Coal and gas competition in global markets

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Abstract

Global consumption of commercial energy totalled 18 Gt of coal equivalent in 2010. With a 28% share, coal ranked second after oil as one of the major sources of primary energy and natural gas (at 21%) ranked third. Gross power generation with coal was approximately 41% and gas 22%. Natural gas as a global commodity is growing rapidly with the advent of unconventional sources such as shale gas. Recently, gas has become the fuel of choice for new power generating plants in some countries. Overall production of coal has increased in the same time-frame. The share of coal in electricity production was constant in Europe from early 2000 but recently increased. This was due to the high cost of gas in Europe and a low emissions penalty levied by the regulator, making coal currently more competitive in Europe compared to gas. Coal utilisation continues to increase in Asia but is facing serious competition with gas in the USA, where the share of electricity generated with coal dropped in 2012. However, natural gas used to generate electricity in early 2013 was below the high level seen during the comparable 2012 period, when low natural gas prices led to significant displacement of coal by natural gas for power generation. The current consensus in the USA is that while coal may recover ground in the short term, it loses in the long term as coal plants are retired. The discovery, production and availability of significant amounts of gas have implications for not only the price of natural gas but also the price of coal as well as supply and demand, and utilisation of both fuels internationally. The interaction between coal and gas in the global markets today is investigated in this review and the near-term outlook and impact on both fuels is presented. In this report, reserves, production and trade, supply and demand, pricing, utilisation and consumption, public attitudes and finally near/short to medium-term prospects are discussed for both coal and gas.

Acronyms and abbreviations

BP	British Petroleum (Global)
C2ES	Center for Climate and Energy Solutions (USA)
CAPP	Canadian Association of Petroleum Producers (Canada)
CBM	coalbed methane
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CIS	Commonwealth of Independent States
CHP	combined heat and power
CNG	compressed natural gas
CNPC	China National Petroleum Corporation (China)
DECC	Department of Energy & Climate Change (UK)
EC	European Commission
EEA	European Environment Agency (Belgium)
ETS	Emissions Trading Scheme
EU	European Union
EURACOAL	European Association of Coal and Lignite (Belgium)
FOB	free on board
FYP	Five Year Plan (China)
GCV	gross calorific value
GDP	gross domestic product
GHG	greenhouse gases
IEA	International Energy Agency (France)
IED	Industrial Emissions Directive
IPCC	Intergovernmental Panel on Climate Change
LCPD	Large Combustion Plants Directive
LNG	liquid/liquified natural gas
Mtce	million tonnes coal equivalent
Mtoe	million tonnes oil equivalent
Mt/y	million tonnes per year
MWD	measurement while drilling
O&M	operation and maintenance
OECD	Organisation for Economic Co-operation and Development
NCV	net calorific value
NEA	National Energy Administration (China)
NEB	National Energy Board (Canada)
NETL	National Energy Technology Laboratory (USA)
NDRC	Energy Research Institute of National Development and Reform Commission (China)
NGSA	Natural Gas Supply Association (USA)
NPD	Norwegian Petroleum Directorate (Norway)
PDFG	Pedro Duran Farell Gasline (Algeria)
PWC	Price Waterhouse Coopers LLP (USA)
R/P	reserve to production ratio
SETIS	Strategic Energy Technologies Information System (Belgium)
US EIA	Energy Information Administration (USA)
US DOE	Department of Energy (USA)
WCA	World Coal Association (UK)
WEC	World Energy Council (UK)

Contents

1 Introduction

In 2010, global consumption of commercial energy totalled 18 Gt of coal equivalent. With a 28% share, coal ranked second after oil as one of the major sources of primary energy and natural gas, at 21%, ranked third. Gross power generation with coal was approximately 41% and gas 22% (*see* Figure 1).

Fossil fuels, including coal and gas, are and will continue to hold the largest share of world total electricity generation capacity, in both the short and medium term. Of the 53% fossil fuel based electricity generation in Europe: 23% is based on natural gas, 16% on hard coal, 11% on lignite and 3% on fuel oil. On a global scale, fossil fuel power generation provides more than 60% of the world's electricity output, of which 42% is coal based. In the USA, 40% of power generation today is based on natural gas firing. Fossil fuel based power generation is also a major contributor to CO_2 emissions.

Natural gas as a global commodity is growing rapidly with the advent of unconventional sources such as shale gas. In recent years gas has become the main choice of fuel for new power generating plants. Overall production of coal has increased in the same time-frame. The share of coal in electricity production was constant in Europe from early 2000. However, this recently increased due to the cost of gas and low emissions penalty levied by the regulator, making coal currently more competitive in Europe, compared to gas. Coal utilisation continues to increase in Asia but is facing serious competition with gas in the USA where the share of electricity generated with coal dropped dramatically in early 2012. However, natural gas used to generate electricity in early 2013 was below the high level which occurred during the comparable 2012 period, when low natural gas prices led to a significant displacement of coal by natural gas for power generation. The current consensus in the USA is that while coal may recover ground in the short term, it loses in the long term as coal plants retire. The discovery, production and availability of significant amounts of gas have implications for the price of natural gas, the price, availability and utilisation of both fuels internationally and for future trends in environmental regulations. The interaction between coal and gas in the global markets today will be investigated in this report and the near-term outlook and impact for both fuels will be presented.

Coal and natural gas have the largest share in the energy mix, particularly for electricity generation, internationally. Coal has been a reliable fuel that has proven abundant in regional supply. Its importance has also grown for energy security reasons. A remarkable increase in the share of natural gas has occurred since the 1990s. Conventionally, switching from coal to natural gas for power generation would benefit the environment by producing less air pollutant and greenhouse gas emissions. However, although there are numerous such conversions, security of supply and fuel mix policies as well as disparity in the availability of natural gas from region to region, are forecast to result in the continued utilisation of coal as a source of energy not only for power generation but also for industry.

It is estimated that there are over 847 Gt of proven coal reserves worldwide. At current production rates this equates to ~118 years availability. Coal reserves are available in almost every country in the world, with recoverable reserves in about 70 countries. The largest reserves by region are in North America, the former USSR, China and India. At current production levels the world had approximately 187 trillion m^3 of proven gas reserves in 2010. This was considered sufficient for 59 years of production, at the then current levels. Unconventional gas, such as shale gas and coalbed methane, remain to be appraised, in detail, globally. However, current estimates suggest that they could double the existing reserves to production (R/P) ratio. Russia is the main conventional gas resource-holder and remains the largest gas producer and exporter. Reserves and production of coal and gas are discussed in Chapters 2 and 3.

Supply and demand are fundamental factors that impact competition between coal and gas on a global

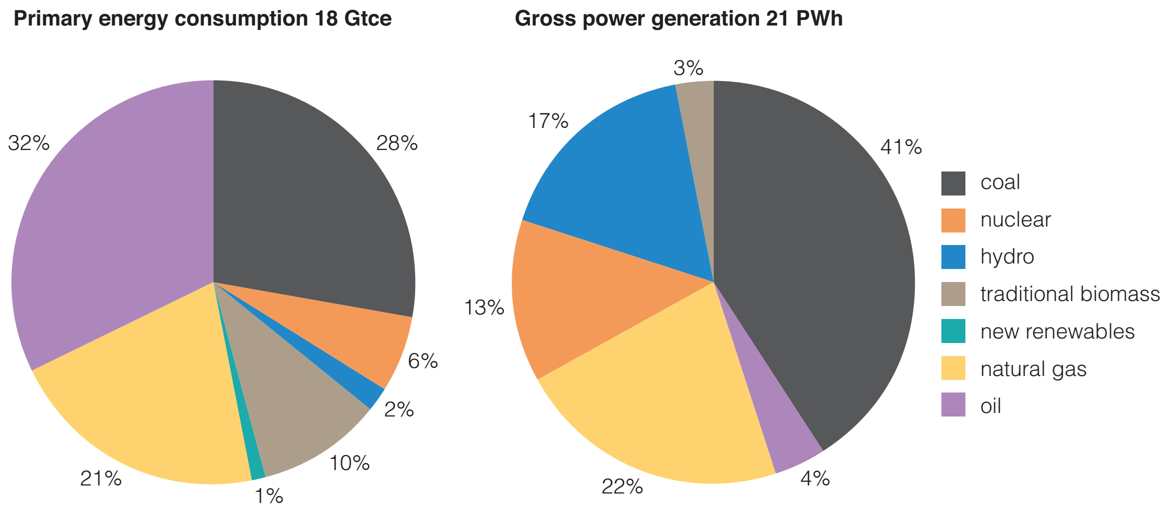

Figure 1 Global primary energy mix and global power generation by primary energy source, 2010 (EURACOAL, 2011)

scale. The marketplace forces of supply and demand decide the price of fuel, which, among other factors, plays a key role in determining the mix of fuels used for electricity generation as well as industry. Maintaining a balanced demand and supply of energy resources is also an important aspect of national energy policy and strategy. Chapter 4 examines the current status and the future trend of supply and demand of coal and gas in major coal/gas consuming nations and regions.

The relative pricing of coal and natural gas is a key factor in determining the competitiveness of and, therefore, the share of either fuel in the overall energy mix in any given market. More importantly, fuel prices can play a major role in decision making with regard to what type of new capacity is to be built. Chapter 5 first gives a brief review of the price trends of coal and natural gas worldwide, focusing on Europe and North America, where coal and natural gas are more likely to compete as the fuel for power generation. Secondly, the question of how electricity utilities decide on generation despatching and building new generation capacity is discussed, with the UK as a typical example of competitive electricity markets.

Although this review discusses competition only between coal and gas, it is worthwhile presenting briefly the situation with regard to nuclear power as it can have a considerable effect on the demand for natural gas and coal for the power sector. Following the Fukushima accident in Japan in March 2011, many governments have reviewed the safety of existing facilities and plans for new nuclear installations. The EU announced plans to stress test all operating nuclear power plants in its 27 member states. A report from the World Energy Council suggested that the Fukushima accident has led to significant changes in nuclear policies in Germany, Italy and Switzerland (WEC, 2012).

In May 2011, the German government made a decision to abandon completely the use of nuclear power by 2022. Eight facilities will be closed permanently, while the remaining nine nuclear reactors will be phased out gradually (one reactor each in 2015, 2017 and 2019 followed by three reactors in 2021 and the last three reactors in 2022). Such a decision to phase out nuclear power over the next decade will constitute a challenge to the country's energy mix. It will also affect the energy system in Europe, since it will mean that more intermittent power output from renewables will have to be delivered to Germany, and more electricity will be traded across boarders. Although it was expected that mainly gas-fired power plants be brought online to balance the system, there are now plans also to build new coal-fired plants in the country. This will have price implications for both the European electricity and gas markets, but the nature or the specifics of this are currently unknown. In Italy, the government has decided to scrap its previous nuclear power plan. A referendum in June 2011 imposed

Table 1 Summary of recent development on nuclear power in the EU (WEC, 2012)

Countries	Operable nuclear capacity as of January 2012, MWe	Policy announcements and actions, March 2011 to February 2012
France	63,130	Continues to support nuclear power while carrying out EU stress test and looking to increase the role of renewables
Germany	12,068	Immediately shut reactors operational before 1980 (7 GW in total) and announced that all other reactors would be closed by 2022
United Kingdom	9920	Affirmed commitment to nuclear power by announcing plans to build eight new reactors by 2025
Sweden	9340	The government is working with the utilities to expand nuclear capacity to replace the 1200 MWe lost in closure of Barseback1 and 2
Spain	7567	Government is firming up its commitment to future nuclear energy
Belgium	5927	Little government support, but the government expressed concern over the feasibility of implementing the phase-out of nuclear plants
Czech Republic	3678	Affirmed plans to boost nuclear capacity to 63 GW by 2032 and review safety
Switzerland	3263	Announced plans to close its five nuclear reactors by 2034
Finland	2736	Affirmed plans to build nuclear power station at Pyäjoki; two units are in planning phase with approval from the parliament and are expected to be operational within 8–10 years.
Bulgaria	1906	No reactors under construction. The construction of two reactors at Belene was suspended in the 1990s. The government and the parliament still need to take the final decision whether to resume, change the site to Kozloduy, or stop the project
Hungary	1889	Parliament has expressed strong support for two new builds, but not proposed yet.
Slovakia	1816	Strong government commitment to the future of nuclear energy
Romania	1300	Affirmed no change to building the proposed Cernovada 3 and 4
Slovenia	688	Nuclear power plant at Krsko (started in 1983) with a designed operational life of 40 years could be given a 20-year extension
Netherlands	482	Public and political support is increasing for expanding nuclear energy
Poland	planning 6000	Affirmed plans to commission its first reactor by 2025
Lithuania	planning 1350	Strong Government commitment to the future of nuclear energy
Italy	Proposed 17,000	A referendum in June 2011 imposed a permanent ban on the reintroduction of nuclear power

a permanent ban on the reintroduction of nuclear power plants. In Switzerland, the government announced its intention to decommission its five nuclear power plants gradually between 2019 and 2034. In addition, Switzerland has suspended the licensing under discussion for three new nuclear power plants.

In other countries, governments seem to be standing by their use of nuclear energy. Table 1 gives an overview of policy announcements and actions relating to nuclear power between the Fukushima accident and February 2012. These decisions for countries to uphold their nuclear plans are motivated by the economics of nuclear power compared to other forms of electricity generation, rising demand of electricity, and the need to reduce dependency on fossil fuels whilst addressing concerns surrounding security of supply and climate change.

Fossil fuels, including coal and gas, are and will continue to hold the largest share of world total electricity generation capacity, in both the short and medium term. On a global scale, fossil fuel power generation provides more than 60% of the world's electricity output, of which 42% is coal based, for example more than 70% of China's installed electricity capacity is based on coal-fired power plants. In the USA, 40% of power generation is natural gas fired. Of the 53% fossil fuel based electricity generation in Europe, 23% is based on natural gas, 16% on hard coal, 11% on lignite and 3% on fuel oil. Utilisation/consumption of both fuels is presented in Chapter 6. In Chapter 7, public attitudes to both fuels are considered. Finally, Chapter 8 presents the short- to mid-term prospects for both fuels on a global and regional scale.

2 Reserves

Coal is a combustible rock of organic origin composed mainly of carbon (50–98%), hydrogen (3–13%) and oxygen, with lesser amounts of nitrogen, sulphur and other elements. Some water is also always present, as well as grains of inorganic matter that form an incombustible residue known as ash. Coal is classified by rank, which is a measure of the amount of alteration it has undergone during formation. Consecutive stages in evolution of rank, from an initial peat stage, are brown coal (or lignite), subbituminous coal, bituminous coal, and anthracite. Increase in rank is due to a gradual increase in temperature and pressure that results in a decrease in water content and therefore an increase in carbon content. A continuous gradation occurs between these ranks resulting in subbituminous coal, bituminous coal and anthracite. Coal resources are the amount of coal that may be present in a deposit or coalfield. This does not take into account the feasibility of mining the coal economically. Not all resources are recoverable using current technology. Coal reserves can be defined in terms of proved (or measured) reserves and probable (or indicated) reserves. Probable reserves have been estimated with a lower degree of confidence than proved reserves. Proved reserves are not only considered to be recoverable but can also be recovered economically. This means they take into account what current mining technology can achieve and the economics of recovery. Proved reserves therefore change according to the price of coal; if the price of coal is low proved reserves will decrease (WCA, 2012).

It is estimated that there are over 847 Gt of proven **coal reserves** worldwide (WCA, 2012). At current production rates (*see* Section 2.2), this equates to ~118 years availability. Proven gas and oil reserves are equivalent to around 59 and 46 years, respectively, at current production levels. Coal reserves are available in almost every country in the world, with recoverable reserves in about seventy countries. The largest reserves by region are in North America, the former USSR, China, Australia, India and Germany. In the European Union (EU), each member state has the right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply. These are retained in the Lisbon Treaty. According to EURACOAL (2011), 80% of EU fossil fuel reserves are in the form of coal and lignite with great potential for further exploitation. The location, size and characteristics of most countries' coal resources are quite well known. What tends to vary much more than the assessed level of the resource – that is the potentially accessible coal in the ground – is the level classified as proved recoverable reserves. Proved recoverable reserves is the tonnage of coal that has been proved by drilling etc. and is economically and technically extractable (WCA, 2012). Distribution of proved reserves of coal in 1991, 2001 and 2011 are given in Figure 2 (BP, 2012b). Coal resources and reserves in different countries and regions are discussed in detail by Minchener (2009) and Kavalov and Peteves (2007). A set of internationally consistent definitions has been established but, for a variety of reasons, almost every coal producing nation applies slightly different classifications. This makes a direct country-by-country comparison of coal availability more difficult (Minchener, 2009).

Gas is made up mainly of methane (CH_4). It is highly flammable and burns almost completely producing no ash and fewer air pollutants compared to coal. Natural gas provides energy that is used in homes as well as industry including power generation. Natural gas reserves indicate availability into the next century and maybe longer. In recent years, natural gas has become a regular choice in power plants to generate electricity. Industry is also using more gas, both as a fuel and as an ingredient for a variety of chemicals. Although exploration indicates that natural gas is plentiful, some uncertainty remains on the cost of production and distribution. During the 1990s, more natural gas was utilised to generate electricity, causing demand for natural gas to grow substantially. The natural gas industry has been able to keep pace with growing demand and produce greater amounts of natural gas through technological innovations. These innovations have enabled the development of natural gas from shale and other formerly 'unconventional' formations that are found in abundance across the world, as well as development from traditional offshore and onshore formations. An introduction to

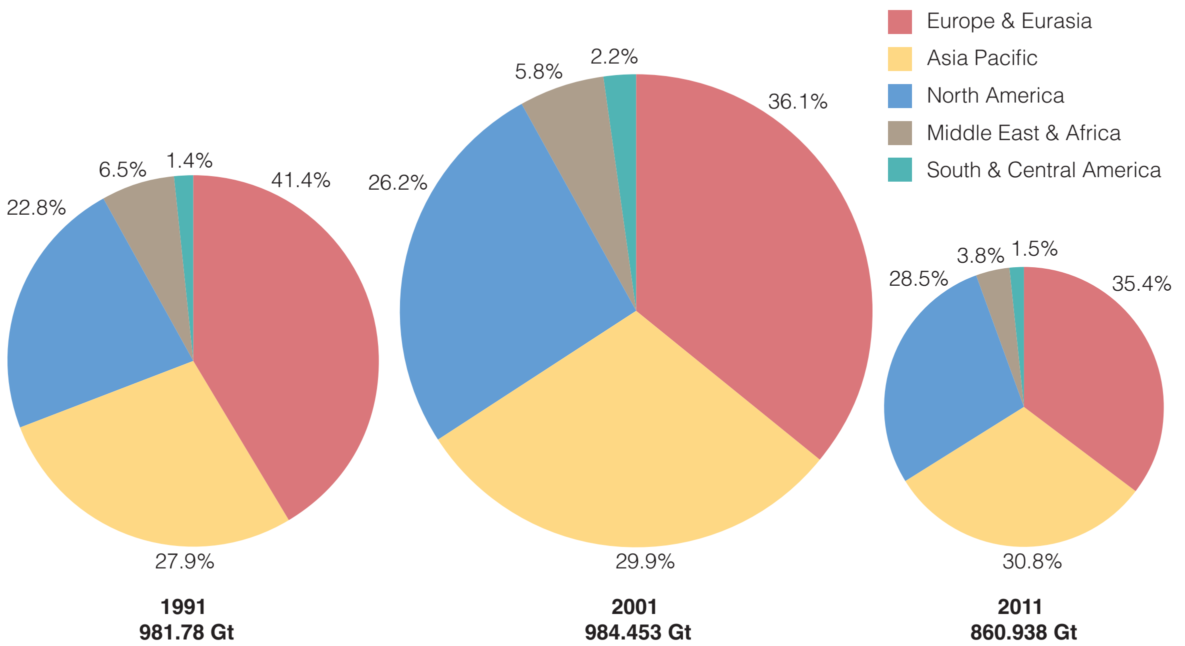

Figure 2 Distribution of proved coal reserves in 1991, 2001 and 2011 (BP, 2012b)

some of the major technological advancements that have been made recently in the production of gas is presented by NGSA (2012). According to NGSA (2012), technological innovation in the exploration and production sector has equipped the industry with the means and practices to increase the production of natural gas to meet rising demand. These technologies aim to make the exploration and production of natural gas more efficient, safe, and environmentally friendly. Although natural gas deposits are increasingly produced from 'unconventional' formations such as shale rock, the industry continues its production pace whilst improving the nature of its operations. The improvements result in fewer wells needed to develop the same amount of gas compared to the past, a decrease in drilling wastes due to increased well productivity and fewer wells, a reduction in the surface impact of the wells due to the use of smaller, modular drilling rigs and slim-hole drilling techniques. Furthermore, new exploration techniques and vibrational sources result in less reliance on explosives, thus reducing the impact of exploration on the environment.

Estimates show large **reserves of natural gas** throughout the world. However, it is very difficult to estimate exactly how much natural gas remains underground. New technologies are being developed to enable ease and greater accuracy in exploration. According to the US DOE (2012), recent estimates show that most of the world's natural gas reserves are located in the Middle East, the Russian Federation and Europe, with these reserves making up nearly 75% of total worldwide reserves. Approximately 16% of the reserves are located in Africa and Asia and another 4% in Central and South America. The USA makes up almost 4% of the reserves (US DOE, 2012). Natural gas proven reserves by country at the end of 2011 in trillion m^3 are listed in Table 2 (Energy EU, 2013).

According to BP (2012a, b), the world had 6609 trillion cubic feet (187.15 trillion m^3) of proven gas reserves in 2010. This was considered sufficient for 59 years of production at current levels. Unconventional gas, such as shale gas and coalbed methane, have yet to be assessed, in detail, globally. However, current estimates suggest they could double the existing reserves to production (R/P) ratio. Distribution of proved reserves of gas in 1991, 2001 and 2011 are given in Figure 3 (BP, 2012b). The IEA (2012a) considers that the world's remaining resources amount of 790 trillion m^3 or 230 years of output at current rates. Russia is the main conventional gas resource-holder and remains the largest gas producer and exporter in 2035. Conventional gas output is also forecast to grow

Table 2 Natural gas proven reserves by country at the end of 2011 (Energy EU, 2013)

Ranking	Country	Trillion m^3
1	Russian Federation	45.8
2	Iran	31.3
3	Turkmenistan	24.7
4	Qatar	24.2
5	US	8.1
6	Saudi Arabia	7.7
7	United Arab Emirates	5.9
8	Venezuela	5.6
9	Nigeria	5.2
10	Algeria	4.4
11	Australia	3.7
12	Iraq	3.7
13	Egypt	2.2
14	Canada	2.0
15	Norway	2.0
16	Kazakhstan	1.9
17	Kuwait	1.7
18	Libya	1.5
19	Uzbekistan	1.5
20	Azerbaijan	1.3
21	Netherlands	1.2
22	Ukraine	1.0
23	Oman	0.9
24	Yemen	0.6
25	Bangladesh	0.4
26	Brazil	0.4
27	Peru	0.4
27	Argentina	0.4
29	Syria	0.4
30	Trinidad & Tobago	0.4
31	Bolivia	0.3
32	Mexico	0.3
33	Bahrain	0.3
34	United Kingdom	0.2
35	Poland	0.2
36	Colombia	0.2
37	Italy	0.2
38	Romania	0.2

strongly in Iraq, Brazil and new producers in East Africa. Unconventional gas accounts in the IEA (2012a) projections for nearly half of the increase in global gas production to 2035. Most of the increase is expected to come from China, the USA and Australia (IEA, 2012a).

Worldwide recoverable shale resources and 2009 consumption and the expansion in newly recoverable gas reserves are shown in Figure 4. Greenstone and others (2012) discuss the potential costs of greater natural gas production and the environmental concerns relating to hydraulic fracturing, which is the technique used to extract natural gas that is trapped in shale rock formations (*see below*). The concerns include groundwater contamination, local air pollution, water usage, methane leakages and seismic incidents.

According to Clarke Energy (2012), coal mine degasification was originally developed to improve miners' safety. The methane-laden mine air may be captured or vented to the atmosphere by exhaust fans. In recent years, studies have estimated that 30–40% of all coal mines produces gas that can be used effectively for power generation. The main component of the primary coal seam gas is methane in a concentration of 90–95%, which develops during the geochemical conversion of organic substances to coal (carbonisation). The coal seam gas is present both as liberated gas in fissures and faults, and as adsorbed gas on the inner surface of the coal and neighbouring rock. Gas derived from coal comes in four key forms (Clarke Energy, 2012; Sloss, 2005):

- coal seam/bed methane;
- coal mine methane;
- abandoned mine methane;
- syngas from underground coal gasification.

Coal seam/bed methane is primary coal seam gas collected from unmined coal beds. The gas is released by drilling down into the coal seams. The associated gas can then be extracted and used in power generation. The gas consists of >90% methane and may be extracted independently of coal mining in some locations. Composition of the gas is normally stable and therefore, according to Clarke Energy (2012), can be fed directly into a natural gas network or a gas engine.

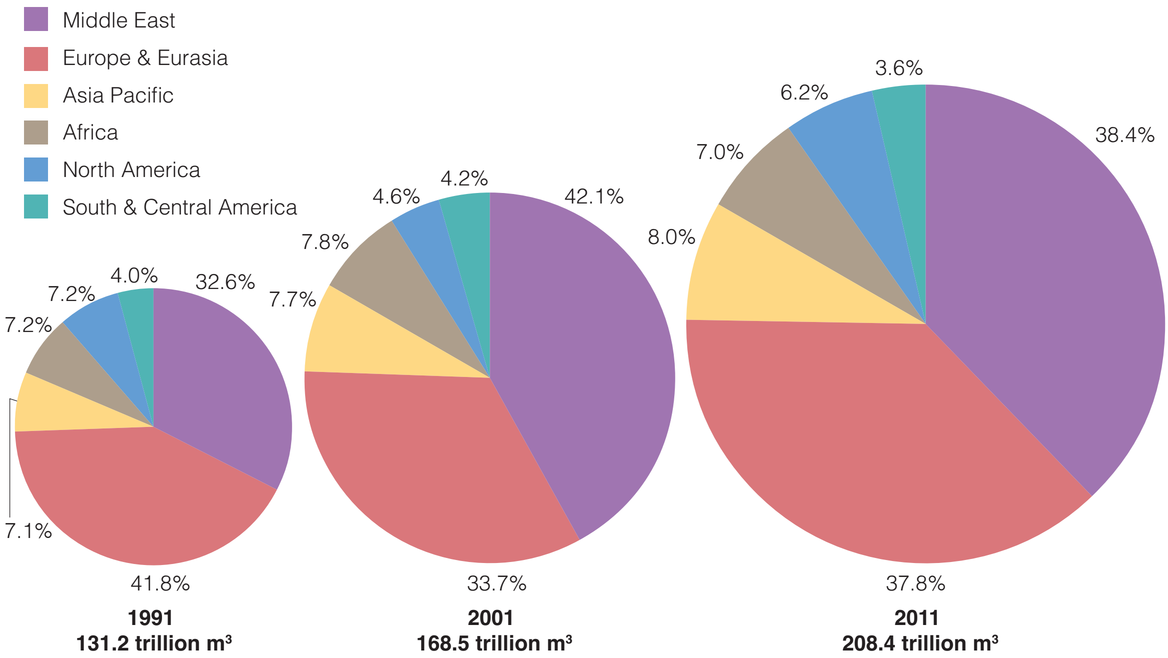

Figure 3 Distribution of proved gas reserves in 1991, 2001 and 2011 (BP, 2012b)

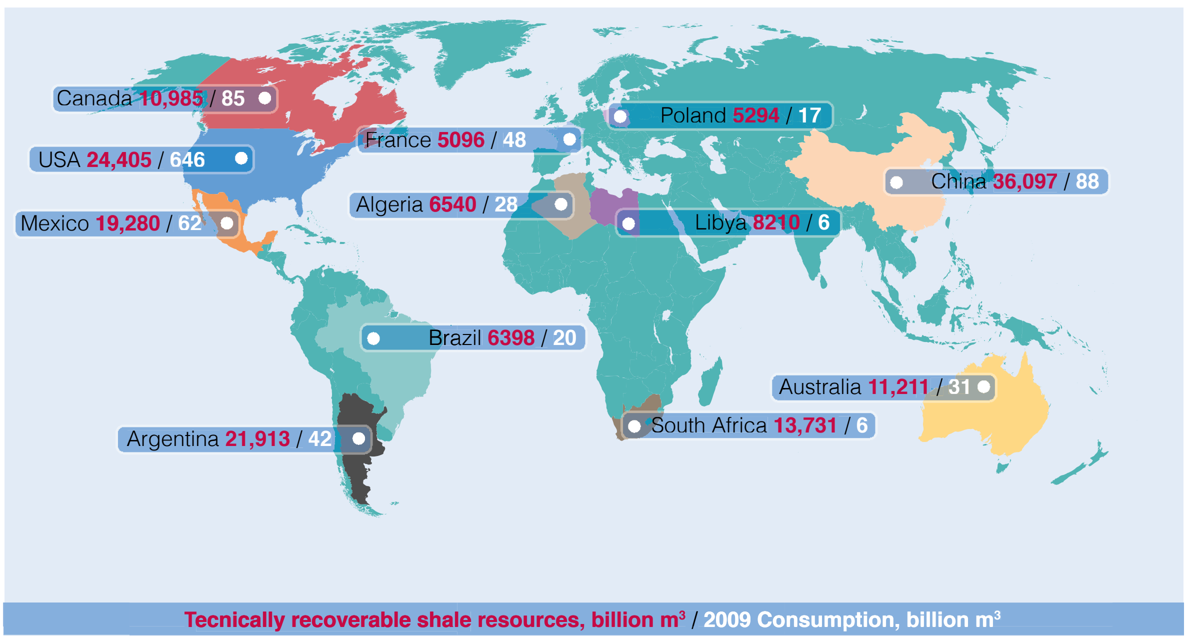

Figure 4 Worldwide recoverable shale resources and 2009 consumption (Greenstone and others, 2012)

Coal mine methane is present and active in working mine sites. The gas is extracted/drained from the air in the coal mine to improve safety and control the release of methane to the atmosphere (US EPA, 2009). The pre-drainage gas is a mixture of air and methane, typically with an oxygen content of 5–12% and methane content that can range from 25% to 60%. Methane released from the worked coal face can be diluted and removed by ventilation systems. These systems dilute methane within

Table 3 Estimates of coal methane gas-in-place* (Talkington, 2004)	
Country	Estimated resource base, trillion m^3
Canada	17–92
Russia	17–80
China	30–35
Australia	8–14
USA	4–11
Ukraine	2–12
India	0.85–4.0
Germany	3.0
Poland	3.0
UK	2.45
Kazakhstan	1.1–1.7
South Africa	1.0
Czech Republic	0.38
Turkey	0.10

* only a fraction of this total is recoverable and the estimates have a 'high' level of uncertainty

the mine to concentrations below the explosive range of 5–15%, with a target for methane concentrations usually under 1%, which complicates its utilisation. The ventilation systems move the diluted methane out of the working areas of the mine into shafts leading to the surface where it can then be destroyed or captured for utilisation rather than allowing it to be released directly into the atmosphere (WCA, 2012). Abandoned coal mines continue to release gas with a methane content of 60–80%. The gas typically contains no oxygen and its composition changes slowly.

