The Global Natural Gas Market

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Global natural gas consumption, both in absolute terms and as a share of the energy usage mix, is continuing to grow. This growth has been driven primarily by changes in patterns of economic activity, energy intensity and energy substitution. Of these, the primary driver has been the switch to natural gas from other sources, primarily oil. Natural gas prices have consistently remained high in recent years, but despite this and the fact that gas has not been given any major preferential advantage compared to other energies, there has been no marked dampening of demand.

As global consumption volumes grow, the divisions between regions that consume natural gas and regions that supply natural gas will become more marked. The Asian OECD member nations[1] and Europe have become the major natural gas importers, with the former Soviet Union states, the Middle East and North Africa dominating natural gas exports. The growth of the gap between natural gas production and consumption is continuing to widen, and greater volumes of trade are necessary to balance supply and demand.

As natural gas supply hubs rise in prominence, natural gas prices are gradually breaking free from their link to oil prices. In the United States and Europe, because the natural gas market has matured, supply hubs have sufficient liquidity for competitive trading, and natural gas is priced for its own value rather than being linked to oil prices. However, an Asian natural gas trading hub is unlikely to develop soon, as this region's markets are still controlled by a small number of larger buyers and sellers, and market liquidity is low. Given the imbalances in regional supply and demand, shipping costs and trade restrictions, natural gas prices are likely to continue to vary by region rather than to converge on global unified price levels.

17.1 An Overview of the Global Energy Market

Natural gas is a growing player in the global energy mix (Fig. 17.1). In 1980, natural gas provided 57 EJ or 19% of the global total primary energy consumption volume of 300 EJ. In 2010, natural gas provided 124 EJ, representing 23% of the 525 EJ global total. Natural gas grew its proportion of primary total energy at a time when global energy consumption was itself rising rapidly. So natural gas demand grew at a faster rate than total energy demand—since 1980, average annual growth rate for natural gas has been 2.6%, compared to 2.0% for total energy.

Natural gas is increasing its share in global and regional energy mixes by displacing oil products

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[1]Japan and South Korea.

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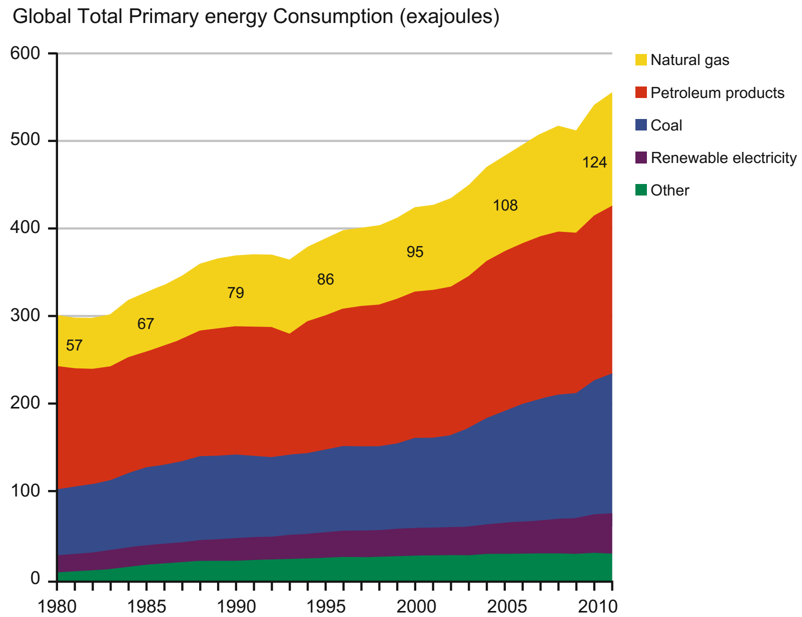

Fig. 17.1 Natural gas's share of global energy consumption. *Note* Data is global total primary energy consumption. *Source* Vivid Economics, based on EIA data

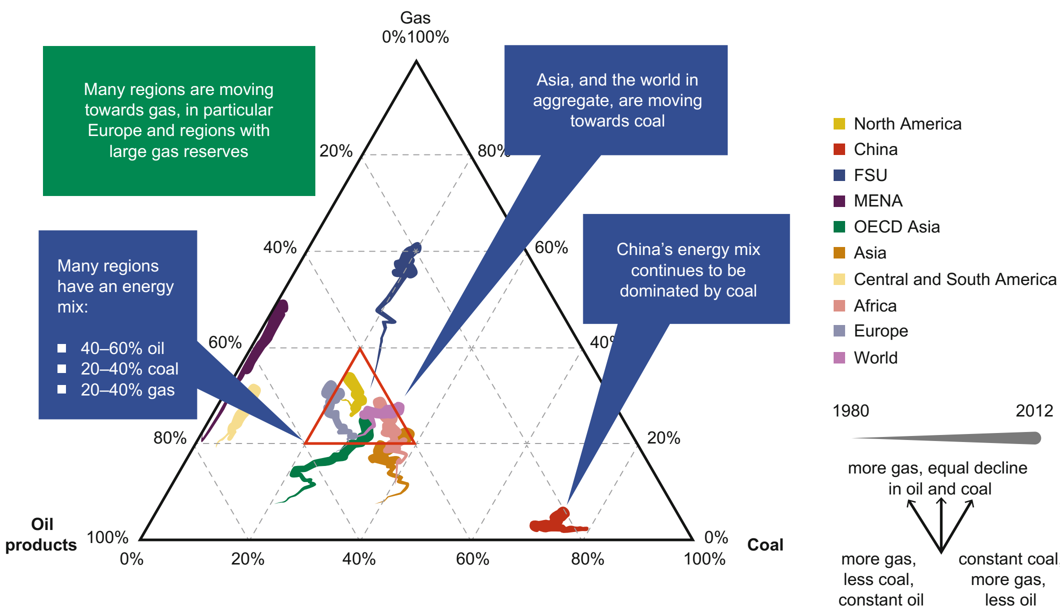

Fig. 17.2 Changes in share in the energy mix between oil, gas and coal. *Note* Data is share of fossil fuel energy; each country's coloured trail along the matrix gets thicker over time; movement toward the apex illustrates increased share of natural gas at the expense of oil (*lower left*) or coal (*lower right*). *Source* Vivid Economics, based on EIA data

and, sometimes, coal (Fig. 17.2). Each region uses differing amounts of oil products, natural gas and coal to supply its primary fossil fuel energy needs each year, and the balance of these energy sources changes over time. In the Middle East and North Africa and countries of the former Soviet Union, for example, natural gas has tended to supplant oil, while in North America and Europe it has taken some of coal's share. In general, the global trend has been toward natural gas consumption in lieu of oil use, with a parallel movement toward coal as well in some regions.

Looking to the future, global energy demand will continue to grow, and demand for natural gas is expected to increase faster than demand for other fossil fuels, continuing the trend of recent years. The IEA has noted that rapid population growth, increasing prosperity and improved access to reliable electricity are driving this trend. Average annual growth rate for natural gas is generally forecast to be 2% from 2012 to 2040.

The growth in natural gas demand in the period to 2040 is expected to be widely dispersed geographically, with Asia and the Americas playing an important role (Fig. 17.3). Asia is expected to account for the largest proportion of global natural gas demand growth during this period (as well as production). In particular, natural gas demand in China is expected to grow by 5.2% a year, accounting for 56% of Asia's natural gas consumption growth. Natural gas demand is expected to grow steadily in other emerging economies as well, with India rising 4.6% a year and Brazil 4.0%. However, OECD member country growth should be slower, averaging about 1% a year.

Power generation will play a significant role in increasing natural gas consumption, accounting for 36% of total growth from 2012 to 2040 (Fig. 17.4). Driven by the petrochemical industry, the industrial sector is also expected to contribute strongly, with an annual growth rate reaching 1.9%. Although natural gas use in transportation is expected to grow strongly at 3.3% a year, this sector will still continue to account for only a small share of total demand, about 9% by 2040.

During the same period, unconventional natural gas (such as shale natural gas) will come to account for an increased proportion of the overall supply mix. Global natural gas resources are widely dispersed geographically, and at the current rate of production, there are 60 years of proven reserves (Table 17.1). Even though US shale natural gas development has seen strong growth, there remain significant uncertainties about the development of shale natural gas in other regions. Currently, there are essentially no other regions outside of the United States that have successfully developed shale natural gas. In Poland, Sweden and Ukraine, resource discoveries have been disappointing, while developments in Algeria, France, South Africa and other countries have met with public opposition.

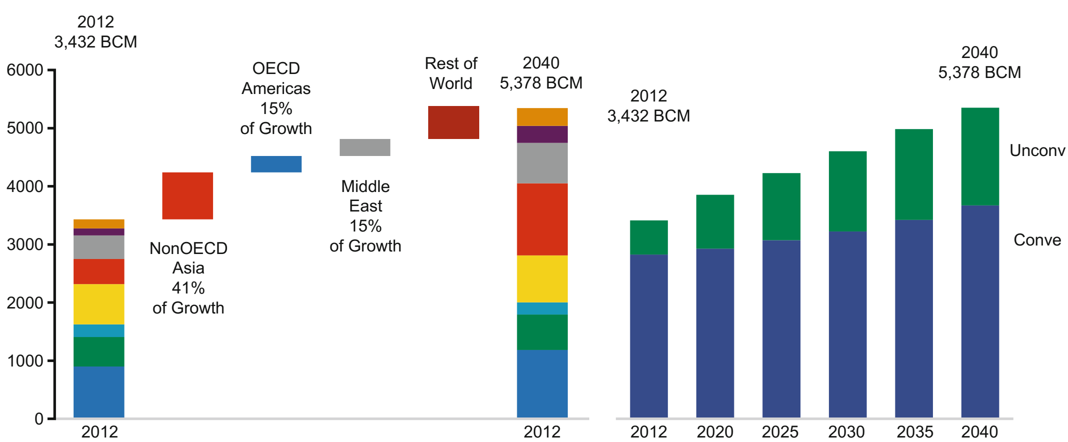

Fig. 17.3 Rising diversity in natural gas supply and demand up to 2040. *Note* bcm is billion m^3. *Source* IEA

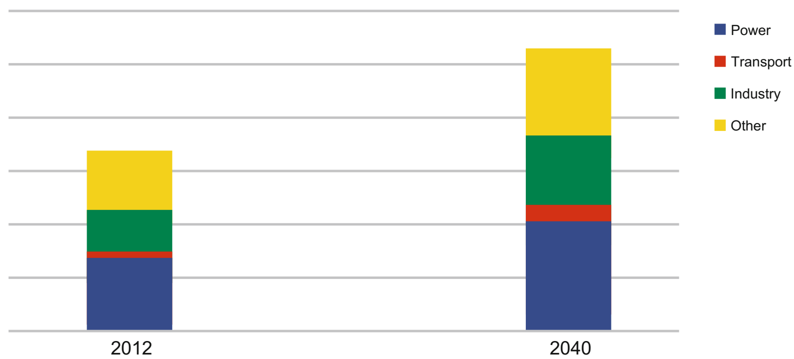

Fig. 17.4 Sources of demand for natural gas 2012 versus 2040. *Source* IEA

17.2 Factors Driving Demand

Driven by a number of factors, global natural gas demand has continually risen in recent years, and is expected to maintain its upward momentum. The three major drivers for this growth are economic activity, energy intensity and switching to natural gas, of which the last has played the biggest role in most countries. On the supply side, the availability of domestic natural gas resources has played an important role. Consistently high natural gas prices have not prevented the fuel source from gaining substantial ground in recent years, albeit from a low base.

17.2.1 The Main Factors Driving Demand

Based on research analysing the natural gas markets in seven different countries (see Chap. 2), it is apparent that economic activity, energy intensity, switching to natural gas and the availability of domestic natural gas resources are the four major factors influencing natural gas demand.

As economic activity increases, so does energy demand, and thus natural gas consumption increases in line with its share of the overall energy mix. From looking at the experiences of various nations, it appears that residential users and power utilities have seen the highest increases

Table 17.1 Remaining technically recoverable natural gas resources (end 2013)

	Conventional	Unconventional				Total	
		Coal gas	Shale natural gas	Coke gas	Sub-total	Reserves	Proven reserves
Eastern Europe/Eurasia	143	11	15	20	46	189	73
Middle East	124	9	4	–	13	137	81
Asia-Pacific	43	21	53	21	95	138	19
Americas OECD member countries	46	11	48	7	65	111	13
Africa	52	10	39	0	49	101	17
Latin America	31	15	40	–	55	86	8
Asian OECD member countries	25	4	13	2	19	45	5
Global	465	81	211	50	342	806	216

Note Data is in trillions of cubic metres
Information source IEA data

in usage, probably because rising household incomes allow people to spend more on heating and power companies in turn increase their use of natural gas to meet the greater general demand for electricity. In addition, natural gas demand from manufacturing industry has also increased, primarily due to a rise in production volume and the corresponding energy demand.

Under certain economic conditions, energy demand will fall in response to a fall in overall energy intensity of economic activity, and natural gas demand will decrease in line with its share of the overall energy mix. A drop in energy intensity is closely related to structural adjustments to industry. The experience of several major natural gas-consuming nations shows that when the service sector rises as a proportion of a nation's output or when a move from heavy industry to light industry occurs, energy intensity will exhibit a downward trend.

When a given industry chooses to replace oil and coal with natural gas, its natural gas consumption rises significantly. Global trend analysis shows that using natural gas to replace oil or coal is the major reason for the rise in natural gas demand. In most markets studied, the change in natural gas demand between 1982 and 2012 linked to switching fuel sources to natural gas was equal to or greater than that attributed to increased economic activity. Research into major natural gas-consuming industries also shows that a large proportion of consumption growth is accounted for by switching from other fuels to natural gas.

As nations develop, the service industry begins to play a larger role in the economy, urbanisation increases, and controls on air pollution become more stringent, leading to a marked tendency towards replacing oil and coal with natural gas. Australia, Europe and the United States have shifted a large portion of their energy mix from coal to natural gas, and China is currently considering similar measures. Many other countries have switched from oil to natural gas. These switches are significantly linked to the proportion represented by the service industry in each country's economy, with growth in the service industry directly affecting demand, especially driven by the need for office heating. Also, legislation aimed at greater urbanisation and improvement of air quality leads to natural gas (thanks to its cleanliness) often being first choice as a substitute energy source.

Finally, the availability of domestic natural gas resources is another factor that prompts energy transition. Domestic reserves are generally the cheapest source of natural gas for a country, and analysis has shown that, regardless of how big the reserves are, they always have an influence on the proportion of natural gas in the country's energy mix. This is partly because nations without natural gas reserves generally lack the infrastructure and systems to support natural gas imports. In addition, countries with domestic supplies and existing infrastructure and institutions are also more open to trade in natural gas, which may further increase the share of natural gas in the energy mix.

China currently is in a period of rapid development, becoming more urban, becoming more concerned with air quality and developing domestic natural gas reserves. These are all characteristics of countries with a high proportion of natural gas in the marketplace. However, if China wishes to promote natural gas, it will need to act to put measures in place that stimulate the transition from coal to natural gas. The experience of other nations suggests that this is more difficult to achieve than a transition from oil to natural gas, and currently only Europe has accomplished it.

