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Natural Gas

Contents

This Chapter is partially based on an updated version of the International Gas Union Strategy Committee report released at the 25th World Gas Conference in Kuala Lumpur in 2012

Strategic insight

1. Summary

In 2012, for the first time in many years, the growth in global gas demand outstripped that of coal. Despite the current economic difficulties, the world might be looking at the 'Golden age of gas', as the global gas market is expected to reach 4 700bcm by 2030. This growth is supported by an increase in gas production potential and expansion of international trade based on a growing number of LNG facilities and high pressure pipelines and will continue for several decades. This average annual growth of 1.4% is slightly higher than anticipated in the IGU commentary provided for the previous edition of the WEC Survey of Energy Resources report published in 2010.

The share of natural gas in primary energy supply is expected to rise from 22% in 2010 to almost 25% in 2030. The total gas market will grow all over the world, but at a different speed in each region or industry. The most significant growth for gas is likely to be in power generation, which could account for 1 900bcm (40%) of the total gas market in 2030. The highest regional growth is expected to take place in Asia driven by the continuing expansion of the Chinese gas market. Proved reserves of natural gas have been identified in every region, with the highest volumes in the Middle East (41%), Europe, including the Russian Federation) (27%) and Asia (15%).

Differences in definitions or coverage can lead to discrepancies: perhaps the most common example in the case of proved gas reserves is the inclusion (intentional or otherwise) of probable reserves in the figures quoted.

On the other hand, as gas reserves are invariably expressed in volumetric terms, they are far less affected by conversion factor differences than oil reserves, for example. Major discrepancies in individual reserve assessments are highlighted below in Country Notes. The discussion of natural gas supply and demand is set in the context of the IGU's regions, which are not identical to the standard WEC geographical regions. However, the differences are essentially marginal and do not invalidate the analysis.

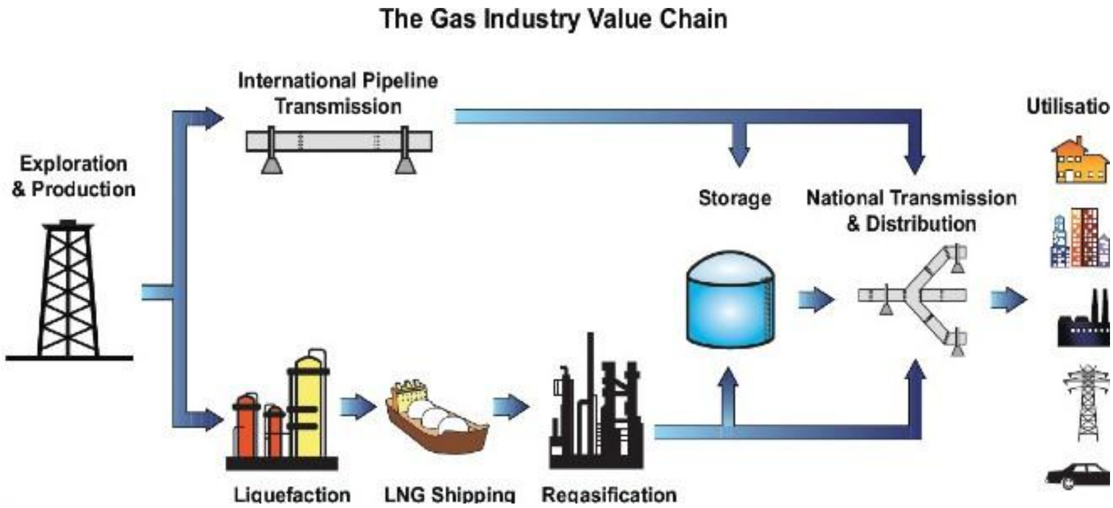
Overall, commercial and regulatory trends suggest that 'gas-on-gas' prices are becoming the dominant global price setting mechanism. Regulated gas prices should increasingly allow a full recovery of costs. However, some form of indexation to oil or oil products will remain of fundamental importance in many parts of the world.

2. Technical and economic considerations

Natural Gas is a mixture of hydrocarbons, of which by far the largest component is the simplest hydrocarbon, methane (CH_4). Methane is an odourless, colourless, non-toxic gas which is lighter than air.

Most of the natural gas that has been discovered so far was almost certainly formed by biogenic processes similar to those that created oil. Over millions of years the residues of decomposed

Figure 1
Source: IGU



organic material exposed to intense pressure and high temperatures have become hydrocarbon minerals, including natural gas. These hydrocarbon minerals can be found both in the original source rock where they were formed (including shale formations) and also in more porous reservoir rocks that are the conventional oil and gas fields. Natural gas also includes some heavier hydrocarbons such as methane (C2H6), propane (C3H8), butane (C4H10), and there can be a wide range of different non-hydrocarbon gases that also occur in the mixture in the reservoir rocks.

Gas value chain

Figure 1 illustrates, in a simplified form, the main components of the gas value chain.

Whilst synthetic natural gas and bio-gas are important components that are increasingly being integrated into the gas chain, the global gas industry, based on conventional and unconventional gas still provides more than 99% of global gas supplies.

The distribution of natural gas around the world is more diverse than oil, but nevertheless a large proportion of natural gas needs to be transported from the producing countries and regions (for example, Norway, Russia, Qatar, the Caspian area and North Africa) to the consuming countries and regions (e.g. Japan, China and Europe) with insufficient domestic and regional indigenous gas supplies. International high pressure pipelines provide direct and reliable links from producers to consumers.

These outstanding engineering achievements remain the main routes for transportation of vast international flows of gas. For example, a recently completed pipeline project Nordstream, Phase 2 (inaugurated in October 2012) which directly connects Russia to Germany via the Baltic Sea over 1200 kilometres is the world's longest underwater natural gas pipeline. At the end of 2012, construction began on the SouthStream project to bring gas from Russia across the Black Sea to Bulgaria and further to Italy and Austria.

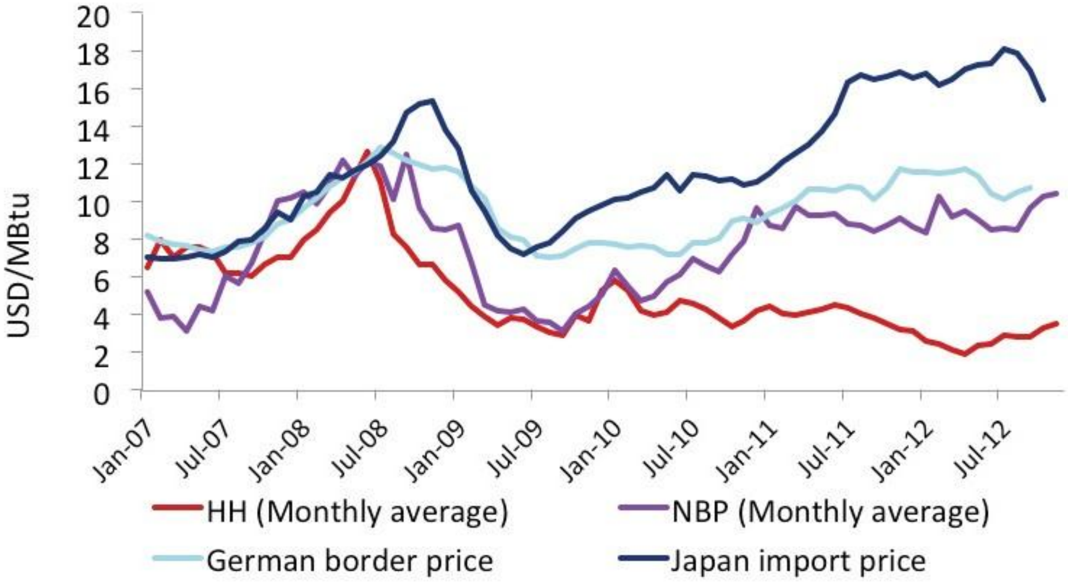
Exploration, production and processing

The offshore gas production in North-West Europe is a good illustration of the three different types of natural gas production that we can broadly categorise by the type of reservoir.

Figure 2

Gas prices have risen, fallen and diverged

Source: updated from IEA 2012 Medium Term Outlook



- ‘Dry gas fields’ requiring very little processing of the reservoir fluids needed to achieve pipeline quality gas - typical in the Southern North Sea
- ‘Condensate gas fields’ in which the heavier natural gas hydrocarbons can be separated as natural gas liquids (NGLs) – typical in the Central North Sea
- Oil fields with ‘associated gas’, sometimes with a natural gas cap that can be produced separately and even temporarily re-injected to enhance oil production – typical in the Northern North Sea.

Once produced natural gas will need some processing. If it is dry gas with very few impurities, then it might be sufficient to check the gas quality and make sure that it is adjusted to the correct pressure and temperature for the next stage of its journey. More likely, however, that it will also be necessary to treat “wet” gas that has come from the upstream reservoir to deal with one or more components that need to be removed to meet the gas quality requirements for onward transportation.

International and National High-Pressure Pipelines

International high pressure pipelines provide direct and reliable links from producers to consumers. These immense achievements of engineering remain the main way for vast international flows of gas. One recently completed project is the Nordstream phase 2 (inaugurated in October 2012) which connects Russia directly to Germany via the Baltic Sea.

Given its length of 1 200 kilometres it is the world’s longest underwater natural gas pipeline. Before the end of 2012, construction began on the SouthStream project to bring gas from Russia across the Black Sea to Bulgaria and onwards to Italy and Austria.

Generally, even larger investments in gas transmission pipelines are taking place in individual countries, particularly in the USA and in China. The shale gas revolution in North America changed indigenous supply patterns and led to many new onshore pipeline projects to enable higher levels of gas production to be brought to market. In the US, however, several

Figure 3

Analysis is based on the eight IGU regions

Source: IGU

of the main shale gas formations are relatively well located, either close to the final market or within the economic reach of existing infrastructure. In contrast, the geographical challenge to deliver indigenous natural gas to the main consuming areas has been far more demanding in China. The final length of the second West-East Pipeline linking gas production in the west to consuming areas in the east was over 8 700 kilometres, including both east and west sections and eight branches, making it probably the world's longest natural gas pipeline. Construction of a third West-East Pipeline of similar proportions was already well under way by the end of 2012 as demand for natural gas in China continues to grow rapidly.

Liquefaction, LNG shipping and regasification

Gas liquefaction, to make natural gas easier to transport by ship (or occasionally by road in tankers) to the market where it is then regasified, has become almost as important as pipelines as a means of international delivery of natural gas. Liquefaction involves pre-treatment to purify the natural gas from pollutants like H_2S or CO_2, remove any traces of heavy metals and control the moisture level. The processed natural gas is then refrigerated to a temperature of approximately minus 161 degrees Celsius. This refrigeration process involves compression, condensation and expansion of refrigerants that exchange heat with natural gas until it becomes a liquefied natural gas (LNG) with one 1/600th of the original volume.

A large LNG fleet of ships (or road tankers) is essential to prevent bottlenecks developing in the supply chain. Since January 1959 when the Methane Pioneer set off for Europe with its modest cargo of liquefied natural gas from the Louisiana Gulf coast of the USA, international LNG trade has developed a global fleet that now amounts to over 350 active ships, the largest carrying up to 266,000 m3 of LNG. Annual worldwide deliveries are equivalent to more than 300 bcm of natural gas i.e. about 10% of global consumption.

Some countries like Japan and Korea have long been reliant on LNG and have based their successful downstream markets on a range of LNG suppliers. The growth of international gas trade also means that many more countries now have LNG reception terminals and there is a flourishing market in LNG deliveries and diversions to the markets with highest value. This flexibility is of course only possible when there are sufficient ships available (a diversion may well result in a longer route) and sufficient capacity in the re-gasification terminals to where a ship might be diverted. The capacity in the re-gasification terminal comprises not only the delivery slot to enable the ship to be unloaded, but also short-term storage of the unloaded LNG and re-gasification (in which LNG is warmed up) before compressing the natural gas into a national or local transmission pipeline.

Storage

The ability to liquefy natural gas means that it can be stored and made available at very high delivery rates, but the process of liquefaction and storing LNG is potentially very expensive.

In many parts of the world gas demand is seasonal and the storage of very large volumes of gas that are needed (for example, for residential space heating in northern hemisphere in winter) is best achieved underground in natural geological formations, particularly if suitable structures can be found near the local pipeline grid that serves the centres of gas demand. One advantage of storing gas in a structure that used to be an oil or gas reservoir is that its natural integrity has been proven for containing reservoir fluids at high pressures.

Another form of underground storage (UGS), that offers potentially higher delivery rates albeit sustainable perhaps over a number of weeks rather than throughout the winter months, is salt cavities. Here, the storage cavities of the optimum shape and size are leached out from the underground salt formation. In all forms of UGS an important component of the storage facility is the 'cushion' gas that remains in the store so that a reasonable withdrawal rate can be achieved. The 'working gas' in the store is injected (compressed) into the UGS on top of the cushion gas and it is this working volume that is taken out for the heating season or for other commercial reasons during the storage cycle.

Local transmission and distribution

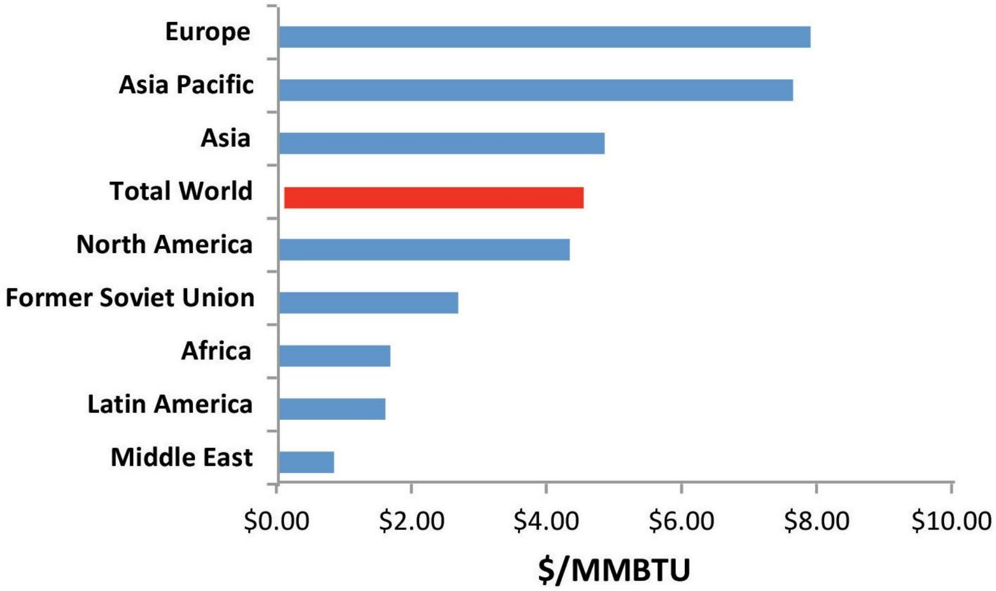
The gas in the transmission system is at high pressure (typically 50-80 bar) and, depending on the final use, may pass through a series of pressure reductions, metering and quality checks leading to low pressure distribution pipeline systems with their own pressure and flow controls and final metering at the supply point of the end consumer. Technology is enabling gas operations and gas markets to develop in ways that should lead to further efficiency improvements in grid operation and utilisation. Smart grid technology as well as smart metering still have a long way to go but have already demonstrated significant fuel savings through grid optimisation at Transmission level.

Utilisation

The economic availability of natural gas combined with its qualities of efficiency, quality, reliability, convenience and responsiveness to the consumers' needs make it an ideal choice for a wide range of uses in many parts of the world.

Industrial gas demand requires a more competitive offering in relation to other fuels, but the proven high efficiency appliances that already exist for natural gas could be a springboard for further growth despite some global economic uncertainty in the manufacturing sector.

Figure 4:
Average wholesale price in each IGU region in 2010
Source: IGU



Natural gas is also a widely used feedstock for the petrochemical industry, and this use is being further developed by some natural gas producing nations as an alternative to exporting LNG or constructing new international pipelines.

Whilst today still at a relatively low level, the use of natural gas as a transport fuel is possibly the most rapidly growing gas use across the world,. There are encouraging signs both onshore, with compressed natural gas (CNG) fuelling millions more cars, trucks, busses and lorries, and offshore with LNG-fuelled ships being favoured over more polluting rivals in environmentally sensitive areas.

Overall, however, the use of natural gas for power generation remains the largest and most important growth sector. How much and how fast the global gas market will grow depends on fundamental economics, which in turn are influenced by politics related to energy and to climate change.

Advances in gas technology.

Wider application of the latest natural gas technologies is delivering benefits along the whole gas chain:

- In exploration, production and the treatment of natural gas, there are ongoing technological improvements and cost reductions for shale gas exploitation, and enhanced gas production through applications of fracking technology in ‘conventional’ low permeability reservoirs.
- Longer and higher pressure transmission pipelines are allowing greater economies of scale in the delivery of gas from remote sources of supply to consuming markets.
- New forms of LNG facilities, including (FLNG) Floating LNG are opening up new markets and expanding the possibilities for gas supply diversity in established markets.
- Distribution systems continue to be upgraded and efficiency gains made through the application of smart grid and smart meter technologies.

Figure 5

Wholesale gas is increasingly priced on the basis of traded gas hubs

Source: IGU

- Replacement of boilers and other appliances with the latest high-efficiency designs is making the use of gas even more economically and environmentally attractive.

Wholesale gas prices vary throughout the world

In 2010, for example, the average regional gas prices varied throughout the world as shown in figure 4 above. Despite the averaging effects that dampen the results over each region, there is still a factor of ten between the regions with lowest wholesale gas prices and the regions with the highest.

The tension that results from such diverse wholesale gas prices across the globe leads to enhanced international trade (to exploit the arbitrage opportunities) and it also leads to pressure to change wholesale gas price formation mechanisms. In particular, customers and retail suppliers in competitive markets are compelled to align their gas costs with the traded market. This effect has led to a trend of wholesale gas prices being linked increasingly to traded natural gas prices as summarised in Figure 5 (overleaf).

There is, however, considerable uncertainty about future gas price formation mechanisms and the extent to which global gas price differences will persist. The overall trend that we have seen since 2005 suggests, however, that ‘gas-on-gas’ price formation will be the dominant global mechanism well before 2030, that regulated gas prices will increasingly allow recovery of full cost (provided these are economically incurred) and that some form of indexation to oil or oil products will still be of fundamental importance in parts of the world where the local gas markets is not open to competition or trading in natural gas is not sufficiently liquid.

Global perspectives of regional gas demand

An ever increasing world population and expected GDP growth in major developing countries have a huge impact on energy consumption and more specifically an impact both on gas demand and gas supply. Environmental issues and also technical developments like advances in shale gas production and cost reduction of renewable energy sources are playing a main role in the future fuel mix. Analysing the main trends in natural gas demand and supply against a background of political and economic uncertainty is therefore a challenging job.

IGU Strategy Committee experts performed both a local ‘bottom-up’ analysis and a top-down consistency check to establish regional expectations of indigenous supply and indigenous demand. This IGU Expert View then results in a Reference Scenario in which each of the eight IGU regions ether have some additional export potential, or may exhibit a supply shortfall that will need to be satisfied by imports from another region

To frame gas supply into a wider energy context, an assessment was made of the development of total primary energy consumption (PEC) in each of the eight IGU regions and the sectors within those regions.

Primary energy demand is expected to increase with an average annual growth of 1.3% from 2010 to 2030. The gas share of primary energy demand would rise from 22% in 2010 to almost 25% in 2030. Whilst the relative share of natural gas is quite different in each region, the share of gas in primary energy demand is expected to grow in all regions, except for the giant North America and CIS markets where the share stays relatively stable. Short-term economic trends, however, have squeezed the gas market in some regions, not least in Europe, where low priced coal, displaced by the shale gas revolution in North America, has undercut gas-fired power generation.

Natural Gas Demand by Region – IGU Expert View (Reference Scenario)

Natural Gas demand is projected to increase by 1.4% per year between 2010 and 2030 to a total of 4.7 tcm. Despite the effects of the recent global economic downturn, when compared with the IGU report of 2009, this new projection is about 300 bcm higher by the year 2030. The increase is spread across the globe, and includes the major production and consumption regions of North America, CIS as well as some increase in Europe. The most dynamic regions in terms of percentage growth are Asia (driven by China), Africa and the Middle-East.

Natural gas demand by market sector – IGU Expert View (Reference Scenario)

In the residential and commercial sector a moderate growth is expected from 0.7 tcm now to well over 0.9 tcm in 2030. The most significant rise is foreseen in Asia, mainly driven by the increased number of homes connected to the gas supply grid.

Gas demand in industry is expected to grow from 800 bcm in 2010 to 1200 bcm in 2030 driven in a large part by developments in the Chinese and Indian economies. Overall future industrial gas demand is somewhat lower than in the 2010 WEC report as industrial output is more constrained in OECD countries whilst on average better energy efficiency is achieved globally.

The increase of total global gas demand in the past two decades was driven, above all, by the need for clean, efficient and competitively priced power generation.

With billions of people needing electricity supplies, this sector is set for continuing growth in the coming decades. The way gas is priced, however, can present some difficult challenges to the economics of power generation projects. In particular, if, as hoped by some producing countries, there were a return to some form of 'oil-parity' in Europe or a full continuation of oil indexation in Asia, then that would reduce the demand for gas-fired power generation below the expectations shown below.

Furthermore, if the gas price for power generation were held unduly low in North Africa and the Middle East, then that would reduce the likelihood of approval for investment in major renewable energy projects and may prevent their successful implementation. This would make global climate change goals more difficult to achieve despite the increased use of natural gas. -

Overall, the global power sector is expected to grow to almost 1600 bcm in 2020 and around 1900 bcm in 2030. The final result in terms of natural gas consumption in the power sector, however, is extremely dependent on the policies concerning renewable energy, which in turn are subject to economic and social pressures.

With a total projected volume of 1900 bcm in 2030, the prospects for gas for power generation are impressive. However, at the same time a lot of uncertainties arise. How will renewable energy sources develop and will they take over part of the electricity market? What will be the influence of CO_2? A correctly implemented emission-trading scheme for CO_2 costs or taxes based on the CO_2 content would benefit natural gas in relation to other fossil fuels. Uncertainty in the price of CO_2, however, creates an additional risk for investment. What will be the impact of CCS plants (Carbon Capture and Storage) on gas demand in the power sector?

