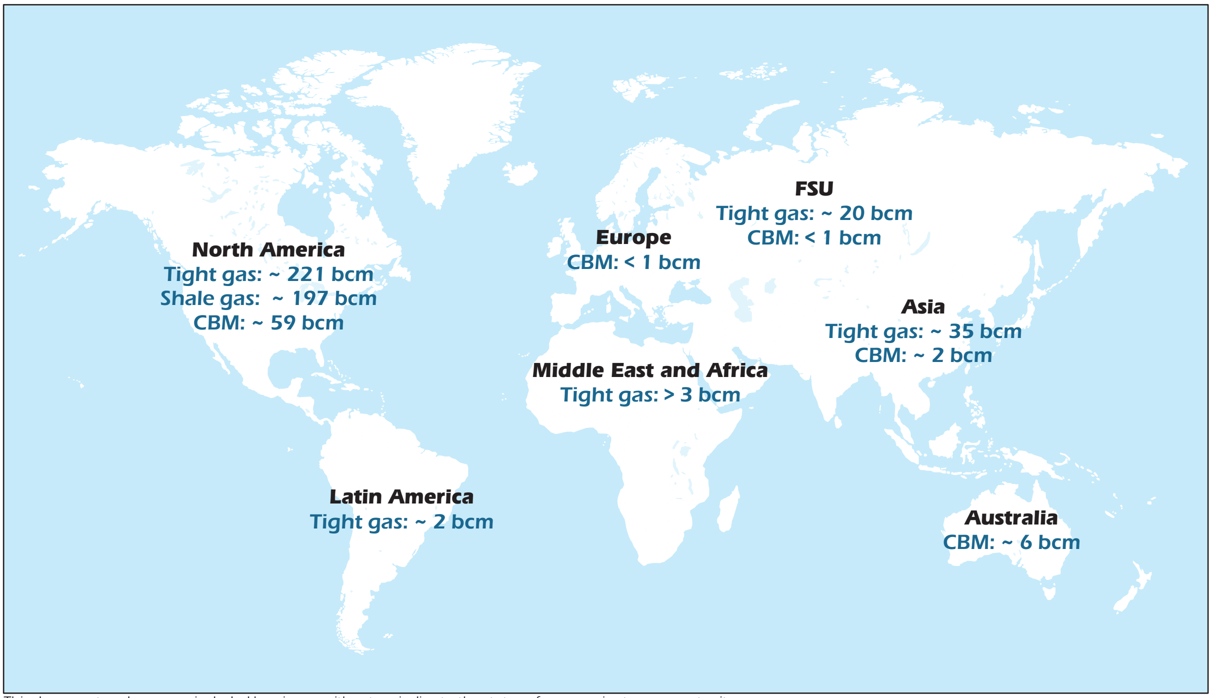
Africa's gas production is estimated to have declined by around 5 bcm in 2011 to reach an estimated 204 bcm, almost twice the level of consumption. This comes essentially from the large drop in Libyan gas production due to the unrest and civil war during most of 2011. As of 2011, around 70% of Africa's gas production remains concentrated in Algeria and Egypt. Changes are only expected when the Angola LNG export plant starts in 2012 and potentially later in the decade if Mozambique and Tanzania start exporting LNG as well. Algerian gas production is estimated to have dropped slightly by 0.5%, while Egyptian gas production increased marginally by 0.6%. Changes in other countries were limited; only Nigeria continued its recovery from the difficult episode of 2009 where production dropped by one-third.

Unconventional gas

In 2011, unconventional gas was still a North American story

Unconventional gas production reached an estimated 550 bcm in 2011, or 16% of total gas supply. There are two key aspects to keep in mind about unconventional gas in the world in 2011. First, this is a North American story, and a key question for the years to come is whether unconventional gas technology will be exported more rapidly than unconventional gas itself from North America. The region still represents the bulk of the world's unconventional gas output, and its unconventional gas production increased by an estimated 57 bcm in 2011, most of it coming from US shale gas developments. Second, despite all the attention given to shale gas, half of the unconventional gas produced in 2011 was still tight gas. Finally, although unconventional gas may have changed the face of global gas markets, production developments were relatively limited in 2011, apart from in North America. Developments in production in other parts of the world were barely noticeable. Beyond the United States, China seems to have been one of the most active countries, having increased tight gas production from the Sulige and Puguang fields. During 2011, oil and gas companies continued to acquire unconventional gas assets and to perform first drilling tests.

Map 1 Unconventional gas production, 2011



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Sources: IEA, EIA, NEC, Total, Shell, CNPC, CUCBM, press releases and articles.

Much more happened with exploration and regulation of shale gas. The debate on the risks and advantages surrounding the exploitation of shale gas has been raging in acknowledgement of the environmental challenges associated with the exploration and production of unconventional gas. The public is particularly concerned about water contamination and the large amount of water required, air pollution, earthquakes spurred by drilling activities, as well as the local impact of intensive drilling activities, such as the visual impact and presence of trucks. Another key aspect is the pace at which the upstream supply chain will be able to provide key material needed to develop shale gas in a significant manner in any countries. Based on the US experience, this would require thousands or tens of thousands of wells. Additionally, many regulators have no or little experience in the upstream sector and need first to catch up to understand the techniques used in unconventional gas production in order to prevent and reduce potential environmental impacts.

Looking forward, most unconventional gas developments over 2011-17 will take place in North America in terms of volumes. In this region, the most important factor will be not policy, but rather oil and gas prices. For any country outside North America, besides public opposition due to environmental issues, significant obstacles to higher unconventional gas production will be factors such as low price levels or inadequate pricing structure for upstream producers, the presence of the service industry in the upstream sector, lack of upstream competition and of access to pipelines. Outside North America, the bulk of unconventional gas developments in the medium term will be CBM and tight gas, not shale gas.

When one looks at the most "promising" countries in terms of shale gas based on the EIA estimates in the report "Shale Gas is a Global Phenomenon", these comprise China, Mexico, Argentina, Brazil, Algeria, Libya, South Africa, France, Poland and Australia. Medium-term developments of shale gas in Argentina, Algeria, Libya, South Africa, France and Mexico are unlikely due to either lack of proper investment framework, infrastructure, service industry, inadequate prices, or strong public opposition. Some countries combine several of these factors. Australia and Brazil already are fully occupied with CBM and pre-salt fields, respectively. This leaves China and Poland as the most likely to develop shale gas in the medium term, but even there, the numbers are unlikely to change the supply picture by 2017.

Regional developments

Unconventional gas sometimes resembles the *Arlésienne,*[5] in that everybody talks about it, but it remains quite elusive when approached. This is particularly true for shale gas, as everyone has been hoping that this new gas resource will be rapidly developed and will provide additional supply to domestic markets. Although there is little doubt that new countries will become unconventional gas producers over the medium term and that global unconventional gas production will increase over the next five years, the unconventional gas story will continue to be dominated by North America and, to some extent, by tight gas, although both shale gas and CBM production are projected to increase. The most noticeable increase in shale gas production over the medium term is likely to take place in North America.

Meanwhile, despite the recent activity and interest in other countries, reaching the production stage will require several years because of the time required to assess the gas in place, find sweet spots to drill, as well as the time necessary to obtain licenses and potentially develop the corresponding infrastructure. It is important to remember that it took several decades for the United States to achieve significant CBM or shale gas production levels. Additionally, public opposition will be a crucial factor which may delay development of some fields. In North America, the drivers for additional unconventional gas production will be primarily the evolution of US oil and gas prices, US supply and demand, as well as, potentially, the decision of the Environmental Protection Agency (EPA). The EPA is conducting a study on the impact of shale gas to be released in 2014, with initial findings available at end-2012. Outside of North America, unconventional gas developments will be driven by developments of fields which are already committed, consisting mostly of CBM and tight gas.

North America

The growth of US unconventional gas will be primarily driven by shale gas, while tight gas and CBM production are expected to be flat at best, potentially declining. US gas production is currently facing surplus, forcing gas producers to move as quickly as possible away from gas. The very low gas pricing

[5] A character in a play by the French writer Alphonse Daudet, about whom everyone speaks, but no one ever sees.

environment is the primary concern for gas production in general, and shale gas in particular. A high number of gas producers have been reported to be refocusing their strategy away from gas towards oil and condensates to benefit from the high oil prices. As highlighted in the section on the United States below, a substantial increase in associated gas will help to compensate for the decline in dry gas fields. The focus will be on the key expected areas for shale gas production growth: primarily Marcellus, as well as, to a lesser extent, Eagle Ford, Haynesville, Bossier, Fayetteville and Woodford. Additionally, shale gas is meeting increasing opposition from regions which have never been traditional oil and gas producers, notably around the Marcellus play, with a moratorium being either decided or debated in New York, Pennsylvania, and New Jersey. President Obama stated in January 2012 that America will develop natural gas “without putting the health and safety of our citizens at risk”, and asked companies drilling on public land to disclose the chemicals they use.

Unconventional gas developments in Canada depend on the evolution of prices and on the export markets, specifically, the extent of net exports to the United States and whether a liquefaction terminal will be built in Kitimat by 2017 (see section on LNG developments in the Trade chapter). Most unconventional gas production in Canada is still tight gas (50 bcm), while CBM accounts for 8 bcm and shale gas for around 3 bcm. Unconventional gas production has actually been increasing, despite the significant drop of Canadian gas production by almost 30 bcm over the past five years. Over the coming years, most developments are expected to be led by tight gas as well as shale gas developments, the latter concentrated in the Montney and Horn River plays in British Columbia. Testing of shale gas prospects is ongoing in Atlantic Canada, while it is subject to public consultations and regulatory reviews in Quebec. LNG exports would obviously accelerate development of these plays, given the number of Asian companies having invested there over the past two years with the clear aim to bring that gas to their domestic markets.

Australia

The unconventional gas story in Australia is mostly concentrated on CBM (also called coal seam gas [CSG]), and will be led by three CBM-to-LNG projects, which are expected to become operational between 2014 and 2016. Demonstrated gas resources are estimated at 3.8 tcm, including around 400 bcm of CBM. Produced since 2003, CBM production has been slowly increasing, reaching about 6 bcm in 2011, or 12% of Australian natural gas production; CBM production is expected to rise slowly until end-2014, when the first CBM-to-LNG projects are expected to come online. Based on the capacity of these projects, an additional 28 bcm of CBM would then come to the markets.

Unlike most of the current Australian gas production, offshore and in the North West, this will represent a shift to the onshore East. Despite this positive growth, CBM development is also encountering farmers’ opposition in Queensland and New South Wales. Australia is also believed to have significant resources of shale gas (around 10 tcm). These Australian shale gas reservoirs are currently being evaluated, but unlike CBM, they are in more remote areas such as the Canning and Cooper basins. Attracted by this remoteness, which tends to minimise the opposition from landowners, companies such as Santos are currently testing and drilling in different basins.

China

China’s search for unconventional gas resources seems to be increasing as rapidly as the forecasts for future gas demand. As already mentioned, the bulk of unconventional gas production in China consists of tight gas, estimated at around 30 bcm in 2011, from Changquing, Sichuan and Puguang gas fields. However, all eyes are on CBM and shale gas for the new 12th FYP (see focus on China in the Demand chapter). There is actually more focus on shale gas, as the country is believed to hold 25 tcm of recoverable shale gas reserves, according to the first official estimates of the Ministry of Land and Resources (MLR). The FYP foresees an optimistic shale gas production development rising to 6.5 bcm/y in 2015 and to between 60 bcm/y and 100 bcm/y by 2020. China has yet to start shale gas production.

However, there are still many challenges ahead, including getting a better evaluation of shale gas resources and mastering drilling technologies, which explains why the Chinese National Oil Companies (NOCs) have been so actively investing in North American shale gas assets over the past three years. But North American drilling technologies may not be directly applicable in China, requiring more time to adapt the technology to Chinese specificities. The FYP actually foresees the completion of a nationwide shale gas survey and appraisal, as well as developing technologies for E&P and evaluation of shale gas potential. This gas resource is likely to get subsidies comparable to CBM, but these are still under negotiations.

The pricing reform started in December 2011 aims at liberalising the upstream prices and therefore promoting the development of shale gas and CBM (see Box 5). The infrastructure remains a key constraint, given the remoteness of potential key basins such as Sichuan, and the need to develop additional infrastructure to bring that gas to the markets. The issue with shale gas is that an estimate of shale gas production comes after drilling starts, which delays even further the related investments in pipeline infrastructure. In this case, the 12th FYP plans to encourage the construction of pipelines between shale gas production centres and the existing network, or if the fields are too remote, encourage the development of small-scale distribution based on LNG and compressed natural gas (CNG).

Another uncertainty is what type of companies will be allowed to take part in China's exploration and production (E&P). The first tender for exploration rights was organised only in June 2011, with four of China's most prospective blocks in the Sichuan Basin (Nanchuan, Suiyang, Fenggang and Xiushan) put up for auction. They were awarded to Sinopec and Henan CBM, perhaps in an attempt to diversify away from CNPC. Foreign companies were not allowed to participate in the first tender. However, foreign investment in exploration and development of shale gas resources is now in the "encouraged" category in the new *Foreign Investment Industry Guidance Catalogue* issued early 2012, as long as these happen within a joint venture with a Chinese company. So far, companies investing in shale gas have been the ones capable of significant investments. CNPC has been active since 2006 and had drilled 11 appraisal wells as of end-2011. CNPC plans to produce 1.5 bcm of shale gas by 2015. Smaller companies would need to find financing as well as gaining access to the pipelines to sell their gas to higher value markets, which is currently impossible in China due to lack of third-party access. In March 2012, Shell signed the first ever production sharing contract (PSC) with CNPC for shale gas exploration. This move represents a step further than having joint entities working on shale gas E&P, highlighting the need to attract and bring foreign technical and operational expertise to tap these new resources.

In the short term, CBM developments are likely to take the lead, as work has been ongoing for a decade now, albeit with relatively disappointing results. There is also controversy on how much CBM is really produced, depending on whether CBM is produced from coal mine extraction or from surface wells (around 2 bcm produced in 2011). Some CBM is currently used locally for power production or use in the transport sector. Previous CBM targets have been missed due to conflicts between coal producers and gas producing companies on overlapping rights as well as lack of access to pipelines, lack of experience, knowledge, and technology. According to the 12th FYP released by the NEA in December 2011, 30 bcm of CBM should be produced by 2015 (16 bcm from surface-level extraction and 14 bcm from underground extraction), although these targets can also appear relatively optimistic. According to the National Development and Reform Commission (NDRC), the installed capacity of CBM-fuelled power generation would exceed 2.85 GW by 2015 and satisfy the residential needs of 3.2 million households. The focus will be on the Ordos, Juggar and Qingshui basins. In particular, the Shanxi province, where Qingshui is located, plans to produce some 20 bcm by 2015. There are still some obstacles to CBM developments, notably the competition between coal and gas producers, which has been a major hurdle until now. Shanxi submitted motions to the National People's Congress to merge the mining rights of coal and CBM to streamline CBM development. In addition, pipeline capacity needs to be developed to bring gas to the market: there is a specific target to develop 12 bcm of pipeline capacity for CBM production. The investments requirements will also be significant, and the Shanxi region alone estimates them to amount to over USD 30 billion over the next FYP. Foreign participation could be crucial to reach such targets.

India

India has been looking at unconventional gas potential as a way to complement its conventional gas resources; however, only CBM has been produced so far and at very low levels. With the third largest proven coal reserves in the world, India has the potential to have significant CBM production. CBM resources have been estimated at around 4.6 tcm. Nevertheless, there are still many obstacles to increase gas production, such as the pricing regime, insufficient infrastructure and the need for a proper regulatory framework.

There has been growing activity with Great Eastern Energy Cooperation (GEEC) developing the Raniganj (South) block in West Bengal, which produced a rate of 86 Mcm/y in September 2011. Essar Oil is developing the Raniganj block in the Bengal basin, where production is expected to reach 1 bcm/y. Essar Oil holds the largest CBM acreage in India. RIL is working on the Sohagpur East and Sohagpur West Blocks, with plans to reach a production level of 1 bcm as well. Given these prospects, Indian CBM production is not expected to be beyond a few bcm by 2017. Meanwhile, mapping is being undertaken on shale gas and a regulatory regime should be put in place by end-2013. This is unlikely to translate into shale gas production before 2017.

Indonesia

Indonesia is believed to have large recoverable CBM resources (estimated at 12.8 tcm), notably located in the South Sumatra (40%), Barito (21%) and Kutei (18%) basins. The government has been particularly encouraging CBM activities, given the rapid increase in domestic gas demand and potentially dwindling conventional gas production. The government has a long-term strategy to use this CBM for domestic power generation or feeding the existing LNG plants at Bontang. Eight blocks were offered in the CBM round in 2011, and seven were awarded. First production started from the West Sangatta I in the East Kalimatan province and Sanga-Sanga. Other CBM plays such as Sekayu and Tanjung Enim are expected to start in 2012, reaching a production of some 2 bcm.

Will Poland light the path for European unconventional gas?

Europe realised not so long ago that it may have some unconventional gas resources, which could postpone the decline of its domestic gas production, but their development seems still paved with obstacles. Work began to better quantify the recoverable resources in a continent which has never been the focus of intense onshore exploration, except in a few countries. In Europe, the focus is clearly on shale gas despite some attempts on tight gas in Germany or on CBM in France and the United Kingdom. There seems to be an East-West divide regarding the approach on unconventional gas, with Eastern European countries trying to reduce their dependency on Russian gas, as illustrated by the Polish and, to some extent, Hungarian and Romanian examples, and Western European countries, which are advancing with more caution, despite some interest in those new gas resources.

However, the recent decision by Bulgaria to put a moratorium on hydraulic fracturing has put this East/West divide in question, while, on the other side, countries such as Spain have begun to consider shale gas developments. More importantly, there has been a surge of public opposition to hydraulic fracturing in Europe. Even if some opposition was anticipated, the scale of public hostility is likely to have caught potential producers and even governments off-guard. Mistrust, fears and concerns of citizens range from water pollution, to earthquakes, long-term effects of introducing chemicals into the earth's subsoil or creating fissures that would remain open. Together with recent disasters such as Macondo and Fukushima, Josh Fox's film "Gasland" probably was a major catalyst for public opposition.

Governments are taking steps to address these challenges through potential new regulation, while the European Commission is considering proposing EU-level regulations. The first move against fracking came from France, which first imposed a moratorium on hydro-fracking in early 2011 and finally revoked the exploration licences of firms engaged in shale gas and oil activities. Similar moratoria have been imposed in Switzerland (Freiburg canton), North-Rhine Westphalia in Germany, Northern Ireland and Bulgaria. In Romania, public opposition has been mounting over the past few months to pass a moratorium as well. Germany's Federal Ministry for the Environment is in negotiations with other federal bodies on new regulations on unconventional oil and gas production, with mandatory environmental impact assessment (EIA). The devil is in the details regarding the rules on potentially water polluting substances, whether it will be done at a federal or Land level, and how the responsibilities will be split between the Ministries and Federal governments.

However, some countries still remain neutral or favourable to unconventional gas. In the United Kingdom, Cuadrilla discovered potentially big resources near Blackpool (6 tcm of gas in place), but some small earthquakes are now threatening the continuation of operations. In contrast, Spain's Basque regional government seems determined to encourage shale gas production. But *the* exception on the European scale is Poland, where unconventional gas production has been strongly encouraged in order to reduce dependence on Russian gas imports.

The outlook for unconventional gas production in Europe seems therefore relatively bleak in the medium term, as there is a risk that opposition to it will spread from one country to another. In this context, Poland remains the European showcase that could ultimately reverse the trend – if significant resources are developed in an environmentally sound manner and trigger some positive changes for Poland's economy in terms of a better payment balance. Should the Polish example not bring positive results, this could deter unconventional gas developments in Europe for many years. A report from the Polish Geological Institute issued in March 2012 estimated that technically recoverable shale gas resources were in the range of 346 bcm to 768 bcm, which is considerably less than the EIA's estimates of 5 tcm a year before. This report is based on 39 wells drilled from the 1950s to the 1980s. It is worth emphasising the considerable uncertainty regarding many shale gas estimates.

The Middle East and Africa

Africa and the Middle East may hold significant recoverable unconventional gas resources of 38 tcm and 23 tcm, respectively, but their development is less a priority due to these regions' plentiful reserves of conventional gas. These unconventional resources consist mostly of tight and shale gas resources. Shale gas prospects are estimated at 14 tcm in the Middle East and 29 tcm in Africa, but prices, as well as regulatory infrastructure, pipeline development, water management and expertise may present obstacles to their further development. While tight gas fields are already developed in the Middle East, shale gas has not yet been considered and is likely to be challenging due to the water requirements in a region where water resources are scarce. Prices, which are usually well below USD 1/MBtu, are another significant disincentive in this region.

Tight gas potential is particularly high in Saudi Arabia, Oman, Jordan, Egypt, Algeria and Tunisia, where some fields are already producing or being developed to complement conventional gas resources. Over the medium term, other tight gas fields in Algeria, such as Timimoun, will likely be developed. Meanwhile, BP is developing the Khazzan and Makarem fields in Oman. In North Africa, some exploration is underway in Morocco and Tunisia as well. Most countries are viewing shale gas prospects as a long-term resource. The most active on shale gas exploration is currently Algeria. South Africa is believed to have shale gas potential in the Karoo basin, but the country put a moratorium in place in early 2011. Over the medium term, there seem to be few prospects to develop shale gas in Africa.

Latin America

Unconventional gas production in Latin America currently consists of tight gas production in Argentina (Aguada Pichana) and Venezuela (Yucal Placer). Argentina could be the most promising country given its alleged tight and shale gas resources, but this requires organisation. Shale gas resources were estimated at 19 tcm by the EIA in April 2011, although estimates await confirmation by drilling. One of the main issues in Argentina has been prices, which are kept low by the government. The Gas Plus programme allows companies to charge USD 4.50/MBtu to USD 7.50/MBtu for such resources which may be a step in the right direction. However, the recent decision to deprive YPF of its licenses, as well as the partial nationalisation of the company, is a negative signal sent to an industry which needs regulatory stability. In particular, these actions in the potentially shale-rich Neuquén province are worrisome and contrast with the previous policy efforts to attract foreign investment. Many companies are active in shale gas exploration, notably YPF, (which in late March made a major shale gas and oil discovery in the Mendoza province), Total, Shell, Chevron, and Apache. Unconventional gas potential could be present in other Latin American countries, notably in Colombia. There is an estimated 0.9 tcm of shale gas in Middle Magdalena Valley and 0.2 tcm of CBM in the Cesar and Guajira basins (69 bcm and 96 bcm, respectively). Peru, where Maple Energy is looking for shale gas, could also have some potential, as well as Uruguay, which currently does not produce any gas. Although Brazil's shale gas resources are estimated to be significant, there is currently very little activity.

Where will new supply come from over 2011-17?

Global gas supply is expected to reach 3 937 bcm by 2017, a 562 bcm increase over 2011, in line with global gas demand growth. Continuous investments in the upstream sector will be a challenge, particularly in regions with recent unrest and those where subsidised gas prices represent a hindrance for future gas field developments, given the growing gap between rising development costs and low domestic prices. Gas production is expected to increase in all regions except Europe. However, the growth differs markedly across regions. Russia and other FSU countries are expected to be the largest providers of additional gas supply, although the production will be constrained by sluggish European gas demand and by the lack of infrastructure to deliver additional pipeline gas to Asia or to Southern Europe. No additional Russian LNG export plant is expected to start by 2017.

Table 9 Gas production, 2000-17 (bcm)

	2000	2010	2011	2013	2015	2017
Europe	303	301	273	267	268	256
Norway	53	110	105	113	116	117
Americas	760	816	863	884	936	975
United States	544	604	653	680	729	769
Asia Oceania	42	61	61	72	95	134
Australia	33	49	49	60	81	118
Latin America	103	161	164	168	176	189
Africa	124	209	204	228	249	261
Middle East	202	475	516	552	566	588
FSU/Non-OECD Europe	726	826	863	926	971	992
Russia	573	637	659	698	739	757
Asia	243	432	431	455	495	542
China	27	97	102	120	141	163
World	2 501	3 281	3 375	3 553	3 757	3 937

Notes: More detailed production data and forecasts by country are available in Table 30 in the chapter "The Essentials" at the end of this publication. 2011 data are estimated. OECD data for 2010 includes revisions from early 2012; data for non-OECD countries are consistent with data from the IEA publication *Natural Gas Information 2011*, except for Iraq which has been updated.

Asia offers a mixed picture, as countries such as China manage to rapidly ramp up their gas production, while neighbouring countries India, Pakistan, Bangladesh have difficulties increasing their gas production. This situation is comparable with Latin America, where gas production struggles to increase in most countries but Brazil, limiting *de facto* potential gas demand increase. In the Middle East, the entire incremental gas production will serve only the sole purpose of meeting growing domestic demand. Africa's output remains largely dependent on two key countries, Algeria and Egypt, as developments in the new Golden Area of East Africa are not expected to take off significantly before 2017. OECD Asia Oceania's gas production will be boosted by over 80 bcm of new LNG export plants coming on line in Australia, while North America continues to see strong growth of US gas production, which finally finds an outlet on the export side.

US gas production defies gravity

What is driving US gas production?

That US gas production has a tendency to exceed the most optimistic forecasts has become a feature of the US gas industry. But now, the question is how long this marvel may continue. Whether history can help to understand what the future may hold is doubtful in these circumstances. In 2006, gas production was at best expected to increase to 600 bcm on the longer term, from a production level of 525 bcm at that time. Production reached a level of 653 bcm in 2011, with additional gas supply coming entirely from shale gas. During 2006-11, offshore gas production declined slightly and other onshore production, mostly conventional, increased. This shale gas came from entrepreneurs such as Chesapeake, which took a bet on a resource of gas that everybody knew, but almost nobody believed in.

This is precisely the quandary with forecasting developments in US gas production, for while the multiplicity of producers is a richness for the US upstream sector, it becomes quite difficult to anticipate US production developments. It is not only a question of anticipating the behaviour of individual fields based on starting dates, reserves and decline rates. Indeed, the production of shale gas plays declines rapidly once the peak is reached. In addition, one needs to understand the behaviour of a multitude of companies, ranging from "mom and pop's" well in the backyard (contributing a little) to the biggest international oil companies (IOCs). US gas production is disaggregated, which is both a blessing and a curse, considering the difficulty to apply "one-size-fits-all" behaviour to each of the market participants. One of the largest oil and gas producers, ExxonMobil, produced around 6% (3.9 bcf/d or 40 bcm/y) of total US gas production in 2011.

Figure 33 Monthly US gas production on a 12-month rolling average

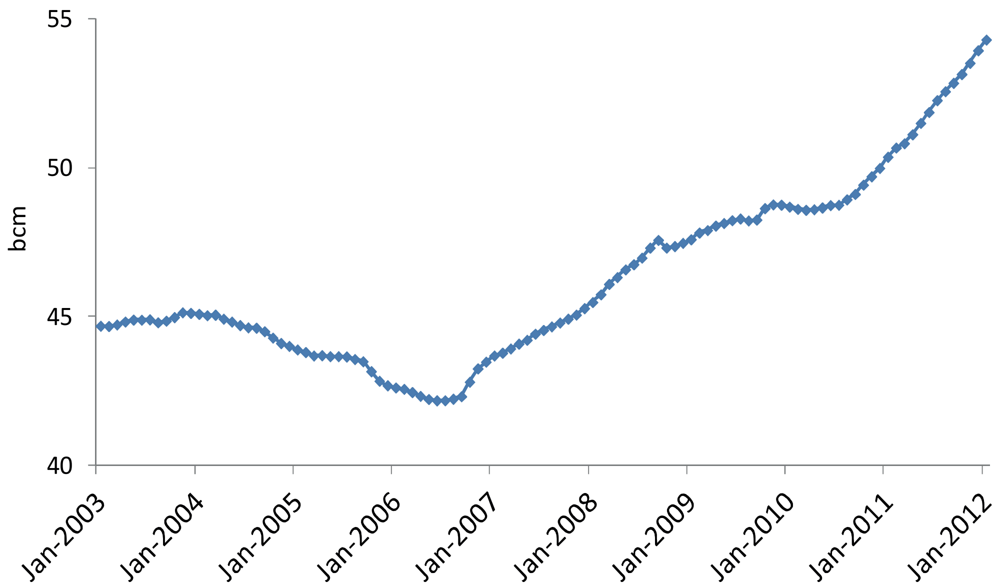
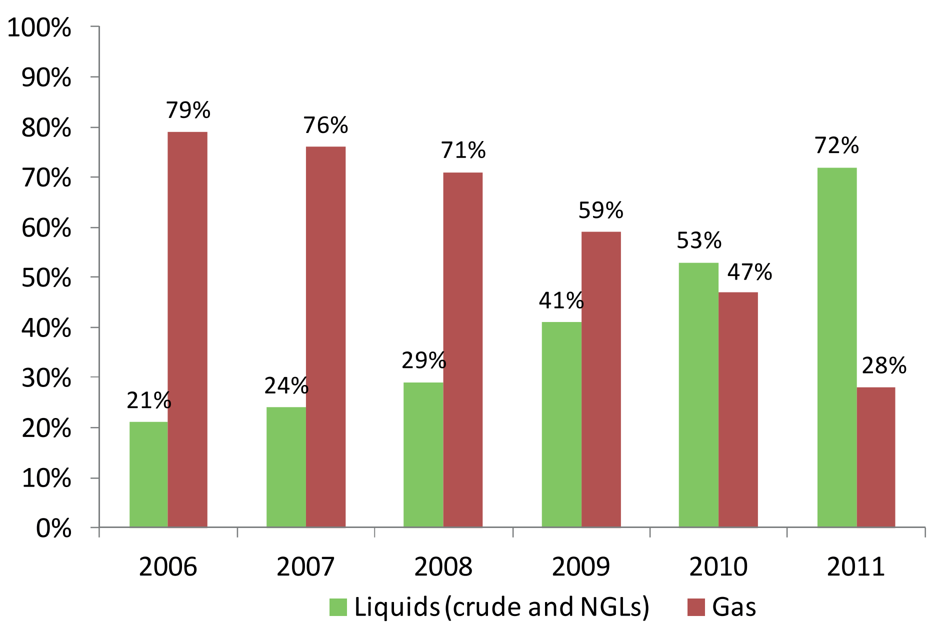


Figure 34 Liquids and gas weight in EOG Resources' North American revenues



Note: Data for 2006-11 is based on North American actual revenues.
Source: EOG Resources Inc.

Box 4 A bonanza in light tight oil and natural gas liquids (NGL) output

The rapid increase in production from light tight oil bearing formations in North America is reducing US light oil imports and will have longstanding effects on the world oil market balance. Horizontal drilling and hydraulic fracturing techniques which have been used to access natural gas are being used to access liquids from the same formations. The combination of these techniques with lessons learned from producing shale gas has greatly boosted oil recovery rates. With oil priced at least ten times higher than gas, companies drilling in shale resources are increasingly focusing on liquids-rich areas. In addition to new condensate and light oil volumes that are expected to come from these plays, companies are also processing the natural gas to produce large incremental volumes of natural gas plant liquids such as ethane, butane, and propane for petrochemical use. US liquids production is expected to grow by 1.5 mb/d from 2011 to 2016 (1 mb/d from light tight oil, 0.5 mb/d from NGLs). This rapid growth will make the United States the top contributor to non-OPEC supply growth in the next five years.

Companies have been producing from the Williston Basin, including the Bakken, in North Dakota, Montana and Saskatchewan since the 1950's. Crude and condensate production from this formation remained under 100 kb/d until 2005, but has since surged to over 500 kb/d. In North Dakota, where the Bakken and Three Forks acreage accounts for almost 90% of production, monthly output has risen by 6% on average over the last six months. Several factors may limit rapid growth from the Bakken in the short term. First and foremost, takeaway capacity from areas of the Williston Basin in North Dakota and eastern Montana could constrain growth, but not until at least end-2013. Second, tight oil production is not cheap, with some estimates placing per barrel production costs as high as USD 80/bbl at marginal areas, and production requires extensive infrastructure to collect small volumes from dispersed wells. Drilling and completion costs sometimes reach USD 10 million/well largely due to the need for longer horizontal laterals and constrained supplies of oilfield services in the Bakken. Another limiting factor will be the extent of drilling that can occur without reducing the pressure in the formation. Analysts maintain that if the Bakken can support multiple wells, then future exploration and development would shift to new prospective areas such as Three Forks and could result in even higher output.

The Eagle Ford shale in southwest Texas is vaulting Texas oil production to almost 1.7 mb/d, a level not seen for decades. In contrast to the Bakken, takeaway capacity and economics are less of a constraint since producers benefit from close proximity to the Gulf Coast refining centre, high gas liquids content, and high initial oil production rates. Production in the area tripled over the course of 2010. Since then, it has more than doubled in 2011 and early 2012 to over 400 kb/d. With rising production, trucking and rail takeaway capacity have also ramped up, and 1 mb/d of new pipeline and 465 kb/d of processing capacity are planned to handle new crude and associated gas production. It is therefore no surprise that these two formations along with shale plays in Colorado, New Mexico, California, and the Midwest are making the country into the single largest contributor to non-OPEC supply growth in 2012.

Shale oil and gas development is also expected to increase field condensate production, which will be used in gas processing plants and fractionation capacity to meet petrochemical demand (rising strongly beginning in 2014) and for use as a diluent in Canadian oil sands projects. The pace of production growth in NGLs may be slower, since new fractionation and storage facilities will be required to fully realise the benefits. Natural gas plant liquids and gas condensate production is forecast to grow by around 600 kb/d, reaching 2.7 mb/d in 2016.

Production of NGLs from shale and light tight oil outside North America is unlikely to make a large contribution to global liquids production until after 2016. The Neuquén basin in Argentina shows promise, but with the recent government takeover of YPF, foreign investors are likely to exercise caution before investing. Canadian light tight oil production already exceeds 150 kb/d, centred largely in the Cardium and Bakken plays in Alberta and Saskatchewan, respectively. However, rapid growth is unlikely in the short term due to the same takeaway capacity constraints as some North Dakota production.

So, why is US gas production still growing despite all the current adverse factors? The surge that took place in 2007-08 was almost entirely driven by increasing shale gas production. It was understandable, given the relatively high gas prices (USD 7/MBtu in 2007 and USD 8.9/MBtu in 2008, peaking at USD 12.7/MBtu in July 2008), as well as progress in drilling techniques and understanding shale gas resources. Since then, prices have been hovering at around USD 4/MBtu (dropping even below USD 2/MBtu on a daily basis) and the possibilities of hedging dropped in concert with future prices (as of April 2012, future prices are crawling back to USD 5/MBtu by 2018). Meanwhile, the number of gas rigs collapsed from a peak of 1 600 in 2008 to 598 in early May 2012 (its lowest level since 2000) as producers have been increasingly turning to oil production or wet gas plays, moving away from gas. Also, production costs have been increasing, notably material and labour costs. Finally, opposition against shale gas drilling has been increasing, prompting some authorities to put moratoria in place, although this response has been relatively limited. Given all these negative factors, natural gas production growth should have slowed down, if not declined. Actually, the growth of the monthly 12-month average production has accelerated: from an average of 47.9 bcm in January 2009, the monthly 12-month average surged to 54.7 bcm in early 2012.

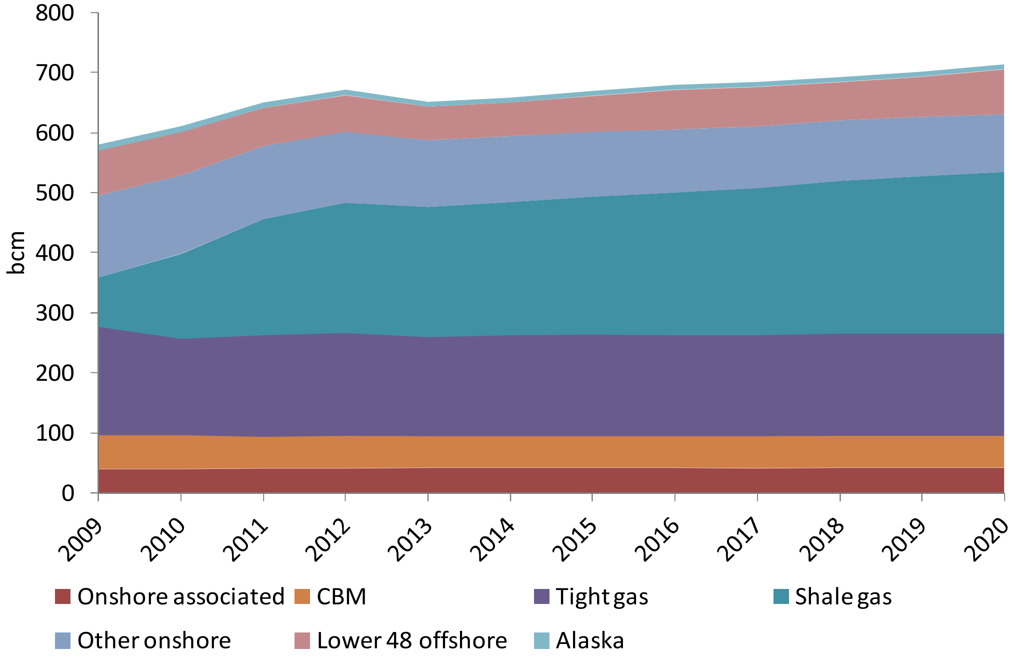
Multiple reasons could explain this accelerating trend. Improvements in the efficiency of drilling and production certainly play a big role and have been constantly mentioned by companies. As actual production costs vary greatly depending on individual play, that production behaviour has to be considered for each individual play (or sometimes part of a play). Additionally, foreign companies and IOCS or Asian companies (such as CNOOC, PetroChina, Reliance, GAIL, Sinopec, Kogas) have been investing in shale gas assets and paying drilling costs, thereby encouraging companies (which also must respect lease agreements) to continue drilling. Independent gas producers have also been reported to have hedged some 70% of their gas production for three years, when prices were still relatively high (USD 5-6/MBtu) so that they were still relying on this to maintain gas production. Increasingly, liquids' revenues are compensating for the low gas prices, as illustrated by the evolution of gas and liquids in EOG's revenues since 2006. But some of these factors should start to wear off. Hedging will be limited in the coming years, given that future gas prices are expected to be still below USD 4/MBtu until 2015.

Is 2012 or 2013 the key turning point?

The recent collapse of US gas prices, mostly due to a very warm winter, has taken most producers by surprise. Even until end-December 2011, the futures for 2012 were on average at USD 3.5/MBtu, which was painful but not lethal for most gas producers. However, an average price of USD 2.5/MBtu for 2012 as of April 2012 is below production costs of many plays, unless the liquid component can compensate, which is the case for associated gas. Moving away from dry gas had been considered for quite some time, as illustrated by EOG's strategy, which is common to many producers, but this latest development, highly publicised by many producers, may have accelerated the trend. Nevertheless, these strategies also depend on the assets, and specifically on their liquid content, which will continue to boost gas production in some plays.