17.2.2 Natural Gas Price Elasticity and China

International experience has shown that demand for natural gas is not sensitive to price changes, and that rises in natural gas prices do not necessarily cause a reduction in levels of natural gas consumption. From 1987 to 2000, global natural gas prices remained stable at low levels and natural gas demand in OECD countries grew rapidly. Beginning in 2000, natural gas prices began to rise, but demand did not react to the price changes, remaining stable in the majority of countries, and growing in others.

China's market performance is consistent with international experience. Since the 1990s, Chinese natural gas consumption has grown rapidly. The rise in natural prices that began in 2000 has not had a marked effect, and growth rates have remained relatively subdued.

Price competition between fuels appears to have only a modest effect on natural gas demand. From 1987 to 2000, the natural gas price remained a relatively constant fraction of the electricity price and the coal price. During that period, natural gas demand rose substantially. After 2000, even though natural gas prices rose substantially, there was no large decline global natural gas demand. During the period 2000–2012, OECD member country residential and industrial natural gas demand only dropped by 8%, despite a 60% price increase in real terms.

The main reason that price competition between fuels has only a minor effect on natural gas demand is that natural gas commands loyalty among its users. Once natural gas demand has been established, it can adapt to a changing economic environment, and this is especially true in terms of residential usage. Once consumers start to use natural gas, they tend not to switch away, because of its quality. Natural gas is a relatively clean source of controllable heat that is easily delivered and easy to use. In comparison with other fuels, such as coal, the characteristics of natural gas may mean that once the infrastructure is in place, residential and industrial users are less troubled by the price.

In summary, the non-price characteristics of natural gas appear to be important drivers of demand, so high natural gas prices in China may not hold natural gas demand back. However, China's energy prices are controlled, which means that China's situation could be different from other nations. In the majority of cases, major natural gas-consuming nations have already implemented energy price market liberalisation, with prices following changes in supply and demand. In China, however, some energy prices are controlled, a situation which lacks responsiveness to changes in supply and demand. The synergy between demand and price in other nations could result in different scenarios in China.

17.3 Supply and Demand Imbalances

Globally, natural gas-producing regions are gradually diverging from demand centres. This imbalance has triggered a boom in global natural gas trade, with a proliferation of international pipeline and LNG projects.

17.3.1 Summary of Global Resources

Unconventional natural gas resources are likely to account for a larger share of total gas supply as development continues. The IEA estimates that global remaining conventional technical recoverable natural gas resources have reached 465 trillion m^3 and unconventional resources, 342 trillion m^3. Between 1994 and 2013, global proved reserves increased by 56%, and available resources are expected to continue to grow. Even though unconventional gas production volumes are expected to increase, the majority of natural gas production is likely to continue to be from conventional resources.

According to current estimates, global natural gas remaining proven recoverable natural gas reserves are approximately 186 trillion m^3. Over the past 30 years, proven recoverable natural gas reserves have grown by 3–4 trillion m^3 a year, and the reserve-to-production ratio has stayed steady at close to 60 years.

For the most part, these reserves are in three countries: Iran (18%), Russia (17%) and Qatar (13%). Turkmenistan also holds a significant share of the world's proven recoverable natural gas reserve, with the other 11 countries among the 15 with the largest reserves holding considerably less (Fig. 17.5).

1. **Centres of demand**

In 2013, global natural gas consumption, including LNG, rose by 1.1% from 2012. During the same period, natural gas international trade volume increased by 2.3%. Global international trade in oil for the same period rose by only 1.7%. The top 10 natural gas-consuming nations

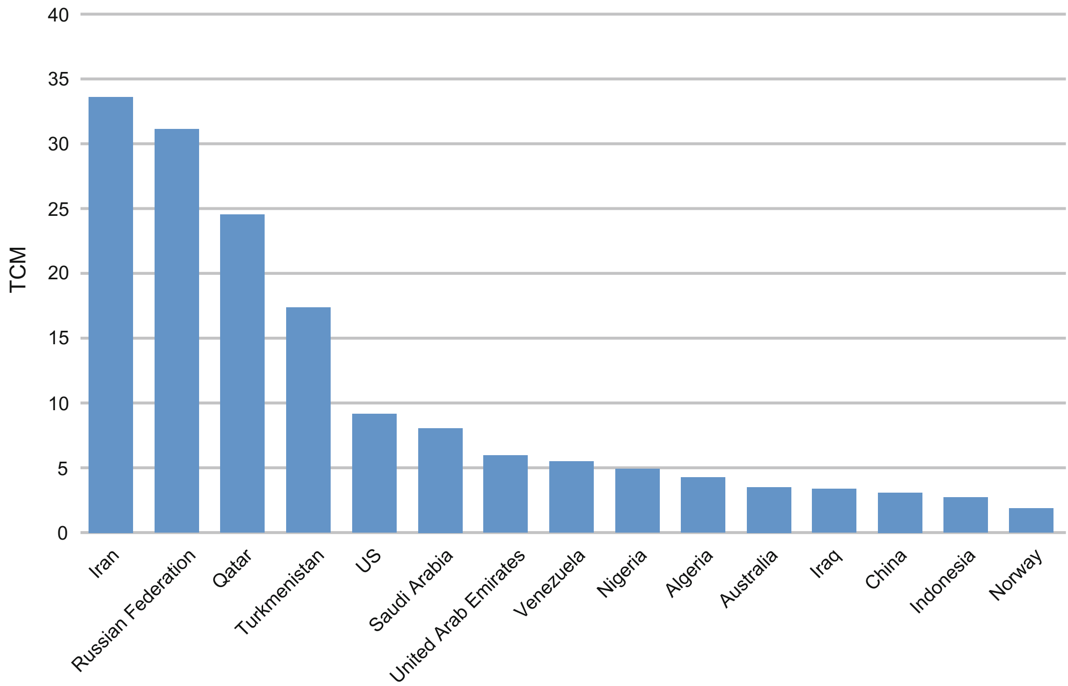

Fig. 17.5 The 15 countries with the largest proven recoverable natural gas reserves. *Source* BP Statistics 2014

consumed a total of 2 trillion m^3, accounting for 61% of total global consumption. These largest consumers were: the United States (22%), Russia (12%), Iran (5%), China (5%), Japan (4%), Canada (3%), Saudi Arabia (3%), Germany (3%), Mexico (3%) and the United Kingdom (2%).

The United States is the largest natural gas consumer, and in 2013 consumed a total of 737 billion m^3. The largest natural gas-consuming industry was power generation, accounting for 33% (this proportion was 25% 10 years ago). The second largest user was industry, accounting for 31% of total volume in 2013 (its share fell below that of power generation in 2008). Shares taken by other uses in 2013 included residential (21%) and commercial (14%). In the next 10 years, with the completion of various LNG liquefaction projects, primarily around the Gulf of Mexico, US natural gas production and the country's LNG exports to Europe and Asia are expected to further increase.

In the United Kingdom, natural gas consumption in the last decade has been more volatile after a sustained period of growth, led largely by increased residential and power generation use of gas. From 1990 to 2003, the share of natural gas used for power generation in the United Kingdom rose from less than 1 to 38%, but this had dropped to 27% by 2013.

Prior to the 2011 Fukushima reactor incident, Japan was already the world's largest importer of LNG. The Japanese government's response to the incident, especially its closure of all nuclear power plants, pushed natural gas consumption in the country even higher. When nuclear power, which had previously accounted for 31% of power generation, was entirely halted, Japan's LNG imports rose from 69 million tonnes to 82 million tonnes. Even though Japan's nuclear power plants are expected to resume operations, continued domestic opposition and new standards make the timing for this uncertain.

Consumption in Russia, the world's second-largest natural gas market, has been volatile in recent years. Use dropped sharply after the 2008 global financial crisis, rebounded strongly, and then softened again going into 2012 and 2013, echoing the country's lower economic growth. In Europe, Germany's 2012 and 2013 natural gas consumption continued to grow despite a reduction on average in EU member state consumption. In the Middle East, Iran, another large consumer, has seen natural gas consumption growth moderate in recent years. Finally, China has seen a brisk rapid growth in natural gas consumption since 2000, placing it now among the world's 10 largest natural gas-consuming countries.

While India is not yet among the world's top consumers of natural gas, policy initiatives—especially in the power generation sector—have led to remarkable increases in use. Domestic consumption nearly doubled from 1995 to 2005, reaching about 37 billion m^3 or 1.3% of total global consumption. However, price controls, a drop in domestic production and issues surrounding LNG infrastructure access have dampened the natural gas market in recent years. As these problems are resolved, India's natural gas consumption will likely resume growth.

2. **Centres of production**

World natural gas production was 3.4 trillion m^3 in 2013, an increase of 1.1% from 2012. Between 1970 and 2013, global natural gas production grew nearly 3.5 times. The largest natural gas-producing countries and their proportions of total global production volume were as follows: United States (20%), Russia (18%), Iran (5%), Qatar (5%), Canada (5%), China (5%), Norway (3%), Saudi Arabia (3%), Algeria (3%), India (2%) and Malaysia (2%). However, from the perspective of export totals for natural gas pipeline and LNG, Russia was the largest exporter, accounting for 22% of the global total, primarily in pipeline natural gas. Ranking second was Qatar (12%), primarily LNG, followed by Norway (10%), primarily in pipeline natural gas.

The United States is already the world's largest natural gas producer, and production is set to increase significantly as several LNG projects come online. The success of US shale natural gas production will soon turn the country from a net importer to a net exporter. LNG exports are expected to start in 2016 as Cheneire's Sabine Pass facility begins operation. By 2020, the United States is expected to have 40 million tonnes in annual liquefaction capacity. There are yet more LNG exports projects in planning, but not all of them are expected to be completed.

The world's second largest natural gas producer, Russia, has been operating a large-scale pipeline gas and LNG export business for a long time. In 2013, Russia produced 605 billion m^3 of natural gas, and pipeline exports to Europe were about 211 billion m^3, with the main destinations being Germany (40 billion m^3), Turkey (26 billion m^3) and Italy (25 billion m^3). Russia also exported 14 million tonnes of LNG, primarily to Japan. It is expected that as the natural gas pipeline between China and Russia enters operation, and with new LNG facility operation commencement, Russia will see further growth prior to 2020 in natural gas production volumes and export volumes.

A significant amount of pipeline natural gas is also exported from Norway, The Netherlands and Algeria to European markets. Dutch gas production is underpinned by production from the Groningen Field, northwest Europe's largest natural gas field and one of the largest in the world. The Netherlands exported 53 billion m^3 by pipeline in 2013, but in 2014 the government lowered the production limit following an earthquake in the region linked to natural gas extraction.

Qatar was the world's largest LNG exporter in 2013, exporting over 78 million tonnes of LNG. The world's largest non-associated gas field straddles the Qatar–Iran border, with some estimates placing the recoverable reserves at 900 trillion cubic feet in the North Field (the Qatari portion) and 500 trillion cubic feet in the South Pars (the Iranian portion). Since production from the North Field began in the early 1990s, Qatari natural gas production has increased from 6.3 billion m^3 in 1991 to 158 billion m^3 in 2013, with most destined for export. Qatar initially developed its LNG export capacity to supply significant volumes to each major market—Asia, Europe and North America—but the North American shale natural gas boom and strong LNG demand in Asia resulted in almost 70% of its LNG going to Asia in 2013. Iranian gas production also increased significantly over the same period, but all of its natural gas is consumed domestically.

Australia is expected to become an important natural gas producer and exporter soon. Although production volume in Australia was 1% lower in 2012 than in 2012, a series of LNG liquefaction projects will become operational over the next few years that will bring Australia's production capacity up to 88 million tonnes, overtaking Qatar to become the world's largest LNG exporter. However, some of these facilities will be the first in the world to use coalbed methane to produce LNG, so some uncertainty remains about these figures.

Even though 2013 production volume was not significant, Papua New Guinea began natural gas production in 2014 as the PNG LNG project came online. This project's annual production capacity is 6.9 million tonnes of LNG, and production capacity expansion plans are being assessed.

Canada is already a major producer of natural gas, and even although its exports are currently limited to pipelines to the United States, the country plans to export more widely. Canada's west coast has a significant number of LNG projects in planning, hoping to take advantage of the region's abundant unconventional natural gas and its access to large LNG importing countries like Japan, South Korea and China.

Based on their abundant natural gas resources, Tanzania and Mozambique are two more countries that could potentially become major LNG exporters. For them, natural gas is a brand new industry, and it is likely to take longer to begin operations. For these—or indeed any—new natural gas projects to attract the necessary financing, they will need long-term commitments from high-quality buyers at prices sufficient to provide adequate returns to both the host country and the developers.

17.3.2 Regional Imbalances

Globally, supply and demand is unevenly distributed between regions. The main producing regions are countries of the former Soviet Union, North America and the Middle East and North Africa (Fig. 17.6). Countries of the former Soviet Union and the Middle East and North Africa are the world's largest exporters of natural gas. The Asian OECD countries, China and Europe are the main importers. In other regions, production and consumption are basically balanced, with the exception of the rest of Africa, which is a relatively small, but growing, exporter.

Because global natural gas consumption has grown, and regional supply and demand are unbalanced, import and export trade volumes are also growing. From 1990 to 2013, global natural gas consumption volumes grew by approximately 70%, but there were relatively large disparities in each region's supply and demand growth rates (Fig. 17.7). Nations exporting natural gas expanded exports, and importing nations likewise increased imports. From 1990 to 2013, approximately 20% of the newly added consumer demand was realised through inter-regional import and export trade.

In recent years, production increases have been supported by large discoveries of conventional, and more recently unconventional, natural gas. Since the late 1980s, there have also been major discoveries of conventional natural gas, especially in the Middle East and North Africa, causing these regions rapidly to become major producers of natural gas. At the same time, production volumes even rose in regions where there had been no major increases in reserves, indicating a preference for domestic sources over imports to meet demand.