The expected gas demand is large, but is also very uncertain when considered against the background of these complex issues.

Gas consumption in the transport sector (mainly Natural Gas Vehicles- NGVs) is expected to become more important, growing from around 90 bcm now to 150 bcm in 2030. Main users are CIS, Middle-East and Asia.

Global and regional natural resource analysis - Gas production and supply

In parallel with the analysis of future gas demand summarised above, our experts studied the available information on gas reserves and projects to establish expected regional supply levels. It is well known that natural gas reserves are abundant to cover the global gas demand for many decades, and the inclusion of some unconventional gas in the reserve base has clearly enhanced economically recoverable reserves in the last few years. Moreover, technological developments and higher energy prices in some regions have increased the economic reserves locally as well as the diversification of sources and routes to bring these reserves to market.

The current developments on unconventional gas, especially shale gas in the United States, are spectacular and have led to upward revisions for the prospects in North America. The potential for unconventional gas in some other regions is also significant. At several places around the globe, like Poland and China, the opportunities for shale gas are being actively investigated.

Regional gas supply potential
For all the regions, the expected gas supplies were not forced to balance with gas demand. The difference between demand and supply indicates possible over or under supply for that region, and hence the likely need for imports or the possibility of export potential.

Overall, increased production will enable world gas supplies (in terms 'pipeline quality' gas) increase to over 4.8 tcm by 2030, with the CIS (dominated by Russia) consolidating its position as the region with largest gas production.

The natural gas supply outlook for **North America** has changed significantly over the last five years. The key change is the economic development and production from natural gas bearing shale resources and the global implications that this has had. Total North American gas production is projected to increase from 810 bcm in 2010 to almost 1000 bcm by 2030. The share of unconventional gas in the US will grow from 60% to over 73% by 2030.

In **Latin America**, natural gas production both onshore and offshore is expected to grow from 150 bcm now to 250 bcm in 2030.

In **Europe**, indigenous resources currently satisfy about half of the gas demand. The largest European producers are Norway (105 bcm), the Netherlands (88 bcm) and the UK (60 bcm). In the period from 2010 to 2030, most of this production will decline with only Norway expected to maintain its production level. Several geological plays in Europe are being explored for "unconventional gas", mainly shale gas reserves. However, this development is currently at an early stage and the economics do not match up with new imports if these are available at competitive (gas hub) prices. The result is that no significant indigenous unconventional gas is included in the European region.

Gas production in **Africa** is expected to more than double between now and 2030, growing to 400 bcm/year, with Algeria and Nigeria as the main suppliers. Half of the production could be exported to other regions, enabling Africa potentially to benefit from international prices whilst contributing significantly to diversification in global gas supply.

The **Middle East** is endowed with a wealth of gas resources, but capital investments remain the main concern due to geopolitical issues and higher capital costs. The largest gas producing countries are, and will remain by far, Iran and Qatar, followed by Saudi Arabia. Iraq holds promising resources and could become a significant gas producer (and exporter). The Middle East total gas production is expected to increase from 480 bcm in 2010 to 840 bcm in 2030. In 2030, around 200 bcm will be exported mainly to Europe and Asia.

In the **CIS**, Turkmenistan, Kazakhstan, Uzbekistan, and Azerbaijan together with **Russia** are the main gas producing countries and should remain in this position in 2030. Together, Russia and the CIS countries account for around 25% of the world's total gas production. Gas production in the region is expected to increase by 45% from 2010 to 2030 when it should reach 1150 bcm.

In **Asia**, gas production has more than doubled in the last decade up to around 210 bcm and the question is whether or not this astounding increase could occur again? Despite substantial proven and potential gas reserves, Asian natural gas production is not keeping pace with demand. Over the next 20 years, IGU experts expect production to reach 460 bcm, but the gap between supply and demand will increase almost seven-fold.

The key challenges to increase gas production are the development of adequate transport infrastructure as new resources are far away from markets, in particular for China and India, and relatively low prices are a constraint in some countries. Additionally, the development of unconventional gas requires appropriate expertise to be developed or acquired. From a regional point of view, China appears as the leading country. By 2011, China was already a relatively large producer – it produced more than Saudi Arabia, and most of its production is conventional gas. IGU forecasts assume a strong growth in China, where production reaches 250 bcm by 2030 and the successful development of both CBM and in a later stage, shale gas. In India gas production will increase markedly reaching around 100 bcm by 2035.

Production in Asia Pacific will grow substantially to 570 bcm in 2030. The region includes big LNG exporters, Indonesia, Malaysia, Australia and Brunei accounting for about 33% of the total world LNG production, but the picture is increasingly complex, with intra-regional trade increasing and Australia becoming a major gas producer and LNG exporter in Asia Pacific as well as a potential global rival to Qatar.

The changing global gas balance

If natural gas demand is increasing from 3130 bcm in 2010 to 4700 bcm in 2030, will there be sufficient gas supply to satisfy this growth? At a global level, the answer is yes. The following figure (Figure 6 overleaf) plots global gas demand and gas supply up to 2030, suggesting that if the projects went ahead and supplies could reach the markets, then there would be a healthy gas supply surplus through to 2030.

Gasification and production projects can of course be delayed or occasionally advanced, and we all know that the economic cycle can give us a bumpy ride, but there is a clear message that natural gas has a global potential for sustained growth during the coming decades. Whilst in practice there may well be periods when it is more a buyers' or sellers' market, we have a clear expectation that supply can continue to satisfy demand in the long run. But, this is predicated on growing international and indeed inter-regional trade.

Inter-regional gas trade

Our global natural gas balance is the outcome of the different regional analyses. In terms of net importers, three regions stand out:

Europe is, and will remain, by far the largest net importer; European net imports could exceed 440 bcm by 2030, a 58% increase compared to 2010 levels. Europe exports only small amounts of LNG from Snøvhit in Norway.

Continental **Asia** is set to become the second largest importing region by 2030, driven by the growing energy requirements of China and India. Imports are multiplied eightfold, with around 270 bcm needed by 2030, compared to around 30 bcm in 2010. We can envisage some exports by pipeline from Myanmar to Asia Pacific.

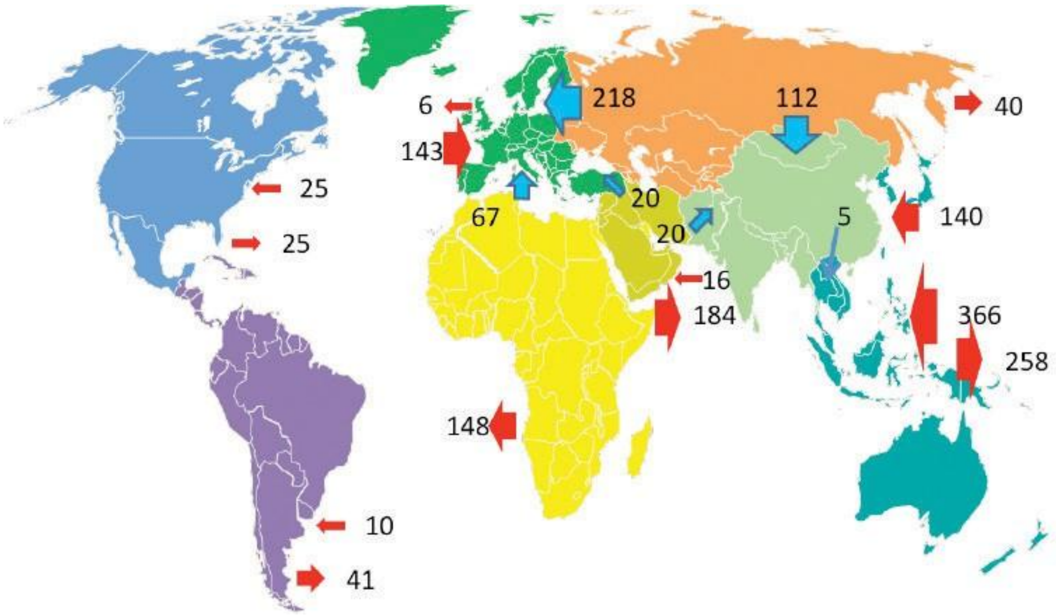
In third position in terms of imports stands **Asia Pacific**. This diverse area will continue to be a net importer, but the rapidly increasing demand in Japan, Korea and the South-East Asian region is partially compensated by the surge in Australian LNG exports. Net imports will almost double to around 80 bcm by 2030.

Whilst the USA will establish and retain some LNG export potential, the **North American** region remains internally balanced. **Latin America and Caribbean** will export around 30 bcm of LNG. In terms of direct trade, the whole of the Americas will remain only physically linked to the rest of the global gas market through LNG imports and exports.

Figure 6

Global LNG and Inter-regional Pipeline Imports and Exports in 2030 (bcm)

Source: IGU



Africa and the **Middle East** have a similar growth in terms of exports, reaching close to 200 bcm of net exports by 2030. The largest exporter remains the CIS region, with a doubling of its gas exports compared to 2010 reaching 370 bcm. These three regions export both LNG and pipeline gas, but only Africa and CIS do not import any gas from the other regions, while the Middle East may continue to remain an LNG importer.

LNG Trade

Global LNG trade is expected to more than double over the coming 20 years, increasing from 300 bcm in 2010 to 660 bcm by 2030. This requires a rapid build-up of liquefaction capacity around the world. There was already a first wave of new LNG capacity that arrived over 2009-11 with over 100 bcm of new LNG capacity coming on line, notably 63 bcm of LNG capacity from Qatar. The next wave will be coming mostly from Australia, Papua New Guinea and Indonesia with some 95 bcm of LNG export capacity having reached FID and expected to start over 2012-17.

North American LNG exports are part of the IGU scenario, but never in very high volumes. Indeed, on a regional basis, the annual supply and demand are very much balanced, and the region continues to import some LNG (Mexico, Quebec) at the same time as it exports LNG (Western Canada, United States). The US LNG terminals may well also have a seasonal role; exporting when prices are sufficiently high in other parts of the world, but importing when the local gas supply/demand is tight and Henry Hub prices are high.

On the import side, **Asia Pacific** remains by far the largest LNG importer, representing around half of total LNG imports by 2030. Europe and Continental Asia follow but the two regions' combined LNG imports are still below that of Asia Pacific (around 140 bcm by 2030). Three other regions also import LNG, but in smaller quantities (below 20 bcm): North America, Latin America and the Middle East.

Overall Regional import/export balances

The figure above summarises the expected developments in global inter-regional gas trade in 2030. Only the main pipeline routes between IGU regions are shown. There are also many international trade routes within each region, for example by high pressure pipeline from Canada to USA, which are not included on this map. There are also ideas for other inter-regional links that we have not included; several of these may well go ahead if favourable economic and political conditions were to prevail.

There is, however, considerable uncertainty about future gas price formation mechanisms and the extent to which global gas price differences will persist. The overall trend that we have seen since 2005 suggests, however, that 'gas-on-gas' price formation will be the dominant global mechanism well before 2030, that regulated gas prices will increasingly allow recovery of full cost (provided these are economically incurred) and that some form of indexation to oil or oil products will still be of fundamental importance in parts of the world where the local gas markets is not open to competition or trading in natural gas is not sufficiently liquid. An ever increasing world population and expected GDP growth in major developing countries have a huge impact on energy consumption and more specifically an impact both on gas demand and gas supply. Environmental issues and also technical developments like advances in shale gas production and cost reduction of renewable energy sources are playing a main role in the future fuel mix. Analysing the main trends in natural gas demand and supply against a background of political and economic uncertainty is therefore a challenging job.

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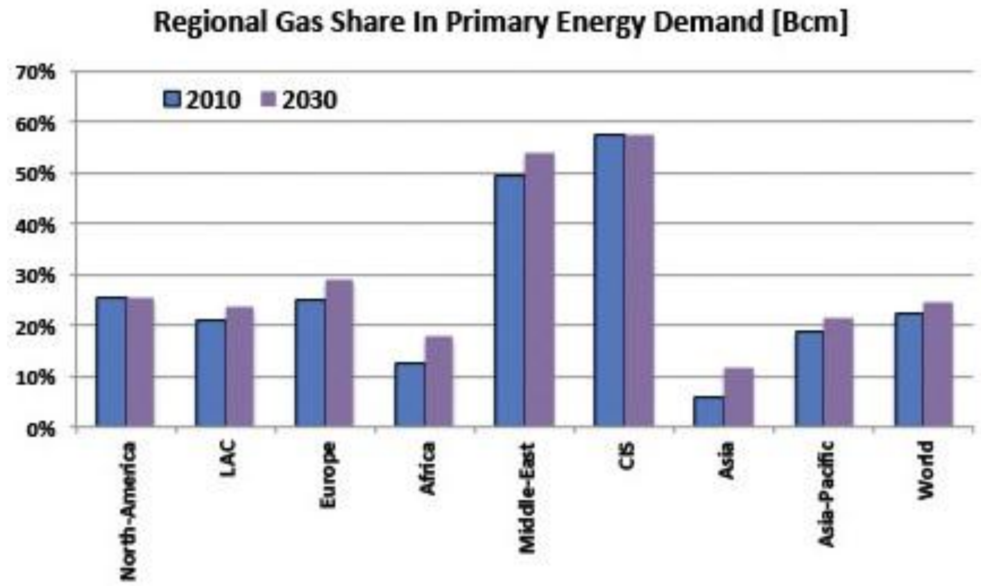
With a total projected volume of 1900 bcm in 2030, the prospects for gas for power generation are impressive. However, at the same time a lot of uncertainties arise. How will renewable energy sources develop and will they take over part of the electricity market? What will be the influence of CO_2? A correctly implemented emission-trading scheme for CO_2 costs or taxes based on the CO_2 content would benefit natural gas in relation to other fossil fuels. Uncertainty in the price of CO_2, however, creates an additional risk for investment. What will be the impact of CCS plants (Carbon Capture and Storage) on gas demand in the power sector?

Figure 7

Changing regional gas share of primary energy – IGU Expert View

Source: IGU



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Gas consumption in the transport sector (mainly Natural Gas Vehicles- NGVs) is expected to become more important, growing from around 90 bcm now to 150 bcm in 2030. Main users are CIS, Middle-East and Asia.

In parallel with the analysis of future gas demand summarised in the above pages, our experts studied the available information on gas reserves and projects to establish expected regional supply levels. It is well known that natural gas reserves are sufficiently abundant to cover the global gas demand for many decades, and the inclusion of some unconventional gas in the reserve base has clearly enhanced economically recoverable reserves in the last few years. Moreover, technological developments and higher energy prices in some regions have increased the economic reserves locally as well as the diversification of sources and routes to bring these reserves to market

The current developments on unconventional gas, especially shale gas in the United States, are spectacular and have led to upward revisions for the prospects in North America. The potential for unconventional gas in some other regions is also significant. At several places around the globe, like Poland and China, the opportunities for shale gas are being actively investigated.

For all the regions, the expected gas supplies were not forced to balance with gas demand. The difference between demand and supply indicates possible over or under supply for that region, and hence the likely need for imports or the possibility of export potential.

Overall, increased production will enable world gas supplies (in terms 'pipeline quality' gas) increase to over 4.8 tcm by 2030, with the CIS (dominated by Russia) consolidating its position as the region with largest gas production.

Figure 8
World - Natural Gas Demand by Region – IGU Expert View
Source: IGU

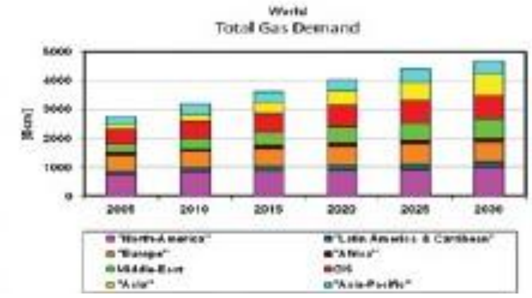
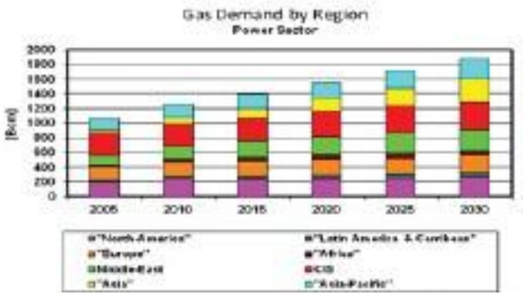


Figure 9
Gas-fired power sector to 2030 – IGU Expert View
Source: IGU



The natural gas supply outlook for North America has changed significantly over the last five years. The key change is the economic development and production from natural gas bearing shale resources and the global implications that this has had. Total North American gas production is projected to increase from 810 bcm in 2010 to almost 1000 bcm by 2030. The share of unconventional gas in the US will grow from 60% to over 73% by 2030.

In **Latin America**, natural gas production both onshore and offshore is expected to grow from 150 bcm now to 250 bcm in 2030.

In **Europe**, indigenous resources currently satisfy about half of the gas demand. The largest European producers are Norway (105 bcm), the Netherlands (88 bcm) and the UK (60 bcm). In the period from 2010 to 2030, most of this production will decline with only Norway expected to maintain its production level. Several geological plays in Europe are being explored for "unconventional gas", mainly shale gas reserves. However, this development is currently at an early stage and the economics do not match up with new imports if these are available at competitive (gas hub) prices. The result is that no significant indigenous unconventional gas is included in the European regional supply forecast.

Gas production in **Africa** is expected to more than double between now and 2030, growing to 400 bcm/year, with Algeria and Nigeria as the main suppliers. Half of the production could be exported to other regions, enabling Africa potentially to benefit from international prices whilst contributing significantly to diversification in global gas supply.

The **Middle East** is endowed with a wealth of gas resources, but capital investments remain the main concern due to geopolitical issues and higher capital costs. The largest gas producing countries are, and will remain by far, Iran and Qatar, followed by Saudi Arabia. Iraq holds promising resources and could become a significant gas producer (and exporter). The Middle East total gas production is expected to increase from 480 bcm in 2010 to 840 bcm in 2030. In 2030, around 200 bcm will be exported mainly to Europe and Asia.

In the **CIS**, Turkmenistan, Kazakhstan, Uzbekistan, and Azerbaijan together with **Russia** are the main gas producing countries and should remain in this position in 2030. Together, Russia and the CIS countries account for around 25% of the world's total gas production. Gas production in the region is expected to increase by 45% from 2010 to 2030 when it should reach 1150 bcm.

In **Asia**, gas production has more than doubled in the last decade up to around 210 bcm and the question is whether or not this astounding increase could occur again? Despite substantial proven and potential gas reserves, Asian natural gas production is not keeping pace

Figure 10
Proven gas reserves in the eight IGU regions
Source: IGU

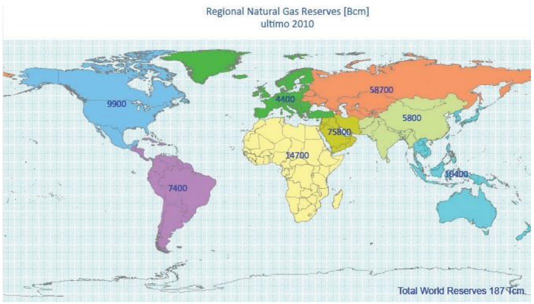


Figure 11
Regional gas production to 2030
Source: IGU

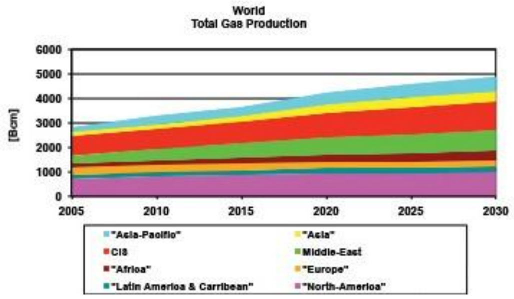
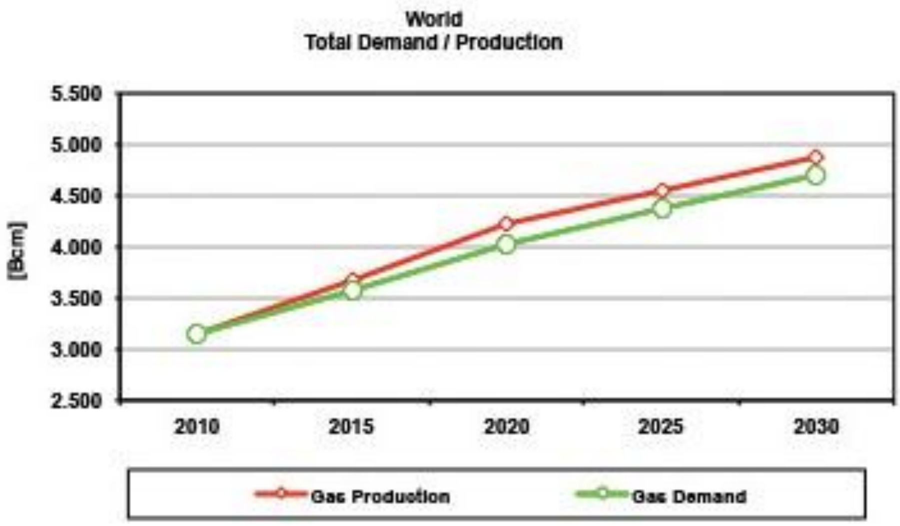


Figure 12
The global gas supply and demand balance – IGU expert view
Source: IGU

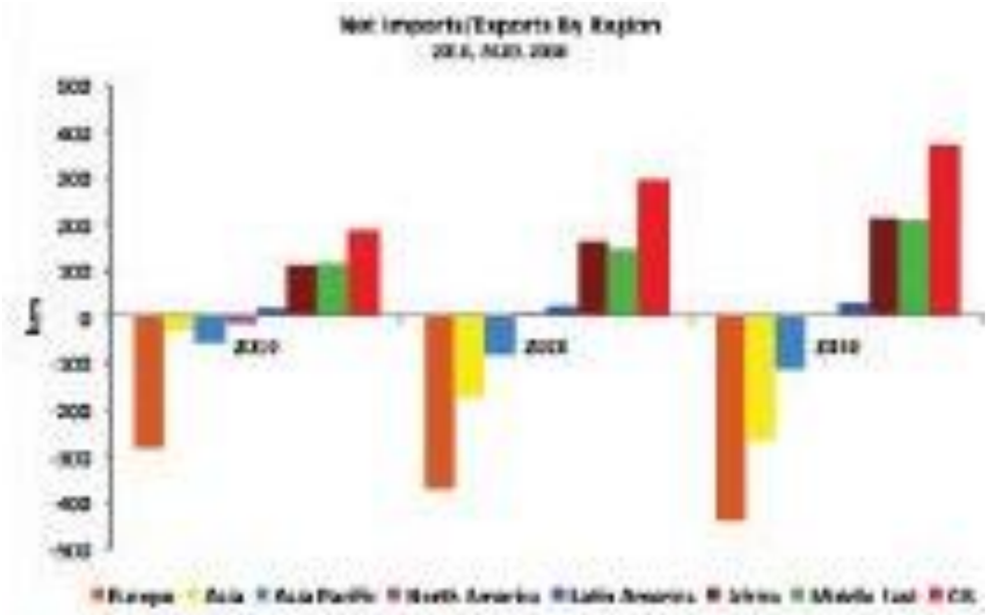


with demand. Over the next 20 years, IGU experts expect production to reach 460 bcm, but the gap between supply and demand will increase almost seven-fold.