Underground coal gasification is a process by which coal is gasified in situ. The technology converts the physical coal to a product gas (a type of synthetic/syngas). It has the potential to unlock vast amounts of energy in coal deposits that are inaccessible or uneconomic to explore using currently available mining technologies. If successful, underground coal gasification would substantially increase the proportion of the world's coal resources that could be classified as recoverable. The technology has a history in the Former Soviet Union, where it was carried out on an allegedly industrial scale. Trials have also taken place in the USA, Europe, Australia and China. Despite these trials and considerable amounts of research activities, no underground coal gasification projects have yet been demonstrated on a commercial scale. There are formidable technical obstacles to be overcome and regulatory issues to be addressed before this is possible. The first commercial-scale underground coal gasification operation is considered likely to be around 2020 (Dong, 2011; Couch, 2009).

Seddon and Clarke (2011) discuss the technical and environmental challenges that are not fully resolved with underground coal gasification. They outline key developments in the field and issues raised by Australian experience, particularly in regard to the contamination of aquifers. The authors discuss the quality of underground coal gasification synthesis gas and its potential use in downstream applications. The clean-up steps required for various downstream applications are described. A key hurdle to up-take of underground coal gasification is considered the overall cost of clean-up which has to be added to the cost of the gas production. The potential of underground coal gasification as a major new feedstock is also described. Coil and others (2012) also discuss the underground coal gasification process, impacts on the environment as well as effects on coal reserves. According to Coil and others (2012), as underground coal gasification could potentially access otherwise unmineable coal, the widespread usage of the technology would dramatically change the balance between the geologic coal resource and economically recoverable coal reserves. It is estimated that underground coal gasification could increase world coal reserves by ~600 Gt providing an abundant coal resource to compete with gas reserves.

Table 3 shows the estimates for coal methane gas in place around the world – this is the estimated total methane trapped in all known coal mines. However, only a fraction of this total gas reserve is recoverable. For example, less than 10% of the current gas in place reserve in the USA is likely to be recoverable with existing technologies (Talkington, 2004). Canada and Russia have the highest potential resources. Sloss (2005) discusses estimated coal methane gas potential reserves in individual countries in detail. As listed above, there are several different forms of methane from coal mines with differing concentrations and flow rates. For details on power projects using methane from coal mines and coalbed methane emissions – capture and utilisation, *see* Sloss (2005, 2006).

3 Production and trade

Fossil fuels, including coal and gas, continue to dominate the fuel mix for electricity production and industry despite their impact on the environment. Regulations have contributed towards reducing detrimental impacts. In the 1990s the relatively cleaner natural gas, compared to coal, became the main choice of fuel for new plants, at the expense of oil, in particular (EEA, 2006). Production from coal and lignite has increased slightly in recent years but its share of electricity produced has been constant since 2000 as overall production increases. The steep increase in overall electricity production has also counteracted some of the environmental benefits from fuel switching.

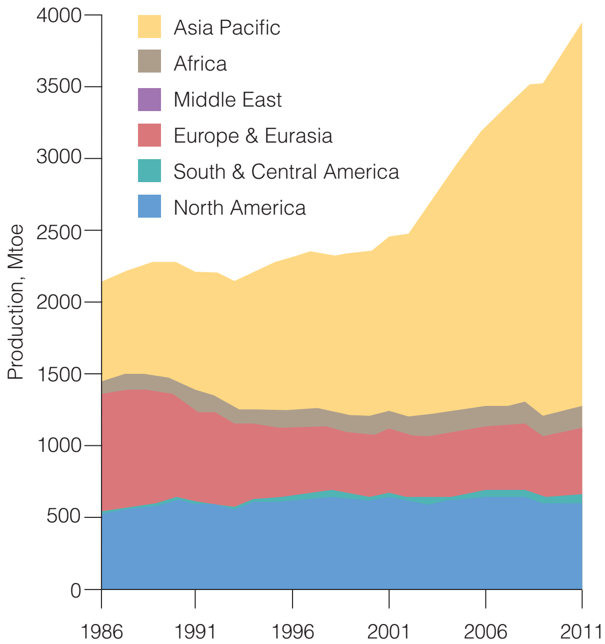

Figure 5 Coal production by region, 2011 (BP, 2012b)

Table 4 The top ten coal producers (including lignite and hard coal) (IEA, 2012a; WCA, 2012)	
Country	Mt (estimated)
China	3471
USA	1004
India	586
Australia	414
Indonesia	376
Russia	334
South Africa	253
Germany	189
Poland	139
Kazakhstan	117

3.1 Coal

World coal production reached 7.2 Gt in 2010, 6.2 Gt of hard coal and 1.0 Gt of lignite. The production of hard coal comprised 5.3 Gt of steam coal and 0.9 Gt of coking coal. Figure 5 shows the production of coal by region in 2011 (BP, 2012b). In 2011, coal production reached a record level of 7.678 Mt increasing by 6.6% over 2010. The annual average growth rate of coal production since 1999 was 4.4% (WCA, 2012). The top ten coal producers in 2011 are listed in Table 4.

Global hard coal trade amounted to over 1 Gt or 14.8% of world coal production of 7.2 Gt. Two thirds of all coal produced worldwide is delivered to power plants, or 90% in the case of lignite. Hard coal production and total exports in 2010 is shown in Figure 6 (EURACOAL, 2011). Global coal production grew by 6.1% with non-OECD countries accounting for virtually all of the growth and China accounting for 69% of the global growth (BP, 2012b).

Within the EU hard coal is mined and produced in the Czech Republic, Germany, Poland, Romania, Spain and the UK. Lignite is produced in Bulgaria, the Czech Republic, Germany, Greece, Hungary, Poland, Romania, Slovakia and Slovenia (*see* Figure 7). In 2010, the EU coal industry produced 133 Mt of hard coal and 396 Mt of lignite. A further 188 Mt of hard coal were imported. Most of the coal and lignite was used in the generation of electricity at power plants. The EU steel industry relies on high quality coking coal for

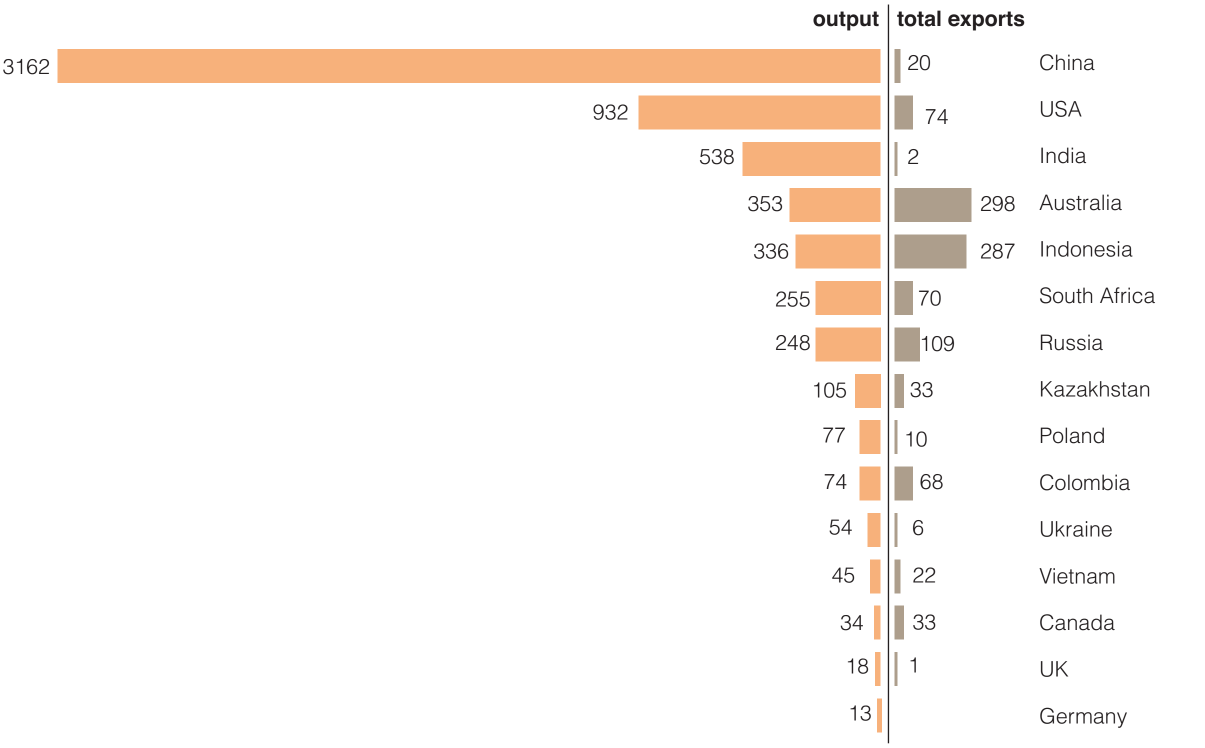

Figure 6 Hard coal production and total exports, Mt (EURACOAL, 2011)

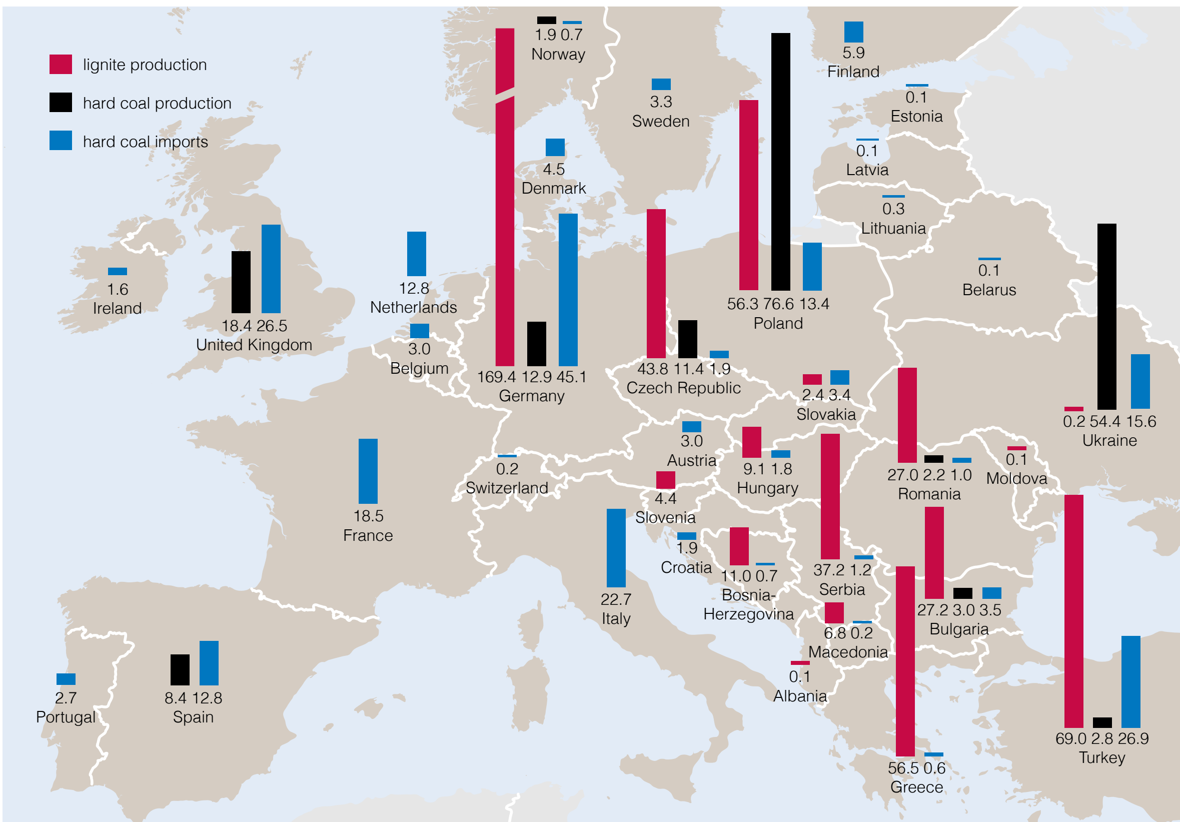

Figure 7 Coal in Europe: lignite and hard coal production and imports in 2010, Mt (EURACOAL, 2011)

its production. The contribution of lignite and hard coal mining to the security of energy supply in Europe is significant but difficult to quantify. Much of the energy imported into EU countries comes from a relatively small number of coal production countries. However, those countries supplying hard coal present an overall lower risk than those countries supplying natural gas. Coal and lignite mined in the EU in 2009 covered 9.7% of EU primary energy demand. Indigenous coal and lignite remain the most important indigenous energy supplies in the EU, exceeding natural gas production in terms of energy supplied (EURACOAL, 2011).

Over recent years there has been a fall in the reserves to production (R/P) ratio**,** which has prompted questions over whether 'peak coal' was reached. Reserves to production (R/P) ratio is a ratio indicating the remaining lifespan of a natural resource (WCA, 2012). This ratio is expressed in terms of years, and is used in forecasting, for example, the future availability of a resource to determine project life, income, employment and other aspects. While applicable to all natural resources, it is primarily used in the oil and gas industry. Peak coal is defined as the point in time at which the maximum global coal production rate is reached after which the rate of production will enter irreversible decline. However, the recent falls in the R/P ratio were attributed somewhat to the lack of incentives to prove up reserves, rather than a lack of coal resources. Exploration activity is typically carried out by mining companies with short planning horizons rather than state-funded geological surveys as there is no economic need for companies to prove long-term reserves. Coal reserves may be extended further through developments including the discovery of new reserves through ongoing and improved exploration activities, and advances in mining techniques, which would allow previously inaccessible reserves to be reached. New developments in conventional tunnelling techniques are discussed by Mishra (2011). In addition, significant improvements continue to be made in how efficiently coal is used so that more energy can be generated from each tonne of coal produced.

While coal is found and used to varying extents in over seventy countries, at present, the bulk of coal production is concentrated in about ten countries while the export market is now dominated by five countries, namely Australia, Indonesia, Russia, South Africa and Colombia. This situation could well change. Some suppliers may not remain in the global export business as they will need to first meet internal and local demands. For example, China and the USA seem likely to become net importers due to domestic coal production pressures arising from long distance transportation problems. Russia may choose to follow the same route for commercial and strategic reasons while Indonesia may also cut back on exports for a wide range of reasons. Others, such as Colombia and Australia may expand their market share significantly, with Australia having the scope to become the independent supplier of choice for much of the global market. In due course, there could well be new entrants to the market, ensuring that a wider ranging distribution of suppliers can be established. However, some of these may not be as reliable as the previous providers (Minchener, 2009).

According to the US EIA (2012), the average minemouth price of coal is forecast to increase by 1.4%/y from 2.04 $/MBtu (1.93 $/GJ) in 2011 to 3.08 $/MBtu (2.91 $/GJ) in 2040 (in 2011 US$). The projected increase in coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. While coal remains the leading fuel of US electricity generation, its share of total generation is slightly lower than projected previously (US EIA, 2013). However, coal production, consumption in the power sector and the production of coal-based synthetic liquids are expected to increase in most years after 2016, but to a lesser extent compared to 2012. None the less, the higher coal exports combined with lower imports is forecast to keep the differences in coal production between previous and current projections relatively small. Although the US EIA (2012) projections indicate domestic coal production increasing at an average rate of only 0.2%/y to 2040, the increase is uneven from 2011 to 2016. After 2016, increases in coal use for electricity generation and exports are expected to lead to a gradual recovery in US coal production. The growth is forecast at an average rate of 0.6%/y.

In the EU, state aid to the hard coal production industry is governed by Council Regulation 1407/2002/EC. This was due to expire on 31 December 2010. Rademaekers and others (2008) carried out an in-depth study evaluating the needs for state aid to the coal industry post 2010. Out of the 13 coal-production member states of the EU, six did not receive any type of official state aid. Two (Estonia and Greece) produced lignite and therefore were not covered by the regulation. Italy had one hard coal producing mine which had not reported any formal state aid. The UK and Czech Republic had restructured their coal production rendering it fully competitive. Finally Bulgaria did not receive any form of state aid after 2008. The remaining seven coal-producing countries receiving some form of state aid under the 1407/2002/EC regulations were Germany, Hungary, Poland, Romania, Slovakia, Slovenia and Spain. Rademaekers and others (2008) recommended that applying a mix of general state aid options post 2010 combined with a coal-specific article on exceptional costs may be the best of possible courses of action. The policy would eradicate unnecessary and high levels of distorted state aid to the industry while simultaneously ensuring a socially and regionally acceptable solution that allows for a certain level of state support in order to ease the negative impacts of sector restructuring and closure of uncompetitive mines.

In 2010, the European Commission approved a Council Regulation on state aid to facilitate the closure of loss-making hard coal mines in the EU by 1 October 2014 (Lang, 2011; Hruska, 2010). This rule which came into force in January 2011 allows state subsidies to be given only to hard coal mines if closure plans are in place. These plans have to ensure that these mines are shut down by 15 October 2014 at the latest. Otherwise the aid will have to be paid back. According to Hruska (2010), the move predominantly affects Germany, Spain and Poland. Policy issues are discussed further in Section 6.1.

3.2 Gas

Production of natural gas by region in 2011 is shown in Figure 8. According to BP (2012a), unconventional gas in the form of shale gas and coalbed methane are expected to account for 63% of North American production by 2030. Sustained growth of shale gas raises the prospect of liquid natural gas exports from North American by 2030 – 5 billion cubic feet per day (~0.14 billion m^3/d). Outside North America, unconventional gas is currently in its infancy but likely to play a growing role in the long term as current technical and regulatory hurdles recede. In Europe, BP (2012a) do not expect major unconventional production before 2020. The decline in conventional supply implies a growing import requirement for Europe, up by more than 60%, from 26 billion cubic feet per day (~0.77 billion m^3/d) in 2010 to 42 billion cubic feet per day (~1.19 billion m^3/d) in 2030. In China, gas production is expected to grow at 6.1%/y. Although coalbed methane and shale gas are expected to contribute 46% to growth, an increasing need for imports is forecast. These are expected to be met by expansion of liquid natural gas and pipeline projects.

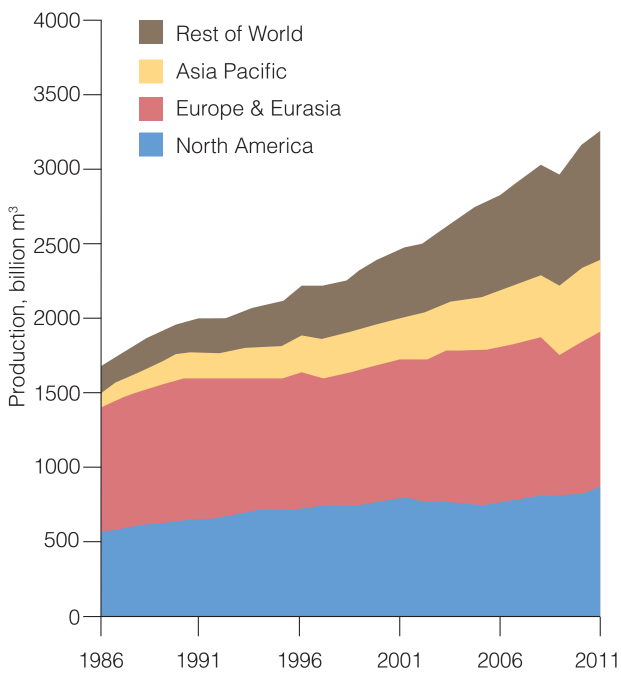

Figure 8 Production of natural gas by region in 2011 (BP, 2012b)

In 2011, global natural gas production grew by 3.1% according to BP (2012b). Despite low

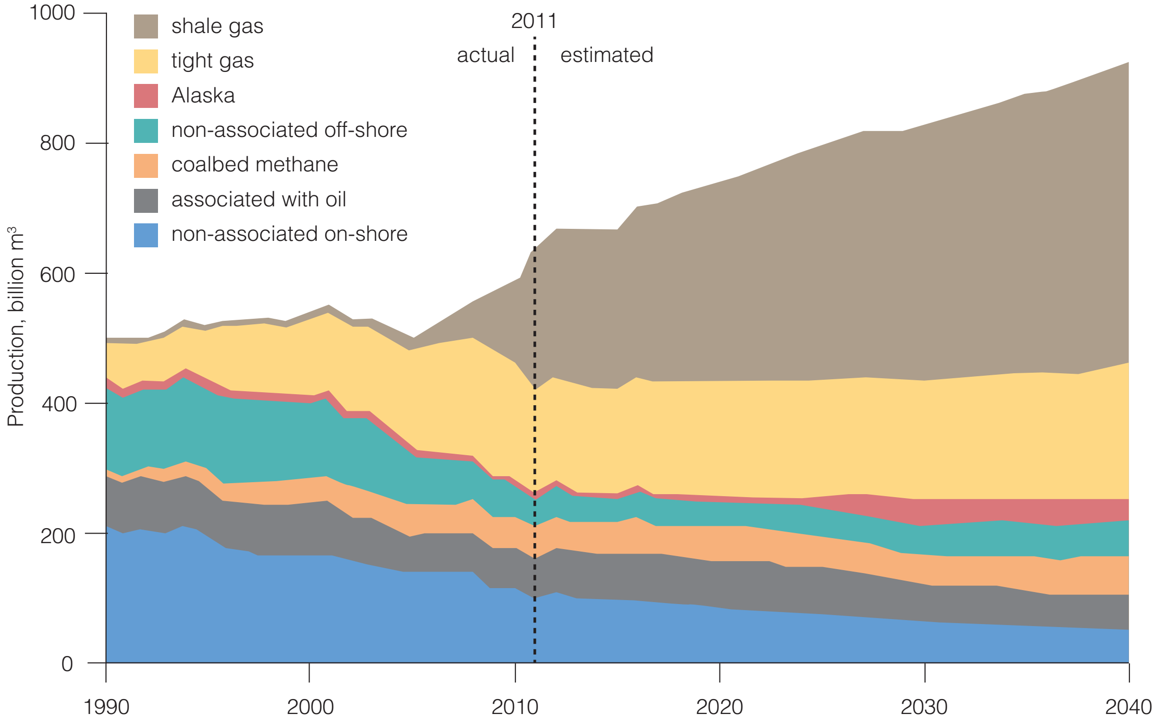

Figure 9 US dry natural gas production by source, 1990-2040 (US EIA, 2012)

gas prices in the USA, it recorded an increase of 7.7% in volumetric gas production and remained the largest gas producer worldwide. Natural gas production also grew in Qatar (25.8%), Russia (3.1%) and Turkmenistan (40.6%). However, production declined in Libya (75.6%) and the UK (20.8%). The EU recorded the largest decline in gas production on record at 11.4% in 2011. This was considered to be due to a combination of mature fields, maintenance and weak regional consumption. According to BP (2012b), as natural gas consumption growth was weak in 2011, global trade increased by a relatively modest 4%. Liquid natural gas trading grew by 10.1%. The UK and Japan were the largest volumetric importers. Liquid natural gas in 2011 accounted for 32.3% of global gas trade.

In the USA, natural gas production is forecast to continue to increase to 2040 outpacing domestic consumption by 2020 and spurring net exports of the gas (*see* Figure 9). According to the US EIA (2012), higher volumes of shale gas production are expected to be central to the higher total production volumes which will result in an earlier transition to net exports than was projected in the previous annual outlook. US exports of LNG from domestic sources is also forecast to rise to approximately 1.6 trillion cubic feet (~45 billion m^3) in 2027 which is almost double the previous projection of 2011. Industry is expected to benefit from the increased production of natural gas and relatively low prices which result in lowering the costs of both raw materials and energy, particularly through 2025. Projections indicate that natural gas prices will remain below 4 $/MBtu (3.78 $/GJ) through 2018. After 2018, natural gas prices are expected to increase steadily as tight gas and shale gas drilling activity expands to meet growing domestic demand for natural gas and offsets declines in natural gas production from other sources. Natural gas prices are forecast to rise as lower cost resources are depleted and production gradually shifts to less productive and more expensive resources. Prices are expected to reach (in 2011 US$) 5.11 $/MBtu (~5.70 $/GJ) in 2030 and 7.41 $/MBtu (~8.26 $/GJ) in 2040 (US EIA, 2012).

According to Greenstone and others (2012) total US natural gas production increased from 18.5 trillion cubic feet (~524 billion m^3) in 2006 to 23 trillion cubic feet (~651 billion m^3) in 2011. Most of the increase is attributed to shale gas production which increased by nearly 50% between 2008 and 2009. Figure 10 illustrates how the production of shale gas has grown in the USA in recent

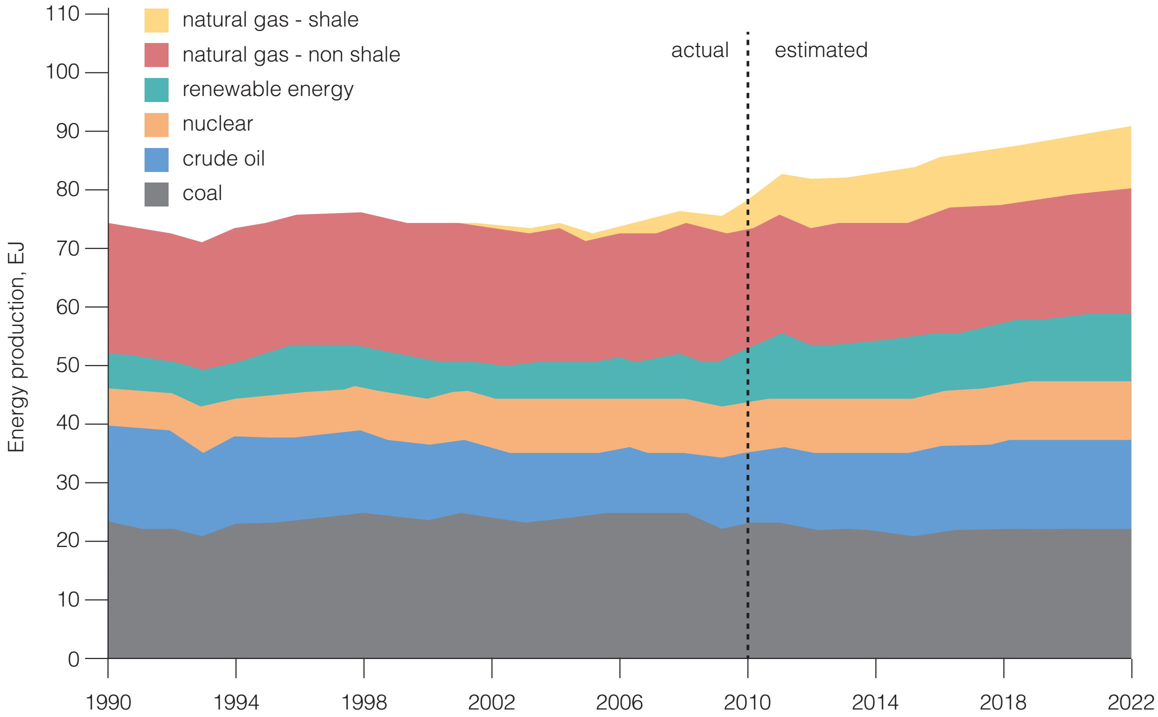

Figure 10 US primary energy production by source (Greenstone and others, 2012)

years and is projected to rise over the next decade compared to other fuels including coal.

Some of the major recent technological innovations in the exploration and production sector include (NGSA, 2012):

- Advanced 3-D seismic imaging: the technology uses traditional seismic imaging techniques, combined with computers and processors, to create a three-dimensional model of the subsurface layers. 4-D seismology adds time as a dimension, allowing exploration teams to observe how subsurface characteristics change over time thus identifying natural gas prospects more easily, place wells more effectively, reduce the number of dry holes drilled, reduce drilling costs, and cut exploration time.
- CO_2-sand fracturing – fracturing techniques have been used since the 1970s to help increase the flow rate of natural gas from underground formations. The technique involves using a mixture of sand proppants and liquid CO_2 to fracture formations, creating and enlarging cracks through which the natural gas may flow more freely. A proppant is a material that keeps an induced hydraulic fracture open, during or following fracturing. The CO_2 then vaporises, leaving only sand in the formation, holding the newly enlarged cracks open. As no other substances are used in this type of fracturing, there are no effluents from the fracturing process that must be removed.
- Measurement while drilling (MWD) systems allow for the collection of data from the bottom of a well as it is being drilled. This allows access to immediate information on the exact nature of the rock formations being encountered by the drill bit. Drilling efficiency and accuracy in the drilling process is therefore improved which allows better formation evaluation as the drill bit encounters the underground formation, and reduces the chance of formation damage and blowouts.
- Slim-hole drilling is drilling a slimmer hole in the ground to get to the natural gas deposits compared to the past. In order to be considered slim-hole drilling, at least 90% of a well must be drilled with a drill bit <6 inches (<15.24 cm) in diameter (whereas conventional wells typically use drill bits as large as 12¼ inches (31.115 cm) in diameter). Slim-hole drilling can significantly improve the efficiency of drilling operations, as well as decrease its environmental impact. Due to its lower cost profile and reduced environmental impact, slim-hole drilling provides an

economical method of drilling exploratory wells in new areas, drilling deeper wells in existing fields, and providing an efficient means for extracting more natural gas from undepleted fields.

- Hydraulic fracturing, also called 'fracking,' or 'frac'ing', is used to extract natural gas that is trapped in shale rock formations. A liquid mix that is 99% water and sand is injected into the rock at very high pressure, creating fractures within the rock that provides the natural gas with a path to flow to the wellhead. A fracking fluid mix also helps to keep the formation more porous. Hydraulic fracturing is now widely used in the USA, with more than 90% of the natural gas wells having used it to boost production at some time.

Before natural gas can be transported efficiently and sold commercially, its impurities must be extracted. The by-products of the extraction process, known as NGLs, include hydrocarbons such as ethane, butane and propane, which can be used as raw materials in the petrochemical markets (PWC, 2012). For more information on the impact of shale gas on the reshaping of the chemicals industry in the USA *see* PWC (2012).

Two other developing technologies in the natural gas industry include the increased use of liquefied natural gas (LNG), and natural gas fuel cells. Cooling natural gas to about –260°F (–157°C) at normal pressure results in the condensation of the gas into liquid form, known as LNG. The process makes the transportation of natural gas easier and more economic, since LNG takes up about one six hundredth the volume of gaseous natural gas. According to the NGSA (2012), technological advances are reducing the costs associated with the liquefaction and re-gasification of LNG. As it is easier to transport, LNG can make the production and utilisation of stranded natural gas deposits from around the globe feasible/economic where the construction of pipelines is uneconomic. When the LNG is vaporised to gaseous form, it will only burn in concentrations of between 5% and 15% mixed with air. In addition, LNG, or any vapour associated with LNG, will not explode in an unconfined environment. Thus, in the unlikely event of an LNG spill, the natural gas has little chance of igniting an explosion. Liquefaction removes oxygen, carbon dioxide, sulphur, and water from the natural gas, resulting in LNG that is almost pure methane. Although it currently accounts for a small percentage of natural gas used, it is expected that LNG use will increase over the next decades.