While reserves of unconventional natural gas reserves, including tight natural gas, shale natural gas and coalbed methane, are largely unconfirmed, they are potentially huge. Their exploitation in the United States since 2002 has fundamentally changed the country's natural gas market, although unconventional production remains minimal in all other regions. However, the potential for unconventional natural gas to

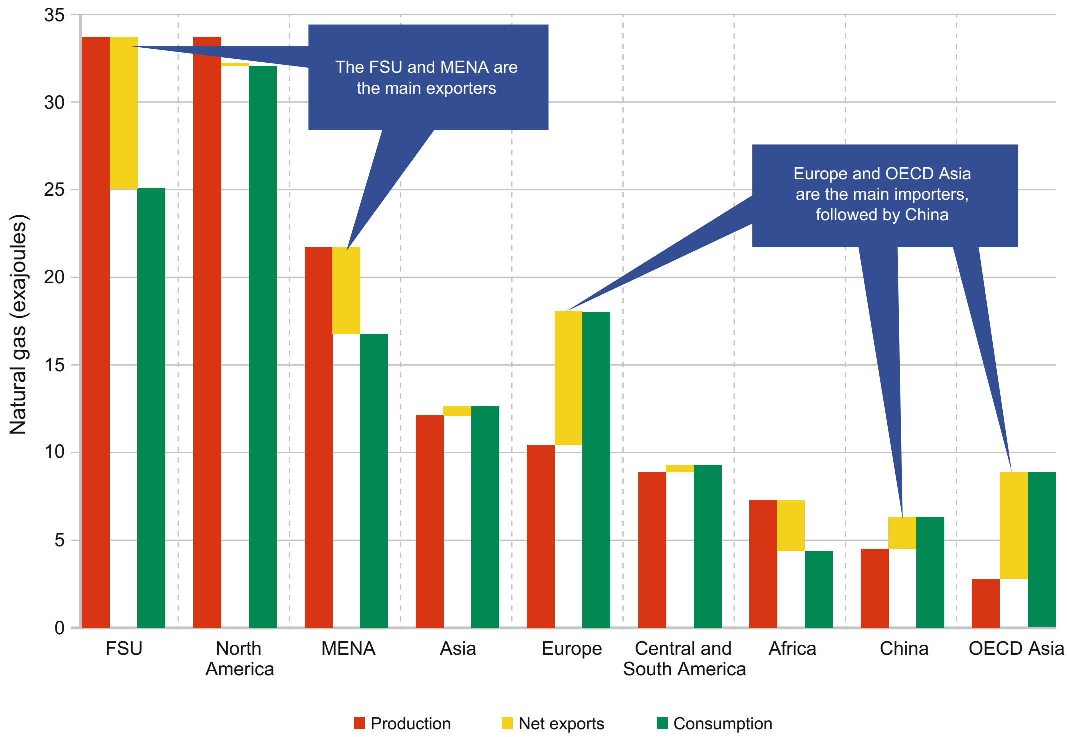

Fig. 17.6 The major natural gas producing and consuming regions. *Note* Data for 2013. *Source* Vivid Economics, based on IEA data

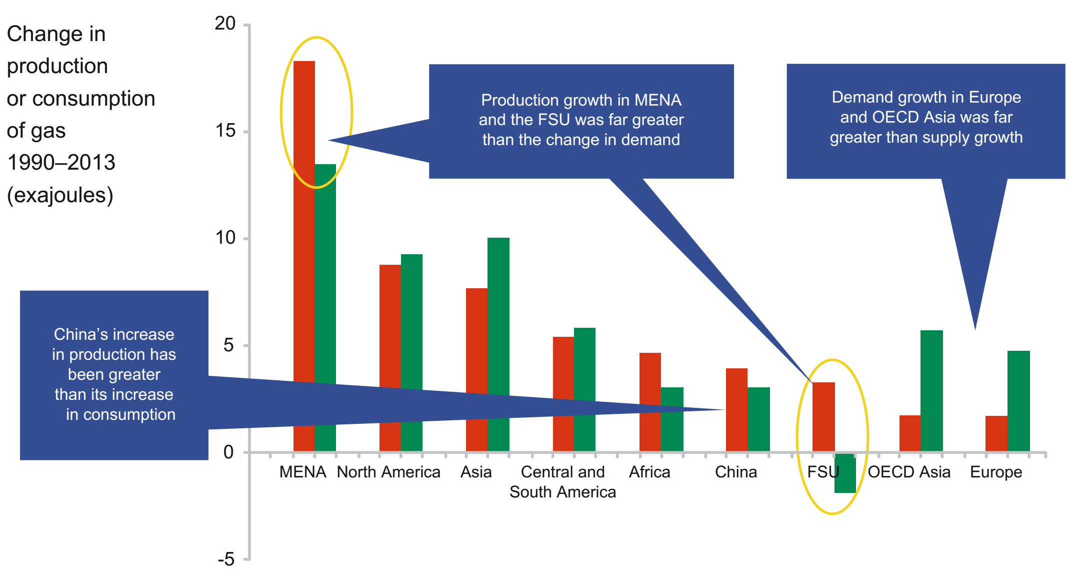

Fig. 17.7 Natural gas supply and demand growth rates of various regions, 1990–2013. *Source* Vivid Economics, based on IEA data

disrupt other regions is large. Unconventional natural gas reserves are mostly distributed in countries without major amounts of conventional natural gas (Fig. 17.8), and if these reserves could be commercially exploited, then the inter-regional imbalance between natural gas producers and consumers would probably be reduced. Such a change would reduce demand for natural gas from countries of the former Soviet Union, the Middle East and North Africa.

As a result of the developments discussed above, the world is increasingly becoming divided into regions that supply natural gas and regions that consume it (Fig. 17.9). The natural result of this situation has been an increase in inter-regional trade.

17.3.3 Inter-regional Natural Gas Trade

With the regional imbalances in natural gas supply and demand, inter-regional trade, especially LNG trade, has been increasing. From 1993 to 2013, natural gas trade over pipeline almost doubled, while LNG trade—albeit from a lower starting point—quadrupled (Fig. 17.10). Natural gas trade over pipeline, however, still dominates the market, accounting for about two thirds of total trade.

1. **Pipeline gas trading**

Since 1993, the volume of natural gas traded over inter-regional pipelines has almost doubled, though the network has not significantly increased its connectivity. In 1993, inter-regional pipeline natural gas trade volume was 470 trillion cubic feet, and 86% of this was exported by the former Soviet Union, with 94% imported to Europe. At the time, the natural gas pipeline network was limited, with most natural gas flowing from the former Soviet Union, the Middle East and North Africa (Fig. 17.11). By 2013, 8.5 trillion cubic feet was being traded annually over pipeline, with the share exported

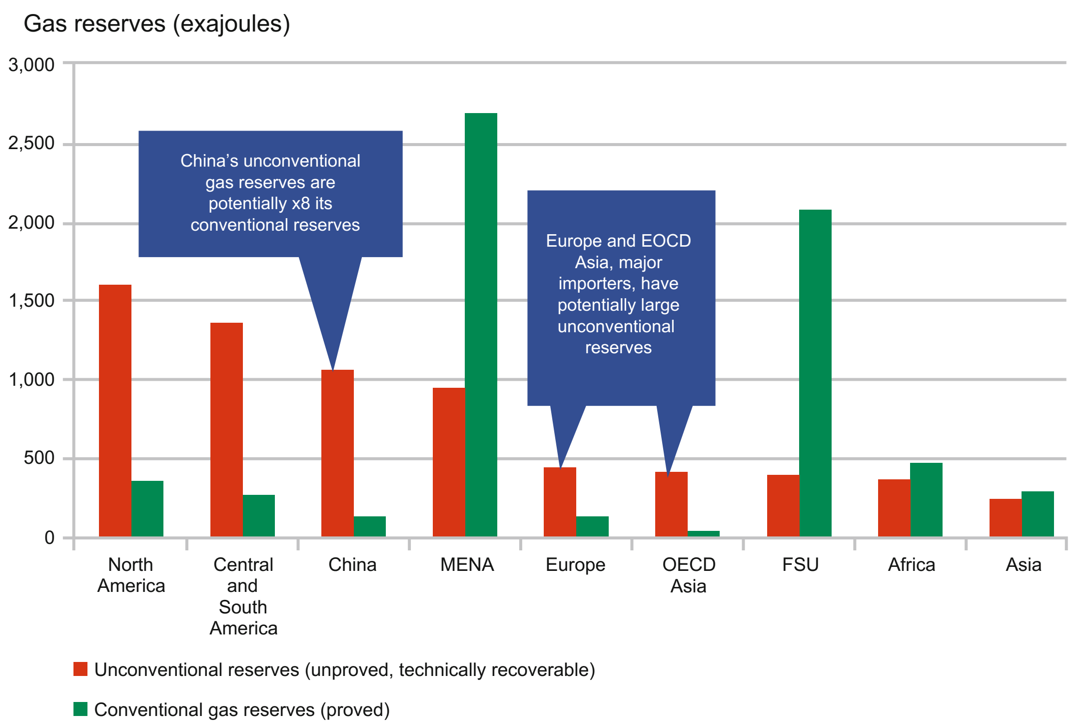

Fig. 17.8 Unconventional natural gas reserves by region. *Note* Data is for 2013; unconventional reserves include tight natural gas, shale natural gas and coalbed methane. *Source* Vivid Economics, based on EIA and IEA data

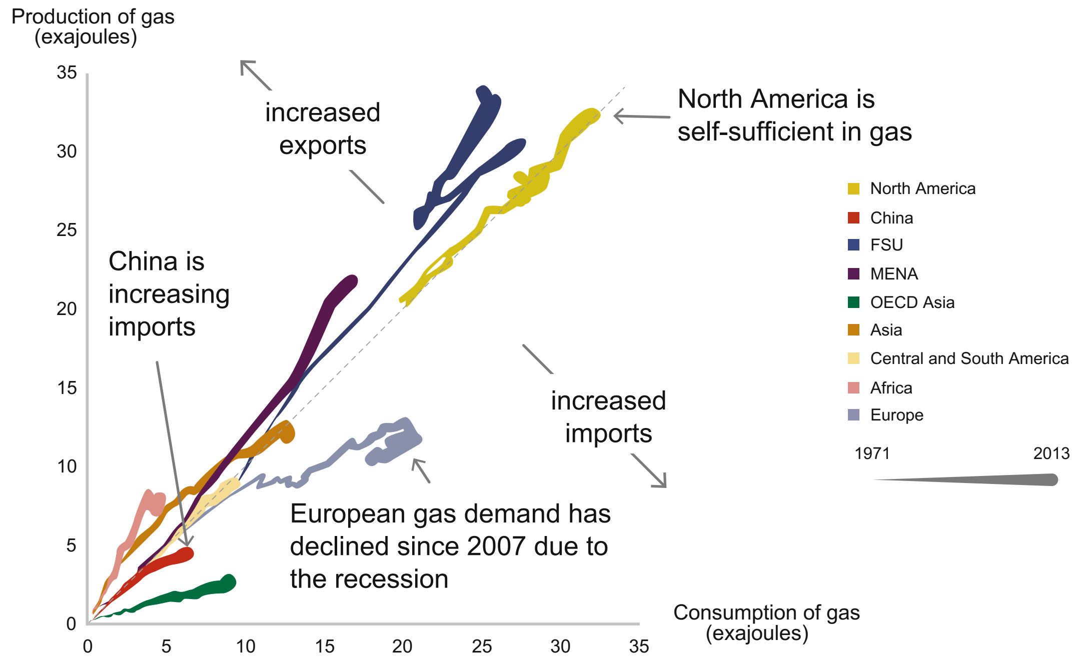

Fig. 17.9 The increasing polarisation of regions into suppliers and consumers of natural gas. *Note* Data is on a gross calorific basis; each country's coloured trail along the matrix gets thicker over time; the dotted midline represents equilibrium between production and consumption, with greater production above the midline and greater consumption below it. *Source* Vivid Economics, based on IEA data

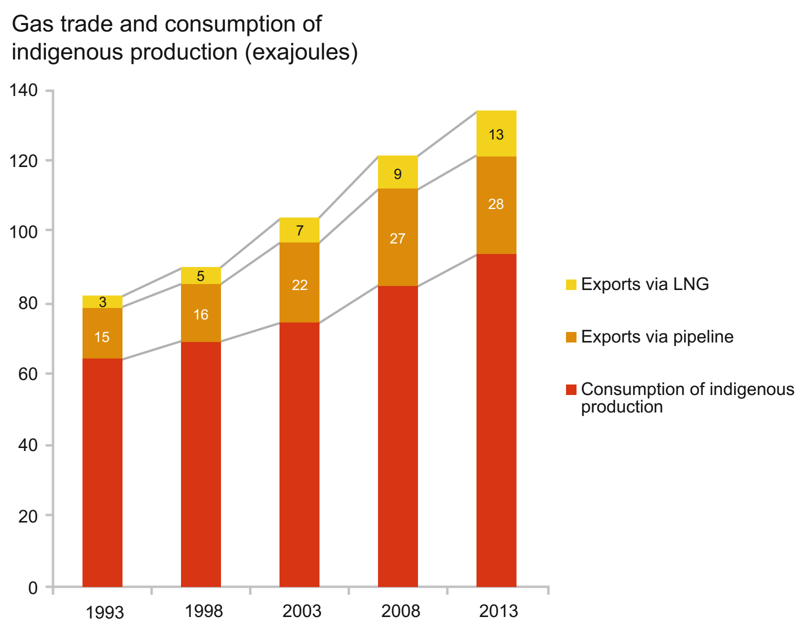

Fig. 17.10 Types of global natural gas trade. *Note* Data is a global aggregate of international trade. *Source* Vivid Economics, based on IEA data

by countries of the former Soviet Union falling to 75%, and European imports to 65%. In the same year, Chinese imports accounted for 11% of pipeline natural gas, exclusively from countries of the former Soviet Union. Even though there had been some small changes between 1993 and

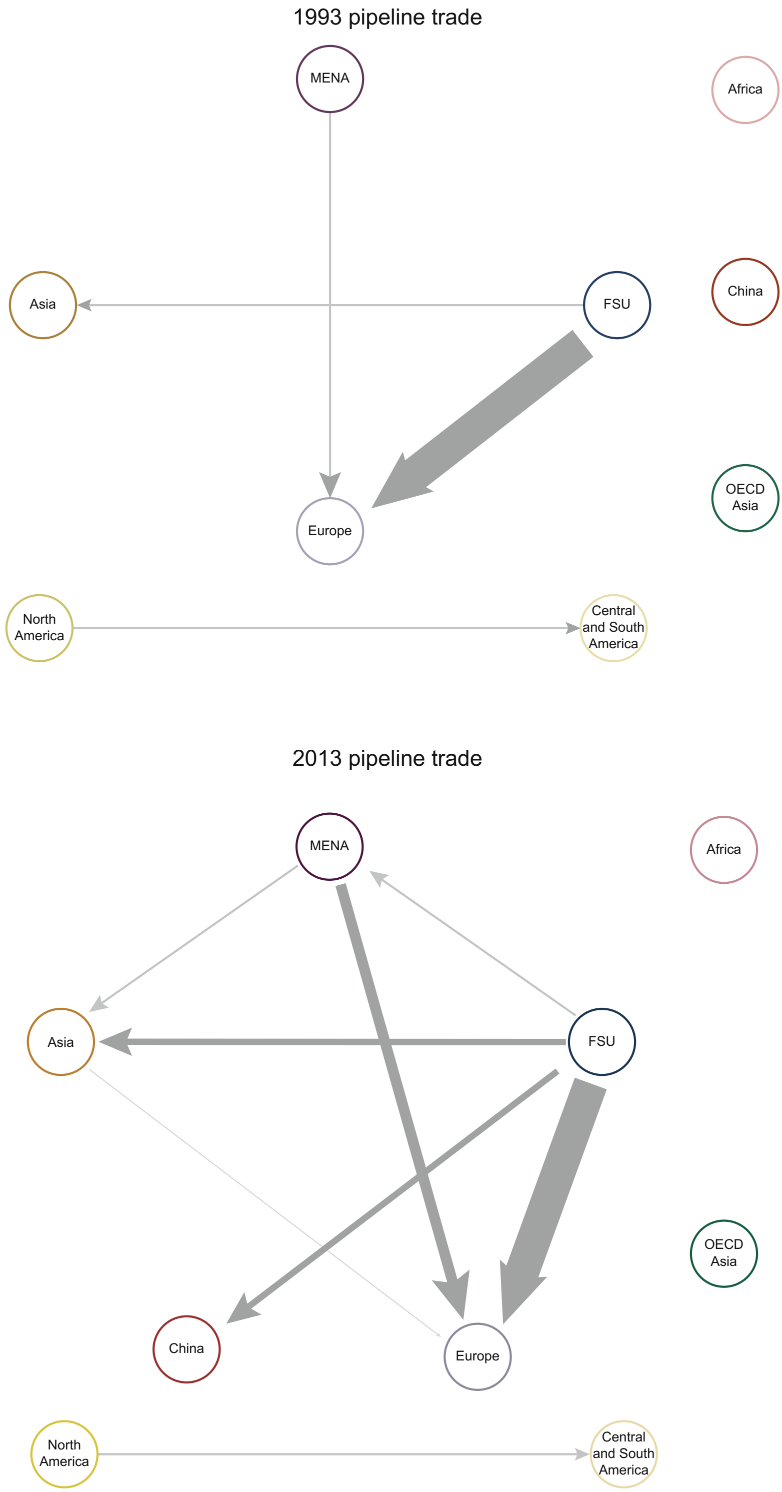

Fig. 17.11 Global inter-regional pipeline natural gas trade. *Note* The thickness of the arrow represents the percentage of global pipeline trade flowing between two regions. *Source* Vivid Economics, based on IEA data

2013, the inter-regional natural gas pipeline network remained relatively limited, especially in light of the global pattern of reserves, production and demand.