The key challenges to increase gas production are the development of adequate transport infrastructure as new resources are far away from markets, in particular for China and India, and relatively low prices are a constraint in some countries. Additionally, the development of unconventional gas requires appropriate expertise to be developed or acquired. From a regional point of view, China appears as the leading country. By 2011, China was already a relatively large producer – it produced more than Saudi Arabia, and most of its production is conventional gas. IGU forecasts assume a strong growth in China, where production reaches 250 bcm by 2030 and the successful development of both CBM and in a later stage, shale gas. In India gas production will increase markedly reaching around 100 bcm by 2035.

Production in **Asia Pacific** will grow substantially to 570 bcm in 2030. The region includes big LNG exporters, Indonesia, Malaysia, Australia and Brunei accounting for about 33% of the total world LNG production, but the picture is increasingly complex, with intra-regional trade increasing and Australia becoming a major gas producer and LNG exporter in Asia Pacific as well as a potential global rival to Qatar.

Figure 13
Changing imports and exports by region
Source: IGU



The changing global gas balance

If natural gas demand is increasing from 3130 bcm in 2010 to 4700 bcm in 2030, will there be sufficient gas supply to satisfy this growth? At a global level, the answer is yes. The following figure plots global gas demand and gas supply up to 2030, suggesting that if the projects went ahead and supplies could reach the markets, then there would be a healthy gas supply surplus through to 2030.

Gasification and production projects can of course be delayed or occasionally advanced, and we all know that the economic cycle can give us a bumpy ride, but there is a clear message that natural gas has a global potential for sustained growth during the coming decades. Whilst in practice there may well be periods when it is more a buyers' or sellers' market, we have a clear expectation that supply can continue to satisfy demand in the long run. But, this is predicated on growing international and indeed inter-regional trade.

Inter-regional gas trade

Our global natural gas balance is the outcome of the different regional analyses. In terms of net importers, three regions stand out:

- **Europe** is, and will remain, by far the largest net importer; European net imports could exceed 440 bcm by 2030, a 58% increase compared to 2010 levels. Europe exports only small amounts of LNG from Snøvhit in Norway.
- Continental **Asia** is set to become the second largest importing region by 2030, driven by the growing energy requirements of China and India. Imports are multiplied eightfold, with around 270 bcm needed by 2030, compared to around 30 bcm in 2010. We can envisage some exports by pipeline from Myanmar to Asia Pacific.
- In third position in terms of imports stands **Asia Pacific**. This diverse area will continue to be a net importer, but the rapidly increasing demand in Japan, Korea and the South-East Asian region is partially compensated by the surge in Australian LNG exports. Net imports will almost double to around 80 bcm by 2030.

Figure 14
Global LNG Exports by Region
Source: IGU

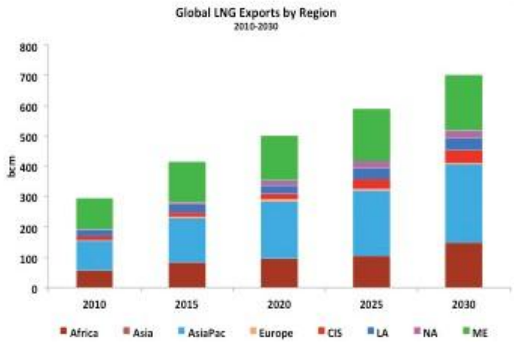
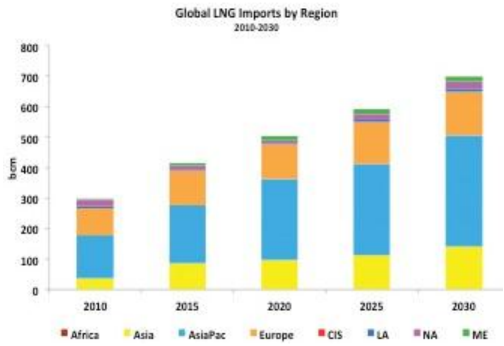


Figure 15
Global LNG Imports by Region
Source: IGU



Whilst the USA will establish and retain some LNG export potential, the North American region remains internally balanced. Latin America and the Caribbean will export around 30 bcm of LNG. In terms of direct trade, the whole of the Americas will remain only physically linked to the rest of the global gas market through LNG imports and exports.

Africa and the Middle East have a similar growth in terms of exports, reaching close to 200 bcm of net exports by 2030. The largest exporter remains the CIS region, with a doubling of its gas exports compared to 2010 reaching 370 bcm. These three regions export both LNG and pipeline gas, but only Africa and CIS do not import any gas from the other regions, while the Middle East may continue to remain an LNG importer.

LNG Trade

Global LNG trade is expected to more than double over the coming 20 years, increasing from 300 bcm in 2010 to 660 bcm by 2030. This requires a rapid build-up of liquefaction capacity around the world. There was already a first wave of new LNG capacity that arrived over 2009-11 with over 100 bcm of new LNG capacity coming on line, notably 63 bcm of LNG capacity from Qatar. The next wave will be coming mostly from Australia, Papua New Guinea and Indonesia with some 95 bcm of LNG export capacity having reached FID and expected to start over 2012-17.

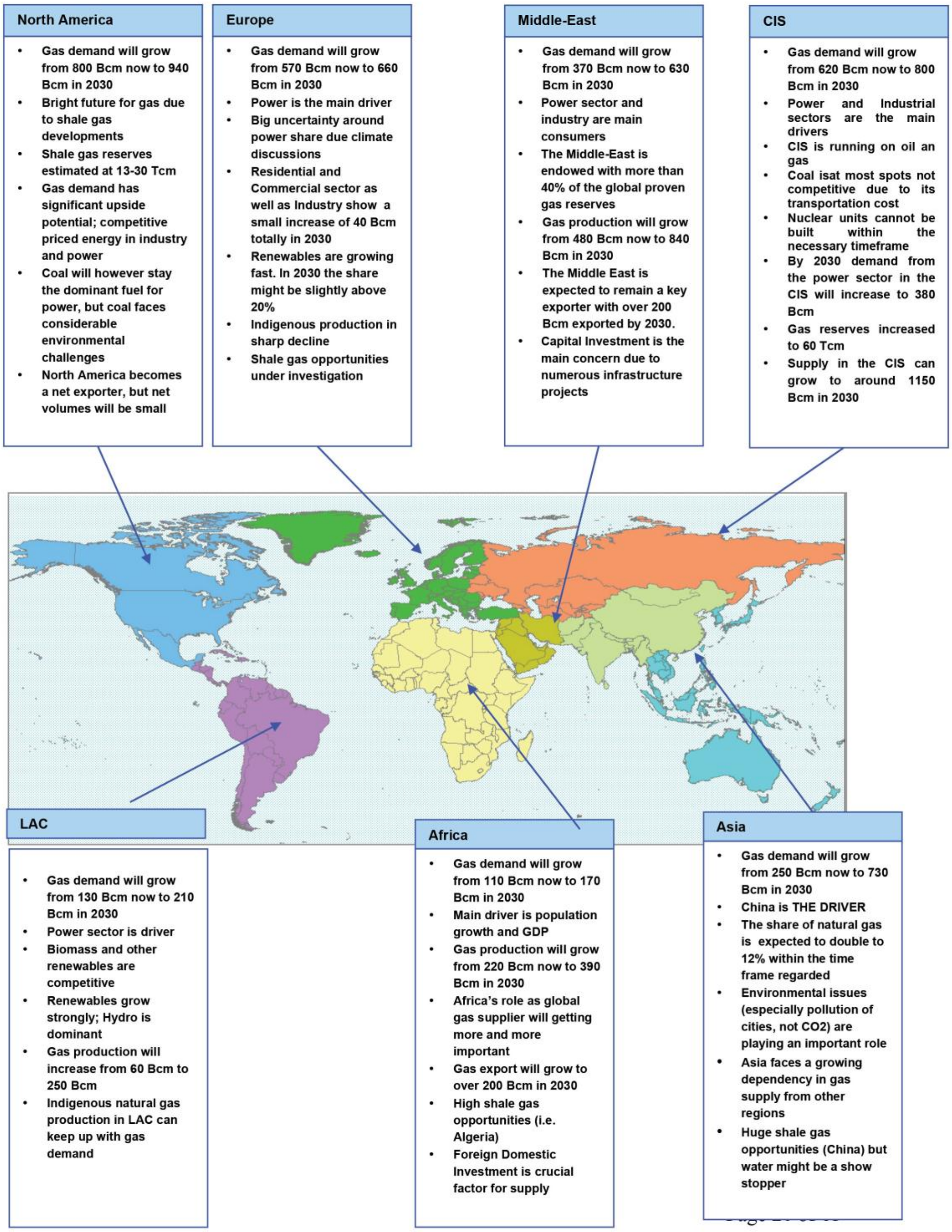
North American LNG exports are part of the IGU scenario, but never in very high volumes. Indeed, on a regional basis, the annual supply and demand are very much balanced, and the region continues to import some LNG (Mexico, Quebec) at the same time as it exports LNG (Western Canada, United States). The US LNG terminals may well also have a seasonal role; exporting when prices are sufficiently high in other parts of the world, but importing when the local gas supply/demand is tight and Henry Hub prices are high.

On the import side, Asia Pacific remains by far the largest LNG importer, representing around half of total LNG imports by 2030. Europe and Continental Asia follow but the two regions' combined LNG imports are still below that of Asia Pacific (around 140 bcm by 2030). Three other regions also import LNG, but in smaller quantities (below 20 bcm): North America, Latin America and the Middle East.

Overall Regional import/export balances

The figure on page 19 summarises the expected developments in global inter-regional gas trade in 2030. Only the main pipeline routes between IGU regions are shown. There are

Technical summary of regional gas supply and demand



also many international trade routes within each region, for example by high pressure pipeline from Canada to USA, which are not included on this map.

There are also ideas for other inter-regional links that we have not included; several of these may well go ahead if favourable economic and political conditions were to prevail.

Already we can see that based on identifiable projects inter-regional trade is set to increase. Trade within each region should also grow because of the shorter delivery routes and lower transportation costs. The world will need a lot of gas, whatever energy path we take in the coming decades. Investing in natural gas should be a ‘no regrets’ solution; a growing global gas market will be an increasingly important part of our sustainable energy future.

Part of this chapter is an update of the IGU Strategy Committee report on ‘new horizons for gas supply, demand and trade’ that was presented at the 25th World Gas Conference in Kuala Lumpur

Reserves and production

1. Global tables

Table 5.1

Natural gas: proved recoverable reserves at end-2011

Notes: The relationship between cubic metres and cubic feet is on the basis of one cubic metre = 35.315 cubic feet throughout

Sources: WEC Member Committees, 2009/10; data reported for previous WEC Surveys of Energy Resources; Cedigaz;Annual Report 2008, OAPEC; Annual Statistical Bulletin 2008, OPEC; Oil & Gas Journal, December 2009; World Oil, September 2009; published national sources

		Reserves	Production		R/P
Country	**bcm**	**bcf**	**bcm**		**years**
Afghanistan	50.0	1 765.7	45.5	1 607.6	1.1
Albania	1.0	35.3	3.0	105.9	.3
Algeria	4 502.0	158 987.1	84.6	2 988.0	53.2
Angola	161.0	5 685.7	.7	25.9	> 100
Argentina	332.5	11 742.5	45.5	1 607.6	7.3
Armenia	164.0	5 791.6			
Australia	788.6	27 849.2	45.0	1 588.8	17.5
Austria					
Azerbaijan	849.6	30 003.4	16.7	589.1	50.9
Bahrain	91.0	3 213.6	12.3	432.6	7.4
Bangladesh	183.7	6 487.3	20.1	710.9	9.1
Barbados					
Belarus	3.0	105.9			
Belgium					
Belize					
Benin	1.0	35.3			
Bhutan					
Bolivia	281.5	9 941.1	14.4	507.5	19.6
Bosnia-Herzegovina					
Botswana					
Brazil	459.4	16 223.3	24.1	852.5	19.0
Brunei Darussalam	390.8	13 801.0	11.8	416.7	33.1
Bulgaria	5.6	197.8			
Burkina Faso					
Burundi					
Cambodia					
Cameroon	135.1	4 771.0			
Canada	1 982.0	69 993.9	188.8	6 669.2	10.5
Cape Verde Islands					
Central African Republic					
Chad					
Chile	98.0	3 460.1	1.5	52.0	66.5
China	3 030.0	107 003.8	102.7	3 626.8	29.5
Colombia	134.1	4 735.7	11.3	397.6	11.9
Congo (DRC)	1.0	35.0			

Congo (Republic of)	90.6	3 199.5	1.2	41.0	78.0
Costa Rica					
Cote d'Ivoire	28.3	1 000.1	1.6	56.5	17.7
Croatia	24.0	846.1	1.8	64.0	13.2
Cuba	71.0	2 507.3	1.2	40.6	61.7
Cyprus					
Czech Republic	4.7	164.6	.2	6.0	27.6
Denmark	52.0	1 836.0	7.1	249.3	7.4
Dominican Republic					
Ecuador	7.9	279.0	.3	10.6	26.3
Egypt	2 186.0	77 198.1	61.3	2 165.9	35.6
El Salvador				.0	
Equatorial Guinea	36.8	1 299.6	6.7	238.0	5.5
Eritrea					
Estonia					
Ethiopia	25.0	882.9			
Faroe Islands					
Finland					
France	7.0	247.2	1.1	39.9	6.2
Gabon	29.0	1 024.1	8.0	282.5	3.6
Gambia					
Georgia	8.5	299.8			
Germany	79.5	2 806.3	12.9	454.6	6.2
Ghana	22.7	799.9			
Greece	1.0	35.0			
Greenland					
Guadeloupe					
Guatemala					
Guinea					
Guinea-Bissau					
Guyana					
Hong Kong					
Hungary	8.1	286.0	2.8	98.2	2.9
Iceland					
India	1 154.0	40 753.3	46.1	1 628.0	25.0
Indonesia	3 992.6	140 999.1	85.6	3 022.2	46.7
Iran	33 790.0	1 193 286.3	150.0	5 297.2	> 100
Iraq	3 158.0	111 524.1	.9	31.0	> 100
Ireland	10.0	353.1	.3	12.2	28.9
Israel	270.1	9 538.5	1.6	54.7	> 100
Italy	62.3	2 200.1	8.3	294.5	7.5
Jamaica					
Japan	40.0	1 412.6	5.0	176.3	8.0
Jordan	6.0	212.9	3.3	116.5	1.8
Kazakhstan	2 407.0	85 002.7	39.3	1 387.9	61.2
Kenya					
Korea (DRC)					
Korea (Republic)	7.1	250.0			
Kuwait	1 798.0	63 496.0	11.7	414.2	> 100
Kyrgyzstan	5.7	199.9			
Laos					
Latvia					
Lebanon					

Lesotho					
Liberia					
Libya	1 495.0	52 795.6	16.8	593.6	88.9
Lithuania					
Luxembourg					
Macedonia					
Madagascar					
Malawi					
Malaysia	2 350.0	82 989.7	66.5	2 348.4	35.3
Mali					
Malta					
Martinique					
Mauritania	28.0	988.8			
Mauritius					
Mexico	487.7	17 223.9	64.3	2 270.0	7.6
Moldova					
Monaco					
Mongolia					
Montenegro					
Morocco	1.4	50.9			
Mozambique	127.0	4 485.0	3.1	110.2	40.7
Myanmar (Burma)	283.2	10 001.1	11.9	421.0	23.8
Namibia	62.3	2 199.8			
Nepal					
Netherlands	1 303.0	46 015.2	81.1	2 863.7	16.1
New Caledonia					
New Zealand	27.6	976.1	4.4	154.2	6.3
Nicaragua					
Niger					
Nigeria	5 110.0	180 458.5	29.0	1 024.1	> 100
Norway	2 007.0	70 876.8	103.1	3 641.0	19.5
Oman	849.5	29 999.9	27.1	957.0	31.3
Pakistan	753.8	26 620.3	42.9	1 515.0	17.6
Papua New Guinea	155.3	5 484.4	.1	3.9	> 100
Paraguay					
Peru	352.8	12 459.1	31.0	1 094.8	11.4
Philippines	98.5	3 478.5	3.0	105.9	32.8
Poland	58.6	2 069.4	5.6	197.8	10.5
Portugal					
Puerto Rico					
Qatar	25 200.0	889 932.4	116.7	4 121.2	> 100
Réunion					
Romania	63.0	2 224.8	11.0	388.5	5.7
Russian Federation	47 750.0	1 686 280.6	669.6	23 646.8	71.3
Rwanda	56.6	1 999.9			
Saudi Arabia	8 028.0	283 507.0	99.2	3 504.3	80.9
Senegal					
Serbia					
Sierra Leone					
Singapore					
Slovakia	14.2	500.1			
Slovenia					
Somalia	5.7	199.9			

South Africa	27.1	957.0	1.0	34.3	27.9
Spain	2.5	89.7	5.0	176.6	.5
Sri Lanka					
Sudan	84.9	2 998.2			
Suriname					
Swaziland					
Sweden					
Switzerland					
Syria	240.7	8 499.9	8.9	315.7	26.9
Taiwan	6.9	243.7	.3	9.2	26.5
Tajikistan	5.7	200.0			
Tanzania	6.5	230.0	.8	27.5	8.4
Thailand	299.8	10 587.4	36.3	1 280.9	8.3
Togo					
Trinidad and Tobago	381.8	13 483.2	42.5	1 499.5	9.0
Tunisia	65.1	2 300.1	2.0	71.7	32.1
Turkey	7.1	250.7	.8	28.3	8.9
Turkmenistan	25 213.0	890 391.5	75.0	2 648.6	> 100
Uganda					
Ukraine	1 104.0	38 987.5	19.4	683.7	57.0
United Arab Emirates	6 089.0	215 031.7	51.3	1 810.9	> 100
United Kingdom	253.0	8 934.6	47.4	1 675.0	5.3
United States of America	7 716.0	272 488.8	648.5	22 901.9	11.9
Uruguay					
Uzbekistan	1 841.0	65 014.5	60.1	2 122.8	30.6
Venezuela	5 524.0	195 078.8	31.2	1 101.8	> 100
Vietnam	699.4	24 699.2	8.5	300.2	82.3
Yemen	478.5	16 898.1	6.2	220.4	76.7
Zambia					
Zimbabwe					
Total World	**209 741.9**		**3 517.8**		**59.6**

Table 5.2
Natural gas: production 2011

Notes: 1. Sources: WEC Member Committees, 2009/10; Cedigaz; national sources

	Reserves		Production		R/P
Country	**bcm**	**bcf**	**bcm**	**bcf**	**years**
Afghanistan	50.0	1 765.7	45.5	1 607.6	1
Albania	1.0	35.3	3.0	105.9	0
Algeria	4 502.0	158 987.1	84.6	2 988.0	53
Angola	161.0	5 685.7	.7	25.9	> 100
Argentina	332.5	11 742.5	45.5	1 607.6	7
Armenia	164.0	5 791.6			
Australia	788.6	27 849.2	45.0	1 588.8	18
Austria					
Azerbaijan	849.6	30 003.4	16.7	589.1	51
Bahrain	91.0	3 213.6	12.3	432.6	7
Bangladesh	183.7	6 487.3	20.1	710.9	9
Barbados					
Belarus	3.0	105.9			
Belgium					
Belize					

Benin	1.0	35.3			
Bhutan					
Bolivia	281.5	9 941.1	14.4	507.5	20
Bosnia-Herzegovina					
Botswana					
Brazil	459.4	16 223.3	24.1	852.5	19
Brunei Darussalam	390.8	13 801.0	11.8	416.7	33
Bulgaria	5.6	197.8			
Burkina Faso					
Burundi					
Cambodia					
Cameroon	135.1	4 771.0			
Canada	1 982.0	69 993.9	188.8	6 669.2	10
Cape Verde Islands					
Central African Republic					
Chad					
Chile	98.0	3 460.1	1.5	52.0	67
China	3 030.0	107 003.8	102.7	3 626.8	30
Colombia	134.1	4 735.7	11.3	397.6	12
Congo (DRC)	1.0	35.0			
Congo (Republic of)	90.6	3 199.5	1.2	41.0	78
Costa Rica					
Cote d'Ivoire	28.3	1 000.1	1.6	56.5	18
Croatia	24.0	846.1	1.8	64.0	13
Cuba	71.0	2 507.3	1.2	40.6	62
Cyprus					
Czech Republic	4.7	164.6	.2	6.0	28
Denmark	52.0	1 836.0	7.1	249.3	7
Dominican Republic					
Ecuador	7.9	279.0	.3	10.6	26
Egypt	2 186.0	77 198.1	61.3	2 165.9	36
El Salvador				.0	
Equatorial Guinea	36.8	1 299.6	6.7	238.0	5
Eritrea					
Estonia					
Ethiopia	25.0	882.9			
Faroe Islands					
Finland					
France	7.0	247.2	1.1	39.9	6
Gabon	29.0	1 024.1	8.0	282.5	4
Gambia					
Georgia	8.5	299.8			
Germany	79.5	2 806.3	12.9	454.6	6
Ghana	22.7	799.9			
Greece	1.0	35.0			
Greenland					
Guadeloupe					
Guatemala					
Guinea					
Guinea-Bissau					
Guyana					
Hong Kong					
Hungary	8.1	286.0	2.8	98.2	3