Fuel cells powered by natural gas are considered a new technology for the clean and efficient generation of electricity (NGSA, 2012). Fuel cells have the ability to generate electricity using electrochemical reactions as opposed to combustion of fossil fuels. Essentially, a fuel cell works by passing streams of fuel (usually hydrogen) and oxidants over electrodes that are separated by an electrolyte. This produces a chemical reaction that generates electricity without requiring the combustion of fuel, or the addition of heat as is common in the traditional generation of electricity. When pure hydrogen is used as fuel, and pure oxygen is used as the oxidant, the reaction that takes place within a fuel cell produces water, heat, and electricity. In practice, fuel cells result in very low emission of pollutants, and the generation of high-quality, reliable electricity. While a pure hydrogen, pure oxygen fuel cell produces only water, electricity, and heat, fuel cells in practice emit trace amounts of sulphur compounds and very low levels of carbon dioxide. However, the carbon dioxide produced by fuel cell use is concentrated and can be readily recaptured, as opposed to being emitted into the atmosphere. In addition, fuel cells can be compact, thus allowing for their placement wherever electricity is needed. This includes residential, commercial, industrial, and even transport settings. As fuel cells are completely enclosed units, with no moving parts or complicated machinery, they are a dependable source of electricity, capable of operating for extended periods of time. Fuel cells also do not have electricity surges, meaning they can be used where a constant, dependable source of electricity is required (NGSA, 2012).

The IEA *Golden Age of Gas Scenario* (IEA, 2012a), shows that natural gas is about to enter a 'golden age', but will do so only if a significant proportion of the world's vast resources of unconventional gas, including shale gas, tight gas and coalbed methane, can be developed profitably and in an environmentally acceptable manner. Advances in upstream technology have led to a surge in the production of unconventional gas in North America in recent years, with the prospect of further increases in production there and the emergence of a large-scale unconventional gas industry in other parts of the world, where sizeable resources are known to exist. The IEA (2012a) considers that the boost this would give to gas supply would bring a number of benefits in the form of greater energy diversity and more secure supply in those countries that rely on imports to meet their gas needs, as well as global benefits in the form of reduced energy costs. However, according to BP (2012a), a promising future for unconventional gas is far from assured as numerous issues need to be overcome, not least the social and environmental concerns associated with its extraction. As producing unconventional gas is an intensive industrial process, it generally imposes a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Unless properly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources in some parts of the world (IEA, 2012a). Schrag (2012) discussed shale gas production and utilisation and climate change.

The technologies and know-how exist for unconventional gas to be produced satisfactorily while meeting the above challenges. However, this has to be supported by a continuous drive from governments and industry to improve performance if public confidence is to be gained and maintained. The industry needs to apply the highest practicable environmental and social standards at all stages of the development process. Governments need to devise appropriate regulatory regimes, based on sound science and high-quality data, with sufficient compliance staff and guaranteed public access to information. Although there is a range of other factors that will affect the development of unconventional gas resources, varying between different countries, the IEA consider that there is a critical link between the way that governments and industry response to these social and environmental challenges and the prospects for unconventional gas production and utilisation (IEA, 2012a).

4 Supply and demand

One of the fundamentals determining the coal versus gas competition is their respective demand/supply balances. In competitive markets, the demand/supply balance is the principal factor that determines the price of fuels. Maintaining a well-balanced demand/supply of energy resources is an important component of a nation's energy policy and strategy. This chapter examines the state of play and the future trend of supply and demand of coal and gas in major coal/gas consuming nations and regions.

4.1 Coal

Coal demand had remained stable (somewhere between 2300 and 2400 Mtoe during 1986-2000. The last decade, however, has seen remarkable growth in coal demand, which was the largest of all primary energy resources and almost equalled the combined growth in natural gas, oil, nuclear and renewables (IEA, 2012a). The main driver was China, where coal consumption increased from 720 Mtoe in 2001 to 1676 Mtoe in 2011 (BP, 2012b). India was the second largest contributor to the growth, from 145 Mtoe in 2001 to 271 Mtoe in 2011 (BP, 2012b). The importance of coal in the global energy mix is now the highest since 1971. Coal is the backbone of electricity generation worldwide, and has been the fuel underpinning the rapid industrialisation of emerging economies. Coal fuels more than 40% of the world's electricity, though this figure is much higher in many countries, such as South Africa (93%), Poland (92%), China (79%), India (69%) and the USA (49%) (Burnard and Bhattacharya, 2011). Coal's key role in the power generation mix is likely to remain in the foreseeable future, regardless of climate change policy, due to the growing energy needs of the developing world.

4.1.1 China

China is the largest coal consumer in the world, accounting for 49.4% (3.12 Gt or 1839.4 Mtoe, excluding Hong Kong) of global total coal consumption in 2011 (BP, 2012b; NDRC, 2012). Coal has played a dominant role in China's energy mix and electricity generation for decades. In 2010, China had 970 GWe of total generation capacity, with thermal generation capacity (predominantly coal) having a share of 73.4%; nearly 81% of China's power output in 2010 was coal fired (NDRC, 2012). The share of coal-fired generation has dropped by 1.1 percentage points compared to the levels in 2005. During the same period, wind generation has increased from 0.1% in 2005 to 1.2% in 2010 (NDRC, 2012). The IEA projected a possible doubling of total generating capacity to 2378 GWe by 2035; coal-fired capacity will have a lower share of 49% by 2035 compared to 73.4% in 2010 under the New Policies scenario (IEA, 2012c). Coal-fired power could still account for 50–60% of the total generation.

Domestic coal production forms a large proportion of the country's coal supplies. By 2010, coal production reached 3.2 Gt, with twelve provinces in the central and western region of the country accounting for 67.7% of national total coal output (NDRC, 2012). Before 2009, China was a major stream coal exporter, chiefly to Asian importing countries. Today, China is one of the largest importers of steam coal in the world. China's hard coal imports increased from roughly 0.4 Mt in 2000 to 163 Mt in 2010 (NDRC, 2012). Imports appear to remain strong as China readjusts its coal and power markets, with the closure of small inefficient coal mines, and development of larger-scale modern mines, while coal-fired power capacity seems to increase apace despite the closure of small units (less than 300 MWe). China's import will have a huge influence over the prices of internationally traded coal, as discussed in Chapter 5.

4.1.2 North America

North America's coal consumption accounted for 14.3% of the world's total in 2011. As the second largest producer and consumer of coal in the world, the **USA** consumed 501.9 Mtoe of coal in 2011, which accounted for 21% of the country's primary energy consumption, compared to oil (37%), gas (25%), nuclear (9%) and renewables (8%) (EIA, 2012). In the USA, use of coal in industry is already overshadowed by gas and electricity such that almost 93% of coal produced in the USA is consumed by the power generation sector; coal remains the dominant fuel for electricity generation, providing 45% of the country's electricity (EIA, 2012). The US EIA projected in its Reference Case that the share of coal in US electricity output would decline to 39% in 2020 and 38% in 2035, due to competition from natural gas and renewables. In absolute terms, coal-fired generation in 2035 is just 2% higher than in 2010 but still 6% below the 2007 pre-recession level (EIA, 2012). In the IEA's projection under the New Policies scenario, coal-fired generation remains broadly flat until 2025 before starting to decline (IEA, 2012a).

In **Canada**, more than 90% coal is located in the western provinces, although there are also reserves in Ontario, Nova Scotia, New Brunswick and Northern Canada (Coal Association of Canada, 2012a). Resources comprise subbituminous deposits (in Alberta), lignite (mostly in Saskatchewan), bituminous coal, and semi-anthracite. Almost all Canadian coal is produced via opencast techniques. There are 24 producing coal mines primarily located in the western part of the country, which provide a strategic advantage because of the close proximity of west coast ports. In 2011, Canada produced 67.1 Mt of coal, of which 37.7 Mt was thermal coal, 29.4 Mt was coking coal. About half of the coal output in Canada is exported, and the majority of the coal exported was steel-making coal (Coal Association of Canada, 2012b). In 2011, exports totalled 32.6 Mt, slightly lower than exported the previous year (Coal Association of Canada, 2012b); the bulk (73%) of the coal exported went to Asia, with 14% shipped to Europe and the Middle East and 13% sold into the US market (Coal Association of Canada, 2012a). Canada consumed 21.8 Mtoe of coal in 2011 (BP, 2012b); the 2009 statistics shows that 87.5% of coal consumed was used by 19 coal-fired power plants in Canada, 6.25% transformed into coke and the remaining 6.25% used for industry energy and non-energy uses (Coal Association of Canada, 2012a). Some provinces rely heavily on coal-fired electricity: Alberta (74%), Nova Scotia (73%) and Saskatchewan (60%).

4.1.3 Europe and Eurasia

The total coal consumption of Europe and Eurasia has recovered from the historic low level of 471.1 Mtoe in 2008 (due largely to the economic downturn) to 499.2 Mtoe in 2011; this is, however, still around 30 Mtoe short of the historic high seen in 2006 (BP, 2012b).

The EU is currently the third largest coal consumer worldwide after China and the USA. Coal covered around 17% of the primary energy demand in the EU in 2009; about 27% of power generation is based on coal, compared to nuclear (28%), hydro (11%) and gas (23%). Coal consumption is dominated by the power sector at 72% followed by coke production at 15% in 2010 (EC, 2011). The use of coal in electricity generation varies widely across the EU member states. In most eastern and southeastern member states, coal and lignite account for a large share of electricity generation (for example, in Poland 88% of electricity was generated from coal in 2009), while coal's share in electricity generation is much smaller in the majority of western member states (for instance, coal's share was just 5% in France in 2009). Around 60% of coal demand was met by indigenous production, with 133 Mt (110 Mtce) of hard coal and 422 Mt (129 Mtce) of lignite produced in 2009. The remaining demand has been provided by coal imports. EU 's main sources of coal import were Russia (30.0%), Colombia (17.9%), South Africa (16.1%), USA (13.9%), Australia (7.7%) and Indonesia (7.1%) (EC, 2011).

Coal consumption of the EU-27 has been on a steady overall decline from the historically high levels in the late 1980s and was 313.6 Mtoe in 2011. Such a decline is the result of a combination of factors: sluggish economic growth and the resulting modest rise in electricity demand; an expansion of natural gas and renewables-based generation capacity; the phase-out of subsidies to indigenous (hard) coal production; the introduction of carbon pricing in the EU; and increasingly stringent environmental regulations. These factors are set to continue to depress coal demand over the foreseeable future (present to 2035), though the rate of decline will depend on the strength of government energy and environmental policies. Under the IEA New Policies Scenario, OECD Europe's primary coal demand in 2035 will be just 60% of the 2010 level (IEA, 2012b). Most of this decline results from reduced coal burning for electricity generation. Load factors at existing coal plants are set to fall, with increased competition from other base load and must-run plants. Few new coal plants are likely to be built given the strong preference for natural gas plants, the unfavourable economics of coal in the long-run (even though under the present market conditions, coal-fired generation is more profitable than gas-fired generation in some European countries such as the UK, *see* discussion in Section 5.3), the threat of heavier carbon penalties in the future and increasing costs to comply with more stringent environmental emission standards. The environmental concerns have led to strong opposition to coal from environmental groups and, in some cases, the local communities, which has made obtaining permission for new coal-fired plants difficult. Industrial coal use is also expected to continue to fall, as a result of declining the heavy industry production, switching to natural gas or electricity, and energy efficiency improvement.

Russia is the largest coal consumer in Europe and Eurasia, and ranks sixth worldwide, with a coal consumption of nearly 91 Mtoe in 2011 (BP, 2012b). Yet coal plays a relatively modest role in Russia's energy mix, meeting only 15% of its total primary energy needs and fuelling about 20% of its electricity generation (IEA, 2009). Despite Russia's ample indigenous resources, the share of coal in total primary energy demand is not expected to increase over the coming two decades. The reasons are twofold: firstly, there are long distances between coal mines in Siberia and the main centres of demand in the European part of the country (mainly the central and Volga Districts); the associated high transport costs make the cost advantage of coal over gas, the predominant fuel in Russia, less evident; secondly, there will be strong growth in nuclear power and renewables (mainly hydropower) as the result of stimulation by the Russian Government's Energy Strategy to 2030, which foresees an increase in the share of non-fossil fuels in the electricity generation mix (IEA, 2009). In its New Policies Scenario, IEA projected fairly flat coal demand in absolute terms from the power sector over the projected period (2009-35). However, there is scope for significantly greater use of coal for power generation, if the programme of building new nuclear reactors does not proceed as currently planned.

The Caspian region, mainly Kazakhstan, is also a considerable consumer of coal, with a fairly stable consumption of 31–35 Mtoe/y during 2006-11. Nearly two-thirds of coal has been used for power generation. In IEA's New Policies Scenario, this region will see a modest growth in coal demand largely because its incremental energy demand will be principally met by natural gas. The planned construction of additional nuclear power, which is to be commissioned towards the end of the projection period (2011-35), also limits the scope for increased use of coal for power generation. Moreover, there is considerable potential to reduce losses of energy in transmission and distribution of electricity, which, if realised, could make up a significant contribution to future electricity demand.

4.1.4 India

India is currently the fourth largest coal consumer in the world, consuming 295.6 Mtoe of coal in 2011 (BP, 2012b). Coal constituted the largest share (42%) of India's total primary energy consumption in 2009 (IEA, 2012b). To put that into context, natural gas had a share of 7%, oil 24%, nuclear 1%, traditional combustible renewables and wastes 24%, and other renewables 2% (IEA, 2012b). Coal has been used extensively both in the power sector and major industries. India's total installed generation capacity reached ~147 GW, of which 82.4 GW were thermal stations (56 coal-based and 10 gas-based) (Mills, 2007). Driven by rapid economic growth, coal demand has been booming with demand rise of about 80% between 2000 and 2010. Notably, coal demand has been increasing at the average growth rate accelerating to 7%/y since 2005 (IEA, 2012b).

With the world's third largest hard coal reserves after the USA and China, India's coal demand has been mostly met by domestic supply. At current production rate, domestic supply can last for more than 200 years. Domestic production consists predominantly of stream coal, while nearly all coking coal demand is provided by imports. India's coal mining is of relatively low cost by world standard, but the coal is generally low in quality (typically, ash content 25–55%, sulphur content up to 7%) (Mills, 2007). Domestic production has increased fivefold since 1980 (Baruya, 2012b). All the growth was from hard stream coal, while lignite and coking coal production barely increased over decades. Coal India accounts for 82% of Indian production, while Singareni Collieries Company Ltd produce 8% and the remaining 10% is produced by a variety of producers (Baruya, 2012b). Coal mining was reserved for the public sector under the Coal Mines Act 1973. An amendment to the act in 1976 enabled two exceptions permitting captive mining associated with iron and steel production, or private companies operating in local markets.

Coal imports remain a small fraction of total supply, but have been increasing year-on-year, and are expected to exceed 60–80 Mt by 2012 (Baruya, 2012b). The rise in coal imports is driven by two main reasons. Firstly, since domestic coal has a high ash content, it needs to be blended with imported coal in order to lower the ash content to meet the quality requirement of coal-fired power stations. Secondly, imported coal plays an important role to fill the gap created by local supply problems. Coal stocks at most Indian power stations can supply demand for just a few days, compared to a normal stockpile of 21 days' supply at a European coal-fired power plant.

In IEA's New Policies Scenario, India's coal demand is forecast to more than double by 2035, making it the world's second largest consumer of coal by around 2025 (IEA, 2012a). To meet such a huge demand, India is poised to become the world's biggest importer of coal soon after 2020, as domestic demand will not be able to keep up with demand. India will thus become a key player in the international coal market. Coal's share of India's energy mix is projected to increase over the next decade to 46% before winding down to 42% towards 2035 (IEA, 2012a). More than 60% of the growth in demand comes from the power sector driven by the government's electrification programme. At present, there is still a large fraction (estimated 300 million) of India's population with no access to electricity. However, the demand projection remains highly uncertain, considering the current under-development of generation capacity and transmission infrastructure. The remaining increase in coal demand comes from industrial consumption and fuel transformation processes, which are projected to grow faster than the demand from the power sector and compete for the power sector's share of total coal consumption.

4.1.5 OECD Asia Oceania

The OECD Asia Oceania region, including Japan, Korea, Australia, and New Zealand, accounts for 6.6% of the world's total coal consumption. These countries, except for New Zealand, are key players in the Pacific coal trading market, with Japan and Korean as major importers and Australia as the major exporter.

Japan is the world's largest coal importer and the fourth largest coal consumer. Coal provided 20–30% of the total primary energy supply in 2010, while gas supplied around 15–17% and oil 38–41% (Baruya, 2012b). Coal consumption has been fairly stable in the range of 120–128 Mtoe, since 2004 except for a dip to 108.8 Mtoe in 2009 (BP, 2012b). Coal is used mainly for power generation (27% of total coal demand), but also used in steel production, cement plants and paper and pulp mills (IEA, 2012b). Japan's coal-fired power plants had a total installed capacity of 44 GWe in 2008, representing 16% of its total installed electricity capacity (Baruya, 2012b). Those installations include some of the most efficient and cleanest power plants of their kind in the world.

Japan's coal demand is projected to decline by 20% from 2009 to 2035 across all sectors, but mainly in the power sector (IEA, 2012a). This is due to the sluggish economic growth (in line with a declining population) and the resulting modest rise in electricity demand. There has been an intensive energy conversation initiative in the wake of the Fukushima nuclear incident, which plays a further role to reduce rise in energy demand. All but two of Japan's 50 nuclear reactors have been shut down since 2011, which had made the world think Japan would turn away from nuclear power. However, Japan's Nuclear Regulation Authority has approved new safety requirements for nuclear plants, which took effect on 8 July 2013, allowing utility companies to apply for the restart of their nuclear reactors. Such a move, backed by the current pro-nuclear government, reversed the commitment of the previous government to phase out nuclear power programme by 2040. If nuclear power is reinstated, the prospect for coal would look even more gloomy.

Since Japan is poorly endowed with fossil fuel resources, supplies of coal and natural gas rely completely on imports. Japan is one of the most influential players in the global seaborne market, accounting for more than 20% of total global coal imports, and has set internationally traded coal prices for a long time. To secure its supply further, Japan has been involved with development of overseas coal mines, for example in Indonesia and Australia. Australia is the single largest supplier to Japan, while Indonesia has expanded its market share steadily since 2000. Japan's other sources of imports are China, Russia, the USA, South Africa, and Canada. A detailed discussion on Japan's coal imports can be found in Baruya (2012b).

In South Korea, coal provided around 29% of the country's total primary energy supplies (247 Mtoe) in 2010, compared to oil (40%), LNG (16%), nuclear (12%), hydro power (0.5%) and other renewables (2.3%) (Ryu, 2012). Coal fuelled 44% of the country's electricity generation coal (218 TWh out of 478 TWh in 2010); nuclear power accounted for 30%, while natural gas CCGT has a share of 21% with the remaining balance provided by oil, hydro and renewables (Baruya, 2012b). The steady rise in coal-fired power over time increased the demand for steam coal in South Korea. Coal consumption has increased by nearly 74% from 45.7 Mtoe in 2001 to 79.4 Mtoe in 2012 (BP, 2012b). Roughly 80% of the country's coal demand is steam coal, and 20% is for the steel industry as coking coal (Baruya, 2012b). Indigenous production provided around half of total coal supply in the 1990s, almost all of which was anthracite hard coal, but domestic coal now constitutes only a tiny fraction (~2.4% in 2009) of total coal supplies, mainly due to higher production cost compared to imported coal. Korea's coal-fired power plants are all located on the coast, and thus it is convenient to use imported steam coal. In addition to bituminous steam coal, anthracite hard coal (~3.5 Mt in 2009) is imported. Given the heavy reliance on coal, South Korea is likely to remain an important market for coal for the foreseeable future. But coal demand is forecast to decline in IEA's New Policies Scenario, largely due to falling demand for electricity and increased use of natural gas, nuclear and renewables.

Abundant resources of cheap coal have made Australia the world's ninth largest coal consumer, just behind South Korea. Some 76% of power generation is coal fired, with hard coal used in New South Wales and Queensland, and lignite in Victoria. Natural gas is more important for other States. Around 10% of the coal fleet is supercritical units built in the last decade, while the remaining capacity is comprised of old subcritical plants built in the 1970s and 1980s. Domestic coal consumption is forecast to decline slowly over the next twenty years, as natural gas and renewables increase their share. This change is underpinned by significant policy initiatives, responding to growing concern over climate change, including an expanded mandatory renewable energy target and carbon pricing.

4.2 Natural gas

Natural gas demand has bounced back strongly from the dip in 2009, thus resuming the consistent upward trend since the mid-1980s, and hit a new historic high of 3.2229 trillion m^3 (or 2.9056 Gtoe) in 2011 (BP, 2012b). Global gas demand rose by an estimated 6.6% in 2010, more than compensating for the earlier fall. Non-OECD demand has jumped ahead of OECD demand since 2008 as a result of strong growth in most non-OECD countries; gas use in China, for example, rose by 21.5% in 2011, making it the fourth largest and fastest growing gas consumer in the world, after the USA, Russia and Iran (BP, 2012b). Gas demand has also been expanding quickly in other parts of Asia and the Middle East as it is the preferred fuel to replace oil in power generation. Most OECD European countries have seen declines in gas demand, while there has been strong growth in OECD North America, Japan and Korea in 2011. Natural gas is expected to be the only fuel to steadily grow in demand in all three outlook scenarios envisaged by the IEA (IEA, 2012b). Overall, the energy policies and the economic growth in non-OECD nations will be the key driving force for future global gas demand.

4.2.1 China

China's 12th Five Year Plan (FYP), for the period 2011-15, establishes new energy targets. Nuclear power and renewables are to be aggressively promoted, with new capacity targets – hydro 120 GW; wind power 70 GW; nuclear 40 GW; solar 5 GW (NEA, 2012). As a result, coal's share in the total primary energy mix is expected to drop from 66% in 2008 to 63% in 2015, although coal consumption will grow substantially in absolute terms. The target for natural gas was set at 8.3% of the primary energy mix or 260 billion m^3 in 2015 (NEA, 2012). From past experiences, the FYP targets are likely to be surpassed. Natural gas production and consumption in China in 2000-15 is shown in Figure 11.

According to the latest national geological survey in 2005, the estimated natural gas reserves reached 56 trillion m^3, with 22 trillion m^3 as recoverable reserves, a 70% increase compared to the last survey in 1994 (IEA, 2012c). The bulk of gas reserves is spread between nine basins, mostly in the western and central-north parts of China. The top three basins in terms of recoverable gas reserves are Ordos basin, Sichuan basin and Tarim basin; the Ordos basin hosts the first array of gas fields developed in the late 1980s. China's offshore gas reserves have been discovered in the East China Sea, the South China Sea and Bohai Bay. China also has vast unconventional gas resources. Reserves of coalbed methane at less than two thousand metres deep are estimated at 36.8 trillion m^3 with 10.9 trillion m^3 considered recoverable (IEA, 2012c). The estimated reserves of shale gas are 134.4 trillion m^3

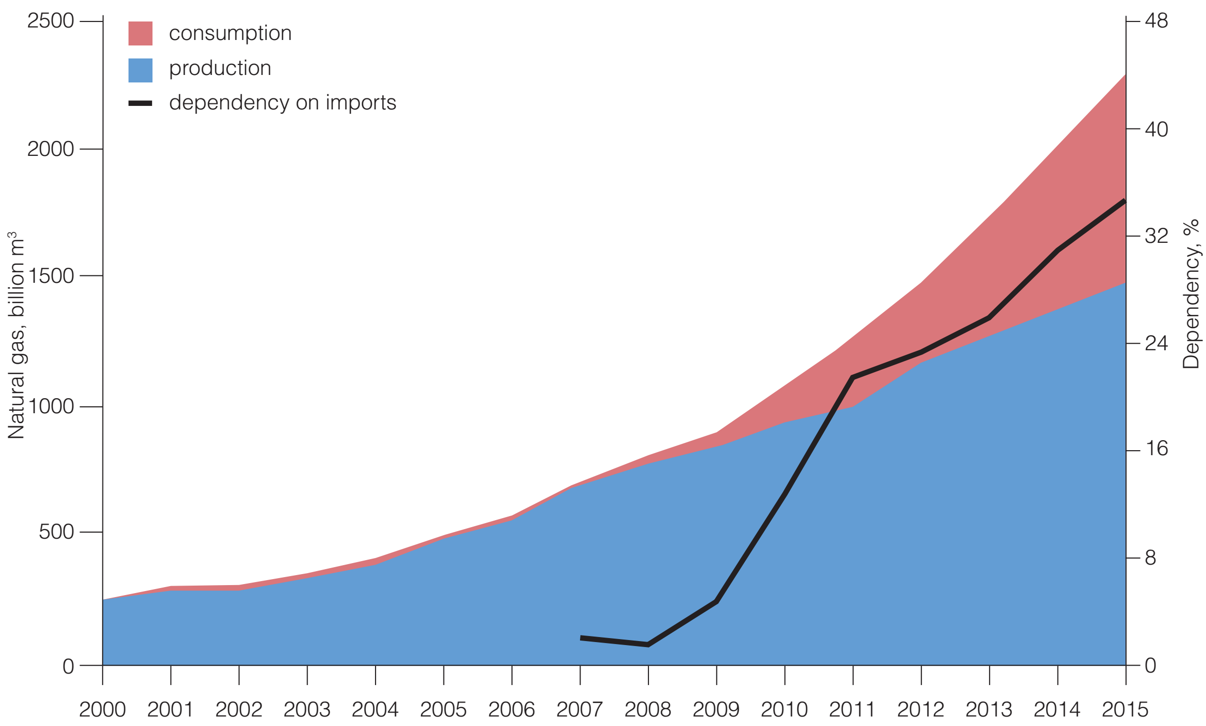

Figure 11 Natural gas production and consumption in China in 2000-2015 (NEA, 2012)

reserves, larger than the coalbed methane reserves, and the recoverable reserves could be as much as 25.1 trillion m^3 (IEA, 2012c).

The Chinese government has placed great importance on unconventional gas, encouraging 'expedition of exploration and development' in the State Government Report 2012. In September 2012, the Ministry of Land and Resources called the second round of exploration licence auction, where for the first time non-state-owned private companies and foreign companies were allowed to compete. Two months later, the Ministry of Finance and the National Energy Administration jointly agreed a subsidy of 0.4 RMB/m^3 for the exploration and development of shale gas during 2012-15 (OCPE, 2013). Thereafter, the Ministry of Land and Resources also released notifications on management of shale gas exploration, extraction and surveillance, which provide guidance and requirements for resource evaluation, R&D, and sector development.

Government supportive policies, in conjunction with higher gas prices, have increased domestic gas production. Gas output has surged from 30.3 billion m^3 in 2001 to 102.5 billion m^3 in 2011, with a compounded average growth rate of about 23.8% (calculated from BP statistics; 2012b). International companies have also been attracted to China's upstream sector. China National Offshore Oil Corporation and Husky Energy, a Canadian oil company, are jointly working on a deep-sea gas field with 170 billion m^3 of recoverable reserves in the South China Sea. Coalbed methane has already been produced commercially, mainly in the Shanxi province. Demonstration of shale gas production has been undertaken in Sichuan and Yunan. The first horizontal well, Wei 201-H1, has been completed, producing 1.77 million m^3 of gas during 150 days of testing (CNPC, 2011). China's oil companies are also buying shale gas resources in North America and working with international oil companies to gain experience that can be applied domestically. For instance, A Sino-US Shale Gas Resources Co-operation Initiative was launched in 2009.

China's natural gas consumption has been growing steadily, already at an average annual rate of 7% in the decade prior to the operation of the West-East pipeline. Thereafter, the annual growth rate jumped to almost 30% on average during 2005-11 (calculated from the BP statistics; BP, 2012b). China consumed 130.7 billion m^3 of natural gas in 2011, up 21.4% from the previous year (BP, 2012b). Indigenous production was 92.3 billion m^3; the shortfall of 38.4 billion m^3 was largely met by imports, estimated to be 31 billion m^3 (BP, 2012b; IEA, 2012c). Almost half of total imports came from Turkmenistan via the second West-East pipeline, which started operation in 2010. The remaining imports were delivered in the form of LNG. Almost 30% of the total LNG imports came from Australia, while Qatar, Indonesia and Malaysia accounted for some 19%, 16% and 13%, respectively (IEA, 2012c). During the 12th FYP period (2011-15), natural gas demand is forecast to rise at a annual compounded rate of 16% and reach 229 billion m^3 in 2015. Imports could account for 34.5% of total gas demand, three times higher than in 2010 (NDRC, 2012).

Over the past two decades, the industry sector has been the largest user of natural gas, accounting for more than half of the country's total gas consumption, but its importance is declining. The residential sector (around 20% of total gas demand), the power sector (5%), and gas and water (combined 10%) are becoming more important sources of demand (IEA, 2012c; Pang and others, 2011). Demand from the latter two sources has increased at a compounded annual growth rate of around 21% and 36.5% respectively during 2000-09 (IEA, 2012c). Gas demand is expected to continue its growth trend, though at a lower growth rate.

While the Chinese government promotes use of natural gas in all sectors in the long term, the near term priority is given to power generation and urban residential use. Since gas accounted for only about 1% of electricity generated in China in 2009, there is still room for increase. However, gas faces strong competition from coal, which is cheaper in most cases (IEA, 2012c). The main driver for developing gas-fired power is the requirement to reduce the air pollutant emissions in large cities. Nevertheless, the cost of fuel will still be a major element of consideration. As such, gas may find a niche role to play in regions far from coal mines. Those regions are typically southeastern coastal provinces, which can have difficulties accessing coal mined in the northern or northwestern parts of the country due to transport constrains of China's rail network (Minchener, 2007). There is still huge potential for further rise in demand from the industry sector, currently the largest user of gas. Switching from coal to gas in industrial plants could lead to both considerable reduction in GHG emissions and increased energy efficiencies. At present, only around 10% of China's population has access to natural gas, well below the world average of 40%. Greater penetration of gas could be achieved driven by government policies and development of distribution infrastructures.

In its New Policy Scenario, the IEA predicted that China's gas demand will grow at an average annual rate of almost 6% in 2008-35. Its total gas demand is expected to reach nearly 400 billion m^3/y by 2035, which accounts for 22% of the total increase in global gas demand (IEA, 2012a). While the power, residential and industry sector all drive up the near-term gas demand, power generation will be the dominant use of natural gas in the long term, accounting for almost half of the total gas use in China in 2035 (IEA, 2012a). Yet gas will still represent just 8% of total electricity production and 9% of total primary energy mix by 2035 (compared to 3% in 2008). China's gas market will still be 20% smaller than that of Russia and 40% smaller than that of the USA, the world's largest (IEA, 2012c).

China's massive increase in gas consumption over the past two decades has been underpinned by faster infrastructure development. Until recently, the gas grid in China had been fragmented, and gas utilisation limited to use as a local fuel or as feedstock for regional chemical fertiliser plants. In China, the larger trunk pipelines are operated by the state-owned oil companies, but the local distribution networks are managed by various local gas distribution companies. The Chinese government is trying to integrate the local gas distribution systems and promotes construction of inter-regional and cross-border long-distance gas pipelines. China National Petroleum Corporation has invested in gas retail projects and pipeline projects designed to transfer gas from gas fields in western and northwestern China to consuming cities on the country's eastern and southeastern coastal regions. Figure 12 shows the gas infrastructure of China.