2. **LNG trading**

The volume of natural gas traded through LNG has more than tripled since 1993, and the network has significantly increased its connectivity. In 1993, inter-regional LNG trade volume reached 2.7 trillion cubic feet, of which 64% was exported from Asia, and 70% was imported by Asian OECD member nations and 25% by Europe. Though networks facilities were limited in 1993, primarily concentrated on trade between Asia and Japan and between Africa and Europe, by 2013 they had expanded significantly (Fig. 17.12). In 2013, inter-regional LNG trade volume had reached 9.1 trillion cubic feet. Of this, 57% was exported by the Middle East and North Africa, while the major importers were Asian OECD member nations (56%), Europe (15%) and China (9%). LNG trade in Asia, excluding China and OECD countries, has become more complex, handling imports and exports, and accounting for just 10% of net inter-regional LNG trade volume, compared to 64% in 1993.

The degree of connectivity in LNG markets has begun to form a global natural gas market. By 2013, the network of LNG trade had become much denser, with many regions connected to each other. The flexibility of LNG delivery means that LNG can be used to exploit arbitrage opportunities across a range of regions, connecting markets together. However, LNG trade is currently dominated by a small number of participants in the Middle East and North Africa, and trade volume on some routes are still low. In addition, there are legal restrictions on exports, such as in the United States, and limitations due to infrastructure capacity. Furthermore, LNG developments remain capital-intensive and risky, and as a result interregional price differences need to be wide to motivate trade. Faced with such problems, even though regional markets are far more connected now than in the recent past,

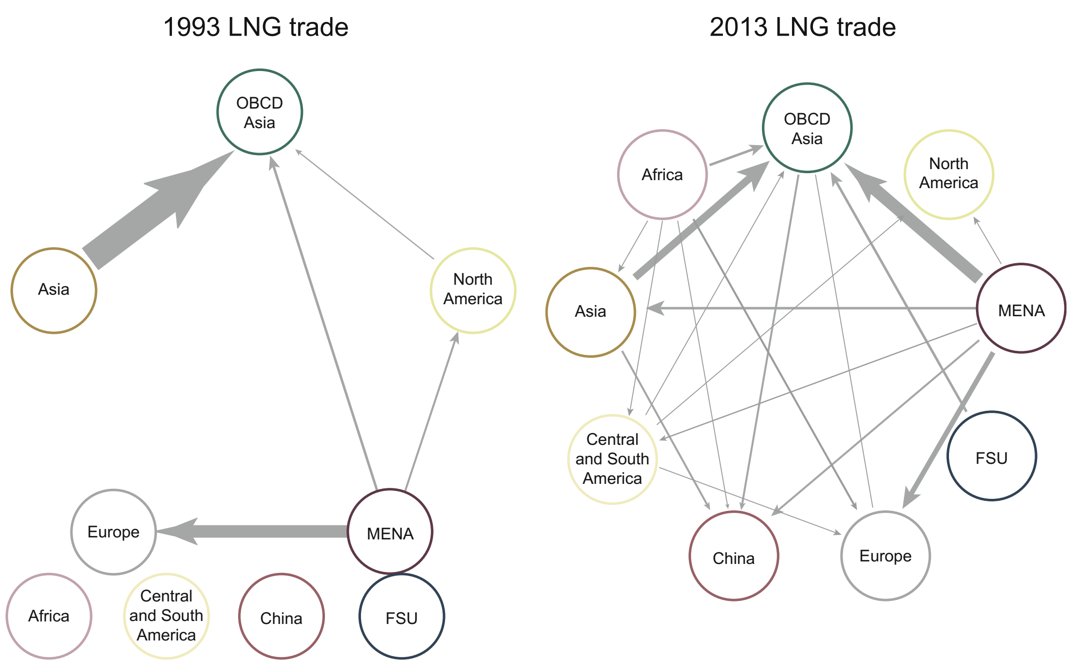

Fig. 17.12 Global LNG trade *Note* The thickness of the arrow represents the percentage of global pipeline trade flowing between two regions *Source* Vivid Economics, based on IEA data

the degree of connectivity is still insufficient to support the formation of a global market.

3. **The problems facing LNG trading**

LNG capacity has increased rapidly, and the expansion is expected to continue. In 2013, LNG liquefaction capacity, which is required for export, was 2.25 times greater than in 2003, while regasification capacity, an import requirement, was twice that in 2003. By 2023, liquefaction capacity is expected to grow almost threefold, while regasification capacity is expected to nearly double. This will bring global liquefaction capacity to almost 40 trillion cubic feet/year by 2023, and regasification capacity to almost 60 trillion cubic feet/year. (Regasification capacity is greater than liquefaction capacity because regasification capacity is distributed across more locations and countries build import capacity to meet peak demand, whereas the flow of exports tends to be smoother, requiring a lower capacity for the same volume.)

However, LNG costs are volatile, and may not fall significantly in the future. In general, the cost of liquefaction plants has increased by 50% over the last decade, and some projects, primarily in Australia, have cost at least twice normal levels. Costs have risen because of higher commodity prices, such as steel, and, in Australia in particular, higher labour costs. This pattern of high costs could persist. Even if commodity prices fall, LNG is likely to remain an expensive process, because the scope for technological breakthroughs is limited, and the large amount of expensive capacity recently added will lock in higher costs. Furthermore, LNG is only competitive with overland pipelines over long distances, such as from the Middle East to Japan (Fig. 17.13).

These issues suggest that LNG is economically limited. This fact could constrain investment, or may require long-term contracts to manage risk. Moreover, it is likely to mean that LNG remains an expensive fuel, serving as a marginal source of supply in markets where supply fails to keep up with demand.

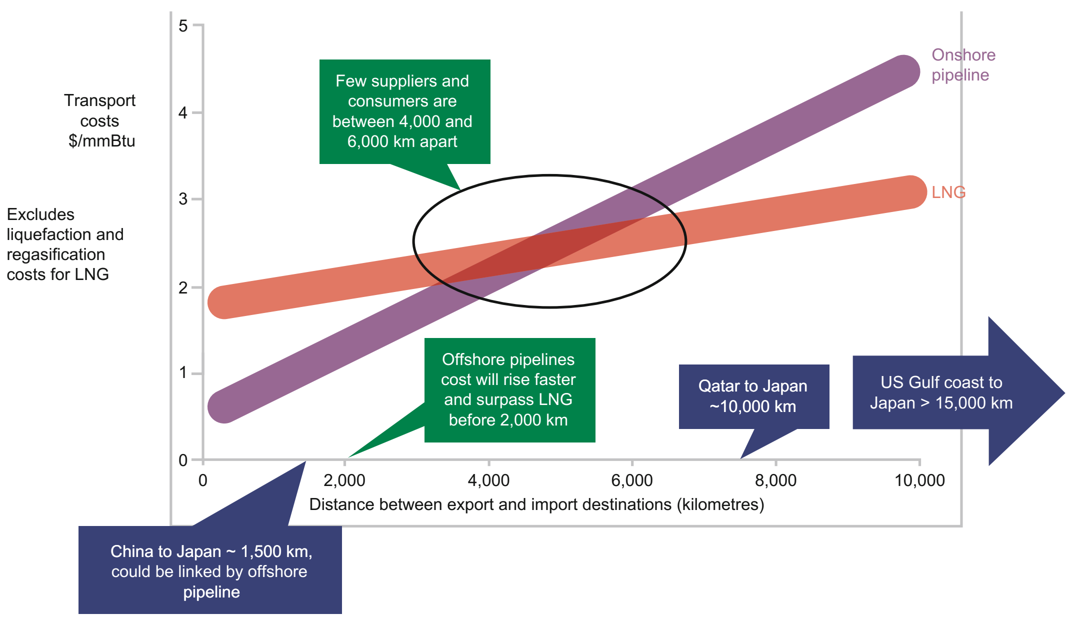

Fig. 17.13 Comparison of competitiveness between pipeline natural gas and LNG. *Source* Vivid Economics based on SBI Energy Institute (2014)

17.3.4 Unconventional Natural Gas Resources

Confirmed unconventional natural gas reserves account for approximately three-quarters of global technically minable reserves. In a 2012 report, the IEA estimated that global confirmed technically minable natural gas reserves amounted to 420 trillion m^3, with 331 trillion m^3 recoverable with unconventional technology. The unconventional resources were 208 trillion m^3 in shale natural gas, 76 trillion m^3 in tight natural gas and 47 trillion m^3 of coalbed methane. In a separate report, the EIA assessed the world's recoverable reserves of shale natural gas at 7299 trillion cubic feet, of which China's share was the largest, followed by Argentina, Algeria, the United States and Canada (Table 17.2).

Unconventional natural gas has transformed the natural gas market in North America. In the United States alone, shale natural gas production is expected grow from 9.7 trillion cubic feet in 2012 to 19.8 trillion cubic feet in 2040, bringing its share of total US natural gas supply from 40 to 53%. This increase in natural gas supply is expected to give US manufacturers an added advantage over foreign competitors and has already resulted in a significant number of projects that seek to liquefy natural gas for export.

North America's success in exploiting unconventional natural gas has inspired other countries. According to IEA estimates, global unconventional natural gas total production volume will reach 928 billion m^3 in 2020, including 454 billion m^3 of shale natural gas, 148 billion m^3 of coalbed methane and 294 billion m^3 of tight natural gas.

Despite the optimism, there nonetheless remain significant uncertainties about how quickly unconventional resources can be brought online outside the US, especially in countries where little or no production has been taken place. Although China is estimated to have unconventional resources totalling about 32 trillion m^3, the government recently reduced its near-term outlook for reaching these reserves. Problems cited included that the resources were spread across more than 500 basins and the geography was difficult, as well as costs, inadequate infrastructure, water disposal concerns, lack of channels for introduction of international companies and a lack of innovation as a result of the small number of participating companies. In another example, Argentina, with about 23 trillion m^3 in unconventional resources, has

Table 17.2 Top 10 countries with technically minable reserves of shale natural gas

Ranking	Country	Shale natural gas reserves
1	China	1115
2	Argentina	802
3	Algeria	707
4	United States	665
5	Canada	573
6	Mexico	545
7	Australia	437
8	South Africa	390
9	Russia	285
10	Brazil	245
	Global total	7299

Units trillion cubic feet
Source US Department of Energy

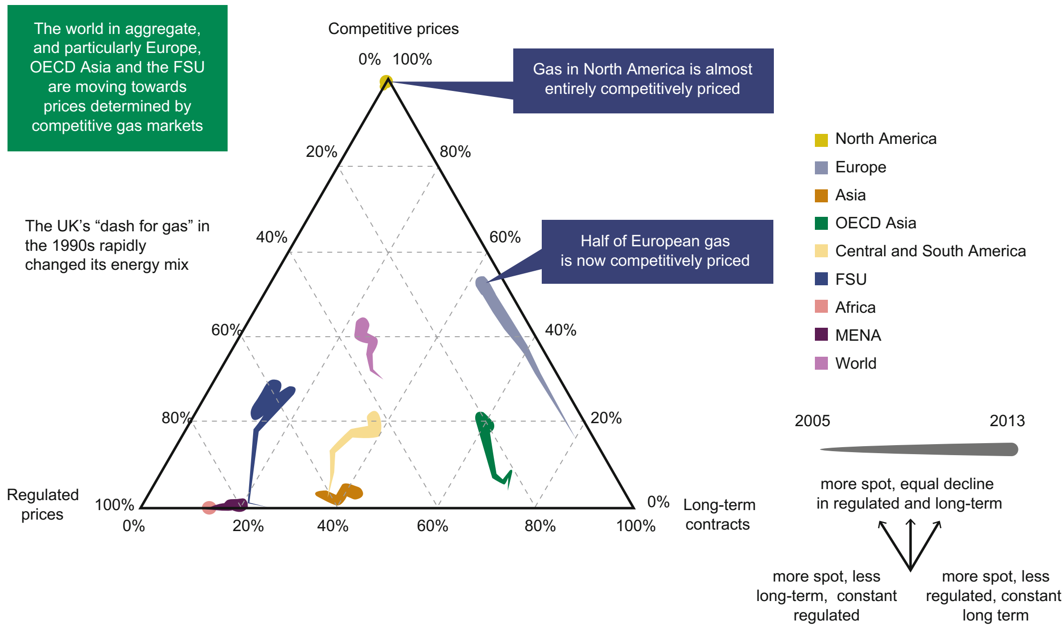

Fig. 17.14 Changes in natural gas contract types. *Note* Each country's coloured trail along the matrix gets thicker over time; movement toward the apex illustrates increased share of natural gas at the expense of oil (*lower left*) or coal (*lower right*). *Source* Vivid Economics, based on IGU data

solid pre-conditions in place, but is constrained by funding and non-technical risks.

17.4 Pricing

Natural gas prices and price-setting mechanisms have evolved over time. While long-term contacts linked to oil prices were once dominant, now price setting is taking different forms across markets, and prices vary by region. A 2014 report from the International Gas Union (IGU) found that 43% of global wholesale volume was based on competitive natural gas pricing, also known as gas-on-gas pricing, and was not indexed to oil prices,[2] while 19% was indexed to oil. The term of contracts is also becoming more diverse, compared to oil-indexed contracts, which tended to be long-term agreements. Prices are being set more often based on competition among natural gas suppliers, on hubs or on spot markets (Fig. 17.14).

In China, where energy price controls are relatively stringent, the mechanisms of natural gas pricing differ greatly from the way they function internationally, with different pricing methods depending on gas source and on use. However, China's natural gas pricing is undergoing reform, and is gradually moving toward national natural gas pricing rules.

Natural gas hubs are an important factor in natural gas pricing mechanisms, given that their core function is to provide a physical connection within the natural gas system and to facilitate competitive pricing. Natural gas hubs break the link between the price of natural gas and oil prices. The competitive pricing that the formation of hubs allows becomes a kind of substitute plan for controlled prices linked to oil prices. In addition, natural gas hubs also form an important component of natural gas downstream markets. See the special discussion in Chap. 19 for the principles, effects and practical cases of natural gas hubs.