Iceland					
India	1 154.0	40 753.3	46.1	1 628.0	25
Indonesia	3 992.6	140 999.1	85.6	3 022.2	47
Iran	33 790.0	1 193 286.3	150.0	5 297.2	> 100
Iraq	3 158.0	111 524.1	.9	31.0	> 100
Ireland	10.0	353.1	.3	12.2	29
Israel	270.1	9 538.5	1.6	54.7	> 100
Italy	62.3	2 200.1	8.3	294.5	7
Jamaica					
Japan	40.0	1 412.6	5.0	176.3	8
Jordan	6.0	212.9	3.3	116.5	2
Kazakhstan	2 407.0	85 002.7	39.3	1 387.9	61
Kenya					
Korea (DRC)					
Korea (Republic)	7.1	250.0			
Kuwait	1 798.0	63 496.0	11.7	414.2	> 100
Kyrgyzstan	5.7	199.9			
Laos					
Latvia					
Lebanon					
Lesotho					
Liberia					
Libya	1 495.0	52 795.6	16.8	593.6	89
Lithuania					
Luxembourg					
Macedonia					
Madagascar					
Malawi					
Malaysia	2 350.0	82 989.7	66.5	2 348.4	35
Mali					
Malta					
Martinique					
Mauritania	28.0	988.8			
Mauritius					
Mexico	487.7	17 223.9	64.3	2 270.0	8
Moldova					
Monaco					
Mongolia					
Montenegro					
Morocco	1.4	50.9			
Mozambique	127.0	4 485.0	3.1	110.2	41
Myanmar (Burma)	283.2	10 001.1	11.9	421.0	24
Namibia	62.3	2 199.8			
Nepal					
Netherlands	1 303.0	46 015.2	81.1	2 863.7	16
New Caledonia					
New Zealand	27.6	976.1	4.4	154.2	6
Nicaragua					
Niger					
Nigeria	5 110.0	180 458.5	29.0	1 024.1	> 100
Norway	2 007.0	70 876.8	103.1	3 641.0	19
Oman	849.5	29 999.9	27.1	957.0	31
Pakistan	753.8	26 620.3	42.9	1 515.0	18

Papua New Guinea	155.3	5 484.4	.1	3.9	> 100
Paraguay					
Peru	352.8	12 459.1	31.0	1 094.8	11
Philippines	98.5	3 478.5	3.0	105.9	33
Poland	58.6	2 069.4	5.6	197.8	10
Portugal					
Puerto Rico					
Qatar	25 200.0	889 932.4	116.7	4 121.2	> 100
Réunion					
Romania	63.0	2 224.8	11.0	388.5	6
Russian Federation	47 750.0	1 686 280.6	669.6	23 646.8	71
Rwanda	56.6	1 999.9			
Saudi Arabia	8 028.0	283 507.0	99.2	3 504.3	81
Senegal					
Serbia					
Sierra Leone					
Singapore					
Slovakia	14.2	500.1			
Slovenia					
Somalia	5.7	199.9			
South Africa	27.1	957.0	1.0	34.3	28
Spain	2.5	89.7	5.0	176.6	1
Sri Lanka					
Sudan	84.9	2 998.2			
Suriname					
Swaziland					
Sweden					
Switzerland					
Syria	240.7	8 499.9	8.9	315.7	27
Taiwan	6.9	243.7	.3	9.2	27
Tajikistan	5.7	200.0			
Tanzania	6.5	230.0	.8	27.5	8
Thailand	299.8	10 587.4	36.3	1 280.9	8
Togo					
Trinidad and Tobago	381.8	13 483.2	42.5	1 499.5	9
Tunisia	65.1	2 300.1	2.0	71.7	32
Turkey	7.1	250.7	.8	28.3	9
Turkmenistan	25 213.0	890 391.5	75.0	2 648.6	> 100
Uganda					
Ukraine	1 104.0	38 987.5	19.4	683.7	57
United Arab Emirates	6 089.0	215 031.7	51.3	1 810.9	> 100
United Kingdom	253.0	8 934.6	47.4	1 675.0	5
United States of America	7 716.0	272 488.8	648.5	22 901.9	12
Uruguay					
Uzbekistan	1 841.0	65 014.5	60.1	2 122.8	31
Venezuela	5 524.0	195 078.8	31.2	1 101.8	> 100
Vietnam	699.4	24 699.2	8.5	300.2	82
Yemen	478.5	16 898.1	6.2	220.4	77
Zambia					
Zimbabwe					
Total World	**209 741.9**		**3 517.8**		**60**

2. Regional tables

Table 5.3

Natural gas: regional summary tables 2011

	Reserves	Production	R/P
Country	**bcm**	**bcm**	**years**
Nigeria	5110	29.0	> 100
Egypt	2186	61.3	36
Libya	1495	16.8	89
Angola	161.0	0.7	> 100
Cameroon	135		
Rest of region	631	22	
Africa total	9718.6	130.2	75
China	3030	102.7	30
Japan	40	5.0	8
Korea (Republic)	7		
Taiwan	7	0.3	27
Rest of region	0	0	
East Asia total	3084	108	29
Russian Federation	47750	669.6	71
Norway	2007	103.1	19
Netherlands	1303	81.1	16
Ukraine	1104	19.4	57
Bosnia-Herzegovina	282		
Rest of region	935	101	
Europe total	53381	974	55
Venezuela	5524	31.2	> 100
Brazil	459	24.1	19
Trinidad and Tobago	382	42.5	9
Peru	353	31.0	11
Argentina	333	45.5	7
Rest of region			
LAC total	7361	203	36
Iran	33790	150.0	> 100
Qatar	25200	116.7	> 100
Saudi Arabia	8028	99.2	81
United Arab Emirates	6089	51.3	> 100
Algeria	4502.0	84.6	53
Rest of region			
MENA total	84689	586	144
United States of America	7716	648.5	12
Canada	1982	188.8	10
Mexico	488	64.3	8
North America total	10186	902	11
Turkmenistan	25213	75.0	> 100
Kazakhstan	2407	39.3	61
Uzbekistan	1841	60.1	31
India	1154	46.1	25
Azerbaijan	850	16.7	51
Rest of region	1163	109	
South & Central Asia total	32627	345.7	94

Indonesia	3993	85.6	47
Malaysia	2350	66.5	35
Australia	789	45.0	18
Vietnam	699	8.5	82
Thailand	300	36.3	8
Rest of region	565	19	
Southeast Asia & Pacific	8695	261	33
Global totals	**209 741.9**	**3518**	**60**

Country notes

The following Country Notes on Natural Gas provide a brief account of countries with significant gas resources. They have been compiled by the Editors, drawing upon a wide variety of material, including information received from WEC Member Committees, national and international publications.

The principal published sources consulted were:

- Annual Statistical Bulletin 2011, OPEC;
- BP Statistical Review of World Energy, 2011;
- Energy Balances of OECD Countries, 2012 Edition, International Energy Agency;
- Energy Balances of Non-OECD Countries, 2012 Edition, International Energy Agency;
- Energy Statistics of OECD Countries, 2012 Edition, International Energy Agency;
- Energy Statistics of Non-OECD Countries, 2012 Edition, International Energy Agency;
- Natural Gas in the World, Cedigaz;
- Ex number of articles and other publications
- Numbers and estimates.

Brief salient data are shown for each country where available, including the year of first commercial production of natural gas (where it can be ascertained).

Note that Reserves/Production (R/P) ratios have been calculated on the basis of gross production less quantities re-injected.

Algeria

Proved recoverable reserves (bcm)	4 499
Production (bcm)	192.4
Consumption (bcm)	28.8
R/P ratio (years)	53.2

According to The Oil and Gas Journal (OGJ), as of January 2012, Algeria's proved natural gas reserves amount to 4 499 bcm, the tenth largest natural gas reserves in the world and the second largest in Africa - after Nigeria. Algeria is the third largest gas supplier to Europe.

Algeria's largest natural gas field is Hassi R'Mel, discovered in 1956. Located in the eastern part of the country, it holds proved reserves of about 2 405 bcm. The remainder of Algeria's natural gas reserves comes from associated locations (they occur alongside crude oil reserves) and non-associated fields in the south and southeast regions of the country.

Algeria's gross natural gas production in 2010 was 192.4 bcm compared with 195.27 bcm in 2009. Of this amount, 90.56 bcm was reinjected for enhanced oil recovery, 99.05 bcm was marketed, while 5.66 bcm was vented/flared.

According to Cedigaz estimates, Algeria's natural gas exports totalled 55.75 bcm in 2010, up from 52.63 bcm in 2009. About 65% of exports, or 36.5 bcm, moved through the natural gas pipelines connecting Algeria with Italy and Spain, while 35%, or 19.3 bcm, was exported by tankers as LNG. Algeria was the third largest natural gas supplier to Europe after Russia and Norway in 2010.

With the start-up of the LNG plant at Arzew in 1964, Algeria became the world's first producer of LNG. In 2010, the country was the seventh largest exporter of LNG in the world, accounting for about 7% of the world's total LNG exports. A new LNG plant with capacity of 218 bcf/y is under construction and due to open in 2013. Gas supplies will be coming from the Gassi Touil fields.

Argentina

Proved recoverable reserves (bcm	378.8
Production (bcm)	40.1
Consumption (bcm)	43.3
R/P ratio (years)	53.2

Argentina has the largest natural gas industry in South America, although its lead has been decreasing in recent years given the strong growth of its Brazilian competitor. It is also estimated that Argentine shale gas resources are the third largest in the world, after USA and China. About 13% of Argentina's 2011 natural gas was produced offshore and approximately 5% came from unconventional gas. The largest natural gas producing companies are Total and YPF which together account for about 50% of total production. Other companies with significant activities in the natural gas sector are Pan American Energy, Petrobras (Brazil), Pluspetrol (Argentina), Tecpetrol (Argentina), and Apache Energy (USA). Transportadora de Gas del Sur (TGS) is the leading natural gas transportation company followed by Transportadora de Gas del Norte (TGN).

Argentina is a net importer of natural gas, importing gas from Bolivia and exporting mainly to Chile and Uruguay. Exports of dry natural gas have dramatically fallen from its peak of 7.67 bcm in 2004 to 0.42 bcm in 2010. Argentina imported 21 LNG cargoes, or almost 1.1 million tonnes of LNG in 2010. Trinidad and Tobago accounted for nearly 90% of those imports, with the remainder arriving from Qatar. Argentine government tenders suggest that LNG imports doubled in 2011.

About 30% of natural gas produced in Argentina is used for power generation.

Australia

Proved recoverable reserves (bcm)	788.6
Production (bcm)	44.9
Consumption (bcm)	27.6
R/P ratio (years)	17.5

Natural gas is Australia's third largest energy resource after coal and uranium. This is unlikely to change up to 2035. Australia may also have significant shale gas resources but they have not been properly researched yet. At the moment there is no shale gas production in Australia. Nearly 92% of Australia's gas resources are located offshore on the North-West coast. Geoscience Australia and ABARE in their assessment of undiscovered conventional gas resources point towards the offshore basins with a total of 3228 bcm (114tcf). At the moment Australia has no proved reserves of tight gas, but identified in-place resources of tight gas are estimated to be (566 bcm or 20 tcf).

In 2010 Australia was the 4th largest LNG exporter in the world and around 48% of its gas production was exported as LNG. Japan accounted for nearly 70% of Australia's LNG exports, followed by China with 21% and South Korea with 5% (BP 2011).

Australia's LNG industry is undergoing a transformation and its capacity is expected to increase fourfold (113 bcm, 4 tcf). In addition to the current export capacity development, including the Pluto project which is scheduled to deliver first LNG exports in 2012, there is some 76 bcm (2.7 tcf) of capacity at various stages of construction. Three of these projects are based on conventional natural gas and located off the coast of Western Australia. Major domestic and foreign natural gas companies operating in Australia include Santos, Woodside, Chevron, ConocoPhillips, ExxonMobil, Origin Energy, BG Group, Apache, INPEX, Total and Shell.

Australia's gas consumption has been growing by 4% per year over the past decade. The main gas users in Australia are the manufacturing industry (32%), electricity generation (29%), mining (23%) and residential (10%) sectors.

At the end of April 2012 there were seven advanced gas-fired electricity generation projects under development with a combined capacity of 975 MW and scheduled to be in operation by the end of 2012 . Three of the projects are located in the Northern Territory while there is one each in New South Wales, Victoria, Queensland and Western Australia. In addition, there are further 42 gas- and CSG-fired generation projects at a less advanced stage with a combined capacity of around 1800 MW.

Azerbaijan

Proved recoverable reserves (bcm)	849.5
Production (bcm)	16.6
Consumption (bcm)	9.9
R/P ratio (years)	50.9

With the start of operations in the Shah Deniz natural gas and condensate field in late 2006, Azerbaijan became a net exporter of natural gas. Almost all of its natural gas is produced in two offshore fields, the ACG complex and Shah Deniz. The ACG field provides associated gas to the Azerigaz system for domestic use via an undersea gas pipeline to Sangachal Terminal at Baku. Azerbaijan is becoming an important supplier of both oil and natural gas. Companies involved in Azerbaijan's natural gas are Azerigaz, Azneft, AIOC, Statoil and BP, Total, LUKoil, SOCAR and OIEC of Iran.

About 66% of the country's total gas production is used to meet domestic demand and the remaining 34% are exported, mainly to Russia, Georgia and Turkey via the Gazi-Magomed-Mozdok pipeline. A small volume of natural gas is shipped to Iran via the Baku-Astara pipeline.

Bangladesh

Proved recoverable reserves bcm	183.7
Production (bcm)	20.1
Consumption (bcm)	20.1
R/P ratio (years)	19.1

Whilst the published volumes of proved gas reserves are not particularly large, much of Bangladesh is poorly explored and the potential for further discoveries is thought to be substantial. Natural gas contributes nearly three-quarters of Bangladesh's commercial energy supplies and it is the main fuel in power stations and fertiliser plants.

Petrobangla (Bangladesh Oil, Gas and Mineral Corporation), a 100 per cent state owned corporation, has the primary responsibility for the natural gas industry in Bangladesh. Petrobangla is managed under the Ministry of Energy and Mineral Resources comprises several groups of companies covering the entire gas value chain: Bangladesh Petroleum Exploration Company, Bangladesh Gas Fields Company, Sylhet Gas Fields Company, Titas Gas Transmission and Distribution Company, Bakhrabad Gas System, Jalalabad Gas Transmission and Distribution System, Western Zone Gas Supply Co. (Poschim Anchal Gas Bitaran Company, WESGAS, a new company for distribution of gas in the western part of Bangladesh), and compressed natural gas company Rupantarita Prakritik Gas Company. Leading Private Companies Involved in the Natural gas industry include Libra Enterprise (www.libraenterprise.com), Gasmin Limited and Foundry Limited.

Bolivia

Proved recoverable reserves (bcm)	281.5
Production (bcm)	14.3
Consumption (bcm)	2.7
R/P ratio (years)	19.5

According to Oil & Gas Journal, Bolivia has the fifth largest reserves in South America. Most of these reserves are located in the eastern region of the country. The production volumes have risen dramatically since 1999.

Brazil is the primary destination for Bolivian natural gas. In 2010 about 68% of Bolivian natural gas was directed to Brazil via the GASBOL pipeline, and 20% to Argentina via the YABOG pipeline.

One-fifth of Bolivian natural gas production is consumed at the domestic market, mainly for electricity production (over one-half of Bolivian natural gas consumption), industry (roughly one-quarter) and transportation (just below one-fifth).

The state owned company YPFB (Yacimientos Petrolíferos Fiscales Bolivianos) and Petrobrás, Repsol YPF, Total, British Gas and British Petroleum and Exxon are the main actors in the market.

Brazil

Proved recoverable reserves (bcm)	459.3
Production (bcm)	24.1
Consumption (bcm)	26.7
R/P ratio (years)	26.5

Brazil's natural gas industry is still fairly new and relatively small compared to the oil sector. OGJ reported that Brazil had 14.7 trillion cubic feet (Tcf) of proved natural gas reserves in 2012. The Campos, Espírito Santo, and Santos Basins hold the majority of reserves, but there are sizable reserves also in the interior of the country. According to Petrobras, the Tupi field alone could contain 5-7 tcf of recoverable natural gas, which if proved, would increase Brazil's total natural gas reserves by 50 %. The other major natural gas market is located in Brazil is Amazon region.

Natural gas production has grown slowly in recent years, mainly due to the lack of domestic transport capacity and low domestic prices. In 2010, Brazil produced 445 billion cubic feet (bcf) of natural gas – the majority of this was associated with oil production. Natural gas consumption is a small part of the country's overall energy mix, accounting only for 7% of total energy consumption in 2010. The largest share of Brazil's natural gas is produced in offshore fields in the Campos Basin in Rio de Janeiro state.

Most of the onshore production takes place in the Amazonas and Bahia states and is used locally due to the lack of transportation infrastructure.

Brazilian gas pipeline network stretches over 4 000 miles, mostly in the South-East and North-East of the country.

With natural gas imports of 445 bcf in 2010, a 50% increase from 2009, Brazil is a major importer of natural gas and demand for gas is growing quickly. Imports are transported by the pipeline from Bolivia and as liquefied natural gas (LNG) from Trinidad and Tobago, Qatar and Nigeria. The anticipated growth of imports is expected to be supplied with LNG rather than with pipelines. Bolivia is the main natural gas supplier to Brazil and its share accounts for 78% of total gas imports. Currently, the main supplies from Bolivia are transported via the GASBOL pipeline, which links Santa Cruz in Bolivia to Porto Alegre in Brazil, via Sao Paulo.

Brazil has two liquefied natural gas (LNG) regasification terminals, both installed in the last two years: the Pecem terminal in the Northeast, and the Guanabara Bay terminal in the Southeast. Both facilities are floating regasification and storage units (FRSU), with a combined production capacity of 740 mcf per day. The Pecem received its first LNG cargo from Trinidad and Tobago in July 2008, while the Guanabara Bay terminal came online in May 2009. Petrobras plans to bring online a third terminal with a capacity of 495 mcf per day in Bahia state in 2013. State-owned Petrobras plays a dominant role in Brazil's entire natural gas supply chain. In addition to controlling the vast majority of the country's natural gas reserves, the company is in charge of the main domestic Brazilian gas production and for gas imports from Bolivia.

Brunei

Proved recoverable reserves (bcm)	390.8
Production (bcm)	11.8
Consumption (bcm)	2.9
R/P ratio (years)	33.1

Brunei is the third largest liquefied natural gas producer in Asia thanks to its strategic location close to the vital sea transport routes, through the South China Sea, linking the Indian and Pacific Oceans. Natural gas was found in association with oil at the Seria and other fields. For many years this resource was

virtually unexploited, but in the 1960s a realisation of the resource potential, coupled with the introduction of new production and transport technologies for liquefied natural gas, made it possible to develop a major gas export project. Since 1972 Brunei has been exporting LNG to Japan, and more recently to Korea. Occasional spot market sales have been agreed and delivered to other destinations, too. About 70% of Brunei's marketed production is exported as LNG, the balance being mostly used in the liquefaction plant, local power stations and offshore oil and gas installations. Small quantities are used for residential purposes in Seria and Kuala Belait.

Canada

Proved recoverable reserves (bcm)	1727.0
Production (bcm)	160.1
Consumption (bcm)	103.3
R/P ratio (years)	10.5

Canada is the world's third-largest producer of dry natural gas and has for many years been the source of most US natural gas imports, before the recent shale gas revolution in the US market. Canada's gas in place from both conventional and unconventional resources is estimated to be almost 113 200 bcm, (Petrel Robertson, 2010).

Despite holding a relatively small share of the world's proved natural gas reserves, Canada is the fourth-largest exporter of natural gas, behind Russia, Norway, and Qatar. All of Canada's current natural gas exports are sent to U.S. markets via pipeline. The proportion of Canada's natural gas production that is devoted to meeting domestic requirements has risen in recent years, while net exports to the United States have fallen. Most of Canada›s natural gas reserves are conventional resources in the WSCB, including those associated with the region›s oilfields.

Other areas with significant concentrations of natural gas reserves include offshore fields near the eastern shore of Canada, principally around Newfoundland and Nova Scotia, the Arctic region, and the Pacific coast. EIA estimates that Canada produced 189.67 bcm of gross natural gas in 2010 of which 166.9 bcm was marketed; 152.8 bcm was dry natural gas), 20.44 bcm was reinjected, and 1.54 bcm was vented or flared.

Canada's natural gas pipeline system is highly interconnected with the U.S. pipeline system. TransCanada operates the largest network of natural gas pipelines in North America, including thirteen major pipeline systems and approximately 37,000 miles of gas pipelines in operation.

A number of major and independent companies, including Encana, Apache, Devon, Quicksilver, and Nexen, are involved in Canada's natural gas industry.

China

Proved recoverable reserves (bcm)	3 030
Production (bcm)	102.7
Consumption (bcm)	130.9
R/P ratio (years)	40.6

The major producing gas fields in China are located in the Sichuan Basin (output of 17 bcm in 2007), the Ordos Basin (15.5 bcm) and the Tarim Basin (12 bcm). According to provisional estimates, in 2008, China's natural gas consumption grew by 11.8% and reached 77.7 bcm. Since 2004, the annual growth was more than 20%, far above the country's GDP growth rate.

With the exception of its own consumption in the energy sector, which uses gas mainly for the development of oil and gas fields, the chemicals and petrochemicals industries are major natural gas consumers in the industrial sector. Natural gas is used as a fuel and feedstock in several industries such as ammonia, methanol and chemical fertilizer production. According to the government's long-term electricity development plan, gas-fired power capacity is expected to reach 70 GW by 2020.

As in the oil industry, China's upstream natural gas sector is dominated by three national Oil Companies (NOCs): CNPC, Sinopec and CNOOC. CNPC now holds approximately 75%

of all domestic gas resources and 80% of China's pipeline network (including major inter-provincial trunk lines). CNPC is also in charge of several major gas import projects, such as the Central Asia pipeline and LNG imports in Jiangsu and Dalian.

There are also a few small-size natural gas producers – mainly owned by local governments. More recently, small-size inland LNG producers operated by private companies have also entered the scene. In Xinjiang, for example, a new private company recently built a small LNG plant with production capacity of 0.6 bcm (432 000 tonnes) per year and delivery of LNG by tanker trucks.