What the past has taught us is to look at shale gas, but not forget the rest. In its latest *Annual Energy Outlook 2012*, the EIA forecasted that US gas production would continue to increase in 2012 by 20 bcm, drop in 2013, and return to 2011 levels. The drop would actually come not from a decline of shale gas production, but of offshore, tight gas and other onshore gas sources, which have been declining for some time. Given the current market circumstances, these features are unlikely to change. So the future hinges on the reactivity of shale gas.

Figure 35 EIA's natural gas production forecasts for the United States



Source: EIA.

The evolution of gas prices during the years 2012 and 2013 and the pressure they will put on companies in terms of lower investments and shut-ins will be key. Meanwhile, there are possibilities to counterbalance this trend with higher associated gas output, and higher recoveries per well. Besides the behaviour of the larger players, that of the smallest producers remains difficult to assess, as well as getting a full picture of individual plays' associated gas production. According to our price assumptions, which are based on the curve as of early April 2012, US prices will remain low at USD 2.5/MBtu in 2012, but will recover to USD 3.5/MBtu in 2013, moving out of the danger zone, but not yet in a comfort zone.

The period 2012-13 is therefore likely to result in slower growth of gas production, including a potentially declining trend for gas production in the second half of 2012 and 2013. This does not mean, however, that gas supply to the US market will be lower in 2012, since, as mentioned before, storage levels are over 20 bcm higher than the five-year average and constitute an additional source of supply. However, over the medium term, gas prices are expected to rise back to over USD 4/MBtu by 2014, resulting in gas production increasing again, as there are still many wells drilled but not completed, or to be connected to the network; associated gas production is projected to increase even faster. Should gas prices remain depressed (below USD 3/MBtu) over more than two years due to low demand induced by lower economic growth or weather conditions, then US gas production is likely to drop in the medium term, as the balance of associated gas would be insufficient to compensate dry gas production decline.

Looking at the individual shale gas plays enables identification of those which are dry and those which may benefit from liquid revenues. Haynesville, Barnett, Marcellus, and Fayetteville together represented almost 90% of US shale gas production in 2011. In the short term, Barnett and Haynesville are expected to see their gas production declining due to a mixture of shut-ins and lower investments. Marcellus, which has been one of the key drivers behind gas production growth over the past five years, is expected to continue to increase strongly, along with Eagle Ford, which benefits from liquid production driving up associated gas. For most other plays, production is expected to be either flat or slightly increasing due to growing light tight oil output driving up associated gas production.

Table 10 Key shale gas plays characteristics

Play	Stage	Characteristics	Short-term outlook
Texas, Louisiana			
Barnett	Mature	Mostly dry gas, oil in the Barnett shale combo play	Lower
Bossier	Early stages	Mostly gas	Flat
Eagle Ford	Developing	Three zones: dry gas, gas condensates, oil	Increasing
Haynesville	Mature	Dry gas	Lower/flat
Pearsall	Early stages	Dry gas	Flat/slight increase
Arkansas, Oklahoma (Centre South)			
Fayetteville	Mature	Dry gas	Flat/slight increase?
Woodford	Developing	Mostly gas, with oil in the Cana-Woodford play	Flat/slight increase
Northeast			
Marcellus	Developing	Mostly dry gas with some liquid rich plays	Increasing
Utica	Early stages	Liquid rich play with associated gas	Flat/slight increase
North			
Bakken	Developing	Oil and liquid rich play with associated gas (flared)	Slight increase
Niobrara	Early stages	Oil and liquid rich play with associated gas	Slight increase

Looking at some of the big gas producers' strategies, a certain number (but not all) have already planned to reduce gas production. A few companies are actually planning to maintain or even increase their production through their liquids assets. A few, including Chevron, are still planning to expand their gas production. The uncertainty will also come from the small players, who, unlike IOCs, cannot rely on their deep pockets to go through a turbulent low gas price environment, and often do not have access to cash flows from foreign investors due to their small size. This may be put at risk in a low gas price environment if they cannot rely on hedging, and external cash flows to help them drilling or cost efficiency in drilling operations.

- ExxonMobil expects North American unconventional gas production to grow by 4% per year in order to meet growing gas demand. More than half of ExxonMobil's gas production comes from onshore Texas and Louisiana, as the company holds strong positions (250 000 acres) in the Haynesville/Bossier shale gas plays where 66 wells were completed in 2011. In the Barnett Shale play in North Texas, 180 wells were completed in 2011 across a leasehold of 235 000 acres. They also have positions in Fayetteville (535 000 acres) with the completion of 185 wells. There are also new areas of development such as Woodford Ardmore, where both gas and oil production are expected to grow.
- Chesapeake, the second largest gas producer in the United States, plans to reduce gas production in 2012 from 2011 levels, due to a reduction of the number of operated dry gas rigs from around 75 to 24. The company produced around 28 bcm of gas in 2011 and will redirect the cash to liquid-rich plays. It is also curtailing around 10 bcm of its gross operated natural gas production located primarily in the Haynesville and Barnett shale plays, and deferring the completions of dry gas wells already drilled but not yet completed, as well as deferring pipeline connections to dry gas wells that have already been completed.
- Devon plans to increase its natural gas production by 1% per year on average over the next five years, but the growth seems mostly concentrated post-2014, while gas production over 2011-13

seems stable at best. With a clear focus on liquids over the medium term, Devon is shifting its production strategy so that gas share is reduced from 65% in 2011 to 48% in 2016, increasing the share of oil to 32% and of NGLs to 20%, compared to 20% and 15% in 2011, respectively.

- Encana plans investments of USD 2.9 billion for 2012, which is 37% lower than in 2011. It aims to minimise investment in dry gas, while focusing on prospective oil and liquids-rich natural gas plays. The company still has around 20 bcm (2 bcf/d) hedged at USD 5.8/MBtu for 2012, but only 5 bcm (0.5 bcf/d) for 2013 at USD 5.24/MBtu. It foresees a drop in its North American production by up 6 bcm, about half due to lower capital investment and half from shutting in production. The second term depends very much on price developments.
- ConocoPhillips presented a stable North American gas production outlook in its investor update in March 2012, based on investments in Eagle Ford and others plays. Although, like other producers, the company avoids investing in dry natural gas in North America, the gas comes out, associated gas production with the liquids coming from their unconventional oil investments.
- Chevron has three million acres under lease covering 13 unconventional oil and gas plays, with 700 000 acres in the Marcellus Shale play, following its acquisition of Atlas Energy in 2011 for around USD 4 billion. Actually, while other companies are scaling back their operations at the Marcellus play, Chevron plans a robust drilling program to increase its Marcellus production in order to catch up. The company also holds 600 000 acres in the Utica shale play, where drilling is planned for 2012.
- Anadarko plans to refocus in 2012 towards oil and liquids-rich assets, and step back from US onshore dry gas activities due to the currently over-supplied North American natural gas market environment. This will be achieved by reducing the number of rigs in Marcellus and Pinedale/Jonah, while curtailing gas production in the Powder River basin. But at the same time, the company plans to continue its drilling program at the Marcellus shale by reaching over 1 800 wells by 2014+ (from 200 wells in 2012) and to triple oil, NGLs and gas production from Eagle Ford between 2011 and 2013, where the sales mix still contains 35% of gas. Likewise, in the Permian oil, Bone Spring and Avalon have sales containing on average 15% and 40% of gas.
- EOG produced around 12 bcm in 2011, 40% of which came from the Barnett shale play, stable from previous years, while at the same time oil production increased by around 50%. The company is moving from gas to oil and liquids, and plans to spend 90% of 2012 capital expenditures on oil and liquids and the rest on gas. The company expects its North American gas production to drop by 11% in 2012, following a 7% drop in 2011 which was actually driven by Canada as US production remained stable.

Russia

In 2011, Russia's gas industry continued its recovery from the dramatic fall in production in 2009, when it collapsed to a low of 572 bcm, a level unseen since 2001. The continuous recovery was driven by both increased exports and higher domestic demand. Production grew by about 22 bcm from 637 bcm to 659 bcm. This production increase covered higher pipeline exports (by 10 bcm) and incremental domestic demand of 13 bcm. Unlike the quick post-crisis recovery in 2010, Gazprom's gas production remained almost flat at 501 bcm[6] in 2011, which takes into account that Gazprom is managing to stabilise production from its old fields, such as Yamburg, with additional gas from a new part of the Zapolyarnoye field, and has not started any new large fields over the past few years. Therefore, the sources of the incremental Russian gas production in 2011 were the independents, such as Novatek (+15 bcm), and the oil companies.

[6] This figure includes the temperature correction from 20°C to 15°C.

Table 11 Russia's gas balance

	2010	2011		2010	2011
Domestic production	637	659	Exports	216	226
Gazprom	500	501	*FSU*	63	70
Oil companies	57	63	*LNG*	13	14
Independents	82	96	*Europe*	139	142
Imports	36	33	Domestic demand	457	470

Notes: All data have been normalised at a temperature of 15°C, while Russian data for natural gas are usually given at 20°C. Numbers may not add up due to rounding. Domestic demand + exports is different from domestic production + imports due to storage.

Provided that there is sufficient domestic and European demand, Russia can significantly increase gas production in the next five years. Indeed, additional LNG exports or pipeline exports to Asia are not expected to materialise before 2017, given the scale of the investments and time needed to develop the corresponding infrastructure. This section looks at the production prospects of Gazprom's old and new fields in West Siberia, the significant potential for production growth from independent producers, along with developments in other areas such as East Siberia, the Far East and Shtokman.

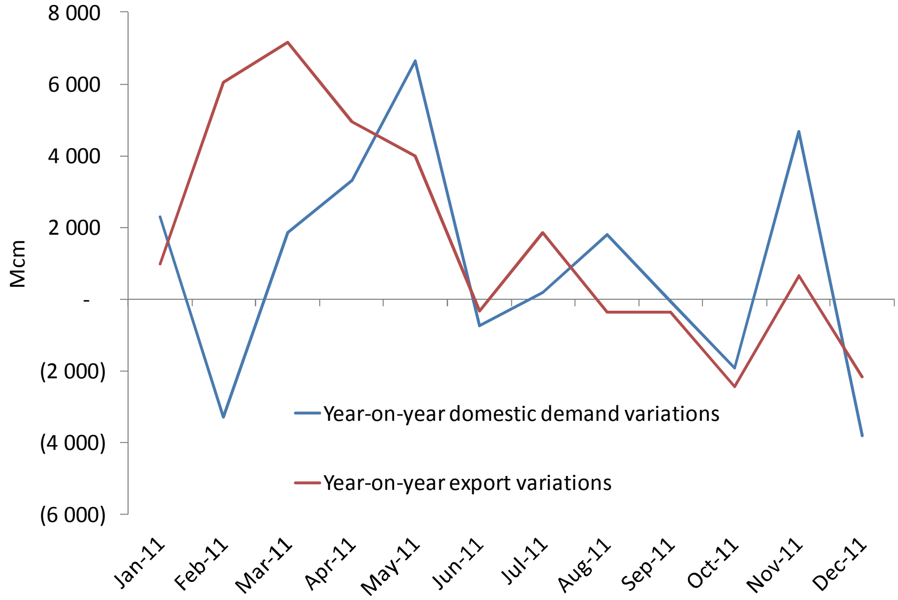
Gazprom's traditional production areas

Over the year 2011, Gazprom had to adjust to large fluctuations in both exports and domestic gas demand, which cannot be covered only by storage. Thus, the company had to vary both its monthly and annual production levels significantly. Although fluctuations in exports were larger in percentage terms, the sheer size of the domestic demand made its variability comparable to that of exports (see Figure 36). Although demand grew by 2.3% y-o-y in 2011, some analysts believe that this growth was actually concentrated in a few regions and industries and will slow down in some of them (Troika, 2012). The regions contributing to the recent demand growth were Sakhalin 1 and 2 production sharing agreements (PSA) projects, which have now reached plateau production, West Siberia, where the growth came from local utilisation of associated gas, Moscow oblast with its rapid growth in residential construction and western Kaliningrad and Leningrad oblasts with growing car manufacturing.

Reducing gas production is simpler than ramping it up, especially when gas is coming from dry gas fields. Therefore, given the decline in the old giant fields, the question arises how Russia actually manages the upward production flexibility required by domestic and foreign demand. Although it is well known that pressure and output in the oldest giant fields[7] has been declining fast, depletion rates have decreased and are estimated to be a less dramatic 11 bcm a year. This slower decline, coupled with drilling into deeper deposits of those fields and the still growing production in the new giant Zapolyarnoe field[8] seem to add enough flexibility to maintain the current level of production in the existing producing fields in the medium term. For example, in the oldest field, Medvezhye, which peaked in 1983, a new phase of production from the deeper Nydin block (deposits at the depth of 1 700 m to 3 200 m) started at end-2011. Similarly, in the largest old field, Urengoyskoe, the Wintershall-Gazprom joint venture started "commercial extraction" from the deepest "Achim" layer (around 4 km deep) in 2011, following a testing phase. Also, in the newer Zapolyarnoe field, Gazprom is already starting to tap into more difficult gas: extraction from the first phase of the "Valanginian" deposits began in 2011, and is planned to increase production by 15 bcm in the medium term.

[7] Medvezhye, Yamburgskoe and Urengoyskoe fields alone accounted for 44% of Gazprom's production in 2009.
[8] Zapolyarnoe started production in 2001 and is sometimes called "the last easy gas".

Figure 36 Year-on-year changes in domestic demand and exports (Mcm)



Still, decline rates of the old fields are significant. For many years, Gazprom has been postponing the development of the new generation of gas fields, but the planned start of production from Bovanenkovo in the Yamal peninsula is more than ever essential for maintaining and increasing output in the West Siberia region. In fact, Gazprom has announced that Bovanenkovo's production will start a little earlier than planned before – in June 2012 instead of the third quarter of 2012. The Bovanenkovo-Uhta 1 240 km-long pipeline, which is going to connect the field to the gas system, is set to be completed in time. Also, the construction of the second parallel line started in early 2012 and is to be finished in two or three years. Thus, Gazprom's total production, based on the old and upcoming fields, can be rapidly increased in the next five years conditional on sufficient demand for this extra gas.

Gazprom's revenues shot up to an estimated USD 150 billion in 2011, compared to USD 118 billion in 2010, but the investment programme for 2012 is going down by about USD 15 billion due to the recent completion of big pipeline projects such as Nord Stream. Still, pipeline projects such as Bovanenkovo-Uhta and the development of the Yamal Peninsula are planned to be the major recipients of Gazprom's investments in the future.

Independent producers

As mentioned above, the independent producers were solely responsible for the 20 bcm production growth in Russia in 2011, with their total output reaching 161 bcm compared to 140 bcm in 2010. Such a strong growth trend is likely to persist in the next five years, potentially increasing Russian gas production by another 50 bcm by 2017. If observers regard Novatek's production growth from 21 bcm in 2004 to 53 bcm in 2011 as very impressive, there is potentially more to come, as the company has announced a 60% increase in capital expenditure for 2012. Since Novatek's largest asset, the Yurkharovskoe field, is approaching its maximum output capacity of 33 bcm, Novatek has acquired new promising fields which will allow it to continue its impressive growth. In 2010, Novatek and Gazprom Neft bought a 51% share of SeverEnergiya, a former Yukos asset, where the other 49% is held by ENI and Enel. SeverEnergiya owns three large wet gas fields in West Siberia, which had been drilled and were ready to start production as soon as in 2003. Production is likely to commence in 2012 and reach 21 bcm by 2015, since the new owners have sufficient capacity for transporting and processing oil products (Gazprom Neft) and gas and condensate (Novatek). Three Russian state-owned banks are providing a USD 4 billion loan for the project.

So far, Novatek has been the single largest independent player, but a recently announced joint venture between Rosneft and Itera has created an entity with a 1.2 tcm resource base, on par with Novatek's. The new joint venture covers a different geographic region, *i.e.* Sverdlovsk oblast, for gas distribution and is not going to compete directly with Novatek. It is more likely to add another strong voice to the debate on access to gas pipelines and lifting the export monopoly.

Oil companies in Russia contribute a significant share to the gas produced, having extracted 63 bcm in 2011. In the medium term, they are likely to increase production significantly, motivated both by gaining a higher share in the gas market and increased fines for flaring associated gas. The new amendment to the legislation on flaring, which requires 95% of associated gas to be utilised, went into force in January 2012, although the original date was to be January 2011. It significantly raises fines, especially for delayed compliance and absence of metering. The new regulation met a lot of resistance from the energy industry, not only in Russia, but in many other countries as well, as it requires significant investments with no return unless the gas is marketable. There is already a new amendment under discussion which will waive some fines for certain fields, such as small fields or fields in early development.

Table 12 Production by Independents, 2011 and 2010 (bcm)

	2010	2011	Production targets
Novatek	36.9	52.2	112 bcm by 2020
Lukoil	15.0	15.6	Global gas production reaches 60 bcm by 2021
Surguneftegaz	13.1	12.6	Can increase to 22 bcm
Itera	12.0	12.3	JV with Rosneft to increase from 25 to 40 bcm
TNK BP	11.4	12.0	Subsidiary Rospan to increase from 2.3 to 15 bcm
Rosneft	11.2	11.6	40 bcm if given third-party access (TPA)*
Others	39.0	42.3	

* This target is different from the JV with Itera plans because the emphasis here is on the separate issue of TPA.

The largest private oil company in Russia, Lukoil, has probably the most ambitious gas production plan. The company is going to significantly boost its overall investments in the upstream by spending around USD 125 billion until 2021. Lukoil is very active outside Russia as well. Gas is set to play an increasingly important role, according to Lukoil's presented strategy: the company's global gas production is expected to rise from 22 bcm in 2011 to 60 bcm in 2021. This strategy relies on domestic gas prices reaching export parity by 2017, which is not certain to happen, especially for gas used for residential heating. The growth in gas production in Lukoil's projects in Russia is planned to come from its four fields in Western Siberia (from the current 8 bcm to 20 bcm) and Uzbekistan (see the Caspian section for more details).

East Siberia and the Far East

Uncertainties surrounding the size of future European natural gas demand and the strong growth of Asian gas markets, coupled with the large hydrocarbon resources available in the eastern part of Russia, are the factors which continue to determine Russia's production strategy. As contract negotiations with China have not been successful so far, and Turkmenistan is increasing deliveries to China and plans to increase contractual volumes from 40 bcm to 65 bcm, Russia has intensified talks with Japan and South Korea. Production in the Eastern part of Russia reached 35 bcm in 2011, including some 14 bcm exported as LNG from the Sakhalin 2 liquefaction plant, which started in early 2009.

Talks with Japan are ongoing on two projects: Vladivostok LNG with a consortium, Japan Far East Gas Co., and Sakhalin III. The source of gas for Vladivostok LNG is not clear at this stage as gas from Sakhalin I (via the completed Sakhalin-Vladivostok pipeline) is still re-injected due to stalled negotiations with Exxon Mobil. The planned pipeline Yakutia-Vladivostok will have a higher capacity (32-60 bcm/y depending on different reports) than the largest possible source for it, the Chayanda field (up to 25 bcm/y). Gazprom has announced that the pipeline construction will start in 2012, although the optimal route has not been chosen yet and exploratory drilling in Chayanda is still continuing. The target production start date for Chayanda is 2016, but given the multiple uncertainties involved, production is unlikely to begin within the next five years. Japan has also expressed interest in joining the Sakhalin III project, although Gazprom had not intended to invite foreign partners. But this may change as the project development is meant to accelerate in order to provide additional gas supplies to Japan, due to its higher gas imports needs after the Fukushima accident.

Another potential importer, Korea, stands out among IEA countries with its strong GDP growth during the years of economic crisis. This growth feeds a very robustly growing demand for electricity and gas-fired generation. Additionally, Korea wishes to diversify imports since it has recently experienced several months of supply disruption from Arun LNG in Indonesia. The relative proximity of the Russian eastern gas resources to Korea makes them a viable alternative to LNG exports. Negotiations between Russia and Korea started in 2003 with a five-year agreement of cooperation between Gazprom and Kogas; in 2010, the parties signed a roadmap for exports to Korea. The document specifies that deliveries of 10 bcm will commence in 2017 with a 25-year duration. According to Gazprom’s Eastern Gas Programme, the sources of exports are going to be Sakhalin III and Chayanda field.

In late March 2012, the Shtokman AG board of directors announced that the FID had once again been postponed. The official explanation for this decision hints at the lack of tax incentives as well as demand uncertainty, especially for pipeline exports to Europe. By coincidence or not, a few weeks later, Russian Prime Minister Putin announced important initiatives on tax incentives for off-shore projects which are planned to go into force by October 2012, and will affect both oil and gas producers.

The incentives include exemption from export duty, reduced extraction tax, waiving value-added tax (VAT) on imported equipment and guarantees of an unchanged tax regime for 15 years. Earlier Murmansk oblast was given a special economic status, which was meant to attract private investments into onshore infrastructure for Shtokman project. However, these concessions are probably not enough for the Shtokman project given that it is not clear which ones will apply to Shtokman. Therefore, after the prime minister’s announcement, Ministry of Finance officials mentioned that there might be a separate decision on Shtokman later. Thus, at this stage, the future of the project is still not clear, as negotiations between the government and the stakeholders continue. However, it is unlikely that this project will start before the end of the decade.

The Caspian region

The Caspian region is a significant holder of gas reserves (12.7 tcm as of 2010 according to the BP *Statistical Review of World Energy 2011*). More importantly, it is ideally located between key markets: Russia has been a traditional buyer of Caspian gas for many years, but it seems to have lost interest due to a combination of lack of demand in its key export market, Europe; the high price for some of these imports, notably Turkmen gas; and the development of the new giant fields such as the Yamal Peninsula.

The only exception to limited additional exports from the Caspian region to Russia are small, but increasing volumes of Azeri gas reaching the southern part of Russia. These supplies make more sense than having to transport gas from Western Siberia across Russia. Europe is keen to diversify its import sources, but has been quite slow in the development of the pipeline infrastructure referred to as the Southern Corridor, while uncertainties on how fast European gas demand will recover prevail. The booming Chinese gas market is not only attracting Turkmen gas supplies, but also since 2012, Uzbek gas supplies. Meanwhile, potential imports from Kazakhstan are still under discussion.

Azerbaijan

Since the publication of the *Medium-Term Oil and Gas Markets Report 2011*, there have been several new developments in Azerbaijan's upstream sector. While natural gas production decreased by 2.2% in 2011, it is expected to only marginally increase over the projection period. In the medium term, the focus is on the development of the second phase of Shad Deniz, but this is unlikely to happen before 2017 due to the lack of infrastructure to transport it to the targeted market, Europe. Nevertheless, Shah Deniz gas can be expected to reach European gas markets by 2018, unless some unexpected developments happen.

In October 2011, Turkey and Azerbaijan finally signed an agreement on prices for exports from Shah Deniz I to Turkey until 2018, and more importantly, on the purchase of 6.6 bcm/y of Shah Deniz II and on the transit of another 10 bcm/y from Shah Deniz II via Turkish territory. Then, in December 2011 a Memorandum of Understanding (MOU) was signed between Turkey and Azerbaijan on the construction of the Trans-Anatolian Gas Pipeline (TAGP). In April 2012, the state oil company of Azerbaijan Republic (SOCAR)'s top officials declared that construction would begin in 2012. This development implies that the competition between alternative Southern Corridor pipelines has now reached the stage when decisions on transport routes are finally taken, including a positive decision on the Trans-Adriatic Pipeline (TAP) (see trade section on investments in pipelines).

Looking beyond 2018, the promising deep-drilling in the offshore Absheron field resulted in the discovery of a major 350 bcm gas deposit by a Total-led consortium (other partners are SOCAR and GDF Suez). The discovery was met with much political enthusiasm since it implies Azerbaijan's ability to potentially deliver significantly higher exports, in the range of 27-38 bcm/y after 2020, compared to the current 7.1 bcm/y, exported to Europe and Russia. Another potential source of gas supplies is the Azeri-Chirag-Guneshli (ACG) deep laying gas. This is currently not covered by the PSA for the shallower resources, and negotiations still have not produced concrete results. The Azeri side has announced a proposal to sign a Risk Service Agreement instead of a PSA.

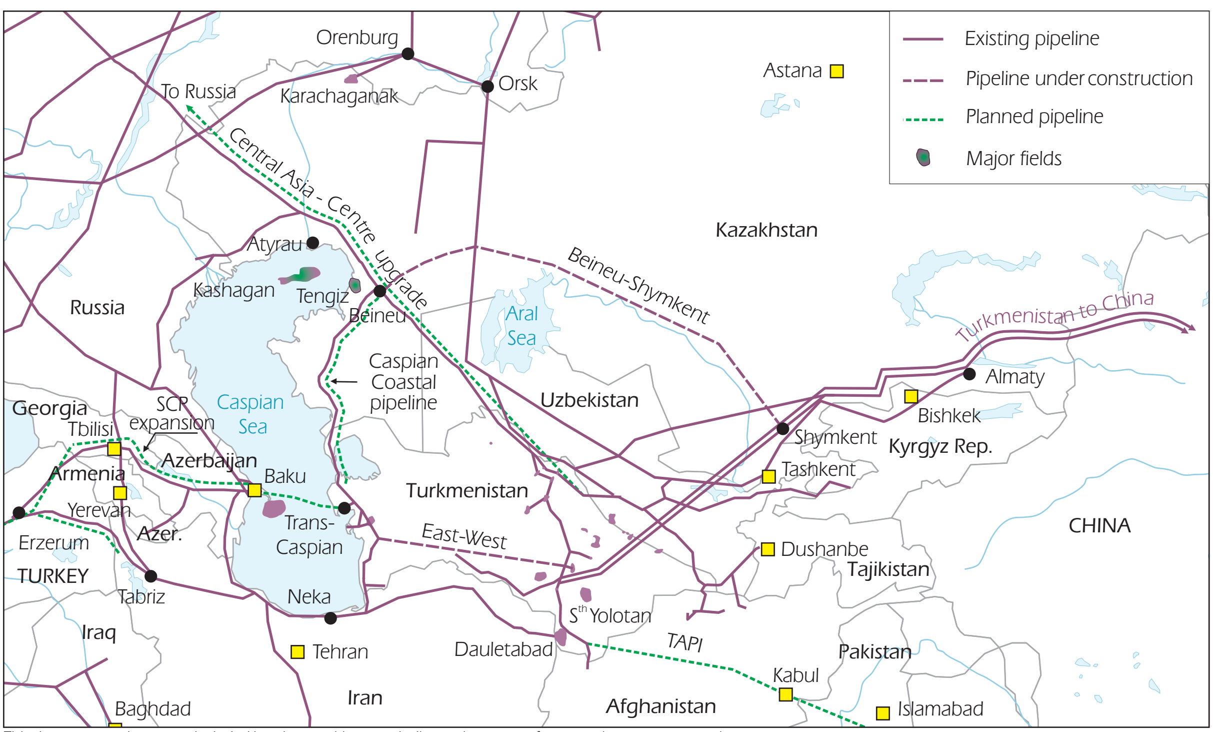
Again, the key uncertainty remains the import volumes that Europe will need beyond 2020. If this "third wave" of Azeri gas exports is synchronised with potential Turkmen exports through the Trans-Caspian pipeline, it would optimise pipeline capacities and transportation costs. In the case that additional European import needs remain limited due to slowly increasing gas demand, Azerbaijan may prefer to develop its gas resources without having to handle the competition from Turkmen gas supplies. Nevertheless, European countries are now negotiating the Trans-Caspian pipeline with one voice after the European Commission decided in September 2011 to lead the talks with Azerbaijan and Turkmenistan.

Turkmenistan

Although it was widely accepted that Turkmenistan possessed very large gas resources, the size of its largest field, South Yolotan, was confirmed in October 2011 by the British company Gaffney, Cline & Associates (GCA): with between 13 tcm and 21 tcm, it exceeds previous estimates. This makes South Yolotan the second largest gas field in the world after the Iranian-Qatari North field.

Total natural gas production increased by an estimated 15 bcm in 2011, although this number is highly uncertain due to the lack of data on Turkmen domestic gas consumption and exports to Iran. Yet, 2011 marks a milestone for the Turkmen gas sector with the start of offshore gas production: the PSA operator Petronas delivered first associated gas from the offshore group of fields Block 1 to the coastal pipeline, from where it can be exported to both Russia and Iran, although Petronas first has to sell the gas to Turkmengaz. The production target for 2012 is 5 bcm/y, but it can be increased to 10 bcm/y in the future. Since demand for exports to Russia is not increasing, this offshore gas is being used domestically at the moment.

Map 2 Transport infrastructure in the Caspian region



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Turkmenistan has also intensified its gas transportation projects. First, the construction of the East-West pipeline across the country started in 2011. This transportation route is going to be about 1 000 km long with a 30 bcm/y capacity, and is supposed to give more flexibility in shipping gas to export markets. As can be seen in Map 2, this pipeline can facilitate moving gas from South Yolotan to the Caspian east coast and then further on in various directions. In reverse flow, the offshore Caspian gas can be transported to the export pipeline to China in Eastern Turkmenistan. Another significant development in transport is the start of the construction of the third line of the gas pipeline to China, which will facilitate the recent agreements about increasing export volumes to China to up to 65 bcm/y. The existing two lines have a capacity of 30 bcm/y and their construction costs have increased significantly by some accounts. The third line's capacity is 25 bcm and it is expected to be completed by January 2014, increasing the total export capacity to 55 bcm.

Kazakhstan and Uzbekistan

Following Kazakhstan's policy objective to reduce its dependence on gas imports (some consisting of swap deals with Russia) and export gas to China, gas production increased by 6% in 2011. The construction of the 1 475 km Beineu-Shymkent pipeline linking resources in the western part of the country to consumption and export areas in the south of Kazakhstan (see Map 2) started in September 2011. The pipeline's capacity will be 10 bcm/y (with a potential upgrade to 15 bcm/y) and is planned to be completed after 2013. In April 2012, Uzbekistan had already started to export gas to China via the existing lines, as it signed an agreement with China to supply up to 10 bcm/y. Part of the gas will be provided by Russia's Lukoil, whose ambitious gas strategy involves significantly increasing gas production in Uzbekistan. Lukoil has PSAs in four different regions in Uzbekistan. In the largest one, Kandym, the company is planning to reach a production level of 12 bcm/y. Lukoil does not market the gas, but sells it to Uzbekneftegaz.

Both Kazakhstan and Uzbekistan are going to supply gas to the Central Asia Gas Pipeline (CAGP), which will be facilitated by a third line of CAGP. Its construction started in December 2011. The first two parallel lines running from Turkmenistan to the Kazakh-Chinese border began delivering gas in 2009 and 2010 respectively. The third line is expected to be finished by 2014 increasing the total transmission capacity to 55 bcm/y.

The Middle East will serve exclusively its domestic gas market

Middle East gas production is expected to serve exclusively the regional gas market needs in the medium term, as it is relatively unlikely that any export project, whether a pipeline or an LNG plant, would be completed by 2017. At best, incremental production could offset import needs in Iran. It is therefore fair to say that Middle East gas demand is almost entirely supply-driven and depends mostly on incremental gas production and, to a lesser extent, on export commitments and on the level of imports that can be achieved.

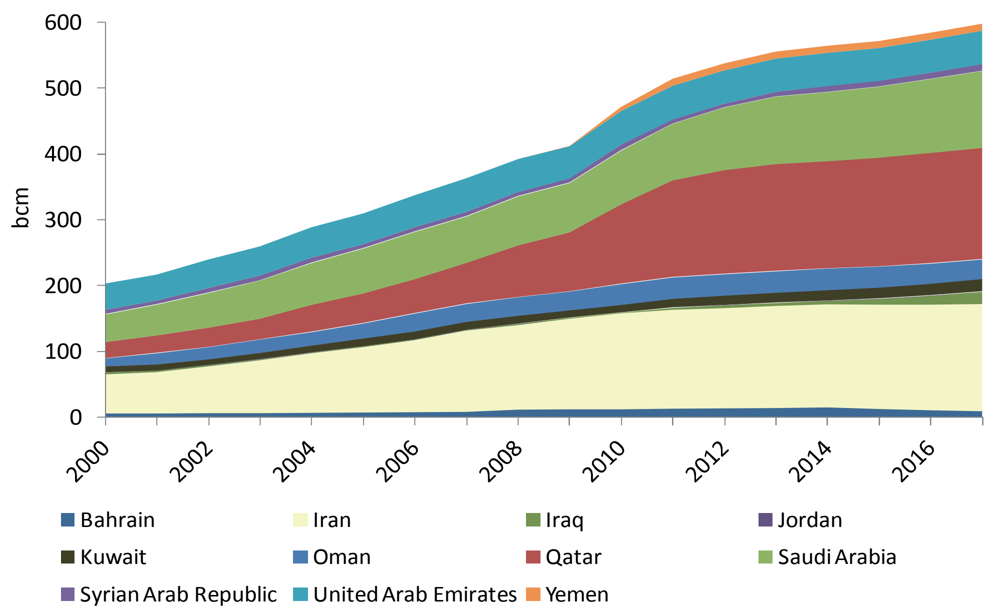
That the Middle East could face gas shortages could appear as a contradiction, given that the region holds significant gas reserves. Actually, while the Middle East holds around 41% of proven gas reserves (76 tcm), these numbers hide wide regional disparities, as Iran and Qatar represent 72% of the region's proven gas reserves (29.6 tcm and 25.3 tcm, respectively, as of 2010), while Saudi Arabia, the United Arab Emirates and Iraq hold respectively 8 tcm, 6 tcm and 3.2 tcm.[9] Much of the gas is associated gas. But significant increases in oil production are only expected in a small number of countries. As highlighted in the *Oil Market Report December 2011*, OPEC crude oil capacity will increase by 2.3 mb/d over 2010-16, with 80% of it coming from Iraq. Additionally, gas prices are

[9] When including additional recoverable conventional and unconventional gas resources, Middle Eastern recoverable gas resources increase to 139 tcm with the following split: conventional gas: 116 tcm, tight gas: 9 tcm and shale gas: 14 tcm.

often maintained at below cost levels, creating a vicious cycle with an artificially high demand without any driver to increase efficiency. According to International Gas Union (IGU), most Middle East wholesale gas prices in 2010 were below USD 1/MBtu, which is well below the development costs of most new generation of non-associated gas fields. This explains why, despite apparent abundant resources, many Middle Eastern countries actually face shortages. A large proportion of associated gas is reinjected in the fields to enhance oil production, while some is still flared or vented, which restricts even further marketed gas production.

Growth in Middle Eastern gas production is expected to slow down considerably over the coming five years, with the build-up from an estimated 516 bcm in 2011 to 588 bcm in 2017 much slower in the absence of the expansion of LNG export capacity in Qatar and difficulties in developing the next generation of fields. Within the region, only Qatar seems able to meet its booming demand and export commitments without any difficulties. Meanwhile, several Middle Eastern countries such as Bahrain and Oman are expected to struggle to keep their domestic production at today's levels, either due to low domestic prices and/or to the difficulty of developing a new generation of tight gas fields, which often do not offer the benefit of liquids revenues.

Figure 37 Gas production in the Middle East, 2000-17



Kuwait is also having difficulties increasing its gas production, notably with the development of Shell's Jurassic Gas Project. The field started producing at end-2007, but production has been behind target; the objective to increase production to 6 bcm/y by 2013 seems compromised by a mix of issues linked both to the nature of the field (which is deep, with high temperature and pressure and high hydrogen sulphide content) and the contractors' lack of experience. Kuwait Oil Company (KOC) nevertheless claims to be able to increase domestic production to around 40 bcm/y by 2020, three times more than today, relying on the Dorra field in the offshore neutral zone and potential non-associated gas discoveries. Saudi Arabia is projected to increase its production markedly due to new gas developments which have either recently started, such as Kurais, Nuayyim and Karan, or will start by the middle of the decade, such as the Wasit Gas Programme.

Iraq is actually one of several wild cards in this region, for despite very high production potential, production has so far been constrained by lack of domestic demand, which is the opposite from what can be observed in many countries. Additional associated gas production in Iraq may be flared, but new developments in terms of fields, infrastructure and power plants could change the outlook. The other wild card in the region is Iran, as much due to political uncertainties as to the difficulty of getting any accurate and reliable information on the current production situation or on future investment plans. Iran, which is currently the Middle East's largest gas producer and consumer, has been struggling to keep up with domestic demand, a situation expected to continue in the medium term. Natural gas production is expected to increase moderately, assuming that the political situation does not deteriorate further.

Qatar: managing ongoing growth

Qatar is probably the only Middle Eastern country which is not struggling with rapidly rising domestic demand or importing from neighbours to bridge the gap between production and demand. Due to its wide gas resource base, the country has been able to increase domestic production and export both LNG (around 100 bcm in 2011) and pipeline gas to the United Arab Emirates and Oman. High oil prices, coupled with NGLs, refined products and record high LNG exports, resulted in exports of hydrocarbons amounting to QR 365 billion (USD 100 billion) in 2011. These revenues enable the country to maintain relatively low domestic gas prices. Qatar's gas production relies almost entirely on one single field, the North Field, on which it has imposed a moratorium for additional exports until 2015 in order to study the effects of the recent production increase on the North Field, although some reports state later dates such as 2016 or 2018. Until then, domestic production developments will depend on the Pearl GTL and Barzan projects dedicated to the domestic market.

The Pearl GTL project started in 2011 and produced an average of 40 kb/d split evenly between NGLs and condensates. It is expected to be fully operational in the third quarter of 2012, producing 120 kb/d of NGLs/condensates and 140 kb/d of GTL. Once operational, Pearl will produce some 17 bcm/y of gas from the North Field. Meanwhile, the Barzan project, developed with ExxonMobil, will produce over 14 bcm/y from the North Field and will be dedicated to the domestic power sector and industry, notably the petrochemical sector. It will be based on two processing trains, starting in 2014 and 2015. This project is the last significant project agreed before the moratorium. Costs recently escalated from USD 8.6 billion to USD 10.3 billion.

Iraq: a giant finally awakens?

Iraq holds 3.2 tcm of proven gas reserves, which in principle could allow the country to have not only a relatively big domestic gas market, but also to export, judging from examples from the region such as Oman or the United Arab Emirates. Until now, infrastructure issues – or the lack thereof – presented the biggest hurdle, from roads, bridges to gas transmission network and gas-fired plants. Although such obstacles are still present, there have been improvements in terms of gas transport infrastructure and 2 913 MW of (new and refurbished) power generation have been added. There are significant investments in new generation, with some 6.5 GW of capacity contracted to come online by 2016. Additionally, there are still tensions between the Iraqi government and the Kurdish Regional Government (KRG), so that companies active with the latter are often blacklisted from taking part in tenders organised by the Iraqi Oil Ministry.