[2]Contracts connected to oil price can also be competitive, but gas-on-gas pricing contracts are normally more competitive, and are more reactive to changes in the market fundamentals.

Due to the great size and rapid development trends of China's natural gas market, as well as previous experience of large-scale international trade in other commodities, policy adjustments for China's natural gas market are likely to have a major impact on global natural gas markets. This study established a model to analyse China's natural gas demand growth in various scenarios and its effects on global natural gas markets, including price, energy mix, and other aspects.

17.4.1 Current Pricing Regulations

The development of a global natural gas market is limited by geography, with most international trade being over natural gas pipelines or by LNG shipping. Geographical limitations and high shipping costs—the construction of international long-distance pipelines, as well as the costs of shipping and storing LNG—restrict trade between different regions, causing the natural gas market to develop distinct regional characteristics, particularly regarding how prices are established (Table 17.3).

Price levels across the regions have also varied significantly, reflecting the changes to the supply and demand for each market (Fig. 17.15). In North America, the influential Henry Hub price generally reflects the supply and demand dynamics in the United States, for example by reflecting seasonal variations, major incidents (such as hurricanes Katrina or Rita) and

Table 17.3 Regional market pricing characteristics

Region	Market description	Method of price formation
North America	Natural gas market with competition-based natural gas pricing. Interconnected infrastructure linking storage, supply and demand hubs	Multiple natural gas indices, with Henry Hub the dominant openly-traded LNG index. Natural gas index reflects North American natural gas supply and demand
Europe	Multiple natural gas markets with varying degrees of competition-based pricing. Markets operate and regulations are developed under a framework established under the European Union, but strong national interests remain. Infrastructure is primarily interconnected, with some bottlenecks	Long-term contracts connected to oil price or oil product prices are being increasingly challenged by competitive pricing, for example from NBP in the UK and Title Transfer Facility (TTF) in the Netherlands
Japan, South Korea, and Taiwan	Markets primarily based on national monopolies and supply in the region primarily under long-term contracts, with some active spot LNG buying to manage supply and demand or some portfolio optimising. Customs data for LNG imports publicly available and can be used to determine the average import price	Strong oil indexation for long-term contracts to the Japan Crude Cocktail (JCC), which is generally defined within individual contracts and lags current oil prices because they are typically based on recent average prices of crude imports into Japan. These are prevalent in Asia and may include price review clauses. Spot cargoes are primarily based on a fixed price, typically negotiated bilaterally or based on tenders. Surveys by various reporting agencies seek to capture this through the Japan Korea Marker (JKM). JKM is not a price for spot cargoes, but is currently the best estimate in the industry
China	Market dominated by state-owned enterprises. Supply based on a mix of domestic production, pipeline imports from central Asia, Myanmar and, soon, Russia and LNG imports. Infrastructure development continuing. Market reforms ongoing	Natural gas market pricing reform ongoing. Natural gas supplied under a mix of cost-plus for domestically produced natural gas and oil-indexed pricing, primarily for imports. LNG price formation similar to Japan, South Korea and Taiwan. Natural gas sold at regulated prices set by a National Development and Reform Commission formula linked to LPG and fuel oil

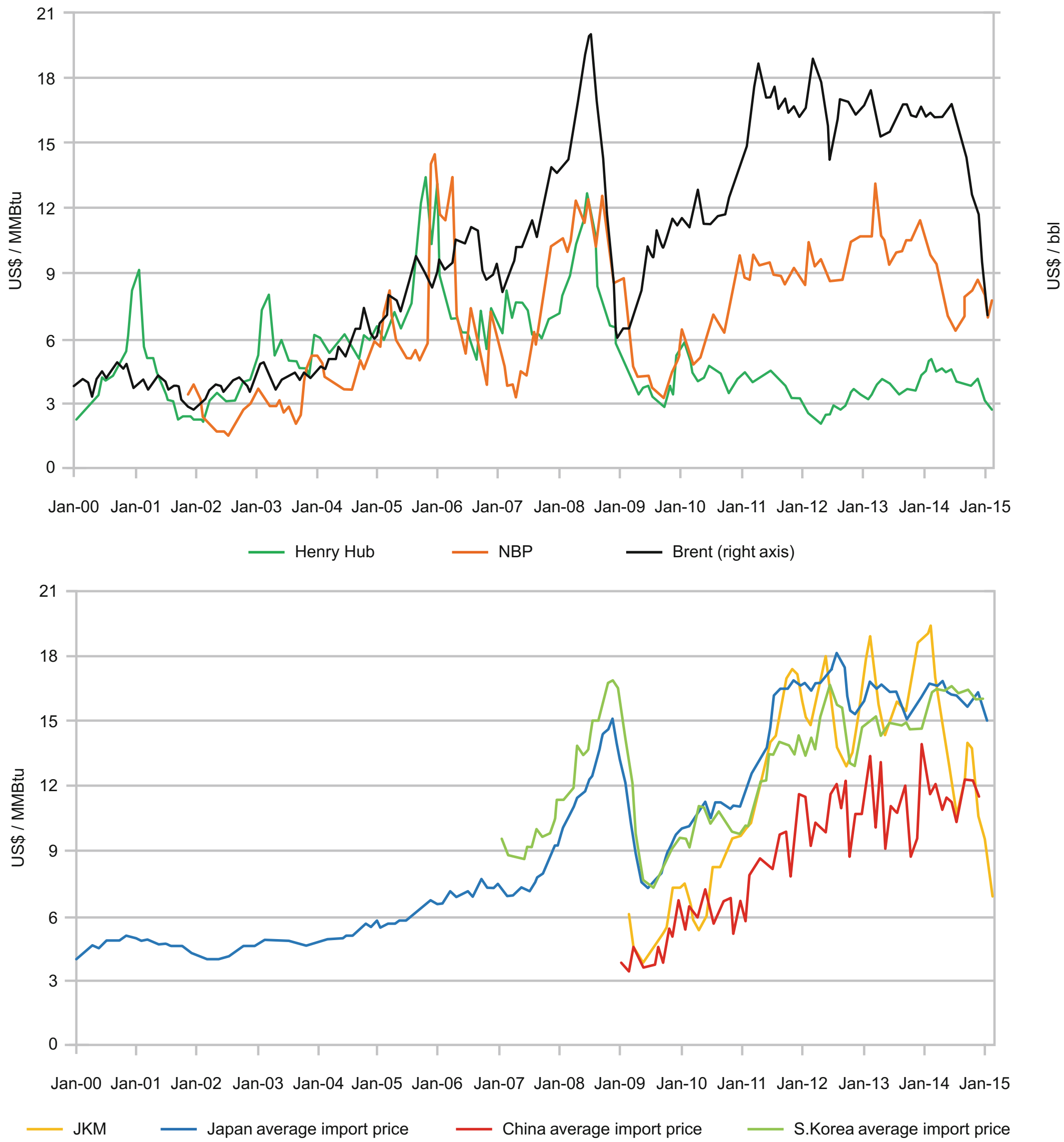

Fig. 17.15 Key price indices and Japan's average import price. *Source* Platts, Energy Intelligence, Intercontinental Exchange, and Heren

longer-term trends (such as the shale natural gas revolution). Indeed, there were periods when US natural gas prices were higher than the average LNG import price in Japan, for instance when the market expected the United States to need substantial LNG imports.

In the past, the Henry Hub price was widely seen as a benchmark for the US market, and many natural gas liquefaction projects around the world were begun targeting exports to the United States based on these prices, relying on the Henry Hub price for their export plan pricing, along with the belief that the United States would be a long-term LNG importer. A significant number of regasification terminals in the United States were also proposed (Fig. 17.16).

The United States was expected to be a long-term LNG importer, and developers were

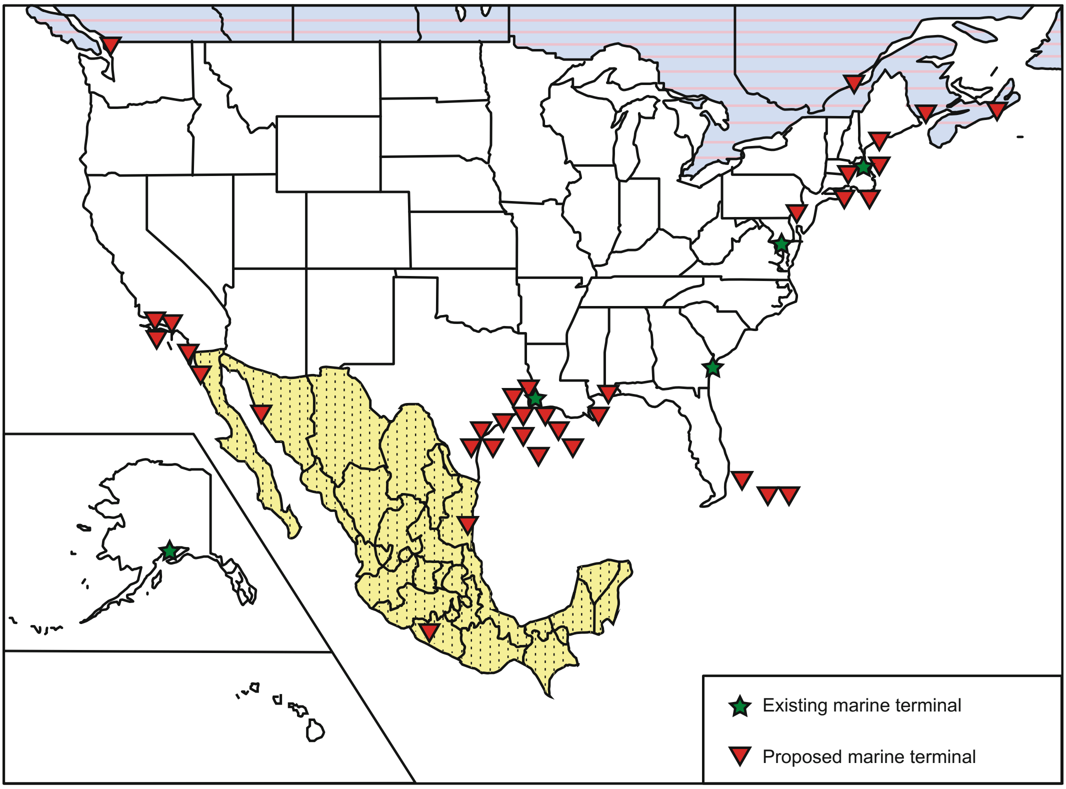

Fig. 17.16 Current and proposed LNG regasification terminals in North America, 2004. *Information source* EIA

willing to price their export plans based on the Henry Hub largely because it was widely accepted as reflecting US supply and demand fundamentals. A significant number of regasification terminals were also proposed in the United States.

In markets in which pricing is predominantly linked to oil indices, prices also respond to changes in supply and demand, but not as efficiently as in competition-based pricing. The mechanism is also complicated by the supply and demand of oil.

One example of this follows new LNG sales and purchase agreements in Asia-Pacific, where prices gradually diverged from oil until around 2005 and slowly retracted (Fig. 17.17). In the early 2000s, project developers in the region had to enter markets relatively new to LNG imports and had the alternative of exporting to the United States. Costs for building LNG projects were lower than current levels, and their oil price outlooks were anchored around historical levels, which had generally been below \$60 a barrel for 15 years. After 2005, higher project costs and greater demand for natural gas led to higher prices, in some cases reaching parity with crude oil. The 2011 nuclear power plant accident in Fukushima, Japan put additional upward pressure on natural gas prices in Asia. More recently, however, natural gas prices have begun to soften, partly a result of lower oil prices, weaker global economies, additional capacity (both completed and proposed) and new projects, such as US LNG exports to Asia.

Looking ahead, natural gas prices, especially LNG exports to Asia-Pacific markets, could become particularly volatile with the onset of LNG exports for the United States, which are primarily indexed to Henry Hub prices. Companies are hoping to capitalise on the US natural gas boom by liquefying the fuel and trading it on international markets. Many projects have been

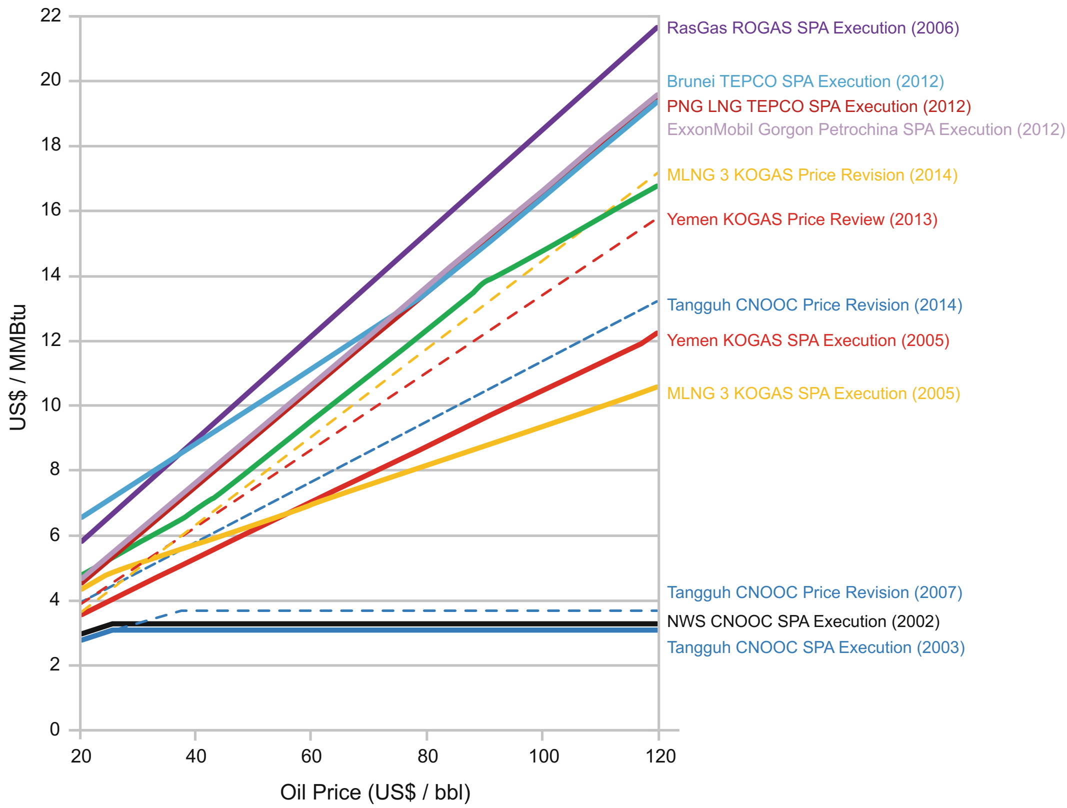

Fig. 17.17 Progressive divergence by different degrees from oil prices of Asian oil-linked natural gas prices. *Source* Wood Mackenzie and public information

announced, but not all will be completed (Fig. 17.18).

In general, pricing of American LNG exports has two components: one linked to Henry Hub prices representing the feed gas and fuel costs, and an annual fixed component representing investment in the liquefaction facility (Fig. 17.19). Based on currently available purchase and sale agreement terms, the "Henry Hub" component is typically 115% of the Henry Hub price, while the second component is based on a fixed dollar amount, with about 15% of this linked to US inflation rates.