Most distribution companies are owned and managed by local governments, while producers directly deliver natural gas to major industrial users. In 2002, the government opened the city gas business to private and foreign companies, and as a result more than 60 private companies are now involved in distributing gas in several cities, including Shanghai and Guangdong. LNG receiving terminals are owned and operated by joint ventures between local government entities, gas users and importing NOCs, such as CNOOC and CNPC.

Colombia

Proved recoverable reserves (bcm)	134.1
Production (bcm)	11.26
Consumption (bcm)	9.08
R/P ratio (years)	11.2

According to the Oil and Gas Journal, Colombia had proved natural gas reserves of 4.7 trillion cubic feet (Tcf) in 2012, up from 4 Tcf in 2011. The early gas discoveries were made in the North-West of the country and in the Middle and Upper Magdalena Basins; in more recent times, major gas finds have been made in the Llanos Basin to the east of the Andes.

The bulk of Colombia's natural gas reserves are located in the Llanos basin, although the Guajira basin accounts for the major part of current production. Natural gas production, like oil production, has been rising substantially in the last few years due to increasing international investment in exploration and development, rising domestic consumption, and new export opportunities. The two biggest natural gas fields in the country, the Cupiaga and Cusiana fields in the Llanos basin, in central Colombia, were acquired from BP by Ecopetrol and Talisman Energy in 2010. Almost all of the gas produced from these fields is re-injected.

Colombia produced 398 billion cubic feet (Bcf) of dry natural gas in 2010, while consuming 321 Bcf. About 57 % of the country's total gross natural gas production of 1,124 Bcf was reinjected to facilitate enhanced oil recovery.

There are some 2,000 miles of natural gas pipelines in Colombia. Empresa Colombiana de Gas (Ecogás) operates most of Colombia's natural gas pipeline network. The three main lines include the Ballena-Barrancabermeja, linking Chevron's Ballena field on the northeast coast to Barrancabermeja in central Colombia; the Barrancabermeja-Nevia-Bogota line, which integrates the Colombian capital into the transmission network, and the Mariquita-Cali line through the western Andean foothills.

Chevron is the largest natural gas producer in the country, producing on average 642 Mcf gross natural gas daily and supplying about 65 % of the country's needs. In partnership with Ecopetrol, the company operates the offshore-Caribbean Chuchupa field in the Guajira basin, the largest non-associated natural gas field in the country.

At present a high proportion of Colombia's gas output (42% in 2008) is re-injected in order to maintain or enhance reservoir pressures. The major outlets for natural gas are own use by the petroleum industry (23% of total gas consumption in 2007), chemicals, cement and other industrial users (27%) and power plants (25%). Residential/commercial consumers accounted for 20%, while CNG use in road transport is still of modest proportions.

Denmark

Proved recoverable reserves (bcm)	51.9
Production (bcm)	7.1
Consumption (bcm)	4.1
R/P ratio (years)	7.3

The Danish WEC Member Committee reports data provided by the Danish Energy Authority (DEA), which does not use the terms 'proved', 'probable', 'possible' and 'additional' reserves, but employs the categories 'ongoing', 'approved', 'planned' and 'possible' recovery. The DEA expresses natural gas volumes in normal cubic metres (Nm3), measured at 0oC and 1 013 mb. For the purpose of the present Survey, all such data have been converted into standard cubic metres, measured at 15oC and 1 013 mb.

Denmark is a net exporter of natural gas. In 2010 it exported approximately 3.2 bcm of gas: 46% to Sweden, 32% to Germany and the rest to the Netherlands.

Today, all natural gas for the Danish market comes from the fields in the Danish sector of the North Sea. DONG has purchased all the gas produced from the Danish fields. The biggest producer of natural gas in Denmark is Dansk Undergrunds Consortium (DUC), which produces gas from a number of fields. In addition, the South Arne Group produces natural gas from the South Arne field.

DONG purchases and transports all natural gas for the Danish market and also distributes gas to customers in Southern Jutland and parts of Zealand. DONG is a state-owned limited company. HNG distributes natural gas in the Greater Copenhagen Area. In Central and North Jutland, natural gas is distributed by Naturgas MidtNord, and on Funen, it is distributed by Naturgas Fyn.

The major part of the national consumption is related to gas-fired CHP plants, manufacturing industries and the residential/commercial sector.

Egypt (Arab Republic)

Proved recoverable reserves (bcm)	2186
Production (bcm)	61.3
Consumption (bcm)	46.2
R/P ratio (years)	35.6

In January 2012, OGJ estimated Egypt's proved gas reserves to reach 77 Tcf, a significant increase compared to the 2010 estimates of 58.5 Tcf. In terms of the natural gas reserves, Egypt ranks third in Africa, after Nigeria and Algeria.

New discoveries offshore the Nile Delta and some finds in the Western Desert have led to the increase in proved reserves. Over 80% of Egypt's natural gas reserves and 70% of its production are located in the Mediterranean and the Nile Delta.

In 2010, Egypt produced roughly 2.2 Tcf and consumed just over 1.6 Tcf of dry natural gas. Gas production is expected to continue to grow to satisfy rising domestic demand, export commitments through the Arab Gas Pipeline and LNG exports. Egypt is expected to continue to play an important role of a reliable natural gas supplier to Europe and the Mediterranean region, although exports are competing with rising domestic demand, particularly in the power generation sector.

The electricity sector accounted for the largest share of natural gas consumption (54%) followed by the industrial sector (29 %), according to Cedigaz. The share of natural gas consumed in the transportation sector has also been rising since the development and deployment of compressed natural gas (CNG) infrastructure and vehicles. According to the Ministry of Petroleum of Egypt, the number of natural gas driven vehicles sold in Egypt between the fiscal years 2004/2005 and 2009/2010 has more than doubled. Major foreign players involved in the development of Egypt gas sector include Eni, BG Group, BP & Apache and GASCO.

Dry natural gas exports, which began in 2003, have been rising rapidly, with the completion of the Arab Gas Pipeline (AGP) in 2004 and the startup of the first three LNG trains at Damietta in 2005. However, after 2006 exports began to level off and in 2010, natural gas exports fell to 535 Bcf, an almost 20 % drop from the year before. Egypt exports around 70% of total natural gas exports as LNG, and the remaining 30% are exported via pipelines. The Arab

Gas Pipeline (AGP) originates in Egypt and provides gas to Jordan, Syria and Lebanon, with recent additions extending the pipeline to Turkey and European markets. Egypt has three LNG trains: Segas LNG Train 1 in Damietta and Egypt LNG trains 1 and 2 in Idku. The combined LNG export capacity is close to 600 Bcf per year with plans to expand in the near future, pending export policy changes and legislation. In 2010, as domestic demand for natural gas increased, LNG exports fell to about 354 Bcf, which was down by 30% from almost 500 Bcf in 2009.

In 2010 half of Egypt's LNG was shipped to Europe, which imported about 180 Bcf, with over half of that destined for Spain (110 Bcf). The US was the second largest recipient of Egyptian LNG in 2010, and imported just over 71 Bcf. Other major destinations included Korea (36 Bcf), Japan (21 Bcf) and Chile (18 Bcf). The recent advances in shale gas technologies are fundamentally changing the natural gas sector's business model and in particular in the North-American market and these changes will have a significant impact on Egypt's future economic development and the entire market

Germany

Proved recoverable reserves (bcm)	175.6
Production (bcm)	11.9
Consumption (bcm)	79.0
R/P ratio (years)	14.7

Despite the country being one of Europe's oldest gas producers, Germany's remaining proved natural gas reserves are still sizeable, and (apart from the Netherlands) they rank as the largest onshore reserves in Western Europe. The principal producing area is in north Germany, between the rivers Weser and Elbe; westward from the Weser in the vicinity of the Netherlands border there is another main producing zone, with more mature fields.

Indigenous production provides roughly 20% of Germany's gas supplies; the greater part of demand is met by imports from the Russian Federation, Norway, the Netherlands, Denmark and the UK. Germany imports 87.57 bcm natural gas. Due to its central location in Europe, Germany is a major natural gas pipeline transit hub for imports from Russia and the North Sea. The main suppliers of natural gas include E.ON, RWE, Wingas, VNG.

India

Proved recoverable reserves (bcm)	1154
Production (bcm)	46.1
Consumption (bcm)	61.1
R/P ratio (years)	25.0

The Indian gas market is expected to be one of the fastest growing in the world over the next two decades. IEA envisages gas demand to increase by 5.4% per annum over 2007-30 (IEA, 2009) reaching 132 bcm by 2030. India's primary energy supply is currently dominated by coal (37%), biomass and waste (27%) and oil (26%) while the share of natural gas is only 6%.

Production has been almost flat since 2002, at 30-32 bcm per year, but jumped to 46 bcm in 2009-2010. Around three quarters of the gas production came from the Western offshore area. Fields located in Gujarat, Assam and Andhra Pradesh are the major sources of onshore gas. Smaller quantities of gas are also produced in Tamil Nadu, Tripura and Rajasthan.

India's natural gas sector, just as the entire energy sector, is dominated by state-owned companies. The Oil and Natural Gas Corporation (ONGC) and Oil India Ltd (OIL) have dominant upstream positions. A handful of Indian and foreign companies such ONGC, BP, RIL, Essar Oil, Arrow Energy, GAIL, and GEECL are active in India's natural gas sector.

There are two main gas transport companies: the former public sector monopoly GAIL and a new entrant, Reliance Gas Transportation Infrastructure Ltd (RGTIL), a company privately owned by Reliance Industries Ltd. As India does not have any pipeline connections, all gas is currently imported as LNG. Current operational LNG import capacity is 13.5 mtpa (18 bcm).

India imports natural gas from Qatar (under a long-term contract), Australia, Trinidad and Tobago, and Russia as well as from a few other countries. Natural gas is mainly used as fuel for power generation and currently its share in the electricity production fuel mix, is according to the Central Electricity Authority (CEA), with gas representing 11% versus 52% for coal and 24% for hydro.

There are an estimated 700 000 natural gas vehicles (NGV) in India making India the fifth country after Pakistan, Argentina, Brazil and Iran in terms of NGVs.

Indonesia

Proved recoverable reserves (bcm)	3994
Production (bcm)	82.8
Consumption (bcm)	41.3
R/P ratio (years)	48.3

According to Oil & Gas Journal, Indonesia had 141 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2012, making it the 14th largest holder of proved natural gas reserves in the world, and the third largest in the Asia-Pacific region. The country continues to be a major exporter of pipeline and liquefied natural gas (LNG). At the same time, domestic consumption of natural gas has nearly doubled since 2004. Natural gas shortages caused by production problems and rising consumption forced Indonesia to buy spot cargoes of LNG to meet export obligations. The government committed to constructing new LNG receiving terminals and gas transmission pipelines to address domestic gas needs, though this could reduce the natural gas available for export.

Indonesia's gas production is the highest in Asia. The main producing areas are in northern Sumatra, Java and eastern Kalimantan. Natural gas production has increased by over a third since 2005. While Indonesia still exports about half of its natural gas, domestic consumption is increasing. Indonesia has for many years been the world's leading exporter of LNG.

The principal domestic consumers of natural gas (apart from the oil and gas industry) are power stations, fertiliser plants and industrial users; the residential, commercial and transportation sectors have relatively small shares.

The state corporation Pertamina accounted for less than 15 % of natural gas production in 2012, according to PwC. International oil companies such as Total, ConocoPhillips and

ExxonMobil dominate the upstream gas sector, while the state-owned utility Perusahaan Gas Negara (PGN) carries out natural gas transmission and distribution activities.

In 2011, Indonesia produced 2.7 Tcf of dry natural gas. Production grew at an annual rate of about 2% over the previous two decades, and Indonesia's 2011 gas production was the eleventh-highest in the world. A little more than half of Indonesia's 2011 production came from offshore fields, according to the Ministry of Energy and Mineral Resources. The government estimates that more than 60 % of the country's conventional gas reserves may be located offshore. An increasingly large share of Indonesia's natural gas production has come from non-associated (purely natural gas) fields in recent years. According to IHS Global Insight, associated gas (found in oil fields) accounted for around 15 % of gross production in 2010. Indonesia's largest fields are located in the Aceh region of South Sumatra and East Kalimantan. Natural gas associated with oil production is often flared when there is no infrastructure in place to make use of the gas. Indonesia ranks tenth in global natural gas flaring according to the Global Gas Flaring Reduction (GGFR) Initiative, but its flaring volume has dropped in recent years from a high of over 175 billion cubic feet (Bcf) in 1997 to around 80 Bcf in 2010, according to satellite data from the National Oceanic and Atmospheric Administration (NOAA)

In 2011, Indonesia consumed 1.3 Tcf of natural gas, or just under half of its total dry gas production. Although the industrial sector accounts for the largest portion of domestic consumption, industry analysts expect the power sector to be the most significant driver of future consumption growth.

Indonesia was the world's eighth largest net exporter of natural gas in 2011. The majority of exports go to Japan as LNG shipments and to Singapore via pipeline connections

Indonesia was the third-largest exporter of liquefied natural gas (LNG) in 2011, following Qatar and Malaysia, according to data from PFC Energy. By year end 2011, Indonesia exported over 1 Tcf of LNG, or about nine % of the world's LNG exports. Mostly a regional supplier to Japan, South Korea, Taiwan, and China, Indonesia lost market share in recent years to LNG producers such as Qatar, Malaysia, Australia, and Algeria.

There are three operational liquefaction terminals in Indonesia, with a combined production capacity of about 1.6 trillion cubic feet per year (Tcf/y). The Bontang LNG terminal in East Kalimantan has a capacity of 1.1 Tcf/y; it is the largest in Indonesia and one of the largest in the world

The next anticipated LNG facility in Indonesia will be the Donggi-Senoro liquefaction plant in Central Sulawesi. The project developers (Mitsubishi, Kogas, Pertamina, and Medco) signed a final investment decision in early 2011 expect the 370 Bcf/y plant to be commercial in 2014. Inpex, a Japanese company, received government approval at the end of 2010 for the Masela liquefaction terminal in the Arafura Sea, but it has delayed the expected startup date of the floating terminal until 2018

Iran (Islamic Republic)

Proved recoverable reserves (bcm)	3 307
Production (bcm)	146.1
Consumption (bcm)	144.6
R/P ratio (years)	22.63

Iran has the second largest gas reserves in the world after the Russian Federation. For two decades, its production growth increased by an average of 10% per annum, yet Iran has only depleted 5% of its gas reserves.

According to Oil & Gas Journal, as of January 2011, Iran's estimated proved natural gas reserves stood at 29601.8 bcm, second only to Russia. Over two-thirds of Iranian natural gas reserves are located in non-associated fields, and have not been developed. Major natural gas fields include: South and North Pars, Kish, and Kangan-Nar.

Iran's natural gas reserves are predominantly located offshore, although significant production originates from onshore oil fields (associated gas). Over two-thirds of Iranian natural gas reserves are located in non-associated fields, and are just recently beginning to be developed. The giant South Pars gas field, only a portion of which is in Iranian territory, comprises over 47% of total reserves. Other large natural gas fields include North Pars, Kish, Kangan-Nar, Golshan, and Ferdowsi fields. USGS estimates that Iran's undiscovered gas resources could be 5660 – 22640 billion cubic meters.

Iran imports natural gas from its northern neighbour Turkmenistan. According to FGE imports jumped to 1.1 Bcf/d between January and October 2011 as a result of completion of the Dauletabad-Hasheminejad pipeline. Iran exports natural gas to Turkey and Armenia via pipeline.

The most significant energy development project in Iran is the offshore South Pars field, which produces about 35% of total gas produced in Iran.

POGC is responsible for LNG development, although various companies including the National Iranian Gas Export Company (NIGEC) are also involved.

Iraq

Proved recoverable reserves (bcm)	3138
Production (bcm)	1.3
Consumption (bcm)	1.3
R/P ratio (years)	2423

Iraq's natural gas resources are not particularly large by Middle Eastern standards: proved reserves (as reported by OAPEC) account for less than 5% of the regional total. Most other published sources quote the same figure, the one exception being World Oil, which gives Iraq's proved reserves as 2 577 bcm.

According to data reported by Cedigaz, Iraq also possesses 5 009 bcm of probable and possible reserves, and states that 70% of Iraq's proved reserves consist of associated gas, with non-associated gas accounting for 20% and dome gas for the balance. A high proportion of gas output is thus associated with oil production: some of the associated gas is flared.

Between 1986 and 1990 Iraq exported gas to Kuwait. Currently all gas usage is internal, as fuel for electricity generation, as a feedstock and fuel for the production of fertilisers and petrochemicals, and as a fuel in oil and gas industry operations.

Iraq's proven reserves of conventional natural gas amount to 3.4 trillion cubic metres (tcm), or about 1.5% of the world total, placing Iraq 13th among global reserve-holders.

Geographically, Iraq's proved gas reserves are concentrated in the South, mostly as the large associated gas reserves in the super-giant fields of Rumaila, West Qurna, Majnoon, Nahr Umr and Zubair. Power sector is the main industrial activity sector for gas use, followed by domestic use. Natural gas companies operating in Iraq are Basrah Gas Company (BGC), Shell and Mitsubishi.

Iraq currently imports natural gas from Iran and the countries are building a gas pipeline expected to be operational next year.

Kazakhstan

Proved recoverable reserves (bcm)	2407
Production (bcm)	20.2
Consumption (bcm)	10.2
R/P ratio (years)	119

Kazakhstan has substantial resources of natural gas and may well become a major player on the world stage. In January 2012, the Oil and Gas Journal estimated Kazakhstan's proved natural gas reserves at 85 trillion cubic feet (Tcf). Natural gas production in Kazakhstan is almost entirely associated gas. The chief discovery so far has been the giant Karachaganak field, located in the North of Kazakhstan, near the border with the Russian Federation. Another major field is Tengiz, close to the north-east coast of the Caspian Sea.

Annual marketed natural gas production has been trending upward from 314 billion cubic feet (Bcf) in 2000 to 388 Bcf in 2009, before it decreased slightly in 2010. While total gross gas production was 1.3 Tcf in 2010, 75 % of the gas produced was re-injected into oil fields to enhance production. The two largest natural gas producing fields are also the largest oil producing fields.

The Karachaganak oil and gas field produced approximately half of Kazakhstan's total gross gas production, totaling about 650 Bcf in 2010. Oil and Gas Journal reported that its production jumped to 784 Bcf in 2011. Wood Mackenzie expects that dry gas production from the Karachaganak field will reach 775 Bcf in 2015 and 1.3 Tcf in 2020.

The Tengiz oil and gas field produced approximately 300 Bcf gross natural gas during 2011, of which 114 was dry gas production, according to Chevron. According to Wood Mackenzie projections, Tengiz will continue to play a significant role in Kazakhstan's gas production and will reach 623 Bcf of dry gas in 2015

Since 2008, Kazakhstan has been producing sufficient volume of dry natural gas to satisfy its domestic demand

Kazakhstan has two separate domestic natural gas distribution networks, one in the west, which services the country's producing fields, and one in the south, which mainly delivers imported natural gas to the consuming regions. Kazakhstan's pipeline network consists of 11,000 kilometers of pipeline, 22 compressor stations, and three underground storage facilities. The main pipelines are the Central Asia Center pipeline, the Bukhara-Ural pipeline, Tashkent-Almaty pipeline, and the Turkmenistan-China pipeline. Kazakhstan currently serves mainly as a transit country for natural gas pipeline exports from Uzbekistan and Turkmenistan to Russia and China.

Kuwait

Proved recoverable reserves (bcm)	1798
Production (bcm)	11.73
Consumption (bcm)	12.62
R/P ratio (years)	153.28

Gas reserves (as quoted by OAPEC and other published sources) are relatively low in regional terms and represent only about 2% of the Middle East total. With the exception of World Oil, which quotes 1 877 bcm, all the main publications give end-2008 levels falling inside a very narrow range (1 780-1 800). According to Oil & Gas Journal, as of January 2011, Kuwait had an estimated 63 trillion cubic feet (Tcf) of proved natural gas reserves. Kuwait's reserves are not significant and this has spurred an extensive drive in natural gas exploration. Kuwait has recently become a net importer of natural gas, leading the country to focus more on natural gas exploration and development for domestic consumption.

As in the oil sector, all of the natural gas resources are owned by the Kuwait Petroleum Corporation (KPC). The Kuwaiti constitution prohibits any use of production-sharing agreements (PSAs) that allow for an equity stake by an IOC in development projects. Therefore, Kuwait is using technical service agreements (TSAs) in order to bring in IOCs to develop more difficult projects.

In February 2010, Shell announced the signing of an agreement with the Kuwait Oil Company under which Shell will provide technical support to KOC in the development of the Jurassic Gas fields of non-associated gas in the northern part of the country. After allowing for a limited amount of flaring and for shrinkage due to the extraction of NGLs, Kuwait's gas consumption is currently 12-13 bcm/yr, nearly one-third of which is used for electricity generation and desalination of seawater.

In 2010, Kuwait produced 1.17 billion cubic feet per day (Bcf/d) of natural gas. This volume was an increase of around 8 % compared with 2009. Given the predominance of associated natural gas in Kuwaiti production, domestic natural gas supplies decreased as a result of lower OPEC crude production quotas. Kuwait increasingly requires supplies of natural gas for the generation of electricity, water desalination, and petrochemicals, as well as increased use for enhanced oil recovery (EOR) techniques to boost oil production. In 2010, Kuwait consumed approximately 529 Bcf of natural gas, which is equal to 1.45 Bcf/d. Since 2008, Kuwait has consumed more natural gas than it has produced. This has compounded the problem of electricity outages by making the availability of feedstock precarious.

In 2010, Kuwait imported 270 MMcf/d of LNG, largely from regional neighbors, Yemen and Oman. Kuwait has also recently exhibited interest in supplies from the impending natural gas project in Southern Iraq

In June 2009, Kuwait signed a deal with Shell to import LNG, receiving the first cargo in August 2009. KPC made another deal with international energy trading firm, Vitol, in April 2010, which will supply Kuwait with LNG cargoes through 2013. Kuwait takes delivery of the LNG at the Persian Gulf's first regasification terminal, Mina al-Ahmadi GasPort. The regasification capacity of al-Ahmadi is approximately 500MMcf/d of LNG.

Libya/GSPLAG

Proved recoverable reserves (bcm)	1495
Production (bcm)	16.81
Consumption (bcm)	6.84
R/P ratio (years)	88.9

Libya is an important exporter of natural gas. Proved reserves - the fourth largest in Africa - have been largely unchanged since 1991, according to OAPEC and other published sources, which – in a rare instance of unanimity – all quote the same figure.