Most of Iraq's gas resources are associated (80%), which is an advantage considering the bright prospects for Iraqi oil production, and they are located in the South Eastern Basrah province. There are also gas fields in the North and the West, most of them non-associated. The largest producing field is Khor Mor in the Kurdistan region, with an output of around 3 bcm/y. According to the Ministry of Oil's data, Iraqi gas production, including flaring, has been relatively flat at 14.5 bcm since 2009, resulting in available gas at around 7.4 bcm. This does not even include KRG production (Khor Mor), which is thought to be consumed mostly in power plants. Yet many statistics indicate gas demand at 5 bcm, leaving the rest going to "shrinkage".

Even though the light at the end of the tunnel is becoming a bit brighter, it is still relatively far away. The most advanced project and the quickest to start is the South Gas Utilisation Project, for which the agreement was finally signed in July 2011, after several years of discussion. This USD 17.2 billion project is led by Iraq's South Gas Company (SGC) (51%), Shell (44%) and Mitsubishi (5%), and focuses on capturing the gas flared from the Rumaila, Zubair and West Qurna-1 oil fields. Shell and Mitsubishi will provide USD 7 billion, Iraq over USD 5 billion, with the rest coming from the project's revenues. The companies will also lend USD 1 billion to the state to help it finance its share of the project. Ultimately, the project could produce some 20-25 bcm/y of gas in the longer term. The gas production will be sold to SGC at international market prices (a Brent price of USD 75/bl would translate into USD 3.22/MBtu for the gas, which shows that not all oil-indexed formulas translate into expensive gas). Then, SGC would resell the gas to the power and industry sectors at USD 1.04/MBtu. Up to 6 bcm/y could also be exported by LNG, although this will take a few years.

Since 2008, the Ministry of Oil has tendered three different oil and gas licensing rounds, offering 11 oil fields and three gas fields. After having been postponed several times, a fourth tender will take place in mid-2012, with 12 blocks on offer, including seven with gas prospects. The three gas fields awarded so far, all of them during the third tender, are in pre-development. Kogas signed the final deal to develop Akkas in October 2011, despite KazMunaiGas' withdrawal earlier in the year. Given Kogas' relatively limited upstream experience, there are question marks on a timely development. The two other fields, Mansuriya and Sibba, are to be developed by consortiums which include TPAO and the Kuwait Energy Company. However, the development of these three fields is lagging behind the Shell gas project and is estimated to take place towards the latter part of the projection period.

Export plans remain controversial due to the urgent need to generate electricity. Iraq nevertheless signed a Strategic Energy Partnership with the European Union in May 2011, whereby both parties committed to "jointly identify the export gas volumes to the world market, including through the Southern Corridor to the EU". This does not refer specifically to the Nabucco pipeline, as Iraq could use any Southern Corridor project. Besides, Iraq is also looking at building a 500 km pipeline to the northern part of Jordan to replace Egypt's erratic supplies. Finally, the LNG option would also give access to international gas markets. Volumes considered are between 4.5 bcm and 6 bcm.

Israel: the richness of the Levantine coast

Israel, the "one single spot in the Middle East that has no oil" as Golda Meir put it, finally discovered a wealth of gas assets in 2009, at least in comparison to the size of its gas market. Since Tamar's discovery, five other fields have been discovered in this area (the latest, Tanin, in February 2012) with combined gross mean resources amounting to around 1 tcm as of April 2012. The two most important fields, Tamar (270 bcm) and Leviathan (560 bcm), are likely to turn Israel at least into a self-sufficient country in the short term and into an export country in the longer term. While developing Tamar should have been relatively straightforward, it was not, due to opposition on the landfall point and arguments regarding taxation. The field is nevertheless expected to start producing in early 2013, but ironically, Israel could need to import LNG during a short interim period to compensate for the irregular Egyptian pipeline supplies which have dropped by 1.7 bcm from 2010 levels. The contract between Egypt and the East Mediterranean Gas group was cancelled by the Egyptian company EGAS in late April 2012. Meanwhile, gas production from Mari-B is declining rapidly. Some relief can be expected from new fields such as Noa, which is due to start by mid-2012, using Mari-B's existing infrastructure. The LNG terminal is planned to be based on a floating storage and regasification unit (FSRU), as it will only be needed for a short time. The Israel Electric Company (IEC) has selected Excelerate to provide the FRSU under a four-year contract and launched a supply tender for LNG in late April 2012. The Tamar field's production is already tied with at least six contracts, including long-term contracts with IEC and Dalia Power Energy for annual volumes of 5 bcm/y and 1.4 bcm/y, respectively.

Israel has little to no experience in upstream issues and none at all when it comes to export policy, which is still to be developed. The country must first decide how much gas it wants to reserve for its domestic market. A government committee has recommended keeping sufficient gas resources to meet the country's demand for 25 years (*i.e.* 400 bcm), and to have the LNG export plant based within Israel. Additionally, each field must be physically connected to the Israeli transmission network and is required to supply a minimum of 15% percent of its annual production to the domestic market, regardless of actual demand requirements. Another issue is that these discoveries are reigniting conflicts with neighbours, for example, the delimitation issues between Israel and Lebanon still need to be settled.

The path towards exports is even more challenging as no final decision has been taken on how gas should be exported. LNG seems to be the favoured option, while a 1 200 km offshore pipeline to Greece is still mentioned, but this is a costly option on account of the depths of the waters (3 000 m). The expected MOU between the countries has now been postponed indefinitely, which makes the pipeline option even more unlikely. A pipeline to Turkey is more feasible, but limits the export flexibility. Several LNG options have been envisaged. An onshore LNG export terminal is difficult due to not-in-my-backyard (NIMBY) issues. The Levantine Coast is short. Using Aqaba's special economic zone on the Red Sea not only requires building transmission pipelines across the country, but also locating an export plant outside Israel and sailing around Yemen, which might not be regarded as an ideal route from Israel's point of view. Eilat, close to Aqaba, but located in Israel, is also being considered. Noble is keen on this option because it permits easier access to the rapidly growing Asian markets. An MOU has already been signed by Noble's partner Isramco to export up to 4.5 bcm/y to Korea.

Israel can export pipeline gas to neighbouring countries, which is more a political decision, although the export price would also play a role. Other options include a floating LNG solution or combining its resources with Cyprus* and building an onshore LNG export plant. In Cyprus, a first discovery, Aphrodite, was made on offshore Block 12 by Noble Energy in 2011. Noble holds 70% of Block 12, and the Delek Group has bought into the rest. The resources have been estimated at around 200 bcm. The most likely option to monetise this gas would be an LNG export plant or to use part of this gas domestically in the power sector (replacing imported heavy fuel oil), or to build a methanol plant.

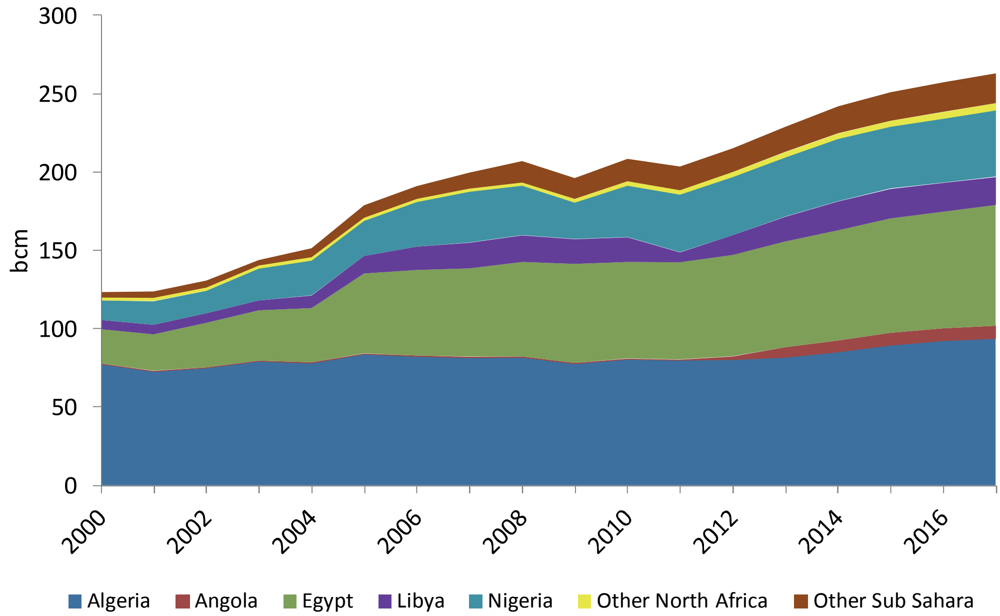
* Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognizes the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus" issue.

Note by all the European Union Member States of the OECD and the European Commission: The Republic of Cyprus is recognized by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Africa

In 2011, Africa produced an estimated 204 bcm, down from 209 bcm in 2010, mostly due to civil war in Libya.

Figure 38 Gas production in Africa



Half of Africa's gas production is currently exported, and three-fourths is concentrated in two countries: Algeria and Egypt. While both countries will continue to largely determine the path of Africa's future production, a few other countries will also influence African gas output over the coming five years: Nigeria, holder of 5.3 tcm of proven gas reserves; Angola, which will start exporting LNG in mid-2012; and Libya, recovering from the conflict in 2011. Total African gas production is expected to rise to 261 bcm by 2017.

East Africa is the one region which is currently attracting the most attention, with large new finds over the past two years. However, as the development of these reserves is largely determined by the construction of LNG export plants, production is unlikely to start before 2018.

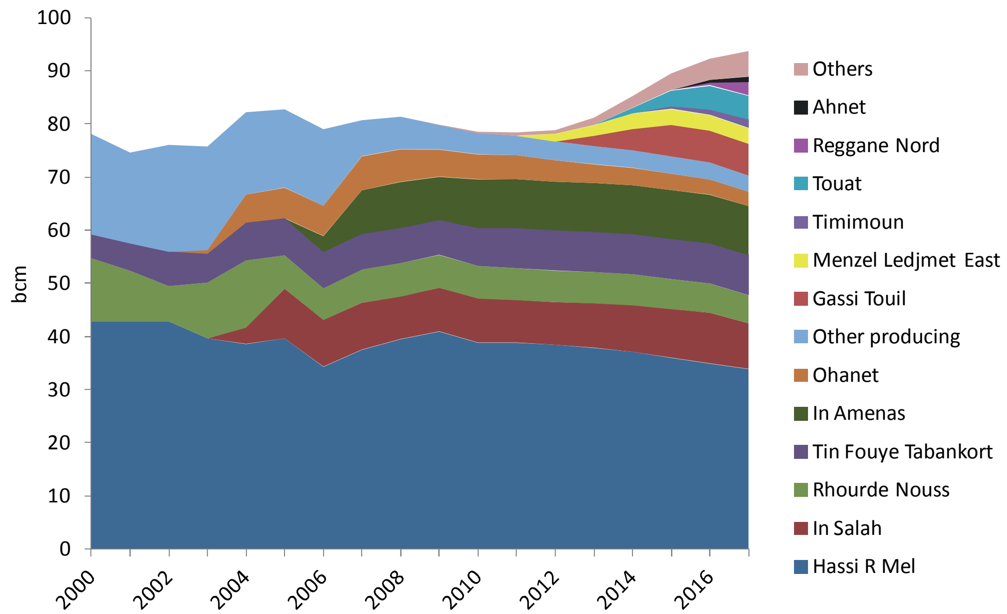
Algeria: is the export growth fading away?

With an estimated 80 bcm produced in 2011, Algerian gas production may be the highest in Africa, but it has been dwindling over the past few years, which prompts the unspoken question: will Algerian supply, in particular, exports, grow over 2011-20 or are all the current projects barely enough to meet the growing domestic gas demand? Based purely on historical data, Algerian gas production peaked in 2005 and never quite recovered. The accident of Skikda made part of the LNG export capacity unavailable, but what remained was never fully used either. The Medgaz pipeline was delayed by two years, partly on account of the collapse of the Iberian gas market, combined with domestic issues. The internal transmission infrastructure is old and needs upgrading and international companies may be reluctant to build pipeline infrastructure between the new fields and the processing facilities at Hassi R'Mel. Over the past two years, many industry sources have commented on the pressure drop of Hassi R'Mel, Algeria's crown jewel, representing 100 bcm of raw gas production against a total of 140 bcm.

Algerian gas statistics can be somewhat challenging in terms of differentiating marketable gas production, gas flared and gas reinjected from the different fields. Hassi R'Mel is estimated to represent half of total marketable gas production, and is thought to have started declining in 2010 (Oxford Institute for Energy Studies, 2011). The depletion rates of mature fields such as Hassi R'Mel, Rhourde Nouss, and Ohanet, as well as the amount of gas needed for reinjection in oil fields, are crucial to be able to estimate the future of Algerian gas production. However, there are significant projects that will start producing by 2017 which can compensate for the loss of production from mature fields. Among them are Gassi Touil, which will support the LNG export plan starting in 2013; Timimoun, Touat, Reggane Nord and Ahnet; as well as small fields in the south of In Salah. Together these fields could add 23 bcm of gas production, if they start on time, which is less than certain, given the delays recently observed and the frequent changes at the top of Algeria's NOC Sonatrach.

Alnaft's approval of Reggane Nord in February 2012 shows the need to fast-track new projects, partly to meet the ambitious (but elusive) planned export targets, but perhaps also to compensate for issues with Hassi R'Mel. The Gassi Touil field in the East is expected to supply the new 6.4 bcm liquefaction unit at Arzew. The year 2013 would see GDF Suez's Touat starting, which would add up 4.5 bcm/y, followed in 2014 by the 1.6 bcm/y Timimoun (Sonatrach, Repsol and Total). Ahnet is foreseen to start by 2015, while Reggane Nord would start only by 2016, six years after the original starting date. It will add 2.9 bcm/y. Given the current climate, some delays have been included in this analysis for the start of the different fields. Furthermore, domestic demand keeps rising. According to demand forecasts for 2010-19 by Algeria's Commission de Régulation de l'Electricité et du Gaz (CREG), annual gas demand is expected to increase by 13 bcm over 2011-17 in the baseline scenario, which corresponds to the incremental gas production.

Figure 39 Algerian gas production is not growing as much as expected



Sources: Oxford Institute for Energy Studies (2011), companies' websites, IEA analysis.

Egypt continues to struggle

Notwithstanding the Arab Spring, upstream oil and gas operations were not substantially affected in Egypt. Only the exports towards Israel, Jordan, Syria and Lebanon were interrupted on several occasions. Despite pipeline interruptions, LNG exports continued to decline in 2011 with the gas redirected to the domestic market. But the challenges lie ahead, as the country faces a rapidly growing gas demand boosted by subsidies, while gas production struggles to keep pace. Over the past 20 years, the focus of the upstream industry has clearly been on gas, which is reflected by the five-fold increase of proven gas reserves between 1990 and 2010. However, proven reserves have increased only marginally since 2006. The capped price paid within PSAs is one of the main issues on the upstream side, but there seems to be light at the end of the tunnel. Indeed, BP and RWE/DEA recently negotiated new terms and a new gas price of USD 3/MBtu at an oil price floor of USD 50/bbl and USD 4.1/MBtu at USD 120/bbl. Moreover, BP is now to sell 100% of the gas, instead of 50% before (the rest going to the State).

Domestic gas prices are a contentious issue because they are controlled by the government and kept low. However, in 2008, prices were increased for energy-intensive users; but the government reversed during the economic crisis in 2009-10. It is now up to the new government to deal with this delicate issue of either increasing prices and disappointing its supporters or keeping them low and threatening new upstream developments. Additionally, some mature fields are declining, so that there is a need to develop new gas production. There are some stranded assets in Egypt, as well as untouched areas, notably the East Mediterranean area, which could very well prove as resource-rich as its Israeli counterpart. The problem is now to convert reserves to production capacity faster.

The West Nile Delta will be one of the largest sources for incremental gas in the medium term. Led by BP, this project focuses on the development of five fields (Giza, Fayoum, Raven, Taurus and Libra) by 2015, which will add some 10 bcm of new gas when they reach plateau. The projected initial capital investments exceed USD 13 billion. Shell and its partners holding the Alam El Shawish West concession expect production to start by 2013 and to bring 2 bcm from the Karam and Assil fields.

East Africa is the new Golden Coast

A new resource centre has been discovered, this time in the quite undeveloped region of East Africa. Until now, gas production and demand in this region were limited to some 6 bcm in Mozambique, South Africa and Tanzania, amounting to a mere 3% of Africa's gas production. Over the past three years, significant discoveries made in Mozambique and Tanzania have drawn the industry's attention to this particular region. Indeed, keeping track of the flurry of ongoing activities is challenging.

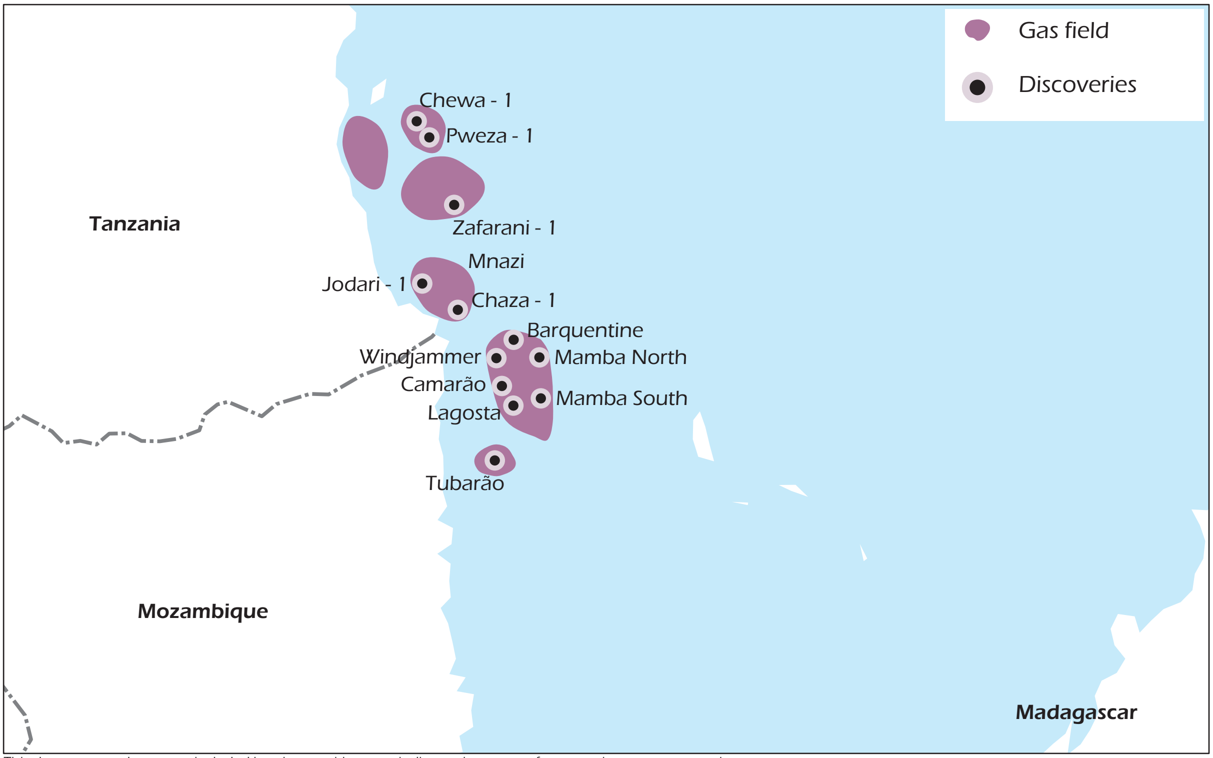
In Mozambique, ENI and Anadarko are the most active. ENI has been concentrating on the Mamba Complex, where it recently made another "giant" gas discovery in March 2012, assessing estimated gas in place at over 1.1 tcm (40 tcf). ENI has a 70% interest, while Galp, Kogas and ENH hold 10% each. While ENI is looking at selling 20% of its stake, Kogas, as well as IOCs such as BP and Shell, are also interested. Meanwhile, Anadarko made several discoveries: Windjammer, Lagosta, Barquentine, Tubarão and Camarão, which together could hold some 850 bcm (30 tcf) of recoverable gas in place.

In Tanzania, British Gas (BG) has been working with Ophyr on the discoveries of Chewa-1 Pweza-1, Chaza-1, Zafarani-1, and the recent discovery of Jodari-1, which brings total gas resources to 198 bcm

(7 tcf) of recoverable gas. Statoil also made a gas discovery (Zafarani-1 well in Block 2), which could hold up to 142 bcm (5 tcf) of gas in place. Wanting to capitalise on these, Tanzania is preparing a new 16-block deepwater licensing round, which could take place in September 2012.

Given the markets' thirst for gas (and LNG in particular), these resources, ideally located near the most LNG hungry markets in the world, are attracting high interest from various types of companies: from IOCs such as BG, Shell, Statoil, but also NOCs such as Chinese and Indian companies. Cove Energy, a project partner of Anadarko in these discoveries with an 8.5% share, is the subject of a bidding war between Shell and Asian companies such as ONGC Videsh, GAIL, and PTTEP, highlighting the interest in this new region. Mitsui, ENH, Bharat PetroResources and VideoCon also have stakes in Anardarko's offshore area. Given the absence of a demand centre in the area, and the remoteness of the closest one, South Africa, LNG appears as the best option to monetise the gas. ENI foresees gas coming from Mozambique by 2018, while Anadarko is looking at a two-train LNG plant (5 mtpa each), which could be expanded to six trains later, with an FID planned for late 2013 and first gas for late 2018/early 2019. In Tanzania, BG needs around 250 bcm (9 tcf) to start working on a two-train LNG export plant. One remaining question is to what extent the domestic market will benefit from these developments. So far, Tanzania's gas demand has been constrained by the lack of infrastructure. CNPC has given a USD 1 billion loan to the government to develop an 8 bcm pipeline by the end of 2013 to supply gas-fired plants. Additional supply will come from additional production from the Songo-Songo and Mzani fields.

Map 3 The new Golden Coast



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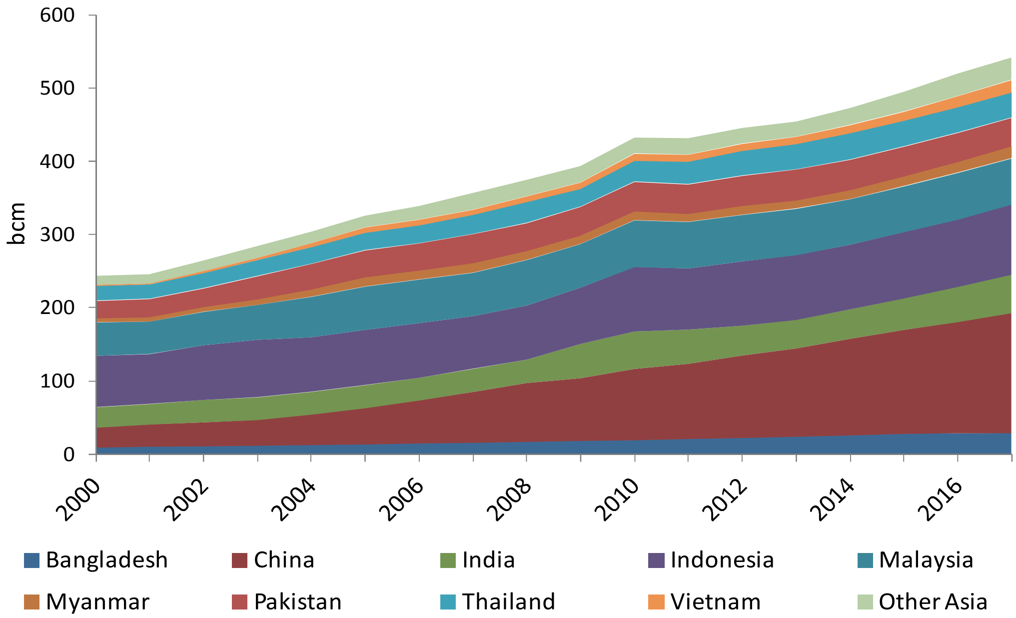
Asia

Asian gas demand (including China) is deemed to be the fastest growing compared to other regions, increasing by 210 bcm over 2011-17. Therefore, there are clear incentives to develop domestic gas production rapidly; however, this strategy clashes with domestic prices maintained at low levels, often too low to incentivise incremental gas production, while domestic gas users would struggle to absorb higher gas prices. Gas production is increasing in most Asian countries, albeit at very different rates. Overall, Asian gas production is expected to increase from 431 bcm in 2011 to 542 bcm in 2017, an increase of over 110 bcm.

Figure 40 Gas production in Asia, 2000-17



Most of this growth (60%) comes from China, while Indonesia, India, Vietnam, Thailand and Myanmar will have small increases. In the case of India, production will first experience a significant drop before reclaiming its peak level in 2010. Gas production in Brunei is projected to decline slightly in the medium term, which will have an impact on its LNG exports; its long-term contract with Japan has indeed been considerably reduced for the ten years to come. Malaysia is expected to keep relatively stable gas production. Finally, Papua New Guinea will start producing by end-2014, when its new LNG export plant comes on line.

China: a wide range of outcomes

Among all Asian countries, Chinese gas production is increasing the fastest, although it is still insufficient to keep up with demand increasing at 13% per year. Gas output has been clearly slowing down, from a pre-2008 level of 18% per year to 5-7% per year over 2008-11. Since 2009, the gap between domestic production and demand has therefore increased, resulting in imports expanding from 8 bcm in 2009 to an estimated 31 bcm in 2011. However, domestic production will remain the backbone of gas supply to the Chinese gas market. There is considerable uncertainty over future domestic production growth, especially regarding unconventional gas supplies, which so far have failed to materialise.

Production is projected to reach 141 bcm by 2015 and 163 bcm by 2017, from an estimated 102 bcm in 2011, but outcomes could vary widely depending on prices, pricing reform, and access to and development of the infrastructure. Should the developments of CBM remain modest and shale gas remain well below targets because of a combination of lack of pipeline infrastructure and slow reform of prices (see Box 5), Chinese domestic gas production would remain much lower. If these challenges are tackled and if shale gas takes off, higher production levels could be reached, although for shale gas, the growth would start to matter significantly towards 2020. In the medium term, gas production is expected to increase at a slower rate than demand.

Box 5 China's pricing reform

Among some proposals to tackle the pricing issue (see the Demand chapter), increasing the ex-plant price by CNY 1.5/m^3 compared to the current average of CNY 1.15/m^3, was suggested, but not advanced. At end December 2011, the NDRC announced the start of a pricing reform in Guangdong and Guangxi, but this reform is actually different as the system is based on a netback approach rather than a cost-plus approach. The reform is so far limited to these two regions. Guangdong is a relatively large consuming area with over 10 bcm consumption, while Guangxi is a small market with a demand of less than 1 bcm. Guangdong sources its gas from offshore domestic production, LNG and started receiving Turkmen gas through the second West-east pipeline at end-2011.

Under the new system, city-gate prices would be linked 60% to fuel oil and 40% to LPG. These linkages reflect the competitors of gas in the industry and household sector, but fail to take into account the competition against coal. These prices are Shanghai customs data, raising the question of when the reform would reach this market. The formula takes calorific differences into account and includes a 10% discount to promote gas use. The system plans for an annual increase in a first stage before moving progressively to quarterly changes. Although this change is not expected to result in a price increase in the short term (prices in these two regions are already among the highest in China), it should ultimately result in price increases when the first change occurs. Monopolistic activities should remain regulated.

Such a reform raises questions on how fast it will be expanded to other regions, how quickly there will be a move towards quarterly price changes and how high the regulated price will have to be to allow for a desired level supply-side delivery and competition. The ultimate goal is to liberalise ex-plant prices and pave the way for the development of unconventional gas based on market prices. This implies moving the reform to regions depending more on domestic supply. Additionally, given that the netback approach covers the cost of producing and bringing gas to the market, defining a price for transportation for third parties will become imperative in order for them to earn the appropriate revenues from their gas. Finally, the reform does not define the level of end-user prices, but encourages establishing upstream and downstream mechanism through public hearings. This is imperative to avoid local distribution companies getting squeezed by having to purchase more expensive gas while being unable to pass through the cost increase. The Guangdong and Guangxi Price Bureaus supervise the local sales prices and should explore and establish a stepwise gas tariff.

The three NOCs – CNPC, CNOOC and Sinopec – dominate the upstream sector and the situation seems unlikely to change appreciably in the medium term. These companies will therefore be the main drivers behind China's growth in gas production over 2011-17. Indeed, most licenses for oil and gas exploration have been allocated to them. As the threshold for exploration to be performed in order to keep the license is low, thereby preventing new entries, other companies have few chances to get these licenses through relinquishment. Consequently, there is little room left for independent Chinese and foreign companies, whose involvement so far has been mostly through partnerships and joint ventures with the big three. Either IOCs team up with small companies with which they have a voice, in which case, the projects may not go forward as these small companies have little influence, or they go with the big three with which they have no say.

CNPC currently accounts for around 75% of total gas production in China and plans to increase production to 120 bcm by 2015. Foreign participation is nevertheless welcome for fields requiring technological capabilities such as tight gas fields, or more recently, other unconventional gas fields such as CBM and shale gas. To change this would require modifying the relevant laws, such as enhancing the mining right withdrawal system, so that compulsory withdrawal is required for enterprises which have the mining right, but fail to meet the investment requirements or to achieve the output within the prescribed time limit. CNOOC currently has exclusive rights to conclude PSCs with foreign companies for offshore developments. However, cooperation in the onshore area is mostly through CNPC and Sinopec.

There are already significant volumes of tight gas (30% of current gas production) produced in China, but other unconventional gas types – CBM and shale gas – are so far relatively untested. Despite official targets displayed in the 12th FYP, there is still much uncertainty on whether these levels could be reached by 2015. To reach these targets, China will need to overcome issues such as new pipeline infrastructure or access to pipelines for CBM producers so that large quantities of CBM can reach coastal markets. Shale gas production/exploration is not expected to be significant by 2015, as the first tender was launched only in 2011 and it will face exactly the same necessities of acquiring pipeline access, in addition to finding the best shale gas-producing spots and overcome technological challenges to produce this new resource. Since CBM development was well below targets, the same could happen with shale gas.

India

Less than two years ago, the future seemed to be smiling for Indian gas production; the recently started Krishna Godavari field quickly ramped up production between April 2009 and mid-2010, exceeding even the planned forecasts. The field was expected to double Indian gas production from 30 bcm to 60 bcm. Indeed, Indian gas production reached 51 bcm in 2010. Since mid-2011, it has become clear that this objective is fading away as the field's production has dropped due to water entering the wells, from the planned 30 bcm/y to 14 bcm/y as of early 2012. Indian gas output consequently decreased by an estimated 9% in 2011. The field's production is expected to decline even further by another 25% by April 2013, reaching 10 bcm/y and staying relatively stable at these levels in 2014.

The entrance of BP into the field's shareholding could help solve technical issues, and reverse the trend but India's gas production is now unlikely to reach 60 bcm/y any time soon, as the development of new gas fields will take time. Indian gas production is expected to reach around 40 bcm by 2012 and remain stable before exceeding 2010 levels by 2017 as new fields come on line. The decision in mid-2010 to increase the Administrative Price Mechanism was a good sign for NOCs such as ONGC, but investments will take time to translate into new fields starting production, so that a reverse in production can only be expected in 2015. In early 2012, the government approved Reliance Industries' plan to produce around 4 bcm/y from KG-D6's satellite fields.

India has been looking with great hope at CBM and potentially at shale gas. So far, after the fourth CBM round, the production is barely noticeable at some million cubic meters. Shale gas production is still a relatively distant goal, as resources are still poorly evaluated. India faces several challenges, including many unexplored areas, the need to develop the transmission network to connect new regions such as the east and the south, as well as the potential new production areas. A stable regulatory and investment framework is also necessary. The decision of the state to have the sole right to decide on volumes and PSC's prices is probably not a good signal to send to foreign investors.

Latin America

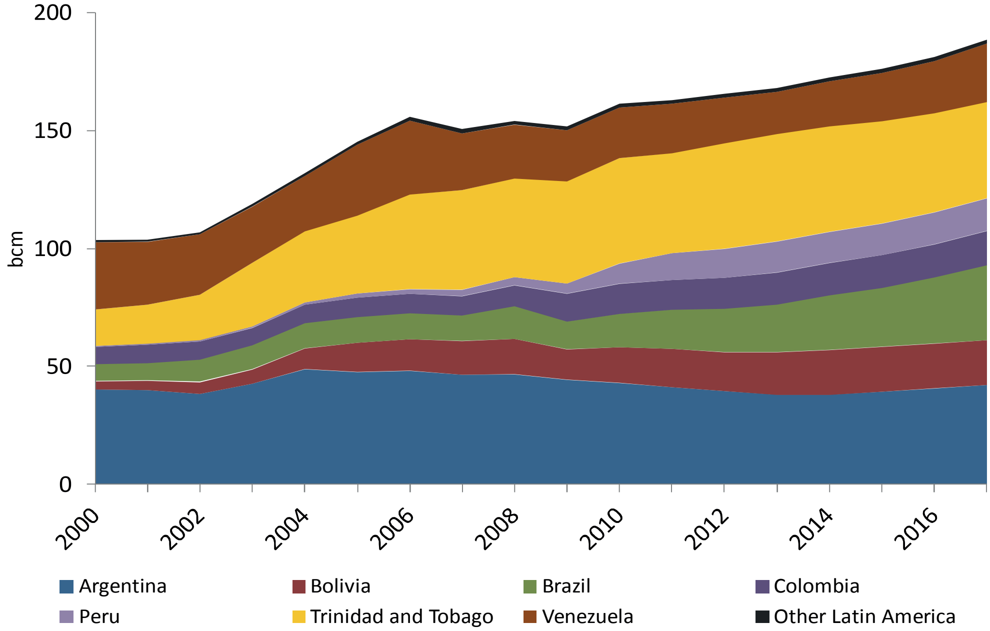
The outlook is not particularly bright for Latin American gas production, if one excludes Brazil from the picture. Argentina, Bolivia and Venezuela may have significant gas reserves, but so far they have all failed to reach their respective production targets, and in the case of Argentina and Venezuela, gas production has actually been declining over the past five years. Overall, Latin American gas production is expected to increase from 164 bcm in 2011 to 189 bcm by 2017. The bulk of this growth (62%) will come from Brazil, with some modest production growth in Bolivia, Colombia, and Peru while gas production in other countries, notably Argentina and Trinidad and Tobago is dwindling.

This is the case in Argentina, due to the decline of mature gas fields, combined with low investments. Argentina's Federal Organisation of Hydrocarbon Producing States (OFEPHI) recently required companies to increase production by 15% over the next two years, with measures taken in case of non-compliance. Particular pressure was put on YPF in early 2012, and its licenses were revoked in several provinces, including Neuquén, Río Negro, Santa Cruz, Chubut, Mendoza and Salta provinces. As of April 2012, YPF, Petrobras, Tecpetrol and Argenta Argentina had also lost some license areas, because they failed to increase production. The government also announced the nationalisation of 51% of Repsol's subsidiary YPF.

This 15% production increase target seems overly optimistic as green fields can rarely be put in production in such a short timeframe. Recent studies have indeed shown that Argentina could be a significant holder of shale and tight gas resources; significant discoveries have been made over the past two years, notably in the Neuquén basin (see section on unconventional gas). This may have actually led the government, worried about Argentina's gas production decline, to think that these resources could be readily available. However, the US example has demonstrated that such development takes time. The real question is what needs to be changed in the investment framework to make the development of shale gas a reality for the end of this decade. In the medium term, production is expected to continue to decline as investors need a clear pricing signal and stable regulatory environment, so that recent measures could actually prove counterproductive.

Brazil is expected to be the fastest growing producer in Latin America, with gas production increasing from 16.7 bcm to 32 bcm by 2017. The Ministry of Mines and Energy foresees raw gas production (which includes a large part of reinjected gas) more than doubling from 33 bcm in 2011 to 88 bcm by 2020. Petrobras, currently the largest producer of natural gas in Brazil, has an ambitious development plan for the upstream business, particularly for oil in pre-salt fields. The E&P segment will invest USD 118 billion in Brazil. Two-thirds will be for production development, and the rest equally split between exploration and infrastructure. The pre-salt areas will absorb 45% of the total E&P investment in Brazil, resulting in an increase in oil production by almost 134% over 2011-20, according to Petrobras. Part of the gas production will be reinjected to enhance oil production. Petrobras started producing gas from the Lula field and a 3 bcm/y pipeline was completed to Mexilhão. So far, plans to build a floating liquefaction plant to serve the domestic or regional market seem to be pushed back to the next decade, probably in order to profit from the experience of the Shell's Australian Prelude floating LNG project.

Figure 41 Gas production in Latin America, 2000-17



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TRADE

Summary

- The global trade balance is visibly shifting to Asia, which is now attracting increasing flows of LNG and pipeline gas, even if OECD Europe remains by far the largest gas importer. While global LNG trade increased by 9% to reach 327 bcm in 2011, most of the incremental LNG supplies were absorbed by Asian markets, notably Japan, which needed to import more LNG following the Fukushima accident, but also by China and India. China is also attracting increasing volumes of pipeline gas from Turkmenistan; these imports almost quadrupled compared to 2010 levels.
- Even if global LNG trade slowed down compared to the 21% increase observed in 2010, it was still increasing faster than global gas demand. The reason behind this slower growth is that only one liquefaction plant came online in 2011.
- In the medium term, global gas trade increases by 35% over 2011-17, driven by both pipeline gas and LNG. Markets will become increasingly tighter until mid-2014, as only 25 bcm out of a total liquefaction capacity of 114 bcm under construction as of late April 2012 is planned to come online over 2012-13. The second wave of new LNG export capacity will start at end-2014, but many plants are expected to start later than originally planned due to a combination of workforce shortages and infrastructure bottlenecks. Global LNG trade grows by 31%, reaching 426 bcm by 2017. Australia will be the main contributor to this growth, along with North America, where LNG export plants are projected to start in 2015. Meanwhile, pipeline trade will increase by 41%, with higher deliveries from the FSU region projected to Europe and China.
- There is considerable uncertainty about where the next generation of LNG export plants beyond those under construction will be located, as there is fierce competition among the 650 bcm of projects currently planned. However, Cheniere's Sabine Pass project in the United States is likely to move forward after gaining the authorisation from the FERC in April 2012. Canada, which has been looking for outlets for its stranded gas, is also a likely candidate. Projects are actively discussed in Australia, Russia, Nigeria, as well as in a few South Asian and West African countries, and much attraction is focussed on the new frontier, namely Tanzania and Mozambique.
- Significant import infrastructure will be necessary in order to meet additional import requirements. As of early 2012, 121 bcm of LNG import capacity are under construction, while the 12 bcm China-Myanmar pipeline is being built and the CAGP from Central Asia to China and Nord Stream pipeline from Russian to Germany are being expanded. The bulk of the new LNG import terminals will be located in China and India, but also in many South Asian countries.
- Regional gas prices continued to drift further apart, with HH gas prices reaching their lowest level in ten years, while European gas prices stabilised at between USD 8 and USD 10/MBtu and Japanese imports prices peaked at USD 17/MBtu in late 2011. Regional prices are increasingly determined by their respective regional dynamics. In Europe, gas prices remain influenced by oil price movements, despite a weaker correlation between them. Notwithstanding the increasing LNG volumes available on global markets, a global gas price did not occur, and North America is expected to remain disconnected from other regional markets over the medium term.
- Volumes traded on European spot markets continued to increase in 2011, with physical volumes traded on the European continent increasing by 8% to reach 162 bcm, while traded volumes jumped by around a third to 542 bcm. Such an expansion was driven by the spread between oil-indexed prices and spot prices, as well as regulatory developments which facilitated gas trading. Despite these positive developments, the NBP remains the only truly liquid spot market.