Buyers gain supply diversity by procuring US LNG exports, but they also acquire some risk. Coupled with contracted destination diversity, which allows shipments to be rerouted to the most favourable markets, US LNG exports can contribute to a beneficial diversified energy supply network. However, US LNG supplies can be less competitive than oil-indexed supplies, depending, among other factors, on movements of global oil prices and Henry Hub natural gas prices (Fig. 17.20).

Compared to Asia, where natural gas contract prices are linked to oil, US natural gas exports have a different risk profile. Many US LNG export sales and purchase agreements include a tolling agreement section, which means that the buyer is responsible for procuring the natural gas to be liquefied, and lower plant utilisation rates would lead to higher unit prices because the buyer continues to pay the fixed component, except in extreme cases. The buyer is responsible for purchasing the natural gas to be liquefied, with the unit price rising with lower liquefaction facility usage rates, because the buyer continuously pays a fixed fee portion, except in

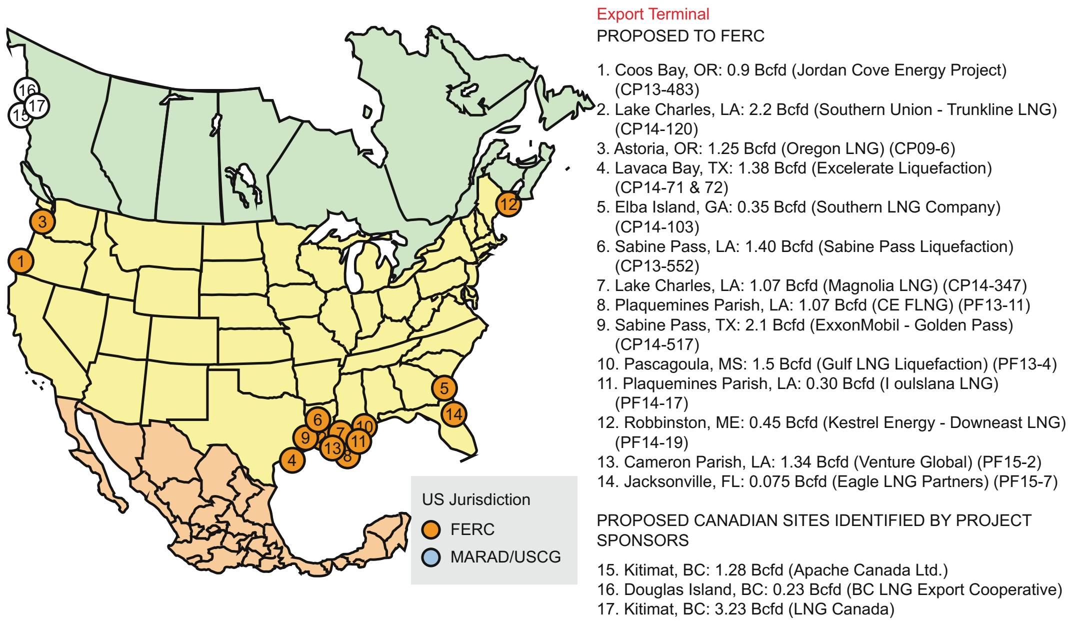

Fig. 17.18 Proposed LNG export terminals in North America, February 2015. *Source* US Federal Energy Regulatory Commission

exceptional cases. In recent periods, oil prices have dropped, and long-term oil price trends are uncertain, with recent Henry Hub prices seeing multiple record lows, highlighting the relative risk of US LNG supply and supplies whose prices are linked to oil.

Even though natural gas pricing mechanisms are trending further toward competitive pricing, the formation of a global unified price is still impossible. However, the growth in inter-regional natural gas trade volume, as well as rises in trading hub or spot market natural gas sales volumes, are prompting the formation of regional markets based on the original national foundations, for example in Europe.

Even if trade and competitive pricing were to promote the formation of a globalised natural gas market, regional prices are likely to continue to exist, and inter-regional price variance could even exceed shipping costs. The reason for this is that natural gas regional demand and supply is often imbalanced: large consumers are not large producers, resulting in the signing of long-term contracts to reduce energy security issues and the potential concentration of market forces. Likewise, formation of a global unified price is not possible, since the flexibility of global trade capabilities is likely to be insufficient, and will be unable to satisfy trade demands that can change at any time. Finally, the potential for economically recoverable unconventional natural gas remains unknown, but if it were to be unlocked at a low cost, as seen in the United States, the volume generated would be more likely to influence prices in the immediate region of the supply rather than in other regions.

17.4.2 The Relationship Between the Price of Natural Gas and the Price of Oil

Natural gas, whether delivered over pipelines or as LNG, has historically been priced based on competing fuels in the receiving markets and supplied under long-term agreements. Examples include exports from the Groningen natural gas field in The Netherlands, where pricing adjustments are tied to the market price of three major types of fuel, or LNG imports to Japan, which are

LNG Sale and Purchase Agreements (SPAs)
Sabine Pass Liquefaction

~20 mtpa "take-or-pay" style commercial agreements
~$2.9B annual fixed fee revenue for 20 years

	BG Gulf Coast LNG	Gas Natural Fenosa	Korea Gas Corporation	GAIL (India) Limited	Total Gas & Power N.A [6]	Centric plc [6]
Annual Contract Quantity (MMBtu)	286,500,000 [1]	182,500,000	182,500,000	182,500,000	104,750,000 [1]	91,250,000
Annual Fixed Fees [2]	~$723 MM [3]	~$454 MM	~$548 MM	~$548 MM	~$314 MM	~$274 MM
Fixed Fees $ / MMBtu [2]	$2.25 - $3.00	$2.49	$3.00	$3.00	$3.00	$3.00
LNG Cost	115% of HH	115% of HH	115% of HH	115% of HH	115% of HH	115% of HH
Terms of Contract [4]	20 years	20 years	20 years	20 years	20 years	20 years
Guarantor	BG Energy Holdings Ltd.	Gas Natural SDG S.A	N/A	N/A	Total S.A.	N/A
Corporate / Guarantor Credit Rating [5]	A- / A2 / A-	BBB / Baa2 / BBB+	A+ / A1 / AA-	NR / Baa2 / BBB-	AA- / Aa1 / AA	A- / A3 / A-
Fee During Force Majeure	Up to 24 months	Up to 24 months	N/A	N/A	N/A	N/A
Contract Start	Train 1 + additional volumes with Trains 2,3,4	Train 2	Train 3	Train 4	Train 5	Train 5

(1) BG has agreed to purchase 182,500,000 MMBtu, 36,500,000 MMBtu, 34,000,000 MMBtu and 33,500,000 MMBtu of LNG volumes annually upon the commencement of operations of Trains 1, 2, 3 and 4, respectively. Total has agreed to purchase 91,250,000 MMBtu of LNG volumes annually plus 13,400,000 MMBtu of seasonal LNG volumes upon the commencement of Train 5 operations.
(2) A portion of the fee is subject to inflation, approximately 15% for BG Group, 13.6% for Gas Natural Fenosa, 15% for KOGAS and GAIL (India) Ltd and 11.5% for Total and Centrica.
(3) Following commercial in service date of Train 4. BG will provide annual fixed fees of approximately $520 million during Trains 1–2 operations and an additional $203 million once Trains 3–4 are operational.
(4) SPAs have a 20-year term with the right to extend up to an additional 10 years. Gas Natural Fenosa has an extension right up to an additional 12 years in certain circumstances.
(5) Ratings are provided by S&P/Moody's/Fitch and subject to change, suspension or withdrawal at anytime and are not a recommendation to buy, hold or sell any security.
(6) Conditions precedent must be satisfied by June 30, 2015 or either party can terminate. CPs include financing, regulatory approvals and positive final investment decision.

CHENIERE

Fig. 17.19 Sabine Pass LNG sale and purchase agreement structure. *Source* Cheniere Energy Inc

priced based on Japan Crude Cocktail prices, an amalgamation of oil prices that is generally defined within individual contracts.

For many years, natural gas contracts have been indexed to the oil price; when the oil price changes, the price paid for natural gas changes as well, using a preset formula. Until about 2008, the link has led to a close correlation between natural and oil two prices (Fig. 17.21). The link loosened in periods when oil price showed high volatility, such as the oil crises, and natural gas contracts tended to be renegotiated. Anticipating a need to rebalance the long-term agreements, some natural gas contracts included clauses allowing price formulas to be reviewed based on an established set of factors.

The connection between oil and natural gas prices started to loosen in 2008, typified by the divergence of Henry Hub prices from oil prices. The separation was partly a result of the US recession and a boom in unconventional natural gas supplies in the United States, which meant

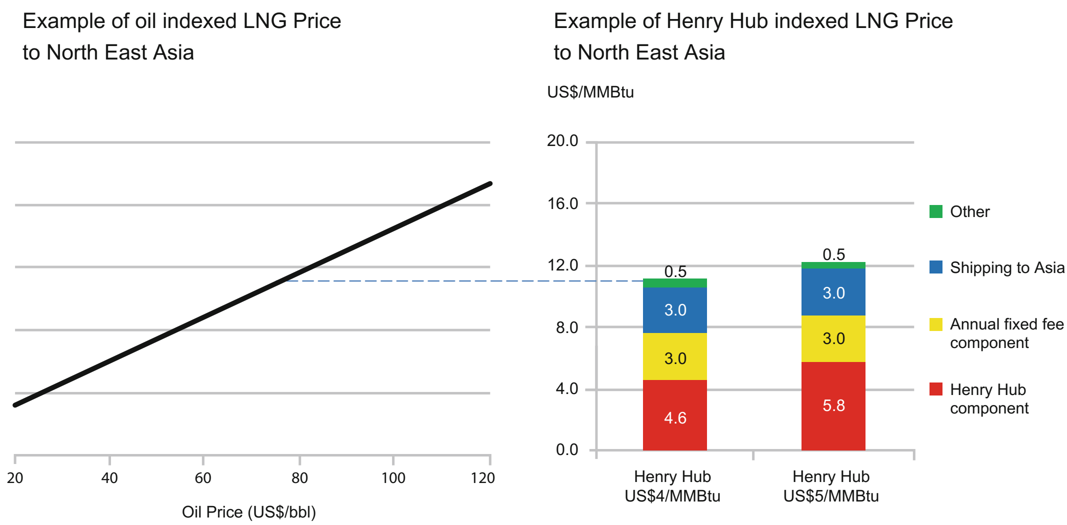

Fig. 17.20 Henry Hub natural gas prices could be higher than natural gas prices linked to oil prices

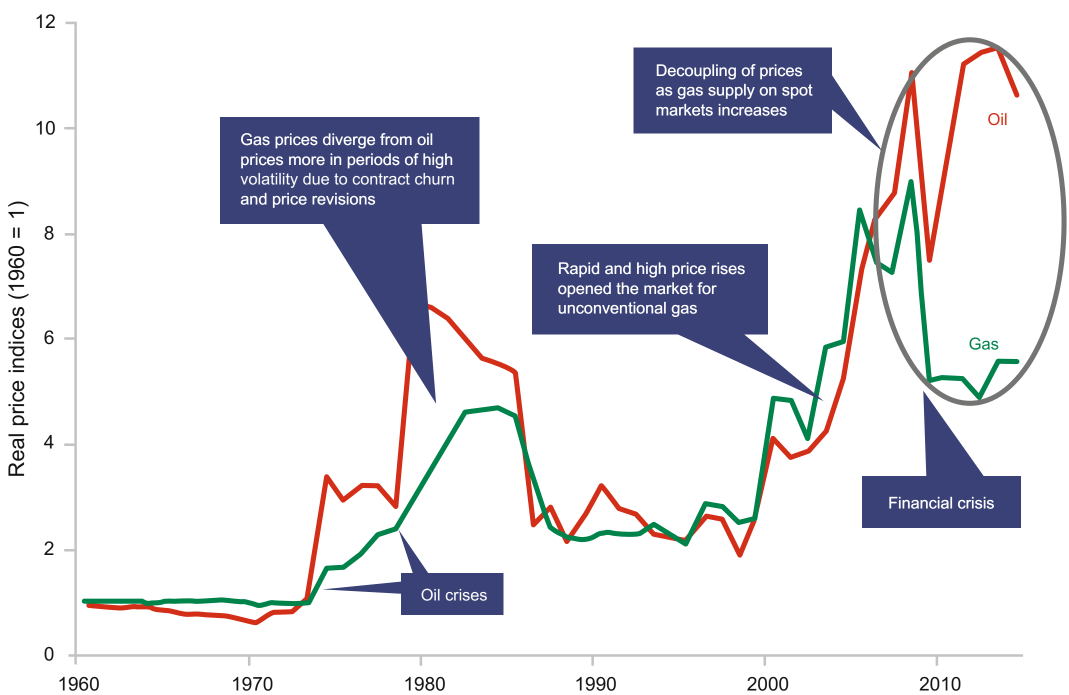

Fig. 17.21 The relationship between natural gas price and oil prices. *Note* Data are indexes of global average prices. *Source* Vivid Economics, based on World Bank data

that the country no longer needed significant LNG imports. In Europe, an economic downturn also triggered decreased natural gas demand, leading to ample supplies, which were increasingly purchased through the natural gas hubs without any link to oil prices.

Recently, the possibility of Russian natural gas supplies that pass through Ukraine being disrupted added market volatility, but prices recovered even as the supply to Europe was reduced. Interestingly, the supply reduction was linked largely to LNG imports to Europe, rather than Russian pipeline deliveries. Strong demand for LNG in Asia-Pacific created arbitrage opportunities, and LNG delivered to European buyers was reloaded by the buyers for sale in Asia-Pacific. Faced with low gas index prices, low demand, or both, buyers in Europe chose to profit by selling to Asia-Pacific buyers at higher prices. The arbitrage opportunity disappeared as oil prices and European natural gas hub prices fell.

Historically, four rationales have supported the need for linking natural gas contracts to the price of oil:

- **Benchmark price**: Natural gas exploration, production and transport are capital-intensive and the industry often requires long-term contracts. To share the risk between buyer and seller, the contract prices generally vary according to a benchmark, and the oil price has provided a transparent and robust benchmark. Also, many of the costs of natural gas development—for example, drilling rigs and skilled labour—are comparable in both oil and natural gas production, and these costs are affected by oil prices. However, in some markets the fundamentals for pricing oil and natural gas have diverged. For instance, in the United States and parts of Europe, sufficiently deep and liquid natural gas benchmarks have become available.
- **Co-production**: Natural gas has been a by-product of oil extraction and sold on similar terms. Exclusive natural gas extraction, however, is becoming more common, even though co-production remains important. In the United States, for example, natural gas is a by-product of shale oil production. Low natural gas prices in the US market are partially a result of high oil prices, which have offered significant incentives to shale projects. The low natural gas prices may not be sustainable or easily replicated outside the United States.
- **Similar routes to market**: Natural gas and oil have similar transport infrastructure, and the same companies have tended to deliver both because of their expertise, market dominance or both. However, natural gas infrastructure has increasingly become more independent.
- **Competition for customers**: Natural gas and oil products were used for power generation and heating, and natural gas was often priced just lower than oil to compete. However, oil products are increasingly used only used for transportation, with other fuels used for power generation.