Building long-distance inter-regional gas pipelines started in the late 1990s. The Ordos (Shannxi)-Beijing pipeline was the first major inter-regional pipeline, completed in 1997, with a capacity of 3.6 billion m^3/y. In 2005, the second Ordos (Shannxi)-Beijing pipeline with a capacity of 12 billion m^3 was completed and extended to a larger number of provinces. China's most ambitious transmission project is the West-East Pipeline, which is the longest in the world. The first West-East pipeline with a capacity of 17 billion m^3/y (completed in 2004) transfers natural gas from Tarim Basin in western China to Shanghai. The second West-East pipeline, connecting Turkmen gas to the Pearl River Delta Economic Zone in southern China, was completed in December 2012 and its capacity is 30 billion m^3/y. In October 2012, the third West-East pipeline also with a capacity of 30 billion m^3/y was launched; it transfers gas from Huoerguosi in Xingjiang to Fuzhou in the Fujian province. In addition, China National Petroleum & Chemical Corporation (Sinopec) built two more inter-regional pipelines from Sichuang to the Yangtze River Delta Economic Zone (the Sichuan-East pipeline) and to the Pearl River Delta Economic Zone (the Sichuan-South pipeline). The China-Myanmar oil and gas pipeline project is another cross-border gas transmission system, which has officially started construction and will have a capacity of 12 billion m^3/y. Moreover, two offshore pipelines have been in operation: one connects the Yacheng gas field in the South China Sea to Hong Kong (finished in 1996), while the other transfers gas from the Pinghu gas field in the East China Sea to Shanghai (completed in 1999). By the end of 2010, the total length of China's domestic gas pipelines reached 40,000 km, with a total capacity exceeding 100 billion m^3/y (IEA, 2012c). These inter-regional and cross-border pipelines are complemented by regional gas transmission networks built in the southwest, the Bohai Rim, Yangtze River Delta, the central South, and the northwest.

Along with gas pipelines, China is expanding its LNG regasification capacity. The country started importing LNG from Australia (North West Shelf) in 2006. It now has five LNG receiving terminals in operation with a total regasification capacity of around 29 billion m^3. These terminals are located in Guangdong, Fujian, Shanghai, Jiangsu and Dalian. Six new LNG terminals are reported to be under

Figure 12 Natural gas infrastructure in China (IEA, 2012c)

construction or expansion, which would increase China's total LNG regasification capacity to over 50 billion m^3 in a few years (IEA, 2012c).

Underground gas storage facilities have been built to improve the ability of the gas grid to respond to seasonal peaks in gas demand. Four gas storage facilities at Dagang, Huabei, Jintan and Liuzhuang are already in operation. However, those facilities account for only about 3% of the country's natural gas sales. CNPC plans to build ten more gas storage facilities during 2011-15 to bring the total capacity to 22.4 billion m^3. When all the planned gas storage facilities are completed, the total storage capacity will present 8–10% of the country's total gas sales, close to the 10–15% average for OECD countries (China Daily, 2011).

4.2.2 North America

The USA is the world's largest gas consumer; its gas consumption reached 690.1 billion m^3 in 2011, up by 2.4% from the previous year (BP, 2012b). Natural gas accounted for a quarter of the USA's total primary energy consumption in 2011, compared to 20% of coal and 36% of petroleum (EIA, 2012). Natural gas consumption has been increasing steadily since 2006 except for a dip in 2009 due to the economic downturn. Consumption rebounded strongly in 2010 to a level that was even higher than the level prior to recession. US natural gas consumption is projected to growth by 0.4%/y from 2010 to 2035 in the AEO 2012 Reference Case,.

Natural gas is used across the country, and the top consuming states in 2010 were Texas, California, Louisiana, New York, Florida and Illinois. The major consumers of natural gas included the electric power sector (31%), industrial sector (28%), residential sector (19%), commercial sector (13%), oil and gas industry operation (6%), pipeline distribution use (3%) and vehicle use (<1%) (EIA, 2011). The US EIA estimated that natural gas consumption will grow by about 0.4%/y from 2010 to 2035, or by 2.5 trillion cubic feet (70.8 billion m^3) in total, to 26.6 trillion cubic feet (753.2 billion m^3) in 2035. This growth in consumption will be led by the use of natural gas in electricity generation.

The electric power sector is the largest user of natural gas and has been the main driving force behind the USA's rapidly rising gas consumption since 2009. Sustained low gas prices due to a boom in shale gas production, in conjunction with increasingly strict environmental regulations, have already shifted electricity utilities' preferred fuel from coal to natural gas, particularly in the southwestern region of the country. Regardless of natural gas price volatility, some utilities have decided to take advantage of low natural gas prices by investing in new gas-fired power plants. The US Energy Information Agency (EIA) projected that the gas consumption in the power sector would grow by 16% in 2012 (EIA, 2012). Nevertheless, in EIA's AEO 2012 Reference Case coal remains the dominant fuel for electricity generation, even though its share declines significantly. In 2010, coal accounted for 45% of US total electricity generation, but its share is projected to drop to 39% in 2020 and 38% in 2035, respectively (EIA, 2012). Competition from natural gas and renewables is the key reason for the declining coal share. The coal-fired electricity generation in 2035 will be 2% higher than in 2010 but still 6% below the pre-recession level (EIA, 2012). Generation from natural gas is projected to grow by 42% during 2010-35, and its share in the electricity mix will rise from 24% in 2010 to 28% in 2035 (EIA, 2012).

The industrial sector is the second largest source of demand for natural gas. Consumption concentrates in a relatively small number of industries, including pulp and paper, metals, chemicals, petroleum refinery, masonry, clay and glass, plastic and food processing. Natural gas is the most important energy source for those industries, accounting for slightly more than one third of total delivered industrial energy consumption (EIA, 2012). Industrial consumption is projected to grow by 8% from 2010 to 2035, reflecting sustained relatively low gas prices (EIA, 2012).

Natural gas is the most used fuel for residential and commercial space heating. homes. Slightly more than half of the homes in the US use natural gas as their main heating fuel. In addition, natural gas is to fuel stoves, water heaters, and other household appliances. The US DOE estimates that in 2011 natural gas is the lowest cost conventional energy source available for residential use, 68% less expensive than electricity. However, demand for natural gas in the residential and commercial sectors is expected to decline as the result of increased energy efficiency and fuel switch to electricity driven by new energy efficiency standards (EIA, 2012).

US natural gas consumption has outpaced indigenous production since 1986; it consumed more natural gas than it produced in 2010, importing 2.6 trillion cubic feet (73.6 billion m^3) from other countries. In the AEO 2012 Reference Case, domestic natural gas production grows more quickly than consumption. As a result, the USA becomes a net exporter of natural gas by around 2022, and in 2035 net exports from the USA could total about 1.4 trillion cubic feet (39.6 billion m^3) (EIA, 2012). The prospects for future US natural gas exports are highly uncertain and depend on many factors that are difficult to anticipate, such as the development of new natural gas production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits and the Arctic.

The increase in domestic gas production from 2010 to 2035 in the AEO 2012 Reference Case results primarily from the continued development of shale gas resources. Shale gas is the largest contributor to production growth. While there is relatively little change in output from tight formations, coalbed methane deposits, and offshore fields, production from onshore conventional gas fields is expected to decline (NETL, 2012).

Shale gas is projected to account for 49% of total US natural gas production in 2035, more than double its 23% share in 2010. Tight gas produced from low permeability sandstone and carbonate reservoirs is the second-largest source of domestic supply in the Reference Case, averaging 6.1 trillion cubic feet (172.7 billion m^3) of production from 2010 to 2035. Coalbed methane production remains relatively flat throughout the 2010-35 projection period, with an average output of 1.8 trillion cubic feet (51.0 billion m^3) per year. Offshore natural gas production is expected to decline by 0.8 trillion cubic feet (22.7 billion m^3) from 2010 to 2014, following the 2010 moratorium on offshore drilling, as exploration and development activities in the Gulf of Mexico focus on oil-directed activity. After 2014 offshore production is expected to continue to rise.

Given the increase in shale gas production in the USA, domestic natural gas prices are projected to remain below their 2005-08 levels through to 2035 due to a rapid supply growth that exceeds demand growth. However, it appeared that following aggressive development of new wells during 2006-08, US natural gas companies seem to be trimming their higher cost production until prices reach higher ground, and many uncompleted wells appear to be put on hold as well. Consequently, the market may never see the lowest prices recorded in 2012 again in the future. In addition, the relatively high levels of underground natural gas storage will also contribute to excess supply in the short term and maintain low prices. As of April 2012, US natural gas storage was at a relatively high level of 70.8 billion m^3, 51% higher than the storage level in the previous year (NETL, 2012).

Although the USA imported 11% of its total natural gas supply in 2010, rapid expansion of domestic natural gas production is changing the USA's dependency on gas imports. Pipeline imports, mainly from Canada, accounted for about 10% of total US gas supply in 2010 and are projected to decrease further over the next two decades (EIA, 2012). In Mexico, as the consumption rate is expected to exceed the production rate, future US exports to Mexico are expected to increase to fill in the gap.

There are 12 existing LNG import facilities located along the gulf and east coasts of the USA. However, the American Gas Association (2011) reported that only 4% of total LNG import capacity was used in 2011 compared to 2007. As long as domestic gas production continues its relative strength against other supply options, the under-utilisation of existing LNG import capacity is likely to continue. The Federal Energy Regulatory Commission has approved an additional 283 million m^3/d of LNG import projects (American Gas Association, 2011). However, recent development in the gas market has placed doubt on the commercial viability of these projects. Indeed, the USA may soon export LNG. It was reported that Cheniere is now developing a project to add liquefaction and export capabilities adjacent to the exiting LNG regasification facility at the Sabine Pass LNG terminal in Louisiana (Cheniere, 2012). Cheniere has entered sale and purchase agreements with several customers, including Total, KOGAS (Korea), and Gail (India). In addition to Sabine Pass, there are several other LNG export terminals planned in the USA and Canada. The US EIA estimated that there will be LNG export capacity of 1.1 billion cubic feet per day (31.15 million m^3/d) in operation in 2016 and that an additional 1.1 billion cubic feet per day of capacity is expected to come online in 2019. At full capacity, these facilities could ship 800 billion cubic feet (22.7 billion m^3) of LNG to overseas consumers per year. However, since LNG will continue to be shipped to the New England region, the actual LNG sold to the international market may be less than those implied figures. In general, future US exports of LNG depend on a number of factors that are difficult to anticipate and thus are highly uncertain. IEA estimated that USA LNG might not take a large international market share considering the fierce competition between global suppliers. None the less, the impact on global markets of the increase in US export capacity is set to be significant because the correlation between international LNG prices and US domestic price is considered to be strong.

Canada is the world's third largest producer of natural gas after the USA and Russia, and the sixth largest consumer of natural gas after the USA, Russia, Iran, China and Japan (BP, 2012b). Total annual production reached160.5 billion m^3 in 2011, more than half of which was exported to the USA (BP, 2012b). Canada is the largest exporter of natural gas to the USA, with Canadian gas accounting for 12.8% of total US gas consumption in 2011 (BP, 2012b). Canada and the USA form a highly integrated regional market facilitated by a large pipeline network between the two countries. Canadian gas production is following similar trends to that in the USA, with conventional gas producing regions in decline, and increasing production of unconventional gas due to ready transfer of technology across the border. In addition, Canadian gas can be exported to the Asian markets via the proposed LNG terminals at Kitimat on the west coast in British Columbia, which have an initial plant capacity of 5 Mt/y LNG output with potential expansion to 10 Mt/y or more (Kitimat LNG, 2012).

The industrial sector is the largest source of demand for natural gas, accounting for 33% of Canada's natural gas consumption in 2011 (CAPP, 2012). Natural gas provides about half of the energy used in the industrial sector. Natural gas is the single largest form of energy used in the residential sector; 22% of Canada's total natural gas consumption in 2011 was for home space heating and cooking. Natural gas currently provides 5% of Canada's electricity generation, making the electric power sector the third largest consumer of natural gas (28%). The remainder of natural gas is consumed by the commercial sector, while transport accounts for a tiny (0.1%) share.

According to estimates by Canada's National Energy Board, the increase in natural gas demand in Canada outweighs the increase in marketable production during 2011-35, under its Reference Case (NEB, 2011). In 2011, 131.0 million m^3/d was available for export and in 2035 that decreases to 102.3 million m^3/d, a 22% drop (NEB, 2011). Demand (excluding gas consumed for gas production and processing) is forecast to increase by 62% from 2011 to 2035, largely from the oil sands sector and the electric power sector. In contrast, domestic natural gas supply increases by 33% (NEB, 2011). The projections are very sensitive to assumptions of gas prices, with a high gas price resulting in more gas available for export and a low gas price rendering Canada a net importer of gas by 2029 (NEB, 2011). More discussion on natural gas prices can be found in Chapter 5.

4.2.3 Europe

Gas demand

Primary energy consumption in the EU-25 reached 1760.1 Mtoe on a net calorific value (NCV) basis in 2010 (EuroGas, 2011). If Switzerland and Turkey were added, the EU-27's consumption totalled nearly 1900 Mtoe. Natural gas accounted for approximately 25% of the EU-25's total primary energy consumption, whilst solid fossil fuels (mostly coal) had a share of 16%. It is noted that a 7% increase in gas consumption between 2009 and 2010 coincided with an 11% increase in renewable energy in the same period (for comparison, coal and nuclear each increased by 3%, while oil fell by 1%) (EuroGas, 2011). This parallel trend illustrates the role of natural gas as an enabler for the penetration of renewable energy, which is expected to continue.

Figure 13 shows the relative importance of coal versus gas, which varies considerably across the EU-27 states. One can group countries broadly into three categories according to the relative sizes of the shares of natural gas and coal in a state's total primary energy consumption. In the first category, countries have relied much more on natural gas than on coal. Austria, Belgium, France, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Romania, Slovakia, Spain, the UK and Switzerland fell into this category. In contrast, other states, including Bulgaria, Czech Republic, Estonia, Finland, Greece and Poland, have consumed significantly more coal than natural gas. The third category comprises states where the two energy resources stood roughly at parity. These states are Denmark, Germany, Portugal, Slovakia, Sweden, and Turkey. Gas versus coal competition thus has distinct features and implications across the three categories of states, and is briefly discussed below.

According to Eurostat's statistics, the EU-27 has seen an almost uninterrupted steady increase in gross inland consumption of natural gas from approximately 370 Mtoe on a gross calorific value (GCV)

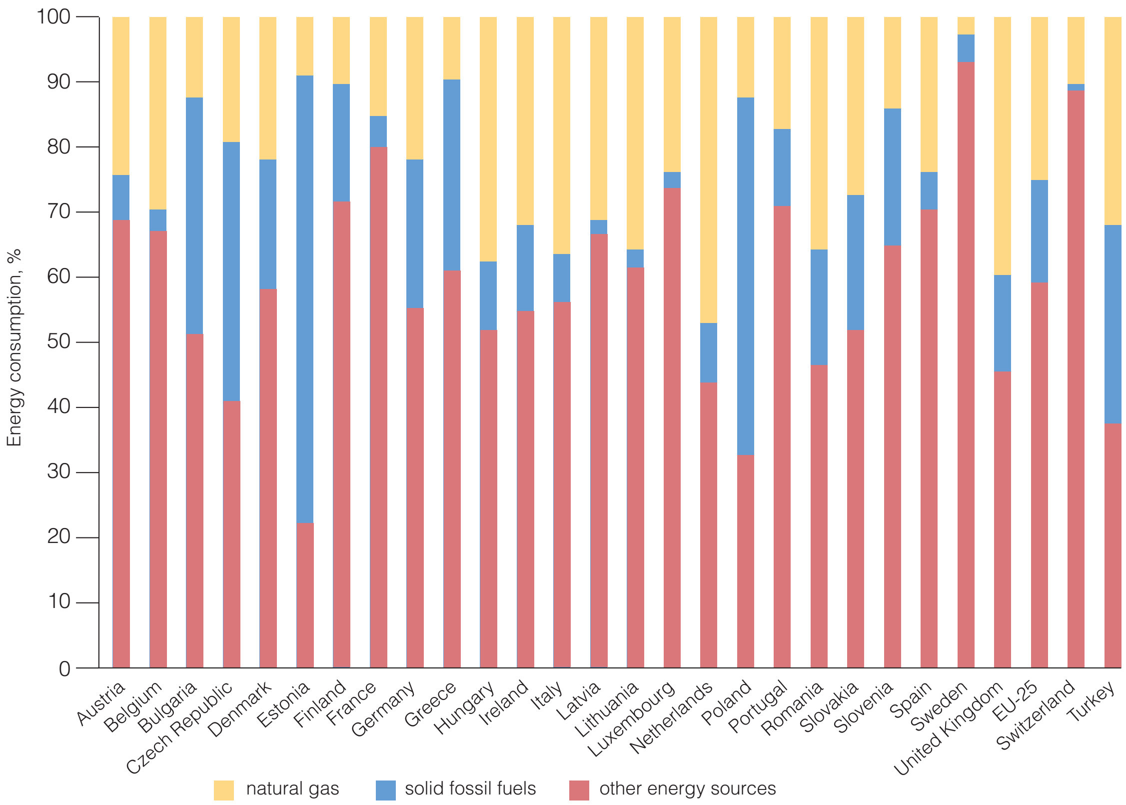

Figure 13 The share of natural gas and solid fossil fuels (mostly coal) in the national total primary energy consumption across the EU member states (EuroGas, 2011)

basis in 1995 to nearly 500 Mtoe (GCV) in 2005 (Eurostat, 2012). Gas consumption peaked in 2005, then dropped to close to 480 Mtoe over the following two years, before recovering slightly in 2007. The economic crisis in 2008-09 resulted in decreased demand for gas, though in 2010 it recovered rapidly close to the peak level seen in 2005. However, the consumption plummeted again to approximately 440 Mtoe in 2011, a level last seen around 2000 (Eurostat, 2012).

EuroGas uses inland deliveries to take stock of demand for natural gas, which represents deliveries of marketable gas to the inland market, including gas used by the gas suppliers for heating and operation of their equipment and including losses in distribution. Power generation, industry, and the residential and commercial sectors are the three dominant sources of demand. The relative importance of these three demand sources varies considerably across the 27 nations. Despite the existence of technology that would allow substitution for oil products (there were around 780,000 natural gas vehicles in 2009), the penetration of natural gas in road transport is currently low, representing only 0.3% of natural gas sales in 2010. Nevertheless, there was a 12% increase in volumes dedicated to transport between 2009 and 2010 (EuroGas, 2010). There could be faster penetration if there were favourable price differentials between gas and oil and direct support from governments.

In the residential and commercial sectors, gas consumption has steadily increased in line with the expansion of infrastructure and the associated rise in the number of gas users. During 1998-2009, gas consumption in those two sectors had seen annual growth of 1.5%, reaching 160 Mtoe in 2009, which accounted for 35% of the total gas consumption and rendered gas the most important fuel in these two sectors (EuroGas, 2010). However, growth is expected to slow considerably in future years, because high market penetration has already been reached in major gas consuming states. In other states, demand from the residential and commercial sectors will also reach saturation point. This is mainly due to moderate population growth in most EU states (even negative growth in some states) as well as a low population density, which may limit the economic scope for further increase in demand. Other factors, such as improved energy efficiency of buildings, adoption of more efficient heating systems and increased competition from renewables, also contribute to limited growth in gas demand. In its Base Case Scenario, EuroGas expected gas sales into the two sectors to peak around 2015 and then to fall slightly back to the 2009 level at around 170 Mtoe (EuroGas, 2010).

Gas is a major fuel for industry, accounting for 31% of the final energy consumption (excluding industrial power generation) of this sector in 2009 (EuroGas, 2010). For industrial use, the price of fuels largely determine their competitiveness. Gas could expand its market share at the expense of oil and coal if it can be supplied at competitive prices. The future energy demand from this sector is unlikely to increase substantially, because the sector is investing in plant modernisation and replacement in the face of international competition to reduce production costs. These efficiency-improving measures limit the scope for more consumption of gas.

The role of natural gas in the power generation sector has become increasingly important since the 1990s, with rapid developments in the UK, Italy and Spain. This was mainly due to the environmental benefits and operating flexibility of gas-fired power plants. In 2009, gas-fired power stations produced 20% of the electricity production in the EU-27, compared with 7.5% in 1990 (EuroGas, 2010). In contrast, hard coal and lignite accounted for 16% and 12%, respectively (EURACOAL, 2010). The natural gas demand of EU-27 between 2009 and 2010 increased by 7.3% to 485.8 Mtoe, while 3% of the increase came from the power sector (EuroGas, 2011). Such a sizeable growth was due both to partial economic recovery and fuel switching to gas. Future demand from the power sector will depend on the growth of electricity demand, relevant energy policies (mainly on nuclear and renewables), integration of renewables into the power grids and evolution of the European CO_2 Emissions Trading Scheme. The relative price competitiveness of gas to coal and oil in conjunction with the CO_2 prices will determine the load factor at which gas-fired power generation will be operated. More discussion on pricing of gas, coal and carbon can be found in the next chapter.

Natural gas is considered to be the fuel that benefits most readily from a switch away from nuclear power. Government anti-nuclear power policy is likely to provide a further boost to natural gas use in electricity generation, notably in Germany, Italy and Switzerland.

A variety of estimates has been made of natural gas consumption over the next two decades or so (by 2030 or 2035). Since the authors did not have access to complete forecasts by commercial information houses such as IHS Global Insight and Deloitte, the discussion in this report will focus on estimates made by the public bodies, including EuroGas, IEA, and the US DOE/EIA.

EuroGas expected that natural gas consumption in EU-27 would increase by 43% from 438 Mtoe in 2005 to 635 Mtoe in 2030. The share of natural gas in EU-27 primary energy mix was expected to rise from 24% to 30% in the same period (18% in 1990); approximately 60% of the total gas demand increase will come from power generation (EuroGas, 2010).

According to World Energy Outlook 2012, gas demand in Europe would recover slowly in the medium term, returning to the level of 2010 only towards the end of the 2010s in the face of relatively high gas prices, strong growth in renewable energy and weak carbon prices (which favour coal in power generation). Thereafter, gas demand would grow more strongly, mainly on the back of increasing demand from gas-fired power generation. In IEA's New Policies Scenario, natural gas demand in Europe would increase from 569 billion m^3 in 2010 to 669 billion m^3 in 2035 at an average annual growth rate of 0.7% (IEA, 2012a).

The US Energy Information Agency (US DOE/EIA) projected that natural gas consumption in OECD Europe will grow by 0.7%/y on average, from 19.5 trillion cubic feet (~550 billion m^3) in 2008 to 23.2 trillion cubic feet (~660 billion m^3) in 2035, primarily driven by increasing use for electricity generation (EIA, 2011). In the EIA 2011 Reference Case, natural gas is second only to renewables as Europe's most rapidly growing source of energy for electricity generation, as its share of total power generation grows from 20% in 2008 to 22% in 2035 (EIA, 2011). This, however, did not take into account the recent actions by some European governments to reduce reliance on nuclear power in the wake of Japan's Fukushima Daiichi nuclear incident.

Despite different assumptions adopted (and hence different figures), the forecasts from all three sources show a modest increase in gas demand, which is mainly driven by increasing consumption for power generation. Many governments in OECD Europe have made commitments to reduce GHG emissions and promote development of clean energy. Natural gas potentially has a dual role to play in reducing GHG emissions, both as a substitute for more carbon-intensive coal-fired generation and as back-up for intermittent generation from renewable energy sources.

However, the European natural gas market has been criticised as being slow to respond to and support electric power markets. The EU has been attempting to implement legislation that would ease third-party access to Europe's natural gas transmission pipelines and thus allow independent operators access to existing infrastructure. The European Commission now has internal market rules for electricity and gas, which give regulated third party access to all transmission and distribution infrastructures and for LNG facilities. Operators of such infrastructures must grant third parties (companies other than their related companies) non-discriminatory access and they earn a regulated return on their investment for such assets. Moreover, since 3 March 2011, the operators of such infrastructures are subject to ownership unbundling (Europa, 2012). Such reform measures remove the previous barriers to growth and should increase spot trading volumes. Nevertheless, some new investment, particularly cross-border gas pipelines and LNG terminals may be exempted entirely or partially from the respective rules of EU energy for a limited period of time at the discretion of national regulators.

Gas supplies

Natural gas supplies are defined as indigenous production plus stock changes and imports minus exports. The largest volume of gas supplied to the EU-27 nations comes from indigenous production, making up 35% of the total net supplies in 2010 (EuroGas, 2011). The Netherlands has become the largest indigenous producer of natural gas, followed by the UK, Denmark, Romania, Italy, Hungary, Ireland, Austria, Germany and Poland in descending order. Despite the recent rise in production in the Netherlands, the IEA forecast that its production will return to gradual decline as the super-giant Groningen field edges closer to depletion and smaller fields reach maturity. The UK continental shelf is also a mature gas production area and proven reserves now amount to 625 billion m^3 (IEA, 2009). Recent new licensing for oil and gas production will help to lessen the declining rate of output. Nevertheless, the UK gas supply, which fell from 115 billion m^3 in 2000 to 45.2 billion m^3 in 2011 (BP, 2012b), is projected to fall further, to 44 billion m^3 in 2015 and to less than 20 billion m^3 in 2030 in the Reference Scenario (IEA, 2009).

Consequently, indigenous gas production in the EU has been in steady decline, and the trend is expected to continue over the next two decades. EU gas supplies are forecast to tail off to just over 100 billion m^3 in 2030, less than half the current level (IEA, 2009). Conventional production is expected to continue its long-term downward path as the existing production reservoirs become depleted and drilling costs increase (Laidlaw, 2012). Production of unconventional gas (mainly coalbed methane (CBM) and shale gas) in Europe is projected to pick after 2020, led by Poland, and to reach 20 billion m^3 by 2030; this partially offsets the rate of decline but is not seen for the moment to change the overall gas supply picture for the EU (IEA, 2012a). Moreover, the prospect for unconventional gas in Europe is limited, constrained by the geology, permitting issues and the lack of an established supply chain.

As the result of the falling indigenous gas production and the modest rise in gas demand, the gas supply gap is widening (Laidlaw, 2012; IEA, 2012a). This gap needs to be filled by gas imports, which the EU is well placed to secure from a variety of external sources. Gas reserves in Russia, the Caspian region, the Middle East and North Africa are within pipeline reach of European markets, and LNG can also be delivered to European consumers from producers around the world, primarily from the Middle East, North and West Africa, and the Caribbean. The pattern of gas trade will depend on a range of factors, including the comparative supply costs of different producers, existing contractual arrangements, the availability of gas for export against domestic consumption, upstream investment risks, the reliability of different supply routes into Europe and government and/or EU policies on supply diversity.

Roughly speaking, there are four main possible gas corridors, with different maturity, challenges and future possibilities.

Northeast corridor

The main Northeastern corridor is from Russia, which is the largest source of imports for the EU. Gazprom has a dominant position in Russian gas production and transportation; it owns the Russian gas transmission system and has a monopoly on gas exports. In 2011, Gazprom, which accounted for around 78% of the Russian gas output, sold 150 billion m^3 to Europe. The largest buyers of Russian gas were Germany, Turkey and Italy. In the same year, gas supplies to the Commonwealth of Independent States (CIS) and the Baltic states totalled 71.1 billion m^3; the largest volumes were delivered to Ukraine, Belarus and Kazakstan. At present, gas delivery is made primarily through two supply pipeline networks in operation: the Northern Lights and Druzhba (Brotherhood) gas pipelines, which supply the Northern EU via Belarus and Poland and South-eastern EU via Ukraine and Slovakia, respectively, *see* Figure 14.

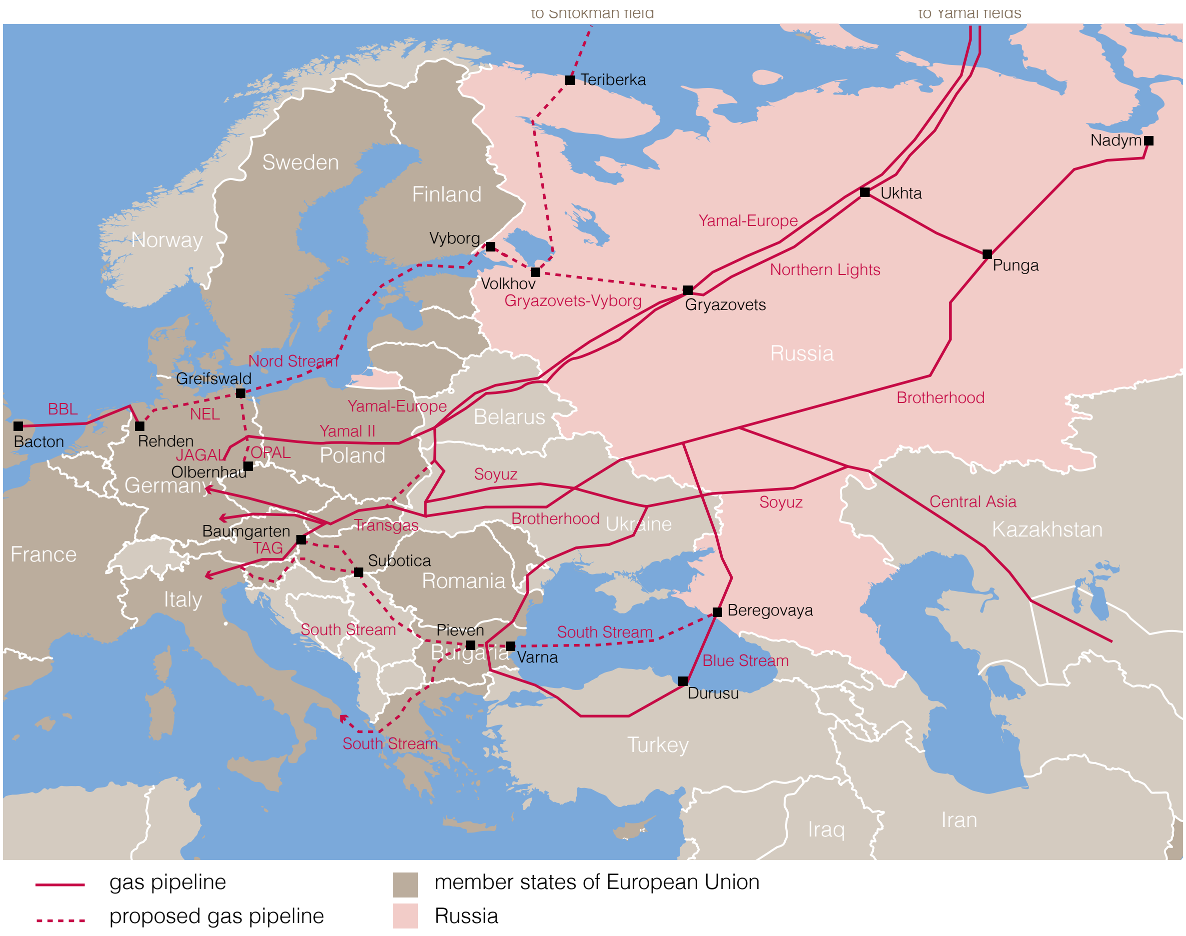

Figure 14 Russian gas export pipelines to Europe (Gazprom, 2012)

Gazprom is actively developing new gas transmission systems. Priority has been given to the Yamal pipeline, which will bring new gas production from the remote Yamal peninsula across Northwest Russia towards Europe, and the Nord Stream pipeline, which will connect Russia directly to Germany across the Baltic Sea. The Yamal-Europe gas pipeline crosses Russia, Belarus and Poland. With a design capacity of 33 billion m^3/y, it connects natural gas fields in Western Siberia, and in the future on the Yamal peninsula, with Germany. The 1997 km section between the Torzhok compressor station in Russia and the joint section with the STEGAL gas pipeline in Germany has been commissioned. In addition, the SRTO-Torzhok gas pipeline, under construction, will increase the capacity of gas deliveries to consumers in Northwest Russia as well as gas exports via the Yamal-Europe gas pipeline. Meanwhile, the Urengoy transportation hub is being expanded with the aim of transmitting extra gas volumes from the developing fields of Nadym-Pur-Trazov region. The Nord Steam pipeline system was started in 2005. A joint venture was set up in Switzerland to manage the design, construction and offshore exploitation of the project. Gazprom holds 51%, while BASF and E.ON each hold 24.5% of the shares. The planned 917 km onshore section of Nord Stream crosses Russia from Gryazovets to Vyborg. The offshore section, with a total length of 1198 km, is planned to be laid along the Baltic sea bed off the coast of Germany with branches to Sweden. It has a design capacity is 55 billion m^3/y and is planned to be completed by 2015 (Gazprom, 2012).