Recent trends

After the massive increase in trade observed in 2010, global gas trade rose moderately in 2011. Trends observed in the past years have been reaffirmed: OECD Europe remains by far the largest importer of natural gas ahead of OECD Asia Oceania, despite a drop in European imports from 2010. The global trade balance is visibly shifting to Asia, which is now not only attracting increasing flows of LNG, but also of pipeline gas. Global LNG trade increased by 9.4% to reach 327 bcm and the bulk of these additional supplies went to the hungry Asian markets. Turkmen exports to China surged as the Central Asia Gas Pipeline was expanded, and represented some 10% of total Chinese gas consumption. The same pattern was observed in OECD Asia Oceania, as Japan needed to import more LNG following the Fukushima accident. Meanwhile, the United States reaffirmed its relative independence from global markets as LNG imports dropped even further to less than 10 bcm.

Other regions are net exporters. The Former Soviet Union region is by far the largest exporter, mostly of pipeline gas to Europe, and the reminder to Asia and the Middle East, while Russian LNG is entirely exported to Asia. Non-OECD Asian imports (excluding China) increased markedly, driven by the demand surge in India due to declining domestic gas production; nevertheless, the non-OECD Asian region remains a net exporting region thanks to Indonesia, Malaysia and Brunei. Latin America and the Middle East present even more mixed situations. LNG imports increased in Chile and Argentina but collapsed in Brazil, which resulted in a small increase of regional LNG imports; Latin American LNG exports were boosted by Peru's LNG plant reaching plateau. The Middle East became the largest LNG exporter – 95% of additional LNG supply in 2011 came from this region, with two-thirds from Qatar alone – but it also faces increasing LNG import needs, while pipeline imports fell following the bombings of the AGP. Africa suffered from lower pipeline exports from Libya and Egypt that a slight increase in LNG exports failed to compensate.

Table 13 Net imports by region, 2011 compared to 2010 (bcm)

	2010	2011
OECD Europe	270	247
OECD Asia Oceania	134	151
China	14	31
OECD Americas	24	-1
Non-OECD Europe	16	17
Latin America	-25	-25
Asia (excl. China)	-46	-38
Middle East	-106	-127
Africa	-106	-93
Former Soviet Union	-152	-175

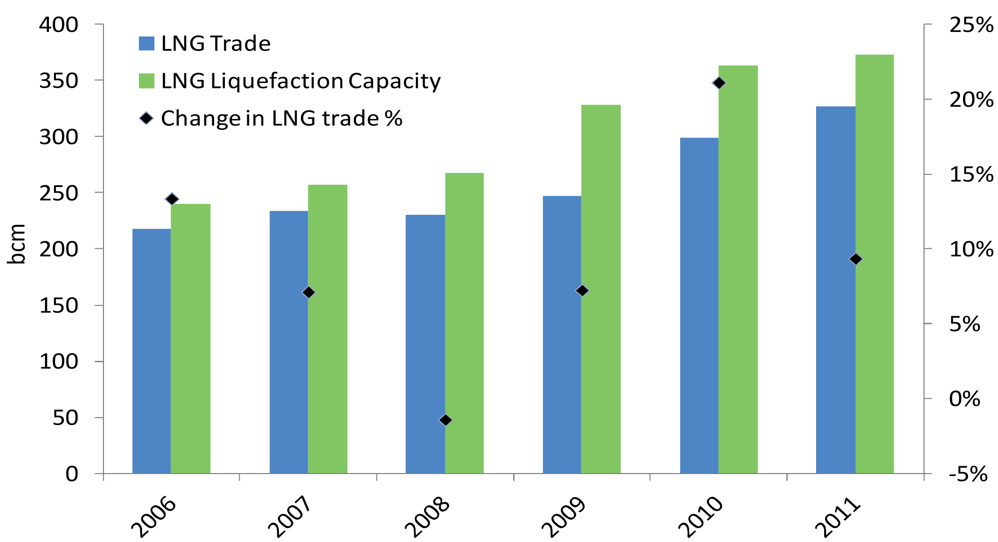
Notes: Data for 2011 are estimated. Net imports are the difference between domestic production and demand, and include storage variations.

The relatively modest expansion of global gas trade is a consequence of a limited increase in global LNG and pipeline infrastructure which occurred in 2011, although this broad statement needs to be qualified. LNG liquefaction capacity increased by only 10.5 bcm, or 2.9%, to reach 373 bcm. However, LNG regasification capacity increased by 82 bcm or 10.4%, so that global regasification capacity amounted to around 870 bcm as of end-2011, which is 2.3 times the global liquefaction capacity. Not only did LNG import capacity increase impressively, but it also enabled new countries such as the Netherlands and Thailand to join the club of LNG importers, while future major LNG importers such as China reinforced their LNG import capacity. But half of the new LNG import capacity originates from an expected country (considering its recent history): the United States. Meanwhile, two new pipelines started in Europe: Medgaz from Algeria to Spain and Nord Stream from Russia to Germany; and the Central Asia Gas Pipeline to China was expanded to 30 bcm.

LNG markets: a healthy growth

Global LNG demand grew by 9.4% to reach 327 bcm (240 mtpa) in 2011, which translates into a global utilisation rate of LNG export capacity of 88%. The remaining 12% is due to outages, feedgas issues, maintenance or LNG plants reaching plateau, so that there is in practice very little spare capacity. Although LNG trade growth slowed down compared to the record increase of 21% in 2010, it is still increasing faster than global gas demand, as it is supported both by new liquefaction plants that started in 2010-11 and growing Asian import needs. These higher LNG imports in Asia compensate for the decline in North American LNG imports, which is a reflection of the US unconventional gas production surge, as well as of stable European LNG imports. This stability is quite remarkable considering the collapse of European demand and of import requirements. Although North America withdrew from global LNG markets, these continue to globalise even further; two new countries started importing LNG, namely Thailand (Map Ta Phut terminal) and the Netherlands (GATE terminal). A single liquefaction plant (Qatargas IV, 10.5 bcm/y) came online in 2011, contributing to the smallest growth in global liquefaction capacity observed in the last five years. Indeed, Qatar's last mega train started operations in February 2011, reinforcing the country's position as the largest LNG producer in the world: Qatar represented 30% of global LNG trade in 2011 and 28% of global LNG export capacity (105 bcm/y as of end-2011). Meanwhile, Australia's Pluto LNG again delayed its completion to May 2012.

Figure 42 LNG trade growth, 2006-11



Note: LNG liquefaction capacity at the end of the year.

Full steam ahead towards the high-priced, booming LNG Asian markets

Asia (including both OECD Asia Oceania and non-OECD Asia) continues to be the most rapidly growing LNG market, with 206 bcm imported in 2011 (63% of global LNG trade). In fact, 86% (24 bcm) of the 28 bcm increase of LNG trade in 2011 targeted Asia. The 12 bcm increase from Japan was driven by the progressive shut-down of nuclear power plants and subsequent replacement by gas-fired plants. Although there is still a growing uncertainty on whether and which nuclear power plants would restart in 2012 in Japan, one can expect that the country would still need more LNG in 2012 than in 2011, as no nuclear power plant is operating as of early May 2012. Korea, China and India also increased LNG imports by between 3 to 5 bcm respectively in 2011. In particular, China, supported by two new regasification terminals and one expansion in 2011, imported 16.6 bcm, highlighting the country's thirst for LNG.

Europe remains the second largest LNG market with 88 bcm imported in 2011, 0.3 bcm less than in 2010. The United Kingdom became the largest European LNG consumer – almost 25 bcm imported or a 30% increase from 2010 – as it became an important outlet for new Qatari LNG exports looking for a market. Spain, Belgium, Turkey and France imported between 15% and 21% less than in 2010. The 4 bcm drop in Spain was not only driven by a 2 bcm drop in demand, but also by new pipeline deliveries from the Medgaz pipeline. Imports in the Middle East and Latin America, two emerging LNG markets, also grew moderately. Argentina's LNG imports more than tripled in 2011 as a new floating regasification and storage unit (FSRU) started commercial operations in 2011, whereas Brazil's LNG imports dropped by three quarters due to higher hydro generation. US LNG imports dropped below the 10 bcm line; in contrast, Canada and Mexico imported roughly 1 bcm more than in 2010, thereby resulting in a small increase of North America's LNG imports.

Table 14 LNG trade in 2011 (physical flows, preliminary figures in bcm)

	Exporter				
Importer	Asia Pacific	Middle East	Atlantic	Total 2011 (*2010*)	Share
Asia	114	72	19	206 (*182*)	63%
Middle East	0	3.6	0.5	4 (*3*)	1%
Europe	2.2	42	43	88 (*88*)	27%
Latin America	1.3	2	6	10 (*7*)	3%
North America	1	9	10	20 (*20*)	6%
Total 2011 (*2010*)	119 (*116*)	129 (*103*)	79 (*81*)	327 (*299*)	
Share	36%	39%	25%		

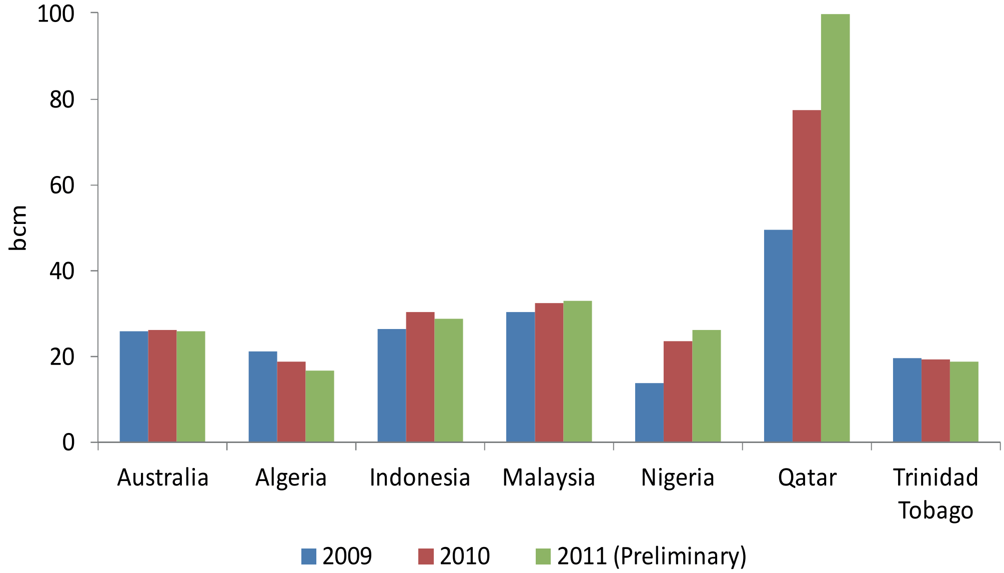
Note: Asia Pacific exporters include Australia, Brunei, Indonesia, Malaysia, Peru, Russia and the United States (Alaska). Middle East includes Abu Dhabi, Oman, Qatar, and Yemen. The Atlantic basin includes Algeria, Egypt, Equatorial Guinea, Libya, Nigeria, and Norway.

The Middle East is now the largest LNG supplier

Although LNG markets tightened, there was sufficient supply throughout 2011. The largest LNG supply increase was observed in the Middle East, which actually satisfied alone 95% of the incremental global LNG demand in 2011. For the first time, the region became the largest LNG supplier in the world, ahead of Asia Pacific. In particular, Qatar exported almost 100 bcm, a 29% increase (22 bcm) from 2010. A look at the evolution of LNG exports of the top seven producers over the last three years shows clearly how Qatar alone has supported the growth of global LNG demand through its massive expansion, while the other major LNG exporters have been either stable or declining. Despite some unrest, Yemen's two trains reached plateau in 2011, exporting 9 bcm.

In the Asia Pacific region, Indonesia, a traditional LNG supplier, reduced LNG exports by 5.5% due to its growing domestic gas demand. However, LNG exports from the other Asian Pacific countries increased slightly and contributed to the moderate export increase of the region, which rose to 119 bcm in 2011. Exports from the Atlantic region were stable, although LNG exports from Algeria, Libya, Egypt and Norway fell by between 0.5 bcm and 2 bcm, due either to feedgas supply issues, civil war in Libya, preference for the domestic market or the temporary shutdown of the Snøhvit LNG. However, higher LNG exports from Nigeria and Equatorial Guinea compensated for these drops.

Figure 43 LNG exports of the top seven LNG producers from 2009 to 2011

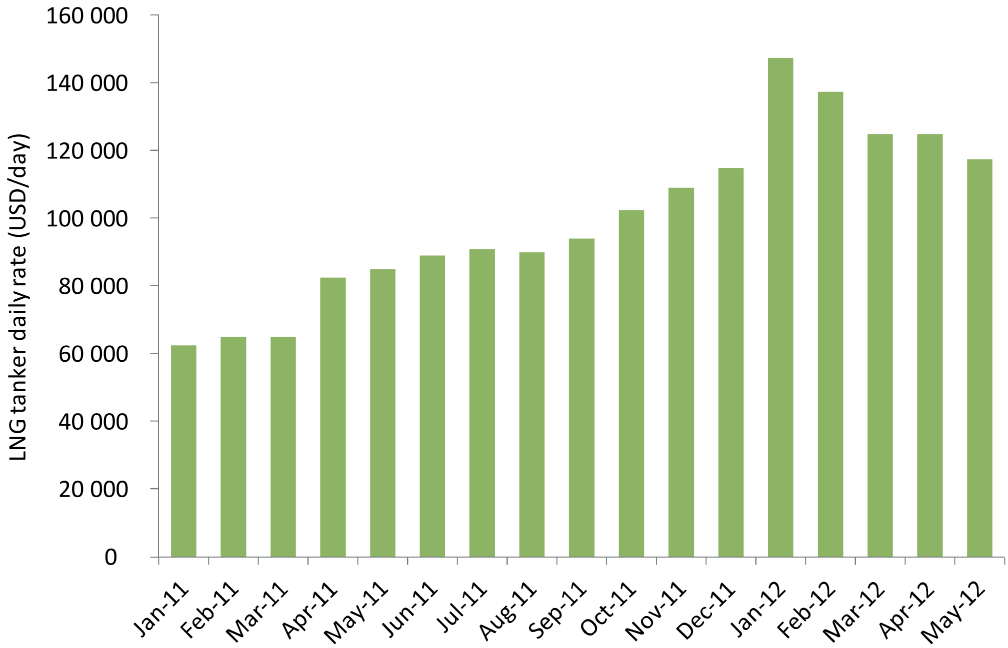


Qatar has been looking for an outlet for its new LNG exports, as the US market, to which Qatar initially intended to send roughly a third of its additional LNG supplies (some 20-25 bcm), was already oversupplied even before the new mega-trains had been completed. In other words, because a planned key market did not materialise, Qatar has been rigorously marketing LNG in the high-priced Asian market as the new outlet for its LNG. The unexpected demand surge in Japan after the Fukushima disaster helped absorb Qatari LNG, while China, India, Korea and Chinese Taipei also steadily increased imports from Qatar. But even if non-OECD Asian imports increased from 37 bcm to around 48 bcm in 2011, this was hardly sufficient to absorb all the incremental Qatari LNG. Even though, in theory, Asian LNG imports grew more than Qatari LNG supplies, there was competition to supply these high-priced markets from the new LNG suppliers of Yemen and Peru, as well as Atlantic LNG suppliers looking for alternative markets – Nigeria, Trinidad and Tobago, and even Norway. Qatar also increased its deliveries to Europe, benefitting from its regasification capacity in both the European market (South Hook in the United Kingdom, Adriatic LNG in Italy) and, quite surprisingly, in the US market (Golden Pass terminal). Italian and UK imports of Qatari LNG reached 27 bcm out of 40 bcm exported to Europe. Meanwhile, the United States imported 2.6 bcm from Qatar, twice as much as in 2010. Although Qatar's strategy of holding regasification capacity at multiple terminals in the European and US markets was originally designed to take advantage of arbitrage opportunities between these regional markets, it could also be a way to dispose of new LNG supplies for which the cost of production is low due to associated NGLs production, and to avoid flooding the Asian LNG market, where Qatar sold its spot LNG at high prices in late 2011.

Shipping is the main constraint in the LNG value chain

As of early 2012, there were 380 LNG tankers operating worldwide, while another 70 were under construction. The daily chartering rate of LNG tankers has been skyrocketing, indicative of the shortage of spare tanker capacity. In January 2011, the daily charter rate of an LNG tanker in the market was over USD 60 000/day. The rate usually follows seasonal demand patterns of the main markets, coming down during summer and going up again in the winter. However, 2011 saw a very unusual trend, particularly after the Fukushima disaster in March. The rate kept rising, reaching over USD 90 000/day in summer 2011 and USD 150 000/day in winter 2011/12. The rise was mainly driven by the higher spot LNG demand in Asia after the accident in Japan, which led to an increasing average transportation distance for LNG. Whereas the rise in LNG spot price slowed toward end-2011, market players were eager to secure near-term LNG tanker capacity in preparation for the foreseeable tight freight market in 2012, pushing up the daily rate to record levels in January 2012. While the rates have come down in early 2012, concerns over potential geopolitical developments or higher Asian spot LNG demand could push the daily rates up again.

Figure 44 LNG tanker daily rate, January 2011-May 2012



Marketing activities accelerate as markets tighten

Is there a return to a seller's market? The quite feverish LNG marketing activity that took place over the past few months may lead analysts to think that way. The recent tightening of global gas markets added to considerable uncertainty over the future evolution of LNG markets, both from the production and the demand sides, notwithstanding uncertainties about pricing mechanisms. Will China be able to absorb all its contracted LNG? What will be the future import needs in Japan? Will Australian LNG be on time? Can the current price spread between Asia and Europe be sustained? Will North America start exporting and undercut existing and future LNG exporters? These are among the key questions which LNG market players are considering.

Quite a few LNG supply contracts were agreed in 2011, particularly from the Australian projects having reached FID. Looking at the LNG that will come online over 2012-17 (based on projects having reached FID), around 81% of the volumes are contracted on a long-term basis. This includes Angolan

LNG, originally contracted for the US market, which is likely to be diverted from the original US target. Meanwhile, Algerian LNG does not have any long-term contract and is likely to be looking for the high-priced market to the extent that shipping capacity allows it. Less than 10 bcm of the LNG coming post-2014, such as part of Wheatstone in Australia, is still not contracted.

Figure 45 New LNG supplies are almost entirely contracted

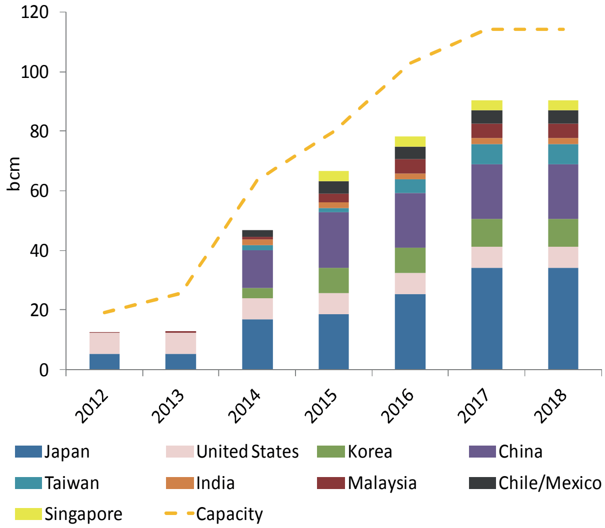
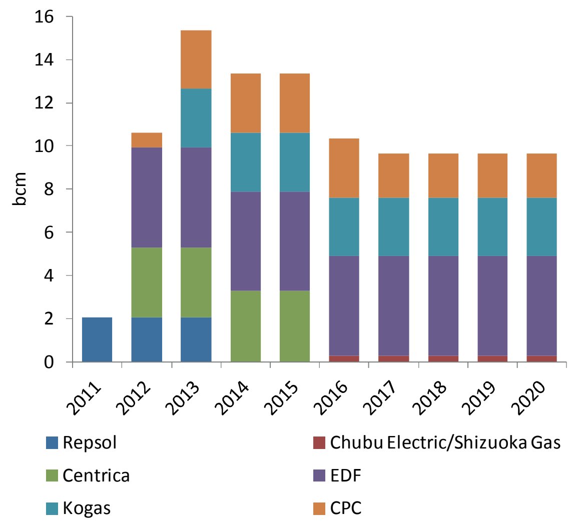


Figure 46 Qatar's new SPAs since end-2010



Meanwhile, existing suppliers were also active, notably Qatar, which had to replace the now self-sufficient US gas market. While it concluded some MOUs after the 2009 oversupply, Qatar failed to finalise many of them until recently as it continued to base prices on oil indexation. However, Qatar managed to finalise four sales and purchase agreements (SPAs) with five companies over the past 15 months, as well as extending EDF Trading's LNG contract. Most contracts are actually long-term contracts, with the exception of those with Centrica and Repsol. These volumes are slightly below the quantities originally earmarked for the United States, although some of Shell's LNG is thought to be going to China. This leaves 20 bcm to market, minus the quantities going to the US Golden Pass terminal. Additionally, MOUs with countries such as India, Malaysia and Argentina are still under discussion. As these new contracts will represent some 10 bcm post-2015 (see Figure 46), this still leaves some flexible spot LNG for the markets, taking a bet on whether spot prices would crash under the new Australian LNG wave arriving to the markets by 2015 or whether delays, combined with surging demand, will send spot LNG prices upwards again. In addition, most of the LNG in the portfolio of international oil companies is flexible and could be redirected to spot markets if market conditions make it profitable.

Two sets of supply contracts attracted much attention from the LNG market. One could lead the United States to export LNG (see section on investments in infrastructure). Another set of interesting contracts is the MOUs between Gazprom and four Indian companies, namely Petronet, Gail, GSPC and Indian Oil Company. Each of them signed a 25-year LNG supply contract of 3.4 bcm/y with Gazprom, starting from the 2016-18 timeframe. These contracts obviously underline the Indian appetite for LNG. Although Gazprom has not explicitly specified the supply source of these LNG deals, it could be either the Shtokman or Novatek LNG projects currently under consideration, although it seems quite unlikely that these projects would be online even by 2018. Otherwise, taking into consideration the remote distance from those projects to Indian terminals, Gazprom may have a swap deal with other LNG suppliers such as Qatar. Thus, Gazprom supplies pipeline gas to Qatar's European customers while Qatar supplies Gazprom's Indian customers in return, each of them taking the maximum advantage of their geographical position.

Box 6 The importance of Qatar for security of global gas supply

The conventional crisis scenario for gas supply security policy, especially in Europe, is a disruption of pipeline supplies, or alternatively, a major field stopping production. In this case, LNG is usually presumed to be available, sometimes at a higher cost, from one of the many LNG producers. Unlike pipeline supplies, LNG is technically flexible and can be re-directed relatively easily. LNG disruptions in the past have been small compared to global LNG trade, and therefore have had a limited impact. The rapid expansion of global LNG liquefaction capacity since 2009 has also reinforced this impression of availability. However, the very same growth hides the fact that global LNG trade, which now represents 9% of global gas demand, has become very dependent on one single gas producer, Qatar, which provided 30% of LNG trade in 2011. A 9% global share masks wide regional differences, as gas markets are considerably less globalised than oil markets. A substantial proportion of global gas demand comes from North America, the Former Soviet Union and several Middle Eastern countries, which have no or negligible reliance on LNG. Some Latin American countries have to import limited amounts of LNG. Europe and, to a lesser but growing extent, China are the only major regions where meaningful competition and substitution between LNG and pipeline gas takes place. However, Japan, Korea, Chinese Taipei and India rely entirely on LNG for their gas imports. Consequently, any event leading to a loss of Qatari LNG supplies could lead to more regional, but severe, effects on energy security.

LNG markets have profoundly changed over the last decade as markets globalised (with the notable exception of North America, which is now disconnected). Flexibility derived from spot and short-term trading became a key feature of global LNG markets. Qatar is the most visible example of this new trend, with large volumes initially earmarked for the United Kingdom and the United States. Due to its geographical position, its strategy on investments along the gas value chain and contracts signed with many countries and companies, Qatar has a unique ability to arbitrage between different regions.

Replacing missing Qatari LNG supplies would be challenging and could have an exacerbated impact on gas prices as markets are already tight. This can be achieved through different options: domestic production increase, notably in North America, Latin America, and possibly in China; alternative pipeline and LNG supplies; fuel switching in the power sector and diversion of supplies from other LNG importing countries. Depending on the timing and length of the disruption, underground and LNG storage could also provide alternative supplies.

There is currently little spare LNG production capacity in the world, as LNG producers tend to produce as much as they can. Therefore, other measures must be employed if there was a disruption. The key challenge would arise in countries entirely dependent on LNG – Japan, Korea, Chinese Taipei, and India. These countries imported an estimated 45 bcm from Qatar in 2011, almost half of Qatar's LNG exports. In Japan as well as in India, the electricity system is operating very near its capacity constraint. This unavoidably limits fuel switching capability, since all power generation capacities are needed to serve power demand. Consequently, these countries must either divert LNG from other markets, *i.e.* mostly from Europe, or interrupt some users, especially in industry through interruptible contracts.

Given the strong growth of its production, the United States could stop importing LNG or re-export all the non-Qatari LNG received (around 7 bcm in 2011). The United States also has a very large potential to switch back to coal from gas in power generation. However, until North America develops an LNG export infrastructure, any adjustment contribution would have to come from reducing LNG imports.

Box 6 The Importance of Qatar for security of global gas supply (continued)

European countries would be able to mitigate the loss of their own LNG supplies (an estimated 41 bcm in 2011) either by switching to coal (assuming a strong gas price reaction) or by depending more heavily on Russian pipeline gas (additional North African gas supplies are limited). Europe would need to reduce gas demand by much more than the volume of Qatari LNG it imports, since redirecting other LNG sources contracted for Europe would be the only feasible option to supply the Asia Pacific region. With the North Stream pipeline operational, Russia's export infrastructure to Europe has sufficient excess capacity. The ability of Russian domestic upstream to ramp up both production and domestic pipeline infrastructure in Russia is likely to be the main constraint.

Meanwhile, Europe has substantial excess capacity of conventional thermal generation due to the combination of weak demand and strong growth of renewables. Coal-fired plants produced 850 TWh of electricity in 2010, implying that they were used at around 4 000 hours. While coal plants could run base load without any difficulty, the key constraint would be the ramp up ability of coal mining in countries that have sufficient export infrastructure – mainly Australia, the United States, Indonesia and Russia. Coal-fired generation could therefore be increased by around 320 TWh by burning 130 million tonnes more coal and extending the utilisation of an average coal plant by around 600 hours a year, without encountering too many constraints on the coal infrastructure side. Accordingly, Europe would be able to free around 65 bcm of gas, at the expense of a substantial increase in CO_2 emissions. Together with increased Russian and possibly Norwegian or Algerian deliveries, this would enable Europe to redirect most of its contracted LNG imports to the Asia-Pacific region. However, such a solution would be contingent on the industry having enough LNG carriers to adapt to a massive switch to Asia.

More importantly, the timing and duration of a potential disruption are crucial. A disruption of a week, a month or more would have different consequences on global gas markets and call for different types of responses. A disruption in late January-early February usually comes at a time when storage is relatively empty at the 50-55% filling rate (the year 2012 being an exception). Demand in Asia is also traditionally higher during this period. This has an impact on the deliverability of storage facilities, which decreases with the volume of gas left in the facility. Should it happen in spring or summer and last for a couple of months, this could affect the refilling of underground gas storages, notably in Europe, where storage refilling depends greatly on gas imports. Consequently, the disruption would have long-lasting effects for the following winter, and gas companies would struggle to meet gas demand of the only customer group which cannot switch to other fuels – residential users. Previous gas supply crises in Europe have proven that storage is the most important element involved in meeting disruptions. Summertime is also when Japanese power demand (and therefore the use of gas-fired plants) is the highest.

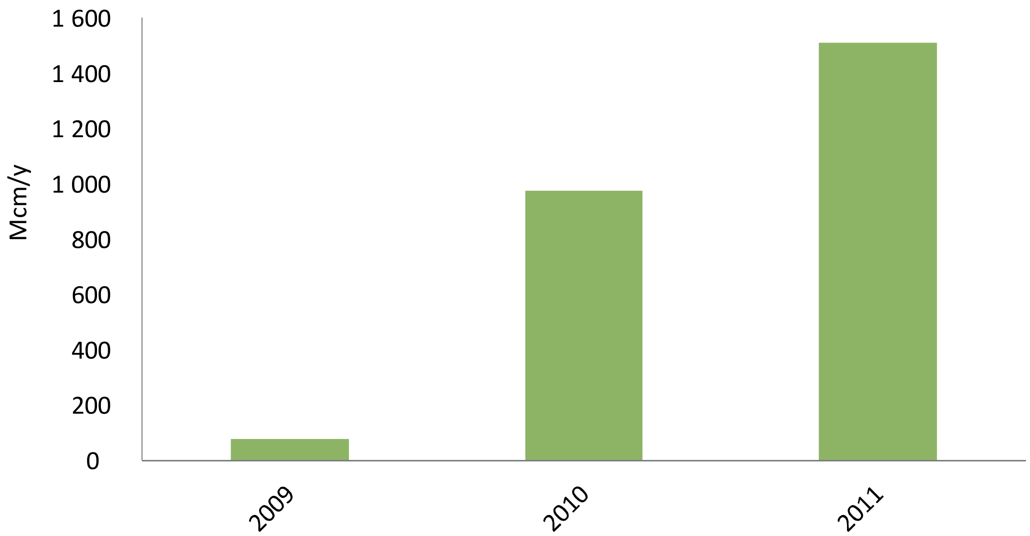
US LNG re-exports act as a safety valve

While the United States has approved only one liquefaction terminal project, US LNG re-exports have been growing substantially since 2009. Re-exporting LNG is just another way to relieve the pressure from an oversupplied US gas market. Although the US government has only approved the Sabine Pass LNG export terminal so far (see later), such re-exports are still possible as this is not US-made LNG, but rather foreign-made LNG. Indeed, the US government does not ban the export of foreign-made LNG arriving to the US regasification terminals.

Four LNG terminals, Sabine Pass, Freeport, Cameron and Cove Point, have been authorised to re-export. The United States actually imports minimum LNG quantities from overseas, mostly in order to maintain the facilities' operational requirements since it takes a lot of time to make a regasification terminal operational when the facility is at ambient temperature. US LNG imports dropped to less than 10 bcm in 2011, 20% below 2010's levels, and 2.3 bcm were imported through the three terminals, which re-exported 1.5 bcm to Asia, Europe and Latin America. LNG imports arriving at other LNG terminals in the United States were not re-exported for lack of authorisation. Even taking into account regasification and storage costs, the profits are quite substantial. In 2011, the average landed price for LNG imports at the first three terminals was USD 7.5/MBtu compared to an average FOB price for re-exports of USD 9.3/MBtu. Actually, there was a marked increase of the spread, from USD 0.7/MBtu during the first half of 2011 to USD 3.4/MBtu during the second half, reflecting tightening gas markets and higher spot prices.

The re-export business is not a totally new business. Belgium is one of the pioneers in this regard, having exported a few LNG cargoes per year to the Asian market in the past. This US re-export business is thus growing rapidly to 20 times as much as in 2009, providing arbitrage opportunities to the US LNG importers such as Sabine Pass, Freeport and Cameron terminals. The trend does not seem to be slowing down, considering the fact that there are existing regasification terminals and domestic gas production is plentiful, leading to decreased demand for LNG imports. However, it may stop if the United States becomes an LNG exporter (see section on investments in infrastructure).

Figure 47 LNG re-exports from the United States, 2009-11



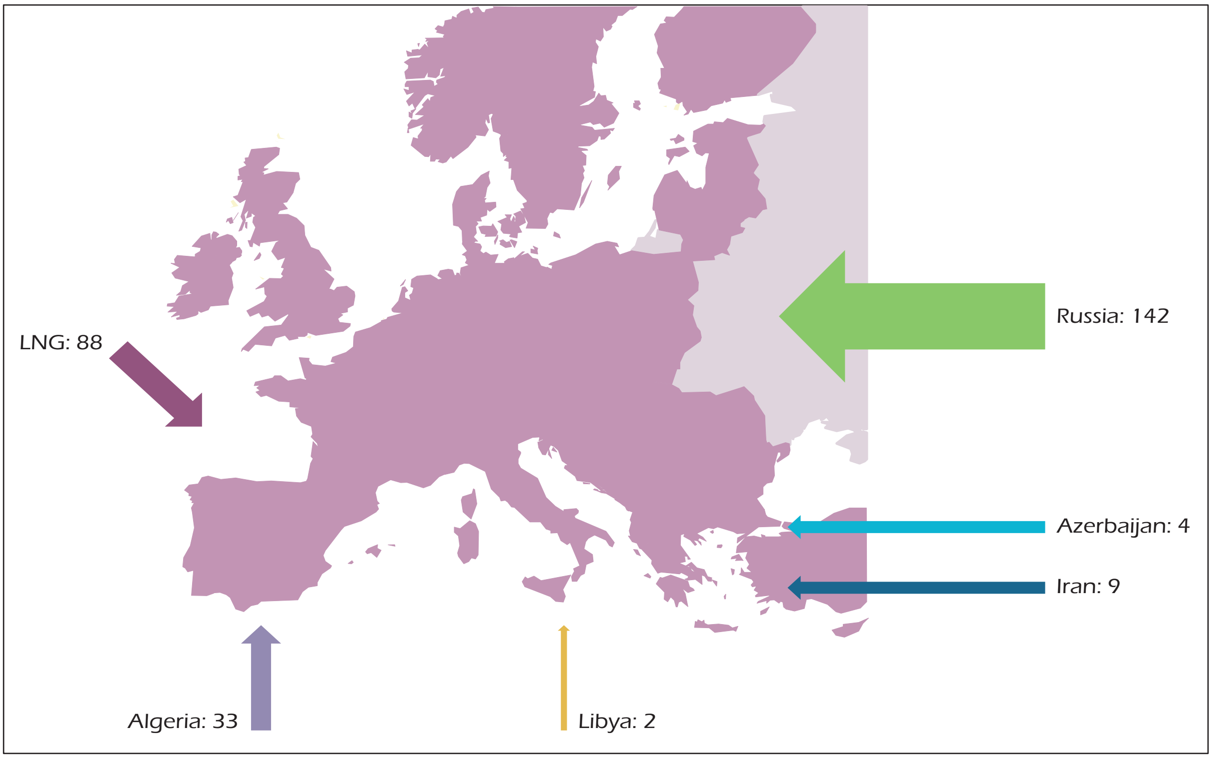
Sources: IEA and the US Department of Energy.

Interregional pipeline trade

Interregional gas trade is mostly a European issue, although Asia is becoming a growing importer of pipeline gas. In 2011, pipeline imports struggled in Europe as demand plummeted, while domestic production collapsed, but not as much as demand, and LNG preserved its position. In contrast, Turkmenistan almost quadrupled its exports to China to 14 bcm. Besides, there are limited exchanges between Africa and the Middle East through the Arab Gas Pipeline and between the FSU and the Middle East with the Iranian imports from Turkmenistan. As already mentioned in the Supply Section, Egypt's exports to the Middle East were cut by more than half following the bombings of the AGP. Lack of data makes it difficult to comment on Iranian imports, but the completion of additional pipeline infrastructure from Turkmenistan suggests that these could have increased in 2011.

While European (OECD and non-OECD Europe) gas demand dropped by around 49 bcm, domestic production lost close to 30 bcm. LNG imports dropped slightly by 0.3 bcm while Iranian imports increased marginally by 0.4 bcm, and Norwegian LNG exports increased by almost 1 bcm. This implies that the balance (18 bcm) comes from pipeline imports as well as stock changes. The year 2011 started with relatively depleted stocks following the cold spells in late 2010, while end-2011 was very mild across Europe, resulting in higher stock levels. This stock difference is estimated at around 13 bcm, which leaves a 5 bcm drop for total pipeline trade. The most obvious change was Libya losing around 7 bcm, while Algeria and Azerbaijan's supplies receded by around 2 bcm and 1 bcm, respectively. Azeri gas exports at 3.8 bcm were below the capacity of the South Caucasus pipeline (7 bcm), while Azeri exports to Russia have been increasing and are expected to double in 2012 to 3 bcm. This actually enabled Russia to increase its export volumes to Europe. Russian imports were particularly strong during the first half of 2011: European buyers tried to refill their depleted storages as well as take advantage of lower gas prices, anticipating higher prices towards the end of 2011 driven by higher oil prices and tightening gas markets. It is worth noting that another key supplier to Europe, Norway, albeit domestic, also decreased deliveries to the European gas market.

Map 4 Gas trade in Europe, 2011 (bcm)



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Recent infrastructure developments

Although 2011 was not a breaking year in terms of new infrastructure developments, the year witnessed some interesting events. The most important was certainly the start in November 2011 of the 27.5 bcm first string of the Nord Stream pipeline linking Russia directly to Germany and bypassing Ukraine. The pipeline was completed on time. This pipeline will have important consequences for internal flows within Europe, notably through Slovakia, the Czech Republic and possibly Poland.

Should European gas demand remain constrained for the years to come due to weak economic outlook and high gas prices, then volumes through these countries could drop from the current levels. So far, limited volumes have been flowing through the pipeline, which reflects the progressive ramp-up to capacity.

Another new pipeline started in 2011, the 8 bcm Medgaz linking Algeria to Spain. Medgaz became operational in March 2011 with a two-year delay due mostly to a lack of demand in Spain. The pipeline delivered 2.2 bcm in 2011, while deliveries through the existing Maghreb pipeline declined only slightly.