As markets have evolved, however, only one of these reasons—the need for a transparent benchmark—remains relevant, but even here in some markets natural gas hubs are now more able to provide a natural gas benchmark.

The fundamental economic rationale for the link between natural gas and oil prices is whether the economic drivers behind the value of oil are similar to those behind the value of natural gas. When oil and natural gas were substitutes—for example when they were both used in power generation—this was often true, and their value would change at the same rate. Now, however, oil is primarily used for transportation, and natural gas is not. The value the market puts on these two fuels is often driven by different forces, so the price of oil no longer reflects the value of natural gas as accurately. Because the uses for natural gas and oil and their production costs have largely diverged, the fundamental economic rationale for a price link is unlikely to be re-established, especially in markets in which natural gas benchmarks are emerging.

17.4.3 Chinese Pricing Mechanisms

China's natural gas is derived from domestic natural gas, imported LNG and imported pipeline natural gas from countries of the former Soviet Union. The different treatment of these resources from different source results in a three-strand pricing mechanism:

- **Domestic natural gas**: Price is determined on a cost-plus basis.
- **Imported LNG**: Contract prices and linked to Japan Crude Cocktail prices, with an S-curve-based ceiling mechanism that limits exposure to oil price movements.
- **Imported pipeline natural gas**: In a pricing mechanism that the IGU has called a "bilateral monopoly", price is based on intergovernmental negotiations and entails significant uncertainty.

The differences inherent in China's pricing structure have already caused a series of market convergence problems, especially in periods when oil prices are high.

Experience from North America and Europe suggests that prices for imported natural gas or LNG can be based on a natural gas index that reflects the supply and demand of the recipient region or country. A relevant natural gas index is only possible, however, if the participants, infrastructure and regulations are in place to form a natural gas hub that is liquid, transparent and widely used. The natural gas index must also be acceptable to financial institutions, which supply credit to developers and buyers. Once in place, a Chinese natural gas index could provide the necessary price signals to attract additional imports as required. Although natural gas market reforms in China continue to gather momentum, international experience suggests that a natural gas hub is not likely to develop soon and intermediate measures may be needed in the interim.

As China continues to reform its natural gas market, pricing mechanisms will need to be allowed to evolve. As an interim measure, the current practice of offering end users natural gas at prices based on the prices of competing fuels can continue. However, this approach exposes importers, especially LNG importers, to risk. LNG imports to China would continue to be driven by global supply and demand factors, and China would have to compete with other buyers on the market. During this time, oil-indexed contracts would continue, at the same time as LNG deals linked to Henry Hub prices gain momentum. If the market is allowed to open further to competition, the mismatch between imported natural gas prices and end-user prices should narrow.

17.4.4 The Influence of Chinese Demand on the World Market

This section analyses the influence of China's natural gas consumption on global energy markets. We will explore three scenarios for Chinese demand: the first where there are no new policies to reduce consumption or stimulate natural gas consumption, and then two scenarios that feature increasing substitution of natural gas for coal, both in the power sector and in the wider economy.

The key findings from the modelling are:

- **Natural gas prices**: Flexible global natural gas supply would dampen any increase in domestic natural gas prices if higher natural gas demand in China put upward pressure on domestic prices.
- **Coal consumption**: Lower Chinese coal consumption would be largely offset by increased coal use in other countries, unless those countries adopt similar policies.
- **Domestic coal**: Policies that encourage only the power sector to reduce coal consumption could result in lower coal prices and a switch to coal from natural gas in industries not covered by the low-carbon policies. Policies aimed at reducing domestic coal production should have broad applicability in order to have the greatest impact.

1. **The three policy scenarios**

Three scenarios for China were developed to illustrate the effects of a reduction in domestic coal consumption—for power generation and for industrial use more widely—and to analyse how readily natural gas could be substituted for coal and what impact these changes would have on global energy markets. These three scenarios (Baseline, Power Generation Sector and All

Sectors) simulate the effects of varying degrees of restriction on coal consumption in China. Each scenario differs in the stringency of the restriction, as well as the sectors that are targeted.

- **Baseline scenario**: China does not introduce any new policy measures aimed at reducing coal consumption or stimulating natural gas consumption. Coal-fired generation capacity in the power sector continues to grow at historical rates for the duration of the 13th Five-Year Plan, from 2016 to 2020. It continues to grow steadily, albeit at a slightly slower rate, after that. This scenario is broadly consistent with recent IEA and EIA analysis. However, given the momentum for change in China's energy policy, it should be viewed as a useful baseline against which to compare the impact of the other two scenarios, rather than a realistic future pathway. For example, the scenario does not take into account current commitments to LNG projects.
- **Power Generation Sector scenario**: China restricts coal consumption in the power sector, reducing investments in coal-fired generation capacity and increasing the effective price of coal for power generation. This scenario is very similar to current policy trends in China, and thus is considered to be the most realistic.
- **All Sectors scenario**: China restricts coal consumption in the power sector, similar to the Power Generation Sector scenario, but extending the restrictions to other sectors of the economy, reducing investment in all coal-intensive capital stock and raising the effective price of coal economy-wide.

2. **The impact on Chinese energy supply and demand**

Restrictions on coal use would raise the effective price of coal and reduce incentives for coal-intensive investments. Coal consumption would peak in 2020 under the Power Generation Sector scenario and in 2018 under the All Sectors scenario. The later peak in the Power Generation Sector scenario reflects the leakage of coal use from the power sector to other sectors of the economy, most notably manufacturing, that would result from restricting coal use only in the power sector.

The decline in coal consumption would be accompanied by an increase in the consumption of natural gas and electricity. Under both the Power Generation Sector and All Sectors scenarios, the share of natural gas in China's energy mix would rise by 2030—to 17% in the Power Generation Sector scenario and to 21% in the All Sectors scenario (Fig. 17.22). The share of natural gas in the power sector would rise to around 15% in both scenarios. Against a backdrop of rising energy demand overall, this would translate into a 70% increase in natural gas consumption in the Power Generation Sector scenario over the Baseline scenario and a 100% increase in the All Sectors scenario.

China's domestic natural gas production would remain below consumption levels in both the Power Generation Sector and All Sectors scenarios, despite an assumed tripling in domestic production by 2030. As a result, the share of natural gas imports in total consumption is estimated to rise to around 50% by 2025 in both scenarios. Given current and planned future pipeline capacity, the LNG share of natural gas imports is estimated to rise to more than 50%. The consumption/production gap would be larger in the All Sectors scenario, where LNG imports are estimated to account for 73% of total natural gas imports.

Restricting coal use only in the power sector (as in the Power Generation Sector scenario) would lead to a leakage of coal use to other sectors, leading to natural gas-to-coal substitution in these sectors. In turn, this would benefit other coal-intensive sectors of the economy, such as manufacturing, as lower coal demand in the power sector would place downward pressure on the price of coal paid by other sectors. On the other hand, an increase in natural gas demand for power generation would place upward pressure on the domestic price of natural gas, putting other gas-intensive sectors, such as residential heating, at a disadvantage because their main substitutes for natural gas are electricity and oil.

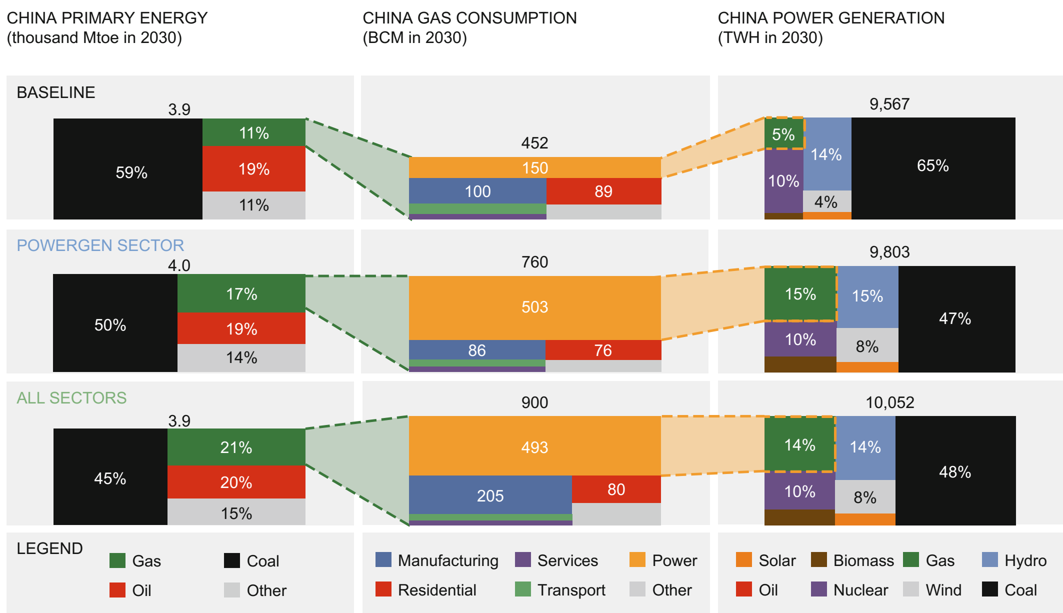

Fig. 17.22 China's 2030 energy mix, natural gas consumption and power generation energy mix, by scenario. *Source* Aurora Energy Research, Global Energy Model

3. The impact on the global energy market

The IEA estimates that emerging economies like China will account for most of the growth in global energy demand over the next two decades, and changes to the energy policies and the energy mix in these economies will have implications for global energy markets. Overall, the modelling indicates that while global coal consumption remains relatively unchanged, natural gas consumption would increase in the Power Generation Sector and All Sectors scenarios (Fig. 17.23).

(I) Impact on coal consumption

In the Power Generation Sector and All Sectors scenarios, decreased coal use in China depresses the coal price enough to stimulate coal consumption elsewhere, leaving total coal consumption largely undiminished at the global level. Both scenarios result in a decrease in Chinese coal consumption, with a greater reduction in the All Sectors scenario than in the Power Generation Sector scenario. However, total global coal consumption by 2030 remains relatively undiminished and roughly the same in both scenarios. This is because global coal supply is relatively price-inelastic, that is, supply is relatively unresponsive to falling demand and hence falling prices. While the reduction in Chinese coal demand would put downward pressure on the coal price, this would not lead to a significant reduction in price. Cheaper coal prices, on the other hand, would lead to increased coal consumption in other countries without similar restrictions on coal use.

Overall, in the Power Generation Sector scenario 96% of the decrease in China's coal consumption is offset by an increase elsewhere, while in the All Sectors scenario 89% of the decrease is offset. One reason for the difference between the two scenarios is the nature of trade flows in the coal market in each scenario. In the Power Generation Sector scenario, some of the coal that would have been imported by China compared to the Baseline scenario would no longer be needed and instead would be consumed closer to its source. In the All Sectors scenario, however, both domestic coal production and coal imports would

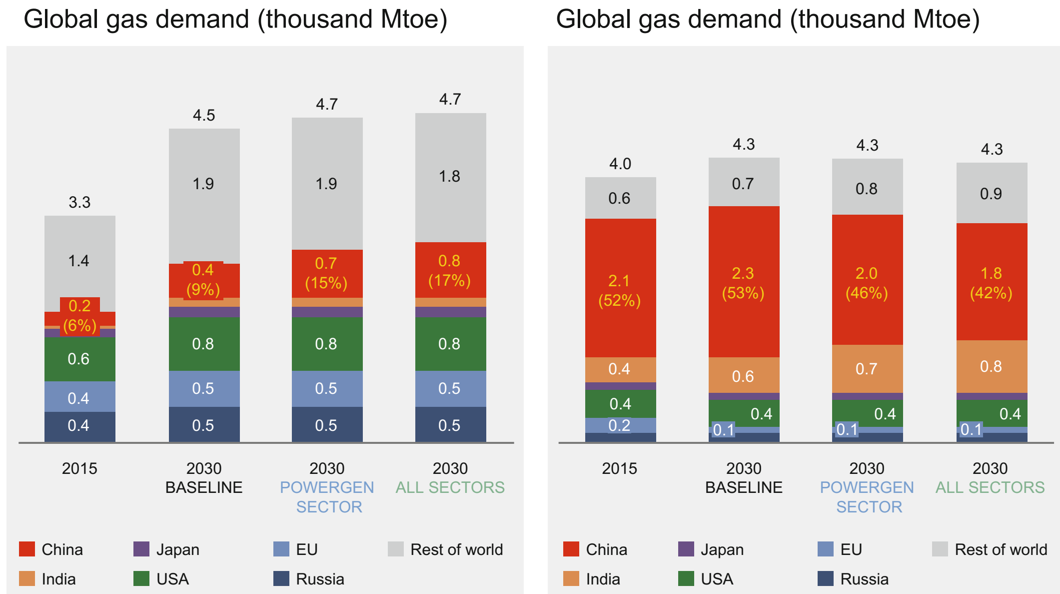

Fig. 17.23 Global natural gas and coal demand, by region and scenario. *Source* Aurora Energy Research, Global Energy Model

be displaced, and China would become a net exporter of coal by 2025. However, countries that consume China's surplus coal production would incur transportation costs, leading to a smaller share of China's coal consumption leaking to other countries.

The coal leakage effect would be driven purely by the economics of lower coal prices—neither the Power Generation Sector nor the All Sectors scenario assumes comparable coal reduction policies in other parts of the world. This effect would be limited if comparable coal restrictions were also in place in other Asian countries. A key implication of this result is that, given the interconnected nature of global energy markets, a meaningful reduction in global coal consumption can only be achieved through a concerted international policy effort.

(II) **Impact on natural gas consumption**

In contrast to coal, natural gas supply is relatively price-elastic, that is, global natural gas supply increases in response to rising demand and rising prices. The supply response mitigates some of the increase in price, resulting in only a modest increase in natural gas hub prices.

Restrictions on coal use in both the Power Generation Sector and All Sectors scenarios would drive substantial substitution away from coal and towards natural gas in China. The higher demand would be met by production from many different geographical regions, including a significant increase in domestic production (Fig. 17.24). The rising share of LNG to meet domestic consumption would push domestic natural gas prices higher, nearing Japanese LNG prices, which would stimulate domestic production.

The modelling indicates that, while increasing Chinese natural gas demand would put some upward pressure on natural gas prices, natural gas-intensive countries like the United States would not decrease consumption substantially in response. Thus global natural gas demand overall would be higher under both the Power Generation Sector and All Sectors scenarios, and the consumption decrease outside China would only be enough to offset about 42% of the increase seen within China.