Since 1970 Libya has operated a liquefaction plant at Marsa el Brega, but LNG exports (in recent years, solely to Spain) have fallen down to only 0.5 bcm/year. Libyan natural gas production and exports to Europe increased considerably since 2003, with the development of offshore fields and opening of the 370-mile Greenstream underwater pipeline from Melitah to Gela in Sicily. Libya is a direct producer and distributor in Italy, Germany, Switzerland and Egypt and exports 9.97 bcm of natural gas.

Natural gas companies in Libya include NOC, ENI, Akakus oil operations, Oillinvest, Gatoil, Tamoil.

Natural gas currently accounts for 45% of fuel for electricity generation. Projects under development include the 800-megawatt power plant in Zwara (Zuwarah), a 600-megawatt Western Mountain Power Project, a 1,400-megawatt power plant to be located on the coast between Benghazi and Tripoli, and the 1,200-megawatt Gulf Stream combined power and desalination complex in Sirt.

Power stations, petrochemical/fertiliser plants and oil/gas industry are the main users of natural gas.

Malaysia

Proved recoverable reserves (bcm)	2350
Production (bcm)	66.5
Consumption (bcm)	35.7
R/P ratio (years)	35.3

According to the Oil and Gas Journal, Malaysia held 83 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2011, and was the fourth largest natural gas reserves holder in the Asia-Pacific region. Most of the country's natural gas reserves are located in Eastern areas, predominantly offshore Sarawak. Exploration of Malaysia's offshore waters has discovered numerous fields yielding natural gas or gas/condensates, mainly in the areas east of the peninsula and north of the Sarawak coast. Proved reserves (as quoted by Cedigaz) stand at 2 330 bcm and rank as the fourth largest in Asia. Other published reserve assessments, whilst not identical, have moved much closer to Cedigaz. They now range from Oil & Gas Journal's 2 350 bcm, via BP at 2 390, to OPEC's 2 475 and World Oil's 2 506.

Gross natural gas production has been rising steadily, reaching 2.7 Tcf in 2010, while domestic natural gas consumption has also increased steadily, reaching 1.1 Tcf in 2010, 42% of production. There are several important ongoing projects that will expand natural gas production in Malaysia even further over the near term. Exploration and development activities in Malaysia continue to focus on offshore Sarawak and Sabah. One of the most active areas for natural gas exploration and production is the Malaysia-Thailand Joint Development Area (JDA), located in the lower part of the Gulf of Thailand. The JDA reportedly holds 9.5 Tcf of proved plus probable natural gas reserves.

Malaysia became a major gas producer in 1983, when it begun to export LNG to Japan. Gas exports have grown ever since, and in recent years the Republic of Korea, Taiwan, and China have become important markets for Malaysian gas supplies via pipeline to Singapore.

Malaysia was the third largest exporter of LNG in the world after Qatar and Indonesia in 2010, exporting over 1 Tcf of LNG, which accounted for 10 % of total world LNG exports. LNG is primarily transported by Malaysia International Shipping Corporation (MISC), which owns and operates 27 LNG tankers, the single largest LNG tanker fleet in the world by volume of LNG carried. MISC is 62-% owned by Petronas.

Domestic consumption of gas has become significant in recent years, in particular in power generation. The other major use of natural gas, apart from own use within the oil/gas industry, is as feedstock/fuel for industrial users. Relatively small amounts of CNG are used in transport, reflecting an official programme to promote its use.

As in the oil sector, Malaysia's state-owned Petronas dominates the natural gas sector. The company has a monopoly on all upstream natural gas developments, and also plays a leading role in downstream activities and the LNG trade. Most natural gas production comes from production-sharing agreements operated by foreign companies in conjunction with Petronas.

The Bintulu LNG complex on Sarawak is the main hub for Malaysia's natural gas industry. Petronas owns majority interests in Bintulu's three LNG processing plants, which are supplied by offshore natural gas fields. The Bintulu facility is the largest LNG complex in the world, with 8 production trains and a total liquefaction capacity of 1.7 Tcf per year following the debottlenecking completed at end-2010, which raised overall capacity by 0.6 Tcf per year.

Mexico

Proved recoverable reserves (bcm)	490.3
Production (bcm)	55.1
Consumption (bcm)	59.1
R/P ratio (years)	8.89

According to OGJ, Mexico had 17.3 trillion cubic feet (Tcf) of proved natural gas reserves as of the end of 2011, a sharp increase of more than 5 Tcf from the year before. The Southern region of the country contains the largest share of proved reserves. However, the Northern region will likely be the center of future reserves growth, as it contains almost ten times as much probable and possible natural gas reserves as the Southern region. Mexico has considerable natural gas resources, but its production pales in comparison to other North American countries and the development of its unconventional shale gas resources is proceeding slowly. Mexico habitually exports relatively small amounts of gas to the USA and imports considerably larger quantities. The country imported 499 Bcf of natural gas from the United States in 2011, which represented an increase of nearly 50 % from the levels of 2010. The United States also imports a very small amount of natural gas from Mexico, but the trade balance is expected to tip even further in the direction of the United States as recent supply and demand trends in both countries are projected to continue.

PEMEX has a monopoly on natural gas exploration. However, private participation is permitted in non-associated gas production. Production of natural gas has been rising since the turn of the century. According to statistics from Mexico's CNH, more than three-fifths of Mexico's natural gas production derived from associated oil and gas fields. Mexico produced an estimated 1.8 Tcf of dry natural gas in 2011, according to revised figures, which represents a slow rate of decline from the year before. Preliminary Mexican government data suggest that natural gas production has continued to fall in 2012.Regulatory bodies report that approximately 250 Bcf of natural gas was vented and flared in 2011. More than half of the country's venting and flaring occurred at Cantarell.

Mexico meets some of its natural gas demand through LNG, but the volume of its imports fell by roughly 20 % in 2011 as pipeline imports from the United States grew dramatically. According to data from the International Energy Agency, Mexico imported roughly 42 % of its LNG from Qatar, 28 % from Nigeria, and 16 % from Peru, and smaller volumes from Indonesia and other countries. The vast majority of Mexico's LNG imports — over 90 % in 2011 — arrive at the Altamira plant in Tamaulipas state, on Mexico's Northeastern coast. Altamira is a joint venture of Royal Dutch Shell (50 %), Total (25 %) and Mitsui (25 %).

PEMEX operates over 5,700 miles of natural gas pipelines in Mexico. The company has eleven natural gas processing centers, with liquids extraction capacity of 5.8 Bcf/d. PEMEX also operates most of the country's natural gas distribution network, which supplies processed natural gas to consumption centers.

The largest use of gas is as power generation fuel with 49% of the total. The energy industry consumed 26%, industrial fuel/feedstock 23%, and residential/commercial users about 2%. Mexican natural gas consumption is dominated by PEMEX operations and electricity demand. According to SENER statistics, PEMEX is the country's single largest consumer of natural gas, representing around 40 % of the country's total.

Myanmar

Proved recoverable reserves (bcm)	283.2
Production (bcm)	12.1
Consumption (bcm)	3.29
R/P ratio (years)	23.4

Myanmar has long been a small-scale producer of natural gas, but recent years have witnessed a substantial increase in its output, principally for export. There appear to be widely differing views on the level of its proved reserves. With the commencement of exports of natural gas to Thailand from two offshore fields, first Yadana and subsequently Yetagun, Myanmar's gas industry has entered a new phase. As offtake by Thailand's 3 200 MW Ratchaburi Power Plant has built up, gas production in Myanmar has moved onto a significantly higher plane.

In Asia-Pacific region, Myanmar stands as the second highest natural gas exporting country after Indonesia. In the fiscal year 2011-12, Myanmar fetched 3.56 billion U.S. dollars through export of gas, up about 640 million dollars from 2. 92 billion dollars in 2009-10 when the highest annual earning was gained with gas export. Natural gas export earned nearly 800 million U.S. dollars in first three months (April-June) of the fiscal year 2012-13.

Natural gas is one of Myanmar's largest sources of export revenue, accounting for about 30% of total exports. The exported gas was produced from the Yadanar and Yetagun gas fields, while other gas fields such as Shwe and Zawthika will start their production in 2013.

Statistics reveal that foreign investment in Myanmar's oil and gas sector had reached 13.815 billion U.S. dollars in 104 projects as of the end of November, 2011, accounting for 34.18 % of the total and standing the second in the country's foreign investment industries after electric power.

Namibia

Proved recoverable reserves (bcm)	62.29
Production (bcm)	0
Consumption (bcm)	0
R/P ratio (years)	0

The Namibian WEC Member Committee comments that the Kudu gas field discovered as long ago as 1974 had never been developed because of a lack of gas production and transport infrastructure. Recently licence-holders Tullow Kudu Ltd., CEICO E & P Co. Ltd. and the National Petroleum Corporation of Namibia (Pty) Ltd. have applied for a 25-year Production Licence based on the transport of the gas by CNG shuttle tankers to power plants and industrial gas markets in Namibia and South Africa.

In March 2010 it was reported that the Russian gas company Gazprom and the National Petroleum Corporation of Namibia (Namcor) were about to take a jointly-held 54% stake in the Kudu field, with Tullow's share being reduced from 70% to 31% and that of Japan's Itochu Corporation from 20% to 15%.

Namibia appears to have a greater potential for gas than for oil. Offshore exploration has identified some possible oil resources.

Netherlands

Proved recoverable reserves (bcm)	1303
Production (bcm)	81.09
Consumption (bcm)	54.08
R/P ratio (years)	16

The Netherlands have been producing gas for decades and its resource base has been in decline in recent years. There are over 400 proved natural gas accumulations in the Netherlands, both onshore and offshore. The remaining gas resources were estimated at 1.3 tcm. Of these remaining resources, the Groningen field accounted for 980 bcm, with 160 bcm to be found in other smaller onshore fields and 164 bcm in offshore formations.

In 2010 total production of natural gas in the Netherlands was over 85 bcm. The Groningen field is by far the largest source of Dutch gas production, and accounted for some 54 bcm of the 2010 total.

Domestic gas consumption in the Netherlands totalled some 54.8 bcm in 2010. Over a third of total gas use was consumed in the transformation sector. With some 96% of all households connected to gas supplies, the residential sector accounted for a substantial share, at 22% of the total, while the commercial and industry sectors each accounted for another 20% of gas use. Almost all space heating in the Netherlands is by natural gas, and over 60% of electricity is produced by gas fired generation, thus causing a strong seasonal pattern in gas use.

The Netherlands is the largest gas producer within the European Union. At the same time, the Netherlands imports and exports large volumes of gas, with roughly 40% of the total volume of gas flows used domestically. In 2010, the Netherlands exported 57.8 bcm of natural gas. The largest portion of these exports, 21.6 bcm, went to Germany while Belgium and the UK were the destinations of some 10 bcm each. Substantial volumes were also exported to Italy (8.7 bcm) and France (7.4 bcm). In the same year, the Netherlands imported nearly 25.8 bcm of gas, primarily from Norway, the UK and `Russia.

Based on the Dutch Administration's outlook for indigenous production and domestic use of natural gas, the Netherlands is expected to shift from being a net- exporter to being a net importer of gas in the period between 2020 and 2025.

Companies involved in Netherland's natural gas sector are Gasunie, GasTerra, Shell, Exxon, NEM, E.ON, DONG, Electrabel, Eneco, RWE, Vattenfall and Delta. GasTerra remains the major player in the wholesale market, with a share of between 70 and 75%. GasTerra is also very active on the European gas market, and has import contracts with suppliers from Russia, Norway and Germany.

New Zealand

Proved recoverable reserves (bcm)	27.64
Production (bcm)	4.36
Consumption (bcm)	4.27
R/P ratio (years)	6.33

Currently, all gas production in New Zealand takes place in the Taranaki basin. Early stage exploration is currently underway in the Canterbury, Great South, Northland, Deepwater Taranaki and Raukumara basins. The MED's Energy Outlook 2010 Reference Scenario predicts that by 2030 around one third of New Zealand's gas production will come from these frontier Basins.

The largest users of gas in New Zealand are Contact Energy and Genesis Energy for electricity generation. Electricity generation accounts for approximately 35 % of annual gas Demand.In New Zealand, 90 per cent of natural gas production comes from two gas fields: Maui (offshore) is mined by the Maui Mining Companies; and Kapuni (onshore) is mined by Shell and Todd. The remainder of the country's gas requirements come from a number of fields including the McKee, Kaimiro, Waihapa/Ngaere/Tariki/Ahuroa and Ngatoro fields.

Nigeria

Proved recoverable reserves (bcm)	5110
Production (bcm)	29
Consumption (bcm)	4.97
R/P ratio (years)	176.2

Nigeria had an estimated 180 trillion cubic feet (Tcf) of proved natural gas reserves as of the end of 2011, according to the OGJ, making Nigeria the ninth largest natural gas reserve holder in the world and the largest in Africa. Despite these vast natural gas reserves, Nigeria produced about 1 Tcf of dry natural gas in 2011 and ranked as the world's 25th largest natural gas producer only. The majority of the natural gas reserves are located in the Niger Delta and, therefore, the gas sector is also exposed to the same security and regulatory issues affecting the oil industry.

Shell dominates gas production in the country, as the Niger Delta, which contains most of Nigeria's gas resources, also houses most of Shell's hydrocarbon assets. The second largest gas producer is Total. Most of Nigeria's marketed natural gas is exported as Liquefied Natural Gas (LNG), with the remainder consumed domestically and exported regionally via the West African Gas Pipeline. Shell Nigeria Gas Limited (SNG), a Shell-owned gas sales and distribution company, also delivers Compressed Natural Gas (CNG) to industries as far as 62 miles away from existing pipelines.

In 2010, Nigeria exported 17.97 million metric tonnes (875 Bcf) of LNG, and became the fifth largest LNG exporter in the world and the largest LNG exporter in the Atlantic Basin. Furthermore, Nigeria's LNG accounted for 8% of the total supplied to the world market and 30% of LNG coming from the Atlantic Basin in 2010. Most of Nigeria's LNG was exported to Europe (67 %), mainly Spain (31 %), France (16 %) and Portugal (12 %), with smaller amounts to Turkey, United Kingdom, and Belgium. Other export destinations include Asia (15 %) and North America (14 %). The U.S. imported 0.86 million metric tonnes (42 Bcf) of Nigerian LNG in 2010, providing 1 % of total U.S. LNG imports.

Norway

Proved recoverable reserves (bcm)	2007
Production (bcm)	103.1
Consumption (bcm)	4.809
R/P ratio (years)	19.46

According to OGJ, Norway had 71 trillion cubic feet (Tcf) of proved natural gas reserves as of January 2012. Despite the aging of its major natural gas fields in the North Sea, Norway has been able to sustain annual increases in total natural gas production by continuing to develop new fields. Norway produced 3.64 Tcf of dry natural gas in 2011, down slightly from the 3.76 Tcf produced in 2010. Production has been generally increasing since 1993 and NPD forecasts it will reach 3.96 Tcf in 2015. Total gross natural gas production was 5.25 Tcf in 2011, of which 1.38 Tcf (26 %) was reinjected to enhance oil production. Norway's single largest natural gas field is Troll, which produced 0.9 Tcf in 2010, according to NPD, representing about one-quarter of Norway's total natural gas production. The three other largest producing fields in 2010 were Ormen Lange (0.7 Tcf), Asgard (0.4 Tcf), and Sleipner Ost (0.3 Tcf). These 4 fields accounted for about 60 % of Norway's total natural gas production.

Norway exported an estimated 3.5 Tcf of natural gas in 2011, 96 % of its production, according to NPD. Most of it was transported to Europe via its extensive export pipeline infrastructure and a smaller amount (4.3 %) via LNG tanker. The country is the second-largest supplier of natural gas to the European Union, behind Russia, supplying about 18 % of Europe's total gas demand in 2010 and ranks fourth in world natural gas production. The largest outlets for Norway's natural gas pipeline exports in 2010 were Germany, the United Kingdom, France, the Netherlands, and Belgium. According to NPD estimates, 2011 shipments of Norwegian LNG totaled an estimated 150 Bcf, up from 138 Bcf in 2010. OECD European countries in 2010 received about 74 % of the total, with Spain importing almost half of that. The United States imported about 5 % or 26.8 Bcf. Norway has long-term contracts with Spain's Iberderola and the U.S.'s El Paso.

As is the case with the oil sector, Statoil dominates natural gas production in Norway. A number of international oil and gas companies, including ExxonMobil, ConocoPhillips, Total, Shell, and Eni have a sizable presence in the natural gas and oil sectors in partnership with Statoil. State-owned Gassco is responsible for administering the natural gas pipeline network.

Oman

Proved recoverable reserves (bcm)	849.5
Production (bcm)	27.1
Consumption (bcm)	17.52
R/P ratio (years)	31.34

Oman is one of the smaller gas producers in the Middle East. Its proved reserves of natural gas are 30 trillion cubic feet (Tcf) as of January 2012, according to OGJ. Due to increasing EOR applications, rising domestic demand, and export obligations, Oman's gas demand has outpaced its production. Oman produced over one trillion cubic feet (Tcf) of natural gas, equal to about 2.75 billion cubic feet per day (Bcf/d) in 2011. Natural gas production has more than doubled in the past decade.

Oman has developed its utilisation of gas to such an extent that oil has long been displaced as the Sultanate's leading energy supplier. Currently, the principal outlet for marketed gas is the power generation/desalination complex at Ghubrah. Other industrial consumers include mining and cement companies.

The Oman Gas Company (OGC) runs the country's natural gas transmission and distribution systems. The OGC is a joint venture between the Omani Ministry of Oil and Gas (80%) and OOC (20%). Oman Liquefied Natural Gas (OLNG)- owned by a consortium including the government, Shell and Total- operates all LNG activities in the Sultanate through its three liquefaction trains in Qalhat near Sur. Although Oman is a net exporter of oil and natural gas, it also imports small volumes of natural gas from Qatar via UAE. The Dolphin Pipeline provides Oman's only natural gas imports, providing approximately 200 million cubic feet per day (Mcf/d).

The pipeline system in Oman consists of 1,250 miles of pipeline, transporting natural gas supplies from production facilities primarily to gas-powered electric plants, participants in the petrochemical and industrial sectors, as well as to the Oman and Qalhat LNG projects. In 2015-16, OGC will add a 143-mile, 36-inch gas pipeline from Saih Nihayda field in Central Oman to service the special economic zone in Duqm on the east coast.

The Oman and Qalhat LNG projects are the sole source of natural gas exports from Oman, with a nameplate capacity of 506 Bcf per year, a daily average of 1.4 Bcf/d. In 2010, Oman exported a total of 406 Bcf, a decline of 2 Bcf from the previous year. Despite facing a gas shortage and increasing domestic demand, Oman exports 55 % of its gas because of term contracts, the first of which expires in 2020. Given shortfalls in natural gas production, in 2007 Oman began to import natural gas. The Dolphin Pipeline system, which transports 2 billion cubic feet per day (Bcf/d) of natural gas from Qatar to neighbouring UAE and eventually to Oman by way of the Fujairah - al-Ain pipeline, provides increasing natural gas supplies, around 200 Mcf/d, for use in electricity generation

Oman requires increased natural gas supplies to meet the growth in its domestic consumption as well as its enhanced oil recovery projects and LNG export obligations

Pakistan

Proved recoverable reserves (bcm)	753.8
Production (bcm)	42.9
Consumption (bcm)	42.9
R/P ratio (years)	17.57

Although the level of proved reserves reported by the Pakistan WEC Member Committee has tended to drift downwards in recent years, natural gas remains an important energy asset for Pakistan. Major gas-producing fields include Sui in Balochistan and Qadirpur, Mari, Zamzama, Sawan and Bhit in Sindh. Less than 2% of natural gas output was associated with oil production in 2008-09. Indigenous natural gas is the largest source of energy supply in Pakistan. Consumption of indigenous natural gas has grown rapidly in all sectors of the economy over the past 15 years, driven by growing availability of gas and a low, government-controlled gas price as compared with alternate fuel prices. The major domestic markets for gas (excluding own use) in that year were power generation (32%), industrial users (26%), fertiliser plants (16%), households and commercial consumers (20%) and fertiliser plants (16%). Rapidly growing quantities of CNG are consumed as an automotive fuel. Pakistan's state-owned PPL and OGDCL produce around 30 % and 25 %, respectively, of the country's natural gas. The two companies are the country's largest natural gas producers. OMV is the largest foreign natural gas producer (17 % of total country's production) in Pakistan. Other foreign operators include BP, Eni, and BHP Billiton. In addition to natural gas import pipelines, Pakistan is pursuing LNG import options to meet energy needs.

Papua New Guinea

Proved recoverable reserves (bcm)	155.3
Production (bcm)	110
Consumption (bcm)	110
R/P ratio (years)	1.41

The Hides gas field was discovered in 1987 and brought into production in December 1991. Other resources of non-associated gas have been located in PNG, both on land and offshore. Up to the present, the only marketing outlet for Hides gas has been a 42 MW gas-turbine power plant serving the Porgera gold mine; offtake averages 14-15 million cubic feet/day. Associated gas produced in the Kutubu area is mostly re-injected into the formation. The PNG LNG project, which is planned to start producing 6.6 million tonnes of LNG from 2014, is moving ahead, with the project operator ExxonMobil stating in March 2010 that all financing arrangements were complete.

Peru

Proved recoverable reserves (bcm)	352.8
Production (bcm)	31.12
Consumption (bcm)	5.41
R/P ratio (years)	11.33

According to the Oil and Gas Journal, Peru had proved natural gas reserves of 12.5 trillion cubic feet (Tcf) in 2012, the fifth largest reserves in South America. Peru's main natural gas reserve is the large Camisea project in southeast Peru. Since production began in 2004, Camisea output has grown by an average of 37 % per year, and it is expected that when site exploration is complete, Peru's proved reserves will be up by another 318 billion cubic feet (Bcf).