While only one liquefaction plant came online in 2011, 11 regasification terminals were completed or expanded, adding 82 bcm of LNG import capacity worldwide. Asia, particularly China, is enhancing its importing capacity, and Thailand also started importing LNG for the first time, marking the start of many South Asian countries becoming LNG importers. The Netherlands opened its first LNG import terminal in Rotterdam. Surprisingly, two terminals opened in the United States. The Golden Pass and Gulf LNG Pascagoula LNG terminals, for which the FID happened well before the shale gas revolution, started commercial operations in 2011 and imported 1.2 bcm of LNG. However, the Gulf LNG Pascagoula terminal has not reported receiving any cargoes yet. Argentina began operation of its second FSRU, thus contributing to the surge in its LNG imports to over 5 bcm.

Table 15 New and expanded LNG regasification terminals operational in 2011

Country	Terminal	Capacity (bcm)	Major stakeholder
China	Fujian Expansion	3.5	CNOOC
China	Dalian	4.1	PetroChina
China	Jiangsu	4.8	PetroChina
Japan	Mizushima Expansion	0.5	Chubu Electric
Thailand	Map Ta Phut (FSRU)	6.8	PTT
The Netherlands	GATE	12.0	Vopak/Gasunie
Sweden	Brunnsviksholme	0.3	AGA Gas
United States	Golden Pass	27.9	Qatar Petroleum
United States	Gulf LNG Pascagoula	13.4	El Paso
Dominican Republic	Punta Caucedo Expansion	2.4	AES
Argentina	Escobar (FSRU)	6.3	Enarsa
Total		82.0	

Sources: IEA and companies' websites.

Medium-term infrastructure investments: the race to bring gas to markets

Bringing gas to markets is as important as developing new gas fields. Identifying a market is a critical component for any supply project; it determines the infrastructure to be built, the project's developments costs, its economics, and which partners to bring along. Anticipating windows of opportunity, adapting to changing market conditions such as price indexation and specific market needs determine whether a project moves forward or not. This is where the difference between LNG and pipelines starts. Pipeline projects have little flexibility once the end-point is decided, unless the market is deep and liquid enough, whereby supplies can potentially be redirected to neighbouring countries or spot markets. LNG is much more flexible: LNG once earmarked for a country can finally end up at the opposite side of the world as seen in the example of Qatar's LNG, part of which was once dedicated to the United States. Flexibility has limits, especially in the short term, due to the tightness in shipping and rising daily shipping costs.

2009-20: accelerate, pause, accelerate

The past three years have witnessed such abrupt changes on global gas markets that many project sponsors are wondering about the next stages. The 2009-11 timeframe saw an accelerated expansion of LNG liquefaction capacity by 105 bcm to 373 bcm by end-2011, as well as the starts of the Nord Stream pipeline, the Medgaz pipeline and the Central Asia Gas Pipeline (CAGP) to China. In this race, LNG won by entering new territories such as the Middle East, Asia and Latin America while enhancing its position in Europe. Interregional pipeline trade took a back seat. Over 2012-13, infrastructure developments will slow down somewhat as only 25 bcm of new LNG export capacity will come on line. Pipeline projects will gain some footage, but most are in a completion mode (Nord Stream and CAGP); the Myanmar-China pipeline will be the only new pipeline. At end-2014, the bell rings again, signalling the start of a second massive wave of LNG projects.

Some key features of this "unconventional decade" are largely determined: Australia rises as a new LNG giant; Southeast Asia becomes an LNG importing region, while China's imports quintuple. But the late 2010s still hold a huge unknown whereby the biggest uncertainty resides in two countries – the United States and China – and can be summarised in two questions:

- Will the United States and Canada export significant amounts of LNG?; and,
- How big will Chinese gas imports be? The last question can also be rewritten as "Will Russia export to China?" or "Is Chinese shale gas for real?".

By their sheer size, both markets have the potential to profoundly impact global gas markets and have very often defied forecasts established with a conventional mindset. Besides, there are also some more "modest" uncertainties, such as the Southern Corridor from the Caspian region moving forward, new LNG supplies from new regions – Eastern Africa has become a very courted bride in a matter of two years, or from the "sleeping LNG giants" – Russia, Nigeria, Iran, and Iraq. The following sections look in depth at the investment picture in order to shed some light on these questions.

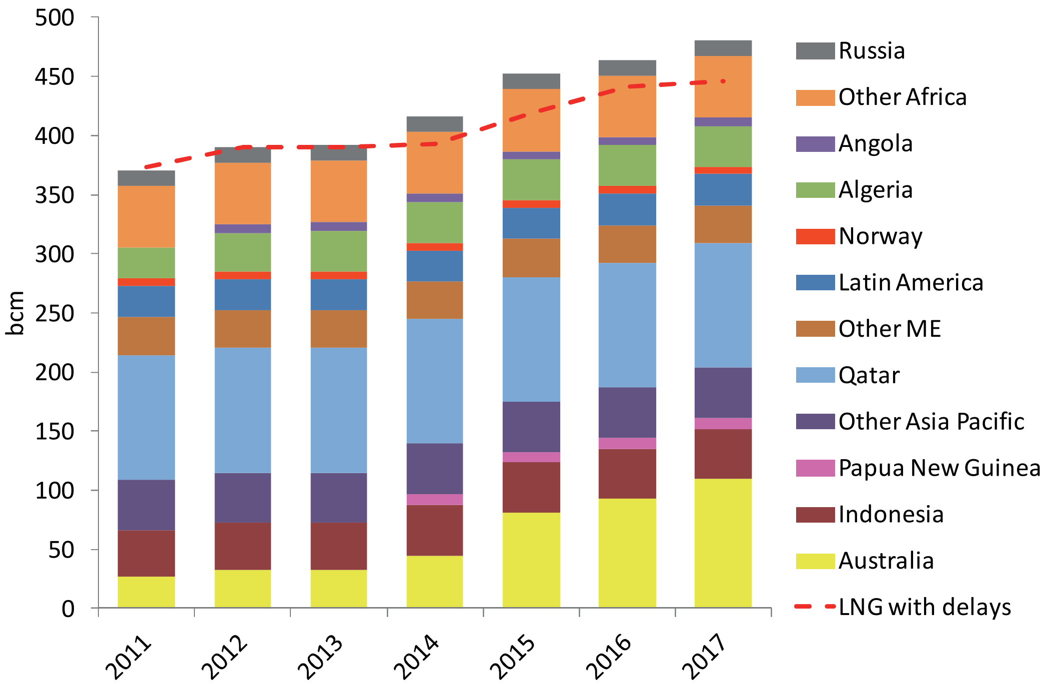
Committed liquefaction projects: the 500 bcm mark is getting close

Taking a nap before the race

After only modest expansion in 2011 with only Qatar's sixth mega-train starting, 13 LNG projects amounting to 114 bcm/y are currently under construction worldwide or recently started and expected to start by 2018. By then, global LNG capacity is expected to reach 481 bcm/y versus 373 bcm/y at end-2011. This takes into account the decommissioning of a few existing LNG plants, but not projects such as Sabine Pass, which has not yet taken FID as of early May 2012.

LNG capacity additions until mid-2014 will remain limited to a mere 25 bcm, a 6.7% increase in capacity. Three projects are coming online in 2012; namely Pluto LNG (which started in May 2012), Angola LNG and potentially Algeria's Skikda. Algeria will have another project, Gassi Touil, starting in 2013. The second wave of LNG exports will start end-2014, this time from Australia, which is expected to overtake Qatar as the largest LNG exporter by 2020. Six LNG projects have reached FID since end-2010. In 2014, the first train of several LNG projects is to be completed: Gorgon LNG, PNG LNG, Queensland Curtis LNG and Donggi Senoro LNG, amounting to 20 bcm/y. The additional trains of these projects will follow over 2015-17, while other projects such as Wheatstone are completed. According to the companies' plans, these projects are expected to be operational by 2018. However, LNG capacity could well increase less than planned given the delays observed on most LNG plants commissioned over the past three years. Assuming delays of over a year for most plants arriving over 2014-17, LNG liquefaction capacity would ramp up more slowly and reach below 450 bcm by 2017 (see Figure 48).

Figure 48 LNG projects under construction (as of May 2012)



Notes: This figure represents LNG export capacity, not LNG trade. The starting dates reflect companies' data, but not the IEA's views.

Table 16 LNG projects under construction (as of May 2012)

Country	Project	Capacity (bcm)	Major stakeholders	Online date
Australia	Pluto LNG*	5.9	Woodside, Kansai Electric, Tokyo Gas	May 2012
Angola	Angola LNG	7.1	Chevron, Sonangol, Eni, Total, BP	Mid-2012
Algeria	Skikda new train	6.1	Sonatrach	End-2012
Algeria	Gassi Touil LNG	6.4	Sonatrach	2013
Australia	Gorgon LNG	20.4	Chevron, Shell, Exxon Mobil	2014-15
Papua New Guinea	PNG LNG	9.0	Exxon Mobil, Oil Search, Papua New Guinea government	2014-15
Australia	Queensland Curtis LNG**	11.6	BG, CNOOC, Tokyo Gas	2014-15
Indonesia	Donggi Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas	2014
Australia	Gladstone LNG**	10.6	Santos, Petronas, Total, Kogas	2015-16
Australia	Australia Pacific LNG**	6.1	ConocoPhillips, Origin, Sinopec	2015
Australia	Wheatstone LNG	12.1	Chevron, Apache, Kufpec, Shell	2016-17
Australia	Prelude LNG***	4.9	Shell, Inpex, Kogas	2017
Australia	Ichthys LNG	11.4	Inpex, Total	2017-18
Total		114.3		

* Pluto LNG started operating in May 2012.
** CMB-to-LNG projects.
*** Prelude is a floating LNG project.
Sources: IEA and companies' websites.

All projects starting after mid-2014 are Australian-based, except Indonesia's Donggi Senoro and Papua New Guinea's PNG. Most will be technically challenging and may face delays due to workforce shortages, capital costs overruns and infrastructure bottlenecks. This includes four first-of-a-kind projects – three CBM-to-LNG projects in Queensland (Gladstone LNG, Queensland Curtis and Australia Pacific LNG) and Prelude LNG. This project, led by Shell, is the world's first floating production, storage and offtake (FPSO) project and Shell waited long for this state-of-the-art technology to materialise. Gorgon has a high CO_2 content in the gas, while Ichthys LNG is Inpex's first project as an operator.

New committed projects will be more expensive

The project costs represent the scope of the difficulties in developing an LNG project and vary depending on several factors, such as the location of the liquefaction plant, its distance from the feedgas supply sources to the processing facilities, the design of the plant, the environmental conditions of the plant site, the technical or regulatory challenges of the gas fields, availability of skilled labour, and the construction period before operation. The timing of the project development also plays an important factor, as an investment wave is likely to lead to cost inflation due to limited engineering, procurement and construction (EPC) capabilities. While LNG demand has been growing rapidly, particularly over the last ten years, the costs of LNG projects have also been rising. LNG development costs have more than doubled since 2003, but this trend is even more evident in Australia, where project development costs almost tripled in Australia over the same period.

A cost comparison follows, to demonstrate how expensive the development costs of recent LNG projects have become. For this assessment, the project costs include not only the development costs of the gas fields, but also the cost of the transmission pipeline (if any), gas separation process, liquefaction facilities, as well as all the associated facilities to bring the project to fruition. In other words, all costs related to the development of the entire LNG project are included. Some projects have production of condensate, propane, butane while others have only natural gas production. In a high oil price situation, the liquids production and sales significantly help the project economics and contribute to an early payback of the massive capital investments. However, this section focuses on the entire picture of LNG project costs, and attempts to describe the trend of what is happening in terms of LNG construction business. Thus, analyses based only on the cost of liquefaction facilities do not also necessarily represent the challenges of upstream or midstream development. It is important to know how much capital investment is required to develop an LNG project as a whole, from gas production to liquefaction.

Among the LNG projects currently either operational, recently completed or under construction, those under construction (green column) tend to be twice as expensive as other projects at different stages of development. The capital costs per tonne of LNG production of Prelude, Gorgon, Pluto, Wheatstone and Ichthys are between USD 2 778 and USD 4 048/tonne of LNG, whereas the equivalent costs for Darwin LNG, Qatargas IV, and Sakhalin II (blue column) are much lower, ranging from USD 1 000 to USD 2 000/tonne of LNG. Furthermore, the US Sabine Pass LNG project (pink column in Figure 49) is unique in the LNG business model, although it still has to reach FID. There is no dedicated feedgas field, as the entire US gas market is a potential supply source.

Given the US gas market's recent developments, supply is believed to be sufficient to meet incremental US gas demand and export needs without any major impact on the US gas prices, at least for the Cheniere project (21.9 bcm contracted). Therefore, no capital investment is required in the upstream development or transmission pipeline. Cheniere's stakeholders simply buy gas from the market, liquefy it and sell it to shippers on an FOB basis. Additionally, LNG storage facilities already exist at the Sabine pass site, so that only the liquefaction plant and LNG loading facilities are still required. In this regard, Sabine Pass's capital cost per tonne of LNG production seems to be very competitive at roughly one fourth of Gorgon LNG project, provided that US gas prices stay low.

Box 7 What is driving up LNG projects costs: focus on Australia

High fuel and material costs, as well as the distance of feedgas supply fields from the onshore liquefaction facilities have been pushing up LNG project costs. Even in resource-rich Australia, for example, onshore conventional gas fields have been developed intensively over time so that most LNG players now tend to look at deep sea offshore blocks for gas reserves large enough to support LNG projects. Most new LNG projects based on conventional gas require subsea transmission pipeline extending several hundreds of kilometres, which raises the total project cost by hundreds of millions of dollars. Ichthys will need over 800 km of subsea transmission pipeline to Darwin, which could raise the entire project's costs by an estimated USD 1 billion.

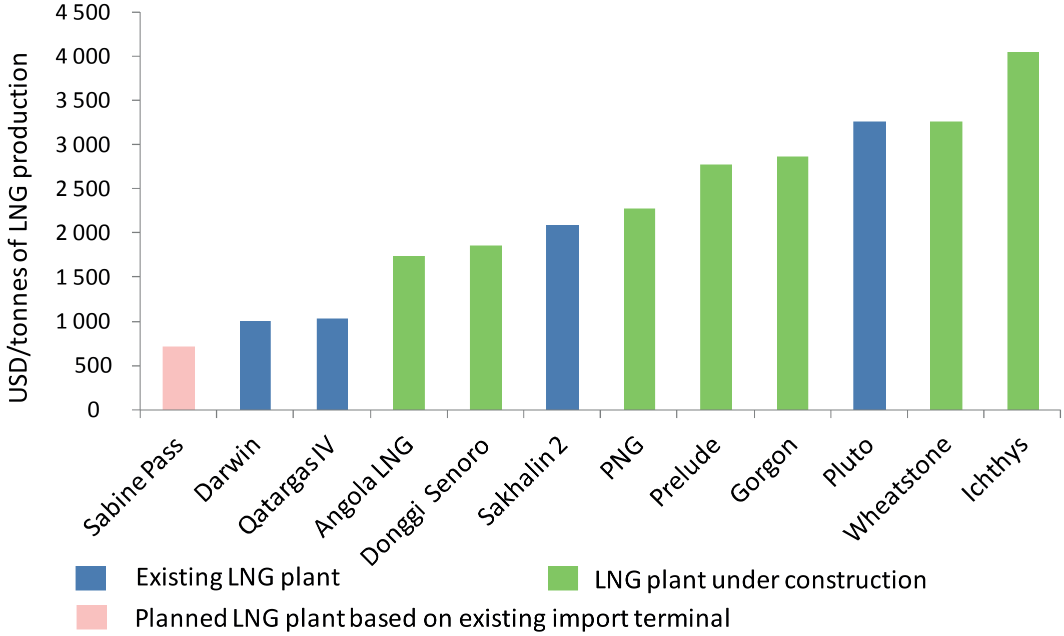
Currently, three CBM-to-LNG projects are under construction in Australia. The initial capital investment required for those projects seems less than conventional gas to LNG projects. However, unconventional gas development will require thousands of wells drilled over the entire project life, and it is still unknown if an onshore unconventional gas-to-LNG project is economically more attractive than a conventional one, since there is no such example yet.

Another key factor is labour cost. Seven out of 13 projects, representing 77 bcm, scheduled for 2014-17 are in Australia. No country has ever experienced the simultaneous development of seven LNG projects located all over the country. Qatar did develop 63 bcm of new LNG capacity over three years, but all projects were located in Ras Laffan. As no one expected such a huge expansion of the Australian LNG industry five years ago, there is now a critical labour shortage for these projects' development. This shortage is pushing the labour cost significantly up. According to Sydney-based recruiting expert Hays, "Salaries have remained at a consistently high level over the past 12 to 18 months and for two years Australia has ranked as the top paying nation for local oil and gas professionals." In Hays' report (Hays, 2011), the annual salary of a drilling engineer is estimated at AUD 180 000 and it goes up to AUD 320 000 for a drilling manager.

It usually takes 48 to 60 months for an LNG project to start commercial operation after reaching FID, and it requires a maximum of 1 500 to 2 000 workers per day per train at the busiest time of construction. Anticipating that the labour shortage will occur soon, the projects will try to recruit as much skilled labour as possible well in advance of the peak period. High labour costs are not expected to come down due to the severe competition over skilled labour recruitment for the coming four years.

Any LNG project requires its environmental impact to be carefully examined, so that appropriate counter-measures to keep the environmental damage minimal are taken. In this regard, Australia is no exception. The preservation of nature is always a very important issue, and particularly in Australia, the selection of the plant site is a crucial milestone due to strict environmental regulations. In some cases, endangered species have habitats near the planned plant site. All the LNG projects currently under construction have been granted environmental approval from local and federal governments before reaching FID. Sometimes, the approval is granted with additional conditions. Compliance with local regulation is very important, but it can require costly countermeasures that need to be in place.

Figure 49 Construction costs (USD/tonnes of LNG) of LNG projects



Where is the next wave of LNG supply to come from?

Around 650 bcm of LNG projects are at the planning stage worldwide, some at preliminary phases of development and others well advanced and close to FID. It is unrealistic to expect all of them to materialise. In general, the stakeholders of any project should identify sufficient gas supply sources to support the project, engage in the front end engineering and design (FEED) of the associated facilities as well as environmental assessment of the project before FID, and find a firm offtaker for their LNG production, preferably on a long-term basis to justify the economic feasibility. This is not a *sine qua non* condition as stakeholders with access to a growing market can also offtake the gas themselves, as illustrated by the PetroChina-Shell project (see below).

In most cases, this marketing activity, while critical, is the most onerous and time-consuming process. Stakeholders need to offer more competitive deals than the others and to act quickly to secure firm offtakers within an appropriate marketing window. The LNG market is obviously growing and globalising, but it will not wait until one gets ready for reaching FID. Among the projects currently at the planning stage, some get more attention than others, notably the North American LNG export projects.

North America: first non-Alaskan exports become a reality

The United States

The United States seems to have had bad timing with LNG. During the 1970s and early 1980s, as demand was rapidly increasing, four terminals were built representing some 57 bcm of LNG import capacity. A rapid drop in import needs from 1979 onwards resulted in these plants being mothballed or underutilised. In 1999, the arrival of a neighbouring LNG supplier, Trinidad and Tobago, combined with perceived growing US import needs, reactivated interest in these plants as well as in new ones. An additional 135 bcm was built over 2005-11, their FID taken well before the surge in US gas production started. These plants, amounting now to 192 bcm of capacity, imported 10 bcm in 2011, and the coming years do not look any better. Now the United States has arrived at a turning point, as incremental demand, combined with exports to Canada and Mexico and LNG re-exports, seem insufficient to absorb the growing amounts of gas production arriving to the market.

This has prompted some LNG import terminal holders to explore a new business opportunity – exporting LNG – using the existing import facilities to the maximum extent. Eight LNG exporting projects are now under consideration. The regulation on LNG exports is mostly based on the 1938 Natural Gas Act, requiring a two-tiered approval regarding LNG exports. Projects first need to apply for the LNG exporting license from the Department of Energy. As LNG exports to Free Trade Agreement (FTA)[10] countries are usually assumed to be in the public interest, these applications are often "granted without modification or delay".

Exports to non-FTA countries involves a more in-depth analysis on whether public interest requirements are met. Seven projects have already been granted a license to export LNG to FTA partners, but they also request an exporting license to Non-FTA partners. LNG export plants also need FERC's approval for the construction of the facilities before any project can go forward. So far, only Cheniere has been granted FERC's approval.

The most advanced project, as of early 2012, is Cheniere's 22.7 bcm/y Sabine Pass terminal in Louisiana. In the last 18 months, Cheniere signed long-term LNG supply contracts for 20 years with four different companies; BG, Gas Natural, Kogas and GAIL, and was granted a license to export to non-FTA partners. In November 2011, Bechtel was awarded the contract to design, construct and commission two liquefaction trains and exporting facilities valued at USD 3.9 billion. In April 2012, the FERC gave its approval to Cheniere to site, construct and operate facilities for the liquefaction and export of domestically produced natural gas at the Sabine Pass terminal. Freeport LNG (28.9 bcm/y), Lake Charles (20.7 bcm/y), and others are keen to follow Sabine Pass and are believed to be under intensive discussion with potential offtakers. In January 2012, it was reported that Freeport LNG awarded FEED contract for three trains (6 bcm/y each) to CB&I joint venture.

Table 17 Applications received by the US Department of Energy to export domestically produced LNG (as of early May 2012)

Project	Capacity (bcm)	FTA Applications	Non FTA Applications	Online date
Sabine Pass	22.7	Approved		2015
Freeport LNG	28.9	Approved	Under DOE Review	2015
Lake Charles	20.7	Approved	Under DOE Review	2018
Carib Energy	0.3 (FTA)/0.1 (Non-FTA)	Approved	Under DOE Review	Na
Cove Point LNG	10.3	Approved	Under DOE Review	2016
Jordan Cove Energy	12.4	Approved	Under DOE Review	2017
Cameron LNG	17.6	Approved	Under DOE Review	Na
Gulf Coast LNG	28.9	Under DOE Review		Na
Total	141.9			

Sources: IEA and companies' websites.

While the possibility of US LNG exports is very attractive for gas producers, LNG import terminals' holders and future potential importers due to the current high spread between US and other

[10] These countries are Australia, Bahrain, Canada, Chile, Costa Rica, the Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Korea, Mexico, Morocco, Nicaragua, Oman, Peru and Singapore. Underlined countries are LNG importers or will be in the next five years.

regional gas prices, it has led to an emerging debate on to what extent the US should export LNG or try to keep the benefits of cheap gas to enhance the competitiveness of the US economy. There is a fear that LNG exports would lead to increasing US gas prices, and consequently raise electricity generation costs. In early 2012, the EIA issued its preliminary findings on the impact of LNG exports on the US market. The report, *Effect of Increased Natural Gas Exports on Domestic Energy Markets,* pointed out potentially larger domestic price increases due to LNG exports. Depending on the export scenario, gas bills would be 3% to 9% higher than the Reference Case and electricity bills 1% to 3% higher. It has to be noted that EIA assumptions were relatively high both in terms of volumes (60 bcm or 120 bcm, well above what Cheniere has been authorised to export) and scale-up of exports (between 10 bcm/y and 30 bcm/y).

The World Trade Organisation (WTO) rules restrict export limitations under Article XI (but allow for export taxes, as well as reciprocity with a country which has export restrictions), while Article XX provides for certain exceptions in cases "relating to the conservation of exhaustible natural resources if such measures are made effective in conjunction with restrictions on domestic production or consumption." One major component for the final decision of US authorities is the notion of "public interest". LNG exports are assumed to be in the public interest, and opponents have to overcome this presumption by making an "affirmative showing of inconsistency with public interest" (DOE, 2011).

There are considerable doubts over whether a USD 2/MBtu price could be sustainable and still provide incentive for US gas producers to continue drilling for gas. Producers will continue when gas is associated with oil or due to their lease agreements, but the current trend to move away as fast as possible from dry gas will continue if prices remain below USD 3/MBtu. Some price increases in the medium and long term seem likely, which the EIA has taken into account in its price assumptions published in both *Short-Term* and *Long-Term Outlooks*.

It is useful to take a closer look at what authorising one project means for the US supply/demand balance, based on the Cheniere's project, which is very close to take FID as of early May 2012. The project's capacity, 22.7 bcm, represents 3.5% of the current US gas production (653 bcm in 2011) and is the average annual demand increase over 2009-11. Hurricanes in September 2008 knocked out 7 bcm of gas production in a single month. Variations between mild and cold years during winter months over the past five years have shown monthly demand variations of 5 bcm in the residential sector; similar variations could be seen during summer for demand in the power sector.

The argument of increased flaring, however, is insufficient to promote LNG exports; flaring and venting amounted to 4.7 bcm in 2011, and total gas flared in North Dakota is estimated to have been 1.7 bcm in 2011. Authorising a single LNG export terminal is not expected to fundamentally change the US gas market, given how the volumes compare with potential annual changes due to weather. Ironically, while US industry is worried about its competitiveness, the pricing formula (discussed in Box 8) ensures that any export market will get more expensive gas than the US industry. Analysing the impact on the United States should also include tax revenues as well as employment. Therefore, the United States is expected to be exporting LNG by 2017, but in a small amount (20 bcm) in order to gauge the effect on gas prices for the US gas market.

Box 8 How competitive are HH spot-indexed LNG exports?

The deals signed between Cheniere and the four companies assume a unique contract price structure, that buyers pay 115% of the HH gas price, to which is added a capacity charge of between USD 2.25 and USD 3/MBtu as the liquefaction cost of natural gas. To that, one needs to add the transportation cost to the market, usually from USD 2/MBtu to USD 6/MBtu. Interestingly, there is no traditional take-or-pay obligation. If the buyers decide not to offtake any LNG from the Sabine Pass terminal at a certain time due to unfavourable market conditions, then they only need to pay the fixed liquefaction cost agreed in advance and do not need to arrange an LNG tanker to offtake the produced LNG physically. It gives the assurance to the terminal's owners to be able to recoup their capital investment and opportunities to the buyers to secure competitively priced LNG, as well as to take advantage of the regional price differentials of LNG markets.

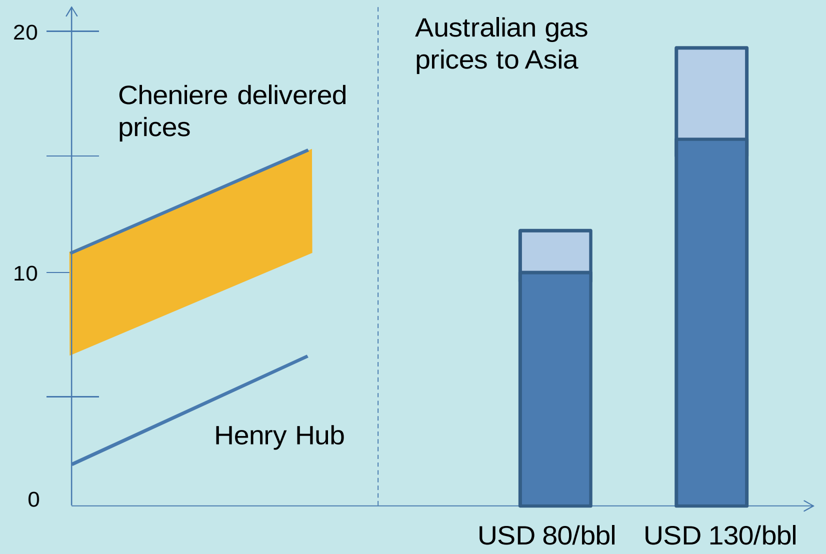
Table 18 Sabine Pass sales contracts (20 years from start-up)

Company	Purchase volume (bcm)	Train to supply	Capacity charge (USD/MBtu)
BG	4.8	1	2.25
Gas Natural	4.8	2	2.49
Kogas	4.8	3	3
Gail	4.8	4	3
BG	2.7	2, 3, 4	3

Sources: IEA and Cheniere.

But the catch is that international gas prices have been varying a lot, and given that capacity charges added to transport costs will be between USD 4 and USD 9/MBtu (assuming a transport cost of USD 6/MBtu to Japan at current rates, plus the USD 3/MBtu capacity charge), nothing can guarantee that such a spread will be maintained over the next 20 years. The evolution of European and Asian gas prices will be a key parameter. Australian LNG contracts to Asia are assumed to have a slope between 13% and 15%, which implies a gas price between USD 10.6/MBtu and USD 12/MBtu for USD 80/bbl and between USD 16.9/MBtu and USD 19.5/MBtu for USD 130/bbl. With oil prices at USD 80/bbl, being competitive implies HH gas prices remaining at current levels. A higher oil price gives advantage to US-based LNG exports. Even with HH at USD 7/MBtu, US exports remain competitive.

Figure 50 Competitiveness of US LNG exports



Canada

Unlike in the United States, the prospect for LNG exports in Canada is seen as unambiguously positive. Deprived from its only export market, the United States, Canada has to find alternatives or resign itself to seeing its production constrained due to lack of demand for exports. The US market price has been as low as USD 2/MBtu and the Canadian gas producers can hardly make a profit out of gas sales at that level. As a result, Canadian production is falling. Kitimat, British Columbia, is now expected to become a centre of LNG export of Canadian shale gas in the second half of this decade.

Although there is no LNG export infrastructure currently in Canada, there are several projects under consideration on the western coast of the nation. Additionally, the Canadian government also suffers from lower gas exports revenues. As a result, both the federal and local governments strongly support the LNG projects development. Additionally, Kitimat is relatively close to the Asian market and much better placed than any project in the United States to enjoy the freight cost saving, as there is no project on the US West coast due to the absence of significant gas production.

Table 19 Potential Canadian LNG projects (as of May 2012)

Project	Capacity (bcm)	Major stakeholders	Expected FID	Target online
Kitimat LNG	13.6+	Apache, EOG Resources, Encana	2012	2016
BC LNG	2.4	BC LNG Export Co-Operative	2012	2016
Shell JV LNG	20.4	Shell, PetroChina, Kogas, Mitsubishi	2013	2017+
Progress LNG	5+	Petronas, Progress Energy	2013	2017+
Total	41.4+			

Sources: IEA and companies' websites.

Kitimat LNG, led by Apache, has a production capacity of 13.6 bcm/y, and currently seems the most advanced project among those under consideration in Canada. In October 2011, the National Energy Board (NEB) granted an export license to the project. In February 2012, BC (British Columbia) LNG, a medium-sized 2.4 bcm/y project, was also granted an export license from NEB. Other players such as Shell and Asian companies are also quite active acquiring shale gas plays in the region with a view to eventually supply gas to their respective LNG liquefaction projects.

Asia Oceania

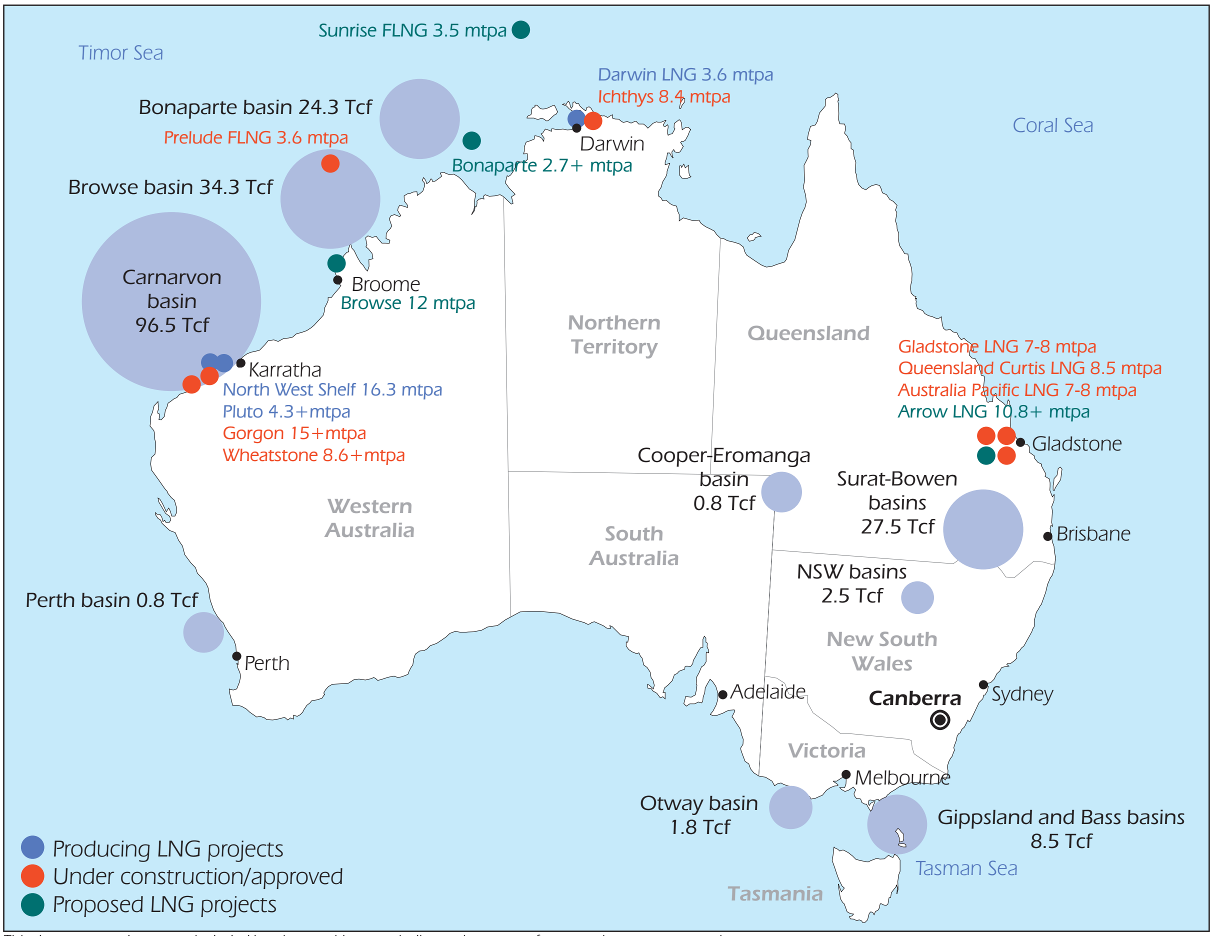
Australia: is the LNG giant still hungry?

Despite 77 bcm of LNG capacity under construction, added to the Pluto LNG plant started in May 2012, Australia could see additional LNG production growth based on the projects under consideration. Seven projects amounting to 55 bcm of planned capacity are estimated to be close to FID. Three projects are based on the expansion of the projects already under construction.

APLNG Train 2, led by ConocoPhillips and Origin, is expecting FID in 2012, after the Train 1 reached FID in July 2011. Substantial work has already begun, including the groundwork for two trains. The project partner, Sinopec, announced the offtake of an additional 4.5 bcm/y from the Train 2 in early 2012, so that APLNG's two trains are now fully sold out.

Meanwhile, Woodside has been trying to locate additional gas supply sources to support Pluto's second train (5.9 bcm/y), but it is not clear whether sufficient gas volumes have been secured or whether marketing activity is ongoing. Woodside's original plan to reach FID for this train in 2011 is now delayed, while the company is currently leading two other potential LNG projects, Browse LNG and Sunrise LNG. In addition, Chevron plans to expand Gorgon by building a fourth train (6.8 bcm/y) on Barrow Island. Gorgon's gas reserves of 40 tcf (1.1 tcm) are sufficient to support the expansion. However, Chevron seems to be taking a rather careful approach towards an expansion. The reasons could be that the project is still at an early stage of construction, with technical challenges such as the CO_2 reinjection. Chevron reached another FID for Wheatstone LNG, which could potentially keep key personnel of the company extremely busy or create a conflict of interest in LNG marketing for expansion between the two projects' partners.

Map 5 LNG projects in Australia (as of May 2012)



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Among the greenfield projects considered, two are floating LNG projects (Sunrise and Bonaparte), and one is a CBM-to-LNG project (Arrow). The 5.4 bcm/y Sunrise LNG project has a reservoir between Australian waters and the Joint Petroleum Development Area (JPDA), where Australia and East Timor governments jointly govern. Although 80% of the gas reserves are believed to be located in Australian waters, both governments agreed to evenly split the project's profits. After a long discussion among the project partners, Woodside proposed building a floating production storage and offloading FPSO in the Timor Sea because that option looked most economically justifiable compared to alternative options. However, the government of East Timor expressed disappointment over this option and insisted on the reconsideration of the plan. Their preferred option is a gas transmission pipeline of 250 km to the coast of East Timor and an onshore liquefaction plant which would create thousands of jobs in the country. The discussion over the best development plan between the project partners and East Timor government is still ongoing. However, once the development plan is agreed between the parties, the project could proceed quickly, since the project partners, Woodside, ConocoPhillips and Shell, are very experienced in the Australian LNG business.

GDF Suez is developing the floating Bonaparte LNG off the coast of Western Australia with Santos, also an operator of Gladstone LNG. Bonaparte's production capacity will be between 2.7 and 4.1 bcm/y. GDF Suez has been very active in marketing its global portfolio LNG in Asia and has signed several short- to mid-term supply contracts with Korea, China, India and Malaysia. Bonaparte LNG, once materialised, could become a reliable supply source of LNG to enhance GDF Suez's portfolio in the Asia Pacific region.

Table 20 Potential Australian and Asian LNG projects (as of May 2012)

Project	Capacity (bcm)	Major stakeholders	Expected FID	Target Online
APLNG (CBM) T2	6.1	ConocoPhillips, Origin, Sinopec	2012	2016
Arrow LNG (CBM)	10.8+	Shell, PetroChina	2012	2017
Pluto T2	5.9	Woodside	2013	2017
Browse LNG	16.3+	Woodside, Chevron, BP, BHP, Shell, Mitsui Mitsubishi	2013	2018
Gorgon LNG T 4	6.8	Chevron, Shell, Exxon Mobil	2014	2018
Bonaparte FLNG	2.7-4.1	GDF Suez, Santos	2014	2018+
Sunrise FLNG	5.4	Woodside, Shell, ConocoPhillips, Osaka Gas	2014	2018+
MLNG T9	4.9	Petronas	2013	2015
Abadi (Floating)	3.4	Inpex, Shell, Energy Mega Persada	2013	2017+
Tangguh LNG T3	5.2	BP, CNOOC, MI Berau	2014	2018
Gulf LNG	9.0	InterOIl	2014	2018
Total	76.5+			

Sources: IEA and companies' websites.