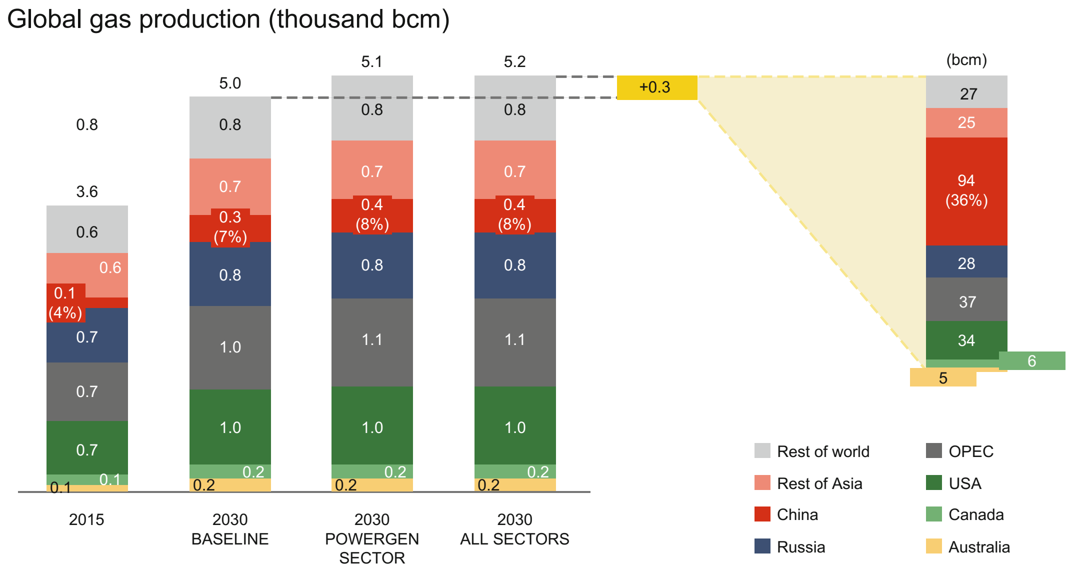

Fig. 17.24 Trends in global natural gas production by region and scenario. *Source* Aurora Energy Research, Global Energy Model

(III) Impact on primary energy consumption

Both the Power Generation Sector and All Sectors scenarios indicate a net increase in global energy consumption (Fig. 17.25). The world's overall energy bundle would effectively become cheaper as the coal price would drop by more than the increase in the natural gas price. The decline in coal consumption in China would be offset by increased coal consumption elsewhere and the increase in natural gas consumption in China would not be offset. Moreover, in China, higher total primary energy consumption would be driven by substituting coal with electricity.

(IV) Changes in energy prices

Substituting natural gas for coal in China would have a large effect on global coal prices and a relatively small effect on global natural gas prices. Global coal prices in 2030 would be lower in both the Power Generation Sector and the All Sectors scenarios compared to the Baseline scenario. In the Power Generation Sector scenario, the difference would be 15% or $12/tonne and in the All Sectors scenario, 26% or $20/tonne (Fig. 17.26). The main drivers for the significant drop in global coal price would be China's exceptional position as the largest consumer in the international coal market—China currently consumes more than half of the world's coal—and the high degree of global integration in the coal market.

Natural gas prices everywhere would increase as a result of rising Chinese natural gas demand, but this increase would be very modest at the major international natural gas hubs: a 3% price increase on average in 2030 across three major natural gas hubs: the NBP in the United Kingdom, the Henry Hub in the United States and the LNG import price in Japan (Fig. 17.27). In all three scenarios, there would be considerable convergence between these hub prices, as global LNG trade increases substantially and average LNG transport costs fall. For instance, the difference between Japanese LNG prices and the Henry Hub price would fall from just more than $12/MMBtu in 2015 to $7–8/MMBtu in 2030, as long-run East Asian LNG prices become broadly equivalent to the Henry Hub price, plus transport costs.

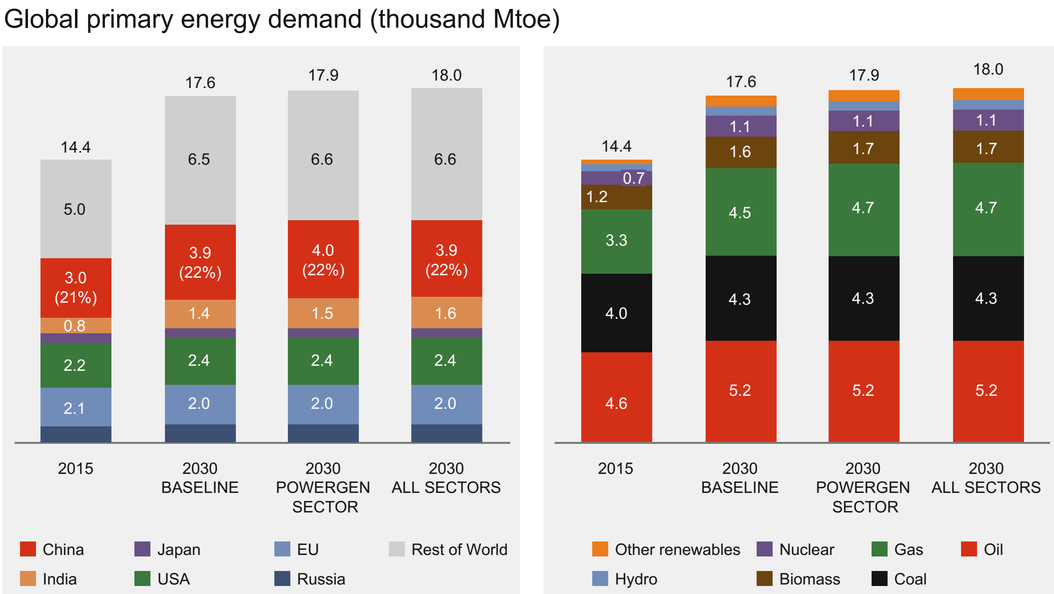

Fig. 17.25 Global primary energy demand 2015–2030 by region and scenario. *Source* Aurora Energy Research, Global Energy Model

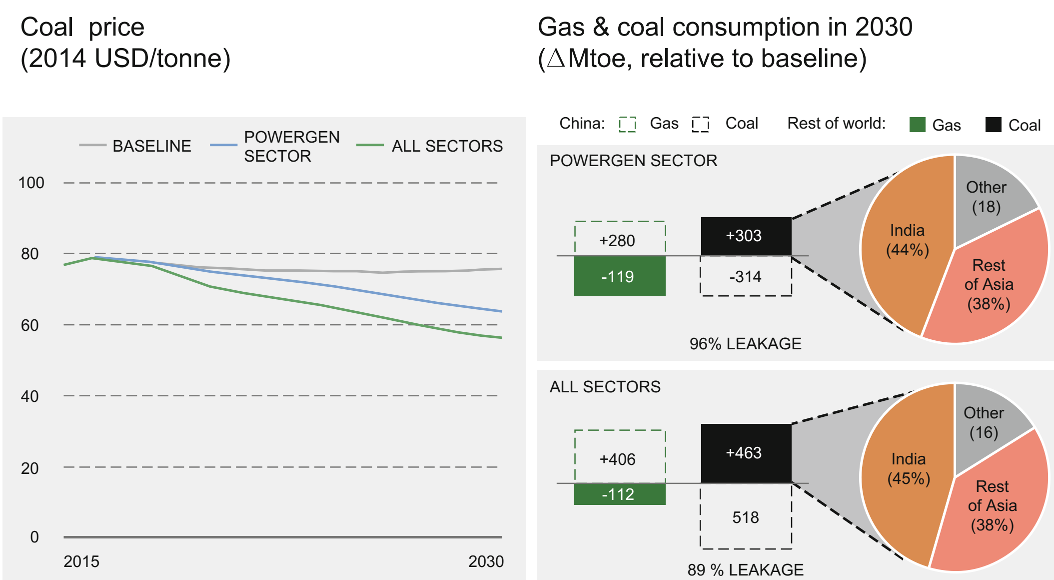

Fig. 17.26 Decline in China's coal demand and leakage of capacity. *Note* Price references ARA 6000 kcal per kg coal. From 2015 to 2018, displayed prices reference current futures prices. *Source* Aurora Energy Research, Global Energy Model

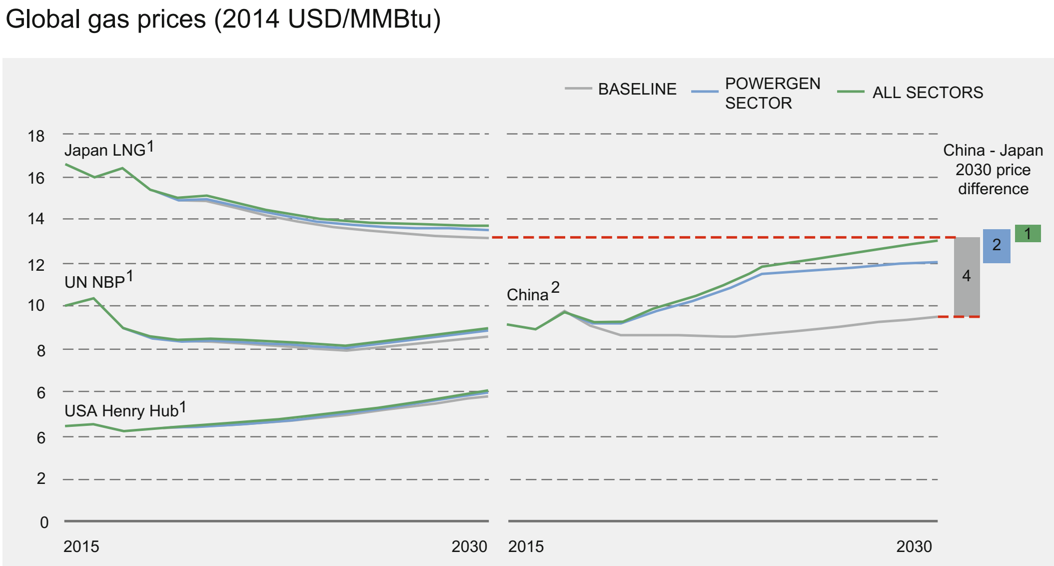

Fig. 17.27 Global natural gas hub price change trend forecasts. *Notes* (1) For 2014–2018, prices shown take into account current futures prices (as of December 12, 2014, converted to real 2014 US$). (2) For China, this is a weighted average producer gas price index (domestic, pipeline, LNG), which equates supply and demand in the AER-GLO model. It includes regasification costs for LNG. Weightings are based on the standard Armington assumption governing trade in CGE model. As a consequence, this figure will not necessarily match wholesale prices at any particular region in the Chinese market. *Source* Aurora Energy Research, Global Energy Model

The increase in global natural gas prices would be much smaller than the decrease in global coal prices for several reasons:

- The increase in Chinese natural gas consumption would be slightly less than the decrease in Chinese coal consumption because there would be some substitution from coal to non-natural gas fuels in China.
- China is a larger player in global coal markets than in natural gas markets, and its decisions linked to coal would have greater implications for global markets.
- Global trade in natural gas is much smaller than that in coal, partly because the rigidity of pipeline supply and the high transport costs for LNG restrict global trade flows.
- Global natural gas supply is more price-elastic than global coal supply, and natural gas production would increase to meet higher demand, while coal production would not fall significantly, creating excess supply and lower prices.

However, domestic natural gas price in China would rise more substantially in both the Power Generation Sector and All Sectors scenarios. By 2030, domestic prices would reach $12/MMBtu in the Power Generation Sector scenario and $13/MMBtu in the All Sectors scenario, compared to between $8/MMBtu and $10/MMBtu in the Baseline scenario. The reason for the disproportionate effect on prices in China is that as China starts substituting natural gas for coal, the increase in natural gas consumption would be made possible by increased natural gas imports, LNG in particular. As a result, natural gas prices in China would converge towards the East Asian LNG price.

4. **A description of the model**

The simulations of three possible energy scenarios for China were based on the Aurora Energy Research global energy model, which is a hybrid of the computable general equilibrium

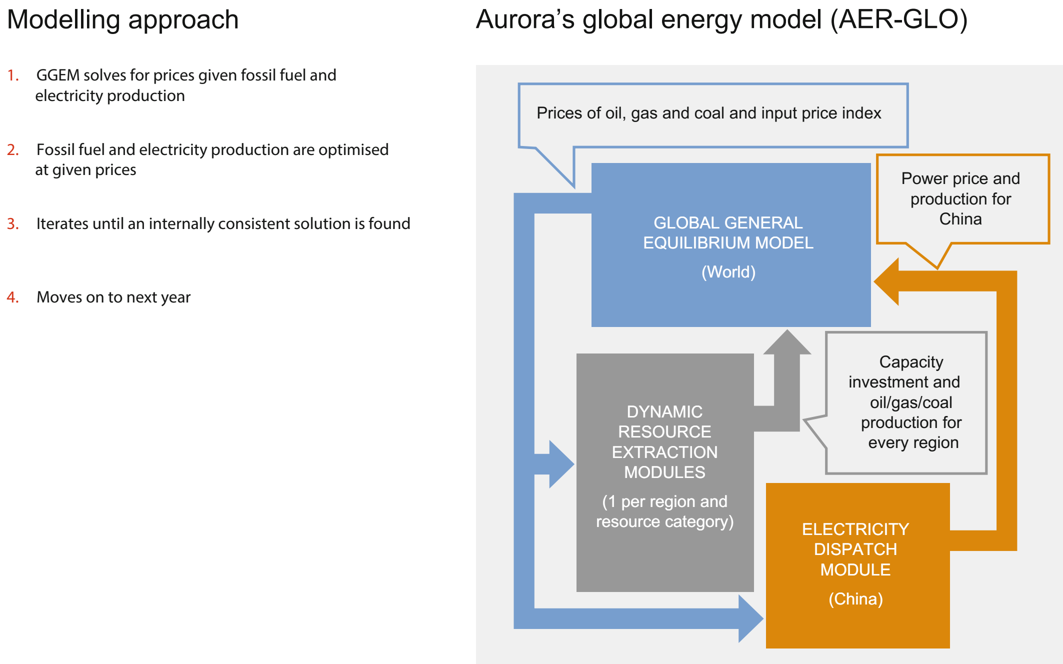

Fig. 17.28 Hybrid computable general equilibrium (CGE) model used by Aurora for global modelling. *Source* Aurora Energy Research, Global Energy Model

model that the company had created to analyse global energy markets.

The model drew from three key building blocks: a global general equilibrium module to represent energy demand and economic activity in all countries, a number of dynamic resource extraction modules to model the supply of oil, natural gas and coal in a dynamic financial setting; and an electricity dispatch module, which emulates the Chinese power sector (Fig. 17.28). The model lets all three modules solve iteratively in each year until an internally consistent solution across all three is found in every year. The hybrid structure combined the benefits arising from the robust structure of global general equilibrium models with the added detail of partial-equilibrium models of fuel extraction and electricity dispatch. Both types of modelling approaches are essential for understanding global energy markets.

The model was used to forecast the impact of energy policy changes on the global economy, as well as individual sectors. In addition, with 129 regions globally and 57 sectors within each region, the model could produce outputs that included country- and industry-specific forecasts of demand and supply of all goods and services, changes in imports and exports, gross regional product, consumption, investments, returns to capital and emissions of greenhouse natural gases and particulate matters.

For this study, the model was calibrated against recent economic and energy data, and envisioned three illustrative energy policy scenarios, in which key Chinese policy parameters relating to coal consumption were changed. These scenarios simulate plausible changes in China's energy policy environment and the effects these are likely to have on global coal and natural gas markets.

A global general equilibrium structure was necessary for modelling the global markets for fuels because of the intimate linkage between energy and future developments in modern economies, the substitutability between different fuels in final energy use, and the uneven distribution of resources across the world. As a result, the impact of China's energy policy on global energy markets provided by the model were driven to a large extent by the interaction of different markets under equilibrium and the resulting substitution between fuels in all geographical regions in the model.