Peru began exporting LNG from its Melchorita plant, South America's first natural gas liquefaction plant, in June 2010. In February 2012, Peru exported 15 Bcf (307,580 metric tons) of LNG according to LNG World News. Melchorita is owned by the PeruLNG consortium, made up of Hunt Oil at 50 %, SK Energy at 20 %, Repsol at 20 %, and Marubeni at 10 %. The plant currently has capacity of 215 Bcf per year, and a second and possibly a third train are planned to be added within the next four to five years. According to Cedigaz, in 2010, Peru shipped LNG cargoes to Spain, the United States, Mexico, China and South Korea. However, the majority of its exports are contracted to go to the LNG terminal in Manzanillo, Mexico. Although the Manzanillo terminal and 186-mile pipeline were completed in September 2011, the need to dredge the harbour for shipping delayed the project until March 2012. The first cargo of LNG was shipped to Manzanillo on March 10, 2012. There are two pipelines carrying natural gas from the Camisea gas fields. The 336-mile Camisea pipeline terminates at the Pisco port terminal, from which liquefied petroleum gases (LPG) are exported. A second 444-mile pipeline runs from Malvinas along the coast to Lima and Callao for distribution to residential and industrial consumers in the capital city. The pipelines are owned by TGP. The distribution of natural gas through pipelines within Peru is controlled by the private consortium Transportadora de Gas Peruano (TGP), made up of Tecgas, Pluspetrol, Hunt Oil, SK Corp, Sonatrach, and Grana y Montero. Spain's Repsol, South Korea's SK Corp, Italy's Tecpetrol, and Algeria's Sonatrach. Pluspetrol operates the natural gas wells at Camisea, making it the largest hydrocarbons producer in the country.

Qatar

Proved recoverable reserves (bcm)	25200
Production (bcm)	116.7
Consumption (bcm)	21.8
R/P ratio (years)	215.9

Qatar controls 14% (over 25 trillion m3) of the total world natural-gas reserves, which makes it the third country in the world in terms of the proved gas reserves only behind Russia and Iran. Today, Qatar is the single largest supplier LNG. The majority of Qatar's natural gas is located in the massive offshore North Field, which spans an area roughly equivalent to Qatar itself.

In 2011, Qatar exported over 117.6 Bcm of natural gas, of which over 80% was LNG primarily to Asia and Europe. The United States received 2.52 Bcm of Qatar's LNG, which represented 26% of total U.S. imports of LNG in 2011. The remaining exports (19.04 Bcm) of natural gas were transferred through the Dolphin pipeline to the United Arab Emirates (UAE) and Oman.

Qatar is the world's leading LNG exporter. In 2011, Qatar exported nearly 100.8 Bcm of LNG. The United Kingdom, Japan, India, and South Korea were the primary destinations for Qatar's LNG exports. Asia was the principal import hub, accounting for 48% of Qatar's LNG in 2011. European markets, including Belgium, the United Kingdom, and Spain were also significant buyers of Qatari LNG, accounting for an additional 42%.

Qatar's LNG sector is dominated by Qatargas Operating Company Limited (Qatargas), which operates four major LNG ventures (Qatargas I-IV).

Companies involved in Qatar natural gas are ExxonMobil, Shell, and Total, Qatar petroleum (QP), Qatargas.

Romania

Proved recoverable reserves (bcm)	63
Production (bcm)	10.59
Consumption (bcm)	12.87
R/P ratio (years)	5.95

After peaking in the mid-1980s, Romania's natural gas output has been in gradual secular decline, falling to around 11 bcm in recent years, only about one-third of its peak level. Indigenous production currently supplies about two-thirds of Romania's gas demand; the principal users are power stations, CHP and district heating plants, the steel and chemical industries and the residential/commercial sector.

Romania has proved natural gas reserves of 726 billion cubic meters (25.94 trillion cubic feet) and is ranked 30th among countries with proved reserves of natural gas. About 75% of Romania's natural gas resources are located in Transylvania, especially in Mure- and Sibiu counties. The largest natural gas field in Romania is the Deleni gas field discovered in 1912 and located in the B- gaciu commune in Mure- County with proved reserves of 85 billion cubic meters or 3 trillion cubic feet.

The local natural gas production is dominated by two very large companies Romgaz with a market share of 51.25% and Petrom with a market share of 46.33%. There are also several smaller companies Aurelian Oil&Gas with a market share of 0.38%, Amromcowith a market share of 1.85%, Lotus Petrol with a market share of 0.13% and Wintershall with a market share of 0.06%.

The national natural gas transmission system in Romania is owned by Transgaz a state-owned company. It has a total network length of 13,110 km (8,150 mi) of pipelines with diameters between 50 mm (2.0 in) and 1,200 mm (47 in). The company also owns a 50% stake in the Arad–Szeged pipeline, a natural gas pipeline from Arad in Romania toSzeged in Hungary, with a length of 109 km (68 mi) and a transport capacity of 4.4 billion cubic meters (0.15 Tcf) per year.Romania also has four other pipeline links to Ukraine used for the import or transit of natural gas.

Russian Federation

Proved recoverable reserves (bcm)	47570
Production (bcm)	669.6
Consumption (bcm)	506.7
R/P ratio (years)	71.1

Russia holds the largest natural gas reserves in the world, and is the largest producer and exporter of dry natural gas. The majority of these reserves are located in Siberia, with the Yamburg, Urengoy, and Medvezh'ye fields alone accounting for about 45 % of Russia's total reserves. In 2011 Russia was the world's largest dry natural gas producer (23.6 Tcf), regaining its status as the world top producer after trailing U.S. production in 2009 and 2010. Russia is also the world's largest exporter (7.2 Tcf).

The state-run Gazprom dominates Russia's upstream, producing about 80 % of Russia's total natural gas output. Gazprom also controls most of Russia's gas reserves, with more than 65 % of proved reserves being directly controlled by the company and additional reserves being controlled by Gazprom in joint ventures with other companies.

Natural gas associated with oil production is often flared. According to the U.S. National Oceanic and Atmospheric Administration, Russia flared an estimated 1,244 Bcf of natural gas in 2010, the most of any country in the world. At this level, Russia alone accounted for about 30 % of total volumes of gas flared globally in 2010. The Russian government has taken steps to reduce natural gas flaring and set a target of 95 % utilization of associated gas by the end of 2012. However, given current the volume of gas flared, it is unlikely companies will achieve this target.

Russia exports significant amounts of natural gas to customers in the Commonwealth of Independent States (CIS) – about 35 % of total exports. In addition, Gazprom (through its subsidiary Gazexport) has shifted much of its natural gas exports to serve the rising demand in countries of the EU, as well as Turkey, Japan, and other Asian countries. About 70 % of Russia's non-CIS exported natural gas is destined for Europe, with Germany, Turkey, and Italy receiving the bulk of these volumes. The remainder of Russia's European gas exports are sold to the newest EU members such as Czech Republic, Poland, and Slovakia.

In addition to dominating the upstream, Gazprom dominates Russia's natural gas pipeline system. There are currently nine major pipelines in Russia, seven of which are export pipelines. The Yamal-Europe I, Northern Lights, Soyuz, and Bratrstvo pipelines all carry Russian gas to Eastern and Western European markets via Ukraine and/or Belarus. These four pipelines have a combined capacity of 4 Tcf. Three other pipelines – Blue Stream, North Caucasus, and Mozdok-Gazi-Magomed – connect Russia's production areas to consumers in Turkey and Former Soviet Union (FSU) republics in the east.

Russia is an exporter of liquefied natural gas (LNG). The majority of the LNG has been contracted to Japanese and Korean buyers under long-term supply agreements. In 2011, Sakhalin LNG exports went to Japan (69.5 %), South Korea (25.7 %), China (2.4 %), Taiwan (1.7 %), and Thailand (0.6 %). The Sakhalin Energy's LNG plant has been operating since 2009 and it can export up to 10 million tons of LNG per year on two trains.

There are a number of proposals in various stages of planning and construction for new LNG terminals in Russia, including: Yamal LNG, Shtokman LNG, Vladivostok.

Saudi Arabia

Proved recoverable reserves (bcm)	8028
Production (bcm)	99.23
Consumption (bcm)	99.23
R/P ratio (years)	80.9

Most of Saudi Arabia's proved reserves and production of natural gas are in the form of associated gas derived from oil fields, although a number of sources of non-associated gas have been discovered. In total, proved reserves of gas rank as the third largest in the Middle East. Other published sources' assessments are generally similar.

Output of natural gas has advanced fairly steadily for more than a quarter of a century. A significant factor in increasing Saudi Arabia's utilisation of its gas resources has been the operation of the gas-processing plants set up under the Master Gas System, which was inaugurated in the mid-1980s. These plants produce large quantities of ethane and LPG, which are used within the country as petrochemical feedstock; a high proportion of LPGs is exported. The main consumers of dry natural gas (apart from the gas industry itself) are power stations, desalination plants and petrochemical complexes.

Saudi Arabia has the world's fifth largest natural gas reserves, but natural gas production remains limited. Its proved natural gas reserves of 288 trillion cubic feet (Tcf) at the end of 2012, are fifth largest in the world behind Russia, Iran, Qatar, and the United States, according to EIA estimates. About 5 Tcf was added in 2012, and over the last decade, Saudi Arabia added over 60 Tcf of natural gas reserves.

The majority of gas fields in Saudi Arabia are associated with petroleum deposits, or found in the same wells as the crude oil, and production increases of this type of gas remain linked to an increase in oil production. About 57 % of Saudi Arabia's proved natural gas reserves consists of associated gas at the giant onshore Ghawar field and the offshore Safaniya and Zuluf fields.

Saudi Arabia does not import or export natural gas, so all consumption must be met by domestic production. According to Saudi Aramco forecasts, natural gas demand in the Kingdom is expected to almost double by 2030 from 2011 levels of 3.5 trillion cubic feet (Tcf) per year.

- Saudi Arabia has four upstream joint ventures in the Empty Quarter:
- South Rub al-Khali Company or SRAK (a venture of Saudi Aramco and Royal Dutch Shell)
- Luksar Energy Limited (a venture of Saudi Aramco and Lukoil)
- Sino Saudi Gas Limited (a venture of Saudi Aramco and Sinopec)
- EniRepSa Gas Limited (a consortium of Saudi Aramco, Eni, and Repsol-YPF)

Domestic demand for natural gas, particularly the delivery feedstock to petrochemical plants, has driven consistent expansion of the Master Gas System (MGS), the domestic gas distribution network in Saudi Arabia first built in 1975. Prior to the MGS, all of Saudi Arabia's natural gas output was flared. The MGS feeds gas to the industrial cities including Yanbu on the Red Sea and Jubail.

Thailand

Proved recoverable reserves (bcm)	299.8
Production (bcm)	36.27
Consumption (bcm)	45.08
R/P ratio (years)	8.26

Since its inception nearly 30 years ago, Thailand's natural gas output has grown almost unremittingly year after year. Much the greater part of Thailand's gas output is used for electricity generation; industrial use for fuel or chemical feedstock is relatively small, whilst transport use (CNG) is increasing rapidly.

PTTEP has a stake in many of Thailand's natural gas producing fields, including Bongkot, the largest field. The largest foreign operator is Chevron, which currently accounts for 70 % of Thailand's natural gas production from 22 offshore fields. Several projects are currently being developed in an attempt to increase Thailand's natural gas supplies over the next few years. The largest of these is PTTEP's Arthit project, off the coast of Songkhla. The country has been able to attract several major international companies to its concessions, most notably Chevron, Mitsui Oil Exploration and Hess. Chevron is the biggest operator in Thailand followed by PTTEP the national oil & gas company.

Thailand has one LNG Import Terminal, the Map Ta Phut Thailand Lng Terminal, belonging to PTTEP, which was commissioned in 2011.

Trinidad & Tobago

Proved recoverable reserves (bcm)	381.8
Production (bcm)	42.46
Consumption (bcm)	22.08
R/P ratio (years)	8.99

In the span of only five years, proved natural gas reserves have declined sharply by over 50 %, from 25.9 Tcf in 2006 to 14.4 Tcf in 2011, according to Oil & Gas Journal as of January 1, 2012. According to PFC Energy, the country may not be able to sustain current output levels through the end of the decade.

Natural gas production currently accounts for just over 85 % of the country's natural resource base. The construction of the country's first LNG train in the 1990s and its completion in 1999 facilitated the increase in natural gas production.

In 2010, the country produced 1.5 trillion cubic feet (Tcf) of natural gas, over three times the level seen in 2000. Domestic consumption of natural gas has steadily increased as well, as domestic demand is supported by government subsidies. Consumption grew to 780 billion cubic feet (Bcf) in 2010, just over double the level at the start of the decade.

The country has benefited from substantial foreign investments, with BP Trinidad and Tobago (BPTT) accounting for almost 60 % of the country's natural gas production. British Gas is the second leading player in the industry, operating nearly a quarter of the natural gas production in the country. National companies participate in the sector as small shareholders in operations

Trinidad and Tobago is the largest supplier of LNG to the United States, and the fifth largest exporter in the world after Qatar, Indonesia, Malaysia, and Australia, according to FACTS Global Energy 2010 figures. EIA data shows that Trinidad and Tobago exported 129 Bcf of natural gas to the United States in 2011, about 37 % of total U.S. LNG net imports, but less than 1 % of total U.S. natural gas supply. In the last five years, U.S. LNG imports from Trindad and Tobago have declined by almost one-third, which reflects the general decline in total U.S. LNG imports.

The Atlantic LNG Company, a consortium led by BP, BG, GDF Suez, and the former Repsol-YPF, operates four LNG trains at Point Fortin, on the south-western coast of Trinidad.

Turkmenistan

Proved recoverable reserves (bcm)	75.04
Production (bcm)	45.3
Consumption (bcm)	20.4
R/P ratio (years)	165.65

Turkmenistan currently ranks in the top six countries for natural gas reserves and the top 20 in terms of gas production. According to OGJ, Turkmenistan has proved natural gas reserves of approximately 265 Trillion cubic feet (Tcf) in 2012, a significant increase from 94 Tcf estimated in 2009. Turkmenistan has several of the world's largest gas fields, including 10 with over 3.5 Tcf of reserves located primarily in the Amu Darya basin in the southeast, the Murgab Basin, and the South Caspian basin in the west. Recent major discoveries at South Yolotan in the prolific eastern part of the country are expected to offset most declines in other large, mature gas fields and will likely add to the current proved reserve amounts.

The country's consumption of total primary energy reached 1 quadrillion Btu. Of this amount, approximately 78 % (0.78 quadrillion Btu) was from natural gas. All of Turkmenistan's power generation facilities are gas-fired.

A majority of Turkmen gas travels to Russia where it is consumed or transits through Russia to end markets in Europe. In November 2010, Turkmenistan's Ministry of Oil, Gas, and Mineral Resources said the country's energy strategy is to more than triple gas production to over 8.1 Tcf/y by 2030.

The Dauletabad field, located in the Amu Darya basin in the southeast, is one of Turkmenistan's largest and oldest gas-producing fields with estimated reserves of 60 Tcf. The field produced approximately 1.2 Tcf/y in 2010 or most of Turkmenistan's gas supply, however, production is declining. Turkmenistan has become a leading gas exporter in the Caspian and Central Asian region. The country exports a majority of its gas because production rates are more than double domestic demand estimated at 720 Bcf/y in 2010. The International Energy Agency assumes exports will rebound and rise to about 3,180 Bcf/y by 2035.

Two pipelines to Iran and China began operations recently, and other routes are under consideration. Maximum existing gas export capacity from Turkmenistan is now close to 3,500 Bcf/y.

Other major pipelines are: Central Asia Center Pipeline (CAC, Korpezhe-Kurt Kui Pipeline (Turkmenistan to Iran), Dauletabad-Khangiran Pipeline (Turkmenistan to Iran), Central Asia-China Pipeline (Turkmenistan to China), Bukhara-Urals Pipeline, East-West Pipeline, Turkmenistan-Afghanistan-Pakistan-India Pipeline (TAPI), Trans-Caspian Pipeline (TCGP).

Ukraine

Proved recoverable reserves (bcm)	1104
Production (bcm)	19.36
Consumption (bcm)	53.16
R/P ratio (years)	57

Ukraine's output of natural gas has been virtually flat since 1994, although production since 2003 has been on a somewhat higher level. The republic is one of the world's largest consumers of natural gas: demand reached 137 bcm in 1990. Although consumption had fallen back to about 75 bcm by 2008, indigenous production met only 26% of local needs; the balance was imported from Russia and Turkmenistan. The consumption of gas is spread fairly evenly over electricity and heat plants, industrial fuel and feedstocks, and the tertiary sector.

Ukraine is a key transit center for Russian natural gas exports to Europe. In order to provide reliable supplies domestically and in Europe more investment in the Ukrainian transport network, more international cooperation, and a more transparent energy sector are needed.

In 2010, Ukraine consumed 2,034.1 BCF (57.6 bn. m3) of natural gas, an increase of 11.0% since 2009, and 72.6 MMboe of crude oil (an increase of 2.7% over 2009).

Despite this Ukraine still has to import about 80% of its natural gas needs, mainly from Turkmenistan and Russia (about two-thirds of its gas in 2012).

United Arab Emirates /UAE

Proved recoverable reserves (bcm)	60.89
Production (bcm)	51.28
Consumption (bcm)	60.54
R/P ratio (years)	118.74

The proved reserves of 215 Tcf of natural gas in the UAE are located almost entirely in Abu Dhabi, as that emirate controls approximately 94 % of the country's endowment with an estimated 201.7 Tcf in 2011. Sharjah has the second-highest volume of proved reserves (8.65 Tcf), followed by Dubai (3.53 Tcf) and Ras al-Khaimah (1.06 Tcf). Production in the UAE is also dominated by Abu Dhabi, with reported gross production of 2.42 Tcf in 2011 far outstripping the other emirates combined (491 billion cubic feet).

Four of the seven emirates possess proved reserves of natural gas, with Abu Dhabi accounting for by far the largest share. Dubai, Ras-al-Khaimah and Sharjah are relatively insignificant in regional or global terms. Overall, the UAE accounts for about 8% of Middle East proved gas reserves.

Rapid growth in domestic energy demand over the past few years has caused the UAE to become a net-importer of natural gas.

Beyond its vast oil reserves, the UAE has 215 trillion cubic feet (Tcf) of proved natural gas reserves, ranking it seventh in the world, according to Cedigaz. The UAE is not as prolific a producer of natural gas as it is of oil, nevertheless it was the 11th-largest producer of natural gas in the world in 2011 (2.91 Tcf). Despite its large endowment, the UAE became a net importer of natural gas earlier this decade.

To help meet the growing demand for natural gas, the UAE boosted imports from neighbouring Qatar via the Dolphin Gas Project's export pipeline. The pipeline runs from Qatar to Oman via the UAE, and is one of the principal points of entry for UAE natural gas imports.

Most of the UAE's natural gas has relatively high sulphur content, making the development and processing of the country's vast reserves economically challenging. Because of this, nearly 30 % of UAE's gross production of more than 2.91 Tcf is re-injected into oilfields as part of the nation's EOR techniques; marketed production in 2011 was just 1.85 Tcf, placing the UAE 17th in the world.

The UAE's total gross production of 2.91 Tcf in 2011 ranked 11th in the world, but its marketed production was almost 40 % lower at just 1.85 Tcf (17th in the world in 2011). Most of this difference is attributable to the UAE's extensive—and increasing—use of enhanced recovery techniques, though the country continues to engage in a small amount of flaring.

Most of the UAE's domestically-produced and imported gas is used in the country's extensive EOR operations and to operate their numerous power plants and de-salinization plants.

Several recent and ongoing projects—the Onshore Gas Development (OGD), Integrated Gas Development (IGD), and Offshore Associated Gas (OAG) projects—seek to boost production of the country's reserves, and are intended to help meet the rapidly-growing demand for natural gas in the country.

Two major facilities - a gas liquefaction plant on Das Island (brought on-stream in 1977) and a gas-processing plant at Ruwais (in operation from 1981) - transformed the utilisation of Abu Dhabi's gas resources. Most of the plants' output (LNG and NGLs, respectively) is shipped to Japan. In 2008, Abu Dhabi's other LNG customer was India.

Within the UAE, gas is used mainly for electricity generation/desalination, and in plants producing aluminium, cement, fertilisers and chemicals

In 2011, total natural gas imports amounted to 616 Bcf, with 300 Bcf going to Abu Dhabi, 298 Bcf to Dubai, and small amounts to the other Emirates. The UAE received nearly 97 % of its natural gas imports from neighbouring Qatar, with 95 % coming via pipeline and the remaining 5 % in the form of LNG shipments to Dubai.

Major companies involved in United Arab Emirates natural gas are: ADNOC, ADCO, ADMA-OPCO, GASCO, shel, total, partex, ADGAS, DUGAS.

Early in 2012, the UAE announced plans to add a second re-gasification terminal—Emirates LNG—offshore at Fujairah, with an initial capacity of 600 MMcf/d and the potential for expansion to 1.2 Bcf/d. The project will help the country meet its growing demand for natural gas, and should be operational in late 2014.

United Kingdom

Proved recoverable reserves (bcm)	253
Production (bcm)	47.43
Consumption (bcm)	81.21
R/P ratio (years)	5.33

According to OGJ, the U.K. held an estimated 9 trillion cubic feet (Tcf) of proved natural gas reserves in 2011, a 12 % decline from the previous year. Most of these reserves occur in three distinct areas: 1) associated fields in the U.K. continental shelf (UKCS); 2) non-associated fields in the Southern Gas Basin, located adjacent to the Dutch sector of the North Sea; and 3) non-associated fields in the Irish Sea The U.K. produced 2.0 Tcf of natural gas in 2010, falling about 5 % compared with the previous year, which was a significantly smaller decrease than last year's 15 %. At 2.0 Tcf, U.K.'s production reached its lowest level since 1992. The largest concentration of natural gas production in the U.K. is the Shearwater-Elgin area of the Southern Gas Basin.

Currently, the U.K. has four LNG import terminals and the country was the eighth-largest importer of LNG in 2010. The longest-operating LNG terminal in the U.K. is National Grid's Grain LNG terminal on the Isle of Grain. U.K. received 55 % of its LNG imports from Qatar in 2009, with the remaining volumes arriving from Trinidad and Tobago, Algeria, Egypt, and Australia. In addition, a tanker carrying the first-ever shipment of LNG from the U.S. to the U.K. arrived on the U.K. shores in November 2010.

Private companies control the U.K. natural gas sector, including production, distribution, and transmission. The largest gas distributor in the UK is Centrica, a spin-off of the distribution assets of formally state-owned British Gas.

Most of the leading oil companies in the U.K. are also the leading natural gas producers, including BP, Shell, and ConocoPhillips. The major gas distribution companies in the U.K., such as BG Group and E.ON Ruhrgas, also have a presence in the production sector.