Arrow LNG is another Queensland CBM-to-LNG project with a proposed production capacity of 10.8 bcm/y based on two trains. It could be expanded up to 24 bcm/y. Following the takeover of Arrow Energy in 2010 by a joint venture between Shell and PetroChina, PetroChina agreed to offtake 5.4 bcm/y from the first train on a long-term basis and Shell also agreed to offtake another 5.4 bcm/y from a second train as a part of Shell's global supply portfolio. In December 2011, this project submitted its environmental impact statement to the local government and is still awaiting state and federal government approval before proceeding with FID. Considering the success of their marketing activity, Arrow LNG is considered to be very close to FID.

Another Woodside project is the 16.3 bcm/y Browse LNG, which is based on four trains and could be expanded up to 34 bcm/y. Woodside has selected James Price Point, 60 km north of Broome, Western Australia as its building site after intensive discussion with the local government and residents. The project has so far secured two Asian long-term offtakers (Osaka Gas and CPC) for over 6 bcm/y, but still has significant volumes to sell. It could therefore decide to start from two trains and expand afterwards. The FID has been postponed to 2013 along with the extension of the retention lease. Some project partners may prefer feedgas supply to the existing NWS facilities rather than a new plant in terms of project economics. Woodside also wishes to dilute the project stake and several companies such as CPC, Osaka Gas, CNPC and Mitsui have shown interest in participating so far. In May 2012, Woodside announced its intention to sell a 14.7% stake in the project to Japanese companies Mitsubishi Corporation and Mitsui for USD 2 billion. The other projects partners must agree before the deal can proceed.

Indonesia and Malaysia: exporting LNG or keeping it for domestic LNG import terminals?

While Indonesia and Malaysia have been among the largest LNG exporters for the last decades, they will be importing LNG from 2012 onwards. Despite that, both countries are still considering LNG export projects. In Indonesia, Inpex's Abadi project is a 3.4 bcm/y floating LNG project. In December 2010, its development plan was approved by the Indonesian government and in July 2011, Shell announced its participation with 30% of the project. Inpex will need Shell's experience in floating technology, as Shell is also leading Prelude LNG (FPSO) in Australia. The Indonesian upstream regulator, BP Migas, is pushing for this project to come online by end-2016. However, it is still in the preliminary stage and planning to embark on FEED in 2012. Shell may be able to offtake substantial volumes from this project as a part of its global supply portfolio, or the LNG may be directed to the future domestic LNG import terminals if the project economics allow for this option.

Another potential Indonesian project is Tangguh Train 3. This expansion, albeit discussed since 2009 when the first train started, has been continuously delayed with no clear reason identified. Most LNG projects in the Asia Pacific region have long-term contracts with Japan and Korea where LNG sales are priced the highest in the global market. Tangguh, however, has limited amounts of its LNG contracted on a long-term basis with Tohoku Electric and Korea, respectively. Most LNG supplies go to China at USD 4 to USD 5/MBtu and to Mexico at HH-indexed prices, which implies a longer payback period of the capital investment compared to other projects. BP announced in early 2012 the amendment of the long-term contract with US Sempra, which delivers LNG to Mexico, in order to sell the LNG at the higher valued market and negotiate with China to increase the price.

In February 2012, Petronas announced the addition of a ninth train at the Sarawak LNG complex. There is no particular feedgas supply source identified for this train, but Petronas expects to be able to secure sufficient feedgas supply to make this expansion a reality. As long as sufficient feedgas is secured, this expansion of an existing project would be relatively easy and quick. FEED is already awarded to two parties: JGC and a joint venture between Chiyoda and Saipem. They will compete for the next step towards Engineering, Procurement, Construction and Commissioning (EPCC) for this train before end-2012. Petronas intends to export the LNG from the new train, but it is not clear how much will be exported, since Malaysia certainly needs LNG for its own regas terminal.

Papua New Guinea: the newcomer faces uncertainty and competition from Australia

Papua New Guinea (PNG) also has a few planned LNG projects, but these projects are still at preliminary stages; considering the political risks associated with project development, any substantial progress within the next five years is relatively unlikely. The 9 bcm/y Gulf LNG, led by InterOil, is probably the most advanced. In February 2012, it was unveiled that Kogas, Japex and Mitsui were in talks with InterOil over potential participation in the project. If any or all of them actually participate, it may expedite the project's development.

Russia: will there be another LNG export project before 2020?

After the closure of the North American gas market it once targeted, Russia aspires to expand its Asian market share with new pipeline and LNG projects, while continuing to play a key role as

Europe's main supplier. With the Sakhalin 2 project started in 2009, Russia has already established a foothold in Japan, Korea, Chinese Taipei and China. Three LNG projects are under consideration, one of which is as large as Gorgon LNG: Yamal LNG (20.4 bcm/y) and Shtokman LNG (10.2 bcm/y) and Vladivostok LNG (13.6 bcm/y). The first two projects could supply the European markets, but supplying Asia is dependant on the northern route climatic conditions. The cost of using ice-breakers or going through the Atlantic Ocean first could be prohibitive. The planned projects' combined capacity of around 45 bcm, if they were all moving forward, would make Russia the third largest LNG exporter, still well behind Australia and Qatar.

Despite ongoing discussions between the partners of the Yamal and Shtokman projects, progress seems slow. Both consortiums were planning to reach FID by end-2011, but it has been delayed to end-2012 or beyond. In 2011, Russia's Gazprom announced the signing of LNG deals with four Indian companies (3.4 bcm each over 25 years), starting between 2016 and 2018, which raises the question of the source of supply. Although still at an early stage of development, Vladivostok LNG is also under intensive discussion between Russia and Japan, which is thirsty for LNG after the Fukushima nuclear incident. Vladivostok LNG is geographically much closer to the Asian market than the other Russian LNG projects, contributing to significant freight cost savings. In 2012, the APEC Summit will be hosted by Russia in Vladivostok and this political event could push forward the economic development of this region, as well as a second LNG project in the far east of Siberia.

Table 21 Potential Russian LNG export projects (as of May 2012)

Project	Capacity (bcm)	Major stakeholders	Expected FID	Target online
Yamal LNG	20.4	Novatek, Total, Statoil	2012	2017+
Shtokman LNG	10.2+	Gazprom, Total, Statoil	2012	2018+
Vladivostok LNG	13.6	Gazprom, Itochu, Japex, Marubeni	2013	2018+
Total	44.2+			

Sources: IEA and companies' websites.

Africa, the Middle East: the ball is in Africa's court

Although Qatar has become the largest LNG exporter in the world, progress on other projects in the region has been relatively slow. Iran is still under the United Nations' sanctions and is not expected to make substantial progress for the next few years, despite the long list of planned projects. In the long term, Israel could export LNG, but no decision has been made on how this LNG will be exported.

Table 22 Potential African and Middle Eastern LNG projects (as of May 2012)

Project	Capacity (bcm)	Major stakeholders	Expected FID	Target Online
Brass LNG	13.6	NNPC, Total, ConocoPhillips, Eni	2012	2016+
NLNG Train 7	11.4	NNPC, Shell, Total, Eni	2013	2018+
Angola LNG T2	7.1	Chevron, Sonangol, Eni, Total, BP	2013	2016
EG LNG T2	4.6	Marathon, GEPetrol, Mitsui	2013	2016
Mozambique LNG	13.6+	Anadarko, Mitsui, Videocon, BPRL, Cove Energy	2013	2018+
Mozambique LNG	Na	ENI	2013	2018+
Iraq	6.0	Iraqi government, Shell, Mitsubishi	Na	2015+
Israel	Na	Noble Energy, Delek	Na	2015+
Total	56.3+			

Sources: IEA and companies' websites.

Nigeria, Angola and Equatorial Guinea

For almost a decade now, Nigeria has been considering a few projects, which have been systematically postponed. Brass LNG, led by Nigerian National Petroleum Company (NNPC), is expecting FID in 2012. NNPC also wishes to reach FID for its NLNG Train 7 in 2013. Those targets are again very ambitious, considering the country's political instability. Moreover, it was anticipated that the Petroleum Industry Bill (PIB) would be approved by both the National Assembly and the President in 2011, but the bill has stalled. The PIB is to provide legal reform and transparency to the country's petroleum industry, including the privatisation of the Nigerian National Petroleum Corporation (NNPC). The delay creates growing uncertainty for foreign investors wishing to make a financial commitment on projects. Both Equatorial Guinea and Angola are considering a second train in their existing LNG facilities, but there has not been much progress confirmed. With surplus capacity of giant Qatar in the region, Equatorial Guinea and Angola may have to engage in price competition to find firm offtakers for their LNG.

Will Mozambique and Tanzania move faster than anybody else?

East African countries, particularly Tanzania and Mozambique, have been attracting much attention recently as a new frontier for LNG projects. From a geographical point of view, this region is very well situated to reach fast-growing markets such as India, China, South Asia or traditional European or Japanese markets. Although the development of LNG projects in the region is unlikely to take place before 2018, it could be accelerated by the support of the local government and offtake agreements with potential buyers. It remains to be seen to what extent a so far non-existent local market could benefit from these resources.

ENI, Anadarko, Statoil, ExxonMobil and several other companies are very active in this region and have made significant gas discoveries, for which resources seem large enough to support multiple LNG projects. Anadarko's project is the most advanced, with its FEED now completed; it is planning to build two trains of 6.8 bcm/y each with FID to be reached in 2013. This new frontier is attracting investors, such as Shell and Asian companies. Moreover, the Tanzanian government is trying to provide an investment environment for the local industry and foreign investors to promote capital investments and expedite gas exports, even though the gas resources in Tanzania are just in the process of being evaluated.

Developing import infrastructure

The next five years will see growing import needs in mostly two regions: Asia – Japan, Korea and non-OECD Asia – and Europe. Imports will slightly increase in Latin America and the Middle East. The largest sources of new supplies will be mostly the Former Soviet Union and Australia, while Africa and North America will contribute to limited amounts of new supplies, both pipeline and LNG. As the demand for LNG increases by one-third or around 100 bcm over 2011-17, new LNG terminals will be developed, particularly in Asia. There are currently almost 870 bcm of LNG import capacity, compared with 327 bcm traded in 2011. In other words, the world's average utilisation rate of regasification terminals is roughly 37.5%, compared with 88% for liquefaction plants.

So why are LNG import terminals still needed? First, the primary reason for this lower utilisation rate is that, in general, a liquefaction plant is designed to produce LNG at almost maximum level constantly throughout a year, unless any issue with feedgas or political instability appears. In addition, regasification terminals are reasonably cheap, only 10-20% of the capital cost of the equivalent liquefaction capacity, which several countries find a reasonable price to have access to the LNG market. However, a regasification terminal is designed to meet seasonal peak demand as well as future demand increases. A terminal can be used to meet only summer or winter demand, as is the case in the Middle East. As a result, the volume of LNG regasified at any terminal fluctuates very much throughout a year. Wrong assumptions on future import needs can also lead to an overbuild of LNG capacity, as is the case in the United States, where the 192 bcm are used at 5% on average. Thus, the total LNG import capacity in a country does not always represent the volume of LNG that is going to be imported. Additionally, some LNG terminals can be built to provide new entrants a foothold on a market where access to existing infrastructure is difficult; this also provides a better negotiating position with LNG suppliers. Finally, aggregators can also use LNG terminals for arbitrage opportunities.

Table 23 LNG regasification capacity (bcm) by region (as of May 2012)

Region	Operation	Construction	Planned
Asia	424	78	184
Japan & Korea	*353*	*20*	*6*
China & India	*49*	*40*	*128*
Europe	192	38	201
France & Italy	*37*	*22*	*80*
Middle East & Africa	7	-	8
North America	222	5	262
United States	*192*	-	*223*
Latin America	25	-	42
Total	869	121	698

Taking all these factors into account, it is far more difficult to evaluate LNG imports at any LNG import terminal than LNG produced at any liquefaction plant, unless it is clearly announced how many LNG cargoes will be shipped to any particular regasification terminal, which is very unusual. There are fewer than 30 LNG import terminals under construction worldwide with over 120 bcm/y worth of import capacity, and surprisingly, almost 700 bcm/y is under consideration. Again, it is very unrealistic to imagine that all this planned capacity will materialise. In comparison, pipelines are much more capital-intensive than LNG regasification and less flexible. The number of interregional pipelines under consideration is relatively limited, and not much is happening apart from a first decision on the much-awaited Southern Corridor.

Europe: is there a need for new import infrastructure?

OECD Europe is the largest importing region, with a preference for pipeline gas, while LNG currently plays a much smaller role in the region. European net imports are expected to increase to 310 bcm over 2011-17. Given this modest growth in import demand, there is barely need for new infrastructure. But diversification of gas supplies continues to be a priority for European energy security. Therefore, some new LNG import terminals (or expansion of the existing terminals), as well as pipelines, are under construction or being considered. However, progress for all types of infrastructure has been slow due to environmental regulations, growing public concerns, competition between different projects or difficulties in securing the corresponding supply sources. In addition, the long-term role of gas in the EU energy system is uncertain. Only six LNG import terminals and a pipeline expansion are currently under construction, as the financial crisis in Europe is deterring capital investment.

The second string of the Nord Stream pipeline, currently under construction, is planned to start by October 2012, although it remains questionable whether the whole Nord Stream pipeline (55 bcm) would really translate into additional gas supplies in the medium term. Much attention is being paid to the Southern Corridor. After almost eight years of competition between different pipelines, the finish line seems near following some last minute rebounds. New competitors appeared at end-2011 for Nabucco, the Interconnector Greece Italy (IGI) and the Trans-Adriatic Pipeline (TAP) with BP's proposed South East European Corridor (SEEP) and Socar's Trans-Anatolian Gas Pipeline (TAGP).

Both pipelines highlight the resolution of Shah Deniz's producers and Azerbaijan to finally move, even without the projects which had been on the table for years, while the decision to pick one of the projects was delayed again, from October 2011 to February 2012. On 26 December 2011, an MOU was signed between Turkey and Azerbaijan on the construction of the TAGP pipeline across Turkey. For Azeri gas to reach Europe, the choice is to either build a pipeline or expand the Turkish network. Finally, TAP has been chosen as one solution, but still leaves room for a second, small pipeline, which could be, for example, a smaller version of Nabucco, or SEEP and TAGP. It seems now unlikely that any project, even TAP, would start before 2018. The IGI, also targeting Italy, is also unlikely to be chosen, as Azerbaijan may prefer to diversify markets, but may be of interest for South Stream.

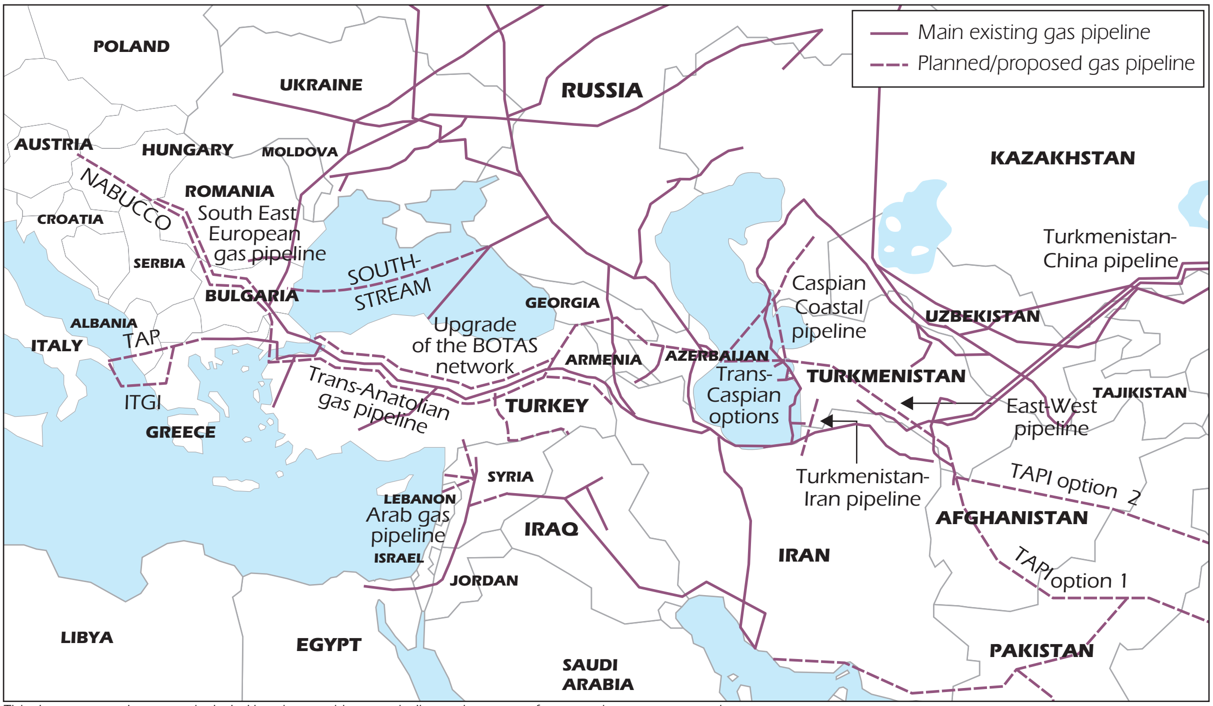
The competition, Russia's South Stream, still plans to take FID in end-2012 for a possible start in late 2015. Again, this pipeline could merely replace existing Russian deliveries through Ukraine to southeastern Europe, trying to block potential Azeri supplies and leaving Ukraine dependent on any incremental European demand that Nord Stream and South Stream combined capacity could not accommodate. No progress has been made on the other pipelines, Gasdotto Algeria Sardegna Italia (Galsi) or the extension of the Arab Gas Pipeline. Due to supply issues and the multiple bombings of the AGP, it seems highly unlikely that its expansion will ever move forward. Europe is also looking at getting natural gas supplies from Israel.

Table 24 Interregional pipeline projects in Europe

Source	Name	Online date	Status	Capacity (bcm)	Sponsors	Estimated costs (Bn)
Russia	Nord Stream II	October 2012	Under Construction	27.5	Gazprom: 51%, BASF, EON: 15.5%, Gasunie, GDF Suez: 9%	EUR 7.4
	South Stream	2015-19*	Planned	63	Gazprom: 50%, ENI: 20%, Wintershall, EDF: 15%	EUR 15.5
Caspian Region	TAP	2017-18	Confirmed	10 (+10)	EGL, Statoil: 42.5%, E.ON: 15%	EUR 1.5
	Nabucco	2018	Planned	8-31	Botas, Bulgargaz, MOL, Transgas, OMV, RWE	Never revised
	SEEP	2018	Planned	16-24	BP	USD 5-6
	TAGP	2018	Planned	10	SOCAR	Na
Algeria	GALSI	2015+	Planned	8	Sonatrach: 41.6%, Edison: 20.8%, Enel: 15.6%, Sfirs: 11.6%, Hera: 10.4%	EUR 2
Egypt	AGP	Na	Unlikely	10		
Iran	Iran Gas Trunkline 9	2015+	Planned	37	NIGEC	EUR 8

Sources: IEA, companies' websites.
Note: The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.
* The pipeline starts at the end of 2015 and its capacity is progressively increased until 2019.

Map 6 The Southern Corridor



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On the LNG side, several LNG import plants are currently under construction in Europe. EDF finally began construction of France's fourth LNG import terminal in Dunkerque, the first French terminal owned by a "new entrant". Spain and Italy are also expanding import capacity, although the Spanish government decided in May 2012 to mothball the terminal in El Musel, because of low gas demand. As in France, Italy's new terminals are not in the hands of the incumbent, ENI. Poland and Lithuania, for which the diversification of gas supply sources away from Russia is an important issue, will become LNG importers. Lithuania decided to charter floating storage and regasification units (FSRU) for ten years, for which the construction is much quicker than building an onshore terminal. There is no dedicated contract for these new LNG terminals, except a very expensive (oil-indexed) supply contract with Qatar for Poland. The LNG could come from Algeria's new trains, Nigeria and/or Qatar; the latter could, indeed, want to expand its market share in Europe. It remains to be seen to what extent the Polish terminal will be used, if shale gas production becomes a reality.

Table 25 LNG regasification terminals under construction in Europe (as of May 2012)

Country	Location	Capacity (bcm)	Major stakeholder	Target online
Spain	El Musel	7	Enagas	2012+
Italy	Livorno	3.8	E.ON	2013
Poland	Swinoujscie	4.8	Gaz System	2014
Lithuania	Klaipedos (FSRU)	3	Klaipedos Nafta	2014
Italy	Porto Empedocle	8	Enel	2015
France	Dunkerque	10	EDF	2015
Total		36.6		

Sources: IEA and companies' websites.
Note: This table does not include terminals' expansion.

Asia

There are three different regional gas markets in Asia:

- a mature market in Japan, Korea and Chinese Taipei, mostly turned towards LNG;
- the "emerging giants" – China and India, two countries with massive import needs. In the medium term, China is the only one where there is actually competition between pipeline and LNG supplies. Pipeline perspectives for India remain remote; and finally
- Southeast Asia is slowly emerging as a new centre for LNG imports, due to the lack of intraregional pipeline connections.

Table 26 LNG import terminals under construction in Asia (as of May 2012)

Country	Location	Capacity (bcm)	Major Stakeholder	Target Online
Japan	Joetsu	2.7	Chubu Electric	2012
	Ishikari	1.9	Hokkaido Gas	2012
	Yoshinoura	0.5	Okinawa Electric	2012
	Naoetsu	2.7	Inpex	2014
	Hibiki	1.4	Saibu Gas	2014
	Hachinohe	1.0	Nippon Oil	2015
Korea	Samcheok	9.2	Kogas	2015
China	Ningbo	4.1	CNOOC	2012
	Zhuhai	5.0	Guandong Power	2013
	Tianjin (FRSU)	3.0	CNOOC	2013
	Shandong	4.1	Sinopec	2013
	Hainan	2.7	CNOOC	2014
	Hebei	4.8	PetroChina	2014
	Yuedong	2.7	CNOOC	2015
India	Dabhol	7.5	Ratnagiri Gas & Power	2012
	Kochi	6.8	Petronet LNG	2012
Indonesia	West Java (FRSU)	5.2	Pertamina	2012
Malaysia	Malacca (FRSU)	5.2	Petronas	2012
Singapore	Jurong Island	8.2	Energy Market Authority	2013
Total		78.7		

Sources: IEA and companies' websites.

The ability of Asian countries to move supply infrastructure projects forward and to attract new supplies differs markedly, in particular due to wide differences between prices that these markets could accommodate. Most countries face the challenge of higher gas procurement costs on global markets. Especially, for existing LNG exporters facing declining production and exports and, at the same time, growing demand and import dependency, it is hard to imagine how they could procure competitive LNG from the global market. It is not economically rationale to buy expensive LNG unless it can foster value-added industry, such as in Japan, Korea and Chinese Taipei. Thus, the utilisation of LNG import terminals in the region will be heavily conditioned by LNG import prices. If they are not competitive enough, one can suspect the development of LNG import terminals in the region would slow down significantly, or that they will be significantly underused.

Japan

Japan will remain the world's largest LNG importer for the next decade. Although Japanese LNG imports surged after the Fukushima accident in March 2011, most of the newly operating LNG import terminals started construction well before then. It is a reflection of the Japanese utilities' strategy to increase gas consumption in the power sector, particularly compared to oil and coal. Terminals under construction are being led by rather new players in the LNG market, namely Hokkaido Gas, Okinawa

Electric and Inpex, rather than the traditional power and gas utilities. The Japanese government is currently reviewing its future energy policy, including strategy on nuclear power plants, and the details are still unknown. However, it seems reasonable to assume that gas-fired power generation will play a major role. Although Japan already has a substantially higher LNG regasification capacity than its actual imports, the weakness of regional interconnectors, the difficulty and cost of LNG storage, as well as the energy security-related objective to maintain spare capacity might lead to additional regasification capacity investment.

Korea

Korea, the second largest LNG importer after Japan, is building a new LNG import terminal, the first ever on the east coast of the country. Although gas demand growth is expected to slow down over the next five years, this terminal will enhance the interconnectivity of Korea's gas transportation network, resulting in stronger gas supply security. While there are also plans to strengthen the storage capacity of existing LNG import terminals, there are few new LNG import terminals under consideration.

China

China is the most rapidly growing LNG market, with seven LNG import terminals under construction, including one FSRU. CNOOC, with three operating terminals, is already the largest LNG importer in China and has four more terminals under construction. But the other NOCs are also building their own terminals, namely Sinopec in Shandong and PetroChina, which is constructing its third terminal in Hebei. In fact, there are many more LNG import terminals planned by the three NOCs or smaller private companies, and some of them are likely to go forward in a medium-term perspective. Although regasification terminals are less capital-intensive than liquefaction plants, they still require hundreds of millions of dollars to build. Therefore, most of them need a strong financial sponsor or financial backbone. In this regard, the three Chinese NOCs are financially strong companies for which it is relatively easy to finance a regasification terminal with favourable governmental support towards natural gas imports. However, some of the smaller shareholders may encounter difficulties in financing their share of the capital investment.

Above all, uncertainties regarding future pipeline imports and shale gas developments will influence LNG developments in China. This will not only affect the construction of future regasification terminals, but also their filling rate. China is currently expanding the Central Asia Gas Pipeline from 30 bcm to 40 bcm; there are also plans to increase the capacity to 65 bcm, although whether China and Turkmenistan would be really comfortable with such interdependency is questionable. Furthermore, the Myanmar-China gas pipeline is under construction, but it is uncertain whether this pipeline will be filled at capacity (12 bcm).

The main uncertainty regarding pipeline supplies comes from Russia. Negotiations between China and Russia have been dragging on for over a decade and always stumble on one key point: the price. Russia is considering exporting 70 bcm by pipeline to China. Besides the price, the route is also a matter of disagreement; two solutions are considered. An Eastern route would tap into the yet-to-be developed Eastern Siberian fields (or possibly Far East fields) and be closer to the markets. The Western route, which taps into Western Siberian gas fields, would be easier to develop rapidly, but much farther away from the markets on the coast. This route would therefore imply higher delivered costs for the final user. Competition between pipeline gas and LNG, primarily determined by price and political choices, as well as future developments of shale gas in China, would be the key components to determine the development of infrastructure to China in the medium term. Nevertheless, given the massive demand growth potential of China, only a very significant development of shale gas could prevent the growth of overall Chinese imports.

India

India is expected to rely much more on LNG than it does today, as domestic gas production struggles. But there are only two LNG terminals under construction, namely Dabhol and Kochi, both expected to start in 2012. Indian domestic gas production is not as big as originally expected, while there are huge needs on the domestic market. There is a plan to import natural gas from Iran via pipeline, but the progress has been very slow. It is very unlikely to see Iranian gas being imported to India, at least within the next five years. So, India must rely on LNG imports going forward, and actually, the option to import LNG in India to feed Pakistan has even been considered. In this regard, the plans to build additional regasification terminals may be accelerated, once expected demand for LNG gains ground.

Southeast Asia

Southeast Asia has been an LNG exporting region for the last four decades, but some countries are now turning into LNG importers, although the region will still remain a net LNG exporter for years to come. In addition to the new terminal started in Thailand in 2011, there are four LNG import terminals currently under construction, three of which are FSRU. LNG is needed due to the failure thus far to expand the regional pipeline network. The dilemma is that Indonesia and Malaysia want to sell their LNG at a high price while buying LNG at a low price. Only one country, the United States, both imports and exports LNG at the same time. The United States has been exporting LNG from Alaska to Asia for over forty years at oil-indexed prices, while it has been importing LNG at HH-linked prices. This has been possible because the United States is one of the top gas producers, as well as the largest, open, liquid and transparent gas market in the world.

In this regard, Indonesia and Malaysia have a lot to learn from the US experience if they also wish to import LNG at competitive prices instead of traditional oil-indexed prices. Expensive LNG is likely to limit the role of gas in the energy mix, since Indonesia especially has substantial coal resources. On the other hand, in domestic applications and industry, its alternatives are oil products (LPG and naphta), so that it might remain competitive. Other Asian countries such as Vietnam, Philippines, Pakistan and Bangladesh are also considering building a regasification terminal due to growing domestic demand for natural gas, but the progress is rather slow. It is very uncertain if their plans will materialise within the next five years.

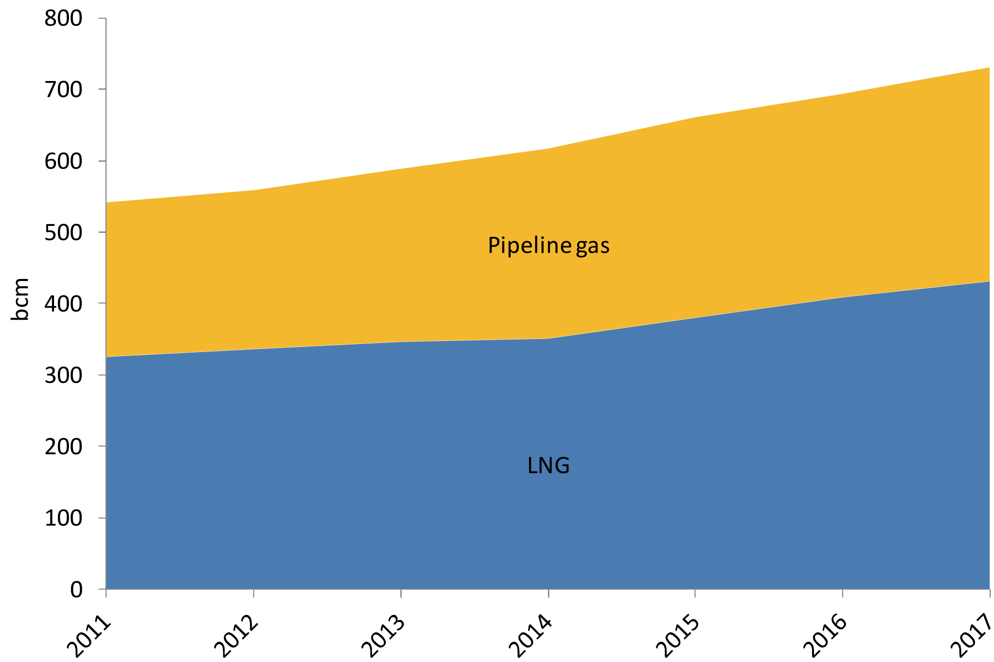
Mexico, Latin America and the Middle East

Mexico is another rapidly growing LNG market. Its LNG demand has doubled over the last three years. There is one LNG import terminal under construction in Mexico. It is the third LNG import terminal in the country, but given the US shale gas revolution, it is uncertain whether there will be new ones. In fact, there are many more terminals under consideration in Latin America, including Jamaica, Uruguay, Argentina, Chile and Brazil, but none of them has made substantial progress over the last eighteen months. Israel and Bahrain are also interested in FSRU and they are reported to be in talks over potential LNG supply from Qatar. However, the details of the plan are still unknown and there has not been much progress in terms of charter or construction of FSRU.

Global trade developments are shifting to Asia

The expected demand increase of 576 bcm calls for a rapid development of global gas trade. Interregional gas trade between the major regions (the three OECD regions, the FSU/Non-OECD Europe, the Middle East, Africa, Latin America, China and the other Asian countries) is projected to grow by 35%, reaching 730 bcm, including 426 bcm of LNG. With an annual growth rate of 5% per year, global gas trade grows faster than natural gas consumption. By 2017, there will be three major importing regions – Europe, OECD Asia Oceania and China, importing respectively 310 bcm, 184 bcm and 113 bcm. While these three regions see their import dependency growing, China's growth is the most impressive, with imports four times higher than in 2011 and seven times higher than in 2010.

Figure 51 Evolution of interregional trade, 2011-17



With the rapid development of LNG highlighted previously in this chapter, one could have thought that LNG's growth rate would exceed that of pipeline gas, but actually interregional pipeline trade increases by 41%, against 31% for LNG. The evolution of interregional trade is very uneven over the projection period; it starts at a very slow pace (3.3% per year) before accelerating in 2015, when it increases at 6% per year, before slowing down slightly at 5% per year over 2016-17. In particular, the evolution of LNG trade is remarkably slow over 2012-14 at 1.4% per year: as highlighted in the section on LNG investments, there is relatively little LNG export capacity coming online during that period. LNG trade develops significantly in 2015, with new LNG plants starting in Australia and in the United States. It is worth mentioning that most new Australian LNG liquefaction plants are projected to start with delays ranging from one to two years, the ones starting first would be the least delayed compared to their initial schedule.

The expansion of pipeline trade is supported by increasing imports from China, both from the Caspian countries and Myanmar, reaching 50 bcm by 2017, from 14 bcm in 2011. Imports to Europe also increase significantly by almost 26% to 236 bcm. However, it is worth remembering that pipeline imports in 2011 were low due to the extremely mild weather, which took away around 30 bcm of gas demand. Even if there were a need to refill storage at the beginning of 2011, in a normal year, imports should have been between 15 bcm and 20 bcm higher. This makes the growth in pipeline trade to Europe less impressive.

On a regional basis, the FSU/Non-OECD Europe region, Africa, Non-OECD Asia excluding China (referred to here as Asia), the Middle East, North America and Latin America are net exporters in 2017. The FSU/Non-OECD Europe region and Africa do not import any gas. Africa's gas exports increase marginally from 94 bcm to 111 bcm, due to the start of Angola LNG mid-2012 and the restart of Libyan gas supplies. The FSU/Non-OECD Europe region is by far the largest exporter of natural gas with over 250 bcm exported by 2017, albeit LNG supplies do not grow over 2011-17, and represent a mere 6% of the region's total exports by 2017. Pipeline exports are growing by 38% over 2011-17. The bulk of the region's exports are therefore by pipeline to Europe, which represents 75% of the region's exports, the rest going to China and the Middle East.

Meanwhile, some countries in the Middle East, Asia and Latin America have to import gas from outside the region in order to meet regional imbalances. Asia and Latin America import exclusively LNG, while the Middle East imports both pipeline gas from Turkmenistan and Africa and LNG. Actually, even if Asia (excluding China) is still a net exporter of LNG and pipeline gas, its net exports halve during the projection period to reach around 20 bcm by 2017. The Middle East remains a significant exporter of natural gas (94% of which is LNG), but its net exports are reduced by 14%. The most significant development takes place in North America with first LNG exports planned to start in 2015, complementing LNG re-exports.