The Pochinki-Izobilnoye gas pipeline is a part of the Russia-Turkey gas pipeline system. The design capacity is 26.2 billion m^3/y. The pipeline will provide an opportunity to supply gas from the fields of the Nadym-Pur-Tazov region to the Blue Stream gas pipeline. At present the construction of the Petrovsk-Frolovo-Izobilnoye linear section is being undertaken.

The latest development is the South Stream pipeline with a design capacity of 63 billion m^3/y, for which an investment decision was made in December 2012. South Stream will transport Russian natural gas from the Russkaya compressor station near Anapa through the Black Sea to Bulgaria and in the future to Serbia, Hungary and Slovenia, then finally to Austria and northern Italy. The previously-conceived alternative Bulgaria-Greece-Ionian Sea-Italy route was abandoned. The project is seen as a rival to the planned Nabucco pipeline.

Most of the transmission system development is driven by Russia's quest for reduced dependency on transit countries, following disputes over gas supply and transit with Belarus in 2004 and with Ukraine in 2006 and 2009. If both Nord Stream and South Stream are built with the capacities currently envisaged, some 118 billion m^3 of new export capacity will be added (IEA, 2012a). This is significantly more than would be required to meet Russia's projected medium-term exports to Europe. These new transmission pipelines have the potential to change the pattern of Russia's export flows significantly and result in lower utilisation of the existing routes through Ukraine and Belarus. With the resulting spare capacity on existing routes, the question remains as to whether transit costs and risks justify the additional up-front investment in new underwater pipeline capacity.

Northwestern corridor

The Northwestern corridor is from Norway. Norway is the second largest exporter to the EU, providing close to 20% of European gas consumption in 2010 (NPD, 2011). In 2010, 92.5% of Norwegian gas production (105.3 billion m^3) was exported via pipelines and 4.7% sold as LNG, whilst domestic sales accounted only for 1.6% (NPD, 2011). Norwegian gas is exported to all main gas consumers in western Europe; in 2010, the UK accounted for 29.5% of Norwegian gas exports, followed by Germany (25.9%), France (11.8%), the Netherlands (10.1%), Belgium (6.4%), Italy (4.7%) and Spain (3.5%). Producing companies on the Norwegian continental shelf have gas sales agreements with buyers in Germany, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark. The Snøhvit LNG liquefaction facility in the Barents Sea delivers 4.3 billion m^3/y of LNG to Europe, and possibly to North America, Brazil and South Korea. The gas sales are expected to peak around 2020 at a level in the range 105–130 billion m^3, and then drop to 80–120 billion m^3 in 2025 (NPD, 2011).

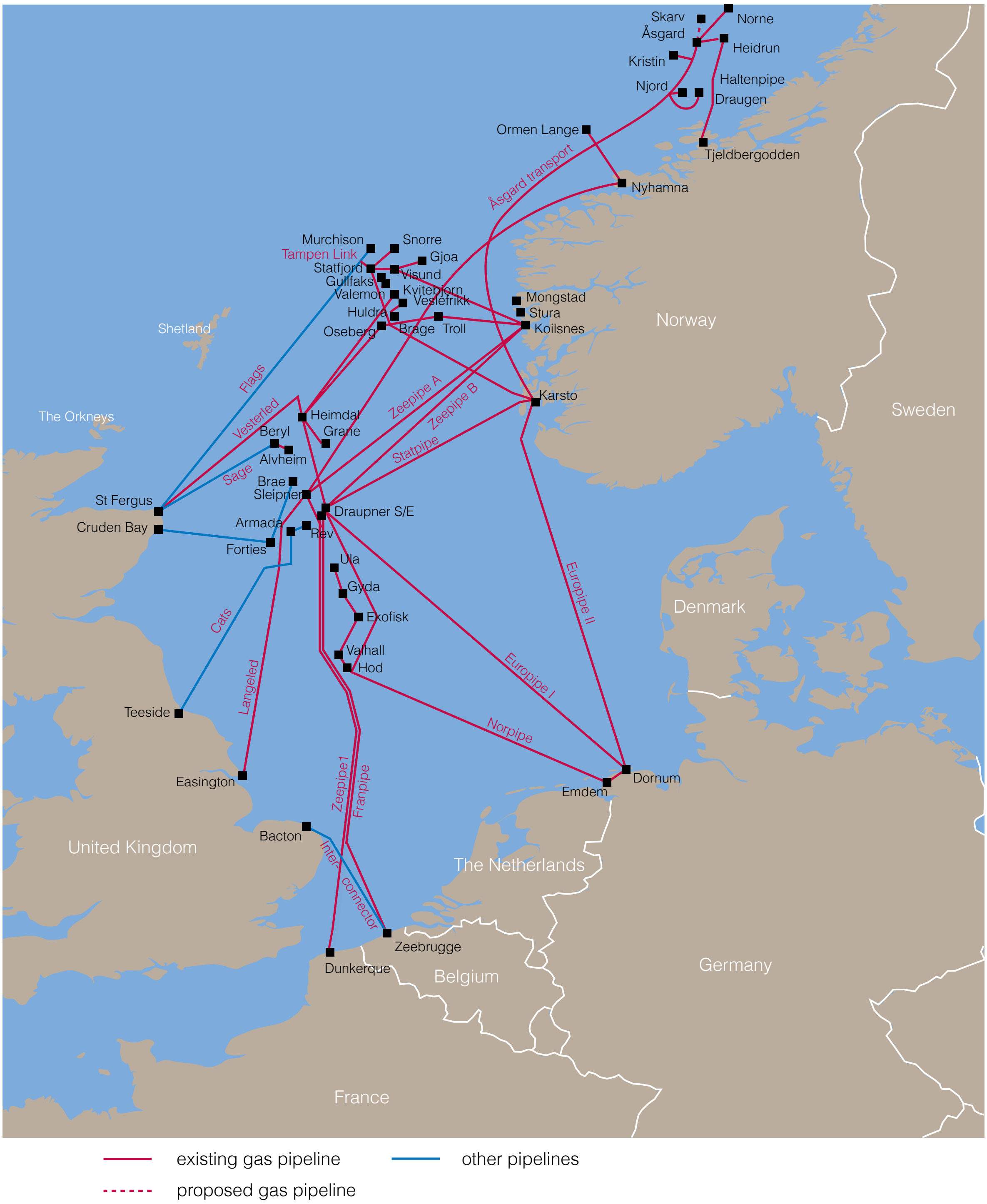

Figure 15 Norwegian gas pipelines (NPD, 2011)

As shown in Figure 15, several pipelines connect to the European markets from the sources in the North Sea. The Langeled, Cats, Sage, Pulsmar, Vesterled and Flags pipelines connect to the UK for consumption or transit. Europipe I/II connect directly to the continental import points in Dornum in Germany; Norpipe connects directly to Emden in Germany. Zeepipe I connects to Zeebrügge in Belgium and Franpipe connects to Dunkerque in France. Transport capacity in the Norwegian pipeline system is currently about 120 billion m^3/y. With sufficient new field developments and market interest, a new pipeline may be required in the medium term to accommodate growth in exports to continental Europe (IEA, 2012a).

Southwestern corridor

The Southwestern corridor is from Algeria. Algeria's gas export capacity is currently about 79 billion m^3/y. That would rise to 89 billion m^3/y by 2013 and 113.5 billion m^3/y by 2030, following completion of current investment programmes. However, there are doubts over the country's ability to increase gas exports because of rapidly rising domestic demand. The past four years have seen steady decline in gas exports from Algeria, from 56.3 billion m^3 of gas in 2010 and 51.5 billion m^3 in 2011(BP, 2012b). The Algerian Government's official forecast shows exports rising to 90 billion m^3 in 2030 (Mott MacDonald, 2010). Algeria has four LNG plants: Arzew, Skikda, Bethioua and Gassi Touil. It has three gas export pipelines:

- Enrico Mattei Gas Line (previously known as Transmed) from Algeria via Tunisia to Italy completed in 1986 with a total capacity of 33.5 billion m^3/y;
- Pedro Duran Farell Gas Line (PDFG; previously known as Gasoduc Maghreb) from Algeria via Morocco to Spain and Portugal, completed in 1996 with a current total capacity of 20 billion m^3/y;
- Medgaz, from Algeria to Spain, completed in 2011 with an initial capacity of 8 billion m^3/y.

Another pipeline is Galsi from Algeria to Sardinia and mainland Italy, which is in the planning stage. Also noted is the proposed Trans-Sahara Gas Pipeline from Nigeria to Algeria. The 4400 km gas line could open up a new route to export gas to Europe by connecting the Niger Delta in Southern Nigeria to Algeria's Mediterranean coast at Beni Saf and on to Europe. The BP Statistical Review shows gas pipeline exports of 34.4 billion m^3 in 2009 and LNG exports of 17.1 billion m^3. Of the pipeline exports, the majority went to Italy, and the rest to Spain, Portugal and Tunisia. The LNG exports were more geographically dispersed, including France, Spain and Turkey.

Southern corridor

The EU is planning a fourth gas corridor, the Southern gas corridor. This corridor carries natural gas from the Caspian region and the Middle East to Southern Europe and into the EU, particularly, to Southern Germany, Austria and Italy. Setting up such an extra gas corridor would enable the EU to diversify its supply sources. Thus, potential disruption caused by technical failure or by politically motivated interruption from one supply source could be reduced and competition improved. This aspect is important to the entire EU but especially relevant for the states of Southeast Europe, where natural gas plays an important role in the energy mix. These countries are currently receiving a large part of their natural gas from a single supplier (Gazprom) and via a single transit route (Ukraine). Moreover, once this corridor is established the EU will have direct access to the natural gas reserves of the Caspian region and the Middle East, which represent nearly half of the world natural gas reserves and have significant export potential.

Despite individual pipeline projects having already been developed by respective companies at the beginning of the 2000s, the southern gas corridor, as an overarching concept, only emerged later. Following the Russian-Georgian war of August 2008 and the Ukraine-Russian gas crisis of January 2009, the southern gas corridor and its key project, the Nabucco pipeline, became a central component of a European debate about diversification, especially from the dependence on gas imports from Russia. In addition to Nabucco, there are other smaller projects, including the TAP and ITGI across Turkish territory and the AGRI and White Stream via the Black Sea. All have the potential to be an important element of the southern gas corridor, and even call into question the future of Nabucco. Figure 16 shows the routes for various Southern corridor gas pipelines.

The EU has made available more than €20 million for various projects through its programme for Trans-European Energy Networks; another €200 and €145 million respectively are set aside for Nabucco and ITGI/IGB by the European Programme for Recovery. Despite the general support for all projects, the European Commission is attaching political priority to the Nabucco pipeline. However, there is continuing debate among the EU member states over what a financially affordable strategic energy supply for the EU should look like in the future. The interests of member states and especially their energy companies in those regions are influencing policy makers, leading to decisions that

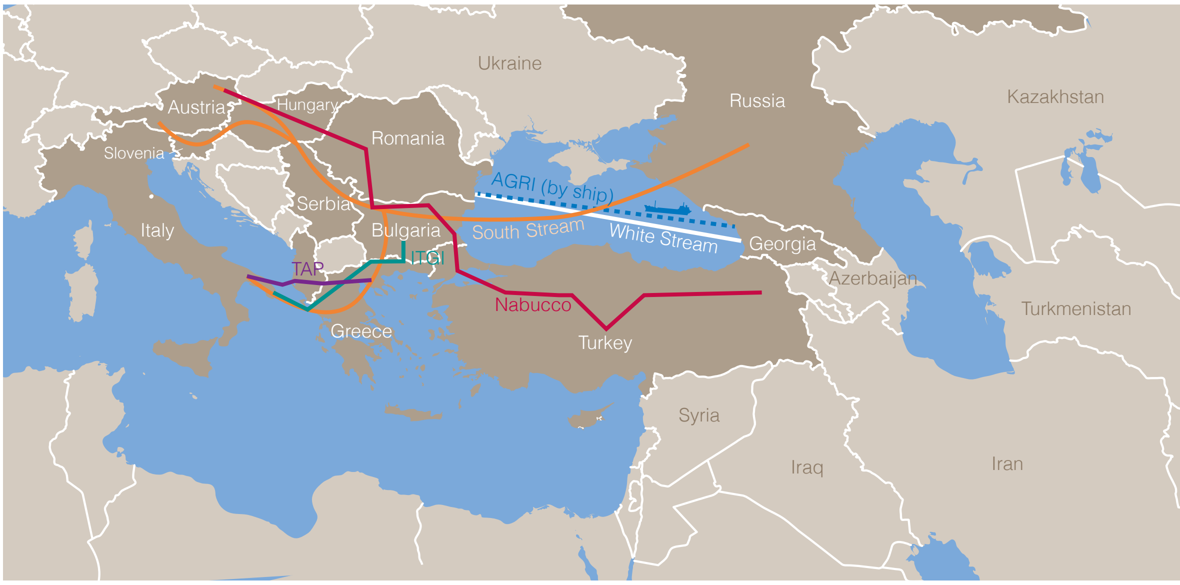

Figure 16 The Southern gas corridor (Meister and Viëtor, 2011)

contradict the EU principles on diversification and transparency. This situation is hampering the implementation of large projects such as Nabucco because long-term investment and operation in the politically and economically unstable Caspian region and the Middle East require special support from both the European Commission and the member states. In contrast, Russia and China are more ready and successful in taking decisions in the competition for the Caspian resources. Table 5 gives details of the pipeline projects in the Southern corridor (Meister and Viëtor, 2011).

Net gas imports into the EU are expected to rise from 302 billion m^3 in 2011 to 525 billion m^3 in 2035, which corresponds to an increase in the share of total EU gas consumption from 63% to 85% (IEA, 2012a). Russia, Norway, Algeria and Qatar have been the four largest importing sources for the EU. Russia as the largest importing source supplied 1272 TWh of natural gas in 2010, whilst Norway and Algeria exported 1074 and 542 TWh of gas to Europe, respectively. Gas imports from these three countries are by means of pipelines. Qatar's supplies totalled 394 TWh and went to only a limited number of nations, including Belgium, France, Italy, Portugal, Luxembourg, Spain, the UK and Turkey. Qatar's increasing share illustrates the growing role of liquefied natural gas (LNG) in the EU gas supply.

Fossil fuels play an important role in **Norway's** economy and energy supply. It is the world's fifth largest oil exporter and the petroleum industry accounts for a quarter of its GDP. Norway is the largest gas producer in OECD Europe nation, and the bulk of its output is exported to the EU. Oil accounted for 39% of Norway's total primary energy consumption in 2010, with gas 18%, coal 3% and others (mainly hydro) 40% (Energy Delta, 2012).

Norway produced 101.4 billion m^3 of natural gas in 2011, of which only approximately 4 billion m^3 was consumed within the country (BP, 2012b). Domestic consumption of gas has been decreasing slightly since the peak level of 4.6 billion m^3 in 2004 (BP, 2012b). However, the IEA's statistics show that Norway consumed close to 6.13 billion m^3 of natural gas in 2010, an almost 3% increase compared to 2009 (Energy Delta, 2012). Of the total consumption of approximately 6.0 billion m^3 in 2009, 73% was used in the energy sector, 4% in the industry sector, 1% by transport, 13% for transformation, and 8% for non-energy use (Energy Delta, 2012).

Norway possesses approximately 1.5–1.6% of the world's total gas reserves; its reserves-to-production ratio at the end of 2010 was nearly 26 years (IEA, 2012a; Energy Delta, 2012). Statoil is the largest operator on the Norwegian continental shelf, responsible for about 60% of the total gas

Table 5 Details of the pipeline projects in the Southern Corridor (Meister and Viëtor, 2011)

Pipeline	Trans-Adriatic pipeline (TAP)	Interconnector Turkey-Greece-Italy (ITGI) + Interconnector Greece-Bulgaria(IGB)	Azerbaijan-Georgia-Romania Interconnector (AGRI)	White Stream	Nabucco	South Stream
Start of project	2003	2007	2010	2005	2004	2007
Companies	EGL 42.5%, Statoil 42.5%, E.ON Ruhrgas 15%	DEPA, DESFA, Edison, BEH, Botas	SOCAR, GOGC, ROMGAZ, MVM at 25% each	GUEU-White Steam Pipeline Company	OMV, MOL, Transgaz, BEH, Botas and RWE at 16.67% each	Offshore: Gazprom 50%, Eni 25%, Wintershall 15%, EDF 10%
Route/length/capacity	(1) Azerbaijan-Georgia-Turkey: built already (2) Turkish and Greek gas network: built already (3) Greece-Albania-Italy: 520 km / 10–20 billion m^3/y	(1)Azerbaijan-Georgia-Turkey (BTE): built already (2) Turkish gas network: built already (3) Turkey-Greece (ITG): built already (4) Greece-Italy (IGI): 807 km / 9 billion m^3/y (5) Greece-Bulgaria (IGB): 170 km / 3–5 billion m^3/y	Azerbaijan-Georgia-Romania-Hungary, where the Georgia-Romania section to be of LNG delivery 7 billion m^3/y	Option 1: Azerbaijan-Georgia-Romania Option 2: Azerbaijan-Georgia-Ukraine Onshore 650 km; offshore to Romania 1100 km; offshore to Ukraine 630 km 8–32 billion m^3/y	Turkey-Bulgaria-Romania-Hungary-Austria total length 3893 km 31 billion m^3/y	Russia-Bulgaria-Serbia-Hungary-Slovenia total length 2380 km offshore: 63 billion m^3/y
Start of delivery	2016 (first stage)	2015	2016	2016 (first stage)	2017	2015

production in Norway. Statoil also develops and participates in key international gas value chains. The gas fields operated by Statoil are Brage, Heimdal, Grane, Glitne, Gullfaks, Heidrun, Huldra, Kristin, Kvitebjørn, Mikkel, Njord, Norne, Ormen Lange, Oseberg, Sleipner, Snorre, Snøhvit, Statfjord, Sygna, Tordis, Troll, Veslefrikk, Vigdis, Visund, Volve and Åsgard. As well as production, the company is responsible for the technical operations of the majority of the export pipelines and onshore facilities in the processing and transportation system for Norwegian gas. The other main state-owned producer is Petoro. International oil and gas companies have also become active.

The gas transportation system of Norway mainly relates to offshore gas pipelines to the UK and continental Europe (see discussion on Europe's northwest gas corridor, page 39). The ownership of the offshore gas pipelines is organised in joint ventures, of which Gassled is the largest. Gassled encompasses all rich and dry gas facilities that are currently in use or those for third party access. All licensees on the Norwegian continental shelf are responsible for selling their own gas output. Gassco AS, wholly owned by the government, was established in 2001 and is the operating company of Gassled responsible for operations, allocation of capacity and development of the transport system. Gassco ensures that all users of the gas transmission system have equal rights in capacity access and development. Gas transport tariffs are governed by regulations issued by the Ministry of Petroleum and Energy, which ensures that economic returns are made from producing fields instead of from the transmission system.

However, there is limited domestic downstream distribution. Gasnore AS is the largest downstream distributor, managing pipeline transportation, LNG production and compressed natural gas (CNG) deliveries. Lyse Gass is another main gas distributor that started operation in 2004. The total length of the Norwegian pipeline system amounts to 7800 km with a capacity of about 120 billion m^3 (Energy Delta, 2012: 2008 data).

There are six receiving terminals for Norwegian gas to Europe: two in Germany, two in the UK, one in Belgium and one in France. The Langeled pipeline, completed in October 2007 is the world's longest offshore pipeline. It has a total capacity equivalent to one fifth of the UK's gas consumption. As of August 2011, there was one large-scale operational LNG liquefaction terminal in Norway, Snøhvit, with a nominal capacity of 4.3 billion m^3/y. There are four additional small-scale LNG liquefaction plants. Norway has no onshore underground gas storage facilities. However it does participate in storage facilities in Germany and also has gas storage agreements in France.

Bolstered by the recent development of fields such as Ormen Lange and Snøhvit, IEA projects a continued rise in Norway's gas production to 120 billion m^3 in 2015 and 129 billion m^3 in 2024, before it falls back slightly to 126 billion m^3 in 2030 (IEA, 2009). Although the oil output has been declining since 2001, natural gas production has continued to increase (except in 2011) and exceeded 100 billion m^3 since 2008. Reserves are estimated at 3 trillion m^3, 1.6% of the global total. There has been an encouraging success rate from recent exploration. Fifteen gas discoveries in 2008 added a total of 49 billion m^3 to 97 billion m^3 to recoverable gas reserves and in 2009 Shell announced the discovery of the Gro field in the Norwegian sea with 10 billion m^3 to 100 billion m^3 of recoverable gas. In contrast to lower upstream investment resulting from the economic downturn in other European regions, there has been continuous heavy investment in the upstream oil and gas sectors. Norway is therefore set to remain an important gas supplier to the European markets.

4.2.4 East Europe/Eurasia

This section briefly covers eleven Commonwealth of Independent States (CIS) (Russia, Ukraine, Belarus, Moldova, Azerbaijan, Armenia, Kazakhstan, Turkmenistan, Uzbekistan, Tajikistan and Kyrgyzstan) and Georgia which withdrew from CIS in 2009. This region, which in aggregate accounts for just under one quarter of global gas production and just under one third of proved reserves, is usually first thought of as a producing region (Pirani, 2011). But it also accounts for just under one fifth of world gas consumption, despite having less than one twentieth of the world's population (Pirani, 2011). States in this region are among the most gas-dependent economies in the world. However, Russia, the largest producer and consumer in this region, is not as gas-dependent as several other CIS countries, and mainly uses its own gas. So do the two large central Asian producers, Uzbekistan and Turkmenistan. The most gas-dependent economies in this region so far are Kazakhstan and Azerbaijan, which relied on significant levels of imports until 2006 after which they became net exporters. But the other seven CIS countries remain net importers.

In the ten years up to 2008, gas consumption in this region rose by 19.50% (1.80% annually on average) from 554.78 billion m^3 in 1998 to 662.96 billion m^3 in 2008 (IEA, 2012a). Gas consumption was dominated by three countries: Russia (453.4 billion m^3), Ukraine (66.7 billion m^3) and Belarus (21.3 billion m^3) (IEA, 2012a). Consumption in Russia rose at a slightly slower rate (17.8%) than in the CIS as a whole. Such increases were driven by steady economic growth (2004-07) in Russia and some other CIS states and declining population in Russia and Ukraine but rising population in other CIS states (Pirani, 2011). The economic crisis in 2008-09 had led to a sharp fall (by 6.5% and 21.5%, respectively) in gas consumption in Russia and Ukraine. The consumption rebounded substantially in Russia between 2008 and 2010, but not in Ukraine. The effect of the crisis on consumption in other CIS states, particularly in central Asia, was much less marked.

The heat and power sector is overwhelmingly dominant in gas consumption, accounting for more than half of the gas consumed. Other significant consumers are the residential sector (13%), industry (15% including 6% for chemical feedstock) and gas transmission and distribution (9%, including pipeline transport and distribution losses). The statistics used here refer to the 2008 data, the year for which the most recent information is available.

Plans for development of the electric power sector, in particular investment in new generation capacity, will affect future gas demand. Gas is the main fuel for power generation in Russia, while it is merely a supplementary fuel in Ukraine (mostly nuclear and coal) and Kazakhstan (mostly coal), the second and third largest economies in this region, respectively. In Russia, there will be a modest increase in electricity demand and thus new generation capacity by 2015, which implies a minimal increase in gas demand from the power sector. Thereafter, new investment might be made in favour of gas-fired generation capacity, provided that economy will continue to recover resulting in increased demand for electricity. The overall impact will only become clear when investment decisions are taken, and these could be postponed. Moreover, while government policy favours diversifying away from gas, previous experience has shown that gas often becomes the fall-back option when investors hesitate to invest in new coal and nuclear capacity. Demand growth from the power sector, which accounts for more than a quarter of the region's gas consumption, will be the key driver for future gas demand growth.

The heat sector is likely to maintain its demand for gas at current rate in the period up to 2015. This is mainly because heat production is mostly integrated with other municipal services and any reforms could be difficult due to institutional challenges. But once reforms are implemented, considerable energy savings could be made in production, distribution and consumption of heat, particularly as old district heating networks are replaced. This could lead to a substantial reduction in gas consumption.

Demand from the residential sector is expected to continue to rise despite the rising prices of gas. The rising gas prices will take effect very slowly and gradually in most states. In Russia and Ukraine, regulated prices for residential customers have begun to increase but remain far below industrial prices and below cost-recovery levels. It is unlikely that government policies in this respect will change soon. Part of the reason is the lack of gas metering systems and other infrastructures to regulate the gas consumption. Moreover, allowing access to gas supply in new residential areas is an important component of government's energy policies in most states of the region. As such, rising gas prices are not expected to lead to any considerable downward trend in gas demand.

In the industrial sector, rising prices and market liberalisation, in conjunction with energy efficiency and energy saving policies, are apparently taking effect. Some industrial companies are making investment in energy savings and efficiency improvements as the advantages of those measures become more generally recognised.

Gas consumption during gas transmission and distribution is expected to decrease, and the potential for savings is vast. For example, Russia's optimisation of its transmission and distribution systems for natural gas, coupled with reductions in gas flaring in its oil and gas industry, could save up to a further 30 billion m^3/y (IEA, 2004). Upgrading the gas transmission and distribution network has been highlighted at the political level in both Russia and Ukraine. Market liberalisation, a more transparent investment framework and the prospect for third-party access all contribute to expected upgrading and modernisation of the gas transmission and distribution system, which will result in significant gas savings.

In IEA's New Policies Scenario, Russian gas demand grows by only 11% between 2008 and 2036, the least among the non-OECD regions, mainly because of continuous improvements in energy efficiency (as out-of-date technologies are replaced) and less waste in part as the consequence of higher prices as subsides are phased out. Demand in the Caspian region grows more quickly, by 50% between 2008 and 2035, mainly driven by consumption for power generation (IEA, 2012a).

4.2.5 Asia Pacific

According to the BP Energy Statistics 2012b, in 2011 countries in the Asia Pacific accounted for 14.6% of the world's total natural gas production, while this region had a share of 18.3% of global natural gas consumption. To put these figures into context, this region held just 8% of global proved gas reserves at the end of 2011 (BP, 2012b).

Figure 17 shows natural gas consumption across countries in this region in 2011. China was the largest consumer in this region, followed by Japan, India, South Korea, Thailand, Pakistan, Indonesia, Malaysia and Australia. The OECD countries in this region (Japan, South Korea, Australia and New Zealand) accounted for 30.6% of total consumption of this region, compared to 22% for China. In 2011, gas consumption in the Asia Pacific region grew strongly, 5.9% year on year (BP, 2012b). This was in part due to strong growth in Japan (11.6%) and South Korea (8.3%), but China's strong growth of 22% was the most significant driving force. In Australia and New Zealand, the consumption of natural gas declined from the previous year. But Australia has increased its consumption overall during the period of 2001-11, while consumption in New Zealand has been declining steadily. All non-OECD countries in this region have been increasing their consumption of natural gas over the past decade. Notably, China and India, both starting from a low base (27.4 billion m^3 and 26.4 billion m^3 in 2001, respectively), have increased their gas consumption at exponential rates, reaching 130.7 billion m^3 and 61.1 billion m^3 in 2011, respectively (BP, 2012b). The non-OECD countries in this region will continue to drive changes in future global gas demand, reflecting their more rapid rates of economic growth and the relative immaturity of their gas markets. In the New Policies Scenario, the IEA forecast an average annually compounded growth rate of 4.2% for non-OECD Asia (6.6% for China and 4.2% for India) and 1.0% for OECD Asia Oceania during 2010-35 (IEA, 2012b). China will make up over one-third of this region's gas demand by 2030, up from over one-fifth in 2011. India will come in a distant second, overtaking Japan post 2020 (PetroMin, 2012).

Currently, the power generation sector leads gas demand in this region, with a share of 43%, and is expected to retain its primary position in gas demand in the foreseeable future (PetroMin, 2012). But its share will decrease partly due to ambitious schemes by some countries to increase their reliance on coal-fired power generation and by others to develop renewable power generation sources. Industrial use of gas is also projected to increase rapidly as gas continues to eat into the share of liquid fuels. The residential/commercial sector is also expected to show strong growth.

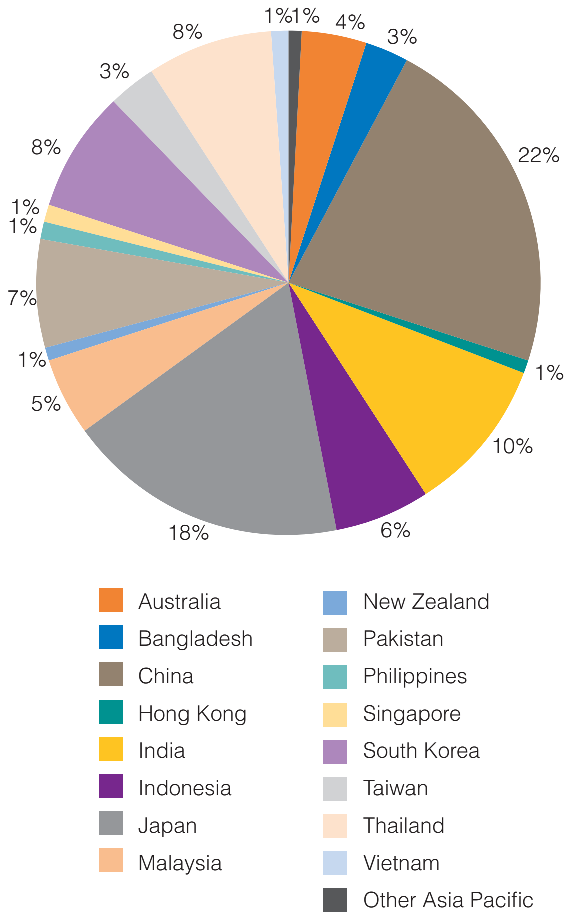

Figure 17 Natural gas consumption across Asia Pacific in 2011 (BP, 2012b)

This region is the principal market for global LNG trade, accounting for 63% of the global total in 2011 (PetroMin, 2012). Strong growth in LNG imports within the region was due to a number of factors. Japan, currently the world's largest consumer of LNG, was responsible for most of the incremental imports to this region, increasing its imports by around 9 Mt/y to 79 t in 2011. Much of the increase was due to increased use of natural gas for power generation to make up for the loss of nuclear power generation capacity. In South Korea, the improved economic performance drove up the LNG imports. A domestic gas shortage in India, as a result of lower production in the KG D6 Basin, pushed up its LNG imports by more than 50%, rendering it the third largest LNG importer in Asia, ahead of China and Taiwan. Start-up of new LNG receiving terminals in China and Thailand also ramp up LNG deliveries into these two countries.