United States of America

Proved recoverable reserves (bcm)	77.16
Production (bcm)	651.3
Consumption (bcm)	689.9
R/P ratio (years)	11.84

The USA possesses the world's fifth largest proved reserves of natural gas, and accounts for almost 4% of the global total. US natural gas proved reserves are now at their highest level since the EIA began reporting them in 1977. Their growth in recent years is largely attributable to the continued development of unconventional gas from shales, reflecting the oil industry's successful application of horizontal drilling and hydraulic fracturing to shale formations. In 2008, proved reserves of shale gas grew by over 50% and by year-end constituted 13.4% of total US proved reserves of natural gas. Two-thirds of the USA's proved shale gas reserves are located in Texas.

The states with the largest gas reserves at end-2008 were Texas (31.7% of the USA total), Wyoming (12.7%), Colorado (9.5%) and Oklahoma (8.5%). Reserves in the Federal Offshore areas in the Gulf of Mexico accounted for 5.5% of the total. About 89% of proved reserves consist of non-associated gas.

Uzbekistan

Proved recoverable reserves (bcm)	1745
Production (bcm)	63.4
Consumption (bcm)	4.1
R/P ratio (years)	7.3

The republic's first major gas discovery (the Gazlinskoye field) was made in 1956 in the Amu-Darya Basin in Western Uzbekistan. Subsequently, other large fields were found in the same area, as well as smaller deposits in the Fergana Valley in the East.

Uzbekistan is a major producer of natural gas, greater than, for example, Egypt or the UAE. It exports gas to some of its neighbouring republics.

The principal internal markets for natural gas are the residential/commercial sector, power stations, CHP and district heating plants, and fuel/feedstock for industrial users. Some use is made of CNG in road transport.

Venezuela

Proved recoverable reserves (bcm)	5524
Production (bcm)	31.2
Consumption (bcm)	33.1
R/P ratio (years)	177

According to OGJ, Venezuela had 195 trillion cubic feet (Tcf) of proved natural gas reserves in 2012, the second largest in the Western Hemisphere behind the United States. In 2011, the country produced 1.1 trillion cubic feet (Tcf) of dry natural gas, while consuming nearly 1.2 Tcf. The petroleum industry consumes the majority of Venezuela's gross natural gas production, with the largest share of that consumption in the form of gas re-injection to aid crude oil extraction. Due to the declining output of mature oil fields, natural gas use for enhanced oil recovery has increased by more than 50 % since 2005. An estimated 90 % of Venezuela's natural gas reserves are associated.

PdVSA produces the largest amount of natural gas in Venezuela, and it is also the largest natural gas distributor. A number of private companies also currently operate in Venezuela's gas sector. Participants with significant assets include Repsol-YPF, Chevron, and Statoil.

In recent years, Venezuela has improved its 2,750 mile domestic natural gas transport network to allow greater domestic utilization and movement of natural gas production with the roughly 190 mile Interconnection Centro Occidente (ICO) system. The ICO connects the Eastern and Western parts of the country, making natural gas more easily available for domestic consumers and for re-injection into western oil fields. Upon its expected completion in late 2012, the ICO will have a capacity of 520 million cubic feet per day (MMcf/d). In addition, the 300 mile SinorGas pipeline project will transport gas produced offshore to the domestic pipeline network via Sucre and Anzoategui. To meet the growing industrial demand, Venezuela imports gas from Colombia and the United States.

Venezuela has by far the biggest natural gas resources in South America and possesses more than two-thirds of regional proved reserves. Substantial quantities of Venezuela's natural gas (amounting to almost 45% of gross output in 2008) are re-injected in order to boost or maintain reservoir pressures, while smaller amounts (12%) are vented or flared; about 10% of production volumes are subject to shrinkage as a result of the extraction of NGLs.

The principal outlets for Venezuelan gas are power stations, petrochemical plants and industrial users, notably the iron and steel and cement industries. Residential use is on a relatively small scale.

Yemen

Proved recoverable reserves (bcm)	478.5
Production (bcm)	6.24
Consumption (bcm)	0.76
R/P ratio (years)	**76.6**

According to the Oil & Gas Journal, as of January 1, 2012, Yemen had 16.9 trillion cubic feet (Tcf) of proved natural gas reserves. Most of Yemen's natural gas reserves are associated gas concentrated in the Marib-Jawf oil fields, which contain 10 Tcf of proven natural gas reserves.

In 2010, Yemen produced an estimated 1,153 billion cubic feet (Bcf) of gross natural gas, of which 890 Bcf was reinjected to provide enhanced oil recovery and 245 Bcf was marketed, including 194 Bcf exported as LNG.

A long-term LNG sales contract with Korea Gas Corporation was signed in 2005, providing the impetus and the investment needed to begin development of the country's natural gas reserves. Contracts were also signed with GDF Suez and Total. All three contracts run for 20 years.

According to Cedigaz estimates, Yemen exported a total of 194 Bcf of LNG in 2010. The principal buyers were South Korea (38 %), the United States (20 %), and China (13 %).

Yemen LNG is the largest industrial project in the country. French company Total holds a 39.6 % stake in the project, followed by Hunt Oil at 17.2 %, Yemen Gas Company at 16.7 %, and 3 South Korean companies - SK Gas at 9.55 %, KoGas at 6 %, and Hyundai at 5.88 % - while other Yemeni investors make up the balance reserves. A long-term LNG sales contract with Korea Gas Corporation was signed in 2005, providing the impetus and the investment needed to begin development of the country's natural gas reserves. Contracts were also signed with GDF Suez and Total. All three contracts run for 20 years.

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Unconventional gas

There are four main categories of unconventional natural gas: shale gas, coalbed methane, gas from tight sandstones (‘tight gas’) and the least well-known methane hydrates.

1. Shale Gas

Today, shale gas is making headlines all over the world. Therefore, this 2013 edition of the World Energy Resources has a special extended feature on shale gas which has effectively revolutionised the gas industry, especially in North America. In its quest for clean, secure, sustainable and affordable supplies of energy, the world is turning its attention to “unconventional” and “new” promising energy resources.

Shale gas is not a “new” energy resource. The first commercial gas well in the USA, drilled in New York State in 1821 was in fact a shale gas well. Over the years, limited amounts of gas were produced from shale formations, until the recent “Shale Gas Revolution” changed the natural gas scene, first in the United States and subsequently in other countries around the globe. This radical transformation occurred in recent years due to the development of a new application of “fracking” technology

Emerging Shale Gas Plays

There are nearly 700 known shales worldwide in more than 150 basins. At present, only a few dozen of these shales have properly assessed production potentials, most of those are in North America. The potential volumes of shale gas are enormous and this is likely to reshape significantly the gas markets in Europe and LNG markets worldwide.

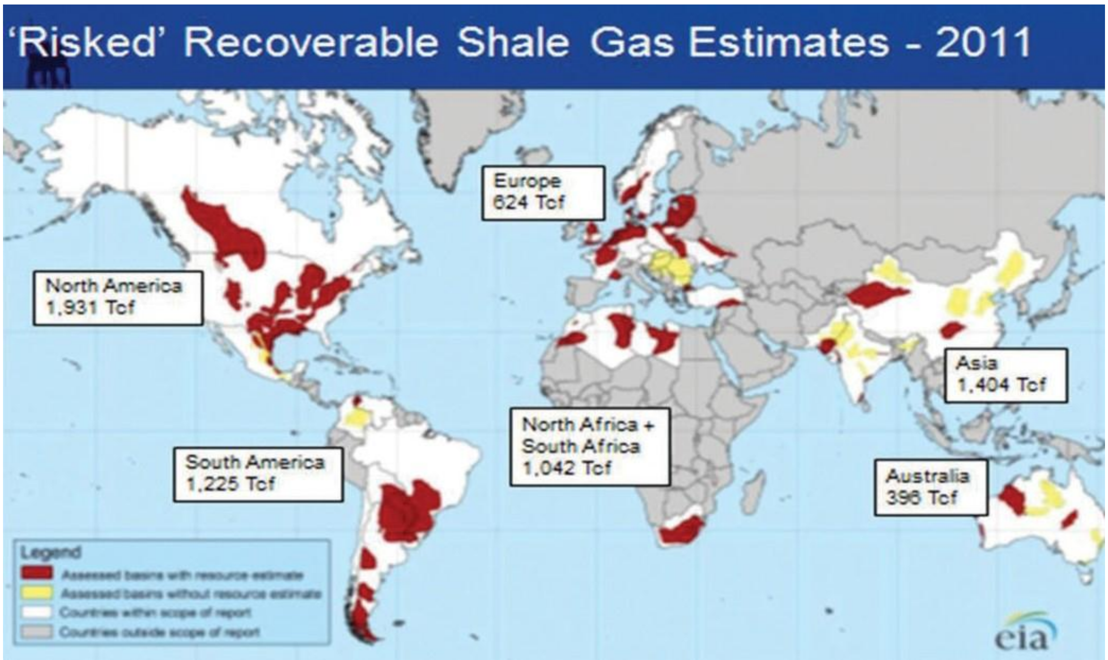
In about 30% of the identified basins there is existing infrastructure that could reduce capital expenditures related to exploitation of shale gas. However, even in these basins there is likely to be significant need for capital expenditures to process, store and distribute the gas through a pipeline system. The capital costs of developing that infrastructure will be considerable and may result in delaying new production from coming online or make the entire endeavour uneconomic. Although capital costs may be significant, shale formations may still be worth exploiting for both financial and strategic reasons.

Shale Gas Resource Base and Current Developments

Oil majors and other global companies are expanding their shale gas activities outside the United States. For example, ExxonMobil and Marathon Oil have launched shale gas operations in Poland, France, Germany, Sweden and Austria. It is believed that the total shale gas resource base is both large and wide-spread around the world. However, this potential resource has not yet been quantified on a national level in the majority of countries. The most credible studies put the global shale gas resource endowment at about 16,110 tcf (456 tcm). It is assumed that nearly 40% of this endowment would be eventually recoverable. The United States and the CIS countries together account for over 60% of the total estimate.

Estimated Shale Gas Potential (2011)

Source: WEC Shale Gas report 2010



European reserves, on the other hand, are not very impressive at slightly over 7% of the global reserves, and China and India on current estimates hardly reach a 2% share each.

It should be emphasised that these are best estimates available today and they can change significantly when proper assessments are performed. The US provides an enlightening case study. In 2007 US shale gas resource base was estimated at 21.7 tcf, and only a year later it jumped up to 32.8 tcf. At the end of 2008 shale gas accounted for 13.4% of US proved reserves of natural gas, compared with 9.1% at the end of 2007.

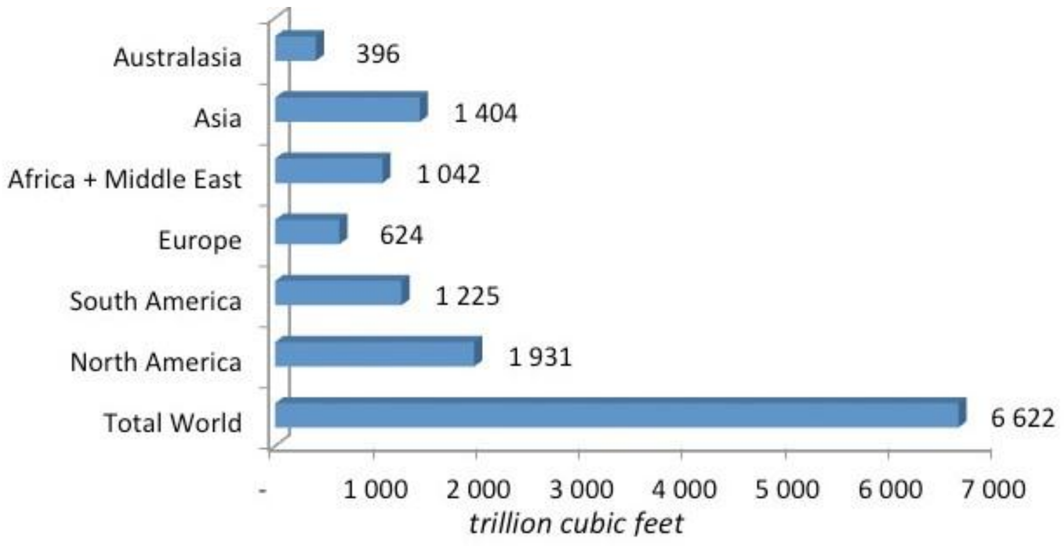
Approximately one half of the mentioned reserves are shale deposits, the rest are contained in coal seams and sandstone. Even if the current attention on shale turns out to be temporary, further development of natural gas infrastructure will be useful for other sources of natural gas. Further, the advancement of technology used to exploit shale gas will spur further technical advancements for other energy resources. An additional major challenge to developing shale plays will be the need for new or expanded pipeline infrastructure to transport gas.[1]

Countries and regions with large conventional gas reserves, like Russia and the Middle East, were not included in the study.

According to the US Department of Energy (DOE), their new estimates should be considered 'risked', which means that the methodology employed 'recognised the sparseness and uncertainty of data and included conservative discounting of the potential resource.' In other words, exploration activity has been sparse in many shale basins, which means that reliable seismic data is not yet available

1 Source: Survey of Energy Resources: Shale Gas – What's New, World Energy Council 2011

'Risked' recoverable Shale Gas reserves by region (2011)
Source: WEC Shale Gas 2011 report



Technologies

The recent advances in shale gas production technologies have been achieved largely by a combination of horizontal drilling with hydraulic fracturing. In this procedure, a well is sunk to a depth somewhat less than that of a known shale gas deposit and then gradually deviated until the drill-bit is running horizontally through the shale bed. Once drilling has been completed, the rock surrounding the horizontal bore is perforated in a number of places and artificial fracturing induced by the high-pressure injection of water combined with special additives and sand - called a proppant - to keep the fracture open. The other major technological improvement was horizontal drilling. The technique per se is not new and is practiced all over the world. The dramatic increase in production rates over vertical wells justified the higher cost of these wells. The majority of them are lined with a steel casing embedded in cement. Whether cased or not, most of the wells have what are known as multi-staged completions. This is a technology involving isolation of the productive zones and fracturing just those zones. Ten or more of these zones are not uncommon. Another technique is directing the well at an angle to the maximum horizontal stress to allow transverse fractures, which maximize production. All of this involves fairly sophisticated geophysical mapping of the rock.

Another new technique is pad drilling, where multiple wells are drilled and completed from a single location. This minimizes the need for roads and reduces the overall footprint of production, especially important in populated areas or farmland and other environmentally sensitive areas. It also allows for a higher level of sophistication in material handling.

While work on shale gas has, to date, been very largely concentrated in North America, and especially the USA, other parts of the world are now following suite, and preliminary resource assessments are being conducted in a number of countries and regions. For example, the ARI paper referred to above specifies three European basins as of particular importance – the Alum Shale in Sweden, the Silurian Shales in Poland and Austria's Mikulov Shale. Together, these basins are estimated to have a shale gas resource of around 1 000 tcf (roughly 30 tcm), of which about 140 tcf (4 tcm) is considered to be recoverable under present economic conditions.

Current Trends and Outlook

A considerable amount of exploration activity is being undertaken to establish the location of viable shale gas reservoirs, mostly by relatively small companies, in Australia, Austria, Canada, China, France, Germany, Hungary, India, New Zealand, Poland, South Africa, Sweden, United Kingdom and the United States.

A balanced view on shale gas

The emergence of shale gas as a potentially major source of energy has been accompanied by a flurry of publicity, both for and against further development of shale gas. The identified benefits of shale gas include:

- potentially enormous resource base;
- lower carbon emissions than from other fossil fuels;
- applicability of the technology throughout the world;
- improved diversity and security of supply for gas-importing countries;
- extension of the production in some existing gas fields and opening-up of new fields;

On the other hand, the drawbacks include:

- uncertainty over costs and affordability;
- questions about the environmental acceptability of the technology;
- poor reporting of decline rates;
- potential shortages of equipment;
- local opposition to shale gas development;

Economics and markets

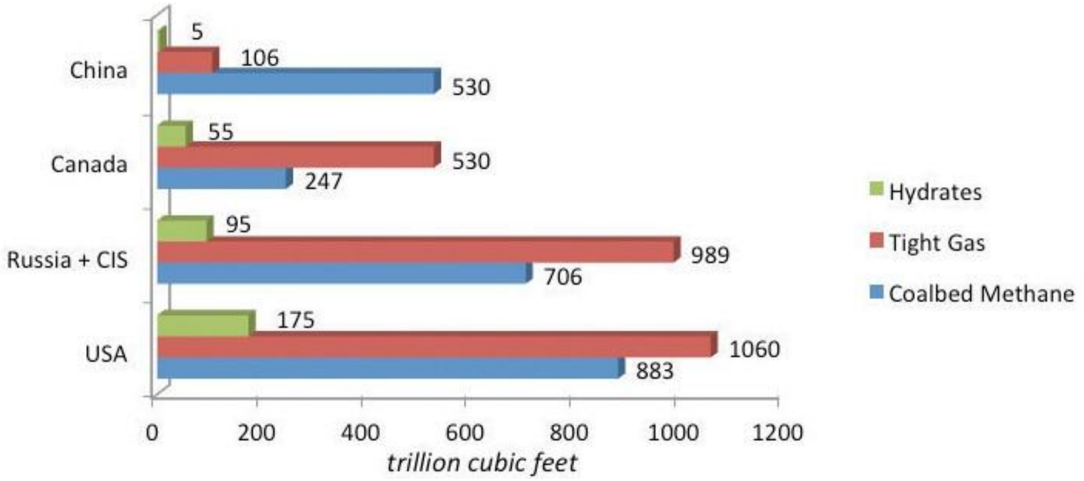
Large international oil companies (IOCs) seem to believe in the long-term economics of shale gas, as Exxon, Total, Shell, CNP, Reliance Industries and others have acquired significant stakes in shale gas resources in North America. These acquisitions, which will require further investments over a period of several years demonstrate the value the oil industry places on the future of shale gas. The increasing participation of oil majors in North American shale gas exploitation brings positive implications for the use of best practices and technologies in drilling and processing. Furthermore, the IOCs will most likely lead exploration activities worldwide.

Shale gas in China – A defining moment for the global energy sector

How much shale gas is there in China and other large emerging economies? A short and frank answer today would be that no one knows yet. However, the leading gas industry players agree that China's shale gas potential is large. US DOE/IEA recently estimated China's shale gas reserves at 1,275 tcf, which is more than the US and Canada's known reserves put together. Further exploration of China's shale gas potential will produce more reliable figures, but this will take some time. At the moment, no one knows with any degree of certainty where the Chinese shale plays are located and whether gas production would be commercially viable. So far, geological assessments have concluded that the most promising locations for shale gas deposits are in North-Western China (Tarim Basin), North-Central China (Ordos Basin) and South-West China (Sichuan Basin).

Recoverable Unconventional Gas reserves (2009)

Source: BGR Energierohstoffe 2009 report



The presence of large oil majors in China indicates that the industry believes in the shale gas future in China. If this assumption is true, shale gas would most certainly change the energy landscape in the country and in the entire world. China's economic growth has been spectacular, and it is set to continue for decades to come. Demand for electricity, for example, is expected to double within the next 20 years. The country is currently adding approximately 1,000MW of installed capacity per week, and over 90% of this capacity is coal-fired. 80% of China's electricity is generated by coal-fired power plants, and the country accounts for nearly 50% of the total coal consumption in the world. Given that coal-fired power plants are the largest emitters of Greenhouse Gases (GHG), the earlier China substitutes coal for shale gas, the lesser the environmental impact this increasing demand will have.

The main commercial argument against development of shale gas in China is the gas transport issue. The success of shale gas in North America was to a large degree based on the existence of an extensive gas pipelines network. There is nothing comparable to that in China, and despite the fact that the government is building pipelines at an unprecedented speed, it will take years if not decades, to achieve the same level of coverage as in North America.

On the other hand, the environmental issues in China do not have the same priority as in North America or Europe. Economic growth is still the paramount goal for the population at large and for political decision-makers. Therefore, the possible negative impact of shale gas development on the environment is not a front line issue.

It appears that there is a consensus in the global gas industry that makes China an attractive market for foreign companies. The global oil majors such as Shell, Chevron and ConocoPhillips are already involved in shale gas activities in China. They are now followed by a myriad of smaller players looking for quick profits, including a number of Chinese companies with no experience in gas or energy business.

It is however clear already today that further development of shale gas in China will have a significant impact on the entire world, both in terms of gas prices and environmental implications.

2. Coalbed methane

Coalbed methane (also known as colliery gas or coal seam gas) is present in some coal seams. It can be found in absorbed form within the coal matrix or unabsorbed in gaseous pockets. The gas generally lacks hydrogen sulphide but has a potentially higher level of carbon dioxide than natural gas. This resource is usually found at depths of 300-2000 metres below ground.

Coalbed methane production is associated with normal coal extraction and to date has only been commercialised where customers for gas are within the locality of the coal mining operation. The extraction of this unconventional gas resource involves horizontal drilling and fracturing techniques related to those used in oil shale extraction. It has been a growing source for gas production in certain regions, notably North America and Oceania. The recent rise in importance of shale gas may have an impact on coalbed methane's role as an unconventional source for natural gas in the future.

3. Tight gas

Tight gas refers to natural gas deposits which are particularly difficult to access from a geological viewpoint. Contained in rocks with very low permeability in deep formation, typically deeper than 4500m, extraction of this gas would require a combination of extraction processes such as the hydraulic fracturing and horizontal drilling. Some countries, such as the United States of America do not make a clear distinction in reported reserves between natural gas and tight gas. Known reserves are found in countries with well-established gas industries, where significant detailed surveying has been conducted; including but not limited to the USA, UK, Russia and Canada.

4. Methane hydrates

Crystalline deposits of methane, the principal component of natural gas, are found in extensive seams under deep water in various parts of the world. A recent academic assessment of gas hydrates calculates the amount of gas hydrates in resource-grade deposits to be at least one third more than 2010 estimates of global natural gas reserves.[2]

A number of countries have clearly demonstrated their interest in this potential form of energy, including Canada, China, Japan, Norway and the United States. In March 2013 the Japanese JOGMEC Corporation was the first company to extract gas from offshore methane hydrates, with the aim of commercial production starting by early 2019.

2 Boswell, R. and Collett, T.S., 2011. Current perspectives on gas hydrate resources. Energy and Environmental Science, 4, 1206-1215