Figure 52 Evolution of LNG exports, 2011-17

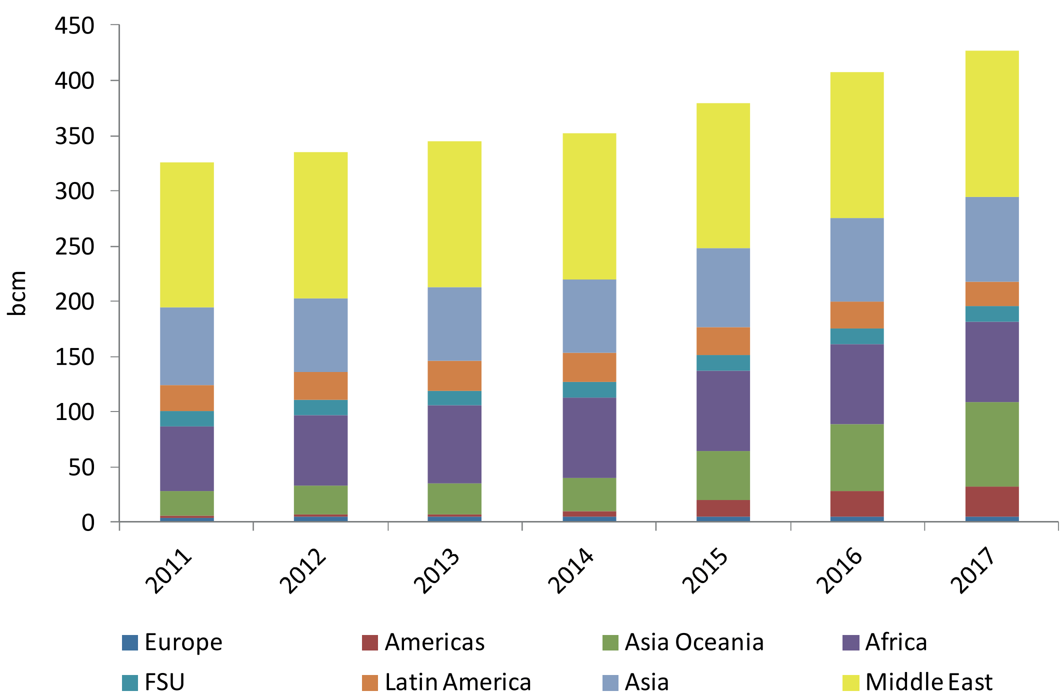
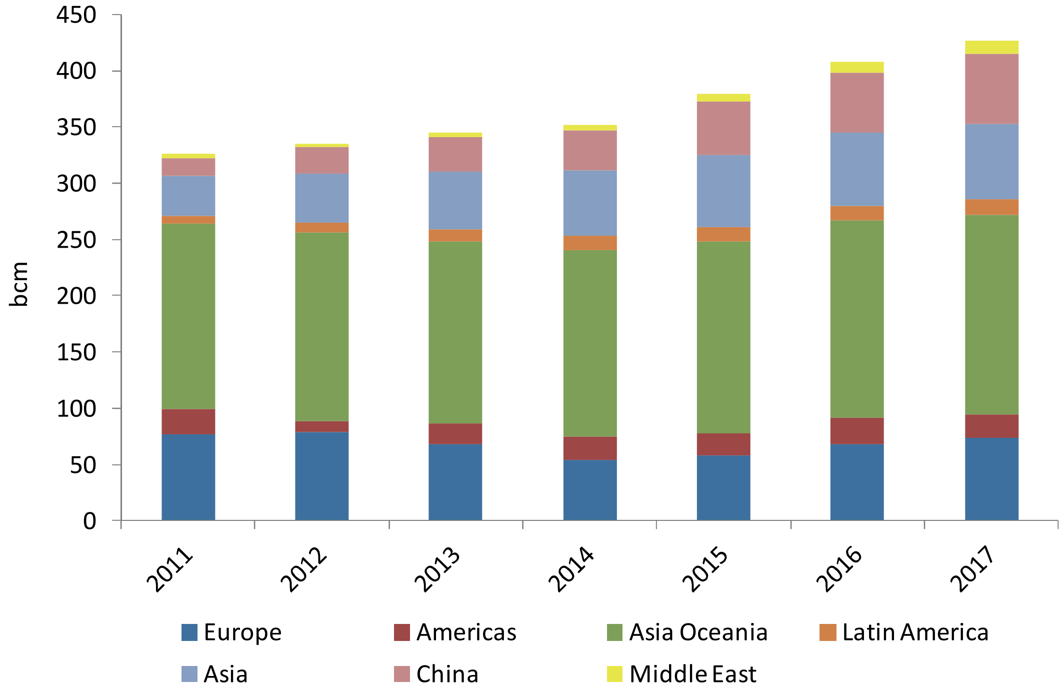
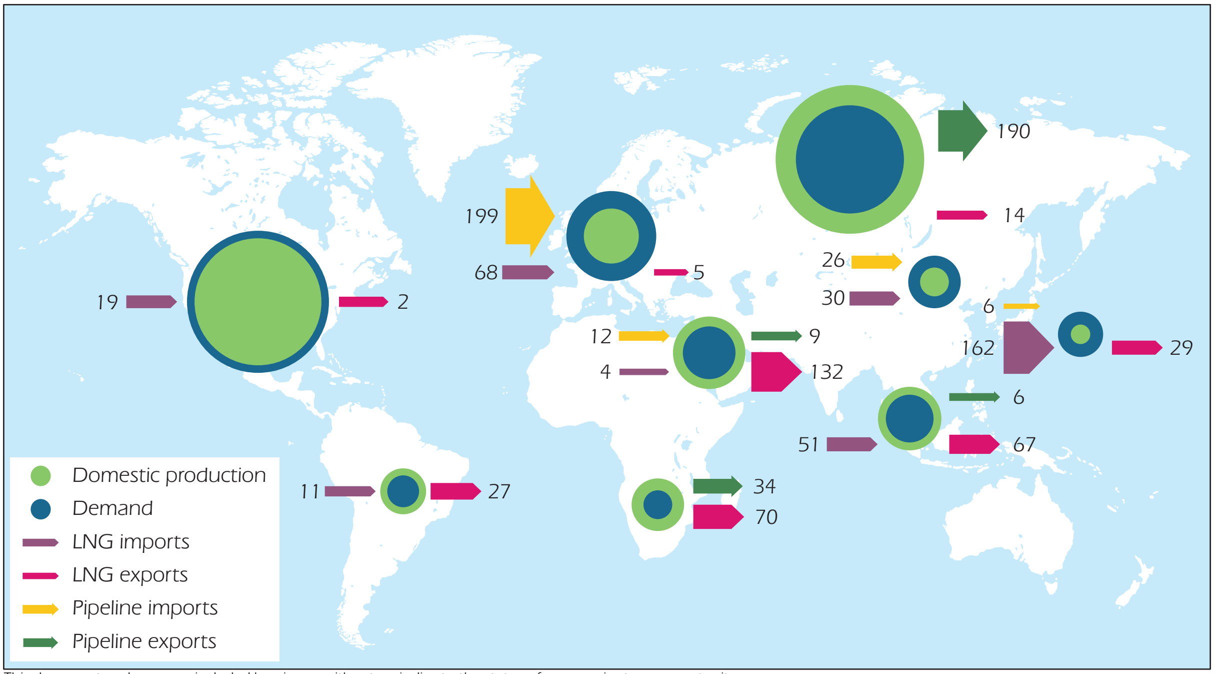


Figure 53 Evolution of LNG imports, 2011-17



Map 7 Global gas trade in 2013



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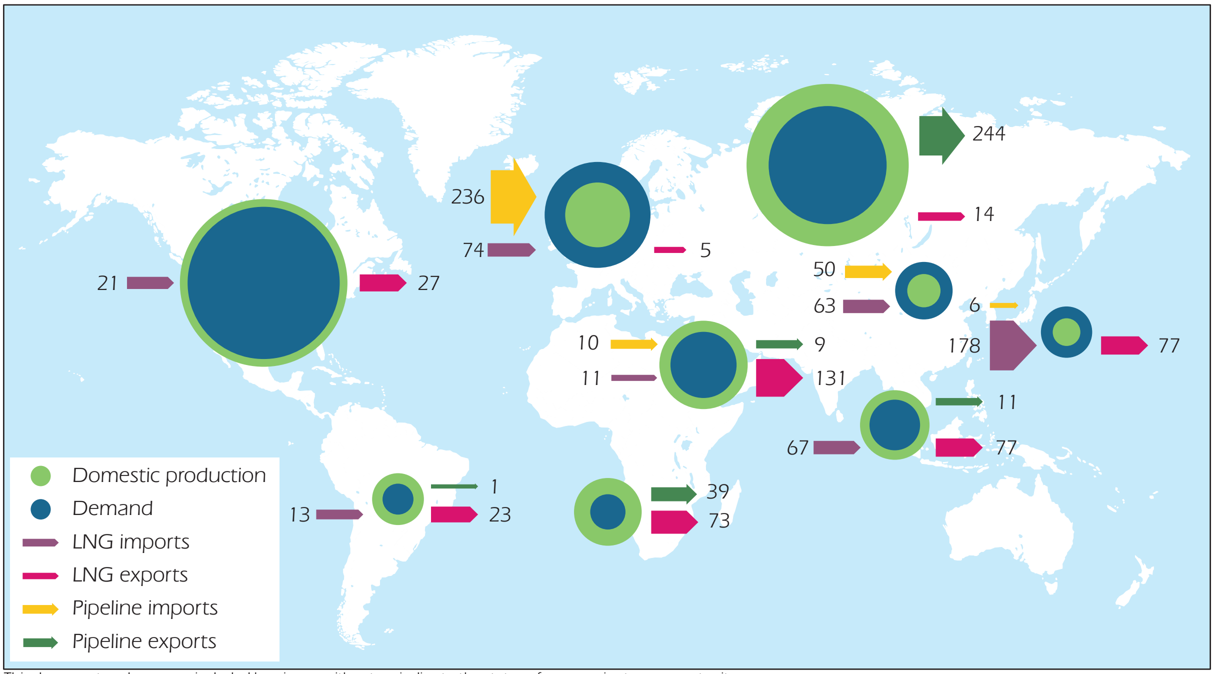
OECD Europe, OECD Asia Oceania and China are all net importers. Both OECD regions also export LNG, although European volumes are limited to Norway (5 bcm). By contrast, LNG exports from Australia (which as a part of OECD Asia Oceania is located near Japan on Maps 7 and 8) are set to expand markedly towards the end of the period reaching 77 bcm of LNG by 2017. Israel becomes self-sufficient by 2015, but does not yet export any LNG or pipeline gas by 2017. Meanwhile, LNG imports are set to increase rapidly in Japan and Korea. During the whole projection period, LNG supplies to China will exceed pipeline supplies. Finally, despite a limited increase in gas demand, OECD Europe becomes more import dependent as its domestic production declines, but keeps a diversified import portfolio consisting of 58% of supplies from FSU/Non-OECD Europe, 28% from LNG, 11% from North Africa, and the balance from the Middle East.

Map 8 Global gas trade in 2017



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Over 2011-17, most additional LNG exports are projected to come from Australia as well as from Africa and North America. Meanwhile, OECD Asia Oceania remains the largest LNG importer, well ahead of Europe. Of note is the rapid increase in LNG imports in Asia and China, amounting to 130 bcm, or one-third of total LNG imports. LNG imports in OECD Americas will remain at the minimum technical requirements. LNG imports in the Middle East and Latin America grow, but their share remains extremely low at 3% each.

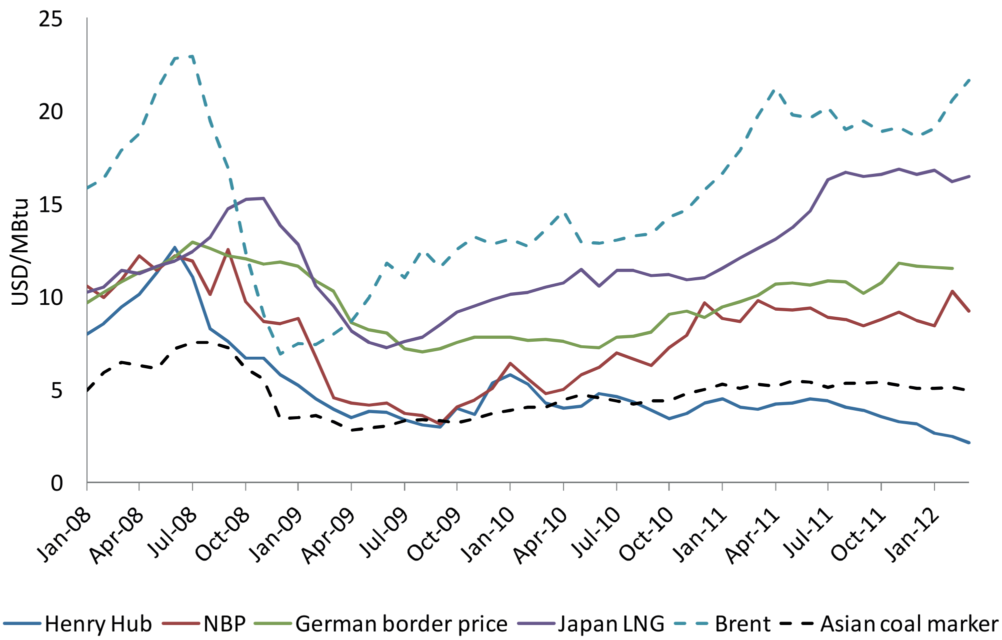
International pricing environment: back to your corner?

The year 2011 saw a continued trend of decoupling natural gas prices, with regional prices (Europe, Japan, United States) being determined by their respective regional dynamics. Despite the increasing volumes of LNG available on global markets, the expected market coupling through LNG has not occurred. On the contrary, 2011 has seen pre-existing trends being reinforced by one-off occurrences that, on the whole, supported a continued divergence of natural gas prices across the globe.

Natural gas prices in OECD Asia Oceania, represented by Japanese LNG import prices, moved away from OECD European and HH prices, closely mimicking oil-indexed prices based on the Japanese Custom Cleared crude oil price (JCC, or Japanese Crude Cocktail). The gap between Japanese LNG prices and HH prices actually widened from around USD 7/MBtu in January 2011 to over USD 13/MBtu in December, as the Japanese LNG price increased by 44%.

In Europe, gas prices continue to be influenced by oil price movements, although oil and gas prices are no longer as correlated as before 2009. The average German border price (at USD 10.6/MBtu) was 32% higher in 2011 than in 2010, while the Brent price increased by 40% over the same period. The relative decoupling of the German price from oil prices reflects an increase in both volumes sold at German hubs from Norway and spot indexation in some long-term supply contracts. These contracts continue to set the upper price limit of available supply, while European spot prices traded on average 15% below these levels in 2011. The average NBP price has nevertheless increased by 37%, reaching USD 9.0/MBtu in 2011. In December 2011, the price differential with oil-indexed prices increased to 25% as spot markets suffered an end-of-year drop due to extremely mild weather. February 2012 saw a jump of the European hub price level due to a sudden increase in demand as a result of extremely cold weather and reduced Russian supplies. However, Day-Ahead prices returned to normalcy within two weeks after Russian supplies dropped below nominated levels (see Box 1).

Figure 54 International gas prices, Asian coal and Brent, 2008-12



Source: ICE, Japanese Customs, and the German customs.

The United States gas prices continue to be decoupled from the international gas market, with HH prices dropping by around 30% over 2011 due to the pressure of increasing US (shale gas) production coupled with extremely mild weather during winter 2011/12, which sent prices well below USD 2/MBtu in the first quarter of 2012. Globally, this results in a three-tier gas market with considerable scope for arbitration. However, infrastructure connecting the three areas continues to lag behind regional supply/demand realities. In the medium term, a possible increase in availability of LNG spot volumes and possible LNG exports from North America could provide energy traders with an increased toolset to pursue arbitrage opportunities.

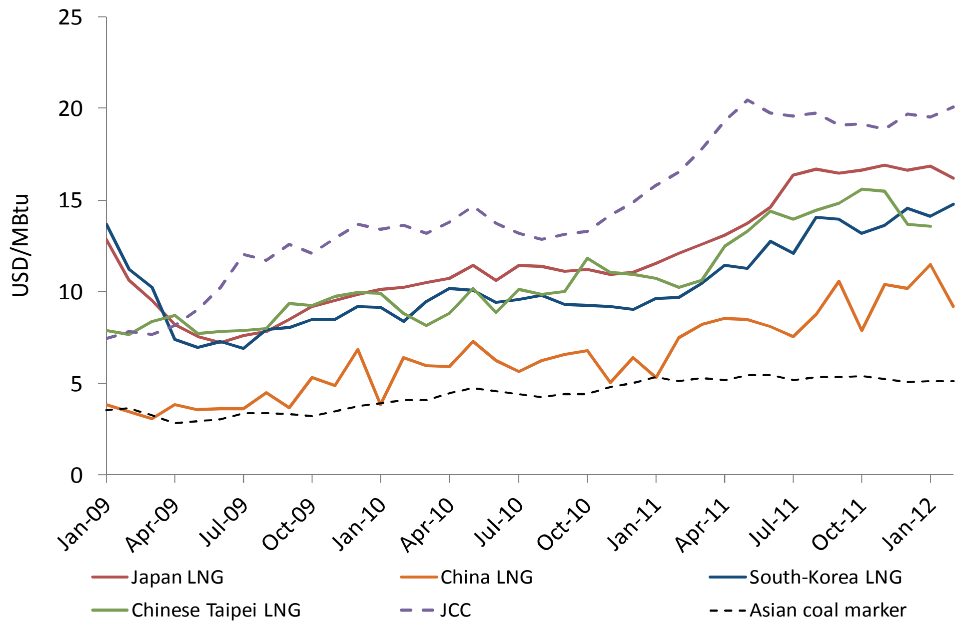
Asian price developments

In 2011, the most notable occurrence in Asia was the substantial increase in Japanese LNG demand to accommodate for the unavailability of a siginficant part of Japanese nuclear generation capacity following the Fukushima accident. In addition, other Asian economies, notably Korea and China, increased their LNG imports from 2010 by 11% and 29%, driven by strong economic growth. Nevertheless, Japan remains by far the largest LNG market in the world, 2.3 times larger than the second largest, Korea. Japanese prices are closely followed by LNG prices in Korea and Chinese Taipei.

Chinese LNG prices currently do not yet fully reflect the Asian price level, due to two long-term contracts at much lower prices that dominate the Chinese import portfolio (USD 3-4/MBtu for 46% of volumes delivered in 2011). This allowed Chinese LNG import prices to compete with Asian coal import prices until the start of 2011. However, as oil-indexed LNG imports from other sources grew, so did China's average LNG import price, moving closer to the Asian average, but still substantially lower (see Figure 55).

Japanese gas prices continue to be oil-linked, since price formation in their contracts continues to be dominated by oil indexation. Additional spot cargoes are valued above or below this level, depending on the availability on the global market. Figure 56 shows that imports from countries considered as spot cargo deliverers (Algeria, Egypt, Equatorial Guinea, Nigeria, Norway, Peru, Trinidad and Tobago, and Yemen) increased considerably after the Fukushima disaster. Since May 2011, they have been accounting for around 10% of total deliveries.

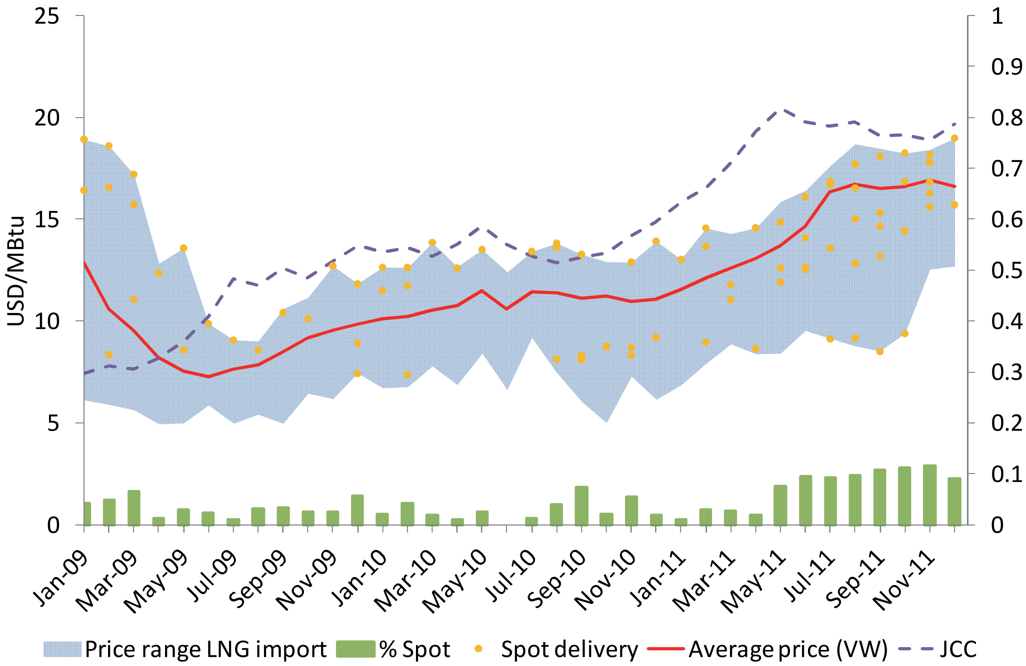
Figure 55 Asian natural gas prices and markers, 2009-12



Source: Japanese Customs, KITA, Chinese Taipei Customs and IEA.

Although one might be inclined to think that spot-purchased volumes would be consistently priced above long-term contracted volumes, this is far from being the case, as 59% of the spot volumes purchased in 2011 were priced below the long-term average price. This indicates that the LNG market was relatively well supplied in 2011, and volumes from the Atlantic were able to make inroads in Asian markets, most notably Trinidad and Tobago, which delivered LNG at around 62% of the average long-term LNG price into Japan after March 2011. Cargoes from Norway, Peru and Nigeria were also cheaper.

Figure 56 Japan LNG import price range and spot deliveries, 2009-11



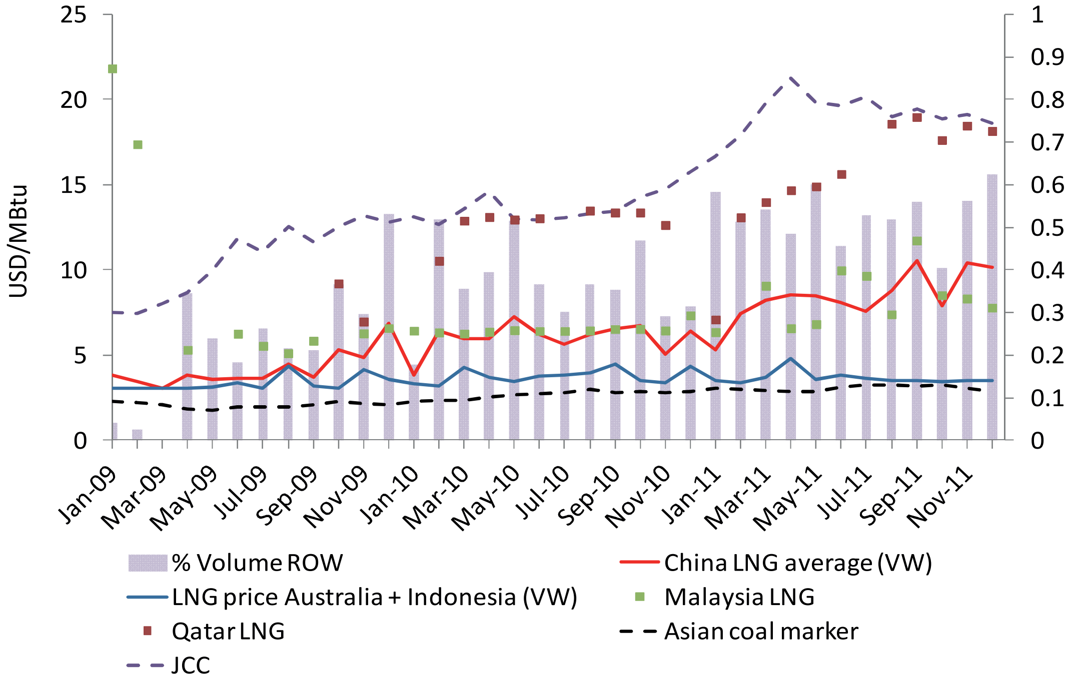
Source: Japanese Customs.

Going into 2012, Japan imported a record volume of 11.1 bcm in January and continued to import at high levels in February (10.4 bcm). It is very likely that the consequences of extended outage of nuclear power generation capacity will continue to push LNG imports to high levels through 2012. This makes the restart of several nuclear power plants a crucial factor in expected LNG demand.

Although China started to import LNG only in mid-2006, LNG imports have surged over the past years. Two long-term contracts with Australia and Indonesia make Chinese LNG imports competitive with Asian coal import prices (see Figure 57). This initially created room for LNG to compete in the Southeast coastal areas. However, from 2009 onwards, the share of LNG from suppliers other than Australia and Indonesia has substantially increased, from 4% in January 2009 to about 62% in December 2011, totalling 8.9 bcm in 2011.

LNG imports from other regions are linked to JCC prices (Qatar LNG), drawing average LNG prices upwards. Currently, the long-term import price paid for Malaysian LNG is likely to set the new floor for LNG imports from within the Asian region to China, since these imports adequately reflect the average Chinese LNG import price.

Figure 57 China LNG import and benchmark energy prices, 2009-11



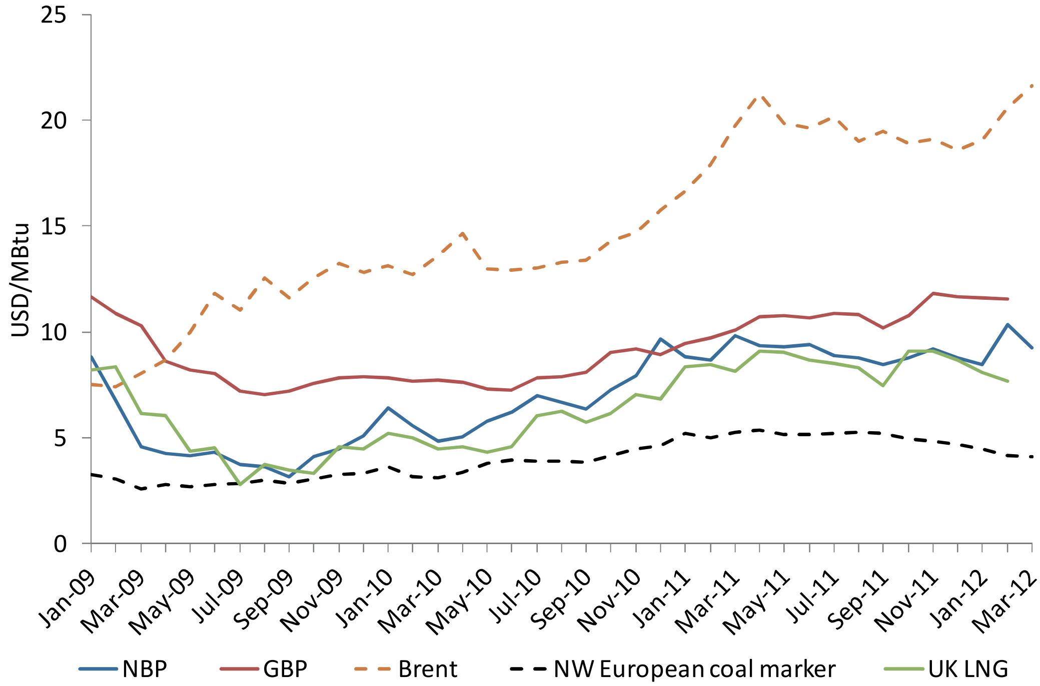
Sources: Japanese Customs, IEA.

European price developments

An ongoing differential between oil-indexed and spot gas prices increased the share of spot indexation in European long-term contracts. This has resulted in an increasing differential between the Brent oil price and the German border price (GBP) since 2009. In 2010, gas markets tightened, while partial spot indexation was introduced in long-term contracts. These two factors contributed to reduce the differential between the UK National Balancing Point (NBP) and the GBP. However, this differential increased once again at end-2011 due to the combination of a strong oil price increase and very weak European gas demand on account of a very mild weather. The average price premium of the GBP on NBP prices was USD 1.6/MBtu in 2011, slightly above the USD 1.5/MBtu premium in 2010.

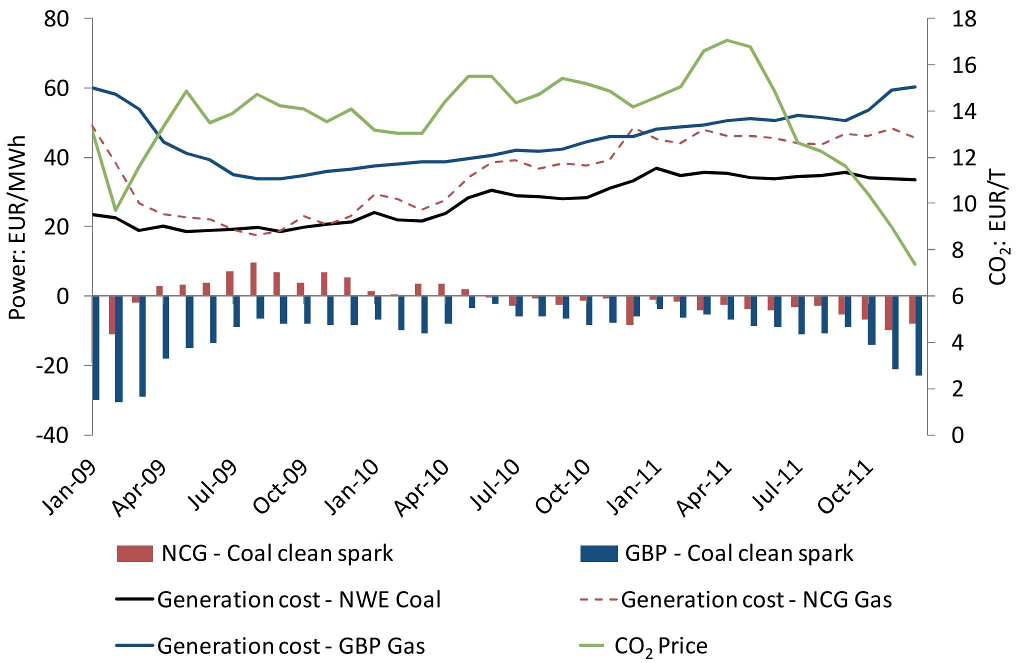
NBP remains the benchmark which other European spot prices follow. Zeebrugge has the smallest differential versus NBP at USD 0.15/MBtu, followed by TTF (USD 0.19/MBtu) and NCG (USD 0.32/MBtu). These increasing differentials reflect transport costs increasing with distance from NBP. As seen in previous years, the seasonal spread between winter and summer NBP prices tends to disappear, with the highest and lowest monthly prices recorded in March and August, respectively. Such a situation is problematic for seasonal storage operations, which traditionally refill storage facilities during the summer. NBP not only has the largest traded volumes in Europe, but it is also the most connected to other world gas markets, attracting by far the largest LNG volumes. Spain does not have a well functioning spot market, while Belgium and the Netherlands have less regasification capacity available. The UK market became the largest European LNG market for the first time in 2011. UK LNG import prices were slightly lower than the average monthly NBP price for most of 2011, and they were also cheaper than NBP imports from Norway.

Figure 58 Northwest European gas prices and Brent, 2009-12



Sources: German Customs, EIA, IEA.

Figure 59 GBP and NCG clean spark versus clean dark in Northwest Europe, 2009-11



Sources: German Customs, IEA, McCloskey, ICE.

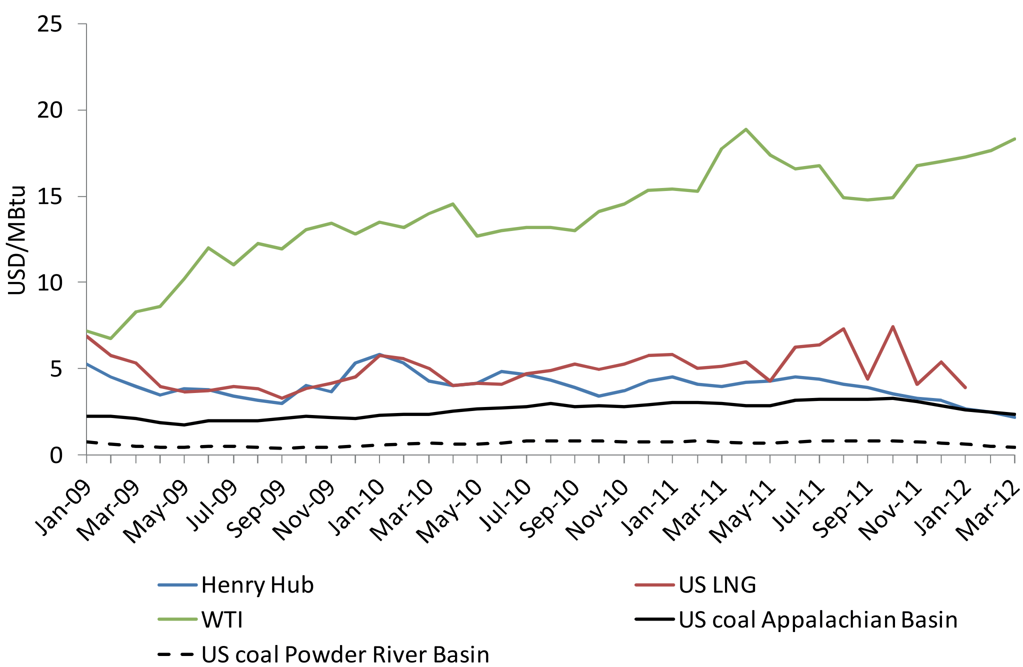
In mid-2011, Nigeria shifted supplies from the United Kingdom to Japan in favour of a possible additional margin of USD 4.5 to USD 6.5/MBtu in Japan (excluding shipping). Margins between imported LNG and NBP prices narrowed considerably during 2011, and imported LNG jumped above NBP prices in October 2011 as Qatari supplies saw a USD 2/MBtu price increase. As Qatar delivered about 85% of UK LNG imports in 2011, this price hike reflects strongly in the LNG import price level.

As for European power generation, CO_2 prices enabled spot-indexed natural gas to become competitive as a source of base-load power from mid-2009 to mid-2010. Figure 59 shows the competitiveness between long-term contracted natural gas (GBP) and spot-indexed natural gas in Northwestern Europe (NBP).[11] Spot gas prices were competitive with coal from mid-2009 to mid-2010, while long-term indexed gas never really became an option for base-load power generation (electricity prices permitting). However, during 2011, neither long-term nor spot-indexed gas was in a position to compete with coal as the marginal source for base-load generation, in part due to a significant drop in CO_2 prices.

US price developments

As a result of continued strong performance of US shale gas production, notably associated gas, HH prices continued their downward trend in 2011. A very mild winter forced them further down by end-2011 and early 2012 to levels unseen since 2002. Gas prices remained relatively stable during the first half of 2011 and then declined 30% from July to December 2011. US gas prices have been firmly decoupled from the WTI oil price since early 2009, showing a average price differential of USD 12.3/MBtu over 2011, more than three times the average 2011 HH spot price.

Figure 60 United States gas price, oil and coal marker, 2009-12



Sources: ICE, EIA, Bloomberg.

[11] Power generation efficiencies are assumed to be 50% for gas and 36% for coal, while gas is assumed to emit 0.4 tonnes of CO_2 per MWh and coal 0.9 tonnes of CO_2 per MWh.

At the end of 2011, HH gas prices dropped close to the calorific equivalent price of coal mined in the Appalachian basin (in the Northeastern United States). Natural gas prices seem to trend towards the coal price, pushing down monthly Appalachian coal prices. Daily HH prices even dropped below Appalachian coal prices in the first quarter of 2012. US LNG imports dropped below 10 bcm in 2010, another 20% drop *vis-à-vis* 2010, reflecting a well supplied market and the minimum amount of LNG required to keep facilities in operation. Until May 2011, LNG cargoes delivered to the United States were priced around USD 1-1.5/MBtu over HH levels. After May 2011, LNG import prices have been oscillating between USD 3.5/MBtu and USD 13/MBtu, due to individual cargoes that were bought at significantly higher prices, while some long-term contracts still import LNG at near HH prices.

With HH gas prices closing in on prices for domestic coal, there may be a significant game change in US power generation, as gas would become competitive as a base-load power source. The potential of coal to gas switching in the United States is analysed in depth in the Demand chapter.

Development of a trading hub in Asia

With at least two functioning, wholesale natural gas markets in major gas consuming regions (North America and Europe), both reflecting a price that closely corresponds to regional supply/demand fundamentals, it is frequently wondered whether a third price benchmark will be established in the developing Asian gas market. The Asian natural gas market is the fastest growing market and is expected to become the third largest gas market by 2017 with 634 bcm consumed. However, the entire Asian-Pacific region lacks a trading platform to facilitate the exchange of natural gas and consequently, a price signal that is able to steer investments in natural gas infrastructures. This issue has come even more to the forefront in the aftermath of the Fukushima disaster, which pushed Asian natural gas prices to record highs based on oil-price indexation and limited buying flexibility for utilities. Despite the relatively high price incentive and limited flexibility in LNG long-term contracts, a move towards a liberalised energy market in several Asian countries remains currently unlikely.

Obstacles to the development of a pan-Asian natural gas trading platform are located in the entire natural gas value chain. These include:
- large discrepancies in the developmental stage of national natural gas markets;
- a lack of third-party access; and
- limited flexibility in LNG supply contracts.

These three factors make an overarching functional trading hub that provides an accurate price signal reflecting regional supply and demand unlikely in the near future.

Downstream: development of a wholesale natural gas market in Asia

So far, the most mature Asian gas markets, Korea and Japan, have suffered from a lack of competition in both the upstream and downstream sector. Traditionally Japanese and Korean companies purchase LNG under long-term contracts with oil-indexed prices, limited flexibility for consumers and high demand certainty for suppliers. These contracts also require limited competition in the downstream sector since LNG buyers need a guaranteed market for distribution to end-consumers.

Currently, commercial parties in Japan and Korea do seem to accept this strategy, with a high emphasis on security of supply, as opposed to price efficiency. Both are reportedly looking at ways to combine natural gas purchases of several companies from both countries. These efforts will clearly not contribute to a more cost-efficient and flexible gas supply system, as buyers will likely require more guarantees when confronted with this kind of buying power.

Several regional economies are looking to start, or increase, natural gas imports, notably China and India, but also Thailand, Indonesia, Malaysia, Vietnam and Singapore. Although this is a very diverse group, both in terms of size and market outlook, all their domestic gas markets suffer from considerable price distortions that rapidly push up demand and distort the functioning of their markets. For most of these economies, the establishment of a wholesale natural gas market will mean a considerable overhaul of their energy sectors. Thus, they are consequentially far from a mature natural gas market situation in which a move towards a liberalised natural gas sector is possible.

Generally, such a move would first include a shift from the current "no market" situation towards a "developing market" situation, with increasing competition between suppliers and consumers at the wholesale level. The subsequent establishment of a functioning wholesale natural gas market with a well functioning liquid natural gas future market (with a reliable price for delivery in the future) can be considered as the "crown" on natural gas market liberalisation. The resulting price signal should give parties enough confidence to steer investments in the natural gas sector.

In parallel, a functioning wholesale market for natural gas will require governments to take a different role than is now common in the various developing markets. In a liberalised system, the government will have to adapt to the role of the regulator and will ultimately move into the role of arbitrator via competition authorities. This will require a consistent mindset towards liberalisation and handing over of control of a part of the economy, frequently perceived as crucial, something that governments will find very difficult to do.

Finally, this process will require the natural gas sector to radically change its form and outlook, if not through outright privatisation and unbundling of a national champion(s), then at least through indiscriminate TPA and increased competition. The establishment of a functioning liquid natural gas exchange will eventually require the involvement of non-traditional parties willing to take price risks on gas volumes for future delivery (usually financial parties). This will further shake-up the composition of parties active in the natural gas markets, irremediably changing its form and outlook. It is clear that most mature Asian gas markets have difficulty progressing towards a liberalised wholesale natural gas market, essential to a price signal based on local demand/supply fundamentals.

Development of a competitive natural gas infrastructure in Asia

A unique Asian perspective on natural gas trade is the limited amount of natural gas that is traded via pipelines between Asian countries. Indeed, natural gas consumed in Japan, Korea and Taiwan is nearly exclusively LNG, since only a very small amount is locally produced. In 2010, gas traded intraregionally via pipelines amounted to 25 bcm, and was mostly concentrated in South Asia. Meanwhile, Asia imported 180 bcm of LNG, half of which came from the Asia-Pacific region.

The only real interregional pipeline trade developed following the opening of the Turkmenistan-China pipeline, which brought Turkmen gas in competition with domestically produced gas and LNG. In most other Asian markets, LNG will represent the majority of future natural gas imports (see section on developing import infrastructure in this chapter). However, LNG regasification terminals are usually built with capacity dedicated to LNG importing companies (frequently national or regional champions), with a specific portfolio of customers in mind. Therefore, LNG regas capacity usually matches these companies' import and sales portfolios, leaving little spare capacity available for competititors. Even if a forecasted demand increase fails to materialise in a developing market, leaving some import capacity unutilised, it may not be available for competitors due to a lack of third-party access. Creating open-source LNG import terminals in non-liberalised gas markets has so far proven difficult, and one of the main developers of this type of terminals, 4GAS, has floundered. Regasification terminals without long-term committed capacity that have been built were constructed in liberalised gas markets, *i.e.* in the United States and in the United Kingdom.

Increasing competition between LNG suppliers to gain market share in Asian markets will therefore be a very difficult process from both a regulatory and commercial perspective. An important factor would be the establishment of indiscriminate TPA to infrastructure and regasification terminals in these markets. This is challenging since most countries are currently not committed to a liberalisation process and, therefore, are not planning to create any TPA regime that would open up existing regas terminals or make the construction of new ones possible. Secondly, since most regas capacity is already committed to companies that have developed them with specific contractual obligations in mind, forcing TPA will not make substantial regas capacity available in the short term, since contractual obligations with LNG producers dictate otherwise.

Contract developments in LNG markets

As long-term supply contracts remain the main vehicle to bring customers and suppliers together in the Asian natural gas market, substantial changes would be required to allow upstream parties (or their customers) to compete directly for market share in national/regional gas markets. In Asia, long-term oil-indexed contracts are currently the norm, and large buyers such as Japan and South Korea continue to commit to oil-indexed prices, with destination clauses and co-investment in upstream projects (like Australia).