In 2011, more than half (~53.5%) of the LNG supplies to this region came from producers in the Asia Pacific, while the Middle East countries (Oman, Qatar, United Arab Emirates, and Yemen) accounted for 35.1% of the total supplies (BP, 2012b). The remaining supplies came mainly from Nigeria and Trinidad and Tobago. The top four suppliers were (in descending order of LNG volumes) Qatar, Malaysia, Indonesia and Australia. Notably, supplies from Australia are likely to increase significantly in the near future, as the country now has seven of the nine global LNG terminals under development, in addition to its existing three terminals.

Looking to the future, the region's dominance over world LNG trade will weaken slightly by 2020 as Atlantic Basin and Middle Eastern demand rises, but it could still account for some 61% of global LNG trade (PetroMin, 2012). This projection is in line with that of IEA in its World Energy Outlook 2012. Japan will remain the heavyweight in the region, holding almost 37% of regional trade by the end of the decade and falling to 31% by 2030. The next largest share will be from South Korea with 18% in 2020, but Chinese LNG demand may overtake Korea's by around 2025. China and India combined could add more than 45 Mt of additional LNG demand by 2030 and represent one of the key growth areas for the Asia Pacific region, especially towards the end of the decade. In addition, Thailand, Malaysia, Indonesia, and Singapore could add another 147 Mt to total LNG demand from the region. Other potential LNG import markets, such as Bangladesh, Pakistan, Philippines and Vietnam represent a market of more than 7 Mt in 2020 and close to 30 Mt by 2030 (PetroMin, 2012).

5 Pricing

The relative cost advantage of coal and natural gas, in addition to other factors such as environmental performance, is a key determinant of the competitiveness of and, therefore, the share of either fuel in the overall energy mix in any given market. The relative price advantage can lead to fuel switching to and from coal for power generation, as already observed in the USA and some European countries. In the short term, with a fixed stock of power plants and related equipment, fuel switching can occur if unutilised capacity or multi-firing facilities are available. More importantly, fuel prices can play a key role in decision making with regard to what type of new capacity to build. This is because power stations and industrial boilers are generally built without multi-firing capabilities, and it can be impractical or expensive to install such equipment or to modify the installation to use another fuel at a later stage. Decisions thus have long-term repercussions on fuel use in power plants that have operating lives spanning many decades. Thus, a good understanding of the drivers behind fuel pricing and the prospects for price trends is vitally important.

This chapter first gives a brief review of the price trends of coal and natural gas worldwide, with a focus on Europe and North America, where coal and natural gas are more likely to compete as the fuel for power generation. Secondly, how electricity utilities decide on generation despatching and building new generation capacity is discussed, with the UK as a typical example of competitive electricity markets.

5.1 Coal price trend

The world coal market is predominantly supplied by domestic production with internationally traded coal accounting for a small fraction (17% of global hard coal production in 2011) (IEA, 2012a). Coal markets are regionalised, with coal price varying markedly across countries and regions. Prices in the domestic markets of coal-producing countries normally reflect local supply/demand characteristics, including production costs and transport constraints, or the price of available competing fuels such as natural gas for power plants. In countries where the coal price is controlled by government, production may respond poorly to changes in demand because the normal market incentives of price may be suppressed. Domestic prices are also affected by government subsidies in some countries such as Germany and Spain, where they are used to maintain operation of local mines. These subsidies place a heavy burden of state aid on government budgets.

International coal prices are normally set in annual negotiation between producers and major customers, although some large buyers prefer spot deals at prices that can be quite volatile. In general, domestic prices are more stable than international prices. However, these two prices can influence each other. In regions where imported coal accounts for a large faction of total coal supply (for example, states in northwest Europe) domestic prices (or coal subsidy in some cases) are linked to international prices. In regions where only a relatively small fraction of coal consumption involves imported coal (for instance some coastal areas in China and India) any shortfall in domestic supply can give rise to demand for imported coal. Such ad hoc coal imports can put a sudden and disproportionate additional demand on the international market, as was seen in 2009, when China entered the import market quite suddenly. This had an immediate and sharp effect on the international price.

As such, there has been a convergence of international coal trade with traditional domestic markets in recent years, with imports increasing in many coal producing regions. Such convergence can place pressure on domestic coal markets. Firstly, imported coal displaces domestic production; secondly, the international price trend may drive up prices in the remaining indigenous market for coal if imports are significant. Therefore, this section focuses on the prices of internationally traded coal.

Internationally traded steam coal is split into two major markets, the Atlantic and Pacific markets. The Atlantic market for steam coal is made up of practically all the major utilities in Western Europe and the utilities located near the coast of the USA. Other less influential buyers include those in Brazil, Morocco and Israel. While steam coal supplies to Europe are regularly shipped from the Pacific producers, the major suppliers to the Atlantic market are from South Africa, Colombia, Russia and Poland. Europe is increasingly an import led market, and acts as leverage to negotiate price contracts with domestic coal producers. In contrast, the USA largely remains a domestically supplied market. The Pacific market is made up of the utilities in Japan, South Korea and Taiwan, as well as increasing trade going into China and now India. Australia, Indonesia, and recently Vietnam, have been the main suppliers to this market. With its proximity to India, South Africa is a major supplier to India, but South African coal does not serve the Far East in the magnitude comparable to Australian and Indonesian coal. A more detailed discussion on the international coal markets can be found in two previous IEA CCC reports (Baruya, 2012a,b)

The prices of internationally traded coal have fluctuated significantly in recent years; prices surged to a record high in 2008, then collapsed in 2009, before rebounding to a level higher than in 2008 in mid 2011 and then falling back thereafter in the Atlantic basin market. To a large extent, the price fluctuation was in response to rapid changes in coal production and trading. The inelasticity of coal demand from utilities and steel mills places substantial strain on coal markets. In some cases, short-term price swings have been caused by weather-related disruptions to supply in key exporting countries, such as flooding in Queensland, Australia in 2011.

Since the global economic downturn in 2008, there has been a divergence between the Atlantic market and the Pacific market. This has led to a shift in pricing patterns across the world, which was not entirely related to shipping costs in different markets. European demand has remained relatively weak due to a weak economic recovery; hence coal prices have been low. Increased supply from the USA (where cheap gas has depressed domestic coal demand and pushed coal into the export market) and Colombia have also helped to keep coal prices low in Europe. In contrast, demand in Asia had continued strong growth, driven by increased imports to China. As such, the prices in the Pacific markets have been relatively high as shown by the Qinhuangdao price marker in Figure 18. Since coal demand from the Pacific market is so high, prices in Asia can be negotiated on a spot basis, which is preferred by Chinese buyers. China now plays a vital role in setting import prices in the rest of the world; the price of China's domestic coal delivered to its southeast coastal regions determines the price of imported coals, which becomes a price marker for other international sales. Before the global economic crisis, delivered prices of steam coal in northwest Europe were set by the free-on-board (FOB) price of South African coal at Richards Bay plus freight. Since then, South African exporters have been able to gain higher margins by exporting to Asia, forcing prices in the Atlantic to follow to the Pacific prices.

The near-term outlook for coal prices depends largely on demand-side factors. In the longer term, production costs will play an important role in determining prices both on international and domestic markets. Costs rise, on one hand, in accordance with the need to exploit poorer quality or less accessible deposits, often located in more remote regions without the necessary infrastructure. On the other hand, the boom in overall mining activities are likely to increase the costs of equipment material, labour and transport.

Moreover, the inter-fuel competition, especially with natural gas in the power sector, will have an important impact on coal prices. The increasing deployment of renewables and uncertainties around nuclear power further complicates the picture. Competition between coal and natural gas are especially notable in EU. Currently, the very low natural gas prices in North America have resulted in more coal being shipped to the European markets. However, this situation may change with a rise in North American gas prices that may make coal more competitive in the power sector. As a result, the supply of coal to the European market will reduce. Power plants in Europe will then need to replace North American coal with imports at higher cost, thus making coal less attractive. On the other hand,

Figure 18 Average fortnightly steam coal prices in selected ports (IEA, 2012a)

additional gas supply to Europe tends to be oil-indexed, undermining many advantages of gas as a power generation fuel and possibly favouring coal as the marginal power source. Moreover, carbon prices are also an important factor in coal demand and thus coal prices in EU.

Coal demand from China and, increasingly, India, remains critical, given the potential for large swings in their coal imports needed to balance domestic coal demand and supply. The recent thermal coal price reform instituted by China's State Council, which cancelled the two-track pricing mechanism for coal and electricity pricing and hence liberalised domestic coal prices, may have a profound effect on international prices (China Daily, 2012). In IEA's New Policy Scenario, the average OECD steam coal price, a proxy for international prices, is assumed to fall back to under 110 $/t (in 2011 US$) by 2015 and then recover slowly to about $115 in 2035 (IEA, 2012a).

5.2 Gas price trend

Figure 19 shows the gas price trend in Europe, North America and Japan in 1996-2011. Gas prices have been historically indexed to prices of oil products or crude oil under long-term contacts of 10–25 years. Gas prices are therefore closely correlated across the three regions. In recent years, there has been a big divergence in gas pricing across the three regions. A glut of gas supply in North America has kept prices at low levels, rendering it a very different gas market from that in Europe and Asia. In Europe, gas prices rebounded strongly after the economic crisis, reaching about 10 $/MBtu (9.45 $/GJ) in 2011. LNG prices stayed high for delivery into Japan, reflecting strong demand from the power sector in the wake of the Fukushima Daiichi nuclear accident.

In North America, a competitive gas market is well established, with gas prices fluctuating in response to a short-term shift in gas demand and supply balance. Oil prices have some influence over gas pricing, though this is set to diminish. With declining LNG imports and abundant domestic shale gas supply, North American prices are set to remain below European and Asia-Pacific prices. The North American gas market remains largely disconnected from the rest of the world. The prospect for gas

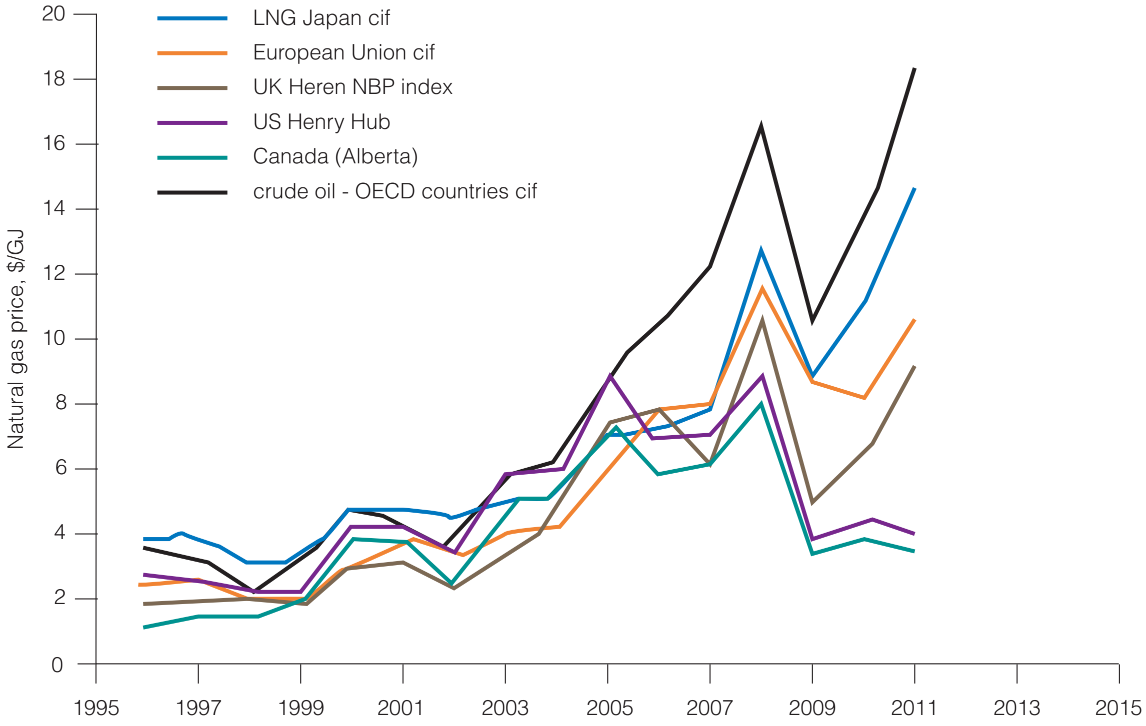

Figure 19 Natural gas price trends in Europe, North America and Japan in 1996-2011 (BP, 2012b)

exports from North America is still somewhat uncertain. The US DOE has been prudent to issue approval for constructing LNG export terminals. Cheniere's Sabine Pass LNG terminal in Louisiana (approved in 2011 with a design capacity of 2.2 billion cubic feet per day: 62.3 million m^3/d) and the Freeport LNG terminal in Texas (approved in 2013 with a design capacity of 1.4 billion cubic feet per day: 39.6 million m^3/d) are the only two projects conditionally approved by the US Federal Energy Regulatory Commission.

In Europe, over 70% of gas is sold under long-term contract. But the role of oil-indexed long-term contracts is reducing and gas prices are increasingly marked to spot gas prices at trading hubs. This is partly due to the falling demand after 2009, which opened up a large differential between lower spot gas price and higher oil-indexed contract prices. Gas suppliers have therefore faced pressure to make changes to the contractual terms. Norwegian producers were the first to offer more pricing flexibility. Gazprom also granted some important concessions on pricing in early 2012, accepting the partial use of spot indexation for a period of three years. Algeria's national oil and gas company, Sonatrach, though resisting pressure to change the pricing terms in its contracts, has indicated that it may be willing to adjust prices while retaining the principle of oil indexation. Interestingly, coal prices can play a role in the evolution of gas contracts in Europe because a glut of natural gas in North America has made more coal available to the European market. This has placed pressure on gas prices and is likely to reduce gas demand from Europe. In principle, transition from oil-linked pricing to spot-indexed pricing may lead to lower import gas prices, given the fact that gas supply remains ample in the short to medium term. But price volatility is likely to increase with sudden price spikes when there is a shortfall in supply. Moreover, gas price will still be correlated to oil prices to some extent in Europe, even if more gas is sold on a spot basis, through indirect linkage with the Asia Pacific markets, as long as gas prices there remain linked to oil prices.

Oil indexation looks set to remain the dominant pricing mechanism in cross-border gas trade in the Asia Pacific region, while domestic prices in most countries continue to be regulated on a cost-of-service basis. Traditionally, gas buyers in this region have placed great emphasis on long-term security of supply. Large-scale buyers from Korea, Japan and China have invested in overseas upstream projects in order to share in the rent that might come about as a result of higher oil prices. As such, any change in gas pricing has more to do with competitive bidding for short-term or spot LNG than to long-term gas trading established in this region. The persistence of much higher LNG prices relative to Europe and North America may lead to pressure to seek more favourable pricing arrangements stimulating competition between different sources of gas supplies (for instance bringing online a cross-border pipeline to China). Consequently, oil indexation clauses may evolve to provide more flexibility, even though oil-linked long-term pricing remains dominant.

Increasingly, gas prices are being indexed, at least in part, to published spot prices of gas, usually at hubs in the country or region where the gas is delivered. In addition, a growing share of traded gas, especially LNG, is sold on a spot basis for immediate delivery. Several large projects, for example Norway's Ormen Lange field and the Angola LNG plant, were built on the basis of pricing at the main trading hub (IEA, 2012a). As the old contracts mature, new contracts tend to cover shorter periods, with growing use of 2–4 year contracts, reflecting the changing gas market conditions worldwide. The drivers behind moving away from oil indexation and long-term contracts are complex, but evolution of new risk management approaches is becoming important. This includes using sophisticated financial instruments (the gas futures market has emerged), cross-participation by buyers in the upstream sector and sellers in downstream projects, and the appearance of portfolio players who own a mix of long-term 'base load' and short-term swing gas. Development of new gas pricing mechanisms will have an important effect on gas prices and gas supply outlook.

5.3 Power generation fuel cost advantage comparison

This section looks at how electricity utilities with a large portfolio of electricity generation capacities make day-to-day decisions on which type of generation to operate and when. For this purpose, it is necessary to introduce an essential tool, the spread between the wholesale price of electricity and the price of fuel adjusted with generation efficiency and the CO_2 emission cost, a key economic measure of the profitability to utilities from operating a certain power station in competitive electricity markets. Spread measure is of less value for day-to-day operations in markets where the price of electricity is centrally managed. Nevertheless, this measure can still be useful in longer term analysis and planning for developing new generation capacity, but for this section discussion refers to short-term issues.

There are four main widely quoted spreads (for example, the McCloskey Coal Report publishes regular data on spark spreads from the UK and Germany):

- **Spark spread** typically refers to the spread for CCGT stations, but in principle could apply to any gas-fired units. Calculation is as follows:
  spark spread [$/MWh] = wholesale price of electricity [$/MWh] – cost of gas [$/MBtu or $/GJ] × heat rate [MBtu/MWh or GJ/MWh]
- **Clean spark** is a spark spread that takes into account the additional costs of CO_2 allowances
  clean spark [$/MWh] = wholesale price of electricity [$/MWh] – cost of gas [$/MBtu or $/GJ] × heat rate [MBtu/MWh or GJ/MWh] – CO_2 price [$/t CO_2] × emission factor [t CO_2/MWh]
- **Dark spread** refers to the spread for coal-fired units. Calculation is as follows:
  dark spread [$/MWh] = wholesale price of electricity [$/MWh] – cost of coal [$/kg] × heat rate [kg/MWh]
- **Clean dark** is a dark spread that takes into account the additional costs of CO_2 allowances.
  clean dark [$/MWh] = wholesale price of electricity [$/MWh] – cost of coal [$/kg] × heat rate [kg/MWh] – CO_2 price [$/t CO_2] × emission factor [t CO_2/MWh]

A negative spread or a sharp decline in one of these spreads indicates that running the power plant is earning no or reduced profits, so that the power utilities would be better off reducing the operation and to either ramp up the type of generation with a better spread or to purchase electricity from the wholesale market while selling the fuel (gas or coal) to the heating market where possible and appropriate. Care should be taken if one uses spreads to compare profitability of power stations across countries and markets. This is because, as seen in the above formulae, the spread calculation is affected by the different levels of efficiency of coal-fired and gas-fired power plants and whether a CO_2 price exists and at what level in a market or country of concern. In countries where there are strict regulations on air pollutants, the efficiency of a power plant can be reduced due to use of comprehensive forms of environmental clean up equipment.

This section takes the UK as an example to illustrate the role of spread measures in comparing the relative competitiveness of coal and gas in power generation. The UK electricity market is one of the most liberalised in the world, and the most liquid and flexible. The recently instituted Electricity Market Reform and relevant supporting policies set in train the transformation of the UK electric power sector, providing a framework for competition between all low carbon technologies to drive innovation and cost reduction and to hedge against cost and delivery risks of technology. As such, the UK market represents the dynamics that other electricity markets may encounter, though possibly to different degrees, in their respective transition to a low carbon future.

As of May 2012, the UK had a total power generation capacity of 87.2 GW, which comprised: coal-fired capacity 27.6 GW (including capacity that cofires coal with biomass, oil and gas); CCGT 28.8 GW; other gas capacities 6 GW (including gas, gas CHP and gas/oil); nuclear power 9.2 GW; hydro 1.7 GW; and wind power 6.4 GW. These figures are based on the statistics of the UK's Department of Energy and Climate Change (DECC, 2012). These statistics show that there is already more gas-fired capacity than coal-fired capacity. In addition, a significant volume of new CCGT capacity is in the planning pipeline; consents have been given to more than 15 GW of capacity and a further 1 GW is under consideration (DECC, 2012). Despite the considerable sum of gas capacity in the pipeline, there is still uncertainty over if and when it will be built.

In terms of volume of electricity generated, gas provided around 34% of total output in 2011, compared to 30% from coal (DECC, 2012). Nevertheless, gas generation currently sets the electricity price for most of the year, as gas-fired generation is the marginal plant used to cover peaking electricity demand.

The UK government is committed (through the Climate Change Act 2008) to meeting the legally binding targets to cut greenhouse gas emissions by 2050 by at least 80% compared to 1990 levels and the obligation under the Renewable Energy Directive for at least 15% of energy to come from renewable sources by 2020. To achieve this, the UK will move to a more diverse range of energy sources to increase security of supply and reduce exposure to volatile fossil fuel prices, as well as to cut emissions. The profit margins of electricity utilities will thus be affected and become uncertain.

Figure 20 shows the clean spark and clean dark spreads from July 2009 to March 2012. The current clean spark spread is low as a result of low electricity prices and high gas prices relative to coal. Low electricity prices are driven by excess amounts of generation capacity. Figure 20 also shows that clean spark spreads have been falling, while clean dark spreads have remained relatively high due to the relative cost of coal and the current low cost of CO_2. These short-term indicators suggest that gas generation is not currently profitable and may explain why some consented plants in the project pipeline have not been built. But there are strong reasons to believe this will not be the case indefinitely, as explained below.

Investment in new gas-fired power is driven by the expected future profitability of these plants, which is in turn determined by the expected revenues and costs of the plants over the course of their economic lives. Revenues are largely driven by wholesale prices, while costs are largely based on the fixed costs associated with building and maintaining the plants and the variable costs associated with the cost of fuel and the cost of carbon.

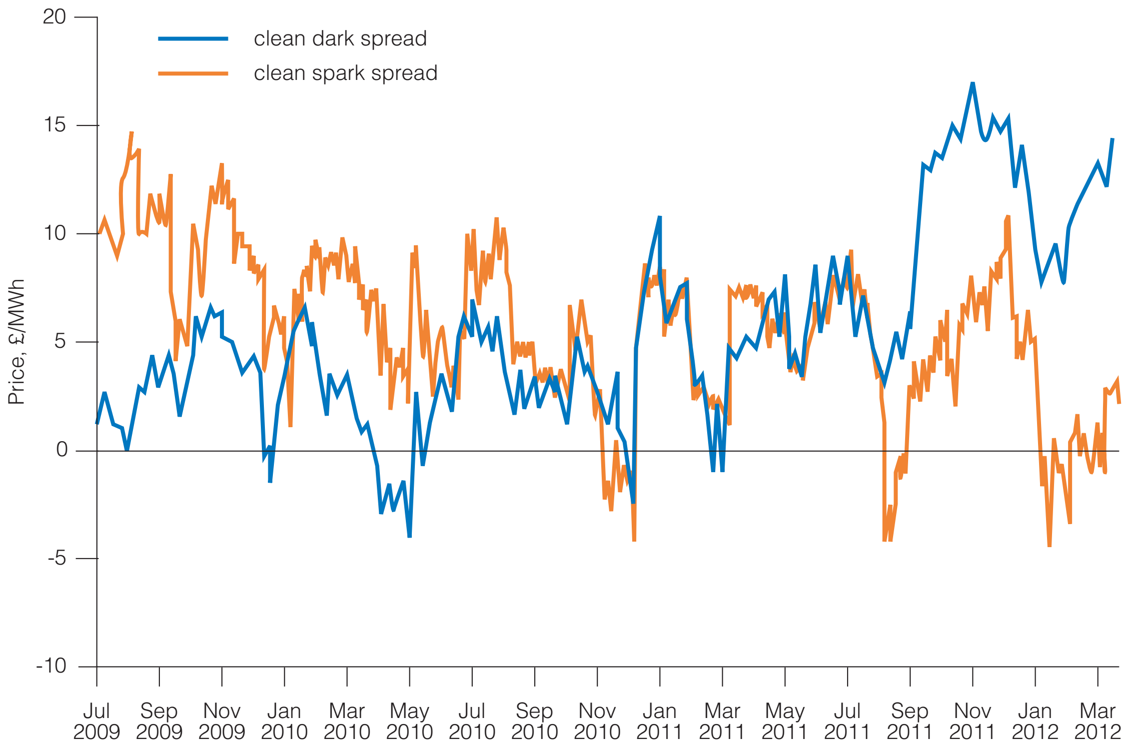

Figure 20 The clean spark and clean dark spreads in July 2009 – March 2012 in the UK (DECC, 2012)

It is expected that the wholesale price of electricity will increase. A key reason for this expected increase is that current excess capacity margin (that is the reserve generation capacity) is expected to decline later in the decade as a result of retirement of existing coal and nuclear plants as well as some old gas plants. Decisions to retire coal plants will be influenced by a number factors such as the tightened air emission standards, the carbon price and the underlying commodity prices. Under the Large Combustion Plant Directive (LCPD) rules, ~8 GW coal-fired generation capacity will be closed by 2016. Even if those plants stay open to burn biomass, low maintenance spend and ~44-year average ages are likely to limit flexibility and reliability. From 2016, the ~20 GW of coal-fired power plants that remains will be required to fit emission reduction equipment, or otherwise become restricted in operating hours (hence not reliable), in order to meet tighter emission standards under the Industrial Emissions Directive (IED). To meet the tighter emission standards, coal-fired power stations need about £2 billion of capital expenditure (estimated by Credit Suisse, 2012), which is prohibitively expensive (especially with the CO_2 price floor reducing profitability) and therefore unlikely to be fully realised. The restricted coal plants are likely to operate at peak load only, thus setting the level of the wholesale price of electricity. Tighter capacity reserve margins should lead to an increase in the base load wholesale price, which should improve the investment case for new gas plants.

The fixed costs of gas-fired power plants are in general lower than those of coal plants of similar capacity. The fuel costs are discussed in the previous two sections of this chapter. For both coal and natural gas, with declining domestic production, fuel costs will be increasingly dependent on international prices, which could be highly volatile. It will be challenging to ensure the security of gas and coal supplies at affordable prices. In addition to diversifying sources of supplies, there needs to be adequate import capacities for both coal and gas. Currently, the import capacity alone could supply over 150% of the UK's annual gas demand (DECC, 2012). But this may soon become inadequate with more gas-fired power plants being built.

The carbon price under the EU emissions trading scheme (ETS) has been very low in recent years.

But the UK government has decided to bolster the carbon price by introducing a CO_2 price floor under the UK government's Electricity Market Reform. The floor is structured via an additional 4.94 £/t of CO_2 tax applicable for the year starting April 2013. The top-up tax is expected to rise to 10 £/t for the year starting April 2014 (Credit Suisse, 2012). The CO_2 floor will raise costs for carbon intensive generation (mainly coal), while lower carbon generations (including CCGT) will benefit. Electricity utilities will pass on the carbon cost to consumers through increased electricity prices.

It could be concluded that while the immediate outlook for gas plants on the system is difficult given current spark spreads, the medium-term outlook is more favourable when changes in market fundamentals are considered. In the longer term, as nuclear and wind power increase, gas-fired generation will despatch less due to higher marginal costs compared to nuclear and wind power. On the other hand, with more intermittent renewables coming online, CCGT, as well as other types of flexible generation and storage, could have a very important role to play in the future generation mix, and that role will depend on the pace and extent of other generation technologies. Taking these together, there is still uncertainty about investment in new gas-fired power plants as these plants will be increasingly reliant on volatile and unpredictable prices to secure the revenues needed to justify investment.

6 Utilisation/consumption

Coal and natural gas have the greatest share in the energy mix, internationally. Coal has been a reliable fuel that has proven abundant in regional supply. Its importance has also grown for energy security reasons. However, a remarkable increase has occurred since the 1990s in the share of natural gas. Fossil fuels, including coal and gas, are and will continue to hold the largest share of world total electricity generation, in both the short and medium term. On a global scale, fossil fuel power generation provides more than 60% of the world's electricity output, with coal providing 42%. In China, 70% of the total installed electricity capacity is coal fired. In the USA, approximately 40% of power generation is also coal based. In Europe, of the 53% fossil fuel based electricity generation; 23% is based on natural gas, 16% on hard coal and 11% on lignite (*see* Figure 21) (SETIS, 2011). Electricity generation, facts and figures for 2012/13 are given in detail by VGB PowerTech (2012). Switching from coal to natural gas for power generation benefits the environment by producing lower concentrations of air pollutants and of greenhouse gas emissions. However, although there are numerous such conversions, security of supply and fuel mix policies as well as disparity in the availability of natural gas from region to region, is forecast to result in the continued utilisation of coal as a source of energy not only for power generation but also for industry.

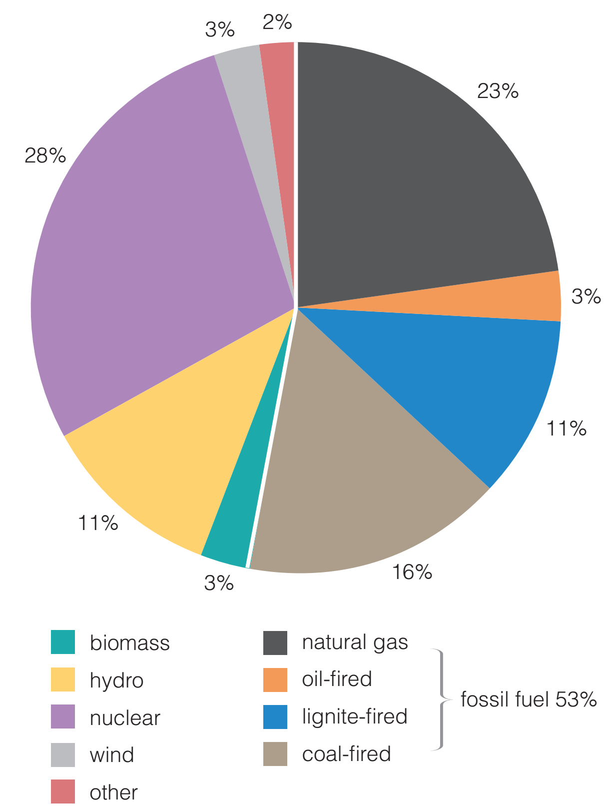

Figure 21 Electricity generation by fuel used in power stations, EU-27 (SETIS, 2011)

Fossil fuel based power generation is a major contributor to CO_2 emissions, with 35% of 2009 anthropogenic CO_2 emissions in the EU-27 resulting from power production. Despite the financial crisis in 2008, which caused a drop in production from energy intensive industries and negative rates of change in the energy and electricity demand in 2009, according to SETIS (2011), electricity consumption is expected to continue increasing in the coming years. Baseline projections for the EU indicate that electricity consumption will grow on average by 2%/y to 2030, with a potentially slightly slower pace each year because of energy efficiency improvement measures and higher fossil fuel prices, in particular natural gas, which will consequently affect electricity pricing. This provides an impetus to improve technologies in coal- and gas-based power generation and more specifically to improving conversion efficiency, as this would result in substantial CO_2 and fuel savings. For example, each percentage point efficiency increase is equivalent to about 2.5% reduction of CO_2 emitted. Power plant efficiency is therefore a major factor that could be used to reduce global CO_2 emissions. For detailed reviews on power generation see the IEACCC website www.iea-coal.org.