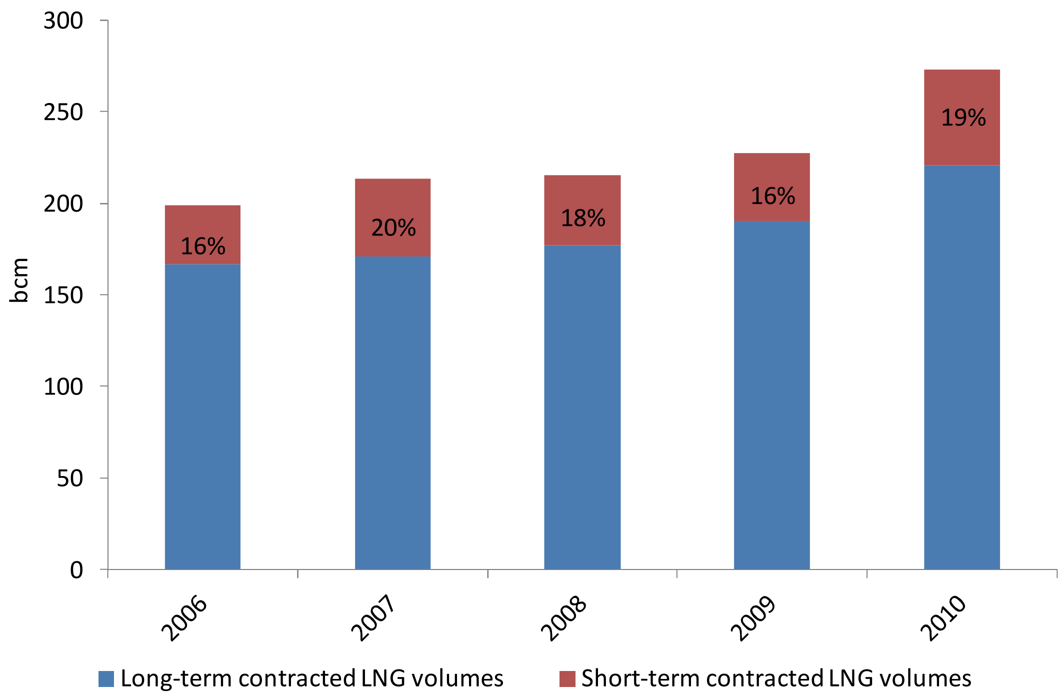
Stringent volume requirements are deemed necessary to recover costs of LNG projects that require substantial upfront investments in production, liquefaction and transport capacity. In turn, it also satisfies the wish of several customers to build a long-term portfolio and increase security of supply. These contract conditions do limit the flexibility of LNG to move across the globe and are even more stringent since LNG producers enforce destination clauses that limit the buyer's ability to divert cargoes to other markets if circumstances or prices require. Destination clauses give suppliers the ability to enforce regional segmentation in their portfolio, limiting LNG's technical ability to serve as an instrument of arbitrage between markets (see the section on pricing environment in this chapter).

In general, a more flexible LNG supply system in Asian natural gas markets will depend on more short-term LNG (to be contracted for up to three years) becoming available on world markets. Availability will remain a point of concern for upstream competition and the eventual development of a price benchmark in the Asian market. New entrants on the LNG import market might be able to look for more flexibility than is currently offered, as their LNG requirements differ from that of traditional buyers. However, flexible spot LNG has so far not risen beyond 20% of global LNG trade, with only half of those reaching the Asian markets.

The availability of future spot LNG availability is a source of much speculation. In 2012, Angola LNG will deliver its entire production of 7 bcm as spot cargoes. Although a major expansion of LNG production is expected from Australia, it is unlikely to provide substantial uncommitted volumes of LNG since the bulk has been contracted, notably by Asian parties. However, the volumes of flexible LNG that do become available from Australia, about 8% (9 bcm) will most likely find their way to the Asian market. Large additional sources of flexible LNG are most likely to come from the United States and Canada, where several LNG export plants are planned.

The contracts signed for Sabine Pass seem to suggest that a substantial share might indeed find its way into portfolio's of global energy companies and be considered flexible. This LNG export facility does not require any destination clause and is based on a spot indexation. It is not entirely sure, however, that Canada's project sponsors would use spot indexation. Nevertheless, if more export ventures succeed in tapping into the shale gas boom, more uncommitted volumes of LNG at Henry Hub prices could become available on world markets. In addition, another source of flexible LNG supply might become available if some long-term contracts that have recouped original investments are renegotiated in such a way that destination clauses are scaled back or dropped altogether. These possible developments might increase the availability of flexible LNG on global gas markets to respond to pricing signals from market initiatives under development such as Singapore.

Figure 61 Short-term traded volumes of global LNG supply, 2006-10



Source: GIIGNL, annual reports 2006 to 2010.

Is Singapore a glimmer of light?

In the medium term, Singapore seems to be a potential candidate to reform its natural gas sector in such a way that a competitive market will evolve. The Singaporean government is pushing for increased competition on the consumer and supplier sides. As Singapore is already one of the major oil trading hubs in Asia, the government has extensive knowledge and experience with regulating the energy commodity trade. This means that commercial and financial parties familiar with energy commodity trade are already present.

In addition, Singapore LNG company (SLNG) is on track to build Singapore's first LNG import facility, which will bring LNG in direct competition with imported pipeline gas for wholesale consumers by end-2013. In a first phase, the LNG import capacity will amount to 4 bcm (3 mtpa), which is fully committed to BG's global portfolio. A second phase will add another 4 bcm (3 mpta) in 2014.

The government has displayed a willingness to support competition in the natural gas sector; but so far, it is not clear how it would facilitate competition between piped natural gas and LNG after the launch of the LNG import terminal, or what amount of import capacity will be available for spot trade. To allow for a reliable pricing signal to develop in this market, it is crucial that these issues be solved in a timely manner. Another challenge would be the increased availability of spot LNG on global gas markets, which is likely to be the most difficult parameter as it is set on the world market.

Perspectives on a future Asian gas benchmark price

For the moment, it is clear that a possible development of a reliable price signal in any Asian market is unlikely to happen overnight and will not necessarily lead to lower prices in most markets, as some frequently assume. A considerable number of developing economies have strict price controls in place for locally produced gas, and they have not initiated policies to develop a liberalised gas market. In addition, the availability of flexible LNG on global gas markets is a variable out of governments' reach, and frequently detrimental to their perceived interest in security of supply. The eventual development of a reliable pricing signal in Asia reflecting local supply/demand fundamentals will, however, allow LNG supply systems to become more efficient and therefore more resilient in handling future gas supply/demand shocks in the Asian market.

Spot market developments

In 2011, volumes of natural gas traded on European hubs broke another high, signalling the market's continued shift away from long-term, oil-indexed contracts to more short-term, gas-indexed contracts as the basis to bring producers and consumers together. In 2011, physical volumes traded on the European continent grew by 8%, adding 12.2 bcm to hub-delivered volumes, totalling 162.3 bcm in 2011. Traded volumes on continental markets jumped by nearly a third in 2011 to 542 bcm, an increase of 116 bcm. Among others, two factors in particular contributed to this growth in 2011:

- the price differential between oil-indexed gas and gas traded on hubs continued to draw consumers towards the hubs; and
- ongoing regulatory developments on the European continent contributed to liberalising natural gas markets and facilitated hub trading (see section on regulatory development below).

The volumes delivered on hubs have seen considerable growth since 2008 compared to the total physical demand in the respective national markets. In 2011, the volumes physically delivered on hubs met 75% of total natural gas demand in the corresponding countries, an 11% increase *vis-à-vis* 2010. This shows that the role of trading hubs as an instrument for natural gas ownership exchange in continental Europe is already considerable and continues to increase. The NBP is still the leading natural gas market in terms of market maturity, since nearly all gas consumed in the United Kingdom is bought and sold on the trading hub (95% in 2011). It is by far the most liquid hub and represents over two-thirds of volumes traded in Europe.

Table 27 Traded and physical volume on NBP and continental hubs (bcm)

Physically delivered								
	NBP	Zeebrugge	TTF	PSV	PEG's	GASPOOL	CEGH	NCG
2003	52.5	10.2	1.3	0.1				
2004	53.2	10.6	2.3	1.0	0.2			
2005	53.7	8.4	3.8	2.0	2.7	0.3	0.7	
2006	60.6	8.6	5.9	4.8	3.8	0.8	4.7	0.1
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	95.8	16.7	31.3	21.5	8.7	29.6	10.9	31.3
2011	79.6	14.3	35.6	23.0	12.8	29.6	11.6	35.5
Traded								
	NBP	Zeebrugge	TTF	PSV	PEG's	GASPOOL	CEGH	NCG
2003	611.0	38.6	2.3	0.1				
2004	551.9	41.1	6.2	1.1	0.3			
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	27.6	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.5	15.6	16.5	9.7	14.9	25.3
2009	1016.1	64.9	73.6	23.5	23.1	28.6	22.8	56.0
2010	1095.5	65.2	106.5	43.1	27.8	65.0	34.1	84.1
2011	1137.2	69.3	151.7	57.7	39.8	75.8	39.2	108.5

Sources: TSOs and regulators.

Notes: TTF: Title Transfer Facility, PEG: Point d'Echange Gaz, PSV: Punto di Scambio Virtuale, NCG: NetConnect Germany. CEGH: Central European Gas Hub.

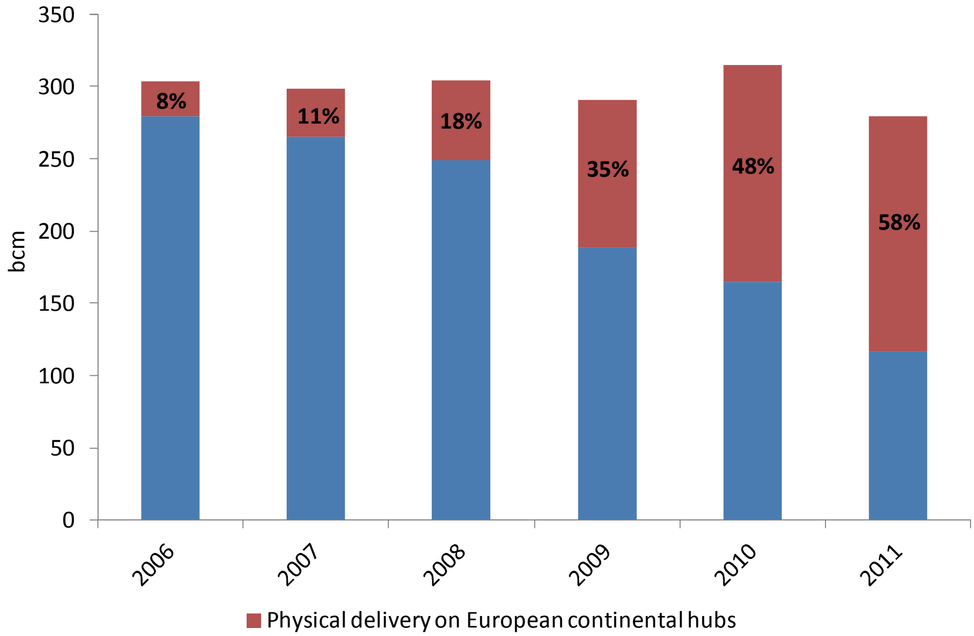
In terms of physically delivered volumes, continental spot markets collectively overtook NBP in 2009 and exceeded NBP by 83 bcm in 2011. However, all continental spot markets are individually smaller and less liquid than NBP on traded, physical volume, and churn. In 2011, NBP and Zeebrugge were the two hubs that saw an actual decrease in physically delivered volumes, dropping by 17% and 14%, respectively. Other continental hubs saw considerable growth in volumes delivered, led by the French PEGs with a 47% increase followed by German NCG and Dutch TTF (both adding +13%). The total volume delivered on the European hubs was 242 bcm in 2011, 4 bcm less than in 2010.

The picture on traded volume was markedly different because of the unrelenting growth in all hubs in 2011. Total volume traded grew by 10%, while trade on the continent surged ahead by 27%. Most notable was trading on Dutch TTF and the French PEGs, which grew by 42% and 43%, respectively. In addition, Italian PSV and German NCG showed robust growth in traded volumes by 34% and 29%, respectively. In comparison, increase in traded volumes on NBP and Zeebrugge by 4% and 6%, respectively, were quite modest, but considering their simultaneous decline in physical volume, this was nonetheless a considerable feat.

Overall, 2011 showed another increase in both physical and traded volume on the continent, where TTF and NCG continue to show considerable promise in attracting physical volume equal to their respective national and regional demands, and accordingly, in trading these developed volumes. In that respect, the Belgian trading hub lags behind in developments in other continental markets.

In general, liquidity is considered to be a measurement of how well a market functions or how well an asset (in this case, natural gas) can be sold, without causing a significant change in its price, at a minimum loss of value. However, measuring liquidity in one all-encompassing indicator that accounts for market size, number of market participants, churn factor, number of products offered, and the bid-ask spread for products offered in a market is nearly impossible. Finally, all indicators are representing the current state of affairs, and do not necessarily give an indication of any future liquidity development.

Figure 62 Physical volume delivered on continental hubs as share of total gas demand[12]



Source: IEA, TSOs and regulators.

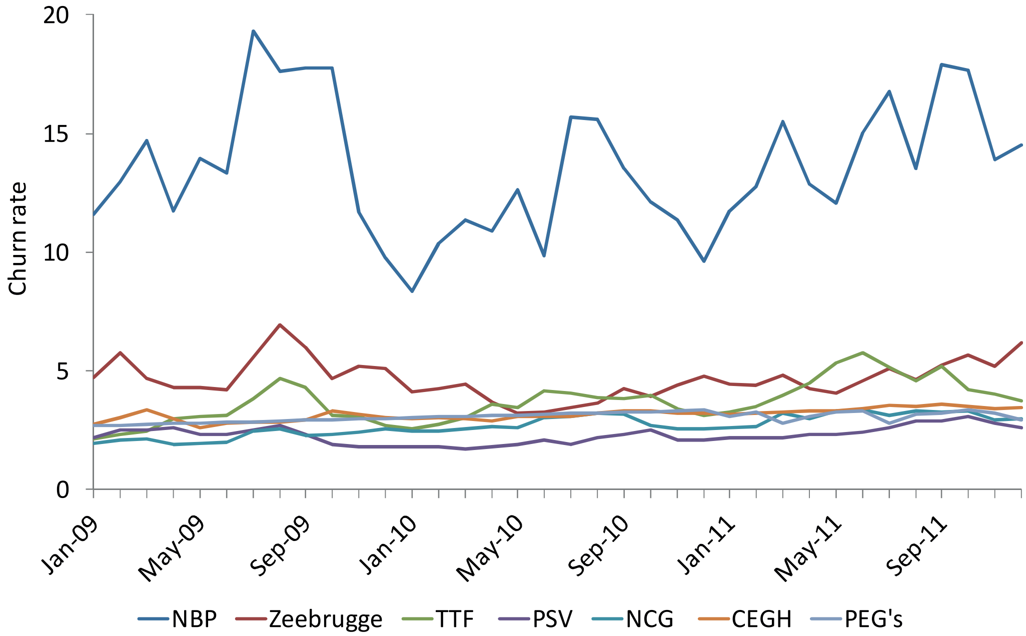
The most basic measurement of spot market liquidity is the churn rate. In general, a churn rate of around or above ten is considered to be a liquid hub, although some parties consider a market liquid at eight and others consider that a churn rate of a minimum of 15 is required. NBP is still the only liquid natural gas market based on its current churn rate, which was 14.3 on average in 2011. Other continental gas markets have shown some progress in the past, but they struggle to break the barrier of a churn rate of four. So far, Zeebrugge and TTF have set themselves aside from the rest on the continent with churn rates of 4.8 and 4.2, respectively. The new balancing regime on TTF introduced on 1 April 2011 has so far had a limited effect on its churn rates. Especially in the third quarter 2011, general insecurity in the natural gas market resulted in limited participation of financial parties on TTF, inducing an actual drop in the churn rate.

Another measure of market liquidity is the time horizon on which products can be traded on a spot market. As financial parties are mostly active on the further side of the curve, the development and increase of a price further away in the future signals increased confidence of financial parties in the market, and that a market is moving away from the balancing function on to a natural gas exchange

[12] Austria, Belgium, France, Germany, Italy and the Netherlands.

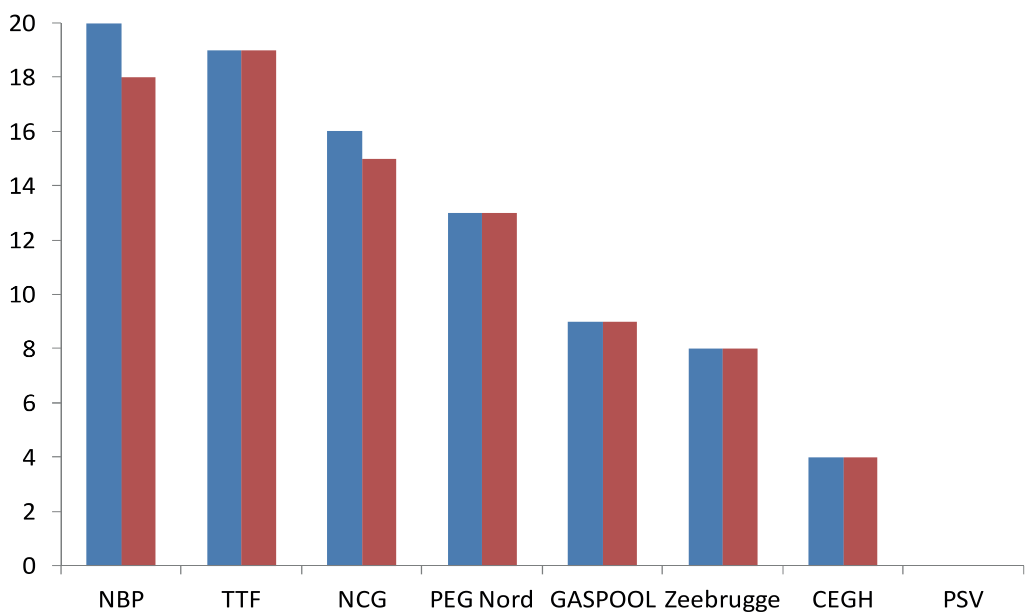
able to generate a price signal. So far, NBP and TTF have a considerable advantage compared to other continental hubs, since both are able to generate reliable prices for gas delivered up to three years in the future. The fact that the number of products traded on these hubs is significantly larger than on other hubs does give an advantage to NBP and TTF.

Figure 63 Monthly churn rates at European spot markets



Source: TSOs and regulators.

Figure 64 ICIS Heren tradability index of European trading hubs Q1 2012



Source: ICIS Heren, 2012.

The increased number of products available on a hub (such as Daily, Monthly, Quarterly, Seasonally, Yearly) is also a sign of the increased confidence that market parties have in the spot market's functioning and liquidity, as these products are usually introduced after extensive market party consultation. Other continental spot markets, such as Zeebrugge and NCG, only set prices for volumes delivered up to one and a half years in the future. NBP and TTF also have smaller bid-ask spread spreads on the future curve than other continental hubs.

This trend is also reflected in the Heren Tradability Index (see Figure 64), an index that compares the tradability of several comparable products on the major European trading hubs (ICIS, 2012). The status of TTF on both product availability and bid-ask spread is reflected in this index, as the average product spread is measured and scored.[13] TTF overtook NBP on the Heren Tradability index for the first time in the third quarter 2011 and was subsequently overtaken by NBP in the first quarter 2012. A major reason for the rise of the TTF is the increased liquidity of its products on the farther end of the curve, with smaller spreads on the curve as well. NBP's liquidity on the prompt of the curve (Within-Day and Day-Ahead) is unsurpassed in Europe, however, it is less pronounced in such an index.

Regulatory developments in Europe

The first European Council meeting on energy in February 2011 confirmed that safe, sustainable and affordable energy contributes to Europe's competitiveness and is an EU priority. The EU plans to continue to build an internal energy market by 2014. As part of these efforts, the Council of European Energy Regulators (CEER) has embarked on developing what has become known as the Gas Target Model (GTM). Broadly, the GTM is expected to deliver well-functioning, interconnected, European wholesale markets that make efficient use of existing infrastructure, secure stable supply patterns and draw in further economic investments. Despite the ambitious target to develop a "one model", it has since become clear that "one-size-fits-all" is not an option for European gas market integration, as different countries will start from very different points of departure.

In 2011, CEER developed a common vision on what a functioning wholesale market should look like by defining a set of parameters for such a wholesale market. These parameters included a churn rate of 8, a Herfindahl-Hirschmann Index below 2000, gas being available from at least three different supply sources, a total gas demand within the entry-exit zone of at least 20 bcm and a Residual Supply Index (RSI) of more than 110% for more than 95% of days per year. On 13 March 2012, the European Gas Regulatory Forum (also known as the Madrid Forum) endorsed the GTM and invited Member States to develop action plans to implement the internal gas market by 2014. However, despite this European framework, individual European TSOs and regulators have continued their efforts to increase functioning of their respective existing wholesale markets. Some examples follow.

On 1 April 2011, a new balancing regime started in the Netherlands. The Dutch TSO, Gas Transport Services (GTS), introduced an hourly balancing system, in which the responsibility for within-day balancing lies with the shippers, as opposed the TSO itself, as was previously the case. To procure the hourly volumes of gas needed to balance the system, a Bid Ladder Price system (BPL) was introduced. The price at which the TSO would have to buy gas to balance the system is determined by the cumulative imbalance, and the costs charged to the causers of the imbalance.

[13] Products compared are the following: within-day, day-ahead, balance-of-month, month-ahead, quarter-ahead, season-ahead, two seasons-ahead, year-ahead, two years-ahead, three years-ahead.

The reform in the Belgian network system was deemed to simplify the system, albeit engendering several issues. The four existing balancing zones will be merged into two, one for each gas quality (low and high), each served by their own trading hub. However, the Belgian TSO Fluxys decided to keep the physical Zeebrugge hub in operation (renamed Zeebrugge Beach), as it plays a major role in facilitating long-term contracts from various sources. Despite the proximity of Belgium to adjacent LNG markets, it is hard to see how three different trading points would facilitate market transparency in a rather small market.

In Italy, even with significant growth in 2011, there is still a lack of confidence in PSV's price signal, due to importance of long-term, oil-indexed supplies. ENI's gas release formula is still considered to be a more reliable price benchmark for Italy. On 1 December 2011, a new balancing platform, PB-Gas, was launched on which the TSO Snam Rete Gas would balance the system by buying and selling volumes of gas from participants that hold storage capacity. After a trial phase until April 2012, individual market parties traded amongst themselves and with Snam Rete Gas to keep the system balanced. In addition, Snam Rete Gas initiated a new virtual storage programme that allows market parties to offer gas at PSV in winter, which is virtually stored at Zeebrugge and TTF via a financial swap. The system aims at increasing competition and linking PSV prices to other hub prices. The programme will start in the fourth quarter of 2012, and will last up to 2015, when additional physical storage capacity is expected to be available.

Central and Eastern Europe continue to lack functioning wholesale natural gas markets. The largest one, the Central European Gas Hub (CEGH) at Baumgarten in Austria, suffers from a lack of liquidity due to the dominance of long-term contracted Russian gas, putting CEGH spot prices at a premium on NCG. However, in October 2011, the Austrian Parliament approved amendments to its Natural Gas Industry Law, including the development of a virtual point of exchange replacing the current physical balancing hub in January 2013. There are also plans to establish an interregional balancing platform with some of the smaller regional TSO's, thereby making the CEGH central to regional balancing, but a key uncertainty is whether new entrants would start trading at CEGH as well, to promote liquidity on the curve.

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Table 28 World gas demand by region and key country (bcm)

	2000	2010	2011	2013	2015	2017
OECD Europe	474	570	520	529	547	561
G4	300	329	288	296	302	303
Western Europe	400	465	410	419	428	434
Central and Southeast Europe	60	88	94	96	105	113
Americas	794	840	862	909	941	969
United States	661	673	690	728	754	779
Asia Oceania	131	195	212	211	227	241
Japan	83	109	121	121	126	129
Latin America	95	136	139	152	163	179
Brazil	9	24	24	32	37	43
Africa	59	103	111	125	139	149
Algeria	18	26	30	36	40	42
Egypt	22	46	49	53	56	58
Middle East	179	369	389	427	444	468
Qatar	11	24	33	45	47	50
Saudi Arabia	42	82	86	101	105	112
FSU/Non-OECD Europe	597	690	705	722	731	735
Russia	391	473	483	493	499	501
Caspian region	83	109	111	117	118	120
Non-OECD Europe	30	28	29	30	32	32
Asia	180	399	424	489	564	634
China	28	110	132	176	226	276
India	28	64	65	64	72	83
ASEAN	85	151	149	165	178	188
OECD	1 400	1 606	1 593	1 649	1 715	1 771
Non OECD	1 111	1 698	1 768	1 915	2 041	2 166
EU-27	477	545	489	497	508	515
Total	2 510	3 303	3 361	3 564	3 757	3 937

Notes: Numbers may not add up due to rounding.
G4: France, Germany, Italy, and the United Kingdom.
Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Spain, Switzerland, and the United Kingdom.
Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovakia, Slovenia, and Turkey.
Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.
Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.
ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam.

Table 29 World sectoral gas demand by region (bcm)

	2010	2011	2013	2015	2017
OECD Europe	570	520	529	547	561
Residential-commercial	230	200	221	224	228
Industry	117	111	113	121	125
Power generation	193	181	167	174	179
Americas	840	862	909	941	969
Residential-commercial	253	255	248	246	245
Industry	196	202	218	225	234
Power generation	276	285	321	341	356
Asia Oceania	195	212	211	227	241
Residential-commercial	50	50	50	51	52
Industry	27	27	31	33	35
Power generation	102	119	113	121	128
Latin America	136	139	152	163	179
Residential-commercial	14	14	14	15	15
Industry	51	52	57	61	65
Power generation	41	41	48	53	60
Africa	103	111	125	139	149
Residential-commercial	7	7	8	9	10
Industry	27	29	35	39	41
Power generation	53	58	64	72	79
Middle East	369	389	427	444	468
Residential-commercial	48	50	51	51	49
Industry	104	107	122	129	139
Power generation	150	155	162	171	187
FSU/Non-OECD Europe	690	705	722	731	735
Residential-commercial	128	122	123	123	123
Industry	128	129	131	134	135
Power generation	350	369	378	382	385
Asia (excl. China)	289	292	313	337	358
Residential-commercial	15	15	17	18	18
Industry	74	75	78	86	92
Power generation	144	145	159	172	183
China	110	132	176	226	276
Residential-commercial	37	44	60	76	90
Industry	32	39	49	62	72
Power generation	23	30	43	58	77
Total	3 303	3 361	3 563	3 756	3 937

Notes: Numbers may not add up due to rounding.
This table does not show other sectors such as energy industry own use, transport and losses. The industry sector includes gas use by fertiliser producers.

Table 30 World gas supply (bcm)

	2000	2010	2011	2013	2015	2017
Europe	303	301	273	267	268	256
Norway	53	110	105	113	116	117
G4	156	82	69	62	59	53
Western Europe	232	173	151	140	138	126
Central and Southeast Europe	10	10	10	10	10	10
Americas	760	816	863	884	936	975
United States	544	604	653	680	729	769
Asia Oceania	42	61	61	72	95	134
Australia	33	49	49	60	81	118
Latin America	103	161	164	168	176	189
Argentina	40	43	42	38	39	42
Brazil	7	14	17	20	25	32
Africa	124	209	204	228	249	261
Algeria	77	80	80	82	89	94
Egypt	22	62	62	66	70	73
Middle East	202	475	516	552	566	588
Qatar	24	121	147	162	165	169
Saudi Arabia	42	82	86	101	105	112
FSU/Non-OECD Europe	726	826	863	926	971	992
Russia	573	637	659	698	739	757
Caspian region	118	154	170	195	201	206
Non-OECD Europe	16	14	14	13	13	11
Asia	243	432	431	455	495	542
China	27	97	102	120	141	163
India	28	51	47	39	43	52
ASEAN	154	218	215	223	230	242
World	2 501	3 281	3 375	3 553	3 757	3 937

Notes: Numbers may not add up due to rounding.
G4: France, Germany, Italy, and the United Kingdom.
Western Europe: Austria, Belgium, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Spain, Switzerland, and the United Kingdom.
Central and Southeast Europe: Czech Republic, Estonia, Greece, Hungary, Poland, Slovakia, Slovenia, and Turkey.
Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan, Uzbekistan.
Non-OECD Europe: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Gibraltar, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Malta, Montenegro, Romania, Serbia.
ASEAN: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam.

Table 31 OECD essentials (bcm)

	Demand (2010)	Production (2010)	Import dependency (%)	Import diversity (HHI)	TPES (2010, %)
Europe	570.4	300.5			26
Austria	9.5	1.7	82	0.40	24
Belgium	19.8	0	100	0.23	28
Czech Republic	9.3	0.2	98	0.78	17
Denmark	5.0	8.2	Net exporter	Na	23
Estonia	0.7	0	100	1.00	10
Finland	4.7	0	100	1.00	11
France	49.1	0.7	98	0.19	16
Germany	97.9	13.0	87	0.31	22
Greece	3.9	0.0	100	0.40	12
Hungary	12.1	2.8	76	0.55	38
Iceland	0.0	0	0	Na	0
Ireland	5.5	0.5	93	1.00	33
Italy	83.1	8.4	90	0.21	40
Luxembourg	1.4	0	100	0.35	28
Netherlands	54.8	88.5	Net exporter	Na	47
Norway	6.1	109.7	Net exporter	Na	19
Poland	17.2	6.0	65	0.81	19
Portugal	5.1	0	100	0.42	13
Slovakia	6.1	0.1	98	1.00	19
Slovenia	1.1	0	99	0.35	12
Spain	35.8	0	100	0.20	28
Sweden	1.5	0	100	1.00	3
Switzerland	3.7	0	100	0.51	11
Turkey	38.1	0.7	98	0.29	30
United Kingdom	98.9	59.8	40	0.33	25
Asia Oceania	195.4	61.0			17
Australia	33.4	49.0	Net exporter	Na	31
*Israel**	5.3	3.2	39	1.00	19
Japan	109.0	3.3	97	0.14	17
Korea	43.2	0.5	99	0.14	15
New Zealand	4.5	4.8	0	Na	20
Americas	839.9	816.3			26
Canada	96.8	159.9	Net exporter	Na	31
Chile	5.3	1.8	65	0.22	14
Mexico	64.7	50.2	23	0.48	30
United States	673.1	604.3	10	0.77	25
OECD	1605.7	1 177.7			24

* The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Table 32 Historical fuel prices (USD/MBtu)

	2005	2006	2007	2008	2009	2010	2011
Natural gas							
Henry Hub	8.84	6.75	6.98	8.86	3.95	4.39	4.00
NBP	6.31	9.56	5.82	10.97	6.80	5.41	8.59
German border price	5.83	7.88	8.00	11.61	8.53	8.03	10.62
Japan LNG	6.02	7.12	7.74	12.66	9.04	10.90	14.78
Oil							
WTI	9.73	11.38	12.46	17.18	10.63	13.69	16.36
Brent	9.38	11.23	12.50	16.72	10.60	13.70	19.18
JCC	8.89	11.04	11.90	17.65	10.45	13.65	18.81
Coal							
US Appalachian	2.38	2.09	1.81	4.27	2.07	2.67	3.07
NW European coal	2.55	2.69	3.72	6.18	2.96	3.82	5.28
Asian coal	2.60	2.37	3.55	6.22	3.31	4.43	5.10

Sources: IEA, ICE, German Customs, Japanese Customs, EIA, Bloomberg, McCloskey, Federal Reserve and European Central Bank.
Notes: All prices are yearly averages, of their respective average monthly prices.
To convert oil prices in USD/bbl, the prices in USD/MBtu have to be multiplied by 5.8. To covert coal prices in USD/ton (6 000 kcal), the prices in USD/MBtu have to be multiplied by 23.8.

Table 33 LNG liquefaction (existing, under construction, projects)

Region	Operation	Construction	Planned
Asia	115	89	166
Australia	33	77	125
Brunei	10	-	-
China	-	-	1
Indonesia	40	3	14
Malaysia	33	-	8
Papua New Guinea	-	9	19
Middle East	137	-	98
Abu Dhabi	8	-	-
Iran	-	-	82
Oman	15	-	-
Qatar	105	-	16
Yemen	9	-	-
Europe	6	-	6
Norway	6	-	6
Eurasia	13	-	100
Russia	13	-	100
Africa	79	20	135
Algeria	27	13	-
Angola	-	7	7
Cameroon	-	-	5
Egypt	16	-	5
Equatorial Guinea	5	-	5
Libya	1	-	8
Mozambique	-	-	14
Nigeria	30	-	83
Tanzania	-	-	9
North America	2	-	118
Canada	-	-	47
United States	2	-	71
Latin America	27	-	24
Brazil	-	-	5
Peru	6	-	-
Trinidad	21	-	-
Venezuela	-	-	19
Total	379	108	647

Note: LNG liquefaction capacity in operation includes Pluto, which started in May 2012, which explains why it is different from the capacity as of end-2011 (373 bcm) quoted in the report.

Table 34 LNG regasification (existing, under construction, projects)

Region	Operation	Construction	Planned
Asia	424	78	184
Bangladesh	-	-	*7*
China	*29*	*26*	*67*
Chinese Taipei	*14*	-	*3*
India	*20*	*14*	*61*
Indonesia	-	*5*	*4*
Japan	*250*	*10*	*3*
Korea	*103*	*9*	*3*
Malaysia	-	*5*	*6*
New Zealand	-	-	*2*
Pakistan	-	-	*5*
Philippines	-	-	*10*
Singapore	-	*8*	-
Thailand	*7*	-	*7*
Vietnam	-	-	*8*
Europe	192	38	201
Albania	-	-	*8*
Belgium	*9*	-	*9*
Croatia	-	-	*4*
France	*25*	*10*	*15*
Germany	-	-	*4*
Greece	*5*	-	*9*
Ireland	-	-	*4*
Italy	*12*	*12*	*66*
Lithuania	-	*3*	-
Netherlands	*12*	-	*21*
Poland	-	*5*	-
Portugal	*6*	-	*3*
Romania	-	-	*5*
Spain	*60*	*9*	*19*
Sweden	*0.3*	-	-
Turkey	*13*	-	-
United Kingdom	*51*	-	*34*
Middle East & Africa	7	-	8
Bahrain	-	-	*4*
Dubai	*4*	-	-
Israel	-	-	*2*
Kuwait	*3*	-	-
South Africa	-	-	*2*
North America	222	5	262
Canada	*10*	-	*16*
Mexico	*16*	*5*	*21*
Puerto Rico	*4*	-	*3*
United States	*192*	-	*223*
Latin America	25	-	42
Argentina	*8*	-	*11*
Brazil	*7*	-	*22*
Chile	*5*	-	*3*
Cuba	-	-	*3*
Dominican Republic	*5*	-	-
El Salvador	-	-	*1*
Jamaica	-	-	*2*
Total	869	121	698

Table 35 Key interregional pipelines planned and under construction

Source	Name	Start	Capacity (bcm)	Length (km)	Sponsors	Estimated cost (bn)
Europe						
Russia	Nord Stream II*	October 2012	27.5	1 200	Gazprom 51%, BASF, E.ON 15.5%, GDF Suez, Gasunie 9%	EUR 7.4**
	South Stream	2015-19***	63	n.a.	Gazprom: 50%, ENI: 20%, Wintershall, EDF: 15%	EUR 15.5
Caspian/ Middle East	Nabucco	2018	8-31	3 296	Botas, Bulgargaz, MOL, Transgaz, OMV, RWE	No new data available
	TAP	2017-18	10 (20)	520	EGL, Statoil 42.5%, E.ON 15%	EUR 1.5
	TAGP	2018	16 (24)	2 000	SOCAR	EUR 5-6
	SEEP	2018	10 (20)	1 300	BP	Na
Algeria	Galsi	2015+	8	1 470	Sonatrach 41.6%, Edison 20.8%, Enel 15.6%, Sfirs 11.6%, Hera: 10.4%	EUR 2
Iran	Iran Gas Trunkline 9	2015+	37	1 470	NIGEC	USD 8
Asia						
Caspian	Central Asia Gas Pipeline Line C*	2014-15***	25	1 840	CNPC, KazMunaiGas, Uzbekneftegaz	Na
	Turkmenistan Afghanistan Pakistan India (TAPI)	2015+	33	1 680	ADB, other investors tbd	USD 7.6
Myanmar	Myanmar-China	2013	12	1 000	CNPC	USD 1.0
Iran	Iran-Pakistan (India)	2015+	7.5 (22)	900 (2 700)	Inter-State Gas Systems, NIOC	USD 7.5
Russia	China Western route (Altai)	2017+	30	2 800	Gazprom	USD 14
	China East route (Sakhalin-Khabarovsk)	2017+	36	1 822	Gazprom	Na
	Korea	2017+	10-12	1 700	Gazprom	Na
Middle East- Africa						
Egypt	Arab Gas Pipeline Extension	2011	10	248	Syrian Gas Company/ BOTAS	USD 0.2
Nigeria	Trans Sahara Gas Pipeline	2015+	30	4 128	Gazprom, Total interested	USD 13-20

Note: This table does not contain any intraregional pipeline.
* Under construction
** Cost for the whole project consisting in two lines.
*** The pipeline starts in the first year quoted and its capacity is progressively increased during the period quoted.

Table 36 Underground storage existing, under construction and planned, working capacity (bcm)

Region	Operation	Under construction/ Planned	Region	Operation	Under construction/ Planned
Europe			North America		
Albania		1.18	*Canada*	25.24	0.86
Austria	7.35	2.75	*United States*	124.30	14.3
Belgium	0.70	0.00	Latin America		
Bulgaria	0.65	2.10	*Argentina*	0.10	-
Croatia	0.55	2.03	*Uruguay*	-	1.70
Czech	2.86	0.39	FSU		
Denmark	1.03	-	*Armenia*	0.13	0.15
France	12.75	2.70	*Azerbaijan*	2.00	3.40
Germany	21.29	12.47	*Belarus*	0.75	1.15
Hungary	6.24	1.30	*Georgia*	-	0.30
Ireland	0.23	0.28	*Kazakhstan*	4.20	Na
Italy			*Kyrgyzstan*	0.06	-
Latvia	2.30		*Russia*	65.5	Na
Lithuania	-	0.50	*Ukraine*	31.00	-
Netherlands	5.26	4.64	*Uzbekistan*	4.10	1.30
Poland	1.83	4.13	Asia		
Portugal	0.18	0.12	*Australia*	2.55	0.36
Romania			*China*	1.90	29.81
Serbia	0.45	3.00	*Japan*	1.17	-
Slovakia	2.77	0.35	*Korea*	-	Na
Spain	2.17	3.96	*New Zealand*	0.38	Na
Sweden	0.01	-	Middle East		
Turkey	2.11	1.60	*Iran*	-	>3.84
United Kingdom	4.81	18.77			

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IEA Publications
9, rue de la Fédération, 75739 Paris cedex 15

Printed in France by CORLET, May 2012
(61 2012 22 1P1) ISBN 9789264177970

Cover design: IEA. Photo credits: © GraphicObsession

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