Competition between coal and natural gas is a complex process that involves the interaction between numerous factors including (Lefevre and others, 1999):

- the relative importance of the fuels in the total energy mix is determined by the availability of coal and natural gas as indigenous resources. Economies with high reserves of coal tend to have higher shares of coal in power generation; economies with high reserves of gas use more gas; those with substantial reserves of both coal and gas tend to use both. Energy exporting countries however deviate from these trends due to the priorities of energy resources for exports. Economies without or those less endowed with coal and natural gas, but with access to the international market, tend to have balanced utilisation of these fuels, though some economies historically preferred to use coal rather than gas;

- the growth in the consumption of coal and natural gas were supported by those economies with local resources of these fuels, and some net energy importing economies with access to these fuels in the international market. Coal has been a mainstay fuel in power generation while gas discoveries, development and utilisation (except in North America) have been more recent. The momentum gained in gas consumption is likely to be sustained in the medium and long term as national and regional gas infrastructures are developed;
- the above trends are partly explained by fuel economics and the economics of electricity generation. Coal is cheaper than natural gas in the international markets. The domestic prices of these fuels however deviate from the international trend. Countries with large reserves of coal tend to have cheaper coal than natural gas and those economies with big reserves of natural gas tend to have cheaper gas than coal. Similarly, for some economies with certain price expectations, discount rates and technical assumptions, the levelised cost of electricity from coal is lower than from natural gas while for some others electricity generated from natural gas has a lower levelised cost than from coal. There are other cost components that must be considered for which natural gas fired technologies have a cost advantage over coal-fired technologies: these are capital costs, non fuel operation and maintenance (O&M) and fuel efficiency;
- one of the main reasons why governments support the development of natural gas resource (as well as for some economies to continue to use imported but more costly natural gas) is because of the environment. Moreover, the rigidity of the command and control approach in environmental regulation favours an increase in natural gas utilisation. Furthermore, the development of more efficient and cost-competitive gas-fired technologies makes natural gas an attractive fuel. The advantages of natural gas on environmental grounds do not diminish the demand for coal. The development of clean coal as well as advanced technologies that comply with stringent environmental standards retains coal as the fuel of choice for those economies traditionally dependent on coal and those with significant coal reserves. Though the capital costs of these technologies are relatively higher, lower coal prices can offset this resulting in a lower levelised cost of electricity.

6.1 Coal

In 2011, coal consumption grew by 5.4%. According to BP (2012b) 'Coal was the only fossil fuel to record above-average growth and the fastest-growing form of energy outside renewables. It accounted for 30.3% of global energy consumption, its highest share since 1969.' In non-OECD countries coal consumption grew by 8.4% while consumption in OECD countries declined by 1.1%.

Coal consumption within the OECD, according to BP (2012a), is expected to decline by 1.1%/y. (2010-30). However, this is offset by growth in the non-OECD countries of 2.1%/y. Rapid coal consumption growth is forecast to end in China after 2020 thus changing the global trend – that is, growth is set to decline from 4.0%/y in 2000-10 to just 0.5%/y in 2020-30. Technological understanding/advancement, and therefore efficiency gains and structural shifts, are expected to reduce coal intensity in China dramatically. It is expected that coal consumed per gross domestic product (GDP) in China will be almost 60% lower in 2030 compared to 2012. However, China is forecast to continue to account for 67% of global coal growth to 2030 and remain the largest coal consumer increasing its share of global consumption from 48% to 53%. In India, BP (2012a) forecasts that the continuing growth will only partially offset the slowing-down of coal in China. India is expected to contribute 33% of global growth in coal consumption to 2030 and its share is forecast to climb from 8% in 2012 to 14% in 2030. India and China together will account for all the global net growth to 2030 (BP, 2012a).

Table 6 Coal's share in electricity generation, worldwide (2008-09) (WCA, 2012)

Country	Share, %
South Africa	93
Poland	90
China	79
Australia	76
Kazakhstan	70
India	69
Israel	63
Czech Republic	56
Morocco	55
Greece	55
USA	45
Germany	44

Coal is used mainly for power generation. In 2010, 37% of global power generation was based on hard coal and 4% on lignite. Table 6 lists the countries where coal provided the major share of electricity generation in 2008-09. Although the situation may have changed marginally in the USA, these countries remain heavily dependent on coal for electricity generation. Other consumers of coal are the iron and steel sector and the process heating market, including cement works, paper mills, food processors and other industries. In recent years, coal has played a smaller role in the heating of buildings, except in several eastern European countries, Turkey, China and North Korea. Albeit, coal-fired district heating and combined heat and power is important in Scandinavian countries. Countries with indigenous coal deposits have, in general, a larger share of coal-fired power generation compared to countries with insignificant or no coal reserves. However, there are exceptions including Taiwan and Israel who import all their coal needs. Coal plays a major role in Japan, not only to the iron and steel industry but also to the power industry where almost a quarter of the electricity in Japan is generated with imported hard coal (EURACOAL, 2011).

Advantages of firing coal include (EURACOAL, 2011):
1 security as it is mined in many countries and traded freely;
2 availability on international markets at relatively stable prices;
3 competitiveness and contribution towards economic growth as a fuel for electricity generation, steelmaking and other industrial activities.

The growth in intermittent electricity from wind and solar power is challenging the design of both electricity markets and system operations. In the EU, fossil fuel power plants are increasingly losing their traditional base-load operating hours towards becoming an 'auxiliary' power provider, with renewable energy having priority despatch, thus demanding that coal-fired power plants operate with greater flexibility. According to EURACOAL (2010), modern coal-fired power plants are more flexible than old gas-fired combined cycle gas turbine (CCGT) plants (10 MW/min) and almost match new gas-fired power plants (38 MW/min). Today, coal-fired power plants run at partial load, providing reserve capacity and a number of system services, competing with gas-fired plants in the respective markets. A modern coal-fired plant can change from full load capacity to 50% in less than 15 minutes and with little efficiency penalty compared to gas-fired plants. For example, a 1 GW plant can provide a 30–40 MW load change each minute. The comparison in ramp rates between old and new hard coal plants and old and new lignite-fired plants is shown in Figure 22. Coal-fired plant efficiency and emissions versus natural gas combined cycle plants in Europe was the subject of a paper by Dodero (2007).

Coal, in the EU, not only plays a major part in the energy mix but also sets a benchmark price in the power sector. The 'coal benchmark' is an important macro-economic element of EU industrial competitiveness. As shown in Figure 23, coal, at 27%, in the EU plays a significant role in power generation. However, the share of coal varies between individual member states. For example, almost half of Denmark's and Germany's electricity comes from coal. More than half in Bulgaria, Greece and the Czech Republic whilst in Poland, 90% of electricity is generated with coal.

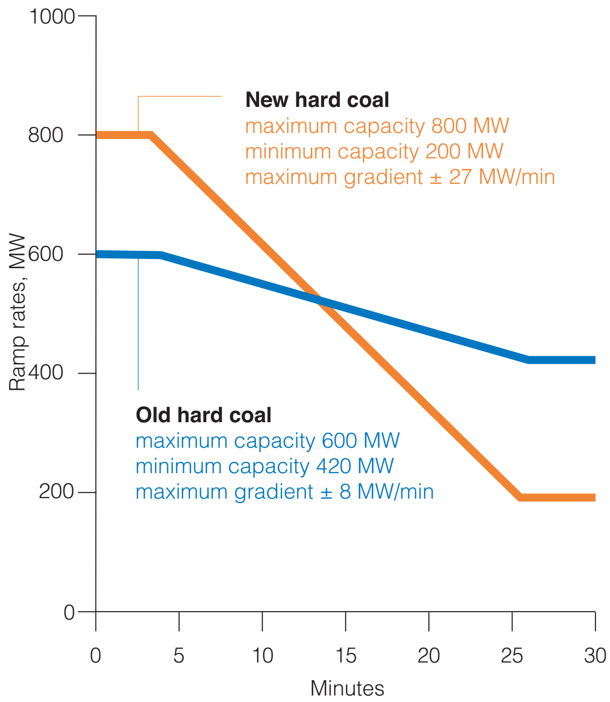

Figure 22 Comparison of ramp rates between old hard coal and lignite and new hard coal and lignite fired plants (Dodero, 2007)

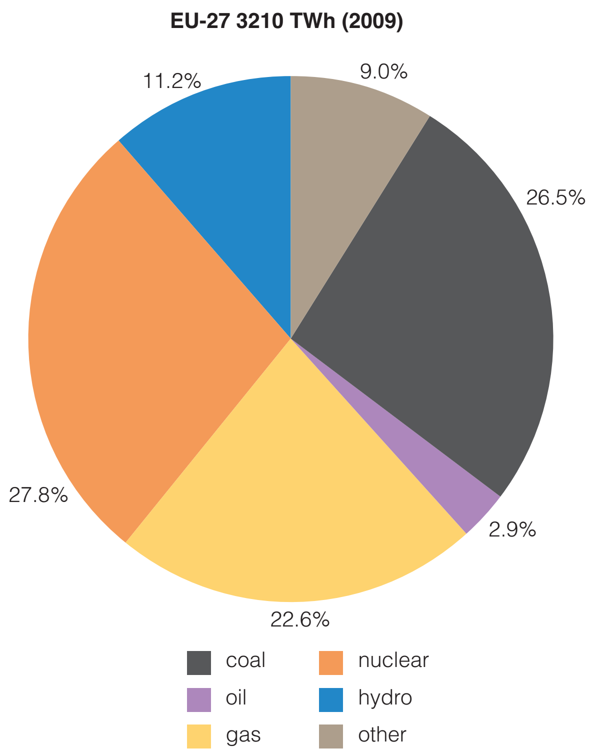

Figure 23 Power generation in the EU, 2010 (EURACOAL, 2011)

The situation is different for coal in the USA. Electric power consumption by fuel type in 2011 in the USA is shown in Figure 24 (Greenstone and others, 2012). The fiercest competition for coal began when natural gas prices fell below the 2 \$/MBtu (1.89 \$/GJ) line in mid 2012. However, increased US coal exports could alleviate the difficult situation of US coal producers. None the less, declining demand is expected to give rise to workforce reduction. The medium-term coal market report 2012 projections for US coal demand by 2017 are 600 Mtce, which indicates a dramatic fall from 697 Mtce in 2011. US production is expected to fall from 771 Mtce in 2011 to 697 Mtce in 2017. India is forecast to increase its influence in the coal markets. The country has large coal reserves, a population of more than 1 billion, electricity shortages and the largest pocket of energy poverty in the world. India is expected to boost its coal consumption. The performance of domestic industry is expected to make India the largest seaborne coal importer by 2017 with 204 Mtce and the second-largest coal consumer, surpassing the USA (OECD/IEA, 2012).

According to the US EIA (2012), total US coal consumption is forecast to increase at an average growth of 0.1%/y. As with production, growth rates for coal consumption are uneven over the projection, with consumption declining by 2.7%/y from 2011 to 2016 but then increasing by 0.7%/y from 2016 to 2040. Coal remains the largest energy source for electricity generation throughout the USA in the EIA (2012) projection period, but its share of total generation declines from 42% in 2011 to 35% in 2040 (*see* Figure 25). This is considered to be due to concerns about greenhouse gas emissions. The low projected fuel prices for new natural gas fired plants are also considered to affect the relative economics of coal-fired capacity as does the continued rise in construction costs for new coal-fired power plants. As retirement of existing units far outpaces new additions, total coal-fired generating capacity is expected to fall from 398 GW in 2011 to 278 GW in 2040 (US EIA, 2012).

Australia is forecast to recover its place as the biggest coal exporter. Despite some issues such

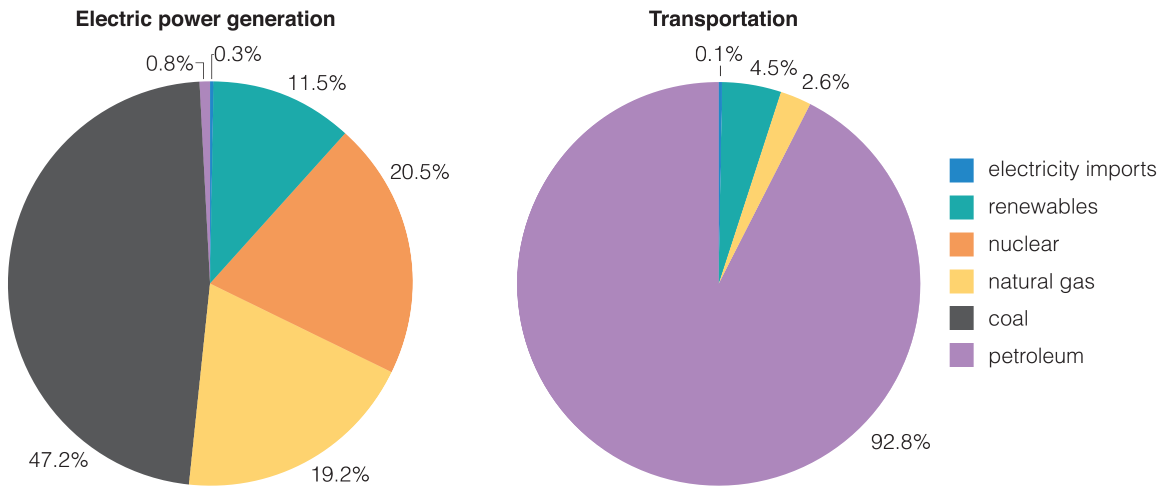

Figure 24 Electric power consumption by fuel type in the USA, 2011 (Greenstone and others, 2012)

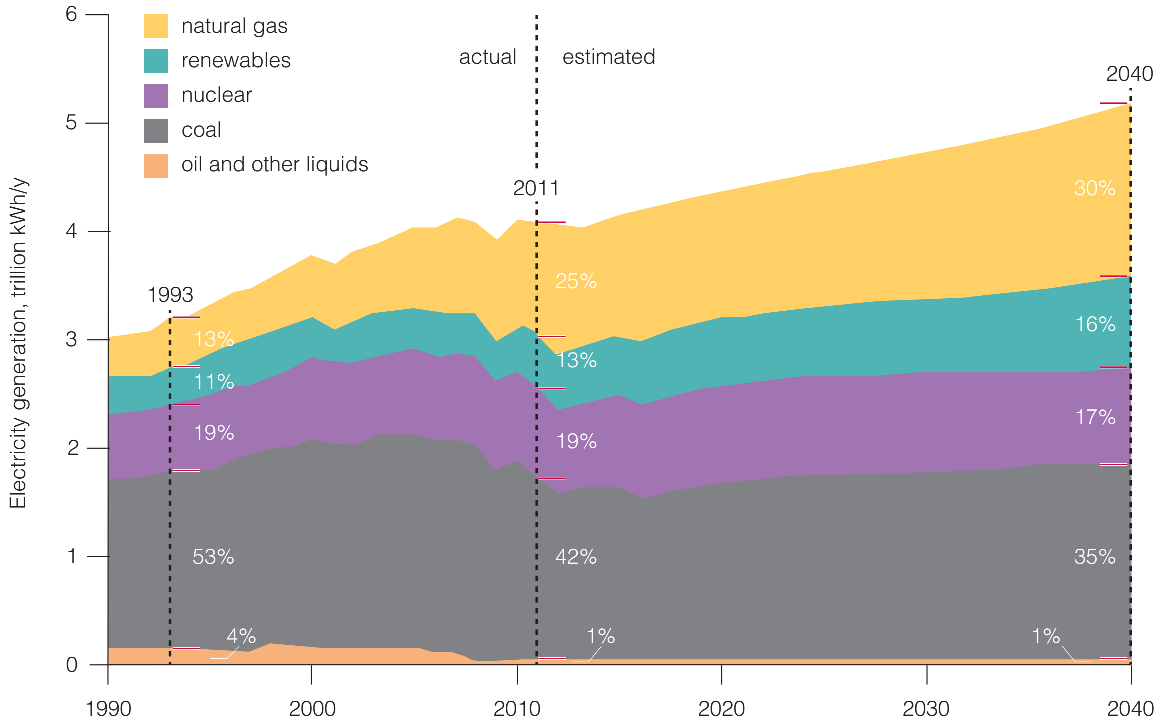

Figure 25 Electricity generation by fuel in the USA, 1990-2040 (US EIA, 2012)

as rising labour costs and domestic currency rate, which currently give Indonesia a competitive advantage, Australia is expected to concentrate on infrastructure and mine expansion investments to become the largest exporter, with 356 Mtce by 2017, well above Indonesia's total exports then of 309 Mtce. Investments are planned and in progress to ensure supply. In 2012, almost 300 Mt/y of terminal capacity and the 150 Mt/y (probable) to 600 Mt/y (potential) of mine expansion capacity, were being planned. This would have been more than enough to meet coal demand in a secure way over the outlook period. However, according to OECD/IEA (2012), low prices and uncertainty about economic growth, especially when related to China, may delay or stop some investments. More recently, in May 2013, the Balaclava Island coal shipping facility in Queensland was shelved due to poor current market conditions in the Australian coal industry, excess port capacity in Queensland and concerns about the industry's medium-term outlook (Xstrata Coal, 2013). Also in May 2013, Port Waratah Coal Services (PWCS) (NSW, Australia) announced that although it will continue to seek development approval for a fourth coal terminal, there is currently no capacity shortfall to be fulfilled due to reductions in contract tonnages from the majority of the Hunter Valley coal producers (PWCS, 2013).

6.2 Gas

Natural gas, according to Timera Energy (2011) has only relatively recently become a global market commodity. North America, Europe and Russia have historically dominated global gas consumption with gas sourced through pipeline networks from production fields. However, declining domestic reserves in these regions lead to a boom in liquefied natural gas (LNG) infrastructure and shipping capacity over the previous decade which has facilitated the global trading of natural gas.

Flexibility in operation, lower investment costs and lower specific CO_2 emissions favour gas-fired power generation. However, the cost of gas varies significantly from region to region; for example in the EU the cost of gas remains higher than coal thus favouring coal-fired power generation.

World natural gas consumption grew by 2.2% in 2011. This was below average in all regions except North America where low gas prices resulted in a robust growth. In China, natural gas volumetric gains in consumption reached 21.5%, Saudi Arabia 13.5% and Japan 11.6%. In the EU gas consumption declined by 9.9%. This was due to factors including a weak economy, high gas prices, warm weather and continued growth in renewable power generation (BP, 2012b).

According to BP (2012a), of the major global sectors, the fastest growth is expected to be in gas-based power generation (2.4%/y) and industry (2.1%/y) which is consistent with historical patterns. Natural gas utilisation in transport is forecast to be confined to 2% of global gas demand in 2030, despite growing four times from 2012 levels. In OECD countries, growth is expected to be concentrated in the power sector (1.6%/y). Efficiency gains and low population growth are forecast to keep industrial (0.9%/y) and other sector (<0.1%/y) gas growth low. BP (2012a) considers that gas utilisation in non OECD countries will be driven by industrialisation, the power sector and the development of domestic resources. Gas consumption is expected to expand most strongly in power (2.9%/y) and industry (2.8%/y).

In the USA, the slow growth in electricity demand, the competitive pricing of natural gas, programmes encouraging renewable fuel use and the implementation of new environmental regulations are forecast to result in increased use of natural gas in power generation (US EIA, 2012). In 2012, PWC discussed the reshaping of the chemicals industry in the USA due to shale gas. According to PWC (2012), for chemical companies, the impact has been to decrease the cost of both raw materials as well as energy. For manufacturing companies, the initial opportunity was supplying the products and services to support shale gas exploration and production. The price of natural gas in the USA dropped dramatically from 12.5 $/MBtu (11.83 $/GJ) in 2008 to approximately 3 $/MBtu (2.84 $/GJ) in 2012. Prices are expected to decline further, at least in the short term, as a result of excess inventory. The sharp drop was accredited to the availability of natural gas in shale formation and the technological advancements in horizontal drilling and fractionation techniques to access the shale gas. The cost of gas (conventional and unconventional) varies greatly from region to region. For example, in Europe the price of gas is four to five times greater than in the USA and six to eight times higher in the Asia-Pacific region. Naturally, these discrepancies affect the utilisation/consumption of the fuel (van der Hoeven, 2012).

Natural gas is expected to play a greater role in the future global energy mix. It can help to diversify energy supply, and so improve energy security. It can also provide the back-up electricity generating capacity needed as more variable renewable capacity comes online. When replacing other fossil fuels, natural gas can also lead to lower emissions of greenhouse gases and local pollutants.

7 Public attitudes

Greenhouse gases are emitted during fossil-fuel power generation. These gases trap heat in the atmosphere, causing it to warm up. Greenhouse gases include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). These gases account for 98% of the greenhouse effect. Other greenhouse gases are various fluorocarbons and sulphur hexafluoride (F-gases). Fossil fuel use is the primary source of CO_2. Land use is also an important source of CO_2, especially when it involves deforestation. Land can also remove CO_2 from the atmosphere through various activities including reforestation and improvement of soil. Agricultural activities, waste management, and energy use all contribute to CH_4 emissions. In addition, agricultural activities, such as fertiliser use, are the primary source of N_2O emissions. The regions that emit the most greenhouse gases are the USA, China, the Russian Federation and Japan. Fluorinated gases (F-gases) are emitted through industrial processes, refrigeration, and the use of a variety of consumer products, which include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF6).

Carbon capture and storage (CCS) mitigates the effects of climate change by capturing and pumping CO_2 underground. According to Lovelace and Temple (2012), it proposes to reduce emissions without curbing the use of fossil fuels and, as a result, has been advocated by energy corporations, governments and international institutions. However, surveys conducted involving the public indicate ambivalence and/or reservations towards CCS. The Global CCS Institute (GCCSI, 2012) provides a comprehensive overview of the state of development of CCS projects until the beginning of September 2012. According to GCCSI (2012), there are eight large-scale CCS projects around the world storing ~23 Mt of CO_2 each year. A further eight projects currently under construction, including two in the electricity generation sector, will increase that figure to over 36 Mt of CO_2 a year by 2015.

The GCCSI review covers 75 large-scale integrated projects. Five of nine new projects are in China. Southern Company's post-combustion Plant Barry in the USA recently became the world's largest integrated CCS project at a coal-fired power plant (25 MW equivalent, CO_2 storage in saline aquifer). Advances in oxyfuel combustion have also been realised through the commissioning of two pilot-scale oxyfuel combustion projects, Ciuden in Spain and Callide in Australia. Two large-scale demonstration power plant projects with CCS are currently under construction and scheduled to start operation in 2014: Kemper County in Mississippi (USA) (pre-combustion, 3.5 Mt CO_2 a year) and Boundary Dam in Saskatchewan (Canada) (post-combustion, 1 Mt CO_2 a year). In Australia the Gorgon CCS demonstration project with CO_2 capture from natural gas processing is on schedule, storage of 3.5 Mt CO_2 a year is planned from 2015 (pre-combustion). In Alberta (Canada) the Quest project is under construction and is due to start operation in 2015, it will capture and store more than 1 Mt of CO_2 a year from hydrogen production at the Athabasca Oil Sands Project (pre-combustion) (GCCSI, 2012; VGB PowerTech, 2012). In May 2012, the UK Department of Energy and Climate Change (DECC) published a cost report on fossil fuel fired power plants with CCS (DECC, 2013).

In 2010, Fernando discussed current public attitudes towards coal-fired power plant in several countries both in the developed and developing world. He compared these attitudes with those reported in an earlier report on the same subject produced in 2006. Since then, the publication of the Intergovernmental Panel on Climate Change (IPCC) report in 2007 and the greater worldwide consensus on the reality of global warming was expected to affect public attitudes. However, events in late 2009 have increased the levels of public scepticism. Fernando (2010) principally collated opinion poll data available on public attitudes towards energy, environment and the use of coal for power generation. Whereas before 2006, surveys of attitudes towards energy sources commonly included coal-fired plant, more recently coal plant are rarely included, presumably as it is assumed that the public would be overwhelmingly opposed. Hence the subject was broadened to include attitudes to climate change. The report included attitudes towards CCS. It also reported what national and international organisations said about the use of coal as that type of information would influence public attitudes. It investigated what the general public and concerned organisations said should be done to reduce the greenhouse effect. Countries and regions chosen for particular focus in the review were the USA, the European Union, the UK, India, Thailand and Australia.

Fernando (2010) concluded that regular polling was conducted on public attitudes towards global warming and energy issues in the developed world, but there was much less information available relating to the developing world. Available data showed that there was much more awareness in the developed world of global warming than elsewhere. Until 2009, there was considerable concern in most countries regarding global warming with less concern in the USA, China, Russia and India. Large majorities in all countries believed it was man-made. However, since late 2009, there has been a dramatic reduction in concern about global warming and the belief that it is man-made in the USA, Europe, the UK and Australia. This is most likely due to the increased scepticism about the scientific basis for global warming. The opposition to the use of coal varies globally. In many countries it is related to global warming but in others it may be associated with pollution associated with power plant waste and health effects or the effects on local communities from mining. In some countries, such as the UK and India, though there are national organisations opposing coal use, there are no dedicated national organisations campaigning in its favour. Some organisations oppose the use of coal for power generation entirely whereas others are willing to consider clean coal technologies, CCS and cap and trade. Major surveys of public attitudes towards greenhouse gas emissions have only recently started to question attitudes to CCS, as until it is demonstrated on a large scale as being technically feasible and economically viable, it will not be regarded as a realistic option. However, data obtained from workshops show that when stakeholders are informed about CCS, there is a moderate level of support. Fernando (2010) considered that it is desirable to have regular polling worldwide using consistent questions to determine trends in public opinion regarding energy sources and global warming.

Ansolabehere and Konisky (2009) described initial local resistance and opposition to the construction of new power plants and other facilities in the USA as a ‘not in my back yard’ reaction. However, other factors also play a role in the reaction. Analysis of public attitudes toward the local construction of new coal, natural gas, nuclear, as well as wind-based power generation units was undertaken to assess the relative effects of the attributes of the fuel source (endowment effects), the weights of these attributes (discrimination effects), and individual characteristics (characteristic effects). The authors found that factors that affect attitudes and are considered as most important, include environmental effects, cost of the fuel and economic benefits. In attempting to site any type of new power plant, Ansolabehere and Konisky (2009) consider that efforts to reduce opposition must also reassure the public on perceived detrimental environmental effects, and provide not only information campaigns but also (in some instances) compensation schemes. It was noted that the public appear less sensitive to economic benefits than environmental impacts. Attitudinal shifts toward more support for converting the energy mix from fossil fuels to alternatives in order to address climate change or to secure a domestic energy supply, may lead to changes in preferences about the siting of different types of power plants. In 2009, Ansolabehere and Konisky’s findings indicated a major long-term political problem for the electricity generation industry in the USA, where coal, natural gas and nuclear power accounted for 90% of electricity generation and would continue to represent the main sources of future power demand. Survey respondents expressed overwhelming opposition to siting such facilities nearby, and, thus, to any major expansion of these power sources. Ansolabehere and Konisky (2009) concluded that the politics of plant siting were likely to push the electricity sector in the direction of alternative power sources. However, the most recent trend in 2012 has been to invest more in gas-fired power generation in new facilities due to the discovery of large resources of the fuel in the USA.

As discussed in Chapter 2, hydraulic fracturing, or fracking, refers to the process by which a fluid – a mix of water, sand, and chemical additives – is injected into wells under high pressure to create cracks and fissures in rock formations that improve the production of these wells. Hydraulic fracturing was first developed in the early 20th century but was not commercially applied until the mid-to-late 1940s.

Hydraulic fracturing is standard practice for extracting natural gas from unconventional sources, including coalbeds, shale, and tight sands, and is increasingly being applied to conventional sources to improve their productivity. According to Cooley and Donnelly (2012), hydraulic fracturing has generated a tremendous amount of controversy in recent years. There are numerous media and other reports on this topic from countries across the world, including the USA, Canada, South Africa, Australia, France, and the UK. It is hailed by some as a game-changer that promises increased energy independence, job creation, and lower energy prices. Others are calling for a temporary moratorium or a complete ban on hydraulic fracturing due to environmental, social, and public health concerns (Cooley and Donnelly, 2012).

In a detailed report on hydraulic fracturing and water resources Cooley and Donnelly (2012) investigated a diversity of viewpoints about the range of concerns and issues associated with hydraulic fracturing. A broad set of social, economic, and environmental concerns were identified by the authors, foremost among which are the effects of hydraulic fracturing on the availability and quality of water resources. In particular, key water-related concerns identified included:

- water withdrawals;
- groundwater contamination associated with well drilling and production;
- wastewater management;
- vehicular traffic and its impacts on water quality;
- surface spills and leaks;
- stormwater management.

According to Cooley and Donnelly (2012), much of the attention about hydraulic fracturing and its risk to water resources has centred on the use of chemicals in the fracturing fluids and the risk of groundwater contamination. The mitigation strategies identified to address these concerns centred on disclosure and, to some extent, the use of less toxic chemicals. Risks associated with fracking chemicals, however, are not considered the only issues to be addressed. The overall water requirements of hydraulic fracturing and the quantity and quality of wastewater generated were identified as key issues. Most significantly, a lack of credible and comprehensive data and information is found to be a major impediment to identify or assess clearly the key water-related risks associated with hydraulic fracturing and to develop sound policies to minimise those risks. Due to the nature of the business, industry has an incentive to keep the specifics of their operations confidential in order to gain a competitive advantage, avoid litigation, and so on. Additionally, there is a limited number of peer-reviewed, scientific studies on the process and its environmental impacts. While much has been written about the interaction of hydraulic fracturing and water resources, the majority of this writing is either industry or advocacy reports that have not been peer-reviewed. As a result, the discourse around the issue is largely driven by opinion. Cooley and Donnelly (2012) consider that this hinders a comprehensive analysis of the potential environmental and public health risks and identification of strategies to minimise these risks.

Cooley and Donnelly (2012), conclude that the dialogue about hydraulic fracturing has been marked by confusion due to a lack of clarity about the terms used to characterise the process. For example, the American Petroleum Institute, as well as other industry groups, using a narrow definition of fracking, argue that there is no link between fracking and groundwater contamination, despite observational evidence of groundwater contamination in Dimock (PA, USA) and Pavillion (WY, USA), that appear to be linked to the integrity of the well casings and of wastewater storage. Therefore, additional work is needed to clarify terms and definitions associated with hydraulic fracturing to support more fruitful and informed dialogue and to develop appropriate energy, water, and environmental policy (Cooley and Donnelly, 2012).

8 Prospects

The prospects for both coal and gas remain strong in the foreseeable future. The International Energy Agency set out three scenarios for future energy supplies:

1. a current policies scenario or status quo scenario in which energy and climate policy frameworks remain unchanged;
2. a *new policies scenario* which assumes political promises and announced plans to limit greenhouse gas emissions are met;
3. a 450 scenario in which the atmospheric concentration of greenhouse gases is limited to 450 ppm of CO_2 to meet the objective of limiting global temperature rise to 2°C compared with pre-industrial levels.

Key results from the new policies scenario are summarised as (EURACOAL, 2010):

- worldwide primary energy consumption increases by 36% to 16.7 Gtoe in 2035 (an annual average increase of 1.2%). Of this increase, 93% occurs in non-OECD countries while energy demand in OECD countries increases only slightly;
- all sources of energy will be in high demand, with fossil fuels representing more than half of the increase in demand;
- oil retains the largest share in the global primary energy mix, although its share drops to 28% in 2035. Demand for coal increases until 2025, but then decreases slowly, while demand for natural gas increases;
- total global electricity demand increases by 75% compared with 2008, mainly in non-OECD countries. In China, electricity demand increases threefold between 2008 and 2035, with a continued strong reliance on coal;
- although the use of fossil fuels for power generation decreases, they continue to dominate with a share of 55% in 2035 (68% in 2008). Coal remains the main fuel for power generation but its share drops from 41% in 2010 to 32% in 2035. Gas use for power generation was expected to remain stable in 2010 at around 21%. However, recent discoveries in shale gas have resulted in increased use of gas for power generation and the trend is expected to continue in some countries, such as the USA, where power generation with gas overtook coal in May 2012;
- global CO_2 emissions to increase by 21% from 29 Gt in 2008 to more than 35 Gt in 2035.

According to BP (2012a, b), global primary energy consumption is projected to grow by an average of 1.6%/y over the period 2010 to 2030. This adds 39% to global consumption by 2030. The rate is projected to decline from 2.5%/y to 2%/y over the next decade and to 1.3%/y from 2020 to 2030. Most of the growth (96%) is expected to be in non-OECD countries. By 2030 energy consumption in non-OECD countries is projected to be 69% above the 2010 level with an average growth of 2.7%/y (or 1.6%/y per capita). This accounts for 65% of world consumption (compared to 54% in 2010). Projected fuel substitutions in OECD and non-OECD countries (2010-30) are shown in Figure 26. In their energy outlook to 2030, BP consider that the fuel mix will change slowly, due to long gestation periods and asset lifetimes. Gas and non-fossil fuels are expected to gain a larger share at the expense of coal and oil. The fastest growing fuels are considered to be renewables (including biofuels) which are expected to grow at 8.2%/y (2010-30). Among fossil fuels, gas is expected to grow the fastest (2.1%/y), oil the slowest (0.7%/y) (BP, 2012a, b).

The power generating sector is expected to remain the fastest growing, accounting for 57% (compared to 54% for 1990-2010) of the projected global growth in primary energy consumption to 2030 (*see* Figure 27). Diversification of the fuel mix is also driven by the power sector in that non-fossil fuels, led by renewables, are expected to account for more than half of the growth. In rapidly developing economies, industry is expected to lead the growth in final energy consumption. Forecasts indicate that the industrial sector will account for 60% of the projected growth of final energy demand to 2030. The weakest growth is expected to be in the transport sector where demand in the OECD is expected

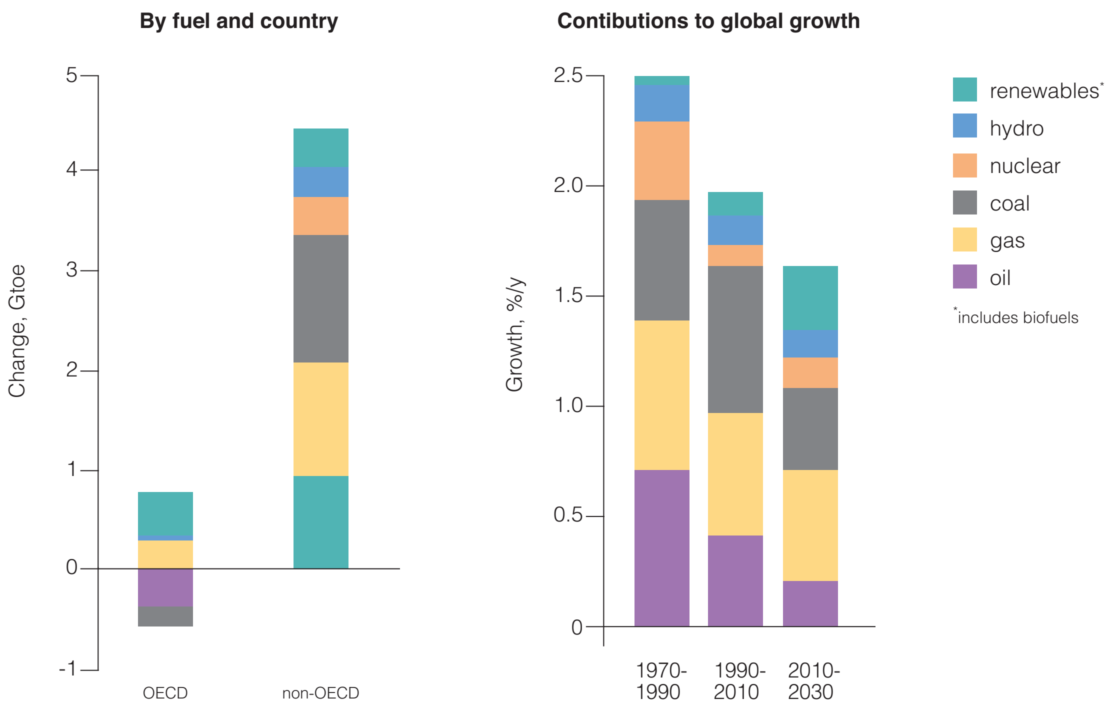

Figure 26 Projected fuel substitution in OECD and non-OECD countries (2010-30) (BP, 2012a)

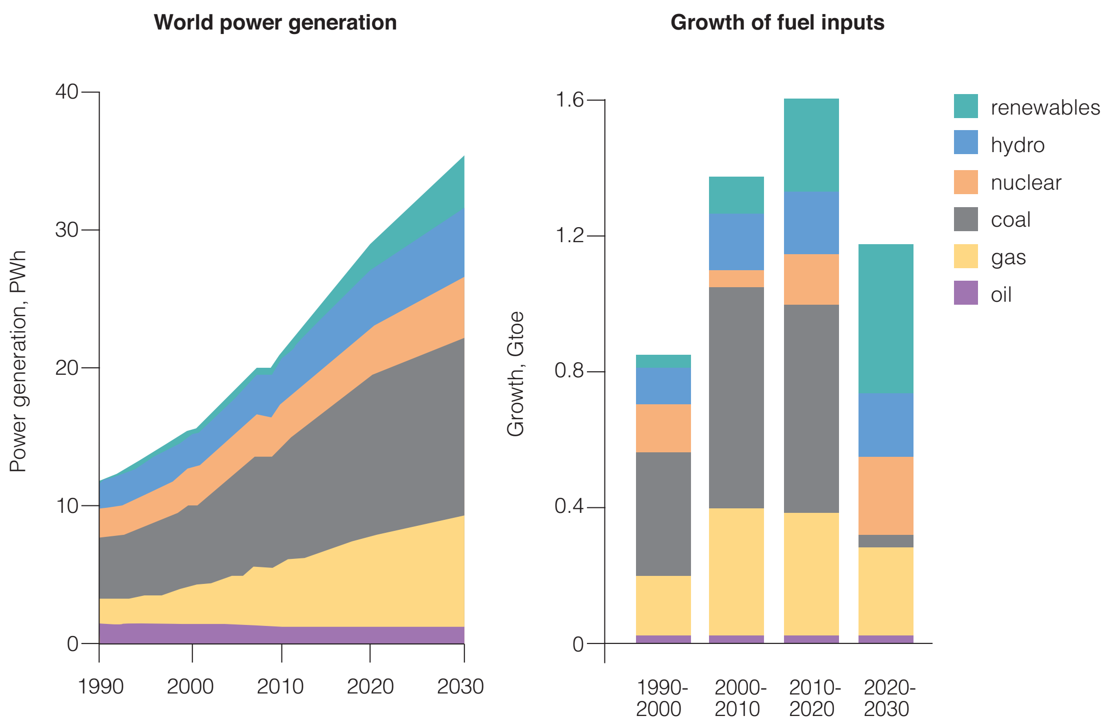

Figure 27 Historical, current and projected growth in the power generating sector (BP, 2012a)

to decline. Diversification is also observed, driven by policy with enablement by technology. Biofuels are expected to account for 23% of transport energy demand growth, with gas contributing 13% and electricity 2% (BP, 2012a, b).

Coal

It is estimated that there are over 847 Gt of proven coal reserves worldwide. At current production rates, reserves equate to ~118 years availability. Coal reserves are available in almost every country in the world, with recoverable reserves in about seventy countries. The largest reserves are in the USA, Russia, China and India. The location, size and characteristics of most countries' coal resources are quite well known. What tends to vary much more than the assessed level of the resource – that is the potentially accessible coal in the ground – is the level classified as proven recoverable reserves. Proven recoverable reserves is the tonnage of coal that has been proved by drilling to be economically and technically extractable. While coal is found and used to varying extents in over seventy countries, at present, the bulk of coal production is concentrated in about ten countries while the export market is now dominated by five countries, namely Australia, Indonesia, Russia, South Africa and Colombia. This situation could change as some suppliers may not remain in the global export market as they need to meet domestic demands.

Coal met 45% of the rise in global energy demand between 2001 and 2011, growing faster even than total renewables. The main driver was the strong growth in non-OECD countries, particularly China and India. Coal fuels more than 40% of the world's electricity, and is expected to remain the backbone of global electricity generation mix, regardless of climate change policy. Despite an increase in coal consumption in absolute terms, coal's share in the world's electricity generation is expected to decrease gradually as many governments are set to promote generation from renewables, nuclear and natural gas. In 2010, the full costs of new coal- (lignite and hard) and gas-fired power generating plants were relatively similar (EURACOAL, 2011).

Historically, natural gas has been more expensive than coal on an energy equivalent basis. The prices of both fuels have been more volatile over the last decade. Worldwide, coal prices have rebounded strongly after a collapse in 2009 following the high levels seen in the summer of 2008. In contrast, gas prices only rebounded markedly in Europe and Asia Pacific, but remained low in North America. There has been a convergence between domestic and international coal markets, in which domestic coal prices are marked to international prices. Consequently, demand from China and, potentially, India may cause large swings in international coal prices. In the natural gas market, it emerges that gas prices are de-indexed to oil and instead are marked to spot gas prices at trading hubs. This change in pricing mechanism will certainly increase the volatility of gas prices, but may also lead to lower gas prices providing ample supplies are available. Increased price volatility will influence the relative competitiveness of coal versus natural gas in power generation, as captured by the spread measures. As such, utilities need to use the spread tool to decide on what type of generation to operate on a day-to-day basis, and to assist their planning on new capacity.

BP (2012a, b) forecasts indicate that over the next decade coal will remain the largest contributor to the growth in fuel use for power generation, accounting for 39%. However, non-fossil fuels, in aggregate nuclear, hydro and other renewables are expected to contribute as much as coal. In the following decade to 2030, 75% of the growth is expected to come from these sources and very little from coal.

Gas

In 2010, world proven gas reserves were reported at 6609 trillion cubic feet (187.146 trillion m^3). This was considered sufficient for 59 years of production at current levels. Global reserves of unconventional gas, such as shale gas and coalbed methane, remain to be appraised in detail. However, current estimates suggest they could double the existing reserves to production (R/P) ratio. The largest proven gas reserves are in the Russian Federation, Iran, Turkmenistan, Qatar and the USA.

Demand for natural gas has been following a consistent upward trend since the mid-1980s except for a dip in 2009. Again, non-OECD countries have largely dominated the growth, overtaking OECD countries in aggregated gas demand in 2008. Natural gas provides around 22% of the world's electricity, and use for power generation will be the major driving force for future growth in gas demand worldwide. Nevertheless, its share in the global electricity generation mix is expected to increase only slightly due predominantly to high prices. In Europe, high gas prices present a higher risk for utilities and consumers compared to coal (EURACOAL, 2011). World natural gas production increased in 2011. While the USA saw the largest national increase, the Middle East recorded the largest regional increment in production. Production growth in Russia and Turkmenistan was partly offset by a large decline in European production. Projections indicate that unconventional gas has the potential to account for nearly half of the increase in global gas production over the next two decades.

As producing unconventional gas is an intensive industrial process, it generally imposes a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from a well. The scale of development can have major implications for local communities, land use and water resources. Hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. The technologies and know-how exist for unconventional gas to be produced satisfactorily while meeting these challenges. However, this has to be supported by a continuous drive from governments as well as industry to improve performance if public confidence is to be gained and maintained.

The contribution of gas in the power sector is expected to remain relatively steady at around 31% through the decades. Natural gas is projected to be the fastest growing fossil fuel globally (2.1%). Non-OECD countries will account for 80% of the global gas demand growth averaging 2.9%/y growth to 2030. Demand for natural gas will grow fastest in non-OECD Asia (4.6%/y) and the Middle East (3.7%/y). In China, gas grows rapidly (7.6%/y) to a level of gas use in 2030 equal to that of the European Union in 2020 (46 billion cubic feet per day or 1.3 billion m^3/d). China's contribution to the global demand increase is projected to be 23%. The share of gas in China's primary energy consumption is expected to expand from 4.0% to 9.5%.

Liquid natural gas (LNG) is expected to represent a growing share of gas supply. Global LNG supply is projected to grow by 4.5%/y to 2030. This is more than twice as fast as total global gas production (2.1%/y) and faster than inter-regional pipeline trade (3.0%/y). LNG is expected to contribute 25% of global supply growth between 2010 and 2030 compared to 19% for between 1990 and 2010 (BP, 2012). According to Noël (2012), LNG trade started in the 1960s and has grown gradually since. However, it was only in the late 1990s and 2000s that it became the default way to commercialising natural gas. Qatar has added 100 billion m^3 (equivalent) of supply to the global LNG market. The new emerging country, according to Noël (2012), is Australia which is expected to overtake Qatar in supplying LNG, by 2018. Some of the gas supplied by Australia is expected to be from coalbed methane, another form of unconventional gas.

According to the IEA (2012a), the prospects for unconventional gas production worldwide remain uncertain. They depend, particularly, on whether governments and industry develop and apply rules that effectively earn the industry what is termed 'a social licence to operate' in order to satisfy public concerns about related environmental and social impacts.

Water issues require further investigation and understanding when extracting shale gas with hydraulic fracturing, as discussed by Cooley and Donnelly. According to Migliore (2012), energy industries are pursuing technologies to reuse the water that comes out of the natural gas wells following the fracking process. Although the water is not usable for drinking or agricultural purposes, when cleaned of chemicals and rock debris it may be used for fracking additional wells. This could significantly reduce the costs that energy companies face in the process of securing as well as disposing of the water. In general, as it is less costly, the wastewater is injected deep underground instead of undergoing a cleaning process. It is expected that the reuse of the wastewater from the hydraulic fracturing process will become more commonplace as shale gas exploration and fracking become more widespread (Migliore, 2012).

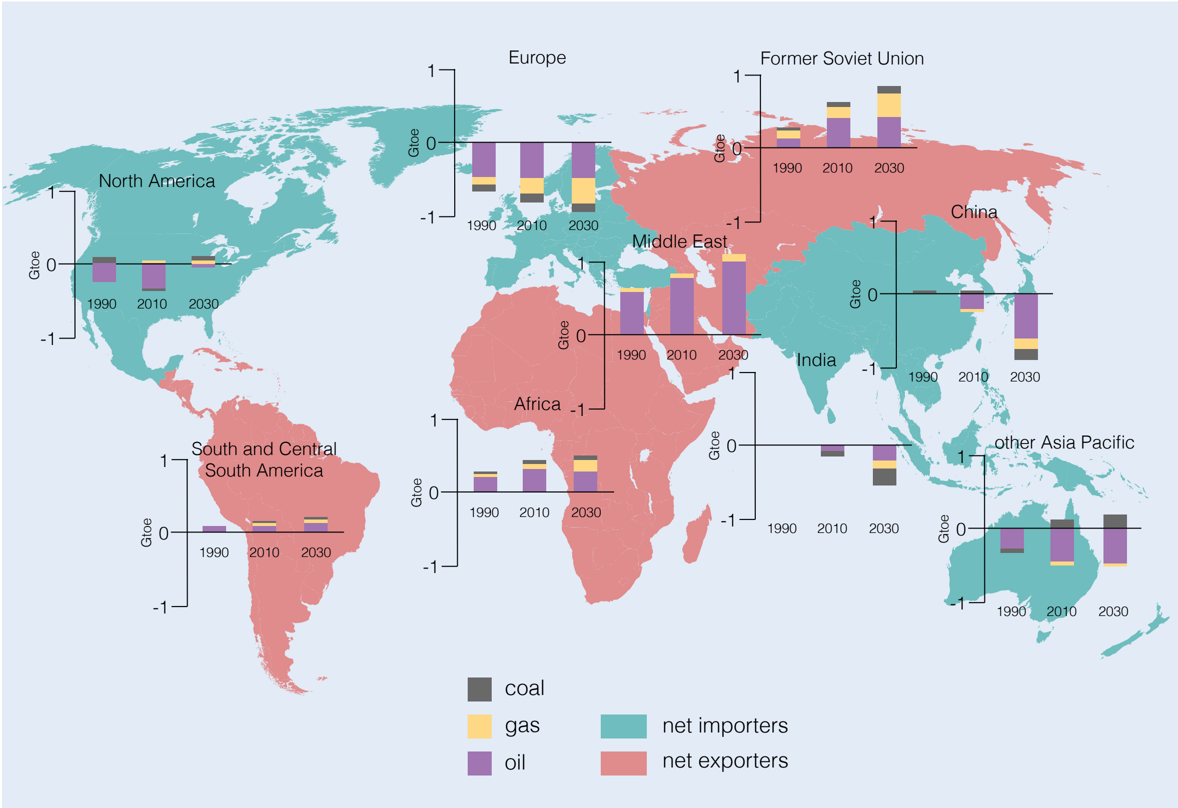

Figure 28 Net importers and exporters and energy imbalances by fuel throughout the world (BP, 2012a)

Coal versus gas

Energy imbalances in a region can affect energy security and thus policy. In Europe, the energy/fuel deficit is expected to remain roughly at 2012 levels for coal but to increase by 65% for natural gas. Among the energy importing regions (*see* Figures 28 and 29), North America will be the exception with growth in biofuel supplies and unconventional gas turning the energy deficit (mainly oil) there into a surplus by 2030. Energy importers in 2012 are forecast to need to import 40% more in 2030 than they did in 2012 with the deficits in Europe and Asia Pacific being met by supply growth in the Middle East, Former Soviet Union countries (CIS), Africa and South and Central America. The energy deficit is expected to increase in China by 0.8 Gtoe (spread across all fuels) and India's import requirements are expected to increase by 0.4 Gtoe (mainly oil and coal). In China, BP (2012a) forecasts that imports of natural gas will rise sharply as demand growth outpaces domestic supply. Gas imports are expected to increase by a factor of sixteen. In addition, China will become a major importer of coal. Reliance on imports of coal as well as gas is expected in India in order to supply the growing energy needs there. European net imports (and imports as a share of consumption) are expected to rise significantly due to declining domestic gas production and rising gas consumption. Indications are that virtually all of the growth in net imports will be of natural gas.

Morris (2012) discussed how pricing was affecting utility decision making in the USA in mid-2012. As natural gas prices dropped dramatically a shift occurred from coal-fired power generation to gas. This shift was also caused by the adoption of new mercury and air toxic standards which lead to the retirement, retrofitting and in some instances fuel switching in these facilities. In the first quarter of 2012 natural gas accounted for 28.7% of total generation compared with 20.7% during the same quarter the previous year. Coal's share in total generation declined from 44.6% to 36% over the same period of time. In addition, a number of new power plants that were formerly proposed as coal-firing facilities have switched to natural gas or combined cycle generation. According to Morris (2012), the

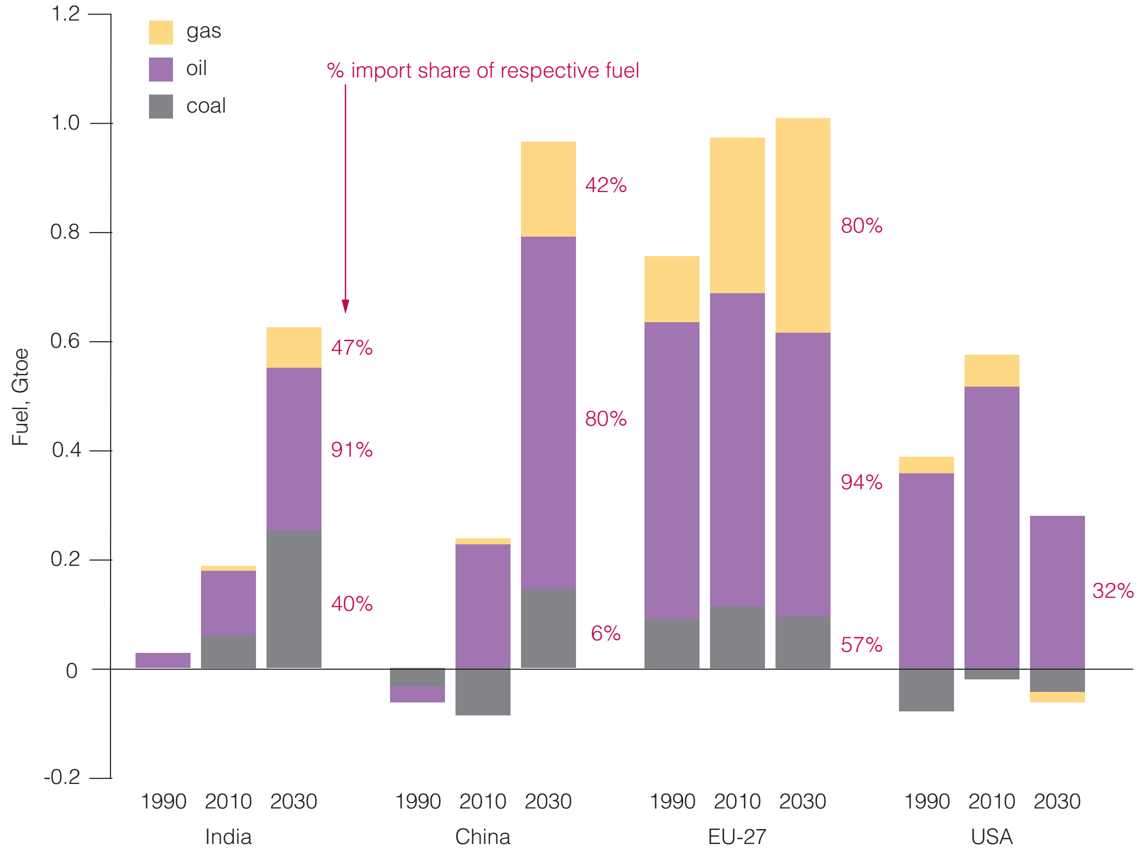

Figure 29 Dependency on imports, by fuel, in India, China, EU-27 and the USA (BP, 2012a)

continued development of natural gas shale resources has contributed to an abundance of natural gas, the average spot price for which in April 2012 was <2 \$/MBtu (<1.89 \$/GJ). The price of gas in the USA is expected to remain low for a short while but to double over the following years due to the high demand for gas as coal is partly replaced with gas in electricity generation. However, if and when the price of gas becomes >5 \$/MBtu (4.73 \$/GJ) then decision-making may change with regard to the economics of coal versus gas firing for power generation. Morris (2012) considers that in the long term, it is expected that gas prices will remain relatively low and thus increase the firing of gas in power generating plants. In comparison, the price of coal remains relatively stable in the USA but could increase due to the export market. Data indicate that natural gas prices would need to increase to almost 10 \$/MBtu (9.46 \$/GJ) in order for developers to consider building a coal instead of a natural gas fired facility. The decreasing trend in natural gas prices in the USA is illustrated in Figure 30. In addition, CCS can be a major consideration when firing coal as estimates show that the price of electricity with CCS in coal-fired plant may increase by as much as 50%, nearly twice as expensive as electricity generated with natural gas without CCS, according to Morris (2012). Data in the USA show not only a shift towards building gas-fired power generating units but also a major coal-to-gas switching activity. In 2011, gas displaced an estimated 140 TWh of coal generation (from 2007-08 generation levels). Piper and Gilbert (2012) discuss in detail the prospects for coal to gas switching in the USA whilst dual fuel (coal and gas) firing was considered and presented by Courtemanche and Penterson (2012) as the new future for the ageing US-based coal-fired boilers.

There was an increase in demand in the USA for gas turbines in the late 1990s and early 2000. However, when gas prices increased after that, the utilisation of gas-fired units was low. The more recent dramatic decrease in gas prices and increased availability has led to the running of these facilities at historically high rates of ~70–80% in 2012. Currently it is expected that >50 GW of gas-fired capacity will come online from 2012 through 2015. This is a portion of a total of 69.5 GW

Figure 30 The trend in natural gas prices in the USA (2008-12) (Morris, 2012)

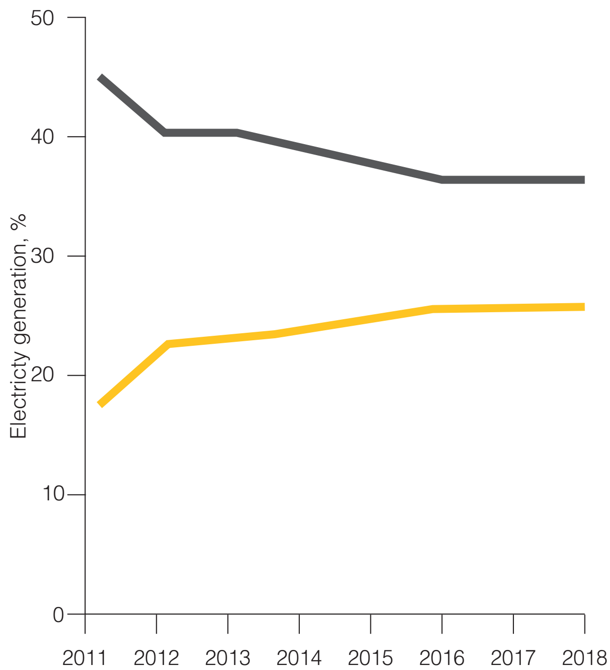

Figure 31 Current and projected share of natural gas combined cycle versus coal-fired power generation in the USA (2011-18) (Morris, 2012)

capacity announced through 2018. Of this, 83% of capacity is planned to be combined-cycle technology and the remainder will utilise simple cycle systems (*see* Figure 31). Despite the shift towards gas, coal is expected to remain a contender in the power generating field in the USA especially with the uncertainty of gas prices remaining as low as they have been (Morris, 2012).

Gloystein and Eckert (2012) analysed the situation in Germany with regard to firing coal compared to gas in power generation. In theory, in order for Germany to achieve the greenhouse gas climate targets and the phasing out of nuclear power over the next decade, a number of gas-fired power plants should be constructed to meet the demand for energy. However, forecasts indicate that electricity from coal for sale in 2013 will be 16 €/MWh more profitable compared to gas, thus making coal the more attractive fuel for power generation in Germany. Incentives to firing gas include tax breaks (an exemption from a fuel tax of 5.50 €/MWh for gas fired plants with >57.5% efficiency) as well as the EU emissions trading scheme (carbon market) requirements, which are more costly to coal-fired units as their emissions are higher. Under the EU trading scheme, large polluters must buy carbon emissions certificates for each tonne of CO_2 equivalent they emit. For details on the EU CO_2 emissions trading *see* Nalbandian (2007). However, for gas-fired plant, the average efficiency is ~50%, recent developments in coal-fired power generation have resulted in several facilities achieving >45% efficiency thus making coal plant competitive with gas-fired power stations. Furthermore, the emissions trading carbon prices are currently below 7 €/t while data indicate that prices >35 €/t would be needed to make gas-fired plants more favourable than coal. Contrary to the dramatic decrease in the price of natural gas in the USA, prices in Europe remain relative high. According to Gloystein and Eckert (2012), there is potential for a fall in gas prices in Europe as the markets for conventional gas become smaller and more natural gas becomes available in the next decade from Azerbaijan, Iraq, Cyprus, Israel and Iran.

In March 2012, Noël discussed the role of gas in Europe. Despite the reported dramatic expansion in gas reserves in different parts of the world, Noël (2012) considers it doubtful that Europe will share in this development. The author also states that gas consumption stopped growing several years before the current economic crisis in Europe and has been declining since. If the current policies and market conditions are sustained, the decline is expected to continue. In the USA, conventional gas production peaked in 2001. Since then the industry has developed new technology to access shale gas. Since 2005 US gas production grew by ~45%. The annual production rate has grown by 220 billion m^3. This is the equivalent of total consumption rates of the UK, Germany and France together or 45% of total EU gas consumption. Exploration for shale gas since then has become more widespread throughout the world. For example, in January 2013 the UK government indicated that it is keen on the potential of shale gas and announced tax breaks for projects as well as instigating the launch of a new Office of Unconventional Gas and Oil (Williams, 2013).

Noël (2012) considers that a rapid growth in gas consumption is probable especially in Asia where there is demand for a wide range of energy sources to satisfy economic growth. However, the author considers the outlook by other organisations such as BP and the IEA to be rather optimistic with regard to gas consumption in Europe. According to Noël (2012) aggregate gas consumption growth in Europe decelerated sharply after the year 2000 and demand peaked in 2005. Data indicate that in the seven largest markets accounting for 85% of EU consumption, weather-adjusted demand declined by 22 billion m^3 in 2011, including more than 10 billion m^3 in the UK and nearly 6 billion m^3 in Germany. Industrial and power generation demand was lower in 2011 compared with 2009, the height of the current, international financial crisis. Noël (2012) concludes that a switch to gas in Europe is likely only if a serious climate change policy and CO_2 targeting takes place. That is not the case under the current climate where the cost of CO_2 credits under the EU emissions trading scheme does not provide an incentive for a reduction in coal use and replacing it with gas.

In the USA, the US EIA (2012) energy outlook indicates that relatively low natural gas prices, facilitated by growing shale gas production, will spur an increase in the industrial and electrical power generating sectors, particularly over the following 15 years. The forecast is that natural gas use (excluding lease and plant fuel) in the industrial sector will increase by 16%, from 6.8 trillion cubic feet per year (~0.19 trillion cubic m^3/y) in 2011 to 7.8 trillion cubic feet per year (~0.22 trillion m^3/y) in 2025. The forecast also shows that although natural gas continues to capture a growing share of the total electricity generating market, its consumption by power plants does not increase as sharply as generation. This is attributed to greater efficiency in new coal-fired plants. After accounting for 16% of total generation in the year 2000, the natural gas share of generation rose to 24% in 2010 and is expected to continue to increase to 27% in 2020 and 30% in 2040. According to the US EIA (2012) forecast, natural gas will also reach other new markets, such as exports, as a fuel for heavy duty freight transportation (trucking) and as a feedstock for producing diesel and other fuels.

In summary, coal remains the main fuel for electricity generation globally and its use is forecast to continue to rise in absolute terms. However, it’s share of total generation is expected to fall while the share of gas is expected to increase, especially in North America.

Today's energy market is undergoing some changes driven by unconventional gas production. For example, a dramatic increase in such gas production in North America is expected to result in making the region a gas exporter. Other countries, such as China, also have significant reserves of unconventional gas which could be used to satisfy future demand. However, the cost of gas varies greatly from region to region. For example, in Europe, the price of gas is currently four to five times greater than in the USA and six to eight times higher in the Asia-Pacific region. The discrepancies in pricing have and are forecast to continue to affect the utilisation of not only gas but also coal. In the USA, more gas is expected to be used for power generation as well as in industry while coal utilisation is expected to increase in Europe to the end of this decade. Factors influencing the increasing appeal of natural gas include sufficient reserves, fuel flexibility and lower environmental emissions and therefore impacts compared to coal. Coal utilisation is expected to decline somewhat not only in the USA but also in Europe in the long run. Older plants are expected to be decommissioned either due to age or inability to meet new regulations. These are expected to be replaced with renewable energy and natural gas plants. In the short term although the use of coal and gas for power generation is fluctuating, they continue to dominate with a share of 55% in 2035 (68% in 2008). Coal remains a main fuel for power generation but its share is forecast to drop from 41% in 2010 to 32% in 2035 (based on the IEA New Policies Scenario). Gas use for power generation was expected to remain stable in 2010 at around 21%. However, the recent discoveries in shale gas have resulted in increased use of gas for power generation and the trend is expected to continue in some countries, such as the USA, where power generation with gas overtook coal in May 2012. In Europe and Asia, coal will continue to have a strong hold due to the higher gas prices.

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